

DECARBONISING LOW GRADE HEAT FOR A LOW CARBON FUTURE

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DECLARATION

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3. Other work is appropriately referenced.
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Robert Sansom

ABSTRACT

More energy is consumed in the UK for heat than either transport or electricity and yet until recently little attention has been given to decarbonising heat to meet the UK's 2050 greenhouse gas targets. The challenges are immense as over 80% of households in the UK use gas for space and water heating. To achieve the UK's greenhouse gas targets will necessitate heat to be almost completely decarbonised and will thus require a transition from gas for heating to a low carbon alternative. However, there is a lack of consensus over which low carbon heat technologies householders should be encouraged to adopt as projections of these vary significantly.

This thesis commences by reviewing those projections and identifying the possible reasons for the variations. Low carbon heat technologies suitable for large scale deployment are identified and a heat demand model developed from which demand profiles can be constructed. An integrated heat and electricity investment model is then developed which includes electricity generation assets but also district heating assets such as combined heat and power plant, network storage and large network heat pumps. A core input into this model is the heat demand profiles. The investment model enables the interaction between heat and electricity assets to be evaluated and so using scenarios combined with sensitivities examines the economics and carbon emissions of the low carbon residential heating technologies previously identified. Throughout this analysis the equivalent cost for gas heating is used as a comparator.

The results suggest that district heating is an attractive option which is robust under most outcomes. However, its economic viability is crucially dependent on a financing regime that is compatible with other network based assets. Also identified is a role for electric storage heaters for buildings with low heat demand.

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NOMENCLATURE

INTEGRATED HEAT AND ELECTRICITY INVESTMENT MODEL

(section 5.3)

SETS

G	Set of thermal generation units g
H	Set of residential heat technologies h where: 1=ASHP 2=Hybrid heat pump 3=Electric storage heaters 4=District heating
D	Set of days in a year, d
T	Set of half hours in a year, t
TEMP	Set of daily temperature scenarios, θ

PARAMETERS

CHP:

$CHP^{CAPCOST}$	CHP levelised capital cost and annual fixed charges (£/MW/a)
CHP^{CAPMIN}	CHP minimum installed capacity [MW]
$CHPW^{COST}$	CHP electricity production cost (£/MWh)
$CHPW^{NLCOST}$	CHP electricity no-load production cost (£/h)
$CHPW^{NLCO2}$	CHP no-load CO ₂ cost (£/h)
$CHPQ^{COST}$	CHP thermal production cost (£/MWh _{th})
$CHPW^{MAX}$	Maximum CHP electricity generation (MW)
$CHPW^{INCCOST}$	CHP incremental fuel cost (£/MWh)
$CHPW^{INCCO2}$	CHP incremental CO ₂ cost (£/MWh)
$CHPW^{MIN}$	Minimum CHP electricity generation (MW)
$CHPQ^{MAX}$	Maximum CHP heat generation (MW _{th})
$CHPQ^{MIN}$	Minimum CHP heat generation (MW _{th})
$CHPW^{STUPCOST}$	Start-up cost of CHP (£/MW)
Z^{CHP}	CHP ratio of Δ Heat to Δ Electricity, i.e. $\Delta Q/\Delta W$ (pu)

λ^{CHP}	Maximum ratio of heat to electricity production in each half hour (pu)
$\text{CHP}^{\text{AVAIL}}$	CHP maximum annual availability (pu)
$\text{CHPW}^{\text{INITIAL}}$	CHP initial commitment status (binary)
Network heat pump:	
$\text{HP}^{\text{CAPOST}}$	Network heat pump levelised capital cost and annual fixed charges (£/MW _{th} /a)
$\text{HP}^{\text{CAPMIN}}$	Network heat pump minimum installed capacity (MW _{th})
HP^{MAX}	Network heat pump maximum heat production (MW _{th})
HP^{MIN}	Network heat pump minimum heat production (MW _{th})
HP^{AVAIL}	Network heat pump maximum annual availability (pu)
η^{HP}	Network heat pump efficiency (pu)
Grid:	
GRID^{MAX}	Maximum export of power to grid (MW)
$\text{GRID}_t^{\text{PRICE}}$	Grid price at time t (£/MWh)
CO ₂ :	
CO_2^{MAX}	Maximum CO ₂ emissions (Mt)
$\text{CO}_2^{\text{PRICE}}$	CO ₂ price (£/t)
Network heat store:	
$\text{HSTO}^{\text{CAPCOST}}$	Network heat store levelised capital cost (£/MW _{th} /a)
$\text{HSTO}^{\text{INITIALQ}}$	Network heat store initial charge (MWh _{th})
$\text{HSTO}^{\text{MAXQ}}$	Network heat store maximum charge (MWh _{th})
$\text{HSTO}^{\text{INMAX}}$	Network heat store minimum charge rate (MW _{th})
$\text{HSTO}^{\text{OUTMAX}}$	Network heat store maximum discharge (MW _{th})
η^{HSTO}	Network heat store static efficiency in each half hour (pu)
$\eta_{\text{HSTO}}^{\text{IN}}$	Network heat store charging efficiency (pu)
$\eta_{\text{HSTO}}^{\text{OUT}}$	Network heat store discharging efficiency (pu)
Multigen:	

$GEN_g^{CAPCOST}$	Generator g levelised capital cost and annual fixed charges (£/MW/a)
GEN_g^{MIN}	Minimum output of generator g (MW)
GEN_g^{MAX}	Maximum output of generator g (MW)
$GEN_g^{INCCOST}$	Incremental fuel cost of generator g (£/MWh)
$GEN_g^{INCCO_2}$	Incremental CO ₂ cost of generator g (£/h)
GEN_g^{COST}	Electricity production cost of generator g (£/MWh)
GEN_g^{NLCOST}	Electricity production no-load fuel cost of generator g (£/h)
$GEN_g^{NLCO_2}$	Electricity production no-load CO ₂ cost of generator g (£/h)
$GEN_g^{STUPCOST}$	Start-up cost of generator g (£/MW)
$GEN_g^{INITIAL}$	Initial commitment status of generator g (binary)
GEN_g^{AVAIL}	Maximum annual availability of generator g (pu)
GEN_g^{CAPMIN}	Minimum capacity of generator g (MW)
Wind:	
$WIND_t$	Wind power available at time t (MW)
$WIND^{COST}$	Wind production cost (£/MWh)
Residential heaters:	
RH_h^{CAP}	Residential heater h installed capacity (MW _{th})
$RH_h^{CAPCOST}$	Levelised capital cost and annual fixed charges of heater h (£/MW _{th} /a)
RH_h^{MAXQ}	Maximum residential heater store charge of heater h (MWh _{th})
RH_h^{INMAX}	Maximum residential heater input of heater h (MW _{th})
η_h^{RH}	Residential heater h static losses in each half hour (pu)
RH_h^{CAPMIN}	Residential heater minimum installed capacity of heater h (MW _{th})
$ASHP_t^\theta$	ASHP & hybrid heat pump efficiency for temperature scenario θ at time t (pu)

$GB^{CAPCOST}$	Total levelised capital cost & annual fixed charges of peaking gas boilers (£/a)
GB^{COST}	Peaking gas boiler heat production cost (£/MWh _{th})
GB^{CAPMIN}	Peaking gas boiler minimum installed capacity (MW _{th})
GB^{MAX}	Maximum peaking gas boiler output (MW _{th})
GB^{AVAIL}	Maximum annual availability of the peaking gas boiler (pu)
$EH^{CAPCOST}$	Total levelised capital cost & annual fixed charges of all peaking electric heaters (£/a)
EH^{CAPMIN}	Peaking electric heater minimum installed capacity (MW _{th})
EH^{MAX}	Maximum peaking electric heater output (MW _{th})
EH^{AVAIL}	Maximum annual availability of the peaking electric heater (pu)
Network losses:	
HNW_t^{LOSSES}	Heat network losses at time t (MW _{th})
ENW_t^{LOSSES}	Electricity network losses at time t (pu)
Φ	Fixed electricity network losses
φ	Variable electricity network losses
γ	Heat network losses (pu)
$HEAT^{CUTOFF}$	Cut-off temperature for space heating, °C
Demand:	
Q_t^θ	Total thermal building demand for temperature scenario θ at time t (MW _{th})
Q^{PEAK}	District heating building peak demand (MW _{th})
Q_t^{ASHP}	ASHP building heat demand at time t (MW _{th})
Q_t^{EH}	Peaking electric heat demand for buildings with ASHP at time t (MW _{th})
Q_t^{HYBRID}	Hybrid pump building heat demand at time t (MW _{th})
Q_t^{GB}	Peaking gas heat demand for buildings with hybrid heat pump at time t (MW _{th})
Q_t^{ESTOR}	Electric storage heater building heat demand at time t (MW _{th})
$Q_t^{DISTRICT}$	District heating building heat demand at time t (MW _{th})
Q^{MAX}	Maximum thermal demand (MW _{th})
$TEMP_d^\theta$	Daily average temperature for temperature scenario θ (°C/d)

W^{MAX}	Maximum non-heat electricity demand (MW)
W^{QMAX}	Maximum heat electricity demand (MW_{th})
W_t	Non heat electricity demand at time t (MW)

VARIABLES

CHP:

chp^{cap}	CHP maximum installed electrical capacity (MW)
chpw_t	CHP electricity output at time t (MW)
chpq_t	CHP thermal output at time t (MW_{th})
$\text{chpw}_t^{\text{status}}$	Commitment status of CHP at time t (binary)
$\text{chpw}_t^{\text{stup}}$	CHP start up indicator at time t (binary)

Network heat pump:

hp^{cap}	Network heat pump installed capacity (MW_{th})
hp_t	Network heat pump thermal output at time t (MW_{th})

Network heat store:

hsto^{cap}	Network heat store installed capacity (MWh_{th})
hsto_t	Thermal energy in network heat store at time t (MWh_{th})
$\text{hsto}_t^{\text{in}}$	Network heat store thermal input at time t (MW_{th})
$\text{hsto}_t^{\text{out}}$	Network heat store thermal output at time t (MW_{th})

Multigen:

$\text{gen}_g^{\text{cap}}$	Generator g installed capacity (MW)
$\text{gen}_{g t}$	Generator g electricity output at time t (MW)
$\text{gen}_{g t}^{\text{status}}$	Commitment status of generator g at time t (binary)
$\text{gen}_{g t}^{\text{stup}}$	Generator start up indicator of generator g at time t (binary)

Grid:

grid_t	Grid export at time t (MW)
-----------------	------------------------------

Residential heaters:

rh_h^{cap}	Residential heater h installed capacity (MW_{th})
----------------------------	---

gb^{cap}	Peaking gas boiler installed capacity (MW_{th})
eh^{cap}	Peaking electric heater installed capacity (MW_{th})
rh_{ht}^{in}	Residential heater h power input at time t (MW_{th})
rh_{ht}^{out}	Residential heater h power output at time t (MW_{th})
rh_{ht}^{sto}	Thermal energy in residential heat store h at time t (MWh_{th})
gb_t	Peaking gas boiler thermal output at time t (MW_{th})
eh_t	Peaking electric heater thermal output at time t (MW_{th})
q_t^{ashp}	Residential ASHP thermal building demand at time t (MW_{th})
q_t^{hybrid}	Residential hybrid heat pump thermal building demand at time t (MW_{th})
q_t^{estor}	Residential electric storage thermal building demand at time t (MW_{th})
$q_t^{district}$	Residential district heating thermal building demand at time t (MW_{th})

ELECTRICITY AND HEAT DEMAND WEIGHTED AVERAGE PRICES

DWA_t^{ELECT}	Demand weighted average electricity price at time t (£/MWh)
$ENERGY_t^{ELECT}$	Energy component of demand weighted electricity price at time t (£/MWh)
$CAPACITY_{PK}^{ELECT}$	Capacity component of demand weighted electricity price at time t (£/MW)
$OP_COSTS_{p\ t}^{ELECT}$	Electricity operating costs from production p at time t (£)
$PRODUCTION_{p\ t}^{ELECT}$	Electricity production from producer p at time t (MWh)
$INV_COSTS_p^{ELECT}$	Levelised electricity investment costs from producer p (£pa)
$PROD_{PK}^{ELECT}$	Electricity peak production from producer p (MW)
N_{ELECT}	Number of half hour periods to allocate electricity capacity costs
DWA_t^{HEAT}	Demand weighted average heat price at time t (£/MWh _{th})
$ENERGY_t^{HEAT}$	Energy component of demand weighted heat price at time t (£/MWh _{th})
$CAPACITY_t^{HEAT}$	Capacity component of demand weighted heat price at time t (£/MW _{th})
$OP_COSTS_{p\ t}^{HEAT}$	Heat operating costs from production p at time t (£)
$PRODUCTION_{p\ t}^{HEAT}$	Heat production from producer p at time t (MWh _{th})
$INV_COSTS_p^{HEAT}$	Levelised heat investment costs from producer p (£pa)
$PROD_{PK}^{HEAT}$	Heat production from producer p (MW _{th})
N_{HEAT}	Number of half hour periods to allocate heat capacity costs

HEAT NETWORK ECONOMIC MODEL (Section 4.3.2)

AF_t^i	Annuity factor for a cost of capital i over a period t (pu)
i	Cost of capital (% pa)
t	Amortisation period
HNW_{LC}	Heat network levelised cost (£/household pa)
IC_{LC}	Heat network infrastructure levelised cost (£/household pa)
CC_{LC}	Heat network connection levelised cost (£/household pa)
$IC^{CAPCOST}$	Total capital cost of the heat network infrastructure (£/household)
$AF_{T_C}^i$	Annuity factor for the heat network infrastructure construction (pu)
$HNW^{MAXUTIL}$	Maximum utilisation of the heat network or maximum households connected (%)
T_C	Heat network infrastructure construction period in years.
$AF_{T_{HNW}}^i$	Annuity factor for the heat network amortisation (pu)
LD^{REVSF}	Load development revenue shortfall factor due to underutilisation of the heat network during the load development period (pu)
$CC^{CAPCOST}$	Heat network connection cost (£/household)
GB^{COMP}	Gas boiler decommissioning and residual life compensation payment (£/household)
$AF_{T_{LD}}^i$	Annuity factor for the heat network load development (pu)

ABBREVIATIONS

ASHP	Air Source Heat Pump
CCC	Committee on Climate Change
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power
CHP	Combined Heat and Power Association
CoP	Coefficient of performance
CWV	Composite Weather Variable
DWA	Demand Weighted Average
DECC	Department of Energy and Climate Change
EA	Emission Allowances
ESME	Energy Technology Institute's Energy System Modelling Environment
ETI	Energy Technology Institute
EU ETS	European Union Emission Trading Scheme
FICO	FICO® Xpress Optimisation Suite
GHG	Greenhouse gas emissions
GSHP	Ground Source Heat Pump
HDD	Heating Degree Day
HIU	Heat Interface Unit
NTS	National Transmission System
RESOM	Redpoint Energy System Optimisation Model
RHI	Renewable Heat Incentive
ROC	Renewable Obligation Certificates

SNT	Seasonal Normal Temperature
SPF	Seasonal Performance Factor
UKERC	UK Energy Research Centre

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This thesis is dedicated to my late wife, Suvarna, who passed away in May 2013. Throughout our marriage she supported me in everything I did and she had no hesitation in supporting my decision to embark on this PhD. Her loss was devastating to me and for some time I struggled to know what to do next. Not just as far as my studies were concerned but in almost everything else. However, I have no doubt that she would have wanted me to continue with this PhD and would have been immensely proud of my achievement.

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PUBLICATIONS

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CHAPTER 1

INTRODUCTION

In 2008 the Climate Change Act was passed and this committed the UK to reducing greenhouse gas emissions (GHG) by at least 80% in 2050 from 1990 levels [1]. The Act comprises a number of actions which include the setting of legally binding five yearly carbon budgets as well as the establishment of the Committee on Climate Change (CCC) to advise the Government on emission targets and to report on progress.

Heat is the largest energy sector in the UK and is responsible for over 25% of CO₂ emissions [2] and substantial reductions are required to ensure targets are met. This chapter commences by giving some background to heat for space and water heating in the UK as well as the current position and associated CO₂ emissions. It then gives an overview of UK heat strategy and policy development and some of the challenges faced in reducing CO₂ emissions. Finally the motivation for the research is described and a summary of the research questions presented.

1.1 Background

For most of the first half of the 20th Century, coal dominated UK primary energy consumption [3]. It was used for the production of electricity and town gas as well as for heating in buildings. With the advent of North Sea natural gas in the 1960s, coal for domestic consumption fell rapidly from 39% in 1970 to 1% in 2008, whereas gas grew from 24% in 1970 to 68% in 2008, Figure 1 [4].

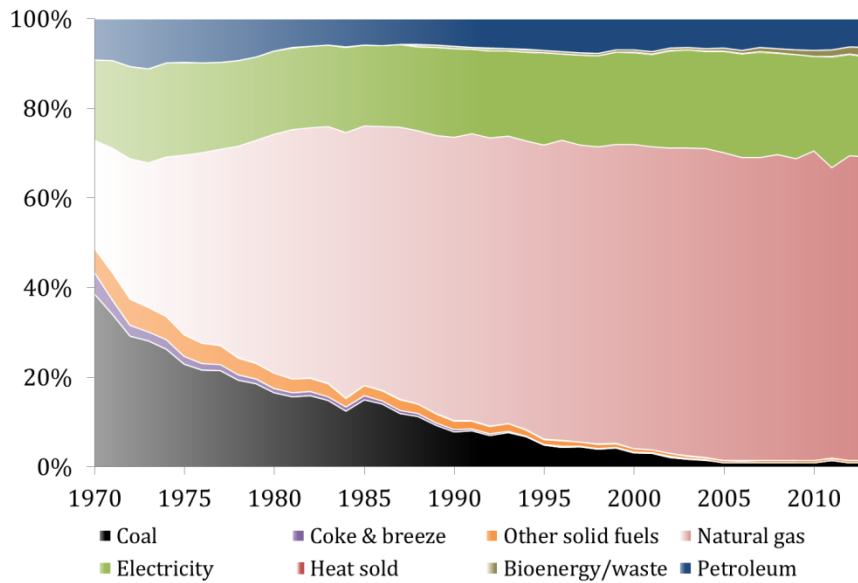


Figure 1: Domestic consumption by fuel in the UK (1970 to 2013) [4].

In response to the oil price crisis in the early 1970s, the UK Government established the Combined Heat and Power (CHP) Group with members drawn from industry, universities, consulting engineers and Government. The Group was chaired by Lord Walter Marshall and its remit was “to consider the economic role of CHP in the UK”. It subsequently published two reports in 1976 [5] and 1979 [6] which concluded that in the longer term CHP “looks an attractive economic and energy saving option” and that strategic plans should be drawn up for the future development of CHP schemes in the UK. Subsequently, grants totalling £0.75m were provided for full scale detailed studies but no major city scheme was implemented [7].

This appears to be the only example of a national heat strategy for the UK and it is not clear why these recommendations were not progressed. However, during the 1970s natural gas became readily available and this seriously undermined the market price for heat, thus damaging the economics of CHP in the short and medium term. In addition the “attractive” economics for CHP in the longer term became less credible as they were based on a “coal/nuclear only future, when oil and gas will no longer be available for building heat”. Gas consumption for heating

grew rapidly and as a consequence most of the CHP schemes in the UK are limited to industrial applications with heat production for commercial and domestic premises contributing less than 1% of total heat consumption in 2009 compared to nearly 80% for gas [8] and [9].

In contrast, the role of CHP and district heating in some other parts of Europe is very different to the UK, particularly in Denmark where CHP has gained over 50% of total power production [10]. Denmark rapidly deployed CHP and district heating after the 1970s' oil price crisis in order to reduce its dependence on imported oil. Without natural gas the economics of CHP for heat production was more attractive, particularly relative to oil. Today district heating represents more than 50% of the heat supplied in Denmark but it remains heavily dependent on fossil fuels, although Denmark has published proposals to relieve itself completely of fossil fuels by 2050 [11]. Core to these proposals is district heating supplied by biomass and waste fuelled CHP as well as large network heat pumps supplied by renewable electricity.

1.2 UK heat and CO₂ emissions

More energy is consumed in the UK for heat than either transport or electricity [4], [8], Figure 2, and yet until recently little attention has been given to decarbonising heat to meet the UK's 2050 GHG targets. Heat is classified as high grade heat for industrial process applications and low grade heat for space and water heating.

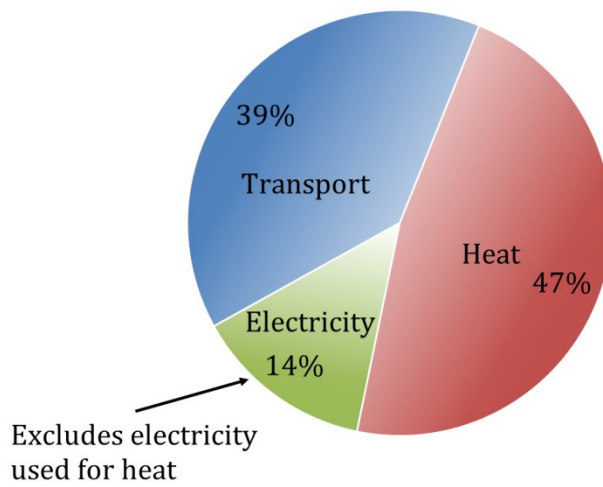


Figure 2: Total UK energy consumption in 2012 [8].

Over 70% of the heat consumed in the UK in 2012 was for low grade space and water heating, most of which was consumed by the domestic sector [8] (Figure 3).

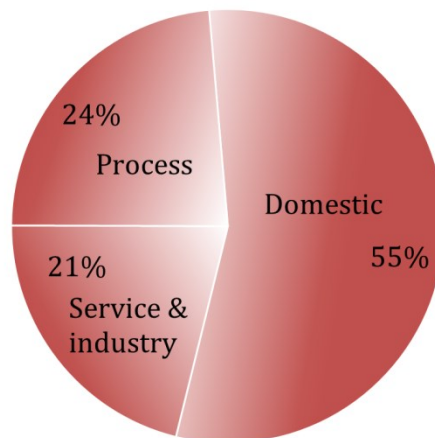


Figure 3: UK heat consumption in 2012 [8].

Total CO₂ emissions for space and water heating were 124 Mt which is more than 25% of the total UK CO₂ emissions in 2012 [8] (Figure 4).

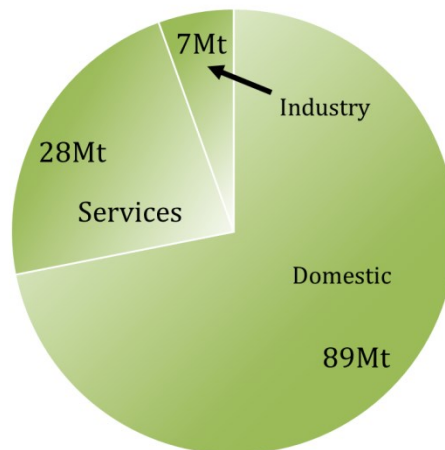


Figure 4: UK CO₂ emissions (Mt) from heat in 2012 [8].

The main fuel used for heat is gas with the remainder mostly split between oil and electricity, Figure 5.

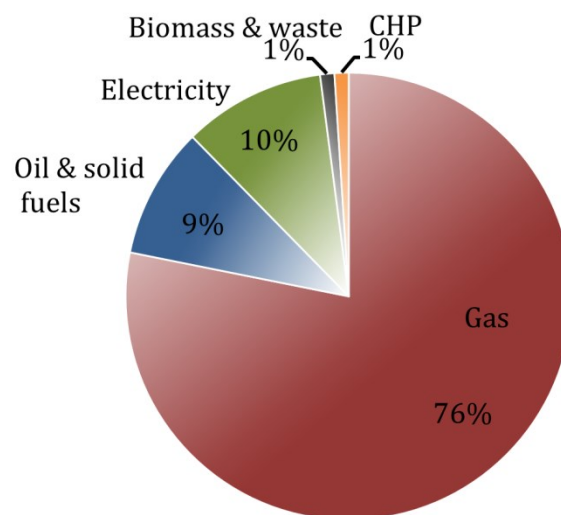


Figure 5: UK space and water heating by source in 2012 [8].

1.3 UK heat strategy and policy

In February 2009 the Department for Energy and Climate Change (DECC) published its first consultation document on its proposed heat and energy saving strategy [12] which gave some initial views as well as policy and financial measures for energy efficiency, including mechanisms to support renewable energy improvements to people's homes. To achieve the UK's 2050 80% GHG reduction target it will be necessary for heat to be almost completely decarbonised, similar to that required for electricity and transport. The consultation proposed measures to reduce energy consumption as well as providing support for renewable heat. This and subsequent reports such as [13], [14] and [15] have provided useful cost and technical data.

In 2010 the Government published its 2050 Pathways Analysis report [16] which explored and presented detailed pathways for all the energy sectors including space heating, hot water and cooling. The pathways were presented as "illustrative" with the objective of facilitating "a discussion about the long term options available".

For heat the analysis examined the factors determining demand. These included changes in the UK's building stock, energy efficiency actions and changes in consumer behaviour such as internal temperature requirements. From this, four trajectories of domestic and non-domestic heat demand from 2010 to 2050 were constructed. The analysis then explored a number of technology pathways focussing on electric options such as resistive heating, ground source heat pumps (GSHP) and air source heat pumps (ASHP) as well as non-electric options such as biogas, biomass and power station heat. From this 16 pathways were constructed with varying combinations of the technology options. To illustrate the range of technology combinations, four are shown in Figure 6.

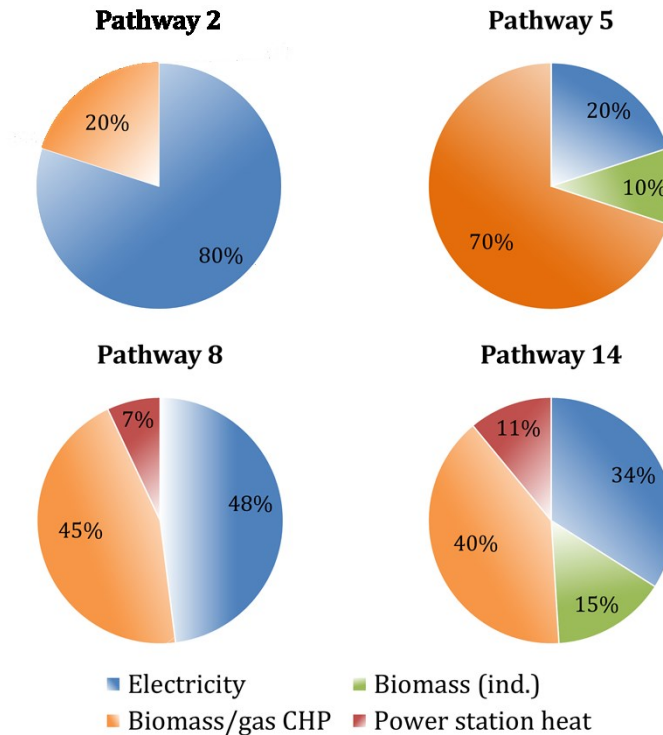


Figure 6: Technology pathways for 2050 [16].

Finally, consideration was given to the advantages and disadvantages, constraints and contingencies for the different heat technologies. For heat pumps it identified a number of performance issues such as heat output, variation in efficiency with air temperature, noise and hot water flow temperature. It noted that heat from thermal power stations is likely to be the most efficient use of primary fuel but would require a substantial investment in the construction of a heat network as well as the proximity of a suitable heat demand to the power station.

The DECC 2050 Pathways Analysis report became a useful starting point for subsequent analyses, and the concept was developed into the UK Government's 2050 Pathways Calculator. This is described "as a framework through which to consider some of the choices and trade-offs we will have to make over the next 40 years" [17]. In particular, it facilitated a greater awareness of the challenges to decarbonise heat. The 2050 Pathways Analysis continues to be developed and along with other analyses such as MARKAL [18] have become useful reference points.

In parallel with the reports published by the UK Government, the CCC published a technical report on decarbonising heat in October 2010 [19]. The report comprehensively covers decarbonising heat in terms of demand, technology, future scenarios and economics. However, it acknowledged that further work needs to be done in areas such as the interactions between the heat and electricity markets (load profiles, capacity requirements, and network reinforcement), CHP, biogas, heat pump performance, district heating and barriers to low carbon heat deployment.

Later in 2011 the UK Government published "The Carbon Plan: Delivering our low carbon future" [20]. This covered all the UK's energy sectors, summarised progress to date and set out how the UK would achieve its 2050 decarbonisation target. For heat (covered under "Buildings") it listed a number of actions which included introducing the Renewable Heat Incentive (RHI) as well as energy efficiency actions via the Green Deal¹. Importantly it stated that it would publish a document on a strategy to decarbonise heat the following year.

In March 2012 the UK Government published "The Future of Heating: A strategic framework for low carbon heat in the UK" [21] which posed questions and sought responses to the high level challenges associated with decarbonising heat through to specific issues associated with reducing heat demand, heat technologies, etc. This was followed by a second document published in March 2013 entitled "The Future of Heating: Meeting the challenge" [22]. This listed a number of specific actions including the establishment of the Heat Network Delivery Unit to provide specialist expertise to local authorities through to the process of developing heat networks as well as whether the RHI should be extended to provide financial support.

¹ The Green Deal was introduced by the UK Government in 2013, see www.gov.uk/government/collections/green-deal-quick-guides

The large scale deployment of heat pumps to replace gas boilers continues to be seen as the core technology in the decarbonisation of residential heat. However, there have been growing concerns over their performance and costs. In 2010 the Energy Savings Trust published its first report on heat pump field trials [23] which raised many concerns, particularly with respect to installation design, installation itself, control and, for ASHPs, the effect of external air temperature [24], [25] and water flow temperature [26]. A second study [27] showed an improvement, although only 9 out of 15 ASHPs met or exceeded the performance criterion to be considered “renewable” under the EU Renewable Energy Sources Directive².

Possibly as a consequence of these concerns, large scale deployment of heat pumps has subsequently been treated with more caution, although it remains the core electric heating technology in National Grid plc’s Future Energy Scenarios [28]. For example, the CCC in its Fourth Carbon Review [29] [30] has expressed reservations on the deployment of heat pumps following a review by Frontier Economics and Element Energy [31]. This identified additional costs, lower performance, and evidence on heat pump durability or life expectancy, commonly assumed to be 15-20 years, to be weak. It also identified low levels of consumer confidence and awareness, poor suitability of the UK’s housing stock and a lack of installer capacity as being the most significant barriers. As a consequence it has reduced its view of uptake from 7 million heat pumps in homes to 4 million by 2030. However, it did conclude “the barriers can largely be addressed by a set of cost-effective policy options, and that a significant level of uptake is still likely to be desirable in the long run”.

In contrast to heat pumps the CCC identified that the evidence base for district heating to contribute to low-carbon heat supply has been strengthened. In 2012 it commissioned AEA Technology and Element Energy to look at scenarios for low carbon heat. Its report [32] identified “greater potential for district heating

² ec.europa.eu/energy/renewables/targets_en.htm

deployment, at 160TWh pa by 2050” and showed that a mix of district heat and heat pumps would have similar emissions and overall cost to a scenario with a very high level of heat pump uptake. The CCC also noted that DECC’s Heat Strategy had identified a greater role for district heating than it had previously allowed for. As a result the CCC has offset the reduction in heat pumps in homes with a higher uptake of district heating, i.e. from 10TWh to 30TWh (from 2% to 6%) of heat for buildings in 2030.

Heat networks will be critical to the large scale deployment of district heating but there is considerable uncertainty over their costs as the UK has relatively little experience with around only 1,800 networks serving approximately 200,000 dwellings and 1,700 commercial and public buildings across the UK [9]. In addition to this, further work needs to be done to enable the economics to be better understood particularly with respect to the impact of heat load density [29] and also the carbon efficiency benefits. At present heat networks receive no financial support, although as mentioned earlier this is under review.

In April 2010 the Government presented its consultation on its initial proposals for RHI [33] followed by publication of firm proposals in March 2011 [34]. This was presented as “the first of its kind in the world” which would provide long-term financial support for renewable heat technologies. It commenced with a non-domestic RHI launched in November 2011 and was followed by a domestic RHI launched in April 2014 [35]. Both schemes pay a tariff for eligible renewable heat technologies and are overseen and administered by Ofgem. The eligible renewable heat technologies for the domestic scheme comprise:

- Air-source heat pumps
- Ground and water-source heat pumps
- Biomass-only boilers and biomass pellet stoves with integrated boilers
- Solar thermal panels (flat plate and evacuated tube for hot water only)

The Government states that the RHI is the main scheme in its heat strategy to support the increase in renewable heat.

1.4 Motivation, aims and objectives

The challenges of decarbonising heat are immense, particularly as over 80% of households use gas for heating. Consequently, the transition from gas for heating to a low carbon alternative will be dependent on individual householders. Financial incentives such as the RHI and, as a last resort, compelling householders to make the transition can be implemented. However, there is a lack of consensus over which low carbon heat technologies householders should be encouraged to adopt as scenario projections of these vary significantly.

As much as the decision may rest with the householder, the impact on the energy infrastructure will be immense. Electrification of heat will require investment in generation capacity as well as transmission and distribution systems. Not only will these investments be financially substantial, they will take time to implement. District heating as an alternative has similar and possibly even greater challenges. Therefore it is essential that the lack of consensus on the way forward is addressed so that a coherent strategy can be formulated and decisions on the way forward be taken.

Hence the motivation for this research is to address this lack of consensus by understanding the possible causes of those differences and addressing each. The objective is not to add to the growing list of projections for low carbon heating technologies but to improve the understanding of the technical and economic performance of each and their prospects for large scale deployment. Most importantly it is to be able to assess the “whole system” impact and in particular, their impact on decarbonising heat.

1.5 Research questions (RQ)

1.5.1 RQ1. What are the key economic drivers for the deployment of low carbon heat technologies suitable for large scale deployment?

The economics of heat technologies continues to be disputed. Much of the analysis that has been conducted is based on poor representation of heating demand and excludes the impact of temperature and storage. These factors can have a significant impact on the economics of heating systems and should be incorporated into any analysis. The principal objective of this research question is to explore a wide range of sensitivities to identify the key drivers that influence the choice of heating technology suitable for large scale deployment. This analysis forms the basis for the subsequent research questions.

Subsidiary questions are:

- What are the principal low carbon technologies suitable for large scale deployment?
- What are the critical factors and/or key influencing factors and /or costs that impact on the economics of heating technology?
- What are the “boundary” conditions, i.e. how much do performance factors or costs have to change to switch the economics from one technology to another and what is the prospect of such changes?
- How does the deployment of low carbon heat technologies compare to continuing with gas? What is the cost differential and what are the associated uncertainties?
- What are the associated carbon benefits of the heat technologies and how do these vary?
- What are the benefits of hybrid heat pumps compared to standard heat pump designs?

1.5.2 RQ2. What are the benefits that arise from heat storage?

Heat systems offer significant potential for low cost energy storage. These range from large network heat stores through to localised or distributed heat storage

using hot water tanks or electric storage heaters. Storage can provide low cost heat capacity, typically halving the capacity requirements of heat sources on a district heating system but also in an integrated system reducing electricity capacity requirements. Storage can provide support to intermittent and inflexible generation and also provide back-up capacity in the event of failures arising from plant outages.

1.5.3 RQ3. What is the impact of reducing carbon limits on the economics of low carbon heating technologies?

Carbon limits will have a direct impact on the amount of fossil fuel that can be consumed by thermal power plant. As the carbon limit is reduced it may be necessary to schedule more low carbon thermal generation such as nuclear or plant fitted with carbon capture and sequestration (CCS) in order to meet demand. However, the key determinant of carbon emissions from heating will be the low carbon heating technologies themselves and another option would be to increase the installation of the heating technologies with the lowest carbon emissions.

1.5.4 RQ4. How does heat density impact heating technology economics?

The traditional “rule of thumb” for the economic viability of heat networks is based around heat density. Yet the evidence to support this is weak and as a criterion, does not appear to be supported in Denmark, Sweden and elsewhere with experience of heat networks. It is also important to consider the heat density impact on the low carbon alternative to a heat network which is likely to be electricity. Reinforcement of the electricity network to support the heat load may be required and so in both cases heat density will have an influence on costs. Hence, there should be a degree of cancellation.

1.5.5 RQ5. How does a strategic approach to heat differ to an incremental approach and what do we need to do to make it happen?

This question will be covered in the final chapter drawing together the key conclusions from the thesis.

1.6 Thesis structure

Chapter 2 identifies the low carbon residential heat technologies suitable for large scale deployment. It commences by reviewing recent investigations and examines why the outcomes vary so significantly.. It postulates that many of the differences may be due to the modelling methodology adopted and, in particular features which are poorly represented in such models.

Chapter 3 describes the space and water heat demand model proposed. Unlike electricity which is half hourly metered there is little available data on heat consumption. As most of the heat technologies suitable for large scale deployment will either be sourced from electricity or be interconnected with electricity then it will be essential to use demand data of sufficient detail to ensure the system impacts are properly modelled. The approach proposed is to synthesise a half hourly heat demand profile using actual data where available. This chapter describes the method adopted and presents some examples of heat and electricity demand.

Chapter 4 examines the cost and performance for each of the low carbon residential heat technologies. An important economic driver from both a consumer and Government perspective is the cost difference of these heat technologies relative to gas heating and the chapter commences by developing cost projections against which comparisons can be made. The economics of district heating is dominated by the cost of the heat network and an economic model is proposed which explores the impact of a number of factors such as financing, heat load development and network utilisation. Finally it presents an assessment of the uncertainties of future costs and their influencing drivers.

Chapter 5 describes the integrated heat and electricity investment model proposed. This incorporates both heat and electricity sources, a high level representation of the heat and electricity network, and the low carbon residential heat technologies identified in Chapter 2. The investment model uses both half hourly heat and electricity demand and uses annual simulation. Due to the lengthy

computing time required as a result of both the duration of simulation and the number of decision variables the investment model is operated in three modes and this is described. The performance and features of the heat technologies are then examined and the modelling approach presented. An example of the investment model's results is shown as well as an example of the model's graphical output. Finally the strength and weaknesses of the investment model are discussed.

Chapter 6 develops the analysis undertaken in Chapter 4 and uses the integrated heat and electricity investment model to address each of the research questions through the use of a number of studies. Chapter 7 presents the conclusions, achievements and areas for further work.

CHAPTER 2

LOW CARBON HEAT SCENARIOS

There have been a number of investigations into reducing carbon emissions from space and water heating. These have examined a range of scenarios exploring heat demand reduction as well as low carbon residential heat technologies. The outcomes vary significantly and so this chapter reviews the principal studies conducted and considers the potential causes of those different outcomes. It then looks more closely at the principal low carbon heat technologies and in particular the performance features which could be influential in their deployment.

2.1 Residential heating technology scenarios for 2050

In 2009 the CCC commissioned a report investigating low carbon heat scenarios for the 2020s [13] [19] and reviewed low carbon heat technologies. It concluded that although heat pumps can provide low-cost abatement at very high volumes there were concerns regarding their suitability for a large portion of the UK's buildings. District heating emerged as an attractive option and the report noted that there were significant barriers to overcome before it could be considered for large scale deployment. These are detailed in a report to DECC [15] which explored the potential cost of district heating. Relative to conventional heating systems, it highlighted a number of barriers to district heating deployment in the UK which are categorised as economic, general institutional issues and the price of carbon.

In preparation for the CCC aviation and shipping review, Element Energy and AEA were commissioned to investigate decarbonising heat in buildings [32]. Their report builds on previous work on renewable heat undertaken for the CCC [19], extending the timeframe from 2030 to 2050. Scenarios for 2050 were constructed

in which the dominant low carbon heat technologies were heat pumps, district heating and direct electric heaters.

DECC's 2050 Pathways Analysis report [16] explored combinations of heat pumps (air and ground source), resistive heating, power station offtake, district heating biogas and biomass as the principal low carbon heat technologies. The Government's Carbon Plan [20] identified a combination of heat pumps and district heating as the main low carbon heat technologies to be deployed in the period up to 2050. Following the publication of DECC's "The Future of Heating: A strategic framework for low carbon heat in the UK" [21], it published its follow up report in 2013 [22] which included an annex detailing analysis of the deployment of low carbon heat technologies [36]. DECC used the Redpoint Energy System Optimisation Model (RESOM2) [37] which has a detailed representation of domestic heat demand, heat technologies, networks and which allows the implications for heat to be explored. In addition DECC used the Energy Technology Institute's Energy System Modelling Environment (ESME) to look at sensitivities, and to compare results with RESOM2. For the RESOM2 model the dominant low carbon heat technologies by 2030 are ASHPs, hybrid gas boiler/heat pump, followed by district heating and GSHPs. By 2050 the dominant technologies are ASHPs, GSHPs and district heating. For the ESME model the dominant low carbon heat technologies by 2030 are ASHPs and biomass and by 2050 ASHP and district heating.

National Grid plc's 2014 Future Energy Scenarios [28] has four scenarios with ASHPs as the dominant low carbon heating technology up to 2030 which is then supplemented by hybrid heat pumps up to 2050. District heating has a nominal role as an assumption is made that it is restricted to new build housing developments and any schemes only use gas and renewable CHP and to align with National Grid plc's CHP scenarios.

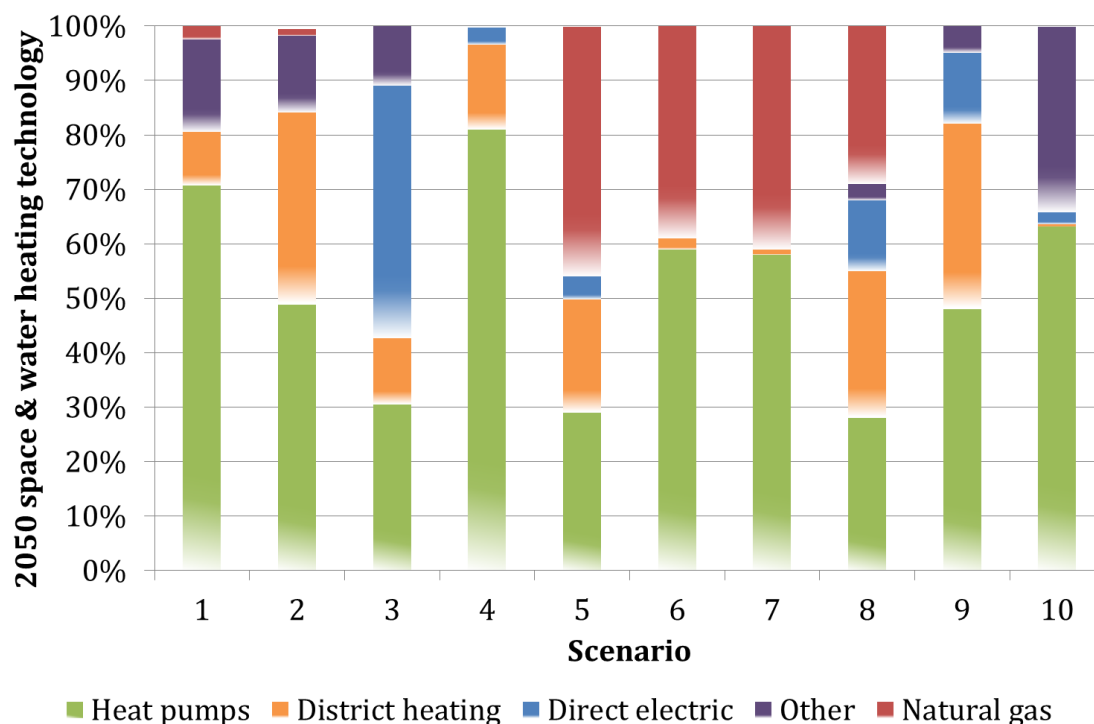
In 2012 Delta Energy and Environment Limited (Delta-ee) [38] were commissioned by the Energy Networks Association to provide a desktop study on

the optimal heating appliance technology pathways required to meet carbon and renewable targets. Heating technologies considered included; air and ground source heat pumps, electric storage heaters, hybrid heat pumps, micro-CHP, solar thermal, biomass and district heat. Delta-ee constructed three scenarios with ASHPs and GSHPs along with district heating but also with electric storage heaters and hybrid heat pumps occurring in one of the scenarios.

Finally in 2013, the UK Energy Research Centre (UKERC) published its Phase 2 scenarios [39]. This used the Markal linear optimisation energy system model of the UK energy system [40]. Heat pumps are the dominant low carbon heating technology with the remainder shared between solar and biomass and with no district heating.

The scenarios for 2050 are all summarised in Figure 7. It can be seen that heat pumps are the dominant low carbon heating technology in most of the scenarios with the highest shares in scenarios 1 and 4. District heating ranges from a close to zero share of the heat demand (scenarios 6, 7 and 10) to around a third in (scenarios 2, 9 and 8). Direct electric or storage heaters also range from a close to zero share of the heat demand in a number of scenarios to nearly 50% in scenario 3.

In four of the scenarios (5, 6, 7 and 8) natural gas retains a significant share of the market with condensing gas boilers, micro-CHP and high efficiency gas absorption heat pumps. However, it is not clear how the required reductions in CO₂ emissions can be delivered as a result.



Scenario³

1 EE&AEA -Policy Extension
 2 EE&AEA - DH, Constrained
 3 EE&AEA – Electrification
 4 DECC – RESOM

5 DECC – ESME
 6 NG - Gone Green
 7 NG - Low Carbon Life
 8 Delta - Balanced Transition

9 Delta - Electrification & Heat Networks
 10 UKERC2 – LC

Figure 7: Space and water heating technology scenarios in 2050 showing share of heat demand.

The conclusion from this review is that there remains considerable uncertainty over the share of residential heating demand in 2050 for low carbon heat technologies. There does appear to be some agreement that heat pumps will have a significant role but considerably less agreement on that for district heating and whether there is any role for direct electric (storage heaters). The next section will explore the possible causes of these differences.

³ i) Heat pumps are mostly ASHPs. ii) “Other” includes solar, biomass and hydrogen. iii) “Gas” includes condensing boilers, gas absorption heat pumps, micro-CHP. iv) Scenarios that do not deliver significant carbon reductions have not been included.

2.2 Modelling methodology

A brief review of the data assumptions used in the modelling of low carbon heat technologies shows some variations but these are not sufficient to justify the cause of the different outcomes. However, there are different modelling methodologies used. These are summarised as follows:

- Element Energy and AEA (scenarios 1, 2 and 3)

The modelling approach adopted uses a spreadsheet based model and includes a representation of the building stock and the cost and performance of the various heating systems considered [41].

- DECC-RESOM2 (scenario 4) and National Grid plc (scenarios 6 and 7)

The modelling approach adopted uses RESOM2, [37] and [42], which is a linear programme that minimises total energy system costs (capital, operating, resource, etc.). It decides what technologies to build and how they should be operated to meet future energy service demands, subject to a set of constraints such as GHG emissions. Heat demand is modelled using five characteristic days comprising one for each season and a 1 in 20 peak day representing an extreme winter. Each characteristic day is split into six diurnal timeslices of 4 hour blocks. The model includes diurnal heat storage at both building level and network levels for district heating. The modelling for National Grid plc (scenarios 6 and 7) only incorporates district heating if it is associated with CHP, i.e. large network heat pumps are not included. This is not the case for DECC (scenario 5) which might explain the higher market share for district heating.

- DECC-ESME (scenario 5)

The modelling approach adopted uses the Energy Technology Institute (ETI) Energy System Modelling Environment (ESME) [43]. ESME is a cost optimisation model similar to RESOM2 but it also includes a Monte Carlo model which considers the impact of uncertainty. Heat demand is modelled using two characteristic days

representing summer and winter, with each day split into five diurnal timeslices comprising one 3 hour block, two 4 hour blocks, one 6 hour block and one 7 hour block. Heat storage is included in ESME but only from one time slice to another.

- Delta-ee (scenarios 8 and 9)

The modelling approach adopted by Delta-EE incorporates a heating “technology performance model”. This evaluates the future cost and performance of heat technologies based on data from DECC, National Grid plc as well as other “public/official sources” [38].

- UKERC:LC (scenario 10)

The modelling approach adopted uses the Markal [40] cost optimisation model which is similar to ESME. Demand is modelled using three characteristic days comprising (summer, winter and intermediate) with each characteristic day split into two diurnal timeslices comprising one 17 hour block and one 7 hour block. The model includes electric storage heaters but does not include network storage for district heating.

2.3 Discussion and conclusions

The modelling comprises cost based models using assumptions from external sources (i.e. scenarios 1, 2, 3, 8 and 9) or cost optimisation linear program pathway based models (i.e. scenarios 4, 5, 6, 7 and 10). Such pathway models may cover the whole of the energy system with huge data sets encompassing electricity, heat, transport and infrastructure as well as spatial and demand data but relatively little detail when it comes to specific technologies. With respect to heat systems there are a number of performance features which are poorly represented in such models:

- i) Space and water heat demand – heat demand is very volatile and highly dependent on weather. A typical load factor for aggregated heat demand is circa 20%, much lower than electricity which is circa 60%. The use of

characteristic days with normalised demand and multiple hour time blocks will lose much of this detail.

- ii) Air source heat pumps performance – heat technologies such as ASHPs will have an efficiency or coefficient of performance (CoP) that will vary with temperature. As a consequence heat output will fall with temperature which may require supplementary heating from less efficient or higher carbon intensity technologies. The approach adopted in the aforementioned scenarios is to use a fixed CoP for the heat pumps possibly supplemented by a lower value for an extreme winter.
- iii) Heat storage – storage is of crucial importance in the design of a heating system as it can provide low cost capacity and provide energy savings from demand side management. The performance of heat storage will be affected by the size of the time blocks particularly if demand is normalised into typical or characteristic days.
- iv) Power plant scheduling – electrification of heat demand has the potential to substantially increase the volatility of total electricity demand adding further complexity to plant scheduling. The linear optimisation programs used are unable to incorporate many of the discrete decisions such as unit start-up and minimum stable generation. This will adversely impact costs and potentially carbon emissions arising from, for example, higher levels of open cycle gas turbines operation.
- v) Heat network investment - Both Markal and ESME use a 10% cost of capital and Markal uses a 20 year lifetime whereas ESME assumes 30 years [40][43]. This is probably appropriate for an investment in energy system infrastructure which is not regulated. However, it will result in a higher levelised cost and as a consequence will adversely impact the overall economics of district heating. For example, if heat networks were regulated similar to other network infrastructure then a cost of capital of 6% over a 40 year finance life would be more appropriate. This is explored in more detail in section 4.3.

Most of these variables can be analysed by simulation models which are able to model such features in detail. Chapter 3 proposes a model which synthesises half hourly building heat demand along with temperature scenarios. Chapter 5 proposes an investment model which incorporates half hourly building heat demand along with electricity demand to simulate the integrated operation of a heat and electricity system. It also includes detailed modelling of heat and electricity sources and the performance features of heat technologies such as ASHPs, CHP plant and storage.

CHAPTER 3

SPACE & WATER HEATING DEMAND

The demand for heating will have a fundamental influence on all the assets required from supply to delivery through to end-user consumption. Heat demand forecasts are frequently presented annualised and although this is helpful for macro-economic analysis, without further refinement it is not possible to determine the assets required to meet short term variations in heat demand. For example, electrification of heat will have a direct impact on peak electricity and the capacity of the assets required to meet this demand.

National heat demand modelling based on building simulation software is computing intensive, requires large amounts of data and incorporates a number of assumptions such as heating control settings and consumer behaviour. These can lead to errors when aggregated on a large-scale. Such models if based on characteristic day data can substantially underestimate peak demand. Calibrating these models to actual data is desirable but not possible as national heat demand data is not available other than in annualised format for heat consumption, e.g. gas, oil, solid fuels, etc., [44].

Hence the first objective was to construct a model that would synthesise half hourly heat demand from actual data where available. These include temperature, daily gas consumption and heat profile data with reconciliation to annual consumption data or demand projections. It is important to note that the heat demand is that required by the building in order to meet the requirements of the inhabitants. The demand data can then be used to support the technical and economic evaluation of low carbon heat technologies such as heat pumps and district heat networks.

This chapter describes the heat demand model and presents some results based on the DECC 2050 Pathways for heat [16]. The half hourly demand data is then used as a core input into the analysis of heat technologies which are then examined in subsequent chapters.

3.1 Methodology

3.1.1 Space and water heat demand model

A representation of the model is shown in Figure 8.

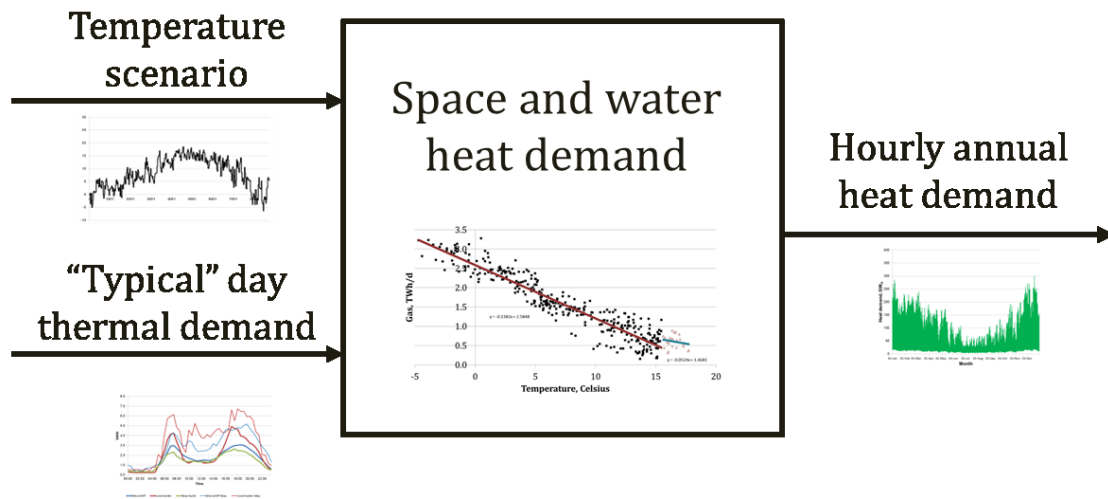


Figure 8: Heat demand model.

The demand for space heating is predominantly determined by external temperature, although there are other factors such as solar gain and wind chill [45]. Currently gas meets nearly 80% of UK space and water heat demand, thus it is a good source of data from which to evaluate the relationship between heat demand and external temperature. Daily NTS (National Transmissions System) demand data are available from [46] and includes daily temperatures. These data include all GB gas demand (Figure 9) and so gas for commercial and domestic space and water heating was extracted using data from [44] to give daily demand data at NTS.

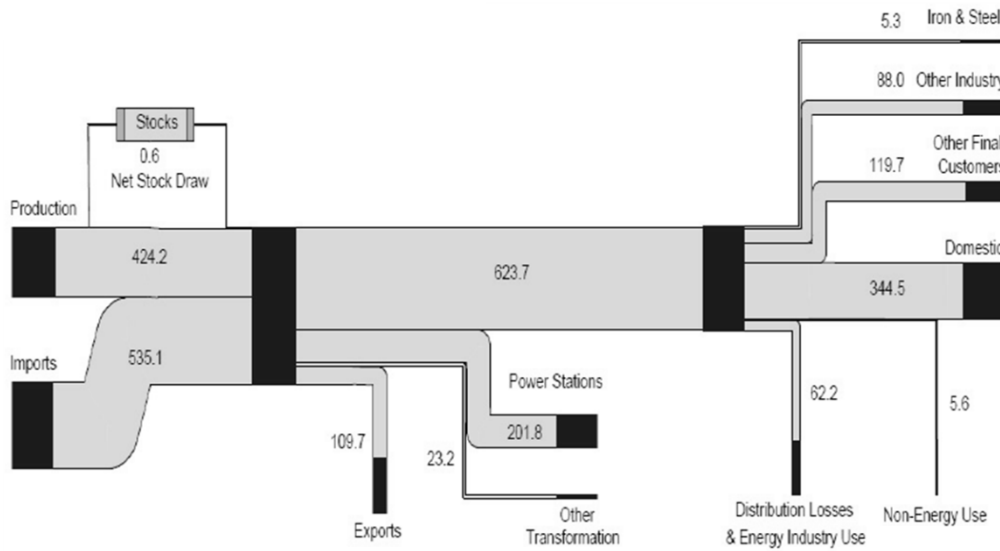


Figure 9: Natural gas flow chart in 2013 (TWh) [44].

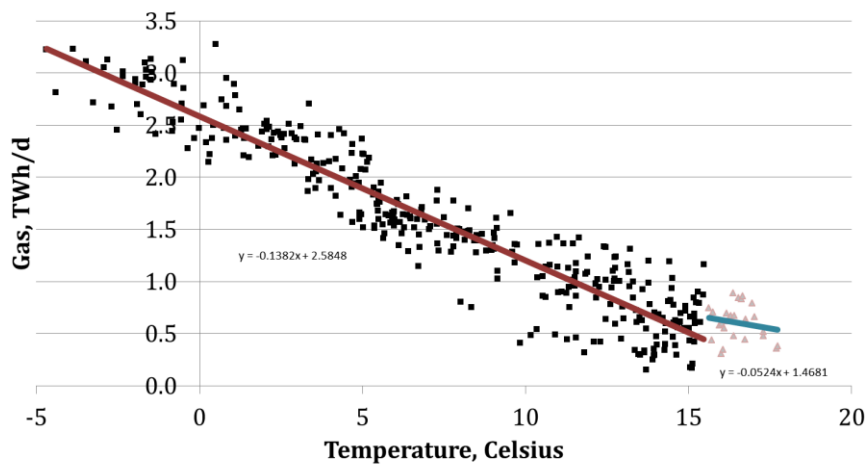


Figure 10: Scatter graph of commercial & domestic daily gas demand against temperature in 2010.

Gas demand is negatively correlated with external temperature [45]. This is illustrated in Figure 10 which presents a scatter graph of commercial and domestic space and water heating gas demand against daily temperature. In the UK the cut-off temperature for space heating is about 15.5°C. Hence above that temperature gas demand is predominantly for water heating.

A two stage linear regression model was constructed and is represented by the red and blue lines in Figure 10. This was repeated for the years' 1998 to 2010 using actual gas demand data [46] and gas duration and daily data derived using the regression models and compared with actual data. National Grid plc uses a similar approach for the production of gas demand forecasts. However, its regression model is based upon a Composite Weather Variable (CWV) which includes other factors in addition to temperature such as wind chill, cold weather upturn and warm weather cut-off [45]. As a result the CWV is a better predictor of gas demand.

Table 1 displays the results for the three temperature scenarios used in this thesis and described later. Below the space heating cut-off temperature, i.e. 15.5°C, the slope is similar for each year but the intercept is lower for 2010 than 2002 and 2003. An explanation for this is that it could be due to a reduction in national gas consumption as a result of improvements in housing insulation and gas appliance efficiency [47]. All three sets of linear regressions have high fitting accuracy (R^2 values) which indicates how well the variability in data is accounted for by the models.

Year	Temperature scenario	Regression parameters	Space heating cut-off temperature (°C)	
			<15.5 °C	>15.5 °C
2002	Normal	Slope	-0.15	-0.05
		Intercept	3.11	1.57
		R^2	0.88	0.11
2003	Mild	Slope	-0.14	-0.03
		Intercept	3.03	1.23
		R^2	0.79	0.10
2010	Cold	Slope	-0.14	-0.05
		Intercept	2.59	1.5
		R^2	0.88	0.08

Table 1: Gas and temperature linear regression models.

However, this is not the case when temperatures are above the space heating cut-off temperature as these have lower values of R^2 which indicate a much weaker relationship between gas consumption and temperature. This is because most of the gas consumption is for residential hot water which is less affected by temperature.

Daily gas profiles were generated by the models and the correlation of actual demand with derived gas demand is shown in Table 2. It can be seen that the correlation is high for all models.

Year	Temperature scenario	Regression model		
		2002	2003	2010
2002	Normal	98%	98%	97%
2003	Mild	97%	97%	97%
2010	Cold	97%	97%	97%

Table 2: Correlation of gas demand with regression model.

Figure 11 shows the comparison for 2010 of “Actual” with “Derived” (from the regression model) for the duration curve and Figure 12 shows the comparison with daily demand. Visual inspection of both figures shows a reasonable match between “Actual” and “Derived”, with an overall correlation of 97% and above for the daily annual demand. As expected the model’s performance is better at higher demands, i.e. below space heating cut-off temperature. This is important as it is the higher demands that will have the greatest impact on the assets required.

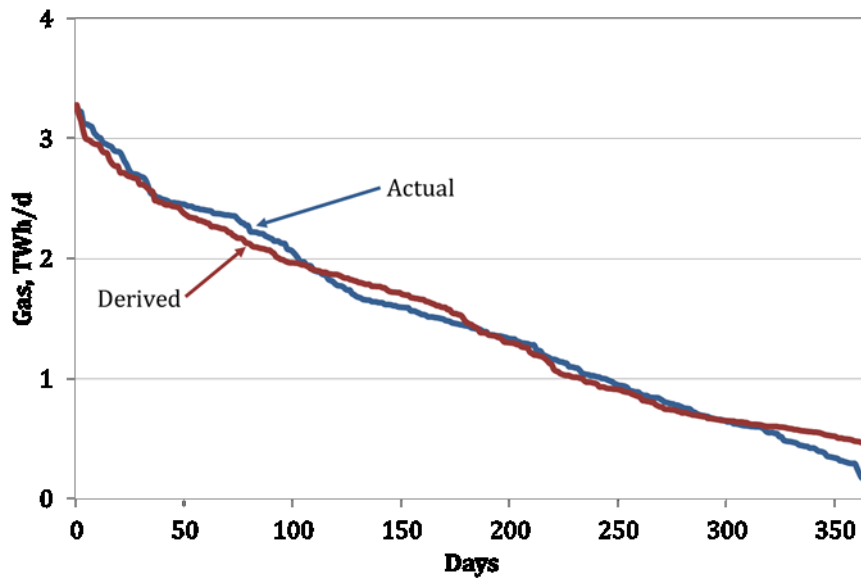


Figure 11: "Actual" versus "Derived" gas annual duration curve for 2010.

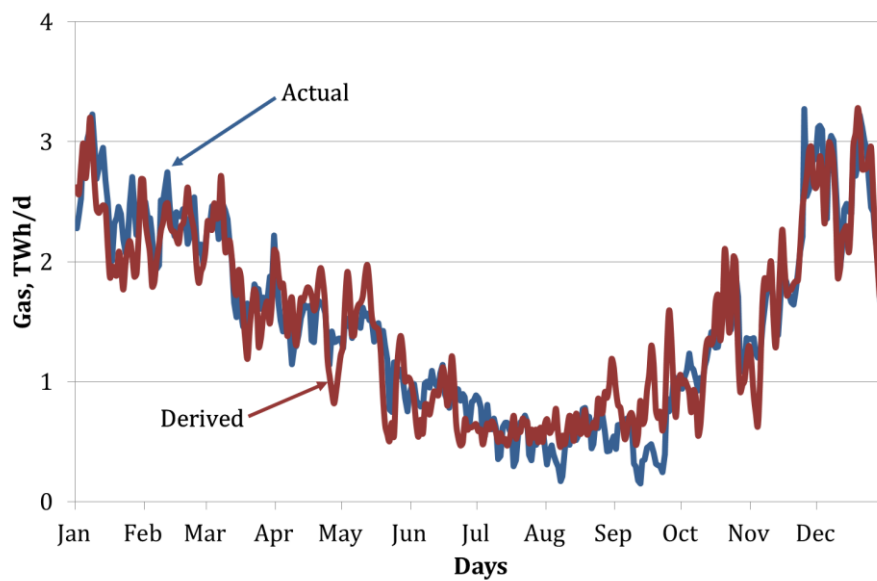


Figure 12: "Actual" versus "Derived" daily gas demand for 2010.

The regression model for 2010 was selected for generic application as it yielded the best performance in terms of the derivation of peak demand which is important for determining asset capacity requirements.

3.1.2 Annual external temperature scenarios

Energy demand is frequently normalised or temperature corrected as it has a dominant influence on consumption. For example, National Grid plc calculates seasonal normal gas demand based on the average weather from October 1987 to September 2004 and also includes an adjustment to compensate for the effect of UK climate warming [45]. However, other methods may be used. e.g. DECC temperature corrects energy consumption based on the average from 1971 to 2010 [48]. Due to the dominant influence of temperature on heat consumption it was considered important to construct temperature scenarios so that the impact of temperature on heat demand can be evaluated.

The gas demand data for the years 1998 to 2010 [46] also includes national average temperature data. Heating degree day⁴ analysis using 15.5°C as the cut-off for heating is shown in Figure 13. It can be seen that 2002 had the lowest and 2010 had the highest heating degree day and were subsequently classified as “Mild” and “Cold” scenarios respectively. The closest to Seasonal Normal Temperature (SNT) based on National Grid’s definition [45] is 2003 and is classified here as “Normal” scenario. Figure 14 displays the daily temperature annual duration curves for the temperature scenarios

3.1.3 Heat demand profiles

The heat demand data collected are based on daily gas demand data and as a consequence it does not vary throughout the day. Thus in order to create intraday demand profiles each half hour period has to be adjusted. The approach adopted here is to create a set of master heat profile data which are then used to scale the demand data for each half hour period.

⁴ Heating degree day is a measure of the demand for space heating and is the number of degrees the daily temperature is below the threshold or cut-off temperature.

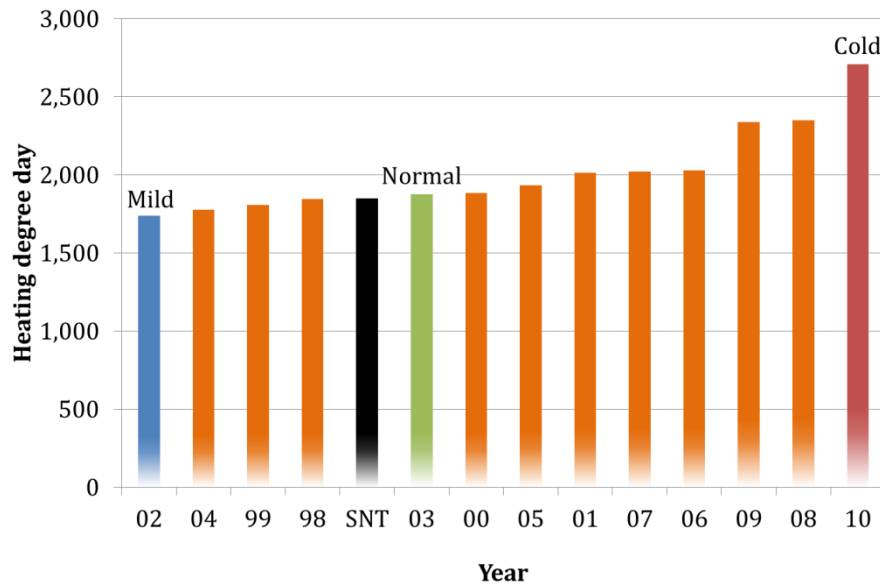


Figure 13: Heating degree days 1998-2010 (15.5°C cut off).

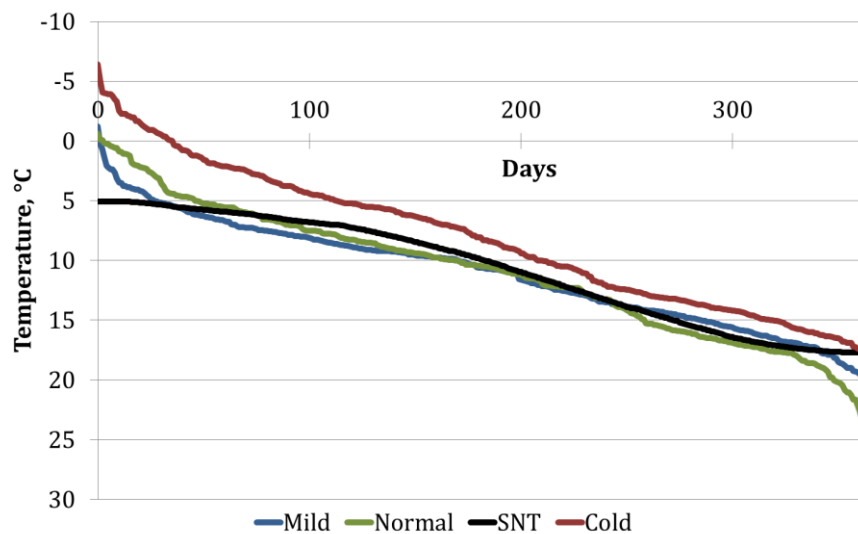


Figure 14: UK daily temperature annual duration curves.

Initially heat profile data were constructed by modelling different types of buildings along with assumptions on hot water consumption [49]. The main problem with this approach is that assumptions also had to be made in terms of other influencing factors such as occupancy behaviour, timer settings, thermostat settings including setback settings, individual radiator settings, etc. These

assumptions are extremely important as they determine the level of diversity in heat demand and, in particular, the resultant Peak Coincident Factor (PCF) which will have a direct impact on the assets required to meet peak heat demand. For example a PCF of 50% means that the sum of the peak heat demand for each building can be reduced by 50% due to diversity. It was therefore considered important to use actual heat demand data if available.

In 2007 the Carbon Trust published its interim report on its Micro-CHP Accelerator project [50]. The project as described by the Carbon Trust involved *“a major field trial of 87 Micro-CHP units in both domestic and small commercial environments as well as a corresponding field trial of 27 condensing system boiler installations to provide a relevant baseline against which to compare Micro-CHP performance. The relative performance of these technologies is also being compared directly under controlled laboratory conditions”*. Importantly *“an extremely rigorous methodology to ensure high quality data capture and to allow robust, independent assessments to be made. At each site up to 20 data parameters are measured at five-minute intervals throughout each day and around 33,000 days of system operation have been analysed so far”*. These data included space and water heating demand data.

Analysis of the data was required to identify the sites with the best quality data for the largest number of sites in simultaneous operation. The main data problem experienced was due to missing data records. As this was sometimes for the same 5 minute interval period for each day, correction was essential to avoid distorting the site's heat profile. The following summarises the site data used:

- 71 domestic buildings constructed from 1650 to 2006 and comprising:
 - 52 Micro-CHP sites (11 to 13kW_{th})
 - 19 Condensing boiler sites (20 to 30kW_{th})
- Located in the Midlands, Northern Ireland, North West and East England.
- Comprising detached, semi-detached and terrace buildings.

- Data collected over the period from October 2006 to March 2007 at 5 minute intervals.

The heat data was converted from 5 minutes' to 30 minutes' intervals and then aggregated into weekday and weekend daily profiles. These are shown in Figure 15 and Figure 16 for sites with micro CHP and condensing boilers respectively.

The following observations were made:

- Weekday and weekend profiles are very similar except for a 1 hour delay in weekend morning peak.
- Magnitude of morning and evening peaks are similar.
- Micro-CHP sites have lower peak demand than condensing boilers probably due to their lower heat output rating.

The figures also display the maximum diversified demand which is $\sim 5\text{kW}_{\text{th}}$ for the Micro-CHP sites and $\sim 7\text{kW}_{\text{th}}$ for the condensing boiler sites.

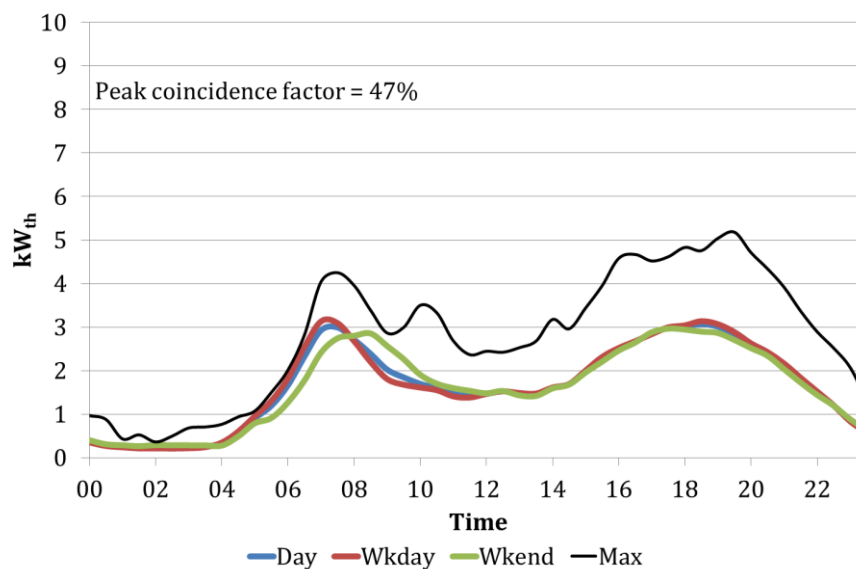


Figure 15: Micro CHP daily heat demand.

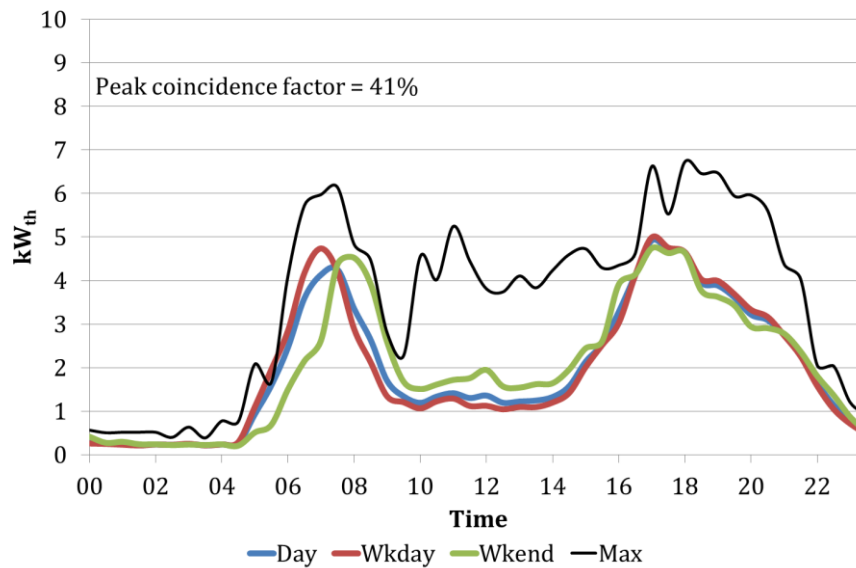


Figure 16: Gas condensing boiler daily heat demand.

The following sets of master heat profile data were used for domestic sites:

- Micro-CHP weekday and weekend
- Condensing boiler weekday and weekend

The selection of the master heat profile data was determined by the maximum rating of the type of heating system installed in the building. So, for example, when modelling heat demand for buildings heated with heat pumps the micro-CHP profile data were used. This is because the maximum heat output of the micro-CHPs used in the Carbon Trust field trial, which ranged from $11 \text{ kW}_{\text{th}}$ to $13 \text{ kW}_{\text{th}}$, is comparable to that of a typical heat pump, i.e. 5 kW_{th} to $14 \text{ kW}_{\text{th}}$ [51]. For heating systems with a higher heat output such as those connected to a district heating system, the condensing boiler master profile data were used. In the field trial the condensing boilers had a maximum heat output which ranged from $20 \text{ kW}_{\text{th}}$ to $30 \text{ kW}_{\text{th}}$.

In the absence of actual heat demand data for commercial sites, comparisons were made between modelled data and data from the Micro-CHP trial. It was decided that it was better to use the domestic profiles for commercial demand rather than

use modelled commercial demand as assumptions would need to be made on diversity. Commercial space and water heating represents less than 25% of total heat demand based on the 2050 DECC Pathways [16] and so the impact of this assumption on total heat demand will be reduced although caution must be exercised when examining commercial heat demand on its own.

3.1.4 Electric heat demand

The heat demand synthesised represents the heat demand by the buildings. This demand can be converted to electric heat demand with assumptions made on the type of heating appliance, i.e. ASHPs, GSHPs and direct heating as well as the percentage of heat demand that is assumed to be electrified.

Electric heating appliances have a lower heat output than a condensing boiler and so the Micro-CHP heat profile was used as this is likely to be more representative. In addition as the heat output of an ASHP will vary with temperature, the model incorporates an adjustment to reflect these variations using a regression model of air temperature and heat output. Figure 17 illustrates this effect based on the Mitsubishi Ecodan 8.5kW_{th} air source heat pump at a 55°C water flow temperature [51].

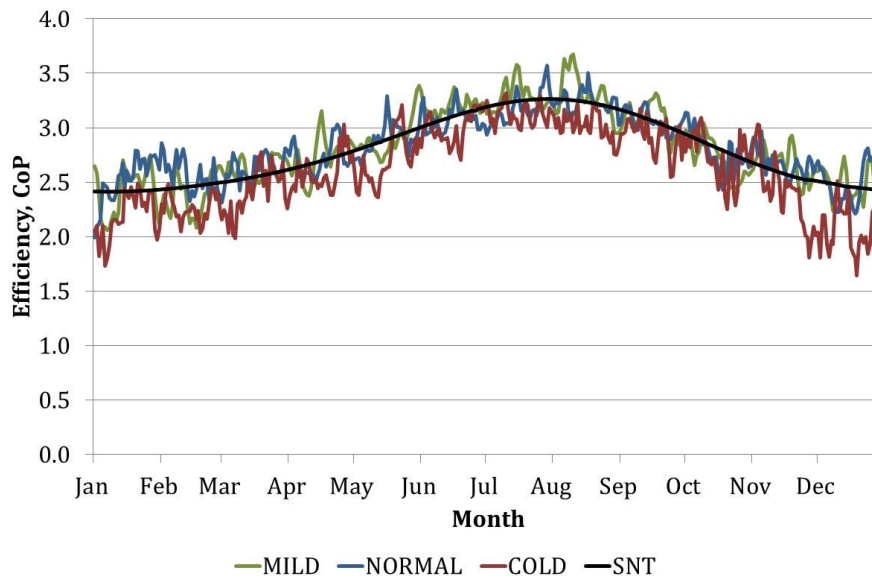


Figure 17: ASHP hourly annual efficiency for temperature scenarios⁵ (pu).

3.1.5 Electricity peak coincidence factor (PCF)

As mentioned previously PCF is very important as it directly impacts the aggregated peak heat demand and therefore the assets required to meet this demand. It can be seen from Figure 15 and Figure 16 that Micro-CHP sites have a higher PCF (47%) than condensing boilers (41%), and this is probably due to the lower thermal output of the micro CHP which results in lower and wider peaks.

Figure 18 shows a scatter plot of temperature and daily peak coincidence factor and it can be seen that PCF increases with reductions in temperature. This might be expected as heating appliances will need to be on for progressively longer periods to meet the increased heat demand as temperature falls. As a consequence the diversity of heat demand will fall and PCF will rise. The winter of 2006/2007 was not particularly cold and the lowest temperature was minus 1.1°C (Central England Temperature daily average). This compares to minus 6.4°C for 2010 and as a consequence a higher PCF would be expected.

⁵ Mitsubishi Ecodan 8.5kW_{th} ASHP efficiency performance at 55°C water flow [51].

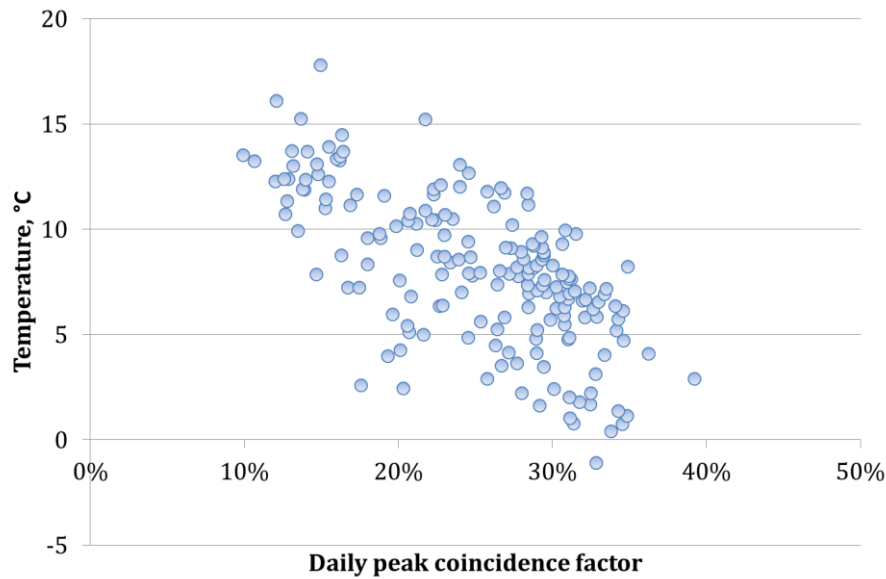


Figure 18: Scatter plot of temperature and daily peak coincidence factor.

Figure 19 shows a scatter plot of temperature and date of occurrence of site peak heat demand where the size of each circle indicates the magnitude of the site peak heat demand relative to other circles. The results appear counter intuitive as they show peak demand occurring over a range of temperatures whereas it might be expected to occur at the coldest temperatures. This illustrates the complexity and importance of other factors which have an influence on heat demand. For example, they might include building occupancy levels, heating controls, supplementary heating, human behaviour and preferences, etc.

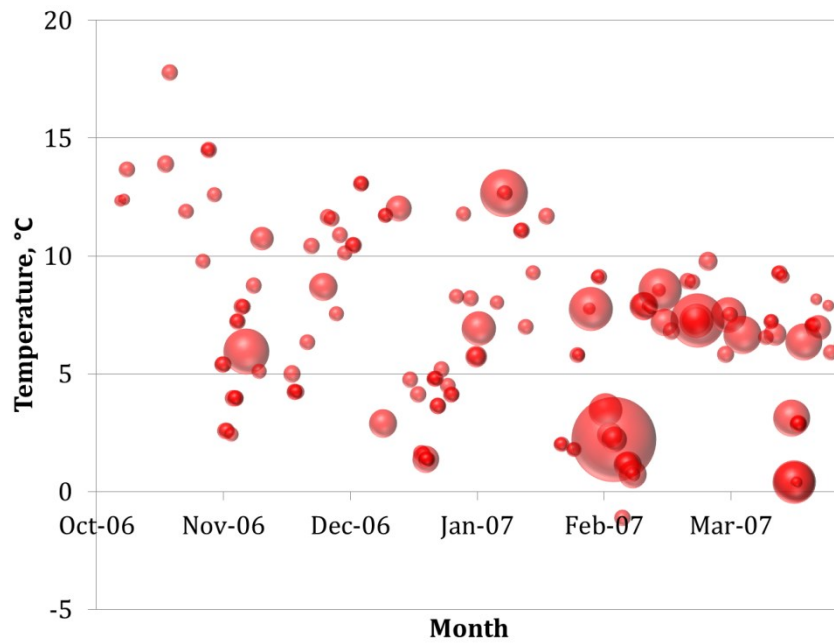


Figure 19: Scatter plot⁶ of temperature & date of occurrence of site peak heat demand.

3.2 Results

3.2.1 National half hourly heat demand

Figure 20 shows the synthesised national half hourly heat demand for 2010 displayed in red and actual half hourly electricity demand in grey from National Grid plc [52] for 2010. It can be seen that heat is extremely volatile with large short term and seasonal variations when compared with electricity. Peak heat demand synthesised is substantially greater at 378GW_{th} compared to 59.6GW for peak electricity demand.

The load duration curves for the synthesised half hourly national heat demand and actual half hourly electricity demand are shown in Figure 21. The heat demand load factor is just under 18% compared to 62% for electricity. Figure 22 displays

⁶ The size of each plot indicates the magnitude of the site's peak demand relative to other plots.

the heat duration curves for each of the temperature scenarios and Table 3 presents the annual energy and peak demand level for each scenario.

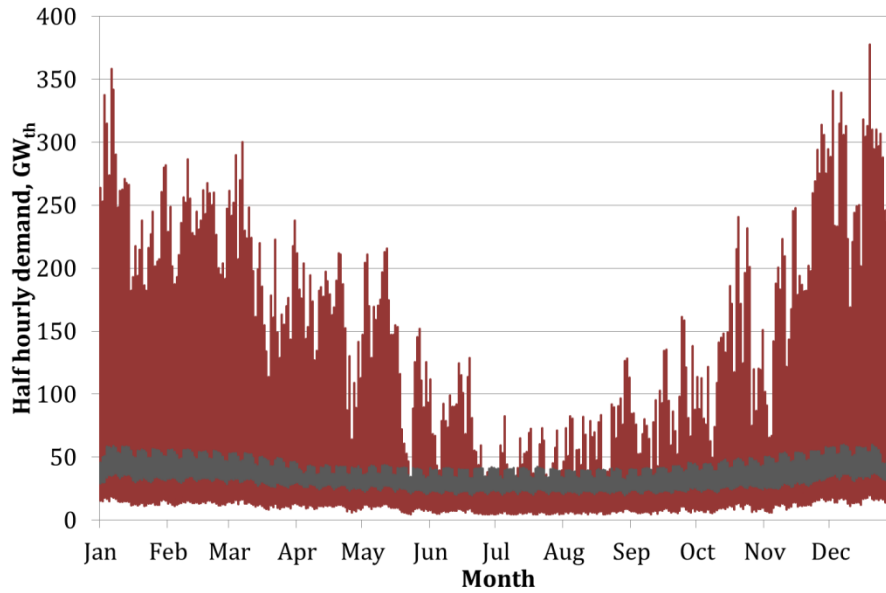


Figure 20: Synthesised national half hourly heat demand (red) for 2010 and actual half hourly national electricity demand (grey) [52].

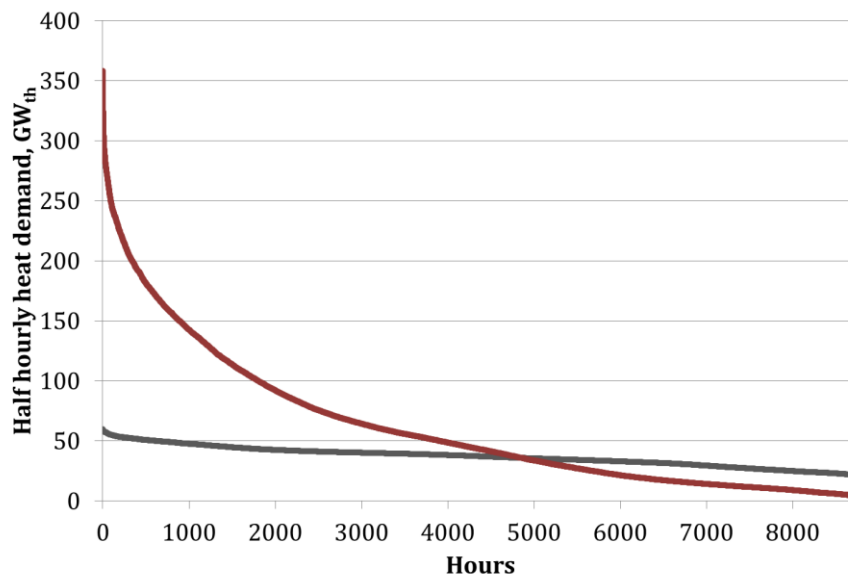


Figure 21: Synthesised national half hourly heat demand duration curve (red) and actual half hourly national electricity demand duration curve (grey) for 2010 [52].

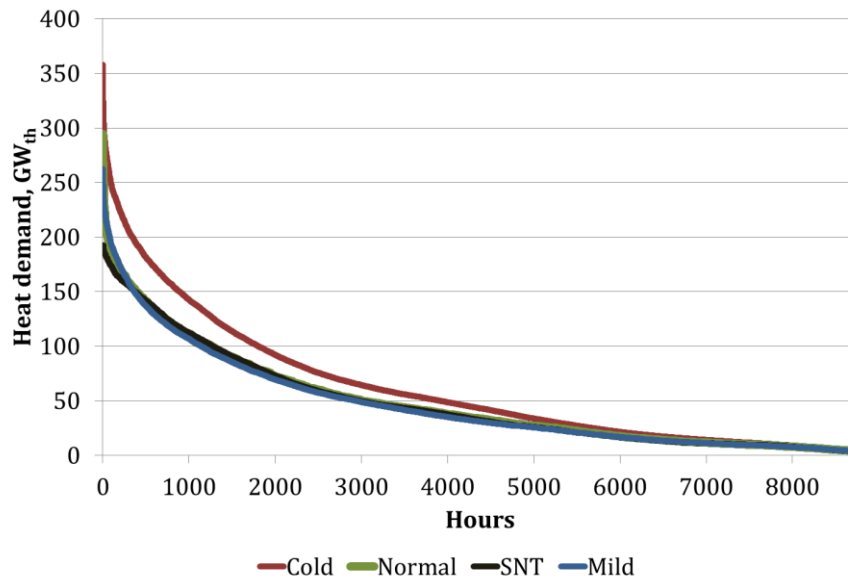


Figure 22: Synthesised national heat demand duration curves for the temperature scenarios.

Temperature scenario	Heat demand	
	Energy, TWh	Peak, GW _{th}
Cold	542	358
Normal	425	294
SNT	418	193
Mild	410	263

Table 3: Heat demand energy and peak demand for each of the temperature scenarios.

Figure 23 compares the “Normal” temperature (green) against “SNT” temperature scenario (black). This illustrates that not only is there a very significant difference in peak demand but also there are very substantial differences throughout the year. As a consequence the assets employed will need to be able to manage such volatile changes in heat demand. For example, heat storage will be very helpful in this respect.

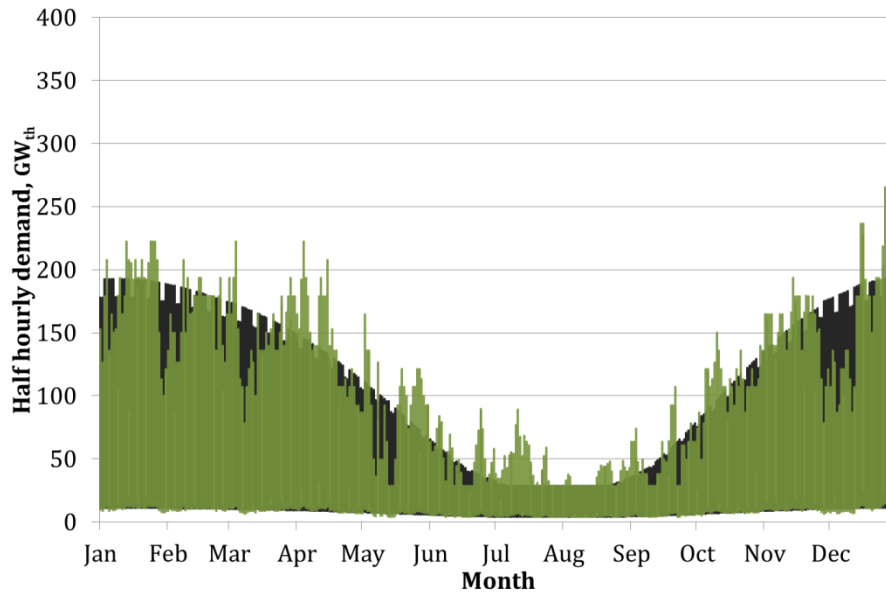


Figure 23: Comparison of synthesised national half hourly heat demand for 2010 with “Normal” temperature (green) against “SNT” temperature scenario (black).

In Chapter 2 it was noted that characteristic days combined with multiple hour time blocks were used to approximate the heat demand in the studies reviewed. The effect of this approximation is illustrated in Figure 24 and Figure 25 which uses three characteristic days comprising (summer, winter and intermediate) with each characteristic day split into two diurnal timeslices comprising one 17 hour block and one 7 hour block. It can be seen that such an approximation substantially underestimates peak demand and will also yield very different results in terms of the performance of assets, particularly at low load factors which is a feature of heat demand.

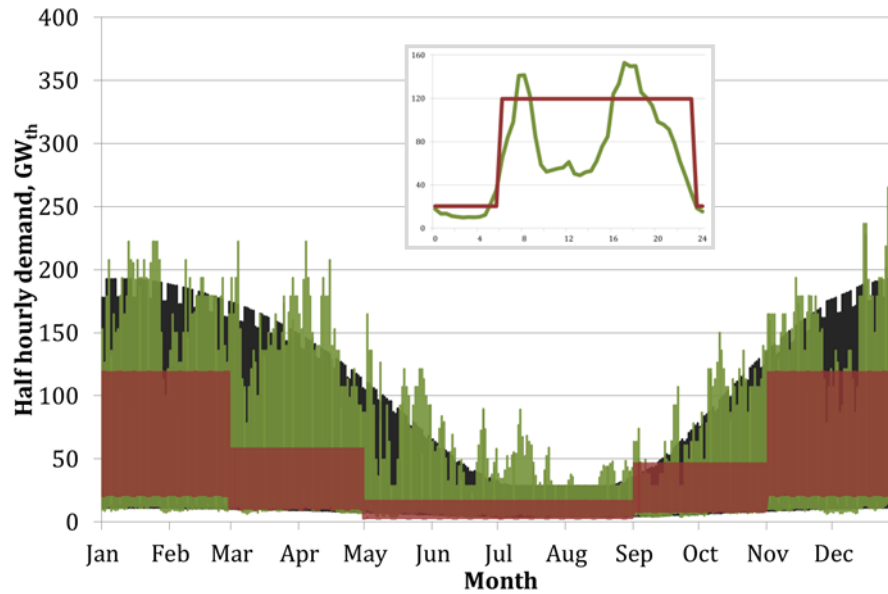


Figure 24: Comparison of synthesised national half hourly heat demand for 2010 with “Normal” temperature (green) against “SNT” temperature scenario (black) and “characteristic day” (brown). The inset figure displays a single day profile.

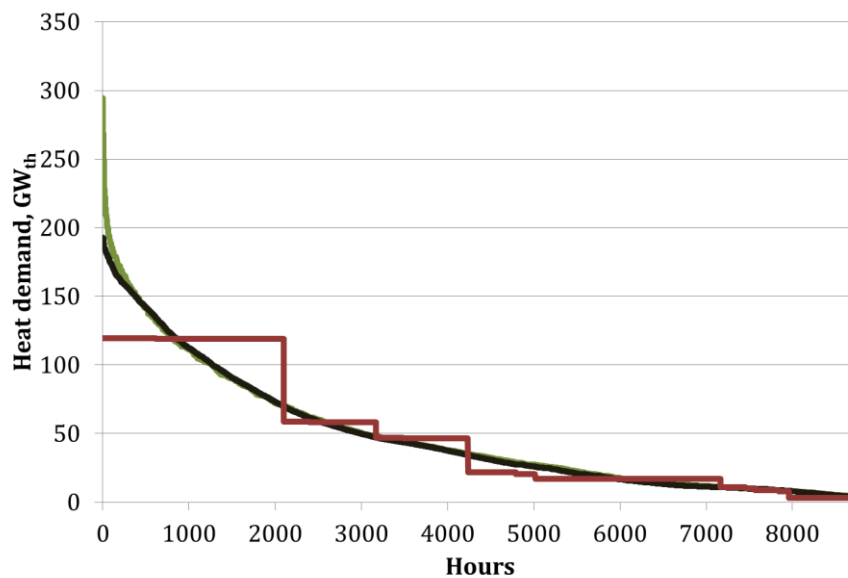


Figure 25: Comparison of synthesised national half hourly heat demand for 2010 with “Normal” temperature (green) against “SNT” temperature scenario (black) and “characteristic day” (brown).

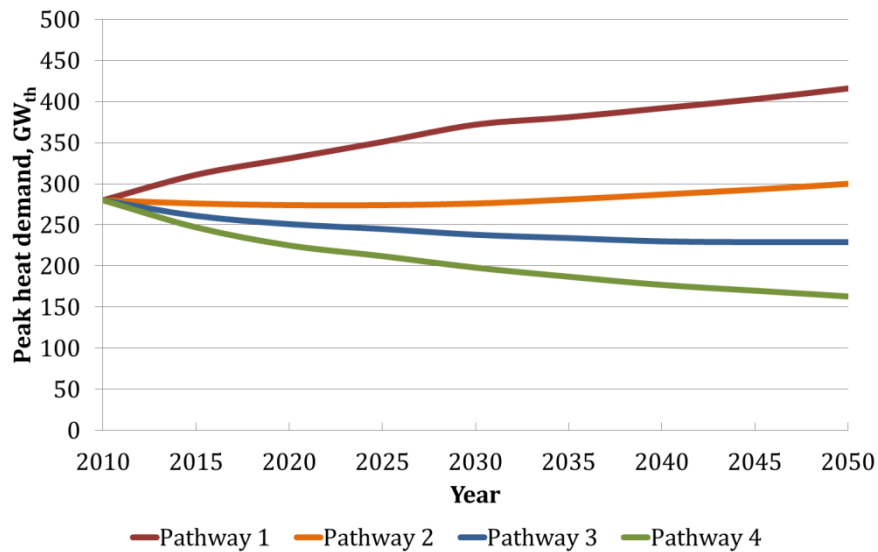


Figure 26: National peak heat demand with “Normal” temperature scenario based on DECC 2050 Pathways for domestic heat demand [16].

The national peak heat demand for domestic heat demand (“Normal” temperature scenario) based on DECC 2050 Pathways [16] (see section 1.3) is shown in Figure 26. It can be seen that there is a substantial variation in peak heat demand. For example Pathway 4 is less than half of Pathway 1 in 2050⁷.

3.2.2 National half hourly electricity heat demand

The national half hourly electricity heat demand will be directly determined by the proportion of heat that is electrified as well as the mix of electric heating appliances. To illustrate the impact of heat electrification it is assumed that 65% of domestic heating appliances are ASHPs and 30% GSHPs. These are similar to the “High Electrification Technology Pathways” from the DECC 2050 Pathways [16]. For commercial heating the reverse applies. The remaining 5% of heating appliances are assumed to be direct electric, i.e. resistive heating. ASHP

⁷ Included within these pathways is an assumption that households increase from ~27million to ~40million by 2050 [16].

performance is based upon that shown in Figure 17 and for GSHPs efficiencies of 350% and 400% are assumed for domestic and commercial appliances respectively.

Figure 27, Figure 28, Figure 29 and Figure 30 present the peak electricity heat demand for the DECC 2050 Pathways 1 to 4. This is the electricity heat demand at the consumer premises, i.e. before distribution and transmission losses. The black line shows the peak demand for the “Normal” temperature scenario and the blue blocks the range from the “Mild” to “Cold” temperature scenarios. The green line is the percentage of heat demand assumed to be electrified, with Pathway 1 the lowest, followed by Pathway 2 and then Pathways 3 and 4 with the same levels of electrification.

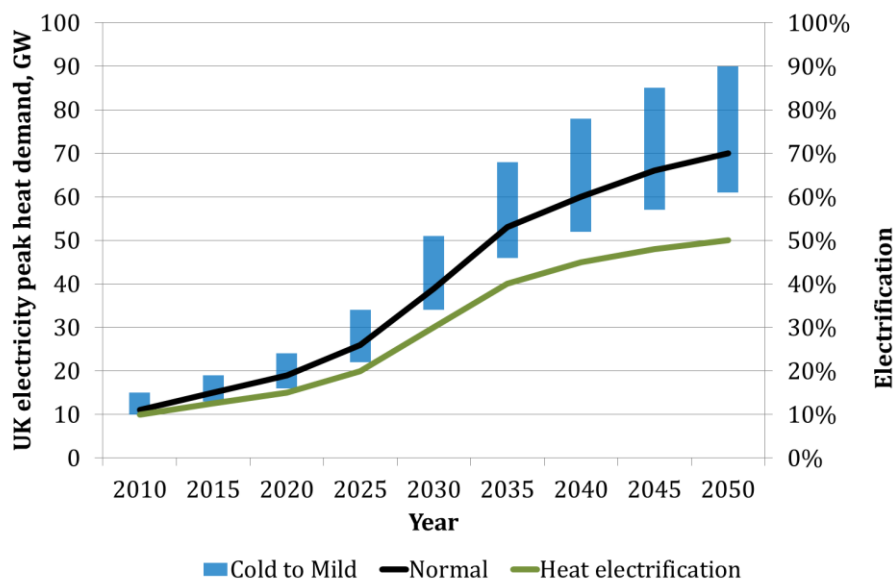


Figure 27: UK electricity peak heat demand at consumer premises for DECC 2050 Pathway 1 [16].

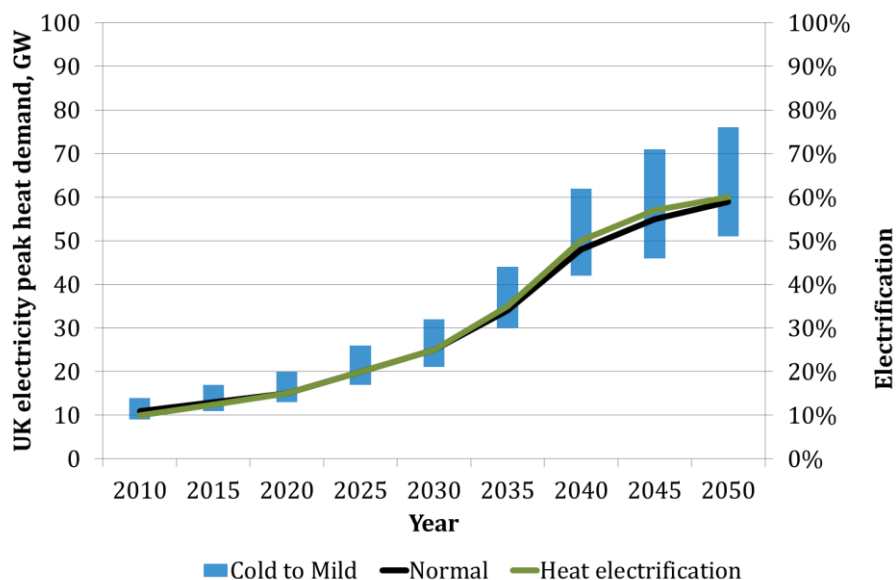


Figure 28: UK electricity peak heat demand at consumer premises for DECC 2050 Pathway 2 [16].

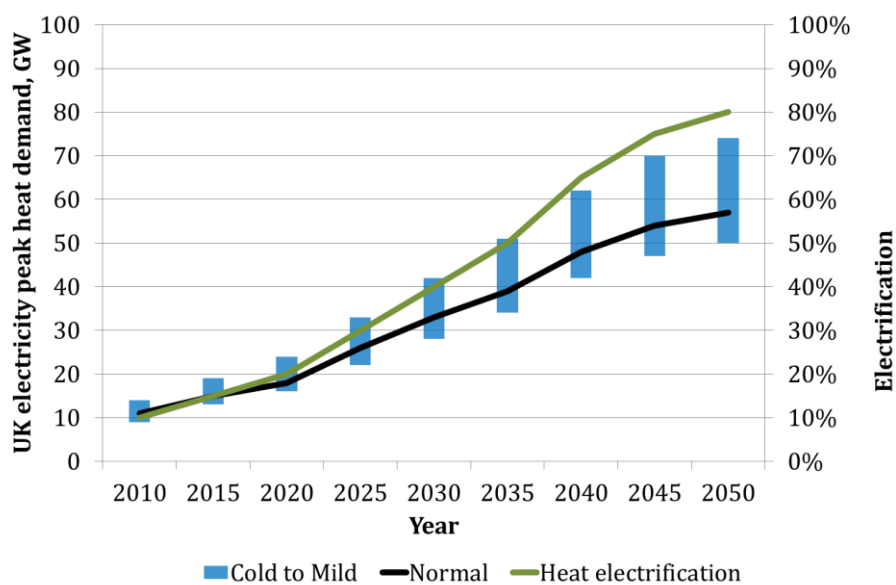


Figure 29: UK electricity peak heat demand at consumer premises for DECC 2050 Pathway 3 [16].

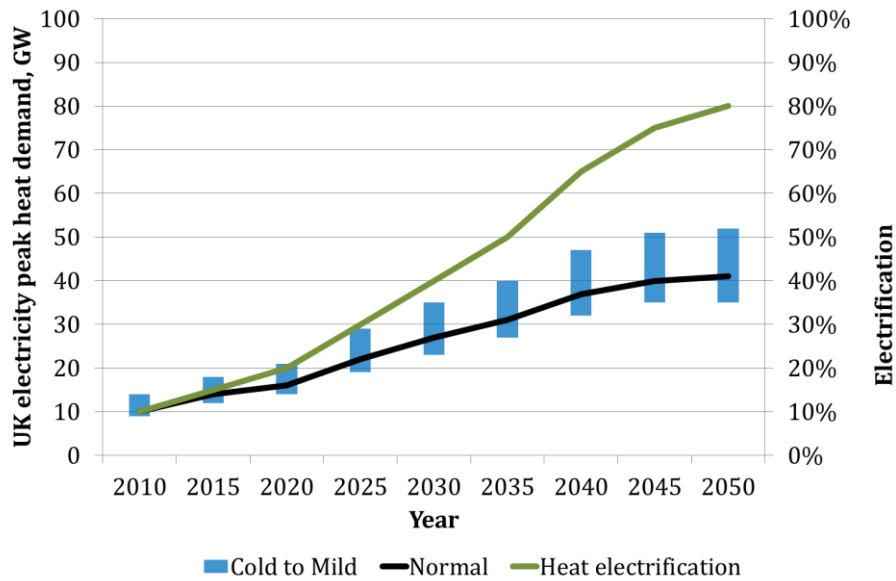


Figure 30: UK electricity peak heat demand at consumer premises for DECC 2050 Pathway 4 [16]

Pathway 1 has the highest peak electricity demand despite having the lowest level of heat electrification. For Pathways 2 to 4 even though the levels of heat electrification are higher these are more than offset by lower heat demand thereby resulting in lower peak electric heat demands.

3.3 Discussion and conclusions

A model is proposed that synthesises heat demand by converting characteristic day heat demand profiles into an annual half hourly demand profile using daily temperature scenarios. The model incorporates actual data where available and can be used to investigate the impact of different heat demands and temperature scenarios as well as the impact on electricity from heat electrification.

Based on DECC 2050 Pathway heat demand, peak heat demand projections were presented which showed a substantial variation in peak heat demand whereby Pathway 4 is less than half of Pathway 1 in 2050. This would have a significant impact on the required assets to ensure peak demand can be met.

The results do need to be treated with some caution, particularly with regard to half hour profiling as this was based on a limited number of sites and over a single winter 2006/07. Although the heat output of a Micro-CHP unit is comparable to a heat pump there are many other differences, e.g. water flow temperature is higher. As better quality heat data becomes available the model can be updated and improved.

Peak coincident factor (PCF) is important in the determination of the assets required to meet peak demand but the winter of 2006/07 was very mild. As there is a relationship between PCF and temperature it is likely that PCF will be higher than measured here under colder weather conditions and this would increase peak demand and therefore the associated assets required to meet this demand.

A further assumption is that the heat pump has been sized to meet the maximum demand required by the building. As temperature falls the heat output from an ASHP will be degraded. For very cold conditions supplementary resistive heating may be required to meet the occupants' requirements and this effect is examined in section 5.4.1. This would further increase peak demand, although space and water heating do offer opportunities for demand side participation and so there may be opportunities to offset peak demand. This is examined in section 6.3.

Finally the results illustrate the increase in sensitivity to electricity demand from changes in temperature. For example, the electricity peak heat demand for Pathway 3 in 2050 is 57GW for the "Normal" temperature scenario which would result in a near doubling of electricity peak demand from current (2013/14) levels. This will require a significant increase in generation capacity as well as substantial reinforcement of transmission and distribution systems.

However, for the "Cold" temperature scenario electricity peak heat demand is further increased to 74GW, nearly 30% higher. To maintain the current level of electricity supply security would require substantial further investment beyond that required for "Normal" temperatures. This could include assets such as

peaking plant and/or demand side management arrangements as well as network reinforcement. Hence, consideration needs to be given to the impact on supply security standards arising from the electrification of heat and is recommended for further work in section 7.3.1.

CHAPTER 4

COST & PERFORMANCE OF LOW CARBON HEATING SYSTEMS

Fundamental to the deployment of low carbon heat technologies is their cost and performance in terms of the environment and consumer acceptability. There are of course other factors but if the economics do not support the technology and their performance is not satisfactory then addressing those other factors will be more difficult. In addition, these technologies will need to address the incumbent heating technology which is predominantly gas. As a consequence decarbonising heat will necessitate encouraging consumers to move away from gas to an alternative low carbon heating technology and hence gas is an important reference point from which to evaluate these alternatives.

This chapter considers each of the low carbon heat technologies judged to be suitable for large scale deployment. The dominant heat pump technology identified in Chapter 2 is ASHPs with GSHPs either not identified or occupying a small segment of this heat market. Hybrid heat pumps effectively comprise two heat technologies, typically an ASHP and a gas boiler [36], [38] and [42] and so along with ASHPs have also been included.

Although electric (storage) heaters are not identified in the scenarios based on cost optimisation models this may be due to modelling limitations discussed in section 2.2. So these have been included here along with district heating with the focus on the modelling of CHP plant.

Cost based scenarios are developed using DECC fuel and carbon price scenarios [53], [54] and [55]. The focus is not specifically on the costs themselves but what

they would need to become in order to switch from one technology to another. As most customers use gas for heating then this is likely to be their reference point and as a consequence it is included here. The DECC fuel and carbon price scenarios are used as the basis to support the analysis and these are supplemented by high and low sensitivities. Each of the heat technologies is then evaluated individually and a range of sensitivities are explored. This forms the basis of the analysis in Chapter 6 using the integrated heat and electricity investment model proposed in Chapter 5.

4.1 Assumptions

Throughout this chapter and the next the analysis is based on the year 2030 which is seen as a key transition year as the UK decarbonises its energy sector [29]. Heat demand is 8.5 MWh_{th} and is based on the DECC 2050 Pathway 3 [16]. Figure 31 displays all the pathways from 2010 to 2050. Sensitivities on heat demand are examined for storage heaters in this chapter and in more detail for all the heating technologies in Chapter 6. Appendix 1 lists the key data.

All prices are in 2013 values and any adjustments made using data from the Office of National Statistics [56]. Present values are based on a 10% (real) pa cost of capital and is used for all technologies except for electricity network investment where 6% (real) pa cost of capital as it is financed under a specific regulatory regime. The finance or amortisation period is 15 years for the heat technologies and 40 years for electricity network investment.

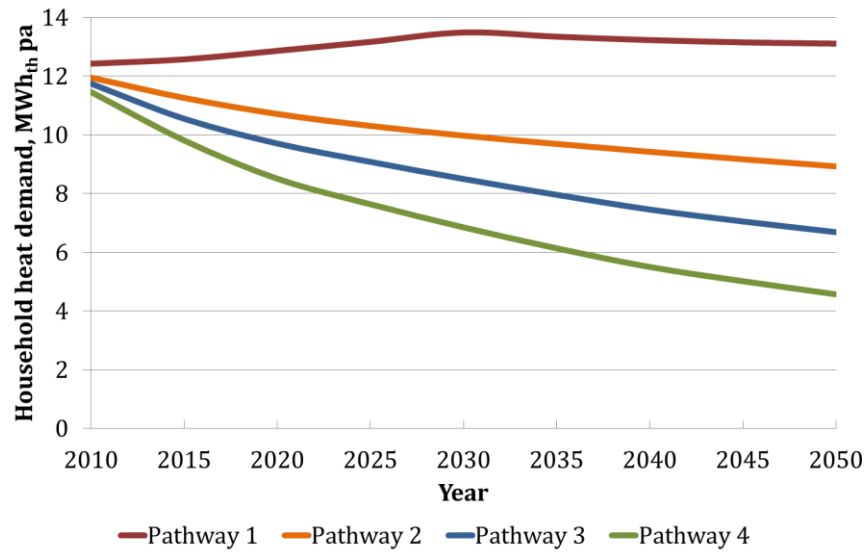


Figure 31: Household heat demand (“Normal” temperature scenario) for DECC 2050 Pathways [16].

4.2 Gas condensing boiler

4.2.1 Capital and other non-fuel costs

Using data from [15] and [38] the capital cost including installation is assumed to be £2,500 with annual maintenance costs of £100 per annum (pa). Assuming a 15 year life, a 10% cost of capital and dividing the capital cost by the annuity factor determined from equation (1), the resulting levelised cost is £329 pa, which with maintenance, is £429 pa.

$$AF_t^i = \frac{1 - (1 + i)^{-t}}{i} \quad (1)$$

where i is the cost of capital % pa and t the expected life of the asset in years.

4.2.2 Impact of gas price projections

The basis for this analysis is the DECC fossil fuel price [53] and carbon value [54] projections. These are produced at regular intervals and are used for long term economic appraisal. As emphasised by DECC they are not forecasts of future

energy prices and are “...based on estimates of fundamentals and other available evidence that represents a plausible range for future prices”. Figure 32 displays gas price scenarios selected which have been supplemented here with a very low gas price scenario as a “stress” sensitivity.

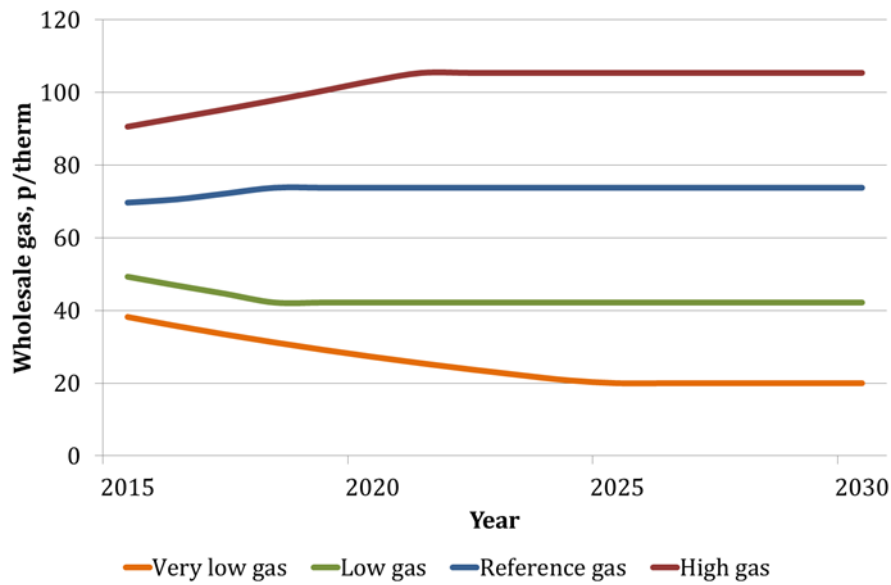


Figure 32: DECC wholesale annual (flat) gas price scenarios (2013 prices).

For comparison purposes and to include the effect of household consumption, the residential prices were changed from £/MWh_{th} to £/household pa. In addition, network charges were added but costs not specific to gas and which are likely to be incurred by other heat technologies were not included. These were identified from Ofgem [58] data and comprise:

- Environmental and social obligations
- Supplier operating costs
- Value added tax
- Supplier pre-tax margin

Finally the capital and other non-fuel costs were added to give the “total cost”.

Figure 33 displays the total cost in £/household pa for each gas price scenario. Network charges were sourced from Ofgem data [58]. It can be seen that despite the significant differences in wholesale gas prices across the scenarios the impact is substantially reduced for total costs. This is mainly due to the reduction in gas costs as a proportion of fixed costs arising from lower household heat demand (Pathway 3) and is illustrated in Figure 34.

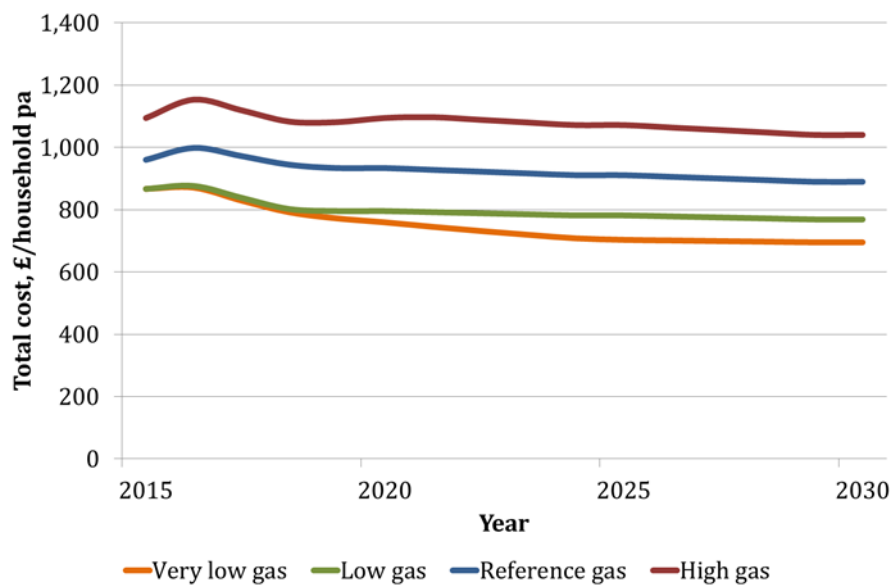


Figure 33: Total cost scenarios for residential gas based on DECC gas price scenarios supplemented by data from Ofgem with Pathway 3 heat demand from DECC 2050 Pathways (2013 prices).

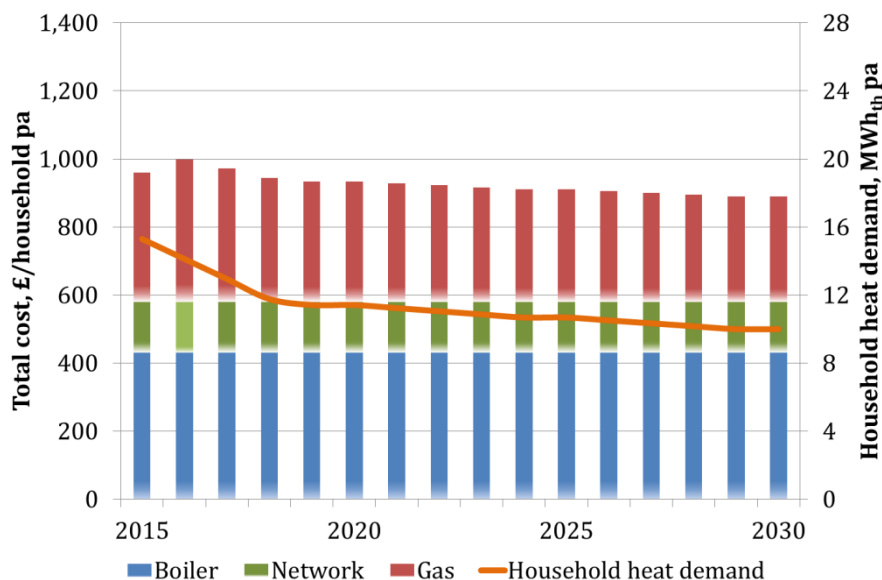


Figure 34: Total cost for “Reference” gas price scenario (2013 prices).

4.2.3 Impact of carbon prices

At present gas for space and water heating is in the non-traded sector of the European Union Emission Trading Scheme (EU ETS) [59] and so Emission Allowances (EA) do not need to be purchased to cover CO₂ emissions. This does not apply to heat technologies such as heat pumps, storage heaters and district heating that are likely to be fuelled from technologies within the traded sector such as thermal power stations. This may be considered perverse given that low carbon technologies incur a carbon related cost whereas gas with higher carbon emissions does not.

For example, the Committee for Climate Change’s 2010 advice on the Fourth Carbon Budget [29] shows emissions from buildings to be 19% of total UK CO₂ emissions in 2030 as shown in Figure 35. However most of the remaining sectors are either within the traded sector of the EU ETS, covered by the Carbon Reduction Commitment⁸ or, for transport, subject to Vehicle Excise Duty or a tax on fuel.

⁸ The Carbon Reduction Commitment (CRC) Energy Efficiency Scheme is a UK government scheme. It is designed to improve energy efficiency and cut CO₂ emissions in private and public sector

Hence there must be some possibility that CO₂ emissions from buildings will be subject to some form of carbon cost. This would have a direct impact on the economics of gas heating. It thus seems appropriate to explore the impact here. This has been done using the DECC carbon scenarios [54] which are displayed in Figure 36 and are described by DECC as “short-term traded sector carbon values for policy appraisal”.

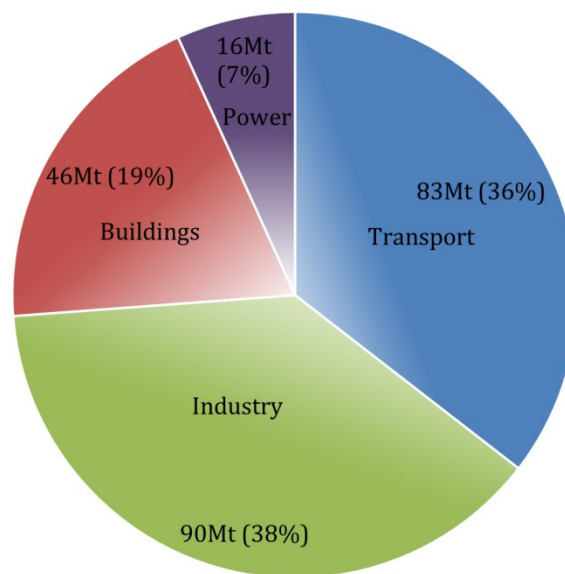


Figure 35: CCC Fourth Carbon Budget projections for UK CO₂ emissions in 2030.

organisations that are high energy users – see www.gov.uk/crc-energy-efficiency-scheme-qualification-and-registration.

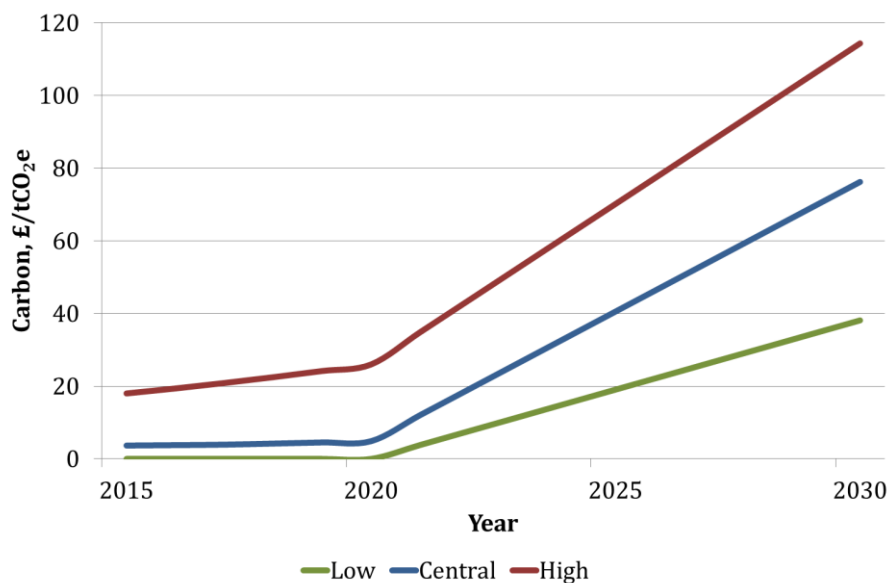


Figure 36: DECC's updated short-term traded sector carbon values for policy appraisal (2013 prices).

Adding any form of taxation to residential energy consumption would be a Government policy decision and is likely to be politically challenging if current concerns over affordability continue. So rather than assign a “High” carbon price scenario to a “High” gas price scenario and a “Low” carbon price scenario to a “Low” gas price scenario, the converse was applied. The rationale for this is that under a high gas price scenario it would be more difficult to add a high carbon cost and arguably less reason to do so. However, under a “Low” gas price scenario the argument would be stronger.

This is illustrated in Figure 37 where it can be seen that it still has a significant impact on total household cost in 2030 ranging from a cost increase of £70/household pa for the “High” carbon price scenario to over £200/household pa for the “Low” carbon price scenario.

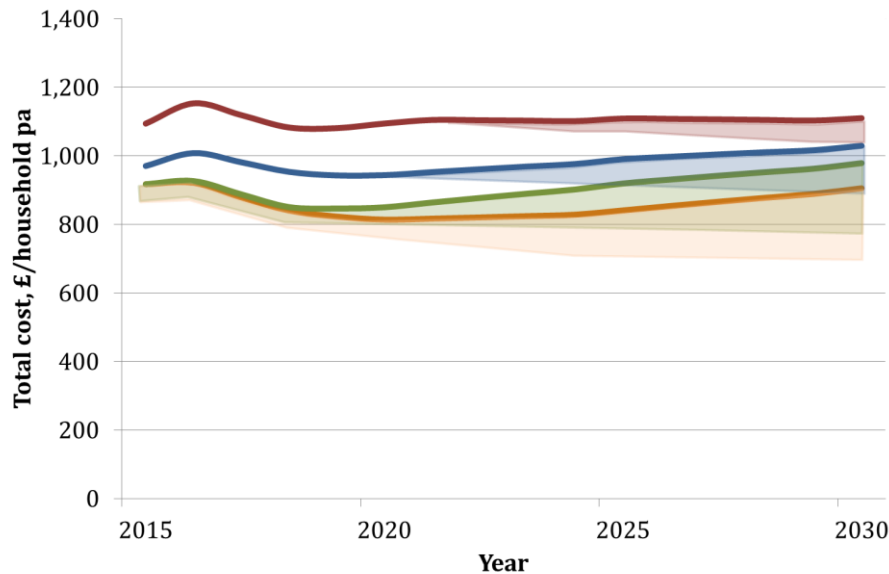


Figure 37: Total cost scenarios with the cost of carbon added (shaded area) for residential gas (2013 prices).

4.2.4 Impact of network charges

Another factor that may impact total costs is network charges. These are assumed to remain constant in real terms. However, as households switch away from gas for heating, network revenue will be lost. The gas network owners would then either need to reduce costs or increase network charges to compensate. On the assumption that cost reductions would be difficult to implement without reducing gas coverage, a reasonable assumption might be that network charges increase inversely proportional to the households lost. However, this is a complex area that warrants further investigation.

There are a number of projections of heat pump installations ranging from 2.5 million by Frontier Economics and Element Energy [31] to 5.6 million by National Grid plc in its Gone Green scenario [28] which would be approximately 25% of households. On the assumption that other low carbon technologies such as district heating and biomass amount to a further 25% of households, then for the purpose of illustrating the impact on network charges a doubling in cost from £150/household pa to £300/household pa (2013 prices) is assumed. This is

equivalent to a 7% pa loss of gas households from 2020 onwards and the effect on total costs for the remaining gas customers is shown in Figure 38.

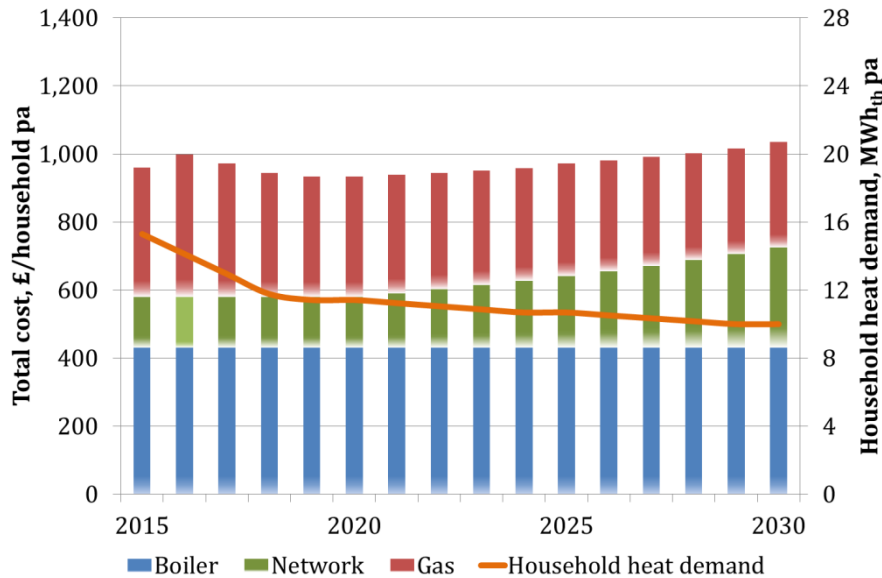


Figure 38: Total cost for “Reference” gas price scenario escalation in network charges (2013 prices).

4.2.5 Summary of results for gas condensing boiler heating

These are shown in Table 4 for 2030 for each of the gas price scenarios combined with carbon and network charge escalation sensitivities. It can be seen that the total costs range from £695/household pa to £1260/household pa.

Sensitivity (£/household pa)	Gas price scenario			
	“Very low”	“Low”	“Reference”	“High”
Base	695	769	890	1040
With carbon costs only	906	979	1030	1110
With network charge escalation only	845	919	1040	1190
With both carbon costs and network charge escalation	1056	1059	1180	1260

Note: “Reference” cost used in Figure 47, shown in **bold**.

Table 4: Condensing gas boiler 2030 total cost scenarios with sensitivities and Pathway 3 heat demand of 8.5MWh_{th} (2013 prices).

4.3 District heating

4.3.1 Capital costs

The main cost of district heating is the heat network itself. The incremental capital and running costs of heat production from CCGT plant is relatively small and can be supplemented by network storage (see section 5.4.4). District heating consists of:

- Infrastructure – comprising the main heat network connecting heat sources to ancillary plant such as pumps and heat substations.
- Connections – comprising branches connecting heat distribution circuits to heat interface units within buildings and heat metering.

There is significant uncertainty associated with costs particularly within the UK and a number of studies have been undertaken to investigate these and their influencing factors. District heating costs have been sourced from Pöyry [15] and as they are in 2009 prices have been adjusted for inflation to 2013 prices [56]. These are shown in Figure 39 for different household types. Pöyry states that costs in the UK are substantially higher than in continental Europe and cites the lack of UK experience with the technology. It suggests that there is potential for a 50% reduction in the cost of a district heat network.

Infrastructure costs range from £0.8k/household to £3.2k/household and the connection costs range from £3.6k/household to £6.4k/household which results in a total heat network capital cost that ranges from £4.4k/household to £8.9k/household.

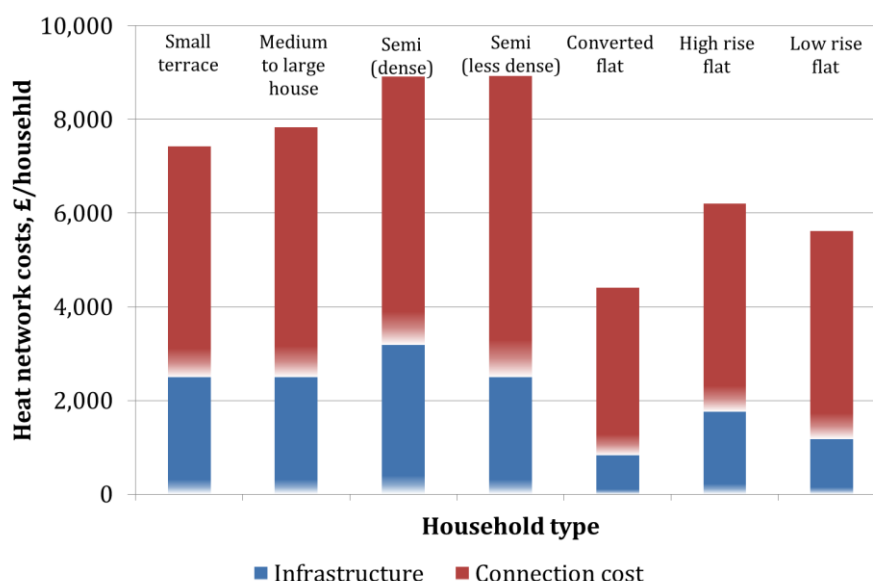


Figure 39: Heat network costs for different household types (2013 prices).

4.3.2 Heat network economic model

There are a number of other factors that need to be considered when evaluating the economics of heat networks:

- Cost of capital and term – at present district heat networks are not regulated and typically require a higher cost of capital, e.g. 10%, and a finance or amortisation term of 15 years which is much shorter than the life of the assets which can be 50 years. (Both Markal and ESME use a 10% cost of capital and Markal uses a 20 year finance period whereas for ESME it is 30 years.) In contrast, if heat networks were regulated similar to other network infrastructure then a cost of capital of 6% over a 40 year finance life would be more appropriate. The “Reference” cost assumption is that the cost of capital and amortisation period is 10% and 15 years and for the “Low” cost case it is 6% and 40 years.
- Interest during construction – as with any major construction project, finance charges will be incurred throughout construction, although in practice there will be some offset from network revenue as circuits are commissioned.

However, the assumption is that the term of the construction is 5 years and there is no network revenue during this period.

- Load development – unless the district heating is connecting new build houses or there is mandating of connection (such as in Denmark) then the heat load will need to be developed. This will take time and will adversely impact revenue. The assumption is that it takes 10 years to develop the load at 10% pa and as a consequence there is a shortfall in revenue which declines over this period to cover financing or the amortisation charge associated with the investment in the heat network infrastructure. However, connection or branch costs are only incurred as the load is developed.
- Network utilisation – there is a risk that load development never achieves 100% without mandating it and so the assumption is that network utilisation does not exceed 90%.
- Gas boiler decommissioning and compensation – where district heating is replacing gas for heating, the existing gas boiler will need to be decommissioned and the householder may need to be compensated for the residual life of the gas boiler. It is assumed that these are both £500 to give a total single payment of £1,000/household.

The heat network levelised cost, HNW_{LC} in £/household pa is the sum of the levelised costs of heat network infrastructure, IC_{LC} , and heat network connection cost, CC_{LC} , i.e.

$$HNW_{LC} = IC_{LC} + CC_{LC} \quad (2)$$

where:

$$IC_{LC} = \frac{IC^{CAPCOST} AF_{T_C}^i}{HNW^{MAXUTIL} T_C} \left(\frac{1}{(AF_{T_{HNW}}^i - LD^{REV_{SF}})} \right) \quad (3)$$

$$CC_{LC} = \frac{(CC^{CAPCOST} + GB^{COMP}) AF_{T_{LD}}^i HNW^{MAXUTIL}}{AF_{T_{HNW}}^i T_{LD}} \quad (4)$$

where:

$IC^{CAPCOST}$ is the total capital cost of the heat network infrastructure (£/household).

$AF_{T_c}^i$ is the heat network infrastructure construction annuity factor (pu) where i is the associated cost of capital and T_c is the heat network infrastructure construction period in years.

$HNW^{MAXUTIL}$ is the maximum utilisation of the heat network or maximum households connected (%) at the end of the load development period, T_{LD} .

$AF_{T_{HNW}}^i$ is the heat network infrastructure annuity factor (pu) where i_{HNW} is the associated cost of capital and T_{HNW} is the amortisation period for the heat network in years.

$LD^{REV_{SF}}$ is the load development revenue shortfall factor due to under-utilisation of the heat network during the load development period (pu).

$$LD^{REV_{SF}} = \sum_{t=1}^{T_{LD}} \left(1 - \frac{t}{T_{LD}}\right) / (1 + i)^t \quad (5)$$

T_{LD} is the period in years taken to develop the load to the maximum utilisation of the heat network, $HNW^{MAXUTIL}$, and where the rate of load development is constant, i.e. $\frac{HNW^{MAXUTIL}}{T_{LD}}$ % pa.

$CC^{CAPCOST}$ is the heat network connection cost (£/household).

GB^{COMP} is the gas boiler decommissioning and residual life compensation payment (£/household).

$AF_{T_{LD}}^i$ is the connection annuity factor (pu) where i is the associated cost of capital and T_{LD} is the load development period n years, i.e. when connections are being made.

4.3.3 Impact of heat network costs

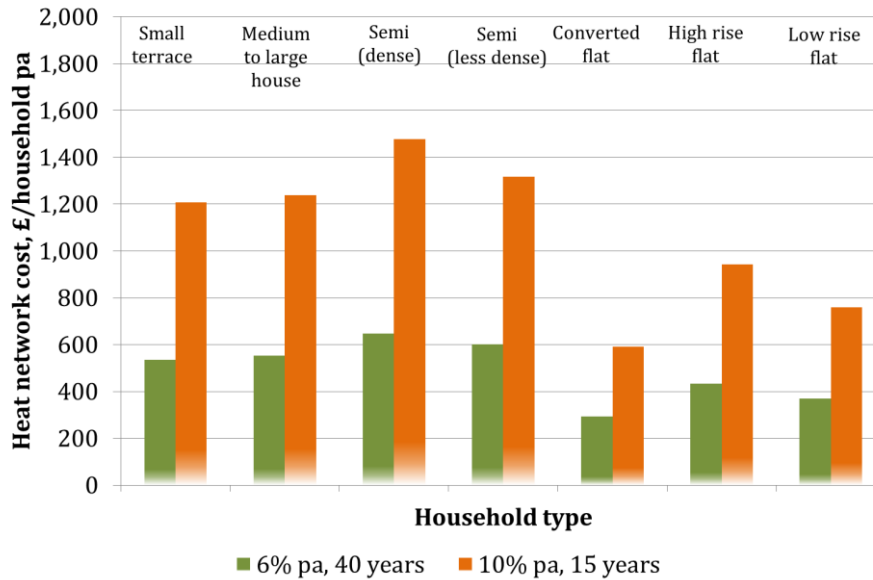
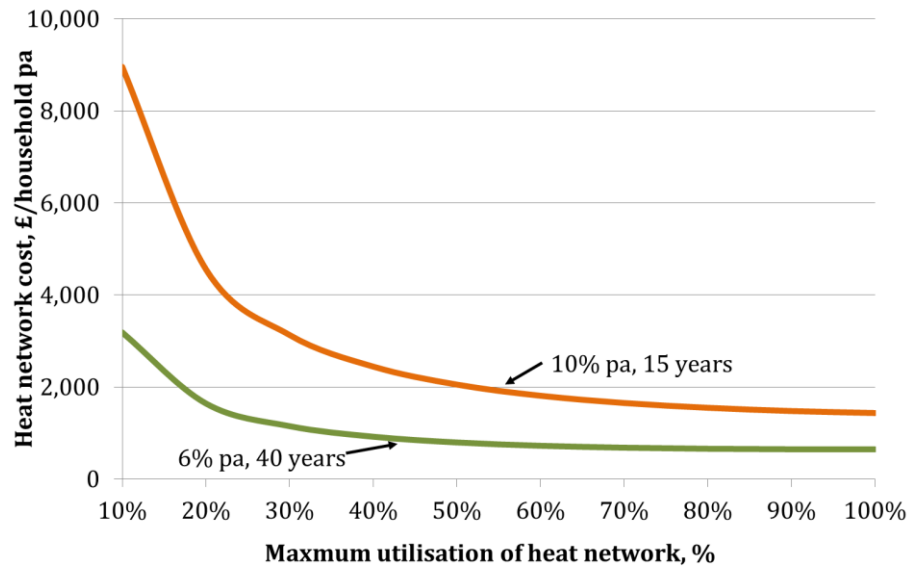


Figure 40: Heat network costs for different household types and with different financing assumptions (2013 prices).

The heat network cost in £/household pa is shown in Figure 40. This is based on the same cost data used for Figure 39 and the heat network economic model proposed in section 4.3.2. It can be seen that the impact of moving from a regulated finance regime with 6% pa cost of capital and an amortisation term of 40 years (green) to a 10% pa cost of capital and an amortisation term of 15 years (orange) results in a doubling or more of the cost.

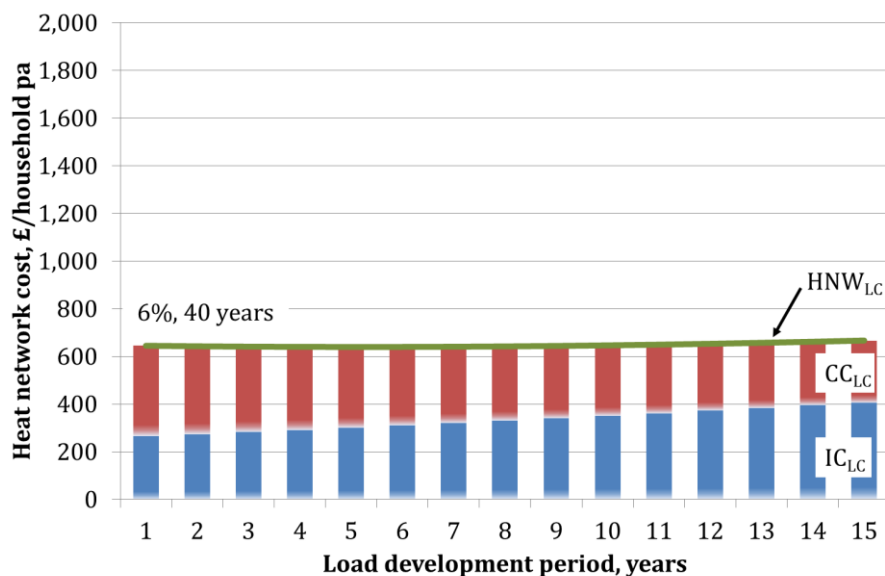
In Figure 41 the impact on levelised cost is shown for varying levels of maximum utilisation or percentage of households connected to the heat network. It can be seen that as the utilisation falls below 50%, the levelised cost increases rapidly illustrating the significance of heat network utilisation levels.



Example shown is for a semi-detached household type (densely populated area) with 90% maximum utilisation.

Figure 41: Heat network costs with different financing assumptions against maximum levels of network utilisation (2013 prices).

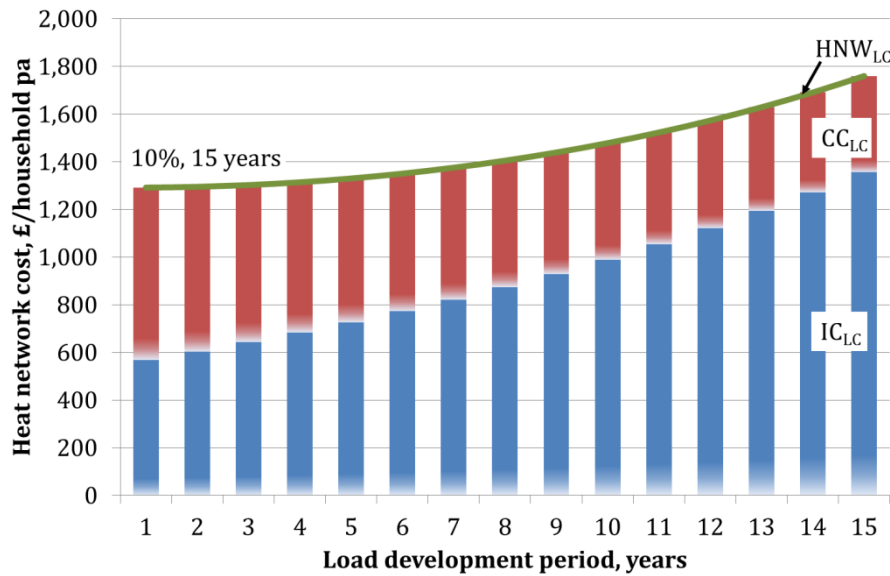
In Figure 42 the impact of varying load development periods is shown for the “Low” cost case, i.e. 6% cost of capital and 40 year amortisation period. It can be seen that the impact on costs is small. This is because connection costs are only assumed to have been incurred once households are connected. As the load development period increases, these costs are delayed and as a result their levelised costs reduce. This provides an offset to the infrastructure levelised costs which is directly affected by the duration of the load development period. Equation (3) shows how the infrastructure levelised cost, IC_{LC} , is directly impacted by the lost revenue due to the under-utilisation of the heat network during the load development period. As the utilisation falls then the infrastructure levelised cost or annual charge to households must increase to compensate.



Example shown is for a semi-detached household type (densely populated area) with 90% maximum utilisation.

Figure 42: Heat network levelised costs with varying load development periods and “Low” cost case, i.e. 6% pa cost of capital and 40 year amortisation period (2013 prices).

However, for the “Reference” cost with a 10% pa cost of capital and 15 year amortisation period the position is very different as shown in Figure 43. It can be seen that the heat network levelised costs are very sensitive to changes in the load development period and as a result substantially increase the risk for heat network development.



Example shown is for a semi-detached household type (densely populated area) with 90% maximum utilisation.

Figure 43: Heat network levelised costs with varying load development period and 10% pa cost of capital and 15 years amortisation period (2013 prices).

4.3.4 Impact of fuel and carbon costs

As discussed in section 5.4.4 there are multiple sources of heat which can be used for district heating. An assumption is made here that the heat is provided by a CHP CCGT operating on gas with an electrical efficiency of 0.5pu, a Z ratio of 6. Allowing for a heat network efficiency of 0.85pu and using Equation 81 in section 5.4.4 results in a fuel to delivered heat conversion efficiency of 2.55pu.

Figure 44 displays the total costs for district heating in 2030 for each of the different gas and carbon scenarios referred to in sections 4.2.2 and 4.2.3 and for different heat network financing based on semi-detached households (densely populated area). It can be seen that the total cost is very sensitive to heat network costs and the very high fuel to heat conversion efficiency results in district heating being much less sensitive to gas and carbon prices.

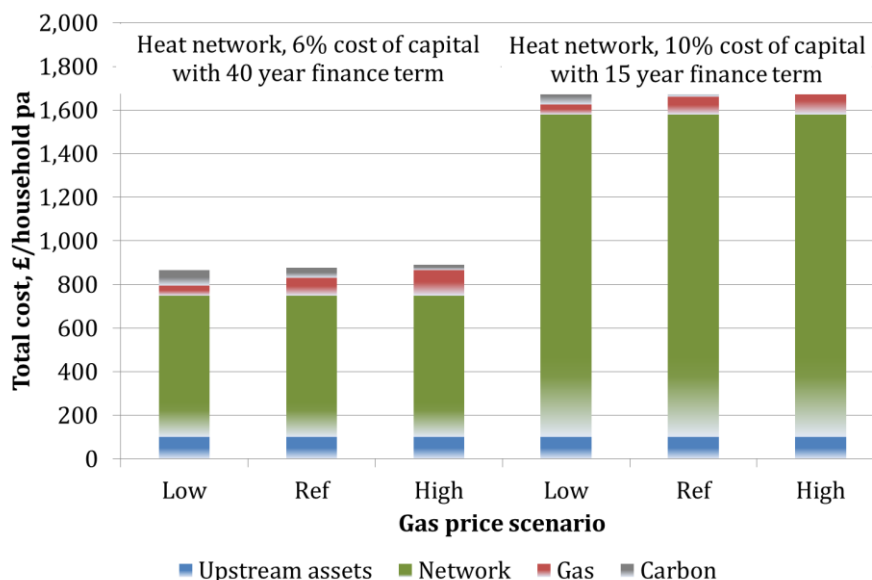


Figure 44: District heating total costs in 2030 against gas and carbon price scenarios and heat network financing (2013 prices).

4.3.5 Summary of results for district heating

These are shown in Table 5 for 2030 for each of the gas price scenarios and heat network financing assumptions. It can be seen that the total costs range from £865/household pa to £1721/household pa.

Heat network financing case (£/household pa)	Gas and carbon price scenario		
	"Low"	"Reference"	"High"
"Reference" - 10% with 15 year finance term	1696	1709	1721
"Low" - 6% with 40 year finance term	865	878	890

Note: "Reference" cost used in Figure 47, shown in **bold**.

Table 5: District heating total costs in 2030 against gas and carbon price scenarios and heat network financing case (2013 prices).

4.4 Electric heating

4.4.1 Heat pumps

The heat pump technologies identified in Chapter 2 suitable for large scale deployment are ASHPs and hybrid heat pumps. The estimated installed cost for an 8.5kW_{th} ASHP is £10k/household [38] [60] with a similar cost for a hybrid heat pump⁹. Delta-ee suggests (Appendix 2) there is some scope for future cost reductions and performance improvements mainly arising from:

- Economies of scale from mass production
- Increases in market competition, particularly from Asian manufacturers
- Reductions in installer margins as experience is gained
- Sourcing of cheaper materials, e.g. replacing copper/brass with aluminium and greater use of plastics

Projected reductions are to £6k/household by 2030 and so for this exercise a 2030 cost of £7.5k/household is used for the “Reference” case with a “Low” case of £5k/household. Based on a product life of 15 years and using a cost of capital for retail appliances of 10% pa, the levelised cost is £986/household pa (“Reference”) and £657/household pa (“Low”).

However, as a consequence of the large scale deployment of heat pumps there will need to be some reinforcement of the electricity network. This will vary and be dependent on a number of variables such as spare circuit capacity, embedded generation and other load, e.g. electric vehicles. The assumption made here is that there are distribution and transmission reinforcement costs of £400/household and £300/kW respectively. This results in an average cost of circa £1000/household which is £66.50/household pa and which has been included in

⁹ This has a lower rated heat pump, e.g. 5kW_{th} , which offsets the gas boiler cost.

the “Reference” case only. It is assumed that for the “Low” case electricity network reinforcement is avoided.

Delta-ee advises that improvements in efficiency or seasonal performance factor (SPF) will be evolutionary and suggests that 10% should be achievable by 2030. These include:

- Efficiency improvement in pumps and fans.
- Improvement in the design of compressors.
- Advancement in the heat exchanger design, particularly tackling the defrosting issue.
- Optimised control systems performance including pumps and fans.
- New system concepts, e.g. CO₂ heat pumps and advanced high temperature systems.

These improvements will, however, be dependent on investment in research and development and a stable and supportive policy towards heat pumps from the Government and Ofgem. At present the ASHP is eligible to receive the RHI subject to accreditation [61]. In 2014 this is 7.3p/kWh_{th}, although the payment is adjusted to take account of SPF, e.g. based on a heat load of 15MWh_{th} pa and a SPF of 2.7, the annual payment is £689.

Figure 45 displays the total annual household cost for heat pump heating in 2030 for each of the electricity price scenarios [57] and for the “Reference” case (£7.5k/household and electricity network reinforcement) and “Low” case (£5k/household heat pump cost with a 10% improvement in SPF). It can be seen that the total cost is very sensitive to the cost of the heat pump and much less so to the cost of the electricity network reinforcement.

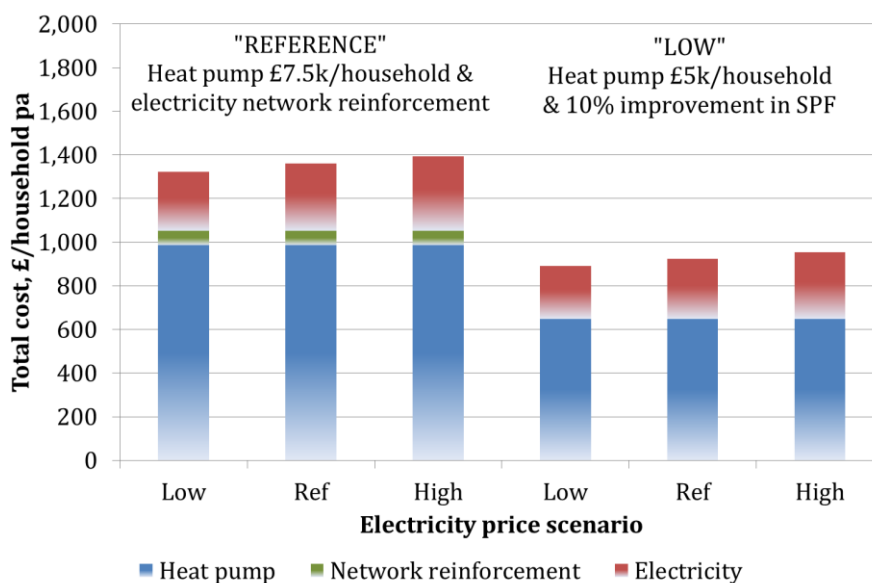


Figure 45: Heat pump total costs in 2030 against electricity price scenarios and heat pump and network reinforcement costs (2013 prices).

4.4.2 Summary of results for heat pumps

These are shown in Table 6 for 2030 for each of the electricity price scenarios combined with different heat pump cost. It can be seen that the total costs range from £891/household pa to £1392/household pa. As noted above, in 2014 the ASHP is eligible to receive the RHI, subject to accreditation. Based on the 2014 RHI tariff and a Pathway 3 heat demand of 8.5MWh_{th} this is approximately £400 pa which would reduce its cost to nearly the "Low" cost case.

Heat pump cost case (£/household pa)	Electricity price scenario		
	"Low"	"Reference"	"High"
"Reference" - £7.5k/household + network reinforcement	1323	1360	1392
"Low" - £5k/household & 10% improvement in SPF	891	924	953

Note: "Reference" cost used in Figure 47, shown in **bold**.

Table 6: Heat pump total costs in 2030 against electricity price scenarios and heat pump and network reinforcement costs (2013 prices).

4.5 Electric storage heaters

As discussed in section 5.4.3, capital costs for electric storage heaters are much lower than for electric heat pumps with a typical installed cost from £500/household to £1,500/household for two large heaters (e.g. 3.3kW input, 1.5kW_{th} output and 23.1kWh_{th} storage) [15] and [38]. So an assumption has been made that the installed cost is £1,500/household based on a product life of 15 years and a cost of capital for retail appliances of 10% pa, which result in a levelised cost of £197/household pa.

The operating costs will be higher than heat pumps due to their lower efficiency. However, their storage capability does mean that they are particularly suitable for demand side management which should reduce their running costs. However, a simulation model is needed to evaluate the potential benefits. It is therefore conservatively assumed that there are no cost savings from storage that can be attributed to storage heaters. These assumptions will be examined in Chapter 6.

It may be possible to avoid network reinforcement up to a certain penetration level on the assumption that storage heaters are scheduled to avoid peak demand. This assumes that electricity prices will be lower during the night. However, with potentially large volumes of inflexible thermal plants such as nuclear, combined with intermittent plants such as wind, this may not be the case in the future. Hence network reinforcement may be necessary to remove network constraints. The assumption made here is that network reinforcement is required and is the same as that required for heat pumps, i.e. £66.50/household pa.

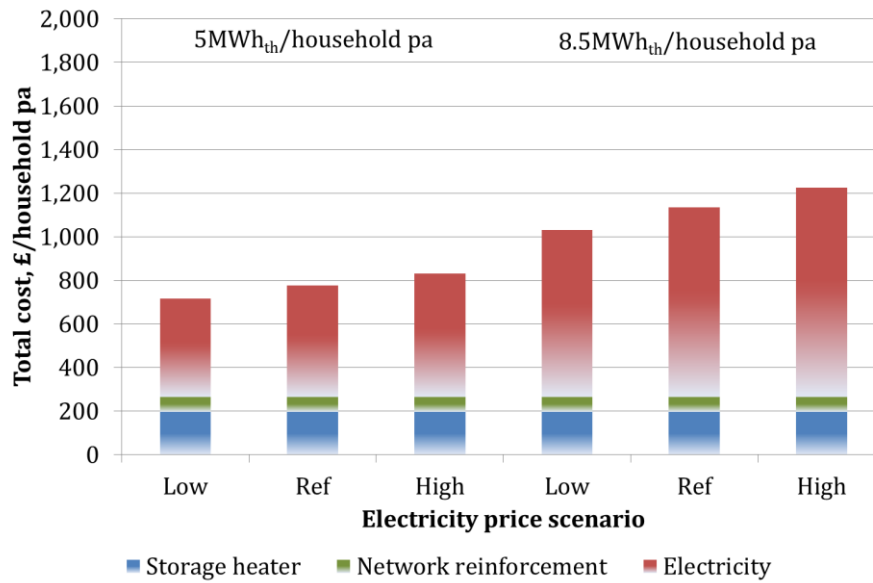


Figure 46: Storage heater total costs in 2030 against electricity price scenarios and heat demand (2013 prices).

Figure 46 displays the total annual household costs for electric storage heating in 2030 for each of the electricity scenarios [57] with the 2050 Pathway 3 demand of 8.5MWh_{th} pa and a lower demand case of 5MWh_{th} pa. It can be seen that the costs are very sensitive to electricity prices.

4.5.1 Summary of results for electric storage heaters

These are shown in Table 7 for 2030 for each of the electricity price scenarios and household heat demand sensitivities. It can be seen that the total costs range from £715/household pa to £1226/household pa.

Household heat demand (£/household pa)	Electricity price scenario		
	"Low"	"Reference"	"High"
5MWh _{th} pa	715	776	830
8.5MWh _{th} pa	1031	1135	1226

Note: "Reference" cost used in Figure 47, shown in **bold**.

Table 7: Storage heater total costs in 2030 against electricity price scenarios and heat pump and network reinforcement costs (2013 prices).

4.6 Future uncertainties of heater technologies

Figure 47 shows the range of uncertainties in total costs for each of the heater technologies. Superimposed onto this range is a base cost figure which uses the Reference cost from the respective table for that heat technology. For district heating and heat pumps a lower figure is shown to illustrate the effect of the "Low" cost cases.

The principal cost uncertainties have been categorised into:

- Policy
- Network costs
- Performance
- Running costs (principally fuel)
- Heater appliance cost

For gas, the uncertainty is a combination of future gas costs, increases in network charges (to compensate for lost revenue as households switch away from gas) and a policy change which introduces some form of carbon levy. For district heating the uncertainty is dominated by the cost of the heat network and, in particular, the associated financing arrangements. For heat pumps it is the installed cost of the heat pump and its performance. Finally for storage heaters it is the electricity cost and whether demand side management can offer cost reductions.

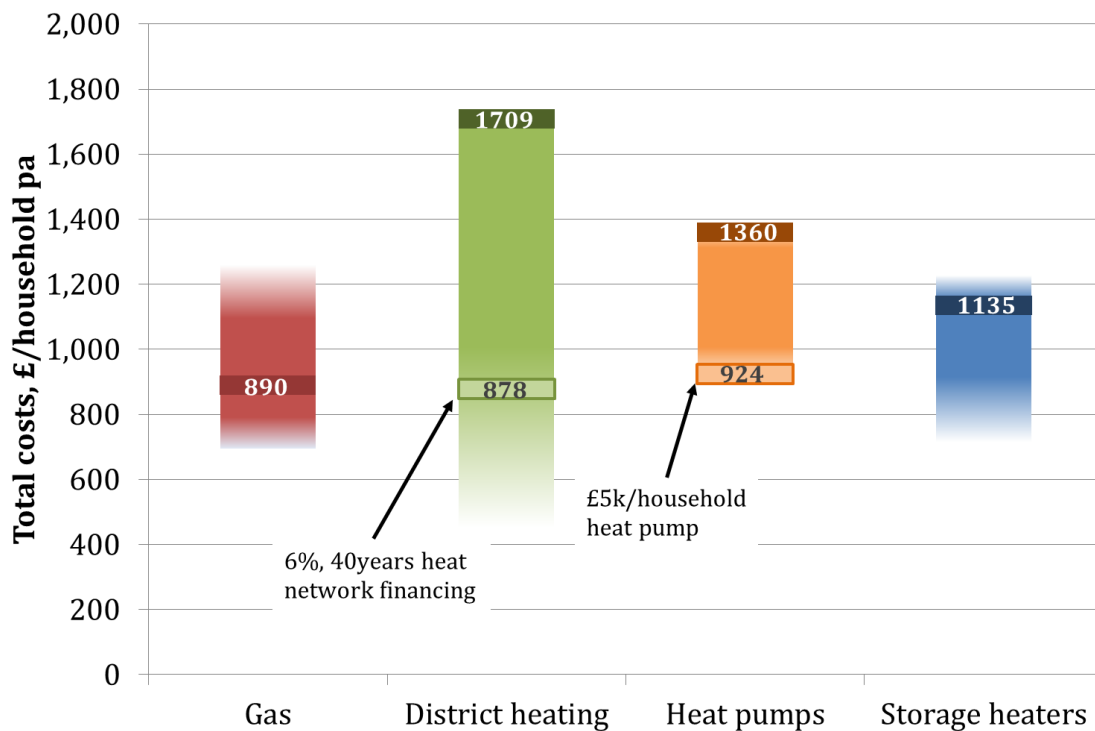


Figure 47: Comparison of the range of total costs for heater technologies with a "base" cost shown (2013 prices).

In Figure 48 a cost and performance uncertainty map for each of the heater technologies is presented (whereby the larger the area the greater the uncertainty). To some extent this is subjective but it does draw attention to the differences between the technologies and the scope for reducing this uncertainty. For example, the network and policy uncertainties associated with district heating can be directly addressed by Government intervention.

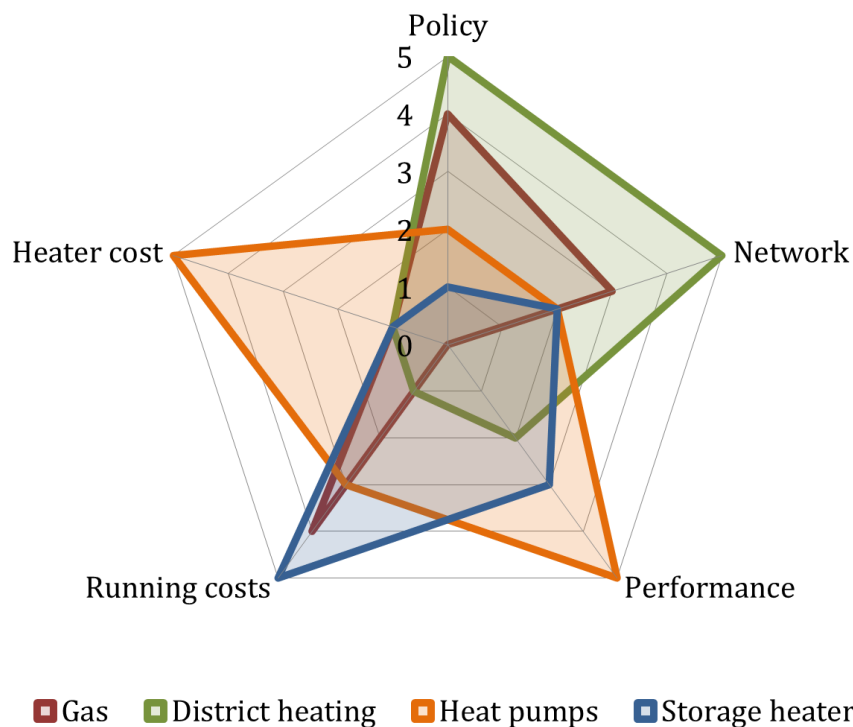


Figure 48: Cost and performance uncertainty map for heater technologies whereby 1=least uncertainty and 5 =most uncertainty

4.7 Discussion and conclusions

Total cost scenarios for each of the heating technologies were developed based on DECC fuel and carbon price scenarios. The total cost includes the cost of the heater appliance, network related costs and running costs, which are principally fuel. Sensitivity cases were also developed to take account of the uncertainties.

Gas was shown to have the lowest cost but is exposed to fuel cost uncertainties as well as increases in network charges and the imposition of a carbon levy.

District heating was shown to have the highest cost as a result of the financing assumptions. A heat network economic model was developed which examined the impact of financing along with other risks such as load development and network utilisation. These risks were shown to be very significant but if more favourable financing is assumed, comparable to that used for electricity and gas networks,

then district heating has the lowest cost and the risks are shown to be much less and more manageable.

Heat pumps were shown to have the next highest costs due to the installation cost of the heat pump. If these can be reduced then they can become competitive with gas. However, the electricity price scenario used is likely to have underestimated prices, particularly as the heat pump load is most likely to occur at times of higher demand.

Storage heaters are ranked behind gas but are most sensitive to electricity costs. Hence they are likely to be more competitive at lower heat demands. It is probable that the electricity price scenario used has overestimated prices by not taking account of the cost reductions from demand side management.

CHAPTER 5

INTEGRATED HEAT & ELECTRICITY INVESTMENT MODEL

Large scale energy systems are complex and involve substantial investment across the supply chain. For example, the assets involved in supplying heat from gas will include the sourcing of gas, the delivery of gas through transmission and distribution systems, the conversion of gas to heat using gas appliances and finally heat delivery using wet radiator systems. Large scale energy systems also have interaction with other energy systems. For example, gas is used not just to heat buildings but also to generate electricity and increases in the demand for gas due to colder weather may cause gas prices to rise. This will feed through to electricity prices and possibly cause generation plants to be rescheduled as a consequence. Similarly, increases in wind generation may result in less gas generation which could cause gas prices to fall and as a result the rescheduling of gas assets such as storage and exports across the interconnector.

District heating systems are most likely to have assets that are connected to the electricity system. A CHP plant will generate electricity as well as heat and changes in either will have an impact on the other. A district heating system is also likely to have substantial heat storage which can be used to support the electricity system. For example, an increase in electricity generation may be met through lower heat production but would require heat demand to be supplied from elsewhere such as storage.

This chapter proposes an integrated heat and electricity investment model that enables such interactions to be explored. It includes the main heat assets such as CHP plant, heat storage (network and building), large network heat pumps,

residential heating technology as well as thermal electricity and wind generation. This is then followed by a description of the modelling of residential heating systems. It commences with ASHP and hybrid heat pump technologies in which the coefficient of performance of the heat pump varies with temperature. These also incorporate a “peaking heat” facility (electric for the ASHP and gas for the hybrid) for when heat demand exceeds the capacity of the heat pumps. It then describes the modelling of the electric storage heaters and finally the district heating system with the focus on the modelling of the CHP plant.

Examples of modelling output are then presented and the chapter ends with a summary of the identified strengths and weaknesses of the investment model.

5.1 Multi Energy System models

In Chapter 2 the modelling approaches adopted to construct low carbon heat scenarios for 2050 and displayed in Figure 7 were reviewed and critiqued. However, there are other multi energy system models or computer tools. Connolly et al conducted a review of such computer tools [62]. The review initially considered 68 models but these were reduced to 37 most of which included electricity and heat but many of which included transport as well.

The models covered a wide range of applications from individual buildings to national energy systems as well as different functionality, including those with a national energy focus and those with a very specific focus, e.g. hydrogen systems. Approximately half the models used time step simulation, e.g. hourly time increments in chronological order, with the remainder pathway style models similar to those discussed in section 2.3. A particular feature of these pathway style models is the normalisation and rationalisation of time periods into multiple hour blocks. As described in section 2.3 this results in a number of performance features which are poorly represented, particularly when this is applied to heat demand.

In order to ensure these and also any other performance features are included, chronological detail should be retained preferably down to half hourly time steps. This enables the operation of an energy system to be more correctly represented as well as the associated costs that would otherwise be missing, e.g. thermal generator unit start-up costs. From the simulation models only 4 were national energy system models with the remainder for a specific focus or application. The national energy system models were:

- BALMOREL [63] – This was developed for the analyses of the power and CHP sectors in the Baltic Sea region to support the identification of relevant policy questions. The model includes heat and electricity and uses linear optimisation to minimise both operating and investment costs. Residential heating assets and systems are not represented.
- EnergyPLAN [64] - This is a deterministic input/output tool developed at Aalborg University, Denmark. It is designed and programmed in Delphi Pascal and includes heat and electricity supplies as well as the transport and industrial sectors. Optimisation is limited to operating costs of a given system and not investments. Residential heating assets and systems are represented but heat pumps use a fixed efficiency and therefore take no account of air temperature on performance. EnergyPLAN is discussed in a number of papers covering large scale integration of wind [65], CHP [66], integrated energy systems [67], renewable energy [68] and the use of waste for energy purposes [69].
- RAMSES [70] - This was developed for the analysis of electricity and district heat production for any number of electricity and district heating areas and is used by the Danish Energy Agency. It uses (partial) linear optimisation to minimise both operating and investment costs. Residential heating assets and systems are not represented and it only includes heating load that is connected to the district heating systems.
- WILMAR [71] - This was developed to analyse the optimal operation of a power system whilst treating wind and load forecasts as stochastic input parameters. It uses mixed integer stochastic linear optimisation to minimise the operating

costs of a given system but does not include investments. Residential heating assets and systems are not represented. WILMAR has previously been used to analyse the change in operating costs due to increased wind-penetrations [72], to simulate the integration of wind power onto the Nordic energy-system [73] and to evaluate how electric boilers and heat pumps can improve the feasibility of large wind-penetrations [74].

All of the models were built specifically to be used in Denmark or the Nordic region. They include heat demand but its relationship with temperature is not included, i.e. heat demand is normalised. Only one of the models (EnergyPLAN) includes the representation of residential heating assets and systems, although heat pumps use a fixed efficiency and therefore take no account of air temperature on performance. As shown in section 3.1.4 and in sections 5.4.1 and 5.4.2, the effect of air temperature on heat pump efficiency and performance can be significant. Neither EnergyPLAN nor Wilmar include investment costs as part of the optimisation process as they are limited to the operating costs of a given system only. Only Wilmar includes mixed integer linear optimisation and therefore is able to incorporate the on/off status and associated costs and performance of individual generating units, e.g. start-up, no-load costs and minimum load. This results in much better and more realistic representation of generator unit scheduling and is explored in sections 6.1.5 and 6.1.6. Hence none of the multi energy system models reviewed incorporate all the features of the integrated heat and electricity investment model proposed in this chapter.

5.2 Overview of integrated heat and electricity investment model

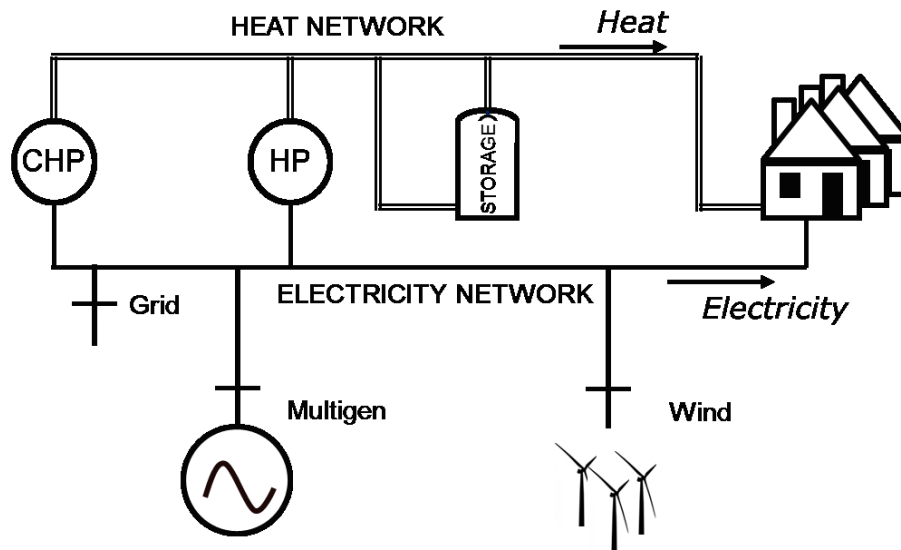


Figure 49: Integrated heat and electricity investment model.

Figure 49 shows a conceptual representation of the integrated heat and electricity investment model. This uses half hourly temperature based heat data derived from the model described in Chapter 3 and electricity demand sourced from National Grid plc [52].

The investment model includes:

- CHP CCGT plant
- Network heat pumps
- Network heat storage
- Thermal generation
- Wind generation
- Household ASHP with supplementary (peaking) electric heating
- Household hybrid heat pump (ASHP and gas) heating
- Household electric storage heater
- Household district heating connection

- Heat and electricity networks are not modelled but heat and electricity network losses are included

The investment model is formulated as a Mixed Integer Linear Program (MILP) and was implemented using the FICO® Xpress Optimisation Suite [75] (FICO). A Microsoft Excel “user friendly” interface was also constructed to facilitate data input and to process output results from FICO. FICO is an optimisation tool comprising two components: Xpress-Mosel and Xpress-Optimizer

- Xpress-Mosel is a model building and development tool specifically designed to be used with Xpress-Optimizer. It allows the user to construct models using mathematical programming in a form that is similar to algebraic notation and it can also access other file forms such as the Excel files used for the Microsoft Excel interface.
- Xpress-Optimizer comprises a suite of high performance optimisation solvers that use algorithms for solving linear, mixed integer and quadratic problems.

FICO was run on a Windows desktop computer with a 3GHz, Intel® Core™ i5-2320 processor and 16GB of Random Access Memory.

Both Dual Simplex only and Dual Simplex with Branch & Bound was used to solve the investment model and the simulation studies run over the time horizon of one year with half hourly time resolution. The objective function is to minimise total cost and this includes all the investment costs associated with the assets (generation, storage, network, large heat pump and residential heating systems) and their associated running costs over the time horizon.

Main outputs are Demand Weighted Average (DWA) costs and CO₂ emissions for each heating technology. The costs are determined by allocating energy costs to each residential heating technology for each half hour and in proportion to its demand inclusive of storage. Levelised investment costs and other fixed costs are proportioned to the half hours (typically 7) when heat and electricity production are at their highest.

To assist with simulation study convergence and feasibility, heat and electricity demand were scaled to the equivalent of 1 million households (reasonable size city) and thermal generation units limited to 10 units with 1 CHP unit. In addition, the investment model has three modes of operation.

- Mode 1 – Residential heating technology mix constrained and relaxed generator model (no binary variables) and solved with Dual Simplex.

Constraining the mix of residential heating technology and using the relaxed generator model substantially reduced the complexity of the investment model. As a result convergence was achieved more rapidly resulting in computer run times of less than 30 minutes for a typical study. All studies were initially run using Mode 1 as this enabled the study to be validated prior to using modes 2 or 3 with their lengthier run times.

- Mode 2 – Residential heating technology mix constrained with full generator model and solved with Dual Simplex with Branch & Bound.

The full generator model includes start-up costs, no-load costs and minimum load operation and thus results in more realistic generator scheduling. For example, when operating the investment model in Mode 1, nuclear plant may be subject to flexible operation with daily starts and with generating unit output scheduled anywhere from zero to full load. In practice nuclear plant is relatively inflexible due to its start-up costs, but also due to technical limitations. In Mode 2, start-up costs and minimum load operation effectively constrain nuclear to inflexible or baseload operation. To include such features, binary variables are required and the problem solved using Dual Simplex with Branch and Bound. This significantly adds to the complexity of the investment model and substantially increases the computer run times from less than 30 minutes for a typical study in Mode 1 to over 24 hours in Mode 2.

- Mode 3 – Residential heating technology mix unconstrained with relaxed generator model (no binary variables) and solved with Dual Simplex.

In modes 1 and 2 the mix of residential heating technologies are constrained. The drawback with this approach is that the mix may be suboptimal and this could distort the DWA costs of these technologies as they are likely to include a constraint cost. As the mix changes the associated DWA cost for each heating technology may also change. By operating the investment model in Mode 3, the mix of heating technologies is optimised thereby removing any constraint cost distortions. Mode 3 is particularly useful for examining the “boundary conditions”, i.e. how much do performance factors or costs have to change to switch the economics from one heating technology to another? The additional decision variables required to enable the heating technology mix to be optimised by the investment model increased computer run times from less than 30 minutes for a typical study in Mode 1 to over 2 hours in Mode 3.

Figure 50 displays a data flow chart of the integrated heat and electricity investment model which summarises the activities performed by the Excel interface and those performed by FICO.

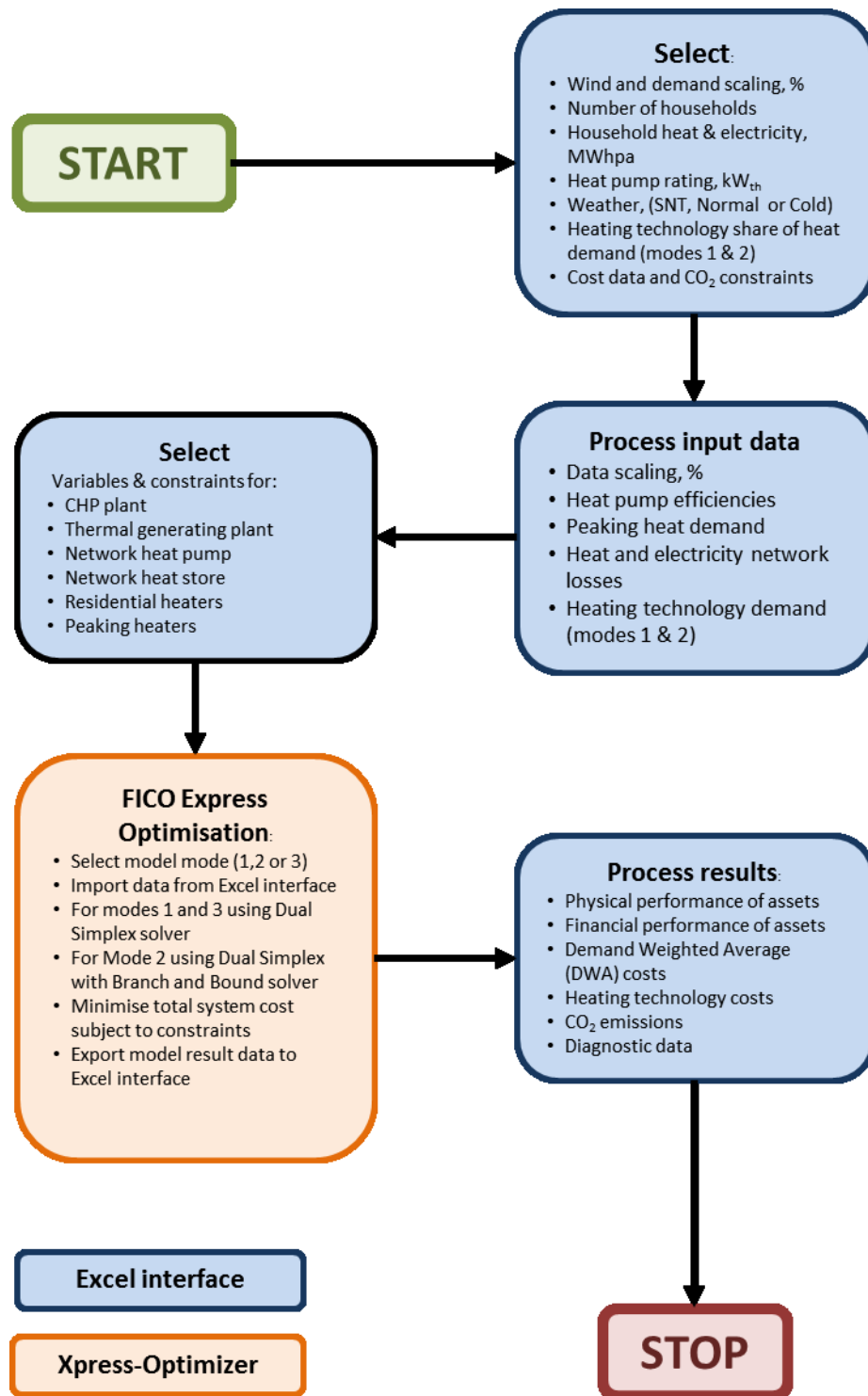


Figure 50: Data flow chart of integrated heat and electricity investment model implemented in FICO® Xpress Optimisation Suite with Excel interface.

5.3 Model formulation

The components are:

- Objective function
- Heat and electricity balance equations
- Constraints
- Parameters
- Variables

The Sets, Parameters and Variables are listed in the Nomenclature on page 21. Upper case letters are used for all parameters and lower case letters for all variables.

5.3.1 Objective function

The objective function shown in equation (6) is to minimise the total operating costs and investment and other fixed costs over the time horizon T (where T is the set of half hours in a year).

$$\textit{Total costs} = \textit{Total operating costs} + \textit{Total investment and other fixed costs} \quad (6)$$

The components of the operating costs comprise:

- CHP fuel and carbon
- Grid electricity exports and imports
- Hybrid heat pump peaking gas boiler fuel
- Wind production
- Thermal generation fuel and carbon

and the investment and other fixed costs of the:

- CHP
- Network heat store (HSTO)
- Network heat pump (HP)

- Thermal generation
- Residential heaters (RH)
- Hybrid heat pump peaking gas boiler
- Air source heat pump peaking electric heater

The following describes each of these in turn.

5.3.1.1 CHP fuel and carbon operating costs

$chpw_t$	CHP electricity output at time t (MW)
$chpq_t$	CHP thermal output at time t (MWth)
Z^{CHP}	CHP ratio of Δ Heat to Δ Electricity, i.e. $\Delta Q/\Delta W$ (pu)
$CHPW^{INCCOST}$	CHP incremental fuel cost (£/MWh)
$CHPW^{INCCO2}$	CHP incremental CO2 cost (£/MWh)
$CHPW^{STUPCOST}$	Start-up cost of CHP (£/MW)
$chpw_t^{status}$	Commitment status of CHP at time t (binary)
$chpw_t^{stup}$	CHP start- up indicator at time t (binary)
$CHPW^{NLCOST}$	CHP electricity no-load fuel cost (£/h)
$CHPW^{NLCO2}$	CHP no-load CO2 cost (£/h)

The CHP fuel and carbon operating costs comprise:

- Incremental running costs
- Start-up costs (Mode 2 only)
- No-load costs (Mode 2 only)

Incremental running costs

The CHP incremental running costs are determined from the sum of the fuel and carbon costs in £/MWh multiplied by the power output of the CHP, i.e.

$$(chpw_t + chpq_t/Z^{CHP})(CHPW^{INCCOST} + CHPW^{INCCO2}) \quad (7)$$

The term " $chpq_t/Z^{CHP}$ " adjusts thermal power into the equivalent electrical power and is a novel feature in the model proposed. This is because it fully incorporates the relationship heat and electricity production, both of which can then be

optimised by the investment model. This is described in more detail in section 5.4.4)

Start-up costs

Start-up costs are incurred every time the CHP unit is started and its commitment status changes from offline to online. When this occurs the binary variable, $chpw_t^{stup} = 1$. So:

$$CHPW^{STUPCOST} chpw_t^{stup} \quad (8)$$

No-load costs

No-load fuel and carbon costs are the fixed operating costs of the CHP unit. When the CHP is online the binary variable, $chpw_t^{status} = 1$. So:

$$(CHPW^{NLCOST} + CHPW^{NLCO2}) chpw_t^{status} \quad (9)$$

Total CHP operating costs

Hence the total CHP operating costs at time t are:

$$\begin{aligned} & ((chpw_t + chpq_t/Z^{CHP}) (CHPW^{INCCOST} + CHPW^{INCCO2}) + CHPW^{STUPCOST} chpw_t^{stup} + \\ & (CHPW^{NLCOST} + CHPW^{NLCO2}) chpw_t^{status}) \end{aligned} \quad (10)$$

5.3.1.2 Grid electricity exports and imports operating costs

$grid_t$	Grid export at time t (MW)
$GRID_t^{PRICE}$	Grid price at time t (£/MWh)

If electricity is sold to the grid (exported) or procured from the grid (imported), sales income or procurement costs will be incurred. These will be a function of exports (or, if negative, imports) at time t and the grid price, i.e.

$$grid_t GRID_t^{PRICE} \quad (11)$$

5.3.1.3 Hybrid heat pump peaking gas boiler fuel operating costs

gb_t	Peaking gas boiler thermal output at time t (MW_{th})
GB^{COST}	Gas cost at time t (£/ MWh_{th})

As described in section 5.4.2, a hybrid heat pump comprises an ASHP and a condensing gas boiler. When the heat demand exceeds the rating of the heat pump at time t , the condensing gas boiler operates incurring a cost which will be a function of the gas cost, i.e.

$$gb_t GB^{COST} \quad (12)$$

5.3.1.4 Wind production operating costs

$WIND_t$	Wind power available at time t (MW)
$WIND^{COST}$	Wind production cost (£/ MWh)

The cost of wind production at time t is determined from the power produced multiplied by the wind production cost, i.e.

$$WIND_t WIND^{COST} \quad (13)$$

5.3.1.5 Thermal generation fuel and carbon operating costs

gen_{gt}	Generator g electricity output at time t (MW)
$GEN_g^{INCCOST}$	Incremental fuel cost of generator g (£/ MWh)
GEN_g^{INCCO2}	Incremental CO ₂ cost of generator g (£/ MWh)
$GEN_g^{STUPCOST}$	Start-up cost of generator g (£/MW)
gen_{gt}^{status}	Commitment status of generator g at time t (binary)
gen_{gt}^{stup}	Generator start up indicator of generator g at time t (binary)
GEN_g^{NLCOST}	Electricity production no-load fuel cost of generator g (£/h)
GEN_g^{NLCO2}	Electricity production no-load CO ₂ cost of generator g (£/h)

The thermal generation fuel and carbon operating costs comprise:

- Incremental running costs

- Start-up costs (Mode 2 only)
- No-load fuel and carbon costs (Mode 2 only)

Incremental running costs

The thermal generator g incremental running costs at time t are determined from the sum of the fuel and carbon costs in £/MWh multiplied by the power output of the thermal generator, i.e.

$$gen_{g,t}(GEN_g^{INCCOST} + GEN_g^{INCCO2}) \quad (14)$$

Start-up costs

Start-up costs are incurred every time the thermal generator g is started and its commitment status changes from offline to online. When this occurs the binary variable, $gen_{g,t}^{stup}=1$. So:

$$GEN_g^{STUPCOST} gen_{g,t}^{stup} \quad (15)$$

No-load costs

No-load fuel and carbon costs are the fixed operating costs of the thermal generator unit. When the generator is online the binary variable, $gen_g^{status}=1$. So:

$$(GEN_g^{NLCO2} + GEN_g^{NLCOST}) gen_g^{status} \quad (16)$$

Total thermal generation operating costs

Hence the total operating costs of thermal generation at time t are:

$$\sum_{g \in G} (gen_{g,t}(GEN_g^{INCCOST} + GEN_g^{INCCO2}) + GEN_g^{STUPCOST} gen_{g,t}^{stup} + (GEN_g^{NLCO2} + GEN_g^{NLCOST}) gen_g^{status}) \quad (17)$$

5.3.1.6 CHP fixed costs

chp^{cap}	<i>CHP installed electrical capacity (MW)</i>
$CHP^{CAPCOST}$	<i>CHP levelised capital cost and annual fixed charges (£/MW/a)</i>

The CHP fixed costs are determined from the installed capacity, chp^{cap} , and the levelised capital cost and annual fixed charges, $CHP^{CAPCOST}$, i.e.

$$chp^{cap} CHP^{CAPCOST} \quad (18)$$

5.3.1.7 Network heat store (HSTO)

$hsto^{cap}$	<i>Network heat store maximum installed capacity (MW_{th})</i>
$HSTO^{CAPCOST}$	<i>Network heat store levelised capital cost (£/MW_{th}/a)</i>

Network heat stores are large insulated water tanks [76]. A number of examples installed in Denmark are described in [77]. These range in size from 6,330m³ to 73,000m³ with energy storage capacities of 0.3GWh to 3.4GWh and discharge capacities of 30MW_{th}/h to 600MW_{th}/h. Typically storage operation will be diurnal although during the summer when demand is low they are also used over the weekend. Heat storage is used to improve the utilisation of assets, contribute to thermal capacity and provide backup thereby improving security of supply.

The network heat store fixed costs are determined from the installed capacity, $hsto^{cap}$, and the levelised capital cost and annual fixed charges, $HSTO^{CAPCOST}$, i.e.

$$hsto^{cap} HSTO^{CAPCOST} \quad (19)$$

5.3.1.8 Network heat pump (HP)

hp^{cap}	<i>Network heat pump maximum installed capacity (MW_{th})</i>
HP^{CAPOST}	<i>Network heat pump levelised capital cost and annual fixed charges (£/MW_{th}/a)</i>

Network heat pumps are large capacity installations connected to a district heating system and most often use water as a heat source. One of the largest installations is in Stockholm and it is rated at 180MW_{th} [78]. Compared to residential heat pumps, they are more efficient with CoP's circa 3.5, are about half the cost in £/kW_{th} and can deliver heat at higher temperatures. For example, a network heat pump installation in Drammen, Norway operates at 90°C [79].

The network heat pump fixed costs are determined from the installed capacity, hp^{cap} , and the levelised capital cost and annual fixed charges, $HP^{CAPCOST}$, i.e.

$$hp^{cap} HP^{CAPCOST} \quad (20)$$

5.3.1.9 Thermal generation

gen_g^{cap}	Generator g maximum installed capacity (MW)
$GEN_g^{CAPCOST}$	Generator g levelised capital cost and annual fixed charges (£/MW/a)

The fixed costs for generator g are determined from the installed capacity, gen_g^{cap} , and the levelised capital cost and annual fixed charges, $GEN_g^{CAPCOST}$. Hence, the total thermal generation fixed costs are:

$$\sum_{g \in G} gen_g^{cap} GEN_g^{CAPCOST} \quad (21)$$

5.3.1.10 Residential heaters (RH)

rh_h^{cap}	Residential heater h maximum installed capacity (MW)
$RH_h^{CAPCOST}$	Levelised capital cost and annual fixed charges of heater h (£/MW/a)

The fixed costs for residential heater h are determined from the installed capacity, rh_h^{cap} , and the levelised capital cost and annual fixed charges, $RH_h^{CAPCOST}$. Hence, the total residential heater fixed costs are:

$$\sum_{h \in H} r h_h^{cap} R H_h^{CAPCOST} \quad (22)$$

5.3.1.11 Hybrid heat pump peaking gas boiler

gb^{cap}	<i>Peaking gas boiler installed capacity (MW)</i>
$GB^{CAPCOST}$	<i>Total levelised capital cost & annual fixed charges of peaking gas boilers (£/a)</i>

The gas boiler fixed costs are determined from the installed capacity, gb^{cap} , and the levelised capital cost and annual fixed charges, $GB^{CAPCOST}$, i.e.

$$gb^{cap} GB^{CAPCOST} \quad (23)$$

5.3.1.12 Air source heat pump peaking electric heater

eh^{cap}	<i>Peaking electric heater installed capacity (MW)</i>
$EH^{CAPCOST}$	<i>Total levelised capital cost & annual fixed charges of peaking electric heaters (£/a)</i>

The gas boiler fixed costs are determined from the installed capacity, eh^{cap} , and the levelised capital cost and annual fixed charges, $EH^{CAPCOST}$, i.e.

$$eh^{cap} EH^{CAPCOST} \quad (24)$$

5.3.1.13 Total cost equation

Substituting equations (7) to (24) in Equation (6) results in the following total cost equation for the time horizon T.

$$\begin{aligned}
\text{Total costs} = & \left(\sum_{t \in T} (\text{chpw}_t + \text{chpq}_t / Z^{\text{CHP}}) (\text{CHPW}^{\text{INCCOST}} + \text{CHPW}^{\text{INCCO2}}) \right. \\
& + 2 \text{CHPW}^{\text{STUPCOST}} \text{chpw}_t^{\text{stup}} + (\text{CHPW}^{\text{NLCOST}} + \text{CHPW}^{\text{NLCO2}}) \text{chpw}_t^{\text{status}} \\
& + \text{grid}_t \text{GRID}_t^{\text{PRICE}} + \text{gb}_t \text{GB}^{\text{COST}} + \text{WIND}_t \text{WIND}^{\text{COST}} \\
& + \sum_{g \in G} (\text{gen}_{g,t} (\text{GEN}_g^{\text{INCCOST}} + \text{GEN}_g^{\text{INCCO2}}) + 2 \text{GEN}_g^{\text{STUPCOST}} \text{gen}_{g,t}^{\text{stup}} \\
& \left. + (\text{GEN}_g^{\text{NLCO2}} + \text{GEN}_g^{\text{NLCOST}}) \text{gen}_{g,t}^{\text{status}} \right) \frac{1}{2} \\
& + \left(\left(\sum_{g \in G} \text{gen}_g^{\text{cap}} \text{GEN}_g^{\text{CAPCOST}} + \sum_{h \in H} \text{rh}_h^{\text{cap}} \text{RH}_h^{\text{CAPCOST}} \right) \right. \\
& \left. + (\text{gb}^{\text{cap}} \text{GB}^{\text{CAPCOST}} + \text{eh}^{\text{cap}} \text{EH}^{\text{CAPCOST}}) \right)
\end{aligned} \tag{25}$$

5.3.2 Heat and electricity balance equations

Heat and electricity balance equations are required to ensure that the energy consumed equals the energy produced inclusive of any losses.

5.3.2.1 Heat balance equation

Q_t^θ	Total thermal building demand for temperature scenario θ at time t (MWth) determined from the Heat Demand Model (see Chapter 3)
q_t^{ashp}	Residential ASHP thermal building demand at time t (MWth)
q_t^{hybrid}	Residential hybrid heat pump thermal building demand at time t (MWth)
q_t^{estor}	Residential electric storage thermal building demand at time t (MWth)
q_t^{district}	Residential district heating thermal building demand at time t (MWth)
gb_t	Peaking gas boiler thermal output at time t (MWth)

eh_t Peaking electric heater thermal output at time t (MWth)

The heat energy balance equation is:

$$Q_t^g = q_t^{ashp} + q_t^{hybrid} + q_t^{estor} + q_t^{district} + gb_t + eh_t \quad \forall t \quad (26)$$

The total heat demand at time t is equal to the sum of all building heat demand whether supplied by electricity or district heating.

5.3.2.2 District heating demand

$q_t^{district}$	District heating thermal building demand at time t (MW _{th})
$chpq_t$	CHP thermal output at time t (MW)
$hsto_t^{out}$	Network heat store thermal output at time t (MW _{th})
$hsto_t^{in}$	Network heat store thermal input at time t (MW _{th})
hp_t	Network heat pump thermal output at time t (MW _{th})
rh_{4t}^{in}	District heating residential heater power input at time t (MW _{th})
rh_{4t}^{out}	District heating residential heater power output at time t (MW _{th})
HNW_t^{LOSSES}	Heat network losses at time t (MWth)

The district heating equation is:

$$q_t^{district} = chpq_t + hsto_t^{out} - hsto_t^{in} + hp_t + rh_{4t}^{out} - rh_{4t}^{in} - HNW_t^{LOSSES} \quad \forall t \quad (27)$$

The district heat building demand at time t is equal to the sum of the heat production from the CHP, the network heat pump and the net change in stored heat energy in the network and residential buildings adjusted for network heat losses.

5.3.2.3 Network heat store

$hsto_t$	Thermal energy in network heat store at time t (MWth)
η^{HSTO}	Network heat store static efficiency in each half hour (pu)
η_{HSTO}^{IN}	Network heat store charging efficiency (pu)
$hsto_t^{in}$	Network heat store thermal input at time t (MWth)
η_{HSTO}^{OUT}	Network heat store discharging efficiency (pu)

$hsto_t^{out}$	Network heat store thermal output at time t (MWth)
$HSTO^{INITIALQ}$	Network heat store initial charge (MWth)

The network heat store energy balance equations are:

$$hsto_t = \eta^{HSTO} hsto_{t-1} + \eta_{HSTO}^{IN} hsto_t^{in} - \frac{hsto_t^{out}}{\eta_{HSTO}^{OUT}} \quad \forall t > 1 \quad (28)$$

$$hsto_t = \eta^{HSTO} HSTO^{INITIALQ} + \eta_{HSTO}^{IN} hsto_t^{in} - \frac{hsto_t^{out}}{\eta_{HSTO}^{OUT}} \quad t = 1 \quad (29)$$

The thermal energy in the network heat store at time t is equal to the stored energy at time $(t-1)$, adjusted for efficiency, i.e. losses, plus the difference between the network store charge and discharge rates, adjusted for efficiency.

5.3.2.4 Residential heaters

H	Set of residential heat technologies h where: 1=ASHP 2=Hybrid heat pump 3=Electric storage heaters 4=District heating
rh_{ht}^{sto}	Thermal energy in residential heat store h at time t (MW _{th})
η_h^{RH}	Residential heater h static losses in each half hour (pu)
rh_{ht}^{sto}	Thermal energy in residential heat store h at time t (MW _{th})
rh_{ht}^{in}	Residential heater h power input at time t (MW or MW _{th})
rh_{ht}^{out}	Residential heater h power output at time t (MW _{th})

These comprise ASHPs, hybrid heat pumps, electric storage heaters and district heating the modelling of which is described in section 5.4. All residential heaters are assumed to include a storage facility.

The residential heater storage energy balance equations are:

$$rh_{ht}^{sto} = \eta_h^{RH} rh_{ht-1}^{sto} + rh_t^{in} - rh_t^{out} \quad \forall h, \forall t > 1 \quad (30)$$

$$rh_{ht}^{sto} = \eta_h^{RH} RH^{INITIALQ_h} + rh_t^{in} - rh_t^{out} \quad \forall h, t = 1 \quad (31)$$

The thermal energy in the residential heaters at time t is equal to the stored energy at time $(t-1)$, adjusted for efficiency, plus the difference between the residential power charge and discharge rates.

5.3.2.5 Heat network losses

HNW_t^{LOSSES}	Heat network losses at time t (MW _{th})
γ	Heat network losses (pu)
Q^{PEAK}	District heating building peak demand (MW _{th})
$Q_t^{DISTRICT}$	District heating building heat demand at time t

Heat network losses are predominantly a function of water flow temperature, heat network infrastructure and pumping load. An approximation has been made whereby the heat loss specified γ in time t is halved when the heat load is half the peak district heat demand. This assumes lower pumping load and operational management of the heat network to reduce temperature losses.

The heat network losses are:

$$HNW_t^{LOSSES} = \gamma \sum_t^T (1 + Q^{PEAK}) \quad \forall t \text{ where } Q_t^{DISTRICT} > (Q^{PEAK}/2) \quad (32)$$

$$HNW_t^{LOSSES} = \frac{\gamma}{2} \sum_t^T (1 + Q^{PEAK}) \quad \forall t \text{ where } Q_t^{DISTRICT} \leq (Q^{PEAK}/2) \quad (33)$$

where Q^{PEAK} is the district heating peak demand.

5.3.2.6 Electricity balance equation

$grid_t$	Grid export at time t (MW)
W_t	Non heat electricity demand at time t (MW)
rh_{1t}^{in}	ASHP power input at time t (MW _{th})
rh_{2t}^{in}	Hybrid heat pump power input at time t (MW _{th})

$rh_{3,t}^{in}$	Electric storage heater power input at time t (MW_{th})
eh_t	Peaking electric heater thermal output at time t (MW_{th})
$ASHP_t^\theta$	ASHP & hybrid heat pump efficiency for temperature scenario θ at time t (pu)
ENW_t^{LOSSES}	Electricity network losses at time t (pu)
hp_t	Network heat pump thermal output at time t (MW_{th})
η^{HP}	Network heat pump efficiency (pu)
$chpw_t$	CHP electricity output at time t (MW)
$WIND_t$	Wind power available at time t (MW)
$gen_{g,t}$	Generator g electricity output at time t (MW)

The power exported to the grid at time t is equal to the difference between total consumption (non-heat electricity demand, heat electricity demand and network heat pump demand) and generation (CHP, thermal generation and wind). Note: $\frac{(rh_{1,t}^{in} + rh_{2,t}^{in})}{ASHP_t^\theta}$ converts the ASHP and hybrid heat pump thermal heat demand to an electrical heat demand.

The electricity energy balance equation is:

$$\begin{aligned}
 grid_t = & \left(W_t + \frac{(rh_{1,t}^{in} + rh_{2,t}^{in})}{ASHP_t^\theta} + rh_{3,t}^{in} + eh_t \right) (1 + ENW_t^{LOSSES}) + \frac{hp_t}{\eta^{HP}} \\
 & - chpw_t - WIND_t - \sum_{g \in G} gen_{g,t} \quad \forall t
 \end{aligned}
 \tag{34}$$

5.3.2.7 Electricity network losses

D	Set of days in a year, d
T	Set of half hours in a year, t
$TEMP$	Set of daily temperature scenarios, θ
Φ	Fixed electricity network losses (pu)
φ	Variable electricity network losses (pu/°C)

$HEAT^{CUTOFF}$	<i>Cut-off temperature for space heating (refer to section 3.1.1)</i>
$TEMP_d^\theta$	<i>Daily average temperature for temperature scenario θ ($^{\circ}C/d$)</i>

Electricity network losses are predominantly affected by circuit loading. It is assumed that circuit loading will increase with reductions in temperature to reflect electrified heat demand and so there will be a corresponding increase in network resistive losses. To take some account of this relationship a simple adjustment is made. It is assumed that losses have a fixed component Φ and will vary inversely with temperature by the specified value φ and by the difference from $HEAT^{CUTOFF}$, i.e. the temperature above which the space heating is assumed to be turned off (section 3.1.1).

The electricity network losses are:

$$\eta_t^{ENW} = \sum_{d \in D} \sum_{\theta \in TEMP} \sum_{t=1}^{48} \Phi + \varphi(HEAT^{CUTOFF} - TEMP_d^\theta) \quad \forall t \quad (35)$$

5.3.3 Constraints

These comprise:

- CHP plant
- Network heat pump
- Network heat store
- Thermal generation
- CO₂ emissions
- Grid
- Residential heaters (Modes 1 and 2)
- Residential heaters (Mode 3)

The following presents the investment model's constraints.

5.3.4 CHP

$CHPW^{MIN}$	Minimum CHP electricity generation (MW)
$chpw_t$	CHP electricity output at time t (MW)
chp^{cap}	CHP maximum installed electrical capacity (MW)
$chpq_t$	CHP thermal output at time t (MW)
Z^{CHP}	CHP ratio of $\Delta Heat$ to $\Delta Electricity$, i.e. $\Delta Q/\Delta W$ (pu)
$CHPQ^{MIN}$	Minimum CHP heat generation (MW_{th})
λ^{CHP}	Maximum ratio of heat to electricity production in each half hour (pu)
T	Set of half hours in a year, t
$CHPW^{MAX}$	Maximum CHP electricity generation (MW)
$CHPW^{AVAIL}$	CHP maximum annual availability (pu)
CHP^{CAPMIN}	CHP minimum installed capacity (MW)

The CHP heat and electricity production constraints must take account of their interaction as described in section 5.4.4. These constraints are illustrated in Figure 57 and are:

$$CHPW^{MIN} \leq chpw_t \leq (chp^{cap} - \frac{chpq_t}{Z^{CHP}}) \quad \forall t \quad (36)$$

and

$$CHPQ^{MIN} \leq chpq_t \leq \lambda^{CHP} chpw_t \quad \forall t \quad (37)$$

So for the CHP electricity production, $chpw_t$, it must be greater than or equal to the minimum constraint and less than or equal to the maximum electricity capacity of the CHP adjusted for heat production. Similarly the CHP thermal production, $chpq_t$, must be greater than or equal to the minimum constraint and less than or equal to the maximum ratio of heat to electricity production λ^{CHP} .

The total annual CHP energy production must be less than or equal to the annual availability limit of the CHP.

$$\sum_{t=1}^T (chpw_t + chpq_t/Z^{CHP}) \leq TCHPW^{MAX}CHP^{AVAIL} \quad (38)$$

The maximum electricity capacity of the CHP must be greater than or equal to the minimum capacity level and less than or equal to the maximum capacity constraint of the CHP.

$$CHPW^{CAPMIN} \leq chp^{cap} \leq CHPW^{MAX} \quad (39)$$

5.3.5 CHP (full generator model)

$CHPW^{MIN}$	Minimum CHP electricity generation (MW)
$chpw_t^{status}$	Commitment status of CHP at time t (binary)
$chpw_t$	CHP electricity output at time t (MW)
chp^{cap}	CHP maximum installed electrical capacity (MW)
$chpw_t^{stup}$	CHP start up indicator at time t (binary)
$CHPW^{INITIAL}$	CHP initial commitment status (binary)

The full generator model includes minimum electricity production and start-up costs and is modelled by using binary unit commitment variables. So if the CHP is scheduled at time t its output must be between its minimum and maximum power output limits. Thus the binary unit commitment decision variable, $chpw_t^{status}$ takes the value “1” when the CHP is online, and 0 otherwise.

$$CHPW^{MIN} chpw_t^{status} \leq chpw_t \leq chp^{cap} chpw_t^{status} \quad \forall t \quad (40)$$

If the CHP is scheduled to be online at time t and it was offline at time $(t-1)$, then a start-up event happens and $chpw_t^{stup}$ is equal to one.

$$chpw_t^{stup} = chpw_t^{status} - chpw_{t-1}^{status} \quad \forall t > 1 \quad (41)$$

$$chpw_t^{stup} = chpw_t^{status} - CHPW^{INITIAL} \quad t = 1 \quad (42)$$

The total no-load cost of the CHP over the whole time horizon is given by:

$$CHPW^{NLCOST} chpw_t^{status} \quad \forall t \quad (43)$$

5.3.6 Network heat pump

HP^{MIN}	Network heat pump minimum heat production (MW_{th})
hp_t	Network heat pump thermal output at time t (MW_{th})

hp^{cap}	Network heat pump installed capacity (MW_{th})
HP^{CAPMIN}	Network heat pump minimum installed capacity (MW_{th})
HP^{MAX}	Network heat pump maximum heat production (MW_{th})

The network heat pump heat production at any time t must be greater than or equal to the minimum constraint and less than or equal to the maximum capacity of the heat pump.

$$HP^{MIN} \leq hp_t \leq hp^{cap} \quad \forall t \quad (44)$$

The maximum thermal capacity of the network heat pump must be greater than or equal to the minimum capacity level and less than or equal to the maximum capacity constraint of the network heat pump.

$$HP^{CAPMIN} \leq hp^{cap} \leq HP^{MAX} \quad (45)$$

5.3.7 Network heat store

$hsto_t^{in}$	Network heat store thermal input at time t (MW_{th})
$HSTO^{INMAX}$	Network heat store minimum charge rate (MW_{th})
$hsto_t^{out}$	Network heat store thermal output at time t (MW_{th})
$HSTO^{OUTMAX}$	Network heat store maximum discharge (MW_{th})
$hsto_t$	Thermal energy in network heat store at time t (MWh_{th})
$hsto^{cap}$	Network heat store installed capacity (MWh_{th})
$HSTO^{INITIALQ}$	Network heat store initial charge (MWh_{th})
$HSTO^{MAXQ}$	Network heat store maximum charge (MWh_{th})

The network heat store charge at any time t must be greater than or equal to 0 and less than or equal to the charge capacity of the heater.

$$0 \leq hsto_t^{in} \leq HSTO^{INMAX} \quad \forall t \quad (46)$$

The network heat store discharge at any time t must be greater than or equal to 0 and less than or equal to the discharge capacity of the heater.

$$0 \leq hsto_t^{out} \leq HSTO^{OUTMAX} \quad \forall t \quad (47)$$

The thermal energy in the network heat store at any time t must be greater than or equal to 0 and less than or equal to the maximum capacity of the network heat store.

$$0 \leq hsto_t \leq hsto^{cap} \quad \forall t \quad (48)$$

The thermal energy in the network heat store in the first half hour of each day, i.e. t' , must be greater than or equal to the network heat store initial stored energy.

$$hsto_{t'} \geq HSTO^{INITIALQ} \quad \forall t' \quad (49)$$

The maximum thermal stored energy in the network heat store must be less than or equal to the maximum capacity constraint of the network heat store.

$$hsto^{cap} \leq HSTO^{MAXQ} \quad (50)$$

5.3.8 Thermal generation

$gen_{g,t}$	Generator g electricity output at time t (MW)
gen_g^{cap}	Generator g installed capacity (MW)
GEN_g^{AVAIL}	Maximum annual availability of generator g (pu)
GEN_g^{CAPMIN}	Minimum capacity of generator g (MW)

The electricity production of generator g at any time t must be greater than or equal to 0 and less than or equal to its maximum generation capacity.

$$0 \leq gen_{g,t} \leq gen_g^{cap} \quad \forall g, \forall t \quad (51)$$

The total annual electricity production from generator g must be less than or equal to the availability limit of the generator.

$$\sum_{t=1}^T gen_{g,t} \leq gen_g^{cap} GEN_g^{AVAIL} \quad \forall g \quad (52)$$

The maximum electricity capacity of generator g must be greater than or equal to the minimum capacity level and must be less than or equal to the maximum capacity constraint of generator g .

$$GEN_g^{CAPMIN} \leq gen_g^{cap} \leq GEN_g^{MAX} \quad \forall g \quad (53)$$

5.3.9 Thermal generation (full generator model)

The following lists the additional constraints for the full generator model.

GEN_g^{MIN}	Minimum output of generator g (MW)
$gen_{g,t}^{status}$	Commitment status of generator g at time t (binary)
$gen_{g,t}$	Generator g electricity output at time t (MW)
gen_g^{cap}	Generator g installed capacity (MW)
$gen_{g,t}^{stup}$	Generator start up indicator of generator g at time t (binary)
$GEN_g^{INITIAL}$	Initial commitment status of generator g (binary)

The full generator model includes minimum electricity production and start-up costs and are modelled by using binary unit commitment variables. So if a generator unit is scheduled at time t its output must be between its minimum and maximum power output limits. Thus the binary unit commitment decision variable, $chpw_t^{status}$ takes the value “1” when the CHP is online, and 0 otherwise.

$$GEN_g^{MIN} gen_{g,t}^{status} \leq gen_{g,t} \leq gen_g^{cap} gen_{g,t}^{status} \quad \forall g, \forall t \quad (54)$$

where $gen_{g,t}^{status}$ is a binary variable

If generator g is scheduled to be online at time t and it was offline at time $(t-1)$, then a start-up event happens and $gen_{g,t}^{stup}$ is equal to one.

$$gen_{g,t}^{stup} = gen_{g,t}^{status} - gen_{g,t-1}^{status} \quad \forall g, \forall t > 1 \quad (55)$$

$$gen_{g,t}^{stup} = gen_{g,t}^{status} - GEN_g^{INITIAL} \quad \forall g, t = 1 \quad (56)$$

where $gen_{g,t}^{stup}$ is a binary variable

5.3.10 CO₂ emissions

$CO2^{MAX}$	Maximum CO ₂ emissions (Mt)
$gen_{g,t}$	Generator g electricity output at time t (MW)
GEN_g^{INCCO2}	Incremental CO ₂ cost of generator g (£/h)

$chpw_t$	CHP electricity output at time t (MW)
$chpq_t$	CHP thermal output at time t (MW _{th})
Z^{CHP}	CHP ratio of Δ Heat to Δ Electricity, i.e. $\Delta Q/\Delta W$ (pu)
$CHPW^{INCCO2}$	CHP incremental CO ₂ cost (£/MWh)
$CO2^{PRICE}$	CO ₂ price (£/t)

The CO₂ emissions are determined from electricity and heat produced from the thermal generation and CHP plant and must be less or equal to the maximum level, i.e. CO_2^{MAX} .

$$CO_2^{MAX} \geq \left(\sum_{g=1}^G \sum_{t=1}^T gen_{g,t} GEN_g^{INCCO2} + (chpw_t + \frac{chpq_t}{Z^{CHP}})CHPW^{INCCO2} \right) / CO2_{PRICE} \quad (57)$$

5.3.11 CO₂ emissions (Full generator model)

$CO2^{MAX}$	Maximum CO ₂ emissions (Mt)
$gen_{g,t}$	Generator g electricity output at time t (MW)
GEN_g^{INCCO2}	Incremental CO ₂ cost of generator g (£/h)
GEN_g^{NLCO2}	Electricity production no-load CO ₂ cost of generator g (£/h)
$gen_{g,t}^{status}$	Commitment status of generator g at time t (binary)
$chpw_t$	CHP electricity output at time t (MW)
$chpq_t$	CHP thermal output at time t (MW _{th})
Z^{CHP}	CHP ratio of Δ Heat to Δ Electricity, i.e. $\Delta Q/\Delta W$ (pu)
$CHPW^{INCCO2}$	CHP incremental CO ₂ cost (£/MWh)
$CHPW^{NLCO2}$	CHP no-load CO ₂ cost (£/h)
$chpw_t^{status}$	Commitment status of CHP at time t (binary)
$CO2^{PRICE}$	CO ₂ price (£/t)

The CO₂ emissions are determined from electricity and heat produced from the thermal generation and CHP plant and must be less or equal to the maximum level, i.e. CO_2^{MAX} .

$$CO_2^{MAX} \geq \sum_{g=1}^G \sum_{t=1}^T (gen_{g,t} GEN_g^{INCCO2} + GEN_g^{NLCO2} gen_g^{status} + (chpw_t + \frac{chpq_t}{Z_{CHP}})CHPW^{INCCO2} + CHPW^{NLCO2} chpw^{status}) / CO2_{PRICE} \quad (58)$$

5.3.12 Grid

$grid_t$ Grid export at time t (MW)
 $GRID^{MAX}$ Maximum export of power to grid (MW)

Grid exports must be greater than or equal to 0 and less than or equal to the maximum grid capacity.

$$0 \leq grid_t \leq GRID^{MAX} \quad \forall t \quad (59)$$

5.3.13 Residential heaters (Modes 1 and 2)

RH_h^{CAPMIN} Residential heater minimum installed capacity of heater h (MW_{th})
 RH_h^{CAP} Residential heater h installed capacity (MW_{th})
 RH_h^{INMAX} Maximum residential heater input of heater h (MW_{th})
 GB^{CAPMIN} Peaking gas boiler minimum installed capacity (MW_{th})
 gb^{cap} Peaking gas boiler installed capacity (MW_{th})
 GB^{MAX} Maximum peaking gas boiler output (MW_{th})
 EH^{CAPMIN} Peaking electric heater minimum installed capacity (MW_{th})
 eh^{cap} Peaking electric heater installed capacity (MW_{th})
 EH^{MAX} Maximum peaking electric heater output (MW_{th})
 rh_t^{out} Residential heater h power output at time t (MW_{th})
 Q_t^h Residential heater h building heat demand at time (MW_{th})
 eh_t Peaking electric heater thermal output at time t (MW_{th})
 Q_t^{EH} Peaking electric heat demand for buildings with ASHP at time t (MW_{th})
 gb_t Peaking gas boiler thermal output at time t (MW_{th})
 Q_t^{GB} Peaking gas heat demand for buildings with hybrid heat pump at time t (MW_{th})
 gb^{cap} Peaking gas boiler installed capacity (MW_{th})

eh^{cap} Peaking electric heater installed capacity (MW_{th})

The residential heater installed capacity of heater h must be greater than or equal to the minimum level and less than or equal to the maximum charge constraint.

$$RH_h^{CAPMIN} \leq RH_h^{CAP} \leq RH_h^{INMAX} \quad \forall h \quad (60)$$

The peaking gas boiler installed capacity of the hybrid pump must be greater than or equal to the minimum level and less than or equal to the maximum input constraint.

$$GB^{CAPMIN} \leq gb^{cap} \leq GB^{MAX} \quad (61)$$

The peaking electric heater installed capacity must be greater than or equal to the minimum limit and less than or equal to the maximum input constraint.

$$EH^{CAPMIN} \leq eh^{cap} \leq EH^{MAX} \quad (62)$$

The heat demand for buildings with heating technology h at any time t must equal the heat demand for that technology.

$$rh_{h,t}^{out} = Q_t^h \quad \forall h, \forall t \quad (63)$$

The peaking heat demand for buildings with ASHP heaters at any time t must be met by electric heaters.

$$eh_t = Q_t^{EH} \quad \forall t \quad (64)$$

The peaking heat demand for buildings with hybrid heat pumps at any time t must be met by peaking gas boilers.

$$gb_t = Q_t^{GB} \quad \forall t \quad (65)$$

The peaking gas boiler heat production at any time t must be greater than or equal to 0 and less than or equal to the maximum capacity of the peaking gas boiler.

$$0 \leq gb_t \leq gb^{cap} \quad \forall t \quad (66)$$

The peaking electric heater heat production at any time t must be greater than or equal to 0 and less than or equal to the maximum capacity of the peaking electric heater.

$$0 \leq eh_t \leq eh^{cap} \quad \forall t \quad (67)$$

5.3.14 Residential heaters (Mode 3)

rh_{ht}^{in}	Residential heater h power input at time t (MW or MW_{th})
RH_h^{INMAX}	Maximum residential heater input of heater h (MW_{th})
rh_{ht}^{out}	Residential heater h power output at time t (MW_{th})
RH_h^{OUTMAX}	Maximum residential heater output of heater h (MW_{th})
rh_{ht}^{sto}	Thermal energy in residential heat store h at time t (MWh_{th})
$RHSTO_H^{MAXQ}$	Maximum residential heater store charge of heater h (MWh_{th})
q_t^h	Residential heater h thermal building demand at time t (MW_{th})
rh_h^{cap}	Residential heater h installed capacity (MW_{th})
Q_t^θ	Total thermal building demand for temperature scenario θ at time t (MW_{th})
Q^{MAX}	Maximum thermal demand (MW_{th})

The residential heater charge rate of heater h at any time t must be greater than or equal to 0 and less than or equal to the maximum charging rate.

$$0 \leq rh_{h,t}^{in} \leq RH_h^{INMAX} \quad \forall h, \forall t \quad (68)$$

The residential heater discharge rate of heater h at any time t must be greater than or equal to 0 and less than or equal to the maximum discharging rate.

$$0 \leq rh_{h,t}^{out} \leq RH_h^{OUTMAX} \quad \forall h, \forall t \quad (69)$$

The thermal energy in the residential heater h at any time t must be greater than or equal to 0 and less than or equal to the maximum capacity of the residential heater store.

$$0 \leq rh_{h,t}^{sto} \leq RHSTO_h^{MAXQ} \quad \forall h, \forall t \quad (70)$$

The thermal energy in the residential heater h at any time t must be equal to 0 in the first half hour of each day, i.e. t' .

$$rh_{h,t'}^{sto} = 0 \quad \forall h, \forall t' \quad (71)$$

The heat demand for buildings with residential heater h is proportioned from the capacity of the heating technology total heat demand Q_t .

$$q_t^h = \frac{rh_h^{cap} Q_t^\theta}{Q_{MAX}} = rh_{h,t}^{out} \quad \forall h, \forall t \quad (72)$$

5.3.15 Parameters

The following parameters are calculated in the Excel interface based on the FICO output:

- Heat demand
- ASHP and hybrid heat pump coefficient of performance
- Heat network losses
- Electricity network losses
- Electricity demand weighted average prices
- Heat demand weighted average prices

5.3.16 Heat demand

The total building heat determined from the Half Hourly Heat Demand model is described in Chapter 3.

5.3.17 ASHP and hybrid heat pump coefficient of performance

D	Set of days in a year, d
T	Set of half hours in a year, t
$TEMP$	Set of daily temperature scenarios, θ
RH_h^{INMAX}	Maximum residential heater input of heater h (MW_{th})
$rh_{h,t}^{out}$	Residential heater h power output at time t (MW_{th})
RH_h^{OUTMAX}	Maximum residential heater output of heater h (MW_{th})
$rh_{h,t}^{sto}$	Thermal energy in residential heat store h at time t (MWh_{th})
$RHSTO_H^{MAXQ}$	Maximum residential heater store charge of heater h (MWh_{th})

q_t^h	Residential heater h thermal building demand at time t (MW_{th})
rh_h^{cap}	Residential heater h installed capacity (MW_{th})
Q_t^θ	Total building heat demand for temperature scenario θ at time t (MW_{th})
Q^{MAX}	Maximum thermal demand (MW_{th})

The ASHP and hybrid heat pump efficiency or CoP is a function of the daily temperature scenario θ .

$$ASHP_t^\theta = \sum_{d \in D} \sum_{\theta \in TEMP} \sum_{t=1}^{48} (TEMP_d^\theta \alpha + \beta) \quad \forall d \quad (73)$$

where α and β are the temperature and efficiency regression coefficients for the ASHP and hybrid heat pump. These values are 0.07 and 2.07 respectively and are based on the Mitsubishi Ecodan 8.5kW_{th} ASHP at 55°C water flow temperature [48].

5.3.18 Electricity and heat demand weighted average (DWA) prices

DWA_t^{ELECT}	Demand weighted average electricity price at time t (£/MWh)
$ENERGY_t^{ELECT}$	Energy component of demand weighted electricity price at time t (£/MWh)
$CAPACITY_{PK}^{ELECT}$	Capacity component of demand weighted electricity price at time t (£/MW)
$OP_COSTS_{pt}^{ELECT}$	Electricity operating costs from production p at time t (£)
$PRODUCTION_{pt}^{ELECT}$	Electricity production from producer p at time t (MWh)
$INV_COSTS_p^{ELECT}$	Levelised electricity investment costs from producer p (£pa)
$PROD_{PK}^{ELECT}$	Electricity peak production from producer p (MW)
N_{ELECT}	Number of half hour periods to allocate electricity capacity costs
DWA_t^{HEAT}	Demand weighted average heat price at time t (£/MWh _{th})
$ENERGY_t^{HEAT}$	Energy component of demand weighted heat price at time t (£/MWh _{th})
$CAPACITY_t^{HEAT}$	Capacity component of demand weighted heat price at time t (£/MWh _{th})
$OP_COSTS_{pt}^{HEAT}$	Heat operating costs from production p at time t (£)
$PRODUCTION_{pt}^{HEAT}$	Heat production from producer p at time t (MWh _{th})
$INV_COSTS_p^{HEAT}$	Levelised heat investment costs from producer p (£pa)
$PROD_{PK}^{HEAT}$	Heat production from producer p (MW _{th})
N_{HEAT}	Number of half hour periods to allocate heat capacity costs

When using FICO, the shadow or marginal electricity and heat prices are computed in £/MWh and £/MWh_{th}. Marginal pricing is very helpful when analysing the

output of the investment model and is used to determine the performance of all the assets (see section 5.6). However, pricing assets using marginal pricing will not ensure cost recovery. Hence, a demand weighted price is separately calculated by the Excel interface. The calculation allocates all costs to half hour periods from which the cost of individual heat technologies can be calculated.

The electricity DWA price is:

$$DWA_t^{ELECT} = ENERGY_t^{ELECT} + CAPACITY_{PK}^{ELECT} \quad \forall t \quad (74)$$

where:

$$ENERGY_t^{ELECT} = \sum_p^P \frac{OP_COSTS_{p,t}^{ELECT}}{PRODUCTION_{p,t}^{ELECT}} \quad \forall t \quad (75)$$

and:

$$CAPACITY_{PK}^{ELECT} = \sum_p^P \frac{INV_COSTS_{PK}^{ELECT}}{PROD_{PK}^{ELECT} N_{ELECT}} \quad (76)$$

The heat DWA price is:

$$DWA_t^{HEAT} = ENERGY_t^{HEAT} + CAPACITY_{PK_N}^{HEAT} \quad \forall t \quad (77)$$

where:

$$ENERGY_t^{HEAT} = \sum_p^P \frac{OP_COSTS_{p,t}^{HEAT}}{PRODUCTION_{p,t}^{HEAT}} \quad \forall t \quad (78)$$

and:

$$CAPACITY_{PK_N}^{HEAT} = \sum_p^P \frac{INV_COSTS_{PK_N}^{HEAT}}{PROD_{PK_N}^{HEAT} N_{HEAT}} \quad (79)$$

The DWA price at time t comprises an energy and a capacity component. The energy component is set to recover the sum of all the running costs (fuel, operation and maintenance, CO₂, etc.) at time t.

The capacity component is set to recover the sum of all the investments costs. However, as investment costs are not specific to individual periods t , a methodology for allocating costs was considered. One method is to allocate the costs equally to each half hour. However, this would not reflect the difference in capacity value in each half hour. Another method is to allocate it all to the individual half hour of maximum production. The problem with this approach when attributing a capacity cost to various technologies is that it can result in large variations, particularly where there is a storage component to that technology. A variation on this is to take several of the highest peaks and to allocate the investment costs equally. From trial and error analysis it has been found that 7 peaks yield a relatively stable result in most cases.

5.4 Performance features and modelling of heat technologies

The following section explores in more detail the performance features of heat technologies referred to in Chapter 4 and their representation in the integrated heat and electricity investment model. All heat technologies modelled include a storage facility. For heat pumps, heat storage is required for efficient operation and typically this is circa 200 litres [51]. A larger heat store would permit pre-heating and thereby offer demand side management and this is explored in Chapter 6. For electric storage heaters this is an inherent feature of their design and although district heating has network connected storage, local or building storage has been included to identify whether or not there are any benefits.

A brief overview of all these heat technologies is given in [36].

5.4.1 Air source heat pumps (ASHP)

Despite relatively little experience in the UK the ASHP is regarded as a mature technology. The performance of an ASHP is commonly measured by the Seasonal Performance Factor (SPF) which is the annual efficiency taking full account of heat output and electricity input, thereby including any auxiliary loads, although there a number of definitions of SPF [35].

The efficiency of an ASHP is directly affected by the air temperature and the water flow temperature¹⁰ of the building's heating system. As the external air temperature falls more energy will be required to maintain water flow temperature and so this will result in a reduction in the CoP. This is shown by the red line in Figure 51 which illustrates this effect based on the Mitsubishi Ecodan 8.5kW_{th} air source heat pump [51].

The thermal rating of the heat pump will be specified at an ambient air temperature (typically 7°C) and hot water flow temperature. As the air temperature falls below the specified ambient air temperature the heat output of heat pump will also fall. This is shown by the blue line in Figure 51.

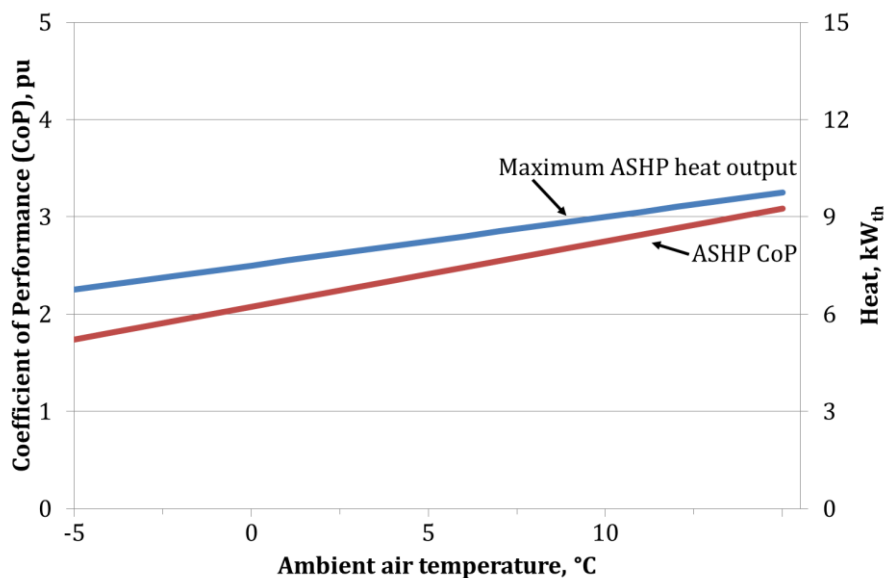
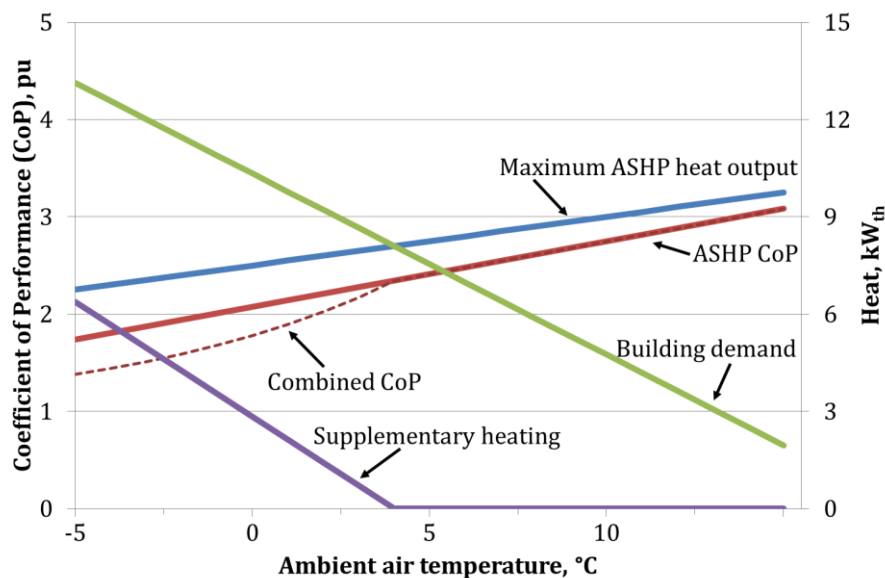


Figure 51: Coefficient of performance and heat output against temperature for 8.5kW_{th} ASHP.

¹⁰ On the assumption that the bulk of the installations will replace gas boilers, it is likely that the installed heat emitters or radiators will be used. As these have been designed to be used with hot water flow temperatures of 70°C to 80°C then it is likely that ASHPs will be operated at their highest flow temperature which is circa 55°C.

However, with the fall in air temperature the heat demand of the building will also increase as illustrated by the green line in Figure 52. Where this exceeds the maximum heat output of the ASHP, supplementary heating (mauve line) will be required to meet the building's heat demand.

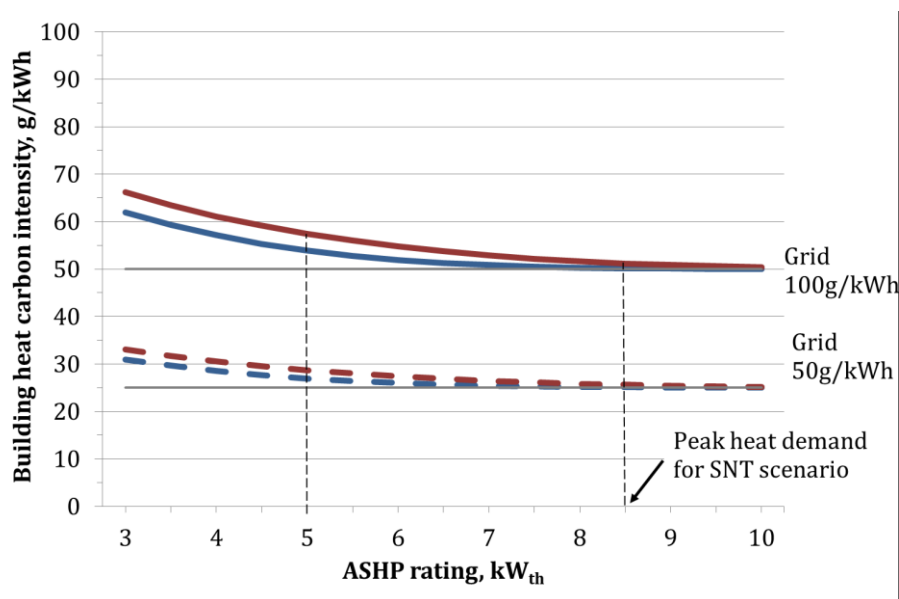
The electric rating of the Mitsubishi Ecodan 8.5kW_{th} ASHP is 2.7kW . On the assumption that supplementary heating is provided by direct electric heating, e.g. convector or fan, then it can be seen from the example shown that this would add another 6kW to the electricity demand for an air temperature of -5°C . This is because its efficiency is closer to 100% or a CoP of 1.0 pu. Hence supplementary heating substantially increases the electricity demand. This feature is included in the investment model.



The building heat demand (green) increases with falls in air temperature. When it exceeds the heat output of the ASHP, supplementary heating is required to meet the building's heat demand. It is assumed here that it is provided by direct electric heating, e.g. convector, fan. As a result it will increase the electric heat demanded by the building and cause the combined CoP (red dashes) to reduce.

Figure 52: Supplementary heating for a building with 8.5kW_{th} ASHP and the impact on combined CoP.

Section 5.3.17 describes the calculation of the ASHP CoP based on the temperature scenario to be used. This calculation is performed within the Excel interface. In the model the rating of the heat pump has been selected so that no supplementary heating is required for the “SNT” scenario. As both the “Normal” and “Cold” temperature scenarios have occurrences of daily temperatures below that of the “SNT” scenario (Figure 14), then on those days supplementary heating is required.

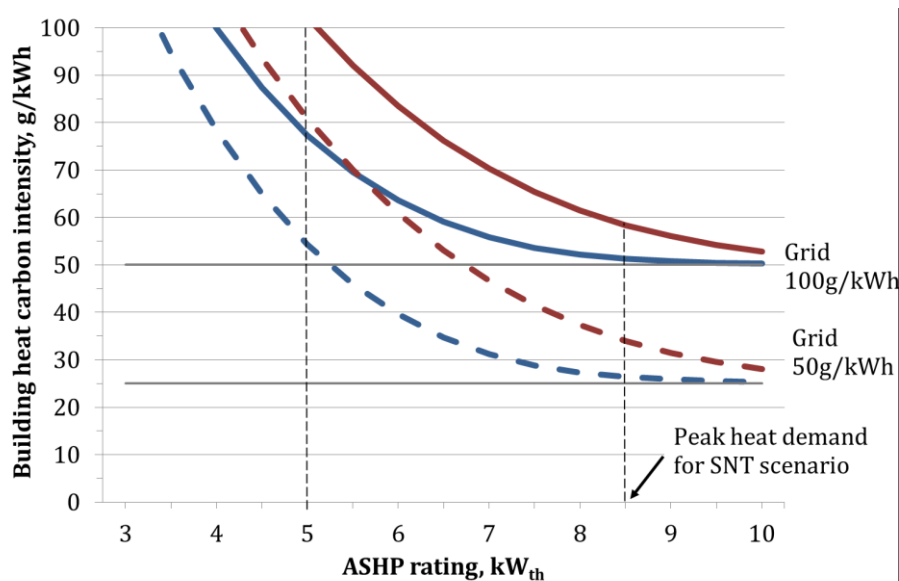


In this example the building peak heat demand is 8.5kW_{th} (for the “SNT” scenario) and the impact on building heat carbon intensity from electric supplementary heating is shown for an annual average grid carbon intensity of 100g/kWh and 50g/kWh . The red and blue lines are for the “Cold” and “Normal” temperature scenarios respectively.

Figure 53: Impact of ASHP rating on building heat carbon intensity from supplementary electric heating.

The impact of electric supplementary heating will be to increase the building heat carbon intensity. In the example shown in Figure 53, the building peak heat demand peak is 8.5kW_{th} (for the “SNT” scenario) and the impact on building heat carbon intensity from electric supplementary heating is shown for an annual average grid carbon intensity of 100g/kWh and 50g/kWh respectively. It can be seen that under both the “Normal” (blue line) and “Cold” (red line) temperature

scenarios the impact on building heat carbon intensity from supplementary heating is small when the ASHP is rated at 8.5kW_{th} . If the ASHP is replaced with one with a lower rated output the impact of supplementary heating becomes more significant. This is because there are more occasions when the output of the heat pump is unable to meet building heat demand and hence supplementary heating is required. For example, at a 5kW_{th} rating the increase in the building's heat carbon intensity is circa 10%.



In this example the building peak heat demand is 8.5kW_{th} (for the “SNT” scenario) and the impact on building heat carbon intensity from electric supplementary heating is shown for a peaking plant carbon intensity of 400g/kWh . The red and blue lines are for the “Cold” and “Normal” temperature scenarios respectively.

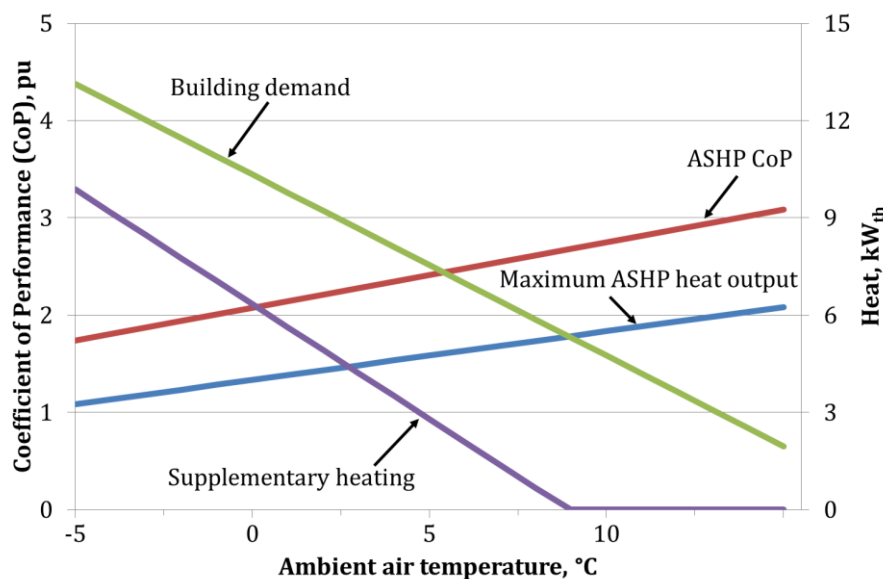
Figure 54: Impact of ASHP rating on building's heat carbon intensity assuming peaking plant with a carbon intensity of 400g/kWh is scheduled to meet supplementary electric heating demand.

However, this assumes that the supplementary electric heating has the same average grid carbon intensity as the heat pump. This is unlikely to be the case as it is more likely that the grid carbon intensity of the supplementary electric heating will be much higher, e.g. if peaking gas turbines are scheduled. This is illustrated in Figure 54 assuming a peaking plant carbon intensity of 400g/kWh . It can be seen

that the impact is much greater, e.g. at 5kW_{th} the building heat carbon intensity is doubled.

5.4.2 Hybrid heat pump (ASHP and gas)

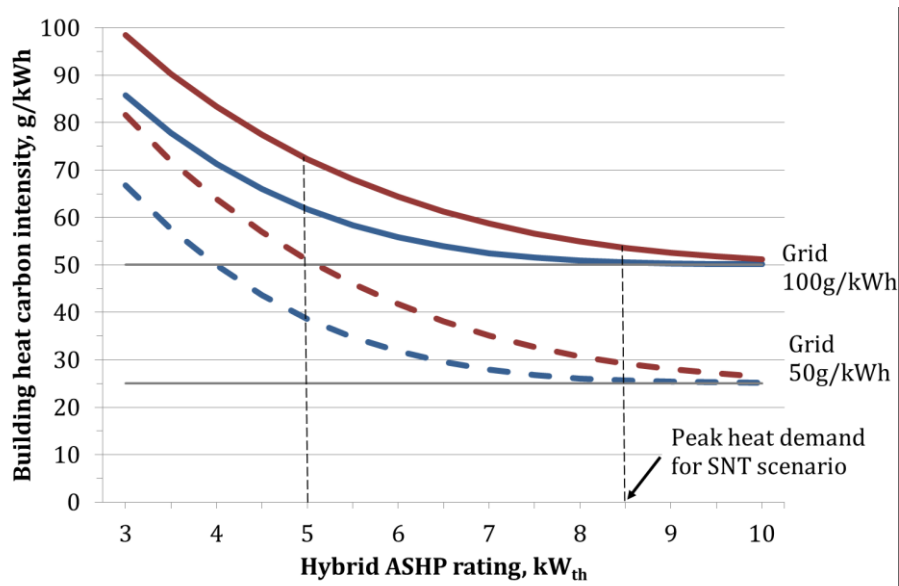
This is a relatively new product/technology although it does combine two mature existing technologies, i.e. the ASHP and the condensing gas boiler. A typical installed cost is approximately the same as an ASHP but the maximum heat output is lower, e.g. 5kW_{th} , with a gas output of approximately 10kW_{th} [38]. This is shown in Figure 55 and when compared to the ASHP in section 5.4.1 it can be seen that more supplementary heating is required due to the lower heat output of the hybrid heat pump. As the supplementary heating is provided by the condensing gas boiler there will be CO_2 emissions which will need to be evaluated.



As the hybrid heat pump has a lower thermal output than the ASHP referred to in section 5.4.1, more supplementary heating is required to meet the building's heat demand. As this is provided by the gas boiler there will be further CO_2 emissions.

Figure 55: Supplementary heating for a building with 5kW_{th} hybrid heat pump and condensing gas boiler.

On the assumption that the hybrid heat pump has a 5kW_{th} rating then it can be seen from Figure 56 that the impact of gas supplementary heating will be to increase the building's heat carbon intensity substantially, e.g. for an average grid carbon intensity of 100g/kWh and 50g/kWh the increase for the "Normal" temperature scenario is nearly 20% and 60% respectively. (This assumes a condensing gas boiler carbon intensity of 215g/kWh [38]).



In this example the building peak heat demand is 8.5kW_{th} ("SNT" scenario) and the impact on building heat carbon intensity from gas supplementary heating is shown for an annual average grid carbon intensity of 100g/kWh and 50g/kWh . The red and blue lines are for the "Cold" and "Normal" temperature scenarios respectively.

Figure 56: Impact of hybrid heat pump rating on a building's heat carbon intensity from supplementary gas heating.

In terms of tonnes of CO_2 emissions the impact is small. For example, under the "Normal" temperature scenario the proportion of heat provided by gas is less than 10%. So for a building heat demand, Q_{Building} , of $8.5\text{MWh}_{\text{th}}$ (based on the DECC 2050 Pathway 3 [16], refer to section 4.1), and assuming carbon emissions from a gas boiler, C_{GB} of 215g/kWh (refer to appendix 2) then the annual carbon emissions, $C_{\text{GB}}^{\text{Total}}$ are:

$$C_{GB}^{Total} = Q_{Building} C_{GB} \quad (80)$$

Substituting the aforementioned values results in a C_{GB}^{Total} of 1.8t pa. So if gas supplementary heating is less than 10% of the total building heat demand then the carbon emissions arising from supplementary gas heating will be less than 180kg pa. This does assume natural gas is used but as the volume of gas used for supplementary heating is quite low then possibly a low carbon alternative such as biogas or hydrogen using standard gas cylinders might be an option worthy of consideration. It also has the added benefit of avoiding gas network charges.

5.4.3 Electric storage heaters

Modern electric storage heaters are very different to those sold in the 1970s and 1980s. They are slimmer, more efficient at holding heat, more controllable and are available with a direct electric heater incorporated to provide top-up heating [76][80]. Although designed for Economy 7 with night-time charging, they can be charged at any other time subject to meeting the demands of the building and this feature is evaluated in the model. Capital costs are much lower than other heating system but the operating costs will be higher due to their lower efficiency. As a consequence they may only be economic for buildings with low heat demands. However, their inherent storage capability does mean that they can improve the utilisation of assets, both production and networks, thereby offering cost savings.

5.4.4 District heating

The key benefit of district heating is that it provides access to multiple sources of low cost heat production. These include CHP units, large heat pumps, wasted heat, solar thermal and geothermal, etc. For example, with a CHP unit, heat production can be less than 20% of the cost of electricity production. This is due to the Z ratio which is a characteristic design feature of a steam thermal generating unit and is a measure of the change in heat produced to electricity lost [81]. Lowe [82] describes it as a virtual heat pump and demonstrates that the performance of the CHP unit will be significantly higher than real heat pumps operating at similar temperatures.

For example a CHP plant with a Z ratio, Z_{CCGT} , of 6 will have a fuel to heat conversion ratio that is double that of a residential ASHP with a CoP, $ASHP_{CoP}$, of 2.7. This is illustrated as follows and is based on a CHP CCGT plant with electrical efficiency, η^{CCGT} , of 0.5pu, electricity network efficiency, η^{ENW} , of 0.93pu and heat network efficiency, η^{HNW} , of 0.85pu. For a heat load supplied by the CHP, the fuel to delivered heat conversion efficiency, η_{HEAT}^{CHP} , is:

$$\eta_{HEAT}^{CHP} = \eta^{CCGT} Z_{CCGT} \eta_{HNW} \quad (81)$$

Substituting the aforementioned values results in a fuel to heat conversion efficiency, η_{HEAT}^{CHP} of 2.55pu.

For the ASHP, the fuel to delivered heat conversion efficiency, η_{HEAT}^{ASHP} , is:

$$\eta_{HEAT}^{ASHP} = \eta^{CCGT} ASHP_{CoP} \eta_{ENW} \quad (82)$$

Substituting the aforementioned values results in a fuel to heat conversion efficiency η_{HEAT}^{ASHP} of 1.26 which is less than half of that for the CHP.

The other key parameter is the heat to power ratio, i.e. λ [81]. This is the maximum heat that can be extracted from a steam thermal unit and is a function of the power output. From both the Z ratio and λ , the relationship between a CHP plant's heat and electricity production can be derived and this is commonly known as the "Iron Diagram". An example is shown for an Alstom combined cycle plant with CHP and is shown in [83] and reproduced in Figure 57. The equations from section 5.3.4 are included to show the boundaries of electricity ($chpw_t$) and heat ($chpq_t$) production.

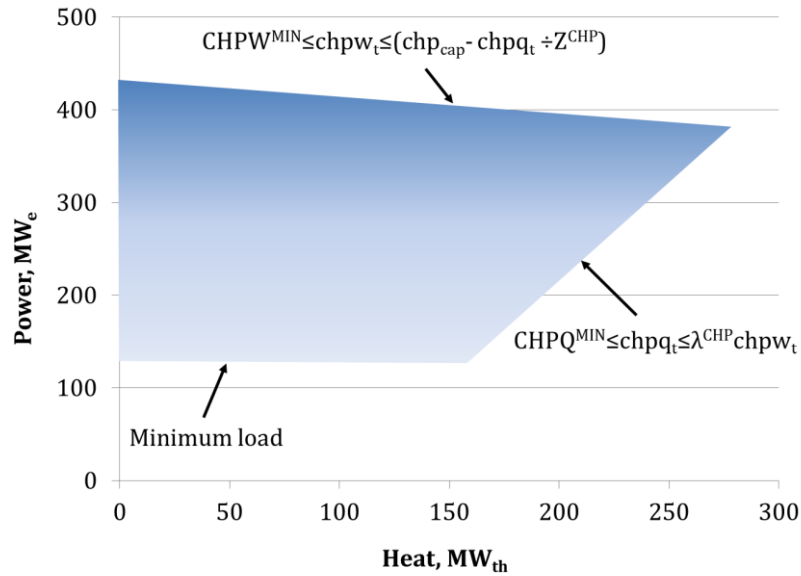


Figure 57: “Iron diagram” for Alstom KA26 Combined heat and power production with a combined-cycle power plant [84].

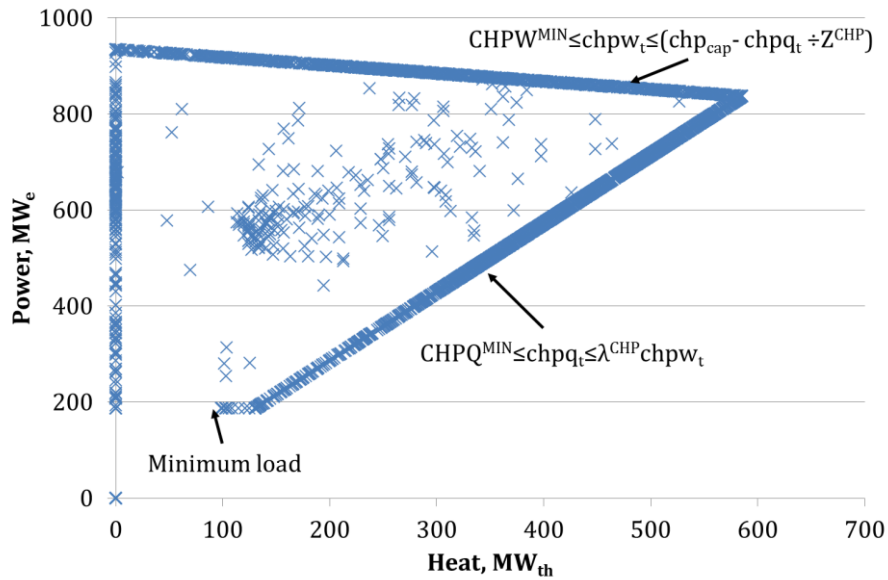
5.5 Model validation

During the model’s construction, each component was separately tested for both normal operation and stress conditions to validate performance, e.g. constraints were not violated. This was supplemented by a comprehensive diagnostic capability incorporated within the Excel spreadsheet interface with the FICO Express tool to enable the performance of each model component to be monitored and individually validated.

An example of the diagnostic capability is shown in Figure 58. This is a half hourly scatter plot for the CHP plant’s heat and power production from the results of Study 1.5 (see section 6.1.5) and validates that the plant operated within its constraints.

Finally, using the diagnostic data and the demand weighted average heat and electricity prices determined from equations (74) to (79) in section 5.3.18, the Excel spreadsheet determines the total cost of each of the heating technologies and also the non-heat electricity demand. The sum of these costs is the total study cost

and this should be the same as that calculated directly by the FICO Express tool from the objective function. If there are any differences then they are highlighted to enable the cause to be investigated.



This example shown is a half hourly scatter plot for the CHP plant's heat and power production from the results of Study 1.5 (see section 6.1.5) and validates that the plant operated within its constraints.

Figure 58: Example of diagnostic data for CHP plant.

5.6 Model results

An example of the investment model's results is shown in Figure 59. This summarises Study 1.3 (see section 6.1.3) and is split into a "Production" and a "Consumption" account with each categorised into the respective assets with operational and financial performance information.

[illegible]

Figure 59: Example of integrated heat and electricity investment model result summary.

The results to note are:

- **A** – This summarises the key operational and financial data for the Production account and comprises all the heat and electricity production assets including the network heat pumps and network heat store.
- **B** – This summarises the key operational and financial data for the Consumption account and comprises all heating technology costs and non-heat electricity consumption.
- **C** – This highlights the hybrid heat pump peaking gas boiler operational data. It can be seen that it provided 358MW_{th} of peak capacity and operated at a load factor of 0.09%. (From analysis of the data files the peaking gas boiler operated for 20 hours.)
- **D** – This is the total study cost demand (£2,500M) and which supports the cost determined from the FICO Express tool.
- **E** – These are the total costs (asset and energy) of the heating technologies in £/household pa.
- **F** – These are the total CO₂ emissions of the heating technologies in g/kWh.

The summary also includes the optimisation performance of the production assets shown as “Optimisation profit” (**H**). These are determined by the FICO Express tool from the marginal or shadow electricity and heat prices. Optimisation is reached when the marginal income “earned” by the asset equals the marginal cost of that asset. For example, the CHP (electric) marginal cost is the incremental cost of its fuel and carbon (see section 5.3.1.1). When this is less than the marginal electricity price the asset is profitable and so optimisation can be improved with more assets of this class. The contrary applies if the marginal cost is more than the marginal electricity price. This continues until either a constraint is reached or the optimisation profit is zero. For the CHP (electric) the optimisation profit is -£10M and this is due to the 400MW minimum generation constraint.

For the network heat pump the marginal income is the marginal heat price and the marginal cost is the marginal electricity price. It can be seen that the optimisation profit is £0M indicating no constraint cost and that optimum sizing has been achieved. For the network heat store there is a constraint cost of -£2M and this is due to the heat store’s initial charge constraint, $HSTO^{INITIALQ}$ (see section 5.3.7).

Hence the optimisation profit provides helpful insights to the study by identifying constraint costs thereby allowing options to be investigated that can either reduce or remove such costs.

In Figure 60 an example of graphical output from the investment model is presented. The charging cycles of both the network and electric storage heaters can be seen along with the operation of the network heat pump.

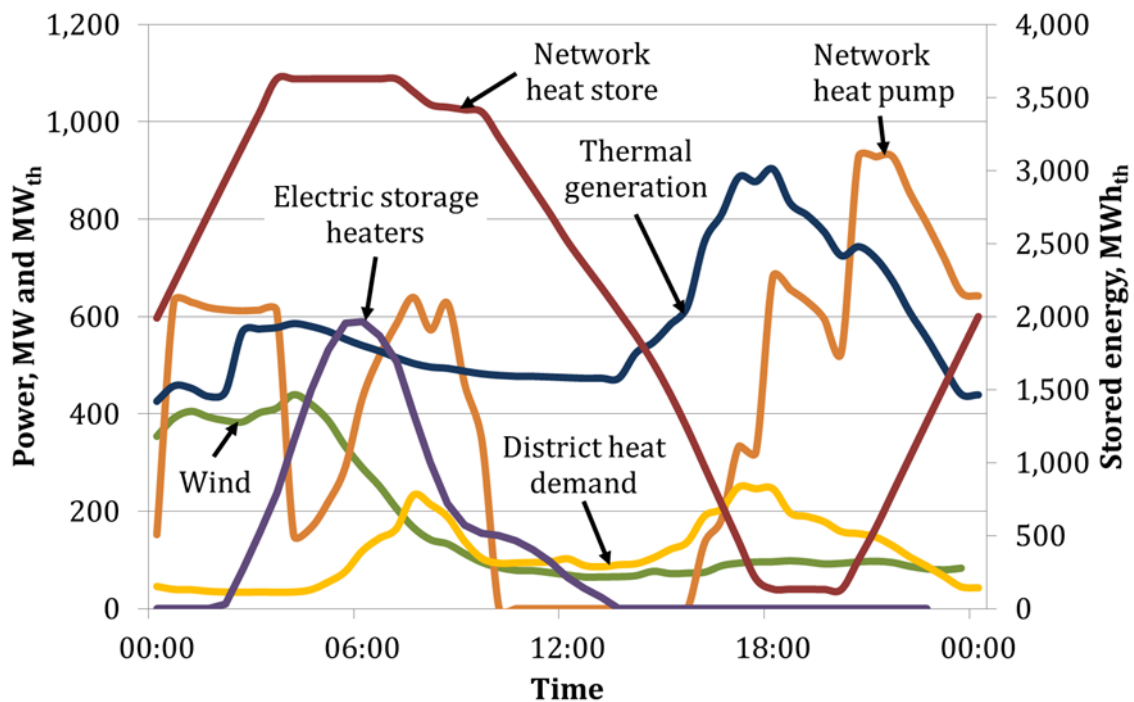


Figure 60: Example of graphical output from the investment model.

5.7 Strengths of the investment model and areas for improvement

The strengths of the investment model are:

- Temperature scenarios. These are used by the heat demand model to construct half hourly heat demand profiles. In the investment model they are used to adjust the maximum heat output and efficiency of the residential heat pumps. They are also used to adjust the electricity and heat network losses to take account of their relationship with temperature.
- Residential heat pumps include supplementary (peaking) heating. This enables the impact of peak heating to be assessed both in terms of cost and carbon intensity.
- Residential heaters include a storage facility. This permits demand side management of heat demand enabling the potential benefits to be analysed. It

is also the basis upon which electric storage heaters are scheduled to meet heat demand.

- Half hourly annual simulation. This enables the volatility of heat demand to be fully incorporated, although it does result in lengthy computer runs for annual simulations. To assist with convergence and feasibility the investment model can be run in different modes without binary variables and a reduced number of decision variables.
- Decision variables can be used for residential heaters. These “schedule” heaters by allocating a share of heat demand (households) and enables the portfolio effects of the heaters to be optimised.
- District heating. These include a CHP representation which incorporates the relationship between heat and electricity production and which can be optimised by the investment model. Also included are network heat pumps and storage.

The areas for further improvement of the modelling are:

- Generator model. This only uses a single incremental cost, it does not include minimum up and down times and ramping rates. Also units are modelled individually therefore the number that can be included efficiently is limited.
- Heat source modelling. This is limited to CHP and network heat pumps. A feature of district heating is that it provides the option to take advantage of multiple sources of heat, e.g. solar, geothermal and wasted heat.
- Heat demand. This is limited to 4 heat demand profiles, i.e. one for each heating technology. As a consequence it only includes a single annual average building heat demand and cannot take account of the portfolio effect of different sized heat demands which might favour one heating technology over another. Therefore separate simulation studies are required to take some account of this.
- Building heat demand profiles. Heat demand profiles do not distinguish between different types of building. These will vary along with the levels of consumption.

- Hot water and space heating combined. As the demand for space heating falls with improvements in building energy efficiency, hot water will represent a larger share of heat demand. For example, under the DECC 2050 Pathway 4, hot water demand could equal that required for space heating.

5.8 Discussion and conclusions

An integrated heat and electricity investment model is proposed that uses half hourly heat data derived from the heat demand model in Chapter 3. It includes heat and electricity assets as well as residential heater technologies. The investment model can be run in 3 modes for computational efficiency and uses Dual Simplex and Dual Simplex with Branch and Bound to solve the model with studies run over the time horizon of 1 year with a half hourly time resolution. The objective function is to minimise costs and this includes all the investment and running costs over the time horizon.

It was shown that the operation of ASHPs can have a significant impact on peak demand and CO₂ emissions. This is predominantly due to the impact of temperature on their CoP and heat output. To incorporate this feature the investment model adjusts CoP with the study's temperature scenario and incorporates supplementary or peaking heat if output from the ASHP is insufficient to meet building heat demand.

In the case of hybrid heat pumps, peaking heat is from a gas boiler. Provided the hybrid heat pump is sized to limit the gas boiler to peaking duty only then the impact of CO₂ emissions is small. A possible low carbon alternative is biogas or hydrogen using standard gas cylinders and these are worthy of further consideration. It also has the added benefit of avoiding gas network charges.

The modelling of CHP plant includes the relationship of heat output to power output, i.e. the Z ratio. This parameter is extremely important to the economics of heat as it determines its marginal production cost. It was shown that this can be less than half that from a residential heat pump.

Examples of investment model output were presented and it was shown that these allow the performance of all the assets to be evaluated, enabling the results to be investigated and validated. Finally the strength and weaknesses of the investment model were discussed.

CHAPTER 6

ANALYSIS & EVALUATION OF HEATING SYSTEMS USING THE INTEGRATED HEAT & ELECTRICITY INVESTMENT MODEL

In Chapter 4 gas and low carbon residential heating systems were evaluated using DECC's energy price scenarios to provide an assessment of their future total costs and associated uncertainties. However, although the analysis can explore the impact of price scenarios and changes in fixed costs such as networks, heating technology costs, etc., it cannot take account of how the energy system will respond to that technology. For example:

- The DECC energy price scenarios are fixed annual average prices and so are unable to take account of the demand profile associated with a heating load. This is because the demand weighted average cost will be a function of the price and demand prevailing in a specific time slice (day for gas and half hour for electricity) and so could vary significantly from the annual average.
- Not only are these costs a function of the prices prevailing at the time of consumption, the prices themselves may also be directly affected thereby impacting costs.
- Storage can delay consumption (subject to constraints) and this can reduce costs. This is of particular importance to technologies with storage capability such as electric storage heaters, but also for district heating where the cost of heat storage is low, particularly relative to electricity [76][77]. Hence there is considerable scope to manage demand using heat storage.
- Large scale deployment of electric heat technologies will have a significant impact on total electricity demand. For example, the load factor of half hourly heat is around 18% and is much lower than electricity which is currently

around 62%, refer to section 3.2.1. As heat is electrified it will cause the electricity load factor to reduce and this will influence the economics of power plants.

- District heating will also have an influence. Even though heat is not directly electrified there is most likely to be significant interconnection with the electricity system from heat production facilities such as CHP and network heat pumps.
- District heating also offers the prospects of providing substantial storage which could be very attractive operationally to a system with large volumes of inflexible plants such as nuclear and intermittent plants such as wind.

There are other factors not explored here such as vehicle electrification, demand side management from Smart metering, decentralised generation and changes to the profile of heat demand from energy efficiency. In addition the impact on the gas grid will be substantial and this will have both operational and investment consequences.

Hence to examine the impact of low carbon heat technologies, simulation modelling is necessary so that these interactions can be accounted for. The integrated heat and electricity investment model proposed in Chapter 5 is used to simulate these interactions. The components of the model are illustrated in Figure 49 and the demand is based on 1 million households using DECC 2050 Pathway 3 heat demand for 2030. Data relating to the investment model is included in appendices 1 and 3 and the model run in the different modes as described in section 5.2.

The first series of studies (studies 1.1 to 1.6) explore the impact of temperature scenarios on heat demand and the effect of normalising demand into characteristic days as described in Chapter 2 and illustrated in Figure 24.

The next series of studies commence with the development of a “Reference” case (Study 2.1) which is subsequently used to explore a series of sensitivity analyses in

studies 2.2 to 2.6, 3, 4 and 5. These address the research questions RQ1, RQ2, RQ3, and RQ4 described in section 1.5 in Chapter 1. For these series of studies the investment model has been run using Mode 3, refer to section 4.1, with the residential heating technology choice unconstrained, i.e. residential heating technology is a decision variable and so the investment model optimises the share of households for each heating technology to minimise total energy costs.

6.1 Studies 1.1 to 1.6 - Impact of modelling and temperature scenarios

Chapter 2 reviewed a number of investigations examining a range of scenarios that explored future heat strategies. It was noted that the outcomes vary significantly and identified a number of features of the models which are poorly represented and which may account for some of the different outcomes. These include heat demand, heat pump performance, storage and power plant scheduling. In the subsequent chapters these are examined and solutions proposed to improve their representation and incorporation into the integrated heat and electricity investment model as described in Chapter 5. Throughout this analysis the total cost of each low carbon heating technology in £/household pa is the key result along with its carbon intensity but gas is referred to as a comparator.

This first series of studies (1.1 to 1.4) explores the impact of heat demand and the investment model has been run in Mode 1, i.e. thermal generators are modelled using a single running cost and with residential heating technologies constrained to 25% of the heating demand (section 5.2). Demand is based on “characteristic days” and uses the same format as Markal, i.e. with each characteristic day split into two diurnal time slices, comprising one 17 hour block “day” and one 7 hour block “night” (section 2.2). This form of modelling is comparable to the cost optimisation linear program pathway based models referred to in Chapter 2. The study was then repeated using the “SNT” and “Normal” temperature scenarios. Figure 24 and Figure 25 illustrate the differences in demand for each. The effect of the “Cold” temperature scenario was then examined.

For the second series of studies (1.5 and 1.6) the investment model has been run in Mode 2, i.e. thermal generators are modelled with start-up costs, no-load costs minimum load constraints and with residential heating technologies constrained to 25% of the heating demand (section 5.2).

6.1.1 Study 1.1 - “Characteristic day” (Mode 1)

Demand is based on “characteristic days” and uses the same format as Markal, i.e. with each characteristic day split into two diurnal time slices, comprising one 17 hour block “day” and one 7 hour block “night” (section 2.2) and illustrated in Figure 24. The resulting generation capacity mix, heating technology costs and carbon emissions are shown in Figure 61. Comparison with the total costs determined in Chapter 4 (Figure 47) show the costs to be approximately 10% higher for heat pumps, 26% higher for storage heaters and with district heating 4% lower.

Carbon emissions for heat pumps and district heating are similar at 58g/kWh and 64g/kWh, whereas storage heaters are higher at 142g/kWh. Gas carbon emissions are much higher at 215g/kWh.

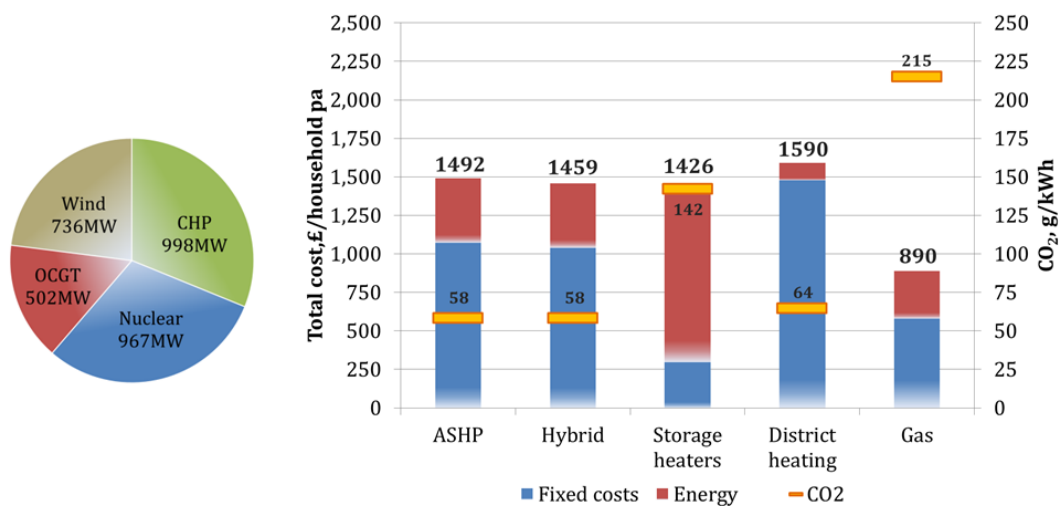


Figure 61: Study 1.1 - “Characteristic day” (Mode 1) - Generation capacity mix, heating technology total costs and carbon emissions.

6.1.2 Study 1.2 - “SNT” temperature scenario (Mode 1)

The generation capacity mix, heating technology costs and carbon emissions are shown in Figure 62. Comparison with Study 1.1, “Characteristic day”, shows the generation mix, heating technology costs and carbon emissions to be very similar. The largest difference in total costs is for storage heaters which have slightly lower costs, i.e. £1383/household pa compared to £1426/household pa for “Characteristic day” studies.

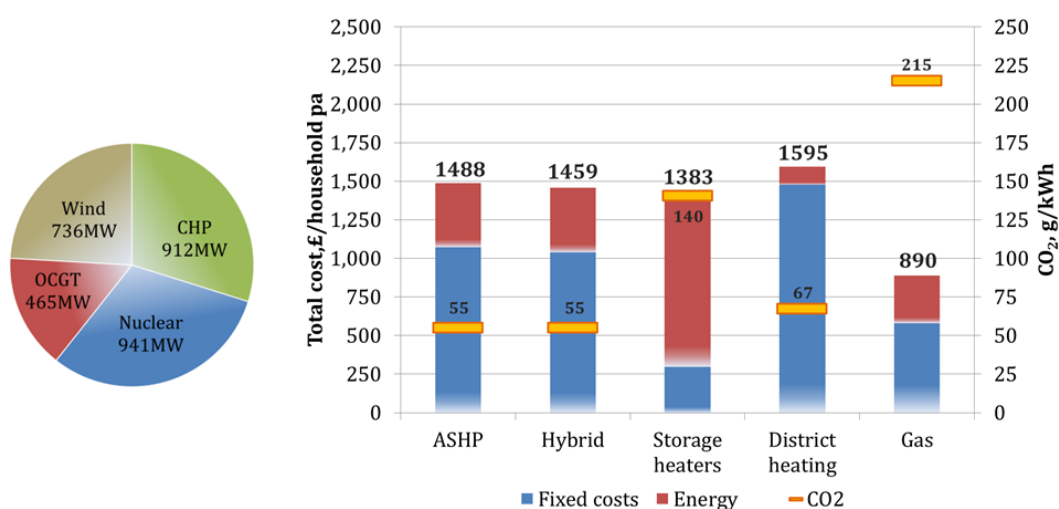


Figure 62: Study 1.2 - “SNT” temperature scenario study (Mode 1) - Generation capacity mix, heating technology total costs and carbon emissions.

6.1.3 Study 1.3 - “Normal” temperature scenario study (Mode 1)

The generation capacity mix, heating technology costs and carbon emissions are shown in Figure 63. Compared to the “Characteristic day” and “SNT” temperature scenarios the main impact on generation capacity mix is lower nuclear and higher OCGT peaking plant to compensate. This is probably a consequence of a higher peak demand and a more volatile demand profile.

Total costs for the heat technologies are similar to the “Characteristic day” and “SNT” studies. The largest difference is with district heating which has slightly

higher costs, i.e. £1679/household pa compared to £1590-1595/household pa “Characteristic day” and “SNT” studies.

Carbon emissions are approximately 20% higher for electric heating due to higher levels of gas OCGT peaking plant operation.

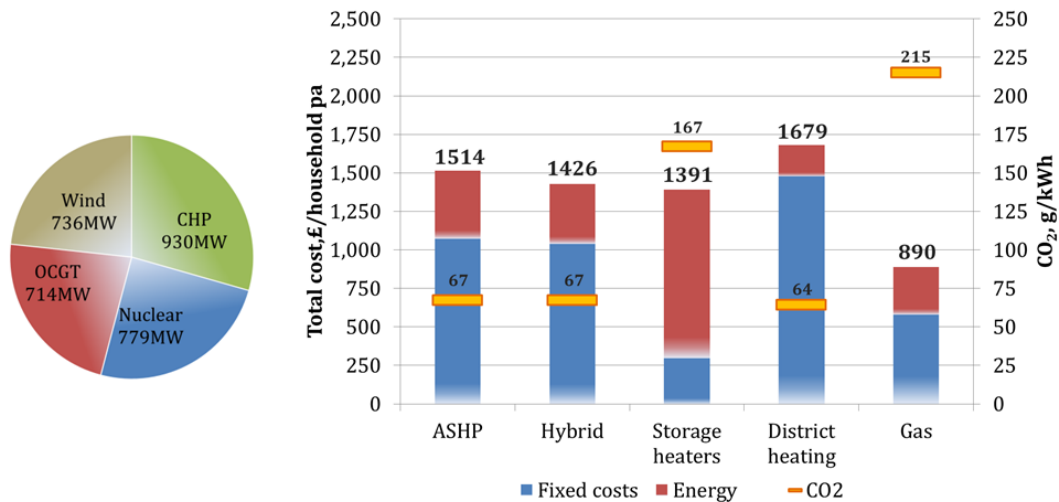


Figure 63: Study 1.3 - “Normal” temperature scenario study (Mode 1) - Generation capacity mix, heating technology total costs and carbon emissions.

6.1.4 Study 1.4 “Cold” temperature scenario study (Mode 1)

The generation capacity mix, heating technology costs and carbon emissions are shown in Figure 64. The main impact on generation capacity mix is more CHP plant (1083MW) compared to the previous studies (from 912MW to 998MW) due to the much higher heat demand during cold weather. Total costs for the heat technologies are higher due to the higher demand from colder weather except for district heating. This is because network heat pump capacity is not required as there is sufficient CHP thermal production combined with more network storage to meet peak demand.

Carbon emissions are mostly higher than the “Normal” temperature scenario due to higher levels of gas OCGT peaking plant operation. Storage heaters are the

exception where there is no change as they are generally charged during off peak periods when gas OCGTs are not operating.

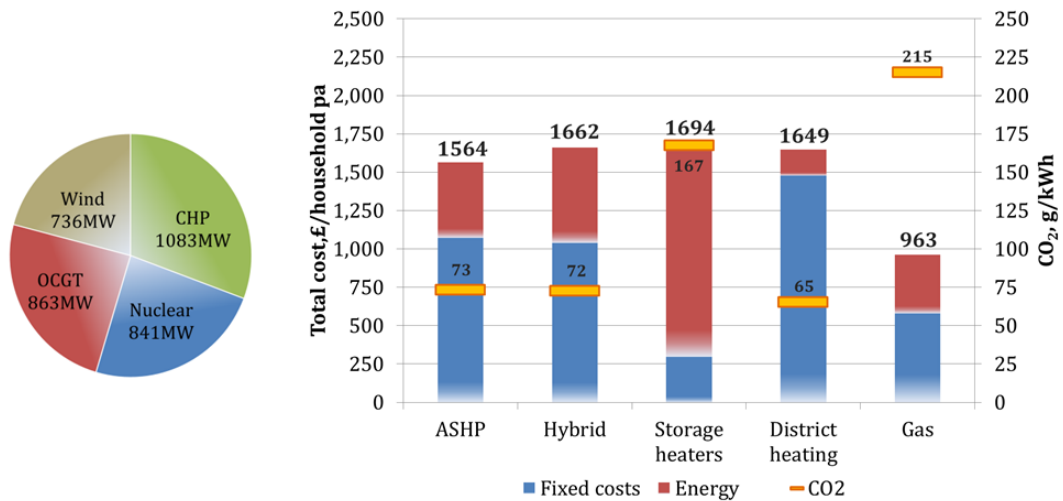


Figure 64: Study 1.4 - "Cold" temperature scenario study (Mode 1) - Generation capacity mix, heating technology total costs and carbon emissions.

6.1.5 Study 1.5 - "Normal" temperature scenario (Mode 2)

The generation capacity mix, heating technology costs and carbon emissions are shown in Figure 65. This study uses Mode 2, the full generator model (section 5.3.9) and as a result start-up and no-load costs are incurred and minimum load constraints have to be met. This significantly impacts nuclear plant and limits it from operating flexibly as it did in Mode 1. For example, in Study 1.3 nuclear plant had 33 starts whereas for this study only 3 starts were incurred. As a consequence more flexible OCGT peaking capacity is required, i.e. 1173MW compared to 714MW.

Relative to Study 1.3, total costs for the heat technologies are 5-7% higher for the heat pump technologies, slightly lower for storage heaters and almost the same for district heating. All the cost increases are due to energy costs and for heat pumps they are between 20-25% higher compared to Study 1.3. Carbon emissions are similar throughout.

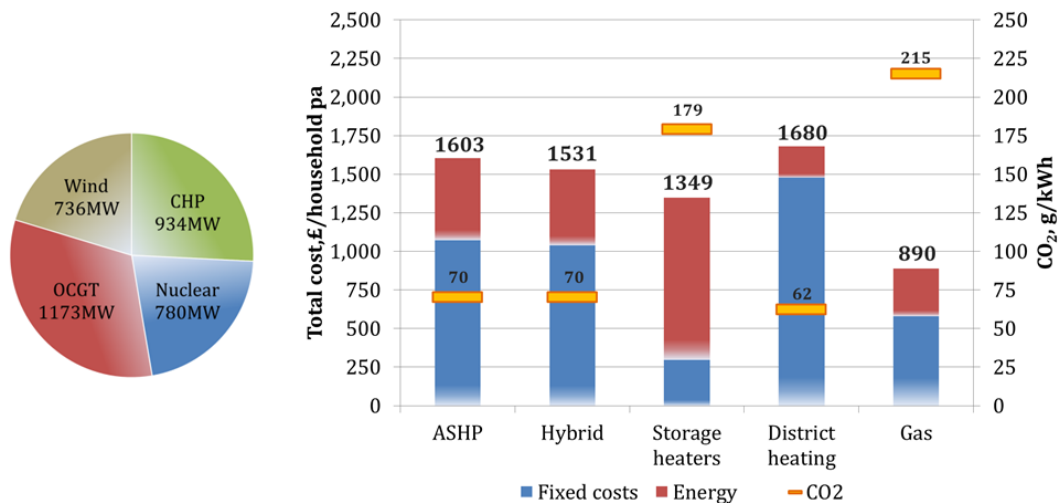


Figure 65: Study 1.5 - "Normal" temperature scenario study (Mode 2) - Generation capacity mix, heating technology total costs and carbon emissions.

6.1.6 Study 1.6 - "Cold" temperature scenario (Mode 2)

The generation capacity mix, heating technology costs and carbon emissions are shown in Figure 66. As for the previous study, Study 1.5, this uses the full generator model (section 5.3.9) and as a result start-up and no-load costs are incurred and minimum load constraints have to be met. This again significantly impacts nuclear plant and limits it from operating flexibly as it did in Mode 1. For example, in Study 1.4 nuclear plant had 135 starts whereas for this study only 15 starts were incurred. As a consequence additional OCGT peaking capacity is required to compensate compared to Study 1.4. As a consequence more flexible OCGT peaking capacity is required, i.e. 1112MW compared to 863MW.

Compared to Study 1.4, total costs for ASHP is 20% higher, all of which is due to energy costs which are nearly 70% higher. For the hybrid heat pump the cost increase is much less and just under 5%. The lower increase is mostly due to higher levels of peaking heat operation from the hybrid heat pump peaking gas boiler.

Carbon emissions are about 10% higher for the heat pump technologies, 20% for storage heaters and about the same for district heating.

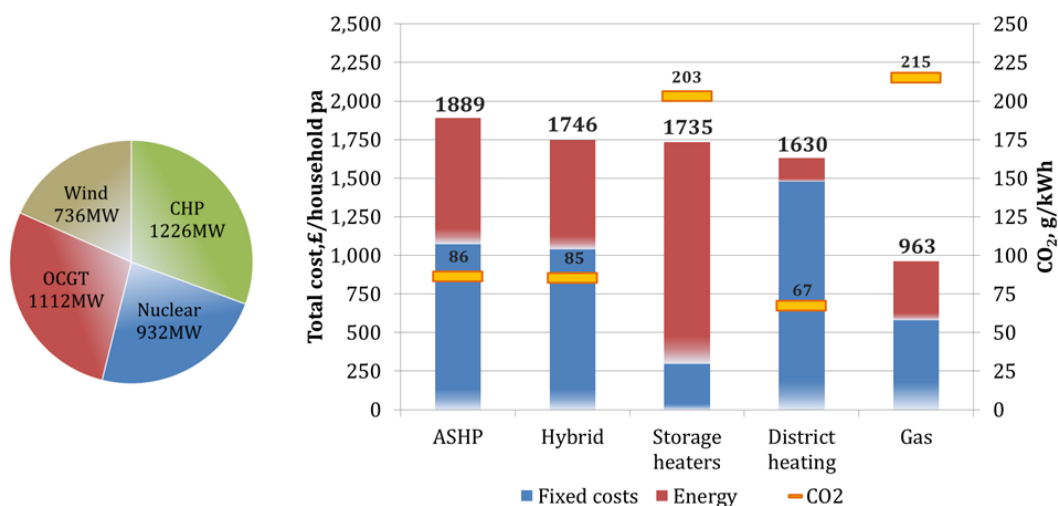


Figure 66: Study 1.6 - "Cold" temperature scenario study (Mode 2) - Generation capacity mix, heating technology total costs and carbon emissions.

6.2 Study 2.1 to 2.6 - Sensitivity studies

The principal objective of these studies is to identify the critical factors that impact on the economics of the heating technologies. This has been done by conducting a series of sensitivity analyses on various parameters. For all the studies, the investment model has been run using Mode 3 (section 5.2) with the residential heating technology choice unconstrained. So in addition to the decision variables that determine the capacity of the upstream assets (thermal generation, CHP plant, network heat pump and network heat store), the capacity or mix of the residential heating technologies are also decision variables. Hence the investment model optimises the share of households for each heating technology to minimise total energy costs.

The heat demand is still based on 1 million households using DECC 2050 Pathway 3 demand but the electricity demand is based on 5million households in order to reflect a more realistic 2030 transition scenario whereby 20% of the heat market

has switched from gas to some other form of heating. In addition, a carbon constraint has been included limiting electricity CO₂ emissions to a maximum of 100g/kWh.

The sensitivity studies are:

- Study 2.1 – “Reference” case
- Study 2.2 – Heat network and residential heat pump capital costs sensitivities with CHP
- Study 2.3 – Gas and carbon costs
- Study 2.4 – Heat demand (“Reference” capital costs)
- Study 2.5 - Heat demand (“Low” capital costs)
- Study 2.6 – Heat network and residential heat pump capital costs (no CHP)

6.2.1 Study 2.1 – “Reference” case

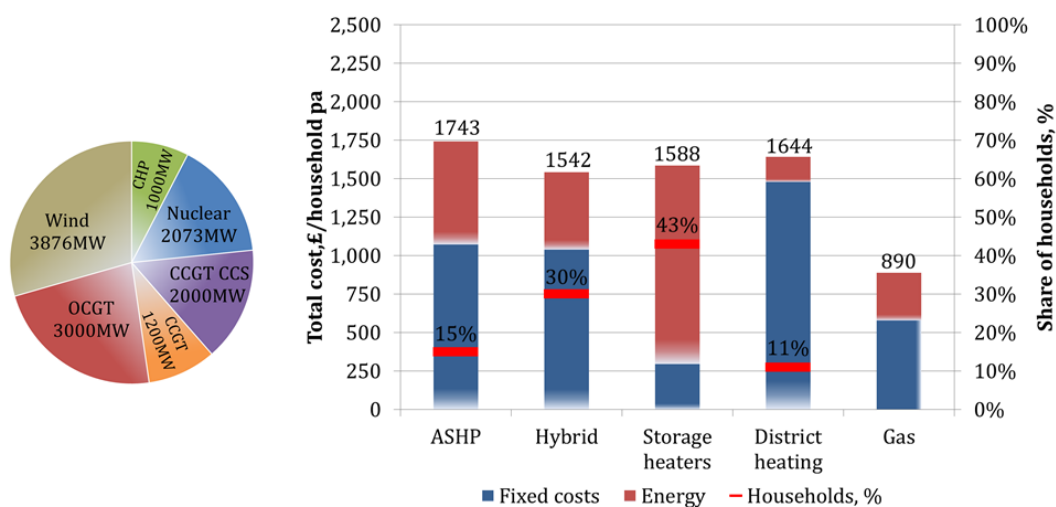


Figure 67: Study 2.1 - “Reference” case. “SNT” temperature scenario - Generation capacity mix, heating technology total costs and share of households.

Figure 67 shows the “Reference” case. In order to keep the electricity CO₂ emissions to the 100g/kWh limit, approximately 80% of the electricity generated comes from low carbon sources. It can be seen that storage heaters have the

largest share of the households at 43%, followed by hybrid heat pumps. Gas has the lowest cost and significant increases in gas prices or reductions in the cost of the low carbon heat technologies are required for them to be competitive with gas.

6.2.2 Study 2.2 – Heat network and residential heat pump cost sensitivities with CHP

Figure 68 shows the change in heating technology share of households as heat network and residential heat pump capital costs are reduced from their “Reference” costs to their “Low” cost sensitivities (sections 4.3.3, 4.4.1 and Table 8). The solid lines are the share of households for each heating technology; the coloured diamond identifies which is the lowest cost heating technology and its cost, the red dashed line with the solid red squares is the gas cost, and the double green line is the average carbon emission from the portfolio of low carbon technologies as a percentage of gas equivalent.

	Cost reduction sensitivities				
	“Reference”	25%	50%	75%	“Low”
ASHP and hybrid heat pump capital cost, £/household	7500	6875	6250	5625	5000
Heat network, £/household pa	1478	1270	1062	854	646

Table 8: Study 2.2 – Sensitivity on heat pump and heat network capital costs (2013 prices).

Storage heaters have the largest share of households at the “Reference” costs and then as cost reductions reach 50%, district heating has the largest share. Breakeven with gas for district heating total costs occurs when cost reductions reach the “Low” cost sensitivity. However, further capital cost reductions are required for ASHP and hybrid heat pumps to achieve breakeven with gas.

The average carbon emissions from the low carbon heat technologies are less than 36% of gas equivalent (77g/kWh) and decline to below 26% (56g/kWh) as district heating (47g/kWh) increases its share of households from storage heaters (85g/kWh).

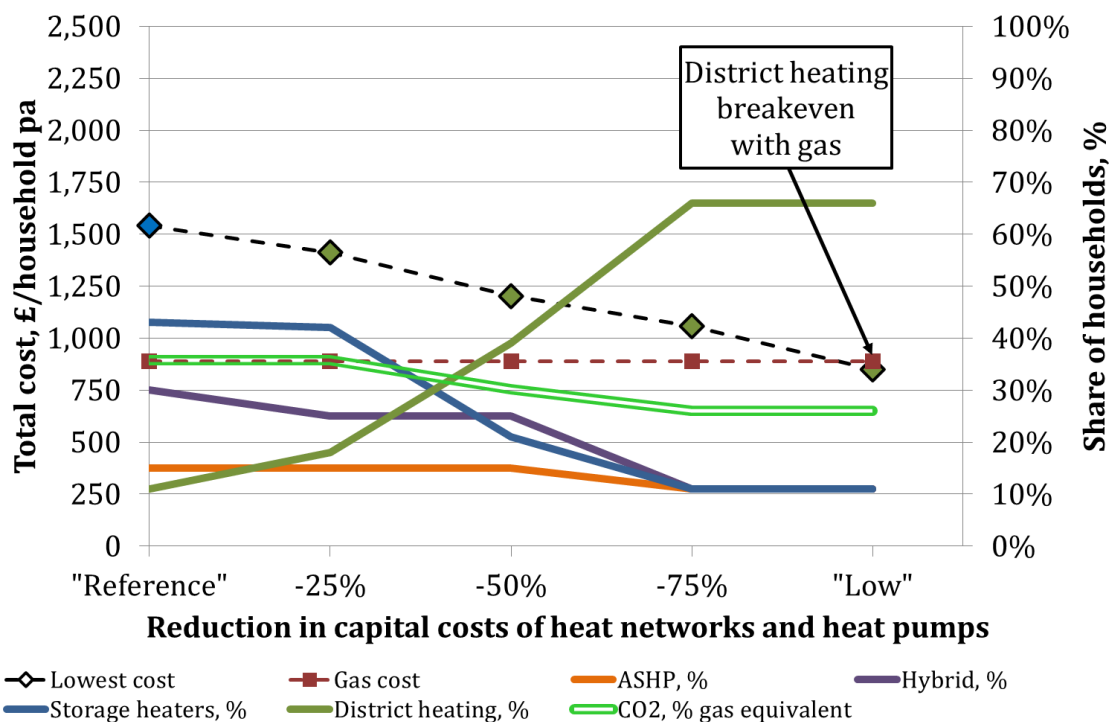


Figure 68: Study 2.2¹¹ - Sensitivity on heat pump and heat network capital costs (2013 prices).

6.2.3 Study 2.3 – Gas and carbon cost sensitivities

Figure 69 shows the change in heating technology share of households for gas and carbon price scenarios (sections 4.2.2, 4.2.3 and Table 9). From the “Very Low” to the “Reference” price scenario, storage heaters have the largest share of households. Above the “Reference” price scenario, district heating gains share of

¹¹ The solid lines are the share of households for each heat technology; the coloured diamond identifies which is the lowest cost heating technology and its cost, the red dashed line with the solid red squares is the gas cost, and the double green line is the average carbon emission from the portfolio of low carbon technologies as a percentage of gas equivalent.

households from storage heaters to achieve the largest share at the “High” price scenario. This is because district heating is much less sensitive to energy costs compared to the other low carbon heat technologies. For example at the “Reference” price scenario the energy cost is £166/household pa and is less than a third of the other heaters’ energy costs and half that of gas. However, breakeven with gas total costs is not achieved at the “High” price scenario and requires even higher gas and carbon prices or higher household demand for this to occur.

The average carbon emissions from the low carbon heat technologies are 36% gas equivalent (77g/kWh) and decline to 26% (56g/kWh) as district heating (45g/kWh) increases its share of households from storage heaters (88g/kWh).

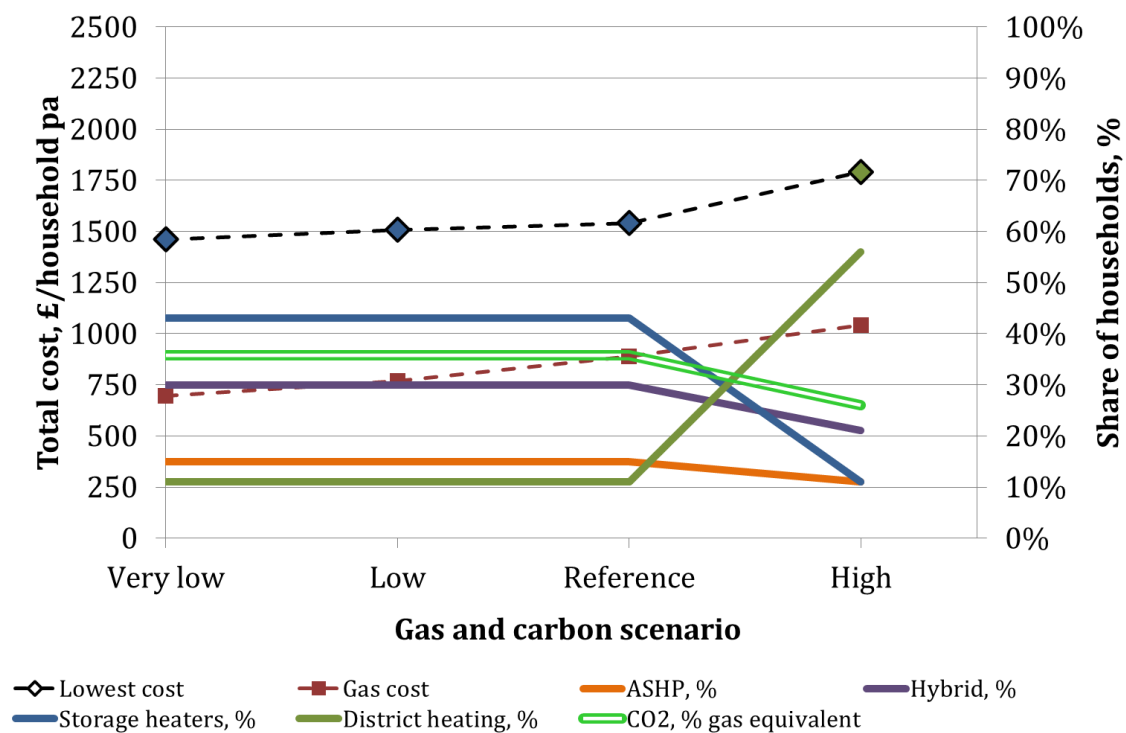


Figure 69: Study 2.3 - Sensitivity on gas and carbon prices (2013 prices).

	Gas and carbon price scenarios			
	"Very low"	"Low"	"Central"	"High"
Gas, p/therm	20.00	42.00	73.80	105.40
Carbon cost, £/t CO ₂	114.35	114.35	76.23	38.12

Table 9: Study 2.3 - Sensitivity on gas and carbon cost (2013 prices).

6.2.4 Study 2.4 – Heat demand sensitivities

Figure 70 shows the change in heating technology share of households for variations in household heat demand from the Pathway 3 2030 heat demand. These range from 50% to 150%, i.e. 4.3MWh pa to 12.8MWh pa. Storage heaters have the largest share of households from 4.3MWh pa but share declines above 6.4MWh pa, i.e. 75% of the Pathway 3 demand. (The shaded block shows the range of average residential heat demand for Pathway 3 and 4 after 2030.) As demand increases, share of households is lost mostly to hybrid heat pumps but then above 8.5MWh pa, district heating increases its share to parity with storage heaters and just below that of hybrid heat pumps. Breakeven with the total cost of gas is not achieved.

The average carbon emissions from the low carbon heat technologies are 36% of gas equivalent (77g/kWh). As the share of households is lost to lower carbon heat technologies, carbon emissions fall to 29% of gas equivalent (62g/kWh).

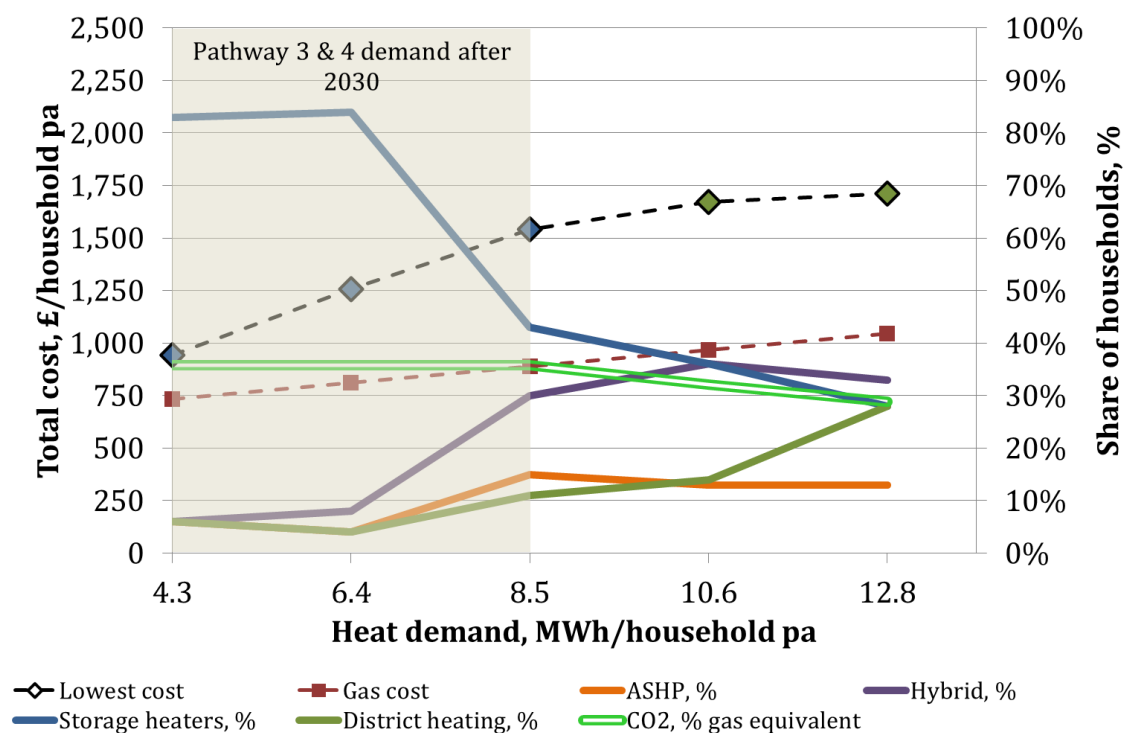


Figure 70: Study 2.4 - Sensitivity on heat demand for "Reference" costs.

6.2.5 Study 2.5 – Heat demand sensitivities with "Low" capital costs for heat pumps and heat network

Study 2.5 is a repeat of Study 2.4 but with the "Low" cost sensitivity for heat pumps and heat network capital costs (Table 8) and is shown in Figure 71. The key difference is that district heating has the largest share of households for the full range of heat demand and increases even further as heat demand increases. Total costs for district heating are comparable with gas.

The average carbon emissions from the low carbon heat technologies are lower than the previous studies at 30% of gas equivalent (65g/kWh) and falls to 18% (38g/kWh) as district heating increases its share of households.

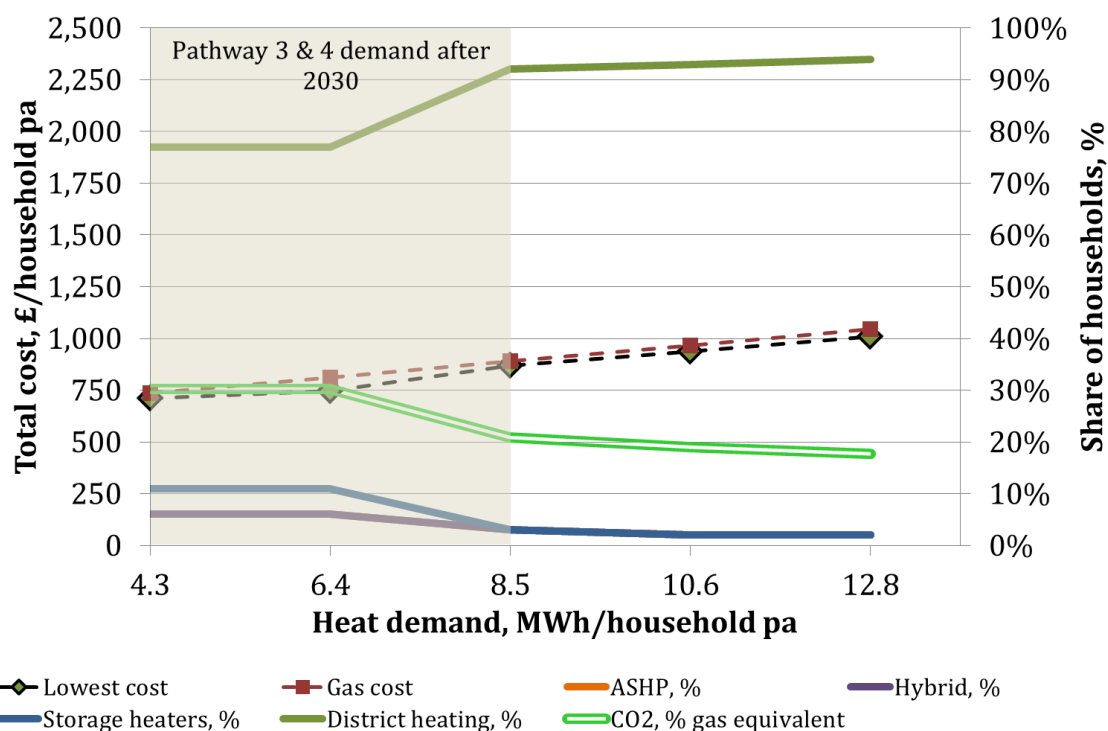


Figure 71: Study 2.5 - Sensitivity on heat demand for "Low" costs.

6.2.6 Study 2.6 - Heat network and heat pump cost sensitivities without CHP

Study 2.6 is the same as Study 2.2 but without CHP and is shown in Figure 72. Heat production is from the network heat pump and additional capital costs are incurred for this heat source. In addition the cost of heat production is higher as the network heat pump has a lower efficiency (350%) than the CHP which is based on its Z ratio (600% - section 5.4.4). Hence district heating costs are higher than in Study 2.2 (shown in Figure 72 by the dotted line). Breakeven with the total cost of gas is almost reached by the "Low" cost sensitivity.

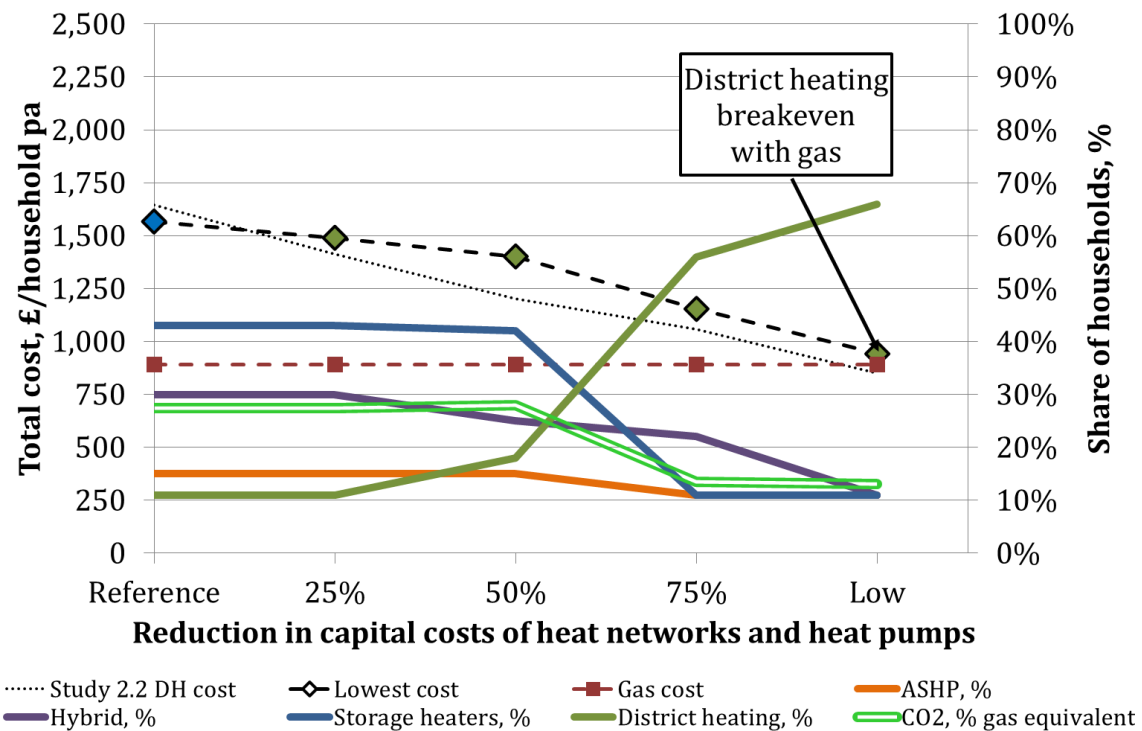


Figure 72: Study 2.6 Sensitivity on heat pump and heat network capital costs with CHP (2013 prices).

The average carbon emissions from the low carbon heat technologies are lower than the previous studies at 27% of gas equivalent (59g/kWh) and fall further to 13% (28g/kWh) as district heating increases its share of households. This is because the heat source is from grid produced electricity with average carbon emissions of less than 100g/kWh whereas the carbon emissions from CHP are approximately 400g/kWh.

6.3 Study 3 - Heat storage

As discussed in section 5.4.4, district heating systems are able to store heat at very low cost and so storage is used to supplement heat capacity, provide back up in the event of a failure of a heat source and can also offer substantial flexibility. For example, the heat produced from a heat source such as a CHP plant can be varied to compensate for changes in electricity production. Any deficit in heat demand can then be met by heat storage. Likewise, the operation of network heat pumps

can be varied with any deficits in heat demand also met by heat storage. Consequently, heat storage has the potential to provide operational benefits. However, to investigate these would require added complexity to the investment model and is beyond the scope of this research although it is recommended for further work.

In addition to network heat stores, heat storage can also be located in households in the form of hot water stores. For heat pumps this is required as a buffer tank for the heat pumps [51]. Subject to space considerations these could be increased in size to permit demand side management to be made available. For storage heaters, heat storage is an inherent feature of their design but there is scope to increase the amount of storage if the benefits can justify the costs.

The modelling of the residential heaters includes a heat storage facility and is described in section 5.3.2.4. This enables the effect of storage to be assessed and for the purposes of this study four levels of storage were examined. The “Reference” sensitivity is the same as Study 2.1 but uses the “Cold” temperature demand scenario. This is followed by two sensitivities to examine no storage and then unconstrained storage. The final sensitivity examines a storage level considered to be the maximum practical. However, this only affected buildings with heat pumps as the unconstrained level would be far too large. The maximum practical level for heat pumps has been set at 12kWh_{th} and is equivalent to a 1,000 litre hot water tank. This is 5 to 10 times the size of most existing hot water tanks and would only be possible where space permits.

Table 10 lists the sensitivities and Figure 73 presents the total costs for each residential heating technology. It can be seen that district heating has the largest benefit from storage with a total costs saving of £318/household pa. For storage heaters the benefit is £82/household pa. Finally for ASHPs and hybrid heat pumps it is £52 and £0/household pa respectively. Limiting storage for heat pumps to 12 kWh_{th} gives a cost saving relative to the “Reference” case of £59/household pa for ASHPs and £89/household pa household for hybrid heat pumps.

Sensitivity	Storage, kWh _{th} /household		
	Heat pumps	Storage heaters	District heating
"Reference"	4	24	17
No storage	0	0	0
Unconstrained	30	24	17
Maximum	12	24	17

Table 10: Study 3 – Impact of storage on total cost (2013 prices).

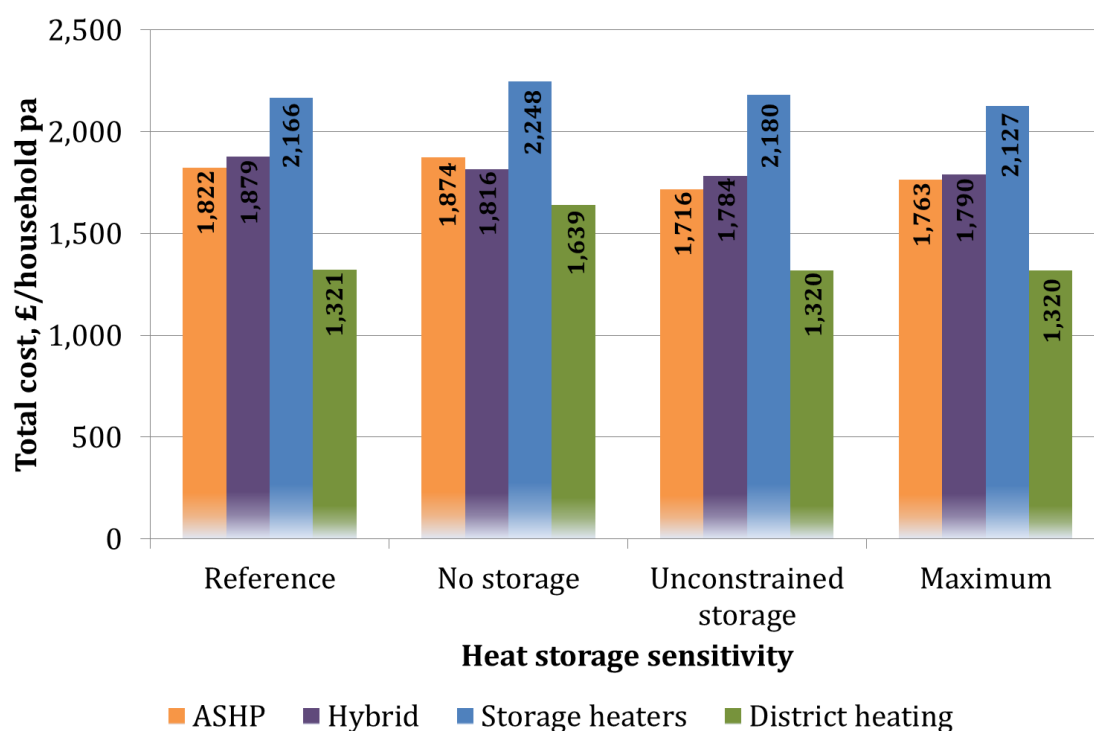


Figure 73: Study 3 – Impact of storage on total costs (2013 prices).

6.4 Study 4 - Carbon limits

So far all the studies have included a carbon constraint to limit electricity or grid CO₂ emissions to a maximum of 100g/kWh. This study examines the impact of changing this limit on total costs and share of households. Figure 74 shows the results for grid CO₂ emissions ranging from 110g/kWh to 53g/kWh. Overall the impact on total costs is not significant with changes within 3% of the average for each heating technology. There is some impact on the shares of households but the

ranking is unaffected. This might indicate that the price of carbon has a stabilising impact on costs by offsetting any cost increases with reductions in the cost of carbon.

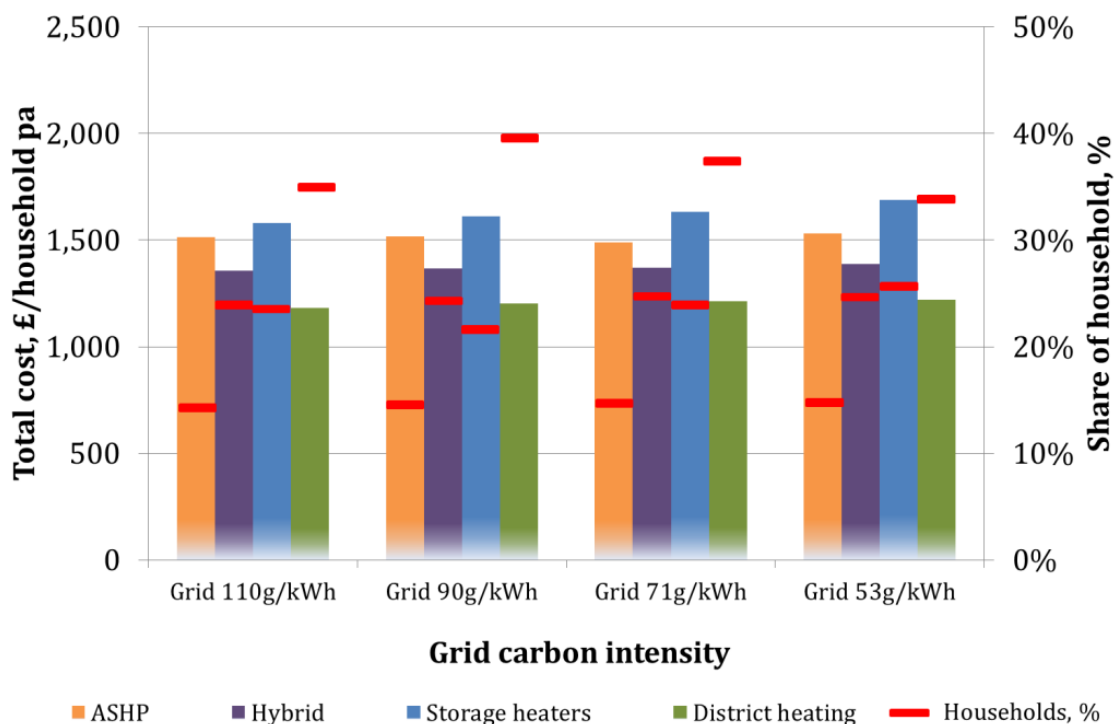


Figure 74: Study 4 - Impact of a carbon constraint on heating technology total costs and share of households (2013 prices).

In Figure 75 the carbon intensity of the heating technologies are shown. It can be seen that as the grid is decarbonised their carbon intensity declines. Most noticeable is the storage heaters where the carbon intensity falls from 118g/kWh to 47g/kWh. District heating is supplied by heat from CHP and so its carbon intensity is higher as a result. Reductions in the carbon limit constrains CHP plant output and as a consequence heat is provided from the network heat pump with output increasing from 0% to 10% of heat production and carbon intensity falling from 65g/kWh to 41g/kWh.

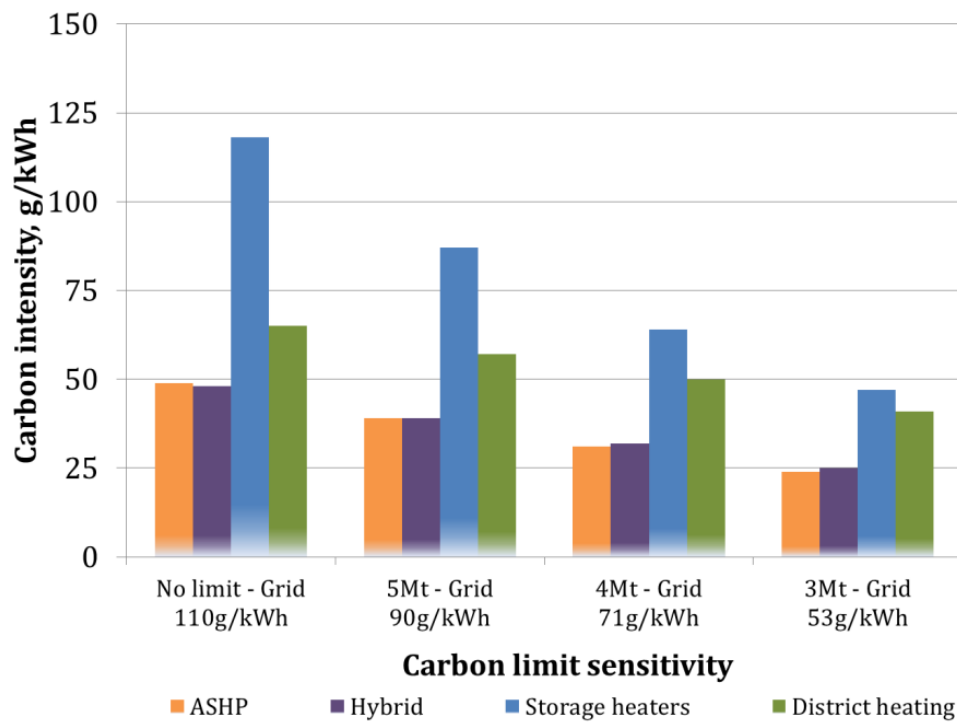


Figure 75: Study 4 - Impact of a carbon constraint on low carbon heater carbon intensity.

6.5 Study 5 - Heat density and district heating

The traditional “rule of thumb” for the economic viability of district heating is based around heat density specified in MW_{th} peak/ km^2 or MW_{th} average/ km^2 . Poyry [15] refers to a heat density above $3\text{MW}_{\text{th}}/\text{km}^2$ based on housing data which plots cumulative heat demand for dwellings compared to heat density. However, it notes that there are other factors such as circuit length and so it may be better to base any assessment on $\text{MW}_{\text{th}}/\text{km}$ or $\text{MWh}_{\text{th}}/\text{km}$ (of circuit length) for economic viability.

It is worthwhile noting that heat density, as a criterion, does not appear to be supported in Denmark, Sweden and elsewhere with experience of heat networks including very small schemes [76] as there are a number of factors that can help to reduce costs. The explanation given is that the cost of digging trenches and burying pipes is likely to be lower due to the general greater ease of excavating in

less crowded streets. It may also be possible to bury pipes in front gardens or under pavements or grass verges thereby avoiding the need to dig up and then reinstate roads.

However, it is also important to consider the heat density impact on the alternative to a heat network for low carbon heat which will be electricity. This is likely to require reinforcement of the electricity network to support the heat load. So intuitively there should be similar trenching costs and a degree of cancellation.

To explore this effect the following case study was constructed based on a reasonable size village of 2000 households. The choices are either to install a heat pump in every household or to construct a community energy system based on a heat network supplied by network heat pumps. The heat source could be ground or water. Network heat pumps will be design specific and so budgetary estimates have been used [83]. An assumption has also been made that heat pump costs have reduced to the “Low” cost sensitivity and heat networks are regulated allowing lower cost financing to be accessed (Table 8).

As described in section 4.3, heat network costs comprise infrastructure and branch costs. The branch costs include the heat interface unit, metering and also a gas boiler compensation payment has been added. Using the same assumptions for load development and maximum utilisation of the heat network and applying the heat network economic model proposed in section 4.3, the branch specific costs can be determined (Table 11). These are the cost of the pipes and trenching from the heat interface unit in the building to the heat network infrastructure. It is this cost which will be most affected by heat density.

Heat network components	Semi-detached (less dense)	
	Capital cost	Levelised cost
	£/household	£/household pa
Infrastructure	3182	350
Branch	3041	134
Heat interface unit and metering	2692	119
Gas boiler compensation payment	1000	44

Table 11: Heat network costs (2013 prices)

In this case study, the branch cost was incremented until breakeven with the heat pump was achieved. It can be seen from Figure 76 that this occurred when the branch network cost was increased by a factor of 3 for hybrid heat pumps and by a factor of just over 4 for ASHPs. No adjustment was made to the electricity reinforcement costs and so as previously mentioned, there should be some further heat pump costs which would increase both breakeven points.

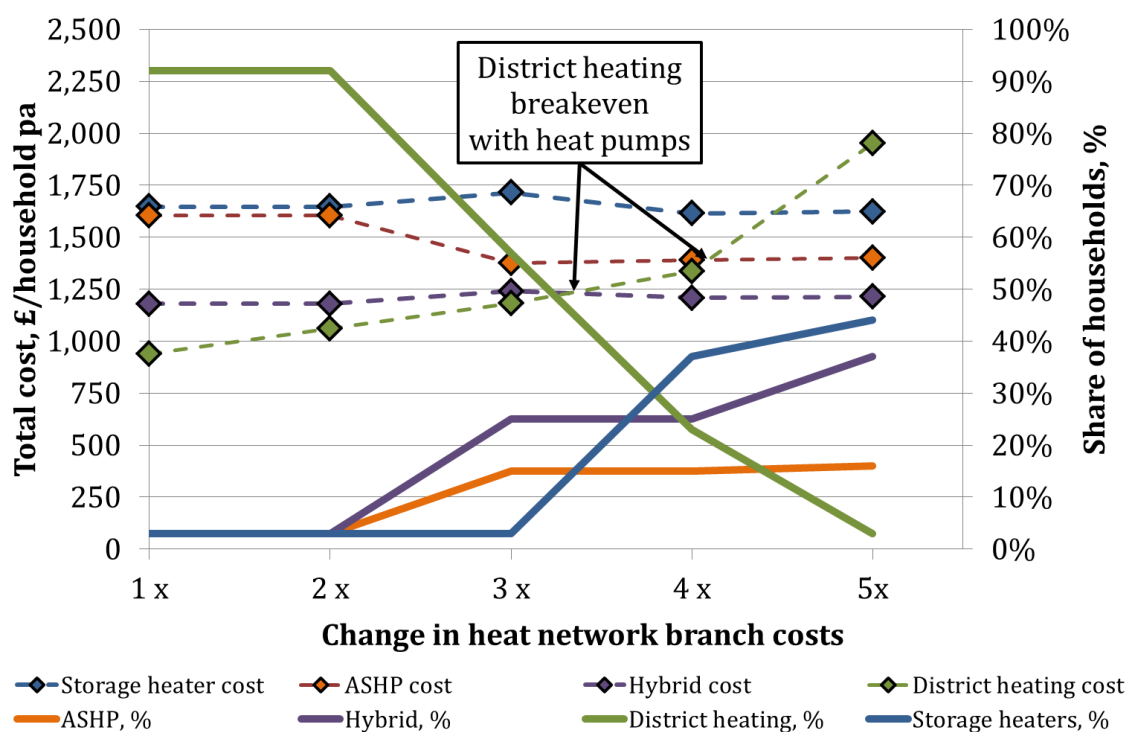


Figure 76: Impact of the change in heat network branch costs on total costs and household share (2013 prices).

It is difficult to reach firm conclusions on the significance of heat density on the viability of district heating from this single case study. Certainly in comparison with gas, district heating would struggle to compete and would deteriorate further with any increases in heat network costs. However, as a low carbon heating option it warrants further consideration, particularly where the alternatives face similar network related costs due to low heat density.

6.6 Discussion and conclusions

6.6.1 Studies 1.1 to 1.6 - Impact of modelling and temperature scenarios

Figure 77 summarises the results from studies 1.1 to 1.6. Comparisons of the modelling methodology using “Characteristic Day”, “SNT” and “Normal” temperature scenarios (studies 1.1 to 1.3) show relatively little difference in the total cost of each of the heat technologies. However, when Mode 1 is compared to Mode 2 (studies 1.5 and 1.6) the differences are much greater due to limitations on plant operation, particularly nuclear. This has a significant impact on plant capacity mix with higher levels of OCGT peaking plant to compensate for nuclear inflexibility and wind intermittency. As might be expected, heat pumps are more affected than storage heaters due to their limited storage capability and so their energy costs are much higher.

For all the studies with heat demand based on normal temperatures the ranking of the heat technologies remained similar. Gas had the lowest cost, followed by storage heaters, then hybrid heat pumps and district heating and finally ASHPs which had the highest costs.

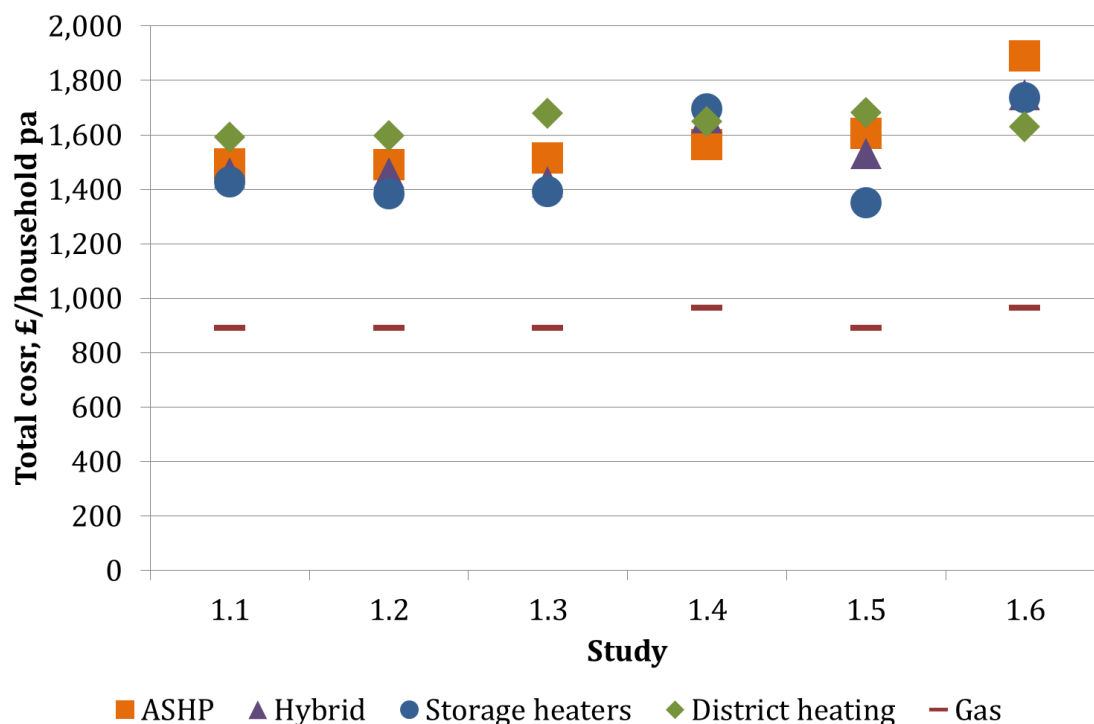


Figure 77: Summary of the results for studies 1.1 to 1.6.

Carbon emissions were lower than gas throughout the studies. For normal temperature heat demand, heat pumps and district heating were similar and within the range 50g/kWh to 72g/kWh whereas storage heaters ranged from 140g/kWh to 167g/kWh. As the grid is decarbonised these figures would be expected to fall further and this was explored in section 6.4.

6.6.2 Studies 2.1 to 2.6 –Sensitivity studies

The studies show that without reductions in capital costs or significant increases in the cost of gas, none of the lower carbon heat technologies can compete with the cost of gas and so they will either require a premium to be paid or a subsidy such as the RHI. With reductions in the heat network levelised costs, district heating can be competitive with gas but this would require a regulatory style finance regime.

In contrast, residential heat pumps are unable to compete with gas and further capital cost reductions are required beyond the “Low” cost sensitivity. Hybrid heat

pumps persistently have lower total costs than ASHPs due primarily to lower demand related costs and running costs for peaking duty. Gas is used for peaking duty with the result that carbon emissions are higher. However, the level of peaking duty for the studies undertaken was less than 8% of the total, but even so total carbon emissions were increased by up to 35%. This was very dependent on heat demand and for higher levels of demand this would increase further and is discussed in detail in section 5.4.2. Hence hybrid heat pump sizing is critical to controlling its CO₂ emissions.

CHP helps to reduce the cost of district heating but network heat pumps can be still be competitive with gas subject to the aforementioned reductions in heat network levelised costs.

At low levels of demand, storage heaters have the lowest total cost and the highest share of households. Total costs are still higher than gas. However, the costs do not include the building's heating system, i.e. radiators, pipework, pump, etc. Hence for new installations these costs should be included. For example, estimates for a flat are approximately £2,500 [15] or £300 pa and would substantially improve the economics of storage heaters as they would have the lowest total cost including gas up to an annual heat demand of 8.5MWh_{th} pa. Carbon emissions are higher for storage heaters but these fall as the grid is decarbonised (section 6.4).

6.6.3 Study 3 - Heat storage

Heat storage offers significant value to district heating. In practical terms a heat store of 17kWh_{th}/household for 50,000 households would be about 50,000m³ [77] which is equivalent in size to a modest size gasometer. However, heat storage suitable for residential heat pumps will be constrained by the building itself and where space is at a premium it is likely to be modest. Electric storage heaters also offer significant storage potential which is an inherent feature of their design.

The cost benefits identified in Study 3 will have been included in the other studies. However, heat storage has the potential to provide operational benefits to the electricity system which warrants further investigation.

6.6.4 Study 4 - Carbon limits

Reducing carbon limits has relatively little impact on total costs for each heating technology and might indicate that the price of carbon has a stabilising impact on costs by offsetting increases with reductions in the cost of carbon levied. As the grid is decarbonised the carbon intensity of all heat technologies decline but most noticeable are storage heaters where the carbon intensity falls from 118g/kWh to 47g/kWh. Reductions in the carbon limit constrain CHP plant output and as a consequence heat is provided from the network heat pump thereby lowering the carbon intensity of district heating reduces.

6.6.5 Study 5 - Heat density and heat density

It is difficult to reach firm conclusions on the significance of heat density on the viability of district heating from this single case study, although the analysis indicates a degree of insensitivity to branch costs and therefore heat density. Certainly in comparison with gas, district heating would struggle to compete and this will deteriorate with any increases in heat network costs. However, as a low carbon heating option it warrants further consideration, particularly where the alternatives face similar network related costs due to low heat density.

CHAPTER 7

CONCLUSIONS, ACHIEVEMENTS & FURTHER WORK

This thesis has investigated the low carbon residential heat technologies suitable for large scale deployment in order to support the UK's 2050 GHG emissions target. It identified the importance of including temperature based scenarios when modelling heat demand, particularly if heat is electrified but also for heating technologies whose performance is affected by temperature such as ASHPs. The transition from gas for heating, to electricity or district heating will substantially increase the level of integration of heat within the UK's energy system. This thesis has shown that investment models that incorporate both heat and electricity are required to enable the technical and economic factors to be properly considered in order to support planning, investment and operation of the UK's energy system.

This final chapter summarises the conclusions reached and addresses the research questions 1 to 4. It then presents a response to Research Question 5 before listing further work.

7.1 Summary of conclusions

In Chapter 2 scenarios for decarbonising heat were examined and consideration given to why the outcomes vary so significantly. There is some agreement that heat pumps, particularly ASHPs, will have a significant role but considerably less agreement on district heating and whether there is any role whatsoever for electric storage heaters. This chapter identified a number of performance features which are poorly represented in the models used and which may have contributed to these differences. In particular it noted that financing assumptions for heat networks are more onerous than assets financed under a regulatory regime.

In Chapter 3 a heat demand model was proposed that synthesises heat demand by converting characteristic day heat demand profiles into an annual half hourly demand profile using daily temperature scenarios. These unique features have enabled UK heat demand to be modelled in sufficient detail to enable the assets required if the heat were to be supplied by district heating as well as the impact on the electricity system from electrification. Based on DECC 2050 Pathway heat demands, peak heat demand projections were presented which showed substantial variations between pathways. Very importantly these results illustrate an increase in sensitivity to changes in temperature if heat is electrified. Hence, consideration needs to be given to the impact on supply security standards arising from electrification of heat.

In Chapter 4 total cost scenarios for gas and each of the low carbon heating technologies were developed based on DECC fuel and carbon price scenarios. Gas was shown to have the lowest cost but is exposed to fuel cost uncertainties as well as increases in network charges and the possible imposition of a carbon levy. District heating was shown to have the highest cost but is very sensitive to financing assumptions. A heat network economic model was developed which examined the impact of financing along with other risks such as load development and network utilisation. These risks were shown to be very significant. If more favourable financing is assumed, comparable to that used for electricity and gas networks, then district heating has the lowest cost and can even be competitive with gas. Heat pumps were shown to have the next highest cost mainly due to the cost of the heat pump. Storage heaters have the next lowest cost after gas but are most sensitive to electricity costs and so they are likely to be more competitive at lower heat demands.

In Chapter 5 an integrated heat and electricity investment model was proposed that uses half hourly heat data derived from the heat demand model proposed in Chapter 3. The investment model can be run in different modes without binary variables and a reduced number of decision variables to assist with convergence and feasibility. District heating includes CHP, network heat pumps and storage. A

novel CHP representation fully incorporates the relationship between heat and electricity production, both of which can be optimised by the investment model along with the electricity assets.

Residential heating technologies include ASHPs, hybrid heat pumps, electric storage heaters and district heating. The temperature scenarios used to construct the half hourly heat demand profiles are also used to adjust the maximum heat output and efficiency of the residential heat pumps. Included in the heat pump is a supplementary (peaking) heating facility for when the heat output of the heat pump is not sufficient to meet heat demand. These features substantially improve the representation of heat pumps and show that they have a significant impact on peak electricity demand and CO₂ emission due to the adverse impact of temperature on efficiency and heat output.

All residential heating technologies include a storage facility to represent building heat storage, e.g. hot water tank, thereby enabling the potential benefits of demand side management to be analysed. The residential heaters can either be constrained to a specified share of the heat demand or assigned decision variables to allow the mix of heating technologies to be optimised by the investment model. As a consequence the portfolio effects of the heaters to be optimised can be explored.

In Chapter 6 a series of studies were presented that investigated the total costs, carbon emissions and “share of households” for the low carbon heating technologies. These studies used the investment model proposed in Chapter 5. Studies 2.1 to 2.6 (refer to section 6.2) examine the sensitivities to a number of key parameters and address Research Question 1 (refer to section 1.5.1). Without reductions in capital costs or significant increases in the cost of gas, none of the low carbon heat technologies can be competitive. However, with reductions in the heat network levelised costs, district heating can be competitive with gas but this would require a regulatory style finance regime.

In contrast, residential heat pumps are unable to compete with gas. Hybrid heat pumps consistently have lower total costs than ASHPs due primarily, to lower demand-related costs. Carbon emissions are higher as a result of the gas used for peaking duty. At low levels of demand storage heaters have the lowest total cost and have the highest share of households but carbon emissions are higher although these do decline as the grid is decarbonised.

Study 3 (refer to section 6.3) examines the benefit of heat storage and addresses Research Question 2 (refer to section 1.5.2). Heat storage offers significant value to district heating but is much less so for residential heat pumps. This is because the size of the heat storage will be constrained by the building itself and where space is at a premium it is likely to be modest.

Study 4 (refer to section 6.4) examined the impact on reducing carbon limits and addresses Research Question 3 (refer to section 1.5.3). This has relatively little impact on total costs for each heating technology and might indicate that the price of carbon has a stabilising impact on costs by offsetting any cost increases with reductions in the cost of carbon levied. As the grid is decarbonised the carbon intensity of all heat technologies decline but most noticeable are storage heaters where the carbon intensity falls from 118g/kWh to 47g/kWh. Reductions in the carbon limit constrain CHP plant output and as a consequence heat is provided from the network heat pump thereby lowering the carbon intensity of district heating.

Study 5 (refer to section 6.5) examined the impact of heat density on the economics of district heating and addresses Research Question 4 (refer to section 1.5.4). It is difficult to reach firm conclusions on the significance of heat density on the viability of district heating from a single case study, although the analysis indicates a degree of insensitivity to branch costs and therefore heat density. Certainly in comparison with gas, district heating would struggle to compete and this would deteriorate with any increases in heat network costs. However, as a

low carbon heating option it warrants further consideration, particularly where the alternatives face similar network related costs due to low heat density.

7.2 Research question 5 - How does a strategic approach to heat differ to an incremental approach and what do we need to do to make it happen?

7.2.1 Strategic versus incremental approach

In many respects any heat strategy will be dependent on network strategy. If gas as an energy vector is substantially diminished, if not eradicated, in order to meet the 2050 GHG carbon targets, then additional network capacity will be required. Hence the choice rests between electricity network reinforcement to cope with the increase in demand from electrified heat or investment in construction of heat networks. The former can be done incrementally and within the current regulatory framework whereas the latter will be a major strategic investment. For example:

- Household heat pumps can be added incrementally to the system. They are essentially householder led and can be viewed as a “pull” technology, i.e. infrastructure investment follows householder adoption. There is a greater chance that it responds to householder need but there is a risk that it is unable to keep up with demand.
- A district heat system will require substantial network investment and it may be many years before the load has developed sufficiently to cover the costs of the investment. It is essentially a “push” technology, i.e. adoption follows infrastructure investment. The risk is that planning assumptions are incorrect and it fails to deliver as expected. However, an inherent feature of district heating is that it provides considerable optionality thereby enabling it to adapt to such changes in assumptions, particularly in terms of the availability of other sources of heat.
- Storage heaters have the lowest capital cost and in the initial phase their adoption may have little impact on infrastructure investment. However,

running costs will be much higher than other technologies although their inherent storage may offset some of these higher costs. Hence their suitability may be confined to low demand buildings.

This thesis has identified that district heating is an attractive option which is robust against most outcomes. However, its economic viability is crucially dependent on a financing regime that is compatible with other regulated network based assets. If not its costs will be higher, the risks greater and its viability for large scale deployment substantially weakened. The position is currently exacerbated with the RHI which provides a subsidy to ASHPs which has been identified by this thesis as having the highest costs and presenting the greatest uncertainties.

This can be addressed by creating a “level playing field” and encompassing heat networks within a regulatory framework comparable to that presently used for electricity and gas. By so doing, investments in networks to support the decarbonisation of heat can take account of the local impact, including reinforcing electricity networks versus investing in heat networks as well as the consequential impact on the gas network which may ultimately mean decommissioning. The benefit of this approach is that it allows decisions on heat decarbonisation to be decentralised thereby taking full account of local factors that are likely to have a major influence on the best way forward.

The alternative is to rely on heat pumps. This thesis has shown that hybrid heat pumps may offer advantages over ASHPs in terms of performance but also cost. At present heat metering is required in order to receive support from the RHI [61] and there is clearly a risk of heat pump under-sizing thereby resulting in higher levels of operation on gas with adverse consequences for carbon emissions. However, this thesis has shown that their carbon emissions are still substantially below gas boilers. It should also be noted that ASHPs may have similar effects if peaking duty is provided by electric heating supplied by carbon emitting peaking plant such as OCGTs.

Storage heaters provide another option and this thesis has shown that for buildings with low heat demand they can be an attractive economic option for large scale deployment. This is on the assumption that heat demand follows a pathway comparable with the DECC 2050 Pathways 3 or 4. Although this thesis has assumed that network reinforcement costs are incurred there is more scope for them to be avoided than with heat pumps and so the costs may be lower and the deployment challenges far less. Carbon emissions are higher than the other low carbon technology but still considerably less than gas and with decarbonisation of the grid, significant reductions are achievable.

7.2.2 What do we need to do to make it happen

If heat networks were to become a regulated activity, consideration would need to be given to other issues such as customer protection and competition in supply. In the UK, district heating is neither regulated nor falls within the remit of the Energy Ombudsman, although a Heat Customer Protection Scheme is currently being prepared under the auspices of the Combined Heat and Power Association (CHPA)¹². This offers the prospect of some protection to customers but proposals on pricing is limited to transparency on charging only.

If district heating were to develop to levels comparable with other forms of heating then action would need to be taken to ensure customers were similarly protected and this would need to include energy costs. These could range from a simple “yard-stick” regime similar to that introduced for electricity in 1990 as well as full competition similar to that currently in place with electricity and gas. The viability of such an arrangement needs investigation and is suggested for further work.

¹² www.heatcustomerprotection.co.uk

7.3 Further work

7.3.1 Heat demand model

This model uses data from a limited number of sites to derive a set of master profiles that were used to synthesise the half hourly heat demand. As better quality heat data becomes available the model should be updated and improved. In particular the heat data collected was from a very mild winter and it would be helpful to get data corresponding to much colder weather conditions.

The results also illustrate the increase in sensitivity to changes in temperature if heat is electrified. An example was given for Pathway 3 in 2050 whereby the electricity peak heat demand is 57GW for the “Normal” temperature scenario and 74GW for the “Cold” temperature scenario, nearly 30% higher. To maintain the current level of electricity supply security would require substantial further investment beyond that required for “Normal” temperatures. This could include assets such as peaking plant and/or demand side management arrangements as well as network reinforcement. Hence, consideration needs to be given to the impact on supply security standards arising from electrification of heat.

7.3.2 Integrated heat and electricity investment model

A number of areas have been identified for improvement. These are:

- Generator model. This only uses a single incremental cost, it does not include minimum up and down times and ramping rates. Also units are modelled individually therefore the number that can be included efficiently is limited.
- Heat source modelling. This is limited to CHP and network heat pumps. A feature of district heating is that it provides the option to take advantage of multiple sources of heat, e.g. solar, geothermal and wasted heat.
- Heat demand. This is limited to 4 heat demand profiles, i.e. one for each heating technology. As a consequence it only includes a single annual average building heat demand and cannot take account of the portfolio effect of different sized heat demands which might favour one heating technology over

another. Therefore separate simulation studies are required to take some account of this.

- Building heat demand profiles. Heat demand profiles do not distinguish between different types of building. These will vary along with the levels of consumption.
- Hot water and space heating combined. As the demand for space heating falls with improvements in building energy efficiency, hot water will represent a larger share of heat demand. For example, under the DECC 2050 Pathway 4, hot water demand could equal that required for space heating.

7.3.3 Gas transmission and distribution system

As householders switch away from gas for heating, network revenue will be lost. The gas network owners would then either need to reduce costs or increase network charges to compensate. The impact could be mitigated on the transmission system if carbon capture and sequestration (CCS) becomes viable for power plant and industrial applications as this would allow gas to continue to be used. For the distribution system there may be an alternative role using hydrogen or biogas or possibly some other application. This is clearly a complex area that warrants further investigation so that strategies can be formulated and decisions taken.

7.3.4 Heat storage

District heating systems are able to store heat at very low cost and along with distributed storage such as electric storage heaters and hot water they have the potential to offer operational support to the electricity system. This may be particularly useful in a system with large amounts of inflexible or intermittent generation.

7.3.5 Heat network regulation

This thesis has demonstrated that the economic viability of district heating for large scale deployment is dependent on a finance regime that is compatible with other regulated networks. However, these regimes have been designed for

existing assets with incremental investment activity operating in well-established regions. Hence the suitability or otherwise for heat networks needs to be investigated and a proposals considered. This also needs to extend to customer protection including whether supply competition is a viable option or whether other options need to be investigated.

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APPENDICES

APPENDIX 1 – MODEL DATA

Household heating appliances [15] and [38]

Condensing gas boiler cost, £	2500
Condensing gas boiler CO ₂ , g/kWh	215
Gas appliance maintenance, £ pa	100
ASHP cost, £	7500
Hybrid heat pump cost, £	7500
Electric storage heaters, £	1500

Heat network assets [15] [83]

Network heat pump cost, £/kWth	500
Heat network cost, £/household	8915
Thermal storage, £/MWh	100

Electricity network reinforcement cost (estimates)

Above LV, £/kW	300
LV, £/household	400

Network losses

Heat	16%
Electricity:	7%

APPENDIX 2 - AIR TO WATER HEAT PUMP EVOLUTION

Delta Energy and Environment provide a specialist heat pump research service and the following information was obtained to supplement information included in its report [38] and referred to in Chapter 2.

Costs reductions from £1,250/kW_{th} to £750/kW_{th} by 2030

Price reduction is more likely to be incremental than step-change, based on:

- Economies of scale and increasing market competition from Asian air conditioner manufacturers offering heating products in Europe. They are already driving down costs and creating strong competition for European players. This is because they can buy components in large volumes (which can be used for their air conditioner business as well) and therefore at lower prices.
- Companies such as Daikin and emerging players such as LG are increasingly aggressive in the market.
- Beyond 2020 Chinese manufacturers offering lower cost products may have a much greater impact in the ASHP market as they begin to get quality and standards right
- Margins are high today because of the low volume of sales and the added costs installers have to add to cover correcting problems. As sales volumes, installer confidence and competition increase, margins are expected to come down.
- Current heat transfer materials are copper/brass whereas aluminium is three times cheaper, although it brings with it problems of corrosion in UK climate. Also there is the possibility to use more plastics.

Performance improvements from 2.8 SPF to 3.1 SPF by 2030

Efficiency increases will be evolutionary but potentially some step-changes could occur. Advances in technology will depend critically on the industry having the confidence to invest in technology development & R&D. This will be driven by a stable supportive policy framework, as well as an increased demand for heat pumps and increasing sales volumes. There is still plenty of scope to increase the

efficiency of heat pumps and a commercial business decision is required to justify the investment.

Efficiency gains could come through areas such as pumps & fans (the Ecodesign Directive will push manufacturers to use more efficient pumps), compressors (these have made leaps in efficiency in the 1990s with digital scroll compressors, similar changes are likely to happen), advancement in heat exchanger design (particularly tackling the defrosting issue), optimised control systems (scope to optimise whole system performance including pumps & fans, not only individual parts of the system), new system concepts (e.g. CO₂ heat pumps, advanced high temperature systems).

APPENDIX 3 – GENERATOR DATA¹

	Efficiency %	Total £/MWh	Investment £/MWh	O&M £/MWh	FUEL £/MWh	CO ₂ £/MWh	No-load ² £/MWh	Fuel ² £/MWh	Noload CO ₂ ² £/MWh	CO ₂ ² £/MWh	Start-up ² £/MW	Hours %
Nuclear												
High		94.0	76.0	13.0	5.0	0.0	0.8	4.2	0.0	0.0	8000.0	91%
Central		80.0	62.0	13.0	5.0	0.0	0.8	4.2	0.0	0.0	8000.0	91%
Low		70.0	52.0	13.0	5.0	0.0	0.8	4.2	0.0	0.0	8000.0	91%
CCGT CCS												
High	50%	95.0	38.0	4.0	50.0	3.0	8.3	41.7	0.5	2.5	45.0	90%
Central	50%	87.0	30.0	4.0	50.0	3.0	8.3	41.7	0.5	2.5	45.0	90%
Low	50%											
CCGT CHP CCS												
High	50%	105.1	44.4	7.0	50.0	3.7	8.3	41.7	0.6	3.0	45.0	90%
Central	50%	95.1	34.4	7.0	50.0	3.7	8.3	41.7	0.6	3.0	45.0	90%
Low		88.0										
CCGT												
High	56%	89.9	14.0	4.0	44.6	27.2	7.4	37.2	4.5	22.7	43.0	93%
Central	57%	87.6	13.0	4.0	43.9	26.7	7.3	36.5	4.5	22.3	43.0	93%
Low		86.0										
CHP CCGT												
High	56%	99.0										
Central	57%	96.0	15.0	7.0	43.9	26.7	8.8	35.1	4.5	22.3	43.0	90%
Low		94.0										
OCGT												
High	40%	195.6	65.0	30.0	62.5	38.1	5.7	56.8	6.4	31.8	9.0	10%
Central	45%	171.4	59.0	23.0	55.6	33.9	5.1	50.5	5.6	28.2	9.0	10%
Low		212.0										

1. Data is based on tables 10 and 12 from DECC [85].

2. Required for Mode 2 operation of the integrated heat and electricity investment model.

3. CHP plant assumed to have a Z ratio of 6 and a heat to power ration, λ of 0.7 (refer to section 5.4.4).

