

Imperial College London

Department of Chemical Engineering

**Development of a systems approach for studying decarbonisation pathways
of heat demand in the UK**

by

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Submitted for the degree of Doctor of Philosophy

Declarations

Declaration of Originality

I hereby declare that the work presented in this dissertation is my own, and that everything that is not my own work has been appropriately referenced.

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Abstract

In the UK, 45% of the total energy demand in 2016 was used for heating purposes, 68% of which was supplied by natural gas. Credible alternatives for decarbonising heat include district heating combined with low carbon heat sources, heat electrification using heat pumps (with a decarbonised electricity system), or hydrogen-fuelled heat technologies. Adoption of these technologies must proceed alongside network infrastructure investment and developments in the broader energy system, such as increased renewable power generation.

At the time of writing, no systematic framework exists that trades off individual building and district heat supply technologies and their associated infrastructures at high spatial resolutions. This work formulates and applies such framework. It presents a mixed integer linear optimisation model that decides on investments and operation of gas, electricity, heat, and hydrogen technologies and associated network infrastructures, for supplying commercial and domestic heat and electricity demands in spatially-resolved urban areas, minimising the net present cost through 2050.

This model is implemented to study four key issues related to heat decarbonisation: Comparing different temperature heat networks for decarbonising heat; the effect of spatial resolution in outcomes of energy systems models for heat; the role of hydrogen in heat decarbonisation pathways in the UK; and the sensitivity of heat decarbonisation outcomes to uncertainty in techno-economic parameters.

Results show that adoption of heat technologies depends, among several factors, on linear heat density, zone-to-zone connectivity, and scenario-specific techno-economic assumptions such as technology, fuels, or electricity prices. Linear heat density adoption thresholds were found for individual technologies. Medium and high temperature heat networks were adopted in high and medium/high linear heat density zones, respectively. Hydrogen boilers were adopted when enabling gas networks to be retrofitted to transport hydrogen. Finally, spatial resolution was shown to be a determining factor for finding cost-effective heat decarbonisation pathways through energy systems models.

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To my father, an academic, for his grounding support

List of Publications

Refereed Journal Publications

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- F. Jalil-Vega, A.D. Hawkes, Spatially resolved optimization for studying the role of hydrogen for heat decarbonization pathways. 2018. *ACS Sustainable Chemistry & Engineering*. DOI: 10.1021/acssuschemeng.7b03970
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Refereed Conference Publications

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- Jalil, F., Hawkes, A. (2015) A mixed-integer linear programme optimisation model for determining optimal infrastructure investments and operation for decarbonising heat demand in the UK. In: 10th Conference on Sustainable Development of Energy, Water and Environment Systems, 27 September-3 October, 2015, Dubrovnik, Croatia.

Conference Abstracts

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Nomenclature

Nomenclature 1: Sets

Index	Description	Set elements
i_{ind}	Individual heat supply technologies	$CHP_{dom}, CHP_{comm}, Boiler_{dom}, Boiler_{comm},$ $Eradiator, HXT1, HXT2, HXT1_{big}, HXT2_{big},$ $ASHP_{dom}, ASHP_{comm}, GSHP_{dom}, GSHP_{comm},$ $HydBoiler_{dom}, HydBoiler_{comm}, HydCHP_{dom}, HydCHP_{comm}$
i_{dist}	District heat supply technologies	$CHPDist1, BoilerDist, ASHPDist, GSHPDist, HydBoilerDist$
e	Electricity supply technologies	PV_{dom}, PV_{comm}
j	Zones	$1, 2, \dots, J$
T	Temperature levels [K]	$T1, T2$
y	Time period [Years]	2015, 2020, 2025, 2030, 2035, 2040, 2045, 2050
h	Time slice [Hours]	$h_1, h_2, \dots, h_H$
a	Fuel type	gas, hyd
b	Demand type	$dom, comm$
n	Network type	$gasn, elecn, heatnT1, heatnT2, hydn$

Nomenclature 2: Decision variables - Technology capacities

Variable	Description	Units
$NCHI_{biindjy}$	New installed capacity of individual heat supply technology i_{ind} for demand type b in zone j in year y	kW
$VCHI_{biindjyy'}$	Vintage capacity of individual heat supply technology i_{ind} for demand type b in zone j installed in year y remaining in year y'	kW
$DCHI_{biindjyy'}$	Capacity of individual heat supply technology i_{ind} for demand type b in zone j installed in year y decommissioned in year y'	kW
$TCHI_{biindjy}$	Total capacity of individual heat supply technology i_{ind} for demand type b in zone j remaining in year y	kW
$OCHI_{bhiindjy}$	Capacity of individual heat supply technology i_{ind} for demand type b in zone j which is operating in timeslice h in year y	kW
$NCHD_{idistjTy}$	New installed capacity of district heat supply technology i_{dist} of temperature level T in zone j in year y	kW
$VCHD_{idistjTyy'}$	Vintage capacity of district heat supply technology i_{dist} of temperature level T in zone j installed in year y remaining in year y'	kW
$DCHD_{idistjTyy'}$	Capacity of district heat supply technology $i_{district}$ of temperature level T	kW

Variable	Description	Units
	in zone j installed in year y decommissioned in year y'	
$TCHD_{i_{dist}jTy}$	Total capacity of district heat supply technology i_{dist} of temperature level T in zone j remaining in year y (it doesn't matter when it was installed)	kW
$OCHD_{hi_{dist}jTy}$	Capacity of district heat supply technology i_{dist} of temperature level T in zone j which is operating in timeslice h in year y	kW
$ND_{i_{dist}jTy}$	Integer variable. Number of district heat supply units of technology i_{dist} of temperature level T purchased in zone j in year y	-
$NDD_{i_{dist}jTy}$	Integer variable. Number of district heat supply units of technology i_{dist} of temperature level T decommissioned in zone j in year y	-
NCE_{ejy}	New installed capacity of electricity supply technology e in zone j in year y	kW
$VCE_{ejyy'}$	Vintage capacity of electricity supply technology e installed in zone j in year y remaining in year y'	kW
$DCE_{ejyy'}$	Capacity of electricity supply technology e in zone j installed in year y decommissioned in year y'	kW
TCE_{ejy}	Total capacity of electricity supply technology e in zone j remaining in year y (it doesn't matter when it was installed)	kW
OCE_{hejy}	Capacity of electricity supply technology e in zone j which is operating in timeslice h in year y	kW

Nomenclature 3: Decision variables - Network capacities

Variable	Description	Units
ICN_{jjmy}	Capacity of network type n that connects zones j and j' installed in year y	kW
$CCN_{jjmyy'}$	Capacity of network type n that connects zones j and j' installed in year y remaining in year y'	kW
$DCN_{jjmyy'}$	Capacity of network type n that connects zones j and j' installed in year y and decommissioned in year y'	kW
TCN_{jjmy}	Total capacity of network type n that connects zones j and j' in year y	kW
NLN_{jny}	New network length of network type n installed within zone j in year y	km
$VLN_{jnyy'}$	Vintage network length of network type n installed within zone j in year y remaining in year y'	km
$DLN_{jnyy'}$	Network length of network type n installed within zone j in year y decommissioned in year y'	km
TLN_{jny}	Total network length of network type n within zone j in year y	km
F_{hjjmy}	Flow in network n from zone j to zone j' in timeslice h in year y	kW
F_{hjny}^{IN}	Flow in network n from outside the boundaries of the city into zone j in time slice h in year y	kW
F_{hjny}^{OUT}	Flow in network n from zone j to outside the boundaries of the city in timeslice	kW

Variable	Description	Units
	h in year y	
F_{hjn}^{CONS}	Flow in network n consumed in zone j in timeslice h in year y	kW
F_{hjn}^{GEN}	Flow in network n generated in zone j in timeslice h in year y	kW
$\dot{m}_{hjj'Ty}$	Water mass flow from zone j to zone j' in timeslice h and year y at temperature level T	kg/s

Nomenclature 4: Decision variables and derived quantities - Fuel and electricity consumption

Variable	Description	Units
$ELEC_{by}^{TOT}$	Total electricity consumed from the grid by demand type b in year y	kWh
$ELECD_y^{TOT}$	Total electricity consumed from the grid by district technologies in year y	kWh
$FUEL_{abhjy}$	Fuel a consumed by demand type b in zone j in timeslice h in year y	kWh
$FUEL_{ahjy}$	Fuel a consumed by district technologies in zone j in timeslice h in year y	kWh
$FUEL_{aby}^{TOT}$	Total fuel a consumed by demand type b in year y	kWh
$FUEL_{ay}^{TOT}$	Total fuel a consumed by district technologies in year y	kWh
CO_2	Total CO ₂ equivalent emissions	tCO ₂ e

Nomenclature 5: Costs elements of objective function

Variable	Description	Units
OP	NPV of total variable system's operation costs	£
MNT	NPV of total annual system's maintenance costs	£
FE	NPV of total system's fuel and electricity costs	£
CRB	NPV of total system's carbon costs	£
CPT	NPV of total system's capital costs	£
EQ	NPV of total equipment's capital costs	£
NTW	NPV of total networks' capital costs	£
DEC	NPV of total system's decommission costs	£
SLV	NPV of total system's salvage value at the end of the modelling period	£
ES	NPV of total system's incomes from selling electricity to the grid	£
$COSTS$	NPV of total system's costs	£

Nomenclature 6: Scalars

Scalar	Description	Value
r	Discount rate	7%
c	Specific heat capacity of water	4.1813 kJ/kg K
y_{final}	Final modelling year	2051
$M, M1$	Big numbers	

Nomenclature 7: Technology parameters

Parameter	Description	Units
$\eta_{i_{ind}}^{ThI}$	Thermal efficiency of technology i_{ind}	-
$\eta_{i_{dist} T}^{ThD}$	Thermal efficiency of technology i_{dist} of temperature level T	-
η_{CHP}^{EI}	Electric efficiency of individual CHP	-
$\eta_{CHP T}^{ED}$	Electric efficiency of district CHP of temperature level T	-
$Cap_{i_{dist} T}^D$	Maximum thermal capacity of technology i_{dist} at temperature level T	kW
$Lt_{i_{ind}}^I$	Lifetime of heat supply technology i_{ind}	Years
$Lt_{i_{dist} T}^D$	Lifetime of heat supply technology i_{dist} at temperature level T	Years
Lt_e^E	Lifetime of electricity supply technology e	Years
$Cost_{bi_{ind}jy}^{CI}$	After diversity capital cost for demand type b of individual heat supply technology i_{ind} in zone j and year y	£/kW
$Cost_{i_{dist}jTy}^{CD}$	Capital cost for district heat supply technology i_{dist} in zone j for temperature level T in year y	£/kW
$Cost_{eyj}^{CE}$	Capital cost of electricity supply technology e in zone j and year y	£/kW
$Cost_{i_{ind}y}^{OI}$	Variable operation cost for individual heat supply technology i_{ind} in year y	£/kWh
$Cost_{i_{dist}Ty}^{OD}$	Variable operation cost for district heat supply technology $i_{district}$ for temperature level T in year y	£/kWh
$Cost_{ey}^{OE}$	Variable operation cost for electricity supply technology e in year y	£/kWh
$Cost_{bi_{ind}jy}^{MI}$	Annual maintenance cost after diversity in zone j for demand type b of individual heat supply technology i_{ind} in year y	£/kW
$Cost_{i_{dist}y}^{MD}$	Annual maintenance cost of district heat supply technology i_{dist} in year y	£/kW
$Cost_{ey}^{ME}$	Annual maintenance cost of electricity supply technology e in year y	£/kW
$Cost_{i_{ind}y}^{DI}$	Decommission cost of individual heat supply technology i_{ind} in year y	£/kW
$Cost_{i_{dist}Ty}^{DD}$	Decommission cost of district I heat supply technology i_{dist} of temperature level T in year y	£/kW
$Cost_{ey}^{DE}$	Decommission cost of electricity supply technology e in year y	£/kW

Nomenclature 8: Network parameters

Parameter	Description	Units
$Cost_{ny}^{NT}$	Diameter dependent capital cost of network n in year y	£/kW km
$Cost_{ny}^{ND}$	Average capital cost of distribution network n in year y	£/km
Lt_n^N	Lifetime of network n	Years
$Loss_T$	Average loss (% of heat generated) of heat distribution network of supply temperature T	-
T_T^R	Return temperature of heat network of supply temperature level T	K

Nomenclature 9: Spatial parameters

Parameter	Description	Units
Rl_j	Road length within zone j	km
$d_{jj'}$	Linear distance between zone j and zone j'	km
$Nb_{jj'}$	1 if zones j and j' are neighbours, 0 if not.	-
Cb_j	1 if zone j is a city boundary, 0 if not.	-

Nomenclature 10: Resource parameters

Parameter	Description	Units
$Cost_{aby}^F$	Fuel price of fuel a for demand type b in year y	£/kWh
$Cost_{ay}^{FD}$	Fuel price of fuel a for district technologies in year y	£/kWh
$Cost_{by}^E$	Electricity price for demand type b in year y	£/kWh
$Cost_y^{ED}$	Electricity price for district technologies in year y	£/kWh
$Sell_y^E$	Electricity price for selling electricity to the grid in year y	£/kWh
Em_{aby}^F	Emission factor of fuel a for demand type b in year y	tCO ₂ e/kWh
Em_{ay}^{FD}	Emission factor of fuel a for district technologies in year y	tCO ₂ e /kWh
Em_{by}^E	Consumption based emission factor of electricity grid for demand type b in year y	tCO ₂ e /kWh
Em_y^{ED}	Consumption based emission factor of electricity grid for district technologies in year y	tCO ₂ e /kWh
$Cost_y^{CO2}$	Carbon price for year y	£/ tCO ₂ e

Nomenclature 11: Demand parameters

Parameter	Description	Units
HP_h	Heat profile parameter in time slice h , expressed as a fraction of peak heat demand.	-
Num_{bjy}	Number of customers of demand type b in zone j in year y	-
Dem_{bhjy}^H	After diversity individual heat demand of customer type b in timeslice h in zone j and year y	kW
Dem_{bhjy}^E	After diversity individual electricity demand of customer type b in timeslice h in zone j and year y	kW
Dur_h	Duration of time slice h	hours

Chapter 1. Introduction

1.1 Introduction

Climate change is one of the grand challenges of the 21st century [1], and heat provision has emerged as one of the most difficult energy services to decarbonise [2]. This is because heat provision has historically relied heavily on fossil fuels, and incumbent low cost end-use technologies have been deeply established. Additionally, there are high costs and complexities associated with the infrastructure transitions that are required for decarbonising heat, such as the installation of heat networks, the installation of hydrogen networks, or the reinforcement of electricity distribution networks needed to support the potential electrification of heat [3].

In the UK, 45% of the total energy demand in 2016 was used for heating purposes; for water and space heating, cooking, and a range of industrial processes [4]. Currently, natural gas provides around 68% of this demand, mainly via its combustion in gas boilers [4]. As a consequence of widespread availability and relatively low cost of natural gas across these end-use sectors, the UK has had a very low penetration of alternative forms of heat provision [5]. However, if the UK is to stay on a path to significant emissions reductions as set out in the Climate Change Act 2008, the means of serving heat demand will need to change radically. This work will present this context and develop a systems modelling approach to holistically address the heat decarbonisation challenge.

Credible alternatives for the decarbonisation of heat demand include district heating combined with any source of low carbon heat, distributed smaller-scale combined heat and power (CHP), electrification of heat using heat pumps (with a decarbonised electricity network), or hydrogen fuelled heat supply technologies. Adoption of these technologies must proceed alongside infrastructure investment, improving energy efficiency of buildings and processes, and developments in the broader energy system such as increased intermittent and inflexible power generation.

At the time of writing most heat decarbonisation modelling either focuses on specific technologies [6, 7], uses coarse temporal/spatial resolution [8, 9], or considers only part of the system [10, 11]. No systematic framework exists that trades off individual building and district heat supply technologies and associated infrastructures at a high spatial resolution. This work formulates and applies such a framework. It presents the Heat Infrastructure and Technology (HIT) model, which is a

mixed integer linear optimisation model that selects gas, electricity, heat, and hydrogen network infrastructure investments, together with heat supply and end-use technology investments and operation, with the objective of minimising the overall cost. The model is formulated as a long-term multi-period energy planning approach within spatially disaggregated regions, considering distances between and within sub-regional zones for infrastructure decisions.

The HIT model is then used to investigate four key issues related to heat decarbonisation in the UK, which were defined when reviewing the literature. These four key issues and their importance are:

- 1. The comparison of different temperature heat networks for decarbonising heat:** As highlighted by the Committee on Climate Change [12], action to reduce emissions from heat is required promptly, and low carbon district heating in heat dense areas is one of the low regret opportunities to decarbonise heat. A trend in lowering heat network temperatures was identified in the literature [13] along with other energy efficiency improvements to enhance the energy system's performance. This study seeks to implement the HIT model to compare the cost effectiveness of different temperature heat networks, and their effectiveness compared to other low-carbon heat alternatives.
- 2. Studying the effect of spatial resolution in outcomes of energy systems models for heat:** Spatial resolution has been identified as a key challenge for modelling energy system transitions [14]. While a broad range of studies at different spatial resolutions can be found in the literature, to date no other authors have comprehensively compared how do results from energy systems models differ when modelling a given area at different spatial resolution levels. Heat decarbonisation is a relevant topic to perform such a comparison study because of the inherent integration of heat supply into the broader energy system, through trade-offs between electricity, gas, and heat infrastructure and technologies, while still maintaining tractability when implementing a model at various spatial scales. This study seeks to quantify differences between optimal solutions for different spatial resolution levels.
- 3. Studying the role of hydrogen in heat decarbonisation pathways in the UK:** As set out by the Committee on Climate Change [12] the role of hydrogen for heating in buildings - specifically whether to retrofit the current gas network to transport hydrogen or not -needs to be evaluated as an alternative for decarbonising heat in the UK. This work seeks to assess the cost-effectiveness of hydrogen compared to other heating energy vectors in a spatially-resolved urban area, considering the economic feasibility of installing new hydrogen

networks or retrofitting existing gas networks to transport hydrogen, when taking into account trade-offs in the broader heat supply energy system.

- 4. The sensitivity of heat decarbonisation outcomes to uncertainty in techno-economic parameters:** The HIT model is a technology rich bottom-up model, and as such it requires many cost and performance inputs to describe network infrastructures, technologies, and energy sources. As many of these inputs are uncertain, this chapter seeks to study the impact of these uncertainties in resulting cost-effective heat decarbonisation pathways.

1.2 Thesis structure

This thesis is organised as follows:

Chapter 1 provides an introduction to this thesis and the general context in which it is placed.

Chapter 2 sets out the general background on heat decarbonisation, carrying out a review of existing analytical approaches for assessing heat decarbonisation pathways. Then, specific literature reviews for the proposed key issues related to heat decarbonisation mentioned previously are carried out, specifically addressing how these have been modelled in other works. For the first key issue, a review on how energy systems models have treated co-existing different temperature heat networks is conducted. For the second key issue, spatial resolution levels utilised in previous works are compiled, and potential comparisons between these levels are identified, highlighting the importance of studying spatial resolution for energy systems models for heat supply. For the third key issue a review on the role of hydrogen for decarbonising heat in the UK is performed. Feasible low carbon hydrogen production routes are described, followed by a description of some of the main safety issues associated to incorporating hydrogen as a heating fuel. Then, a brief review on the role of hydrogen as an urban transport fuel is conducted. This section finalises with a review of hydrogen in energy systems models, through revising previous works that have assessed hydrogen as an alternative for heat provision. This chapter concludes with the general objectives of this thesis and with the specific objectives for each of the four key issues related to heat decarbonisation here studied.

Chapter 3 explains the methods used in this thesis. The first section presents the formulation of the HIT model proposed in this work, and states the assumptions made and input parameters used. Subsections in the Methods chapter describe the details, specific formulations, assumptions, and

scenarios for the four specific key issues related to heat decarbonisation that were studied using the HIT model.

Chapter 4 presents and discusses the results for the study on different temperature heat networks for different scenarios.

Chapter 5 shows the obtained results on how spatial resolution affects outcomes of energy systems models for heat, and discusses these results for different urban/rural areas.

Chapter 6 discusses the results obtained for potential hydrogen deployment for heat, when implementing a formulation for retrofitting the current gas network, compared to a formulation where a hydrogen network is modelled as totally independent to gas. The role of hydrogen for heat decarbonisation is studied for a set of hydrogen prices and emission factor scenarios.

Chapter 7 shows results for an investigation of the sensitivity of heat decarbonisation outcomes to a range of important techno-economic parameters of the HIT model. The results focus on the influence of variations in some of the main input parameters in outputs of the HIT model, such as optimal technology mix, technology uptakes, costs, and carbon emissions. A discussion on possible cost-effective heat decarbonisation pathways under different scenarios is performed for a series of price/cost assumptions.

Chapter 8 summarises the main findings and gained insights, and examines the limitations of this work providing directions for future research.

Chapter 2. Background

According to the Department for Business, Energy & Industrial Strategy [4], 45% of the total energy consumption in the UK in 2016 was used for heating purposes. Figure 2-1 shows the breakdown of the total energy consumption into heat, transport, and other uses. The exploded view shows the breakdown of heat-related energy consumption by end-use. As shown in this figure, water and space heating account for 36% of the total energy consumption in the UK.

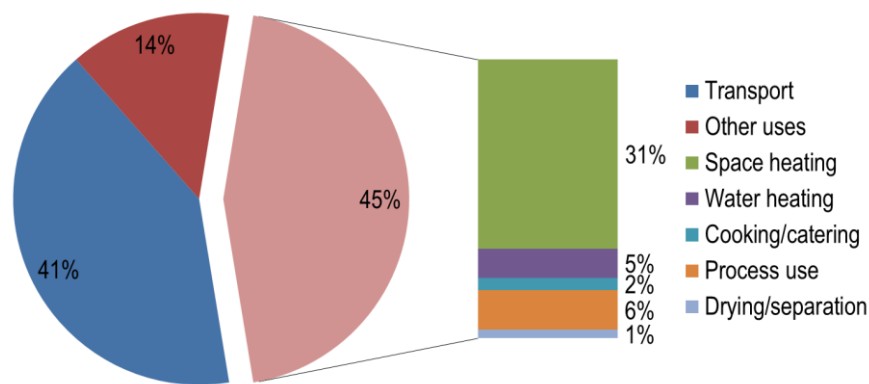


Figure 2-1: Overall final energy consumption shares for heat and other end uses. Exploded view on the right corresponds to heat related energy consumption. Based on data from [4].

Figure 2-2 shows the breakdown of fuel use for heat in 2016, drawn from [4]. This figure shows that in the UK, 68% of all heat is generated from natural gas across the domestic, service, and industrial sectors. Moreover, considering sector-specific data from [4], 90% of UK domestic dwellings in 2015¹ had natural gas boilers to serve their heating demands. In the service sector, 72% of heating and hot water demand was served by natural gas in 2016, presumably via its combustion in gas boilers. In this context, this work seeks to develop a systems approach to systematically assess the different alternatives of heat provision for a cost-effective heat decarbonisation in the domestic and service sectors.

¹ No data was available for the year 2016.

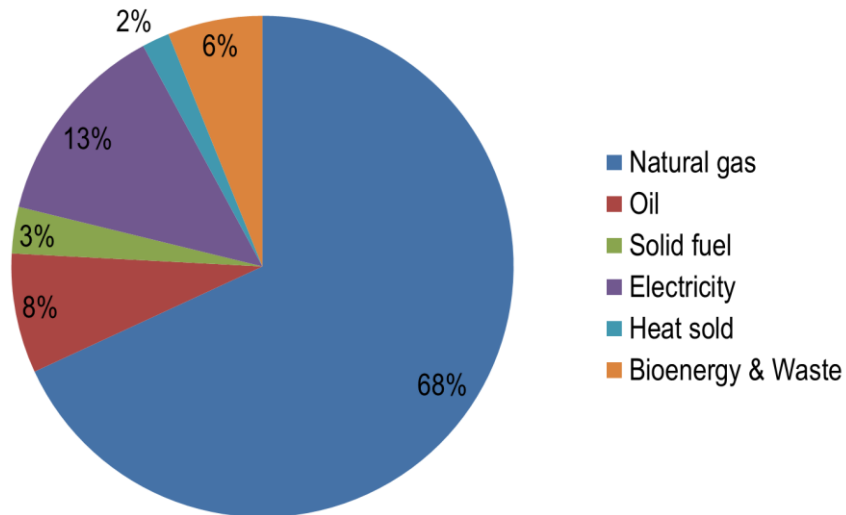


Figure 2-2: Fuel breakdown for heat use based on data from [4].

2.1 Approaches to heat decarbonisation

It is clear from most studies that the continued use of natural gas as a core heating fuel is not likely to be consistent with long-term climate change mitigation targets [15]. The literature sets out a range of approaches to heat decarbonisation, which can broadly be categorised into variants that rely on one or a combination of; (a) decarbonised electricity, (b) low or zero carbon gases such as hydrogen or bio-derived/synthetic methane, (c) heat networks supplied with heat from low carbon sources, and (d) efficiency and behavioural change related approaches.

Lund *et al.* [16], based on the Danish case, conclude that the best heat decarbonisation solution is a gradual expansion of district heating supplied by combined heat and power (CHP) plants, together with individual heat pumps. Connolly *et al.* [17] propose a heat strategy for the European Union based on district heating and individual heat pumps, which can potentially reduce primary energy consumption and carbon emissions. When identifying challenges for a future non-fossil heat supply, Lund *et al.* [13] also propose a “4th generation” of district heating that includes lower network temperatures, efficiency improvements, and higher integration and synergies with the rest of the energy system. Also with regard to heat networks, Troup [18] argues that they are a good investment for heat decarbonisation today, with a view to decarbonising the supply of heat to these networks via biofuels or other low carbon alternatives towards 2030. Troup [18] also argues that the main capital investments for heat networks are in network infrastructure, which outlives the heat supply equipment, and is therefore an important enabling measure for future low carbon heat.

Dominković *et al.* [19] show that interconnecting geographically distributed heat networks can potentially reduce primary energy consumption and CO₂ emissions. This could suggest a possibility of gradually installing heat networks when economically feasible and interconnecting them in a posterior stage.

Heat pumps are also commonly cited as a useful alternative to decarbonise heat in less dense areas [18, 20], or by using central and booster heat pumps to supply heat networks. One potential advantage of heat pumps is that they perform well with low heat supply temperatures, and therefore could complement lower network temperatures [6]. Heat pumps have been shown to generate natural gas savings with the subsequent reduction in associated carbon emissions [7]. They are also attractive in the sense that at least part of their heat output can be classified as renewable, and further interest is motivated by the fact that the share of low carbon electricity generation has increased consistently in Europe and the UK in the years up until the time of writing [21]. Heat pumps do face some challenges though, including the requirement of reinforcing the electricity network to cope with augmented electricity demand, high upfront equipment capital costs, and the potential need to replace internal building heat emitters with more expensive low temperature variants.

In [22], Dodds *et al.* present fuel cell technologies and hydrogen as alternatives for low carbon heat. Hydrogen is proposed as replacement for gas in countries with an extensive gas infrastructure, or for supplying heat networks through hydrogen CHPs. They also suggest the possibility of scaling up and expanding current hydrogen infrastructure, or building new hydrogen networks. Further interest in this possibility has been motivated by the H21 Leeds City Gate project [23], which proposed that the cost of transforming the Leeds city gas network to hydrogen from a low carbon source was both plausible and potentially cost-effective.

Overall, while a broad range of approaches have been presented, the general conclusion of studies is unequivocal; overall decarbonisation targets cannot be met without addressing heat decarbonisation [3, 12, 24]. The range of options and trade-offs is vast, and while initial studies have recognised this problem, no systematic and comprehensive study has emerged that considers this range with sufficient detail. Moreover, the studies cited above either implicitly or explicitly show that analytical methods that consider not only the different supply and end-use options, but also infrastructure trade-offs, are needed to inform decision makers about the best pathways towards decarbonisation of heat.

2.1.1 Classification of energy systems models

Several classifications for energy systems models are available in the literature. For example, models can be classified between optimisation, simulation, or accounting. Optimisation models find the least cost configuration and/or operation of a system, given a set of constraints. Simulation models simulate how agents, who may be producers or consumers, respond and behave given different inputs or scenarios (for example prices, policies, etc.), by finding market equilibrium. Accounting models account for the user-specified outcomes, and are used to manage data and results. Hybrid models can combine different aspects of these models [25]. Pfenninger et al. [14] identify four model paradigms and their primary focus: Energy system optimisation models which focus on developing normative scenarios; energy system simulation models which focus on forecasting scenarios; power system and electricity market models which are used for operational decisions, business expansion or planning; and qualitative and mixed approaches which are used for narrative scenarios.

Another classification is the top-down versus bottom-up models. Top-down models use aggregate variables such as energy, capital, and labour, to represent production functions and outputs for the different sectors in a system. The inputs and outputs of a base historical year are used to calibrate the parameters for the production functions. Users can usually select elasticities of substitution between the different inputs to produce a unit of output. Among top-down models, besides the Computable General Equilibrium, there are also macro-econometric models, which use econometrically calculated coefficients to simulate capital flows between sectors and analyse their impacts on the main macroeconomic indicators of each sector (GDP, labour, investment, etc.), aggregating them into national indicators. On the other hand, bottom-up are technology rich models which incorporate detailed technology data such as inputs, outputs, costs, and techno-economic parameters. Each sector is built as a series of technologies that emulate the real world processes. Technology mixes can be determined by the least cost solution or by other economic behaviours. Hybrid models include characteristics of bottom-up and top-down approaches. For example, some top-down models include technology specifics for some energy producing sectors. On the other hand, some bottom-up models include effects of the whole economy on the energy system [26, 27].

A further aspect in energy systems is the amount of information available to the decision maker. Most optimisation models assume perfect foresight, where all the information for the modelling time horizon is available for the decision maker from the beginning. Uncertainty is incorporated by using models to evaluate different scenarios. Although this approach gives optimal and ideal

solutions, it does not describe the reality of a decision maker, in which they do not have all the information in prices, costs, and other constraints. An alternative is using a myopic or short-sighted approach, in which nearer decisions weight more, and more information is available for the short-term. Real world decisions are often made adaptively by adjusting decisions to changing markets and technologies, throughout long time horizons [28, 29]. Also related to the information availability, a model can be stochastic or deterministic. While deterministic models use deterministic (certain) projections for technologies, costs, prices, etc., stochastic models allow for uncertainty in these parameters [30].

Table 2-1 presents some classifications for energy system models, and the main features, advantages, and disadvantages of the different types of models.

Table 2-1: Some classifications for energy systems models. Based on information from [14, 29, 31, 32].

Classifications	Main features	Advantages	Disadvantages
Optimisation	Typically linear programming for least cost solution. Exogenous demand. Model chooses the technology set based on constraints and costs. Can optimise investment and operation.	Powerful and consistent for back casting. Useful when many options exist.	Usually assumes perfect competition in the economic system. Penny-switching problem, unless constrained cautiously. Difficult to evaluate policies or behaviours that are hard-to-cost. Data intensive. Assumes energy is the only factor for technology choices.
Simulation	Rather than generating optimal futures, they predict the most likely evolution for the system. Consider various signals and simulate the agents' behaviours.	Does not assume optimal behaviour. Can consider other factors apart from energy that influence technology choices. Can be built modularly and allow for the use of different methods in the models.	Does not find global optimal solutions. Haven't solved the issues with uncertainty in order to predict the future.
Accounting	The user explicitly accounts for the outcomes of producers' and consumers' decisions, in order to evaluate outcomes of scenarios.	Transparent and simple. No assumptions on perfect markets. Is able to evaluate hard-to-cost factors. Not so data intensive.	Does not optimise or find the least cost solution, so not suitable when a lot of alternatives exist. Does not necessarily give consistent forecasts solutions, as for example demand and supply forecasts.
Bottom-up	Each sector is built as a series of technologies that emulate the real world processes, so as a unit of output in these models is produced by a mixed of outputs of individual technologies.	Provides details on the operation of technologies. Models can be able to resemble realistic processes.	Very data intensive for characterising each technology and process. Need to make simplifications in order to integrate the data, for example, for spatial aggregation or temporal resolution.
Top-down	Use aggregate variables such as energy, capital and labour, to represent production functions and outputs for the different sectors in a system.	Requires less data for the implementation. Useful when details are not needed. Need less computational requirements.	Does not provide technology and operation details. Does not take into account the interactions between different agents at a micro-level.
Perfect foresight	Decision-maker has complete information about the future.	Approach reaches and optimal solution.	Does not describe the reality of a decision maker.
Myopic	Decision-maker has only certain information about the present or short-term.	More realistic approach, in which more information is available for the short-term.	Does not reach the optimal solution as if all the information had been known before taking all decisions.

Classifications	Main features	Advantages	Disadvantages
Deterministic	Models have certain information on projections for technologies, costs, prices, demands, etc.	Simpler projections.	Does not represent the reality in which decision-makers make decisions.
Stochastic	Models can include uncertainty in the inputs or projections.	Resembles reality better than a deterministic approach. Is able to consider different scenarios or probabilities in the same run.	Longer processing times for including stochasticity. Difficult to assign probabilities or probability functions in the formulation of the model.

2.1.2 Energy system models for the assessment of heat decarbonisation

There are a vast range of energy systems models used for analysing the energy scenarios resulting from different policy measures. Through optimisation, simulation, or accounting, the different models analyse energy systems, obtaining varied results such as type and number of technologies; supply, demand, and prices of different energy carriers; or environmental impacts for different energy scenarios, among others. A first set of regional, national, or subnational energy systems models was identified [26, 33-38]. These are economy-wide models that emulate the entire energy market, including heat, electricity, and transport. The models approaches include simulation, optimisation, or mixed approaches. As these models are economy-wide and national, regional, or multi-regional, specific aspects associated to heat such as spatial distributions of supply, demand, and network infrastructure are not modelled in detail.

Hall et al. [39] suggest a single classification schema to classify energy systems models, in order to allow for energy actors to identify different model potentials and understand their basis. Table 2-2 shows a categorisation of available energy system modelling approaches used to analyse heat decarbonisation or heat techno-economics, based on some of the categories proposed by [39] and other relevant categories for this study.

Table 2-2: Different models and categorisation based on [39] and other relevant fields

Model	Purpose of the model	Model structure	Geographical coverage/ spatial resolution	Sectorial coverage	Time horizon	Time step	Technology inclusion	Demand characteristic inclusion	Cost inclusion	Analytical approach/ methodology/ Mathematical approach	Distribution networks inclusion	Heat network modelling	Other relevant comments for this research
A model for structural and operational optimisation of distributed energy systems [40]	General: exploring Specific: heat supply.	Demand: Exogenous Supply: Modelled	Urban area divided into zones	Heat and electricity	One year	Year divided into two month intervals, with day/night period for each. .	Heat supply technologies	Different user-defined heat and electricity demand profiles.	Heat network cost, technology costs, operation and maintenance (O&M) costs, fuel and electricity costs.	Bottom-up/ Optimisation/ Mixed integer linear programming (MILP).	Heat networks included	Heat networks modelled in detail with pipe lengths, diameters, and losses. Binary variables for existence of heat networks.	Heat networks modelled in detail. Other distribution infrastructure not modelled. No lifetime of assets considered.
EnerGis [41]	General: exploring Specific: geographical information system for a more detailed assessment of heating options.	Demand: heat demand modelled for different building types based on measured and simulated data. Supply: Modelled	Urban area divided into zones.	Heat supply	Medium term	User-defined, 4 periods in this research.	Heat supply technologies	Demand for heat in different building types (residential, public/ commercial, industrial).	Investments, fuel costs, heat network infrastructure costs, fuel and electricity costs.	Bottom-up/ Simulation, optimisation/ Analytical methods MILP.	Heat networks included	Heat networks modelled as MILP. Integer variables for existence of heat networks between zones and within zones.	Heat networks modelled in detail. Other distribution infrastructure not modelled.
EnergyPLAN [42]	General: forecasting, exploring Specific: energy supply and demand	Technologically detailed. Demand: Exogenous. Supply: modelled	National, regional	Electricity, heat, transport.	1 year and medium term by aggregating years	Hourly	Renewables for electricity supply, heat supply technologies in buildings	Demand for electricity and heat in buildings.	Fuel costs, investments, O&M, carbon.	Bottom-up/ Simulation, operation optimisation/ Analytical programming	Electricity, gas, and heat networks.	Optimises operation of user-defined networks and technologies	The model optimises the operation of a user-defined system. No published studies include fine spatial resolution for heat.
ESME [43]	General: Exploring Specific: Demand, supply, environmental impacts	Models major energy flows. Demand: exogenous. Supply: modelled	UK divided into 12 regions.	Whole energy sector, including heat in buildings.	Short and long term	Seasons and intraday divisions	Renewables, recoverable heat, national and regional level	Residential heat and transport supply not included.	Annualised investment, O&M, fuel costs, energy import costs.	Bottom-up/ Optimisation, Monte-Carlo/ Linear programming	Not included	District heating supply options modelled as cost per KW.	Model does not consider sub-regional spatial aspects nor detailed network infrastructure.
MARKAL [44]	General: exploring. Specific: energy supply	Technologically detailed. Demand: exogenous.	National, local	Energy sector	Medium-long term	User-defined.	Renewables for electricity generation. Detailed	Detailed electricity and heat demand in	Annualised investment, O&M, fuel costs, energy	Bottom-up/ Optimisation/ Linear programming,	Gas, electricity, heat, and other	Distribution is modelled as exchange processes.	Networks are not spatially explicit in UK MARKAL or US

Model	Purpose of the model	Model structure	Geographical coverage/ spatial resolution	Sectorial coverage	Time horizon	Time step	Technology inclusion	Demand characteristic inclusion	Cost inclusion	Analytical approach/ methodology/ Mathematical approach	Distribution networks inclusion	Heat network modelling	Other relevant comments for this research
		Supply: modelled					transport modes.	buildings.	import costs, costs and revenues of exogenous energy and material imports/ exports, energy taxes and subsidies, carbon costs.	dynamic programming	commodities distribution included.		EPA MARKAL.
Multi-objective design optimisation of distributed energy systems through cost and exergy assessments [45]	General: Exploring Specific: Distributed energy systems	Demand: Exogenous Supply: Existence, types, sizes, and numbers of devices modelled, with corresponding daily operation strategy.	No spatial representation	Electricity, cooling and heating.	One year.	Hourly demands for four representative season days.	Distributed heat, electricity, and cooling supply technologies, and thermal energy storage.	Given user demand includes electricity, domestic hot water, space heating, and space cooling	Capital costs, O&M.	Bottom-up/ Optimisation/ Multi-objective linear programme.	Networks not modelled.	No networks modelled.	No networks modelled, no spatial representation
Multiobjective optimisation of energy systems and building envelope retrofit in a residential community [46]	General: Exploring Specific: Energy systems and building retrofitting	Demand: Modelled in a first step simulation Supply: Modelled technologies sizes, and operation strategies. Retrofit modelled.	No spatial representation	Electricity and heat	One year	Hourly	Heat and electricity supply technologies in buildings. Retrofitting measures	Electricity and heat demand for different building categories.	Annualised investment costs, fuel costs	Bottom-up/ Simulation, optimisation/ multi-objective optimisation/ Multi-objective MILP.	Heating distribution networks modelled as a binary variable associated to cost.	Heating distribution networks modelled as a binary variable associated to cost.	Networks not modelled in detail and no spatial representation
NEMS [35]	General: Exploring Specific: Balance generation, consumption and prices in US economy.	Demand: Projected. Disaggregated into industry, transport, domestic and commercial. Supply: 4 supply modules	National, sub-national. 22 US regions.	Energy system	Medium-term (25 years)	Yearly	Power generation, buildings, transport, and industry.	Projected sectorial demand by Census division.	Capital, operating, fuel costs, transport costs, carbon costs.	Hybrid/ Agent-based, accounting, optimisation in power sector, simulation in demand sector/ Coupled partial equilibrium and	Major gas pipelines included.	Modelled as exchange processes.	No networks modelled, no spatial representation

Model	Purpose of the model	Model structure	Geographical coverage/ spatial resolution	Sectorial coverage	Time horizon	Time step	Technology inclusion	Demand characteristic inclusion	Cost inclusion	Analytical approach/ methodology/ Mathematical approach	Distribution networks inclusion	Heat network modelling	Other relevant comments for this research
OSeMOSYS [36]	General: Exploring Specific: Match energy supply and demand.	Demand: Four end-use demand modules. Supply: Modelled	User input	Energy sector	Medium to long term (Up to 2050)	Yearly, 3 seasons, 2 intraday variation	Flexible due to modular design.	Flexible due to modular design.	Capital, operating, salvage value.	linear programme Bottom-up/ Optimisation/ Linear or mixed integer linear programme	No networks modelled	No networks modelled	No networks modelled, no spatial representation
POLES [37]	General: Forecasting Specific: Detailed econometric long term energy outlooks.	Demand: Exogenous. Energy prices determined endogenously. Supply: Simulated	Global, divided into 47 regions	15 energy sectors	Up to 2050	Yearly	Power generation, buildings, transport, industry	Projected demand in 66 world regions in following sectors: industry, buildings, transports, agriculture	Capital, operating, fuel costs, transport costs, carbon costs.	Hybrid/ Minimum cost and simulation/ Partial equilibrium	Major gas pipelines included.	Modelled as exchange processes.	No networks modelled, no spatial representation
PRIMES [34]	General: Exploring Specific: Projecting energy demand, supply, prices.	Demand: Simulated. Prices determined endogenously. Supply: Simulated	European countries.	All energy sectors	Medium to long term	Yearly	Power generation. Transport modes, economy wide end-use technologies	Projected energy demand for each European country	Capital, operating, fuel costs, transport costs, carbon costs.	Hybrid/ Agent based/ Equilibrium model	Modelled trade of energy carriers	As exchange process	No networks modelled, no spatial representation
SEDS [30]	General: Exploring Specific: Balance generation, consumption and prices in US economy, considering input uncertainties	Demand: Simulated. Prices determined Supply: Simulated	National (US), multi-regional	Energy sectors	Up to 2050	5-year periods	Power generation. Transport modes, economy wide end-use technologies	Projected sectorial end-use service demand	Capital, operating, fuel costs, transport costs, carbon costs.	Hybrid/ Simulation/ Equilibrium	Modelled trade of energy carriers	No heat networks modelled	No networks modelled, no spatial representation
Sifre [47]	General: Exploring Specific: Optimising energy systems operation	Demand: User specified. Supply: User-specified energy system, modelled operation	One zone or region	All energy system	User specified, one year in this research	Hourly	Energy conversion, transmission and end-use technologies	User-specified energy service demands.	Total operating costs	Bottom-up/ Optimisation/ MILP	Gas, electricity, heat, and other commodities distribution included.	Distribution is modelled as exchange processes	Networks are not spatially represented. Capital expenses not included in the model.

Model	Purpose of the model	Model structure	Geographical coverage/ spatial resolution	Sectorial coverage	Time horizon	Time step	Technology inclusion	Demand characteristic inclusion	Cost inclusion	Analytical approach/ methodology/ Mathematical approach	Distribution networks inclusion	Heat network modelling	Other relevant comments for this research
TIMES [48]	General: exploring decarbonisation pathways, least cost technology assessment Specific:	Technologically detailed. Demand: exogenous. Supply: modelled.	Global, national, regional, local	Energy sector	Medium-long term	User defined Seasonal, weekly, daily variation time slices	As MARKAL	As MARKAL	As MARKAL	As MARKAL	Gas, electricity, heat, and other commodities distribution included.	Gas, electricity, and heat distribution are modelled as exchange processes.	Networks are not spatially explicit in UK TIMES.
TURN model, [49, 50]	General: Exploring Energy supply, integrated approach Specific:	All prices and costs are exogenous. Supply: modelled. Demand: exogenous energy service demands (heat and electricity).	Urban scale, cities divided into smaller zones of varying sizes and shapes.	Electricity and heat.	Medium-long term	Time periods and time steps, user-specified.	Heat and electricity supply technologies in buildings, user-specified	Residential, energy service demand (heat and electricity)	Capital costs, O&M, fuel prices, carbon prices.	Bottom-up/ Optimisation/ MILP	Electricity, gas, and heat networks.	Networks modelled via distance between zones. If a zone is connected, all buildings can access the network. One pipe size between zones.	Model does not consider lifetimes of infrastructure and technologies

When analysing the models that include heat supply presented in Table 2-2, it can be seen that there is a gap in modelling infrastructure trade-offs with a fine spatial resolution. The models reviewed either include different distribution networks at national or regional levels without considering spatial aspects [43, 44], or model heat networks at a higher resolution without considering trade-offs against other distribution networks such as gas, electricity, or hydrogen [40, 41], or do not include the lifetimes of technologies and infrastructure when comparing different supply alternatives [49, 50]. According to [14], spatial resolution is a key challenge going forwards in energy systems modelling, particularly for heat where demand density and infrastructure costs can potentially lead to very different decisions.

More specific research gaps were observed in the literature when comparing different energy systems models and their applications. These will be reviewed in more detail in Sections 2.2, 2.3, and 2.4, setting out the background for three of the key issues related to heat decarbonisation that were identified and studied in this research.

2.2 Different temperature heat networks

This section describes approaches for modelling district heating, focusing on the inclusion different of temperature heat networks. Lund *et al.* [13] describe three generations of district heating. The first generation was introduced in USA in the late 1800's, and was based on steam pipes in concrete ducts. Due to high losses and safety issues, these systems became outdated. The second generation was introduced in the 1930's, and supplied heat via pressurised water at over 100°C. This was taken over in the 1970's by the third generation, which supplied heat via pressurised water at temperatures below 100°C. They identify a trend towards lower distribution temperatures, and as mentioned before, describe a fourth generation that includes higher system integration and efficiencies, and lower temperatures. The following section reviews models that have been implemented or used for the assessment of different temperature heat networks in the context of integrated energy systems. This analysis derives in identifying opportunities to define a study to assess the introduction of different temperature heat networks as an alternative for heat decarbonisation pathways in the UK.

2.2.1 Models for the assessment of different temperature heat networks

Lund *et al.* discuss [16] the role of district heating in systems with higher penetration of renewable generation. By using GIS and energy systems analysis tools (EnergyPLAN model) they model the Danish system in different district heating scenarios combined with specific technologies. They

conclude that district heating is the most cost-efficient alternative to reduce fuel demand and CO₂ emissions from heat compared to micro-CHP based on natural gas, electric heating, and micro-CHP based on hydrogen fuel cells, and that the most cost-effective solution would be the gradual incorporation of district heating together with individual heat pumps. It is emphasised that the analysis contemplates a progressive improvement of district heating technologies, which considers lower temperatures, lower return temperatures, and lower space heating demands. Additionally, the study has included the use of waste incineration and waste heat recovery from industrial processes. Münster *et al.* [51] use the same methodology but using the Balmorel simulation model (rather than the EnergyPLAN model) to discuss the role of district heating in a future Danish energy system. They conclude it is economically feasible to expand the current district heating networks together with installing heat saving measures.

Li and Svendsen [52] simulate a low temperature district heating network in 30 low-energy residential houses in Denmark, and compare it with a medium temperature district heating network. The low temperature network's supply and return temperatures are set to 55°C and 25°C respectively, while the medium temperature networks supply and return are set as 80°C and 40°C. They conduct an energy and exergy analysis and conclude that low temperature networks have a higher heat loss reduction potential than medium temperature networks, because of the better match of heat qualities between supply and demand. Brand and Svendsen [53] acknowledge the importance of lowering the supply temperatures for district heating networks, and conduct a study in which they use the IDA-ICE software to simulate a Danish single-family house from the 70's in a district heating network. The aim was to study how different stages of refurbishment could affect the possibility of using lower supply temperatures in the network, underlining the importance of implementing heat saving measures together with decreasing heat network supply temperatures. Tunzi *et al.* [54] optimise the operating temperature in a UK district heating system. They show that though fine regulation of mass flows and supply and return temperatures in district heating systems, energy consumption can be reduced while maintaining the same comfort level.

Using evolutionary algorithms, a group of optimisation models which particularly assess heat demand and heat networks use multi-objective optimisation methods (cost and emissions minimisation). Weber *et al.* [55] develop a method for designing district energy systems which decomposes the multi-objective optimisation into one Master non-linear optimisation problem solved by an evolutionary algorithm together with a thermodynamic simulation, and one Slave single-objective mixed integer linear programming problem. The master optimisation seeks to minimise CO₂ emissions and total costs. It defines the design size and characteristics of the

network's heating and cooling technologies, the supply temperatures, the thickness in the pipe insulations, and carbon tax values. The technologies which are optimised in the master optimisation are the ones connected to the network, and linked to more than one building. The slave optimisation solves the optimal network design for local technologies (which provide heat to single buildings) and their operation strategy, through a cost minimisation objective function. Given a master set of decision variables which is iteratively found through an evolutionary algorithm and thermodynamic models, the slave optimisation finds values for design variables (node selections and connections, pipe diameters, size of local technologies) and for operational variables (pump electricity consumption per hour, heat and cooling distribution to buildings, mass flow rates, operation of network and local technologies, and fuel and electricity consumptions). This method results in a Pareto frontier with various optimal points. In this work the consumption profile is described as two periods: night and day.

Fazlollahi *et al.* [56] build on this model by proposing a multi-period approach through a *typical days definition*, and by extending the post-processing stage. Later on Fazlollahi and Maréchal [57] integrate biomass resources into the multi-period, multi-objective optimisation. The developed model is a mixed integer non-linear problem (MINLP), which again divides the decision variables into a master and a slave set. The master set includes maximum available size of equipment and types of available equipment, and is solved through an evolutionary algorithm. With these variables, superstructure alternatives for the network are defined. Then, a thermo-economic model simulation calculates the cost, heat transfer, enthalpies, and power requirements of the equipment selected as a superstructure. The third step is solving a MILP that defines optimal network operation to minimise costs using the inputs from the thermo-economic simulation, the available energy sources, and the energy consumption (temperature and power levels). The algorithm is iterated in order to find a Pareto optimal frontier. The input for the master optimisation is a list of available equipment, and the decision variables are the maximum available capacity of equipment and type. The constraints include the thermo-economic model, the slave optimisation, and the economic and environmental evaluation from the previous iteration. The main input for the thermo-economic simulation is the equipment maximum available size (from the master optimisation), the efficiencies (electrical and thermal) of this equipment, and their market cost function. With these inputs, the results for this stage are the thermodynamic states, performances, and turnkey costs of technologies. Finally, the slave MILP is a minimum cost, multi-period optimisation model that optimises the operation (utilisation) of the equipment in a yearly basis. Main constraints are the heat balances of each temperature interval and overall heat balance, the electricity balance, electricity cascading and residual electricity cascading. This model does not consider the existence of

networks: the energy system is composed by a demand side and a supply side. The supply side is assumed to be a central power plant, with all the conversion technologies located within.

In [58] Fazlollahi *et al.* use the same method for designing heat networks, incorporating in the slave optimisation the heat losses, equipment's technical limits, and the possibility of heat cascading from a higher temperature interval to a lower one in each location. Also, the design of the heat network is developed based on the geographical information system (GIS), in order to optimise the configuration of the network and the locations of the plants. The heat balance is performed for each location and time step, including a variable that represents available heat from other locations at each temperature interval, and residual heat at each temperature level that can be transferred to other locations through the network. In this model, heat losses in pipelines are modelled using the pipelines' lengths and the temperature differences of the flows [59], and a constraint for maximum utilisation rate for the pipelines is added. Additionally, Fazlollahi *et al.* [60] include the decision of integrating heat storage tanks, their volumes, temperature intervals and operation strategy. Finally Fazlollahi *et al.* [61] extend the model by including transportation besides the network design. The optimisation of transportation and logistics determines the shipping of resources from plants or warehouses to their final destination through available roads and transportation systems.

2.2.2 Infrastructure and technology trade-offs in different temperature heat networks

This section analyses and identifies gaps from the literature presented in Section 2.2.1. Lund *et al.* [16] and Münster *et al.* [51] seek to explore pathways for district heating networks at national levels. As previously described in Table 2-2, EnergyPLAN optimises operation of user-defined networks and technologies. No published studies include fine spatial resolution for heat. Likewise, in [51] the model is implemented at a national level without a fine spatial resolution. In [52-54], existing designs of different temperature district heating networks are simulated, and their operations are optimised. These studies do not seek to design or plan the installation of district heating networks nor to compare the installation considering infrastructure trade-offs with other energy vectors.

The other group of studies reviewed [55-61] build on a three-stage model that optimises investments and detailed operations on networks and end-use technologies. These models present a detailed description of different temperature heat networks and heat dynamics. However, no study uses a single spatially-resolved framework that trades off infrastructure and end-use technologies to compare the cost-efficiency of different temperature heat networks compared with other heat supply alternatives. Therefore, the study of the first key issue related to heat decarbonisation seeks to explore the effect on heat decarbonisation pathways when allowing for the possibility of including

different temperature heat networks, in a single-framework spatially resolved model that takes into account energy supply, end-use technologies, and infrastructure trade-offs.

2.3 The effects of spatial resolution in outcomes of energy systems models for heat

This section presents the background for the second key issue related to heat decarbonisation that was identified in the review of the literature. Spatial resolution has emerged as an important challenge for modelling energy system transitions [14]. While many studies exist at different spatial resolutions, for example modelling a group of consumers, districts, cities, or regions/nations, there are yet no comprehensive studies that compare how results from energy systems models differ when modelling at different spatial resolution levels. Heat decarbonisation is an apposite topic for a study comparing spatial resolutions. This is because the system that meets heat demand is inherently integrated across the energy system, with potential trade-offs between many energy carriers, infrastructures and end-use options. Therefore, it represents well the typical characteristics of broader energy systems, while still remaining relatively tractable given the challenges of collecting data and implementing models at multiple spatial resolutions. Finally, it is also a key challenge in overall heat decarbonisation: As stated by the Committee on Climate Change [12], a deep reduction in emissions from heat in buildings is necessary to meet the Climate Change Act targets and the UK's contribution to the Paris Agreement.

In order to place this study in context, this section shows how a selection of system models have been applied for heat-focused applications in the existing literature, their spatial resolution levels, and how infrastructure is modelled within them. Based on this, the potential importance of spatial resolution is highlighted.

2.3.1 National optimisation system models that include heat supply

National and larger-scope models typically have very coarse spatial resolution. For example, Dodds and Mc Dowall [62] use the UK MARKAL model and characterise the UK into a single region, in order to assess the cost-effective future of the UK gas network. Dodds and Demoullin [63] adapt the UK MARKAL model and also describe the UK as one aggregated region to examine the economic feasibility and benefits of converting the UK gas grid to transport hydrogen. Pye et al. [43] implement the ESME model which uses a coarse disaggregation of the country into sub-regions to investigate the influence of uncertainty in techno-economic parameters, in cost-effective energy transition pathways. Another example is the EnergyPLAN [42] model, which simulates and optimises

the operation of user-defined systems with a coarse disaggregation of a country into sub-regions. Several studies from the Heat Roadmap Europe project use this tool, such as [64], in which the potential of district heating and heat savings to decarbonise heat are analysed².

This, however, does not mean that these models are unable to reflect spatial constraints or opportunities. For example, while each energy service demand is typically characterised as a time series for each region, it is possible to constrain end-use technologies to serve a limited portion of that demand, or to disaggregate the demand into different types (e.g. urban vs rural) based on the spatial (or other) characteristics of that demand. Similarly, while infrastructure in these models is often characterised via simple linear processes, those processes can be disaggregated and/or constrained to better represent a spatial aspect of that infrastructure (e.g. in UK TIMES, high and low pressure gas infrastructure is disaggregated [65]). Furthermore, the energy supply sources in these models are often represented via stepped supply curves, which can be used to characterise the spatial aspects of supply (e.g. location-based renewable potentials [66, 67]).

Therefore, while coarsely resolved models such as most national models are certainly capable of indirectly representing spatial issues, it is clear that results become dependent on the assumptions in the studies that generated the related input data. Shortcomings of these models are not mainly in their formulations per se, but rather on the data base that is used to spatially describe heat demands and their location relatively to prospective heat supply. The aggregation of demand and supply over large areas is what can potentially cause variations in outputs.

2.3.2 Urban optimisation system models for heat

At the urban scale, a group of models exist in the literature in which the modelled area is more explicitly spatially resolved, either via “top-down” subdivision of geographical areas into zones, or via “bottom up” representation of a network of nodes based on individual buildings, consumers or other entities. Selected publications that can be categorised as such are described below.

In the category of models that take the approach of subdividing a geographical zone, there are several relevant publications. Girardin *et al.* [41] develop a geographical information system to model energy systems in urban areas. They argue that modelling advanced integrated energy systems requires a detailed definition of energy service demands, and illustrate this with spatially

² It is noted that any of the modelling frameworks used in these studies, TIMES/MARKAL, ESME and EnergyPLAN can and have also be applied at finer spatial resolutions. However, this is rarely done for national level studies due to tractability issues.

resolved case studies. Binary variables are used to represent networks between zones and networks within zones. Resolution is not stated, but the model is a disaggregation of the Geneva district.

Keirstead *et al.* [49] study the impact of combined heat and power (CHP) planning restrictions on the efficiency of an urban energy system using the TURN mixed integer linear optimisation model. The studied city is divided into grids of 400 m × 400 m square cells. TURN is applied again in Keirstead and Calderon [50] to study spatial effects, technology interactions, and uncertainty in policy input parameters, using the city of Newcastle as a case study. They disaggregate the city into middle layer super output areas [68] and find the optimal technology mix and demand side measures in dwellings for supplying heat and electricity. A Monte Carlo analysis is then performed to understand the impact of uncertainty of certain parameters in the optimal solution. Finally, the model is applied to one neighbourhood using a finer resolution. This is the only example in the literature identified where different spatial resolutions were used in one model, and is discussed further in the section below. In [69] Pantaleo *et al.* the RTN model is adapted to consider biomass in urban energy systems. They divide a generic city into 16 cells and specify which cells have road connections between them for biomass transportation, and which cell connections are available for gas and heat networks.

Jennings *et al.* [70] implement the RESCOM urban energy systems model to find the optimal investment and operation strategy for supply and demand side technologies for space heating and hot water demand in a 29.6 km² London borough, subdivided into 19 spatial nodes. This mixed-integer linear optimisation model is formulated for the residential sector and heating demands only.

The other group of models, in which representative consumers/buildings/entities are modelled as nodes and connections between them represent distribution networks, usually (but not always) use a finer spatial resolution. Table 2-3 shows a selection of these models, the purpose of the research, and the number of nodes or spatial resolution used in the respective case study.

Table 2-3: Selection of models in which representative consumers/buildings/entities are modelled as nodes and connections between them represent distribution networks.

Reference	Purpose of the research	Case study, nodes, and spatial resolution
Mertz et al. [71]	Non-linear model for optimising configuration and design of district heating networks. Detailed calculations of heat losses and pressure drops.	One node represents each consumer and producer. Illustrative case study of one producer and four consumers.
Weber and Shah [72]	Model for optimising the energy service technology mix in an eco-town.	One node corresponding to each building, and some aggregated nodes for low energy service demand buildings to improve solution time. Case study models 31 consumer nodes and 1 plant node.
Prasanna et al. [73]	Optimisation model used for assessing the energy performance of a district energy system with low temperature heat.	The district consists of 30 nodes or energy hubs. 17 nodes represent buildings, 3 represent entry points, and the rest represent branches in the network, to illustrate an accurate representation of the network routing.
Morvaj et al. [74]	Model for district heating network sizing, operation and layout.	Case study of 11 different residential buildings and 1 commercial building. One building per node.
Morvaj et al. [75]	Optimisation framework to determine optimal design of a distributed energy system. Design of heat networks and electricity distribution grid constraints, together with operation.	One building per node, or buildings that are connected to the same grid connection point are aggregated into a node. Case study models 37 buildings.
Mehlerer et al. [76]	Mixed integer linear optimisation model to determine optimal technology mix and operation for heat and power demand, including heat networks.	The model is applied to 10 and 20-building cases. One building per node.
Casisi et al. [77]	Optimisation model for optimal layout and operation of a distributed generation system, including district heating network.	Case study of 6 public buildings, one building per node.
Yang et al. [78]	Optimisation model to design distributed energy systems in urban areas, including energy distribution networks and operation.	Urban area in South China. 4 nodes: 3 representing individual commercial/public buildings, and 1 representing aggregated residences.
Rees et al. [79]	Mixed methodology for designing energy infrastructure in new build schemes.	New build community in South Wales consisting on commercial/public buildings and 720 domestic properties. Buildings are clustered together in 15 nodes.
Fichera et al. [80]	Complex network approach to model an urban area and optimise the links that represent energy exchange between nodes, or distribution networks.	Urban area of $1400 \times 1400 \text{ m}^2$ with 500 houses distributed randomly among it.
Haikarainen et al. [40]	A model for structural and operational optimization of distributed energy systems	Case study inspired in a small city in Southern Finland. Six existing and two potential suppliers. Consumers lumped together in 26 nodes, two of them representing industrial areas.
Weber et al. [81]	Network synthesis for a district energy system: a step towards sustainability	Case study of 8 nodes representing 8 buildings.

Reference	Purpose of the research	Case study, nodes, and spatial resolution
Li and Svendsen [52]	Simulation of a low temperature district heating network to find optimal supply/return temperatures for reducing energy losses.	Hypothetical Danish network supplying 30 residential houses of 145 m ² . One node per consumer.
Tunzi <i>et al.</i> [54]	Modelling and optimising the operating temperature in a UK district heating system to improve its energy performance.	Small-scale district heating network in the north of Nottingham. 7 buildings of which 2 are office buildings, 1 is a domestic building, and 4 are live/work buildings. One building per node, plus 1 supply node.

2.3.3 Importance of spatial resolution

As discussed by Pfenninger *et al.* [14], national and international energy systems models are being challenged by new emerging concerns such as distributed energy generation or renewable potentials. This translates into the need of more spatial detail than what the current established national scale models require or provide. On the other hand, maintaining coarser spatial resolutions is required to maintain practical solving times. Analysing the revised urban models, it is observed that the first group of models which divide areas into sub-zones, generally study areas such as districts or cities. The second group of models which assign each consumer to a node are able to model networks in higher detail, but in return have limited spatial coverage. There is a trade-off between capturing complexity and maintaining model tractability.

Specifically regarding heat networks, Morvaj *et al.* [75] highlight the importance of models providing information on location of technologies, heat network layouts, and de-centralisation level, and argue that bottom-up models can address these requirements, as opposed to top-down models. Nielsen and Möller [82] describe how the competitiveness of heat networks depends on heat densities, which makes them competitive in urban areas, and analyse the potential of future district heating in Denmark. They conclude that expansion potentials for district heating differ throughout areas depending on production costs and geographic placement of demands. This provides a further argument on why top-down approaches may be insufficient for modelling heat networks and strain the need to include spatial considerations. Nielsen [83] develops a geographic method for high resolution heat planning. He illustrates for two zones with the same surface area and heat densities, how statistical based methods can lead to different results for heat networks design compared to using spatially explicit approaches. Persson *et al.* [84] present a methodology to find heat balances in subnational zones in the EU27 administrative units, and identify heat synergy zones with high heat waste and heat demands. They conclude that while only a fraction of the total spatial area is part of strategic heat synergy zones, the zones represent around half of the excess heat volume and around a third of heat demand. This is crucial in order to identify potentials of large-scale district heating

using waste heat, and shows why a sub-national resolution is relevant when analysing the feasibility of district heating.

The importance of spatial resolution in energy systems models for heat has been discussed by the aforementioned authors. Nevertheless, only Keirstead and Calderon [50] have compared results at different scales. The whole city of Newcastle was modelled with a coarser resolution, and then one of its neighbourhoods was modelled at a finer resolution (lower layer super output areas [68], explained in Section 3.2.). The comparison was performed to illustrate how spatially disaggregated modelling can inform policy decisions for low carbon community schemes and provide better information compared to the total city modelling, in terms of, for example, location of CHP units. Indeed they conclude that a higher resolution is important in order to obtain insight on location of technologies and connection between zones. However, rather than comparing results between different resolution levels, their work using a finer resolution was used to provide more details on certain results. Therefore, to date no other authors have performed a comparison of identical areas at different resolution levels, or sought to generalise results across different rural/urban classifications.

Given this gap in the literature, the second key issue related to heat decarbonisation studied in this work is how spatial resolution influences results from energy systems models for heat decarbonisation. This study seeks to quantify differences between optimal solutions for different resolution levels.

2.4 The role of hydrogen in heat decarbonisation

According to the Committee on Climate Change [12], the role of hydrogen for heating and hot water in buildings should be considered in the context of heat decarbonisation. Specifically, the decision on converting the existing gas network infrastructure to supply hydrogen in buildings has gained great attention in the year prior to the time of writing [63]. Some of the benefits of maintaining the existing gas infrastructure for hydrogen besides the economic value of utilising the installed assets are the simplicity of installing hydrogen heat supply technologies, the low costs of some of these compared to other heat supply end-use technologies, and the general acceptance towards gas heat supply technologies. Additionally, gas energy vectors are flexible - compared to, for example, electricity - as gas is storable, easily transportable, and can be used for heat, electricity generation, or as a transport fuel. Nevertheless, several uncertainties remain regarding the technical feasibility of replacing gas by hydrogen in networks, emission levels of a potential hydrogen energy vector, and associated costs [85].

Several authors are studying scenarios for a technically and economically feasible decarbonisation of gas networks through retrofitting them to transport hydrogen. Dodds and Demoullin [63] assess the technical feasibility of converting the UK gas network to deliver hydrogen for heat by using interviews supported by literature review. Additionally they assess the economic benefit of this option using the UK MARKAL energy system model. They conclude that hydrogen can be distributed safely in low pressure polyethylene pipes and that depending on conversion and capital costs, hydrogen micro-combined heat and power (CHP) fuel cells could be a cost-effective heat decarbonisation measure. Dodds et al. [22] examine the potential of hydrogen and fuel cell technologies to deliver secure, affordable and low carbon heat in high-income countries. They argue that hydrogen fuel cell CHPs have lower net emissions than natural gas fuelled and electricity-based heating systems, when considering current electricity generation mixes in most countries. This is under the assumption that hydrogen is produced from low carbon sources such as via steam methane reforming together with carbon capture and storage. Additionally, they identify a gap in heat decarbonisation scenarios produced by energy systems models, since fuel cells and hydrogen technologies are not incorporated into the heat supply technology pool and are thus *a priori* disregarded as feasible alternatives.

The H21 Leeds City Gate project [23] studies the technical and economic possibility of converting the existing gas network in Leeds to 100% hydrogen. The UK has been undertaking the Mains Replacement Programme which aims to upgrade most iron distribution pipelines to polyethylene. The study concludes that the new polyethylene gas network has appropriate characteristics for conversion to hydrogen, with minimum reinforcement in certain zones. This reinforcement can be made at marginal retrofitting costs compared to gas network capital costs. Likewise, Speirs et al. [85] suggest that gas network decarbonisation options can be attractive for countries such as the UK that have a well-developed gas network. Additionally, they suggest that even for countries with low gas network penetration, the cost of building low pressure hydrogen networks may be competitive compared to other decarbonisation alternatives such as installing air source or ground source heat pumps.

2.4.1 Feasible low carbon hydrogen production

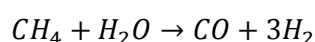
The main advantage of hydrogen compared to natural gas is that hydrogen combustion produces no CO₂ emissions, or that it can be used in fuel cells producing no direct emissions. Nevertheless, depending on the primary energy supply, production route, and transport methods used, supply chain emissions could be potentially higher than those associated to the combustion of natural gas [85]. There is a range of hydrogen production routes with different associated supply chain

emissions and costs. This section gives an overview of the main low carbon routes used in global hydrogen production.

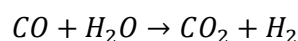
2.4.1.1 Hydrogen from natural gas: Steam methane reforming with carbon capture and storage (CCS)

The main production route for hydrogen nowadays, around 48% of global production, is via steam methane reforming [85-87]. In this method, the reformer reacts natural gas with high temperature steam in the presence of a nickel catalyst to produce hydrogen and carbon monoxide. A second reaction, the water gas shift, reacts steam with the generated carbon monoxide, producing more hydrogen and CO₂. The chemical reactions occurring are the following [86]:

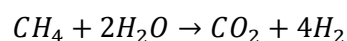
Reforming reaction



Water gas shift reaction



Total



In order to produce low carbon hydrogen from natural gas steam reforming, the process must be coupled with carbon capture and storage (CCS). CCS is constituted by the processes of extracting, purifying, compressing, transporting, and storing the CO₂ produced from methane reformers [88]. According to Speirs et al. [85], different works state that between 71%-92% of the CO₂ produced in steam methane reformers can be captured. The most feasible options for capture from steam methane reformers are pre-combustion and post-combustion capture which refer to the stage in the steam methane reformer at which CO₂ is captured, either before or after fuel is burnt in the reformer furnace. The chosen technology depends on specific project design limitations: while pre-combustion can yield higher capture fractions, post-combustion is more suitable as a retrofitting alternative.

Further research in storing of CO₂ is needed for achieving global scale feasibility. Major uncertainties include carbon storage costs and cumulative capacity, storing and release rates, transport from source to store, and climate impacts [88, 89], among others.

2.4.1.2 Hydrogen from water: Electrolysis

Around 4% of global hydrogen is produced via electrolysis of water [85]. In electrolysis, water molecules are broken down into hydrogen and oxygen by applying electric current in an electrolysis

cell. The three main electrolyzers used in cells are alkaline electrolyzers, proton exchange membranes, and solid oxide electrolyzers [90]. While alkaline electrolyzers are the most mature technology, they are unsuitable to couple with intermittent energy sources such as renewable generation. Proton exchange membrane electrolyzers on the other hand are highly compatible with variable energy supply such as electricity from renewable sources. Solid oxide electrolyzers are the least developed but operate at higher temperatures and are suitable for coupling with waste heat sources. A range of efficiencies for the different systems can be found and are shown in Table 2-4.

The potential for low carbon hydrogen production through water electrolysis will depend on the decarbonisation level of the electricity used, and on the efficiencies of the systems used. In the UK, onshore and offshore wind generation is expected to increase over time. Qadrdan et al. [91] study the role of power-to-gas, which converts electricity into hydrogen, in this increasing wind generation scenario. Their results showed that in a high wind scenario this solution can reduce wind curtailment, decreasing gas and electricity operation costs in Great Britain. In cases where hydrogen is produced via electrolysis with excess renewable electricity generation (such as wind or solar), not only the systems costs are decreased, but also the produced hydrogen serves as a form of storage [92], and has low associated emissions.

2.4.1.3 Hydrogen from biomass or coal: Gasification

The gasification of coal or biomass is a mature process for producing hydrogen at large scales. 18% of global hydrogen production is currently from coal [85]. The coal gasification process consists of the oxidation of coal with high temperature steam, producing syngas, which is a combination of hydrogen, carbon monoxide, steam, and carbon dioxide. The syngas then goes through a water gas shift reaction described previously, in order to obtain hydrogen and carbon dioxide. Due to the high carbon content in coal, as for the case of steam methane reforming, the process must be coupled with CCS for the gasification of coal to yield comparable emissions to other hydrogen production routes [93].

Another alternative is utilising the same gasification process to produce hydrogen from biomass or solid waste [85]. When using biomass or waste in gasification, the moisture content needs to be kept low. Wood and sugar cane are suitable crops, among many others [93, 94]. The formation of tar is a complicated issue that arises from biomass gasification. Tar is a viscous liquid with heavy hydrocarbons that can produce blockages in downstream processes, affect equipment, or reduce the process efficiency or end-product quality. It can be reduced by thermal cracking, steam reforming, dry reforming, carbon formation or partial oxidation, although all these add costs and

complexity to the process [85, 94]. For the case of biomass gasification, when including CCS to the process the produced hydrogen has the potential to have associated negative greenhouse gas emissions as the crop growth removes CO₂ from the atmosphere.

2.4.1.4 Comparison of low carbon hydrogen production routes

Table 2-4 shows a general comparison for three hydrogen production routes reviewed.

Table 2-4: General comparison of hydrogen low carbon production routes

Production method	Hydrogen source	Production rates	Efficiency	CO ₂ Emissions [gCO ₂ e/KWh]	Source
Steam methane reforming with CCS	Natural gas	Typically 150 – 440 MW	60-90%, typically around 70%. CCS reduces efficiency by 5-14%	23-150	[23, 85, 90]
Electrolysis from renewable electricity sources	Water	Typically 1-2.5 MW	50-90%	25-178	[23, 85]
Gasification (with CCS for coal)	Coal or biomass	Typically 250-500 MW	40-65%	Coal: 50-180 Biomass: -371-504	[85, 93, 95]

2.4.2 Safety

One of the main concerns of using hydrogen as an energy vector is the issue of safety. High pressure transmission and distribution iron and steel pipes are not safe for transporting hydrogen due to potential embrittlement. As hydrogen is a small molecule, it diffuses into any defect or pore, producing ductility loss and higher fracture risk. The same risk exists for lower-pressure distribution pipes made from iron and steel. Polyethylene pipes do not present this problem. As the UK is undergoing the Mains Replacement Programme mentioned previously, distribution pipelines are being replaced by polyethylene pipes. High pressure transmission and distribution networks would need to be constructed from a different material if the UK were to transport hydrogen by pipelines [63].

A potential hazard in polyethylene pipes is leakage in connection pipes. According to the H21 Leeds City Gate project [23], natural gas polyethylene pipe systems can be assessed and retrofitted so that pressures fall within safety limits and leakages in connection pipes are minimised, at relatively low average costs per kilometre. They identify however several hydrogen potential safety issues, due to its high flammability. Because of this, hydrogen steam methane reformer or storage locations could present a safety hazard; so could its potential leakage in domestic properties. However, the HyHouse

study conducted by Kiwa Gastec [96] concluded that in spite of its high flammability, as hydrogen has a high stoichiometric mixture together with a low density and high diffusivity, the high concentrations of hydrogen in air required for combustion are very difficult to reach in domestic properties. The H21 Leeds City Gate report claims that this hazard is comparable to other flammable gases such as natural gas. The report suggests that current natural gas codes in the UK would need to be revised and adjusted for the inclusion of hydrogen. For example, as highlighted by Dodds and Demoullin [63], as hydrogen is odourless and its flame is invisible, they suggest that hydrogen sensors should be fitted into dwellings and that flame detection should be an issue to further investigate.

2.4.3 Hydrogen in transport

Offer et al. [97] compare different technologies for sustainable road transport based on their lifecycle costs in 2030. They conclude that both hydrogen fuel cell vehicles and battery electric vehicles have a role to play in future sustainable transport, and that both should be pursued and supported simultaneously. Thomas [98] compares hydrogen fuel cell electric vehicles and battery electric vehicles. He concludes that although battery electric vehicles present lower costs of fuel per km and higher initial access to charging infrastructure, hydrogen fuel cell electric vehicles are superior. This is argued because fuel cells take up less space and weight less than batteries, present lower capital and life cycle costs, and take much less time to refuel, among other advantages. Qadrdan and Shayegan [99] compare the fuel economy of hydrogen and gasoline, and conclude that hydrogen is more cost effective as a transport fuel. They identify the construction of supply infrastructure as the major barrier for hydrogen transport development, and suggest that combined gasoline-hydrogen fuelling stations are more cost-effective than pure hydrogen fuelling stations. Yang and Odgen [100] suggest that in dense urban areas, a regionalised infrastructure rollout of a hydrogen system for transport should be planned, which involves pipelines and fuelling stations for hydrogen fuelled vehicles. Proposed cost-effective hydrogen production routes for supplying transport-related hydrogen demand in the UK are through biomass gasification [101] and steam-methane reforming with CCS [101, 102]. Dodds and Ekins [103] use the UK MARKAL model to compare results with a coordinated high impact study that states that fuel cell vehicles are ready for commercial deployment. They conclude that implementing relevant constraints, the UK MARKAL model results are in line with these studies, and that fuel cell vehicles should be internalised in energy systems models, as an early adoption would enable optimum penetration by 2050.

From all these studies, it is derived that transport would benefit from the same hydrogen infrastructure as heat supply, and therefore it seems straightforward to consider a coordinated

planning strategy for deploying hydrogen infrastructure for transport fuel and heating purposes. However, as highlighted by Murugan and Brown [104], fuel cells for transport require high purity hydrogen to prevent the catalysts from degrading. Combustion of hydrogen for heat, on the other hand, does not require these levels of purity, and little is known about the purity of piped hydrogen. Also, the cost-benefit of different transport hydrogen options has not yet been thoroughly investigated. Therefore it is concluded that further research on the technical feasibility of this integration needs to be carried out before incorporating hydrogen for transport and for heating purposes into the same infrastructure in energy systems models.

2.4.4 Hydrogen in energy systems models

At the time of writing few studies assess hydrogen as an energy vector by considering the whole heat energy system in an integrated and spatially resolved manner. This section reviews studies which have included hydrogen into energy system models.

Qadrdan et al. [105] present a model for investigating optimal hydrogen supply through 2050 for Iran. This model takes electricity and transport hydrogen demand as inputs, and gives the optimal hydrogen supply pathway, including production routes to meet different demands and pipeline sizes. This model does not include demand for heat, and presents a regional spatial resolution. In [91], Qadrdan et al. develop an optimisation model that integrates electricity and gas networks, exploring the potential of including Power-to-Gas systems. In this work the option of including electrolyzers to convert electricity into hydrogen and further injecting it at allowable levels into the gas grid was made available. The model is an operational optimisation that finds the minimum cost for supplying gas and electricity demand. Low and high electricity demand days were modelled for different wind scenarios. The study models a simplified UK National Transmission System to decide optimal location of electrolyzers, and shows that these Power-to-Gas systems can reduce wind curtailment in high wind periods, and improve gas and electricity dispatch by producing gas at cheap electricity periods. This model is focused on the energy supply and transmission side, with end-use technologies not being explicitly characterised.

Samsatli et al. [106] propose a mixed integer linear optimisation model that integrates wind, hydrogen, and electricity networks and technologies. Great Britain is broken down into 16 transmission zones. The model determines design, operation, and location of wind turbines, electrolyzers, fuel cells for conversion from hydrogen to electricity, and hydrogen storage technologies, as well as electricity and hydrogen transmission networks. Hydrogen demand for

transport is added into the transmission regions. This model is focused on generation and transmission of hydrogen and electricity for transport, and does not include demand for heat.

Dodds and Demoullin [63] use the UK MARKAL model to evaluate the economic feasibility of retrofitting the UK gas grid to transport hydrogen. An advantage of this model is that it includes several production routes for hydrogen, together with transportation and end-use technologies. As the UK is undergoing the Mains Replacement Programme, they assume that there are no costs for converting low pressure distribution gas networks for hydrogen, but that transmission and high pressure distribution pipelines need to be rebuilt. Besides the results mentioned previously regarding a potential role for hydrogen-fuelled micro-CHPs for heat decarbonisation, this research points out that the most economically feasible route for hydrogen production is via coal gasification or natural gas steam-methane reforming with CCS. Dodds and McDowall [107] also use the UK MARKAL model to study different decarbonisation options for the UK gas network, including bio methane, hydrogen injection into natural gas, and converting the gas network into hydrogen. They conclude that converting the gas network to transport hydrogen is the only possible cost-effective alternative for decarbonising gas for heating. Both of these works ([63] and [107]) systematically compare different alternatives for heat supply by considering the whole energy system. However, network infrastructures are modelled as energy exchange processes and thus do not provide spatially explicit solutions.

Balta-Ozkan and Baldwin [108] present a framework in which a spatially explicit hydrogen module is included into the UK MARKAL energy system model, and explore the trade-offs between production, delivery, and end-use of hydrogen. They characterise the UK hydrogen network with 6 supply and 12 demand centres. However, this coarse spatial resolution does not allow for the evaluation of infrastructure trade-offs at an urban scale and for the assessment of low pressure gas network retrofitting. Moreno-Benito et al. [109] present a spatially explicit multi-period optimisation model to develop hydrogen supply chain infrastructure, and apply this model for analysing the UK's development of hydrogen infrastructure to obtain a cost-effective transition towards a sustainable hydrogen economy. This research considers regional and local transmission and distribution of hydrogen. However, since it is implemented to evaluate the hydrogen supply chain infrastructure, it does not take into account the other energy vector infrastructures.

2.5 Research objectives

Based on the conducted literature review, this section sets out the general objectives of this thesis, followed by the case-specific objectives.

2.5.1 General objectives

Given the lack of existing analytical tools that (a) include a sufficiently granular spatial characterisation, (b) include supply, infrastructure and end-use technologies, and (c) include a bottom-up techno-economic depiction of the technical options, the aims of this work are to:

- Formulate and apply a spatially-resolved model of energy supply, infrastructure, end-use technology and demand to study cost effective heat decarbonisation pathways.
- Include within this model the three key different distribution networks (electricity, gas and heat), lifetime of technologies and of network infrastructure, explicit infrastructure trade-offs, and different demand profiles.
- Apply this model to study the four key issues related to heat decarbonisation pathways in the UK previously described, in order to:
 - Demonstrate the types of insights that this model can generate.
 - Gain specific insights in the four identified key issues related to heat decarbonisation aforementioned.

The presented research addresses the gap in existing energy planning models, which rarely capture the before mentioned trade-offs at a sufficient spatial resolution for evaluating heat decarbonisation approaches. In a broader perspective, this research concerns the optimal use of energy resources, and how to plan and develop more sustainable and optimised energy systems.

It is emphasised that improving heat decarbonisation modelling in terms of temporal resolution is beyond the scope of this work. As discussed later, the framework is intended to capture seasonal and diurnal variations of flows, but not to account for second-to-second or minute-to-minute variations. It is noted that the relative flexibility of the supply-demand balance in heat provision may offer value to the overall energy system, and these finer time resolutions will be considered in future research. Additionally, it is also emphasised that the inclusion of energy efficiency measures such as insulation or behavioural changes are also beyond the scope of this model. As discussed later, demand projections are taken as inputs to the model, and the inclusion of energy efficiency measures are assumed to be included in these demand projections.

2.5.2 Specific objectives

Following the literature review, the finding of gaps revealed three key issues related to heat decarbonisation in which the HIT model will be applied. The specific research objectives for each of

these studies, plus a fourth case in which the variation of input parameters is analysed, are the following:

2.5.2.1 Key issue 1: The comparison of different temperature heat networks for decarbonising heat

The objectives of this work are to apply the HIT model to study decarbonisation pathways for heat supply in a UK urban area, considering trade-offs between energy supply, end-use technology, demand, and network infrastructure when including the possibility of introducing both high or medium temperature heat networks.

2.5.2.2 Key issue 2: Studying the effect of spatial resolution in outcomes of energy systems models for heat

The objectives of this study are to provide insight on how spatial resolution influences results from energy systems modelling for studying heat decarbonisation. It seeks to quantify the difference between optimal solutions for three different resolution scales across a representative range of urban/rural areas in the UK, and analyse results to infer the reasons behind them.

2.5.2.3 Key issue 3: Studying the role of hydrogen in heat decarbonisation pathways in the UK

This work aims to fill the in gap of assessing the cost-effectiveness of hydrogen as an energy vector compared with others, by considering the whole urban level heat supply system in an integrated manner. The objective is to study the economic feasibility of installing hydrogen networks or retrofitting the existing gas network to transport hydrogen, when considering trade-offs in the whole heat supply energy system in a spatially-resolved urban area. Two cases for hydrogen networks are studied in this research: The first case allows for installing a hydrogen network that is independent of the gas network. The second case allows for retrofitting the existing gas network to carry hydrogen. These two cases seek to find what kind of hydrogen network design enables a cost-effective deployment of hydrogen as an energy vector for supplying heat demand.

2.5.2.4 Key issue 4: The sensitivity of heat decarbonisation outcomes to uncertainty in techno-economic parameters

The objective of this section is to study the influence of input parameter variations in outputs of the HIT model regarding optimal technology mix for heat decarbonisation. As many of the main input parameters of the HIT model are uncertain, this study aims to understand what the possible cost-

effective heat decarbonisation pathways are under different scenarios. For this, high and low cost/price scenarios for heat supply technologies, networks, fuels, electricity, and carbon are modelled and compared to a base case.

Chapter 3. Methods

This research formulates and implements the HIT model. The base model is first presented in [110]. In the following subsection the model is generally described. Then, a detailed formulation of the full model is presented, followed by inputs and sources used. Finally, the model is applied to study four key issues related to heat decarbonisation which were defined from the literature review presented in Sections 2.2, 2.3, and 2.4, in addition to a sensitivity analysis to study the influence of uncertainty in the main input parameters of the HIT model in optimal results. The specific methodologies for each of these four studies are described in detail in Section 3.4.

3.1 General description of the model

The HIT model is a mixed integer linear programme that minimises the total system cost for investment and operation of heat and electricity supply technologies and infrastructure from 2015 through 2050. The time horizon is divided into 5-year periods. Time periods are further subdivided into time slices to reflect seasonal and diurnal demand variations. Demand profiles for different consumer types are modelled.

The modelled region is spatially disaggregated into zones, characterising zone and region topology through input data. Inputs include heat demand and electricity demand for appliances per zone and consumer type; gas, heat, and electricity network infrastructure costs; heat supply technology techno-economic parameters; and fuel, electricity, and carbon prices. Further networks can be added in the framework developed, as has been done in this research for a second lower temperature heat network, or for a hydrogen network. The model makes investment decisions at the beginning of each time period regarding heat end-use technologies, network infrastructure, district level heat supply technologies, and sources of energy supply. It also determines operational decisions for the installed technologies in diurnal and seasonal time slices. Outputs include size and locations of individual and district level heat supply technologies in each time period, operation of heat supply technologies in each time slice, electricity consumption/generation from/into the grid in each zone and time slice, and carbon emissions. Lifetimes of network infrastructures and heat and electricity supply technologies are included to inform commissioning and decommissioning decisions.

Figure 3-1 shows the general model architecture. Arrow colours show heat, electricity, and gas flows. Heat and electricity demands need to be supplied to domestic and commercial individual

buildings. The model chooses to purchase natural gas and/or electricity from the transmission grid. If these are purchased, a distribution network that carries gas/electricity into the urban area modelled and between zones needs to be in place. Here, there are two alternatives: The first alternative is that natural gas or electricity are fed directly into end-use heat supply technologies at the individual building level, in which case distribution networks within zones that reach individual buildings need to be in place. The second alternative is that natural gas or electricity are fed into district level heat supply technologies. In this case, a heat distribution network within (and eventually between) zones that reaches individual buildings needs to be in place. District level heat supply technologies will supply heat into this district heating network, and heat will be delivered into buildings through heat exchangers connected to the heat network. Electricity demand is always supplied from the electricity network. District level or individual level combined heat and power (CHP) technologies sell electricity back into the distribution network.

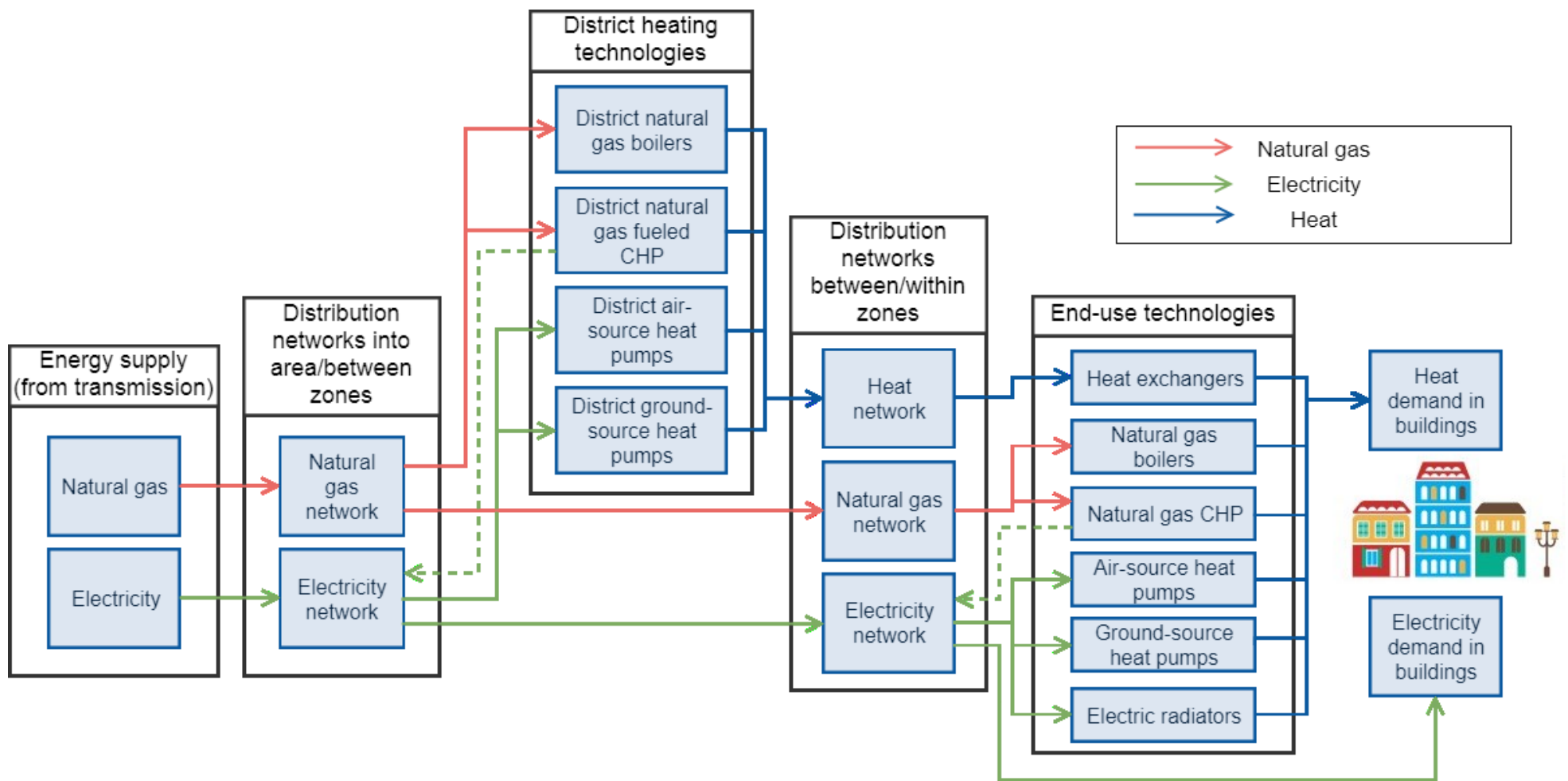


Figure 3-1: Basic HIT model architecture. ASHP: air-source heat pumps. GSHP: ground-source heat pumps. CHP: combined heat and power units.

3.2 General input data

Table 3-1 shows the general inputs used for modelling. Case-specific inputs are described in each case description in Section 3.3.6.

Table 3-1: General model inputs and sources, based on [110].

Inputs	Description and sources
Spatial resolution	Urban areas are disaggregated into Middle Layer Super Output Areas (MSOAs) obtained from the Office for National Statistics [68].
Road lengths and distance between zones	Road lengths obtained from [111] for different modelled areas and zones. Distance between zones calculated from zone population weighted centroids obtained from [112].
Modelled time horizon	From 2015 to 2051, plus 2013 used as a calibration base year.
Time periods	5-year periods from 2015 to 2050, when investment and decommissioning decisions take place.
Time slices	16 time slices drawn from the UK TIMES model [113] are used to reflect seasonal and diurnal variation. Annual heat and electricity demand is allocated into time slices drawn from the UK TIMES model [113], and electricity demand allocation into time slices derived from Elexon profile classes [114]. Elexon profiles are used by the electricity system operator in the UK to allocate unmetered consumption into a profile shape for balancing and settlement purposes. See Appendix A, Table A-1 to Table A-5.
Demand types	In these works one commercial and one domestic demand profiles were modelled, although the HIT model allows for a number of demand profiles to be included. A simplifying assumption was made that annual heat and electricity demands remained constant throughout the modelled time horizon. According to [115], although energy efficiency in domestic buildings has risen over time, the average internal temperature in homes has risen as well. These effects combined with housing growth have offset energy efficiency gains over time.
Heat and electricity demand	Annual gas and electricity demands for MSOAs were obtained from [116, 117]. Gas consumption was converted into heat demand assuming a gas boiler combustion efficiency of 81% [50]. Unallocated consumption for a given area for domestic and commercial was distributed proportionally over all MSOAs for each sector. Demand weighted into time slices as explained previously.
Gas and electricity prices	Retail prices for gas and electricity were obtained from the central scenario in [118] for commercial and domestic sectors. For district technologies, wholesale fuel prices were used. Retail prices were multiplied by 0.84 to discount the price of distribution [119], as the model endogenously includes the cost of distribution networks. See Appendix B, Table B-1.
Emission factors	Gas and electricity emission factors obtained from [120] for each sector. See Appendix B, Table B-2.
Carbon prices	Non-traded carbon prices in the UK obtained from the central scenario in [120]. See Appendix B, Table B-2.

For calculating network costs, two complementary approaches were adopted; an element of cost for connections between zones, and another element for costs within zones. For networks between zones, the distance between zone centres is fixed, and the decision variable is the network capacity

between zones [kW]. The capacity is expressed in power units, and it reflects the diameter of pipes or cables for electricity, heat, gas, or hydrogen networks. The costs associated to network connections between zones are average costs per unit length and power [£/kW km]. These costs were calculated by gathering cost data per unit length for different cable and pipe diameters (for heat, gas and electricity networks), and calculating the maximum power transporting capacity for each. A linear regression between power transporting capacity in the abscissa and cost per unit length data in the ordinate was performed, obtaining the desired cost per unit length and power as the slope of the linear regression. Table 3-2 shows the cost data and assumptions used for this calculation, as well as the coefficients of determination for the linear regressions (R^2). Table 3-3 shows the values obtained for electricity, gas, and high temperature heat networks.

Table 3-2: Cost data and assumptions for calculating network costs between zones and coefficient of determination for the linear regressions. SOURCE: [110].

Network	Cost data sources and assumptions	Sources and assumptions for maximum power through pipes/cables calculations	R^2
Electricity network	Unit costs for overhead and underground lines, for different distribution voltage levels [121]. The cost for different distribution voltage level was weighted by the split of overhead and underground lines for each voltage level in the UK obtained from [122].	Maximum current for different cable diameters obtained from catalogues [123] for different voltage distribution levels. With distribution voltage and maximum current, the maximum power was calculated for each cable diameter.	0.995
Gas network	Wales & West Utilities mains replacement matrix [124].	Low pressure (LP) lines were assumed, as 83% length of distribution lines are LP [63]. Maximum power calculated for different diameters by assuming gas calorific value at standard conditions as 35.4 [MJ/m ³] [125], a line pressure of 50 [mbar], line temperature of 5°C, and maximum gas velocity of 20 [m/s][126]. The LP distribution network operates at pressures under 75 [mbar].	0.973
High temperature heat network	Cost data obtained from [127] for 2015, 2030, and 2050.	Maximum flow velocity for different diameters obtained from [128] for maximum pressure drop of 200 Pa/m. Assumed temperature difference of 30°C between supply and return.	0.881

Networks within zones on the other hand are assumed to follow road layouts. The decision variable is the length [km] of each network within each zone and it is associated to an average cost per unit length. Table 3-3 shows the network costs and parameters used in this research for networks between and within zones. Sources for costs within zones are shown for gas and heat networks. For electricity networks, unit costs for overhead and underground lines were obtained from [121] for different distribution voltage levels. An average cost per length was obtained by weighting these costs by the split between different voltage distribution levels in the South West Region (obtained

from [129]) and the split between overhead and underground lines for each voltage level (obtained from [122]).

Table 3-3: General network costs and parameters.

Name	Description	Capital cost within zones [£2015/km]			Capital cost between zones [£2015/kW km]			Distribution losses	Lifetime [years]
		2015	2030	2050	2015	2030	2050		
Elecn	Electricity network	96,600	96,600	96,600	3.4	3.4	3.4	Accounted for in electricity prices	50
Gasn	Gas network	740,000 [85]	740,000	740,000	3.03	3.03	3.03	Accounted for in gas prices	50
HeatnT1	Heat network supply/ return temperature 80/50°C	874,000 [130]	874,000	874,000	5.8	5.61	5.37	28% of generation [130]	50

Table 3-4 shows the techno-economic parameters for district and individual level heat and electricity supply technologies. Capital and fixed maintenance costs are input into the HIT model as a cost per kW. For the domestic sector, heat and electricity supply technology costs were modelled as zone dependent, to incorporate the fact that dwellings need to purchase technologies in standard sizes as opposed to purchasing the exact capacity to meet peak heat demand. In order to include zone dependent costs, the total capital and maintenance costs for each technology in Table 3-4 were divided by after-diversity peak heat demand in each zone, obtaining technology costs per kW of after diversity peak heat demand per zone. In this way, the total costs reflects actual equipment sizes, and the capacity decision variables represent actual heat demand served by technologies, as opposed to representing fractions of spare capacity within them. This is performed for the domestic sector as it is assumed that domestic properties present relatively homogeneous heat demand profiles in each zone. On the other hand, as demand profiles are not necessarily homogeneous in each zone for the commercial sector, after-diversity heat peak demand does not resemble peak heat demand per property. Therefore, capital and fixed maintenance costs per kW for the commercial sector are not zone dependent, and are simply the costs in Table 3-4 divided by the size or thermal output of the technology.

Table 3-4: Techno-economic parameters for individual and district level technologies.

Name individual level technologies	Description	Thermal Output ³ [kW]	TOTAL CAPEX 2015 [£2015]	TOTAL CAPEX 2030 [£2015]	TOTAL CAPEX 2050 [£2015]	Efficiency (thermal/electric)	Lifetime [years]	Available	OPEX [£2015/year]	Source
CHP_dom	Domestic Stirling gas CHP	12	4960	4180	4180	0.8 (0.74/0.06)	15	2015	5% CAPEX	[131]
CHP_comm	Commercial Stirling gas CHP	23	6200	5230	5230	0.8 (0.74/0.06)	15	2015	5% CAPEX	[131]
Boiler_dom	Domestic condensing gas boiler	24	2400	2400	2400	0.89	15	2013	10% CAPEX	[132, 133]
Boiler_comm	Commercial condensing gas boiler	36	2630	2630	2630	0.90	15	2013	10% CAPEX	[132, 133]
Eradiator	Domestic electric storage heater	15.6	2840	2840	2840	0.90	15	2015	10% CAPEX	[133, 134]
HXT1	Domestic heat exchanger (includes heat interface unit and heat meter)	12	2010	1800	1510	1	20	2015	60	[127]
HXT1_big	Commercial heat exchanger (includes heat interface unit and heat meter)	100	2280	2030	1710	1	20	2015	68	[127]
ASHP_dom	Domestic air source heat pump	9	9000	7650	7650	2.54	20	2015	5% CAPEX	[135, 136]
GSHP_dom	Domestic ground source heat pump	9	17100	14400	14400	3.27	20	2015	5% CAPEX	[135, 136]
ASHP_comm	Commercial air source heat pump	15	13010	9260	9260	2.56	20	2015	5% CAPEX	[133]
GSHP_comm	Commercial ground source heat pump	15	27410	18860	18860	2.84	20	2015	5% CAPEX	[136, 137]
PV_dom	Domestic solar photovoltaics	2.5	4630	3420	3420		20	2015		[138]

³ For solar photovoltaics, the thermal output field represents electrical power output.

PV_comm	Commercial solar photovoltaics	10	14390	10650	10650		20	2015		[138]
Name district level technologies	Description	Thermal Output ⁴ [kW]	TOTAL CAPEX 2015 [£2015]	TOTAL CAPEX 2030 [£2015]	TOTAL CAPEX 2050 [£2015]	Efficiency (thermal/electric)	Lifetime [years]	Available	OPEX [£2015/year]	Source
CHPDist1	District level CHP unit	10000	8470000	8470000	8470000	0.8 (0.52/0.28)	20	2015	36000	[127]
BoilerDist	District level gas boiler	10000	724000	724000	724000	0.9	20	2015	680000	[127]
ASHPDist	District level air-source heat pump	10000	5090000	4390000	4390000	2.54	20	2015	20000	[135]
GSHPDist	District level ground-source heat pump	10000	16980000	14200000	14200000	3.27	20	2015	40000	[135, 139]

⁴ For solar photovoltaics, the thermal output field represents electrical power output.

3.3 Model formulation

This section presents a full description of the HIT model formulation, detailing the constraints and objective function.

3.3.1 Installed, vintage, and decommissioned capacities of heat and electricity supply technologies

Vintage capacity in a year is defined as all installed capacity of a given technology that has been installed previously and not decommissioned. Vintage capacity also keeps record of the year when the remaining technologies have been installed, in order to track when they need to be decommissioned. Equations (3.1), (3.2), and (3.3) show the definition of vintage capacities for individual level heat supply technologies, district level heat supply technologies, and individual level electricity technologies, respectively. These equations state that the vintage or remaining capacity of a technology in year y'^* that was installed in year y , is the new installed capacity in year y , minus what has been decommissioned until year y'^* .

$$VCHI_{bi_{ind}jyy'^*} = NCHI_{bi_{ind}jy} - \sum_{y'=0}^{y'^*} DCHI_{bi_{ind}jyy'} \quad \forall bi_{ind}j, y \leq y'^* \quad (3.1)$$

$$VCHD_{i_{dist}jTy'^*} = NCHD_{i_{dist}jTy} - \sum_{y'=0}^{y'^*} DCHD_{i_{dist}jTy'} \quad \forall i_{dist}jT, y \leq y'^* \quad (3.2)$$

$$VCE_{ejyy'^*} = NCE_{ejy} - \sum_{y'=0}^{y'^*} DCE_{ejyy'} \quad \forall ej, y \leq y'^* \quad (3.3)$$

Equations (3.4), (3.5), and (3.6) show total installed capacity of individual level heat supply technologies, district level heat supply technologies, and individual level electricity technologies, in a given year. The total installed capacity in a given year is the sum of all the remaining or vintage capacity of a certain technology, independently of the year it was installed.

$$TCHI_{bi_{ind}jy'} = \sum_{y=0}^{y'} VCHI_{bi_{ind}jyy'} \quad \forall bi_{ind}jy' \quad (3.4)$$

$$TCHD_{i_{dist}jTy'} = \sum_{y=0}^{y'} VCHD_{i_{dist}jTy'} \quad \forall i_{dist}jTy' \quad (3.5)$$

$$TCE_{ejy'} = \sum_{y=0}^{y'} VCE_{ejy'} \quad \forall ejy' \quad (3.6)$$

Equations (3.7), (3.8), and (3.9) establish that individual heat supply technologies, district level heat supply technologies, and electricity supply technologies must be decommissioned once they have met their lifetimes. However, the sum in these equations allow for technologies to be decommissioned before they have met their lifetimes as well.

$$NCHI_{bi_{ind}jy} = \sum_{y'=0}^{y+Lt_{i_{ind}}^I} DCHI_{bi_{ind}jyy'} \quad \forall bi_{ind}jy \quad (3.7)$$

$$NCHD_{i_{dist}jTy} = \sum_{y'=0}^{y+Lt_{i_{dist}T}^D} DCHD_{i_{dist}jTy'} \quad \forall i_{dist}jTy \quad (3.8)$$

$$NCE_{ejy} = \sum_{y'=0}^{y+Lt_e^E} DCE_{ejyy'} \quad \forall ejy \quad (3.9)$$

Boundary conditions for vintage and decommissioned capacity of individual level heat supply, district level heat supply, and individual level electricity supply technologies are shown in Equations (3.10) to (3.15). These conditions state that for vintage capacity to remain in a given year, and for technologies to be decommissioned in a given year, they must have been installed previously.

$$VCHI_{bi_{ind}jyy'} = 0 \quad \forall bi_{ind}j, y > y' \quad (3.10)$$

$$VCHD_{i_{dist}jTy'} = 0 \quad \forall i_{dist}jT, y > y' \quad (3.11)$$

$$VCE_{ejyy'} = 0 \quad \forall ej, y > y' \quad (3.12)$$

$$DCHI_{bi_{indj}yy'} = 0 \quad \forall bi_{indj}, y \geq y' \quad (3.13)$$

$$DCHD_{i_{distj}Ty} = 0 \quad \forall i_{distj}T, y \geq y' \quad (3.14)$$

$$DCE_{ejyy'} = 0 \quad \forall ej, y \geq y' \quad (3.15)$$

3.3.2 Heat and electricity supply technology installed and operating capacities

Equations (3.16), (3.17), and (3.18) restrict individual level heat supply, district level heat supply, and individual level electricity supply operating capacities in a given time slice to be at most the total installed capacity of that technology.

$$OCHI_{bhi_{indj}y} \leq TCHI_{bi_{indj}y} \quad \forall bhi_{indj}y \quad (3.16)$$

$$OCHD_{hi_{distj}Ty} \leq TCHD_{i_{distj}Ty} \quad \forall hi_{distj}Ty \quad (3.17)$$

$$OCE_{hejy} \leq TCE_{ejy} \quad \forall ejy \quad (3.18)$$

Equation (3.19) establishes that technologies must follow heat load. This constraint ensures that each dwelling has an individual level heat supply technology. Equation (3.19) is implemented as an equality constraint for micro CHP units, so that the micro-CHPs are not allowed to dump heat in order to sell electricity.

$$HP_h \cdot OCHI_{b \text{ peak } i_{indj}y} \leq OCHI_{bhi_{indj}y} \quad \forall bhi_{indj}y \quad (3.19)$$

New capacity variables are continuous variables defined by the total capacity of a certain technology purchased in a zone. Equations (3.20), (3.21), and (3.22) ensure that whole units of district level heat supply technologies are installed and decommissioned.

$$ND_{i_{distj}Ty} \cdot Cap_{i_{dist}T}^D = NCHD_{i_{distj}Ty} \quad \forall i_{distj}Ty \quad (3.20)$$

$$NDD_{i_{distj}Ty} \cdot Cap_{i_{dist}T}^D = \sum_{y' < y} DCHD_{i_{distj}Ty'y} \quad \forall i_{distj}Ty \quad (3.21)$$

$$ND_{i_{dist}jTy}, \quad NDD_{i_{dist}jTy} \in \mathbb{Z}^+ \quad (3.22)$$

Equation (3.23) sets all capacity variables to be non-negative.

$$\begin{aligned} NCHI_{bi_{ind}jy}, \quad VCHI_{bi_{ind}jyy'}, \quad DCHI_{bi_{ind}jyy'}, \quad TCHI_{bi_{ind}jy}, \\ OCHI_{bhi_{ind}jy}, \quad NCHD_{i_{dist}jTy}, \quad VCHD_{i_{dist}jTy}, \\ DCHD_{i_{dist}jTy}, \quad TCHD_{i_{dist}jTy}, \quad OCHD_{hi_{dist}jTy}, \quad NCE_{ejy}, \\ VCE_{ejyy'}, \quad DCE_{ejy}, \quad TCE_{ejy}, \quad OCE_{hejy} \geq 0 \end{aligned} \quad (3.23)$$

3.3.3 Networks

Networks are modelled through two different approaches explained in Section 3.2: one approach for networks between zones, and one approach for networks within zones. The following sections detail both formulations.

3.3.3.1 Infrastructure between zones

The variable $CCN_{jj'nyy'}$ denotes a network connecting two zones that has been installed in year y and still remains connected by year y' . Equation (3.24) defines a connected network between zones when it has been installed and not decommissioned.

$$CCN_{jj'nyy'} = ICN_{jj'ny} - \sum_{y'=0}^{y'^*} DCN_{jj'nyy'} \quad \forall jj'n, \forall y \leq y'^* \quad (3.24)$$

Equation (3.25) on the other hand, defines the total connected network capacity between two zones in a given year, independently of when it was installed.

$$TCN_{jj'ny} = \sum_{y' \leq y} CCN_{jj'ny'y} \quad \forall jj'ny \quad (3.25)$$

A base year run is performed as explained in Section 3.5 to determine an initial network topology for current gas and electricity networks. Network topology refers to network capacities and lengths, and which zones are connected to each other by which network types. Initial networks are assumed to

be decommissioned linearly throughout the 8 modelled time periods, as shown in Equation (3.26). Also, installed networks need to be decommissioned at most when they have met their lifetimes, as stated by Equation (3.27).

$$DCN_{jj'ny_0y} = \frac{ICN_{jj'ny_0}}{8} \quad \forall jj', y_0 < y, n = gas, elec, n \quad (3.26)$$

$$ICN_{jj'ny} = \sum_{y'=0}^{y+Lt_n^N} DCN_{jj'nyy'} \quad \forall jj'ny \quad (3.27)$$

Equation (3.28) constraints all network capacities to be non-negative, while Equations (3.29) and (3.30) state that remaining and decommissioned networks can only exist if they were previously installed.

$$ICN_{jj'ny}, \quad CCN_{jj'nyy'}, \quad DCN_{jj'nyy'} \geq 0 \quad \forall jj'nyy' \quad (3.28)$$

$$CCN_{jj'nyy'} = 0 \quad \forall jj'n, \quad \forall y > y' \quad (3.29)$$

$$DCN_{jj'nyy'} = 0 \quad \forall jj'n, \quad \forall y \geq y' \quad (3.30)$$

Network connections between zones in this model are bound to be symmetric, as shown in Equations (3.31), (3.32), and (3.33). This assumption leads later to divide the capital costs by two in Equation (3.75).

$$ICN_{jj'ny} = ICN_{j'jny} \quad \forall jj'ny \quad (3.31)$$

$$CCN_{jj'nyy'} = CCN_{j'jnyy'} \quad \forall jj'nyy' \quad (3.32)$$

$$DCN_{jj'nyy'} = DCN_{j'jnyy'} \quad \forall jj'nyy' \quad (3.33)$$

3.3.3.2 Infrastructure within zones

For infrastructure within zones, $VLN_{jnyy'}$ denotes the vintage network installed in year y that remains in place by year y' . Equation (3.34) defines this variable as networks within zones that have been installed and not decommissioned.

$$VLN_{jnyy'} = NLN_{jny} - \sum_{y'=0}^{y'^*} DLN_{jnyy'} \quad \forall jn, \forall y \leq y'^* \quad (3.34)$$

Equation (3.35) shows the total remaining network length within a zone at a given time period, independent of when it was installed.

$$TLN_{jny} = \sum_{y' \leq y} VLN_{jny'y} \quad \forall jny \quad (3.35)$$

As for networks between zones, initial gas and electricity networks are assumed to be decommissioned linearly throughout the 8 modelled time periods, as shown in Equation (3.36). As before, Equation (3.37) states that installed networks need to be decommissioned at most when they have met their lifetimes.

$$DLN_{jny_0y} = \frac{NLN_{jj'n_y_0}}{8} \quad \forall j, y_0 < y \quad n = gasn, elec n \quad (3.36)$$

$$NLN_{jny} = \sum_{y'=0}^{y+Lt_n^N} DLN_{jnyy'} \quad \forall jny \quad (3.37)$$

Regarding border conditions for network lengths, Equation (3.38) constraints network lengths within zones to be non-negative. Equations (3.39) and (3.40) establish that vintage and decommissioned networks can only exist if they have been previously installed.

$$NLN_{jny}, \quad VLN_{jnyy'}, \quad DLN_{jnyy'} \geq 0 \quad \forall jnyy' \quad (3.38)$$

$$VLN_{jnyy'} = 0 \quad \forall jn, \forall y > y' \quad (3.39)$$

$$DLN_{jnyy'} = 0 \quad \forall jn, \forall y \geq y' \quad (3.40)$$

The following subsections explain how network lengths are defined within zones for gas, electricity, heat, and hydrogen networks. All networks need to be able to supply the technology mix in each zone. Installed capacity of individual level heat supply technologies is constrained to serve after diversity peak heat demand. Thus, the fraction of installed technologies that consume gas, heat,

electricity, or hydrogen, over the total peak heat demand per zone, equals the heat demand percentage served by each network within each zone. This fraction multiplied by the total road length in each zone corresponds to the total network length of each network within each zone.

3.3.3.2.1 Gas network length

Equation (3.41) shows the gas network length within zones. The gas network length is equivalent to the ratio of installed individual level gas boilers and gas-fuelled micro-CHPs to the total peak heat demand in a zone, multiplied by the zone's total road length. This would be the most optimistic case for gas network lengths within zones, as it implies that gas networks are built only along roads in which dwellings are connected to the gas network. The implicit assumption is that in each zone the dwellings that are connected to the gas network are clustered together. In reality it might occur that gas networks are built along a whole zone's road layout, while still having some dwellings not connected to the grid. This formulation is more realistic however for heat networks and for electricity networks' reinforcement associated to electricity-based heat supply technologies, as they should be expanded or reinforced as needed. The difference is that gas networks are already installed at the beginning of the modelled time horizon.

$$\frac{\sum_{b, i_{ind}=boilers, \text{ gas CHPs}} TCHI_{bi_{ind}jy}}{\sum_b Dem_{b \text{ peak } jy}^H \cdot Num_{bjy}} \cdot Rl_j = TLN_{j \text{ gasn } y} \quad \forall jy \quad (3.41)$$

3.3.3.2.2 Electricity network length

All dwellings are assumed to be connected to the electricity grid at the beginning of the modelled period, in order to supply demand for appliances. Electricity networks need to be able to supply the historical electricity demand for appliances in a zone, plus the new individual level heat supply technologies that consume electricity, such as electric radiators and heat pumps. Therefore, the electricity network should be equivalent to the whole zone's road length (hence the 1 in Equation (3.42)), plus a reinforced length for supplying electricity consuming heat supply technologies. The reinforced length in a zone is the ratio of total electricity consuming heat supply technologies to the total peak heat demand, multiplied by the total road length, as shown in Equation (3.42).

$$\left(\frac{\sum_{b, i_{ind}=ASHP, GSHP, eradiators} TCHI_{bi_{ind}jy}}{\sum_b Dem_{b \text{ peak } jy}^H \cdot Num_{bjy}} + 1 \right) \cdot Rl_j = TLN_{j \text{ elec } y} \quad \forall jy \quad (3.42)$$

3.3.3.2.3 Heat network length

Equation (3.43) shows the heat network length within a zone, which is equivalent to the ratio of heat exchangers to the total peak heat demand, times the road length. If different temperature levels of heat networks are available, each of them needs to comply separately with Equation (3.43) (one equation for each network).

$$\frac{\sum_{b, i_{ind}=HXS} TCHI_{bi_{ind}jy}}{\sum_b Dem_{b\ peak\ jy}^H \cdot Num_{bjy}} \cdot Rl_j = TLN_{j\ heatn(T^*)y} \quad \forall j T^*y \quad (3.43)$$

3.3.3.2.4 All networks

Finally, Equation (3.44) states that the sum of network lengths within zones for all heat supply technologies should equal the total road length. This equation guarantees that networks are installed together with technologies and no extra networks are installed before they are in use.

$$\sum_T TLN_{j\ heatn(T)y} + TLN_{j\ gasn\ y} + \left(\frac{\sum_{b, i_{ind}=ASHP, GSHP, eradiators} TCHI_{bi_{ind}jy}}{\sum_b Dem_{b\ peak\ jy}^H \cdot Num_{bjy}} \right) \cdot Rl_j = Rl_j \quad \forall jy \quad (3.44)$$

3.3.3.3 Energy balance in each zone

Equation (3.45) shows the energy balances in each zone for each network. This equation states that the net energy flow into a zone minus the net energy flow that leaves the zone needs to equate the zone's energy consumption minus its generation.

$$F_{hjny}^{IN} - F_{hjny}^{OUT} + \sum_{j'} F_{hj'jny} - \sum_{j'} F_{hjj'ny} - F_{hjny}^{CONS} + F_{hjny}^{GEN} = 0 \quad \forall hjny \quad (3.45)$$

The following sub-sections show the equations for energy consumption and generation within zones for each network.

3.3.3.3.1 Gas network energy consumption and generation

Energy consumption from gas networks is defined in Equation (3.46). Consumption from gas networks is the sum of gas consumption from individual level and district level gas-fuelled heat

supply technologies. Gas consumption of heat supply technologies can be expressed as the heat output of a given technology divided by its thermal efficiency, to represent how much energy from gas is consumed to generate heat. On the other hand, Equation (3.47) establishes that no gas is generated within zones.

$$F_{hj\ gasn\ y}^{CONS} = \sum_{\substack{b, \\ i_{ind}= \\ boilers, \\ CHPs}} \frac{OCHI_{bhi_{ind}jy}}{\eta_{i_{ind}}^{ThI}} + \sum_{\substack{T, \\ i_{dist}= \\ boilers, \\ CHPs}} \frac{OCHD_{hi_{dist}jTy}}{\eta_{i_{dist}\ T}^{ThD}} \quad \forall hjy \forall jy \quad (3.46)$$

$$F_{hj\ gasn\ y}^{GEN} = 0 \quad \forall hjy \quad (3.47)$$

3.3.3.3.2 Electricity network energy consumption and generation

Equations (3.48) and (3.49) show electricity consumption and generation within zones, respectively. Electricity consumption is defined in Equation (3.48) as the electricity demand from appliances, plus the heat output divided by thermal efficiencies (or coefficients of performance for heat pumps) for each electricity consuming heat supply technology.

$$F_{hj\ elec n\ y}^{CONS} = \sum_b Dem_{bhjy}^E \cdot Num_{bjy} + \sum_{\substack{b, \\ i_{ind}= \\ ASHP, \\ GSHP, \\ radiator}} \frac{OCHI_{bhi_{ind}jy}}{\eta_{i_{ind}}^{ThI}} \quad (3.48)$$

$$+ \sum_{\substack{T, \\ i_{dist}= \\ ASHP, \\ GSHP}} \frac{OCHD_{hi_{dist}jTy}}{\eta_{i_{dist}\ T}^{ThD}} \quad \forall hjy$$

Electricity generation in each zone is the electricity generated by individual level electricity generating technologies, plus electricity generated from individual level micro-CHP units and district level CHP units. For CHP units, the generated electricity is expressed as the heat output multiplied by the ratio of electric to thermal efficiencies, as shown in Equation (3.49).

$$F_{hj\ elecny}^{GEN} = \sum_e OCE_{hejy} + \sum_T OCHD_{h\ CHPdist\ jTy} \cdot \frac{\eta_{CHPdist\ T}^{ED}}{\eta_{CHPdist\ T}^{ThD}} + \sum_b OCHI_{bh\ CHPind\ jy} \cdot \frac{\eta_{CHPind}^{EI}}{\eta_{CHPind}^{ThI}} \quad \forall hjy \quad (3.49)$$

3.3.3.3.3 Heat network energy consumption and generation

Equation (3.50) shows the energy consumption from heat networks, which is equal to the heat delivered by heat exchangers to individual dwellings divided by their thermal efficiency. Each heat network temperature level should be expressed in a separate equation.

$$F_{hj\ heatn(T^*)y}^{CONS} = \sum_{\substack{b, \\ i_{ind}=HX(T^*)s}} \frac{OCHI_{bhi_{ind}jy}}{\eta_{i_{ind}}^{ThI}} \quad \forall hjT^*y \quad (3.50)$$

On the other hand, energy generated into heat networks in each zone is the heat generated by district level heat supply technologies installed in the zone, as shown in Equation (3.51). In this model, heat network distribution losses are expressed as a percentage of heat generation.

$$F_{hj\ heatn(T^*)y}^{GEN} = \sum_{i_d} (1 - Loss_{T^*}) \cdot OCHD_{hi_{dist}jT^*y} \quad \forall hjT^*y \quad (3.51)$$

3.3.3.3.4 Further energy flows, networks, and demand constraints

This section presents further constraints that link energy flows with network and demand constraints. While Equation (3.48) ensures that individual-dwelling electricity demand is met within zones, a further constraint is needed to secure individual-dwelling heat demand is supplied by individual-level heat supply technologies, for all time slices and demand types. This constraint is imposed through Equation (3.52).

$$\sum_{i_{ind}} OCHI_{bhi_{ind}jy} \geq Dem_{bhjy}^H \cdot Num_{bjy} \quad \forall bhjy \quad (3.52)$$

Regarding energy flow between zones, Equation (3.53) defines the energy flow between zones for heat networks as the water mass flow rate multiplied by the temperature difference between supply

and return pipes (heat extracted in the exchange). This equation should be defined for each heat network temperature level modelled.

$$\dot{m}_{hjj'T^*y} \cdot (T^* - T_{T^*}^R) \cdot c = F_{hjj' \text{ heatn}(T^*)y} \quad \forall hjj'T^*y \quad (3.53)$$

More generally, Equation (3.54) ensures that for all networks, there can only be energy flow between zones if a network is in place, and that the network capacity needs to be large enough to transport the flow through it.

$$F_{hjj'ny} \leq TCN_{jj'ny} \quad \forall hjj'ny \quad (3.54)$$

Equations (3.55) and (3.56) constrain networks between zones to be installed only between neighbour zones, while Equation (3.57) states that energy flow between a zone and itself must be zero. Likewise, Equation (3.58) imposes mass flow in heat networks to be zero between a zone and itself.

$$ICN_{jj'ny} \leq Nb_{jj'} \cdot M \quad \forall hjj'ny \quad (3.55)$$

$$CCN_{jj'nyy'} \leq Nb_{jj'} \cdot M \quad \forall hjj'nyy' \quad (3.56)$$

$$F_{hjj'ny} = 0 \quad \forall hny, j = j' \quad (3.57)$$

$$\dot{m}_{hjj'Ty} = 0 \quad \forall hTy, j = j' \quad (3.58)$$

Energy flows from and to outside the city boundary are constrained to zones which are city boundaries, as expressed in Equations (3.59) and (3.60).

$$F_{hjnny}^{IN} \leq Cb_j \cdot M \quad \forall hjnny \quad (3.59)$$

$$F_{hjnny}^{OUT} \leq Cb_j \cdot M \quad \forall hjnny \quad (3.60)$$

Finally, regarding energy flows, all variables are constrained to be non-negative, as shown in Equation (3.61).

$$F_{hjny}^{IN}, F_{hjny}^{OUT}, F_{hjj'ny}, F_{hjny}^{CONS}, F_{hjny}^{GEN}, \dot{m}_{hjj'Ty} \geq 0 \quad \forall hjj'nTy \quad (3.61)$$

3.3.4 Fuel and electricity consumption and CO₂ emissions

Hourly fuel consumption of individual level and district level heat supply technologies are defined in Equations (3.62) and (3.63), respectively. The sum over all time-slices and zones shows the total annual fuel consumption per zone which is expressed in Equations (3.64) and (3.65) for individual and district level heat supply technologies.

$$FUEL_{abhjy} = \sum_{i_{ind} fuel: a} \frac{OCHI_{bhi_{ind}jy}}{\eta_{i_{ind}}^{ThI}} \cdot Dur_h \quad \forall abhjy \quad (3.62)$$

$$FUELD_{ahjy} = \sum_{T, i_{dist} fuel: a} \frac{OCHD_{hi_{dist}jTy}}{\eta_{i_{dist} T}^{ThD}} \cdot Dur_h \quad \forall ahjy \quad (3.63)$$

$$FUEL_{aby}^{TOT} = \sum_{hj} FUEL_{abhjy} \quad \forall aby \quad (3.64)$$

$$FUELD_{ay}^{TOT} = \sum_{hj} FUELD_{ahjy} \quad \forall ay \quad (3.65)$$

For electricity consumption from the grid, Equation (3.66) shows the annual consumption by demand type for individual dwellings, while Equation (3.67) shows the electricity consumption from district level technologies.

$$ELEC_{by}^{TOT} = \sum_{hj} Dem_{bhjy}^E \cdot Num_{bjy} \cdot Dur_h + \sum_{\substack{hj \\ i_{ind}= \\ ASHP, \\ GSHP, \\ radiator}} \frac{OCHI_{bhi_{ind}jy}}{\eta_{i_{ind}}^{ThI}} \cdot Dur_h \quad \forall by \quad (3.66)$$

$$ELECD_y^{TOT} = \sum_{\substack{hjT \\ i_{dist}= \\ ASHP, \\ GSHP}} \frac{OCHD_{hi_{dist}jTy}}{\eta_{i_{dist} T}^{ThD}} \cdot Dur_h \quad \forall y \quad (3.67)$$

The total system's equivalent CO₂ emissions are obtained for the modelled time horizon, as shown in Equation (3.68). These are obtained by multiplying all electricity and fuel consumptions by electricity and fuel emission factors, and adding over all modelled years and demand types.

$$CO_2 = \sum_{aby} FUEL_{aby}^{TOT} \cdot Em_{aby}^F + \sum_{ay} FUEL_{ay}^{TOT} \cdot Em_{ay}^{FD} + \sum_{by} ELEC_{by}^{TOT} \cdot Em_{by}^E + \sum_y ELECD_y^{TOT} \cdot Em_y^{ED} \quad (3.68)$$

3.3.5 Objective function

The objective function is the net present value of the total system's costs. All cost components are added and minimised, as expressed in Equation (3.69).

$$\min COSTS = MNT + OP + FE + CRB + CPT + DEC - SLV - ES \quad (3.69)$$

3.3.6 Costs

Finally, all costs are added in present value and minimised over the modelled time horizon. Equations (3.70) and (3.71) show the fixed and variable (respectively) operation and maintenance costs. Fixed operation and maintenance costs are associated to installed capacity, while variable costs are associated to operating capacity.

$$MNT = \sum_{biindjy} TCHI_{biindjy} \cdot Cost_{biindjy}^{MI} \cdot \frac{1}{(1+r)^y} + \sum_{idistjTy} TCHD_{idistjTy} \cdot Cost_{idistjTy}^{MD} \cdot \frac{1}{(1+r)^y} + \sum_{ejy} TCE_{ejy} \cdot Cost_{ejy}^{ME} \cdot \frac{1}{(1+r)^y} \quad (3.70)$$

$$\begin{aligned}
OP = & \sum_{bhi_{indy}} OCHI_{bhi_{indy}} \cdot Dur_h \cdot Cost_{i_{indy}}^{OI} \cdot \frac{1}{(1+r)^y} \\
& + \sum_{hi_{distjTy}} OCHD_{hi_{distjTy}} \cdot Dur_h \cdot Cost_{i_{indy}}^{OI} \cdot \frac{1}{(1+r)^y} \\
& + \sum_{hejy} OCE_{hejy} \cdot Dur_h \cdot Cost_{ey}^{OE} \cdot \frac{1}{(1+r)^y}
\end{aligned} \tag{3.71}$$

Equation (3.72) shows the cost of purchasing fuels and electricity form networks. On the other hand, Equation (3.73) defines the cost associated to carbon emissions. Electricity and fuel consumptions are multiplied by their emission factors, and these are multiplied by the carbon price.

$$\begin{aligned}
FE = & \sum_{aby} FUEL_{aby}^{TOT} \cdot Cost_{aby}^F \cdot \frac{1}{(1+r)^y} + \sum_{ay} FUEL_{ay}^{TOT} \cdot Cost_{ay}^{FD} \cdot \frac{1}{(1+r)^y} \\
& + \sum_{by} ELEC_{by}^{TOT} \cdot Cost_{by}^E \cdot \frac{1}{(1+r)^y} \\
& + \sum_y ELECD_y^{TOT} \cdot Cost_y^{ED} \cdot \frac{1}{(1+r)^y}
\end{aligned} \tag{3.72}$$

$$\begin{aligned}
CRB = & \sum_{aby} FUEL_{aby}^{TOT} \cdot Em_{aby}^F \cdot Cost_y^{CO2} \cdot \frac{1}{(1+r)^y} \\
& + \sum_{ay} FUEL_{ay}^{TOT} \cdot Em_{ay}^{FD} \cdot Cost_y^{CO2} \cdot \frac{1}{(1+r)^y} \\
& + \sum_{by} ELEC_{by}^{TOT} \cdot Em_{by}^E \cdot Cost_y^{CO2} \cdot \frac{1}{(1+r)^y} \\
& + \sum_y ELECD_y^{TOT} \cdot Em_y^{ED} \cdot Cost_y^{CO2} \cdot \frac{1}{(1+r)^y}
\end{aligned} \tag{3.73}$$

Capital costs are divided into the cost of individual and district level technologies- or equipment cost- and the capital cost of networks. Equation (3.74) shows the cost of equipment, Equation (3.75) shows the capital cost of networks, and Equation (3.76) shows the total capital costs.

$$\begin{aligned}
CEQ = & \sum_{bi_{ind}jy} NCHI_{bi_{ind}jy} \cdot Cost_{bi_{ind}jy}^{CI} \cdot \frac{1}{(1+r)^y} \\
& + \sum_{i_{dist}jTy} NCHD_{i_{dist}jTy} \cdot Cost_{i_{dist}jTy}^{CD} \cdot \frac{1}{(1+r)^y} \\
& + \sum_{ejy} NCE_{ejy} \cdot Cost_{ejy}^{CE} \cdot \frac{1}{(1+r)^y}
\end{aligned} \tag{3.74}$$

$$NTW = \sum_{jj'ny} \frac{ICN_{jj'ny}}{2} \cdot d_{jj'} \cdot Cost_{ny}^{NT} \cdot \frac{1}{(1+r)^y} + \sum_{jny} NLN_{jny} \cdot Cost_{ny}^{ND} \cdot \frac{1}{(1+r)^y} \tag{3.75}$$

$$CPT = EQ + NTW \tag{3.76}$$

Decommissioning costs of equipment are shown in Equation (3.77).

$$\begin{aligned}
DEC = & \sum_{bi_{ind}jyy'} DCHI_{bi_{ind}jyy'} \cdot Cost_{i_{ind}y'}^{DI} \cdot \frac{1}{(1+r)^{y'}} \\
& + \sum_{i_{dist}jTy'} DCHD_{i_{dist}jTy'} \cdot Cost_{i_{dist}Ty'}^{DD} \cdot \frac{1}{(1+r)^{y'}} \\
& + \sum_{ejyy'} DCE_{ejyy'} \cdot Cost_{ey'}^{DE} \cdot \frac{1}{(1+r)^{y'}}
\end{aligned} \tag{3.77}$$

Individual and district level electricity generating technologies are assumed to sell the generated electricity to the grid. Equation (3.78) shows the incomes from electricity generated and sold to the grid by these technologies.

$$ES = \sum_{h jy} F_{hj}^{GEN} \cdot Dur_h \cdot Sell_y^E \cdot \frac{1}{(1+r)^y} \tag{3.78}$$

Finally, Equation (3.79) shows the salvage value at the end of the modelled time horizon, assuming a lineal depreciation of networks and equipment along their lifetimes.

$$\begin{aligned}
SLV = & \sum_{bi_{ind}jy} VCHI_{bi_{ind}jy y_{final}} \cdot Cost_{bi_{ind}jy}^{CI} \cdot \frac{Lt_{ind}^I - (y_{final} - y)}{Lt_{ind}^I} \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{i_{dist}jTy} VCHD_{i_{dist}jTy y_{final}} \cdot Cost_{i_{dist}jTy}^{CD} \cdot \frac{Lt_{i_{dist}T}^D - (y_{final} - y)}{Lt_{i_{dist}T}^D} \\
& \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{ejy} VCE_{ejy y_{final}} \cdot Cost_{ejy}^{CE} \cdot \frac{Lt_e^E - (y_{final} - y)}{Lt_e^E} \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{jj'ny} \frac{CCN_{jj'ny y_{final}}}{2} \cdot d_{jj'} \cdot Cost_{ny}^{NT} \cdot \frac{Lt_n^N - (y_{final} - y)}{Lt_n^N} \\
& \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{jny} VLN_{jny y_{final}} \cdot Cost_{ny}^{ND} \cdot \frac{Lt_n^N - (y_{final} - y)}{Lt_n^N} \cdot \frac{1}{(1+r)^{y_{final}}}
\end{aligned} \tag{3.79}$$

3.4 Specific methods for studying four key issues in heat decarbonisation

As previously mentioned, this research studies four key issues related to heat decarbonisation using the HIT model. The specific methods and inputs used for each of these four studies are detailed in the following sections.

3.4.1 Different temperature heat networks for decarbonising heat

As discussed previously in Section 2.2.2, this work aims to apply the HIT model to study decarbonisation pathways for heat supply, considering trade-offs between energy supply, network infrastructure, end-use technology, and demand. Specifically, this section is designed to study the trade-offs between the aforementioned elements and the three key distribution networks (electricity, gas, and heat) in an urban area, when including the possibility of introducing both high or medium temperature heat networks.

The HIT model formulated in Section 3.3 was implemented, adding the option to introduce a medium temperature heat network additionally to the high temperature heat network described in Section 3.2. This only means that there will be 4 networks n , with one equation for each heat network temperature level when specified previously in the model formulation. For example, there will be one Equation (3.43) specifying network length for each heat network temperature level, or one energy balance (Equation (3.45)) for each heat network. Infrastructure costs and parameters for the implemented medium temperature heat network are presented in Table 3-5.

Table 3-5: General network costs and parameters.

Name	Description	Capital cost within zones [£2015/km]			Capital cost between zones [£2015/kW km]			Distribution losses	Lifetime [years]
		2015	2030	2050	2015	2030	2050		
HeatnT2	Heat network supply/return temperature 70/40°C	Costs are considered as HeatnT1 costs multiplied by a factor of 1.41 obtained from comparing network costs in [139] for both cases in Scenario 2. This is because bigger diameter pipes are needed for lower heat network temperatures.						13% of generation [130]	50

The techno-economic parameters used in this research for heat exchangers, heat interface units and heat meters for the medium temperature heat network are shown in Table 3-6.

Table 3-6: Techno-economic parameters for medium temperature heat exchangers

Name of individual level technologies	Description	Thermal Output [kW]	Techno-economic parameters
HXT2	Domestic heat exchanger (includes heat interface unit and heat meter)	12	All techno-economic parameters for medium temperature heat exchangers are considered the same as for HXT1 (See Table 3-4).
HXT2_big	Commercial heat exchanger (includes heat interface unit and heat meter)	100	All techno-economic parameters for medium temperature heat exchangers are considered the same as for HXT2_big (See Table 3-4).

For district level heat supply technologies, efficiencies when operating at medium temperatures are shown in Table 3-7. Capital and operating costs are the same as the ones shown in Table 3-4.

Table 3-7: District level heat supply technology efficiencies and technical parameters when supplying medium temperature heat networks.

Name district level technologies	Description	Thermal Output [kW]	Efficiency (thermal/ electric))	Lifetime [years]	Available	Source
CHPDist1	District level CHP unit	10000	0.8 (0.52/0.28)	20	2015	[127]
BoilerDist	District level gas boiler	10000	0.9	20	2015	[127]
ASHPDist	District level air-source heat pump	10000	2.8	20	2015	[135]
GSHPDist	District level ground-source heat pump	10000	3.5	20	2015	[135, 139]

The urban area modelled was the City of Bristol. The City of Bristol consists of 55 MSOAs. The spatial disaggregation modelled is presented in Figure 3-2 and Figure 3-3. These figures respectively show the heat density and linear heat density for the modelled zones, drawn from heat demand inputs per MSOA. Linear heat density is calculated as the total annual heat demand in a zone, divided by the zone's total road length. Additionally, the zone labels are presented for later analysis. Only three city boundary zones were made available as entry points for gas and electricity. These are zones 14, 31 and 50.

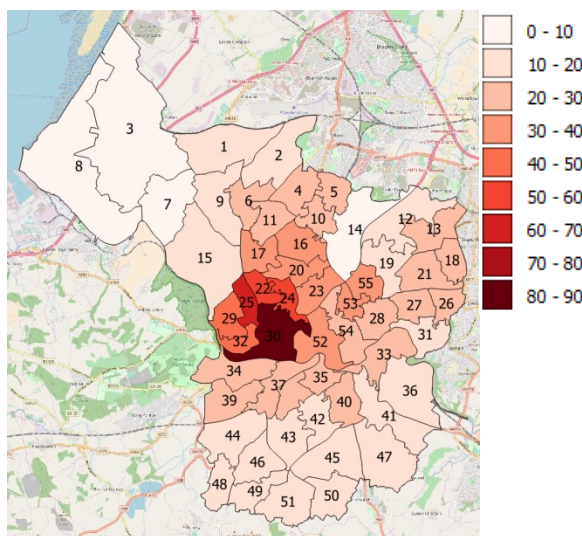


Figure 3-2: City of Bristol zone labels and heat density based on MSOA statistics [kWh/m²].

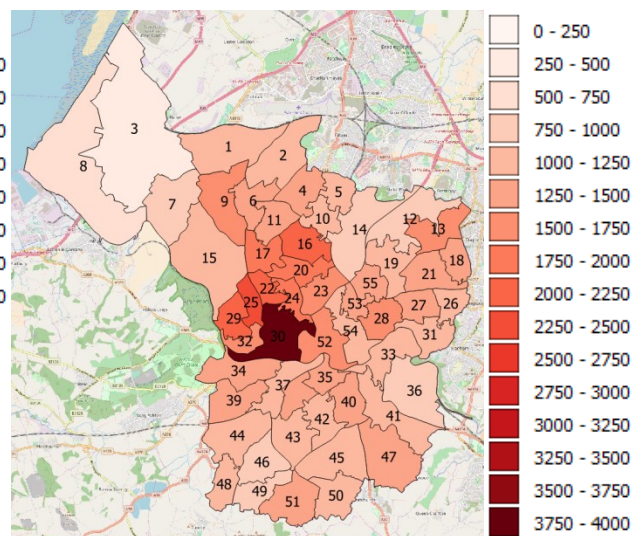


Figure 3-3: City of Bristol zone labels and linear heat density based on MSOA statistics and road lengths [kWh/m].

Finally, two scenarios were defined in this study: Scenario 1 used all parameters as explained in Section 3.1. In contrast, Scenario 2 assumes that gas combustion emissions are half of emissions associated to natural gas for district level technologies. This is intended to depict a scenario where bio-derived or synthetic methane, mixed with natural gas, is utilised by these technologies. For

Scenario 1, two cases were run: Case 1 where only high temperature heat networks were made available, and Case 2 where medium temperature heat networks were also available. Table 3-8 describes the 3 combinations of cases and Scenarios modelled.

Table 3-8: Description of cases and scenarios

Scenario	Description	Case	Description
1	Emission factors obtained from [120].	1	High temperature heat networks available
1	Emission factors obtained from [120].	2	High and medium temperature heat networks available
2	Emission factors are half of emissions associated to natural gas [120] for district level technologies.	1	High temperature heat networks available

3.4.2 The effect of spatial resolution in outcomes of energy systems models for heat

As previously identified in Section 2.3.3, this section seeks to illustrate and quantify how optimal results from energy systems models for heat decarbonisation change when using different spatial resolutions to model a same area. The study was performed for portions of 6 UK Local Authorities, covering a range of urban/rural areas according to 2011 Census rural urban classification [140]. Three levels of spatial resolutions were implemented for each Local Authority: Lower layer super output areas (LSOAs) [68], middle layer super output areas (MSOAs) [68], and the total aggregated Local Authority area. Table 3-9 shows the defined thresholds for MSOAs and LSOAs according to the Office for National Statistics [68].

Table 3-9: LSOA and MSOA thresholds in England and Wales [68].

Geography	Minimum population	Maximum population	Minimum number of households	Maximum number of households
LSOA	1,000	3,000	400	1,200
MSOA	5,000	15,000	2,000	6,000

For LSOA level, annual commercial gas and electricity demands were not available from [116, 117], so only the domestic sector was modelled for this spatial resolution study. Therefore, only MSOAs which were mostly residential were included. The MSOAs that were considered mostly residential were those for which domestic heat demand accounted for over 70% of the total MSOA heat demand. Table 3-10 shows the Local Authorities modelled in this work, covering the full range of urban/rural classifications according to [140]. The table also displays the total and modelled number of MSOAs and LSOAs for each Local Authority.

Table 3-10: Modelled areas and rural/urban classification.

Local authority	Rural/urban classification and description [140]	Number of MSOAs: modelled/total number	Number of LSOAs: modelled/total number
Selby	Mainly Rural (rural including hub towns $\geq 80\%$)	4/10	20/50
Winchester	Largely Rural (rural including hub towns 50-79%)	10/14	49/70
Lancaster	Urban with Significant Rural (rural including hub towns 26-49%)	13/18	67/89
Bristol	Urban with City and Town	18/55	88/263
Nottingham	Urban with Minor Conurbation	18/38	89/182
Lambeth	Urban with Major Conurbation	12/35	61/178

Figure 3-4 shows the MSOAs that were found to be mostly residential according to the aforementioned criteria, for each Local Authority modelled.

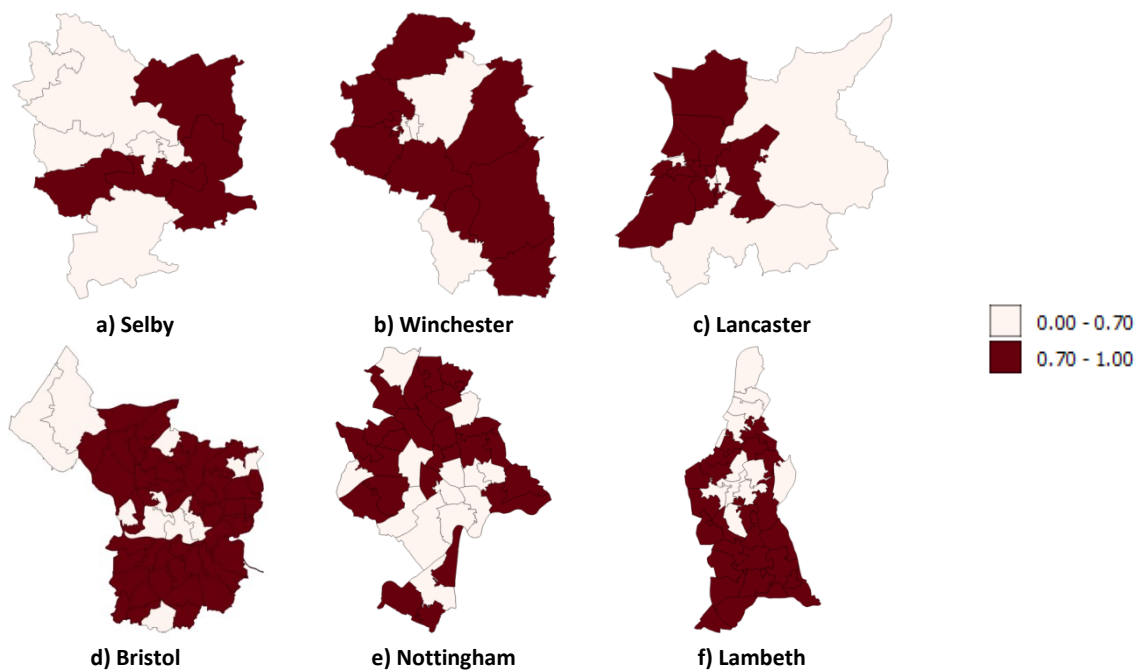
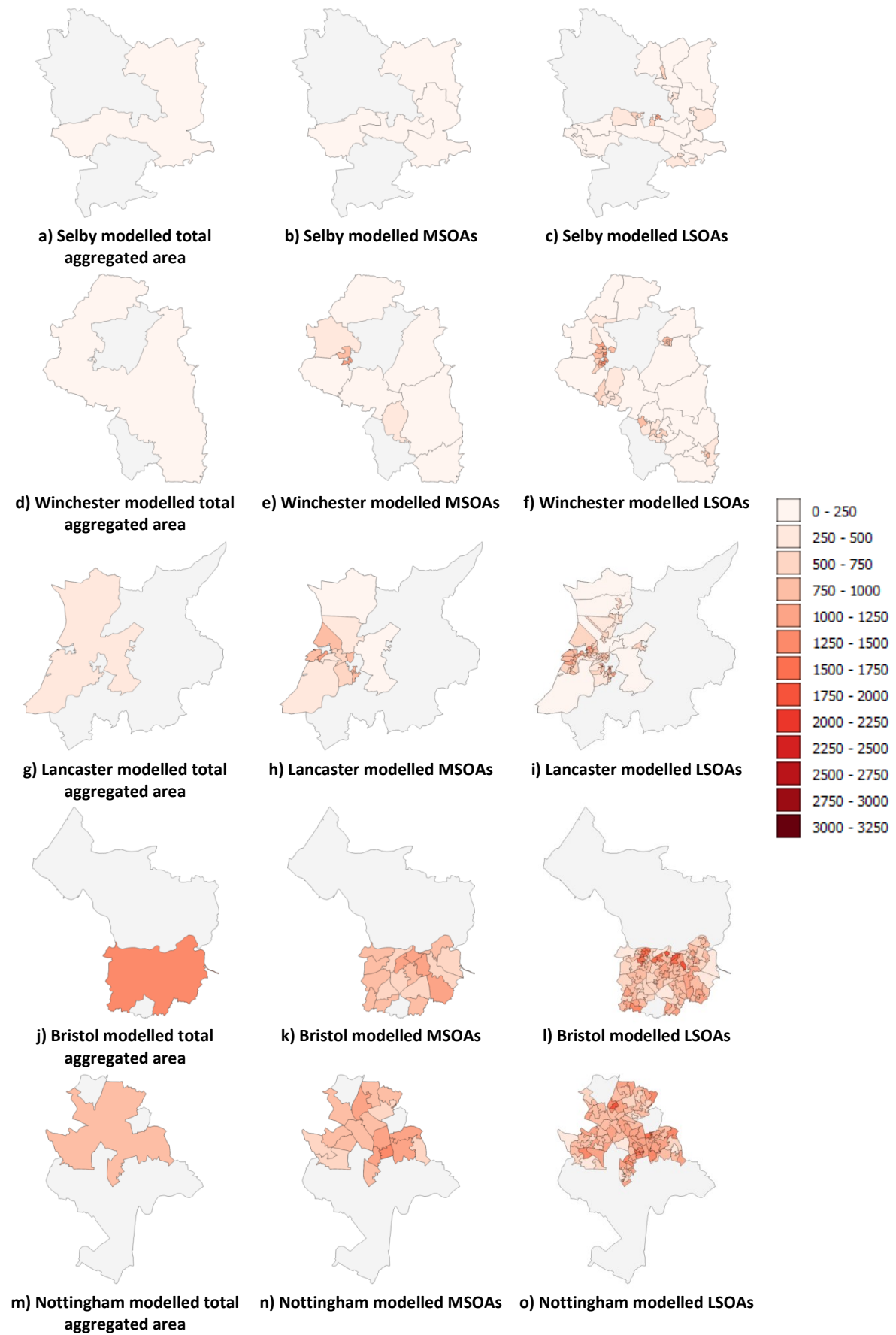


Figure 3-4: Fraction of domestic heat demand per MSOA. Calculated from commercial and domestic gas consumption data per MSOA [141].

Based on Figure 3-4, the modelled areas were selected for each of the 6 Local Authorities. The total aggregated areas were chosen as mostly residential MSOAs that were connected between each other. In order to keep the problem tractable, when subdivided into LSOAs, total aggregated areas were chosen so that the number of LSOAs was less than 100 for each Local Authority. The modelled areas are shown in Figure 3-5. The figure also shows the linear heat densities for the three levels of spatial resolution modelled, for the six Local Authorities. Linear heat densities were drawn from input heat demands and road lengths within zones.



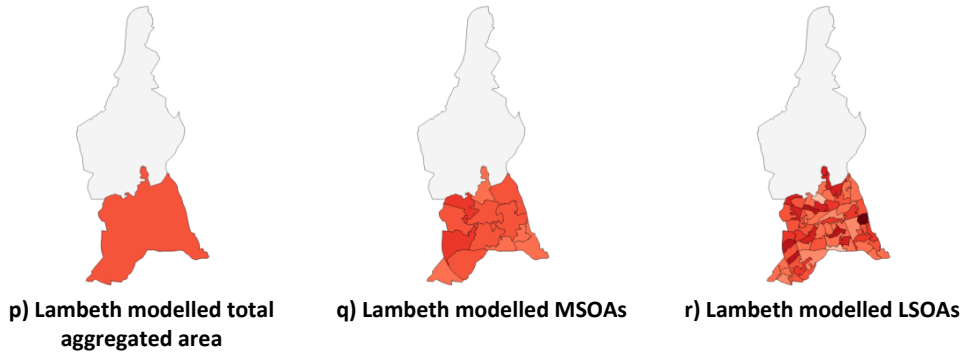


Figure 3-5: Modelled zones and linear heat density [kWh/m] per Local Authority for MSOA, LSOA, and total aggregated area levels. Linear heat density calculated from gas consumption data [141] and road lengths per LSOA [111].

3.4.3 The role of hydrogen in heat decarbonisation

This work modifies the base HIT model presented in Section 3.3 to include hydrogen networks and hydrogen-fuelled heat supply technologies. Two formulations are presented:

1. **Formulation A** introduces the possibility of including a hydrogen network which is independent from the gas network.
2. **Formulation B** introduces the possibility of including a hydrogen network by retrofitting the existing gas network to convert it into hydrogen (considering that existing low pressure polyethylene gas networks can be converted into hydrogen at relatively low cost compared to the total system cost [23, 139]).

The following section explains the modifications and additions made to the model for both of these formulations.

3.4.3.1 Modifications to the HIT model for formulations A and B

The following equations were implemented for both formulations. First, as for natural gas micro-CHPs, Equation (3.80) is implemented as an equality constraint for hydrogen micro-CHP units, so that the micro-CHPs are not allowed to dump heat in order to sell electricity.

$$HP_h \cdot OCHI_{b\ peak\ i_{ind}jy} = OCHI_{bhi_{ind}jy} \quad (3.80)$$

$$\forall bhjy, i_{ind} = hydCHP_{dom}, hydCHP_{comm}$$

An extra set of network variables representing hydrogen networks was added, together with individual and district level hydrogen-fuelled heat supply technologies. To estimate the network length that is built within zones, the total road length of the zone is multiplied by the fraction of dwellings that are connected to the hydrogen network. This fraction can be estimated as the total

installed capacity of hydrogen supplied technologies, over the peak heat demand. For example, if 40% of peak heat demand in a zone is served by hydrogen boilers, the length of the hydrogen network would be 40% of the zone's total road length. This length multiplies the average cost per unit length in the cost function. Equation (3.81) shows the hydrogen network length within zones.

$$\frac{\sum_{b, i_{ind}=hyd\ boilers, hyd\ CHPs} TCHI_{bi_{ind}jy}}{\sum_b Dem_b^H peak\ jy \cdot Num_{bjy}} \cdot Rl_j = TLN_{j\ hydn\ y} \quad \forall jy \quad (3.81)$$

Equation (3.44) defined previously states that the sum of network lengths within zones for all heat supply technologies should equal the total road length. This equation is updated as shown in Equation (3.82) to include hydrogen networks.

$$\sum_T TLN_{j\ heatn(T)\ y} + TLN_{j\ gasn\ y} + \left(\frac{\sum_{b, i_{ind}=ASHP, GSHP, radiators} TCHI_{bi_{ind}jy}}{\sum_b Dem_b^H peak\ jy \cdot Num_{bjy}} \right) \cdot Rl_j + TLN_{j\ hydn\ y} = Rl_j \quad \forall jy \quad (3.82)$$

Regarding energy balances, energy consumption and generation for hydrogen networks is equivalent to those of gas networks. Consumption from hydrogen networks (Equation (3.83)) is the sum of hydrogen-fuelled heat supply technologies, equivalent to the heat output of a given technology divided by its thermal efficiency. As for gas, it is assumed that no hydrogen is generated within zones and all hydrogen is injected via the transmission network from outside the city boundary into the city's hydrogen distribution network, as imposed by Equation (3.84).

$$F_{hj\ hydn\ y}^{CONS} = \sum_{\substack{b, \\ i_{ind}= \\ hyd\ boiler, \\ hyd\ microCHP,}} \frac{OCHI_{bhi_{ind}jy}}{\eta_{i_{ind}}^{ThI}} + \sum_{\substack{T, \\ i_{dist}=hyd\ boiler\ dist}} \frac{OCHD_{hi_{dist}jTy}}{\eta_{i_{dist}\ T}^{ThD}} \quad \forall hjy \quad (3.83)$$

$$F_{hj\ hydn\ y}^{GEN} = 0 \quad (3.84)$$

Finally, hydrogen fuelled micro-CHPs were added to the equation for electricity generated and injected into the grid in each zone, as shown in (3.85).

$$\begin{aligned}
F_{hj}^{GEN} = & \sum_e OCE_{hejy} + \sum_T OCHD_{h \text{ CHPdist } jTy} \cdot \frac{\eta_{CHPdist T}^{ED}}{\eta_{CHPdist T}^{ThD}} \\
& + \sum_b OCHI_{bh \text{ CHPindgas } jy} \cdot \frac{\eta_{CHPindgas}^{EI}}{\eta_{CHPindgas}^{ThI}} \\
& + \sum_b OCHI_{bh \text{ CHPindhyd } jy} \cdot \frac{\eta_{CHPindhyd}^{EI}}{\eta_{CHPindhyd}^{ThI}} \quad \forall hjy
\end{aligned} \tag{3.85}$$

Equations (3.80) to (3.85) are the additions to the base HIT model for Formulations A and B. The following equations are the supplementary equations introduced for Formulation B, when gas networks can be retrofitted into hydrogen networks.

3.4.3.2 Additional modifications to the HIT model for formulation B only - Retrofitting the current gas network

For Formulation B, a proxy network which is the total low pressure network for gas and hydrogen, HGn , is introduced as a new element in the network sets. $gasn$ and $hydn$ continue to represent the gas and hydrogen networks that fuel heat supply technologies. The HGn network represents the total gas network installed, including what is initially gas and then retrofitted into hydrogen. $hydn$ is the part of the total low pressure network, HGn , that is retrofitted into hydrogen and is represented as an added-on cost. $gasn$ is the part of the total low pressure network, HGn , that remains as gas network exclusively. Flow balances are performed over heat networks, electricity networks, $gasn$ and $hydn$. All equations that define new installed network lengths and capacities, remaining network lengths and capacities, and decommissioned network lengths and capacities are used to define $gasn$ and $hydn$ as in Formulation A. The total network capacities and lengths for HGn are defined as the sum of the gas and hydrogen network capacities and lengths, as shown in Equations (3.86) and (3.87).

$$TCN_{jj' HGn y} = TCN_{jj' gasn y} + TCN_{jj' hydn y} \quad \forall jj' y \tag{3.86}$$

$$TLN_{j HGn y} = TLN_{j gasn y} + TLN_{j hydn y} \quad \forall jj' y \tag{3.87}$$

The same equations are defined for the other network variables, as defined in Equations (3.88) to (3.93).

$$ICN_{jj' HGn y} = ICN_{jj' gasn y} + ICN_{jj' hydn y} \quad \forall jj' y \quad (3.88)$$

$$CCN_{jj' HGn yy'} = CCN_{jj' gasn yy'} + CCN_{jj' hydn yy'} \quad \forall jj' yy' \quad (3.89)$$

$$DCN_{jj' HGn yy'} = DCN_{jj' gasn yy'} + DCN_{jj' hydn yy'} \quad \forall jj' yy' \quad (3.90)$$

$$NLN_{j HGn y} = NLN_{j gasn y} + NLN_{j hydn y} \quad \forall jy \quad (3.91)$$

$$VLN_{j HGn yy'} = VLN_{j gasn yy'} + VLN_{j hydn yy'} \quad \forall jyy' \quad (3.92)$$

$$DLN_{j HGn yy'} = DLN_{j gasn yy'} + DLN_{j hydn yy'} \quad \forall jyy' \quad (3.93)$$

Finally, the network capital costs are added over the total low pressure network, *HGn*, and over the hydrogen network, *hydn*. The capital cost associated to *HGn* is the average cost for a low pressure polyethylene gas network. The capital cost associated to *hydn* is the average retrofitting cost to convert a gas network into a hydrogen network obtained from [85] and shown in Table 3-12. This cost is the average cost per length that the H21 Leeds City Gate project incurred in, in order to retrofit the natural gas polyethylene pipes to carry hydrogen, by reinforcing connection pipes and critical pressure pipes to ensure safe hydrogen transport. This cost also includes the additional infrastructure needed for medium and low pressure gas networks to be able to supply the necessary hydrogen volumes. Capital costs and salvage values of network infrastructures are shown in Equations (3.94) and (3.95). In this way, the proxy network is used to keep track of the real costs and infrastructure lifetimes, while the net gas and hydrogen networks (*gasn* and *hydn*) are used to reflect the net network capacities for energy balances.

$$NTW = \sum_{\substack{jj'y \\ n \neq gasn}} \frac{ICN_{jj'ny}}{2} \cdot d_{jj'} \cdot Cost_{ny}^{NT} \cdot \frac{1}{(1+r)^y} + \sum_{\substack{jy \\ n \neq gasn}} NLN_{jny} \cdot Cost_{ny}^{ND} \cdot \frac{1}{(1+r)^y} \quad (3.94)$$

$$\begin{aligned}
SLV = & \sum_{bi_{ind}jy} VCHI_{bi_{ind}jyy_{final}} \cdot Cost_{bi_{ind}jy}^{CI} \cdot \frac{Lt_{ind}^I - (y_{final} - y)}{Lt_{ind}^I} \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{i_{dist}jTy} VCHD_{i_{dist}jTy_{final}} \cdot Cost_{i_{dist}jTy}^{CD} \cdot \frac{Lt_{i_{dist}T}^D - (y_{final} - y)}{Lt_{i_{dist}T}^D} \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{ejy} VCE_{ejyy_{final}} \cdot Cost_{ejy}^{CE} \cdot \frac{Lt_e^E - (y_{final} - y)}{Lt_e^E} \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{\substack{jj'y \\ n \neq gasn}} \frac{CCN_{jj'nyy_{final}}}{2} \cdot d_{jj'} \cdot Cost_{ny}^{NT} \cdot \frac{Lt_n^N - (y_{final} - y)}{Lt_n^N} \cdot \frac{1}{(1+r)^{y_{final}}} \\
& + \sum_{\substack{jy \\ n \neq gasn}} VLN_{jnyy_{final}} \cdot Cost_{ny}^{ND} \cdot \frac{Lt_n^N - (y_{final} - y)}{Lt_n^N} \cdot \frac{1}{(1+r)^{y_{final}}}
\end{aligned} \tag{3.95}$$

3.4.3.3 Input data and case description

Formulation A and B were both run for a case study of the City of Bristol. The city was subdivided into its 55 MSOAs [68]. Inputs for commercial and domestic heat and electricity demands were the same as for Section 3.4.1. Table 3-11 shows the techno-economic parameters for the hydrogen-fuelled individual and district level heat supply technologies that were added in this section. As shown in Table 3-11 individual heat supply hydrogen technologies were made available from 2020 or 2025, depending on the technology. Table 3-12 shows the techno-economic parameters for hydrogen network infrastructure, for formulations A and B.

Table 3-11: Techno-economic parameters for hydrogen-fuelled individual and district level heat supply technologies

Name individual level technologies	Description	Thermal Output [kW]	TOTAL CAPEX 2015 [£2015]	TOTAL CAPEX 2030 [£2015]	TOTAL CAPEX 2050 [£2015]	Efficiency (thermal/ electric)	Lifetime [years]	Available	OPEX [£2015/ year]	Source
HydBoiler_dom	Domestic hydrogen condensing boiler	24	2400	2400	2400	0.84	15	2025	10% CAPEX	[132]
HydBoiler_comm	Commercial hydrogen condensing boiler	36	2630	2630	2630	0.90	15	2030	10% CAPEX	[132]
HydCHP_dom	Domestic hydrogen micro-CHP	12	11560	4690	4690	0.87 (0.48/0.38)	15	2020	5% CAPEX	[131]
HydCHP_comm	Commercial hydrogen micro-CHP	23	19390	7030	7030	0.88 (0.51/0.37)	15	2020	5% CAPEX	[131]
Name district level technologies	Description	Thermal Output [kW]	TOTAL CAPEX 2015 [£2015]	TOTAL CAPEX 2030 [£2015]	TOTAL CAPEX 2050 [£2015]	Efficiency (thermal/ electric)	Lifetime [years]	Available	OPEX [£2015/ year]	Source
HydBoilerDist	District level hydrogen boiler	10000	724000	724000	724000	0.9	20	2015	36000	[142]

Table 3-12: Network parameters

Name	Description	Capital cost within zones [£2015/km]			Capital cost between zones [£2015/kW km]			Distribution losses	Lifetime [years]
		2015	2030	2050	2015	2030	2050		
Formulation A									
Hydn	Hydrogen network	740000 [85]	740000	740000	3.03	3.03	3.03	Accounted for in hydrogen prices	50
Formulation B									
HGn	Total gas and hydrogen proxy network	740000 [85]	740000	740000	3.03	3.03	3.03	Accounted for in hydrogen prices	
Hydn	Hydrogen network retrofit	10000 [85]	10000	10000	0.041	0.041	0.041	Accounted for in hydrogen prices.	50

As for gas and electricity, the assumption of the HIT model is that hydrogen is centrally produced and readily available from the transmission system to purchase at retail prices. According to [85], as hydrogen production routes vary, retail prices and associated equivalent carbon emissions can vary as well. Estimates for retail hydrogen prices range from 4.9 to 18.4 p/kWh, with an average of 9.3 p/kWh. Equivalent carbon emissions associated to producing hydrogen via steam methane reformers with carbon capture and storage (CCS) range from 23 to 150 gCO_{2e}/kWh. To tackle these uncertainties, three scenarios for hydrogen retail prices and two scenarios for associated carbon emissions were considered for each formulation. Regarding hydrogen price scenarios, Scenario HP1 represents average hydrogen prices as projected in [85]. Scenario HP2 represents sale price estimates excluding point of conversion as projected in [23], and Scenario HP3 represents low hydrogen price estimates as projected in [85]. These are shown in Table 3-13. Projected retail prices include production costs, transmission costs, distribution costs, taxes and profits. Distribution costs are then discounted as these are included endogenously through distribution network costs.

Table 3-13: Hydrogen price scenarios

Hydrogen price scenario	Hydrogen price [2015 p/kWh]	Source	Comments
Scenario HP1	9.3 (all sectors)	Average hydrogen prices as projected in [85]	Prices multiplied by 0.84 [119] to discount price of distribution, which is endogenously included in the model as distribution networks.
Scenario HP2	7.5 (all sectors)	Sale price estimates excluding point of conversion as projected in [23]	
Scenario HP3	4.9 (all sectors)	Low hydrogen prices as projected in [85]	

Finally, two scenarios were considered for hydrogen equivalent carbon emissions, assuming the production route is via steam methane reforming with carbon capture and storage (CCS). These scenarios assume a carbon capture of 90%, as set out in [23]. Scenario HE1 and Scenario HE2 for equivalent carbon emissions are shown in Table 3-14.

Table 3-14: Hydrogen equivalent carbon emissions assuming production route via steam methane reforming with CCS

Hydrogen emissions scenario	Equivalent carbon emissions [kgCO _{2e} /kWh]	Source	Comments
Scenario HE1	0.0495	[23]	Including electricity for sequestration (Scope 1+2)
Scenario HE2	0.027	[23]	UK carbon budget basis (Scope 1)

For both formulations, gas networks are imposed to decommission linearly through 2050, and costs for new gas networks are as defined for *Gasn* in Table 3-3 and for *HGn* in Table 3-12, for

formulations A and B respectively. A further case was defined for formulation B, in which considering that the Mains Replacement Programme is taking place in the whole UK, gas network costs are considered to be a sunken cost, and therefore they are not included in the model. Equivalently, this would be the same as not imposing a decommissioning profile for gas networks.

3.4.4 The sensitivity of heat decarbonisation outcomes to uncertainty in techno-economic parameters

As a bottom-up model, the HIT model is very data intensive. As previously explained, some of the main inputs are the costs and technical parameters of individual and district level heat supply technologies, the costs of distribution networks, the prices of electricity and fuels, the carbon price, and other technical parameters such as the rate of carbon capture associated to hydrogen production, or heat network losses, among others. All these parameter values correspond to projections, and are thus associated to uncertainties related to technological developments, international markets, or even international politics. Therefore, it is important to assess how the variation in input parameters affects the results of the HIT model.

In order to do so, a Base Case with central assumptions was defined. Some of the main input parameters were varied one at a time while leaving the others constant at the Base Case values. The sensitivity analysis was performed with the HIT model allowing for only high temperature heat networks, and allowing for retrofitting the current gas network to convert it into hydrogen by using Formulation B, as described in Section 3.4.3.2.

3.4.4.1 Base Case Definition

Individual and district level heat and electricity supply technology parameters and costs used for the Base Case are the ones shown in Table 3-4, and in Table 3-11 for hydrogen technologies. Costs and network losses for electricity, gas, and heat are the same as presented in Table 3-3. Costs shown in Table 3-12 for Formulation B are used for the proxy total hydrogen and gas network, and for the cost of retrofitting or reinforcing the gas network to convert it into hydrogen.

Base Case gas and electricity emission factors and prices for the commercial and domestic sectors, as well as carbon prices, are central scenarios described in Table 3-1. The Base Case hydrogen price corresponds to the price described for Scenario HP2 in Table 3-13, which represents sale price estimates excluding point of conversion as projected in [23].

As discussed previously, hydrogen associated equivalent carbon emissions vary depending on the production route [85]. For the Base Case, it was assumed that hydrogen is produced via steam methane reformers with carbon capture and storage (CCS), with a carbon capture of 90%. Hydrogen emissions were assumed to include emissions from electricity used for carbon sequestration (Scope 1+2). According to [23], hydrogen Scope 1 emissions produced via steam methane reforming with a 90% capture rate are 26.97 [gCO₂e/kWh], and Scope 2 emissions associated to electricity used for carbon sequestration are 22.56 [gCO₂e/kWh]. The sum of these two values was the Scope 1+2 hydrogen emissions assumed for 2015. However, emissions for electricity used in this work are projected to decrease through 2050 [120]. Therefore, Scope 2 emissions were decreased through 2050, in direct proportion to the decrease in grid average consumption based electricity emission factors for the industrial sector [120]. Table 3-15 shows the calculated Scope 1+2 emission factors for hydrogen from 2015 to 2050.

Table 3-15: Calculated hydrogen emission factor (EF) Scope 1+2, based on [23] and [120].

Year	EF [gCO ₂ e/ kWh]	Year	EF [gCO ₂ e/ kWh]	Year	EF [gCO ₂ e/ kWh]	Year	EF [gCO ₂ e/ kWh]	Year	EF [gCO ₂ e/ kWh]	Year	EF [gCO ₂ e/ kWh]
2015	49.53	2021	38.41	2027	34.73	2033	31.17	2039	29.65	2045	28.73
2016	45.74	2022	37.51	2028	33.48	2034	31.12	2040	29.47	2046	28.57
2017	43.03	2023	35.94	2029	32.66	2035	30.42	2041	29.20	2047	28.46
2018	42.49	2024	36.39	2030	32.46	2036	30.36	2042	29.18	2048	28.47
2019	41.55	2025	35.80	2031	32.15	2037	29.92	2043	28.93	2049	28.33
2020	39.96	2026	34.82	2032	31.86	2038	29.62	2044	28.71	2050	28.32

Finally, the urban area modelled for the Base Case was the City of Bristol, broken down into its 55 MSOAs. Zone linear heat densities calculated from heat demand inputs are the ones presented previously in Figure 3-3. Gas and electricity networks were imposed to decommission linearly through 2050.

3.4.4.2 Sensitivity scenario definitions

High and low scenarios were modelled for various parameters. High and low gas, electricity and hydrogen price scenarios were modelled and compared to the Base Case. Table 3-16 shows the high and low price scenarios across sectors, together with the Base Case scenario. Prices for 2015 and 2030 are shown as referential values. See Appendix C, Table C-1 and Table C-2 for detailed electricity and gas price scenarios.

Table 3-16: Gas, electricity and fuel price scenarios.

Parameter	Scenario	Source	Value 2015 [2015p/kWh]		Value 2030 [2015p/kWh]		Further assumptions
Gas price	Low	[118]	Commercial:	2.3	Commercial:	2.6	All prices are multiplied by 0.84 [119].to discount the price of distribution, which is endogenously included in the model as distribution networks.
			Domestic:	4.1	Domestic:	3.8	
			Industrial:	1.8	Industrial:	2.1	
Gas price	Base Case	[118]	Commercial:	2.6	Commercial:	3.5	
			Domestic:	4.2	Domestic:	4.7	
			Industrial:	2.1	Industrial:	3	
Gas price	High	[118]	Commercial:	2.9	Commercial:	4.6	
			Domestic:	4.2	Domestic:	5.9	
			Industrial:	2.4	Industrial:	4.1	
Electricity price	Low	[118]	Commercial:	9.2	Commercial:	13.9	
			Domestic:	14.6	Domestic:	18.2	
			Industrial:	7.8	Industrial:	12.5	
			Wholesale:	3.9	Wholesale:	5.4	
Electricity price	Base Case	[118]	Commercial:	9.9	Commercial:	14.8	
			Domestic:	14.5	Domestic:	19.2	
			Industrial:	8.5	Industrial:	13.3	
			Wholesale:	4.4	Wholesale:	6.6	
Electricity price	High	[118]	Commercial:	10.6	Commercial:	15.6	
			Domestic:	14.6	Domestic:	19.9	
			Industrial:	9.2	Industrial:	14.1	
			Wholesale:	4.9	Wholesale:	7.9	
Hydrogen price	Low	Low hydrogen prices [85]	4.9 (all sectors)		4.9 (all sectors)		
Hydrogen price	Base Case	Sale price estimates excluding point of conversion [23]	7.5 (all sectors)		7.5 (all sectors)		
Hydrogen price	High	Average hydrogen prices [85]	9.3 (all sectors)		9.3 (all sectors)		

Table 3-17 shows referential values for high, low, and Base Case scenarios for carbon prices. See Appendix C, Table C-3, for detailed carbon price scenarios.

Table 3-17: Carbon price scenarios

Scenario	Source	Value 2015 [2015£/tCO ₂ e]	Value 2030 [2015£/tCO ₂ e]	Value 2050 [2015£/tCO ₂ e]
Low carbon price	[120]	31.2	39.2	112.1
Base Case	Non-traded central scenario [120]	62.4	78.5	224.1
High carbon price	[120]	93.6	117.7	336.2

Sensitivity scenarios were defined for network costs as well. The Base Case scenario costs for heat networks within zones was obtained from [85]. In this report, a range of heat network costs

obtained from data from different networks is presented. Analysing this data, four sensitivity scenarios which are in accordance to reported costs were defined with respect to the Base Case: 40% higher than Base Case, 20% higher than Base Case, 20% lower than Base Case, and 40% lower than Base Case. These same percentages were used for the networks between zones for each scenario. Additionally, due to the lack of available data for electricity and gas network costs, the same percentages were used for defining sensitivity scenarios for gas and electricity networks. As mentioned previously, Base Case network costs are those presented in Table 3-3. Referential values for networks within zones are presented in Table 3-18, together with sensitivity scenario definitions.

Table 3-18: Sensitivity scenario definitions for network costs

Network	Base Case Scenario capital cost within zones [£2015/km]	Low	Mid Low	Mid High	High
Heat	874,000	40% lower than Base Case	20% lower than Base Case	20% higher than Base Case	40% higher than Base Case
Gas	740,000	40% lower than Base Case	20% lower than Base Case	20% higher than Base Case	40% higher than Base Case
Electricity	96,600	40% lower than Base Case	20% lower than Base Case	20% higher than Base Case	40% higher than Base Case

Finally, different scenarios were modelled for some individual level technology costs. The technologies modelled were chosen as the ones which present higher cost variations or uncertainties in the literature: air-source heat pumps, ground-source heat pumps, hydrogen micro-CHP units, and natural gas micro-CHP units. Based on reviewing available costs in the literature, and since a large range was found, scenarios for sensitivity were defined to be consistent with the ranges chosen for network costs. Table 3-19 shows the referential Base Case values, and the scenario definitions for individual technology capital costs. It is important to highlight that for the whole sensitivity analysis each parameter was varied while maintaining all the others constant at the Base Case values. However, for the case of individual level technologies, both commercial and domestic costs for each technology were varied simultaneously. This is, taking air-source heat pumps as an example, the low price scenario was modelled by simultaneously reducing the commercial and domestic air-source heat pump capital costs by 40%. The same was done for ground-source heat pumps, natural gas micro-CHPs, and hydrogen micro-CHPs, for each cost scenario.

Table 3-19: Sensitivity scenario definitions for individual level technologies,

Name (See Table 3-4 and Table 3-11 for descriptions)	Base Case CAPEX 2015 [£2015]	Base Case CAPEX 2030 [£2015]	Low	Medium Low	Medium High	High
CHP_dom	4960	4180	40% lower than Base Case	20% lower than Base Case	20% higher than Base Case	40% higher than Base Case
CHP_comm	6200	5230				
ASHP_dom	9000	7650	40% lower than Base Case	20% lower than Base Case	20% higher than Base Case	40% higher than Base Case
ASHP_comm	13010	9260				
GSHP_dom	17100	14400	40% lower than Base Case	20% lower than Base Case	20% higher than Base Case	40% higher than Base Case
GSHP_comm	27410	18860				
HydCHP_dom	11560	4690	40% lower than Base Case	20% lower than Base Case	20% higher than Base Case	40% higher than Base Case
HydCHP_comm	19390	7030				

3.5 Calibration and border constraints

For all four studies described, a base year calibration (chosen as 2013) was adopted for determining network capacities and technologies in place at the beginning of the modelling time horizon. A minimum cost optimisation was run for one year of operation in order to determine base year network topology⁵. The assumptions and constraints for the base year were that heat demand is supplied exclusively by gas boilers, electricity demand is supplied exclusively by the electricity grid, and no heat nor hydrogen networks are in place.

Domestic properties were not allowed to purchase commercial technologies, and commercial properties were not allowed to purchase domestic technologies (shown in the description of domestic technologies in Table 3-4, Table 3-6, and Table 3-11).

The base year results were used as initial conditions for networks and installed boilers in each zone when running the case from 2015 to 2051. Additional constraints were imposed for decommissioning initial capacity. Networks were enforced to decommission linearly over the modelling time horizon. One half of initially installed gas boilers were enforced to be decommissioned in 2020, and half in 2025, reflecting the average life of gas boilers in the market.

⁵ This is a necessary assumption due to lack of available data on existing network topology. It is noted that if pre-existing network topology data were available, this could be provided to the model as an input, negating the need for this step.

The same constraints as for the base case were applied for entry points of gas and electricity and for domestic and commercial property purchases.

The commercial software GAMS v28.8.3, CPLEX solver, was used for implementing and solving all the cases.

Chapter 4. Different temperature heat networks for decarbonising heat

Figure 4-1 shows the total share of individual heat and electricity supply technologies for the three cases and scenarios. Results show that individual-building electricity generation systems (e.g. PV), or micro-CHP units are not cost effective in the studied scenarios, as all electricity is purchased from the grid. For both scenarios, it is observed that the most cost-effective pathway for heat supply in the domestic sector is the adoption of heat networks, together with the use of some individual dwelling gas boilers. For the commercial sector, gas boilers are progressively replaced by a combination of heat networks and air-source heat pumps, the latter reaching between 60% and 66% of the installed commercial capacity by 2050 for the three cases and scenarios.

In Scenario 1, Case 2 (when two temperature heat networks are available), the optimal heat supply combination is given by a mix of high and medium temperature heat networks, with a slightly higher overall heat demand supplied by heat networks by 2050 (72% overall penetration versus the 71% overall penetration for Scenario 1, Case 1). It is also worth noticing that in Scenario 1, Case 2, the domestic sector is mainly supplied by high temperature heat networks (as in Case 1), with a small uptake of medium-temperature heat networks, respectively reaching 76% and 8% of the domestic sector's installed capacity by 2050. Conversely, the commercial sector for Scenario 1, Case 2, is mainly supplied by medium temperature heat networks, with an uptake of 32% of the installed commercial capacity versus 2% of the commercial capacity corresponding to high temperature heat networks.

In Scenario 2, when lower emissions of gas for district heating are assumed, there is a slightly faster penetration of heat networks in the initial years for both the commercial and domestic sectors. From 2020 to 2035, the overall heat network penetration for Scenario 2 is 1% higher each year compared to the base case, and reaches approximately the same uptake from 2040 onwards.

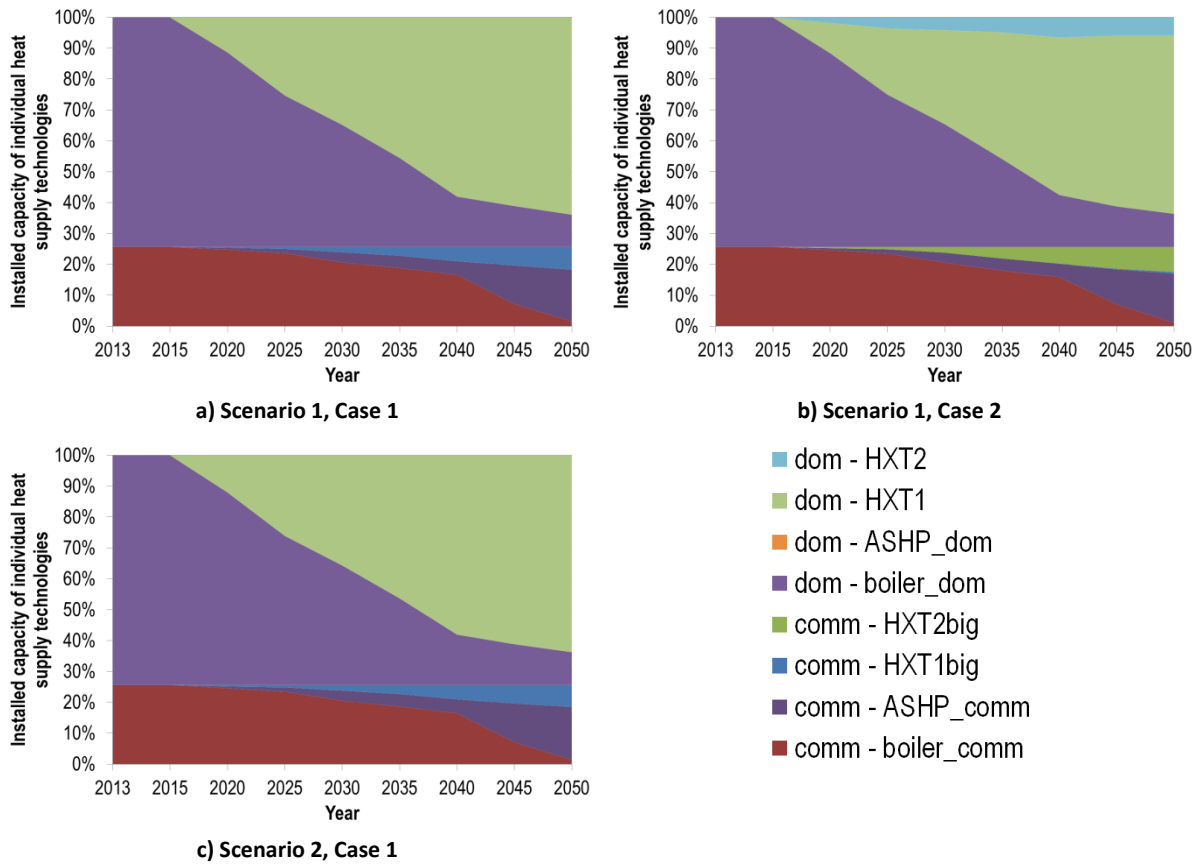


Figure 4-1: Percentage of total capacity of individual heat supply technologies

Figure 4-2 shows the installed capacity of individual heat and electricity supply technologies for the three cases and scenarios.

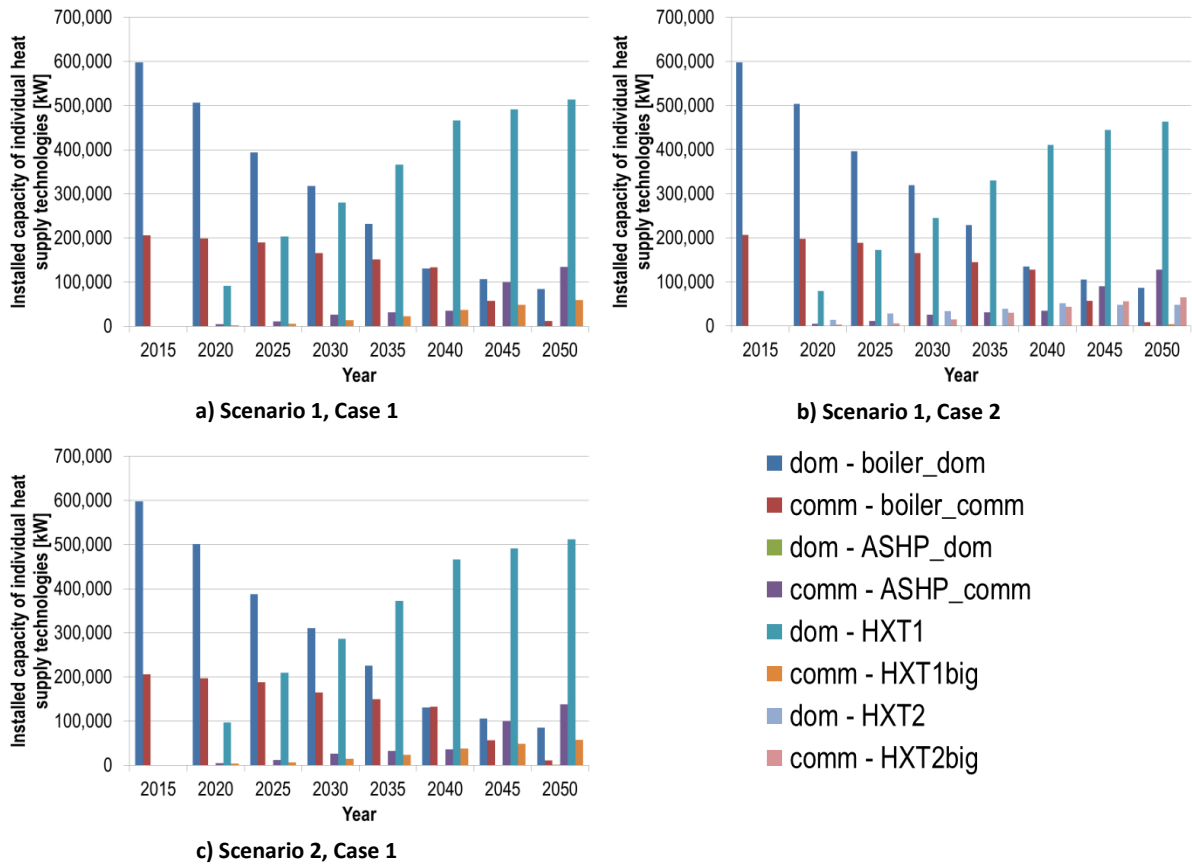


Figure 4-2: Total installed capacity of individual heat supply technologies

Figure 4-3 shows the district heat supply technologies over time for both scenarios and cases. For Scenario 1, heat networks are mainly supplied by air-source heat pumps together with some district level gas boilers. Scenario 2 on the other hand is mainly supplied by district level boilers in the initial years, with a stronger adoption of district level air-source heat pumps from 2040 onwards. These results together with the results presented in Figure 4-1 show that for the topology studied heat electrification in the domestic sector is more effectively reached through introducing heat grids and supplying them via heat pumps, rather than installing individual heat pumps for single buildings. For the commercial sector- as mentioned before- heat is mainly supplied by air-source heat pumps towards 2050, together with heat networks. This means that air-source heat pumps have a large role in heat decarbonisation pathways, either by supplying heat to individual dwellings, or by supplying heat into heat networks at a district scale. This highlights the importance of considering the associated infrastructure costs when comparing different end-use technology options, not only stand-alone technology life cycle costs (capital, operation and maintenance, carbon, decommission, etc.). In essence, there are trade-offs between infrastructure costs and end-use technology costs which can lead to less obvious solutions. In the case of the domestic sector, this is demonstrated

through the fact that the costs of reinforcing the electricity grid makes it more effective to electrify heat via district technologies than through individual level technologies.

For Scenario 1, results for Case 1 and Case 2 show that when medium temperature heat networks are also available the optimisation model selects some of these (Figure 4-3b) to the detriment of high temperature heat networks. Also, there is an overall higher participation of air-source heat pumps supplying both networks. This means that the higher network cost of the medium temperature network is counterbalanced by the higher coefficient of performance of heat pumps operating at medium temperatures, and by the lower network losses. This again shows the importance of trade-offs between infrastructure and end-use technologies.

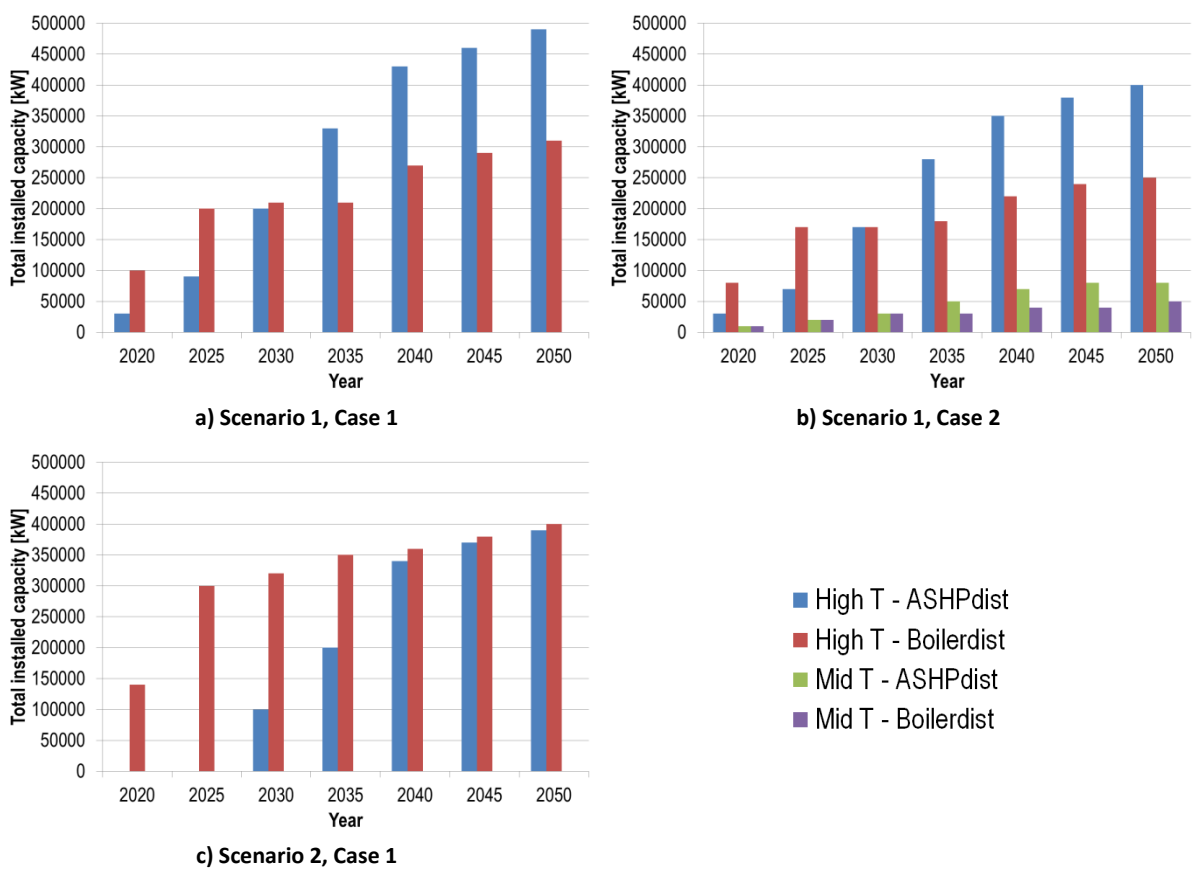
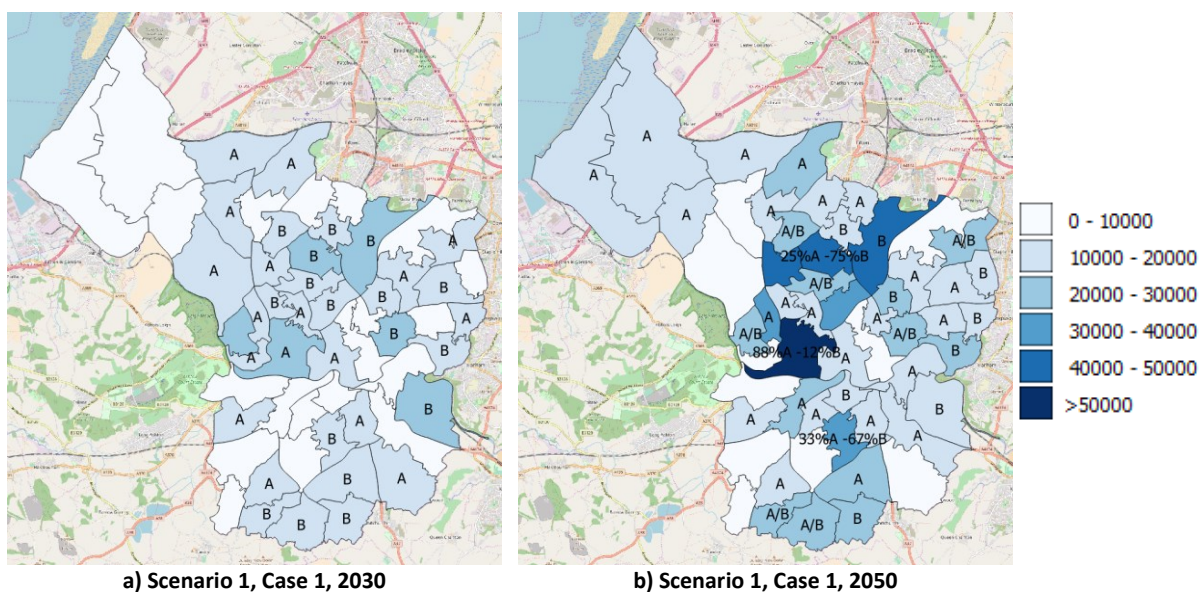


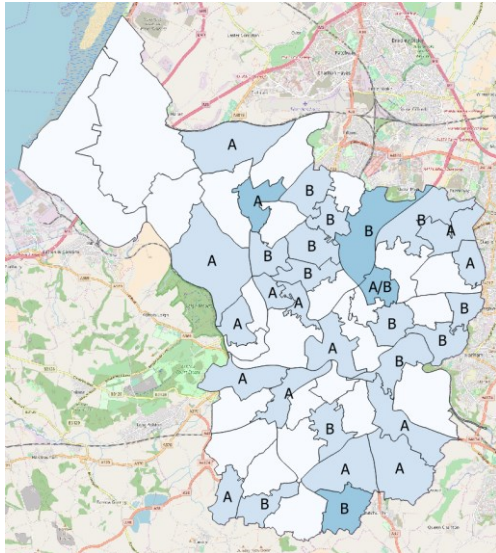
Figure 4-3: Total district level heat supply technologies installed capacity

Figure 4-4 shows in which zones district heat supply technologies are installed over time for both scenarios. Comparing these with Figure 3-2, it can be seen that district heat technologies are installed in the most heat dense zones. Comparing these results with Figure 3-3 however shows that there is a better correlation with linear heat density and location of district heat technologies. For example zones 8 or 51 have low heat densities, but relatively higher linear heat densities, and particularly for high temperature networks in Scenario 1 district technologies are installed within

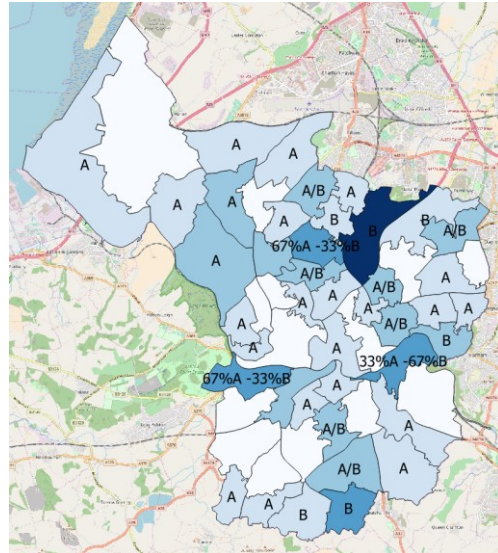
them. However, heat density and linear heat densities are not the only factors to be considered in the decision of where to install district technologies. Connectivity with other heat dense zones is also a determining factor. For example, zones 22 and 25 are both heat dense and linear heat dense. They are neighbours, and both are also neighbours with zone 30 and other linear heat dense zones. For both scenarios zone 22 presents a higher installation of district technologies, despite it having lower heat and linear heat densities than zone 25. This can be attributed to the fact that zone 22 is connected to more zones with higher heat and linear heat densities. Therefore the location of district heat technologies is dependent on linear heat density and on zone-to-zone connectivity, which reflects the ability to aggregate demands and build larger heat networks. A third factor that was identified that determines the location of district heat technologies is when zones are defined to be entry points for gas and electricity. All three defined entry points (zones 14, 31, and 50) present high installation of district technologies for both scenarios. This can be attributed to less distance of gas and electricity networks being needed to supply district heat supply technologies.

On the other hand, when comparing high and low temperature network cases in Scenario 1, results show that when two temperature networks are available, medium temperature district heating supply technologies are installed in the highest linear heat density zones (zones 17, 20, 22, 25, 29, 30, and 52 by 2050). It is interesting to note that only medium temperature heat network supply technologies are installed in the three highest linear heat density zones (Zone 22, 25, and 50), while the other aforementioned high linear heat density zones present a combination of high and medium temperature heat network supply technologies.

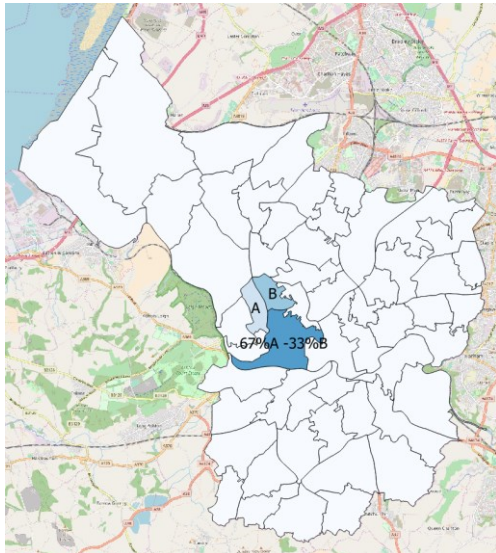




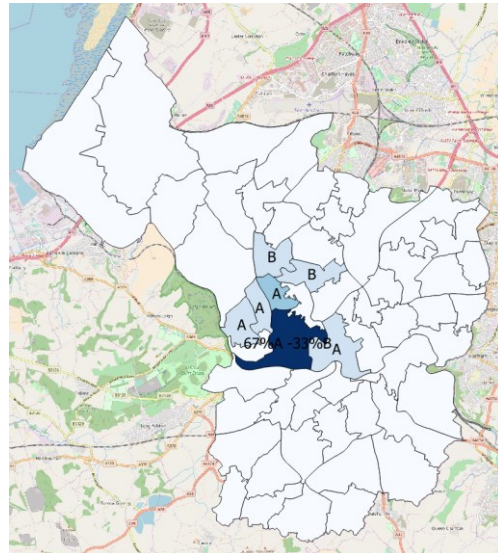
c) Scenario 1, Case 2, High-T heat networks, 2030



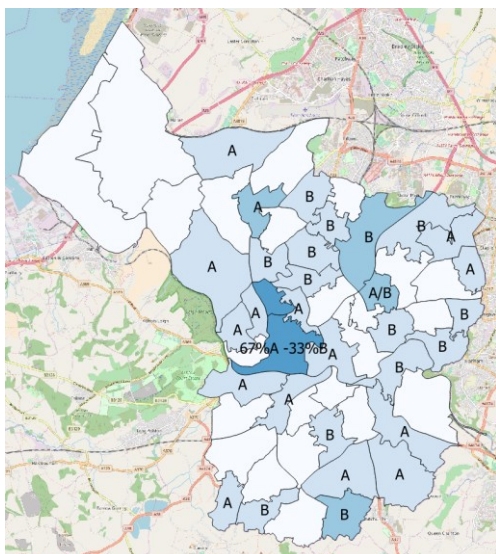
d) Scenario 1, Case 2, High-T heat networks, 2050



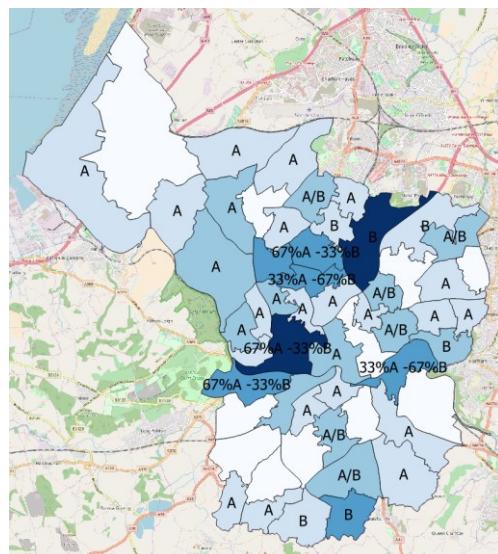
e) Scenario 1, Case 2, Mid-T heat networks, 2030



f) Scenario 1, Case 2, Mid-T heat networks, 2050



g) Scenario 1, Case 2, total heat networks, 2030



h) Scenario 1, Case 2, total heat networks, 2050

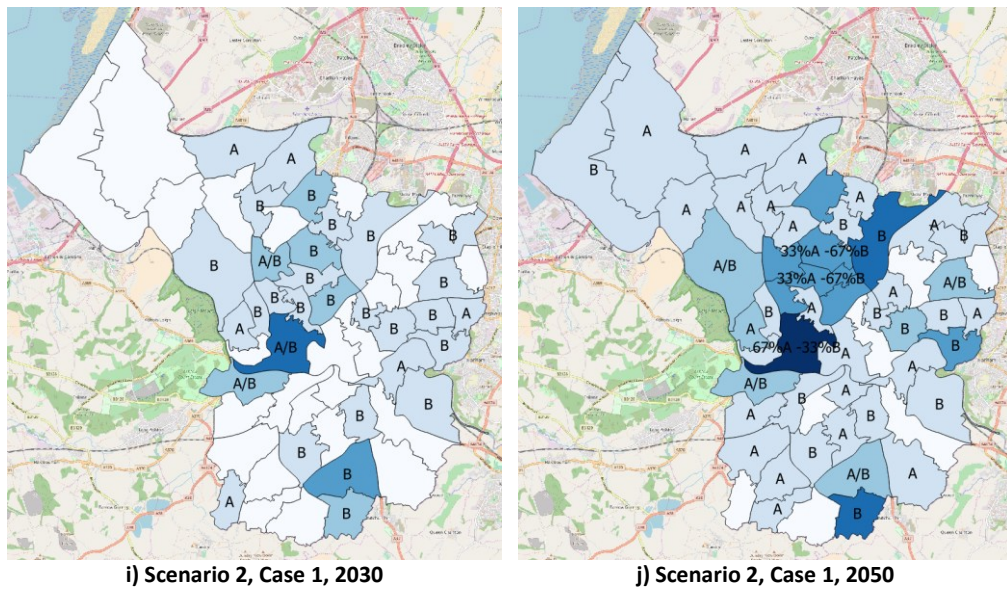


Figure 4-4: Location of district heat supply technologies, [kW]. A: Air-source heat pumps. B: Gas boilers

Figure 4-5 shows the penetration of heat networks over time for both scenarios. Comparing these figures with Figure 3-2, and Figure 3-3, there is a correlation between heat network penetration and heat density, although linear heat density is a better indicator. For example zones 7, 13, and 47, have relatively low heat densities with relatively high linear heat densities, and for both scenarios and cases there is a relatively high penetration of heat networks within them. The comparison between cases and scenarios shows that determining linear heat density thresholds for heat network penetration is case specific. The thresholds vary for emission levels of gas considered in both scenarios for district heating technologies, and for different temperature heat networks. When comparing Case 1 and Case 2 for Scenario 1, a higher overall penetration of heat networks is achieved when two temperature networks are available, as discussed previously. Also, as in for the case of district heat technology locations, heat networks penetration also depends on zone connectivity. This makes it even more challenging to determine a universal linear heat density threshold for heat network adoption.

Despite these caveats, in general terms (and disregarding zone 52 which is discussed later) it can be said that for Scenario 1-Case 1, for linear heat densities of over 250 kWh/m there is a heat network penetration of more than 40% by 2050, and for linear heat densities of over 1250 kWh/m and 2250 kWh/m there is a heat network penetration of over 60% and 90% respectively by 2050. For Scenario 2, for linear heat densities of over 250 kWh/m there is a heat network penetration of over 30% by 2050; for linear heat densities over 750 kWh/m heat network penetration is higher than 60%; and for linear heat densities of over 2250 kWh/m there is over 80% of heat network penetration. These thresholds however are general guidelines, as they do not take into account the aspect of

connectivity between zones, which these results show can materially influence cost effectiveness. Another aspect that is not considered when finding thresholds is the ratio of commercial to total demand, which is discussed later in relation to zone 52.

When two heat network temperatures are available, there is a less direct heuristic threshold. For Scenario 1-Case 2, the temperature networks complement each other. Medium temperature heat networks only appear at linear heat densities over 1750 kWh/m. For linear heat densities over 1750 kWh/m, some zones achieve between 10% and 20% of medium temperature network penetration by 2050. When linear heat densities are higher than 2000 kWh/m, all zones present medium temperature heat network penetrations over 10% by 2050. When linear heat densities exceed 2250 kWh/m, medium temperature heat network uptakes are over 70% by 2050, while an uptake over 90% is observed for the highest linear heat density zone (over 3750 kWh/m) by 2050. Conversely, for the high extreme of linear heat density (over 3750 kWh/m), no high temperature heat network is observed. High temperature heat network penetration is observed to increase with linear heat density up to linear heat densities of 2000 kWh/m, and then decreases. In this work, high temperature heat networks only appear in zones with linear heat densities up to 2500 kWh/m, although more zones with linear heat densities between 2500 kWh/m and 3750 kWh/m would be needed in order to generalise this observation. For linear heat densities under 2000 kWh/m, high temperature heat network uptakes are higher than 40% and 60% by 2050 when linear heat densities are greater than 250 kWh/m and 750 kWh/m respectively. Overall, when two heat network temperatures are available a higher total heat network penetration was observed, with medium temperature heat networks appearing in the most linear heat dense zones, and high temperature heat networks being present in lower linear heat density zones.

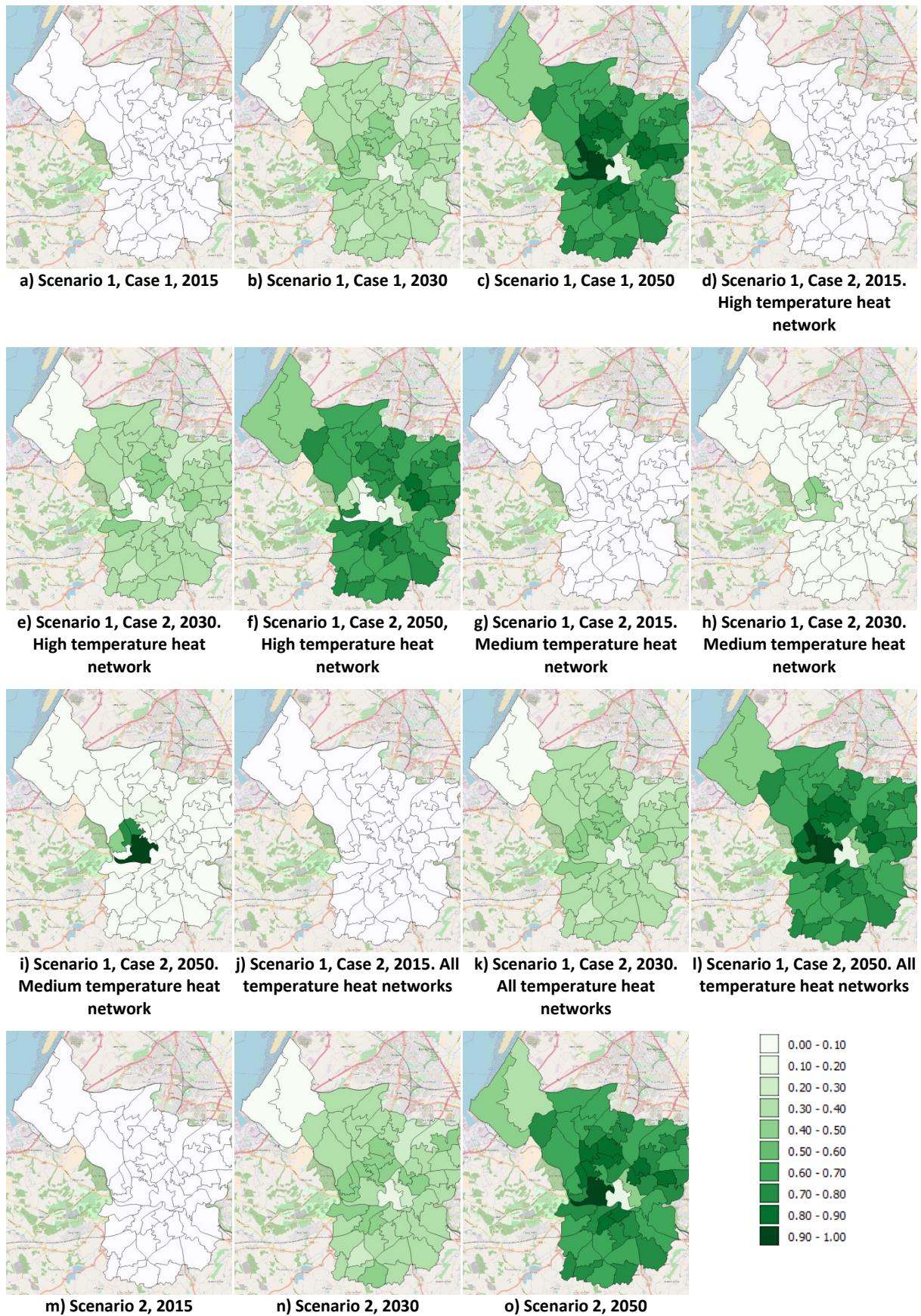


Figure 4-5: Heat network penetration

Figure 4-6 shows the penetration of air-source heat pumps over time for the modelled zones and cases.

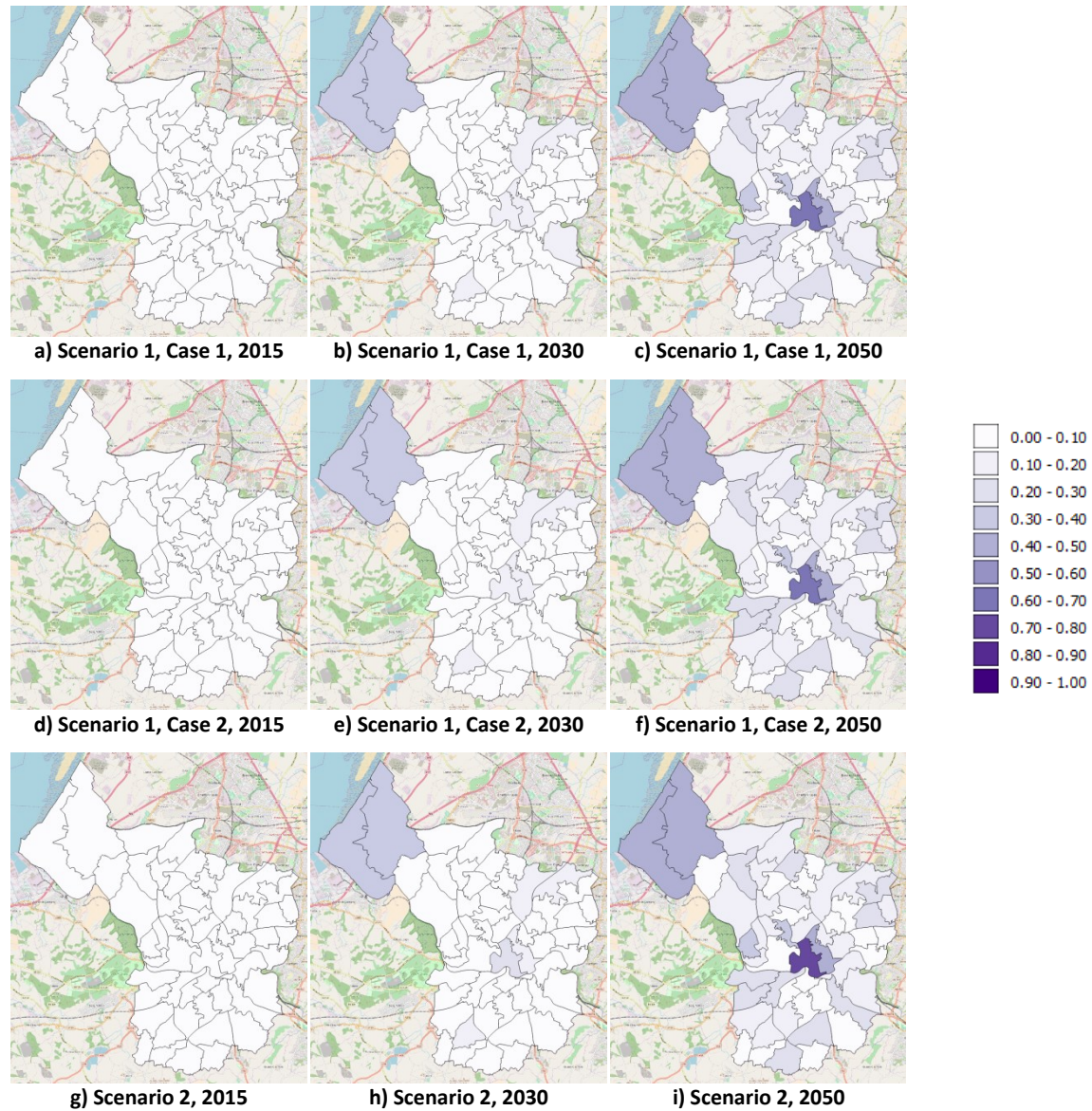


Figure 4-6: Air-source heat pump penetration

Comparing Figure 4-6 with Figure 3-3, a correspondence is observed between high air-source heat pump penetration and low linear heat densities. However, as for heat network penetration, linear heat density is not the only factor influencing air-source heat pump uptake. Figure 4-7 shows the ratio of commercial to total heat demand in each zone. As air-source heat pumps are mostly adopted in the commercial sector in all three modelled cases, the commercial demand ratio was found to be an important determinant for commercial air-source heat pump uptake, in addition to linear heat density. No air-source heat pumps are observed in zones in which commercial demand is less than 10%, independent of linear heat density. For example, even zone 20 which has a relatively

high linear heat density presents no air-source heat pump uptake in all three cases. Air-source heat pump adoption is determined by a combination between linear heat density and commercial demand participation. For example, zone 52 presents a relatively low linear heat density, with a high (over 80%) commercial demand, and the highest air-source heat pump uptake of all zones; over 66% for the three cases. On the other hand, zone 30 has high commercial demand participation but very high linear heat density, and thus no air-source heat pumps. Therefore, up to a certain threshold of linear heat density, commercial demand participation is the determining factor for the adoption of air-source heat pumps: high commercial demand zones present high air-source heat pump uptakes, while low commercial demand zones present low air-source heat pump uptakes. Above a certain level of linear heat density, linear heat density is more determinative than commercial demand participation in the adoption levels of air-source heat pumps.

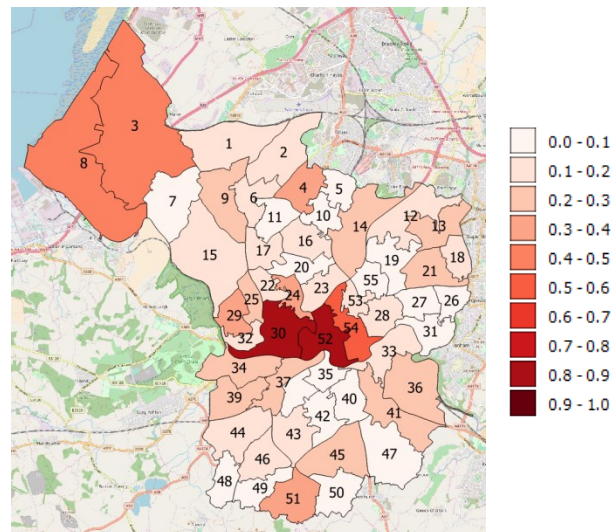


Figure 4-7: Ratio of commercial to total demand per zone

Finally, a sensitivity analysis was conducted for low and high price scenarios for gas and electricity [118] (see Appendix C, Table C-1 and Table C-2) and for low and high carbon price scenarios [120] (see Appendix C, Table C-3). These scenarios were studied for Case 1 –when only a high temperature heat network was available –and for Case 2 –when high and medium temperature heat networks were available. For both cases, each parameter was changed to the low and high prices while leaving the other two constant at central price scenarios. Figure 4-8 shows the results for Case 1, and Figure 4-9 shows the results for Case 2, for the low, central, and high gas, electricity, and carbon price scenarios.

Figure 4-8a), b), and c) show the heat network penetration over time for the mentioned scenarios, while Figure 4-8d) shows the total system's cost, total cost of carbon, and total system's CO₂

equivalent emissions, normalised to the highest value for each. These results show that the final heat network penetration by 2050 does not vary considerably for high and low electricity price scenarios, ranging from 68% to 71% respectively. For low and high gas price scenarios, heat network penetration varies from 67% to 74% respectively by 2050. Carbon price scenarios were observed to have the highest effect in heat network penetration, obtaining a range from 67% to 76% by 2050 for low and high carbon price scenarios respectively. For the low carbon price scenario, commercial and domestic boilers represent 6% and 13% of the total individual level installed heat supply capacity by 2050, with air-source heat pumps covering 14% of the individual level installed heat supply capacity. For the high carbon price scenario on the other hand, commercial and domestic boilers represent only 0.6% and 6.5% of the total individual level installed heat supply capacity, with air-source heat pumps covering 17% by 2050. The uptake of heat networks is faster and higher by 2050 for the high carbon price scenario, followed by the high gas price scenario. Figure 4-8d) shows that for the low carbon price scenario the cost of carbon and total system's cost are the lowest, while total carbon emissions are the highest, as more individual gas boilers are operating. For electricity prices on the other hand, the low price scenario generates lower carbon emissions, carbon costs, and total costs than the central and high price scenarios, as more district and individual level air-source heat pumps are purchased. Finally regarding gas prices, the lowest carbon emissions are reached in the high gas price scenario, as this generates the lowest participation of gas boilers. Of all scenarios modelled, the high gas price scenario is the one that generates the lowest total equivalent CO₂ emissions, followed by the high carbon price scenario, and then by the low electricity price scenario.

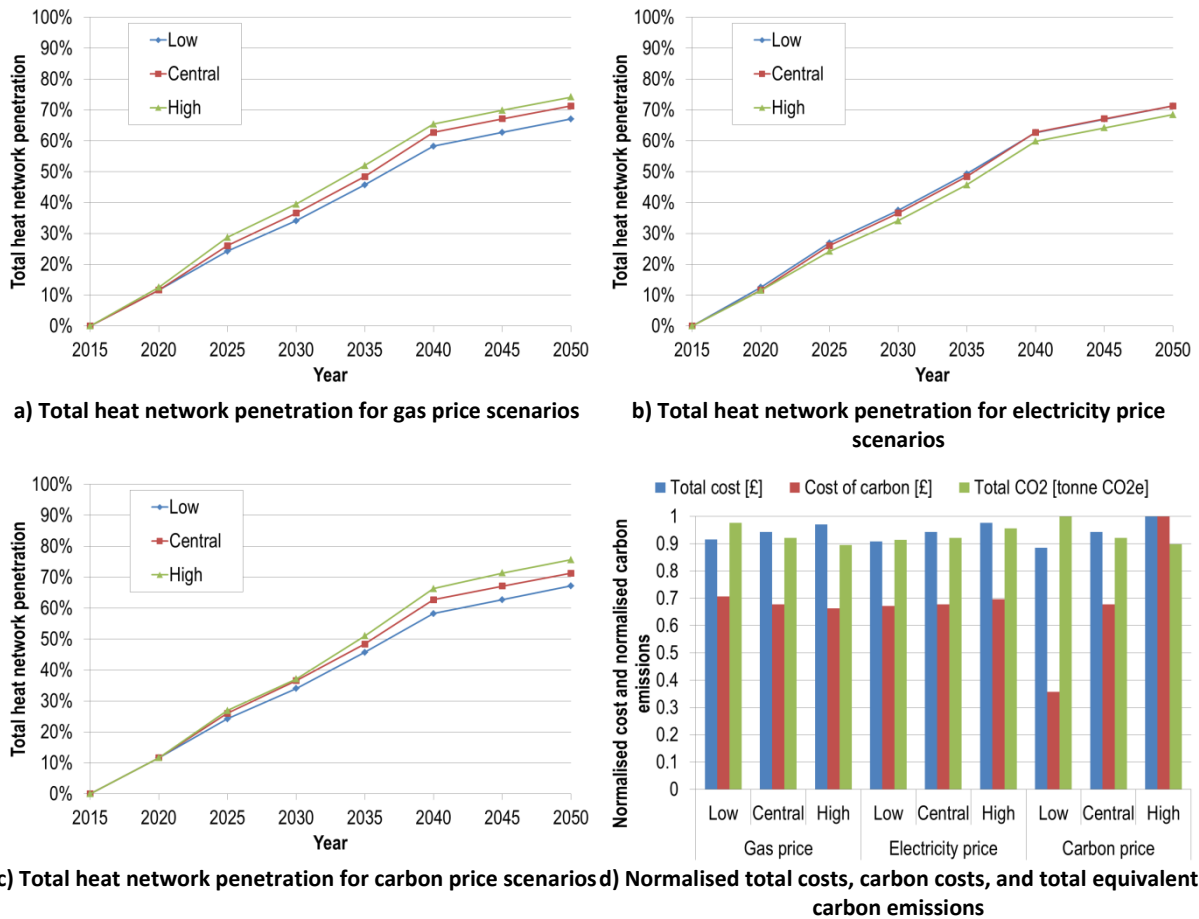
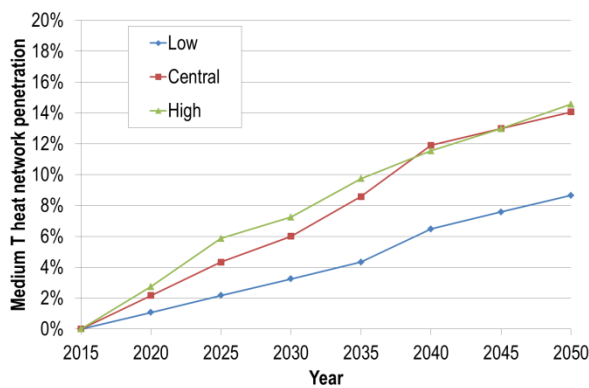


Figure 4-8: Sensitivity analysis for Case 1 –Only high temperature heat networks available

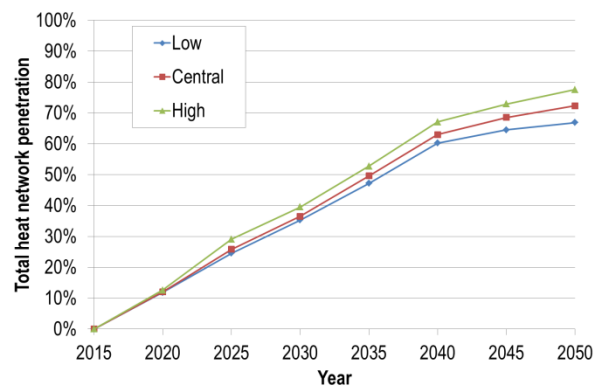
Figure 4-9a), c), and e) show the medium temperature heat network penetration over time for Case 2, while Figure 4-9b), d), and f) show the total heat network penetration over time for the aforementioned scenarios. Figure 4-9g) shows for Case 2 the total system's cost, total cost of carbon, and total system's CO₂ equivalent emissions, normalised to the highest value for each. As for Case 1, the total heat network penetration by 2050 is not considerably affected by electricity price scenarios, varying from 71% to 74% for high and low electricity prices. Moreover, the uptake of medium temperature heat networks is approximately the same by 2050 for all electricity price scenarios: around 14%. Gas price scenarios present a total heat network uptake by 2050 in the range of 67% and 78% corresponding to low and high prices respectively, with medium temperature heat networks representing 9% and 15% respectively. Low and high carbon prices generated a variation in total heat network penetration by 2050 from 68% to 77% respectively, with medium temperature heat network uptake displaying the most significant variation; from 9% to 17% respectively. Low and high carbon price scenario results are very similar to those of Case 1. For the low carbon price scenario commercial and domestic boilers represent 6% and 12% of the total individual level installed heat supply capacity by 2050, with air-source heat pumps corresponding to 14% of

individual level installed capacity. For the high carbon price scenario commercial and domestic boilers represent 0.5% and 6.5% of the total individual level installed heat supply capacity, with air-source heat pumps covering 16% by 2050. Slightly lower penetrations of gas boilers and heat pumps compared to those for Case 1 are attributed to higher overall heat network penetrations when two network temperatures are available.

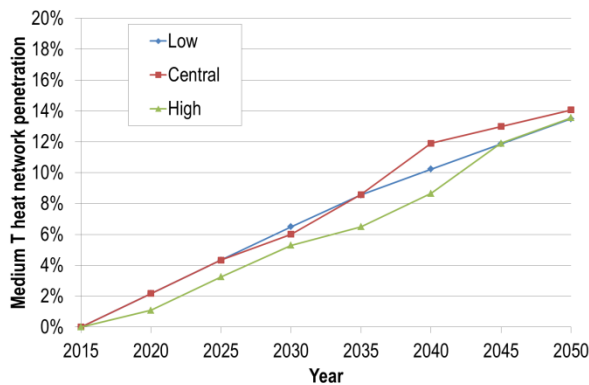
For Case 2, heat network uptake by 2050 is higher for the high gas followed by the high carbon price scenario. As for Case 1, Figure 4-9g) shows that the low carbon price scenario generates the lowest carbon and total system's cost with the highest carbon emissions, as more individual gas boilers are operating. The low electricity price scenario generates lower carbon emissions than for central and high scenarios, as air-source heat pumps are in operation. Finally the lowest carbon emissions are reached in the high gas price scenario when gas boilers display the lowest participation. As for Case 1, the high gas price scenario is the one that generates the lowest total equivalent CO₂ emissions of all, followed by the high carbon price and low electricity price scenarios.



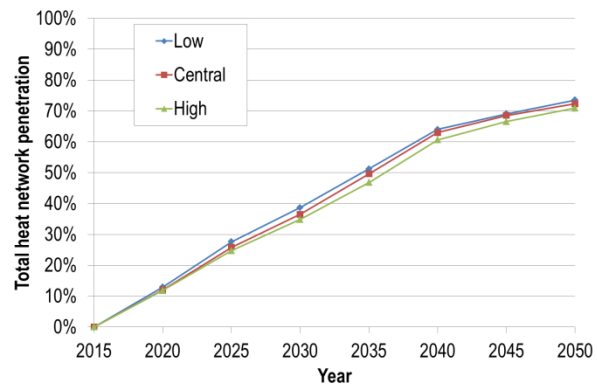
a) Medium temperature heat network penetration for gas price scenarios



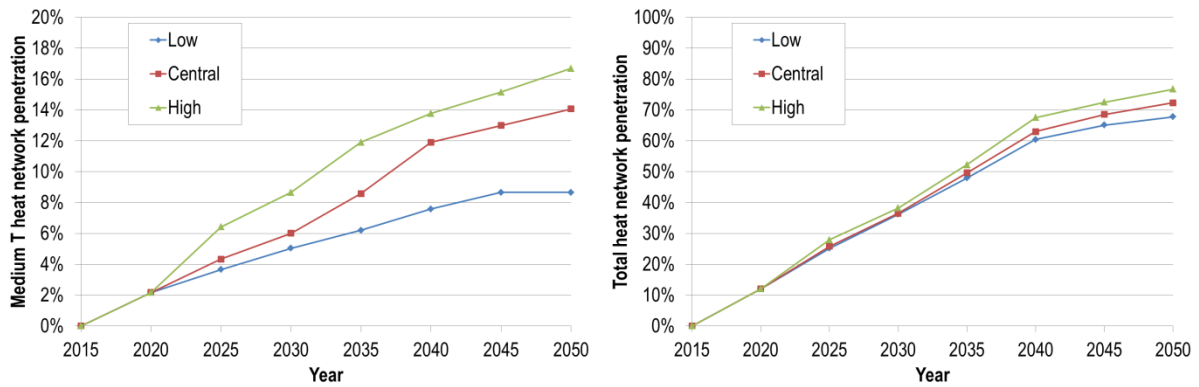
b) Total heat network penetration for gas price scenarios



c) Medium temperature heat network penetration for electricity price scenarios

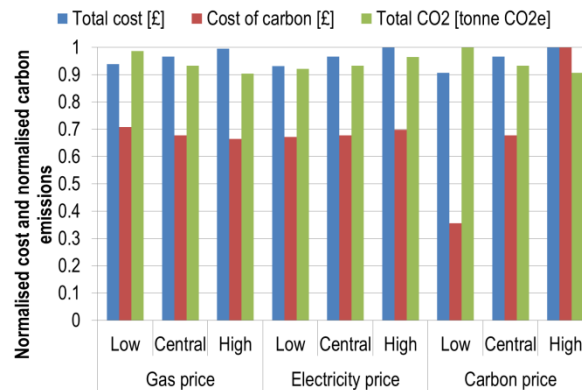


d) Total heat network penetration for electricity price scenarios



e) Medium temperature heat network penetration for carbon price scenarios

f) Total heat network penetration for carbon price scenarios



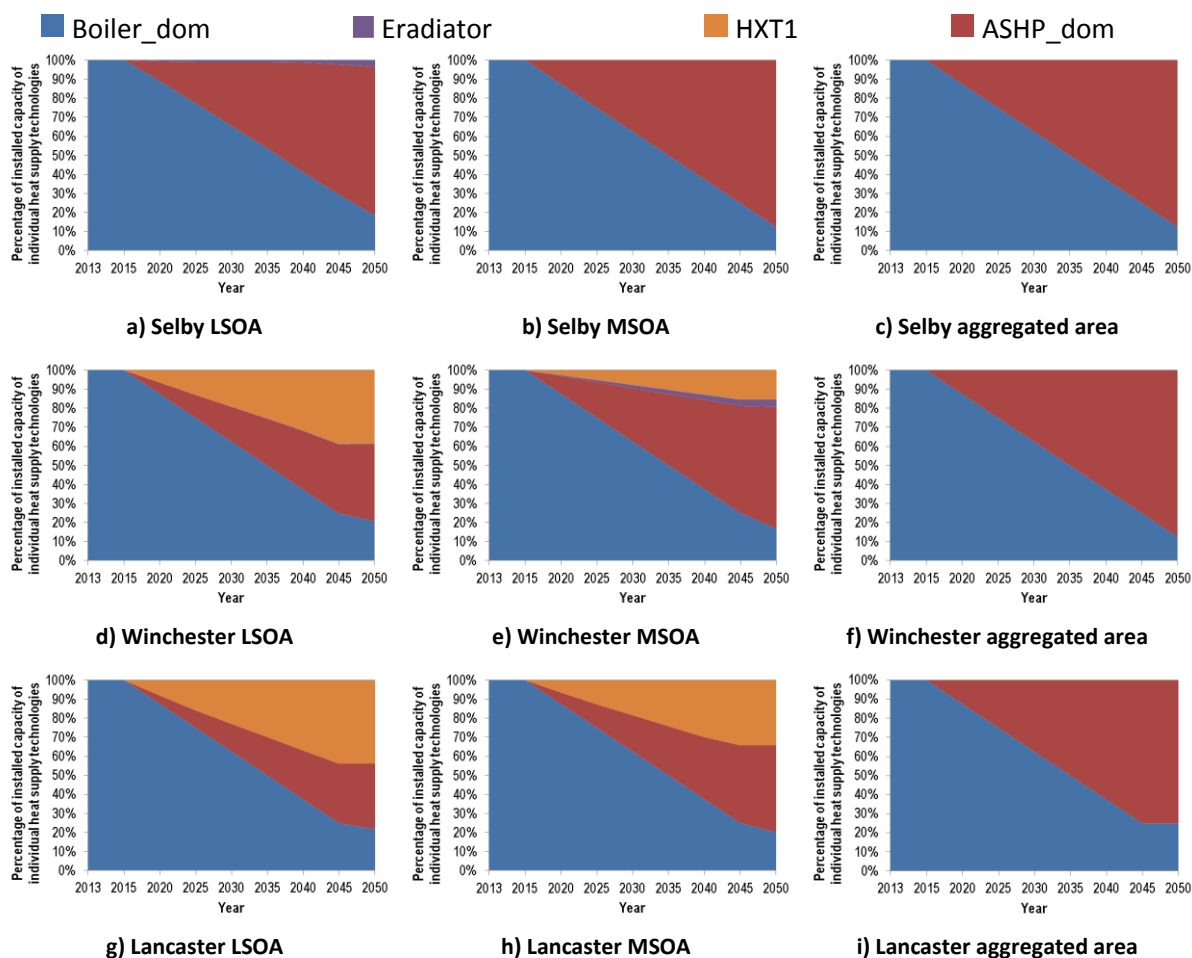
g) Normalised total costs, carbon costs, and total equivalent carbon emissions

Figure 4-9: Sensitivity analysis for Case 2 –High and medium temperature heat networks available

As set out by [12], action is required now in the UK for lowering carbon emissions from heat. Opportunities include installing individual building heat pumps, low carbon heat networks in cities, or increasing biomethane injection into the gas grid. This model provides a tool for studying the most cost-effective pathways for implementing these measures. For example, for the three cases and scenarios detailed previously results show a cost-effective timeline for installing high and medium temperature networks in different zones, and the total cost-effective heat network penetration per zone according to its linear heat density and demand topology. For the particular case of Bristol, according to [143], the Bristol City Council is planning to install heat networks across the City for supplying low carbon heat and power, in order to achieve their CO₂ emissions reduction targets of 80% by 2050 (and intermediate milestones as well). Among others, one example of how this model can be applied for energy policy planning would be implementing a cap on total carbon emissions for different time periods in order to achieve specific reduction targets, and finding cost-effective strategies to achieve these targets.

Chapter 5. The effect of spatial resolution in outcomes of energy systems models for heat

Figure 5-1 shows the percentage of total installed capacity through 2050 of individual level heat supply technologies for the six modelled Local Authorities, and for the three spatial resolution levels. With modelled gas, electricity, and carbon price scenarios and for the assumed techno-economic parameters for equipment and infrastructure, heat is supplied at the individual residential level by a mixture of air-source heat pumps, gas boilers, electric radiators, and heat exchangers connected to heat networks. For all six Local Authorities corresponding to different urban/rural classifications, results show that cost-effective heat decarbonisation pathways and heat supply technology mixes vary through 2050 depending on the spatial resolutions used for modelling.



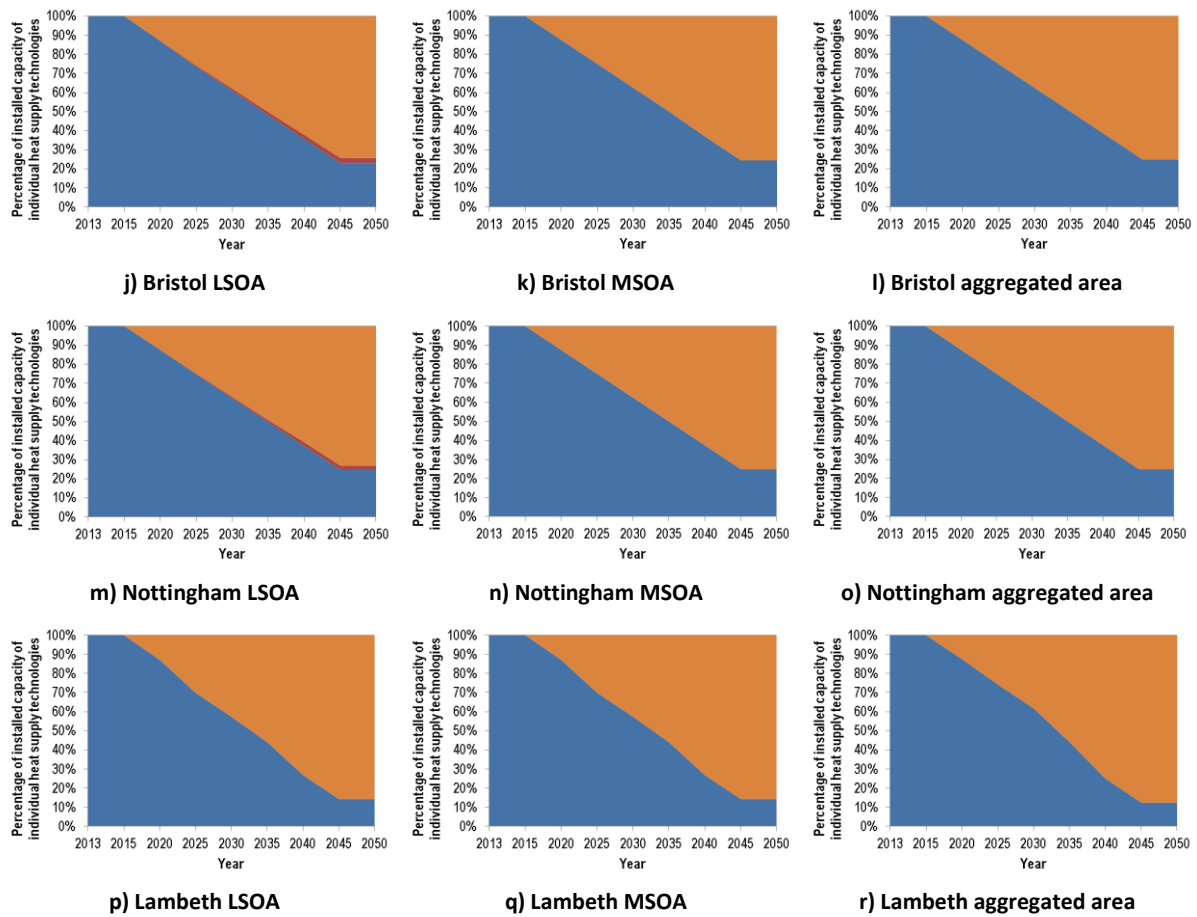


Figure 5-1: Total installed capacity of individual level heat supply technologies for 6 local authorities and spatial resolutions

Figure 5-2 shows the difference defined in Equation (5.1) in heat network uptake between MSOA or total aggregated area resolutions, and LSOA resolution. Figure 5-3 shows the difference in air-source heat pump uptake between MSOA or total aggregated area resolutions, and LSOA resolution.

$$\begin{aligned} \text{Difference} = & |(LA \text{ or MSOA heat network uptake}) \\ & - (LSOA \text{ heat network uptake})| \end{aligned} \quad (5.1)$$

These figures show that when modelling the total aggregated area, differences of up to 44% of heat network uptakes and 48% of air-source heat pump uptakes are observed in relation to LSOA resolution level. When modelling MSOA resolution level, differences of up to 24% are found for heat network and air-source heat pump uptake with respect to LSOA resolution level.

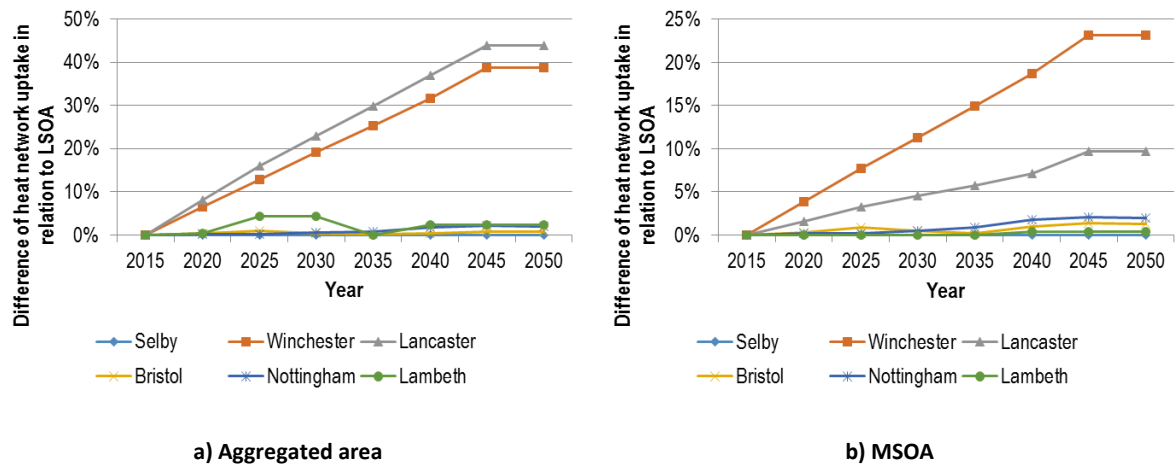


Figure 5-2: Difference in heat network uptake in relation to LSOA resolution

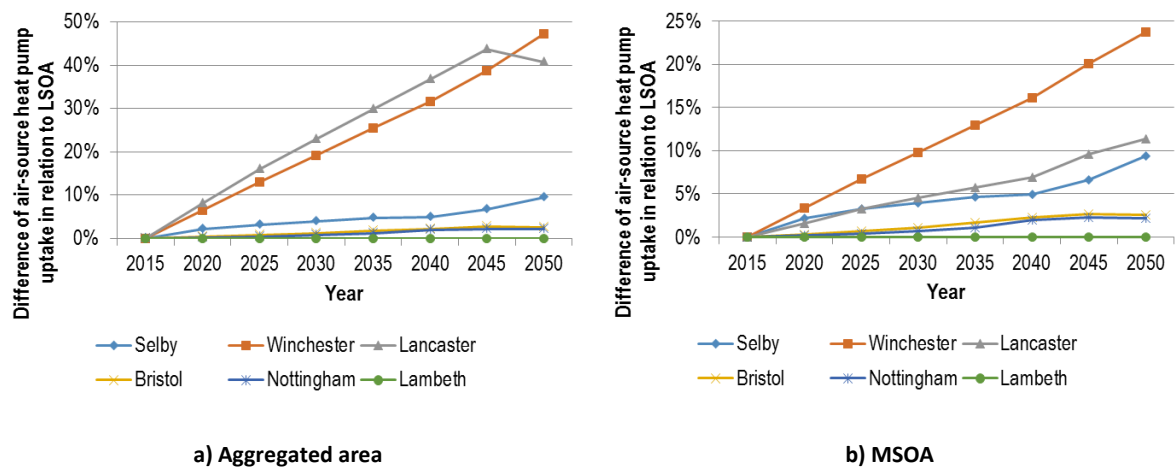


Figure 5-3: Difference in air-source heat pump uptake in relation to LSOA resolution

When analysing Figure 5-1, Figure 5-2, and Figure 5-3, a very small difference is observed between the three resolution levels for the case of Lambeth. Similarly, small differences are observed between results for the three resolution levels for the cases of Nottingham and Selby. These three Local Authorities represent the high and low extremes of linear heat densities (see Figure 3-5). Technology uptake thresholds are observed to be highly dependent on linear heat density, particularly for district heating [144, 145]. One of the reasons for this is that networks represent a very important part of district heating costs. The capital costs of pipes, insulation, and particularly the cost of building trenches, are high compared to, for example, electricity networks. Therefore, it becomes cost-effective to install heat networks when a sufficient number of dwellings can be served per unit length, as this achieves lower costs per dwelling than if dwellings are located far from each other in low linear heat dense areas. For these techno-economic parameters, heat networks are observed to replace boilers when reaching a certain linear heat density threshold, while air-source heat pumps replace gas boilers under this threshold. When all or most of the zones fall over the

linear heat density threshold, as Lambeth, only heat networks are observed. Equally when all zones fall under the linear heat density threshold, as Selby, mostly air-source heat pumps are observed. This shows that spatial resolution is important for modelling heat supply pathways when there is enough variability of linear heat density over zones. An important implication of this result is that when modelling homogeneous zones it may be more efficient to model more aggregated areas. However, results are scenario-specific and dependent on input techno-economic parameters, which means that if other technologies were introduced in the model or different costs were assumed, the heat density thresholds for technology adoption could change. Thus, which cases fall into high and low extremes are scenario-specific.

Figure 5-4 shows results for the case of Lambeth in further detail. Comparing Figure 5-4a) with b), c) and d), and comparing Figure 5-4e) with f), g), and h), the correspondence between linear heat density and heat network penetration is observed for LSOA and MSOA levels, especially by 2030. Figure 5-4 also shows that even for this urban area with the highest overall linear heat density, a wider range of linear heat densities is observed across zones at LSOA level compared to MSOA level. This translates into some zones having lower adoption of heat networks, even by 2050. These results show that spatial resolution is a key factor if these types of models are used for informing decisions regarding cost-effective network design and expansion. For all the cases modelled, even when the average network penetration for MSOA resolution is similar to the total LSOA network penetration, a more spatially resolved model shows which specific zones would benefit more from heat networks, which allows for more cost-effective planning.

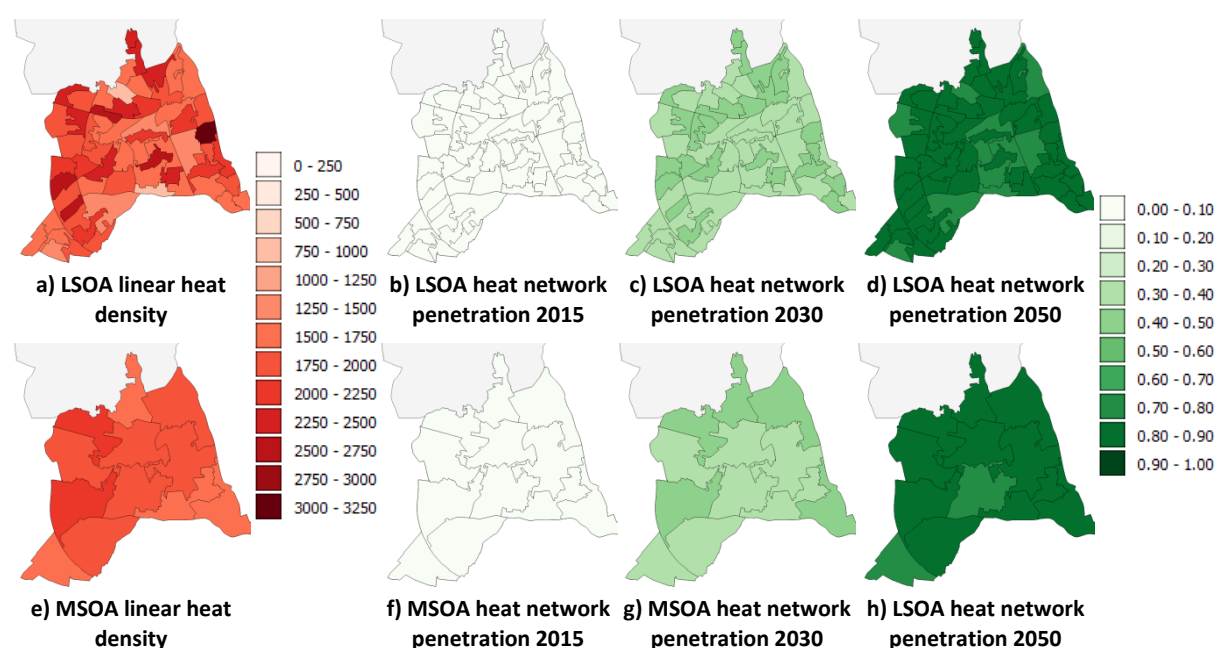


Figure 5-4: Lambeth linear heat density [kWh/m] and heat network penetration for LSOA and MSOA resolution levels.

Figure 5-5 shows detailed results for the case of Lancaster. As for the case of Lambeth, a direct relationship between linear heat density and heat network penetration is observed, and an inverse relationship between linear heat density and air-source heat pump penetration can be seen. This case is also a good illustration of how finer spatial resolution affects outcomes in systems models for heat. As seen in Figure 5-1, Figure 5-2, and Figure 5-3, the cases of Lancaster and Winchester present the highest differences in heat pump and heat network uptake between resolution levels. Winchester is defined as largely rural, while Lancaster is defined as urban with significant rural. This means that these two Local Authorities present wider heat demand (or linear heat density) variations throughout their areas, responding to the mixture between urban and rural MSOAs. Therefore, as observed in Figure 5-5a) and Figure 5-5h), a wider range of linear heat densities is observed at the LSOA resolution level compared to the MSOA level, and obviously compared to the single aggregated area resolution. For largely urban areas, even though there can be significant linear heat density variations between zones –as for example the case of Lambeth –linear heat densities are high enough to fall over the uptake thresholds discussed previously in Chapter 4, and therefore not necessarily affect final heat network or heat pump penetrations. Since Lancaster has a mixture of urban and rural zones, average linear heat densities per zone vary more widely and can fall over or under adoption thresholds when using different resolutions to model the same area. This is made clear when comparing LSOA versus MSOA heat network and heat pump penetrations by 2050 in Figure 5-5, demonstrating again how spatial resolution is a key factor when using these types of models to inform cost-effective energy planning.

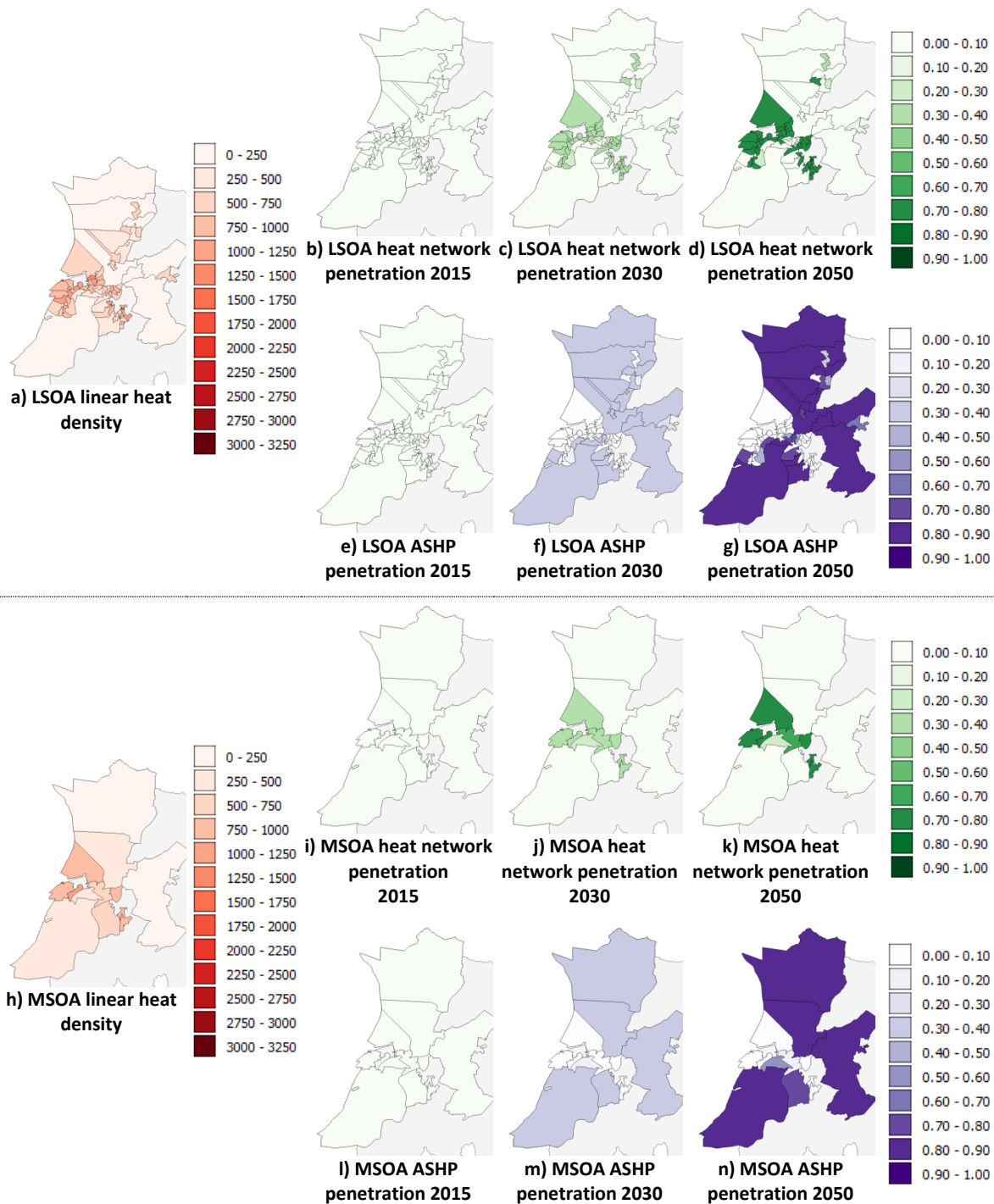


Figure 5-5: Lancaster linear heat density [kWh/m], heat network penetration, and air-source heat pump (ASHP) penetration per zone for MSOA and LSOA spatial resolution levels

For all the cases studied and the assumed techno-economic parameters, when heat networks were installed they were served by a combination of district level gas boilers and air source heat pumps. Figure 5-6 shows the location and capacity of district level heat supply technologies for the case of Bristol, by 2050. When designing a heat network, the LSOA resolution level provides more precise information on the optimal location and capacity of technologies. Moreover, it can be observed that

not all LSOA district heating supply technology locations correspond with MSOA locations. This can be attributed to the effect of averaging demand throughout larger areas at MSOA level, and on the difference in demand topology when modelling different resolution levels. Furthermore, the total aggregated area resolution level only provides information of aggregated capacity. This reinforces the previously discussed idea on the importance of spatial resolution when using models to inform cost-effective network planning and design.

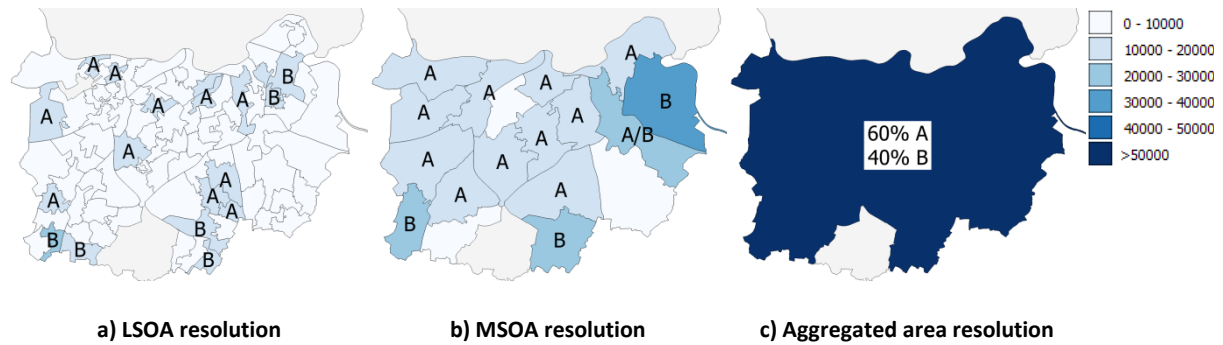


Figure 5-6: Bristol capacity [kW] and location of district level heat supply technologies by 2050. A: District level air-source heat pumps. B: District level gas boilers.

Finally, a sensitivity analysis was conducted for the case of Lancaster by changing gas, electricity, and carbon prices to low and high, while leaving the other two constant at central prices. Table 5-1 shows the scenario numbers and parameters varied for the analysis.

Table 5-1: Scenarios for sensitivity analysis. See Appendix C, Table C-1, Table C-2, and Table C-3.

Scenario	S1	S2	S3	S4	S5	S6
Parameter	Low gas prices [118]	High gas prices [118]	Low electricity prices [118]	High electricity prices [118]	Low carbon prices [120]	High carbon prices [120]

Figure 5-7(a)-(c) show the differences in heat network penetration between MSOAs and LSOAs, and between LSOAs and total aggregated areas, for the six price scenarios. Figure 5-8(a)-(c) show the differences in air-source heat pump penetration between resolution levels for the different price scenarios. Firstly, for all scenarios, a general tendency of increasing differences in air source heat pump and heat network penetrations between resolution levels is observed throughout the modelling time horizon. Low gas, electricity, and carbon price scenarios present higher differences than their high price scenario counterparts when comparing both LSOA against MSOA resolutions, and LSOA against aggregated area resolutions. The only point in which the high price scenario presents a higher difference than the low price scenario is in air-source heat pump penetration in 2050, when comparing LSOA versus aggregated area at high carbon prices. For all scenarios studied, differences in heat network penetration between LSOA and aggregated area resolutions reach 40%

to 50% by 2050, and 7% to 13% when comparing LSOA with MSOA resolutions. For heat network penetration, the highest differences between LSOA and aggregated areas and between LSOAs and MSOAs are found for low electricity prices (49% and 13% respectively by 2050). This can be explained because a low electricity price scenario makes heat pumps more competitive, therefore moving the linear heat density adoption threshold for heat networks (discussed previously in Chapter 4) to a higher value. As Lancaster is an area with rural and urban zones, more zones will fall under the threshold, independently if they are aggregated or not. Although high carbon and high gas prices could also have this effect, Figure 5-7(b) shows that the low electricity price scenario produces the highest effect in heat network uptake differences between resolution levels.

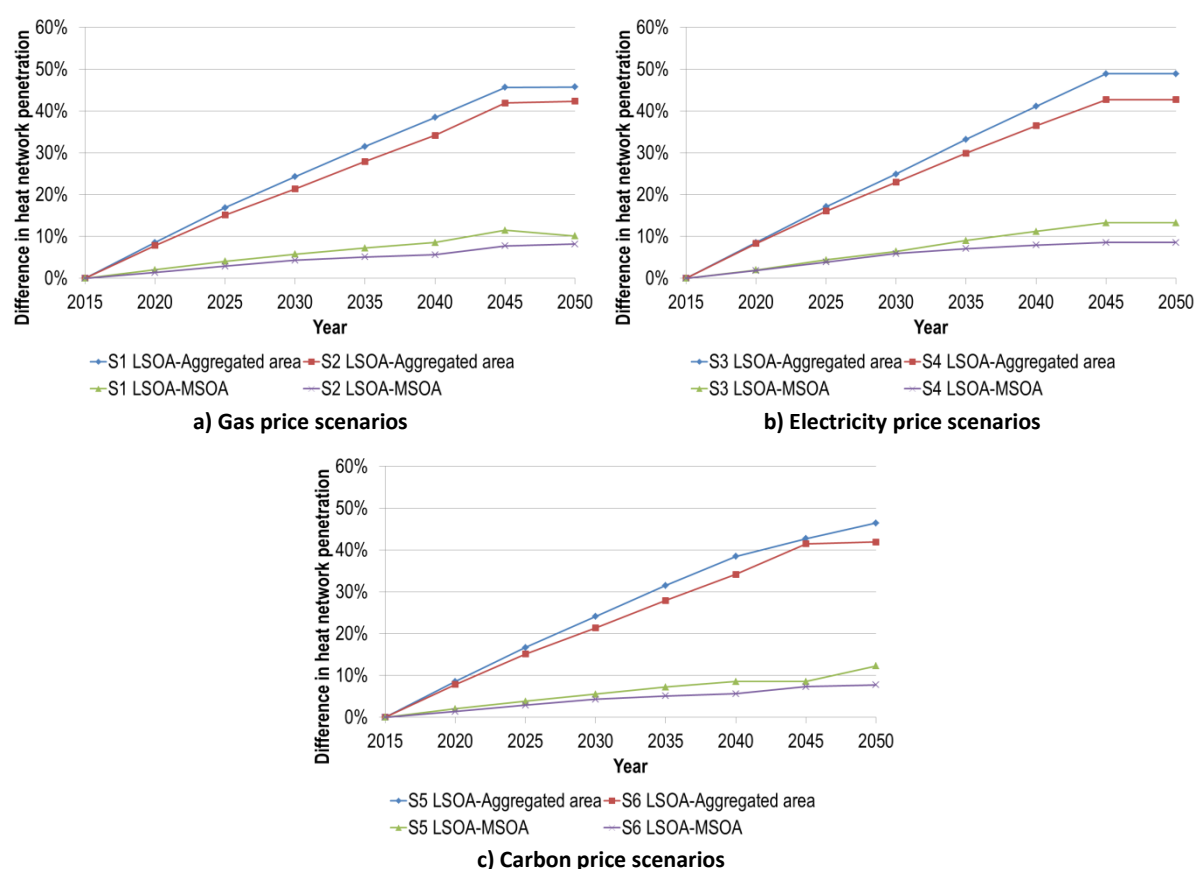


Figure 5-7: Difference in heat network penetration between resolution levels for different gas, electricity, and carbon price scenarios – Lancaster

Differences in air-source heat pump uptakes between LSOA and aggregated area resolutions also reach 40% to 50% by 2050, and 8% to 13% when comparing LSOA with MSOA resolutions. The highest difference when comparing LSOA with aggregated area resolutions is for high carbon prices (50% by 2050), followed by low electricity prices (46%); and for low electricity prices when comparing differences between LSOAs and MSOAs (13%). Again, as for heat network penetrations, these scenarios make heat pumps more competitive. Therefore the linear heat density adoption

threshold for heat networks is moved to higher values, with more zones falling under the threshold and thus making heat-pump adoption more cost-effective for a mixed urban/rural area as Lancaster.

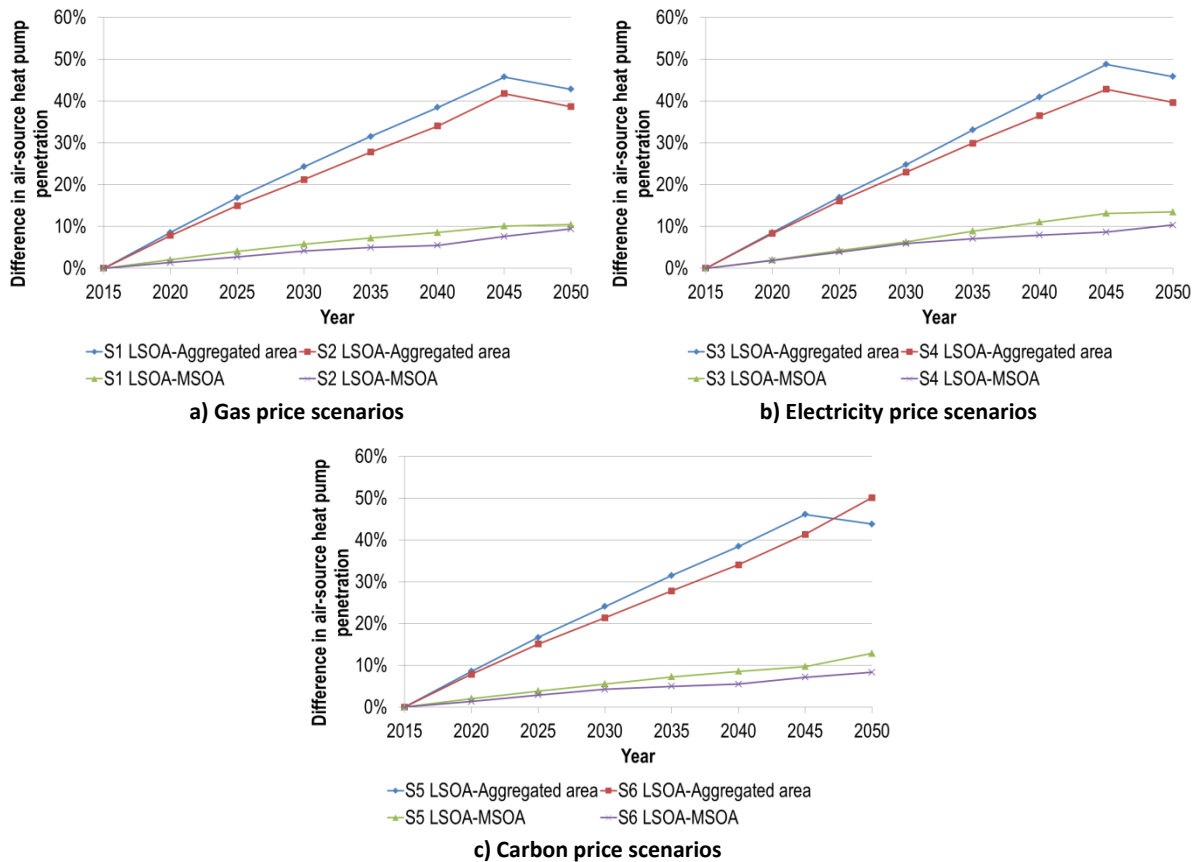


Figure 5-8: Difference in air-source heat pump penetration between resolution levels for different gas, electricity, and carbon price scenarios – Lancaster

Finally it is worth noting that the spatial resolutions here modelled are closely related to the UK available data. The resolutions chosen were MSOA and LSOA levels because of available heat and gas demand and consumer data. Also, the decision of only modelling the domestic sector was made because of the lack of demand data for the commercial sector at LSOA levels. Arguably there are optimal spatial resolutions beyond the ones here modelled that could provide more cost-effective or detailed outcomes. The spatial resolutions in each study need to be assessed depending on what type of outputs are being sought, as previously mentioned. However, it is important to acknowledge that the spatial resolutions used in each study will be subject to the type of inputs of each model, and are many times constrained by the corresponding data availability. Additionally, aggregation levels will also determine the tractability of the involved models. Therefore, other factors such as the extension of the modelled regions are also crucial when defining spatial resolutions in each study.

Chapter 6. The role of hydrogen in heat decarbonisation

6.1 Independent hydrogen network

This section presents results for Formulation A, when the hydrogen network is modelled independently of the gas network. The share of individual level heat supply technologies for Formulation A was the same for hydrogen price scenarios HP1 and HP2, and for the both hydrogen emission scenarios HE1 and HE2. Results are shown in Figure 6-1. In the domestic sector, as the gas network is decommissioned towards 2050, gas boilers are replaced by heat exchangers connected to heat networks, reaching 85% of the domestic supply capacity by 2050. In the commercial sector, gas boilers are progressively replaced towards 2050 by a combination of heat exchangers and air-source heat pumps. By 2050, the participation of air source heat pumps reaches 64% of the commercial installed capacity, and 16% of the total installed capacity. Heat exchangers on the other hand represent 30% of the installed commercial heat supply capacity, and 71% of the total heat supply installed capacity by 2050. No participation of hydrogen technologies is observed in the domestic or commercial sectors. For all these scenarios, heat networks are supplied by air-source heat pumps together with gas boilers, as shown in Figure 6-2. Therefore, the lower hydrogen network costs compared to heat network costs do not offset the lower end-use technology costs (heat exchangers versus hydrogen technologies), together with the gains in efficiency and eventual gains in carbon costs of district level air-source heat pumps.

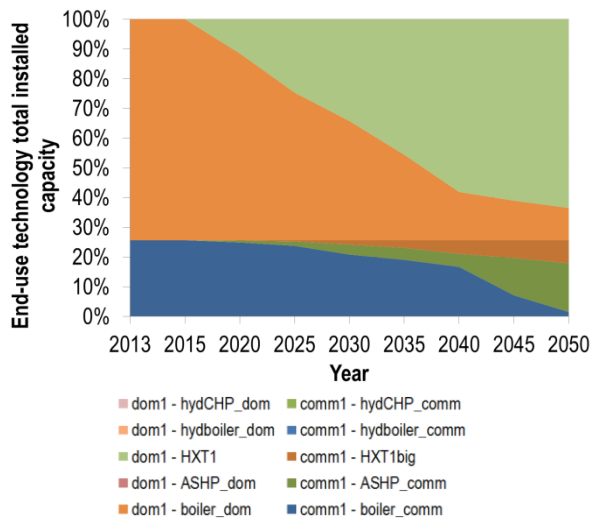


Figure 6-1: Total installed capacity of individual level heat supply technologies. Formulation A – Hydrogen price scenarios HP1 and HP2 and both emission scenarios.

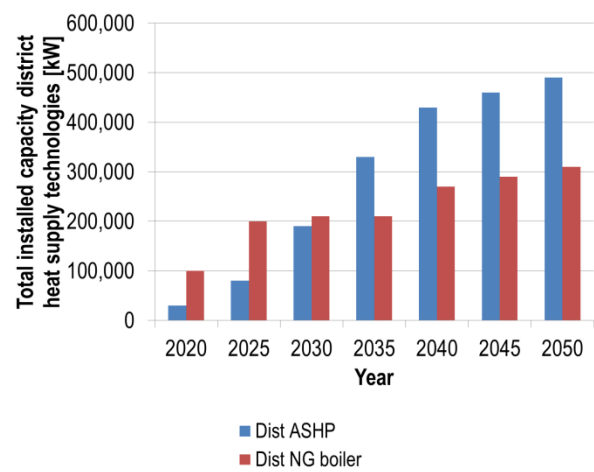


Figure 6-2: Total installed capacity of district level heat supply technologies. Formulation A – Hydrogen price scenarios HP1 and HP2 and both emission scenarios.

For hydrogen price scenario HP3 (low hydrogen price projection), and emission scenario HE1 (which includes emissions used for electricity used in carbon sequestration), the end-use technology mix is almost the same as for the previously discussed scenarios, as observed in Figure 6-3. For this case, heat network penetration reaches 86% of the domestic installed capacity, 26% of the commercial installed capacity, and 71% of the total heat supply installed capacity by 2050. Individual air-source heat pump penetrations on the other hand reach 65% of the commercial installed capacity and 17% of the total heat supply installed capacity by 2050. For this case, heat networks are supplied initially by district level air source heat pumps and gas boilers, with district level hydrogen boilers being purchased from 2035 onwards, and progressively replacing natural gas boilers, as shown in Figure 6-4. Therefore for a low hydrogen price scenario, hydrogen boilers become competitive for supplying heat networks when considering independent hydrogen networks.

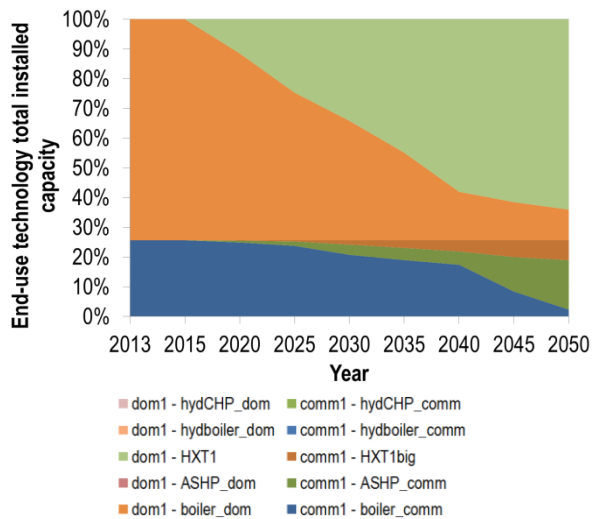


Figure 6-3: Total installed capacity of individual level heat supply technologies. Formulation A – Hydrogen price scenarios HP3 and emission scenario HE1.

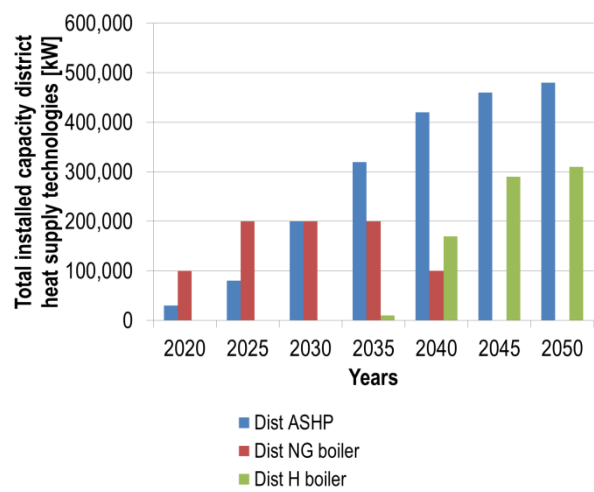


Figure 6-4: Total installed capacity of district level heat supply technologies. Formulation A – Hydrogen price scenarios HP3 and emission scenario HE1.

Finally, for low hydrogen price scenario HP3 and emission scenario HE2 (which excludes emissions used for electricity used in carbon sequestration), results for the end-use technology mix and district level heat supply technologies are shown in Figure 6-5 and Figure 6-6 respectively. For this case, the penetration of individual level heat supply technologies for the domestic sector is approximately the same as for the previous cases, with heat exchangers connected to heat networks progressively replacing gas boilers and reaching 85% of the domestic heat supply installed capacity by 2050. However the end-use technology mix for the commercial sector differs from the previous cases, as there is a very low penetration of district heating: only 1% of the commercial installed heat supply capacity. Instead, hydrogen boilers take its place, reaching 34% of the commercial installed capacity by 2050. Air-source heat pumps continue playing an important role in supplying commercial heat demand, representing 59% of the commercial installed capacity by 2050. Regarding the total installed capacity for this case, air-source heat pumps, district heating, and hydrogen boilers represent 15%, 64%, and 9% of the total share by 2050. This shows that the lower costs associated to hydrogen emissions for this scenario are able to offset the network and technology costs in the commercial sector, compared to district heating. With regards to district heat supply technologies, in this case (as in the previous case) heat networks are supplied initially by district level air-source heat pumps and gas boilers. From 2040 on, as gas boilers are decommissioned, hydrogen boilers take their place. The total supply capacity is lower than in previous cases, as hydrogen boilers are installed in the commercial sector to the detriment of district heating.

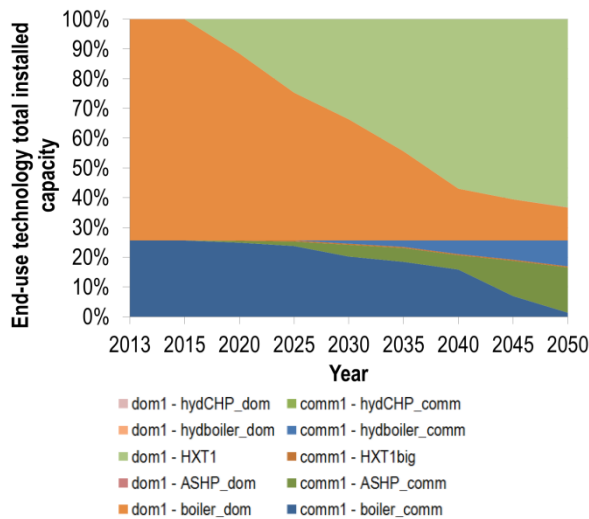


Figure 6-5: Total installed capacity of individual level heat supply technologies. Formulation A – Hydrogen price scenarios HP3 and emission scenario HE2.

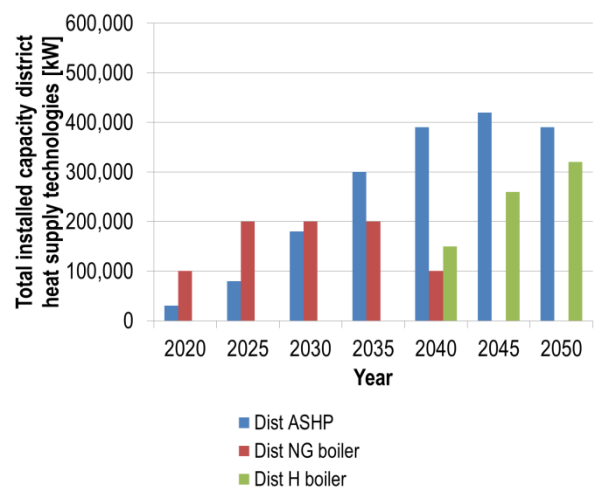


Figure 6-6: Total installed capacity of district level heat supply technologies. Formulation A – Hydrogen price scenarios HP3 and emission scenario HE2.

Table 6-1 shows a summary of the figures that represent results for total installed capacity of individual level heat supply technologies and total installed capacity of district level heat supply technologies, for the 2 hydrogen emission and 3 hydrogen price scenarios described in Table 3-13 and Table 3-14, for Formulation A.

Table 6-1: Summary of figures for installed capacity of individual and district level heat supply technologies for Formulation A, according to hydrogen emission and price scenarios described in Table 3-13 and Table 3-14.

Hydrogen emissions scenarios	Hydrogen price scenarios		
	HP1	HP2	HP3
HE1	Figure 6-1, Figure 6-2	Figure 6-1, Figure 6-2	Figure 6-3, Figure 6-4
HE2	Figure 6-1, Figure 6-2	Figure 6-1, Figure 6-2	Figure 6-5, Figure 6-6

Figure 6-7 shows the heat network penetration per zone by 2050, for Formulation A, hydrogen price scenarios HP1 and HP2, and both hydrogen emission scenarios. Figure 6-8 and Figure 6-9 show the heat network penetration by 2050 for hydrogen price scenario HP3, and emission scenarios HE1 and HE2 respectively. General results for technology uptakes are strongly dependant on linear heat density (Figure 3-3), as discussed in Chapter 4. Linear heat density adoption thresholds are also case and scenario specific, and dependant on demand topology and on the commercial/domestic demand ratio. With this in mind, general adoption thresholds are hereafter described. For the scenarios represented in Figure 6-7, when there is no uptake of hydrogen networks, results are as described in Chapter 4, Scenario 1, Case 1: for linear heat densities of over 250 kWh/m, 1250 kWh/m, and 2250 kWh/m, heat network penetration is over 40%, 60%, and 90% respectively by 2050. For hydrogen price scenario HP3, emission scenario HE2, it can be observed from Figure 6-9

that heat network penetration increases with linear heat density, up to a linear heat density of between 2000 and 2250 kWh/m. Beyond this threshold, heat network penetration begins to diminish. Under this threshold, for linear heat densities over 500 kWh/m and 1250 kWh/m, heat network penetration is greater than 40% and 60% respectively.

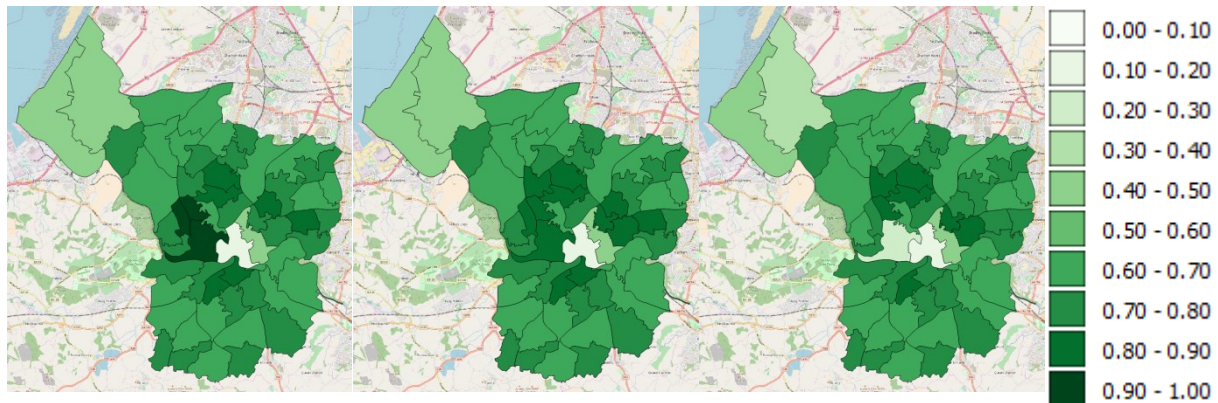


Figure 6-7: Heat network penetration by 2050, formulation A, hydrogen price scenarios HP1 and HP2, hydrogen emission scenarios HE1 and HE2.

Figure 6-8: Heat network penetration by 2050, formulation A, hydrogen price scenario HP3, hydrogen emission scenario HE1.

Figure 6-9: Heat network penetration by 2050, formulation A, hydrogen price scenario HP3, hydrogen emission scenario HE2.

For hydrogen price scenarios HP1 and HP2, and both emission scenarios; and for hydrogen price scenario HP3 and emission scenario HE1, no individual level hydrogen boilers were installed (as discussed previously for Figure 6-1 and Figure 6-3). For these scenarios the adoption of air-source heat pumps was exactly as discussed previously in Chapter 4, Scenario 1, Case 1: Up to a certain threshold of linear heat density air-source heat pump uptakes are directly related to commercial demand levels. For hydrogen price scenario HP3 and hydrogen emission scenario HE2, Figure 6-10 and Figure 6-11 shows the hydrogen boiler and air-source heat pump penetrations respectively by 2050. In this scenario, while air-source heat pumps are installed as previously discussed, the uptake of hydrogen boilers is directly related to higher linear heat density zones. Hydrogen boiler installation begins at linear heat densities above 2000 kWh/m, with uptakes over 10% by 2050. At linear heat densities over 2250 kWh/m, hydrogen boiler penetration is more than 20% by 2050. More varied linear heat density zones over this range would be needed to find further adoption thresholds, but for the highest linear heat density zone (beyond 3750 kWh/m), an uptake of over 70% of hydrogen boilers was observed by 2050.

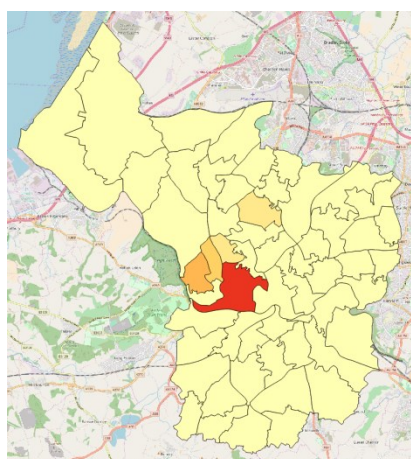


Figure 6-10: Hydrogen boiler penetration by 2050, formulation A, hydrogen price scenario HP3, hydrogen emission scenario HE2.

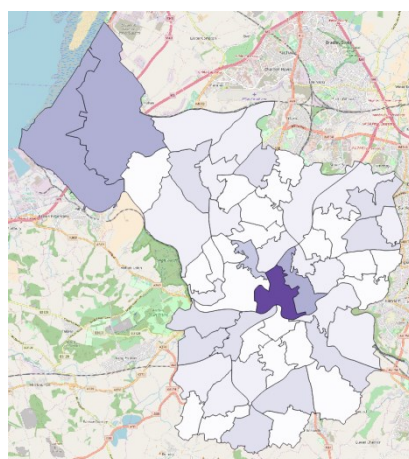
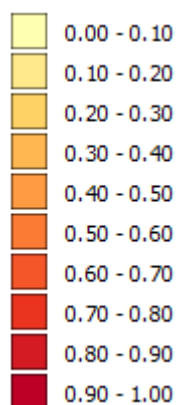


Figure 6-11: Air-source heat pump penetration by 2050, formulation A, hydrogen price scenario HP3, hydrogen emission scenario HE2.

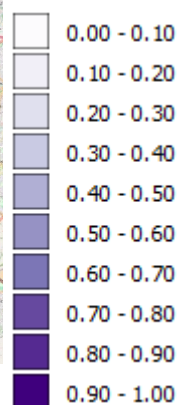


Table 6-2 shows a summary of the figures for heat network, air-source heat pump, and hydrogen boiler penetrations per zone by 2050, which represent results for the analysed scenarios modelled through Formulation A.

Table 6-2: Summary of figures for heat network, air-source heat pump, and hydrogen boiler penetrations by 2050 for Formulation A, according to hydrogen emission and price scenarios described in Table 3-13 and Table 3-14.

Hydrogen emissions scenarios	Hydrogen price scenarios		
	HP1	HP2	HP3
HE1	Figure 6-7	Figure 6-7	Figure 6-8
HE2	Figure 6-7	Figure 6-7	Figure 6-9, Figure 6-10, Figure 6-11

6.2 Retrofitting the gas network to transport hydrogen

In this section, results are analysed for Formulation B, when the option of retrofitting the existing gas network to convert it into hydrogen is in place. Section 6.2.1 describes the scenarios in which gas networks are imposed to decommission linearly through 2050, and costs for new gas networks are as defined for *HGn* in Table 3-12. Section 6.2.2 describes and discusses the results for the scenario in which gas network costs are considered to be a sunken cost because of the Mains Replacement Programme, and therefore no costs are associated to new gas networks.

6.2.1 Normal gas network costs

When considering the possibility to retrofit the gas network, added to the constraint that gas networks are decommissioned linearly from 2015 to 2050 results are very similar to those in Section 6.1. This is because in order to install hydrogen networks, the gas network needs to be rebuilt (as it

was previously decommissioned), and a marginal added cost per kilometre is summed in order to retrofit it into hydrogen (the added cost is marginal compared to other network costs). For hydrogen price scenarios HP1 and HP2, results are exactly as results obtained previously in Section 6.1. For hydrogen price scenario HP3, Table 6-3 shows which figures correspond to which hydrogen price and emission scenarios.

Table 6-3: Summary of figures for installed capacity of individual and district level heat supply technologies for Formulation B, according to hydrogen emission and price scenarios described in Table 3-13 and Table 3-14.

Hydrogen emissions scenarios	Hydrogen price scenarios		
	HP1	HP2	HP3
HE1	As Section 6.1	As Section 6.1	Figure 6-12, Figure 6-13
HE2	As Section 6.1	As Section 6.1	Figure 6-14, Figure 6-15

Results for hydrogen price scenario HP3 and hydrogen emission scenario HE1 are very similar to results for the same scenario for Formulation A (presented in Figure 6-3 and Figure 6-4), and are shown in Figure 6-12 and Figure 6-13. As in the same scenario for Formulation A, heat network penetration reaches 86% of the domestic installed capacity by 2050, however with a slightly higher participation of commercial installed capacity, with 31% penetration of the commercial demand by 2050. Individual air-source heat pumps reach 62% of the commercial installed capacity and 16% of the total heat supply installed capacity by 2050. The difference with respect to the Formulation A equivalent scenario, lies in the fact that in Formulation A, the model chooses to install a slightly higher capacity of hydrogen boilers to supply heat networks, while in this case a higher penetration of district level air source heat pumps is observed. This is because for the former, hydrogen infrastructure is slightly cheaper.

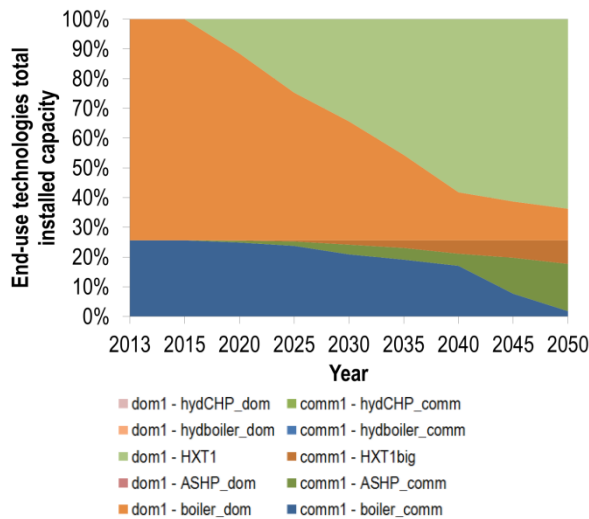


Figure 6-12: Total installed capacity of individual level heat supply technologies. Formulation B – Hydrogen price scenario HP3 and emission scenario HE1.

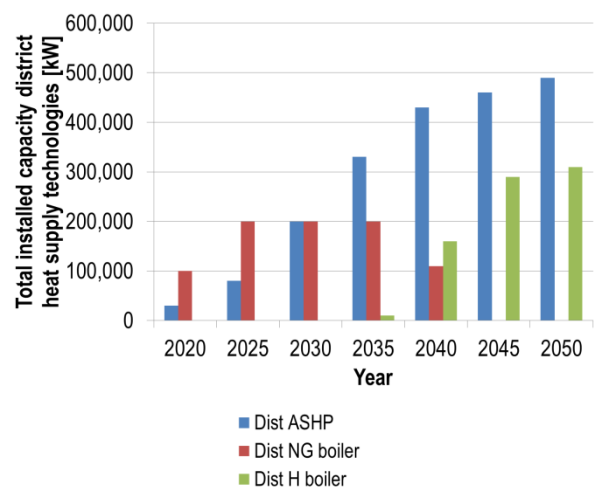


Figure 6-13: Total installed capacity of district level heat supply technologies. Formulation B – Hydrogen price scenario HP3 and emission scenario HE1.

Finally, for low hydrogen price scenario HP3 and emission scenario HE2, end-use and district level heat supply technology results are presented in Figure 6-14 and Figure 6-15. Compared to results for the same scenario in Formulation A, while the domestic sector's technology mix is approximately the same with a progressive uptake of heat networks that reaches 86% of the domestic installed capacity by 2050, the commercial sector's results are different. For this formulation, heat supply in the commercial sector is an intermediate result between hydrogen emission scenarios HE1 and HE2, for Formulation A's HP3 hydrogen price scenario. For the commercial sector, hydrogen boiler participation is lower than previously, reaching 21% of the commercial installed capacity in 2050, and a higher penetration of heat exchangers is observed: 16% of the commercial installed capacity. Air-source heat pumps continue playing an important role in supplying commercial heat demand, representing 59% of the commercial installed capacity by 2050. With regards to total installed capacity, air-source heat pumps, district heating, and hydrogen boilers represent 15%, 68%, and 5% of the total share by 2050. A higher penetration of heat networks is observed in this formulation. This translates into more district level air-source heat pumps and hydrogen boilers supplying heat networks, with the same participation of gas boilers as in Formulation A, and with no district level gas boilers uptake after 2040. This shows that when hydrogen networks are more expensive, decarbonisation of heat occurs at a higher level, through low carbon district level heat supply technologies.

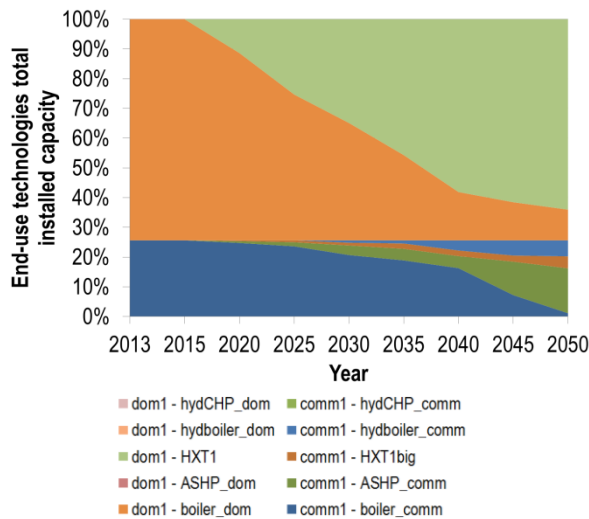


Figure 6-14: Total installed capacity of individual level heat supply technologies. Formulation B – Hydrogen price scenario HP3 and emission scenario HE2.

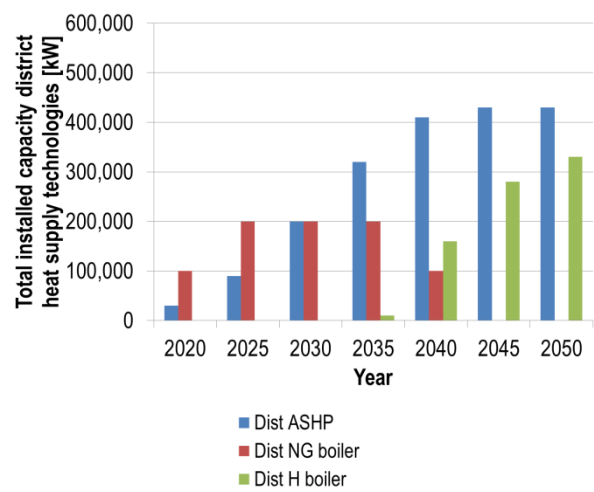


Figure 6-15: Total installed capacity of district level heat supply technologies. Formulation B – Hydrogen price scenario HP3 and emission scenario HE2.

Finally, zone specific end-use technology uptakes by 2050 for hydrogen price scenario HP3 and hydrogen emission scenario HE1 are shown in Figure 6-16, Figure 6-17, and Figure 6-18. The same behaviour as in Formulation A is observed with different thresholds: heat network penetration increases with linear heat density, up to a linear heat density of 2250 kWh/m, after which it begins to decrease. Under this value, for linear heat densities over 500 kWh/m and 1250 kWh/m, heat network penetration is greater than 40% and 60% respectively. Hydrogen boiler installation begins at linear heat densities above 2250 kWh/m, with uptakes over 10% by 2050. For the highest linear heat density zone (over 3750 kWh/m), an uptake of 46% is observed by 2050.

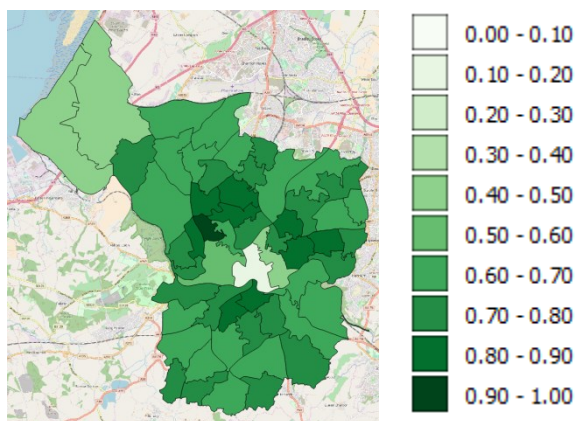


Figure 6-16: Heat network penetration by 2050, hydrogen price scenario HP3, hydrogen emission scenario HE2.

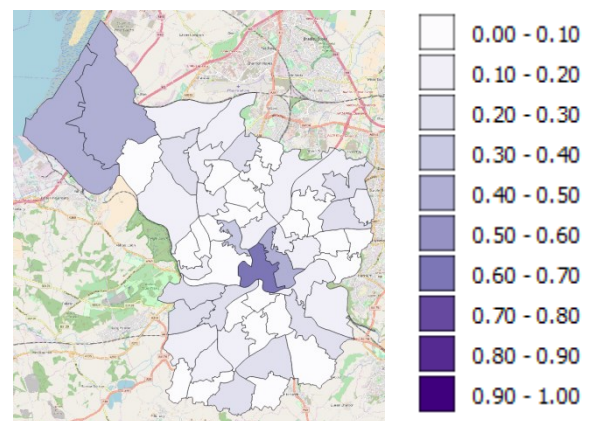


Figure 6-17: Air-source heat pump penetration by 2050, hydrogen price scenario HP3, hydrogen emission scenario HE2.

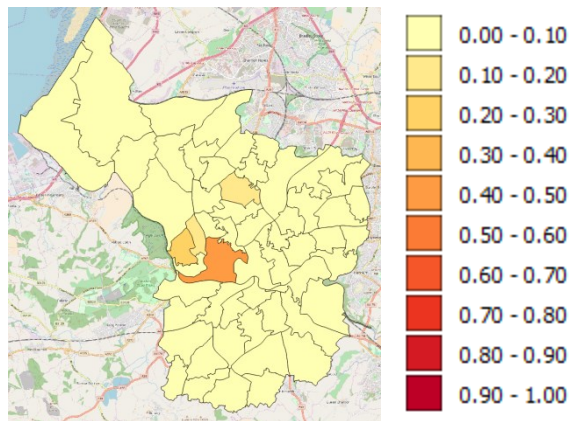


Figure 6-18: Hydrogen boiler penetration by 2050, hydrogen price scenario HP3, hydrogen emission scenario HE2.

6.2.2 Gas networks considered as sunken cost

In this section, results are analysed for Formulation B, when the option of retrofitting the existing gas network to convert it into hydrogen is in place. For these scenarios, no cost is associated to new gas networks, and therefore a higher penetration of gas networks is observed in all cases. For hydrogen price scenario HP1, results for emission scenarios HE1 and HE2 are the same. Installed capacities for individual level and district level heat supply are shown in Figure 6-19 and Figure 6-20 respectively. Figure 6-19 shows that the cost-effective individual heat supply pathway is a progressive uptake of heat exchangers replacing gas boiler in both, domestic and commercial sectors. However, a slower adoption pathway of heat exchangers is observed compared to scenarios presented in Section 6.1, and a lower penetration by 2050 is observed: by 2050 district heating reaches 74% of the domestic installed capacity, 29% of the commercial installed capacity, and a total overall installed capacity of 62%, the rest being individual gas boilers. No air-source heat pumps are observed at the individual level heat supply, as their efficiency gains do not offset the end-use technology higher costs compared to heat networks, and the higher network costs compared to gas networks. Added to all results presented previously, these show that for hydrogen price scenario HP1, hydrogen-fuelled heat supply technologies are not cost-effective in any of the studied hydrogen emission scenarios, for the techno-economic parameters assumed. Additionally, as gas networks are considered as a sunken cost and no cost is associated to new gas networks, lower penetrations of other forms of heat provision different to gas, such as heat networks or air-source heat pumps, are observed. However, it is interesting to observe that despite gas networks having no cost, heat networks are still competitive in the domestic sector.

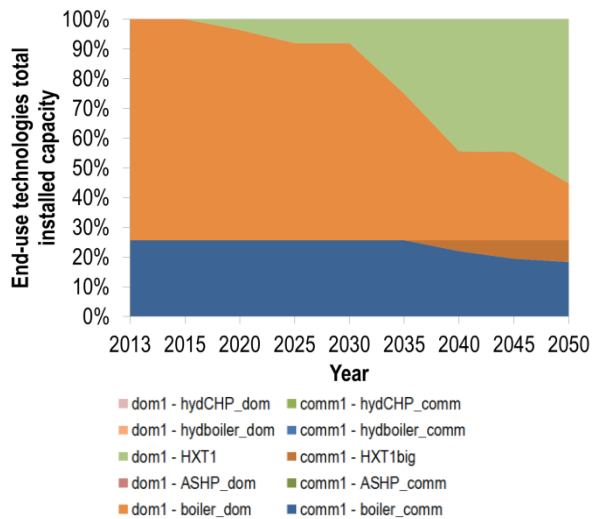


Figure 6-19: Total installed capacity of individual level heat supply technologies. Formulation B – Hydrogen price scenario HP1 and emission scenarios HE1 and HE2.

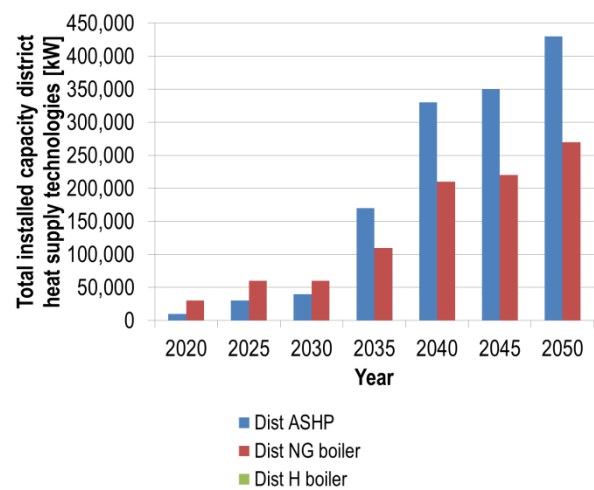


Figure 6-20: Total installed capacity of district level heat supply technologies. Formulation B – Hydrogen price scenario HP1 and emission scenarios HE1 and HE2.

Figure 6-21 and Figure 6-22 show the end-use technology mix and district heat supply capacity respectively for hydrogen price scenario HP2, and hydrogen emission scenario HE1. In this scenario, as gas networks are decommissioned, gas boilers are replaced by heat exchangers connected to heat networks in the commercial and domestic sectors through 2050. Additionally, hydrogen boilers are cost-effective in the domestic sector, reaching 11% of the domestic heat supply installed capacity by 2050, and 8% of the total installed capacity. Heat networks for this case represent 59% of the total installed individual heat supply capacity, and are supplied by a combination of natural gas district boilers and district level air-source heat pumps. No hydrogen boilers are observed, even though capital costs and efficiency of both, hydrogen and natural gas district level boilers, are assumed to be equal. This shows that the lower hydrogen carbon emissions do not offset its higher price compared to natural gas.

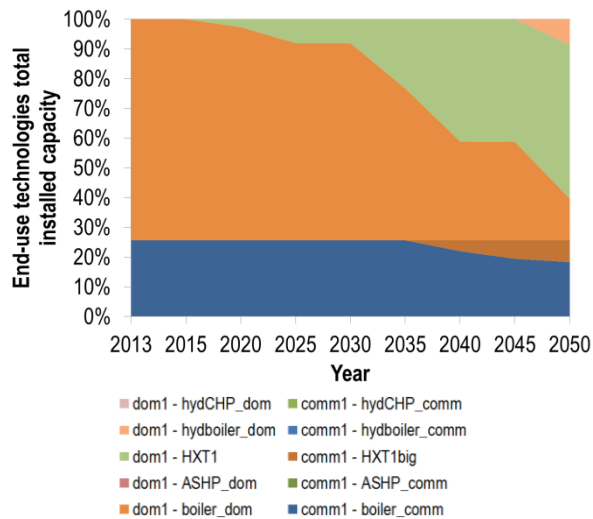


Figure 6-21: Total installed capacity of individual level heat supply technologies. Formulation B – Hydrogen price scenarios HP2 and emission scenario HE1.

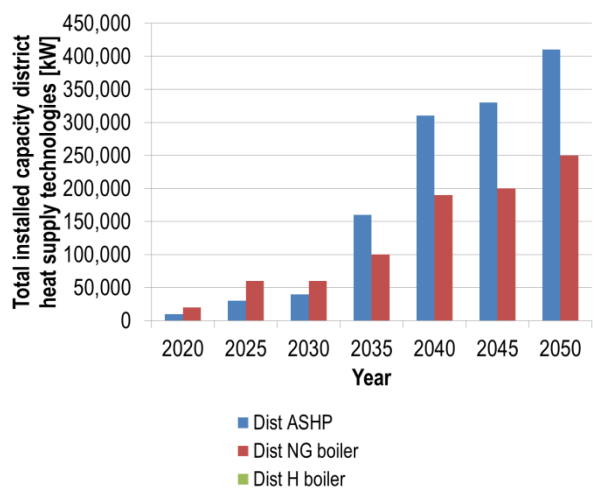


Figure 6-22: Total installed capacity of district level heat supply technologies. Formulation B – Hydrogen price scenarios HP2 and emission scenario HE1.

Individual level heat supply capacities and district level heat supply capacities for hydrogen price scenario HP2 and hydrogen emissions scenario HE2 are shown in Figure 6-23 and Figure 6-24 respectively. As emissions from hydrogen are reduced, carbon costs associated to hydrogen are decreased, and hydrogen boilers become more competitive. For this case, hydrogen boilers' participation not only increases in the domestic sector (compared to Scenario HP2-HE1), but also hydrogen boilers are observed in the commercial sector. Hydrogen boilers reach 39% of the domestic installed capacity and 36% of the commercial installed capacity by 2050, with an overall participation of 38%, to the detriment of heat networks. Heat exchangers represent 58% and 29% of the domestic and commercial installed capacities respectively, with an overall installed capacity of 50%. As in the previous case, heat networks are supplied by a combination of district level air-source heat pumps and gas boilers, with an overall lower installed capacity, which is observed when comparing Figure 6-24 with Figure 6-22. Although the capacities differ to those of Figure 6-22, the same tendency of heat networks being supplied by air-source heat pumps and gas boilers is observed.

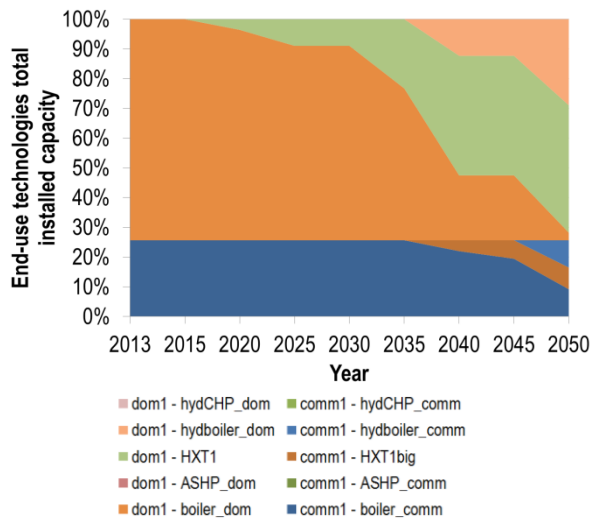


Figure 6-23: Total installed capacity of individual level heat supply technologies. Formulation B – Hydrogen price scenarios HP2 and emission scenario HE2.

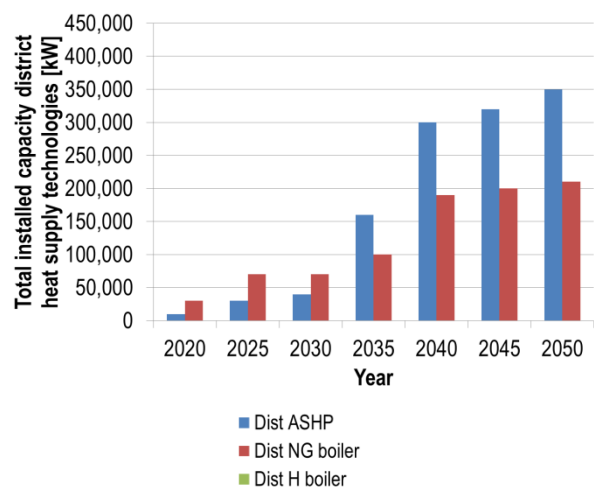


Figure 6-24: Total installed capacity of district level heat supply technologies. Formulation B – Hydrogen price scenarios HP2 and emission scenario HE2.

Low hydrogen price scenarios (HP3) results are shown in Figure 6-25, Figure 6-26, Figure 6-27, and Figure 6-28. Figure 6-25 and Figure 6-26 show installed capacity of individual and district level heat supply technologies for hydrogen emissions scenario HE1; while Figure 6-27 and Figure 6-28 show installed capacities for hydrogen emissions scenario HE2. For emissions scenario HE1, Figure 6-25 shows that hydrogen boilers completely replace gas boilers in the commercial sector, and replace both gas boilers and a portion of heat exchangers in the domestic sector, reaching 86% of total penetration by 2050. No participation of individual supply gas boilers is observed by 2050, and a lower participation of heat networks is obtained for the domestic sector compared to the average hydrogen price scenarios. Heat exchangers only represent 18% of the domestic installed capacity, which corresponds to 13% of the overall installed individual capacity. For low hydrogen price scenario HP3 and low hydrogen emissions scenario HE2, Figure 6-27 shows that individual heat supply installed capacity is similar to hydrogen emission scenario HE1, but with a higher installation of hydrogen boilers in the domestic sector. By 2050, only 6% of the domestic installed capacity is supplied by heat networks, which corresponds to 4% of the total individual level installed capacity. The rest of the domestic demand and the whole commercial demand in this case are supplied by hydrogen boilers by 2050, which represents a 96% of the total individual level heat supply installed capacity. For both emission scenarios (HE1 and HE2), heat networks are supplied by a combination of district boilers and district level air-source heat pumps as for the previous formulations and scenarios. However, Figure 6-26 and Figure 6-28 show that for low hydrogen prices not only a high participation of hydrogen boilers at the domestic heat supply level is observed as discussed previously, but also at the district level hydrogen boilers replace gas boilers for supplying heat

networks from 2040 on. These figures use the same scale as Figure 6-22 and Figure 6-24, showing how district heat supply capacity is reduced in these scenarios. For all these scenarios in which replacement of gas networks is considered a sunken cost, higher hydrogen boiler penetrations are observed throughout the modelling horizon, as the cost of retrofitting the gas network into hydrogen is marginal compared to other network costs.

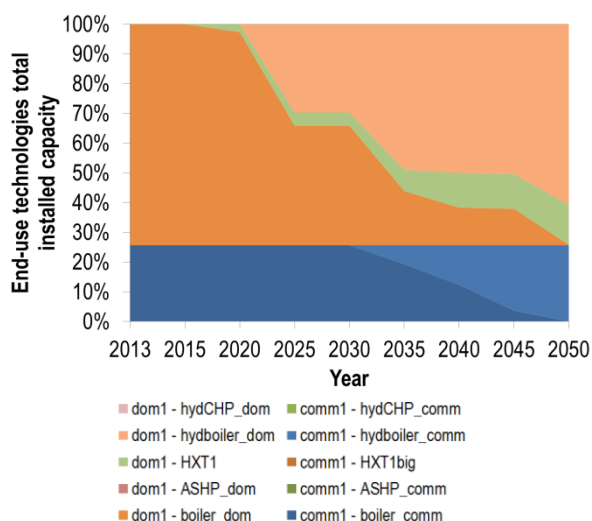


Figure 6-25: Total installed capacity of individual level heat supply technologies. Formulation B – Hydrogen price scenarios HP3 and emission scenario HE1.

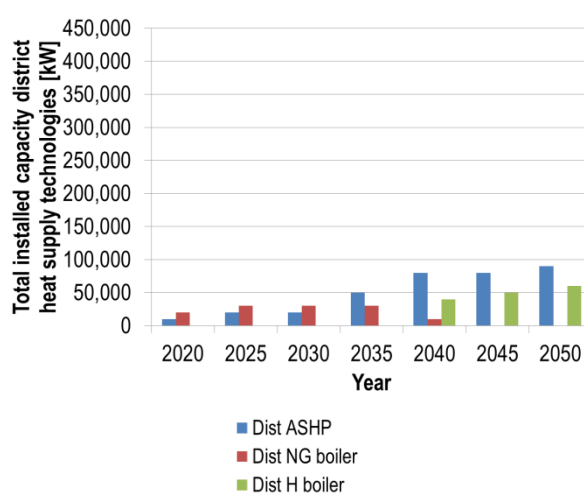


Figure 6-26: Total installed capacity of district level heat supply technologies. Formulation B – Hydrogen price scenarios HP3 and emission scenario HE1.

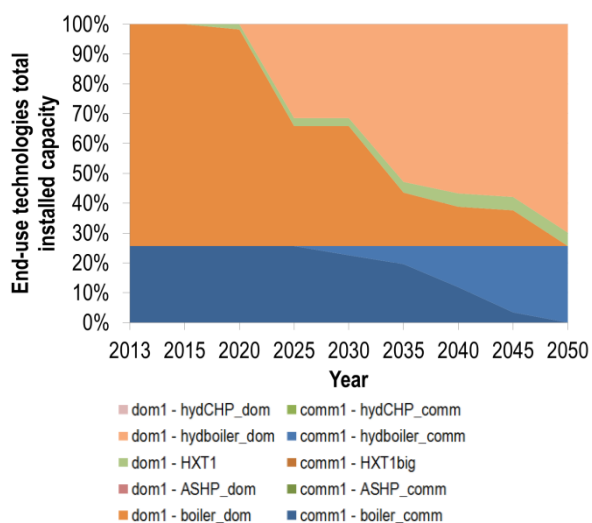


Figure 6-27: Total installed capacity of individual level heat supply technologies. Formulation B – Hydrogen price scenarios HP3 and emission scenario HE2.

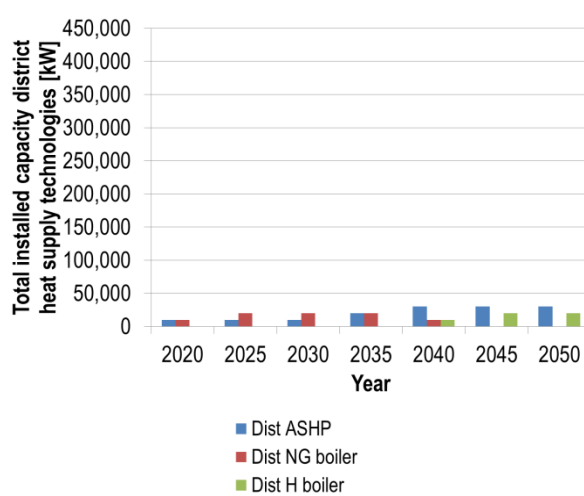


Figure 6-28: Total installed capacity of district level heat supply technologies. Formulation B – Hydrogen price scenarios HP3 and emission scenario HE2.

Table 6-4 shows a summary of the figures that represent results for total installed capacity of end use technologies and total installed capacity of district level heat supply technologies, for the 2 hydrogen emission and 3 hydrogen price scenarios described in Table 3-13 and Table 3-14, modelled through Formulation B.

Table 6-4: Summary of figures for installed capacity of individual and district level heat supply technologies for Formulation B results, according to hydrogen emission and price scenarios described in Table 3-13 and Table 3-14.

Hydrogen emissions scenarios	Hydrogen price scenarios		
	HP1	HP2	HP3
HE1	Figure 6-19, Figure 6-20	Figure 6-21, Figure 6-22	Figure 6-25, Figure 6-26
HE2	Figure 6-19, Figure 6-20	Figure 6-23, Figure 6-24	Figure 6-27, Figure 6-28

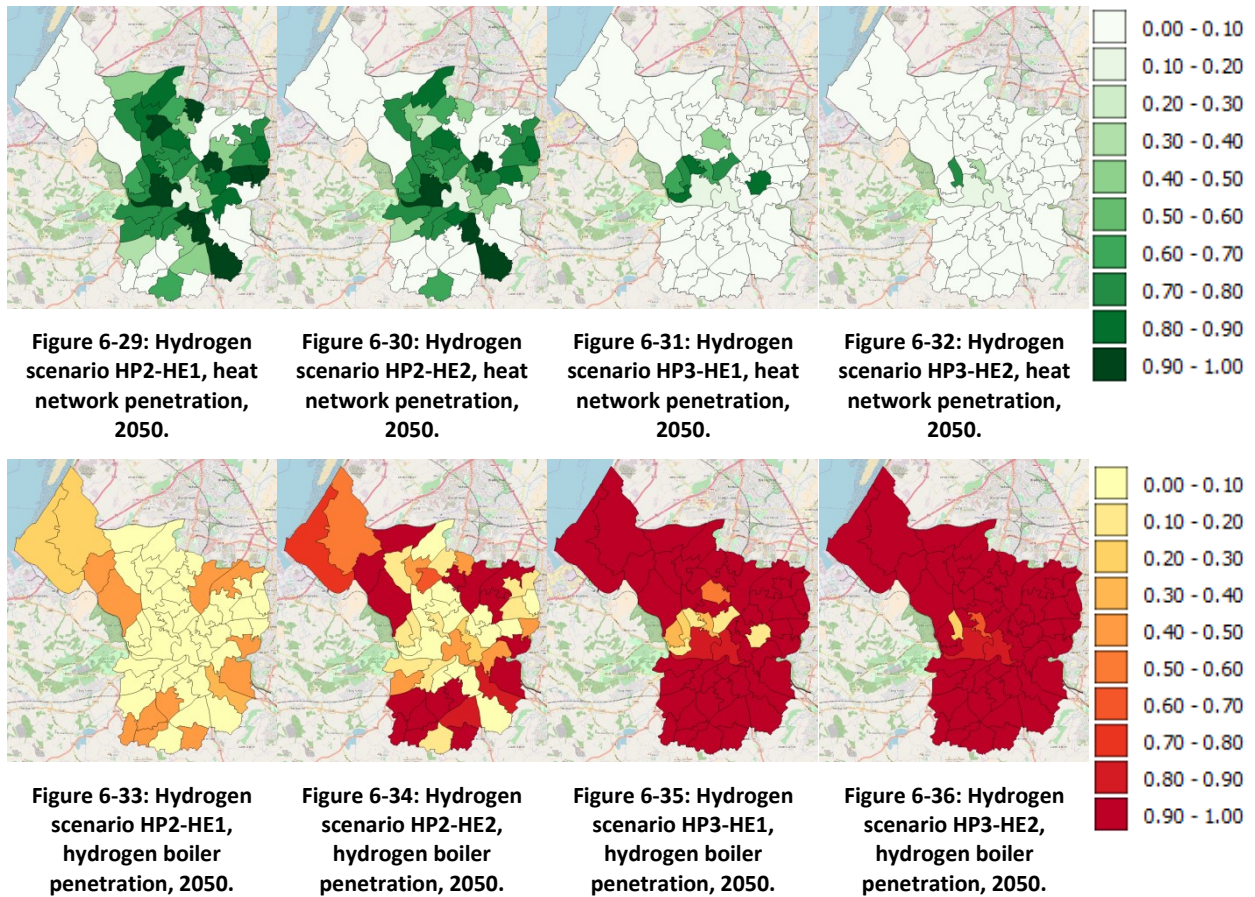
Figure 6-29 to Figure 6-32 show the heat network penetration per zone by 2050 for hydrogen price scenarios HP2 and HP3. Figure 6-33 to Figure 6-36 show the hydrogen boiler penetration per zone by 2050 for hydrogen price scenarios HP2 and HP3. As no hydrogen boiler penetration is observed for hydrogen price scenario HP1, zone-specific results will not be further discussed. Table 6-5 shows the hydrogen price and emission scenarios to which Figure 6-29 to Figure 6-36 correspond.

Table 6-5: Summary of figures for results on hydrogen boiler and heat network penetration, according to hydrogen emission and price scenarios described in Table 3-13 and Table 3-14.

Hydrogen emissions scenarios	Hydrogen price scenarios	
	HP2	HP3
HE1	Figure 6-29, Figure 6-33	Figure 6-31, Figure 6-35
HE2	Figure 6-30, Figure 6-34	Figure 6-32, Figure 6-36

For hydrogen price scenario HP3, Figure 6-31 and Figure 6-35 show the heat network penetration and hydrogen boiler penetration per zone by 2050, for hydrogen emissions scenario HE1. For this low hydrogen price scenario, a high hydrogen boiler penetration was observed throughout zones when the gas network was allowed to be retrofitted into hydrogen at no extra gas network cost. As analysed before, all zones adopt either heat networks or hydrogen boilers, displacing natural gas completely by 2050. This heat supply mix achieves a reduction of 8% in equivalent carbon emissions compared to hydrogen price scenario HP1, and an 88% reduction by 2050 compared to the first modelled year, 2013. For this case, a high heat network uptake of between 60% and 90% is observed to be cost-effective in a relatively intermediate to high linear heat density range of 2000 to 2500 kWh/m. For hydrogen emission scenario HE2, Figure 6-32 and Figure 6-36 show the heat network and hydrogen boiler penetration per zone by 2050. In this scenario gas boilers are also completely displaced, with an almost full penetration of hydrogen boilers. Two zones present a heat network uptake of 16%, and two zones present higher heat network penetrations. These zones are the highest linear heat density zones, and zone 52, which has a high commercial demand. All other zones are fully supplied by hydrogen boilers.

For hydrogen price scenario HP2, Figure 6-33 and Figure 6-34 show that linear heat density adoption thresholds for hydrogen boilers are higher than for hydrogen price scenarios HP3. For hydrogen emission scenario HE1, hydrogen boilers are only installed in zones with linear heat densities under 1250 kWh/m. For hydrogen emission scenario HE2, it is observed that hydrogen boiler penetration increases with linear heat density, up to a certain threshold, where it starts diminishing. Zones with linear heat densities in the range of 750 kWh/m to 1250 kWh/m present the highest hydrogen boiler uptakes, with over 80% of penetration by 2050.



Finally, it is important to highlight that all the results presented here are sensitive to input techno-economic parameters for technology and network infrastructure costs, and to demand topology. Therefore, the results presented are specific for the input parameters used in this research.

Chapter 7. The sensitivity of heat decarbonisation outcomes to uncertainty in techno-economic parameters

Figure 7-1 and Figure 7-2 show the Base Case individual and district level heat supply installed capacity through the modelled time horizon. Further results will be compared and analysed against this Base Case.

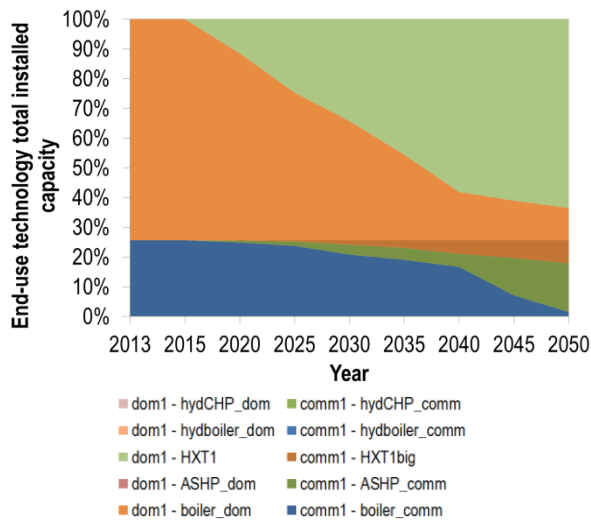


Figure 7-1: Total installed capacity of individual level heat supply technologies-Base Case.

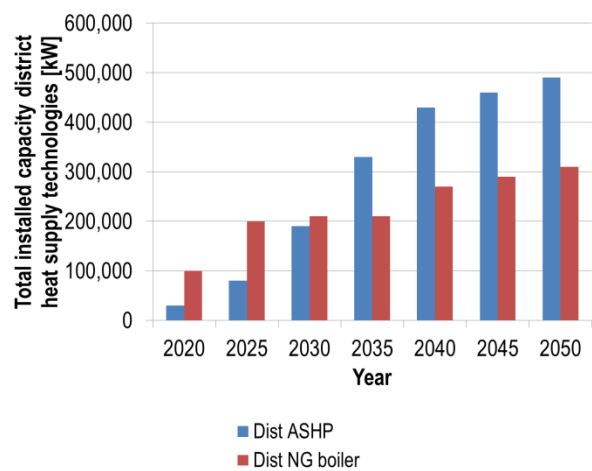


Figure 7-2: Total installed capacity of district level heat supply technologies-Base Case.

7.1 Electricity and fuel price scenarios

Results for fuel and electricity price scenarios are shown in Figure 7-3, Figure 7-4, Figure 7-5, and Figure 7-6. The results for each scenario are normalised to the Base Case result values. Figure 7-3 shows the total cost, total carbon emissions, and total cost of carbon for the whole modelled time horizon for fuel and electricity high and low price scenarios. Figure 7-4 shows district level air-source heat pumps and gas boilers installed capacities, for low and high electricity and fuel price scenarios. Figure 7-5 and Figure 7-6 show heat network and individual level air-source heat pump penetrations respectively through 2050.

For the modelled scenarios, the ones which present a lower difference in total cost, total carbon emissions, and total cost of carbon compared to the Base Case are the hydrogen price scenarios. Firstly, as observed in Figure 7-1 and Figure 7-2, for the Base Case there is no uptake of hydrogen technologies. Therefore, for the high hydrogen price scenario the results are the same as for the Base Case. For the low hydrogen price scenario, a slight decrease in total carbon emissions and

carbon cost is observed with respect to the Base Case. This is associated to the fact that the low hydrogen price makes it cost-effective to purchase some individual level hydrogen boilers in the commercial sector, reaching 5.2% of the total individual level heat supply installed capacity by 2050. Additionally, carbon emissions are also reduced in this scenario. From 2035 onwards, district level hydrogen boilers progressively replace district level gas boilers, replacing them completely and reaching approximately the same levels as gas boilers in the Base Case by 2050.

The lowest total system's cost is obtained with the low electricity price scenario, followed by the low gas price scenario. For the low electricity price scenario, this is achieved through a combination of a relatively high participation of individual level air-source heat pumps in the commercial sector, and a high participation of district level air-source heat pumps, both operating at low electricity prices, as observed in Figure 7-6. This reduction causes a subsequent reduction in carbon costs, obtaining the second lowest total carbon costs of all fuel and electricity price scenarios. The low gas price scenario presents the second lowest total system's cost. For this scenario, a high participation of district level gas boilers and a very low participation of district level air-source heat pumps compared to the Base Case are observed throughout the modelled time horizon as shown in Figure 7-4. Overall low participations of heat networks and individual level air-source heat pumps compared to the Base Case are observed in Figure 7-5 and Figure 7-6. In this low gas price scenario, a high participation of gas boilers is obtained to the detriment of lower carbon alternatives, attaining the highest carbon emissions (and subsequent costs associated to carbon) produced by the system compared to other fuel and electricity price scenarios.

The highest system costs are found in the high electricity price scenario, followed by the high gas price scenario. In the high electricity price scenario the lowest heat network penetration is obtained throughout the modelled time horizon as shown in Figure 7-5. Although individual level air-source heat pumps continue to serve around 18% of the individual heat demand and present a higher uptake compared to other scenarios as shown in Figure 7-6, Figure 7-4 shows that district level air-source heat pumps present a lower participation than in the Base Case. The overall effect is a lower participation of heat networks, and therefore higher uptakes of individual level gas boilers to compensate. This, added to the high participation of gas boilers supplying heat networks as exhibited in Figure 7-4, produces the second highest equivalent carbon emissions compared to the other fuel price scenarios, as seen in Figure 7-3. The high gas price scenario on the other hand presents the highest heat network penetration of all fuel and electricity price scenarios (see Figure 7-5), and the fastest uptake of individual level air-source heat pumps, with one of the highest overall

penetrations throughout the modelled time horizon (see Figure 7-6). This is the scenario that generates the lowest system's equivalent carbon emissions.

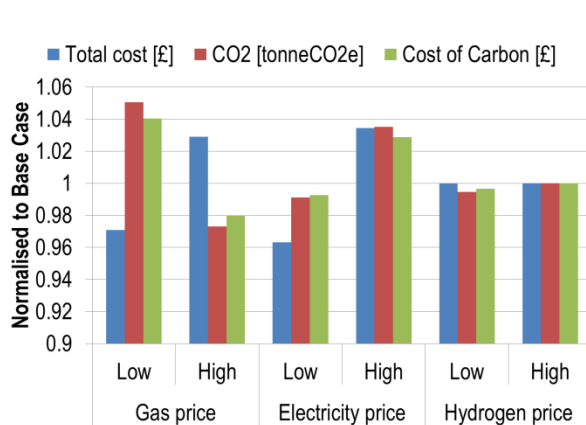


Figure 7-3: Total system cost, total carbon emissions, and cost of carbon, for fuel and electricity price scenarios, normalised to the Base Case.

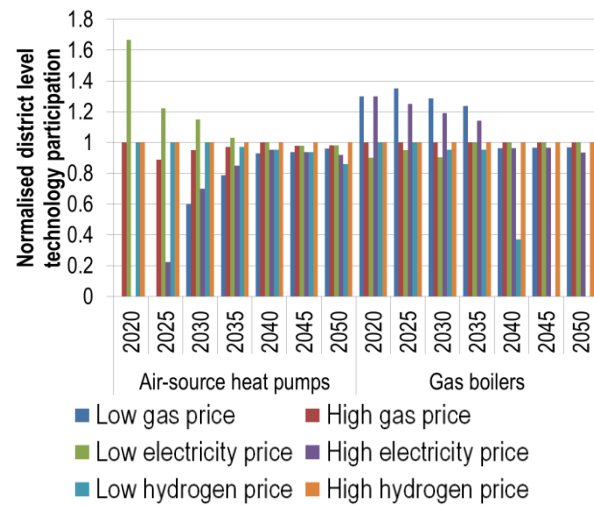


Figure 7-4: District level air-source heat pumps and gas boilers installed capacity normalised to Base Case, for low and high electricity and fuel price scenarios.

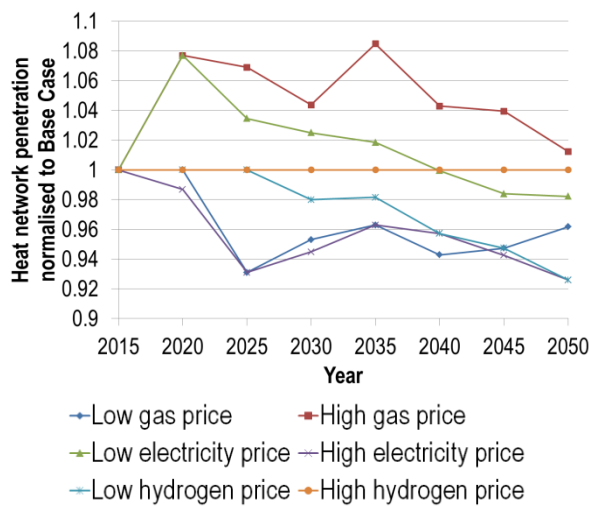


Figure 7-5: Heat network penetration for low and high electricity and fuel price scenarios, normalised to Base Case.

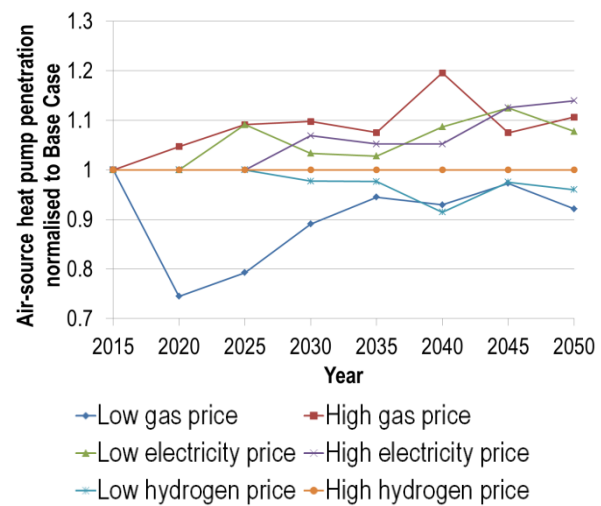


Figure 7-6: Air-source heat pump penetration for low and high electricity and fuel price scenarios, normalised to Base Case.

7.2 Carbon price scenarios

Figure 7-7 and Figure 7-8 show results for carbon price scenarios. Figure 7-7 shows the total system cost, total carbon emissions and total cost of carbon for high and low carbon price scenarios, normalised to the Base Case. Figure 7-8 shows individual level air-source heat pump and heat network penetrations, together with district level air-source heat pump and gas boiler installed capacities for the modelled time horizon, for low and high carbon prices, normalised to the Base Case. For the high carbon price scenario, the highest system total cost and the highest reduction in

total carbon emissions is obtained compared with fuel and electricity price scenarios. In a high carbon price scenario the total carbon emissions are 97% of the Base Case's carbon emissions. This is achieved with a higher individual level air-source heat pump penetration throughout the time horizon compared to the Base Case as observed in Figure 7-8, together with a higher uptake of district level air-source heat pumps supplying heat networks. Also, as for the low hydrogen price scenario, from 2040 onwards district level hydrogen boilers are purchased, reaching approximately the same levels as district level gas boilers from the Base Case by 2050. District level hydrogen boilers are installed to the detriment of district level gas boilers, which can be observed in the radical decrease of district level gas boilers in Figure 7-8.

Conversely, for the low carbon price scenario, the lowest system cost and cost of carbon, together with the highest total carbon emissions are obtained. In this scenario the total carbon emissions are approximately 7% higher than in the Base Case. Figure 7-8 shows that in the low carbon price scenario heat networks and individual level air-source heat pumps present a lower penetration than the Base Case throughout the entire modelled time horizon. No other low-carbon alternatives are purchased at the individual level, which means that the difference between air-source heat pumps and heat networks compared to the Base Case is covered by gas boilers. The highest individual level gas boiler participation throughout the modelled time horizon is seen in the low carbon price scenario, compared to all fuel and electricity price scenarios analysed previously. In addition, the lowest participation of district level air-source heat pumps and the highest participation of district level gas boilers are obtained in all modelled time periods, as can be observed in Figure 7-8.

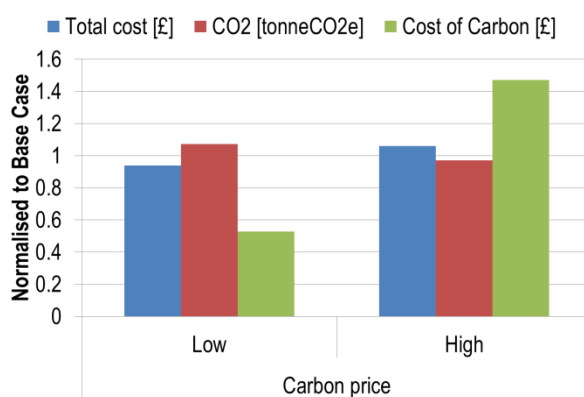


Figure 7-7: Total system cost, total carbon emissions, and cost of carbon, for carbon price scenarios, normalised to the Base Case.

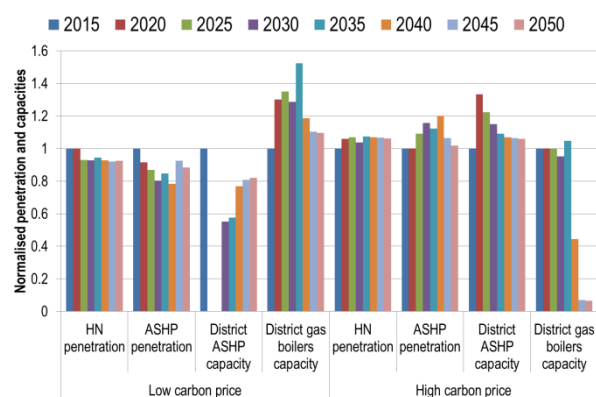


Figure 7-8: Heat network (HN) penetration, air-source heat pump(ASHP) penetration, district gas boilers installed capacity, and district ASHP capacity normalised to the Base Case for carbon price scenarios.

These results show that if the heat supply technology mix was centrally planned from a cost-effective point of view, carbon prices are an effective way to achieve decarbonisation of heat.

7.3 Network cost scenarios

This section presents results for network cost scenarios. Figure 7-9 shows the total system cost, total carbon emissions, and total cost of carbon for heat, electricity, and gas network cost scenarios described in Section 3.4.4.2, normalised to the Base Case. This figure shows that the highest influence in total system costs and carbon emissions is obtained when varying heat network costs, with the least influence being caused by electricity network costs. An important factor to consider that explains this variation is the actual cost quantities that are varied. A wide range of heat network costs can be found in the literature as discussed previously, and based on these variations the equivalent percentage variations were used for defining gas and electricity network cost scenarios. However, Base Case electricity network costs are approximately 11% of the Base Case heat network costs. Therefore a 20% or 40% cost increment in electricity networks is more likely to cause a lower variation in results than the same percentage increment in heat network costs. Likewise, Base Case gas network costs represent approximately 85% of the Base Case heat network costs.

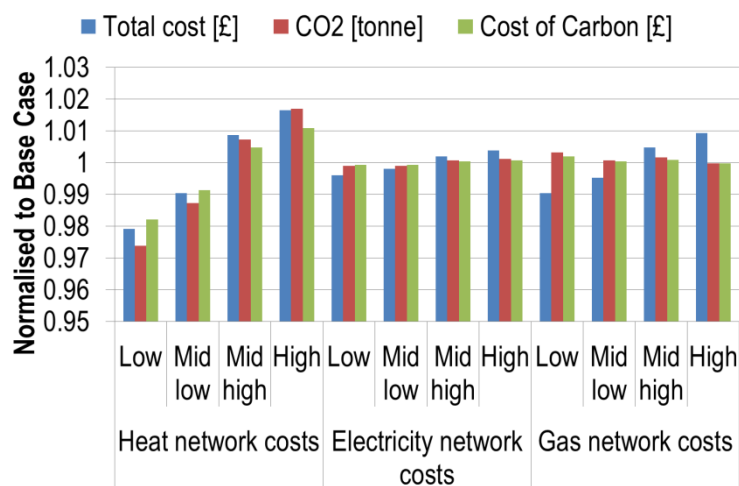


Figure 7-9: Fuel and electricity total system cost, total carbon emissions, and cost of carbon, for network cost scenarios, normalised to the Base Case.

Results for heat network cost scenarios in Figure 7-9 show that the highest carbon emissions reductions and lowest system costs are achieved at low heat network costs, and increase as the costs escalate. Figure 7-10 shows heat network and individual level air-source heat pump penetrations for heat network cost scenarios compared to the Base Case. Figure 7-11 shows installed capacity of district level air-source heat pumps and gas boilers for the four heat network cost scenarios, normalised to the Base Case. As observed in Figure 7-10, low heat network costs cause the highest heat network penetration, in hand with the lowest individual level air-source heat pump penetration. Carbon emission reductions can be attributed to a high district level air-source

heat pump installed capacity supplying heat networks throughout the modelled time horizon, as seen in Figure 7-11. Compared to the Base Case, the installed capacity of district level air-source heat pumps is 33% higher in the initial years, and 24% higher in 2050. The high heat network cost scenario, on the other extreme, produces the highest carbon emissions and system cost, as observed in Figure 7-9. Figure 7-10 shows that for this high heat network cost scenario, the highest penetration of individual level air-source heat pumps is achieved throughout the modelled time horizon, reaching 230% of the Base Case air-source heat pump penetration in 2030. Despite this high air-source heat pump penetration, high carbon emissions are obtained because as heat networks are less competitive, an overall higher penetration of individual level gas boilers is obtained to the detriment of heat networks, which present the lowest penetration of all heat network cost scenarios.

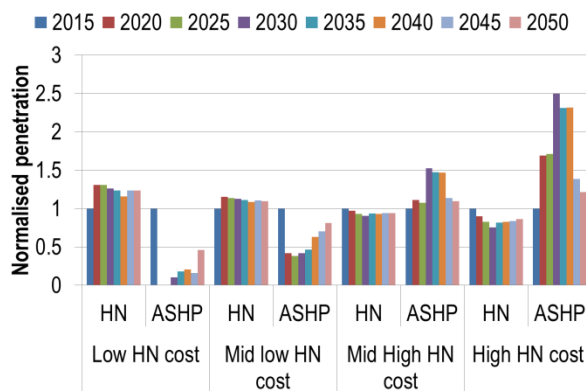


Figure 7-10: Heat network (HN) and air-source heat pump (ASHP) penetration for heat network cost scenarios, normalised to Base Case.

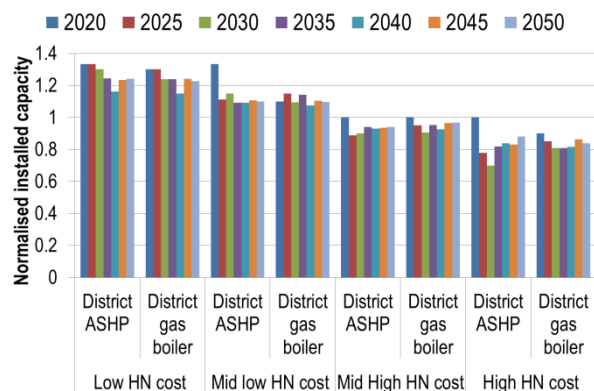


Figure 7-11: District level air-source heat pump (ASHP) and gas boiler capacities for heat network cost scenarios, normalised to Base Case.

Figure 7-12 shows heat network and individual level air-source heat pump penetrations for the four electricity network cost scenarios, while Figure 7-13 shows installed capacity of district level air-source heat pumps and gas boilers, both normalised to the Base Case. As shown in Figure 7-9, mid low and mid high electricity network cost scenarios present nearly the same total cost, total carbon and carbon costs as the Base Case. Figure 7-12 and Figure 7-13 show that for these scenarios heat network penetration and district level supply capacities are the same as for the Base Case. While for the mid high electricity network cost scenario air-source heat pump penetration is the same as for the Base Case as observed in Figure 7-12, a slightly higher air-source heat pump penetration is obtained for the mid low cost scenario. This higher penetration varies between an increment of approximately 2% and 8% throughout the modelled time horizon compared to the Base Case.

Regarding the low electricity cost scenario, Figure 7-12 shows lower heat network and higher air-source heat pump penetrations than the Base Case. Although heat network penetrations for this

scenario remain close to those of the Base Case, air-source heat pump uptakes vary between 9% and 34% more than the Base Case throughout time. Compared to the Base Case, individual air-source heat pumps not only replace individual level gas boilers, but they also reduce heat network uptakes, and as observed in Figure 7-13 this also reduces the uptake of district level gas boilers. All this explains why carbon emissions, their associated cost and the total system's cost in this scenario is lower than the Base Case, as seen in Figure 7-9. On the other extreme, in the high electricity network cost scenario nearly the same heat network penetration than in the Base Case is obtained (slightly higher in 2030-2035), along with lower air-source heat pump penetrations (up to 11% lower in 2040). In this scenario the uptake of individual level gas boilers is higher than in the Base Case, and the slight increase in heat networks is supplied by district level gas boilers as shown in Figure 7-13, obtaining higher carbon costs and emissions, as observed in Figure 7-9.

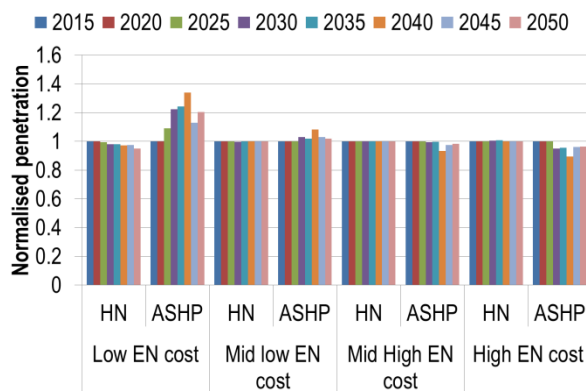


Figure 7-12: Heat network (HN) and air-source heat pump (ASHP) penetration for electricity network (EN) cost scenarios, normalised to Base Case.

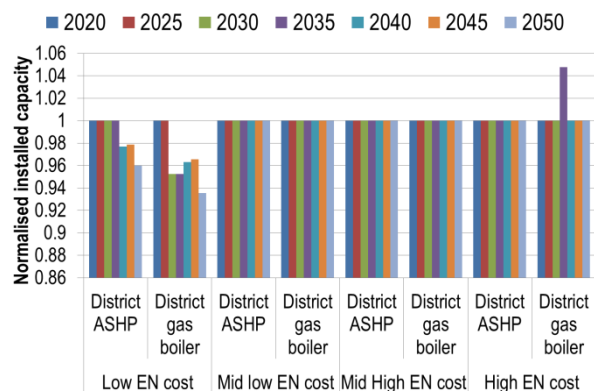


Figure 7-13: District level air-source heat pump (ASHP) and gas boiler capacities for electricity network cost scenarios, normalised to Base Case.

Finally, Figure 7-14 shows the normalised heat network and individual level air-source heat pump penetrations, and Figure 7-15 shows the normalised installed capacity of district level air-source heat pumps and gas boilers, for gas network cost scenarios. Figure 7-9 shows that as gas network costs increase, the total system cost increases as well. Also, as gas network costs increase there is a slight decrease in carbon emissions and carbon costs. Analysing Figure 7-14, this can be attributed to the increment in individual level air-source heat pump penetration as gas network costs increase. For the low gas network cost, lower than Base Case air-source heat pump and heat network penetrations are obtained. This means that higher individual level gas boiler uptakes are observed, with the subsequent associated increase in carbon emissions in relation to the Base Case. For high gas network costs on the other hand, higher heat network and air-source heat pump penetrations are seen in Figure 7-14, with a therefore lower participation of individual level gas boilers and thus lower system's carbon emissions.

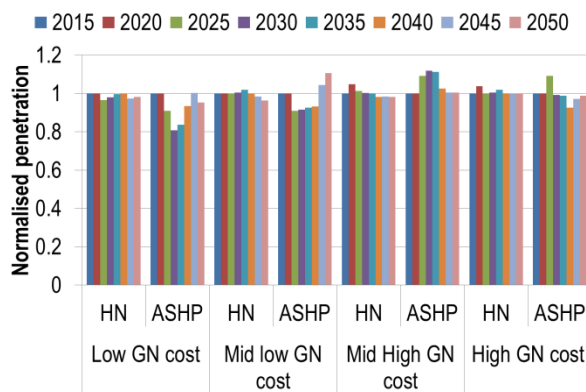


Figure 7-14: Heat network (HN) and air-source heat pump (ASHP) penetration for gas network (GN) cost scenarios, normalised to Base Case.

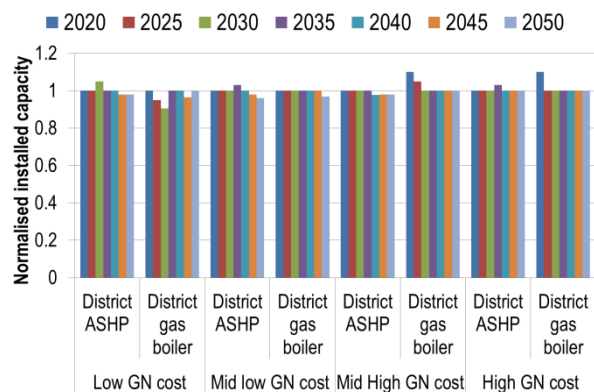


Figure 7-15: District level air-source heat pump (ASHP) and gas boiler capacities for gas network cost scenarios, normalised to Base Case.

7.4 Individual level heat technology cost scenarios

Individual level heat supply technology cost scenarios were studied for gas fuelled micro CHP units, individual level air-source heat pumps, ground-source heat pumps, and hydrogen fuelled micro-CHPs. In all ground-source heat pump and hydrogen fuelled micro-CHP scenarios modelled, results obtained were the same as for the Base Case. That is, no uptake of ground-source heat pumps and hydrogen fuelled micro-CHPs was observed for any of the cost scenarios analysed. Additionally, as the Base Case does not present any uptake of natural gas-fuelled micro-CHPs, only the mid low and low cost scenarios for these were considered. All scenarios for individual level air-source heat pumps were analysed, and results are here presented.

Figure 7-16 shows the total system's cost, carbon emissions and cost of carbon for the aforementioned individual level air-source heat pumps and gas fuelled micro-CHP scenarios, normalised to the Base Case. Figure 7-17 shows the normalised district level air-source heat pumps and gas boilers installed capacity for the studied scenarios. Figure 7-18 and Figure 7-19 show the normalised heat network and air-source heat pump penetrations respectively, for technology cost scenarios. As expected, Figure 7-16 shows that as air-source heat pump costs increase, the total system's cost increases as well. It is interesting to note that carbon emissions and carbon costs increase with individual level air-source heat pump costs, up to the mid high cost scenario. However, the high air-source heat pump cost scenario presents lower carbon emissions than the mid high cost scenario, which will be discussed later. Figure 7-19 shows that for low air-source heat pump cost, uptakes of between 186% and 315% of the Base Case are obtained throughout the modelled time horizon. For this low cost scenario as well as in the mid low air-source heat pump cost scenario, lower heat network penetrations are observed than in the Base Case, as observed in Figure 7-18.

This means that a large portion of heat demand is being supplied by air-source heat pumps which are not only a low carbon alternative because of the assumed electricity grid decarbonisation, but also because their coefficients of performance in this study range between 2.54 and 2.56. Therefore, lower system carbon emissions are achieved.

In the mid high and high air-source heat pump cost scenarios on the other hand, lower uptakes of air-source heat pumps than in the Base Case are obtained as seen in Figure 7-19. In the mid high cost scenario, the heat network penetration is also slightly lower than in the Base Case, which demonstrates the importance of analysing scenarios from a system-wide perspective. In this case for example, the increase in air-source heat pump costs in the mid high cost scenario increases the zone linear heat density adoption threshold in which gas boilers are not competitive anymore, and therefore a higher penetration of gas boilers is observed, even to the detriment of heat networks, which is not necessarily intuitive. For the high air-source heat pump cost scenario, the lowest air-source heat pump penetration is observed. For this scenario, heat network penetration is higher than in the Base Case and than in the mid-high air-source heat pump cost scenario. This increase however does not cover the decrease in individual level air-source heat pumps, so a higher participation of individual level gas boilers and district level gas boilers supplying heat networks is observed, which explains the increase in carbon emissions with respect to the Base Case. However, in this case some participation of hydrogen fuelled district level boilers is observed. Also, as more heat networks than in the mid high cost scenario are installed, a lower gas boiler penetration than in the mid high cost scenario is observed throughout the modelled time horizon. For example, in 2050 the individual level gas boiler participation for the high cost scenario is around 10%, while for the mid high cost scenario it is around 13%. This and the district level hydrogen boilers supplying heat networks explain the lower system carbon emissions in the high cost scenario compared to those in the mid high cost scenario shown in Figure 7-16.

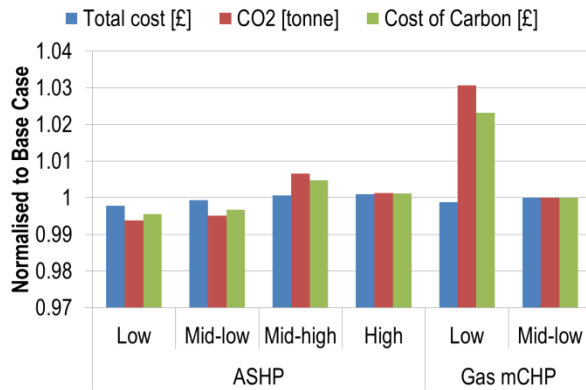


Figure 7-16: Fuel and electricity total system cost, total carbon emissions, and cost of carbon, for individual level technology cost scenarios, normalised to the Base Case.

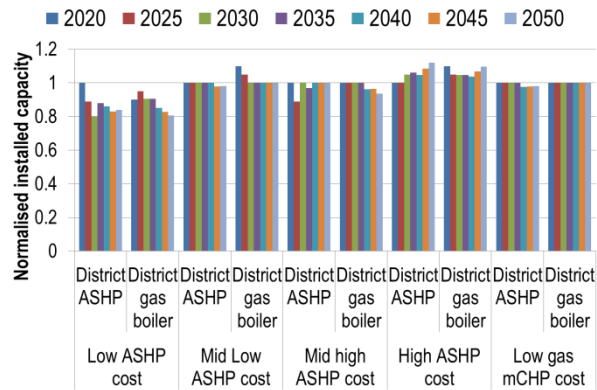


Figure 7-17: District level air-source heat pump (ASHP) and gas boiler capacities for individual level technology cost scenarios, normalised to Base Case.

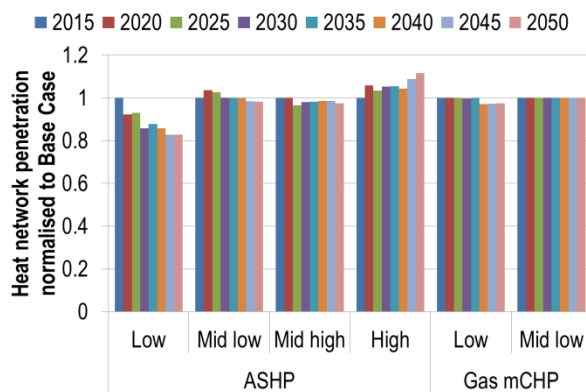


Figure 7-18: Heat network penetration for individual level air-source heat pump (ASHP) and gas micro CHP (mCHP) cost scenarios.

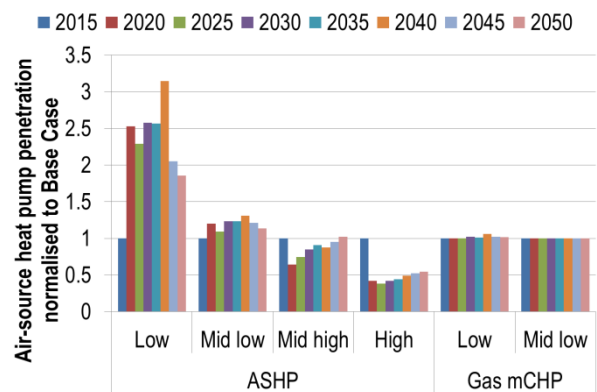


Figure 7-19: Air source heat pump (ASHP) penetration for individual level ASHP and gas micro CHP (mCHP) cost scenarios.

Regarding gas fuelled micro-CHPs, no uptake is observed in the mid low cost scenario. Therefore the same results as for the Base Case are obtained, as seen in Figure 7-16, Figure 7-18, and Figure 7-19. However, in the low cost scenario an important participation of gas fuelled micro-CHPs is observed in the domestic sector as shown in Figure 7-20. An interesting insight from this figure is that in the low capital cost scenario, gas fuelled micro-CHPs are a transition technology. The common factor of all the modelled scenarios in this work is that the participation of gas boilers and overall of gas fuelled systems decreases through 2050. Also, as Figure 7-21 shows, in the Base Case (and in all other scenarios as well) the emissions from gas and total emissions are reduced throughout time. For the low cost micro-CHP scenario, individual level domestic gas boilers are more abruptly reduced than in the Base Case (Figure 7-1), with gas-fuelled micro CHPs taking their place in the transition to 2050. As seen in Figure 7-20, an important participation is observed in the domestic sector between 2025 and 2040, decreasing again towards 2050. This mean that for the low capital cost scenario, gas fuelled micro-CHPs are more cost effective than gas boilers, which can be explained because of the gains in selling electricity to the grid. Figure 7-16 shows that in this scenario higher carbon emissions

are obtained than in the Base Case. This is because not only overall efficiencies of micro-CHPs in this work are lower than gas boiler efficiencies (80% versus 89% respectively), but also because part of the gas fuelling micro-CHP units is being used to produce electricity (74% is used for producing heat, and 6% is being used to produce electricity), so overall more gas is used for meeting heat demand. As observed in Figure 7-18 and Figure 7-19, heat network and individual level air-source heat pump penetrations are almost the same as in the Base Case, so nearly all the difference in carbon emissions and cost of carbon can be attributed to micro-CHP units taking over natural gas boilers.

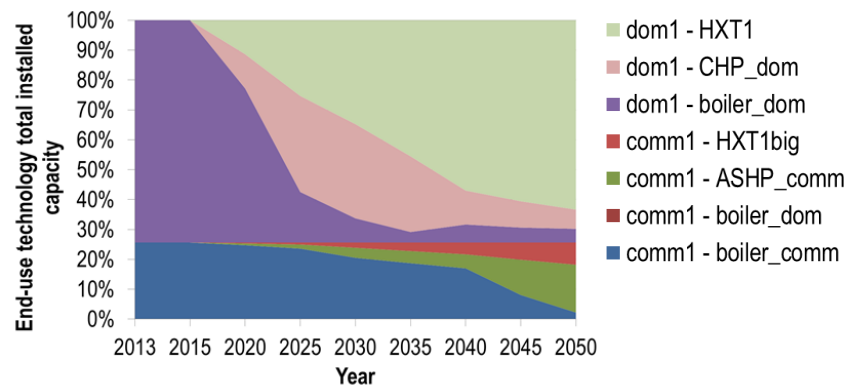


Figure 7-20: Total installed capacity of individual level heat supply technologies-Low gas micro CHP cost scenario.

7.5 Heat decarbonisation - All scenarios

This section analyses the decarbonisation of heat in all scenarios. Figure 7-21 shows the annual equivalent carbon emissions from gas and electricity for the Base Case. This figure shows that by means of a central scenario carbon price, a cost effective heat supply technology mix achieves carbon emissions reductions of 88% from 2015 to 2050 in the Base Case.

Figure 7-22 shows the evolution over time of equivalent carbon emissions for fuel, electricity, and carbon price scenarios, normalised to the Base Case. Figure 7-23 shows equivalent carbon emissions through 2050 for heat, electricity, and gas network cost scenarios, and Figure 7-24 shows equivalent carbon emissions for the analysed individual level technology cost scenarios, normalised to the Base Case. Comparing all these scenarios, it is found that the scenario that achieves lower carbon emissions by 2050 is the high carbon price scenario. This scenario also achieves the lowest total system carbon emissions over the whole modelled time horizon, obtaining 2.8% less total carbon emissions than the Base Case. On the other hand, in the low carbon price scenario the highest carbon equivalent emissions are obtained by 2050, together with the highest total system emissions;

7.3% higher than the Base Case. These results show that if the heat supply was centrally planned in a cost-efficient way, the carbon price is an effective measure for achieving heat decarbonisation.

A further conclusion from analysing these figures is that system-wide measures such as network costs, fuel prices, electricity prices, or carbon prices, have a higher influence in technology mixes and system carbon emissions than individual level heat technology costs, even with technology cost reductions or increases as high as 40%. This further demonstrates the importance of using system-wide models that include trade-offs in fuel and electricity prices, carbon prices, infrastructure, end-use and district technologies, to study the decarbonisation of heat. This also outlines the importance of taking into account the whole lifecycle costs of networks and technologies, rather than only considering short term technology costs.

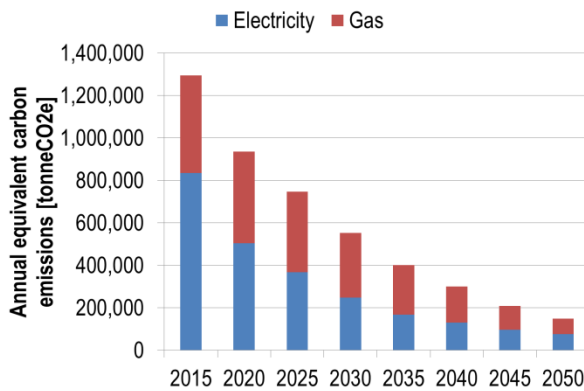


Figure 7-21: Annual equivalent carbon emissions from gas and electricity.

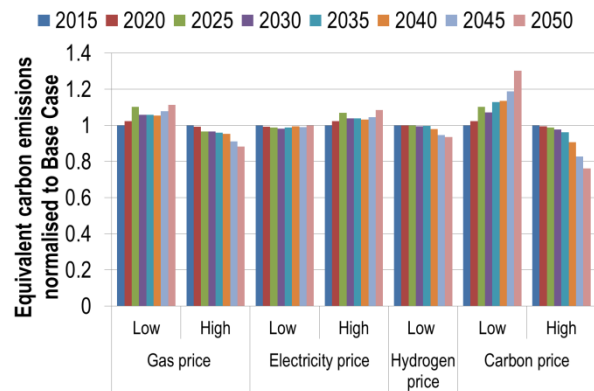


Figure 7-22: Equivalent carbon emissions over time for fuel, electricity, and carbon price scenarios, normalised to the Base Case.

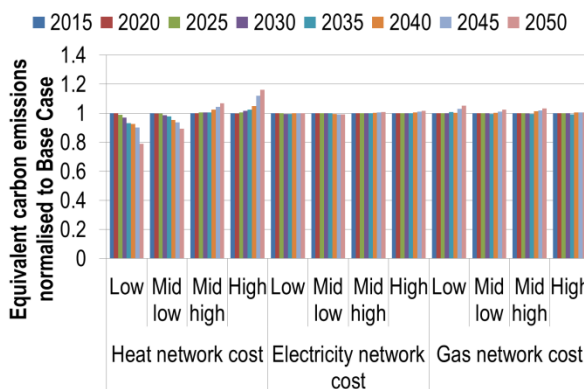


Figure 7-23: Equivalent carbon emissions over time for heat, electricity, and gas network cost scenarios, normalised to the Base Case.

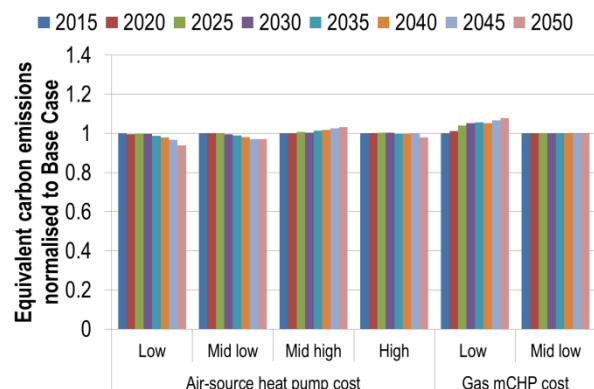


Figure 7-24: Equivalent carbon emissions over time air-source heat pumps and micro-CHP (mCHP) cost scenarios, normalised to the Base Case.

Chapter 8. Conclusions and future work

8.1 General conclusions

This thesis has presented the HIT spatially resolved model for the analysis of heat decarbonisation pathways. The model includes the economic and technical characterisation of the whole heat supply chain, including primary energy costs, end use technologies, and infrastructure. The novelty of this model is that it captures trade-offs between heat supply, end-use technologies, and gas, electricity, heat, and hydrogen network infrastructure at a high spatial resolution. The model has been applied to study four key issues related to heat decarbonisation in the UK, to demonstrate the trade-offs between technology and infrastructure options. Specific conclusions for each of the four key issues studied are discussed in the following sections.

8.2 Different temperature heat networks for decarbonising heat

When using the HIT model to study the trade-offs between different temperature heat networks for decarbonising heat, results show firstly that the inclusion of resolved demand and infrastructure topology in heat decarbonisation models can certainly influence the characteristics of the heat decarbonisation pathways created. For example, for the scenarios considered, heat electrification in the domestic sector is more cost-effectively reached through installing heat networks supplied by air-source heat pumps, rather than by installing individual building heat pumps. This is due to the additional costs these individual technologies require related to the reinforcement of the electricity grid. In the commercial sector, however, decarbonisation of heat can be cost-effectively reached by a combination of air-source heat pumps and heat networks. Air-source heat pumps are shown to play an important role in heat decarbonisation pathways, either at individual building or district levels, highlighting the importance of taking into account infrastructure as well as technology costs and performances when comparing cost-effective technology mixes.

Secondly, heat network and air-source heat pump penetrations and the location of district heat technologies are dependant on linear heat density, on zone-to-zone connectivity and topology, and on the commercial heat demand participation in zones, in addition to specific techno-economic assumptions. This further demonstrates the importance of considering spatial aspects in the planning of energy transitions. For the cases modelled, it is observed that linear heat density is a good indicator of district heating adoption and air-source heat pump penetration for the case when

only high temperature heat networks are available. For linear heat densities of over 250 kWh/m, the heat network uptake by 2050 is over 40%, and for linear heat densities of over 1250 kWh/m and 2250 kWh/m, heat network penetration exceeds 60% and 90% respectively by 2050. Yet in the scenarios where a medium temperature network is also available, linear heat density is less indicative of optimal heat network adoption, with cases of high adoption in low linear heat density zones, driven by favourable demand and network topology.

When the option of installing a medium temperature heat network was available, a mix between high temperature heat networks and medium temperature networks was selected by the model, with a higher penetration of the latter, and a higher overall penetration. This means that the higher coefficient of performance for district level heat pumps when delivering lower temperature heat, and the lower network losses in medium temperature networks, were able to offset the higher network costs. In general terms, some medium temperature heat networks appear in some zones with linear heat densities over 1750 kWh/m, and in all zones with linear heat densities over 2000 kWh/m. Linear heat densities over 2250 kWh/m produce medium temperature heat network uptakes over 70% by 2050. When both temperatures are available, high temperature heat network penetrations are observed to increase with linear heat densities up to 2000 kWh/m, and then decrease. For linear heat densities greater than 250 kWh/m and 750 kWh/m (and under 2000 kWh/m), high temperature heat network penetration is over 40% and 60% by 2050 respectively. A total overall heat network penetration was reached when both temperatures were available, with medium temperature heat networks appearing in the most linear heat dense zones.

Finally, regarding individual level air-source heat pumps, these were mostly adopted in the commercial sector. Air-source heat pump adoption was found to be determined by a combination between linear heat density and commercial demand participation. Although numerical thresholds were not determined, the general tendency showed firstly that high air-source heat pump uptakes were observed for low linear heat densities. Secondly, up to a certain linear heat density threshold, commercial demand participation was the determining factor for the adoption of air-source heat pumps, with a direct relationship between commercial demand participation and air-source heat pump uptakes. Over that linear heat density threshold, linear heat density was observed to be the determinant factor for adoption levels of air-source heat pumps.

8.3 The effect of spatial resolution in outcomes of energy systems models for heat

This chapter presented a study on the effect of spatial resolution when modelling heat decarbonisation pathways. Firstly, results show the importance of modelling spatial resolution for optimal allocation of heat supply technologies across different urban/rural areas. For the local authorities modelled in this research which represent the six UK urban/rural local authority classifications, results for technology mix and location of technologies through 2050 vary when modelling LSOAs, MSOAs, and total aggregated areas. For the studied cases, with central price estimates, differences of up to 44% in heat network uptake and 48% in air-source heat pump penetrations were observed when comparing LSOA results with total aggregated area results. These differences were observed to increase to around 50% under low electricity price or high carbon price scenarios.

Secondly, it was observed that for high and low extremes of linear heat density areas (i.e. highly urban and highly rural) results are less dependent on spatial resolution. Technology uptake thresholds are determined by linear heat density (among other indicators). Therefore, in areas with consistently high or low linear heat densities, or in highly homogeneous linear heat density areas, lower discrepancies are observed between results for different resolution levels. In other words, spatial resolution is important when there is sufficient variability of linear heat density throughout zones. The level of variability required depends on assumptions of techno-economic parameters and demand topology.

Finally, results reinforce the view that it is important to use finer resolutions when using optimisation models to inform network design and expansion. Even for the cases in which the total overall network penetrations are similar between different resolution levels, a higher spatial resolution provides more detailed information on zones that would benefit more or faster from heat networks. Additionally, higher resolution levels provide more accurate information on optimal location of district heat supply technologies, allowing for a more cost-effective design.

8.4 The role of hydrogen in heat decarbonisation

The HIT model was extended to study the role of hydrogen in heat decarbonisation by the use of two formulations: Formulation A, which assumed that hydrogen networks will be built independently of the current natural gas network; and Formulation B, which was designed for the current natural gas

network to be retrofitted into a hydrogen network. Heat supply pathways for three different hydrogen price and two hydrogen emission scenarios were analysed.

For Formulation A, under the assumption that a hydrogen network would be built independently of gas networks, results for the two highest hydrogen price scenarios conveyed no hydrogen participation for any of the emission scenarios. As gas networks are imposed to decommission through 2050, they are progressively replaced by heat exchangers connected to district heating in the domestic sector, and by heat exchangers and individual level air-source heat pumps in the commercial sector. Heat networks in these scenarios are supplied by district level air-source heat pumps and gas boilers. For the third and lowest hydrogen price scenario (HP3), results for the highest of the two hydrogen emission scenarios (HE1) showed that the individual level heat supply technology mix was nearly the same as for the previously described cases. No participation of individual level hydrogen boilers was observed. However, a role for hydrogen fuelled district boilers was observed in this scenario, with hydrogen boilers supplying heat networks from 2035, and replacing natural gas boilers from 2040 on. District level hydrogen boilers together with air-source heat pumps were observed to be the technologies supplying heat networks entirely by 2050. Finally, for hydrogen price scenario HP3 and the lowest hydrogen emission scenario (HE2), besides from hydrogen boilers supplying heat networks as previously discussed, a further role for individual level hydrogen boilers was observed in the commercial sector, representing 34% of the commercial individual level heat supply installed capacity by 2050.

For Formulation B in which the option to retrofit the existing gas network to convert it into hydrogen is made available, the six combinations of hydrogen price and emission scenarios were analysed for two cases. In the first case, the gas network capacity is decommissioned linearly through 2050, and the retrofitting of the gas network to convert it into hydrogen needs to be performed over an existing gas network, at a marginal retrofitting cost. Therefore, in order to extend the hydrogen network, gas networks also need to be installed. In the second case modelled through the second formulation, no cost is associated to the gas network. This case assumes that as the Mains Replacement Programme is currently taking place in the UK which means that all gas distribution pipes are being replaced by polyethylene pipes, the gas network costs are considered as sunken costs, and therefore not added in the network replacement costs. Therefore, in this case the inclusion of hydrogen networks is at a marginal retrofitting cost.

Results obtained in the first case -in which the gas network is decommissioned linearly through 2050, and in which in order to extend the hydrogen network a new gas network needs to be

previously installed -are very similar to those of Formulation A. This is because all costs and techno-economic parameters used are the same, and the only difference lies in an extra marginally low cost needed to retrofit the gas network to convert it into hydrogen. For the two highest hydrogen price scenarios (HP1 and HP2), results were the same as in Formulation A, with no hydrogen participation in any of the emission scenarios. For the lowest hydrogen price scenario HP3 and emission scenario HE1, a role for hydrogen is seen for supplying heat networks together with district level air-source heat pumps, as for Formulation A. For this case the participation of district level air-source heat pumps is slightly higher, as hydrogen infrastructure costs is (marginally) higher as well. Finally, for the lowest hydrogen price scenario HP3 and lowest emission scenario HE2, hydrogen boilers not only supply heat networks as for emission scenario HE1, but also individual-level hydrogen boilers are observed in the commercial sector, reaching 21% of the commercial installed capacity by 2050.

When analysing results for Formulation B for the second case in which new gas networks are assumed to be a sunken cost, higher participations of gas and hydrogen boilers are observed in all modelled scenarios. For high hydrogen price estimates, a cost-effective pathway for heat decarbonisation towards 2050 is replacing gas boilers by heat networks supplied by a combination of district level heat pumps and gas boilers. No participation of hydrogen networks is observed for high hydrogen price scenarios. However, at lower estimates of hydrogen prices (HP2 and HP3), the gas network is incrementally replaced by hydrogen boilers and heat networks in the commercial and domestic sectors, when the gas network is allowed to be retrofitted into hydrogen. For hydrogen price scenario HP3, hydrogen boilers represent 86% and 96% of the total individual level installed capacity for hydrogen emission scenarios HE1 and HE2 respectively. Also, an uptake of district level hydrogen boilers supplying heat networks is observed for low hydrogen prices, to the detriment of gas boilers, obtaining a heat network heat supply of mainly district level air-source heat pumps and hydrogen boilers.

This shows that retrofitting the existing gas network into hydrogen is a cost-effective heat decarbonisation pathway for the UK, when hydrogen retail prices are in the average to low projection ranges. These results are consistent with those from Dodds and McDowall [107], Speirs et al. [85], or Sadler et al. [23], who conclude that there is an opportunity to re-evaluate the Iron Mains Replacement Programme in order prepare the gas infrastructure for a more sustainable hydrogen network.

8.5 The sensitivity of heat decarbonisation outcomes to uncertainty in techno-economic parameters

The HIT model is a technology-rich bottom-up model, and therefore many uncertainties exist in the input assumptions. In this section a sensitivity analysis of the main input parameters of the HIT model was performed in order to study the influence of input parameter variations in heat decarbonisation scenarios. High and low cost/price parameters for individual level heat supply technologies, networks, fuels, electricity, and carbon were varied leaving the rest constant, and results were compared with a Base Case with central cost assumptions.

For gas, electricity, and hydrogen price scenarios, the ones which present a lower difference in total cost and total carbon emissions compared to the Base Case are the hydrogen price scenarios. In the low hydrogen price scenario, a 5.2% difference in individual level hydrogen boilers was observed, together with district level hydrogen boilers replacing district level gas boilers from the Base Case. From all fuel and electricity price scenarios, the lowest system cost and second to lowest carbon emissions are obtained in the low electricity price scenario, with a high uptake of individual and district level air-source heat pumps. The second lowest system cost is obtained in the low gas price scenario, through a high uptake of individual and district level gas boilers to the detriment of lower carbon alternatives, which generate the highest system carbon emissions of all fuel and electricity price scenarios. The highest system costs are found in the high electricity price scenario, in which a low participation of air-source heat pumps serving heat networks and a high individual level gas boiler uptake generate the second highest equivalent carbon emissions compared to the other fuel price scenarios. Lastly regarding fuel and electricity prices, the high gas price scenario achieves lowest system's equivalent carbon emissions through a combination of high heat network penetrations and a fast uptake of individual level air-source heat pumps.

With regards to carbon prices, the high carbon price scenario presents the highest system's cost, and achieves the highest reductions in the system's equivalent carbon emissions compared to all other modelled scenarios, with 2.8% less emissions than the Base Case. This is achieved through a high individual level air-source heat pump penetration, high uptakes of district level air-source heat pumps supplying heat networks, and the inclusion of district level hydrogen boilers supplying heat networks. Conversely, the low carbon price scenario obtains 7.3% more total system's emissions than the Base Case, at the lowest system costs, which are the highest total emissions of all modelled scenarios. Lower penetrations of heat networks and individual level air-source heat pumps are obtained in this scenario compared to the Base Case, with the highest penetration of individual level

gas boilers. Additionally, a lower participation of district level air-source heat pumps and a higher participation of district level gas boilers are observed supplying heat networks.

Regarding network cost scenarios, heat network cost variations are the ones which produce higher variations in costs and emissions of all network cost scenarios, with electricity having the lowest influence. Compared to network cost scenarios, the highest carbon emissions reductions and lowest system costs are achieved at low heat network costs, and increase as heat network costs increase. At low heat network costs, high heat network penetrations supplied by air-source heat pumps are observed. As heat network costs increase, heat network penetrations decrease, with higher gas boiler uptakes, producing higher carbon emissions. In low electricity network cost scenarios, lower heat network and higher air-source heat pump penetrations than in the Base Case are obtained, achieving lower carbon emissions. As electricity network costs increase, so does the uptake of individual level gas boilers. Less air-source heat pumps are observed, with higher system carbon emissions. For the low gas network cost, higher individual level gas boilers than in the Base Case are obtained, with lower heat network and air-source heat pump penetrations, and a subsequent rise in carbon emissions. As gas network costs increase, higher heat network and air-source heat pump penetrations are obtained, with lower gas boiler uptakes and carbon emissions.

The only individual level heat supply technology cost scenarios here studied that produced variations in outputs were air-source heat pump cost scenarios, and the low gas fuelled micro CHP cost scenario. As air-source heat pump costs increase, lower uptakes of air-source heat pumps are obtained. Carbon emissions also progressively increase up to the mid-high cost scenario. In this scenario, as zone linear heat density adoption thresholds for air-source heat pumps increase, so does the threshold in which gas boilers are not competitive anymore, obtaining a higher gas boiler uptake and a lower heat network uptake, which demonstrates the importance of analysing scenarios from a system-wide perspective. In the high air-source heat pump cost scenario, carbon emissions decrease with respect to the mid-high cost scenario, as higher heat network penetrations are observed to the detriment of gas boilers, and some district level hydrogen boilers are observed as well. Finally, in the low gas fuelled micro-CHP cost scenario, micro-CHPs were found to be a transitional technology, replacing gas boilers in the domestic sector in an interim period before 2050, and decreasing towards 2050.

Finally, comparing all cost scenarios, it is concluded that if heat supply was centrally planned in a cost-efficient way, the carbon price is an effective measure for achieving heat decarbonisation. Also, results show that system-wide measures such as network costs, fuel prices, electricity prices, or

carbon prices, have a higher impact in heat decarbonisation scenarios than individual level heat technology costs. This further demonstrates the importance of using system-wide models that include trade-offs between energy supply, infrastructure, technology and demands, to study the decarbonisation of heat.

8.6 Limitations and future work

The HIT model presented in this thesis is an integrated energy systems model to study heat decarbonisation pathways. The study on spatial resolution shows that results from modelling are dependent on the spatial resolutions used. As the model aggregates consumers into zones, the results are sensitive to the aggregation level. Therefore, care needs to be taken when using this model for finding optimal heat supply technology mixes, since coarse resolutions can produce very sub-optimal pathways.

Concerning heat and electricity demands per zone, a limitation of the model is that input demands are aggregated, and therefore output end-use technology capacities are also aggregated in each zone. Hence, if the chosen spatial resolution is too coarse, aggregated capacities may not be detailed enough for a specific case study.

Networks are also modelled in an aggregated way, and therefore this model is suitable for broader strategic planning rather than site-specific design. The model does not consider dynamic analyses in pipelines or electricity cables. Therefore, for network design, additional dynamic analyses should be performed to determine technical feasibility. Also, an average cost per length is considered when purchasing networks within zones. Depending on dynamic analyses, geographic elements, or road topologies, network costs could vary in different zones. The aggregation into time slices also impedes the possibility to perform dynamic analyses.

Performed sensitivity and uncertainty analyses for different parameters show that variations in optimal technology mixes are very dependent on input parameters. Therefore, when using this model for studying heat supply pathways, it is important to create a range of scenarios for input parameters, to understand the range of solutions that could be obtained with uncertain parameters. The model does not endogenously take into account, for example, uncertainty in gas and electricity prices.

Based on the literature review, future work includes using this model to study more extensive heat decarbonisation options. For example, when comparing different temperature heat networks, 4th

generation district heating has been gaining attention. For this, the HIT model could be extended to include a low temperature heat network, together with booster heat pumps, and efficiency improvements. Moreover, an interesting modification would be to explore the potential for interactions between different temperature networks, either via waste heat utilisation or heat cascading from the return of a higher temperature heat network, together with the inclusion of booster technologies.

When using the HIT model for studying the role of hydrogen in heat decarbonisation, future work includes introducing future demand for hydrogen fuel cell vehicles, in order to explore potential synergies between fuel charging and heat infrastructure for hydrogen. As concluded by Dodds and Ekins [103], introduction of fuel cell vehicles should be internalised in energy systems models, as an early adoption would enable optimum penetration. In the same line, Yang and Ogden [100] suggest that a regionalised infrastructure rollout of hydrogen for transport should be planned. These and other studies reviewed in Section 2.4.3 suggest that an energy systems model that includes hydrogen infrastructure for transport and for heat could derive into a more cost-effective urban planning. In the HIT model, for example, a spatially-distributed increasing hydrogen demand corresponding to increasing penetration of fuel-cell vehicles could be included, together with the possibility of including different sized of fuelling-stations throughout zones. In this way, the aspects of infrastructure trade-offs and spatial resolution of the HIT model could be exploited to study the synergies between hydrogen for transport and heat. Another extension of this work is modelling transmission and hydrogen production facilities, including location constraints that guarantee safe hydrogen production and storage facilities.

Similarly, synergies between electric vehicle infrastructure and electricity infrastructure for heat can be explored. Spatially distributed transport related electricity (or hydrogen) demand for electric vehicles could be added as a third consumer demand profile. This would include the reinforcement needed in the electricity grid to supply additional demand from electric vehicles, together with cost effective locations of charging infrastructure. Therefore, the HIT model could find a system cost-effective pathway for supplying heat, electricity, and hydrogen, for domestic, commercial, and transport demands.

Further additions to the HIT model could be to include the power sector. Transmission could be included as a long connection between zones, connecting the city boundaries with proxy zones where power plants could be potentially built. Power plants could then be modelled as integers, as currently district technologies are modelled supplying the district heating networks. Another

potential addition would be to include some industrial sectors as points for feeding waste heat into district networks, or as points of high demands. Finally, by including a cap on emissions from heat, this model can be used to effectively study the trade-offs between energy supply options, infrastructure and equipment costs, and thereby provide new insight on possible heat decarbonisation pathways.

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Appendices

A. Time slices and demand allocation from UK TIMES

Table A-1: Allocation into seasonal and intraday time slices from UK TIMES [113].

Season	Season	Season	Season	Intraday	Intraday	Intraday	Intraday
Winter (W)	Spring (P)	Summer (S)	Autumn (A)	Night (N)	Day (D)	Evening peak (P)	Late evening (E)
25.0%	25.0%	25.0%	25.0%	29.2%	41.7%	12.5%	16.7%

Table A-2: Resulting time slices and hours per year in each time slice from UK TIMES [113].

Resulting time slice	Resulting fraction of year in each time slice	Hours per year in each time slice [h]
WN	7.3%	639
WD	10.4%	913
WP	3.1%	274
WE	4.2%	365
PN	7.3%	639
PD	10.4%	913
PP	3.1%	274
PE	4.2%	365
SN	7.3%	639
SD	10.4%	913
SP	3.1%	274
SE	4.2%	365
AN	7.3%	639
AD	10.4%	913
AP	3.1%	274
AE	4.2%	365

Table A-3: Domestic heat demand allocation into time slices from UK TIMES [113].

Time slice	Space heat (81.4% of total domestic heat demand)	Hot water (18.6% of total domestic heat demand)	Weighted total domestic heat demand
WN	6.5%	7.4%	6.7%
WD	22.6%	11.0%	20.5%
WP	11.1%	5.3%	10.0%
WE	7.7%	2.2%	6.7%
PN	4.6%	7.3%	5.1%
PD	12.2%	11.0%	12.0%
PP	6.8%	5.3%	6.5%
PE	4.1%	2.2%	3.8%
SN	0.6%	6.5%	1.7%
SD	0.9%	9.6%	2.6%
SP	0.3%	4.8%	1.2%
SE	0.2%	1.8%	0.5%
AN	3.7%	7.3%	4.4%
AD	9.8%	10.9%	10.0%
AP	5.5%	5.3%	5.4%
AE	3.3%	2.2%	3.1%

Table A-4: Commercial heat demand allocation into time slices from UK TIMES [113].

Time slice	Space heat (83.2% of total commercial heat demand)	Hot water (16.8% of total commercial heat demand)	Weighted total commercial heat demand
WN	6.2%	7.2%	6.4%
WD	22.6%	10.8%	20.6%
WP	10.2%	5.2%	9.4%
WE	7.7%	2.2%	6.7%
PN	4.6%	7.2%	5.0%
PD	12.5%	10.8%	12.2%
PP	6.6%	5.2%	6.3%
PE	4.4%	2.2%	4.0%
SN	0.7%	6.8%	1.7%
SD	1.0%	10.1%	2.5%
SP	0.5%	5.1%	1.2%
SE	0.4%	2.0%	0.7%
AN	3.8%	7.2%	4.3%
AD	10.0%	10.8%	10.2%
AP	5.3%	5.2%	5.3%
AE	3.6%	2.2%	3.3%

Table A-5: Domestic and commercial electricity demand allocation into time slices based on UK TIMES [113] and Elexon profiles [114].

Time slice	Domestic electricity demand allocation	Commercial electricity demand allocation
WN	4.6%	5.2%
WD	13.2%	17.7%
WP	5.9%	3.3%
WE	5.7%	3.1%
PN	4.3%	4.3%
PD	10.9%	15.0%
PP	4.3%	2.7%
PE	5.0%	2.6%
SN	3.9%	3.6%
SD	9.9%	10.0%
SP	3.7%	4.0%
SE	4.4%	2.4%
AN	4.0%	3.9%
AD	10.7%	14.5%
AP	4.6%	2.6%
AE	4.9%	2.5%

B. Emission factors, gas, electricity, and carbon prices

Table B-1: Electricity and gas prices [118].

Year	Electricity Prices			Gas Prices		
	Commercial [2015p/ kWh]	Domestic [2015p/ kWh]	Wholesale [2015p/ kWh]	Commercial [2015p/ kWh]	Domestic [2015p/ kWh]	Wholesale [p/ therm]
2012	9.4	14.4	4.9	2.9	4.7	62.4
2013	9.4	15.2	5.3	3.1	4.9	69.8
2014	9.8	15.8	4.4	3.0	5.1	50.4
2015	9.9	14.5	4.4	2.6	4.1	45.4
2016	10.8	15.0	4.8	2.7	4.0	46.9
2017	11.3	16.0	5.2	2.7	4.2	47.7
2018	11.3	16.7	4.8	2.7	4.2	47.9
2019	12.0	17.2	4.6	2.8	4.2	48.2
2020	12.5	17.6	4.9	2.9	4.2	51.0
2021	13.1	17.7	5.4	3.0	4.3	53.8
2022	13.3	18.1	5.8	3.1	4.5	56.7
2023	13.6	18.0	6.0	3.2	4.3	59.5
2024	14.4	18.4	6.5	3.3	4.4	62.3
2025	15.0	19.3	6.7	3.4	4.6	65.1
2026	15.1	19.3	6.9	3.5	4.7	66.5
2027	15.2	19.7	6.9	3.5	4.7	66.5
2028	14.7	19.4	6.6	3.5	4.7	66.5
2029	14.6	19.1	6.6	3.5	4.7	66.7

2030	14.8	19.2	6.6	3.5	4.7	66.6
2031	14.8	19.2	6.6	3.5	4.7	66.6
2032	14.8	19.2	6.6	3.5	4.7	66.6
2033	14.8	19.2	6.3	3.5	4.7	66.6
2034	14.8	19.2	6.7	3.5	4.7	66.6
2035	14.8	19.2	6.1	3.5	4.7	66.6
2036	14.8	19.2	6.1	3.5	4.7	66.6
2037	14.8	19.2	6.1	3.5	4.7	66.6
2038	14.8	19.2	6.1	3.5	4.7	66.6
2039	14.8	19.2	6.1	3.5	4.7	66.6
2040	14.8	19.2	6.1	3.5	4.7	66.6
2041	14.8	19.2	6.1	3.5	4.7	66.6
2042	14.8	19.2	6.1	3.5	4.7	66.6
2043	14.8	19.2	6.1	3.5	4.7	66.6
2044	14.8	19.2	6.1	3.5	4.7	66.6
2045	14.8	19.2	6.1	3.5	4.7	66.6
2046	14.8	19.2	6.1	3.5	4.7	66.6
2047	14.8	19.2	6.1	3.5	4.7	66.6
2048	14.8	19.2	6.1	3.5	4.7	66.6
2049	14.8	19.2	6.1	3.5	4.7	66.6
2050	14.8	19.2	6.1	3.5	4.7	66.6

Table B-2: Central carbon price and emission factors for electricity and gas [120].

Year	Carbon price	Emission factor			
	Central (non-traded) [2015£/tCO ₂ e]	Electricity			Gas
		Domestic [kgCO ₂ e/kWh]	Commercial [kgCO ₂ e/kWh]	District [kgCO ₂ e/kWh]	All sectors [kgCO ₂ e/kWh]
2012	59.7	0.534699115	0.524906091	0.515113067	0.18445
2013	60.6	0.49687707	0.487776757	0.478676445	0.18445
2014	61.5	0.43627985	0.428289377	0.420298903	0.18445
2015	62.4	0.460784406	0.452345131	0.443905856	0.18445
2016	63.4	0.383405525	0.376383446	0.369361366	0.18445
2017	64.3	0.327922261	0.321916359	0.315910457	0.18445
2018	65.3	0.317060065	0.311253104	0.305446144	0.18445
2019	66.3	0.297889246	0.292433399	0.286977552	0.18445
2020	67.2	0.265409693	0.260548709	0.255687726	0.18445
2021	68.4	0.233738144	0.229457226	0.225176308	0.18445
2022	69.5	0.215263021	0.211320475	0.207377928	0.18445
2023	70.6	0.183286904	0.179930001	0.176573098	0.18445
2024	71.7	0.192470862	0.188945754	0.185420647	0.18445
2025	72.8	0.180383341	0.177079616	0.173775892	0.18445
2026	74.0	0.160350031	0.157413217	0.154476403	0.18445

2027	75.1	0.158571552	0.155667312	0.152763071	0.18445
2028	76.2	0.133023965	0.130587629	0.128151292	0.18445
2029	77.3	0.116292975	0.114163067	0.112033159	0.18445
2030	78.5	0.112132488	0.110078779	0.108025071	0.18445
2031	85.7	0.105817497	0.103879448	0.101941398	0.18445
2032	93.0	0.09986513	0.098036098	0.096207066	0.18445
2033	100.3	0.085882437	0.084309498	0.08273656	0.18445
2034	107.6	0.084863748	0.083309467	0.081755186	0.18445
2035	114.9	0.070535923	0.069244057	0.06795219	0.18445
2036	122.2	0.069140137	0.067873834	0.066607531	0.18445
2037	129.4	0.060351707	0.059246365	0.058141022	0.18445
2038	136.7	0.054050201	0.05306027	0.05207034	0.18445
2039	144.0	0.054803737	0.053800005	0.052796274	0.18445
2040	151.3	0.051164134	0.050227062	0.04928999	0.18445
2041	158.6	0.045500651	0.044667306	0.04383396	0.18445
2042	165.9	0.045115268	0.044288981	0.043462694	0.18445
2043	173.2	0.040107605	0.039373034	0.038638462	0.18445
2044	180.4	0.035455549	0.03480618	0.034156811	0.18445
2045	187.7	0.035988789	0.035329654	0.034670518	0.18445
2046	195.0	0.032768006	0.032167859	0.031567713	0.18445
2047	202.3	0.030334647	0.029779067	0.029223488	0.18445
2048	209.6	0.03067424	0.030112441	0.029550641	0.18445
2049	216.9	0.027771195	0.027262565	0.026753935	0.18445
2050	224.1	0.027521594	0.027017535	0.026513477	0.18445

C. Low and high electricity, gas, and carbon prices for sensitivity

Table C-1: Low electricity and gas prices for sensitivity [118].

Year	Low electricity prices			Low gas prices		
	Commercial [2015p/ kWh]	Domestic [2015p/ kWh]	Wholesale [2015p/ kWh]	Commercial [2015p/ kWh]	Domestic [2015p/ kWh]	Wholesale [2015p/ therm]
2012	9.4	14.4	4.9	2.9	4.7	62.4
2013	9.4	15.2	5.3	3.1	4.9	69.8
2014	9.8	15.8	4.4	3.0	5.1	50.4
2015	9.2	14.6	3.9	2.3	4.1	37.5
2016	9.7	14.4	4.0	2.2	3.7	34.5
2017	10.0	14.9	4.2	2.1	3.7	31.9
2018	9.9	15.5	3.6	2.0	3.6	29.3
2019	10.4	15.7	3.3	1.9	3.5	27.2
2020	11.4	16.4	3.4	2.0	3.4	28.8
2021	11.3	16.1	3.8	2.1	3.5	30.4
2022	12.1	17.0	4.1	2.1	3.5	32.0

2023	12.0	16.4	4.2	2.2	3.4	33.7
2024	12.8	16.9	4.7	2.3	3.4	35.3
2025	13.4	17.8	4.8	2.3	3.5	36.9
2026	13.3	17.6	4.9	2.4	3.5	38.5
2027	13.8	18.3	5.1	2.5	3.6	40.1
2028	13.7	18.2	5.0	2.5	3.6	41.7
2029	13.8	18.1	5.1	2.6	3.7	43.4
2030	13.9	18.2	5.4	2.6	3.8	45.0
2031	13.9	18.2	5.4	2.6	3.8	45.0
2032	13.9	18.2	5.7	2.6	3.8	45.0
2033	13.9	18.2	5.4	2.6	3.8	45.0
2034	13.9	18.2	5.5	2.6	3.8	45.0
2035	13.9	18.2	5.0	2.6	3.8	45.0
2036	13.9	19.1	5.4	2.6	3.8	45.0
2037	13.9	19.3	5.5	2.6	3.8	45.0
2038	13.9	19.5	5.6	2.6	3.8	45.0
2039	13.9	19.7	5.6	2.6	3.8	45.0
2040	13.9	19.9	5.7	2.6	3.8	45.0
2041	13.9	20.0	5.7	2.6	3.8	45.0
2042	13.9	20.2	5.8	2.6	3.8	45.0
2043	13.9	20.4	5.9	2.6	3.8	45.0
2044	13.9	20.6	5.9	2.6	3.8	45.0
2045	13.9	20.8	6.0	2.6	3.8	45.0
2046	13.9	21.0	6.1	2.6	3.8	45.0
2047	13.9	21.2	6.1	2.6	3.8	45.0
2048	13.9	21.4	6.2	2.6	3.8	45.0
2049	13.9	21.5	6.3	2.6	3.8	45.0
2050	13.9	21.7	6.3	2.6	3.8	45.0

Table C-2: High electricity and gas prices for sensitivity [118].

Year	High electricity prices			High gas prices		
	Commercial [2015p/ kWh]	Domestic [2015p/ kWh]	Wholesale [2015p/ kWh]	Commercial [2015p/ kWh]	Domestic [2015p/ kWh]	Wholesale [p/ therm]
2012	9.4	14.4	4.9	2.9	4.7	62.4
2013	9.4	15.2	5.3	3.1	4.9	69.8
2014	9.8	15.8	4.4	3.0	5.1	50.4
2015	10.6	14.6	4.9	2.9	4.1	53.3
2016	11.8	15.6	5.7	3.2	4.3	59.3
2017	12.6	17.0	6.3	3.3	4.7	63.5
2018	12.7	17.9	6.0	3.5	4.9	66.4
2019	13.5	18.6	6.0	3.6	5.0	69.2

2020	13.8	18.9	6.2	3.8	5.1	73.7
2021	14.7	19.0	7.1	3.9	5.3	78.3
2022	14.7	19.8	7.2	4.1	5.4	82.8
2023	15.2	19.5	7.5	4.3	5.4	87.4
2024	15.9	19.8	8.0	4.5	5.6	92.0
2025	16.5	20.7	8.3	4.6	5.7	96.5
2026	16.1	20.6	8.3	4.6	5.9	96.5
2027	16.5	21.0	8.3	4.6	5.9	96.5
2028	15.8	20.8	7.9	4.6	5.9	96.5
2029	15.6	20.0	7.8	4.6	5.9	96.5
2030	15.6	19.9	7.9	4.6	5.9	96.5
2031	15.6	19.9	8.2	4.6	5.9	96.5
2032	15.6	19.9	8.3	4.6	5.9	96.5
2033	15.6	19.9	7.4	4.6	5.9	96.5
2034	15.6	19.9	7.8	4.6	5.9	96.5
2035	15.6	19.9	6.8	4.6	5.9	96.5
2036	14.8	19.2	6.8	4.6	5.9	96.5
2037	14.8	19.2	6.8	4.6	5.9	96.5
2038	14.8	19.2	6.8	4.6	5.9	96.5
2039	14.8	19.2	6.8	4.6	5.9	96.5
2040	14.8	19.2	6.8	4.6	5.9	96.5
2041	14.8	19.2	6.8	4.6	5.9	96.5
2042	14.8	19.2	6.8	4.6	5.9	96.5
2043	14.8	19.2	6.8	4.6	5.9	96.5
2044	14.8	19.2	6.8	4.6	5.9	96.5
2045	14.8	19.2	6.8	4.6	5.9	96.5
2046	14.8	19.2	6.8	4.6	5.9	96.5
2047	14.8	19.2	6.8	4.6	5.9	96.5
2048	14.8	19.2	6.8	4.6	5.9	96.5
2049	14.8	19.2	6.8	4.6	5.9	96.5
2050	14.8	19.2	6.8	4.6	5.9	96.5

Table C-3: Low and high carbon prices for sensitivity [120].

Year	Carbon price	
	Low [2015£/tCO ₂ e]	High [2015£/tCO ₂ e]
2012	29.8	89.5
2013	30.3	90.9
2014	30.7	92.2
2015	31.2	93.6
2016	31.7	95.0
2017	32.2	96.5
2018	32.6	97.9

2019	33.1	99.4
2020	33.6	100.9
2021	34.2	102.5
2022	34.7	104.2
2023	35.3	105.9
2024	35.9	107.6
2025	36.4	109.3
2026	37.0	111.0
2027	37.5	112.6
2028	38.1	114.3
2029	38.7	116.0
2030	39.2	117.7
2031	42.9	128.6
2032	46.5	139.5
2033	50.2	150.5
2034	53.8	161.4
2035	57.4	172.3
2036	61.1	183.2
2037	64.7	194.2
2038	68.4	205.1
2039	72.0	216.0
2040	75.6	226.9
2041	79.3	237.9
2042	82.9	248.8
2043	86.6	259.7
2044	90.2	270.7
2045	93.9	281.6
2046	97.5	292.5
2047	101.1	303.4
2048	104.8	314.4
2049	108.4	325.3
2050	112.1	336.2