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Decarbonising Heat: Low-Carbon Heat Scenarios for the 2020s

Report for the Committee on Climate Change

NERA Economic Consulting

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Summary of Key Findings

- Heat accounts for nearly half of UK CO_2 emissions. This project finds that low-carbon sources could reduce emissions from heat by one third by 2030, consistent with a trajectory for economy-side decarbonisation to 2050.
- Based on the assumptions in the "central" scenario, significant emissions abatement could be provided at low or even negative cost. However, achieving the emissions reductions necessary to meet the 2050 target trajectory will require more expensive measures.
- Heat pumps appear an attractive option for the decarbonisation of space heating, complemented by bioenergy for high-temperature heat. Deeper abatement would depend on overcoming challenges associated with the provision of low-carbon electricity. The attractiveness of heat pumps depends on improvements in the technology over the next two decades.
- We also explore an alternative route with large cities heated through waste heat from thermal power stations provided through district heating, and with larger contributions from biogas and other bioenergy. This route would require significant co-ordination and potentially changes to market arrangements.
- Risks to heat sector decarbonisation include failure to promote energy efficiency or the uptake of low-carbon technology over the next two decades, as well as less favourable performance of, or more significant barriers to, key technologies. (On the other hand, even higher abatement may be feasible with either higher CO_2 prices, or if bioenergy became available in greater quantity or at lower cost.)

Heat accounts for approximately half of UK energy use and associated CO_2 emissions. Meeting the UK's ambitious target to cut greenhouse gas (GHG) emissions 80 percent by 2050 therefore will require very significant cuts in emissions from heat. These can be achieved both by reducing heat use through energy efficiency, and by reducing the emissions intensity of heating. The Government is in the process of developing and implementing various policies designed to put the UK on a path towards reduced emissions from heat, including a range of energy efficiency policies and the planned Renewable Heat Incentive.

The Committee on Climate Change, in its capacity to advise the Government on strategies for achieving UK emissions targets, has already investigated the potential to reduce GHG emissions during the first, second, and third carbon budget periods (2008-2012, 2013-2017, and 2018-2022, respectively). The Committee now wishes to consider scenarios for using low-carbon heat technologies to reduce emissions from heat generation in the fourth budget period (2023-2027), and more generally during the decade from 2020 to 2030. This report provides input to the Committee's work on the fourth carbon budget, which is due to be delivered to Government by the end of 2010.

The UK Government has adopted the Committee's recommendation that the UK should reduce its greenhouse gas (GHG) emissions by at least 34 percent relative to 1990 by the end of the third budget period. For the period to 2022, this will require annual reductions of 2-3 percent, with an increased rate of emissions reductions required thereafter.

The fourth budget period and beyond, then, will require significant emissions reductions. Substantial reductions in energy use through improved energy efficiency are likely to provide an important element of this. However, the deep cuts envisioned will also require significant (and ultimately, near-complete) decarbonisation of the energy used for heating. The primary goal of the current project has been to consider the cost and feasibility of a range of strategies for effecting this decarbonisation.

At a high level, there are three distinct technological "paths" that could be followed to put the UK onto the required heating emissions trajectory. The first of these relies on combining widespread deployment of heat pump technologies with decarbonisation of the power sector. The second is the use of bioenergy—both through the use of the existing gas network to transport biogas, and through solid or liquid biomass—as a primary source of low-carbon heat. The third technology path is the use of district heating networks, complementing (and perhaps ultimately, superseding) the existing gas network as the main carrier of energy for heat.[1]

Each of the three approaches has advantages and disadvantages, which we explore in more detail below and in the main report, both qualitatively and quantitatively. Table ES.1.1 provides a summary of some of the key considerations.

[1] There are of course other technologies that also could provide low-carbon heat, including solar thermal, but they are not candidates to supply a significant share of UK heating demand during the period in question.

Table ES.1.1
High-Level Paths for Heat Decarbonisation

Strategy / Technology	Advantages	Disadvantages
"Electrification strategy": Heat pumps	Mature industry Potentially low cost	Feasibility and cost of grid decarbonisation uncertain Suitability for existing building stock uncertain
"Bioenergy strategy": Biogas / biomass	Biogas uses existing gas infrastructure	Availability of suitable feedstock uncertain Some gasification technology not yet viable Wider sustainability issues associated with bioenergy
"District heating strategy"	Flexible – can use multiple low-carbon heating sources	Establishing new pipe networks expensive Coordination of decentralised heating decision-makers difficult

As discussed below, our analysis suggest that the heterogeneity of heating requirements across various sectors of the economy will mean that the best strategy is not a "pure" version of any of the three paths set out above, but one that combines elements of each. The scenarios that we have modelled reflect this heterogeneity, including combinations of the three paths. The detailed examination of heat use that underlies our quantitative analysis makes it possible for us to explore a wide range of parameters that affect the potential and cost of each technology path for different heat users across the UK economy.

The heterogeneity of heat demand and supply also means that analysis of abatement potential and cost is a complex undertaking. Quantitative estimates of abatement cost and potential requires the use of a large quantity of data as well as a large number of assumptions and uncertain projections. In developing scenarios for the 2020s, the project has built upon and extended previous work by NERA and AEA to analyse low-carbon heat and the supply curve for renewable heat. The work has extended technology assumptions and input data to cover the period to 2030, and also has incorporated additional technologies to reflect potential developments over the next 20 years. The technologies covered by the analysis include a range of air-source heat pump configurations, biogas from anaerobic digestion as well as bio-SNG, biomass combustion, combined heat and power at a variety of scales, ground-source heat pumps, solar thermal, as well as methods to provide low-carbon heat through district heating. We consider varieties of these technologies that are currently not commercially viable, including synthetic biogas from gasification of biomass as well as heat pumps with heat storage to shift electricity load profiles.

The large number of parameters means that analysis of uncertainty is particularly important. We investigate the sensitivity of the results (including the costs and effectiveness of different strategies) to assumptions about technological progress, progress in meeting energy efficiency targets, fuel prices, and assumptions about the rate of penetration of the technologies within the UK building stock (and the factors determining this rate, such as discount rates and barriers to uptake).

We summarise here some of the key results that emerge from our analysis.

Low-carbon heat technologies could reduce emissions from the heat sector by one-third by 2030.

Figure ES.1
"Central" Abatement Potential from Heat Sector by Technology (2030)

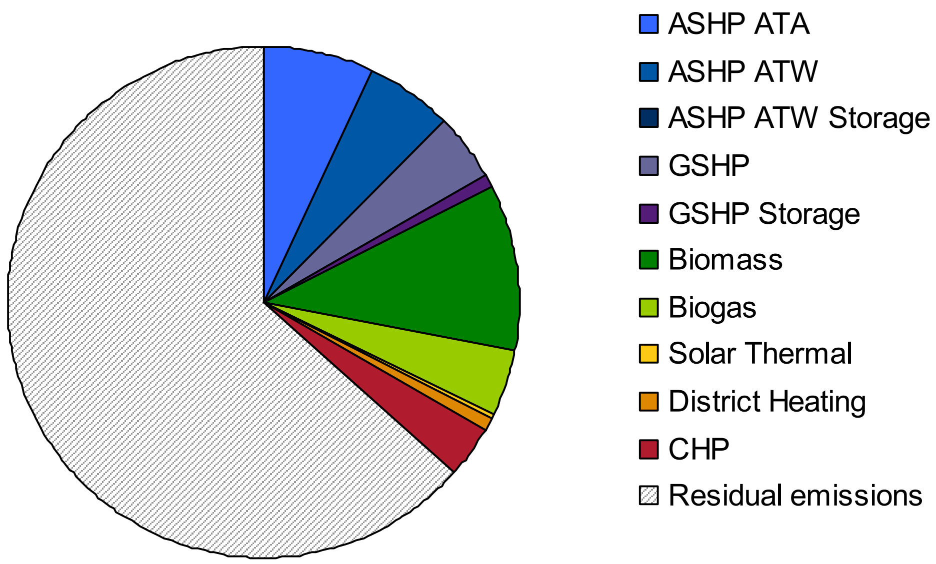


Figure ES.1 illustrates the abatement potential from different technologies in 2030 in the "central" scenario.[2] We project "business as usual" (BAU) emissions from heating equal to 165 $MtCO_2$ in 2030 (down from an estimated 173 $MtCO_2$ in 2010).[3] The figure shows the abatement potential from measures with costs less than a threshold level of CO_2 prices (starting at £50-70 for measures undertaken in 2020, and rising to £113/tCO_2 in 2030). The total abatement potential is around 62 $MtCO_2$, or 38 percent of BAU emissions. (This corresponds to year-on-year emissions reductions of 3.5 percent in the 2020s, consistent with

2 The intention of this project has been to explore a range of potential options for the 2020s. The "central" scenario provides a point of departure for exploring a range of different issues that influence abatement potential and cost. However, the terminology should not be taken to suggest that this scenario necessarily carries more weight or is more important than other scenarios presented.

3 The BAU estimate assumes that the 2030 heat demand is met by the same mix of heating technologies that are currently used.

the overall trajectory for decarbonisation by 2050.) As the figure indicates, in the "central" case, heat pumps provide half of the abatement, reducing net emissions by nearly to 20 percent. Heat pumps are followed by biomass, which provides the vast majority of abatement for industrial process heat. Also contributing to the abatement potential is biogas (primarily injected into the gas grid), with district heating delivering only a small amount of abatement.

The table below summarises some of the detailed modelling results for the "central" scenario for 2030.

Table ES.1.2
Headline Results of "Central" Modelling Scenario (2025, 2030)

Variable	Units	2025	2030
Total emissions abatement	MtCO2	39	62
In EU ETS	MtCO2	9	9
Outside EU ETS	MtCO2	30	53
Displacement of fossil fuels	MtCO2	47	78
Emissions from heat pump electricity use	MtCO2	-8	-16
BAU emissions	MtCO2	159	165
% of emissions reduced	%	24%	38%
Remaining emissions	MtCO2	120	102
Low-carbon heat output	TWh	226	350
Total heat demand	TWh	606	627
Share low-carbon heat output	%	37%	56%
Total cost	£m	1,293	1,557
Average abatement cost	£/tCO2	33	25

Low-carbon technologies could provide some 350 TWh of heat by 2030, meeting over 55 percent of heat demand. The difference between the 38 percent reduction in emissions and the 56 percent share of heating supply is due primarily to the fact that some of the low carbon heating technologies (notably heat pumps) retain some emissions during this period. Thus although heat pumps account for around 17 percent of the abatement relative to BAU, they account for 28 percent of total heat output from the above technologies.

The work has also investigated regional variation in abatement potential. In general, Wales, Scotland, and particularly Northern Ireland have higher abatement potential than the UK average, primarily because of greater use of coal and oil for heating.

Based on the assumptions in the "central" scenario, significant emissions abatement could be provided at low or even negative cost. However, achieving the emissions reductions necessary to meet the 2050 target trajectory will require more expensive measures.

Table ES.1.3 shows a breakdown of emissions abatement and costs, by technology.

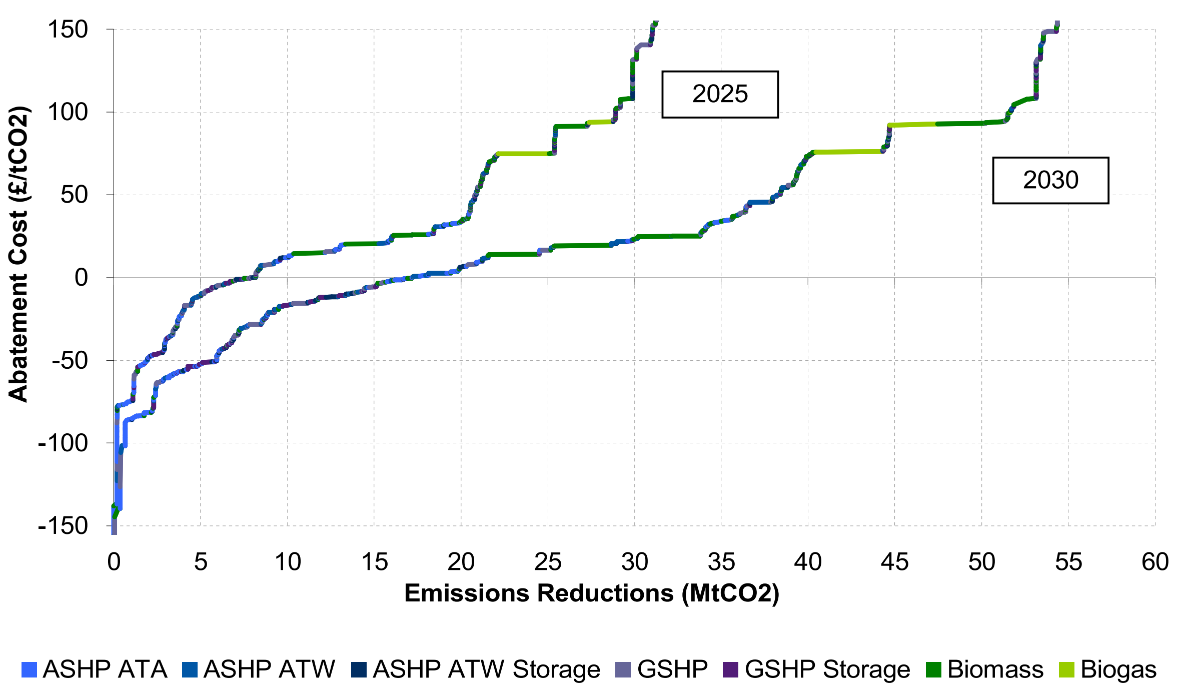
Table ES.1.3
Abatement Cost and Potential by Technology in “Central” Modelling Scenario (2030)

Technology	Total emissions abatement	Total Cost	Average abatement cost
	$MtCO_2$	£m	£/tCO_2
ASHP ATA	7.2	-167	-23
ASHP ATW	9.2	93	10
ASHP ATW with Storage	2.1	-32	-15
GSHP	6.7	148	22
GSHP with Storage	3.4	-92	-27
Biomass boilers	19.6	772	39
Solar thermal	0.8	280	342
Biogas	6.6	555	84
District heating	1.3	-	-
CHP	5.2	-	-
Total	62	1,557	25

Note: Modelling suggests that, under favourable circumstances, district heating and CHP can provide abatement at “negative” cost. However, as costs are more uncertain for these technologies than for the others shown we have excluded (zeroed) them in this table.

A more detailed breakdown of the costs is shown in Figure ES.2. This also shows the relationship between abatement volume and cost per tonne of CO_2 for the years 2025 and 2030. (District heating and Combined Heat and Power are not shown.)

Figure ES.2
Marginal Abatement Cost Curve for Low-Carbon Heat (2025, 2030)



Note: This figure does not represent abatement from district heating and combined heat and power, which we regard as more uncertain. In the "Central" scenario these contribute 6.5 $MtCO_2$ of abatement (and up to 11 $MtCO_2$ in other scenarios explored in this report).

The abatement cost curve shows the magnitude of low-cost abatement, and also illustrates that abatement costs decrease over time while the potential for abatement increases. The reason for the increase in potential over time is due both to the natural market cycle of replacement of heating systems, and to improvements in technology performance and cost that make low-carbon heating more attractive.

An important factor contributing to the "negative cost" abatement is the use of a discount rate of 3.5 percent, and the assumption that there is no cost to overcome barriers to each technology (although the trajectories are consistent with the existence of such barriers). Private discount rates may be significantly higher, and previous research also has suggested that demand-side barriers may add to the perceived cost of adopting low-carbon heat technologies. We explore scenarios with higher discount rates as part of the sensitivity analysis.

The "central" scenario results suggest that the electrification strategy is very attractive for space heating. Heat pumps can provide abatement even when powered by gas-fired electricity generation, but deeper abatement depends on overcoming challenges associated with the provision of low-carbon electricity. The attractiveness of heat pumps depends as well as on improvements in heat pump technology over the next two decades.

Despite the attractiveness of heat pumps, electrification appears to be only a partial solution to decarbonising heat, because the suitability of heat pumps for various heat loads is limited. The results based on the assumptions used in "central" scenario suggest that electrification approach is preferred for those sectors where heat pumps are viable, but that use of bioenergy is also required.

The viability of electrification as a strategy appears relatively robust to changes in electricity carbon intensity and cost. The majority of the electricity powering heat pumps in the "central" scenario is generated by new entrant CCGT (along with some nuclear generation), and the scenario thus does not depend on decarbonising electricity supply. Under a grid decarbonisation scenario the higher electricity cost makes some heat pumps less attractive; however, the lower emissions from power generation mean that total abatement achieved is similar to that in the "central" case.

The large heat pump abatement potential in our "central" scenario nonetheless depends on a number of projected developments serving to improve heat pump attractiveness. This includes significant projected technological improvements in heat pump performance, simultaneous significant reductions in cost, as well as the development of heat pumps with very large heat storage potential, which do not currently exist in the market. If these various improvements were not forthcoming, overall costs could increase significantly. Moreover, the widespread electrification of the heat sector would place significant demands on the electricity system, including requirements for large amounts of new generation capacity as well as grid reinforcement.

To test the robustness of the conclusion about electrification, we investigate a range of sensitivity scenarios, starting with an "Alternative" scenario in which heat pumps are less attractive for a number of reasons.[4]

The "Alternative Scenario" has a reduced role for heat pumps and makes up for this shortfall in abatement through increased contributions from bioenergy and district heating. We assume that bioenergy is used where it can be (in preference to electrification), resulting in significant quantities of both biogas and biomass combustion. The scenario also sees the development of 40 TWh of district heating, half of which takes low-carbon heat extracted from large thermal power plant.

Our analysis suggests that around 240 TWh of biomass fuel could be available from UK sources assuming sufficiently high prices, with potential for additional imports. In the "central" scenario 100 TWh is assumed to be available for heating, most of which is used for biomass combustion, with some 17 TWh used in anaerobic digestion and gasification plants.

In the alternative scenario this constraint is relaxed, and 140 TWh of biomass is used for a range of heat applications. This includes significant amounts of biomass combustion, as well

4 These include higher electricity prices, reduced technical improvements in heat pump efficiency, reduced improvements in heat pump capital costs, and somewhat more restrictive assumptions about suitability.

as 46 TWh of biogas and heat output produced from anaerobic digestion and through the gasification of solid biomass.

In addition to increased bioenergy use, the alternative scenario includes significant quantities of district heating. We have identified 90 TWh of high-density urban heat load favourable to the use of district heating, and consider a scenario where 40 TWh of this potential is developed by 2030.

Our analysis suggests that district heating is a cost-effective abatement option only when low-carbon heat can be provided at (very) low costs. In the long run, the main potential candidate for this role is heat extracted from large-scale thermal power plant. Under favourable circumstances, this could provide a source of large volumes of low-cost heat at low carbon intensity. The source of heat would continue to be available provided thermal power plant continues to operate at significant load factors (including when fitted with CCS). However, more research into the associated barriers and overall viability to using this source of heat is required. Other sources that could contribute to low-carbon district heating include more conventional combined heat and power, and various forms of energy from waste.

Under the scenario developed, a combination of bioenergy and district heating sources provide an alternative to heat pumps without recourse to measures with costs in excess of the CO_2 prices assumed for the period, sketching an alternative route to the widespread electrification in the central case. However, this scenario would rely on heat sources – notably heat from large scale power plant and biogas from the gasification of solid biomass – that require significant development of technology and / or institutional arrangements and market incentives. In addition, the costs associated with district heating are extremely uncertain because of barriers to its uptake. The social costs of overcoming these barriers are not well quantified.

In addition to the “Alternative Scenario” we also consider additional variations on the “Central” case.

Up to 50 percent more abatement than estimate in the “Central” case could be achieved in a “Best-Case” scenario with a higher CO_2 prices and fewer restrictions on resource availability and technology suitability. At the other extreme, a “Worst-Case” scenario with ineffective policy to promote energy efficiency and low-carbon heat sees only limited emissions reductions, with total emissions less than 10 percent beneath 2010 levels by 2030.

Higher CO_2 prices (leading to higher thresholds for eligible abatement) would extend the potential, primarily by increasing the use of bioenergy. Key areas for additional abatement include increased substitution of natural gas by biomass in industry, as well as higher volumes of biogas produced through the gasification of solid biomass.

The extent of heat demand provides an important backdrop. In a “Low Energy Efficiency” scenario, emissions are 20 percent higher than in the “central” scenario. Other important influences include fossil fuel prices, which influence the cost of abatement and therefore the cost-effective potential available given the assumed CO_2 prices.

We also investigate the impact of using higher discount rates to evaluate the cost of low-carbon heat technologies. With discount rates more similar to those used by private organisations and individuals, the cost of abatement increases very substantially, and the abatement potential is reduced by 30-40 percent given the CO_2 prices assumed for the period.

Gas-fired combined heat and power can reduce emissions if the alternative is new gas-fired power generation. It becomes less attractive with lower grid CO_2 intensity. Other forms of CHP could provide low-carbon heat opportunities even with a decarbonised electricity grid.

The desirability of investing in new CHP capacity as an abatement option in this period depends directly on the nature of the power generating capacity it would replace. The "Central" modelling scenario uses the CCC's "medium emissions intensity" assumptions for the electricity sector, with new peak load capacity served by CCGTs. Gas-fired CHP can provide abatement in this case (albeit with reduced running hours). CHP ceases to provide emissions reductions at the point where the new entrant power plant it displaces emit 0.28 tCO_2 or less per MWh of electricity output.

Other forms of CHP may also have a role:

- Where low grid-intensity scenarios include CCS power stations, it is possible to extract heat from steam turbines to provide joint heat and power at very low carbon intensity. However, this would depend on the use of large-scale district heating networks to transport the heat to end-users. (More generally, using "waste heat" from existing thermal plants amounts essentially to turning them into CHP plants.)
- Biomass CHP also can provide potential for emissions abatement. However, this requires relatively large amounts of biomass, so may not be desirable in scenarios where the overall biomass resource is scarce. Except if it were to displace biomass-only power plant, it also looks like an expensive abatement option.

For the period beyond 2030, a variety of demand-side constraints on the suitability of technologies limit the potential for abatement. Unless these can be overcome, the scope for further reductions in emissions from heat may be curtailed.

Barriers and technical challenges to the further expansion of low-carbon heat include space requirements, heat grade requirements, and environmental concerns (air emissions and noise pollution). There is little data on the performance of heat pumps in the UK building stock, and little experience to judge the significance of other potential obstacles to their use (notably, noise pollution). Overall, we estimate that the use of heat pumps may face significant challenges in around 50 percent of domestic heat and 30 percent of non-domestic space heating applications (depending on the level of insulation that can be achieved). Heat loads for which alternatives to fossil fuels may be particularly difficult to find include 60 TWh of heat demand from uninsulated solid wall houses as well as 50 TWh of industrial process heat not easily served by the combustion of solid biomass. Biogas may be the option facing the least obstacles for these and other hard-to-reach heat demands.

Achieving deep reductions in the fourth budget period are likely to require a variety of different measures, some of which imply relatively high cost of abatement. From our analysis, the main contender is a mix of electrification of space heating alongside bioenergy for higher-temperature heat. However, district heating utilising heat from power stations merits more investigation as an alternative for dense urban areas.

If electrification proved more difficult or expensive than assumed in the central case, a second route would be to make greater use of bioenergy and district heating. Under favourable conditions, heat from power stations could provide abatement on a very large scale and at costs no higher than those of heat pumps. However, we regard this route as quite speculative given the state of research, and the barriers are likely to be significant.

Our analysis suggests various ways that the results are sensitive to different assumptions. In many cases, which assumptions turn out to be accurate may only be revealed much closer to the fourth budget period.

Our study also identifies a range of issues that may be worth investigating further now:

- Integrated analysis of interactions between heat and power sectors. Intersections identified and partly explored in this project include various issues arising for heat pumps (new capacity requirements, load profiles of new electricity demands created, need for grid reinforcement) as well as combined heat and power (value of flexibility, reduced load factors for gas-fired plant).
- More detailed study of biogas potential and options. This could extend both to more detailed study of potential (ideally on a spatial basis), technology and plant options, and the merit of alternative uses of biogas across different end uses.
- Reviewing the findings of this work in light of field trials of heat pump performance due to be published later in 2010.
- More comprehensive analysis of the feasibility and costs and benefits of extracting heat from large-scale power plant.
- Analysis of the range of barriers to the low-carbon heat options identified, and analysis of policy options, including consistency of current policy framework with the longer term scenarios presented here.
- Improving the estimate of district heating potential, and an estimate of both the social cost of overcoming the barriers to large-scale expansion of district heating networks, and the adjusted costs of the networks if some of these barriers (e.g. accelerated and high connection rates) cannot be overcome.
- Further analysis of the requirements and potential for serving district heating networks with waste heat from power stations.

1. Introduction

1.1. Background

Heat accounts for approximately half of UK energy use and associated CO_2 emissions. Meeting the UK's ambitious target to cut greenhouse gas (GHG) emissions 80 percent by 2050 therefore will require very significant cuts in emissions from heat. These can be achieved both by reducing heat use through energy efficiency, and by reducing the emissions intensity of heating. The Government is in the process of developing and implementing various policies designed to put the UK on a path towards reduced emissions from heat, including a range of energy efficiency policies and the planned Renewable Heat Incentive.

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At a high level, there are three distinct technological "paths" that could be followed to put the UK onto the required heating emissions trajectory. The first of these relies on combining widespread deployment of heat pump technologies with decarbonisation of the power sector. The second is the use of bioenergy—both through the use of the existing gas network to transport biogas, and through solid or liquid biomass—as a primary source of low-carbon heat. The third technology path is the use of district heating networks, complementing (and perhaps ultimately, superseding) the existing gas network as the main carrier of energy for heat.[5]

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An important possibility is that the heterogeneity of heating requirements across various sectors of the economy will mean that the best strategy is not a "pure" version of any of the three paths set out above, but one that combines elements of each. The detailed examination of the nature of heat use that underlies our quantitative analysis makes it possible for us to explore a wide range of parameters that affect the potential for and cost of each technology path for different heat users across the UK economy.

1.2. This Report

This report presents our methodology and the results of our analysis, in the form of detailed scenarios for the feasible adoption of low-carbon heat technologies in the period 2020-2030. These are built up through a projection of future heat demand, and an assessment of the feasibility of meeting this through a range of low-carbon technologies, including air- and ground-source heat pumps, biomass combustion, solar thermal, biogas, as well as combined heat and power and district heating.

The analysis presented in this report is organised as follows.

As a foundation for the other analysis, our first step is to develop projections of heat demand and a produce detailed map of UK heat use by a range of end-user segments. This detailed categorisation allows for subsequent analysis of the cost and potential of low-carbon technologies, and is described in Chapter 2.

A key potential alternative to heat generation from fossil fuels is bioenergy of various forms. In Chapter 3 we develop scenarios for the supply of solid biomass, biogas from anaerobic digestion, synthetic biogas from gasification, and a review of the potential role of liquid biofuels.

In Chapter 4 we assess various technical challenges to the adoption of low-carbon heat technologies. These include space requirements, the ability to provide the heat grade required for different end-user applications and environmental considerations (notably, air quality concerns and noise pollution). We assess each of these challenges for each technology and a large number of end-user applications, to produce a detailed, bottom-up estimate of the technical potential of the various technologies. In addition, we also consider challenges to the overall electricity system of the substantial new loads that would be created through the widespread adoption of heat pumps, as well as the implications of combined heat and power production in the context of a decarbonised electricity grid.

This is followed by an analysis of district heating in Chapter 5. We provide a new estimate of the potential for district heating, using recently completed analysis of the spatial distribution of heat demand, and assess the role this may perform in the overall reduction of emissions from heating. We also discuss the barriers to district heating, and the timeline of deployment required for a large-scale roll-out.

To develop consistent scenarios that account for supply-side and demand-side constraints, and also identify the least-cost abatement options, we make use of a detailed model of the UK heat sector and supply curve for low-carbon heat technologies. The methodology and extension of this model to 2030, as well as key input assumptions, are described in Chapter 6.

In Chapter 7, we present the results for a number of scenarios, characterising abatement potential and cost. We also investigate scenarios for key factors including different developments of the electricity sector, bioenergy availability, and energy efficiency. In addition, we explore the sensitivity of the results to different fuel prices, technology assumptions, and cost methodologies.

Chapter 8 concludes.

2. Heat Demand Projections

The first task for our analysis has been to develop detailed projections of heat demand for the period 2020-2030 for a wide range of heat users across the UK economy. The sections below present our methodology for the domestic, industrial, and commercial / public sectors. In our subsequent modelling we consider the impact of changes to our central heat load assumptions, due to differences in energy efficiency improvements over the period. We therefore also discuss how heat loads in each sector would differ if we varied assumptions about efficiency improvements.

2.1. Domestic Sector Heat Demand Projections

We developed projections of heat demand for the domestic sector for the period 2020-2030 from a number of sources. We started with current heat loads for different building types and combined these with projections of the domestic uptake of energy efficiency measures that were previously developed by the Committee on Climate Change. These assume close to full uptake of cavity wall and loft insulation as well as large-scale uptake of other measures before the 2020s, but vary in their assumptions surrounding the uptake of solid wall insulation (SWI) as well as some other measures. We then combined these projections for the existing housing stock with assumptions about the characteristics of new build.

We then used a variety of sources to split the overall UK domestic heat demand by location, counterfactual fuel, house type, and building age / construction. The following sections provide further details.

2.1.1. Overview of segmentation

Figure 2.1 shows how we categorise domestic heat loads. Each heat load segment is associated with one of three house types, one of three fuel counterfactuals, one of three locations, and one of four ages / fabric types. Overall, there are 108 domestic demand segments or house types represented in the model.

Figure 2.1
Heat Load Segmentation (Domestic)

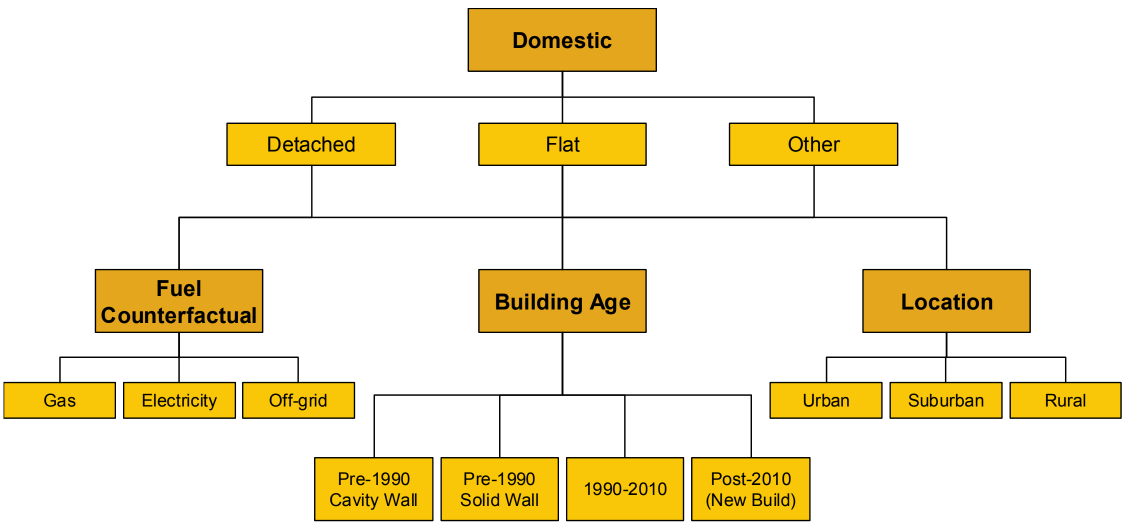


Table 2.1 summarises the sources of the parameters we use to define the per-household and aggregate UK domestic heat load projections for the domestic sector.

Table 2.1
Inputs Used to Develop Per Household Heat Loads

Parameter / Variable	Data sources	Comments
Actual per HH heat load (existing dwellings in 2005)	The UK Potential for Community Heating with Combined Heat and Power" Study by BRE	BRE Data are for 2005
Average weather conditions per HH heat load (existing dwellings for 2005 stock)	BRE Domestic Energy Fact File 2007 England, Scotland, Wales & Northern Ireland (2005 data) (DEFF) (2005 data) Degree Day Data	We corrected the 2005 per HH heat demand to reflect average annual degree days for the period 1985-2005, using DEFF to estimate space vs. hot water heating loads.
Relative per HH heat loads by house type (existing dwellings, 2005)	"The UK Potential for Community Heating with Combined Heat and Power" Study by BRE	Used to estimate relative annual heat demands by dwelling type, age (combined with assumptions about efficiency of heating equipment).
	English Housing Condition Survey (ECHS) Scottish House Condition Survey (SHCS) Key Findings 2008 NI Housing Condition Survey (NIHCS) 2006	Used to estimate relative heat loads by dwelling location, age and wall type.
Per HH heat loads by house type (existing dwellings, 2010)	DECC UEP Model	Used to estimate the decrease in heat load of average housing stock from 2006 to 2010
Per HH heat load by house type (existing dwellings, 2011-2030)	CCC energy efficiency uptake assumptions	Used to develop trajectory of annual heat demands for pre-1990 cavity wall, pre-1990 solid wall and 1990-2010 dwellings
Per HH heat loads by house type (new dwellings, 2010)	CLG Zero Carbon Homes Impact Assessment (p. 28 – based on 2006 building regulations)	We assume the same heat demands in line with targets regardless of location, implying limited difference in floor area and that insulation standards will compensate for variations in weather and wall exposure.
Per HH heat loads by house type (new dwellings, 2011-2030)	Consultation on Code for Sustainable Homes and the Energy Efficiency standard for Zero Carbon Homes	We assume the same standards from 2016 onwards.

As noted in Table 2.1, we base our assumptions about new build heating demands for 2010-2016 on the specific heating requirements (kWh/m^2) for 2006 building standards, as set out in the CLG Zero Carbon Homes Impact Assessment (p. 28). We interpolate between 2006 and proposed standards for 2016 to estimate the per-household space heating loads for houses built between 2010 and 2016. We multiply these standards by the average areas for each dwelling type, obtained from the EHCS 2007. We combined these space heating loads with deemed hot water loads from the RHI consultation and internal gains estimated from non-heating electrical demand figures presented in the BRE district heating studies to calculate delivered heat loads for heating and hot water in 2010.

We calculate total heating loads for new build dwellings in 2016 by using targets for space heat load set out in "Sustainable New Homes – The Road to Zero Carbon, Consultation on the Code for Sustainable Homes" and from the Energy Efficiency standard for Zero Carbon Homes.[6] We added to this the deemed hot water loads (assumed to be equal to the 2010 assumptions) and deducted the internal gains from electrical appliances which the proposed space heating targets do not account for. The final heat loads for new build are summarised in Table 2.2.

Table 2.2
Heat Loads for New Build (2010 and 2016+)

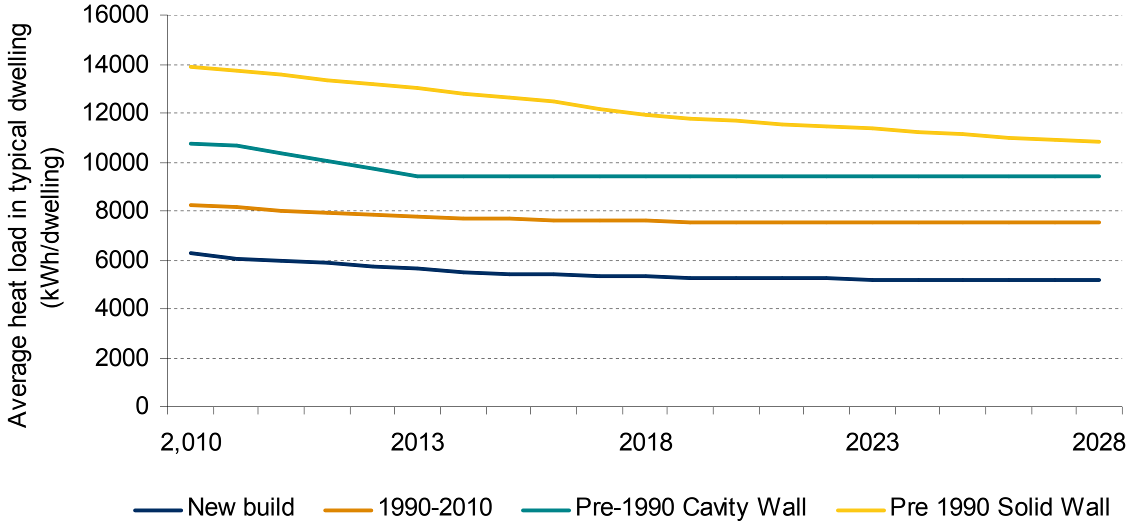
	Total Heat Loads (kWh/year)	
House Type	**2010**	**2016 and later**
Detached	8,600	6,600
Flats	5,400	4,000
Others (terrace, semi-, bungalow)	6,300	4,700

After 2016, we assume that the per-household heat demand for new dwellings is constant, although this assumption can be revised within the model.

Figure 2.2 shows the development of domestic heat loads for one house type ("Other houses", which includes semi-detached and terraced houses) over the period 2010-2030. The figure shows the average useful heat demand of all stock in this category. Although we assume the average heat load of a single new dwelling built in 2030 is the same as one built in 2016, the average across all new (post-2010) dwellings continues to fall as older dwellings are replaced.

6 Dwellings should be constructed in 2016 to achieve a space heating demand of 39 kWh/sqm for flats and mid terraces and 46 kWh/sqm for end terraces, detached houses and bungalows

Figure 2.2
Development of Average Heat Load per Dwelling, by Age / Fabric



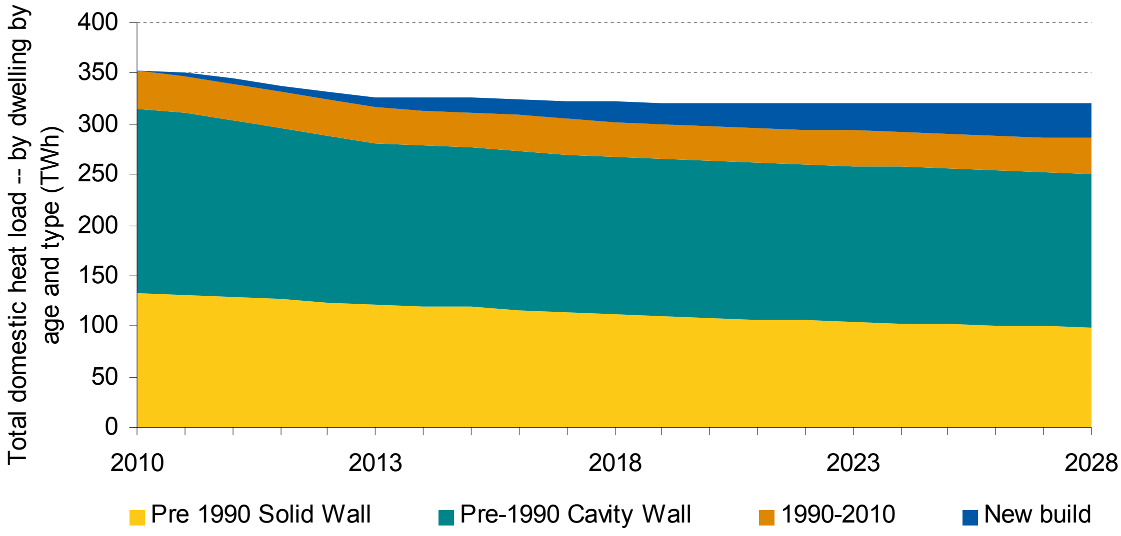
To calculate the overall UK heat demand from the domestic sector, we combine the per-household data with data on the shares per house type and total population of the housing stock. We use EHCS, SHCS, and NIHCS data for the splits.

Table 2.3
Inputs Used to Develop Building Stock Population and UK Heat Demand

Parameter / Variable	Data Sources	Comments
Number and proportion of different house segments	DEFF (2005 data)	Provides split of dwellings by fuel type, dwelling type and age in 2005
	EHCS, SHCS, NIHCS	Provides split of dwellings by location type (urban, suburban, rural) and wall type
2010 Stock Numbers	EHCS, SHCS, NIHCS for population total	Used to project stock numbers to 2010 for base year and for 2011-2030.
	UEP 38 model assumptions	Approximately 270,000 – 310,000 new dwellings / year from 2006-2030;
		0.2% of pre-1990 stock demolished annually
England, Scotland, Wales and Northern Ireland housing useful heat demand	Combination of all above	Calculated by multiplying heat loads from Table 2.1 by stock estimates. We calibrate the resulting total energy input to ensure agreement with overall heat demand (including electrical heat) from DEFF.

Figure 2.3 shows the development of the UK domestic heat demand over the period 2010-2030 in the "Central" energy efficiency scenario (see next section).

Figure 2.3
Composition of Heat Load ("Central" Scenario)



2.1.2. Additional scenarios for domestic energy efficiency

As noted above, we rely on projections of total uptake of energy efficiency measures in the existing housing stock that were provided by the CCC. The projections are not differentiated by house type. We have assumed that both cavity wall and solid wall insulation are taken up only by pre-1990 dwellings, whereas all other energy efficiency measures are assumed to be applicable to all existing dwelling types.

The energy efficiency scenarios for the domestic housing stock differ in their assumptions about the rate of uptake of solid wall insulation. In addition, the high-efficiency scenario differs from the low and central scenarios in the uptake of some additional efficiency measures (e.g., floor insulation) with relatively minor impacts on overall heat demand. In the central heat load scenario some 2 million households install solid wall insulation (SWI) by 2020, with this trend continuing so that a total of around 3.5 million have installed SWI in 2030. In the low efficiency scenario, the uptake of solid wall insulation is significantly slower, with uptake of only 0.3 million in 2020 and 0.6 million in 2030. Finally, the high efficiency scenario reaches 2.7 million in 2020 and 5.7 million in 2030, corresponding to 80 percent of the total potential. For reference, the uptake is shown in Table 2.4.

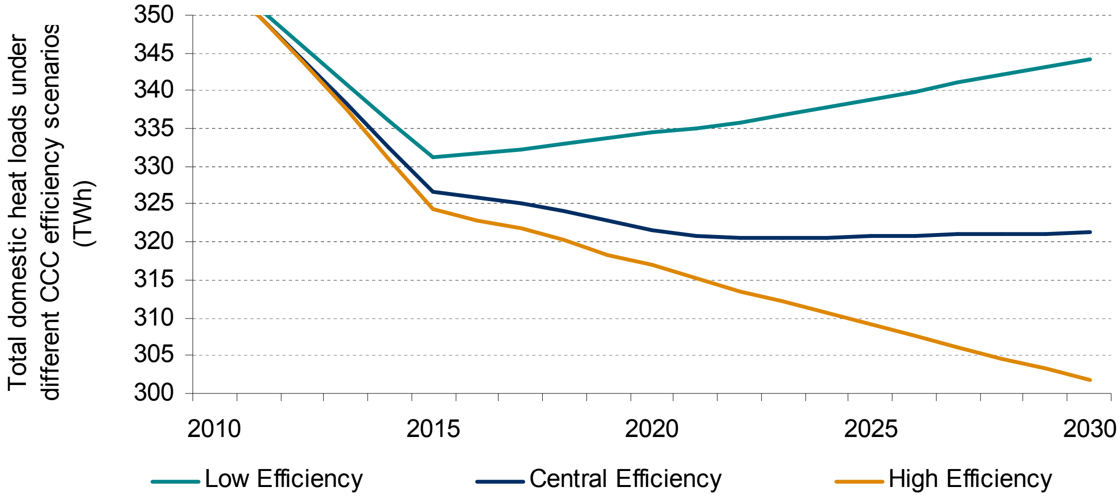
Table 2.4
Domestic Energy Efficiency Scenarios

Scenario	Uptake (million dwellings)	
	2020	2030
Low efficiency	0.3	0.6
Central efficiency	2.0	3.5
High efficiency	2.7	5.7

Source: CCC assumptions

Figure 2.4 compares the trajectory of total UK domestic heat loads under the three scenarios. The high scenario leads to 18 TWh additional savings from SWI relative to the central scenario in 2030, with other measures contributing another 3 TWh of savings. By contrast, energy use in the low scenario is 23 TWh higher than in the central scenario.[7]

Figure 2.4
Comparison of Total Domestic Heat Load, Selected Scenarios



2.2. Commercial / Public Sector Heat Demand Projections

We have developed the projections of heat demand for the commercial / public sector from several sources. Our starting point is a set of data made available by BRE[8] in 2005, which shows the detailed mapping of heat demands by commercial and public sub-sector and by end-use (i.e. space heating, water heating, lighting etc.); also disaggregated according to fuel used. We then update this energy use using the DECC UEP model projected energy outputs to move from the original 2002 BRE base year to a new base year at 2008, while also removing non-heat energy use. We then use UEP to project energy use for the sector up to 2030.[9]

2.2.1. Segmentation

The commercial / public sector is split into categories similar to those we use for the domestic (and the industrial) sector. The heat load is split according to the fuel counterfactual

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7 This chart shows final heat demand. The underlying fuel consumption trajectory follows a pattern similar to that implied by DECC's UEP 38, although it is around 5 percent higher.

8 This data is for the year 2002 and was supplied confidentially to the Carbon Trust for a range of policy costing exercises including a study for the Energy Efficiency Innovation Review (2005-06).

9 UEP only extends to 2025, so we extrapolate the trend from UEP out to 2030.

(electricity, gas or off-grid), location (urban, suburban and rural) and age (pre-1990, 1990-2010, and post-2010). We also distinguish between small and large heat loads in the sector.[10]

In total this represents 108 possible segments, of which 24 are not populated (because we assume no non-net-bound heating in urban and suburban areas), leaving a total of 84 segments used in modelling.

We made use of detailed fuel-use data for non-domestic buildings in England and Wales and for Scotland and Northern Ireland, to account for the different weight that each fuel is given in each. This information is used to establish the size of each demand segment in our modelling.[11]

2.2.2. Assignment of energy demand to age categories

The combination of BRE data with UEP growth provides us with heat load projections for the commercial / public sector, and we need to divide this into our demand segments for modelling. To do this, we must make assumptions about the rate at which existing building stock is demolished, the rate at which new build occurs, and the relative energy intensities of each age group over time. Table 2.5 summarises the inputs that we use to calculate the proportion of the total commercial / public sector heat load demand for each age cohort:

Table 2.5
Inputs Used to Develop Commercial / Public Heat Loads

Parameter / assumption	Data sources	Parameter value / comments
Aggregate sector heat demand (2010-2030)	UEP38	Reflects GVA growth and efficiency improvements
Energy intensity of existing buildings	Central assumption set to align with UEP	1.1% improvement per year
Energy intensity of new buildings	Assumption	35 percent more efficient than 2008 stock average
Demolition rates	Assumption	Assume 80-year life, implying 1.25 percent of pre-1990 stock demolished per year

Together these determine the distribution of the age and corresponding heat demand of the building stock.

UEP shows increasing heat loads between 2020 and 2030 in the commercial / public sector, despite assumed reductions in the energy intensity of the associated economic activity – and

[10] BRE's analysis differentiates between 10 sub-segments (e.g. commercial offices, health, warehouses etc.) which we aggregate into our own "Public" and "Private" sub-segments to use in our modelling. The "Public" segment is composed of the sub-segments "Education", "Government" and "Health" in the BRE data. All other sub-segments are assumed to belong to the "Private" segment. These sub-segments are distributed across urban, suburban, and rural areas in different proportions, which affects the overall proportions of heat load in each location.

[11] The fuel-split data were derived from two DECC publications: "Total sub-national final energy consumption 2005, 2006, 2007" (URN: 10D/P18A) and "Energy Consumption in the UK Overall data tables 2009 update".

of the existing building stock. Given the assumed gradual demolition and replacement of older buildings, the increases in heat demand can only be explained by expansion of the building stock itself, through new build. We can use the above data and assumptions to estimate the proportion of building stock of each age, and of the heat demand accounted for by each age cohort.

Table 2.6
Heat Load Distribution by Building Age (Commercial / Public Sector)

Age category	2010	2015	2020	2025	2030
Pre-1990	75%	65%	54%	44%	36%
1990-2010	25%	24%	22%	20%	18%
Post-2010	0%	11%	24%	36%	47%
Total	100%	100%	100%	100%	100%

Source: AEA Analysis

2.2.3. Energy intensity scenarios

As noted in Table 2.5, our central scenario assumes that the energy efficiency of commercial / public sector buildings improves at a rate of 1.1 percent per year over the period 2010-2030. We also assume that the energy intensity of new build is 35 percent lower than that of the 2008 building stock (this allows us to calibrate heat demands to what is projected in UEP). We assume no further improvements in the energy efficiency of these buildings.

We also consider two alternative scenarios. The associated assumptions are presented in Table 2.7, below.

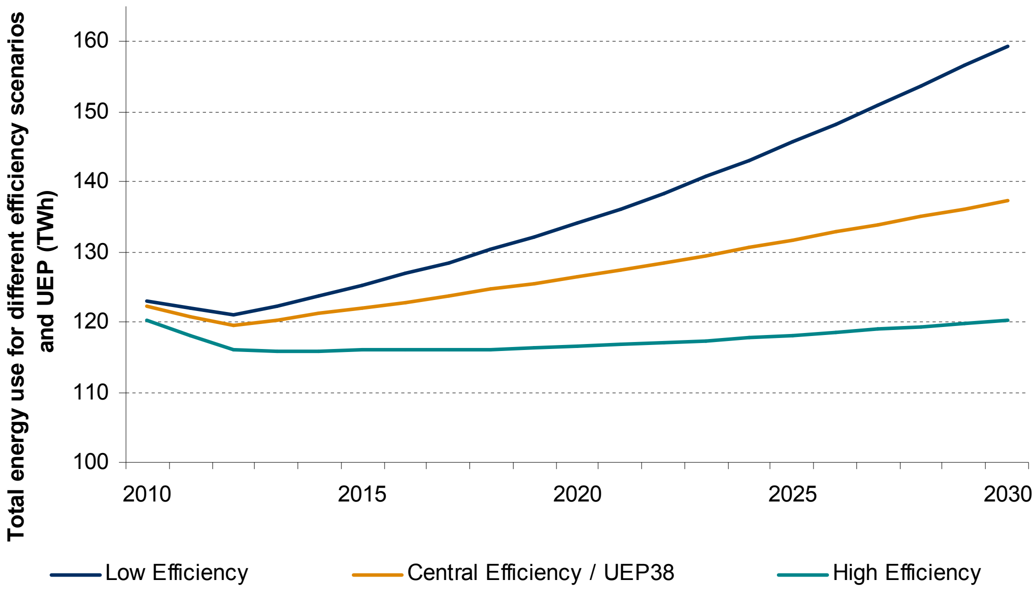
Table 2.7
Energy Intensity Improvements (Commercial / Public Sector)

Scenario	Existing build annual energy intensity improvement (p.a.)	Existing build cumulative improvement (2010 to 2030)	New build improvement (relative to 2008)
Low	0.8 %	15 %	30 %
Central	1.1 %	20 %	35 %
High	1.9 %	31 %	40 %

Source: AEA analysis

Because we have calibrated the central scenario to match the projections in UEP, the total heat demand in the central scenario is identical to UEP. Total heat demand under the three scenarios is shown in Figure 2.5.

Figure 2.5
Heat Load Projections (Commercial / Public Sector)



2.3. Industrial Sector Heat Demand Projections

2.3.1. Segmentation

Like the domestic and commercial / public sectors, the industrial sector is split into a number of heat demand segments. The total heat load is split by size (large and small), by heat grade (high temperature direct dry process heat from combustion used for example in steel processing; low temperature steam or hot water based process heat, and finally space heating). We also split the total heat load by counterfactual fuel (gas, electricity and off grid fuels), by age (pre-1990, 1990-2010 and post-2010) and by location type (urban, suburban and rural location).

In total this represents 162 possible segments, of which 72 are not populated (because we assume no off grid heating in urban and suburban areas and because we assume that electric industrial process heating cannot be replaced by other technologies leaving a total of 90 segments used in modelling.

2.3.2. Heat Projection Scenarios

We have developed the projections of heat demand for the Industrial sector using the output from the current ENUSIM model, which is currently being used to identify potential reductions under future Climate Change Agreements (a study for DECC yet to be published).

The ENUSIM outputs are used to develop two sets of information:

- Mapping of the heat demands (both high and low temperature) amongst detailed industrial sub-sectors at the base year of 2008.[12]
- Identification of a sub-sector 'useful energy demand' projection to which we then add an efficiency improvement effect. This latter efficiency effect can be identified and varied separately (as an annual % change) for total process heat, space heating (both fossil fuel and electricity based) and high temperature process heat.

The industrial heat demand projections therefore result from changes in the following two components:

- Energy intensity resulting from changes (usually improvements) in energy efficiency and process technology.
- A sector structural shift effect, which is independent of the energy efficiency effects; and reflects future changes in sectors 'useful' energy demand resulting from factors such as product changes, 'standing losses' and production rationalisation projected forward in time. These projections are fixed from historic data modelling

Three energy efficiency scenarios have been prepared: central, higher efficiency and lower efficiency. These relate to the take-up rate of efficiency improvement measures, while the structural effect is fixed by historical behaviour.

- Central scenario: to match the UEP38 central scenario performance an 18 percent improvement in efficiency is required between 2008 and 2027
- High efficiency scenario: assumes a 30 percent reduction in heat demand due to technical efficiency between 2008 and 2027;
- Low efficiency scenario: assumes zero savings between 2008 and 2027.

Our absolute heat initial load levels are based on ENUSIM, which allows us to include electricity used for heating, and to identify and classify different types of heat demand.[13] In the central case, the technical intensity improvement has been set in each of the heat type cases to match the UEP38 indexed "central" energy projection change overall. By matching the heat demands to the indexed energy projections, the heat projections are made consistent with the rates of growth and underlying efficiency changes in the UEP central case. This gives the efficiency intensity improvement implicit in providing the same overall change as seen by UEP38; however, also taking the structural change projections into account. The overall rate of efficiency improvement is typically 1.8 percent per year, but less for high temperature heat where the improvement is only about 1 percent per year.

12 ENSUIM does not include coverage of heat used in refinery processes. Some steel sector energy use also is not included (there is some discussion whether the use of coke is best viewed as energy consumption or as a feedstock in this context).

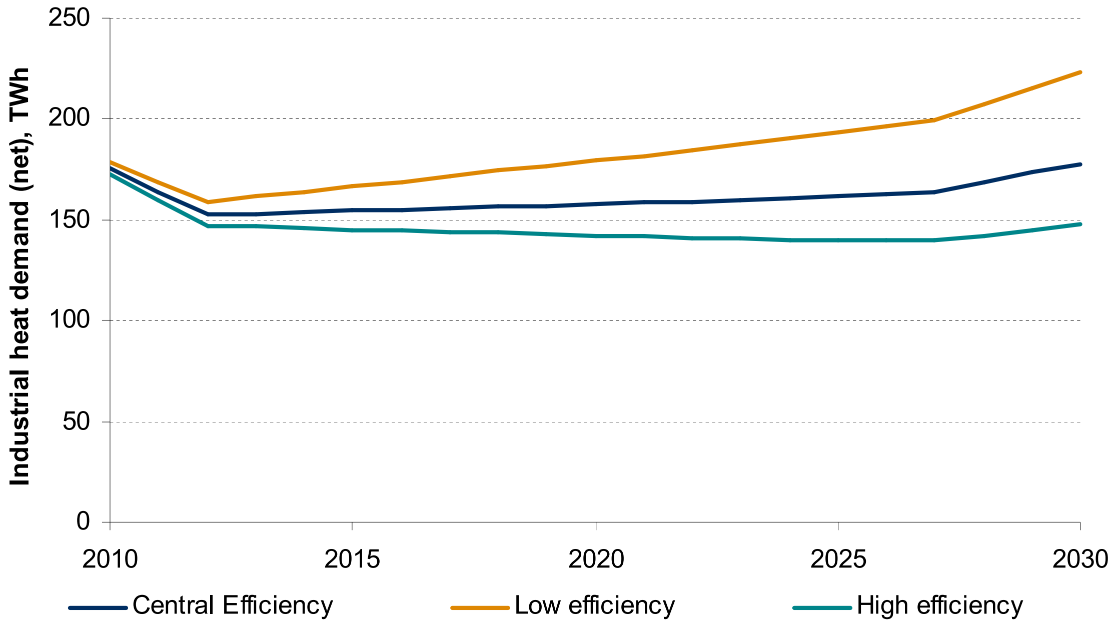
13 We include electricity used for space heating in the projections, but do not include electric process heat, as these are difficult or impossible to substitute with other sources of heat.

The subsector growth scenarios for the ENUSIM model required that we disaggregate the sectors in the UEP 38 growth projections to the more detailed subsector levels. To do this we adopted the same method as used for the Climate Change Committee CO_2 budget MACC study, but using the revised UEP38 sector projections. Essentially, we use the differences between the rates of growth in the detailed ENUSIM subsectors, according to a study carried out by Oxford Economics in 2007; and scale these different growth rates to be consistent with changes in the higher-level UEP sectors.

The Oxford Economics projections (which are industrial sub-sector output projections – both GVA and physical outputs, depending on sector) are also used directly in the projection calculations to make allowance for economic growth against the background of improving efficiencies.

Figure 2.6 below summarises the heat load projections for the industrial sector

Figure 2.6
Total UK Industrial Heat Load Projections



2.3.3. Other considerations

For fuel splits in the devolved administrations, we made use of the data used for the commercial / public sector, as described above. Scarcity of data on the age range of manufacturing sites, their locations (urban, suburban and rural) and their size distributions means that these proportions had to be assumed, and may need to be revised as better information becomes available.

3. Bioenergy for Heating

3.1.1. Scenarios for Biomass Supply

In this section we present an analysis of biomass supply from UK indigenous sources, as an input into considering scenarios for biomass available for heat.

3.1.2. Overall availability of UK biomass

We have reviewed a number of studies of UK biomass resource to produce an overall estimate of UK biomass resource in the 2020s. Appendix A contains a more detailed summary of the underlying data and its use. In broad terms, we have relied on E4tech (2009) as a starting point for the estimate, but made revisions to estimates of feedstock from energy crop and short-rotation forestry to account for the analysis in ADAS (2009), and also revised the estimated quantity of waste wood using information in WRAP (2008 and 2010). Biomass Task Force (2005) was used to confirm some of the other estimates.

Our summary findings are presented in Table 3.1. As the table shows, the large majority of the resource is provided from energy crops. Short rotation forestry and straw are the next two largest categories, with small contributions from a number of other sources.

Table 3.1
Summary Estimate of UK Biomass Resource by Feedstock Category

Final estimate	2020	2030	2020	2030
	modt	modt	TWh	TWh
Energy crops	10	30	50	150
Straw	3	3	19	19
Forestry residues	1	1	5	5
Stem wood	1	1	5	5
Short rotation forestry	-	8	-	38
Arboricultural arisings	0	0	2	2
Sawmill co-product	1	1	5	5
Waste wood ('clean')	1	1	5	5
Waste wood ('treated')	1	1	6	6
Waste paper and card	1	1	4	4
MSW (total)				
Total	20	48	101	238

Not all of these types of feedstock can be used for all applications. A broad categorisation is provided in Table 3.2. Table 3.3 in turn shows how this maps to the overall amount of biomass resource available to different end-use sectors. The main implication is that the large majority of biomass potentially would be suitable for commercial and industrial applications, but only around 20 percent of the estimated resource is suitable for domestic applications.

If the resources identified in the studies are now categorised according to the end-use then we have the results as summarised in Table 3.2 below.

Table 3.2
Consolidated Estimates of UK Biomass Resource by Quality

Category	Description	Resources	2020 modt	2030 modt	2020 TWh	2030 TWh
1	Clean wood - high quality/low ash -	Stem wood. SRF, sawmill co-product	2	10	10	48
2	Residues and clean lower quality wood	Energy crops, straw, FR and clean element of waste wood (industrial + construction), arboricultural arisings	16	36	81	181
3	Treated wood and other wastes - only suitable for industrial use	Treated waste wood (MSW and demolition), paper and card	2	2	9	9
Total	-	-	20	48	101	238

Note: Modt denotes “million oven-dried tonnes”.

Table 3.3
Total UK Biomass Resource Available for Each End Use Category

Sector	Categories	2020 modt	2030 modt	2020 TWh	2030 TWh
Domestic	1	2.0	9.5	10	48
Commercial	1 + 2	17.7	45.2	92	229
Industrial	1 + 2 + 3	20.2	47.6	101	238

3.1.3. Scenarios for biomass availability

The above gives an estimated upper bound on the amount of indigenous biomass fuel that could be made available in the 2020s. In practice, a number of considerations will influence how much of this will be brought to market as fuel, and then in turn what share will be used for heat rather than other applications.

Broadly speaking, the main considerations include:

- The extent to which required changes in practice are implemented (waste collection, regulation of by-products, agricultural and silvicultural practice, etc.).
- The creation of supply chains and arrangements for reliable fuel supply.
- The extent of competition from non-energy use for biomass or land resource (notably, agricultural land for energy crops)
- The extent of competition from other uses for biomass fuel for transport and electricity
- The weight given to, and stringency of, sustainability criteria, including life-cycle CO_2 emissions as well as biodiversity and other local environmental impacts.
- The availability of imports to supplement indigenous supply (including for other sectors which otherwise would need to rely on indigenous biomass resource).

To reflect these and other considerations, we use three scenarios for the availability of biomass to the heat sector. [14] The scenarios have been developed by the CCC, for consistency with other assessments. They have the following characteristics and assumptions:

- High scenario: 200 TWh of biomass available to the heat sector. This amount is equivalent to nearly all UK indigenous resource being used for heating. This is consistent with only limited use of biomass in electricity generation, and reliance on imports for biofuels in the transport sector. According to E4tech (2009) estimates, the scenario also is consistent with relying on abandoned or marginal agricultural land for the production of energy crops, with limited adverse sustainability implications.
- Central scenario: 100 TWh of biomass available to the heat sector, corresponding to half the amount in the high scenario. This is a more conservative scenario, where not all of the UK potential resource is available to the heat sector. This is consistent with a more conservative assessment across the range of factors noted above. It also corresponds broadly to the share of heat that cannot be served by other low-carbon heat technologies.
- Low scenario: 50 TWh of biomass available to the heat sector. This is a highly conservative scenario intended to explore and illustrate the consequences of using only limited biomass to reduce emissions from heating.

In addition, the scenarios separately the share of feedstock represented by clean, high-quality wood with low ash content suitable for domestic combustion. Table 3.4 summarises the scenarios.

Table 3.4
Biomass Supply Scenarios

Scenario	Year	Suitable for all heat loads (including domestic)	Suitable only for non-domestic heat loads[1]	Total potential
-	-	TWh	TWh	TWh
Low	2020	5	45	50
Low	2030	5	45	50
Central	2020	5	45	50
Central	2030	20	80	100
High	2020	9	76	85
High	2030	40	160	200

Note: District heating can use biomass resource that is suitable for non-domestic heat loads.

An immediate observation is that a relatively small amount of biomass has sufficiently low ash content and other properties required for use in the domestic sector. In the central scenario, for example, 20 TWh in 2030 would serve a heat load of around 17 TWh, or 6 percent of the total domestic-sector heat load. This restriction means that much of the domestic sector will need to rely on either heat pumps or district heating for the supply of low-carbon heat.

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14 These scenarios do not include food and agricultural waste streams suitable for anaerobic digestion. These are estimated separately in section 3.2.1 below.

3.2. Scenarios for Biogas Supply

In this section we present scenarios for the supply of biogas. We first discuss anaerobic digestion, and then the production of synthetic natural gas (SNG) through gasification of biomass (bio-SNG).

3.2.1. Anaerobic digestion

The production of biogas through anaerobic digestion (AD) can make use of two main categories of feedstock. The main route is to use of various waste streams and various agricultural residues, of which food waste is the most important category. This can offer the prospect of biogas production at relatively low cost. However, the potential is limited to the amount of feedstock available.

A second route is to make use of dedicated energy crops suitable for AD (including maize silage, grain, and grasses). This can expand the potential significantly, depending on the amount of agricultural land made available for feedstock production. However, the use of valuable feedstock increases the cost significantly.

In this section, we focus on developing estimates for the availability of food waste, as the most important single determinant of AD potential in the near- and medium term. In later sections, we extend this to considering the use of dedicated energy crops.

We then sketch the broad models for the production of biogas, distinguishing waste management plants from farm enterprise models of AD.

3.2.1.1. Current food waste quantities

In 2009, AEA produced a set of projections for biogas energy output to 2020. It was assumed that the scope for energy crops, in AD plants, would be limited to a small number of AD plants that will be run mainly by agricultural enterprises. This was based on the trends observed to date (WRAP, October 2009). We extend this analysis to the period 2020-2030 below.

A number of reports have estimated the likely pathways for biogas feedstock availability over the near to medium future. In this section we summarise the main findings regarding food waste availability.

WRAP (2008) reports that food waste production amounts to around 18 million tonnes per year, of which 6.7 million tonnes is discarded by UK households.

NNFCC (July, 2009) report suggests that there is 8.7 million tonnes food waste available from commercial and industrial sectors, of which there is 1.6 million tonnes from retailers, 4.1 million tonnes from food manufacturers and 3 million tonnes from food service and restaurants.

According to Defra (January, 2009) the UK produces over 100 million tonnes of organic material per year that could be used to produce biogas; comprising 12-20 million tonnes of food waste (approximately half of which is municipal waste collected by local authorities, the rest being hotel or food manufacturing waste); 90 million tonnes of agricultural material such as manure and slurry; and 1.73 million tonnes of sewage sludge.

While the quantitative estimates within different sub-categories of food waste are uncertain, the overall quantity of biodegradable food waste that is reported in different sources is around 18 million tonnes per year, and this is what we have assumed in this report as available in 2008. We have divided the total amount among four different sub-categories as shown in Table 3.5 below.

Table 3.5
Assumed Quantities of Food Waste by UK Regions (Tonnes/Year) in 2008 as Used in the Current Projections

Type of waste	England	Wales*	Scotland*	NI*
	t/y	t/y	t/y	t/y
Food waste - household	5,360,000	300,000	570,000	470,000
Food waste - commercial	4,800,000	270,000	510,000	420,000
Food waste - industrial-PPC returns	2,080,000	120,000	220,000	180,000
Food waste - industrial – other	2,160,000	120,000	230,000	190,000

Notes: 1.The figures for Wales, Scotland and NI have been adjusted using population equivalent values of 5.6 percent, 10.7 percent and 8.7 percent compared to England

2. The category 'industrial PPC returns' is taken from Defra's Food Industry Sustainability Strategy work that AEA was appointed to undertake (Defra, February, 2007) and ultimately comes from Environment Agency data based on PPC Returns. The EA data, from 2005, are based on the releases and transfers from sites classified as 'Animal, Vegetable and Food', as reported to the Pollution Inventory and represent the quantities of waste transferred off site for disposal or recovery[15]. Overall the 'industrial PPC returns' amount to around 2.6 million tonnes per year.

In addition to information about municipal and industrial waste, we also make use of information on agricultural activity and wastes. For this, we derive livestock waste data using livestock numbers reported in Defra (December, 2005), which were in turn derived from 2004 Livestock Census data. For the purpose of the current analysis it is assumed that the livestock numbers have not changed significantly.

3.2.1.2. Projections for future domestic food waste availability

Predictions of future food waste depend on a number of complex factors, including the effect of health, diet, environment, as well as because of uncertain effect of efforts to reduce and collect pre-sorted food waste[16].

At present some 5 percent of food waste is collected for recycling but we estimate that this will rise to around 45 percent for that from the household and commercial categories and

15 Liquid waste that is tankered straight to a waste treatment facility would be included in the controlled waters category and is not included here; as it is likely to be accounted for through sewage treatment works

16 Several ongoing campaigns such as Love Food Hate Waste are expected to take some time (typically five years) to have a noticeable impact on the amount of food waste arisings.

around 65 percent for the industrial categories, amounting to an increase of around 1 million tonnes per year capacity for food waste alone by 2020. This target could be further enhanced by the Defra and WRAP's ambition of bringing 1,000 AD plants into operation by 2020. WRAP's strategy, focussed on delivering the rising need for recycling food waste, is based on waste prevention, collection and sorting, processing of biodegradable fraction, recycling and market developments. Feedstock from agriculture and livestock is currently not part of this strategy.

The overall impact of these policies on the amount of feedstock for anaerobic digestion is uncertain. In the long run, these efforts may lead to a slow decrease in the total amount of food waste, but the pace and magnitude are highly uncertain.

Projections for the total amount of recoverable household food waste vary widely, ranging between maintaining volumes at current levels of around 27 million tonnes, to increases to as much as 38 million tonnes per year by 2020.[17] For the purpose of this analysis we have assumed that the household waste quantities will remain at their current levels.

3.2.1.3. Projections for non-domestic food waste availability

The uncertainty is still greater for non-domestic food waste projections. Figure 3.1 shows the projections of commercial and industrial food waste from two categories of retail and wholesale, and food and drink processing industry in England. This chart is derived from a recent review by ADAS (2009), and shows projections to 2030 of the total amount of waste aggregated across all regions in England. The food waste from retail and wholesale sector is expected to increase, while that from the food and drink industry is expected to decline quite significantly between 2006 and 2030. The net overall effect is a slight decrease in the total amount of food waste from the non-domestic sector to 2030. We make the assumption of constant amount of food waste available from this sector.

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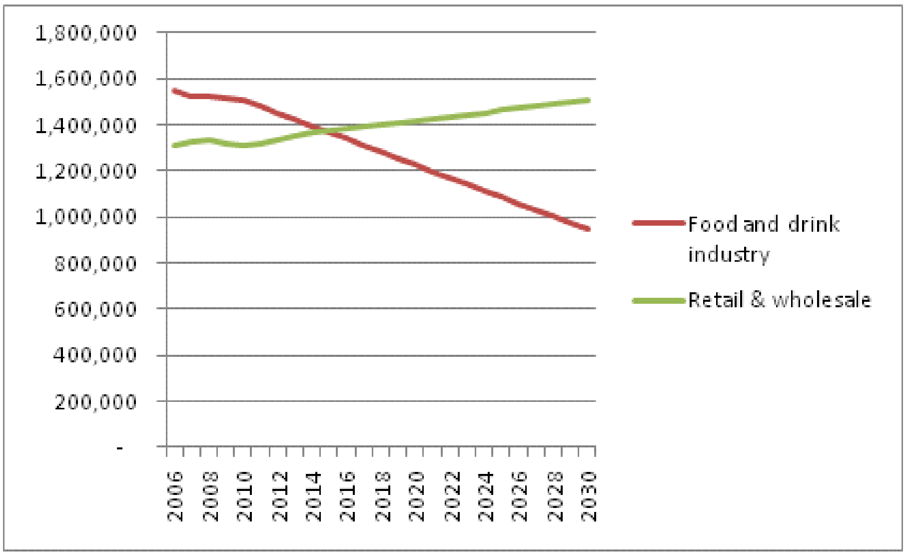
[17] Parfitt, J (2009); Taking out the Rubbish: Municipal waste composition, trends & futures; a presentation made by Julian Parfitt, of Friends of the Earth, on 27 April 2009; based on summary data from WRAP report WR0104, March 2007.

Figure 3.1
Projections of Commercial and Industrial Food Waste from Two Key Categories in England



Source: AEA analysis based on ADAS (2009)

3.2.1.4. Additional factors affecting the availability of food waste

The amount of food waste available for AD depends on other what proportion of the total available waste is diverted to other waste forms of waste management. The most important alternative route is composting, which has increased significantly in recent years. The current quantity of waste composted is around 5 million tonnes.[18] Projections for future trends typically assume that composting will be superseded by AD, provided sufficient incentives for the production of biogas are put in place; there also is the prospect that some composting plants may convert to AD (WRAP, February 2010).

Changes to legislation also may affect the amount of food waste available for AD. EU Legislation likely to be introduced in 2010 includes provisions to classify food waste as part of the broader bio-waste category. This legislation would aim to introduce measures for waste prevention, a separate collection of waste and recycling, and other infrastructure and administrative changes. It is unclear at this stage what impact such legislation would have on total amount of waste available (and suitable) for anaerobic digestion.

3.2.1.5. Other sources of feedstock for AD

In addition to food waste, livestock waste arising can be used for AD. We have used previous work by AEA work for Defra's Sustainable Agricultural Strategy Division to assess the contribution this could make (Defra, December 2005).

The other main potential source of feedstock is energy crops (grass and/or whole crop silage). We have included a small amount of energy crops, to reflect on recent developments in farm enterprise AD plants, where the use of energy crops is supported under the Bioenergy Capital

18 WRAP presentation at EU Biowaste Conference, February 2010.

Grant Scheme. The experience here has been that energy crops generally are not being used as a primary feedstock or fuel inputs. Instead, they are used primarily to balance seasonal variations in dairy cattle slurry and to provide guaranteed output energy. Based on this we have assumed that energy crops will provide a minor feedstock contribution, equivalent to just under half of the energy produced from dairy cattle manures.

3.2.1.6. AD plant projections

There currently are two distinct commercial approaches to anaerobic digestion plants in the UK:

- Farm enterprise AD plants: these are based on large farm estates, dealing with livestock wastes and other wastes, with any summer shortfall balanced using energy crops.
- Local centralised AD plants. These plants tend to process food waste from households and commercial premises. This can be supplemented by other waste feedstock (such as livestock slurry). In general, large plants will tend to use readily available food waste, while smaller plants will be using mixed waste.

The main sources of revenue for both categories of plant include the sale of energy output, sale of digestate (a potential substitute for mineral fertiliser), and subsidies through either the renewables obligation or the renewable heat incentive. But any large-scale deployment of AD plants will quickly run into infrastructure problems, unless the supply chains (starting from project design, engineering and services) and local infrastructure are upgraded and reinforced.

3.2.1.7. Summary projections for the 2020s

Table 3.6. summarises our assessment of AD feedstock availability. The total technical potential amounts to 26,000 GWh of feedstock. Our assessment is that not all of this is likely to be made available. Although the majority of food waste could be collected and used for AD, the share of livestock waste arisings is smaller, reflecting both the lower energy value and more significant changes to practice that would be require to recover the full technical potential. Taken together, our central projection is limited to 19,600 GWh of feedstock in 2030.

Table 3.6
Total Technical and Projected Realised Biogas Potential from Waste (2020 and 2030)

Feedstock type	2020		2030		Technical potential
	Assumed availability	GWh	Assumed availability	GWh	GWh
Food waste - household	45%	3,317	85%	6,265	7,370
Food waste - commercial	45%	2,970	85%	5,610	6,600
Food waste - industrial-PPC returns	65%	1,859	95%	2,717	2,860
Food waste – other industrial	65%	1,931	95%	2,822	2,970
Sub total		10,076		17,413	19,800
Dairy cattle	20%	324	40%	647	1,619
Other cattle excl. calves	5%	27	10%	54	543
Dry sows	15%	17	30%	34	114
Sows plus litters	15%	9	30%	18	60
Fatteners 20-130 kg	40%	190	60%	285	476
Weaners (<20 kg)	15%	26	30%	51	171
Poultry	15%	244	30%	487	1,624
Sub total		837		1,578	4,607
Energy crop (40% of dairy cattle)		129		631	1,843
Total		**11,042**		**19,622**	**26,249**

Note: There are wide disparities between different estimates of the total amount of food waste. The above estimates of biogas potential therefore are uncertain.

The analysis assumes that the total technical potential does not change as it is mainly dependent on food and livestock waste arisings, with an increase in the use of energy crops that is linked to the cattle slurry.

For comparison, another assessment (Defra, 2009) suggested that the anaerobic digestion of food waste, livestock slurries, sewage sludge and energy crops in 100 large-scale commercial plants and as many as 1,000 smaller AD plants could produce biogas to contribute approximately 10-20 TWh of heat and power 2020.[19] The Renewables Advisory Board (RAB/DECC) projected around 500 MWe (or 2 TW heat output) from AD plants - this could mean between 300 and 1000 AD plants depending on the scale. An assessment by NERA and AEA for DECC (NERA andAEA, 2009) projected 11 TWh of gas production as the realistic potential in 2020.[20]

19 DEFRA-DTI-DfT (2007) and Enviros (2008). According to Defra (2009), these numbers are based on estimates calculated for the Biomass Strategy and consultant research on renewable heat to estimate the potential contribution of any individual technology in 2020, where the higher end of the range can only be achieved if steps are taken to overcome constraints to the maximum deployment of the technology – taking into consideration only non-financial constraints.

20 DECC (July 2009); Study entitled The UK Supply Curve for Renewable Heat Study for the Department of Energy and Climate Change; produced by NERA/AEA.

3.2.2. Biogas from gasification (bio-SNG)

A substitute for natural gas can be manufactured using a thermal gasification process to firstly decompose the biomass into a gas containing carbon monoxide and hydrogen (Syngas), and then recombine these components to form methane.

All gasification processes have four steps:

1. A fuel pre-treatment step to change the physical properties of the feedstock into a form suitable for the gasification reactor. Typically this would include as a minimum drying and size reduction but may also encompass thermal processes, such as pyrolysis or torrefaction that partially decompose the material.
2. The gasification reactor itself that coverts the biomass to a gas comprising carbon monoxide, carbon dioxide and hydrogen (Syn-gas). Inevitably the gas also contains a wide range of contaminants.
3. A gas cleaning and conditioning step removes contaminants and the carbon dioxide, and adjusts the proportions of the gas components to suit the final synthesis step.
4. The final synthesis step that converts the hydrogen and carbon monoxide to methane. In addition to producing methane, this step is highly exothermic, producing heat at a temperature of 350°C. The efficient use of this heat is essential if the best overall resource use efficiencies are to be achieved.

From a survey of current activity in the biomass gasification field we have identified two technology routes currently under development.

A route using fluidised bed gasifiers at a commercial scale of approximately 50 MW gas output. These we feel are suited to operation at a regional level, drawing fuel resource locally and feeding into the low pressure network. We refer to this as the regional option in this report.

A route using entrained flow gasifiers at a commercial scale of approximately 600 MW gas output. These are based around proven coal technology and would be best located in a large industrial complex that could use the heat produced from methane synthesis. We refer to this as the national option in this report.

These two routes are summarised below in Table 3.7.

Table 3.7
Options for Thermal Gasification Routes to Bio-SNG

Option	Gasifier	Scale	Fuel type	Waste heat usage	Gas grid
Regional	Fluidised bed	50MW gas	Commercial grade fuels	District heating, industrial steam or power generation	Medium pressure distribution
National	Entrained flow	600MW gas	All grades including waste. Can use coal if necessary, some C removal possible.	Industrial steam or power generation	High pressure transmission

It is very uncertain which of these options is the most technically advanced or appropriate for the UK. In our opinion there is probably a role for both with the larger units in coastal locations using waste materials and imported biomass and regional units complementing biogas installations in a local strategy.

3.2.2.1. Maximum supply available in the 2020s

The production of BioSNG is not a developed technology. The resource available will therefore depend on the rate at which the technology can be developed, proved and introduced to the market.

Regional scale technology is currently being developed in Austria and Sweden. The Gussing pilot plant in Austria is currently proving the chemistry of the process. The first demonstration at half full scale is expected to be built in Gothenburg within the next three years. This will need to be tested before the next stage of scale up. If successful, commercial replication will take place.

Some elements of the national scale technology are currently being tested at full scale at the Schwarze Pumpe chemical works near Dresden in Germany. Other elements are being tested at the CHOREN biomass to diesel fuel facility, also in Germany. Plans are being made for a BioSNG configuration in Germany with in the next three or four years. Commercial replication will take place after this.

The development of these technologies is taking place outside the UK and as such we have little ability to influence the direction. The UK is unlikely to host any of the early demonstrations with only a limited contribution being made to the UK carbon budget in the next few years.

Given the significant uncertainties, any projection will be very uncertain. A suggested technology status and development path of the technologies are shown in Figure 3.2. We consider it plausible that the UK could have three regional scale installations and one large national scale installation in operation by the early 2020s. We further assume three times this capacity in 2030 as a reasonable estimate of the early growth phase of the market. Table 3.8

shows the corresponding gas and useful heat output capacity associated with this scenario in 2020 and 2030.

Table 3.8
Scenarios for Bio-SNG Capacity Deployed in 2020 and 2030

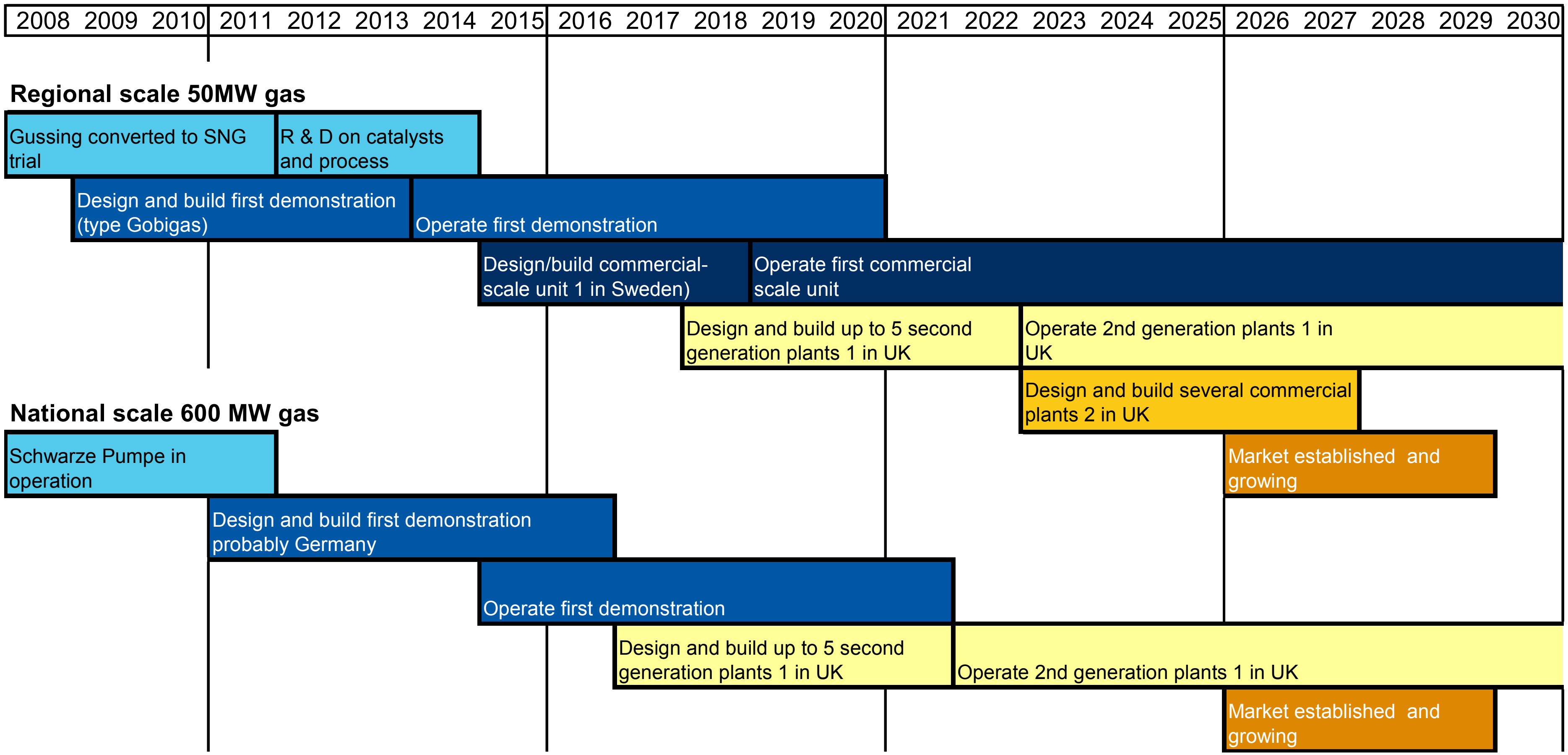
			Capacity		Output			
Year	Scale	Installations	Gas	Local heat	Gas	Local heat	Total output	Feedstock use
		units	MW	MW	TWh/year	TWh/year	TWh/year	TWh/year
2020	National scale	1	600	200	4.8	1.6	6.4	8
	Regional scale	3	150	50	1.2	0.4	1.6	2
	Total	4	750	250	6	2	8	10
2030	National scale	3	1800	600	14.4	4.8	19.2	24
	Regional scale	9	450	150	3.6	1.2	4.8	6
	Total	12	2250	750	18	6	24	30

Note: These estimates have been derived assuming 3:1 ratio of useful gas output to on-site heat use, 8,000 hours operation and 80 percent overall efficiency

Reaching the above level of gasifier capacity would require the use of 30 TWh of biomass by 2030. This is a significant share of the total assumed in the central case (100 TWh).

We show the broad timeline associated with the above scenario overleaf.

Figure 3.2
Development of Thermal Biogas Technologies



3.2.2.2. Use of heat output

The thermal gasification route to Bio SNG involves the synthesis of methane which is strongly exothermic producing high grade heat as steam at 350 deg C. The ability to use this heat is critical to the overall efficiency and economics of the process. In the national scale case the installation is assumed to be located on a chemical manufacturing complex that can use this heat. The bio SNG installation in the regional case could be collocated with a district heating system. The grade of heat produced also is sufficient to be used for power production outside of the heating season. Optimising the supply chain and location of Bio SNG installations is an important subject worthy of more detailed study.

3.2.2.3. Opportunities to balance electrical loads

Some of the gasification processes proposed for SNG need oxygen to be supplied to the process, this is normally achieved using cryogenic or membrane separation processes. It also would be possible to use electrolysis for oxygen production when electricity is in surplus. This is particularly advantageous because biomass gasification has a deficit of hydrogen in the synthesis gas which is normally redressed by converting some of the carbon monoxide. This however reduces the efficiency of the process. Using hydrogen from electrolysis as a feedstock would avoid this loss and thus provides a method of storing in the natural gas system the energy from temporary overproduction on the electrical network.

3.2.2.4. Need for gas storage

Bio-SNG production would be relatively inflexible, producing a constant quantity of gas that is not easily adapted to swings in demand. Smaller facilities would be likely be connected to low-pressure parts of the gas transmission and distribution network. If production exceeded demand, gas storage therefore may be required. We consider this only a limited concern for the 2020s, however, as the amount of inflexible biogas production will be will be relatively low compared to overall gas demand.

Large installations will be located on the high pressure grid where the high flows will make storage unnecessary and the plant can run continuously as baseload.

3.3. Scenarios for Liquid biofuels

There exists a wide variety of fuels that fall under the category of "liquid biofuels". We summarise those included in this category in the Table 3.9 below.

Table 3.9
Liquid Biofuels on Sale in the UK

Biofuel	Source	Issues	Potential Applications
Biodiesel,	UK manufacture, international trade	High viscosity at low temperature makes unsuitable for domestic	Commercial boiler fuel
Biodiesel/ kerosene blend	UK manufacture	Low carbon abatement due to mineral component.	Domestic boiler fuel
Bio-ethanol	UK and international supply	Not suitable for boiler fuel in current form due to volatility. Can be gelled however to form low vapour pressure fuel. Ethanol from wheat can have low GHG balance.	Clean flame industrial burners, small boilers. (virtually unused for heat most as used as blending stock in transport fuel.)
Virgin vegetable oils UK origin	Rape oil from food oil production	Competition with food. Higher viscosity at low temperature.	Commercial boiler fuel, direct fired industrial equipment
Palm and other oils from overseas	SE Asia, S America	Competition with food. Acute sustainability concerns	Commercial boilers, direct fired industrial equipment
By-product tallow from rendering	UK Market	Competition with existing soap and cosmetics industry. Solidifies at low temperature	Commercial and industrial boilers, widely used in rendering plant, direct fired industrial equipment
Tall oil from paper making	Imported from Scandinavia and N Europe	Acidic viscous liquid. Competition existing uses	Industrial boilers, direct fired industrial equipment
Used cooking oil from commercial waste collection	Locally sourced from existing recycling structure	Animal fat contamination can affect waste status. Limited availability.	Commercial and industrial boilers, direct fired industrial equipment

The availability of UK supplied fuels is substantially lower than solid biomass fuels and most have alternative uses. Liquid biofuels are used for transport and it will be a policy matter whether the limited liquid biofuels resource will be used for the heat or transport market.

The resource could be increased by import of overseas produced oils but many of these are currently the subject of acute concern over the potentially poor life cycle GHG balance, the impact on the local environment, and the impacts on indigenous populations.

There are however some applications that could be addressed usefully by liquid fuels.

- Domestic applications in older properties with unavoidably high heat loads could have some measure of carbon reduction by using a biodiesel/kerosene blend. This product is being developed by the industry and should be on the market in time for the RHI. The intention is to introduce a 30% blend but higher percentages may be possible.
- Industrial ovens, kilns and other fired equipment that is now supplied with mineral burning oil or natural gas could be converted to liquid biomass.

On balance, despite the exceptions, it would seem wise not to rely on these for the projections and modelling work due to the limited supply, potential sustainability concerns in extending it and the competing transport market.

4. Selected Technical Challenges

4.1. Suitability of Different Technologies – Key Considerations

4.1.1. Overview of methodology

In assessing the suitability of low-carbon heat technologies for different end-user applications we have grouped constraints into three categories;

- ***Physical space***: the space required for installation of the primary elements such as boiler and fuel store, solar panels, ground coils, thermal storage, etc. as well as feasibility of taking fuel deliveries.

- ***Heat grade:*** the match of the heat grade available from the technology to the application. For example, low temperature heat from a heat pump is not suitable for a high temperature industrial application, and heat pumps also are unlikely to provide sufficient heat output for large domestic loads (notably, uninsulated dwellings).

- ***Other factors**:* The most relevant considerations are environmental factors, including air quality limitations and noise in urban environments.

We have assessed each of the 1436 technology and end-user combination, awarding a grade of 0, 1, 2, or 3 to represent unsuitable, low, medium and high suitability, respectively, to each of the above categories. We then combine the three assessments to determine a final suitability rating, discussed in more detail below.

4.1.1.1. Assumptions for the physical space factor

Space limitations are particularly important in the domestic sector. We have applied the following principles:

- Flats often are too small to fit individual low-carbon heat installations. A more realistic assessment of potential is to consider the potential for communal heating equipment. Nonetheless, some constraints on space remain to account for the low ratio of footprint to volume (e.g., the smaller area available to fit collectors or external heat pump parts).
- Urban and suburban domestic properties heated by biomass have reduced suitability to reflect the requirement for fuel storage and delivery. Rural properties are not thought to present a problem.
- Off grid properties are assumed to have more space than those on the gas grid irrespective of their location. In practice most are in rural areas where space is less likely to be a problem.
- Suitability of smaller properties (flats, terrace and semis) that use technologies with storage is reduced compared to the same technology without storage, reflecting the substantial footprint for the water accumulator.
- To reflect the difficulty of locating ground loops, ground source heat pumps are excluded from urban smaller properties, except for new build where it is assumed some form of provision can be made at design stage. Larger properties are allowed but have reduced

suitability as they are assumed able make allowance within the boundaries of the premises.

- Industrial sites are assumed to have more space available than domestic or commercial, and we assume that space will not be a limitation for any technology.

4.1.1.2. Assumptions for the heat grade factor

We have assessed primary heating systems, rather than secondary or complementary heating options. For example, heat pumps used to supply combustion air preheat for furnaces are not included in the assessment, nor are small air-to-air split heat pump units that provide occasional heating and cooling for domestic or small commercial premises. (See below for a discussion of air-to-air heat pumps).

The starting point for the assessment is a consideration of the ability of the existing system to accept the new heat generation technology. Thus only combustion systems are suitable for high temperature applications, and heat pumps are less suitable in dwellings with high heat losses.

Other principles used for the assessment include:

- Replacing electricity is always assumed to be more difficult than other fuels. This is because electricity is usually selected for some specific technical or economic factor in spite of its very high cost. Substituting for this factor may be more complex than replacing oil or gas.
- New build has much lower heat demand than existing buildings. We assume that building regulations require incorporation of renewables. Both these factors tend to increase the suitability.
- Older properties are less suitable for low temperature sources as they require large outputs into conventional radiator systems. In particular, heat pumps may not be able to respond adequately to low temperatures, with a resulting loss in comfort. We assume that heat pumps are unsuitable for uninsulated dwellings, but can be used in a proportion of insulated homes.
- Air-to-Air heat pump systems are assumed to operate through whole house ventilation systems. This makes them unsuitable in older domestic properties where such systems are difficult to implement and would in any case be unable to carry the volume of heat necessary.
- Heat pumps of all types are assumed to be unsuitable for all process heat applications as they cannot provide adequate temperature.

4.1.1.3. Assumptions for environmental factors

The environmental factors we have considered include impacts on air quality and noise pollution.

Individual biomass boilers are excluded from terraced and semi-detached houses in urban areas as a proxy for air quality concerns. Larger properties and flats (treated as blocks) are allowed, as pollution abatement should be possible.

Urban domestic properties are assumed to be less suitable for ASHP due to external noise. Commercial and industrial applications are assumed to be capable of mitigating noise to the point where it does not reduce the suitability.

4.1.2. Implications for the Potential for Low-Carbon Heat

To assess the implications of the suitability analysis for the potential for low-carbon heat we aggregated the three suitability scores in each segment to represent a share of the total heat load in the segment that could be served by the technology. We have used a number of different rules for this, to produce different scenarios for suitability.

First, in all scenarios, a zero in any category takes precedence and the application is marked as unsuitable for the technology. For the individual scenarios, we apply the following algorithms:

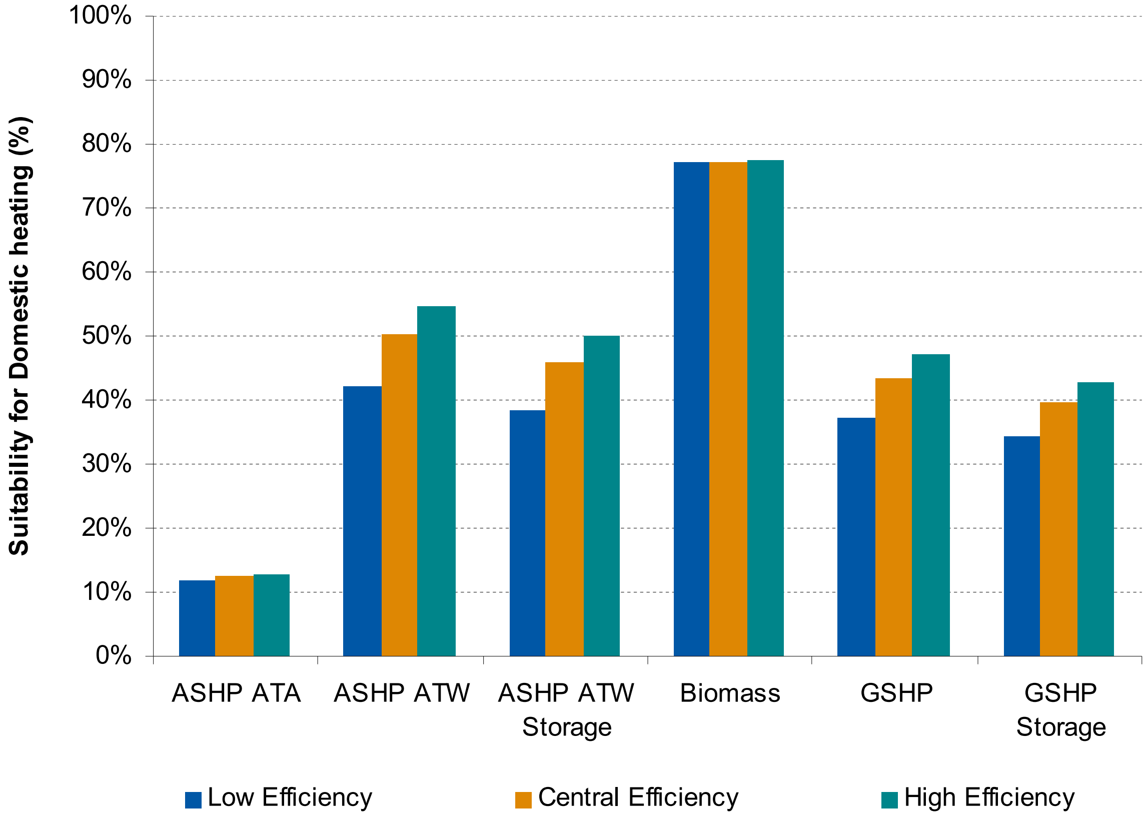
- **Low scenario**: The overall suitability is determined by the lowest score of the three factors. This means that the highest hurdle determines the suitability and could be seen as a pessimistic assessment.
- **High scenario**: The overall suitability is determined by the average of the three factors. The assumption in this case is that favourable circumstances for one or two of the factors can help overcome difficulties on other dimensions. This is likely to be an optimistic assessment.
- **Central scenario**: This scenario falls between the low and high scenario, calculating a weighted average by attaching twice as much weight to the factor with the lowest score as to the other two factors.

Once we have calculated the values as described, we interpret the result as the proportion of heat load in each demand segment that can be served by each technology. We apply these proportions to the heat load projections outlined in section 2, and this yields the technical potential for individual low-carbon heat technologies.

4.1.2.1. Potential in the domestic sector

The central scenario for the share of heat load assumed to be suitable for each technology in the domestic sector is shown in Figure 4.1. The data are shown for the middle of the fourth budget period (2025), and refer to applications where the relevant technology is the main heating source. The lowest share is air-to-air ASHPs, where only 10-12 percent of the heat load is suitable, mostly in new build homes. As noted above, the assessment for heat pumps depends on the scenario for solid wall insulation, which in turn varies with the heat demand scenario. For air-to-water ASHPs, the suitable share ranges between 42 percent in the low energy efficiency scenario and 55 percent in the high energy efficiency scenario (this would rise to 60 percent if the full potential for SWI were implemented). Other heat pumps (ATW with storage and GSHPs) have somewhat lower suitability shares, reflecting the higher space requirements of these technologies. Finally, biomass has the highest suitability, with just over three-quarters of the heat load marked as potentially suitable.

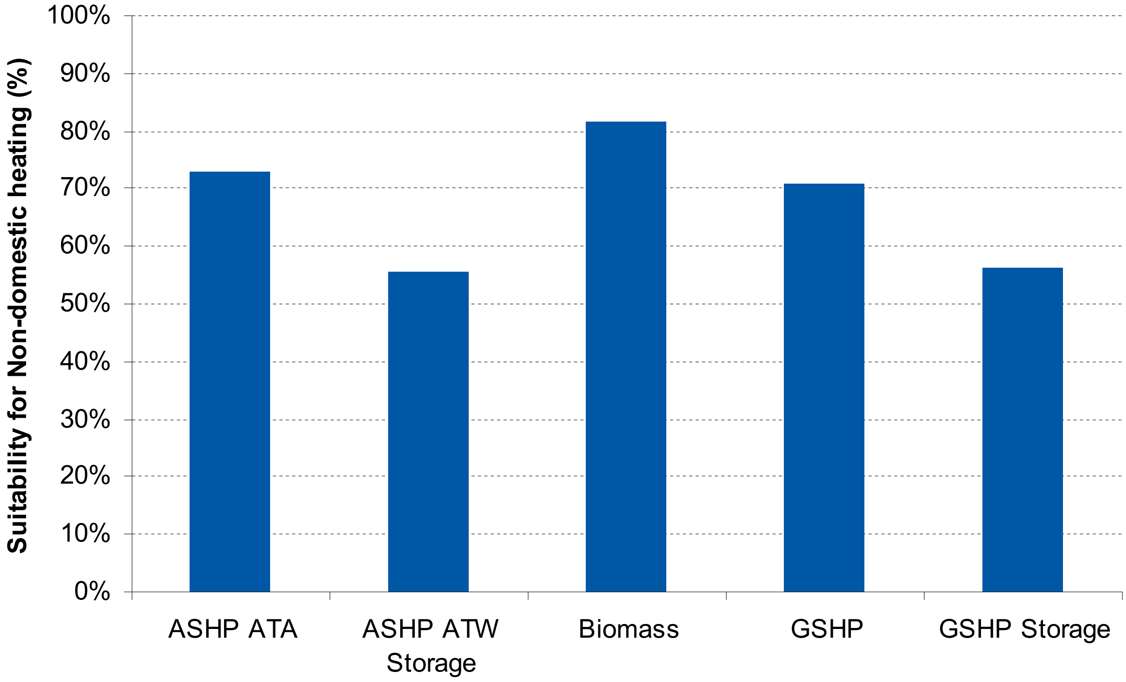
Figure 4.1
Suitability of Individual Low-Carbon Technologies for Domestic Heating (2020)



4.1.2.2. Potential in the non-domestic space heat sector

A similar figure for non-domestic space heating is shown in Figure 4.2. The shares generally are higher than for the domestic sector, in the range of 50-80 percent. As in the domestic sector, heat pumps with storage have slightly lower suitability than do heat pump systems without storage, while biomass has higher suitability than the other technologies.

Figure 4.2
Suitability of Low-Carbon Technologies for Non-Domestic Space Heating (2020)



4.1.2.3. Industrial process heat

The final category is industrial process heat. For this, we use the analysis detailed below in section 4.2. We assign all low-temperature process heat as suitable in principle for biomass. Heat pumps are excluded as the heat grade they produce is too low for the vast majority of applications which use steam or hot water close to boiling point. For the high-temperature category 50 percent is assigned as suitable, corresponding to the "easy" category in Table 4.1 below. In subsequent scenario analysis, we also consider a "low" case where only the 29 percent of high-temperature heat assigned to the easy category is considered suitable, and a "high" case, where all of the easy and moderate as well as half of the difficult category are marked as suitable, resulting in a share of 85 percent of total process heat suitable for biomass.

4.1.2.4. Additional adjustments for electric heating

In addition, we have made a further adjustment to the suitability of low-carbon alternatives to electric heating. With some exceptions (for example, very small heat loads), the use of electricity for heating is significantly more expensive than either natural gas, oil, or solid fuels. Despite this, a substantial proportion of total heat demand is served by electric heating. We have not been able to investigate the reasons for the prevalence of electric heating in any detail, but it seems likely that the same barriers that prevent the adoption of fossil fuel fired heating systems also would stand in the way of the use of some or all renewable heat technologies. These may include space constraints, safety considerations, or other factors.

To reflect these factors in the modelling, we assume that half of the heat load served by (non-industrial process) electric heating is suitable for the conversion to low-carbon heat. This assumption would benefit from being refined through further research; however, it seems a more realistic representation of the potential for low-carbon heat than one that implies wide-spread switching from electricity to other technologies, given that widespread switching from electricity to fossil-fuel-fired heating has not taken place. In addition to the adjustment to potential, we also make adjustments to the counterfactual cost of switching to electric heat.

4.1.2.5. Summary of suitability scenarios

In sum, the central scenario thus results in an assessment where the share of heat demand suitable for biomass is around 80 percent in the domestic and non-domestic space heating sectors. However, as noted above, the use of biomass heat can be limited by the availability of biomass feedstock, and this technology therefore is an unlikely candidate for meeting a large share of heat demand in these sectors. The more relevant limit therefore is the constraints on the suitability of heat pumps, which amounts to 40-50 percent in the domestic sector, and around 70 percent for non-domestic space heat. Finally, around 50 percent of industrial process heat is assessed as suitable for biomass.

4.2. Use of Biomass in Industry

To inform the development of a low biomass scenario, we have analysed what heat loads can be served by biomass but not by any other form of low-carbon heating technology. To determine the heat demand we make the assumption that biomass is essential only where the grade of heat used (temperature at the point of use) is too high for any of the alternatives, or that the chemical nature of biomass is necessary to the process. These requirements are found almost exclusively in the industrial sector where biomass could be used to heat process steam boilers, ovens, kilns and dryers.

The broad options for biomass use for these applications are discussed below.

4.2.1.1. Conversion of biomass to gas and use in kilns and ovens

Through the 1980s several biomass gasifiers were built across Europe to fire kilns to produce high quality lime fillers in the paper industry. There is still one in operation in Varoe in Sweden, and possibly one in Austria. These units are very capital intensive, however, so their adoption was always sensitive to the level of the oil price. Technically there are few problems with the technology.

The same principle was recently extended to the glass industry, again in Sweden – for glass melting. This was a much smaller gasifier using pellet fuel.

Simple gasifiers are widely used in China for metallurgical ovens, brick kilns and similar. They are often fuelled with coal but can use anything else that comes to hand such as rice husks etc.

KTH in Sweden has been investigating high temperature gasification to generate high flame temperatures for metallurgical ovens but it is some way from commercial as yet.

4.2.1.2. Direct use in kilns

Cement kilns use a range of waste fuels including biomass. The fuel is mixed with the feedstock and burns out as it progresses through the kiln. The ash goes into the product. Typical fuels are tyres, waste wood, waste solvents, recovered waste from MSW, etc. Price is the main consideration but the effect of the ash composition on the cement is also important. Tyres are very popular, but are not classed as biomass. "Alternative" fuels typically can replace up to 25 percent of conventional fuels in such applications.

Pulverised sawdust is used in driers in the timber industry.

4.2.1.3. Direct fired ovens

There has been some recent interest in wood-pellet-fired bakery ovens. These use a self contained pellet burner module to replace an oil burner in a standard oven. There is no reason why this concept should not be extended to other process ovens.

4.2.1.4. Charcoal as a reductant in metallurgical furnaces

Charcoal is used in some non-ferrous processes and the Brazilian iron and steel industry has recently announced its intention to replace coal with charcoal from plantation eucalyptus.[21] Modern European iron blast furnaces prefer to use coal coke because of its mechanical strength, but in the future, based on current coal dust injection, perhaps up to 25 percent could be replaced by injecting fine charcoal through the base of the furnace.[22]

4.2.1.5. Categories of industry use

Based on the above, the way in which industry uses biomass can be categorised as follows;

- Easy – fuel for process heat and hot water boilers. The technology is known, established and available. Also included in this category is direct feed to cement kilns.
- Moderate – involves the use of thermal gasification to produce a fuel gas, but there are few requirements on gas quality. Aggregate dryers, brick kilns, metal reheat etc.
- Difficult - involves the use of thermal gasification to produce a fuel gas, but there are stringent requirements on gas quality. Typically plate glass, fine ceramic kilns.

The table below shows a projection of heat use broken down by industry sector and the proportion of each of the above categories. This assessment was carried out based on AEA estimates, using the ENUSIM heat load data described in section 2.3.

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21 See http://www.cop15brasil.gov.br/en-US/?page=noticias/green-steel-for-the-brazilian-steel-industry

22 The method of charcoal production needs to be monitored if GHG abatement benefits are to be realized from this approach. In current practice the volatile gases from carbonisation are often vented to atmosphere and the resulting methane release is likely to result in a negative GHG balance. Some charcoal production also results in large emissions from land-use change due to deforestation. Large-scale production could be managed and regulated but realising the benefit would be complex and not a straight substitution for fossil carbon.

Table 4.1
Industrial Heat Loads Categorised by Suitability for Biomass Use (2022)

Sector	Type of heat				Typical applications	Proportion substitutable			Heat loads		
	Space	Electric space heating	Low-temp. process	High-temp. process		Easy	Moderate	Difficult	Easy	Moderate	Difficult
	TWh	TWh	TWh	TWh		%	%	%	TWh	TWh	TWh
Bricks	0.0	-	-	3.5	Clean flue gas to kilns	-	100%	-	0.0	3.5	-
Cement+lime	0.0	-	-	12.7	Kiln direct firing, clean gas kilns	100%	-	-	12.7	-	-
Ceramics	0.4	-	-	1.9	Fas fired ovens	-	100%	-	0.4	1.9	-
Chemical	0.9	-	31.4	6.0	Process steam, kilns	33%	33%	33%	34.2	2.0	2.0
Construction	-	-	-	-		-	-	100%	-	-	-
Electrical Eng	4.3	0.2	-	5.4	Process steam	-	100%	-	4.5	5.4	-
Energy	-	-	-	-		-	-	100%	-	-	-
Food and Drink	5.6	1.6	6.8	8.1	Process steam	-	100%	-	14.0	8.1	-
Glass	0.1	-	-	5.4	Melting ovens	-		100%	0.1	-	5.4
Mechanical Eng	8.8	0.2	-	15.6	Process steam, ht Ovens	33%	33%	33%	14.2	5.1	5.1
Aluminium	0.0	-	-	2.9	Ovens	-	67%	33%	0.0	1.9	0.9
Other NFM	0.0	-	-	2.5	Ovens	-	33%	67%	0.0	0.8	1.7
Non Met Minerals	0.1	-	-	-		-	-	100%	0.1	-	-
Other Industries	1.4	0.4	1.7	0.7	Ovens Process steam	33%	33%	33%	3.7	0.2	0.2
Paper and board	1.4	0.4	5.6	2.7	Process steam	100%	-	-	10.1	-	-
Printing	-	-	2.6	0.0	N/A	-	-	100%	2.6	-	-
Plastics	0.9	0.2	0.4	2.7	Process heat, curing Ovens	-	67%	33%	1.5	1.8	0.9
Steel	0.0	-	3.3	14.1	Ovens, furnaces	-	33%	67%	3.3	4.7	9.5
Textiles	1.0	0.0	1.7	0.3	Process steam	67%	33%	-	3.0	0.1	-
Vehicle Eng	1.9	-	2.3	1.1	Process steam	100%	-	-	5.3	-	-
Total	**27**	**3**	**56**	**86**					**110**	**36**	**26**

Source: AEA analysis

The above analysis suggests that there is around 110 TWh of current industrial heat load that is very suitable for biomass but not for any other technology. Another 36 TWh present moderate challenges to biomass use, and the remaining 26 TWh would be difficult to meet through the use of biomass.[23]

4.3. Heat Pumps and Electricity Requirements

Switching from the UK's current reliance on gas-fired central heating to having a significant proportion of central heating system based on electrically-driven heat pumps will require potentially significant investment in additional generating capacity. This section explores some of the associated technical considerations.

4.3.1. Factors affecting suitability and performance of heat pumps

The efficiency of heat pumps, represented by the coefficient of performance, is one of the most important technical determinants of their attractiveness as an abatement technology. Some current models have technical specifications with COPs that can exceed 4, but actual performance in real-world settings and in conditions typical of UK housing stock is not well documented. In prior work for DECC and the CCC we have assumed COPs start from relatively models current levels around 2.0-2.5, with expectations that they will increase going forward and plateau at some point during 2020-2030.

To gauge current and future progress in heat pump technology, as part of this and other projects we spoke with manufacturers and suppliers. The areas where there could be improvement were:

- Refrigerant formulation to give better low temperature performance
- Better de-icing cycles
- More efficient compressors
- Recovering energy from the decompression stage.
- Better inverter drives.
- Intelligent controls to optimise the HP and the connected system.

The consensus among manufacturers was that there was some way to go but all were in the nature of incremental improvements. There were no breakthroughs expected. Some work is being done on using carbon dioxide as a fluid but the COPs are similar to conventional refrigerants (the primary advantage of these systems, which are sold mostly for commercial hot water heating, is the higher output temperatures attainable).

The pattern of increase in the COP was derived from past developments and the conversations with the industry. We assume increases in the COP for space heating reaching 1.5 above current levels. The resulting COPs of up to 4.5 in domestic applications and 5.5 in non-domestic application seem reasonable given current developments. Both Mitsubishi and

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[23] This analysis does not include the heat demand from refinery and integrated steelworks processes that are not included within the industry heat demand projections.

Sanyo have released ATA models with COPs in excess of 5, where the current market good performers are at about 3.5. These are only small units (just 2.5 kW output) but they show the direction of improvements in the technology.

In addition to these assumptions about space heating COPs, we make other adjustments to reflect various other factors influencing heat pump COPs applying to the 4th budget period. The efficiency of a heat pump decreases with the magnitude of the temperature difference between the heat source and the heat load. Thus for ASHPs the unit will be less efficient in winter when ambient temperatures are low and when supplying sanitary hot water at a high temperature. To account for this seasonal variation, we assume that the COPs achieved by ASHPs in the domestic sector are a composite of values for space heating and sanitary hot water services. We calculate the COP as a weighted average of reported seasonal performance factors from SAP and CERT, typically 3 with a reduced COP of 2 for water service for ASHPs. An allowance was also made for the use of an immersion heater in summer with a COP of 1. GSHPs have higher COPs as the ground temperature is both less variable and (in winter) warmer than the air. [24]

Buildings of different ages also differ in the temperature of the water that must be used to keep them warm. Older buildings are less well insulated, and therefore tend to require higher-temperature radiators. Newer buildings, in contrast, lose less heat, and therefore can be kept warm using lower temperature radiators or under-floor heating. The radiator output temperature has a significant impact on the efficiency of heat pumps, and we have used a higher COP for new houses built to high insulation standards and able to make use of lower temperature under-floor heating or low temperature radiators. Older properties are assumed to use higher temperature radiators.

4.3.2. Impact of heat pumps on generation capacity requirements

For example, if all of the heat loads suitable for heat pumps adopted the technology, this could mean on the order of 200 TWh per year in aggregate heat demand. Understanding the electrical capacity requirements of this heat load is not a simple calculation, however. One cannot simply take the annual heat load (in TWh) and divide this by the COP and the number of hours in a year to estimate the required electrical capacity. The electricity requirements of heat pumps (represented, for example, by a load profile) depends not only on the coefficient of performance (which itself varies seasonally and depending on whether or not heat is for space heating or hot water heating – and more generally on the temperature differential created), but also on the time of day (because heating is often turned off during the night), day of the week (because weekdays and weekends differ), and time of year that the heat pump is operating.

Based on some simplified assumptions, we estimate that every 10 TWh of annual heat load served by heat pumps would require additional generating capacity of 0.75 GW. Thus 200 TWh of heat load would require 15 GW of additional generating capacity. The seasonal nature of the heat load means that much of this electrical capacity actually would not be needed during much of the year. Ignoring hourly variations in heating demand over the

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[24] This adjustment has a more pronounced effect in smaller properties and newer ones, where hot water is a much larger proportion of total domestic heat load.

course of a typical day, the load factor on the generating plant is likely to be no more than 64 percent. However, accounting for variations in heat loads throughout the day can lead to significant reductions in the estimated load factor.[25]

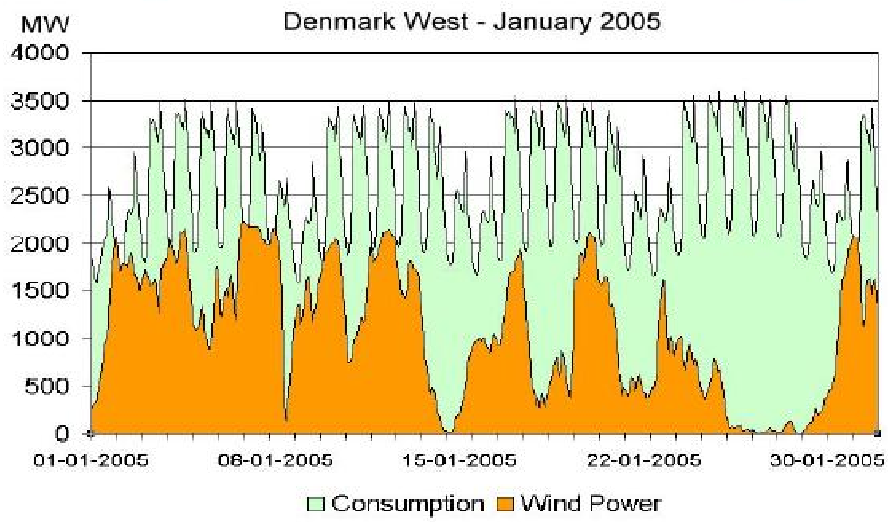
It is outside the remit of this report to investigate the implications of heat pumps for the electricity system in detail, but we have identified below some additional factors that could affect the attractiveness of heat pumps if not addressed.

An examination of the weekly (8-day) load curve shows a considerable variation between day and night with a lesser variation from day to day. Under some grid decarbonisation scenarios there will be a decreasing amount of capacity that can be dispatched at short notice to balance demand and supply. At the same time there will be an increase in intermittent sources such as wind power coupled with an increase of nuclear and coal CCS best suited to serving base load. The impact of wind power is particularly significant as the peak capacity could be on the order of the total demand at some times of the day. (As an illustration we show the capacity figures from western Denmark which has a high penetration of wind power on the system.)

In the sections that follow we discuss the implications of heat pumps for the electricity generating system and the power grid. As we discuss below, the deployment of large numbers of heat pumps could present difficulties for the grid but depending on the characteristics of the systems installed, also could help to manage the load and the impacts of increased intermittency from wind power and solar. This management could for example be by a combination of heat storage, in individual or district heating systems, and remote management of load by the network operator.

25 For example, if we restrict space heating to 18 hours per day and no storage of heat the estimated load factor falls from 64 percent to 53 percent. (For this example, we assume that hot water heat load can be spread throughout the day – because hot water can be stored effectively – and therefore that low utilisation of generation capacity is not a concern for the heat load associated with hot water.) A more detailed assessment would need to consider heat and power demand profiles in parallel, as well as the financial incentives created by the relevant price structures.

Figure 4.3
Western Denmark Wind penetration



Source IEA Task 33Task Meeting, Fall 2009, Breda, The Netherlands November 2-5, 2009, Danish country report.

4.3.3. Heat pumps as a problem for the electricity grid

In addition to requirements for additional generating capacity, a high penetration of heat pumps could give rise to a number of problems with the design and operation of the supply network and grid. For a start, the overall increased demand may require the construction and reinforcement of transmission and distribution infrastructure. This will increase the total cost of using heat pumps. The type and scale of the required investments will depend in part on the load profile of the electricity that is required to serve the heat demand. Electricity required during peak periods is likely to place greater demands on the transmission and distribution systems than electricity that can be used during off-peak periods. As with the discussion of generation capacity above, this indicates a need to consider the respective load profiles of heat and power simultaneously, including the prospects for storage and load shifting for both types of energy. The cost of grid upgrades should be included in estimates of the costs and potential for heat pumps.

It has also been suggested that another difficulty with heat pumps in the domestic sector is that that the UK's single phase domestic distribution system may make it sensitive to the high starting currents of the compressor motors in heat pumps. (For example, a 5 kWe ASHP can have a 58 amp starting current, whereas the maximum operating current is typically 15 amp.[26] The latest models of heat pump however have direct current motors that are capable of soft starts and variable speed control, which reduces the current required. Whilst these systems

[26] H. Singh et al. / Renewable Energy 35 (2010) 873–878

are more expensive, their improved performance will make them the product of choice within the next decade. Thus we consider that the impact on the network will be minimal.[27]

4.3.4. Heat pumps as an opportunity for the electricity grid

If heat pump electricity demand could be shifted so that it did not occur at peak periods – or could respond to other loads on the system -- it could provide opportunities for remote balancing. This could be done if sufficient heat storage were available in the heat system to retain the energy until it was needed by the consumer. This could be in the form of storage at the individual property or by strategically placed storage within a district heating system.[28]

To model the costs and potential take up of heat pumps with storage we developed a hypothetical system design that could shift the electricity demand by five hours. (This would take advantage of the current night-time and mid-day off-peak periods on the Economy 10 tariff). The costs and performance data were then inserted into the economic model to determine the impact on deployment.

The hypothetical heat pumps with storage used in the model were based on a 9kW heat output pump linked to a 2500 litre accumulator store. This is quite a large storage system—equivalent in size to a moderately-sized closet; for comparison typical hot water cylinders are much smaller, at around 150-200 litres . Systems designed for larger heat pumps were assumed to be modular to preserve the height to diameter ratio, and hence the stratification of the hot water, under a standard ceiling height.

We assumed that the system would operate at the same output temperature as if it were operating without storage, to optimise COP, but five hours earlier. So if it were a warm day the temperature in the accumulator would be lower than on a cold day. Using an Economy 10 tariff allows recharge during the day so five hours of night charging will then give five hours use in the morning occupancy period, and then temperature would fall during the day while the accumulator charged again ready for evening occupancy.

This type of operation would give almost 100 percent off-peak for week days and typical occupancy patterns in a well-insulated home. Weekend and higher occupancy would need a boost in the middle of the day which would mean either running the accumulator hotter overnight or using some supplementary heating. This could require around 30 percent additional heat supply per day (that is, 2 x 0.3 = 0.6 additional days' heat supply). Over the week this would be 7/7.6 = 92% off-peak for space heating.

Hot water would need to come from a dedicated circuit at 55 degrees. We assume this would be used during peak demand periods. If this were 30 percent of the space heating load then we would have 7/(7 + 0.6 + 7.6 x 0.3) = 71 percent off-peak. In fact some of the water might be heated during off-peak hours, so the final proportion of heat load demand occurring during off-peak hours would be anywhere between 70 to 90 percent.

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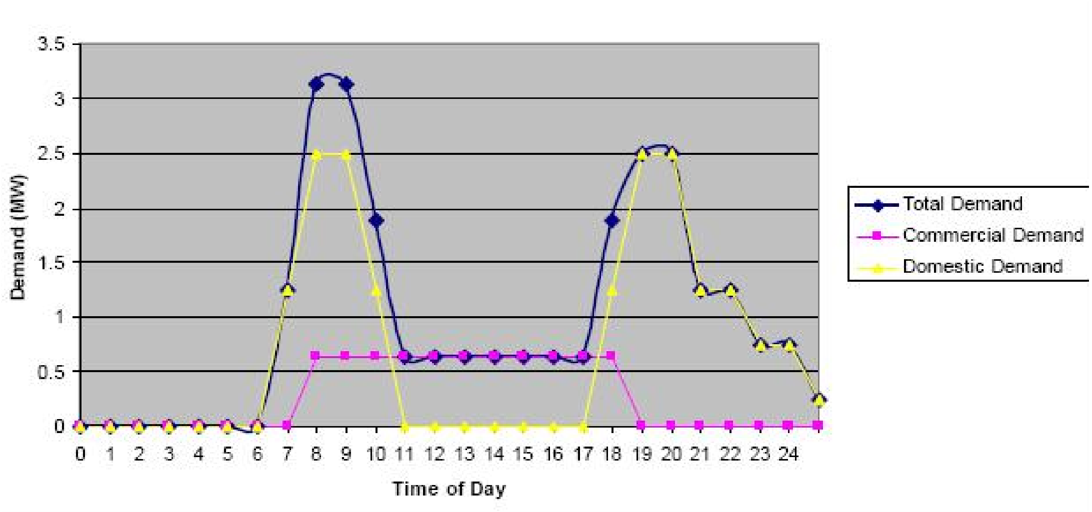
[27] In addition, the asynchronous motors in heat pump compressors consume reactive power. With a large number of heat pumps, this could place significant demands on the distribution grid. However, the use of inverter-connected drives is likely to be standard by the 2020s, which should mitigate this potential problem.

[28] It is not clear what mechanism would be in place, if any, to compensate heat pump owners for providing the electricity grid with this ancillary balancing service.

Another alternative to the above approach to storage would be to always operate at higher water temperature, to minimise storage volume and shift hot water into off- peak hours as well, but this would reduce the overall efficiency of the system. CO_2-based compressor systems can overcome some of this problem by allowing higher output temperatures. We would expect systems to be designed to optimise the relative costs of on- and off peak, maximum size of accumulator, system efficiency, and the rate the house leaks heat.

Commercial installations would not offer the same potential for load shifting due to the nature of commercial heat load profiles (see Figure 4.4 below). Here it would be better to run the heat pump normally during the afternoon and store overnight to avoid the high rates in the morning peak. Commercial installations using the above hypothetical hot water storage system would suffer a reduced COP relative to more conventional air-to-air systems. (Air-to-air systems typically produce low-temperature heat for ventilation systems, with associated efficiency advantages over hot-water systems.)

Figure 4.4
Heat Demand Profiles from a District Heat System – Winter Day



Source: AEA Internal information.

In addition to the above application of heat storage, there could be additional benefits to storage that we have not been able to investigate within the scope of this study. These include the possibility that the storage system could act as a heat sink for solar thermal collectors, thus decoupling them from the hot water demand and making all heat useable as opposed to the current 50 percent. In addition, waste heat from commercial operations could be absorbed whenever produced and used when necessary.

5. The Role of District Heating

In this section we provide a discussion of district heating, introducing the technology and various qualitative issues. These serve as background to the scenarios for district heating deployment we provide in section 6.4.3.

5.1. Introduction to District Heating

District Heating (DH, also known as Community Heating) refers to the provision of heat where the heat is generated centrally and then distributed, usually using hot water or less commonly steam as the heat medium, to users within a locality by means of network of pipes. Usually the heat is used directly, feeding into existing conventional heating systems on consumer sites such as radiator central heating either directly or via heat exchangers where water would flow to the consumer at about 80-90ºC and return at about 50-60ºC. District heating can also be used in conjunction with heat pumps, which would boost the heat to useful temperatures. This would be energy-efficient as waste heat at low temperatures, such as heat recovered from a power station's condenser at about 20-30ºC could be used and would still result in higher COPs in the heat pump than would be the case using colder heat sources such as the ground.[29]

While DH has been used in the UK since the 1950s it currently only provides a small proportion (c. 2%) of total heat demand in the UK. This contrasts markedly with other countries such as Finland and Demark, where 49% and 60% respectively of total heat demand is provided by DH. In urban areas in these countries, in excess of 90% of all buildings are connected to DH networks.

As DH is only a means for delivering heat to users, the carbon intensity of the heat it supplies is dictated by the heat generating technology and fuel sources that feed into it. However, DH can present carbon savings compared to conventional technologies (i.e. on-site heat generation) for the following reasons:

DH can utilise waste heat from power generation and other industrial processes that would otherwise be rejected into the environment.

DH can present "economies of scale" in supplying a large number of small heat demands from a small number of large heat sources. This opens up the opportunity to use highly efficient processes, such as Combined Heat and Power.

Additional strengths of DH are that:

- DH can distribute heat from processes that would be challenging or undesirable to implement at the individual scale (e.g. biomass, Energy from Waste etc.)
- It is technology neutral, allowing for a variety of different types of heat sources can connect to the same system. This diversity enhances security of supply for end customers

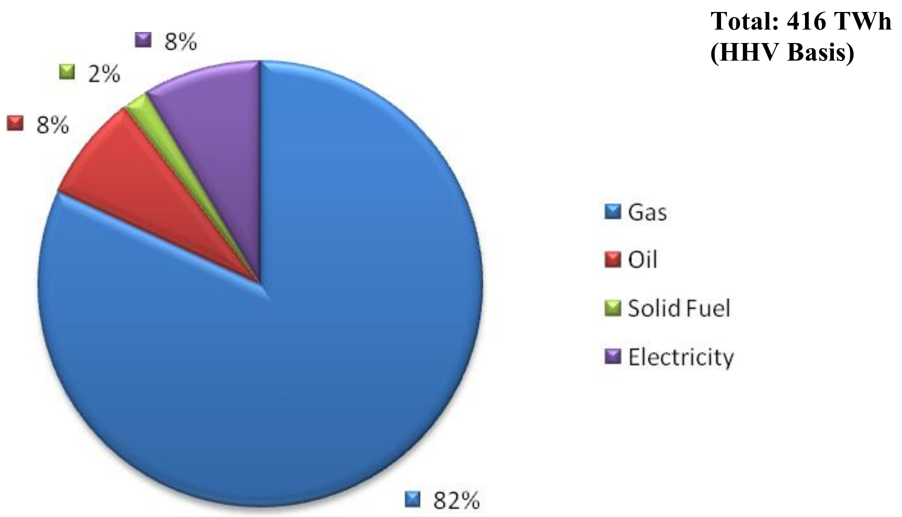
[29] Of course, the costs of having to have heat pumps to boost the heat rather than distributing heat at a readily useable temperature would of course be higher so these options would need to be costed and compared.

and facilitates "future-proofing" in that emerging low-carbon technologies can be retro-fitted to connect to the network once they become economically viable.

- As noted above, the presence of a district heating infrastructure opens opportunities to harvest low grade heat from domestic and commercial sources by using a heat pump system to deliver heat to the DH return pipes. Possible sources could be the cooling of electronic equipment, air conditioners, building scale CHP and machinery.

Figure 5.1 shows that domestic heat production in the UK is currently dominated by the use of natural gas, which is normally consumed on-site to produce heat for space heating and domestic hot water. This dominance has been largely due to the past availability of North Sea gas, which contributed to low energy prices and insulated the UK from volatile international energy prices. Falling North Sea gas production, combined with the requirement to lower carbon emissions may therefore make DH more attractive in the UK

Figure 5.1
Estimated Domestic Heat Usage by Fuel Source in 2007



Source: DECC Energy Trends, September 2009 (Special Feature – Estimates of Heat use in the UK)

Work by Pöyry Energy and AECOM[30] in 2009 established that, under the current market and regulatory environment, the economic potential for DH in the UK was about 14% of UK Building Heat Demand (equal to approximately 83TWh/year). This has been confirmed by work by AEA within this project using the recently established DECC UK Heat Map[31], which established that an estimated economic potential for DH of some 90TWh/year exists within the UK. However, work by AEA[32] in 2007 indicated that the technical potential for

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30 *The Potential and Costs of District Heating Networks – A Report to the Department of Energy and Climate Change,* Pöyry Energy Consulting and AECOM, April 2009

31 http://chp.decc.gov.uk/heatmap

32 *Analysis of the UK potential for Combined Heat and Power,* AEA Technology, October 2007.

DH (with CHP) could be as great as 230TWh/year, which is equivalent to approximately 40% of current UK Building Heat Demand.

From the above it is clear that there is a substantial gap between economic and technical potential within the UK, indicating the presence of significant barriers to deployment at this time.

5.2. Barriers and Potential Remedies

In its report *The Potential and Costs of District Heating Networks*, Pöyry Energy and AECOM identify a series of barriers to the deployment of DH in the UK. The report advises that that barriers can grouped into three types; economic, institutional and carbon price. The report discusses these barriers in depth and makes it clear that the barriers are complex in nature and are closely inter-related.

Based on the Pöyry/AECOM report, the principal barriers for DH can be summarised as follows:

- **Perceived Lack of DH development expertise in the UK**. The low level of DH penetration to date is expected to lead to higher development costs than in countries with high DH penetration as contractors are likely to incorporate higher contingency costs to cover construction risk. Furthermore, this perception may also lead to investors seeking higher returns in response to this apparent risk, thereby increasing the cost of capital. This barrier would be expected to diminish as DH penetration increases and experience grows.
- **Demand risk.** A DH network needs to achieve a certain level of initial demand (known as base load) at which revenues are sufficient to deliver a return on investment. Furthermore, investors will wish to see to this demand is secure in the long-term. This base demand can be difficult to achieve if this is dependant on a large number of small demands connecting to the system and difficult to maintain where customers are not fixed into long-term contracts. This uncertainty over demand will therefore mean that a higher return will be sought by investors.
- **Public Perception.** Successful deployment of DH will be dependent on convincing consumers to connect to the new system. However, DH does not have a strongly positive public image in the UK due to negative press in the past regarding inefficient operation of schemes and a lack of flexibility. While modern systems have overcome these drawbacks, such opinions may still need to be addressed. Pöyry/AECOM contrasts this with the situation in other countries, where DH is preferred due to its perceived reliability and availability. Recent public attitudes research conducted by the UK Green Building Council and Zero Carbon Hub33 found a positive view of DH networks as a key component of community infrastructure.

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[33] In support of their report *Sustainable Community Infrastructure*

- **Need for Co-ordinated Action between Multiple Parties.** The successful development of a DH network cannot be readily undertaken by any one party. Instead, development requires close co-operation between a range of groups including: local authorities, developers, housing associations, businesses and contractors. Achieving this level of co-operation can often be difficult.
- **Concerns regarding DH becoming redundant in the future**. While DH can demonstrate carbon savings over current prevailing technologies (i.e. gas central heating and electric heating) there is concern that these savings could be diminished by future developments such as decarbonisation of grid electricity.[34]
- **Need for Public-Sector Support.** Examples in the UK and other European Countries have shown that the development of large-scale DH networks generally require strong support / leadership from the public sector, particularly at the local government level. This is in order to provide a stabled policy environment that private-sector investors will require in order to invest in a project. However, the support for such development can vary between Authorities due to the factors such as:
  - Environmental/sustainability matters not being seen as a high priority issue in comparison to education, waste management etc.
  - Individual authorities not possessing necessary expertise to lead such development. Authorities need to be informed about matters including heat mapping, incorporating DH into spatial planning policy and procurement options for DH.
- **Current Policy Context.** AECOM/Pöyry identify cases of current policy that places DH at a disadvantage against other technology options. Examples given include:
  - Current building regulations encourage developers to install electric heating in new buildings, rather than considering DH or CHP as alternatives.
  - Application of planning policy guidance from CLG35 requiring LPAs to apply target percentage of the energy to be used in new developments to come from decentralised and renewable/low-carbon energy sources has been applied in an inconsistent manner between local authorities. For example, some local permitting authorities (LPAs) permit only renewable energy technologies to contribute to this target – therefore deterring developers from considering DH utilising fossil-fuel heat sources.
  - Social landlords are restricted by Housing Corporation regulation from increasing rents to cover investment in energy efficiency measures even though these will result in lower fuel bills for tenants.

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34 In fact, the existence of a variety of distribution infrastructures can actually provide town and city managers with flexibility in exploiting and utilising different sources and grades of thermal energy.

35 Department for Communities and Local Government

- **Carbon Price**. Pöyry/AECOM assert that low/zero carbon technologies are disadvantaged by the fact that costs for conventional technologies do not reflect the cost of carbon. As investors are not provided with a firm "carbon price" signal it does not allow for carbon savings to be recognised financially.[36]

In considering the above barriers, we have identified a number of areas for action summarised in Table 5.1 below.

Table 5.1
District Heating - Target Areas for Action

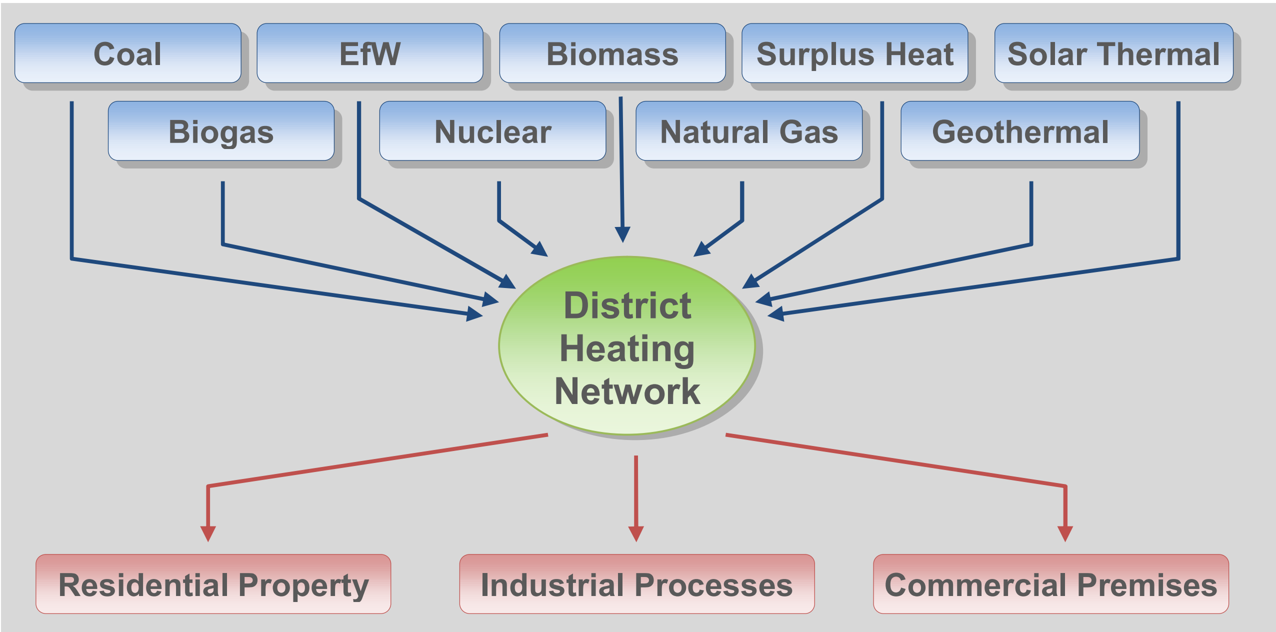
Target Area	Consequences	Actions
Increase awareness of DH as a heat supply option	Addresses public perception Demonstrates to investors that technology is established	Promote successes of existing DH schemes in the UK and EU.
Develop UK supply chain for DH	Reduce construction risk and consequent capital costs Lower returns sought by investors due to project risk	Provision of support (e.g. capital grants, insurance, low-interest loans) for initial round of DH development projects. Facilitate knowledge sharing between UK engineering companies and EU counterparts
Minimisation of demand risk	Delivers secure source of revenue, reduces consequent returns sought be investors	Base DH networks around large "anchor" loads able to commit to long-term agreements. Examples include: social housing, public buildings, hospitals and industrial premises.
Address existing policy measures that deter implementation of DH	Remove barriers that unintentionally act as a disincentive for DH.	Undertake review of current policy to identify such perverse incentives and implement measures to eliminate these.
Empower and educate Local Authorities on their in deploying DH.	LAs are better equipped to identify opportunities for DH in their area and take a leading role in their development.	Central Government to provide guidance and support to LAs through Best Practice guidance for matters such as: heat mapping and energy masterplanning, incorporating DH into spatial planning policy and procurement of DH. Enable to LAs to place planning conditions on new developments in relation to DH if appropriate. Place duty upon LAs to review opportunities for the deployment of DH in their area.

[36] However, analysis by AECOM/Pöyry in the same report indicates that the influence of such a carbon price on DH potential is small in comparison to other factors such as cost of capital.

5.3. Heat Sources Suitable for District Heating

A strength of DH is that it is technology neutral, permitting heat from a variety of heat sources to be transported to heat users. Figure 5.2 provides a summary of the types of heat source that can potentially connect to DH systems. Indeed, as the distribution infrastructure can be expected to have a longer lifespan (c. 40 years) to that of most heat sources (c. 15-25 years) it is conceivable that a DH network will be served by a varying profile of heat sources over its lifetime. This in turn presents the opportunity for the carbon intensity of heat to be decreased in a staged manner over the lifetime of the network in response market conditions.

Figure 5.2
Varieties of Heat sources for District Heating



Whilst all of the above sources have the potential to connect to a DH network the ease with which this can be achieved can vary.

- **Coal**-based supply can deliver very good reliability and availability with most suitable supply option being the use of heat from coal-fired power stations. Power stations offer limited opportunities for surplus heat use when optimised for power generation as the heat rejected will be typically low grade. However, stations can be configured such that heat is extracted from the steam cycle and the station operates as CHP. As most existing capacity is located away from centres of population this would present high connection costs. Therefore, future development would benefit from new stations being constructed in locations that present economically viable opportunities for stations to connect to DH networks. Future viability will also be heavily dependant on the successful implementation of carbon capture and storage (CCS).
- **Natural Gas**-based generation can deliver very good reliability and availability. It can be deployed in a variety of forms and sizes from standalone boilers through to large-scale power stations. It is largely unconstrained by factors such as site access, air quality and space allowing it to be deployed at small-scale within urban areas. Equally, gas-fired

generation in the form of CCGT power generation can provide heat where this is extracted from the steam cycle so the plant operates as CHP. Currently most large-scale capacity is located away from centres of population thereby presenting high connection costs. Due to its flexibility, gas-fired sources are well-placed to serve as the foundation for developing DH networks in the short and medium term. However this influence can be expected to diminish in the long term as fuel costs rise and carbon reduction requirements increase. Beyond this point, capacity would be limited to large-scale generation, which can be equipped with CCS.

- **Biomass** can deliver good reliability and availability. It can be deployed either as heat-only boilers or as CHP. Siting can be constrained by factors such as site access, air quality limits and (particularly for CHP) available space. Heat produced will contribute to renewables and carbon reduction targets.
- **Surplus Heat** from industrial processes (e.g. power generation, oil refining, bulk chemicals etc.) will contribute to carbon reduction targets due primary energy savings delivered by displacing heat from conventional sources. However, sources may be intermittent in nature and heat generated may also be of a low grade (e.g. low temperature water) preventing the heat from being injected into the DH system. While this may be overcome by incorporating a “boost” source (e.g. gas boiler) to achieve DH system conditions this may diminish carbon savings. Industrial processes can also be distant from points of demand, potentially incurring high connection costs.
- **Solar Thermal** will contribute to carbon reduction and renewables targets but most of the heat is generated in summer and therefore most of the contribution is to heating hot water with a little space heating possible in spring and autumn. The technology requires large available area - can be deployed where space already in use (e.g. roof tops) but better suited to open plots.
- **Energy from Waste (EfW)** can deliver good reliability and availability. It can also provide other benefits such as reduction of residual waste going to landfill. Siting of facilities can be constrained by factors such as site access, air quality limits and available space. However, waste management authorities will seek to locate facilities near to the point of origin, potentially placing them within economically viable range of centres of population. Emerging technologies such as gasification and pyrolysis of waste may present future opportunities by allowing smaller EfW facilities to be developed, overcoming the location constraints identified above. Supply of heat to the surrounding community will contribute to meeting environmental permitting requirements and may have positive impact on public opinion of such developments. Biomass element of wastes will contribute to renewables and carbon reduction targets. In particular the use of biogas derived from food waste in CHP could also make a useful contribution given the location of waste arisings close to population centres.
- **Biogas** is generated by the anaerobic digestion of wastes. Location of facilities can be constrained by factors such as site access and space requirements. Siting of facilities will also be influenced by the type of waste being received. Potential for biogas from sewage treatment works is good as these will tend to be located near to centres of population but facilities handling agricultural/food wastes may not be within economic range. Heat sources using biogas may also experience competing demands for biogas to be injected into the natural gas network.

- **Nuclear** power stations can deliver heat with very good reliability and availability. Power stations offer limited opportunities for surplus heat use when optimised for power generation as the heat rejected will be typically low grade. However, stations can be reconfigured such that heat is extracted from the steam cycle and the station operates as CHP. Most existing capacity is located away from centres of population, thereby presenting high connection costs. Future development would benefit from new stations being constructed in locations that present economically viable opportunities for stations to connect to DH networks. Such development is unlikely to be sited sufficiently close to major cities.
- **Geothermal** sources, which include the use of heat pumps, can deliver heat with reasonable reliability and good availability. Where the earth's crust is thin, usually in areas of high volcanic activity, high temperature heat is available in the ground for direct use. A prime example of this is Iceland where heat has been extracted for district heating for decades. However this is not common and the only such scheme in the UK is in Southampton. However, the earth or large bodies of water are still an effective store of heat gained in summer for use in winter and this low grade heat can be efficiently extracted using a heat pump. Siting of facilities will be constrained by the availability of a suitably large heat source (e.g. aquifer or lake). Such facilities may be constrained by available space but would not have as demanding requirements for site access as other options such as biomass. Heat produced would contribute to renewables and carbon reduction targets. Heat generated tends to be low/medium grade, which may be incompatible with DH systems conveying high-grade heat. This may be overcome by incorporating a "boost" source to achieve system conditions however this may diminish carbon savings.[37]
- **Power stations**. The future potential deployment of CCS for coal and natural gas-fired generation presents an opportunity for DH in that this will create a substantial source of surplus and low-carbon heat that could be supplied to DH networks. In the past, configuration of large-scale power generation to supply heat has not been considered favourably as increasing heat output leads to reduced power output. This may be seen as undesirable in the context of a heat supply environment largely reliant on electric heating, especially where this is combined with air or ground-source heat pumps, which are currently capable of generating 4 to 6 units of heat for each unit of electricity consumed.

However, the underlying thermodynamics of a power generation process indicate that the increase in heat efficiency due to the extraction of heat will be considerably greater than the corresponding decrease in power efficiency, as discussed in section 6.4.2.5.

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[37] Heat pumps used in conjunction with District heating offer the opportunity to use low cost surplus renewable electricity to store energy. This concept is used in countries with a large share of hydropower such as Sweden where spring melt and autumn precipitation create surplus power which is sold cheaply and used for heating and energy storage in hot water tanks etc. To achieve temperatures suitable for DH, a large multi MW scale heat pump is required such as the one employed at Värtan Ropsten in Sweden which has a 180MW capacity. (See http://www.friotherm.com/downloads/vaertan_e008_uk.pdf)

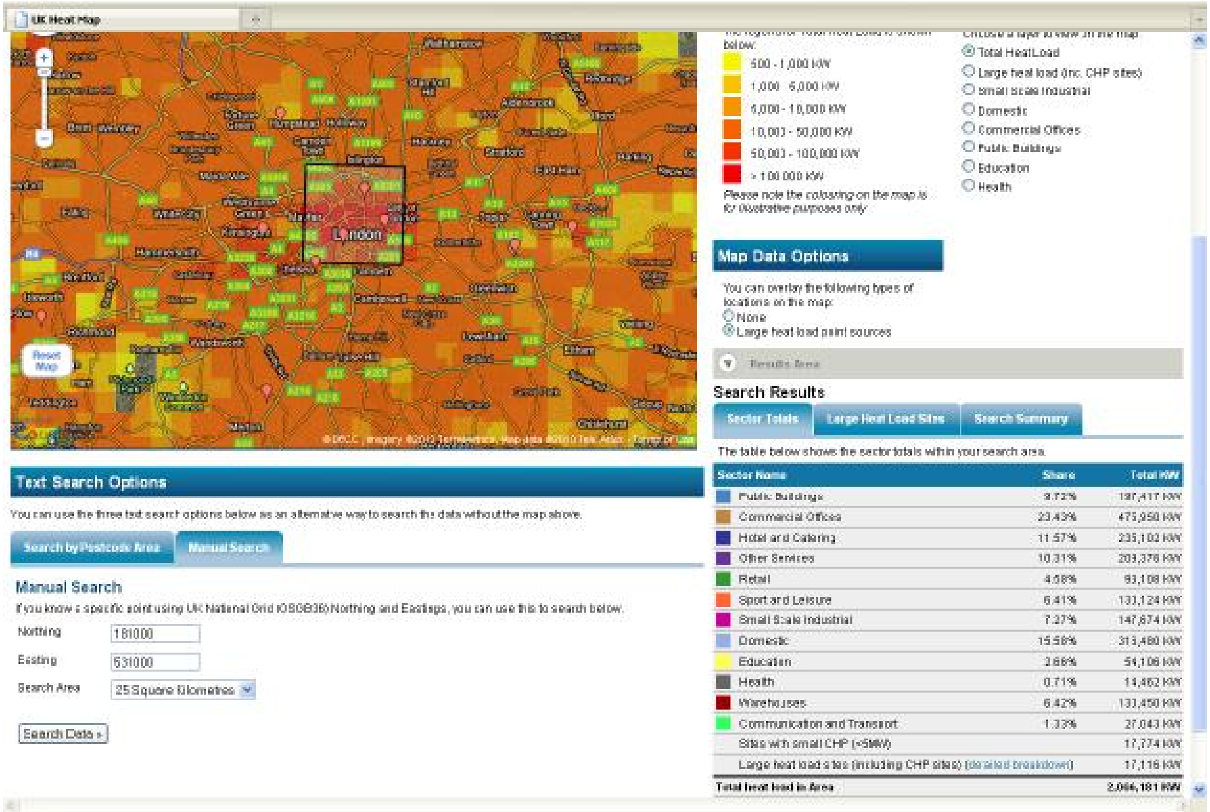
A similar situation could occur in the UK following large scale deployment of large intermittent sources such as offshore wind farms in periods of low electricity demand and high wind supply. In the case of the UK the heat source is more likely to be ambient air and the scale smaller, but the basic principle of using surplus electricity to generate and store heat energy should be valid.

Where the extracted heat can be put to useful purposes, the supply of heat from centralised generation can even compete with alternative supply options such as heat pumps. The challenge, therefore, is developing arrangements whereby heat that can be extracted can also be put to some use.

5.4. Heat Loads Suitable for District Heating

A first estimate of the potential heat loads suitable for DH was produced using DECC's new heat map searching areas with high heat load concentrations in the UK's largest towns and cities and industrial areas.[38] An example of this is shown in Figure 5.3

Figure 5.3
Heat Map Search Example



We have applied the following rule of thumb assumptions on the heat-map data to assess the suitability for DH based on AEA's experience of DH studies. An area was deemed as potentially suitable for district heating if:

- Area Heat Load density >5MW/Sqkm; and
- Area Housing heat load constitutes <50% of total heat load

Or

[38] http://chp.decc.gov.uk/heatmap/

- At least one large heat load >5MW is present

Or

- Area Heat Load density >50MW/Sqkm

Ignoring "non-economic" barriers, areas with the above heat densities or large anchor loads would typically be good candidates for DH schemes supplied by low carbon technologies, assuming 100 percent connection. These thresholds above are based on AEA's experience on community energy schemes. More detailed work would be required to assess the viability of individual schemes, which depends on the specific geography, building types and connection rates which is outside the scope of this study. We note that achieving 100 percent connection rates may be difficult, and failure to do so would result in higher costs. In principle this assesses whether each individual scheme in isolation is likely to be economic but does not consider non-economic barriers or the cost impact of implementing all potential schemes across the UK which may be higher due to increased demand or lower due to increased competition and know-how.

Using this method suggests that the total suitable heat load in the UK amounts to 90 TWh/year in 2030 (this is not far from Pöyry's estimate of 83 TWh/year). Table 5.2 breaks down the heat loads by city/industrial area and Table 5.3 shows the heat loads by, domestic, commercial/public and industrial sectors.

Table 5.2
Total High-Density Heat Loads Suitable for DH

Total Economic DH Potential in 2030 by city		
City/Industrial Area	Total Economic DH Potential	
	MWt	TWh/Yr
UK (2030)	24,501	91
Greater London	7,646	23
Greater Birmingham	1,904	7
Greater Manchester	1,268	4
Merseyside	841	3
Greater Sheffield	721	2
Teesside	1,721	11
Immingham	1,243	10
Nottingham	898	3
Hull	714	3
Bradford	680	3
Glasgow	594	2
Leeds	581	2
Southampton	550	3
Stoke	383	1
Bristol	381	1
Cardiff	370	1
Derby	304	1
Coventry	288	1
Newcastle	285	1
Edinburgh	285	1
Belfast	267	1
Leicester	267	1
Paisley	219	1
Huddersfield	199	1
York	179	1
Aberdeen	172	1
Northampton	172	-
Portsmouth	165	1
Dundee	152	1
Drewsbury	148	1
Newport	142	1
Carlisle	132	-
Wakefield	110	-
Swindon	90	-
Doncaster	87	-
Swansea	71	-
Inverness	67	-
Sunderland	65	-
Brighton	53	-
Perth	46	-
Barnsley	40	-

Table 5.3
Total High-Density DH Potential by Sector

Total Economic DH Potential by sector and year with projected heatloads				
	Domestic	Service Sector	Industrial	Total
Year	TWh/Yr	TWh/Yr	TWh/Yr	TWh/Yr
2010	32	26	36	94
2015	29	26	36	91
2020	29	26	36	91
2025	28	26	36	90
2030	29	26	36	91

5.5. Time Scales for Deployment

In considering the development of large-scale DH networks there are two principal options available:

1. Single Network model. This is where DH is developed as a single network from project inception. Here the network is constructed with a small number of large heat producers and with distribution mains branching out to serve heat supplies. This approach has "scale of supply" benefits but is capital intensive due to the large upfront capital expenditure required. The system will also have substantial heat supply capacity at commencement of operation – therefore a substantial amount of demand will need to be secured upfront in order to manage demand risk.
2. Cluster Network model. Here the DH network is initially developed as a series of small energy clusters serving a geographically small area centred upon one or more "anchor" loads and served by a single small heat source (e.g. natural-gas CHP). This approach requires less upfront capital infrastructure due to its limited initial coverage. However demand risk can be managed by sizing the scheme such that the majority of each cluster's capacity is met by the anchor load. As the clusters become more established, they can expand to take on more loads as they become economically viable. This expansion will normally require an increase in the supply capacity of a network either by the expansion of the existing heat sources or connection of additional sources. As these clusters grow they may then merge with each other to share heat sources.

Timelines for the above options are presented Figure 5.4 below.

In order to achieve the deployment of DH described above on an appreciable scale it is recognised that the barriers to deployment identified in section 5.2 will need to be addressed.

Central Government has recently issued documents that address the development of DH networks; the first is the Household Energy Management Strategy (HEMS)[39] issued by

[39] *Warm Homes, Greener Homes: A Strategy for Household Energy Management,* Department of Energy and Climate Change (DECC) with Department for Communities and Local Government (CLG), March 2010

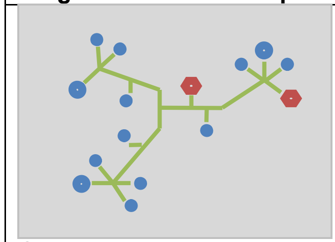
DECC and CLG while the second is a proposed planning policy statement (PPS) on planning for a low carbon future[40] recently issued by CLG for consultation.

[40] *Consultation on a Planning Policy Statement: Planning for a Low Carbon Future in a Changing Climate,* Department for Communities and Local Government, March 2010

Figure 5.4
Potential DH Network Developments and Timelines

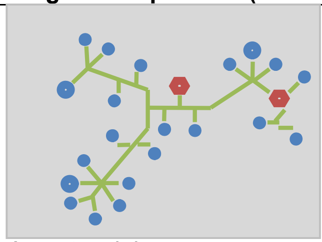
Single Network Model Development Timeline

Stage 1 – Initial Development



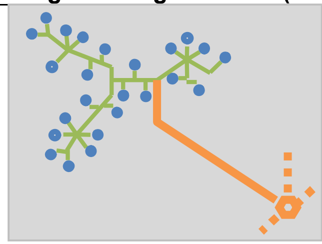
Single heat network constructed based around a small number of large heat sources (e.g. Biomass/EfW CHP). Heat distribution constructed to carry heat out to key "anchor" loads identified in the process of heat mapping. Smaller loads near to network also connected.

Stage 2 – Expansion (0 – 20 years)



As network becomes more established it will be able to expand to take connect to additional loads that have since become economically viable. Scope for expansion may be larger than for cluster model due to the greater amount of infrastructure already in place.

Stage 3 – Regeneration (25 years +)



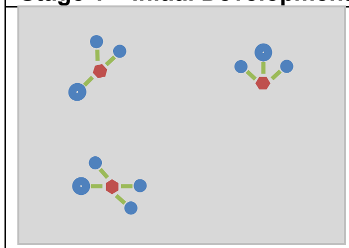
Original heat sources will have reached the end of their lives and will need to be replaced with new low/zero carbon heat sources. This is likely to include surplus heat from power stations. While development control should seek to locate such sources relatively close to areas with heat demand there may still be the requirement to transport surplus heat over long distances (10 to 20km). This can be achieved using high capacity "transmission" mains.

Key

- Heat Load
- Anchor Heat Load
- Distribution Pipeline
- Transmission Pipeline
- Heat Source (small)
- Heat Source (large)
- Power Station or other surplus heat

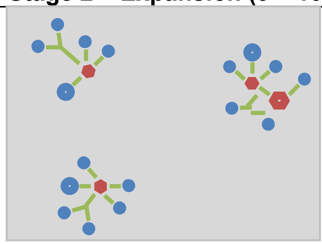
Cluster Network Model Development Timeline

Stage 1 – Initial Development



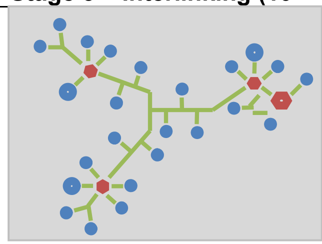
One or more independent cluster networks developed based around key "anchor" loads (e.g. social housing, hospitals, universities etc.) and other loads in the vicinity. Each cluster served by a single, small heat source (e.g. gas CHP)

Stage 2 – Expansion (0 – 10 years)



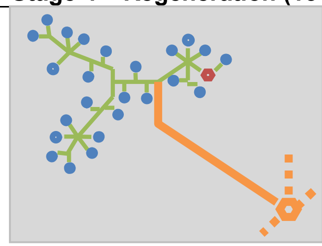
Clusters expand as they become more established to connect additional loads that have become economically viable. Individual heat sources grow in capacity to meet demand or are reinforced with larger heat sources (e.g. EfW CHP)

Stage 3 – Interlinking (10 – 15 yrs)



Inter-connectors installed to share excess heat capacity between clusters. Inter-connector routes selected to permit further connection with economic demands situated between clusters.

Stage 4 – Regeneration (15 years +)



Original heat sources will have reaching the end of their lives. These will need to be replaced with new heat sources, which may include surplus heat from power stations. This may be carried over long distances using high capacity "transmission" mains.

5.6. DECC/CLG HEM Strategy

A supporting paper to the HEM strategy provides an enabling framework for District Heat and Cooling. The paper identifies the following objectives and their associated timescales:

- Between 2010 and 2012 Government action will focus on increasing profile and credibility of DH as low-carbon heat solution.
- Between 2010 and 2015 Government will for increased capacity in skills and supply chain. Action will also be focussed upon the development of those opportunities with the most immediate potential for DH. This would be expected to focus upon dense, mixed-use urban communities including blocks of flats and social housing as well as new-build developments where they are close to existing heat supply opportunities.
- To 2020: DH development will be driven largely by incentives such as the Renewable Heat Incentive (RHI) and policies such as zero carbon homes and non-domestic buildings. By this point it is intended that a framework will be in place to allow standalone sources of renewable heat to connect to existing networks and to decarbonise the heat supply into the future.
- Beyond 2020: Established networks will begin to link together and thereby be able to expand into areas of less dense heat demand.

The model from deployment presented in the framework closely resembles the cluster model described above. The paper clearly states that the public sector will have core role in developing opportunities for DH. In particular local authorities will have a leading role in establishing opportunities for DH within spatial planning strategy, formation of ESCOs and the brokering of heat loads with other public sector bodies such as healthcare trusts and social housing bodies. At the national level, central government would need to facilitate opportunities such as the supply of surplus heat to DH from power generation and industrial processes as these would be beyond the remit of a single local authority.

Specific actions identified to implement the above framework include:

Establishment of a Heat Market Forum to advise Central Government on the development of a Heat Market. Initially the forum is expected to hold a purely advisory role although this may develop into a regulatory role over time. The forum would focus upon the development guiding principles for standards of service and consumer protection through the development of a “Code of Practice for Heat Networks”.

DECC is to commission a National Heat Map (covering at least England) to enable Local Planning Authorities to undertake a clear assessment of opportunities for DH and for this to be delivered on basis consistent with other authorities.

Central Government will introduce an online Community Energy Information Hub, which will seek to provide guidance to local authorities on matters such as raising project finance, forming ESCOs, technical standards and consumer protection in the form of a “How to…” guides. The hub would also seek to provide advice on energy master planning.

Central Government will consider the implementation of a series of measures to incentivise the deployment of DH. These are expected to include:

- Identifying the supply of heat from a DH network as means of attaining the zero-carbon standard for homes or non-domestic buildings.
- Provision of uplifts within the RHI for DH networks that deliver heat to "hard to treat" homes.
- Provision of funding, through the Homes and Communities Agency (HCA), for 14 DH infrastructure projects in England.
- Permitting Local Planning Authorities to make use of the existing Community Infrastructure Levy system as a source of financial support for the deployment of DH.
- Development of initial guidance on how to manage interconnection between networks and multiple suppliers which will become more relevant as DH networks grow.

CLG Proposed PPS

The proposed new PPS[41] entitled *Planning for a Low Carbon Future in a Changing Climate* was issued for consultation by CLG in March 2010. The finalised PPS is expected to replace the existing supplement to PPS1[42] and PPS22[43], which both refer to low-carbon development.

While the purpose of the new PPS is to set out a planning framework for low-carbon development in general, it proposes the following policies that are pertinent to DH:

Policy LCF1.4 requires that LPAs assess opportunities for decentralised energy (including, but not limited to DH) in their area. This assessment should include up-to-date mapping of heat demand and possible sources of supply. One of the areas that LPAs directly should consider is the securing of *"District heating networks based on renewable energy from waste, surplus heat and biomass, or which could be economically converted to such sources in the future"*.

Policy LCF2.1 requires that Regional Strategies plan for substantial new development in locations and ways which, amongst other things, *"provide for energy, in particular heat, to be gained from existing decentralised energy systems, including those integrated with waste management, or where there are clear opportunities for new or extended decentralised energy systems."*

Policy LCF4.1 requires that LPAs set how any opportunities for DH identified through heat mapping will be supported.

Policy LCF6.1 states that LPAs, in assessing the suitability of sites for new development, should consider the potential for the development on the site to contribute to heat demand where a DH network exists or could be developed.

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41 Planning Policy Statement

42 *Planning and Climate Change: Supplement to Planning Policy Statement 1,* Department for Communities and Local Government

43 *Planning Policy Statement 22: Renewable Energy,* Department for Communities and Local Government

Policy LCF7.3 state that where there are existing, or firm proposals for, decentralised energy systems with excess capacity LPAs can place the expectation on new developments for them to connect to these systems or to be designed to connect in the future.

The measures identified within the HEMS and proposed new PPS do seek to address these barriers identified in Section 5.2 in the following ways:

Increase awareness of DH as a heat supply option. The creation of a Community Energy Information Hub will serve to raise awareness of DH. The profile of DH amongst investors will also be raised by the provision of initial funding for DH by the Homes and Communities Association (HCA).

Develop UK supply chain for DH. The funding of 14 DH infrastructure project through the HCA can be expected de-risk these initial projects and establish an experience base within the UK. However, the measures do not address the possible benefits presented by the formation of links between UK companies and companies outside the UK with DH experience.

Minimisation of demand risk. Demand risk can be minimised by developing networks around "anchor" loads which equate to a substantial proportion of the network capacity and can commit to long term agreements. The Proposed PPS Policy LCF1.4 will address this by placing a requirement on LPA to undertake heat-mapping of their area, thereby identify any potential anchor loads. This will be supported by the creation of a national heat map for England, which will enable LPAs to undertake such an exercise in a more consistent manner.

Address existing policy measures that deter implementation of DH. The policy measures set out above do not specifically address this action in this area. This would therefore be an area that would benefit from further action by the Government.

Empower and educate local authorities about their central role in the deployment of DH. Measures within the Proposed PPS confer a number of responsibilities upon local authorities including the assessment of opportunities for decentralised energy (Policy LCF1.4), establishing how opportunities for DH will be supported (LCF4.1) and assessing suitability of new developments for connection to DH (LCF6.1). In turn, the proposed PPS also give LPAs the power to place the expectation on new developments to connection to an existing DH system (Policy LCF7.3). The creation of the Community Energy Information Hub will also play an important role in providing LAs with the requisite knowledge and skills to order to fulfil this role. Given that this tool is seen as the principal means to address this barrier, the efficacy of the hub should be closely monitored.

To summarise, the measures identified by the Government in the HEMS and proposed PPS, if implemented can be expected to address many of the barriers to deployment for DH. As such the focus of any oversight on Government policy should focus on ensuring that the identified measures are implemented and their efficacy monitored. Furthermore, it should be ensured that Government seek to identify and address individual policies that inadvertently discourage DH.

Based on the framework presented with the HEMS it is anticipated that events would need to progress along the following approximate timeline in order to deliver the deployment of DH at an appreciable scale within the forthcoming carbon budget period.

Table 5.4
Timeline of District Heating Deployment

Year	Milestones
2010/ 2011	National Heat Map goes online Community Energy Information Hub Created Secure HCA funding for 14 DH "demonstration" schemes Draft PPS on Low Carbon Energy is Finalised Commence review of existing policy/legislation that inadvertently act as a disincentive to the development of DH (e.g. building regulations, implementation, Housing Corporation regulation of RSLs) Heat Market Forum established and begins development of Code of Practice for Heat Networks.
2012	LPAs begin to produce assessment for decentralised energy for their respective areas. HCA funding for DH demonstration schemes awarded to up to14 projects. Complete review of existing policy/legislation restricting development of DH – produce series of recommendations for amendment of policies in question.
2013	Start construction of demonstration DH projects. Heat Market Forum to have established a draft "Code of Practice for Heat Networks". Begin process of establishing framework by which surplus heat from power generation/industry can be provided to DH networks in the future. Will need to over matters such as incentives for plant operators to supply surplus heat and planning controls to ensure locations for new developments take in account the ability to supply heat to DH.
2014	Implement RHI uplift for schemes feeding into DH networks. All LPAs to be in possession of a completed assessment for decentralised energy in their respective areas. Undertake interim review of demonstration projects. Should cover any difficulties encountered by developers in order to inform future policy development.
2015	First demonstration DH schemes come into operation. Code of Practice for Heat Networks to be finalised. Implement requirements for new power plants seeking consent to consider the ability to supply heat to DH networks. This may include placing a requirement on all new applicable developments to be "DH-ready" (i.e. incorporating features allowing heat to be extracted in the future). Carry out review of success of DH framework implementation so far – particular focus will need to be given on whether incentives provided so far are sufficient to foster development of DH networks beyond the demonstration projects already receiving public support. Consider need for further support (e.g. Capital Grants) or incentives.
2017	All demonstration DH schemes now in operation.
2019	First "DH-ready" power projects commissioned.

6. Methodology for Low-Carbon Heat Scenarios

The objective of this analysis is to analyse different scenarios for low-carbon heat supply, and the attractiveness of different technologies and approaches under different developments for key inputs, such as electricity cost and CO2 intensity, the availability of bioenergy, and different levels of growth in key industries. We develop scenarios to identify the potential for emissions reductions, the associated total cost, and the levels of abatement associated with different marginal costs of emissions reductions.

To construct the scenarios we make use of a modelling framework developed by NERA and AEA to evaluate the UK potential for low-carbon heating options. The model contains a characterisation of UK heat demand, organised by a number of detailed categories relevant to the cost, suitability, and performance of low-carbon heating options, as outlined in 2. It also uses a large range of input assumptions about technology cost and characteristics as well as fuel costs and other inputs. The model accounts for a range of constraints including the suitability of technologies for particular applications, the biomass resource available for biogas and biomass combustion, the feasible expansion in supply capacity, the level of heat demand and turnover of heating equipment stock, as well as the constraints imposed by the interaction of different low-carbon heat measures.

For this project, we have extended the modelling time period to 2030. Modifications include a more detailed categorisation of demand, extended projections of technology costs and performance, the addition of new technologies, a new bottom-up assessment of the suitability of technologies, and a revision of scenarios for supply-side developments.

In the sections below, we summarise the main model features and the modifications made. Further details on the modelling methodology can be found in NERA and AEA (2009) as well as NERA (2010).

6.1. Technologies and Demand Segments

A key feature of low-carbon heat is the large number of potential technologies as well as characteristics of end-user applications. Within the model we distinguish between a number of technologies as well as end-user characteristics to reflect the heterogeneity in abatement cost and potential of different low-carbon heat options.

6.1.1. Low-carbon heat technologies

The previously published supply curve covered the following technologies:

- Air source heat pumps (ASHPs)
- Biogas for injection into the gas grid
- Biomass combustion
- Biomass district heating (Biomass DH)
- Ground source heat pumps (GSHPs)
- Solar thermal

For this project, we have made the following additions and modifications:

- added ASHPs and GSHPs with heat storage
- distinguished air-to-water and air-to-air heat pumps in more detail.
- expanded biogas analysis to encompass gasification of biomass as well as biogas produced from anaerobic digestion; and
- modified the approach to estimating the potential for abatement from district heating and CHP.

6.1.2. Heat Demand Segments

The characteristics of the heat load can significantly affect the suitability, performance, and financial viability of low-carbon heat technologies. Relevant differences include the suitability of particular technologies, the size of the heat load, the incumbent heating fuel, load factor, amount of additional adaptation of heating systems required, and various other considerations. We represent these through a detailed mapping of UK heat demand to different heat demand segments, as noted in section 2. In summary, the segments represented are:

- **Consumer segment:**
  - Domestic (residential)
  - Commercial / public
  - Industrial
- **Consumer sub-segment:**
  - Domestic building type: detached houses, flats, other houses (semi-detached, other)
  - Commercial public: small private, large private, small public, large public
  - Industrial: small low-temperature process heat, large low-temperature process heat, small high-temperature process heat, large high-temperature process heat ,small space heating, large space heating
- **Fuel counterfactual:**
  - Natural gas,
  - Electricity, and
  - Non net-bound fuels (heating oil, LPG, solid fuels)
- **Location:**
  - Rural,
  - Urban, and
  - Suburban

- **Building age and fabric:**
  - Pre-1990, solid wall construction;
  - Pre-1990, cavity wall construction;
  - 1990-2010; and
  - New build (post-2010).

The main modification from previous versions of the model has been to refine the representation of the domestic sector to separately identify solid-wall houses from cavity-wall houses, and also to break out new buildings separately from the existing stock.

Eliminating some redundant combinations, the revised segmentation results in over 266 distinct demand segments, each of which can be combined with the technologies described above (excluding biogas injection).

6.2. Overview of Approach to Modelling of Low-Carbon Heat Potential

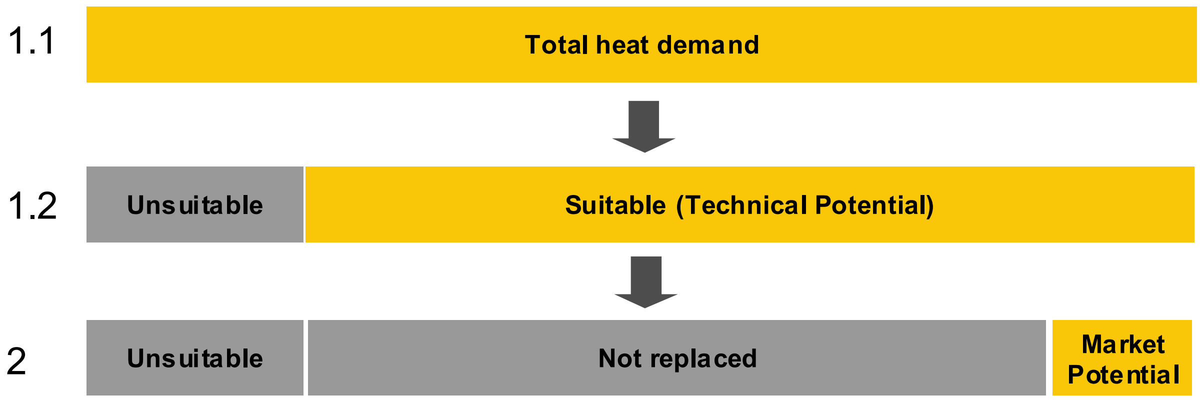
Given the above categories, a number of steps are required to identify the least-cost approach to abatement. The technologies modelled are substitutes to each other, and a number of options need to be evaluated for each end-user segments. In addition, a realistic portrayal of abatement potential needs to account for a number of constraints on the uptake of technologies, including the level of heat demand, the suitability for particular applications, the relative abatement cost, the rate at which new equipment replaces existing equipment, the available bioenergy resource, and the capacity of supply industry to ramp up deployment. We outline below how these and other factors are accounted for in the modelling.

The first steps in the modelling can be characterised as follows:

1. **Technical potential:** The first step is to estimate the maximum technical potential for each low-carbon heat technology. This accounts for two factors:
   1.1. the total level of heat demand, and
   1.2. the suitability of each technology to serve different types of heat load.
2. **Market potential:** Each year, only a small proportion of heating equipment is replaced. This subset of the technical potential gives what we refer to as the market potential for a given technology and year.

The relationship of the market potential to the total heat demand is shown in Figure 6.1.

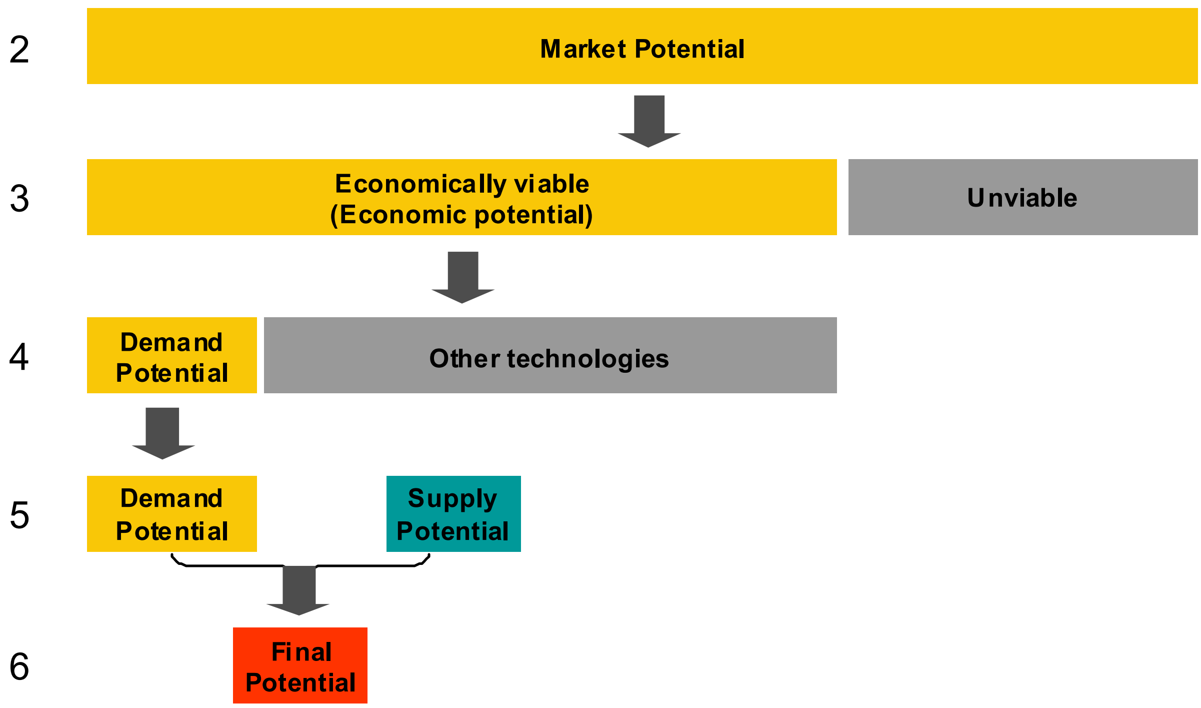
Figure 6.1
Overview of Technical Potential and Market Potential for a Single Technology (1 of 2)



The market potential ***for a given technology*** is further affected by a number of demand-side and supply-side considerations. Figure 6.2 summarises the steps that we apply for each technology to arrive at its final potential:

3. **Economic potential:** This is the portion of the market potential that has a CO_2 abatement cost no higher than a pre-specified threshold CO_2 price. The size of the economic potential thus depends on the cost and emissions characteristics of the technology and its counterfactual, as well as the input assumption about CO_2 prices.
4. **Demand potential:** The economic potential considers a single technology in isolation. The next step is to account for the interaction of the low-carbon heat technology in question with other low-carbon heat technologies. Even though the given technology may have a lower abatement cost than the threshold CO_2 price, *another* low-carbon heat technology may be able to serve the same heat load while offering a lower cost of abatement. In determining the demand potential, we account for these interactions, giving preference to the cheaper abatement options. The abatement potential of one low-carbon heat technology therefore depends on the pattern of uptake of other technologies.
5. **Supply potential**: It also is necessary to account for constraints on the supply of low-carbon heat technologies. This has two components:
   - 5.1. constraints on the total bioenergy resource available; and
   - 5.2. constraints on capacity to install and service new low-carbon heat technologies.
6. **Final potential:** In the last step, the final potential is estimated accounting for the joint impact of all of the above factors, using an iterative procedure.

Figure 6.2
Overview of Technical Potential and Market Potential for a Single Technology (2 of 2)



This representation is schematic and highly simplified. In the actual modelling, it is necessary to account jointly and simultaneously for all of the above factors, while also minimising the overall cost of abatement. For example, if one technology is limited by supply potential, this affects the demand for other technologies; if the suitability of one technology is restricted this may increase the potential for alternative options; the threshold CO_2 price determines uptake in a given year, which in turn can influence the supply constraints in subsequent years; etc.

One implication of this is that the marginal abatement cost curve (MACC) for low-carbon heat cannot be accurately characterised *ex ante* and in the absence of modelling; rather, modelling can be used to determine a least-cost composition of technology uptake that in turn implies an *ex-post* MACC.

We describe each of the steps above in more detail below.

6.2.1. Technical potential for an individual technology

The technical potential is limited by the total demand for heat, and the suitability of low-carbon heat technologies to serve this demand.

We incorporate the heat demand projections presented in section 2 into the modelling. This gives a detailed projection for each of the 266 demand segments, for the period to 2010. In addition, because the reduction in total heat demand embodied in the projections is achieved in part through the improvement in energy efficiency, they imply a reduction in the size of the average heat load, which in turn has an impact on the levelised per-MWh cost of heat.

The effect is particularly pronounced in the domestic sector, where capex represents a proportionately larger share of the total levelised cost of heat. We incorporate the declining size of average heat loads in the modelling to capture this impact.

The heat demand is combined with the assessment of suitability, as outlined in section 4.1. The suitability assessment varies by suitability scenario, as well as by scenario for heat demand and over time.

6.2.2. Market potential: heating equipment replacement

The second step in the demand-side assessment is to calculate the *market potential* for each technology. This is defined as the size of the market for replacement heating equipment that each technology could feasibly serve in the relevant time period. We calculate market potential by assuming a stock replacement rate linked to the counterfactual technology lifetime. With an average lifetime of around 15 years, this means that around two-thirds of the total heat load come forward as a candidate for the uptake of low-carbon technologies over the 2020-2030 period.

We have considered the possibility of representing the accelerated uptake of technologies, by allowing for the replacement of existing heating equipment before the end of its useful life. However, our assessment is that this is a relatively unlikely source of additional heat market carbon abatement. For example, if replacement could be gradually accelerated by two years, so that by 2030 replacement took place on a 13-year schedule instead of a 15-year schedule, the total heating equipment for replacement over 2020-2030 would increase from 67 to 71 percent. However, by 2035, when all of the pre-existing equipment in place in 2020 would anyway have come up for replacement, there would be no net gain in terms of annual emissions. While there would be some impact on cumulative emissions, in the longer run this would be impact would be very small compared to other factors. Moreover, accelerated depreciation would come at an increased cost, as functioning conventional heating technologies are written off before the end of their useful life.

There are two main exceptions to the stock replacement approach to defining the market potential. First, solar thermal is complementary to, rather than a substitute for, existing heating equipment. The market potential therefore is estimated as the total number of heat consumers that have not already taken up the technology.

Second, the market potential for biogas injection also is not dependent on the replacement of existing heating equipment. Instead, the main potential limitation is the total local off-peak gas demand.

6.2.3. Economic potential: CO_2 price threshold

The market potential is further restricted by applying a threshold value for the cost of abatement. This depends on the cost of measures and on the carbon price assumptions used in the modelling.

6.2.4. Demand potential

The economic potential defines an upper bound on the adoption of a *single* low-carbon heat technology. However, a general feature of marginal abatement cost curves is that the adoption of one measure affects the emissions abatement potential available from other measures included in the curve. As noted, in the case of low-carbon heat this is particularly relevant, as many of the measures are direct substitutes. This means that the use of one technology fully excludes the potential for the use of other technologies to serve the same heat demand.

We rank the uptake of technologies in order of their abatement cost, so that each end-user segment is assigned the technology with the lowest cost per tonne of carbon dioxide (tCO_2) abated, subject to other demand-side and supply-side constraints (including the condition that the cost of abatement does not exceed the threshold CO_2 price). The uptake model thus is not a consumer choice model, which would consider the least-cost option to serve a given heat load (potentially subject to a carbon price). Ranking by abatement cost also means that the total volume of abatement achieved does not enter into the technology assignment. This is relevant because heat pumps do not eliminate all of the emissions of the incumbent heating technology, so may offer a lower volume of abatement than do biomass technologies.

We refer to the potential available once these interactions have been accounted for as the "demand potential", which we estimate through modelling.

6.2.5. Supply potential

The demand potential can be further restricted and reconfigured by limitations to supply potential. This is defined as the available supply of a technology, given a situation where demand is not a constraint. The model accounts for two main sources of such restrictions: constraints on biomass supply and constraints on supply industry capacity.

6.2.5.1. Biomass availability

The modelling incorporates a constraint on the available bioenergy resource, using the scenarios for biomass available for heat uses described in section 3.1.1. The total amount of biomass used across biomass combustion and district heating is restricted not to exceed the estimates of the total available suitable resource in each scenario. The constraint also is implemented to ensure that constraints on feedstock use (notably, the much more limited resource suitable for domestic applications) are accounted for.

As noted in section 3.2.1, there also is potential to use biomass feedstock for the production of biogas. We include biomass used for gasification and AD within the overall biomass constraint.[44]

6.2.5.2. Supply industry constraints: 2020 starting point

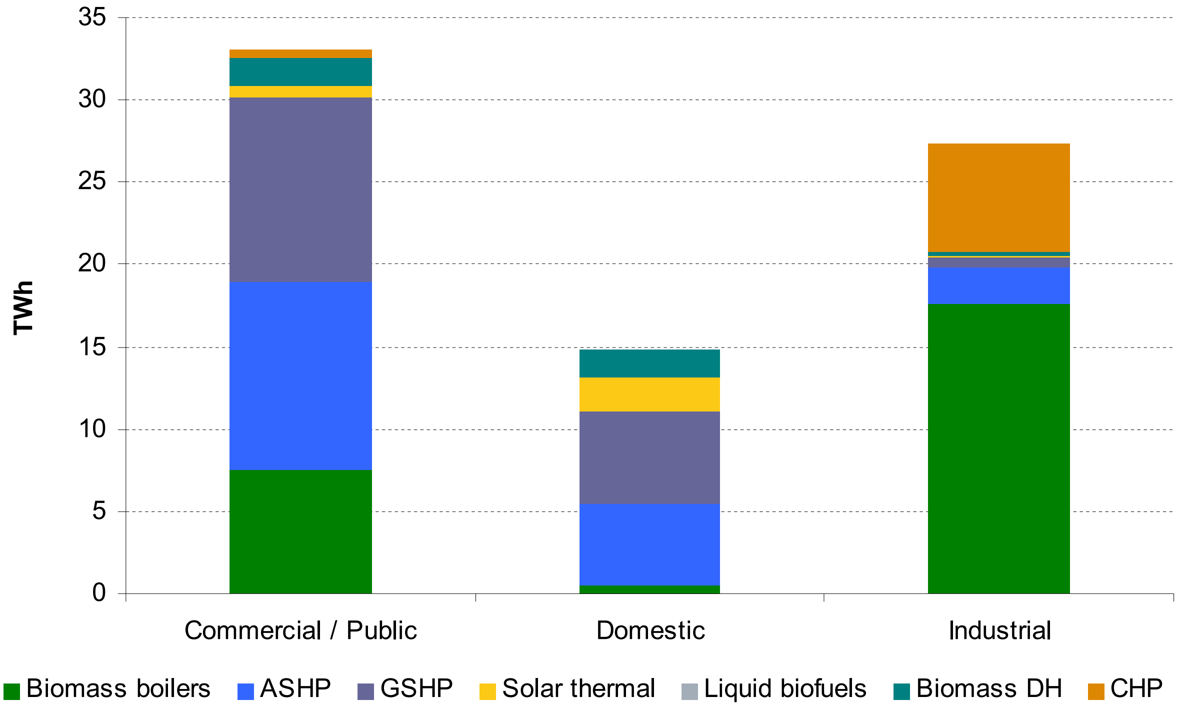
Current penetration of low-carbon heat technologies in the UK is minimal, accounting for less than one percent of total heat supply – and only negligible amounts outside industry process heat. Given the low current levels, the extent of feasible deployment at the start of

44 For anaerobic digestion the competition between uses is limited, as the core waste feedstock stream is not suitable for combustion uses. For synthetic biogas, however, the same biomass could be used. In practice, the consideration is relevant only to low and central cases, as the constraint on biomass is far from binding in the "high" biomass scenario, as we discuss further in section 7.4.2.

the 2020s is highly uncertain, and yet is a potentially important factor in determining the potential for further expansion to 2030.

Our starting point for this analysis corresponds to the projected deployment of low-carbon heating technologies outlined in DECC's recent consultation for the Renewable Heat Incentive (DECC 2010). This consists of heat output in 2020 of 68 (75 including baseline) TWh from a mix of heat pumps, biomass combustion, and solar thermal, corresponding to 12 percent of energy used for heating, and reducing emissions by about 17 $MtCO_2$ per year illustrated in Figure 6.3). The baseline low-carbon heat deployment is included in the modelling and reported alongside subsequent projected uptake of low-carbon heat technologies.

Figure 6.3
Assumptions for Low-Carbon Heat Deployment in 2020



Source: NERA Analysis

For the projection of future growth, the annual supply capacity of the industry in 2020 arguably is more important than the total installed capacity. To get a starting point for industry capacity, we have developed assumptions about 2020 industry capacity using data from NERA's previous analysis of potential deployment of renewable heat in NERA (2010), corresponding to the total deployment scenario. In 2020, the total industry capacity across all technologies amounts to the supply of heating equipment to serve just under 16 TWh of additional heat load.

This level of industry expansion implies an ambitious increase in renewable heat deployment to 2020. It is predicated on a number of factors, including that the RHI subsidy levels are sufficient to overcome financial and non-financial barriers to result in the large-scale expansion of consumer uptake, and that this in turn is sufficient to stimulate significant supply industry investment and growth.

6.2.5.3. Supply industry constraints: supply capacity growth

Having established the 2020 starting point, we then develop scenarios for the growth of the supply of low-carbon heat technologies and services. There are several potentially relevant constraints on supply growth, including shortage of skilled workers, limited infrastructure, small number of companies, institutions, and other elements of the supply chain required to deploy low-carbon heat.

Our approach to capturing these is to limit the maximum year-on-year growth in installation capacity. In the central scenario, we use a limitation of 30 percent. (Thus, the theoretical maximum additions in 2021 amount to 21 TWh, or 30 percent more than the 16 TWh of capacity added between 2019 and 2020.)

The actual supply constraint is updated dynamically based on previous year's modelled deployment. This in turn accounts for a range of other constraints, including resource constraints and demand-side constraints, as described above. The 30 percent growth therefore is an upper bound that may not be realised for all technologies in all years. Notably, once an industry is at a sufficient size to meet all demand for new equipment, it does not grow further.

We consider 30 percent year-on-year growth an ambitious target. It is on a par than the highest observed rates of growth observed for individual technologies in favourable conditions where low-carbon heat technologies have become mass market technologies (see NERA and AEA (2009) for a discussion). Sustaining such growth would require a policy framework that provided sufficient financial or regulatory incentives to effectively displace the incumbent heating technologies as the default choice for new heating equipment.

6.2.6. Final potential

The final abatement potential requires simultaneous modelling of all of the above considerations. The model estimates the least-cost marginal abatement cost curve by ordering technology options by their marginal abatement cost, ensuring that the cheapest available technology is used to fill a given heat demand segment. The technology adopted by consumers in a given segment therefore depends jointly on all of the various factors discussed above. For example, limited supply potential may prevent the uptake in a given segment of the low-carbon heat technology with the lowest marginal abatement cost; this in turn would lead to the uptake of another technology; which in turn would influence the available demand potential for other technologies. The final pattern of uptake thus depends on the joint consideration of all of the above factors.

The potential for CO_2 abatement cannot be deduced simply from the aggregate constraints on demand or supply potential. For example, given an aggregate constraint on domestic ASHPs, the amount of CO_2 abatement and associated resource cost depends heavily on which domestic segments take up the technology, which in turn depends on the interaction with the potential for other technologies. The final abatement potential therefore depends on the interaction of the supply potential as well as the various factors that influence demand.

6.3. Cost of Low-Carbon Heat and Other Modelling Assumptions

6.3.1. Technology characteristics and cost

For each demand segment, we use estimates of technical and cost characteristics to develop an estimate of the cost of using each of the low-carbon heat technologies to serve the heat load. Overall, eliminating unsuitable combinations and redundancies, the model evaluates more than 1,400 combinations of technology and end-user characteristics, for each year in the period 2020-2030.

Specifically, we use estimates of the following quantities for each low-carbon heat technology and each relevant incumbent (fossil fuel or electric heating) technology:

- Capex (including equipment costs, installation costs, auxiliary works, etc.);
- Fixed opex (chiefly maintenance)
- Lifetime
- Thermal efficiency / seasonally adjusted coefficient of performance
- Load factor
- Representative size

The technical data builds on those developed by AEA for previous work and documented in detail in NERA and AEA (2009). For a given technology, the various parameters can vary significantly between different demand segments. The demand segmentation therefore also translates into significant cost heterogeneity.

For this project, we have extended estimates of the above factors to 2030. The main differences are a continued reduction of capex for several technologies, as well as improved performance, particularly for heat pumps (see below). We also have developed new cost estimates for additional technologies, including domestic air-to-air heat pumps, and air- and ground-source heat pumps with storage. We outline the main modifications and additions to these assumptions in section 6.3.1.1.

We estimate costs on a levelised basis over the equipment lifetime, using additional assumptions about fuel prices and discount rates. The model then calculates the resource cost of low-carbon heat as the difference between the levelised cost of each low-carbon heat technology and its relevant counterfactual fossil fuel or electric heating option. The cost estimate optionally can include estimates of demand-side barrier costs, such as time costs or inconvenience associated with the use of low-carbon heat.

Finally, the cost of abatement is calculating by relating the resource cost to the net CO_2 abatement associated with the use of each technology. This in turn is calculated by applying standard emissions factors for fuel combustion as well as assumptions about electricity CO_2 intensity to the energy input used by each counterfactual and low-carbon heat technology.

6.3.1.1. Revision to capex and performance assumptions

We have extended the assumptions about heat pump cost and performance to 2030. Although assessments vary by segment, the following are indicative of the projections:

- Heat pump, solar thermal, and domestic biomass boiler capex goes down by 32 to 44 percent on current levels by 2030, with the steepest reductions in the heat pump capex (the cost of other technologies, including large biomass combustion, are not assumed to decline). (A fixed installation cost element means up-front costs are not the same as capex.)
- Heat pump performance increases by adding up to 1.5 to the current estimated COPs for space heating, for final space-heating COP values in the range 3.5-5.5 in 2030, depending on the type of heat pump and application. (As noted above, these are further adjusted to reflect various factors, including the need to provide hot water).

These assumptions imply a significant improvement in the financial and abatement attractiveness of heat pumps. As the technology assumptions are uncertain and also key drivers of the modelling results, we make this one of the areas of sensitivity analysis.

6.3.1.2. Heat pumps with heat storage

In addition to projecting the performance of standard heat pumps, we explore the possibility of using heat storage to shift electricity demand from heat pumps to off-peak hours. Systems of this type are not currently commercially available, so the design and characteristics are by necessity somewhat speculative. However, they could be a plausible future development if the price of electricity differed sufficiently during peak and off-peak hours, or if regulatory instruments were used to force their use. We consider both GSHP and ASHP systems, and domestic as well as non-domestic applications. The systems we consider are ones capable of shifting electricity load by around five hours while maintaining the same heat output capacity over the course of 24 hours.

The heat pumps with storage differ from the standard heat pump systems in the following ways:

- Capex: the tank storage systems have higher up-front costs, primarily associated with the cost of the tank and its installations.
- Opex: increased opex to reflect the additional components of the system.
- Performance: For air-based systems, the intermediate step of first heating water and then extracting the heat for use in a ventilation system leads to a reduction in the coefficient of performance. (For water-based system this effect is negligible.)
- Suitability: The option to store heat has significant space requirements so is unlikely to be suitable where space is scarce. For example, a standard domestic system would require a storage tank with a volume of 2.5 cubic metres, a volume corresponding to a sizeable cupboard. We account for this by reducing the number of buildings in which the technology can be taken up.
- Barrier costs: Another impact of the space requirements is that even where the technology is suitable, it is likely to face significant costs in the form of lost space. (As noted in

section 6.3.3, following a steer from the CCC these costs are not included in the "central" scenario and associated sensitivity analysis.)

- Electricity cost and CO_2 intensity: the use of storage allows for the use of off-peak electricity with lower cost and CO_2 intensity (see section below)

6.3.2. Fuel and carbon cost assumptions

6.3.2.1. Fossil fuel prices and emissions factors

We use fuel prices provided by the CCC, sourced from DECC guidance on the evaluation of policies affecting greenhouse gas emissions (DECC, 2010). These scenarios in turn are derived from DECC's Updated Energy Projections (UEP). The prices we use are not retail prices, but rather the "variable component" of retail prices. This excludes from the retail price various items, including taxes, network costs, and emissions allowance costs. For consistency with the DECC guidance we use these lower prices to calculate resource costs. For all quantities other than fuel and electricity we use standard retail prices (including taxes and fixed cost elements) for the calculation of resource costs.

The prices used for individual fuels and electricity in the model differ for the domestic, commercial / public (large and small), and industrial sectors. For the non net-bound counterfactual segment we have calculated a weighted average price based on the prices for coal and heating oil (burning oil in the domestic sector) in the relevant sector, using the current split between solid fuels and oil fuels in the most recent data from DUKES.

When evaluating the total levelised cost of heat we calculate a weighted average of the prices that will obtain over the equipment lifetime, accounting for changes to heat demand as well as the discount rate applied to future costs and benefits. For the evaluation of options undertaken in 2020, all of the fossil fuel prices in the period to 2035 thus are taken into account, although future prices are given less weight than near-term prices.

We use standard emissions factors for fossil fuels. As with prices, we use the weighted average of each sector's non net-bound fuel use to calculate emissions. For gas, we use the fossil emissions factors throughout the period, and thus do not consider the possibility that the gas displaced may have some component of biogas. This amounts to assuming that reductions in gas consumption from the adoption of low-carbon heat technologies will result in reduced supply of natural gas into the gas grid, but not a reduction in the amount of biogas injected.

6.3.2.2. Biomass prices and emissions factors

For biomass prices we use prices provided by the CCC of £37/MWh for pellets suitable for domestic use and £31/MWh for wood chips. These correspond to import prices estimated by E4tech (2009), and reflect "resource costs" rather than prices that are likely to be faced by consumers.

Following guidance from the project Steering Group, we assume that the combustion of biogas and biomass is associated with no CO_2 emissions.

6.3.2.3. Electricity sector scenarios

The electricity prices used for this work have been provided by the CCC. The CCC has developed three scenarios for low, medium, and high emissions intensity of electricity during the 4th budget period. The main features of these scenarios are described in the table overleaf. To reflect the seasonal and daily load profile of heating, various assumptions have been made about the nature of the plant that can feasibly serve the relevant heat loads. The assumptions reflect, for example, the lower load factor that can be achieved by plants serving highly seasonal loads. The adjustments have been carried out to match monthly load profile, and therefore may be an underestimate (as swings in diurnal loads may be more pronounced). Box 6.1 describes the high level thinking behind each of the three electricity scenarios. Appendix B presents a more detailed discussion from the CCC about the rationale for and development of the scenarios.

Box 6.1
CCC Electricity Scenarios

1. **Low emissions intensity**: The first scenario assumes there is no technical or economic limit on the amount of low-carbon plant that can be built. Thus any new demand can be met by nuclear and CCGT CCS, even where these plants are running at low-load factors.

2. **Medium emissions intensity**: The second scenario assumes that there is no technical constraint on building low-carbon plant, but that there is an economic constraint in that only low-carbon plant which can be run baseload is built. This could also represent a world where CCGT CCS was unavailable. In this scenario, any new demand which can be met by plants running at load factors of more than 75% is met by nuclear. All demand that is met by plants running at load factors of below 75%, including demand which comes on within the daily peak, is met by CCGT.

3. **High emissions intensity**: The third scenario assumes that there is a constraint on all new low-carbon build. This could be, for example, because of supply chain or skills constraints on the building of new nuclear. It could also be because additional demand from heating is not anticipated far enough in advance to build nuclear which has much longer lead times than CCGT . In this scenario, any new demand is met with CCGT.

It is unlikely that a power plant serving any new space heating load would be able to maintain a 75 percent load factor, because of the seasonal variation of space heating. Heating demand for hot water is likely to be much less variable across the year, and therefore probably would be able to be met using baseload plant.

In addition to these three scenarios, we have included a fourth scenario from the CCC that is considers the possibility that the medium emissions intensity scenario is realised, but at a higher cost. Table 6.1 summarises the electricity scenario assumptions.

Table 6.1
Summary of Electricity Scenarios and Assumptions

		Demand added at peak times only			Demand added at peak and off-peak, or off-peak only		
Scenario	**Description**	**Plant**	**LRMC £/MWh**	**Emissions intensity tCO2/MWh**	**Plant**	**LRMC £/MWh**	**Emissions intensity tCO2/MWh**
Low emissions intensity	Unconstrained build of nuclear and CCGT CCS	LRMC and emissions intensity of CCGT CCS running 12 hours per day, (adjusted for seasonality)	£159	0.06	Weighted average of nuclear and CCGT CCS, adjusted for seasonality and assuming nuclear meets load which is on the system for more than 67% of time (below that level it becomes cheaper to run CCGT CCS).	£108	0.02
Medium emissions intensity	Unconstrained build of baseload low-carbon plant (nuclear). No CCGT CCS, all non-baseload demand met by CCGT	LRMC and emissions intensity of CCGT running 12 hours per day, (adjusted for seasonality)	£96	0.43	Weighted average of nuclear and CCGT, adjusted for seasonality and assuming nuclear meets load which is on the system for more than 75% of hours.	£90	0.21
High emissions intensity	No additional build of low-carbon plant. Unconstrained build of CCGT.	LRMC and emissions intensity of CCGT running 12 hours per day, (adjusted for seasonality)	£96	0.43	LRMC and emissions intensity of CCGT running baseload, adjusted for seasonality.	£74	0.43
Medium emissions intensity, **High cost**	Unconstrained build of baseload low-carbon plant (nuclear). No CCGT CCS, all non-baseload demand met by CCGT	LRMC and emissions intensity of CCGT running 12 hours per day, (adjusted for seasonality	£136	0.43	Weighted average of nuclear and CCGT, adjusted for seasonality and assuming nuclear meets load which is on the system for more than 75% of hours.	£105	0.21

6.3.2.4. Carbon prices and EU ETS coverage

The carbon prices used in the modelling are those set out in DECC guidance on the evaluation of greenhouse gas emissions.[45] They are used in the modelling to calculate the cut-off point for abatement measures, so that no measures with an abatement cost higher than the cut-off level are undertaken. However, they are not incorporated in the cost of abatement itself.

The prices are differentiated by the "traded" and "non-traded" sectors, where the traded sector denominates emissions covered by the EU ETS. We have adjusted the size of the large industrial process heat segments so that total emissions closely match reported 2008 emissions from industrial installations under the EU ETS, and the "large" assignation thus is equivalent to EU ETS coverage. We have further cross-references this with a detailed proprietary database of industrial heat use developed by AEA for the analysis of CHP potential. As a simplification, we do not account for the *c.* 2 $MtCO_2$ of emissions from large public and large commercial installations outside industry.

The carbon prices start at £25 / tCO_2 in 2020 in the traded sector and £60 / tCO_2 in the non-traded sector. They then converge on £70/tCO_2 in 2030, and rise rapidly thereafter on a trajectory to £200/tCO_2 in 2050. Like with fuel prices, we calculate a weighted average CO_2 price to reflect the cost over the lifetime of new equipment. Under the "central" scenario discount rate, this results in an effective CO_2 price for the traded sector of £50/tCO_2 in 2020 in the traded sector and £70/tCO_2 in the non-traded sector, rising to £113/tCO_2 in 2030 in both sectors.

6.3.3. Discount rates and "hidden and missing" costs

Discount rates are used in the model to calculate levelised costs of the different technologies. Discount rate assumptions therefore affect the relative importance of up-front costs (capex) and future variable costs (opex) in decisions about heating technologies. We test the sensitivity to discount rates (and associated hidden and missing costs – see below) using a scenarios approach.

6.3.3.1. Conceptual background on discount rates and hidden/missing costs

Individuals and many private organisations evaluate energy investment decisions using real discount rates that various analyses suggest are significantly higher than the social discount rate of 3.5 percent. Survey evidence suggests that individuals may employ discount rates in excess of 30 percent for the evaluation of low-carbon heat technologies, while econometric studies of energy purchase decisions, as well as a wider literature on individual time preference and discounting, give many examples of still higher rates. Meanwhile, many commercial organisations for which energy is not a primary input to production apply very stringent "payback criteria" when assessing the attractiveness of investments in energy equipment – for example, requiring payback over 3-5 years is equivalent to evaluating an investment using a discount rate of 18-33 percent for equipment with a lifetime of 15 years.

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45 DECC, 'Toolkit for guidance on valuation of energy use and greenhouse gas emissions', http://www.decc.gov.uk/en/content/cms/statistics/analysts_group/analysts_group.aspx

There are varying views in the literature on the explanation and hence appropriate treatment of the discrepancy between these high private rates and the typically lower social rates. Explanations typically fall within three broad categories. They are not mutually exclusive, but decisions about how private discount rates should be treated depend in large part on the relative weight that each explanation is given:

The first category is that, as most evidence suggests, private individuals and organisations employ *time preference rates* in excess of 3.5 percent. This in turn may stem from factors including higher (opportunity) cost of capital, individual preferences (for households), or risk premiums reflected in private-sector borrowing rates. For firms, they may reflect the opportunity cost of scarce capital and the need for capital rationing rules. In all cases, they may reflect uncertainty about any costs and or benefits of the potential investment.

The second category is that the social discount rate and (imputed) private discount rates differ because there are *"hidden and missing" costs* that may not be fully reflected in the cost or performance characteristics of technologies. Examples relevant to low-carbon heat technologies include (the risk of) reduced performance or comfort, disruption to production, hassle and time costs, the value of space given up for equipment or fuel stores, or nuisance factors such as noise. Where such costs are present, consumers require higher offsetting future benefit to be willing to undertaken investment in low-carbon heat or other energy technologies. In econometric studies that seek to estimate discount rates, these hidden and missing costs often are not estimated explicitly, and therefore are reflected in estimates of the discount rate. In such cases where the econometric model has been mis-specified, what appears as a high discount rate is actually the additional, less tangible cost of the technology choice, which may not be related in any way to the *distribution* of costs and benefits *over time*.

The traditional welfare-economic perspective is that apparently perverse market behaviour, unless it can be imputed to market failures, is likely to be reflective of social costs. On this view, under the second category of explanation, there is nothing "wrong" with the high discount rates found by empirical studies (although they may not indicate time preference), but they reflect real underlying costs that should be acknowledged and accounted for. This can present a challenge for modelling if explicit estimates of private "hidden and missing" costs are not available. In practice, the best approach often is to employ high discount rates as a proxy for better estimates of the actual hidden and missing costs.

A third category of explanation for the discrepancy between the social rate of tie preference and higher private discount rates is what may be termed *consumer "irrationality"*. On this view, the social discount rate is also the rational discount rate for an individual, so failure to undertake measures which look attractive when evaluated at that rate is to the individual's own detriment. Individuals (and by extension society) would in fact be better off if they applied the lower rate. There are varying potential explanations for consumers' failure to undertake measures that are to their own benefit, ranging from inconsistent preferences to simple lack of information. Regardless of the underlying reason, the corollary of this third explanation is that decisions that look financially attractive when evaluated at the social discount have net positive social benefits even if they appear to be unattractive when evaluated at consumers' discount rates.

6.3.3.2. Modelling approach to discount rates and hidden/missing costs

In our modelling we consider three scenarios that allow us to test how heat sector emissions abatement potential and cost varies with assumptions about discount rates.

Given the uncertainty about the relationship of the discount rate to social costs, the CCC asked us to consider a range of scenarios. The CCC asked us to use the social time preference rate suggested by the Treasury Green Book for evaluating public projects (3.5 percent) for the majority of scenarios, including the "central" scenario. We also model scenarios using higher "private" discount rates and explicit estimates of barrier costs. Thus, we have applied the 3.5 percent discount rate assumption to the alternative scenarios for energy efficiency, bioenergy availability, electricity sector assumptions, fuel prices, technology assumptions, and other issues investigated in this project. Following the above discussion of discounting and barriers, this corresponds to the following assumptions:

- Where decision-makers apply higher rates of time preference / capital cost higher than 3.5 percent, this is chiefly because their behaviour is distorted by market failures or other factors which should not be regarded as social costs.
- The hidden and missing costs that may cause observed or imputed private discount rates to exceed 3.5 percent in empirical studies fall into one of two categories:
  - They are illusory and should not be regarded as social costs, or
  - They can be overcome (at no cost) by policy, so that given some policy action, individuals would be prepared to undertake the corresponding energy investments at the lower discount rates.

We consider two additional scenarios where we assume that the higher discount rates that are applied by private actors reflect real social costs. For the first of these, we apply discount rates that are higher than 3.5 percent, but still below many of the rates that emerge from empirical analyses. For the domestic sector, we use a rate of 16 percent, and for the non-domestic sectors, a rate of 12 percent. We do not include other hidden / missing costs or barriers.

Finally, we consider a scenario in which we assume that heat users make decisions about heat technologies using a discount rate of 18 percent (this is equivalent to assuming that they require a five-year payback on equipment with an expected life of 15 years). In addition to applying the higher discount rate, we also include explicit barrier costs where these have been estimated.[46]

[46] See NERA and AEA 2009 for a description of the barriers included. Note that in its stated preference study of energy choices by households, Element Energy found that consumers apply discount rates in excess of 25-30 percent, and *in addition* attributed significant "hidden" costs to attributes such as taking up extra space in the home and requiring fuel delivery. Our assumptions are therefore well within the range of their estimates.

6.4. Approach to Other Specific Technologies

There are a number of technologies for which the assessment of abatement potential and cost needs to take a somewhat different approach than described above. We briefly discuss some of these issues below.

6.4.1. Biogas

6.4.1.1. Types of plant modelled

We model biogas as a stand-alone operation, comparing the cost of biogas injected to the gas grid with the cost of wholesale gas. The types of plant are those described in section 3.2. AD units include central waste-management AD plants of 2-5 MW, using food waste as the primary feedstock, but supplemented by livestock waste arisings as noted in section. We also include farm-based AD plants of a few hundred kW size, and use a mix of feedstock with heavier emphasis on agricultural and livestock waste feedstock, and with some use of energy crops. The costs of these plants are those developed in previous work by NERA and AEA (2009).

For gasification we model both the large central gasification plant and smaller regional plants. Costs are built up from bottom-up estimates of components for the large units, with increased costs per unit capacity for the smaller plants. We assume that these use feedstock with the same price as regular biomass fuel. For the large plants, we assume that all of the heat can be used and, as an approximation, attribute to it the same value as heat derived from natural gas boilers (this may be conservative, given the high grade of heat gasifiers provide). For small-scale plants we assume that 75 percent of the heat can be used.

6.4.1.2. Potential and uptake

In the central case, we place a limit on deployment on the lines indicated in section 3.2, with a maximum of 20 TWh of output from AD plants and 18 TWh from gasification plants. We subject uptake to the same rule as other technologies, comparing the implied cost of abatement with the threshold CO_2 price trajectory.

We evaluate only heat uses of biogas, and have not compared costs to other uses, including electricity generation.

6.4.2. Combined Heat and Power Generation

Combined heat and power (CHP) is the simultaneous generation of heat and electricity. Because CHP makes use of the heat created in the electricity generation process it can achieve overall efficiency significantly in excess of that feasible through the separate generation of the equivalent heat and electricity.

The CO_2 reduction potential of CHP stems from its ability to use fuel more efficiently. However, where electricity is generated through means other than combustion processes – notably, from nuclear power or wind power – the ability of CHP to contribute to abatement is less clear-cut. Intuitively, where the CO_2 intensity of the electricity displaced by CHP is lower, the net CO_2 reductions feasible through CHP also are reduced.

In this section, we evaluate the potential role for CHP to contribute to CO_2 reductions in the context of the power sector scenarios presented in section 6.3.2.3. We first provide an overview of different size categories of CHP, and then develop estimates of abatement cost and potential of four types of CHP:

- conventional gas-fired CHP
- biomass CHP
- micro CHP; and
- heat extraction from large power stations.

The assessment is done on the basis of the central power sector scenario described above. It thus is not an assessment of the abatement potential for CHP in the near term, or in other scenarios (e.g., with different values of imported and exported power).

6.4.2.1. Overview of categories of CHP

CHP can be broadly categorised into five size ranges.

6.4.2.1.1. Micro CHP

Micro CHP category contains small CHP units (less than $2kW_e$ capacity) suitable for domestic applications. There are two main routes for CHP at this scale. First, currently available units are based on Stirling engines. Although the basic technology is established, the technology is not yet commercially available at scale.

Second, several options for small-scale CHP based around fuel cells are under development. Fuel cells have the attraction of higher electrical efficiencies than can be achieved by Stirling engines at this scale. In addition, fuel cell CHP could offer the option of using carbon-free fuels such as hydrogen derived from renewable sources, although this is a more distant prospect and would depend on competing uses for hydrogen.

Fuel cell CHP is still an emerging technology, and its viability (operational efficiency, durability, availability) is dependent on further technological development. Views on the likely time before emergence of commercially available units vary. Some manufacturers claim that fuel cell CHP may be available within the next few years, and certainly before the 2020s. The recently introduced feed in tariffs for sub-5MW electricity include support for up to 30,000 micro CHP units, with the aim of contributing to the development and commercialisation of the technology.

6.4.2.1.2. Mini CHP

The mini CHP category encompasses CHP applications with a power capacity between 2 and $50kW_e$ and is currently dominated by units based around small reciprocating engines and some Stirling engines. These units have been shown to be economically viable in some applications (e.g. small commercial, leisure facilities) but their use at this time is largely limited by high unit price.

Like in the micro CHP category, there is a prospect that mini CHP could be based around fuel cells with higher electrical efficiency.

6.4.2.1.3. Small CHP

In this category we group together units with an electrical capacity between 50 kW_e and 5 MW_e. CHP units in this category employ a variety of technologies (e.g. reciprocating engines, gas turbines, steam turbines) and can be used in large commercial premises, public buildings as well as small-scale district/communal heating systems or small industrial sites. These currently represent the majority (about 90 percent) of installations and about 10 percent of installed CHP capacity.

Small CHP is fuelled predominately by natural gas, although recent trends show a move towards the use of renewable fuels in response to support form measures such as the Renewables Obligation.

In the future, CHP at this scale could make use of emerging technologies including pyrolysis and gasification of renewable fuels. These technologies are likely to be limited to industrial or district/communal applications.

6.4.2.1.4. Large CHP

Large CHP category contains units with a capacity between $5MW_e$ and $50MW_e$. Approximately 10 percent of schemes and 25 percent of total UK installed CHP capacity are in this size range. Schemes at this scale most commonly use gas turbines, steam turbines and combined cycles. These plants are used on large industrial sites and for larger district heating networks.

6.4.2.1.5. Very large CHP

This category covers CHP with an electrical capacity in excess of $50MW_e$ and will be encountered on industrial sites which fall under the EU ETS. These plants will employ gas turbines, steam turbine and combined cycles. This size range accounts for only a small proportion of the number of schemes but accounts for approximately 65 percent of total CHP capacity in the UK.

At sizes above $300MW_e$ CHP plants would have significant power generation capacity, and like other electricity generating plant would offer the possibility of making use of carbon capture and storage.

6.4.2.2. Gas-fired CHP

To model the abatement potential of CHP we have developed technology assumptions for three main categories of CHP: gas engine CHP, open-cycle gas turbine CHP, and combined cycle gas turbine (CCGT) CHP. For each category, we have assigned a typical heat-to-power ratio, overall efficiency, and other characteristics based on an assessment of likely new CHP schemes. We summarise these in the below table.

Table 6.2
Modelling Assumptions for Gas-Fired CHP

CHP Category	Indicative size bands MW_e	Indicative heat-to-power ratio	Overall efficiency %	Electric efficiency %	Thermal efficiency %
Gas Engine	<3.5	1.2	83%	37%	46%
Large OCGT	3.5-40	1.2	86%	32%	54%
CCGT	>40	0.6	83%	51%	32%

Notes: The efficiency is given for the net calorific value / lower heating value of gas.

To calculate the abatement cost and potential for different applications, we have mapped these stylised CHP types to different demand segments. The mix of technologies we use is based on previous detailed modelling by AEA (on behalf of DECC) of CHP uptake to develop projections for CHP across a large range of sectors and applications (AEA, 2010). This suggested just over half of capacity might be in the form of small-scale applications (such as community heating schemes, or small commercial / public space heating loads) using gas engines. The other half are predominantly medium to large industrial applications providing process heating loads using combined cycle CHP schemes.

We calculate the abatement cost and potential per unit of *heat* produced. This treats electricity generation like a “co-product” to heat: each MWh of heat output from CHP has associated with it a “negative” cost corresponding to the export value of the electricity produced, and also the emissions reductions corresponding to the counterfactual electricity generation displaced (based on the Grid predicted future carbon intensities) by the CHP electricity output. This means that the abatement of CHP depends strongly on the characteristics of the electricity generation that it displaces, as we discuss in more detail below.

Each CHP scheme is also assumed to include sufficient boiler capacity to meet the heat demand and provide back-up facilities. This reflects standard practice for CHP, providing backup during maintenance and is an important element in enabling the flexible sizing and use of the electricity generating capacity.

6.4.2.2.1. Emissions intensity and savings of gas-fired CHP

The emissions intensity per unit of heat output from CHP depends very strongly on the features of the electricity generation it displaces. For an analysis of the 2020s, the relevant comparison is with the emissions characteristics of *new* electricity generating capacity that otherwise would be built to serve the same electricity demand. As described in section 6.3.2.3, our central grid-intensity electricity scenario assumes that new capacity to serve peak electricity demand is CCGT plant with an emissions intensity (net, including losses) of 0.43 tCO_2/MWh_e; whereas new capacity serving off-peak electricity demand is assumed to be a mix of nuclear power and CCGT plant, with an average emissions intensity of 0.21 tCO_2 / MWh_e.

Figure 6.4 shows the emissions intensity of heat from gas-fired CHP as it varies with different characteristics of grid electricity. The figure compares the emissions intensity of a stand-alone modern gas boiler with the mix of CHP described above.[47] The first bar shows the emissions intensity of an efficient conventional gas boiler, which emits 0.22 tCO_2 per MWh of heat output. The next three bars show the *net* emissions intensity of CHP per MWh of *heat* output, accounting for the electricity generation that the CHP displaces under different scenarios for grid CO_2 intensity:

- The second bar from the left shows the impact of displacing new CCGT power stations, with an emissions intensity of 0.43 tCO_2 / MWh_e. This corresponds to peak generation in the central grid decarbonisation scenario. Thus, if gas-fired CHP runs primarily during peak hours and displaces CCGT, the use of CHP can bring the emissions intensity down from 0.22 tCO_2 / MWh heat to 0.14 tCO_2 / MWh heat. The net abatement thus is 0.08 tCO_2 / MWh heat output, corresponding to a 36 percent reduction in emissions.
- The third bar shows the situation if CHP were to displace new *off-peak* (i.e. base-load) plant, with a weighted-average emissions intensity of 0.21 tCO_2 / MWh_e. At this reduced CO_2 intensity for electricity, the net CO_2 emissions intensity of heat generation from CHP doubles, to 0.28 tCO_2 / MWh heat. Thus if gas-fired CHP were to replace base-load electricity in our central scenario, this would lead to a net increase in emissions by 25 percent compared to stand-alone gas boilers and the grid providing the same output.
- The final bar shows the situation if CHP were to displace new power plant with practically no CO_2 emissions (0.06 tCO_2 / MWh_e, corresponding to peak-time power output the low grid-intensity electricity scenario). In this case, heat generation from CHP has an emissions intensity of 0.39 tCO_2 / MWh heat, or nearly double that of a stand-alone boiler and the grid.[48]

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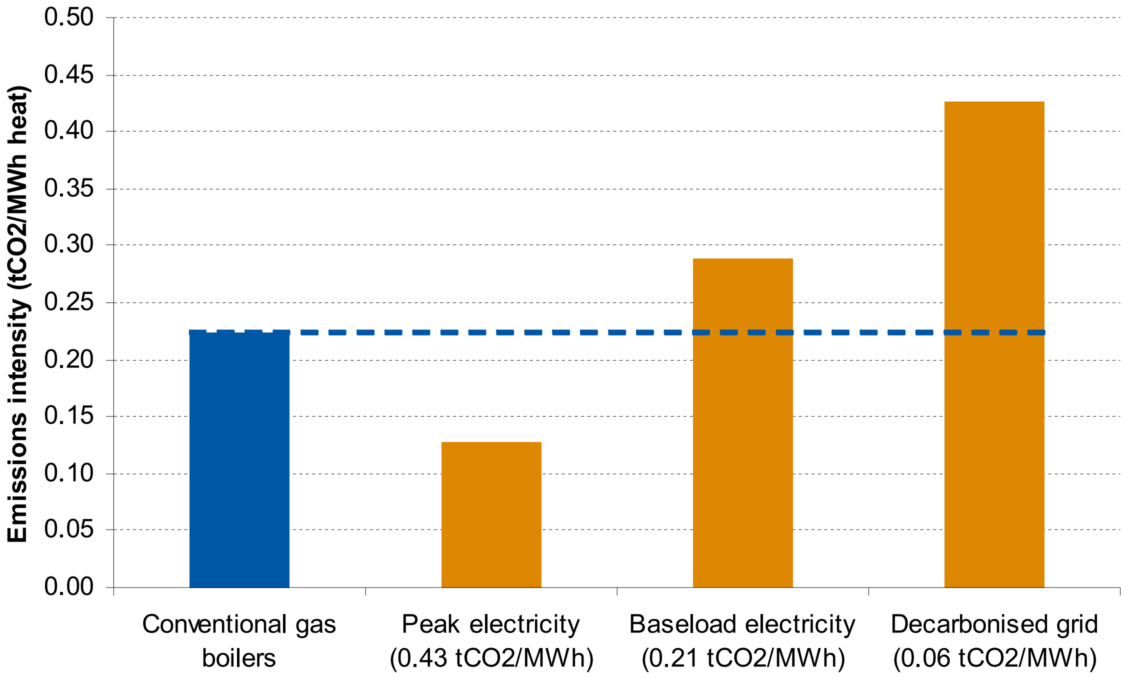
47 The CHP mix represented here is the weighted average of the categories shown above, with a heat-to-power ratio of 1, overall combined efficiency of 83 percent (LHV), and utilisation of 5,000 h / year (see below).

48 The emissions intensity of heat from gas-fired CHP is equal to that of a conventional boiler plus the grid when the average CO_2 intensity of the *displaced* grid electricity is 0.28 tCO_2 / MWh.

Figure 6.4
Emissions Intensity of Gas-Fired CHP under Different Counterfactual Electricity CO_2 Intensity



Source: NERA/AEA calculations as explained in text.

6.4.2.2.2. Electricity generation load profile of gas-fired CHP

The above analysis shows that, with the assumptions in the central grid intensity case, the abatement potential of CHP depends directly on its generation load profile. If CHP were to run only during normal working hours, it could contribute to emissions abatement by taking the place of new CCGT plant. However, running gas-fired CHP as baseload plant would imply the displacement of a mix of nuclear and CCGT power plant, resulting in a net increase in emissions.

Gas-fired CHP can be run flexibly, with the potential for a wide range of utilisation patterns. Much of the potential for CHP is in industry with near-constant heat demand (in excess of 8,000 hours per year). However, it is not necessary for CHP electricity generation to mirror the pattern of heat demand. It is standard practice for CHP schemes to include sufficient backup boiler capacity to enable them to meet the required heat load without also generating electricity. Meanwhile, gas fired CHP can be turned on and off at relatively small cost or loss in operational efficiency Many CHP operators therefore turn off the CHP plant and use boilers to serve the heat load whenever electricity prices are lower than the net cost of electricity generation.

For this analysis, we have assumed that CHP generates electricity for 5,000 hours per year (i.e, a 57 percent load factor), with any heat load in excess of this amount met by boilers. This level of utilisation is almost identical to the current average load factor for installed CHP capacity. In the context of the central grid CO_2 intensity scenario, it implies CHP would displace peak-hour electricity plant.

In practice, the utilisation achievable by CHP would depend on the precise characteristics of the power sector. A 57 percent load factor seems broadly consistent with low off-peak electricity prices that would likely be associated with the presence of significant electricity generating capacity with low short-run marginal cost. However, depending on the precise electricity market trading arrangements, this level of utilisation may be on the high side for an electricity system with significant quantities of intermittent (wind) capacity, in which gas-fired generation generally may experience a combination of lower load factors and the system overall more price spikes. It has not been possible to take this or other detailed electricity market features into account in this project. Additional research would be required to elucidate the likely generation profile of CHP plants in a situation with significant quantities of wind power and nuclear on the system.

Our assumption about the number of running hours does have a significant impact on abatement potential. The lower the running hours for the CHP unit, the higher the share of the time when heat needs to be met by supplementary conventional boilers. Lower CHP utilisation thus leads to less electricity generation, and reduced CO_2 emissions abatement. For example, if the running hours for CHP were 3,000 per year (a 34 percent load factor) instead of 5,000 hours, the CO_2 savings per unit heat output would be reduced from 0.08 tCO_2 / MWh to 0.05 tCO_2 / MWh.

6.4.2.2.3. Gas-fired CHP abatement cost

Reducing the running hours for CHP also increases its cost, as the benefit of combined electricity and heat generation accrue for less of the year. Despite this, CHP has a very low cost of abatement under the assumptions here. The cost per tonne CO_2 ranges between negative £220-310/tCO_2 depending on CHP type, with a weighted average of negative £300/tCO_2.[49] Under the assumptions used here, conventional gas-fired CHP therefore could be a cost-effective method of abatement.

Like with other negative abatement costs, the question arises why an apparently favourable technology is not in greater use already, especially given a history of policy intervention to encourage CHP use (the EU ETS, CCL exemptions, etc.). At high level, the answer is that a number of “barriers” can make CHP appear less favourable in practice. These include the value achievable from CHP electricity output under UK electricity market trading arrangements, access to grid connection, commercial risk and the use of high discount rates by many organisations with potential for CHP, and other factors. Consistent with the overall approach in this project, we do not include the cost of such barriers in the central scenario, but assume that they have been overcome.

Nonetheless, we note that the low cost of abatement from CHP is relatively robust to less favourable assumptions. For example, the negative cost of abatement remains with the use of discount rates more similar to those used by commercial organisations that could use CHP (e.g., a discount rate of 15 percent over 10 years), or if reducing the running hours to 3,000 hours per year.

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49 As with heat pumps and other technologies leaving some residual emissions, the numbers are very large (in absolute value) in part because the denominator (the extent of emissions abatement) is smaller; a technology that reduces emissions by 36 percent will always tend to have a large (negative or positive) abatement cost compared to technologies that eliminate all emissions.

6.4.2.2.4. Gas-fired CHP abatement potential and scenarios

This analysis suggests that conventional gas-fired CHP could have a role as a low-carbon technology as long as there is a prospect of conventional CCGT generation otherwise being added to the electricity system, and if the heat load would otherwise be served by conventional boilers.

In developing a scenario for the 2020s, we use an estimate of the heat load suitable for CHP in process heat, commercial / public heat loads, and district heating as a starting point. We then give precedence to biomass combustion over gas-fired CHP where the abatement cost of biomass combustion does not exceed the threshold cost of carbon. This is because although gas-fired CHP looks attractive when considered in terms of the abatement cost per tonne of CO_2, it offers lower absolute abatement than does biomass.[50] Achieving ambitious abatement targets in the 4th budget period is likely to require reliance on biomass (or other technologies that can reduce emissions to near zero) where these are not prohibitively expensive. Other factors that affect the total potential include the improvement in industrial energy efficiency, and the possibility that some existing gas-fired CHP may be replaced by biomass (which would depend on policy). Finally, as noted above, a more comprehensive estimate would need to ensure consistency with the power market scenario, which we have not considered here.

Accounting for these factors, we suggest that 65-75 TWh of heat may in principle be suitable for CHP within the overall low-carbon scenario considered here. With the above assumptions about running patterns and other CHP characteristics, this would correspond to 8 GW_e of CHP capacity. The corresponding emissions reductions would be 5.25 $MtCO_2$, compared to a situation where the same heat load were served by conventional boilers (and the electricity demand met by new-build CCGTs).[51]

6.4.2.2.5. Conventional CHP and "lock-in"

Another consideration is whether gas-fired CHP constitutes "lock-in" to a relatively high emitting technology. The main reason that this may be a concern is that CHP offers much less opportunity for retrofitting electricity generating plant with carbon capture and storage. Where this is an important option for reductions in power sector emissions, the continued addition of gas-fired CHP in the 2020s could present higher costs for subsequent emissions reductions. Nonetheless, CCS may also be an option at large-scale CHP at large industrial sites (and at power stations operating in CHP mode, as we discuss below).

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50 In this case, choosing the lower cost abatement option (CHP) forecloses the possibility of achieving greater abatement of the same emissions (through biomass boilers). The result would be that meeting the overall abatement trajectory for the 4th budget period would become more expensive, because even higher cost measures would need to be used to reduce emissions from remaining (non-CHP) heat loads.

51 This may be relatively conservative. In 2008 CHP capacity amounted to 5.7 GWe , producing around 28 TWh of electricity and 52 TWh of heat. An additional 1.5-1.7 GWe of capacity (mainly large-scale CCGT based CHP) is expected to be added in the next two years. Recent detailed projections, including work by AEA (2010) for DECC, has suggested that significantly more CHP may be in place by the early 2020s. We adopt a conservative number for CHP to avoid the risk of inconsistencies with other aspects of the analysis (notably the power sector), but suggest that further joint analysis of the power and heat sectors would be required to refine this estimate.

6.4.2.3. Biomass CHP

We also have investigated the characteristics of biomass CHP. Compared to gas-fired CHP, current biomass CHP has significantly lower overall efficiency (in the 45-60 percent range, compared to more than 80 percent for gas-fired CHP), while capex, fuel cost, and other costs are higher. The types of biomass CHP considered and their efficiency characteristics are summarised in table Table 6.3.

Table 6.3
Modelling Assumptions for Biomass CHP

CCGT category	**Size band** MW_e	**Heat-to-power ratio**	**Overall efficiency** %	**Electric efficiency** %	**Thermal efficiency** %
Biomass Air Turbine	<1	2.2	60%	19%	41%
Small Biomass Steam Turbine	1-5	1.6	43%	16%	27%
Med Biomass Steam Turbine	5-25	1.6	46%	18%	29%
Large Biomass Steam Turbine	>25	1.6	50%	19%	31%

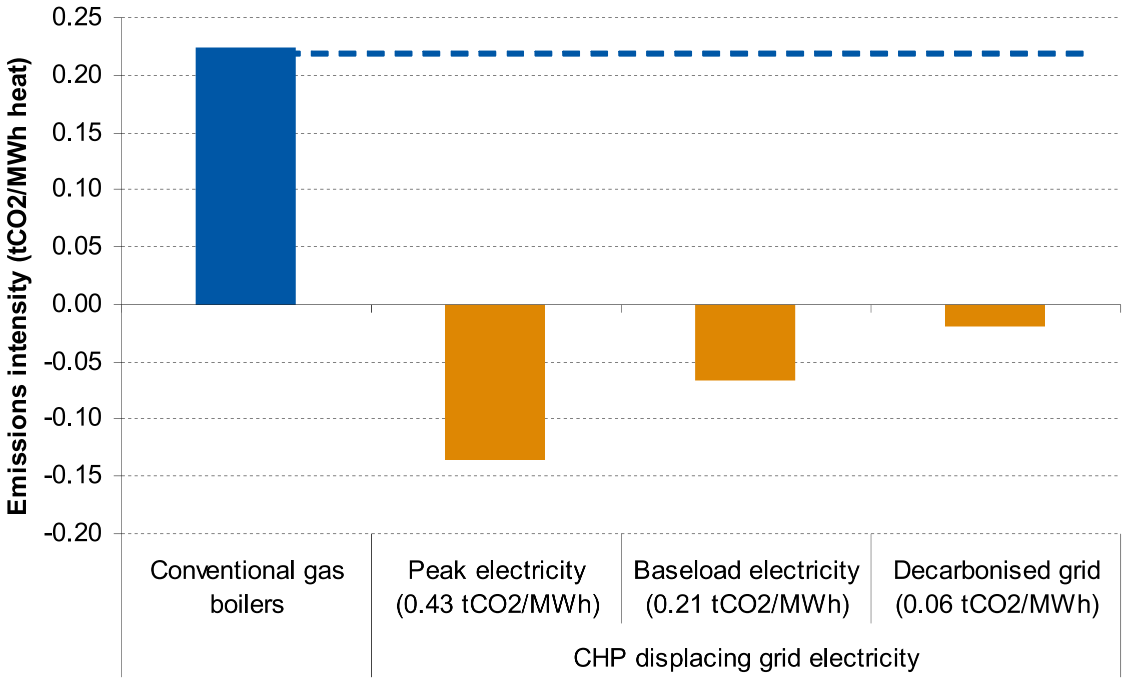
The lower overall efficiency (and higher heat-to-power ratio) means that the implied electric efficiency is significantly lower than it is for conventional CHP.[52] This has important implications for the cost-effectiveness of the technology.

6.4.2.3.1. Emissions intensity and savings of biomass CHP

On the other hand, with the assumption that biomass fuel has zero net CO_2 emissions, the emissions reductions are substantial compared to gas boilers. Figure 6.5 is analogous to the one for conventional CHP, above, with each bar showing the net emissions associated with one MWh of heat output. The values for biomass CHP thus are negative, reflecting the emissions avoided through displaced electricity generation. As in the above figure, the net abatement is the difference between the emissions associated with a gas boiler (indicated by the blue line) and the net emissions intensity of CHP. Where biomass CHP displaces peak electricity in the central case, the net abatement thus is 0.36 tCO_2 per MWh of heat: 0.22 tCO_2 through avoided emissions from gas boilers, and a further 0.14 tCO_2 from emissions avoided from electricity generation. The emissions intensity remains negative for the other electricity scenarios, though with decarbonised grid there is little gain beyond the displacement of the gas boiler emissions.

52 This applies to biomass CHP with a heat-to-power ratio of around 1.6. Much higher overall efficiency of up to 85% can be achieved from heat-led biomass CHP operating at the maximum feasible heat-to-power ratio of around 7. We investigate the implications of this for the conclusions below.

Figure 6.5
Emissions Intensity of Biomass CHP under Different Counterfactual Electricity CO_2 Intensity



Source: NERA/AEA calculations as explained in text.

6.4.2.3.2. Abatement cost of biomass CHP

Whereas gas-fired CHP offers modest emissions reductions of around 35 percent at very low cost per tonne CO_2, biomass CHP has the opposite characteristics of relatively large emissions reductions but high cost per tonne CO_2. The cost in the CCC's "medium emissions intensity" electricity scenario ranges between £130-180 / tCO_2, with an average of £160/tCO_2, relative to conventional gas boilers. This is above the threshold CO_2 prices for the 2020s (even accounting for the future higher prices in the 2030s). The analysis therefore suggests that, on the basis of cost per tonne of abatement, biomass CHP displacing gas may have a relatively limited role to play.

This suggestion is strengthened by comparing the abatement cost of biomass boilers and biomass CHP. We find that biomass boilers have lower abatement costs, of around £50-80/ tCO_2 for the high load-factor applications considered here. Moreover, not only is the cost of biomass CHP higher per tonne CO_2, but the *incremental* abatement cost of using biomass CHP instead biomass boilers is very high, at over £300 / tCO_2 for each additional tCO_2 of abatement achieved. Biomass CHP therefore is able to provide higher levels of abatement (per unit heat output) than biomass boilers only at costs much higher than the CO_2 prices used for this analysis. The underlying reason for this is the relatively lower overall efficiency, which means that the additional gain from generating electricity does not offset the lost heat output.

As with conventional CHP, a more comprehensive analysis would need to integrate the analysis of the heat markets with power markets. The above analysis compared biomass CHP to grid CO_2 plus either gas boilers or biomass boilers. It is possible that biomass CHP is a less expensive abatement option than the *separate* use of biomass in boilers and for biomass electricity generation (this depends on the heat to power ratio and the associated respective efficiencies) – but this suggests that separate generation of both heat *and* power from biomass is an even less attractive abatement option.

6.4.2.3.3. Implications of different applications

One of the reasons for the high abatement cost in the above finding is the low overall efficiency of biomass CHP at the heat-to-power ratios specified. The efficiency can be increased significantly by operating at a higher heat-to-power ratio. At the maximum ratio (on the order of 7:1), biomass-fired steam turbine based CHP can achieve efficiency of over 80 percent. This mode of operation would be feasible provided market incentives were in place to encourage significant heat extraction.

However, an increased heat-to-power ratio does little to reduce the abatement cost of biomass CHP, which remains high at an average of £130 / tCO_2. The reason for the continued high abatement cost is that, although efficiency is increased, the net emissions abatement achieved is much lower when less power is produced, while capex is higher compared to stand-alone heat generation.

In sum, increasing the heat extraction is not sufficient to render biomass CHP a significantly more attractive abatement option.

6.4.2.3.4. Abatement scenario for biomass CHP

Given the above findings, we do not include significant additional deployment of biomass CHP in our scenarios. Pre-existing projections suggest that biomass CHP serving 7 TWh of heat demand may be in place by 2020, through support under the renewables obligation and renewable heat incentive (AEA, 2010). We include this in the baseline, but do not model any additional deployment of biomass CHP through the 2020s.

These conclusions are based on the above assumptions and bottom-up assumptions about costs. However, this does not mean that biomass CHP could have no role under other scenarios. Examples of factors that could alter conclusions include higher availability / lower price of biomass, or a greater role for stand-alone biomass electricity generation.

6.4.2.4. Micro CHP

Developing scenarios for micro CHP is complicated by the fact that the technology is still in development. With limited experience to draw on, it is difficult to develop a sense of what a typical system will look like, or what future costs, performance, or feasible utilisation may be. We have adopted the basic assumptions used in DECC's recent analysis of micro-CHP in the context of developing feed-in tariffs (Element Energy, 2009). This analysis investigated a Stirling engine and fuel cell CHP option, with the characteristics summarised in the below table.

Table 6.4
Modelling Assumptions for Micro CHP

CHP Category	Electric capacity kW_e	Heat-to-power ratio	Overall efficiency %	Electric efficiency %	Thermal efficiency %
Stirling engine	1	6	85%	12%	73%
Fuel cell CHP	1	1	85%	43%	43%

These units are capable of generating 1 kW of electric output. The Stirling engine option has an associated heat output of 6 kW. This level of heat output would be insufficient as sole heat source except in small, well insulated dwellings. Meanwhile, the fuel cell option has a heat output of 1 kW. The fuel cell system therefore would always be supplemented by a conventional boiler, either integrated with the unit or separately.

Costs are highly speculative given the immaturity of the technology. We follow the assumptions in Element Energy (2009), which suggest that the cost of Stirling engine option could be reduced from current levels of £3,500 per unit to £3,150 per unit, similar to the cost of a new gas boiler in our modelling. The fuel cell option has a more radical reduction in price, from current indicative levels of £8,000 to a future level of £3,900 by 2020. We keep these prices throughout the 2020s, as further reductions must be seen as highly speculative.

The efficiency assumption of 85 percent may be optimistic. Achieving this level of efficiency places restrictions on the running patterns, and it is at present unclear whether either technology would be able to sustain such efficiency in actual running patterns (recent field trials of Stirling engine micro CHP by the Carbon Trust suggested this may be difficult, and there is very limited information on the fuel cell products).

As with other CHP options, the number of running hours has an important influence on both the CO_2 reduction potential and the cost of micro CHP. There are two main considerations that limit the feasible running hours in the scenario considered here:

- First, as in the case of conventional gas-fired CHP, micro CHP has the potential to reduce emissions in our central power grid decarbonisation scenario only if it does not displace baseload generation. Generation therefore needs to be limited to peak hours (nor more than 17 hours / day).
- Second, we do not consider the option of running the CHP unit when its heat output is not required.

Accounting for these, we use indicative running hours for the fuel cell option of 4,000 hours per year. This is consistent with a limited number of hours of operation per day to provide hot water for all of the year, as well as extended running hours for a portion of the year to contribute to space heating. This may be a relatively optimistic scenario. A more detailed assessment accounting for the impact of start-up and shut-down, the restriction of no off-peak generation, and other factors may find that most applications would only achieve a smaller number of annual feasible running hours.

For the Stirling engine, the running hours depend on the total heat demand of the house. For total heat loads of 12,000 kWh (representative of much of the existing semi-detached housing stock), the running hours would be up to 2,000 hours per year. Larger houses may achieve higher running hours of up to 3,000 hours per year. We use the latter, more favourable assumption in our scenario.

6.4.2.4.1. Emissions intensity of micro-CHP

To calculate and report the emissions savings, we use the same approach developed above for larger-scale gas-fired CHP: that is, we report emissions per unit heat output.

With the assumptions above, Stirling engines provide almost no emissions abatement. This is because the low electrical efficiency means insufficient electricity is generated to offset the loss in overall efficiency relative to a condensing gas boiler (assumed to have an efficiency of 94 percent[53]). On this basis, and given the more favourable assumed characteristics of fuel cell CHP, we do not consider Stirling engine micro-CHP as an option for the 2020s.

Fuel cell micro-CHP achieves a more significant reduction in emissions, ranging from 16 percent in a large house (with 18,000 kWh of heat demand per year), to 23 percent in smaller houses (12,000 kWh of heat demand per year). Fuel cell micro-CHP with the above characteristics would be able to reduce the CO_2 emissions of a new build house by just over half.

6.4.2.4.2. Abatement cost of micro CHP

The above assumptions about the reductions in cost of fuel cell technology reduce the cost of fuel cell micro-CHP to levels not much higher than gas boilers, and with overall efficiency only marginally lower. Once we take into account the higher value of electricity, it therefore is no surprise that the cost per unit of heat falls below that of boilers. With the central fuel and electricity cost assumptions, fuel cell micro-CHP reduces the cost per unit heat by around 1.5 p/kWh. In this scenario, emissions reductions therefore can be achieved at negative cost – although as noted below the total amount of reductions is likely to be limited.

6.4.2.4.3. Abatement scenario for micro-CHP

The absolute emissions reductions achieved by micro-CHP are lower than for other low-carbon technologies, including heat pumps. The role for micro-CHP in the 2020s therefore is likely to be limited to “hard-to-treat” houses with sufficient space to accommodate micro CHP, but characteristics that present obstacles to other low-carbon technologies. The most significant single category is likely to be uninsulated solid wall houses, especially in urban settings. Heat pumps are likely to have relatively poor performance in these dwellings, and heat pumps also may be less suitable in these settings because of noise. As noted in section 4.1, urban settings also present challenges for biomass combustion, including adverse impact on air quality as well as space constraints on fuel delivery and storage. From the perspective of absolute emissions reductions, the obstacles to other technologies would need to be relatively significant to warrant the use of fuel cell CHP. For example, heat pumps only need to achieve a seasonally adjusted COP of 2.6 to offer greater absolute savings than fuel cell

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53 As with other technologies, we compare micro CHP against a new boiler, consistent with the overall modeling approach of considering options for the replacement of heating equipment at the end of its life.

CHP in smaller houses. Our projections suggest significantly higher COPs for well-insulated houses.

However, the main constraints for the fourth budget period may be the ability to grow a large industry. For illustration, even if fuel cell CHP developed quickly, so that all of the 30,000 units envisioned under the FITs were installed by 2015, and an industry with a capacity of 15,000 units per year were then available, a subsequent growth in industry capacity of over 50 percent per year would be required to reached 2.5 million units by 2025. This number of units would serve a heat load of 10 TWh, saving around 0.4 $MtCO_2$ per year. Even with optimistic assumptions, the role for micro-CHP in emissions abatement therefore appears limited until 2025.

It is not clear that continued installation micro CHP beyond 2025 would continue to have a role. Adding new units in the late 2020s, with the majority of their working life in the 2030s, would save CO_2 only if new electricity capacity in the 2030s continued to be provided by standard CCGTs. This scenario is unlikely to be consistent with continued decarbonisation. At the point when the emissions intensity of new electricity capacity reaches 0.27 tCO_2 / MWh, micro-CHP no longer provides any emissions savings over the use of gas boilers, and at grid intensities below this level it has a higher emissions intensity than a combination of stand-alone-boiler-plus-grid.

In sum, our assessment is that fuel cell micro-CHP could play a minor in reducing domestic-sector emissions in hard-to-treat houses, but that the potential is limited. Although it can supplement other technologies to offer additional emissions abatement potential, this is limited in the short- to medium- term both by the significant residual emissions associated with the technology, and by the limited time available to roll out significant numbers of a technology still under development. Meanwhile, the role for micro-CHP diminishes in the long term with the likely gradual decarbonisation of the electricity grid (unless, of course, electricity from micro-CHP is similarly decarbonised).

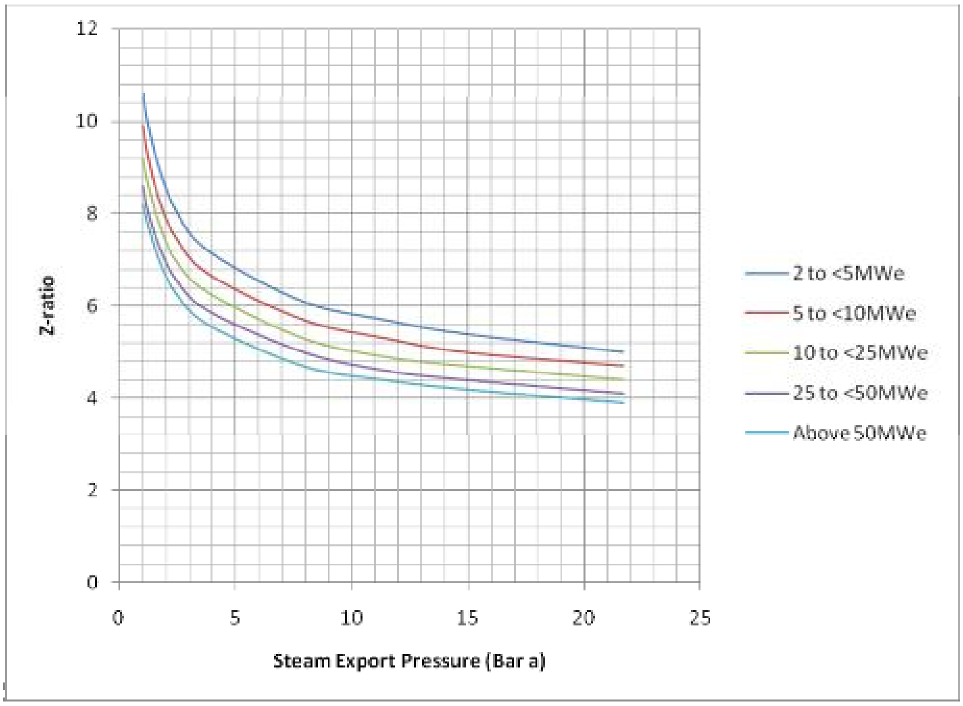
6.4.2.5. Extraction of heat from existing / large-scale power stations

A fourth category of CHP is to extract heat from existing large-scale thermal power plant. Conventional power stations discard heat corresponding to between 35 percent and 55 percent of their energy input through cooling towers. In a standard condensing steam cycle the condensed water is usually at very low temperatures not suitable for space heating or hot water. To be useful the temperature of the exhausted steam must be extracted from the steam turbines at pressures suitable to deliver hot water for district heating at about 100ºC. Doing this causes some back-pressure on the steam expansion path and therefore leads to small losses in power output. The trade-off between heat gained and electricity lost is known as the "Z" ratio, which is a function of the steam turbine size, operating pressures and heat extraction pressure. For example, a steam turbine with a fully condensing (no heat extraction) capacity greater than 50MWe will have a Z ratio of 4 at a steam extraction pressure of about 20 Bar (high pressure required only for industrial processes), and a Z ratio of 8 at a steam extraction pressure of about 1 Bar (suitable for district heating supply).[54] In

[54] To take a specific example, if heat is to be extracted from a 1,000 MWe fully condensing power station with annual efficiency of 40 percent, then assuming the fuel input is maintained constant, at a Z-ratio of 7, extracting 700 MW of

other words, the extraction of eight units of heat at a temperature suitable for a district heating network would reduce the electricity output by one unit. The relationship between turbine size, steam export pressure, and the Z ratio is illustrated in Figure 6.6.

Figure 6.6
Variation of Z-Ratio with Turbine Size and Steam Export Pressure



6.4.2.5.1. Overview of power station as a source of low-carbon heat

The retrofitting of power stations to run in CHP mode would require a number of initial investments. The main technical requirement is the modification of existing turbines to enable steam extraction. The amount of heat produced would be very large, with large-scale city-wide district heating networks the only feasible source of heat demand. This in turn requires the construction of a heat transmission pipe to connect the power station to the district heating mains.

There are no current examples of such retrofitting in the UK. However, in more general terms, the cogeneration of heat and power in large plants is a significant feature of visions for long-term decarbonisation in other countries, including Finland and Denmark. There 49 and 60 percent, respectively, of total heat demand is provided by DH through ambitious energy policies. For example Denmark has had 4 aggressive policies, Dansk Energipolitik 1976 which was designed to safeguard Denmark against energy supply shocks like those of 1973/74, Energiplan 81, Energi 2000 and the forthcoming Energi 21.[55] One attractive feature is that the heat source is available as long as thermal power plant continues to be used.

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heat will reduce electricity output by just 100 MW, converting this station to CHP with an overall efficiency of about 64 percent (36 percent for electricity and 28 percent for heat).

55 http://www.videncenter.dk/Groenne%20trae%20haefte/Groen_Engelsk/Kap_01.pdf

In this analysis, we assume heat extraction at a Z ratio of 7 for 4,000 hours per year. As we discuss below, this raises a number of auxiliary issues, notably the implications of the changes to power station running patterns.

This analysis is not a fully evaluation of the technical and other challenges that would be involved in making this source of heat available but provides an indication of the extent of the potential and the magnitude of cost involved. The findings suggest that more detailed analysis would be warranted.

6.4.2.5.2. Illustrative potential: analysis of 12 existing power stations

To estimate the potential to use power station heat we have analysed twelve existing power stations near urban centres (identified by AECOM/Pöyry). We have cross-referenced these against the heat demand of nearby cities, using the heat map methodology described in section 5.4 to identify high-density heat demand suitable for district heating. The below table show the characteristics of the power stations and nearby cities. The distance between the power stations and the near city varies between 2 kilometres and 20 km. In total, these power stations could provide 19 TWh of heat, or 70 percent of the high-density heat demand identified in the 10 cities.

Table 6.5
Illustrative Power Stations Near Urban Centres

Power Station	Nearby city	Distance to city	Electric capacity (current)	Electric capacity (CHP mode)	Heat capacity (CHP mode)	City high-density heat demand	District heating potential
		km	GW	GW	GW	TWh	TWh
Barking	East London	10	1.0	0.9	0.6	4.2	2.0
Littlebrook GT & Littlebrook D	SE London	15	1.5	1.4	0.8	4.2	3.0
Tilbury B	Tilbury	20	1.1	1.0	0.6	4.2	2.2
Enfield	N London	10	0.4	0.4	0.2	4.2	0.8
Ratcliffe	Nottingham	6	2.0	1.8	1.1	2.5	2.5
Fiddler's Ferry	Liverpool	15	2.0	1.8	1.1	3.3	3.3
Kingsnorth	Medway	10	1.9	1.8	1.1	0.4	0.4
Teesside Power Station	Middlesborough	2	1.9	1.7	1.0	0.6	0.6
Saltend	Hull	6	1.2	1.1	0.7	1.2	1.2
Seabank 1 & 2	Bristol	8	1.2	1.1	0.7	2.1	2.1
Uskmouth	Newport	5	0.4	0.3	0.2	0.6	0.6
Peterborough	Peterborough	2	0.4	0.4	0.2	0.6	0.6
Total			**14.9**	**13.7**	**8.2**	**28.0**	**19.3**

The above identifies the plant that from an assessment of distance to sufficient high-density heat loads would be the most promising candidates for conversion to CHP operation. They may be indicative of the total heat generating potential that – with the creation of the associated district heating schemes – could be created by 2030 in an ambitious scenario.

The total long-run technical potential for heat extraction is likely to be significantly higher. The above stations correspond to only some of the total current UK coal-fired and CCGT electricity generating capacity. Future thermal capacity may be lower, both because of increased used of wind power and nuclear (which is unlikely to be sited sufficiently close to major cities), and because of reduced load factors among coal plant and CCGTs. On the other hand, operation in CHP mode would be feasible also for thermal power plant using CCS. Overall, there is no theoretical reason why power station heat could not provide much of the 90 TWh of high-density heat demand identified in above (which in turn is not an exhaustive estimate of heat loads suitable for district heating).

A full investigation of the potential would require a more exhaustive study than has been feasible in this project. This would need to account both for the proximity to major heat loads among existing plant and the scope for new thermal capacity to be deliberately co-located and / or co-developed with cities with sufficient heat density to be suitable for district heating schemes. It also would need to account for the impact on the overall electricity system of running the CHP-enabled plant relatively inflexibly (see below).

6.4.2.5.3. Emissions intensity of power station heat extraction

Operating existing plant in CHP mode results in the need for additional power generation to make up for the generation lost through heat extraction. The generation of this power in turn would create some additional emissions. Note that the relevant emissions intensity is not that of the particular power plant that is converted to CHP operation, but rather that of the new entrant plant constructed to make up for the generation shortfall. In the central grid intensity scenario used for this project, this is either new CCGT with an emissions factor of 0.43 tCO_2 / MWh for peak load plant, or 0.21 tCO_2 / MWh for baseload power plant.

At a Z ratio of seven, the heat extracted from power stations has very low emissions intensity in either scenario. Accounting for 10 percent heating losses in the delivery of heat from the power plant to the end-user, the emissions intensity for peak load electricity is 0.07 tCO_2 / MWh delivered (0.43 / 7 / 0.9). Although this is higher than zero-rated biomass, it is significantly lower than most other technologies. For example, 0.07 tCO_2 / MWh is around half the emissions intensity of the mix of gas-fired CHP discussed above, or 37 percent lower than the emissions intensity of a heat pump with a seasonally adjusted COP of 4.

6.4.2.5.4. Cost of power sector heat extraction

The conversion of large-scale plant to CHP operation would entail large initial capital expenditure as well as an ongoing cost associated with the loss of power output. However, the cost per unit of heat output is small compared to most other heat sources.

It would be necessary at the outset to convert the turbines to CHP operation. AEA estimates this cost at around 2 percent of power sector capex. For the ten power plant identified above, the associated expenditure varies between £5-20 million, depending on the type of power plant and its size, with a weighted average of £14 million.

The other large up-front cost is the construction of a heat transmission pipe for connection to a district heating scheme. This cost depends both on the heat output capacity (determining the require pipe diameter) and the distance to the relevant district heating network. For the ten power stations identified above costs vary widely, between less than £10 million to over £100 million. The estimated weighted average is around £60 million.

The cost of lost power per MWh of heat is given by the value of electricity (£96 / MWh in the central case) divided by the Z ratio of seven and adjusted for the 10 percent heat loss.

Putting these factors together, the levelised cost of heat at the point of injection to the district heating network is £18 / MWh when evaluated at a 3.5 percent discount rate and a time period of 20 years use for the pipe.

This is significantly cheaper than nearly all other heat sources on a per-MWh basis. However, the full cost of abatement needs to account for the cost of the district heating network. We discuss this in more detail in the next section, where we outline our overall approach to the modelling of district heating cost and potential.

6.4.2.5.5. Additional costs associated with loss of flexibility

On the simple model described above, the heat is extracted for around 4,000 hours per year assuming both that the power station would anyway generate for the relevant share of the year, meaning that the extraction of heat does not affect the running pattern of the power station. In practice, these favourable circumstances are unlikely to apply to all power stations, and the requirement to adjust running hours to match the profile of heat demand would entail the loss of valuable flexibility. As noted above, the value of flexible operation may become still greater in a future scenario with significant quantities of intermittent wind generation.

In terms of the calculations above, there would be a cost not only of making up for lost power generation, but also a reduced value to the power that remains produced. Evaluating the cost of lost generation flexibility is beyond the scope of this project but would be an important aspect of further work providing a fuller assessment of the potential to make use of power station waste heat for district heating.

6.4.3. District heating

In this section we describe information relevant to developing scenarios for district heating. In general terms, scenarios for district heating need to consider the following general issues:

- **Availability of suitable heat load.** As discussed above, district heating requires sufficient heat density to keep costs manageable.
- **Availability of sufficient potential of low-cost and low-carbon heat.** Given the high cost of the district heating network itself, the cost of the heat input needs to be lower than can typically be achieved in stand-alone applications. We have analysed the cost of a number of heat sources, and describe below the sources that are likely to hold most promise.
- **Feasibility of deployment.** The construction of district heating involves significant lead times. Any scenario therefore needs to account for the feasible rate of expanding networks in the 20 years before 2030.

We discuss each of these issues below and suggest two indicative scenarios for district heating.

6.4.3.1. Availability of suitable heat loads and DH counterfactual

We take the 90 TWh identified in section 5.4 as a first estimate of heat loads suitable for district heating. Information from the heat map indicates that the relevant sources of heat demand require heat for just under 4,000 hours per year.

To model the cost of district heating we need to specify the cost of the relevant counterfactual. We take the approach of calculating the average cost of using conventional boilers and electric heating to serve the urban heat loads. There is significant variation in both the cost and emissions characteristics of urban heat loads, reflecting differences in the size of heat load as well as fuel use. This amounts to an assumption that it is not feasible to direct the district heating network specifically to heat sources whose emissions intensity or cost is higher than average. This may be a conservative assumption for small schemes, but seems appropriate for large-scale schemes.

6.4.3.2. Cost and characteristics of district heating pipe network

The first step in assessing which heat sources could cost-effectively serve district heating is to estimate the cost of the DH network.

Data held by AEA from work on past district heating projects suggests that large-scale urban district heating schemes cost of around £1,500 per kW of capacity, with opex of around 1 percent of total capex per year. We assume that heat losses would amount to 10 percent of the heat produced.

With these assumptions, the levelised cost of district heating network alone is high. For example, with a 50 year lifetime, 3.5 percent discount rate, and 4,000 operating hours per year these assumptions mean that the cost of the pipe network alone is £22/MWh on a levelised basis (assuming 4,000 hours of operation per year).

6.4.3.3. Abatement cost of different potential heat sources

The high cost of the pipe network, and the reduced efficiency from heat losses in the pipe network, means that district heating low-carbon heat must be provided at low cost to offer the prospect of cost-effective abatement.

Most of the potential heat sources listed in section 5.3 have costs and emissions characteristics that preclude their use as the main source of heat for the purpose of cost-effective emissions in a district heating network. For example, with the above assumptions about biomass, the cost of delivered heat is in the region £85-90 / MWh, resulting in abatement costs relatively to the DH counterfactual in excess of £110 / tCO_2. This exceeds the threshold CO_2 prices used in the modelling here.

The main potential source of low-carbon heat are various forms of CHP. The extraction of heat from power stations under the assumptions outlined above can produce heat at a cost around £20 / MWh delivered, with a CO_2 intensity of 0.07 tCO_2 / MWh. Meanwhile, highly efficient gas-fired CHP with the characteristics outlined above and operating can provide heat at around costs of £25/MWh delivered, depending on the heat-to-power ratio and other characteristics, with a CO_2 intensity of 0.16 tCO_2 / MWh.[56] Both these sources have the prospect of delivering heat at a cost lower than that of the DH counterfactual cost of £59 / MWh. The associated abatement cost therefore would be negative.

6.4.3.4. Barriers and other factors relevant to DH scenarios

The overall picture from the above discussion is that, under the above cost assumptions, district heating could have a large potential role in delivering low-carbon heat. The CO_2 intensity of a combination of conventional CHP and heat from power stations is similar to or lower than that of heat pumps, which is the main alternative for low-carbon heating in urban areas. Under the above assumptions, the average cost of abatement also is lower.

Much more detailed research than has been feasible within this project would be required to fully investigate the true social cost – and therefore cost-effectiveness – of different levels of district heating deployment. A key issue is that of the "barriers" that have held back district heating deployment in the past—ranging from incomplete connection rates, disruption, coordination difficulties, risk—as well as the costs of regulation introduced to overcome these. To our knowledge, even detailed dedicated studies of district heating have not been able to develop such estimates.

Simple calculations indicate that the effect of failure to removing barriers could be large. For example, using a simple approach of applying a higher discount rate to proxy for barriers results in significantly higher overall costs: at a discount rate 12 percent levelised cost of the network rises from £22 / MWh to £54/MWh.

It also would be necessary to analyse the complex regulatory and electricity market issues associated with significant increases in CHP. In the case of large-scale power stations key issues include the regulatory requirements and the potential cost of lost flexibility in generation noted above. The issue of flexibility arises also for conventional gas-fired CHP.

Finally, the model of deployment for district heating differs very significantly from that of heat pumps, which is the main alternative for low-carbon heat in urban settings. Both the construction of large city-wide DH networks and the conversion of power stations to CHP would require significant coordination and regulatory changes. By contrast, heat pumps can be rolled out through what is at heart a retail market for consumer durables. Some of the policy initiatives and approaches required for district heating roll-out were discussed in section 5.5 and 5.6, above. However, this too is an area that would require significant work to achieve a more complete estimate of the desirability and feasibility of district heating.

Despite these limitations, we judge that the significant abatement potential and favourable abatement costs estimated above provide a strong *prima facie* case for including low-carbon district heating in the mix of low-carbon sources in the 2020s. We therefore propose two indicative scenarios, as detailed below.

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[56] As with other gas-fired CHP, this depends on the ability to displace only peak electricity. We have accounted for this by reducing the running hours to 3,000 hours per year for the CHP, with the remaining 1,000 hours served by boilers.

6.4.3.5. DH scenarios

As discussed above, the timetable for the deployment of large-scale city-wide district heating networks supplied by heat extracted from power stations depends on three major investments:

1. The installation of a network of heating clusters and their subsequent joining into a single system by the installation of ring mains.
2. The adaptation and building of new utility scale power plant to make them capable of heat extraction.
3. The construction of trunk pipelines from thermal power plant to the developing and developed district heating networks.

In addition to these rate-determining steps there is a need for smaller investments in renewable and conventional heat generation capacity, either to supply heat in the initial phases and to provide back up and balancing in the final configuration (in the case of heat supplied from power stations), or as the main source of heat.

We sketch below the assumptions used to develop our modelling scenarios. There are based on our knowledge and experience, and our broad understanding of the major influences on deployment, its costs and sensitivities. However there is little actual UK experience on which to draw. Developing more detailed scenarios would require more significantly more work.

"Central scenario"

In this scenario DH networks grow organically from the current base of less than 1.0 TWh/year. The top five cities in Table 5.2 develop DH by virtue of the high population density. Some clusters remain independent and some links are made, especially where economic opportunities are offered by the presence of sources of waste heat or other favourable circumstances. Within these cities around 10 percent of the potential is installed by 2020, giving 5 TWh/year, and a further 10 percent is installed by 2030, giving 10 TWh/year. The potential includes 1-2 projects to link these networks to large power plant.

"High scenario"

In this scenario we assume that current policy measures result in a start on the networks in ten of the largest cities between 2015 and 2020. The networks are assumed to grow linearly over a period of 5–10 years and beyond, passing 40 TWh in 2030. We would expect the first power station links to be installed when the first networks become large enough for the investment to become economically viable, possibly by 2020. This would take the form of an initial demonstration in the subsequent few years (assumed here to successful), whereupon up to 10 additional power stations would be connected in the years to 2030.

The potential of 40TWh/year in 2030 is supplied by 20 TWh/year from power stations, and another 1-2 TWh/year extracted from pre-existing EfW electricity plants. The balance could be provided by a number of different sources. However, for the purposes of the modelling we represent this heat by gas-fired CHP.

In practice, the heat used in district heating networks is likely to be more idiosyncratic than represented here. One of the benefits of a district heating network is the ability to accept surplus heat from a range of local sources. These may include low-cost local biomass waste streams, heat from waste gasification / pyrolysis units, and industrial waste heat and various other forms of surplus heat from local sources. This can help bring down the cost of heat, although it is difficult without more detailed analysis to estimate what the actual cost might be. These are not specified in the modelling, but as would need to be provided at cost similar to that of heat from CHP to be cost-effective.

The heat load in 2020 would reach on the order of 12-15 TWh. As explained above this would be before the installation of the links to the thermal power plant so the capacity would be fulfilled by a mix of biomass and conventional energy sources.

7. Results for Low-Carbon Heat Scenarios

In this section we present a number of scenarios for CO_2 abatement through the use of low-carbon heat technologies in the 2020-2030 period. We begin with the "central" scenario, and then consider a range of alternative scenarios to test sensitivity of the results to different assumptions. One of the purposes of the scenarios is to consider the conditions required for one or another of our three high-level decarbonisation strategies to "dominate" the others – or at least to change the balance between them. The scenarios do not necessarily represent equally likely possible outcomes, but are intended to shed light on how the results are sensitive to different assumptions about very uncertain factors.

Because our central scenario results in significant uptake of heat pumps, the next scenario we consider is a "high bioenergy" scenario, in which conditions for the use of biomass and biogas are significantly more favourable.

We then consider alternative assumptions about the extent of decarbonisation of the power sector, using the electricity cost and CO_2 intensity scenarios described in section 6.3.2.3.

We also consider:

- Higher deployment scenario: this scenario contains more optimistic assumptions about factors limiting the uptake of low-carbon heating options.
- Heat demand scenarios: alternative assumptions about the development of energy efficiency.
- Sensitivity scenarios: impact of alternative assumptions about key inputs, including:
  - Fossil fuel prices
  - Technology assumptions
  - Discount rates and hidden / missing costs

7.1. "Central" Scenario

We use the modelling framework described above to estimate a scenario where uptake prioritised based on the cost of abatement. As we describe in more detail below, this results in a scenario with very substantial expansion of heat pumps for space heating in all end-user sectors. This is supplemented by biomass fuel in applications where heat pumps cannot be used, notably industrial process heat, as well as biogas replacing some of the use of natural gas across all sectors (through injection in the gas grid).

We summarise below the underlying assumptions in this scenario, as well as a variety of results for individual technologies and sectors.

7.1.1. Summary of "central" scenario assumptions

We summarise the assumptions of the central scenario in Table 7.1

Table 7.1
Summary of Assumptions in Central Scenario

	Key features in central scenario
Demand-side constraints	
Heat demand	▪ Central projections for domestic, commercial / public, and industrial sectors, corresponding to heat demand of 627 TWh and business-as-usual emissions of 165 MtCO2 in 2030. ▪ Corresponding improvements in energy efficiency and reductions in the size of average heat loads
Suitability	▪ Suitability of biomass combustion for around 80 percent of heat loads in the domestic as well as non-domestic space and heating, nearly all low-temperature process heat, and 50 percent of high-temperature industrial process heat. ▪ Around 50 percent of the total domestic heat load, and just over 70 percent of non-domestic space heating, considered suitable for heat pumps.
Rate of uptake	▪ Uptake at the rate of stock replacement, corresponding to around 7 percent of total heat demand each year.
CO_2 price	▪ CO_2 prices for the traded sector starting at £13/tCO_2 in 2020, rising to £70/tCO_2 in 2030 and £135/tCO_2 in 2040. ▪ CO_2 prices for the non-traded sector starting at £60/tCO_2 in 2020, rising to £70/tCO_2 in 2030 and £135/tCO_2 in 2040.
Supply-side constraints	
Bioenergy scenarios	▪ Trajectory of total biomass available to the heat sector starting at 50 TWh in 2020 and reaching 100 TWh in 2030. ▪ Trajectory of biomass suitable for domestic applications starting at 2.5TWh in 2020 and reaching 10 TWh in 2030.
Starting point for analysis	▪ 67 TWh of heat demand served by low-carbon heat technologies in 2020, based on projections developed for the RHI consultation (DECC 2010b). ▪ Annual industry supply capacity in 2020 of 16 TWh.
Industry supply growth	▪ Up to 30 percent growth in industry supply capacity per year.
Cost and key inputs	
Technology development	▪ Significant improvements in heat pump COP, with seasonally adjusted space-heating reaching 4-5.5 by 2030. ▪ Continued reductions in capex, reaching 62 percent of current levels for heat pumps in 2030, and around 70 percent for solar thermal and domestic biomass combustion.
Fuel and biomass prices and emissions factors	▪ Central fossil fuel prices assumptions contained in DECC (2010a). ▪ Biomass prices of £31/ MWh for the domestic sector and £37 / MWh for the non-domestic sector over the 2020-2030 period. ▪ Gas emissions factors at full fossil natural gas. ▪ Zero emissions factor for biomass and biogas combustion
Electricity prices and emissions factors	▪ Peak electricity cost of 96 £/MWh and emissions factor of 0.43 tCO_2/MWh. ▪ Off-peak electricity cost of 90 £/MWh and emissions factor of 0.21 tCO_2/MWh. ▪ Additionally, cost of grid reinforcement of £20 / MWh for peak and £13 / MWh for off-peak electricity.
Discount rates and barriers	▪ 3.5 percent discount rate applied to all evaluations. ▪ No barrier costs included in the social cost of abatement.
Additional technologies	
Biogas	▪ AD potential of up to 20 TWh of biogas by 2030. ▪ Bio-SNG potential of up to 18 TWh of biogas by 2030.
District heating	▪ Up to 10 TWh of district heating powered by heat extraction from 2-3 power stations and EfW plants, as well as gas-fired CHP.
CHP	▪ 8 GW of gas-fired CHP serving 69 TWh of heat load.

7.1.2. Summary results: total abatement potential and cost

The headline results for the central scenario are shown in Table 7.2. We estimate abatement potential of 39 $MtCO_2$ by 2025, increasing to 62 $MtCO_2$ by 2030, inclusive of the pre-existing low-carbon heat technologies assumed to be in existence in 2020. This corresponds to 24 and 38 percent of the estimated emissions that would result if these heat loads were served by the incumbent fossil fuel technologies. In heat output terms, some 350 TWh, or 56 percent of heat demand, is served by low-carbon technologies by 2030.

The emissions abatement achieved by 2025 has an average cost of £33 / tCO_2 in 2025. Improvements in technology and other factors cause this to fall thereafter, to an average cost of £25/tCO_2 in 2030. This average contains a mix of measures of widely varying costs.[57] As we discuss below, the modelling thus suggests that some low-carbon heat technologies (in particular air-to-air heat pumps and heat pumps with storage) could become cheaper than the incumbent fossil-fuel boiler technologies by the end of the 2020s, while district heating using power station waste heat also could have lower cost than its counterfactual.[58]

Table 7.2
Headline Results, "Central" Scenario

Variable	Units	2025	2030
Total emissions abatement	MtCO2	39	62
In EU ETS	MtCO2	9	9
Outside EU ETS	MtCO2	30	53
Displacement of fossil fuels	MtCO2	47	78
Emissions from heat pump electricity use	MtCO2	-8	-16
BAU emissions	MtCO2	159	165
% of emissions reduced	%	24%	38%
Remaining emissions	MtCO2	120	102
Low-carbon heat output	TWh	226	350
Total heat demand	TWh	606	627
Share low-carbon heat output	%	37%	56%
Total cost	£m	1,293	1,557
Average abatement cost	£/tCO2	33	25

Heat pumps have the dual effect of displacing fossil fuels burned in boilers (or electricity used in direct electric heating), but also consuming grid electricity. Thus, although heat pumps displace 45 $MtCO_2$ of emissions from conventional heating in this scenario, 16 $MtCO_2$ of this reduction is offset by the emissions from the additional electricity required to

57 District Heating and CHP costs are included in the table at an average abatement cost of zero. As noted in sections 6.4.2 and also in chapter 5 , these technologies can provide abatement at negative cost under favourable circumstances, but also are subject to important barriers. Given the uncertainty about the true cost of abatement we exclude these (negative) costs .

58 This is not equivalent to saying that these technologies would be undertaken by consumers in the absence of continued policy support. An important difference is that the cost is evaluated at a discount rate of 3.5 percent, which is significantly lower than the rates likely to be used by the majority of heat consumers for the evaluation of investments in heating equipment.

power the heat pumps. This points to a potential dilemma with the widespread application of heat pumps: although the technology often offers the lowest-cost abatement option, the overall net abatement achieved is limited to 65 percent of the original emissions. (For some categories it is significantly lower; for example, air-to-water heat pumps in the domestic sector achieve only 50 percent net abatement.) By contrast, technologies using zero-carbon fuels such as sustainable biomass could reduce all of these emissions (albeit likely at higher cost per tonne). In the longer run, where grid electricity may be further decarbonised, this may be less of a concern, but in the medium run the widespread use of heat pumps results in significant residual emissions that are not reduced.

The large majority of the *net* 2030 emissions reductions are outside the EU ETS. Although some 25 MtCO2 of emissions are abated within the EU ETS by replacing fossil fuels with lower-carbon alternatives, the net abatement accounting for additional power sector emissions from increased heat pump use amounts to just 4 $MtCO_2$.

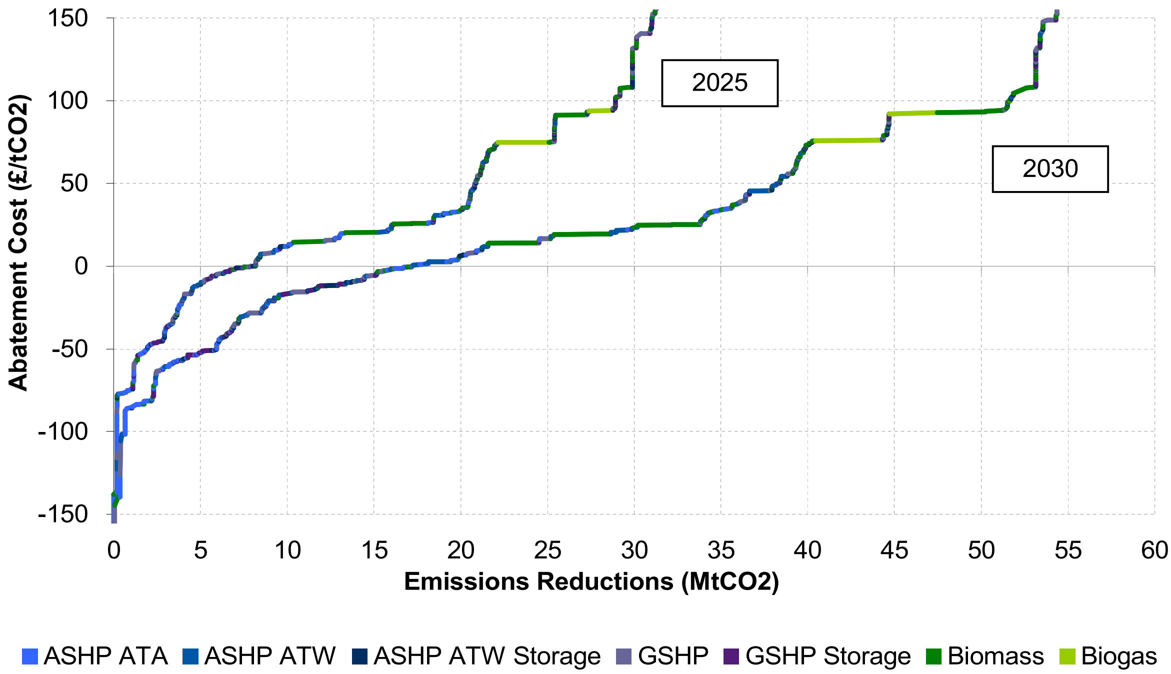
7.1.3. "Central" Scenario MACC curve

The above results can be represented in a marginal abatement cost framework. Figure 7.1 relates the abatement undertaken (shown in $MtCO_2$ on the horizontal axis) to the marginal cost of abatement (shown in £/tCO_2 on the vertical axis), ordered in ascending order of marginal abatement cost.[59] The individual segments are coloured by technology. To improve the clarity of representation, the figure has been truncated to show only those measures which have an abatement cost between -£150 and £150 per tonne CO_2.

As the figure shows, around 17 $MtCO_2$ of the 62 $MtCO_2$ 2030 abatement potential is obtainable at negative cost. Around 20 $MtCO_2$ come at a cost greater than £50 / tCO_2. The figure also illustrates how costs fall over time, with higher average cost for the 2025 abatement potential. The potential increases over time both because of the natural market cycle of replacement of heating systems, and because of relative improvements in technology performance and cost that make low-carbon heating more attractive.

[59] As noted in section 6.2.1, this is not a stand-alone or *ex-ante* MACC, but rather a representation of the *ex-post* modelling results in a MACC-style framework.

Figure 7.1
***Ex-Post* Marginal Abatement Cost Curve ("Central" Scenario)**



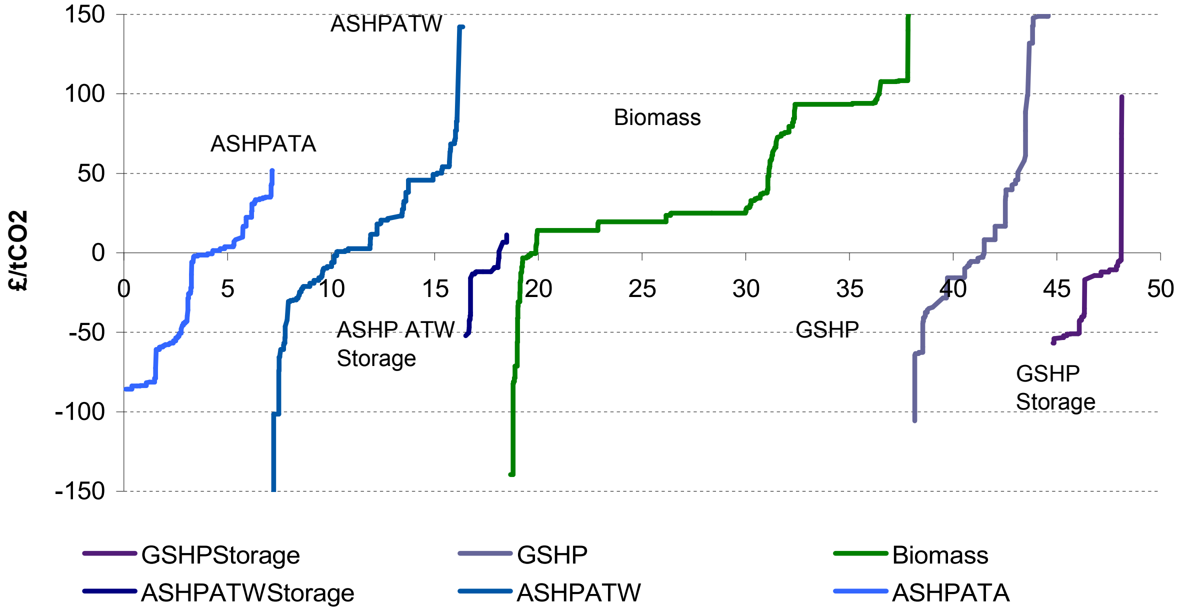
Notes: As set out in section 6.3.2.4, we apply a threshold CO_2 price in 2030 of £113 (which reflects the weighted average discounted expected price for measures undertaken in that year). The ex-post MACC includes abatement potential above this threshold level because of the persistence of low-carbon heat that has been supported by the RHI prior to 2020.

This figure does not represent abatement from district heating and combined heat and power, which we regard as more uncertain. In the "Central" scenario these contribute 6.5 MtCO2 of abatement (and up to 11 MtCO2 in other scenarios explored in this report).

The extent of large negative-cost potential depends strongly on the discount rate used. We explore the impact of alternative assumptions about discount rates below.

The role of the different technologies is clearer in Figure 7.2, which represents the same data in a different format. In this figure, the data have been ordered first by technology, and then in order of increasing cost. This shows that although very low-cost options exist for all technologies, air source heat pumps (without storage) and some ground-source heat pumps account for the large majority of negative-cost potential. Biomass combustion has a two-tier abatement cost, with the replacement of non net-bound fuel counterfactual at an abatement cost of £20-40 / tCO_2, and the displacement of natural gas in the region of £100/tCO_2.

Figure 7.2
***Ex-Post* Marginal Abatement Cost Curve by Technology ("Central Scenario")**



Note: This figure does not represent abatement from district heating and combined heat and power, the cost of which we regard as more uncertain. In the "Central" scenario these contribute 6.5 $MtCO_2$ of abatement (and up to 11 $MtCO_2$ in other scenarios explored in this report).

The most striking feature of this MACC is the wide spread of cost, and particularly the very low marginal abatement cost of some options.[60]

Some of the options represented here have costs in excess of the carbon prices for the 2020-2030 period. This occurs for two reasons. First, some of the potential shown is accounted for by the low-carbon heat technologies already in place in 2020. These follow a pattern of uptake determined by the Renewable Heat Incentive rather than by its abatement cost, and include some options with high CO_2 abatement costs. Second, as noted in section 6.3.2.3 we account not only for the carbon prices in the 2020-2030 period when applying the carbon price threshold to uptake, but account also for the future higher carbon prices that will obtain over the course of the lifetime of the measures undertaken.

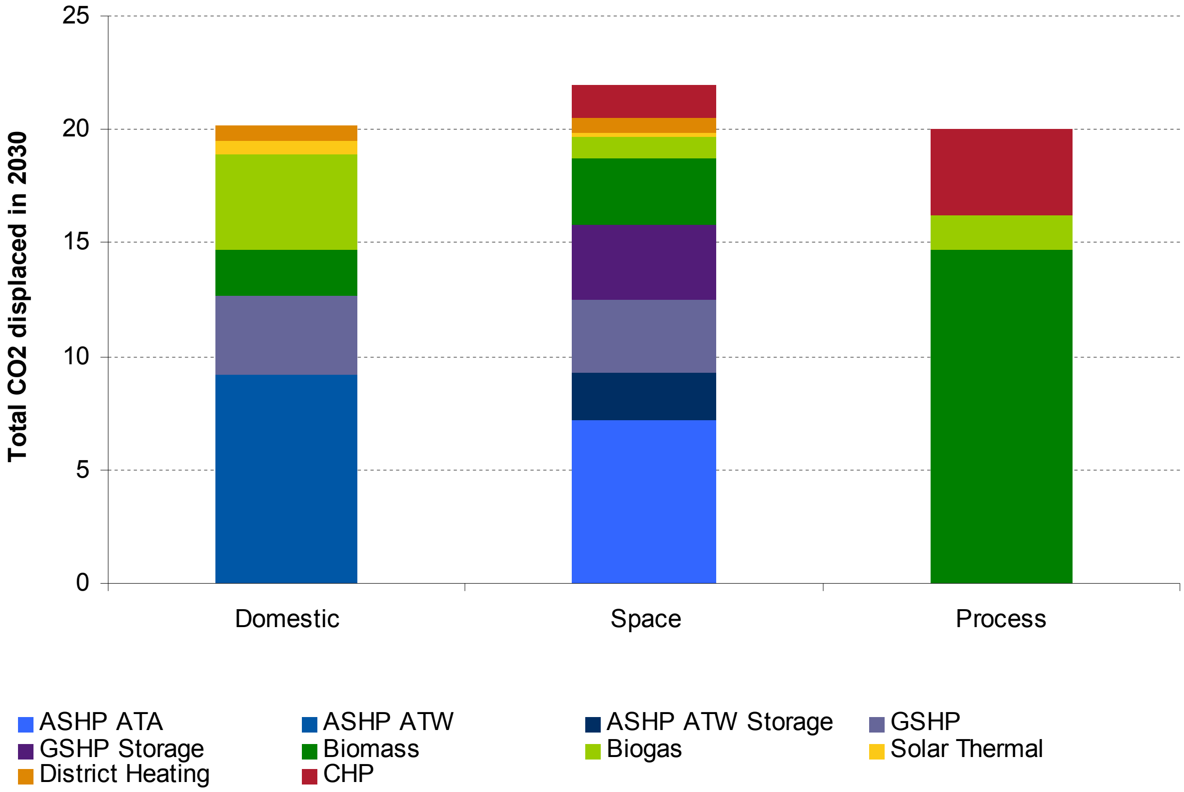
7.1.4. Composition of abatement by technology and end-use

We show the composition broken down by domestic heat, non-domestic space heat, and industrial process heat in Figure 7.3. Across all sectors, biomass accounts for 20 $MtCO_2$, or 32 percent of the total emission abatement. This is concentrated to the industrial process sector, where it is one of the few available options (the others are CHP and biogas), although just over 5 $MtCO_2$ of emissions are reduced through the use of biomass combustion in the domestic and non-domestic space heating sectors. In the latter two categories, air-source heat pumps dominate, accounting for 18 $MtCO_2$, or 30 percent of the total, while ground-source

60 In part, the very low cost of heat pumps springs from the fact that they only partially reduce the original emissions. For example, a heat pump with a COP of 3.5 replacing a gas boiler will reduce emissions by 0.1 tCO_2 / MWh. At a cost of -£10 / MWh, the abatement cost therefore is negative £100 / MWh. By contrast, a biomass boiler with the same per-MWh cost would have an abatement cost of negative £45/tCO_2.

heat pumps account for remaining 10 $MtCO_2$ of abatement. With only small differences between peak and off-peak costs of electricity, the storage option is relatively less attractive for ASHPs, although there is more uptake for GSHPs. District heating accounts for 1.3 $MtCO_2$ of abatement, while biogas and CHP contribute 5 $MtCO_2$ each. The mix of technologies contains only a small amount of solar thermal, corresponding to the installations already in place in 2020. This is an immediate consequence of the carbon price threshold, which even with high carbon prices is significantly lower than the cost of abatement from solar thermal.[61]

Figure 7.3
Composition of Abatement by Technology and End-Use ("Central" Scenario)



The figure shows that although non-domestic space heat accounts for only 25 percent of total BAU emissions from heat generation in 2030, it is the largest source of emissions abatement, at just over 20 $MtCO_2$, or 35 percent of total abatement. This is due to a combination of a high starting point stimulated by the RHI in 2020, relatively low-cost abatement options, and a higher share of heat loads suitable for heat pumps than in the domestic sector.

Figure 7.4 reproduces the abatement profile in relation to the total emissions from each sector. The shaded grey area represents the residual emissions in 2030 (including emissions from

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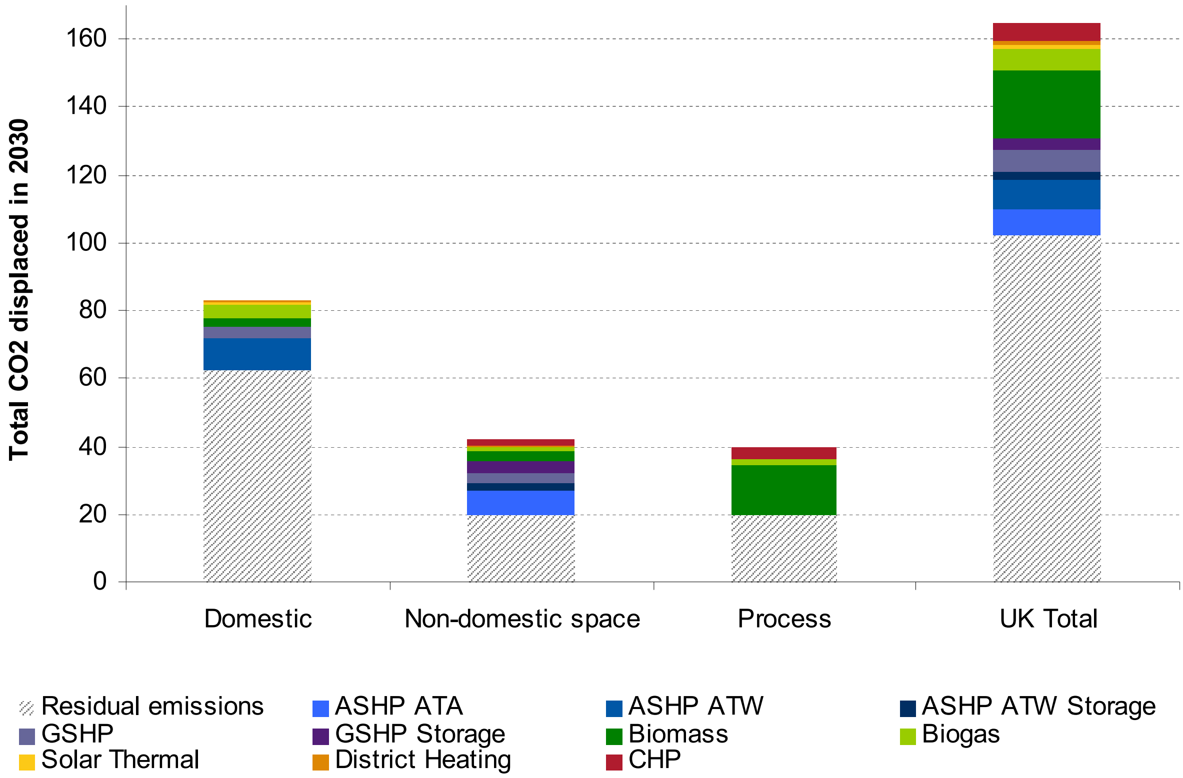
61 For illustration, a domestic solar thermal installation costing £4,000 and yielding 2 MWh of heat output to supplement a gas boiler has an abatement cost of around £600/tCO_2 when evaluated at a 3.5 percent discount rate. Although costs can be brought down for larger scales, or if replacing other types of fuel, the cost of abatement remains higher than the threshold carbon price used in all of the scenarios in this project.

heat pump electricity use), while the coloured segments show the abatement by technology and end-use, as in the preceding figure. The combination of lower suitability and less favourable starting point results in a much lower share of abatement in the domestic sector. Meanwhile, lower suitability and the limited availability of biomass places an upper bound on the extent of abatement from industrial process heat.

Figure 7.4
Composition of Abatement and Residual Emissions by Technology and End-Use ("Central" Scenario, 2030)



7.1.5. Results for Devolved Administrations

Finally, we also present results for the "Central" scenario broken out for the Devolved Administrations, drawing on the heat load data developed as described in Chapter 2.

Table 7.3
Headline Results for "Central" Scenario, by Devolved Administration (2030)

Variable	Units	Central - England	Central - Wales	Central - Scotland	Central - NI	Total
Total emissions abatement	MtCO2	49	4	7	3	62
In EU ETS	MtCO2	7.4	0.7	1.4	-0.0	9.5
Outside EU ETS	MtCO2	41	4	5	3	53
Displacement of fossil fuels	MtCO2	62	5	8	3	78
Emissions from heat pump electricity use	MtCO2	-13	-0.9	-1.5	-0.6	-16
BAU emissions	MtCO2	133	10	17	5	165
% of emissions reduced	%	37%	41%	40%	49%	38%
Remaining emissions	MtCO2	84	6	10	3	102
Low-carbon heat output	TWh	281	22	36	11	350
Total heat demand	TWh	513	38	61	16	627
Share low-carbon heat output	%	55%	59%	58%	71%	56%
Total cost	£m	1,261	93	136	67	1,557
Average abatement cost	£/tCO2	26	22	20	26	25

England, Wales and Scotland tend to have similar results, with Northern Ireland diverging the most because of the absence of gas as a counterfactual fuel. The absence of gas makes the low-carbon options more attractive, and leads to higher predicted uptake in Northern Ireland, and a correspondingly greater share of low-carbon heat and emissions reductions.

7.2. Alternative Scenario: High Bioenergy and District Heating

The "Central Scenario" relies to a great extent on the electrification of heat supply to reduce emissions, with heat pumps accounting for half of the emissions reductions. This raises the question: what alternative routes are available in a scenario where this level of heat pump deployment is either infeasible or not cost-effective? In this section, we try to outline some of the alternative routes that could be taken to keep emissions reductions in the heat sector on track to achieve the deep cuts required to meet the 2050 target.

To do this, we develop a scenario with assumptions that lead to reduced heat pump uptake but increased uptake of both bioenergy and district heating.

7.2.1. Summary of alternative scenario assumptions

The "Alternative Scenario" has three components:

- Less favourable assumptions for heat pumps
- More favourable assumptions for bioenergy;
- Higher deployment of district heating

7.2.1.1. Less favourable assumptions for heat pumps

There are a number of potential reasons that heat pumps may turn out to be less attractive than assumed in the "Central Scenario". To explore this we consider the joint impact of the following changes:

- Higher cost of electricity: we use the scenario with high electricity prices and central grid intensity.
- Less technological improvement: we limit the improvement in the COP, so that instead of the space-heating COP increasing by 1.5, its increase is closer to 1 (corresponding to an improvement in overall COP of around 0.5 in domestic applications).
- Reduced potential: we use the scenario with lower suitability for heat pumps.

These cumulatively make heat pumps significantly less attractive, and reduce their abatement by around 15MtCO_2. We discuss this and other scenarios for heat pumps in more detail in section 7.3.

7.2.1.2. Alternative scenario bioenergy assumptions

We make three modifications to create a scenario that makes greater use of bioenergy combustion to reduce emissions from heat.

First, we assume that up to 200 TWh of bioenergy is available for heat production, consistent with the high biomass availability scenario described in section 3.1.1. The additional resource could potentially be used for both biomass combustion and for the production of biogas for injection into the gas grid.

Second, we make the assumption that, where biomass combustion can be used at costs lower than the CO_2 threshold level, they are taken up in precedence over other technologies. A potential motivation for the preference given to biomass combustion would be to achieve greater abatement potential by using technologies that contribute greater emissions abatement. As noted above, under the CCC's "medium emissions intensity" electricity scenario heat pumps result in emissions from electricity generation corresponding to around 35 percent of the emissions they offset by displacing fossil fuels. In contrast, sustainable biomass has zero emissions under the assumptions used here. Even where biomass is more expensive, it therefore can achieve higher absolute abatement. The significance of this relative abatement potential depends on whether or not decarbonisation of the electricity sector can continue after this period. If it can, then heat pumps also can be decarbonised to near zero emissions. However, in the central grid intensity scenario used here, bioenergy may be absolutely necessary to achieve overall abatement targets where conditions for heat pumps are less favourable.

Third, we relax the constraint on the supply growth of biomass combustion. Industry supply is allowed to grow by 50 percent, year-on-year. In practice, this highly ambitious rate is not achieved over the entire period, as demand-side constraints (suitability and heating equipment turnover) start to limit uptake instead.

7.2.1.3. Alternative scenario district heating assumptions

The final modification is to make use of the high district heating scenario described in section 6.4.3. The associated 40 TWh of urban heat loads are reserved for DH, and thus are not available for other low-carbon technologies.

7.2.2. Summary results

These assumptions result in a scenario with similar level of abatement as the "central" case, but a very different composition of low-carbon heat technologies.

Headline results for the scenario are shown in Table 7.4. The total amount of abatement is 54 $MtCO_2$, marginally lower than the level in the central case. However, the underlying contribution from heat pumps is much smaller, at 14 $MtCO_2$ instead of 29 $MtCO_2$. The additional 12 $MtCO_2$ of abatement are achieved through a combination of greater use of biomass, biogas, and district heating (each of these adds 4 $MtCO_2$ abatement relative to the "Central" scenario). As a result of the higher abatement cost from heat pumps, as well as the use of higher-cost alternatives, the cost increases somewhat, to an average of £32/tCO_2 in 2030, as compared with £25/tCO_2 in the "central" scenario.[62]

Table 7.4
Comparison of Headline Results for "Central" and "Alternative" Scenarios (2025, 2030)

Variable	Units	Central (2025)	Central (2030)	Alternative (2025)	Alternative (2030)
Total emissions abatement	MtCO2	39	62	38	60
In EU ETS	MtCO2	9	9	11	21
Outside EU ETS	MtCO2	30	53	27	39
Displacement of fossil fuels	MtCO2	47	78	43	66
Emissions from heat pump electricity use	MtCO2	-8	-16	-5	-6
BAU emissions	MtCO2	159	165	159	165
% of emissions reduced	%	24%	38%	24%	36%
Remaining emissions	MtCO2	120	102	121	105
Low-carbon heat output	TWh	226	350	221	312
Total heat demand	TWh	606	627	606	627
Share low-carbon heat output	%	37%	56%	37%	50%
Total cost	£m	1,293	1,557	2,010	3,198
Average abatement cost	£/tCO2	33	25	53	54

The main conclusion from these results is that greater availability of bioenergy and district heating can offer an alternative route to achieving the levels of emissions abatement of the

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[62] The cost in 2025 is in fact lower in the DH & bioenergy scenario. This arises because of the low cost of district heating, which is partly offset by increased use of more expensive bioenergy in subsequent years (as large-scale bio-SNG facilities come online).

central case. The cost is significantly higher because low-cost heat pumps are not available under the scenario assumptions, and higher-cost biogas and biomass have to be used instead. To avoid distorting the results with highly uncertain and stylised estimates of cost, we have assigned a cost of zero to district heating served by power station waste heat. If, however, this could achieved at the very low abatement cost shown in stylised form in section 6.4.2.5 the cost increase relative to the central scenario would be much smaller. We consider the analysis of the full social costs of district heating and the feasibility and cost of large-scale use of power station waste heat important areas for future research.

7.3. Robustness of heat electrification: electricity sector and technology scenarios

A key message from the "central" scenario is that heat pumps can provide the main source of abatement of emissions from space heating. To test the robustness of this finding, we have investigated a number of factors affecting the abatement cost and potential of heat pumps. The main conclusion from these is that the attractiveness of heat pumps as a main strategy of abatement is relatively robust to plausible scenarios for the electricity sector, but that a combination of other factors could reduce their attractiveness significantly.

7.3.1. Electricity sector scenarios

The discussion in section 4.3 showed that the expansion of heat pump use would place significant demands on the electricity system. As with many of the other key inputs, there is substantial uncertainty surrounding the development of the power sector, in particular the rate at which low-carbon power generation comes online. The electricity sector scenarios have been designed with a view to mapping the range of plausible trajectories, including a low, medium and high emissions-intensity grid. We use the scenarios for electricity cost and emissions factors outlined in section 6.3.2.3.

Our overall conclusion is that the total abatement potential does not vary much between these scenarios. The headline results for the scenarios are shown in Table 7.5. Total abatement is similar across all four, ranging between 58 and 62 $MtCO_2$ / year in 2030 (25-31 $MtCO_2$ abatement from heat pumps). The biggest impact instead is on the average cost of abatement, which is highest in the low grid-intensity scenario (£49 / tCO_2), and lowest in the high grid intensity scenario (£22/tCO_2). That is, despite the higher grid emissions, the lower costs in the high-intensity scenario make heat pumps look more attractive, and the reverse is true in the more expensive low-intensity scenario. Based on these scenarios, and the associated CO_2 price thresholds restricting uptake, decarbonisation of electricity supply to power heat pumps leads to no additional abatement, but significantly increases the total cost of abatement. However, decarbonising heating has a significant impact on the emissions from direct electric heating, resulting in a significant drop in total residual emissions relative to the other scenarios.[63]

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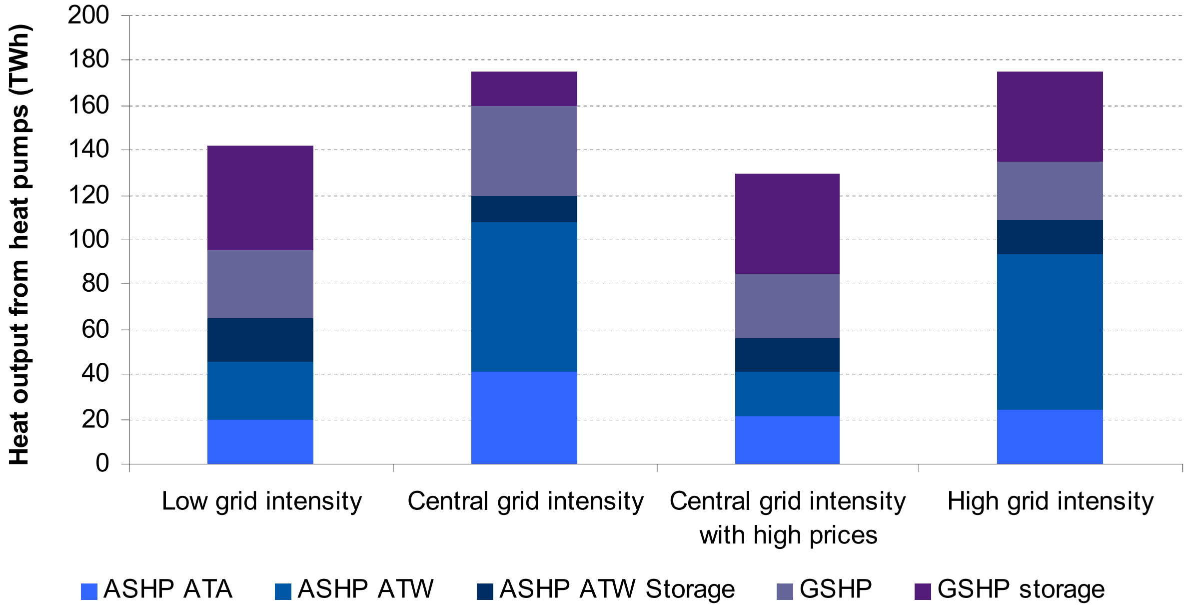
[63] As noted in section 6.4.2 the abatement potential of CHP is strongly affected by the CO_2 intensity of new power generation plant. CHP makes the same abatement contribution in the high and central grid intensity scenarios, but does not provide any abatement in the low grid intensity scenario.

Table 7.5
Headline Results, Electricity Sector Scenarios (2030)

Variable	Units	Low grid intensity	Central	Central grid intensity with high prices	High grid intensity
Total emissions abatement	MtCO2	58	62	59	59
In EU ETS	MtCO2	12	9	16	7
Outside EU ETS	MtCO2	46	53	43	53
Displacement of fossil fuels	MtCO2	59	78	68	78
Emissions from heat pump electricity use	MtCO2	-1	-16	-9	-19
BAU emissions	MtCO2	142	165	165	165
% of emissions reduced	%	41%	38%	36%	36%
Remaining emissions	MtCO2	84	102	106	105
Low-carbon heat output	TWh	247	350	304	349
Total heat demand	TWh	627	627	627	627
Share low-carbon heat output	%	39%	56%	48%	56%
Total cost	£m	2,820	1,557	2,225	1,326
Average abatement cost	£/tCO2	49	25	38	22

Figure 7.5. shows the underlying heat pump uptake, in TWh of yearly heat output in 2030. In the low grid CO_2 scenario, uptake is reduced by 35 TWh. However, this reduction in uptake is almost exactly offset by reductions from emissions used to power the heat pumps, which accounts for the very small change in total emissions abatement in the above table. Similarly, the central grid intensity scenario with high prices sees a significant drop in heat pumps. In this case, too, there is an offsetting effect, as there is a significant shift towards the use of heat pumps with storage. This counteracts the reduction in abatement to some extent (because off-peak power has lower emissions). Finally, the high grid intensity case sees almost the same amount of heat pump uptake as the central case, and also has more storage – however, the increase in off-peak generation does not lead to more emissions abatement, because the off-peak electricity generation has much higher CO_2 intensity than in the central case.

Figure 7.5
Heat Output from Heat Pumps Categories in Different Electricity Sector Scenarios (2030)



The above analysis provides a good indication of the relationship between different aspects of electricity sector developments and the abatement potential and cost of heat pumps. However, it also illustrates the complexity of the factors at work. As noted in section 4.3, the potential impacts are complicated, and we highlight three areas that we think would merit further investigation:

First, the analysis uses costs for grid reinforcement (provided by the CCC) based on current TUoS and DUoS charges. Although this provides an approximation, it is not clear that these charges are similar to the costs that would be associated with the additional grid reinforcement required to serve the very significant new electricity loads implied by the above heat pump deployment. It also is not clear that using these prices fully captures the value of shifting electricity load from peak to off-peak (which in turn would depend on the extent to which such peak shifting could avoid additional grid reinforcement). We consider these important areas for further analysis.

Second, although the above scenarios were designed to take into account some of the implications for load factors that generators supplying heat pumps would face, a more detailed analysis of seasonal and diurnal load profiles could result in lower load factors, and therefore higher costs of the associated electricity supply.

Finally, the above results require the caveat that they omit any consideration of the opportunity cost of space associated with using the storage option of heat pumps (consistent with the general cost methodology not to include non-financial costs or "barriers" in the assessment). That is, the results assume that the installation of large storage tanks in a large number of dwellings and commercial buildings is not viewed as a cost (or as having implications for property values, which amounts to the same thing) by end-users.

7.3.2. Technology characteristics and suitability

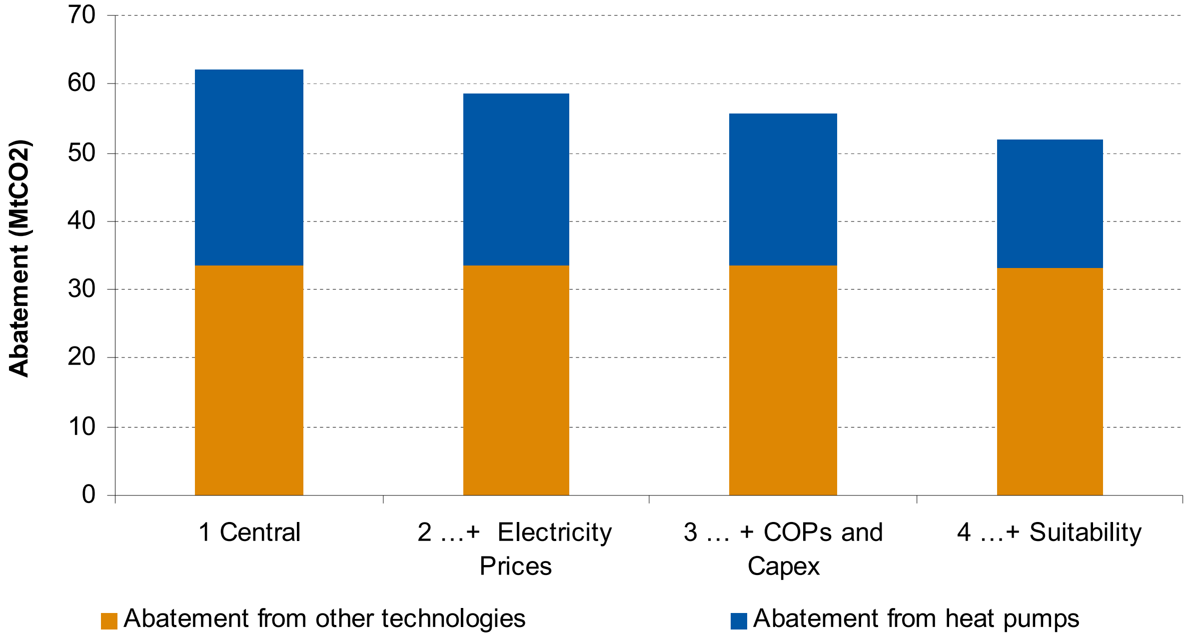
To further investigate the robustness of cost-effective abatement from heat pumps to changes in assumptions we have constructed a series of scenarios that are gradually less favourable to their use. We compare four scenarios

- **Scenario 1:** The "central" scenario.
- **Scenario 2:** Like Scenario 1, but applying the "high" electricity price scenario.
- **Scenario 3:** Scenario 2 but also capping improvements in heat pump COP and capex. This scenario caps the improvement in overall (space + hot water) COP at 0.5, corresponding to an improvement of around 1 for space heating. This is motivated by the significant uncertainty both about current seasonally adjusted heat pump performance in the UK, and the extent to which this can improve in the future in the context of improvements in technology and energy efficiency. The scenario also limits the reduction in capex over the period to 25 percent.
- **Scenario 4:** like scenario 3 with restricted heat pump suitability.
  This restricts the suitability using the low scenario developed in section 4.1.2. Potential factors include poorer-than-expected performance in retrofit installations, greater problems with noise pollution in dense areas, and greater difficulties with grid reinforcement.

Scenario 4 thus corresponds to the scenario used in the high bioenergy and district heating scenario described in the preceding section.

The below figure shows the impact of these scenarios on emissions reductions from heat pumps as well as total abatement. There is a gradual decline in total abatement, starting at 62 $MtCO_2$ in the central case, reaching 56 $MtCO_2$ in scenario 3., and 52 $MtCO_2$ in scenario 4. In this scenario, heat pumps provide 35 percent of total abatement, as compared with 45 percent in the central scenario. The significance of these results depends on how likely one judges these different outcomes to be.

Figure 7.6
Robustness of Heat Pump Uptake to Less Favourable Assumptions



7.4. Additional Scenarios

We further supplement the central scenario with a number of other scenarios for key input assumptions.

7.4.1. Increased deployment scenario

The central scenario results a 56 percent share of low-carbon technologies. To reflect the uncertainty surrounding the assumptions of CO_2 price, supply constraints and the suitability assessment, we present below a more optimistic scenario, with a combination of factors resulting in higher uptake of low-carbon technologies than in the central scenario.

Specifically, we make the following modifications from the central case:

- **Higher CO_2 price threshold:** the economic potential is increased to include measures with an abatement cost higher than the threshold in the central scenario, but no higher than implied by the "high" scenario for CO_2 prices.

- **More optimistic suitability assessment:** the heat load suitable for low-carbon heat technologies is increased by using the "high" scenario described in section 4.1.2.

- **No constraints on industry supply growth:** We impose no limitation on the available supply of low-carbon heat. This is intended to represent a situation with more widespread early deployment, and more flexible long-term industry response to increases in demand.

- **Higher bioenergy availability:** biomass availability is increased to the high scenario described in section 3.1.1, reaching 200 TWh in 2030.

- **High District heating potential:** increase from 10 TWh in 2030 to 40 TWh in 2030.

These factors combine to give significantly higher deployment of low-carbon heat, summarised in Table 7.6. More than 70 percent of heat demand is met through low-carbon heat technologies. Total abatement increases to 88 $MtCO_2$, compared to 62 $MtCO_2$ in the "central" case. The average abatement cost increases, but at £39/tCO_2 remains relatively low.

Table 7.6
Headline Results, High Deployment Scenario

Variable	Units	Central	High deployment
Total emissions abatement	MtCO2	62	88
In EU ETS	MtCO2	9	16
Outside EU ETS	MtCO2	53	72
Displacement of fossil fuels	MtCO2	78	106
Emissions from heat pump electricity use	MtCO2	-16	-18
BAU emissions	MtCO2	165	165
% of emissions reduced	%	38%	54%
Remaining emissions	MtCO2	102	77
Low-carbon heat output	TWh	350	479
Total heat demand	TWh	627	627
Share low-carbon heat output	%	56%	76%
Total cost	£m	1,557	3,398
Average abatement cost	£/tCO2	25	39

We have investigated which of the four factors (CO_2 price, suitability, supply industry, bioenergy, district heating) is the more significant.

The large majority of additional abatement results from the increased availability of bioenergy. Abatement through biomass combustion increases by 13 $MtCO_2$, while abatement from bio-SNG increases by 7 $MtCO_2$. Bioenergy thus account for the large majority of the additional abatement, as a result of jointly relaxing the bioenergy constraint and increasing the carbon price while also assuming higher suitability for biomass in industrial process heat.

The remaining increases are attributable to the large share of district heating (an additional 4 $MtCO_2$) and heat pumps (2 $MtCO_2$). The increase in suitability and CO_2 prices thus has a relatively small impact on abatement from heat pumps.

Another conclusion is that relaxing the supply growth constraint on its own has little impact. This reflects the fact that supply industry constraints become less important over the medium term – always on the assumption that they can be overcome in the near term to result in a sizeable low-carbon heat industry by 2020 as a starting point for future growth.

We consider the high deployment scenario an extreme estimate of the abatement that could be achieved by 2030. In particular, this level of biomass combustion in industry would require very strong policy intervention to make continued use of fossil fuels infeasible.

7.4.2. High barriers to low-carbon heat

As noted in section 6.3.3.2, following a steer from the CCC we have calculated the abatement costs and potential in the preceding sections using a discount rate of 3.5 percent. The project also has explored two scenarios that modify these assumptions by using higher discount rates more in line with the rates likely to be used by private decision-makers in evaluating investments in low-carbon heat technologies. This is consistent with an approach to social cost-benefit analysis that places more weight on actual individual behaviour.

Here we present two scenarios that consider alternative discount rate assumptions. In the "Mid-high" barriers scenario, we apply a 12 percent discount rate for the non-domestic sectors, and a 16 percent rate for the domestic sector. These are in line with the rates used in the recent RHI consultation. As noted in section 6.3.3, many estimates of private discount rates are in excess of these rates. The 12 and 16 percent rates therefore need not imply that *all* of the difference between observed private discount rates and the social rate of 3.5 percent is attributable to social costs, but rather that some share is likely to be. This scenario excludes barriers to uptake.

The second scenario, "High barriers", applies an 18 percent discount rate in all sectors, and includes explicitly quantified barriers to uptake. These barriers are not intended to be exhaustive, but reflect prior research that has attempted to quantify the barriers.

Headline results for these scenarios are shown in Table 7.7, showing that the choice of discount rate has a very significant impact on the abatement potential and cost. Total abatement declines by 18 – 24 $MtCO_2$ in the discount rate scenarios, to 44 - 38 MtCO2, and the abatement comes at a significantly higher cost (54 £/tCO_2 in the mid-high scenario, and 103 £/tCO_2 in the high scenario).

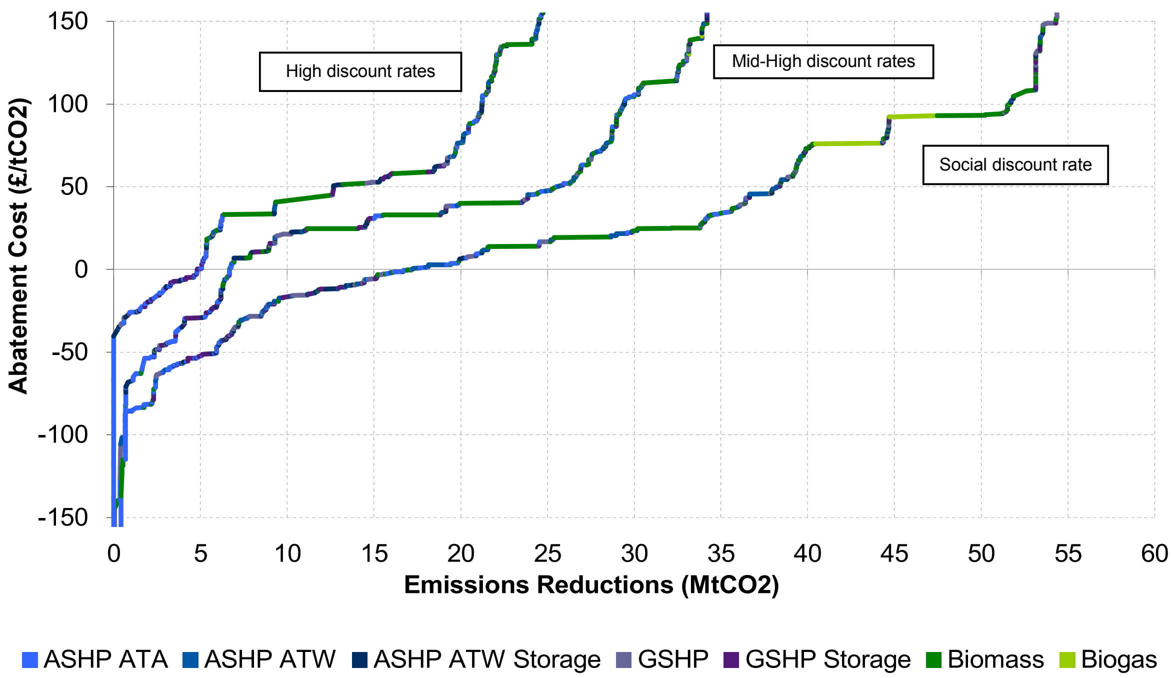
Table 7.7
Headline Results, Higher Discount Rates

Variable	Units	Central	Mid-high barriers	High barriers
Total emissions abatement	MtCO2	62	44	38
In EU ETS	MtCO2	9	11	12
Outside EU ETS	MtCO2	53	33	26
Displacement of fossil fuels	MtCO2	78	53	44
Emissions from heat pump electricity use	MtCO2	-16	-9	-6
BAU emissions	MtCO2	165	165	165
% of emissions reduced	%	38%	27%	23%
Remaining emissions	MtCO2	102	120	127
Low-carbon heat output	TWh	350	244	206
Total heat demand	TWh	627	627	627
Share low-carbon heat output	%	56%	39%	33%
Total cost	£m	1,557	2,415	3,887
Average abatement cost	£/tCO2	25	54	103

Note: For scenario descriptions, see main text above.

The impact on the cost curve representation of the results is shown in Figure 7.7. The amount of negative-cost abatement is reduced from around 17 $MtCO_2$ to as little as 5 $MtCO_2$, and the extent of average savings available from this negative-cost potential also is much lower. There also is a much lower quantity available at moderate carbon prices, with 23 $MtCO_2$ less abatement at £50/tCO_2 or less in the high discount rate scenario than in the "Central" scenario.

Figure 7.7
Marginal Abatement Cost Curve under Higher Discount Rates



7.4.3. "Worst-Case" scenario

The "Worst-Case" scenario presented here analyses the combined impact of several policy failures, and some technology / industry assumptions we have made in the central case. These include: low industry growth rate, low technology improvements, low suitability, low uptake of energy-efficiency measures, and a low RHI starting point. It also includes high discount rates and barriers, as in 'High barriers' scenario. Abatement from low-carbon heat sources in this scenario is only half that in the central case, while residual emissions are 50 percent higher. The combination of higher discount rates and less favourable technology assumptions also results in significantly higher average cost of abatement.

Table 7.8
Headline Results, "Worst-Case" Scenario (2030)

Variable	Units	Central	Worst case
Total emissions abatement	MtCO2	62	32
In EU ETS	MtCO2	9	13
Outside EU ETS	MtCO2	53	19
Displacement of fossil fuels	MtCO2	78	36
Emissions from heat pump electricity use	MtCO2	-16	-4
BAU emissions	MtCO2	165	186
% of emissions reduced	%	38%	17%
Remaining emissions	MtCO2	102	154
Low-carbon heat output	TWh	350	170
Total heat demand	TWh	627	709
Share low-carbon heat output	%	56%	24%
Total cost	£m	1,557	3,626
Average abatement cost	£/tCO2	25	114

7.4.4. Bioenergy scenarios

The next set of scenarios concerns the availability of bioenergy. We use the low and high scenarios described in section 3.1.1, and summarised in the below Table 7.9.

Table 7.9
Biomass Availability and Costs Assumptions

Scenario (maximum biomass availability)	2020	2025	2030	Biomass price (chips)	Biomass price (pellets)
	TWh	TWh	TWh	£/MWh	£/MWh
Low biomass availability	50	50	50	31	37
Central biomass availability	50	75	100	31	37
High biomass availability	85	142	200	31	37

The headline results for these scenarios are shown in Table 7.10. Reducing the biomass availability has a significant impact on abatement, reducing it by 10 $MtCO_2$. However, increasing the amount of available biomass does not lead to a large increase in abatement. An additional 4 TWh of heat demand is served by biomass in the high scenario, leading to just 1 $MtCO_2$ additional abatement. Because biomass has a higher abatement cost than the average, reducing / increasing its uptake also reduces / increases the average abatement cost.

Table 7.10
Headline Results for Biomass Availability Scenarios (2030)

Variable	Units	Central	Low biomass availability	High biomass availability
Total emissions abatement	MtCO2	62	52	63
In EU ETS	MtCO2	9	5	10
Outside EU ETS	MtCO2	53	47	53
Displacement of fossil fuels	MtCO2	78	69	79
Emissions from heat pump electricity use	MtCO2	-16	-16	-16
BAU emissions	MtCO2	165	165	165
% of emissions reduced	%	38%	32%	38%
Remaining emissions	MtCO2	102	112	102
Low-carbon heat output	TWh	350	317	354
Total heat demand	TWh	627	627	627
Share low-carbon heat output	%	56%	50%	56%
Total cost	£m	1,557	1,186	1,639
Average abatement cost	£/tCO2	25	23	26

The analysis suggests that, whereas the biomass constraint is binding in the low and central scenarios, it is not in the high biomass case, because the heat sector uses only 105 TWh of the 200 TWh available in 2030. We have investigated the reason for this, and find that the carbon price threshold is insufficient to induce switching from gas to biomass for industrial process heat. This is the case for both the traded and non-traded sector at the start of the 2020s. As carbon prices gradually increase, more potential is undertaken, and by 2030 the full suitable potential shows cost-effective abatement. Nonetheless, the cumulative abatement in 2030 is reduced by the fact that biomass combustion is not adopted in the earlier years.

In sum, with higher carbon prices significantly more abatement from biomass combustion could be available.[64]

7.4.5. Energy efficiency scenarios

Our final category of scenarios investigates the impact of different assumptions about the extent of energy efficiency improvements. We use the scenarios outlined in sections 2.1.2, 2.2.3, and 2.3.2 for the individual consumer sectors.

There are three main considerations that determine the interaction between energy efficiency and the potential for abatement.

[64] This is why we increase the CO_2 price threshold in the “Alternative” scenario.

1. With lower energy efficiency the level of fossil fuel consumption (and therefore level of emissions) is higher, so the scope for abatement through substitution with low-carbon sources also is greater in absolute terms.
2. Reduced uptake of insulation in the domestic sector reduces the suitability of heat pumps, as discussed in section 4.1.2, which reduces the abatement potential. This would tend to counteract some of the effect of 1.
3. With a binding biomass constraint, the total feasible abatement from biomass is unrelated to energy efficiency. With lower energy efficiency, biomass thus is able to eliminate a smaller proportion of total emissions. This, too, would tend to counteract some of the effect of 1.

The headline results for the central, high, and low efficiency scenarios are shown in Table 7.11. The BAU emissions projections are different for the three scenarios, reflecting our assumptions regarding the efficiency improvements in these scenarios. The share of low-carbon heat in total heat supply increases, from 56 percent in the central case to 59 percent in the high efficiency case. This is a direct effect of increased uptake of heat pumps in insulated buildings in the domestic sector and the increased share of heat that can be served by the available biomass. The share of emissions reductions therefore also increases marginally, from 38 to 39 percent of total BAU emissions. However, the absolute amount of emissions abatement falls (from 62 to 58 $MtCO_2$), as less fossil fuel is displaced overall. The converse relationship holds in the low efficiency case, with lower penetration (50 percent of heat supply), and lower share of abatement (35 percent of emissions abated) but higher absolute reductions in emissions (64 $MtCO_2$).

Table 7.11
Headline Results, Energy Efficiency Scenarios

Variable	Units	Central	High efficiency	Low efficiency
Total emissions abatement	MtCO2	62	58	64
In EU ETS	MtCO2	9	8	11
Outside EU ETS	MtCO2	53	49	54
Displacement of fossil fuels	MtCO2	78	73	80
Emissions from heat pump electricity use	MtCO2	-16	-15	-16
BAU emissions	MtCO2	165	147	186
% of emissions reduced	%	38%	39%	35%
Remaining emissions	MtCO2	102	89	122
Low-carbon heat output	TWh	350	332	354
Total heat demand	TWh	627	560	709
Share low-carbon heat output	%	56%	59%	50%
Total cost	£m	1,557	1,536	1,422
Average abatement cost	£/tCO2	25	27	22

7.4.6. Fuel prices

The cost of fossil fuels has an immediate impact on the cost of heat from conventional boilers, and therefore also on the implied abatement cost of displacing these with low-carbon sources.

We investigate this by modelling scenarios with "low", "high" and "high-high" fossil fuel price assumptions, drawn from the DECC prices described in section 6.3.2.1.

The results for these sensitivities are shown in Table 7.12. The strongest impact is on costs, which increase significantly in the low fossil fuel price case to give an average abatement cost of £65 / tCO_2. Conversely, in the high-high case, the average cost falls sharply, to *negative* £60/tCO_2. In the low scenario the total amount of abatement also falls by 15 $MtCO_2$ (just under 25 percent), as some of the options undertaken in the central case are no longer below the abatement cost threshold. In the high and high-high case, while there is increased penetration of low-heat technologies, the amount of emissions abatement actually remains roughly constant at 62 to 63 MtCO2. This is because the composition of measures changes, with a stronger emphasis on heat pumps, which have lower net abatement, as well as proportionally higher levels of replacement of gas rather than of non net-bound fuels or electricity.

Table 7.12
Headline results, Fossil Fuel Price Sensitivity Analysis

Variable	Units	Low Fossil fuel prices	Central Fossil fuel prices	High Fossil fuel prices	High high Fossil fuel prices
Total emissions abatement	MtCO2	47	62	63	62
In EU ETS	MtCO2	16	9	7	6
Outside EU ETS	MtCO2	31	53	55	56
Displacement of fossil fuels	MtCO2	55	78	81	80
Emissions from heat pump electricity use	MtCO2	-8	-16	-18	-18
BAU emissions	MtCO2	165	165	165	165
% of emissions reduced	%	29%	38%	38%	38%
Remaining emissions	MtCO2	117	102	102	103
Low-carbon heat output	TWh	247	350	358	357
Total heat demand	TWh	627	627	627	627
Share low-carbon heat output	%	39%	56%	57%	57%
Total cost	£m	3,072	1,557	-1,164	-3,731
Average abatement cost	£/tCO2	65	25	-19	-60

There is an important caveat to the results. The fossil fuel prices are sourced from DECC's UEP modelling, whereas we understand that the electricity costs have been produced through separate analysis by the CCC. This means there is no co-variation of electricity costs and fossil fuel prices, with electricity costs remaining unchanged even as gas prices change between scenarios. (In electricity markets where new entrant plant include CCGTs, by contrast, it would be expected that higher / lower gas prices would be associated with higher / lower long-run marginal cost of generation)

This has implications for the cost of low-carbon technologies. Heat pump costs depend on electricity prices, whereas conventional heating other than electric heating depends on fossil fuel prices. The effect of keeping electricity costs constant while varying fossil fuel prices therefore exaggerates the cost difference between heat pumps and conventional boilers. It therefore is likely that the above results exaggerate the cost impact of both higher and lower fossil fuel prices.

Similar considerations arguably apply to biomass prices, which also are kept constant across the fossil fuel price scenarios. The scenarios we model are ones in which the level of biomass supply would require well-developed markets, where biomass is a close substitute for fossil fuels in many applications. Such a situation is likely to mean that biomass prices are correlated to some extent with the price of fossil fuels. To the extent this is the case, the effect again would be to reduce the cost impact of higher or lower fossil fuel prices.

7.5. High-Level Summary of Selected Scenarios

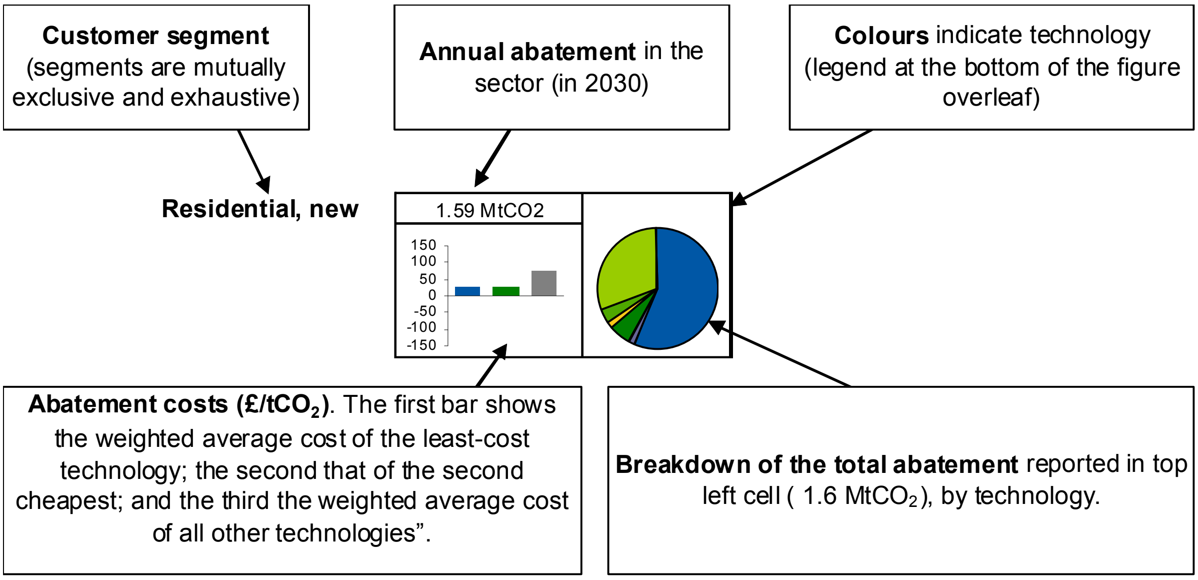
In this section we compare a selection of the above scenarios, presenting more detail on the abatement cost and emissions reductions associated with individual technologies in a number of end-user segments. The segments we use are summarised in the below table.

Table 7.13
Heat Demand Segments in Summary Representation

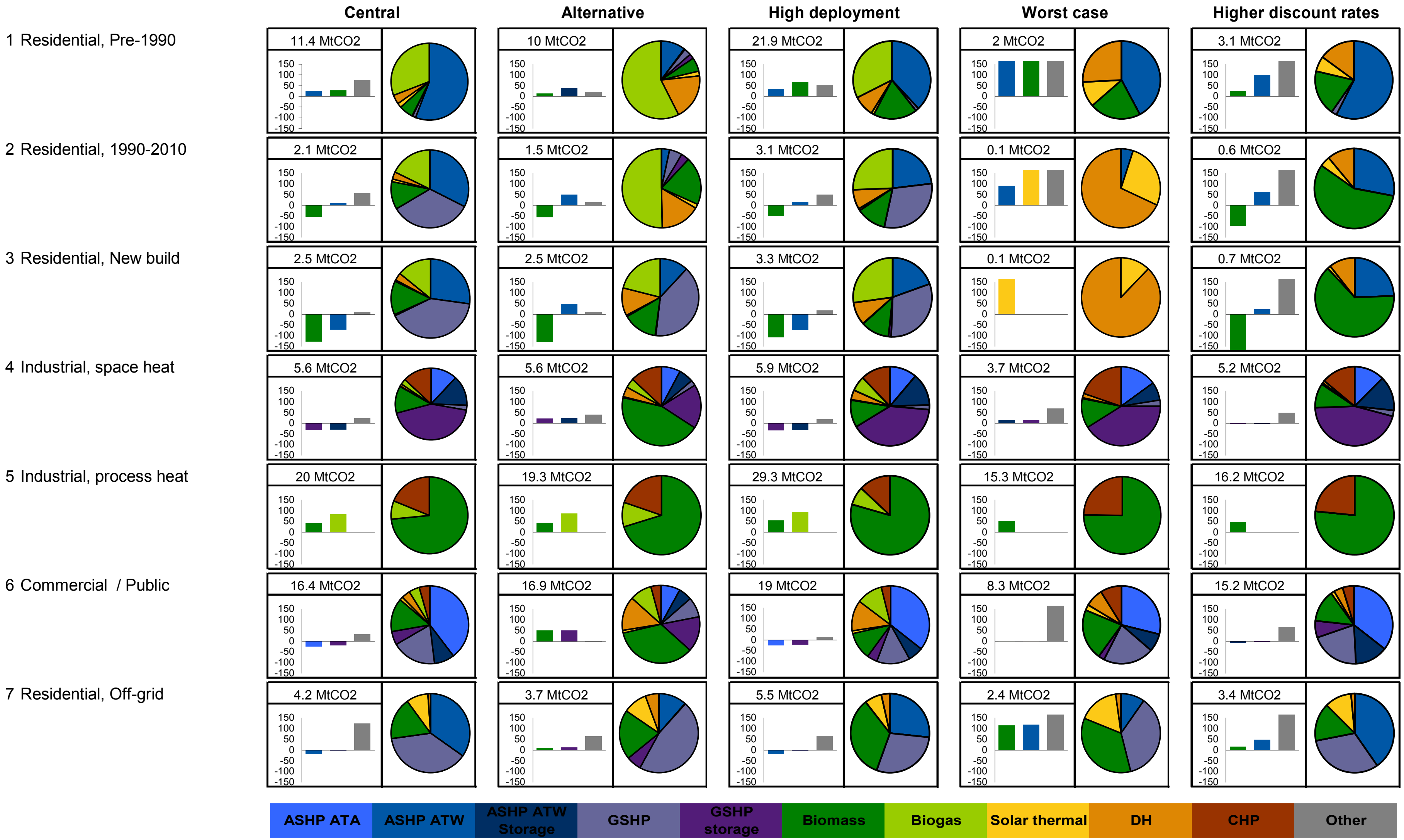
Segment ID	Customer segment	Subsegment	Fuel
1	Residential	Pre-1990 installations	On-grid
2	Residential	1990 - 2010 installations	On-grid
3	Residential	Post-2010 installations	On-grid
4	Industrial	Space heat	All
5	Industrial	Process heat	All
6	Commercial / Public	All ages and types	All
7	Residential	All ages	Off-grid

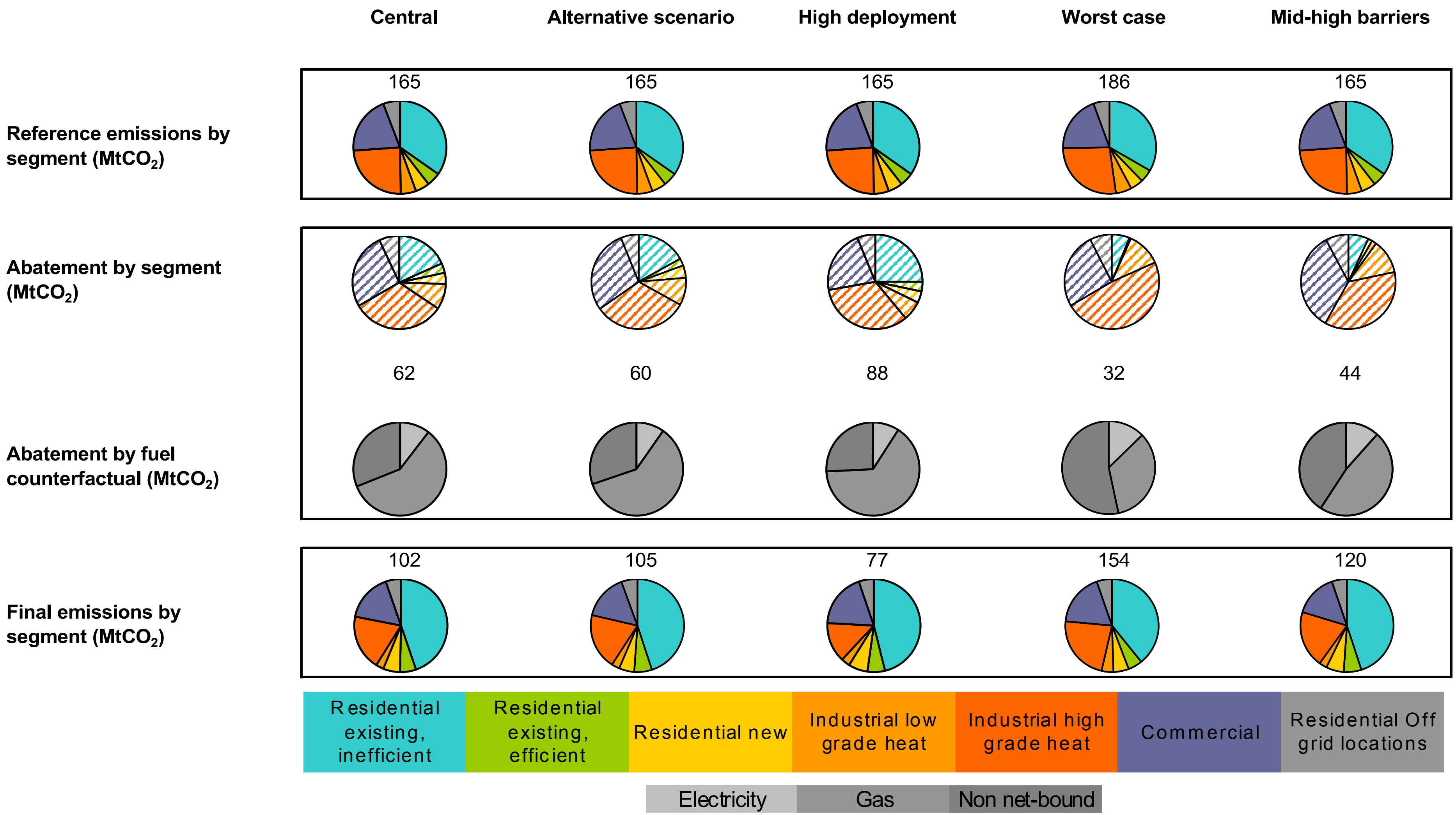
The segments are selected to be mutually exclusive and exhaustive of the heat demand represented. For each segment and scenario, we present a range of information, including the total abatement, the average abatement cost of the two least-cost technologies, and the composition of total abatement by technology (for biogas injected into the gas grid we have pro-rated the abatement by current shares of gas use.) The below figure provides a key to reading the summary results that are presented further down.

Figure 7.8
Key to the Summary Figures



Summary figures in this format are shown overleaf for each consumer segment and five scenarios.


Central
Alternative
High deployment
Worst case
Higher discount rates
1 Residential, Pre-1990
11.4 MtCO2
10 MtCO2
21.9 MtCO2
2 MtCO2
3.1 MtCO2
2 Residential, 1990-2010
2.1 MtCO2
1.5 MtCO2
3.1 MtCO2
0.1 MtCO2
0.6 MtCO2
3 Residential, New build
2.5 MtCO2
2.5 MtCO2
3.3 MtCO2
0.1 MtCO2
0.7 MtCO2
4 Industrial, space heat
5.6 MtCO2
5.6 MtCO2
5.9 MtCO2
3.7 MtCO2
5.2 MtCO2
5 Industrial, process heat
20 MtCO2
19.3 MtCO2
29.3 MtCO2
15.3 MtCO2
16.2 MtCO2
6 Commercial / Public
16.4 MtCO2
16.9 MtCO2
19 MtCO2
8.3 MtCO2
15.2 MtCO2
7 Residential, Off-grid
4.2 MtCO2
3.7 MtCO2
5.5 MtCO2
2.4 MtCO2
3.4 MtCO2
ASHP ATA
ASHP ATW
ASHP ATW Storage
GSHP
GSHP storage
Biomass
Biogas
Solar thermal
DH
CHP
Other


Central
Alternative scenario
High deployment
Worst case
Mid-high barriers
Reference emissions by segment ($MtCO_2$)
165
165
165
186
165
Abatement by segment ($MtCO_2$)
62
60
88
32
44
Abatement by fuel counterfactual ($MtCO_2$)
Final emissions by segment ($MtCO_2$)
102
105
77
154
120
Residential existing, inefficient
Residential existing, efficient
Residential new
Industrial low grade heat
Industrial high grade heat
Commercial
Residential Off grid locations
Electricity
Gas
Non net-bound

The following are some of the messages emerging from this overview:

- Heat pumps provide the large majority of abatement in the domestic sector, with ASHPs the cheapest of the measures undertaken and the majority of abatement in the pre-1990 segment that constitutes the majority of the heat load. There also is a significant role for GSHPs in post-1990 houses as well as off-grid. There is no domestic uptake of heat pumps with storage, indicating that the additional cost is not outweighed by the additional abatement achieved.
- ASHPs also are the dominant technology for non-domestic space heating, providing half the abatement in the commercial / public segment. There a substantial share of heat pumps with storage, and in the industrial space heat sector in particular there is significant adoption of GSHPs with heat storage.
- In the Alternative Scenario with high bioenergy and district heating heat pumps play a much smaller role in the domestic sector, with their place taken by biogas and district heating. However, there still is use of heat pumps in off-grid locations as well as new build. The scenario also sees adoption of biomass combustion for industrial space heating, as well as in the commercial / public sectors (although to a lesser extent than industry).
- The large majority of the additional abatement in the high deployment scenario is in pre-1990 houses and industrial process heat, with only modest increases in other segments. This is consistent with these segments containing a very large share of the residual fossil fuel use in the "Central" scenario. All technologies increase significantly in the pre-1990 segment, with the largest increase in district heating and biomass combustion.
- The low deployment scenario sees sharp reductions in abatement across the board, and especially in pre-1990 houses. Abatement in the commercial / public segment also drops significantly. By contrast, the use of biomass for process heat continues to supply a significant quantity of abatement. There are only minor shifts in technology composition, except that neither heat pumps nor biomass combustion remain viable abatement options in small domestic heat loads. This leaves biogas as the main option for these segments, which, although it represents the majority of abatement in these segments, is very small in absolute quantity.
- Only biomass combustion, biogas and CHPs are suitable for industrial process heat. The total abatement from this segment can vary significantly by scenario, ranging from 20 $MtCO_2$ in the "Central" scenario, to almost 30 $MtCO_2$ in the High Deployment scenario. However, as discussed above, relaxing the constraint on biomass availability on its own does not lead to as much increase in abatement from biomass as one might expect, as much of the abatement comes at a cost higher than the carbon prices in the central case.
- Higher discount rates affect all technologies, but biomass less than others. This is because the initial capex is a relatively small share of the overall levelised cost. Heat pumps, by contrast, are more significantly affected, as much of the levelised cost of heat pumps is incurred up-front.

8. Conclusions

Our analysis suggests that low-carbon heating technologies could reduce emissions from heat use by one-third or more by 2030. However the assumptions that underpin these results are uncertain, along a number of dimensions.

Our analysis indicates that the best approach to reducing emissions from heat in the fourth budget period varies by heat demand segment, and is sensitive to underlying assumptions. Using the CCC's "medium emissions intensity" scenario for the electricity sector and other "Central" scenario assumptions, heat pumps can provide low-cost abatement at very high volumes, suggesting that of our three high level strategies set out at the start, electrification shows the most promise. However, the unsuitability of heat pumps for a large share of UK heat loads raises the need for other strategies / technologies to come into play if the UK's long-term emissions targets are to be met.

We test various factors likely to affect the abatement potential from and cost of heat pumps, and find that some (electricity price and emissions intensity, efficiency) have surprisingly little impact on abatement potential, although more impact on cost. If a combination of circumstances mean that heat pumps become significantly less attractive, then meeting the UK's long-run targets is feasible, but only with significant increase in use of bioenergy (at higher cost thresholds) and district heating.

District heating emerges as a potentially very attractive abatement option, provided barriers to its adoption can be overcome at negligible cost, and provided very low-cost sources of (waste) heat can be connected. This is likely to require a concerted effort to provide a "proof of concept".

Gas-fired CHP may still have a role during the 2020-2030, but the desirability of investing in new capacity to reduce emissions in this period depends on the nature of the generating capacity the CHP would replace. The CCC's medium emissions intensity scenario for the electricity sector have new CCGTs serving peak loads, and gas-fired CHP can still provide abatement in this case. Gas-fired CHP becomes unattractive if the (average) emissions intensity of the capacity it replaces falls below 0.28 tCO_2/MWh. Other forms of CHP (including district heating from power plant "waste heat" and renewable CHP) may provide longer-term abatement options, but the costs and barriers could be substantial.

A better understanding of barriers and hidden / missing costs is a key factor affecting the availability of low-cost abatement during this period. If the high discount rates apparently in use by decision-makers do in fact reflect barriers that are real social costs, it may be difficult to meet UK emissions targets affordably.

Our analysis suggests various ways that the results are sensitive to different assumptions. In many cases, which assumptions turn out to be accurate may only be revealed much closer to the fourth budget period. However, our analysis also identifies a number of topics that would be worth investigating further now.

- Integrated analysis of interactions between heat and power sectors. Intersections identified and partly explored in this project include various issues arising for heat pumps (new capacity requirements, load profiles of new electricity demands created, need for grid reinforcement) as well as combined heat and power (value of flexibility, reduced load factors for gas-fired plant).

- More detailed study of biogas potential and options. This could extend both to more detailed study of potential (ideally on a spatial basis), technology and plant options, and the merit of alternative uses of biogas across different end uses.
- Reviewing the findings of this work in light of field trials of heat pump performance due to be published later in 2010.
- Fuller analysis of the feasibility and costs and benefits of extracting heat from large-scale power plant.
- Analysis of the range of barriers to the low-carbon heat options identified, and analysis of policy options, including consistency of current policy framework with the longer term scenarios presented here.
- Improving the estimate of district heating potential, and an estimate of both the social cost of overcoming the barriers to large-scale expansion of district heating networks, and the adjusted costs of the networks if some of these barriers (e.g. accelerated and high connection rates) cannot be overcome.

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Appendix A. Biomass Supply

This appendix provides further details on the information sources used in deriving the total amount of biomass resources, as outlined in section 3.1.1. Below, Table A.1 to Table A.5 show the projections of total biomass resource available in 2020 to 2030. The last table summarizes the information source, and the way in which all the various sources of data have been used.

Table A.1
Resource Quantities Derived by E4tech (2009)

Resource	Form	2008		2020		2030	
		modt	TWh	modt	TWh	modt	TWh
Energy crops	chips				50		150
Straw	bales	0.3	1.9			3.3	19
Forestry residues	chips	-	-	1.0	5		
Stem wood	logs	0.3	1.3	0.9	5		
Arboriculutral arisings	logs/chips	0.3	1.7	0.4	2		
Sawmill co-product	chips/saw dust/	0.1	0.7	1.1	5		
Waste wood	pieces	1.1	5.3			8.4	41
Waste: paper and card		1.2	3.6				
Waste: food/kitchen		3.0	2.8				
Waste: garden/plant		3.7	4.4				
Waste: textiles		0.1	0.3				

Notes: The E4tech report does not supply a tabulated version of results, so data has been extracted from notes on methodology and in some cases, graphical presentations

Table A.2
ADAS (2009) Estimates of Biomass Potential

Cropping source	Currently produced biomass	Potential future biomass production
	Oven dry tonnes (million)	Oven dry tonnes (million)
Wheat straw	4.2	-
Barley straw	1.6	-
Oilseed rape straw	2.3	-
Straw from set-aside brought into cropping 2008	-	1.2
Miscanthus on 2008 set-aside area	-	3.6
Miscanthus (currently 5036 ha)	0.1	-
Miscanthus on 5% arable land	-	1.8
Temp grassland - misc/SRC	-	1.6
Rough grazing - SRF	-	7.5
SRC (currently c.3000 ha)	0.0	-
Transport network	0.5	-
Urban green space	1.8	-
Conifer woodland	1.9	-
Broadleaf woodland	2.4	-
Total	14.7	15.7

Source: Addressing the land use issues for non-food crops in response to increasing fuel and energy generation opportunities. NNFCC project 08-004, ADAS, 2008

Table A.3
Biomass Task Force Estimates of Biomass Availability

Sector	Potential future biomass production	
	Oven dry tonnes (million)	TWh
Forestry waste and arboriculture arisings	1.5	6.7
Energy crops	0.3	1.5
Straw	3.0	12.5
MSW	7.6	19.0
Waste wood	3.0	9.9

Table A.4
Estimates by Pöyry Forest industry consulting and Oxford economics for WRAP

Sector	Potential future biomass production (modt)
Industrial	0.43
Construction	1.1
Demolition	1.06
Municipal	0.58
Total waste	3.16

Table A.5
Summary of Data Sources

Study	Notes / observations	Conclusion
E4Tech	Thorough study. Aggressive energy crop deployment. Waste resources underestimated. Short rotation forestry not itemised (but may be included as energy crop).	Use as a basis for estimates.
ADAS for NNFCC	Agricultural focus, does not include waste. Includes short rotation forestry as specific item.	Use for short rotation forestry and confirmatory
WRAP study	Waste wood only.	Use for waste wood.
Biomass Task Force	Broad survey. Very pessimistic energy crop predictions.	Confirmatory.

Appendix B. CCC Electricity Sector Assumptions

This appendix reproduces a note by the CCC outlining the electricity sector assumptions underlying the scenarios described in section 6.3.2.3 of the main body of the report. These scenarios, as well as the analysis and assumptions described in this Appendix, have been provided to NERA by the CCC. They are not based on NERA analysis or NERA's views on the power sector.

Introduction

This note sets out scenarios for marginal emissions intensity and cost in the electricity sector, which can be used to assess the cost and emissions implications of a change in electricity demand from heat in the in the 2020s.

The methodology for determining the marginal emissions intensity and cost necessarily simplifies the complex impacts that additional demand for electricity has on the marginal plant and on system costs. Where major simplifications have been made, a conservative approach has been taken, meaning that on balance, the costs of the additional demand from heat are more likely to have been overestimated than underestimated.

Approach to choosing marginal plant

Any extra demand for electricity from heat in the 2020s could either increase the use of existing capacity, or cause additional new capacity to be built.

New build or existing plant

In the scenarios set out in this note it is assumed that all changes in demand for electricity affect the build of new plant, rather than the use of existing plant.

For demand added at peak time, new plant must be built if the following assumptions apply:

- No additional demand side flexibility is available in the counterfactual. If a heat technology needs power at peak time, then new plant has to be built.
- The power sector capacity margin65 stays constant when extra demand is added, so any additional demand that is added at peak time will necessarily result in new plant being built, rather than eating into the capacity margin.

Demand added at off-peak time will also affect the build of new plant over the long run. Demand coming on at off-peak time will change the daily profile of total electricity demand, increasing the amount of demand that can be met by baseload plant. In the short run, some (but not all) off-peak demand could be met by increasing the load factors of existing fossil-fuelled plant. However, for

[65] The capacity margin is the capacity kept on the system to ensure the expected demand of the system is met even under situations of unexpected failure of generation during system peak demand or unusual or unanticipated increases in demand.

simplicity it is assumed that all this additional off-peak demand is met by new baseload plant. This is a reasonable simplification:

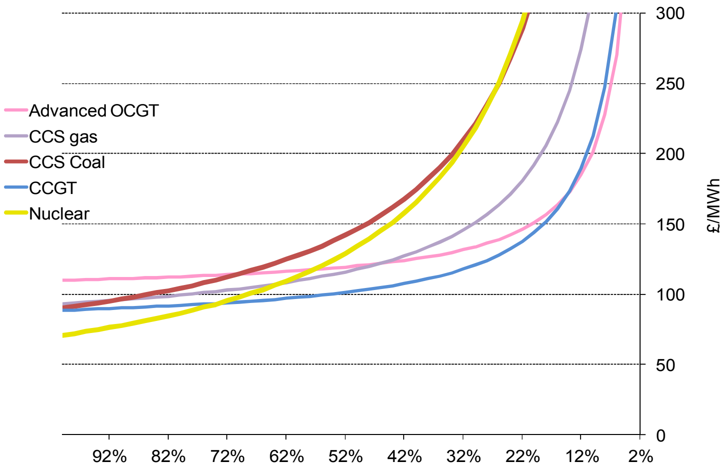
- Where the new baseload plant is low-carbon (e.g. nuclear), by the late 2020s, assumptions on the carbon price mean it will be more economic to build new baseload plant than to use existing plant (the long run marginal cost of nuclear will be lower than the short run marginal cost of existing fossil fuelled plant).
- Where the new baseload plant is fossil fuelled, the costs and emissions factors are similar to those of existing plants (both the long run marginal costs of new fossil plant and the short run marginal cost of existing plant are dominated by the assumed high carbon prices by the late 2020s).

Choice of new build plant

It is assumed that the choice of new plant is made between nuclear, CCGT and CCGT CCS:

- Nuclear is likely to be the cheapest low-carbon plant at high load factors, while CCGT CCS is likely to be the cheapest low carbon plant at lower load factors.
- New CCGT is likely to be the plant on which there are the least constraints on build and which is most technically flexible (able to meet within day swings in demand).

Figure B.1
LRMC of Plants in 2030 at Different Load Factors



Source: CCC analysis

Scenarios

The following three scenarios have been put together with the aim of covering a wide range of economic and technical power sector outcomes in the 2020s. These scenarios are not intended to be predictions of possible outcomes, rather they are meant to represent boundary cases for the range of possibilities:

1. Low emissions intensity: The first scenario assumes there is no technical or economic limit on the amount of low-carbon plant that can be built. Thus any new demand can be met by nuclear and CCGT CCS, even where these plants are running at low-load factors.

2. Medium emissions intensity: The second scenario assumes that there is no technical constraint on building low-carbon plant, but that there is an economic constraint in that only low-carbon plant which can be run baseload is built. This could also represent a world where CCGT CCS was unavailable. In this scenario, any new demand which can be met by plants running at load factors of more than 75% is met by nuclear. All demand that is met by plants running at load factors of below 75%, including demand which comes on within the daily peak, is met by CCGT.
3. High emissions intensity: The third scenario assumes that there is a constraint on all new low-carbon build. This could be, for example, because of supply chain or skills constraints on the building of new nuclear. It could also be because additional demand from heating is not anticipated far enough in advance to build nuclear which has much longer lead times than CCGT . In this scenario, any new demand is met with CCGT.

Table B.1 shows the appropriate marginal plant assume for three scenarios, depending on whether additional demand occurs at peak or off-peak, or a mixture of both.

Table B.1
Choice of Marginal Plant

Scenario	Description	Demand added at peak time only	Demand added at off-peak and peak time, or at off-peak time only
1. Low emissions intensity	Unconstrained build of nuclear and CCGT CCS	CCGT CCS	Nuclear and CCGT CCS, assuming nuclear meets load which is on the system for more than around 65% of hours (below that level it becomes cheaper to build CCGT CCS).
2.Medium emissions intensity	Unconstrained build of baseload low-carbon plant (nuclear). No CCGT CCS, all non-baseload demand met by CCGT .	CCGT	Weighted average of nuclear and CCGT, assuming nuclear meets load which is on the system for more than 75% of hours (below that level it becomes cheaper to build CCGT)
3. High emissions intensity	No additional build of low-carbon plant. Unconstrained build of CCGT.	CCGT	CCGT

Assumed Load Factors

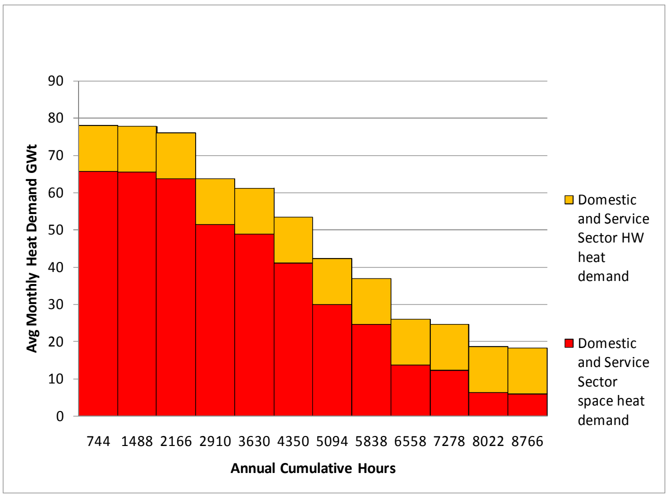
Adjustment for seasonal demand for heat

Space heat demand is highly seasonal (Figure B.2). Assuming that all additional heat demand follows the load profile set out in Figure B.2, each additional unit of heat demand adds a proportion of GWh which can be met by baseload plant, and a proportion of demand that must be met by plant running at a range of much lower load factors.

The seasonal shape of demand impacts on both the choice of plant, and the associated costs and emissions factors:

- Not all plant which is added at off-peak time will be running at baseload. Once the seasonal shape of demand is taken account of, only around 50% of demand added at off-peak times can be met with baseload plant.
- This affects the choice of plant – in scenario 1, non-baseload demand is met by CCGT CCS, and in scenarios 2 and 3 non-baseload plant is met by CCGT.
- The costs and emissions intensities are also affected, both are weighted according to the proportion of demand met by each type of plant, and the costs are weighted by the proportion of each type of plant running at each load factor.

Figure B.2
Domestic and Service Sector Heat Demand



Source: AEA analysis of BRE data

Adjustment for plant coming on at peak and off-peak

Demand that comes on at peak times only is assumed to result in plants which can only run only 12 hours out of 24. This is a very rough simplification and will depend on the daily profile of heat demand during peak times, details of this were not available when this methodology was being put together. This assumption may be revised for subsequent modelling when these details are available.

Demand that comes on at off-peak time only or at peak and off-peak times is assumed to allow plants to run 24 hours of 24.

Demand which comes on at off-peak time only will reduce the costs of meeting some peak demand, since baseload low-carbon plant, instead of low-load factor CCGT can be used to meet this peak demand. For simplicity, this impact is not taken account of in this note. The costs of off-peak heat demand are thus likely to be somewhat overestimated.

Cost and emissions estimates:

Resource cost rather than price should be used to cost any additional demand as estimating price would involve making assumptions about the market structure. Where a new plant is built, the relevant resource cost is the long run marginal cost. The cost of allowances under the EU ETS (EUAs) are not included in the marginal cost estimates, since these marginal cost estimates will be used in the analysis to calculate abatement cost .

Costs and emissions intensities include transmission costs and losses at 8%. Distribution costs are not included in these figures but will be included separately in the heat analysis.

High fuel price sensitivity

The costs for the medium scenario were also recalculated using DECC's high-high fuel prices.

Marginal cost and emissions intensity assumptions are set out in Table B.2. overleaf.

Table B.2
Marginal Costs and Emissions Intensity for Additional Heat Demand

		Demand added at peak times only			Demand added at peak and off-peak, or off-peak only		
Scenario	**Description**	**Plant**	**LRMC (£/MWh)**	**Emissions intensity $kgCO_2/kWh$**	**Plant**	**LRMC £/MWh**	**Emissions intensity $kgCO_2/kWh$**
Low emissions intensity	Unconstrained build of nuclear and CCGT CCS	CCGT CCS running 12 hours per day, (adjusted for seasonality)	£159	0.06	Weighted average of nuclear and CCGT CCS, adjusted for seasonality and assuming nuclear meets load which is on the system for more than 67% of time	£108	0.02
Medium emissions intensity	Unconstrained build of baseload low-carbon plant (nuclear). No CCGT CCS, all non-baseload demand met by CCGT	CCGT running 12 hours per day, (adjusted for seasonality)	£96	0.43	Weighted average of nuclear and CCGT, adjusted for seasonality and assuming nuclear meets load which is on the system for more than 75% of hours.	£90	0.21
High emissions intensity	No additional build of low-carbon plant. Unconstrained build of CCGT.	CCGT running 12 hours per day, (adjusted for seasonality)	£96	0.43	CCGT running baseload, adjusted for seasonality	£74	0.43

		Demand added at peak times only			Demand added at peak and off-peak, or off-peak only		
Scenario	**Description**	**Plant**	**LRMC (£/MWh)**	**Emissions intensity $kgCO_2/kWh$**	**Plant**	**LRMC £/MWh**	**Emissions intensity $kgCO_2/kWh$**
Medium emissions intensity - high fuel and other generation costs	Unconstrained build of baseload low-carbon plant (nuclear). No CCGT CCS, all non-baseload demand met by CCGT	CCGT running 12 hours per day, (adjusted for seasonality)	£136	0.43	Weighted average of nuclear and CCGT, adjusted for seasonality and assuming nuclear meets load which is on the system for more than 75% of hours.	£105	0.21

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