Renewable Heat Technologies for Carbon Abatement: Characteristics and Potential

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Executive Summary

Heat accounts for approximately half of UK energy use and associated CO_2 emissions (around 263 $mtCO_2$). In the UK nearly all heat is provided by fossil fuels and electricity. In principle, renewable technologies could be used to meet much of this heat demand. This report provides background on the major renewable heating technologies that are currently available and presents the results of detailed modelling of the UK heat market to estimate the potential for CO_2 emissions abatement using these technologies.

The technologies covered in this report are biogas combustion, biogas injection into the gas grid, biomass boilers (individual and district heating), ground- and air-source heat pumps, and solar thermal (water) heating. Each of these technologies is in use in significant volumes worldwide – although not in the same countries and regions. The characteristics of the building stock, geography, climate, and heat demand may render certain technologies less suitable in the UK than elsewhere.

Use of both air-source and ground-source heat pumps is widespread in several European countries, and in the form of reversible air conditioning air-source heat pumps are rapidly becoming a standard technology in the commercial sector in the UK. However, there is significant uncertainty about their suitability for large parts of the UK domestic sector, where the potentially high electricity input required (due to a relatively low coefficient of performance, or COP) means that the cost of abatement is high in many cases. Ground-source heat pumps can offer higher COPs, but high capital costs increase costs in many applications. Biomass boilers have the potential to replace fossil fuels across a range of domestic, industrial, and commercial / public sector applications. Recent research suggests that there is significant biomass resource that could be turned into fuel, and there also increasingly is an international market for biomass fuels. Solar thermal is by far the most expensive technology for carbon abatement, because it can only supply a relatively small proportion of most typical heat loads, and entails significant up-front costs.

In all cases, the low current penetration of these technologies in the UK means that the feasibility of mass market adoption is uncertain. We have calculated a maximum abatement potential[1] of just over 90 $MtCO_2$ by 2022 at costs up to £1000 per tCO_2. Of this, 70 $MtCO_2$ are available at costs up to £300 tCO_2. However, due to a number of constraints, the realistic potential is much lower.

The Marginal Abatement Cost Curve (MACC) that we estimate for 2022 is shown in Figure ES-1.[2] The vertical axis in the figure shows the marginal cost of abatement, in pounds per tonne of carbon-dioxide (£/tCO_2). The horizontal axis shows the amount of emissions reductions, in million tonnes of CO_2 ($MtCO_2$).

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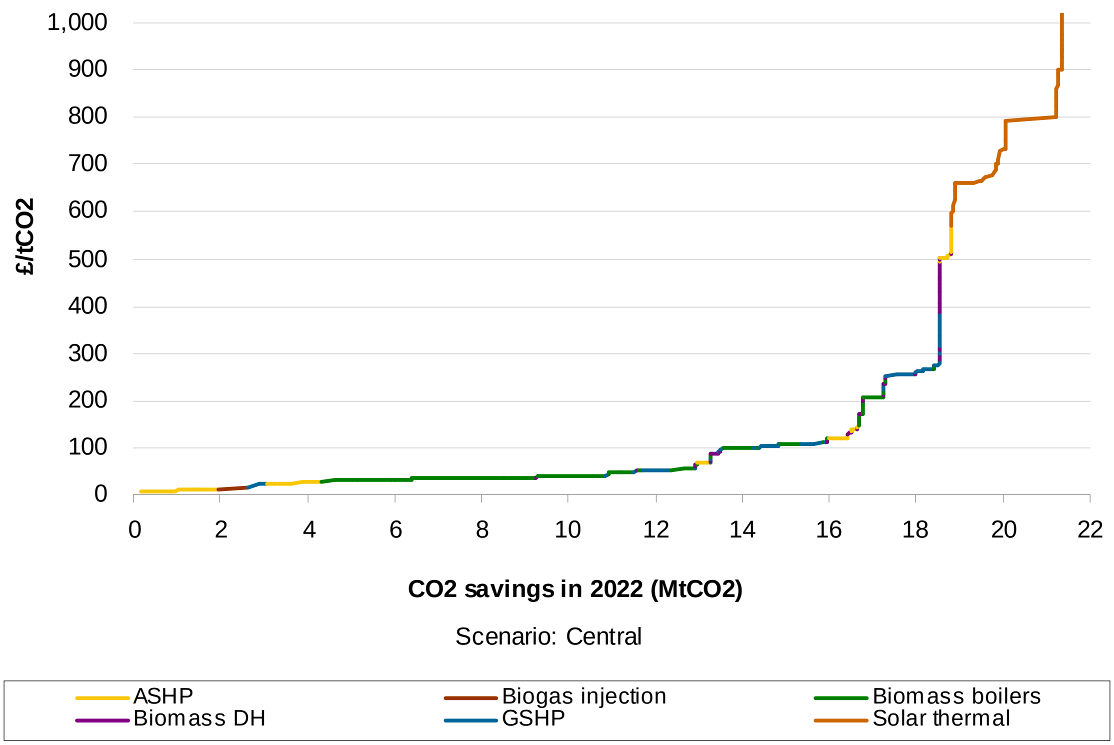
1 As described in the main report, this "modified maximum technical potential" reflects the annual replacement rates of heating systems. This maximum potential figure therefore does not reflect every heat consumer that could in principle install renewable technologies, because by 2022 not all existing heating equipment will have been replaced.

2 A marginal abatement cost curve shows the amount that emissions can be reduced by individual measures, arranged in order from lowest cost per tonne of reduction to highest cost.

Figure ES-1
Realistic Abatement Potential of Renewable Heat by Technology (2022)



Renewable heat offers low-cost abatement through a mix of technologies. The use of air-source heat pumps (particularly in non-domestic applications) accounts for some of the cheapest potential, with contributions also from ground-source heat pumps, biogas injection, and biomass boilers. The majority of the 12 $MtCO_2$ of abatement achievable at a cost of £50 / tCO_2 or less is accounted for by biomass, and the same is true for the 14 $MtCO_2$ of abatement costing less than £100/tCO_2.[3]

Above £100/tCO_2, the cost of additional abatement rises quickly, with ground-source heat pumps, biomass district heating, and solar thermal achieve representing much of the higher-cost potential. The figure does not reflect any abatement potential that may be available from combined heat and power (CHP) using renewable fuels, because CHP technology requires analysis that was beyond the scope of the current study. Renewable CHP could offer significant additional abatement potential not reflected above.

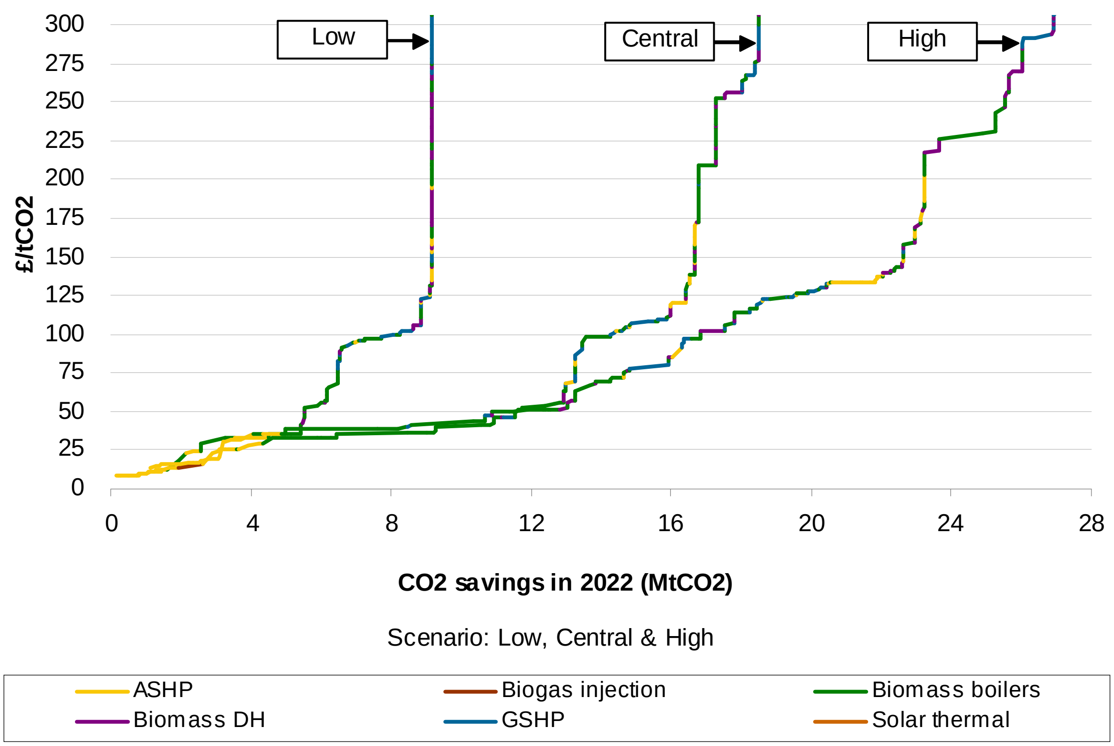
The above MAC curve reflects various assumptions about different constraints on the expansion of renewable heat use. We have modelled alternative assumptions, and Figure ES-2 shows a comparison of three sets of assumptions. In a “low growth” case – representing a more pessimistic view on the feasible expansion of supply of renewable heat – some 5

[3] For reference, the 12 $MtCO_2$ abatement available for less than £50/tCO_2 corresponds to 34 TWh of heat output, or around 5 percent of projected heat demand in 2020 / 2022. Note that the amount of renewable heat reflected by each point on the MACC is not proportional to the amount of CO_2 saved, because each technology and fuel counterfactual replaced has different CO_2 emissions characteristics.

$MtCO_2$ are available at a cost of £50 / tCO_2 or less. Under a more optimistic "high growth" case there is more potential, especially at costs above the £50 / tCO_2 mark.

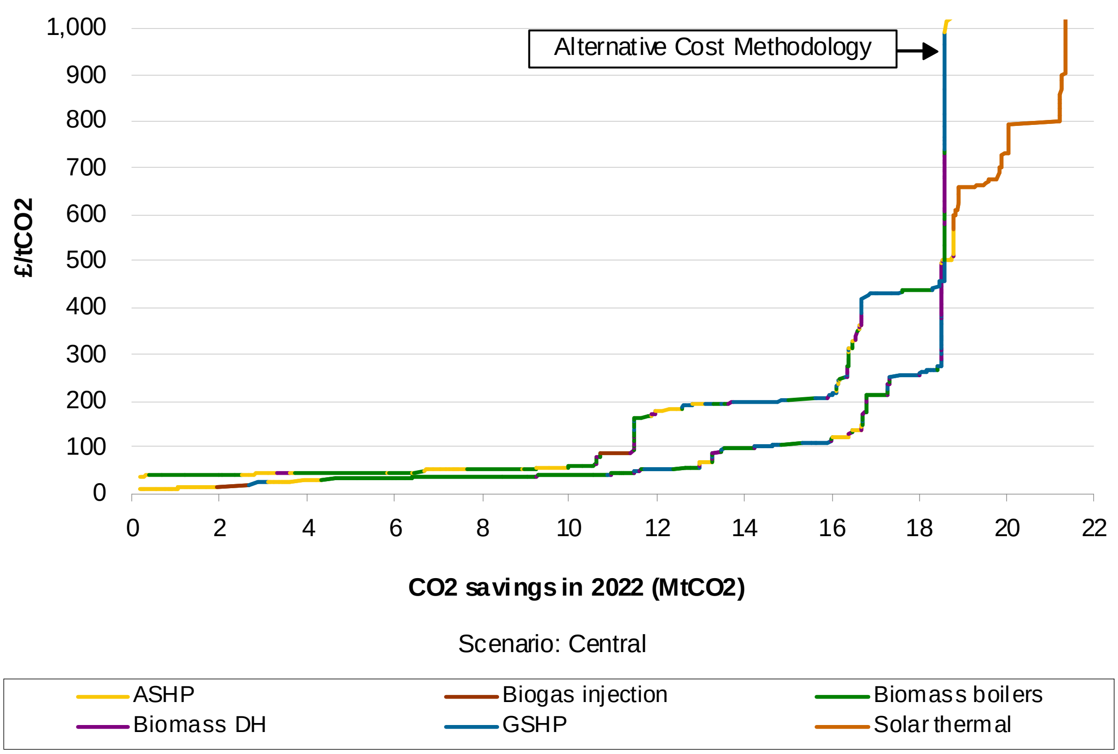
For comparison, the central case corresponds to a market share of renewable heat in new heating equipment sales of around 30 percent by 2022 (in the domestic sector this amounts to close to 300,000 households; in the other sectors sizes are more variable, so the number of installations is less informative), while the high case corresponds to a share of just over half of all heating equipment sold. In all cases, biomass is the technology with the most significant contribution to abatement.

Figure ES-2
Realistic Abatement Potential of Renewable Heat by Technology; Detail (2022; Low, Central, and High Uptake Scenarios)



The cost calculations underlying the above MAC curves use a discount rate of 3.5 percent, and do not include the cost of overcoming demand-side barriers (although the trajectories are consistent with the existence of such barriers). In reality, 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 renewable heat. Using an alternative cost methodology that accounts for these factors raises the cost significantly. For example, the abatement available at £50 / tCO_2 or less is reduced from 12 $MtCO_2$ to 7 $MtCO_2$ in the central case. Figure ES-3 compares the abatement potential in the central case to a case that accounts for private discount rates and barrier costs.

Figure ES-3
Comparison of Realistic Abatement Potential Using Standard and Alternative Methodologies (2022)



Finally, these results also depend on assumptions about biomass prices, which like other fuel prices are uncertain—and which may be subject to upward pressure given the likely increase in demand for biomass fuels.

In summary, there does appear to be significant potential to reduce CO_2 emissions using renewable heat technologies, with the lowest costs achieved using biomass and air-source heat pumps in the non-domestic sectors. Other technologies provide further potential, but at costs that may be relatively high compared to other abatement measures outside of renewable heat. Achieving widespread uptake of renewable heat technologies will almost certainly require financial support, and providing this support is the purpose of the government's planned Renewable Heat Incentive. It remains to be seen whether this financial support will be sufficient to promote the high levels of uptake reflected here. For some technologies the expansion of renewable heat may also require additional policies to overcome selected barriers, such as unfamiliarity, lack of established supply chains, coordination problems associated with district heating, etc. The evidence available from other countries suggests that given sufficient financial incentive – which also reflect potential hidden costs associated with some of these barriers – many of the renewable heat technologies considered here can enter the mainstream.

1. Introduction

1.1. Renewable Heat Background

European Union targets agreed at the end of 2008 commit the UK to sourcing 15 percent of its energy from renewable sources by 2020. This target applies to all energy use, including energy used for electricity generation, heating, and transportation.

The UK already has a framework to promote renewable electricity generation through the Renewables Obligation, and to promote renewable transport fuels through the Renewable Transport Fuels Obligation. In the Heat and Energy Saving Strategy published in February 2009, the Government proposed to add to these policies a new feed-in tariff to promote small-scale renewable electricity, and a new Renewable Heat Incentive to promote renewable heating technologies.

In its Renewable Energy Strategy (RES), the government estimates that the total demand for heat in the UK in 2008 was 711 TWh (excluding electricity used for heat).[4] Of this total, 54 percent of heat is consumed by the residential sector, another 30 percent is used in industry, and the remaining 16 percent is used by the commercial and public sectors. Most heat is for space heating of buildings, with heating of hot water and industrial process heating (which typically requires special equipment and high temperatures) also significant.[5] The vast majority (around 80 percent) of homes are heated with gas, with electricity and "non-net-bound" fuels (primarily oil) approximately splitting the remaining households. In industry and the commercial / public sectors there is a more diverse fuel mix: the government estimates that 47 per cent of industrial heat is from natural gas, 26 per cent from oil, 19 per cent from electricity, and the remainder from other fuels.[6]

The available data suggest that at present less than one percent of UK heat demand is met using renewable energy sources. The RES suggests that to meet the UK's overall renewable energy targets, 12 percent of heat demand could be met using renewables in 2020. This represents a dramatic increase, and the strategy acknowledges the challenge that these targets represent.

1.2. Project Background and Report Structure

This report has been prepared for the Committee on Climate change to accompany a new marginal CO_2 abatement cost model for renewable heat technologies. The model has been developed by NERA Economic Consulting, with original technical inputs provided by AEA Energy and Environment. As part of the current project Entec UK has reviewed the original technical input assumptions.

This report is divided into two parts. The first part includes chapters providing background information about various renewable heat technologies. These chapters have been developed

[4] HM Government (2009) The UK Renewable Energy Strategy

[5] BERR (2008a) Heat Call for Evidence.

[6] BERR (2008a) Heat Call for Evidence, BERR, 2008, page 13

under NERA's direction, by Entec, with Element Energy providing a more detailed review of air source heat pumps.

We present information about a range of renewable heat technologies, including (in alphabetical order):

- Air-source heat pumps;
- Biogas combustion and injection;
- Biomass boilers and CHP;
- Biomass district heating;
- Electric heating (from renewable electricity);
- Ground-source heat pumps; and
- Solar thermal.

For each technology, the chapter provides:

- A brief overview of the technology,
- A discussion of the factors affecting performance and suitability, including applicability to different types of end-user segments;
- Information on current costs;
- Current UK penetration of technology;
- Brief discussion of what has limited uptake and how this may change in the future;
- Selected lessons from international experience (particularly in countries where it is a mass market technology);
- Factors affecting the impact of the technology on carbon emissions.

The second part of this report provides details about the renewable heat abatement cost model, including assumptions about constraints on supply and on uptake. It then presents the resulting abatement cost curves associated with the renewable heat technologies considered.

2. Air-Source Heat Pumps

This chapter provides an in-depth assessment of heat pumps, with a focus on air-source heat pumps. It provides an assessment of the technical potential and expected cost of the technology in 2022 as well as the factors affecting performance and the circumstances most likely to be suited to use of this technology.

2.1. Technology Overview

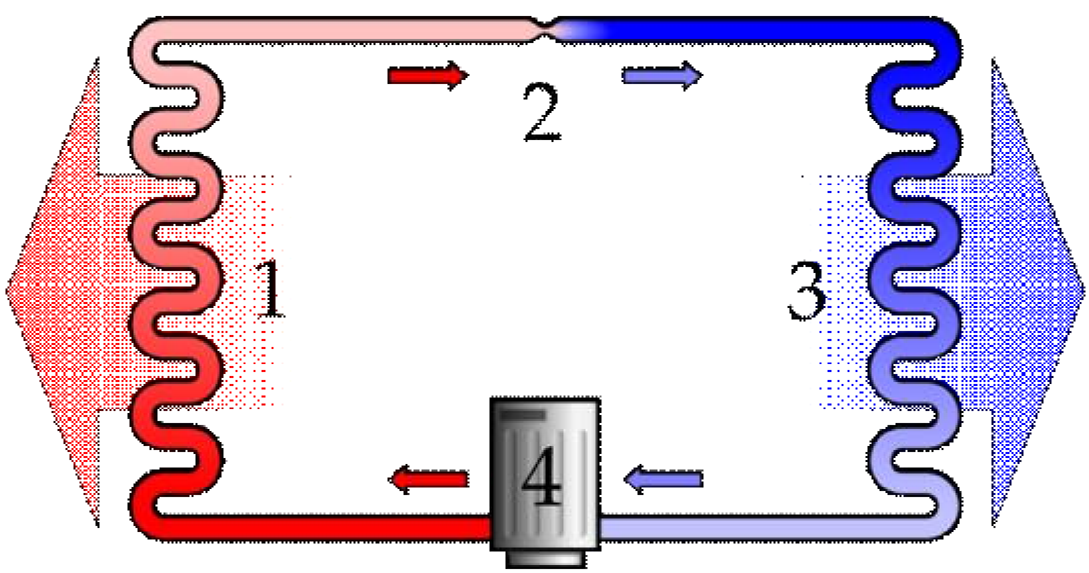
2.1.1. Overview of heat pump technology

Heat pump is a very broad term applying to a machine which transfers heat from one place to another by evaporating and condensing a working fluid. There are a number of applications for heat pumps, the most common of which is in a domestic refrigerant where a heat pump transfers heat from the inside of the fridge to the outside. Another common application is in chillers used to provide cool air to office buildings.

In recent years, heat pump technology has developed to provide heating for buildings. In this case, heat is extracted from outside the building either from the air (an Air Source Heat Pump, or "ASHP") or from coils buried in the ground (a Ground Source Heat Pump or "GSHP"). This document focuses on the use of ASHPs for heating buildings in the UK. GSHPs are covered in the next chapter.

All heat pumps work on the same basic vapour compression refrigeration cycle, as illustrated in Figure 2.1.

Figure 2.1
The vapour compression refrigeration cycle:
1) condenser, 2) expansion, 3) evaporator, 4) compressor



A refrigerant is compressed (4) to a high pressure and temperature vapour. It is then passed through a condenser (1), which is in effect a heat exchanger that releases some of the heat to the environment (as on the back of a fridge). The cooler high pressure fluid now passes through an expansion valve (2), which lowers the pressure and causes the refrigerant to become colder. This is now passed through the evaporator (3), where the cold refrigerant draws heat from a heat exchanger (as inside a fridge) and warms up. The refrigerant now passes through the compressor to be heated up again before dumping its heat in the condenser (1) again and the cycle continues.

ASHPs work on the exact same cycle, but instead of drawing heat from the inside of a refrigerator and dumping it into the air at the back of the fridge, they draw heat from the colder outside environment and dump it indoors, thereby heating up the building. In effect this is the reverse of what an air conditioning unit does – in fact many air conditioning units are capable of running in reverse, in order to offer both heating and cooling. All ASHPs work on this basic principal, though there are many variations in technical specifications. It is also possible to purchase ASHP systems which are able to operate in reverse, providing air conditioning in the summer months – these systems are considerably more expensive however.

The most important performance metric of all heat pumps is the Coefficient of Performance, or "COP". The COP is a measure of the heat energy provided by the heat pump, divided by the electrical work that has to be put in – it is similar to efficiency, but COPs are usually greater than 1. These high COPs reflect the fact that heat pumps simply transfer heat from one place to another and hence the bulk of the heat delivered to the building is renewably sourced from the outside, with a small electrical energy input to drive the compressor. The implication is that 1 unit of electricity can deliver in the region of 3-5 units of heat.

COPs for heat pumps in the UK vary considerably depending on a number of factors including outside air temperature, heat loss from the building, hot water usage etc, so the figure of interest for ASHPs is the 'seasonal COP', which is the average COP of the heat pump over a year.

The main technological variation between ASHPs is the distinction between air-to-air heat pumps and air-to-water heat pumps:

§ Air-to-air heat pumps – in these devices, air is blown through the condenser heat exchanger (1), to draw heat from the refrigeration fluid. This hot air is then delivered to the area to be heated through air vents. These systems are more likely to be found in UK commercial buildings. Air based heating systems are relatively uncommon in UK homes (though they are popular in Sweden and the US).

§ Air-to-water heat pumps – in these devices a counter-flow heat exchanger is used in the condenser (1), in which water flows in the opposite direction to the refrigeration fluid, drawing heat from it. The hot water is then circulated through a 'wet' heating system, i.e. under-floor ground loops, radiators, etc. For the majority of UK homes, water based heating systems are used and hence air to water heat pumps will be most common.

2.1.2. Description of salient technical issues

The COP of an ideal heat pump can be expressed as:

$$COP - \frac{T_{hot}}{T_{hot} - T_{cold}} - \frac{T_{hot}}{\Delta T}$$

This implies that in order to maximise the COP, the temperature difference between hot and cold, ΔT, must be minimised. Since the outside air temperature (in the case of ASHPs) cannot be varied artificially, the maximum COP is therefore achieved at minimum T_{hot}, or minimum output ('flow') temperature. This requires heat pump system design to aim to achieve as low an emitter (radiator, under-floor loop) temperature as possible, in order to make them perform optimally. There are a variety of reasons why achieving a suitably low T_{hot} may not be possible (either technologically or economically) and this limits the suitability of heat pumps in many locations, as discussed in detail in Section 2.4.

If heat pumps were able to overcome the compatibility issue and be deployed in large numbers, this would have a significant impact on peak grid load and would require extra peak grid capacity, as discussed in Section 2.7.3.

Other issues to be considered are the proximity of the external ASHP heat exchangers to each other and to other objects, e.g. in blocks of flats. There is a minimum distance required between external heat exchanger unit groups and between the building and the heat exchanger. These vary by manufacturer and an example is included in Figure 2.2.

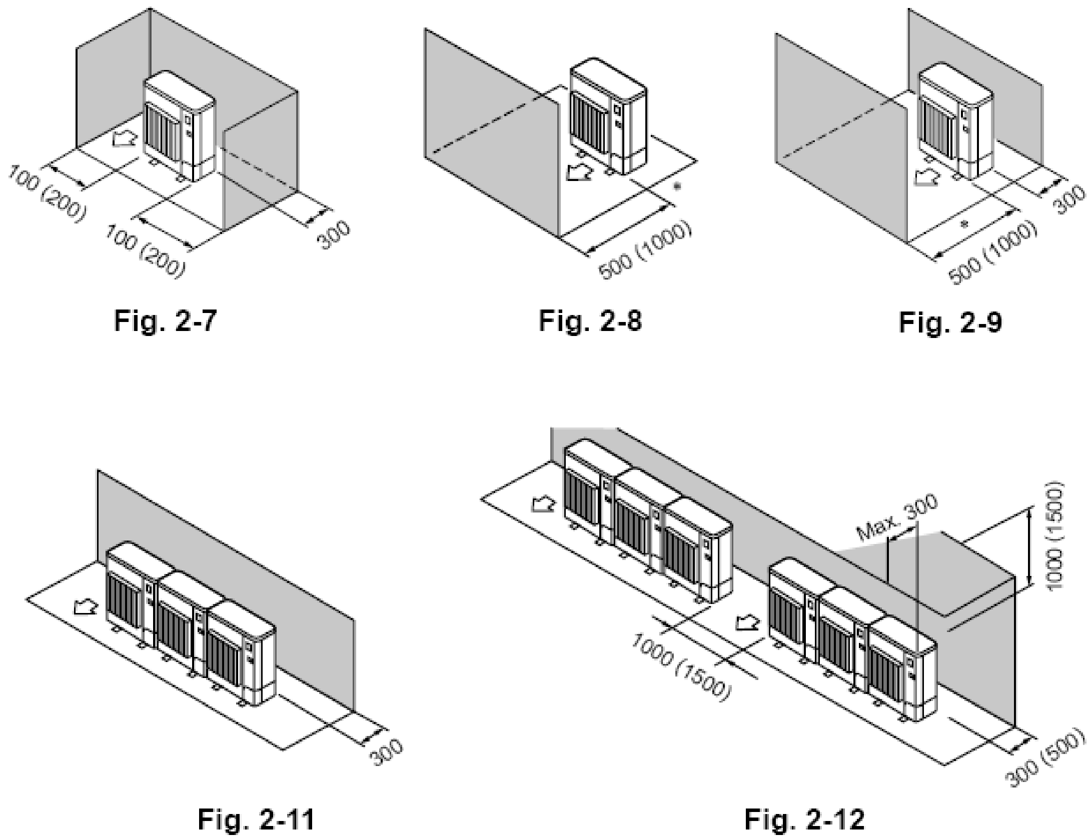
The main salient issues for domestic heat pumps can be summarised below:

§ Limited compatibility with older existing housing stock, where a higher flow temperature is required than can be provided economically (or physically) by the heat pumps.

§ Impact of large numbers of heat pumps on the grid, with widespread uptake requiring significant upgrade of existing peak grid capacity.

§ Physical compatibility issues, e.g. space to house the external ASHP equipment.

Figure 2.2
Minimum installation distances for ASHP external units[7]



7 Mitsubishi Ecodan installation manual

2.2. Applicability to Different Types of End-User

2.2.1. Commercial

The use of ASHPs in commercial buildings is already a mature option, which is considered against a range of alternatives when designing buildings. Developers of modern constructions generally consider the use of reversible chillers which can provide both heating and cooling in offices or hotels – in this way they can use the air conditioning system in reverse when heating is required, without the need for an expensive stand-alone heating system. These systems make up a mature market and can already compete with other existing technologies, but the focus of this document is on less mature technologies aimed at domestic users.

2.2.2. Industrial

The potential for industrial use of air source heat pumps is limited because of the difficulty in generating the high temperature heat required to drive industrial processes. Also the need to extract heat from the air places a limit on the amount of heat which can actually be extracted (there is a limit to the amount of heat in a given volume of air and hence large area of coils are required to extract the high heat demands associated with industrial needs).

The main use of heat pumps in industry is in the use of waste heat streams. Heat pumps could be used with lower temperature waste heat streams from industrial processes to upgrade that heat for heating of buildings etc.

2.2.3. Domestic

The domestic UK market for ASHP technology is relatively new and current economics have not allowed it to fully develop, although markets in a number of other European countries have seen significant uptake over the last decade. These ASHPs are stand-alone units, which are sized to provide the entire heat demand of a home. Recent technological developments have made them competitive in terms of running costs, but a lack of awareness and a high capital cost, with little or no funding available have lead to very low levels of uptake so far in the UK. Additionally, a large part of the existing UK housing stock is incompatible with current commercially available technology. This is set to change with the introduction of the renewable heat incentive[8] (RHI) and recent technological developments in Continental Europe.

2.2.4. Current UK penetration of technology

As mentioned above, current UK penetration of ASHPs for commercial buildings is widespread, driven primarily by the commercial air conditioning market, whose penetration in offices, hotels and retail outlets exceeds 25 percent (50 percent in Central London).[9] They

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8 Enabling powers for a Renewable Heat Incentive (RHI) were passed in the Energy Act (2008), with initial consultation due in the course of 2009 . The scheme is planned to be in place in April 2011, and will provide support for heat production for a wide range of renewable heat sources.

9 Heat pumps in the UK: Current Status and Activities, ETSU, 2000

are widely used in offices and hotels, being used in reverse in summer as air conditioning units.

At the other end of the scale, domestic air-to-water heat pumps are a relatively new technology in the UK. A recent report for BERR estimated that by the end of 2007 under 500 air source heat pumps had been installed in the UK[10]. However, with the recent introduction of new more efficient models into the UK market, installation numbers have been on the increase.

One of the leading manufacturers in the UK sold roughly 130 units per month in 2008, whilst Mitsubishi (another leading manufacturer) has a 2009 sales target of 4000 units. Both manufacturers expect to ramp up production and sales significantly over the next few years – for example Mitsubishi is moving production to Scotland in a dedicated plant and has a very large worldwide production capacity that could be converted if required. Most large manufacturers require installers to attend a training course to become qualified installers in order to ensure that their products are used in appropriate environments. Courses are readily available in the UK.

There are a number of other manufacturers in the market, both Continental European and British, each offering models suitable to different heat demands, flow temperatures and space requirements.

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[10] Number of microgeneration units installed in England, Wales, Scotland and Northern Ireland Wales – BERR (2008)

2.3. Lessons from International Experience

2.3.1. Sweden

The market for domestic heat pumps in Sweden has shown strong growth for more than a decade, due to escalating oil prices in conjunction with an increase in energy related taxes. The technology is now fully recognised both by consumers and decision makers and has become the number one choice for retrofitting as well as for new construction of single family homes.

The rapid market growth for heat pumps is the most important reason behind the fact that Sweden has reduced the use of heating oil for domestic heating by more than 50 percent over the last 15 years. Today (2008) nearly 650,000 heat pumps supply Swedish homes with 15 TWh of heat per year[11]. This accounts for a 15 percent share of Swedish households[12], and the Swedish single family home heat pump market is now self-sustaining and has reached maturity.

The size of the heat pump market as well as the split of types of heat pump is shown in Figure 2.3 below. The number of boiler replacements on the Swedish heating market has been considerably above normal over the last few years, with very high oil prices and increased environmental concern contributing to this surge in demand. Heat pump installations peaked at 120,000 units in 2006 and the market for replacement heating systems has now saturated, leading to a reduction in sales in 2007 and in 2008.

There remains a strong presence of GSHPs in the domestic heat pump market. There also is a significant share of air-to-air heat pumps, while sales of air-to-water heat pumps have increased recently as his technology has advanced. Exhaust air/heat recovery heat pumps also hold a strong position in new-build single family home sector. The competition among the actors in the heat pump sector is fierce, which has led to considerable price reduction. Commercial and multi-family building heating is however still dominated by district heating, but heat pump growth in this sector is strong.

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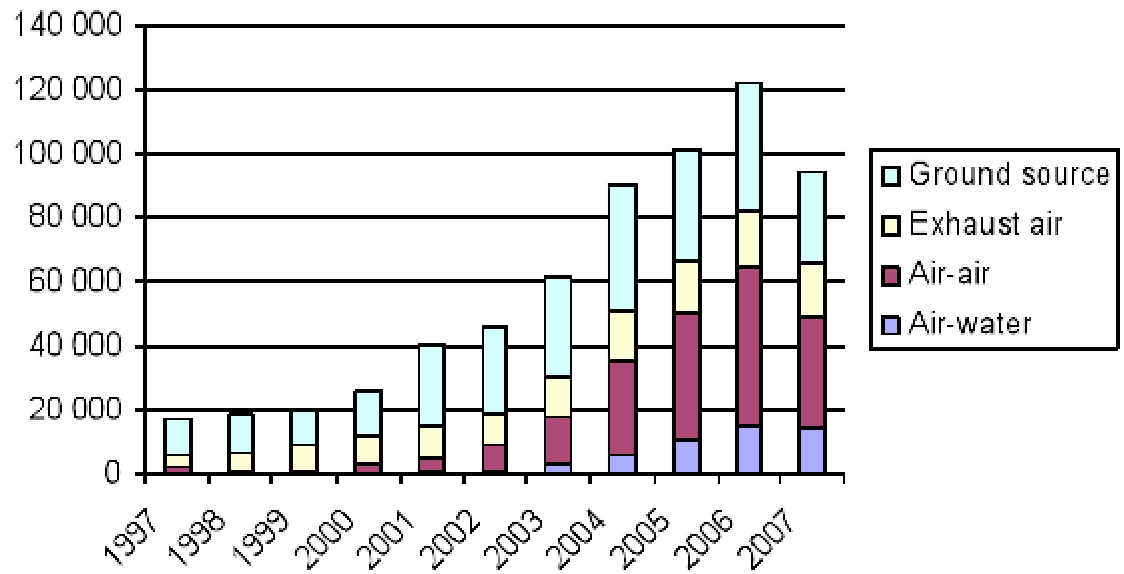
11 European Heat Pump Statistics Outlook 2008, European Heat Pump Association, 2008

12 Statistics Sweden, http://www.scb.se/Pages/TableAndChart____146284.aspx

Figure 2.3
Historic heat pump sales in Sweden



Source: European Heat Pump Statistics Outlook 2008, European Heat Pump Association, 2008

The heat pumps used in Sweden differ in some respects from ones that would be suitable for UK homes. Air-to-air heat pumps have been popular in Sweden in part because they offer a cost-effective route to replacing direct-fired electric heating, which has been more prevalent in Sweden. The situation for GSHPs also differs, with bore-hole GSHPs more popular than slinky coil systems for both climatic and geological reasons.

2.3.1.1. Subsidies

The first substantial growth in domestic heat pump sales in Sweden was spearheaded by a Government procurement competition which required a substantial performance improvement over existing heat pump technology. The motivation behind this competition was a desire to reduce the strain on the grid from the widespread use of electric heating in Sweden.

Subsidies were later introduced to encourage further uptake and these are now available as a tax reduction on the replacement of direct electric heating. Grants of 30 percent (up to a maximum of €3,300) of the labour costs for installation of district heating, ground source heat pumps, biomass boilers or solar thermal collectors are also available. In order to fulfil the requirements an application for a heat pump installation must be accompanied by a calculation verifying that the use of electricity for heating will not exceed 35% of the electricity used prior to the installation, i.e. a minimum seasonal COP of 2.85 must be achieved.

However, the main driver behind the large-scale take-up may be policies that significantly increase the cost of heating using traditional technologies. This includes a CO_2 tax of around £80 / tCO_2, as well as energy taxes (these jointly add a 100 percent tax on the price of household heating oil). This, along with rising fossil fuel prices other factors, has made heat pumps significantly more attractive financially. For example, in recent years the annual cost of heating for a representative detached Swedish house using oil-fired or direct-fired electric heating has been close to £3,000 per year (combined capital and variable costs), whereas the cost using GSHPs has less than £2,000 per year.[13]

2.3.2. Switzerland

The Swiss heat pump market has grown significantly since the beginning of the 1990s. The fact that the Federal Energy Office identified heat from heat pumps as renewable at an early stage paved the way for heat pumps to take part in the national energy program 'Energie 2000' that was launched in 1993. The succeeding program 'Energie Suisse' set an ambitious target aiming at a total stock of 100,000 heat pumps in operation by 2010, or a 3% share of Swiss households[14].

This target has already been surpassed: in 2007 heat pumps reached a market share of 73 percent in the new-build housing sector, with ASHPs making up 55 percent of the heat pump market, to 45 percent from GSHPs. Although heat pump sales are concentrated in the new-build sector, the retrofit market has been growing for several years – in 2006 the retrofit market accounted for 20 percent of all heat pumps sold, or 3,000 units per year. The heating market has now reached the stage where more heat pumps than oil or gas boilers are sold.

The Swiss Federal Government has played a vital role in the development of the national heat pump market, by focusing on three main tasks:

§ Assembling all the major market players, to concentrate marketing and lobbying activities in a common association, the FWS.

§ Quality assurance.

§ Reducing economic barriers by financial incentives for consumers.

A combination of fossil fuel price increases and the successful intervention of the Swiss government have ensured the progressive development of the Swiss heat pump market, as shown in Figure 2.4.

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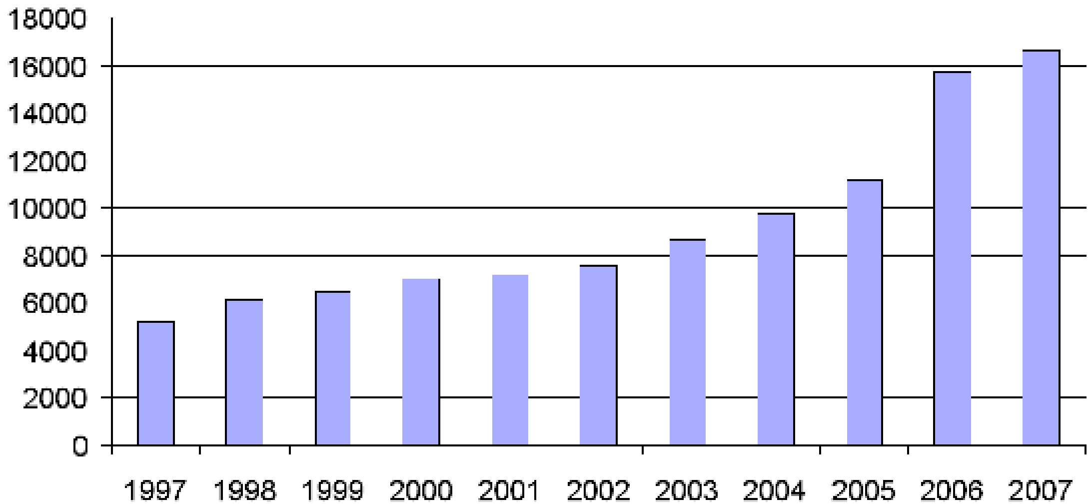
13 Energimarknadsinspektionen, 'Uppvärmning i Sverige 2007, (Swedish Energy Market Inspectorate report EMIR 2007:03).

14 Swiss Federal Statistical Office, http://www.bfs.admin.ch/bfs/portal/en/index/themen/01/04/blank/key/haushaltstypen.html

Figure 2.4
Historic heat pump sales in Switzerland[15]



2.3.2.1. Subsidies

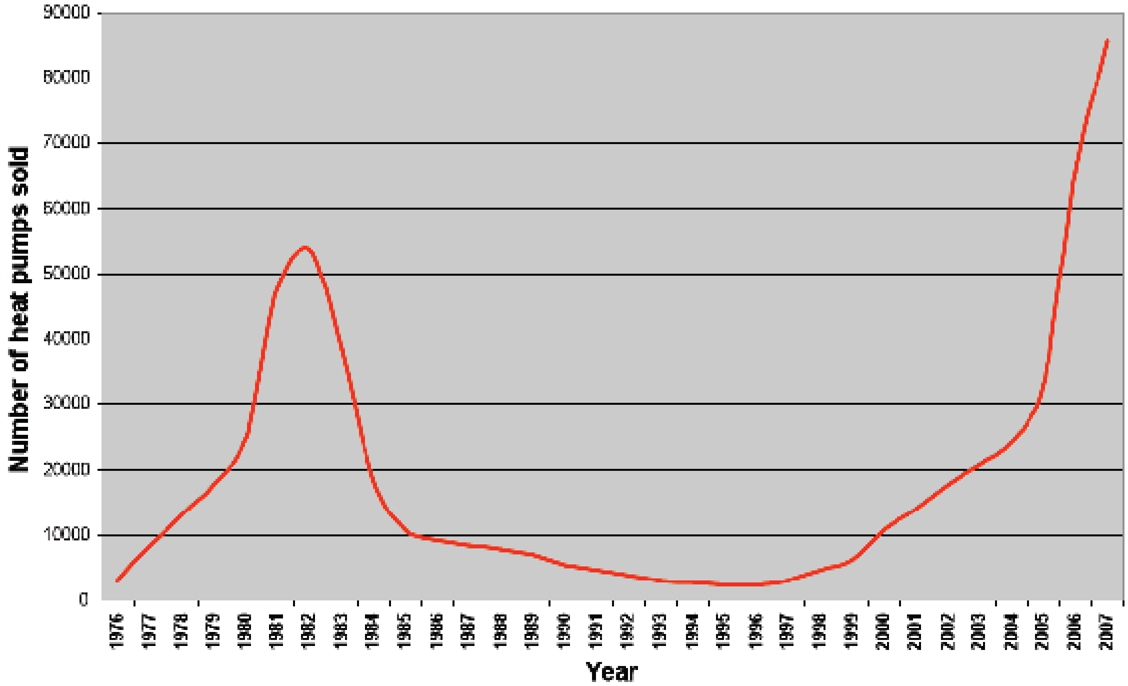
Switzerland offers a tax rebate for investments supporting the use of renewable energy during renovations and this includes heat pumps. Various other subsidies from the state as well as from utilities also exist.

2.3.3. France

As with many other European countries, the first development of the heat pump market occurred in France between 1975 and 1985, in the aftermath of the oil crisis. However, this initial market development was unsuccessful, due to a lack of skilled installers and the quality of the machines which led to poor performance and many breakdowns. This resulted in a lack of confidence in heat pumps, which, in combination with the oil counter-shock and the reduction in Government incentives, led to an almost complete disappearance of the market for over 10 years, as shown in Figure 2.5.

15 European Heat Pump Statistics Outlook 2008, European Heat Pump Association, 2008

Figure 2.5
Historic heat pump sales in France[16]



In 1997, the heat pump market was again kick started by Electricité de France (EDF), in association with the French environment and energy management agency (ADEME) and the French mining and geological research board (BRGM), with a focus on a controlled development of the market based on quality, in order to avoid reproducing the mistakes of the past. The initial market emphasis was on new-build single-family homes with well understood thermal needs and the opportunity to install low temperature under-floor heating. This approach allows for maximal heat pump performance.

2.3.3.1. Subsidies

In 2005, an income tax rebate was introduced, which subsidises 50% of the capital cost of the equipment. This subsidy, in combination with increasing fossil fuel prices, has resulted in very strong market growth since 2005, bringing the heat pump sales to nearly 90,000 units in 2007 and bringing the total number of heat pump installations to 280,000 since 1997, or just under 1 percent of the total number of French households.[17]

Moreover it has influenced the structure of the heat pump market: Prior to the implementation of the income tax rebate, about 98 percent of heat pumps were installed in new-build dwellings. In 2007, about 13 percent (around 11,000 heat pumps) were installed in existing dwellings. Air-to-water technology benefits the most from the income tax rebate as it is the

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[16] European Heat Pump Statistics Outlook 2008, European Heat Pump Association, 2008

[17] Institut National D'Etudes Demographiques, http://www.ined.fr/en/pop_figures/france/couples_households_families/households_number_people/

easiest to install when replacing an old boiler. In 2007, about 60 percent of the air-to-water sales were installed in existing dwellings.

2.3.4. Summary of international experience

It is clear that if modern, technologically mature heat pumps are offered with the right level of financial support, there is significant potential for rapidly increasing heat pump sales. A heat pump market accounting for a considerable proportion of new-build and retrofit heating sales can be achieved in less than ten years.

Different types of heat pump are successful in different markets, depending on local circumstances. Clearly the incumbent technology has an effect on the economics of the heat pump replacing it and this will significantly alter the level of uptake seen. For example, in Sweden, where there are significant taxes on electric and oil-fired heating, heat pump uptake has been very rapid and has led to a market share of 15 percent of all households in only 10 years. Growth in Switzerland and France has been much slower, as seen in Table 2.1.

It is worth noting also that several of the countries presented here produce significant amounts of their electricity from nuclear power and hydro-electricity. The fact that so much of the electrical output in these countries is from low-carbon sources means that the emissions implications of the adoption of heat pumps may be different in these countries from the implications in the UK (although it is the marginal emissions intensity, rather than the average, that is relevant when assessing CO_2 emissions impacts).

Table 2.1
Summary of Selected International Experience with Heat Pumps

Country	Cumulative installations	Nature of support	Notes
Sweden	650k	Procurement competition followed by tax breaks	Mostly air-to-air and ground source heat pumps. Air-to-water heat pumps more recently. 15% of all households in 10 years.
Switzerland	100k	Controlled market development followed by tax rebate	3% of all households in 10 years
France	280k	Controlled market development followed by tax rebate	1% of all households in 10 years.

2.4. Factors Affecting Performance and Suitability

2.4.1. Level of technological maturity

The technology behind most types of ASHP is mature, with larger ASHPs having been around for many years in providing heating for larger buildings.

However, domestic air-to-water heat pumps are fairly new to market, especially in the UK. The newest inverter-led designs which allow the compressor speed to be adjusted to match the outside air temperature and the heat demand of the house, have allowed COPs up to a maximum of between 4-5 in ‘ideal’ properties using low-temperature under-floor central heating. The maximum ‘flow’ temperature (temperature of the water coming out of the heat pump) is currently in the region of 55°C. However, recent technological developments have now overcome this barrier in Continental Europe and UK products will soon be capable of reaching flow temperatures as high as 70°C – tests have shown that this is achievable at significantly lower but acceptable, seasonal COPs in the region of 2.5-3.[18]

Another area of innovation is in refrigerant technology. The most popular domestic refrigerant is currently R134a, but there has been a recent trend towards using CO_2 as a refrigerant, as this has a much lower global warming potential than the former and has advantageous refrigerant properties. Although technically feasible, this is currently uneconomical on a domestic scale and research is ongoing into bringing the costs down. Any advance in this field would help to produce high-COP ASHPs capable of operating over a wide range of flow temperatures.

With these innovations in mind, it is likely that domestic air-to-water heat pumps have the potential of improving significantly over the coming years, with seasonal COPs and compatibility improving accordingly. Unfortunately however, there is no reliable method of estimating the improvements in COP that may be achieved through the development of new technologies, since many of these technologies are closely guarded by manufacturers and because the only reliable COP estimates come from real-life, measured, seasonal COPs. With increasing market penetration expected in the UK, it is also likely that we will see significant cost reductions, as illustrated in Table 2.2. These costs compare with an average condensing boiler installation cost of around £2,500 in the UK – thus ASHPs are currently around three times as expensive as gas condensing boilers, and by 2020, they are still expected to be nearly twice as expensive. Running costs will depend heavily on retail electricity prices and on the seasonal COPs achievable – see section 2.5 for further details.

[18] High Temperature Heat Pumps in France, EDF R&D, 2008

Table 2.2
Cost projections for ASHPs to 2020[19]

Year	Marginal cost £ / kWth	Fixed cost £ / installation	Maintenance Cost £ / yr
2007 and before	£200	£6,500	£44
2008	£193	£6,280	£44
2009	£187	£6,073	£44
2010	£181	£5,877	£44
2011	£175	£5,694	£44
2012	£170	£5,524	£44
2013	£165	£5,365	£44
2014	£161	£5,216	£44
2015	£156	£5,080	£44
2016	£152	£4,953	£44
2017	£149	£4,836	£44
2018	£145	£4,728	£44
2019	£142	£4,629	£44
2020	£140	£4,538	£44

2.4.2. What has limited uptake and how may this change in the future?

In the UK, domestic ASHPs have only recently developed as a mature technology capable of providing energy savings at a reasonable price. Early trials at the start of the decade have only recently led to widely available products for UK homes. As a result, uptake of domestic ASHPs has been limited by a lack of availability in the UK market and technological development. In addition, in the UK there has been a limited financial incentive to consider heat pumps, in contrast to the situation in France (tax breaks) or Sweden (subsidies and higher energy costs). Finally, there is a limited knowledge about the technology in the UK, which derives from a lack of installed products and a lack of awareness in both the public and the private sector.

However, recent technological developments and a commitment from ASHP manufacturers to mass-market rollout throughout the UK and Continental Europe is currently making ASHPs perform better by bringing COPs up and is also driving prices down. Various public bodies have recently recognised the potential of heat pumps and are now helping raise awareness of their potential[20]. Furthermore the upcoming Renewable Heat Incentive and the

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19 The financial incentive components of major energy retrofit strategy for English homes: a Study, Element Energy and NERA Economic Consulting, 2009. NB: these costs do not include the cost of converting properties to be compatible with low flow temperatures and therefore current UK ASHP designs. The costs of heat pump systems presented here are very similar to the costs used in the MACC model, although they are not identical.

20 For example the Energy Saving Trust - http://www.energysavingtrust.org.uk/Generate-your-own-energy/Air-source-heat-pumps

classification of heat output from heat pumps as renewable[21] should provide a significant incentive for further uptake of heat pump technology in the next decade.

2.4.3. Technical constraints on heat pump potential

Many domestic air-to-water heat pumps have a maximum flow temperature of around 55°C (with an auxiliary electrical heater to achieve higher temperatures for e.g. legionella disinfection in hot water tanks), in order to minimise the temperature difference between inside and outside and hence maximise the COP (as discussed in Section 2.1.2). This means that heat emitters (under-floor loops, radiators, etc) cannot be run at very high temperatures.

This is not a problem in new-build, well insulated homes, where low temperature under-floor loops or low temperature radiators can be installed. In most existing UK buildings however, high temperature radiators are the main type of emitter in use and currently run at considerably higher temperatures, up to a maximum of around 90°C.

The reason for this is that older homes are less well insulated and hence experience significant heat loss through the walls and roof. In order to maintain a constant inside temperature, a large amount of heat must be delivered by the heating system. Radiators have a limited area through which to emit this heat and as a result tend to be run at high temperatures.

Through discussions with domestic ASHP manufacturers, it was found that most post-2000 homes should have sufficient insulation to enable ASHPs to run at lower flow temperatures and to make them run at economical seasonal COPs of roughly 3 and above. However, pre-2000 homes may require significant modifications (see section 2.4.4) in order to attain these COPs – these homes account for the vast majority of the existing UK housing stock (and an even greater proportion of heat demand). One manufacturer went as far as to say that homes with solid walls should not be considered for ASHPs, since the heat losses could not be brought down enough (without very expensive measures such as solid wall insulation) to achieve compatibility with the low flow temperatures of current UK ASHP designs, in order to offer economical COPs.

However, with the recent introduction of condensing boilers in the UK market, the trend has been for decreasing temperatures, since condensing boilers work at lower temperatures – this means that the most recent heating systems would be more compatible with ASHPs than older systems. Additionally, there have recently been developments in heat pump technology (most notably in Continental Europe), which allows them to operate at significantly higher flow temperatures, of up to around 70°C, at the expense of a reduction in COP (see below). This would allow a significantly larger proportion of the existing UK housing stock to achieve compatibility without any modifications.

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21 Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable sources, Commission of the European Communities, 2008

2.4.4. Getting around constraints

There are two solutions to the problem of incompatibility in older, less energy efficient homes:

- To install larger radiators throughout the home – this increases the available surface area for heat exchange and enables the heating system to be run at lower temperatures (it must be noted however that many existing heating systems were installed with significantly over-sized radiators, so replacing radiators may not always be necessary). Installing large-surface-area, low-temperature heating systems, such as under-floor loops are another solution (but very unlikely due to the excessive cost of removing and relaying all the flooring), or alternatively new technologies such as thermal skirting boards (which may provide a cheaper alternative).
- To reduce the heat loss from the home – by installing extra insulation (be it cavity wall, loft, or solid wall insulation) and hence reduce the heat demand required by the radiators and the temperature at which they need to be run.

In many homes both these solutions may be required and in the oldest, least well insulated homes, it may never be possible to operate radiators at low enough temperatures for ASHP (or GSHP) compatibility.

Additionally, COPs at higher flow temperatures are much lower than for optimal systems (such as under-floor loops) which run nearer 35°C. For example at a flow temperature of 55°C COPs for many UK products approach 2.5 (or 3 for GSHPs). This has the effect of reducing the competitiveness (and CO_2 benefits) of heat pumps versus other technologies in older retrofit properties, especially when taking into account hot water usage, etc, which may further reduce the seasonal COP achieved.

A balance must be achieved between the additional cost of insulating a home/installing larger radiators and the competitiveness of heat pumps at the minimum possible emitter temperature achieved post-modification. Clearly a significant number of properties will remain unsuitable, either technically or economically, for heat pumps. However, a large number of homes could be made compatible with relatively cheap (above the cost of installation in Table 2.2) modifications such as cavity wall and loft insulation (measures which are intended to be carried out on all cavity walled homes by 2015), especially those homes with over-sized radiators.

2.4.5. Available evidence on heat pump performance

Heat pump trials are essential to determine the suitability of ASHPs in different portions of the existing housing stock. A Scottish Government study was recently undertaken[22], which included a variety of dwellings types using ASHPs and concluded that they performed satisfactorily, were very well received by consumers, saved money on fuel bills (on average), could contribute to reducing fuel poverty (not taking into account installation costs) and even contributed to certain unexpected benefits, such as improved energy efficiency behaviour.

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[22] The Scottish Renewables Heating Pilot, Scottish Government, 2008

Unfortunately, the technical data collected were too unreliable to achieve any meaningful technical results and has not been released.

A study in France by EDF[23] on modern, high flow temperature (up to 65-70°C) ASHPs concluded that they could successfully be installed and run in even the oldest of solid wall dwellings and achieve reasonable seasonal COPs of between 2.5 and 3. This is a very important conclusion as it suggests that there is no need to modify existing dwellings in order to achieve ASHP compatibility.

Mitsubishi are currently undertaking their own study in a variety of homes, using their 'Ecodan' ASHP technology and this will aim to measure real-life seasonal COPs. The Energy Saving Trust is also currently undertaking an ASHP study. Neither study has yet reported, but preliminary results are expected in late 2009.

2.4.6. Issues that remain to be resolved

Between the various heat pump trials underway, it is essential to gather enough data to resolve the correlation between annual heat demand (or heat loss), emitter sizes and temperatures and seasonal COPs, in order to determine a generic suitability algorithm, which could be used in the future to determine the suitability of ASHPs in any home.

On the technological development side, there is a need to ensure that high COPs are achievable at high flow temperatures, in order to maximise compatibility with the existing housing stock. Research into more efficient refrigerants such as CO_2 could also contribute to this aim, as well as making mass market use of heat pumps more environmentally friendly.

Another factor which will affect the economics of ASHPs is the price of electricity relative to gas and heating oil. If the relative price of electricity falls, the COP required to make heat pumps economically viable will fall and ASHPs will become an attractive option to a wider variety of homes. However, running ASHPs at lower COPs would reduce the CO_2 abatement benefits of this technology, since the CO_2 output from ASHPs is equal to grid intensity divided by COP – this negative effect might however be countered by an increase in ASHP suitability and therefore uptake.

2.5. Financial Viability

When compared against conventional technologies, it is important to understand the requirement for as high a COP as possible. The fuel used by ASHPs is electricity, which is (currently) roughly four times as expensive as gas and twice as expensive as oil.

This means that for every unit of heat required, only a quarter as much electricity should be used to maintain the same running costs as for a conventional gas boiler, or half as much for a conventional oil boiler.

Factoring in the capital cost of the technology is less straightforward, since different properties require differently sized heat pumps – for example an 8kW ASHP in 2020 would cost roughly £3,000 up-front more than a conventional boiler under our cost assumptions (in

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[23] High Temperature Heat Pumps in France, EDF R&D, 2008

a modern property not requiring any modifications), or about £310 annually assuming a 3.5% discount rate.

For a new-build house with a heat demand of roughly 8000kWh/year, this increase in ongoing costs would contribute to an additional running cost of roughly 4p/kWh (£310 divided by 8000 kWh), thus making an ASHP 4 times as expensive as gas and 2.7 times as expensive as oil in this particular home. The result is a requirement for any ASHP to be installed in that home to have a seasonal COP of at least 2.7, if the home is off-gas, or 4 if it is on-gas, for the technology to be economical. If the comparison is with electric heaters, the only requirement would be that the COP be greater than 1.3. NB: if a higher discount rate of 10% was used, this would increase the COPs required to 4.4 for on-gas homes and 2.9 for off-gas homes.

This illustrates the significant restrictions on the performance required from ASHPs to be economically viable without any support in the mass on-gas markets – many ASHP manufacturers quote COPs as high as 5, but these are in optimal low-temperature heating systems and actual seasonal COPs may be significantly lower. The lower rates achieved in practice would limit the cost-effectiveness of ASHPs in many properties.

The most important variable in determining the economic suitability of ASHPs when competing against legacy technologies such as gas or oil boilers, is the electricity/fossil fuel price ratio. Clearly if this changes in the future (e.g. if there is another oil shock, or if the cost of de-carbonising the grid added significantly to the price of electricity), this will affect the COP required to make ASHPs cost effective – the more expensive fossil fuels become, the lower the COP required and the more expensive electricity becomes, the higher the COP required. If ASHPs can be designed to run on reduced electricity tariffs (such as Economy 7) for as much time as possible, this will help to reduce the COP required for economic competitiveness.

The upcoming RHI and the classification of heat output from heat pumps as renewable should lead to a larger number of properties becoming economically viable for ASHPs at the currently available COPs. This should provide a significant incentive for further uptake of heat pump technology in the next decade.

All these factors will affect the number of homes which are economically compatible with ASHPs and will also help to determine which homes are worthwhile modifying to ensure physical compatibility. There is a large potential for ASHPs in the UK, but it is the economics which will decide how much uptake actually occurs.

Table 2.3
Fuel and electricity prices and ratios (EST, 2008)[24]

	Mains gas	On-peak electricity	Economy 7 electricity	Heating oil	LPG
Price (kWh)	4.03p	13.95p	8.27p	6.09p	5.93p

[24] Current Energy Prices and Carbon Dioxide Emissions, EST, November 2008

Electricity/fuel price ratio	3.46	n/a	n/a	2.29	2.35

If fuel prices were to vary enough in favour of ASHPs and/or if technological developments improve seasonal COPs and mass market uptake brings costs down, it would not be unreasonable to assume that ASHPs might eventually become economically viable without any form of support.

2.6. Potential Taking Into Account Constraints and Suitability

ASHPs have the potential to provide much of the UK's domestic heating requirements, under the right conditions. This section aims to predict the maximum and realistic potentials for installations of ASHPs by 2022, under various technological development and housing stock energy efficiency scenarios. The realistic potential scenarios assume:

- Sufficiently generous financial support under an RHI (or other supportive policy) to encourage the predicted level of uptake.
- Development of grid capacity to a sufficient extent to support the extra peak load required by large increases in the number of ASHPs.

2.6.1. Potential in new-build homes

All new-build homes can have ASHP compatibility built-in so as to achieve high seasonal COPs, i.e. with low temperature heating loops and very well insulated. Indeed, the majority of new build homes are already constructed based on low temperature heating systems suitable for condensing boilers. With the absolute number of new build homes in the UK being 213,700 in financial year 2005/6[25], this equates to roughly 2 million potential ASHP installations by 2022. Given current economic conditions, however, it is very difficult to arrive at reliable projections about the level of future house-building in the UK.

The UK has a similar number of properties as France, which was able to achieve significant industry growth to 100,000 units per year (from a low base of around 25,000) within two years of offering a subsidy (albeit with a history of other policies to encourage their uptake). Given the limited industry base in the UK today it may be realistic to assume that the UK could achieve sales of 75,000 units per year by 2012.[26]. If uptake could be ramped up to 100,000 units per year[27] in the new-build sector once the renewable heat incentive is

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25 Table 209 Housebuilding: permanent dwellings completed by tenure and country. CLG., www.communities.gov.uk/pub/313/Table209_id1511313.xls

26 France started from an industry base of 30,000 annual sales in 2005 (when the subsidy was introduced) and achieved nearly 90,000 by 2007 – this equates to a growth rate of roughly 70% per year. Assuming this growth rate can be achieved in the UK and assuming roughly 15,000 sold in 2009 (from manufacturer estimates), this would result in roughly 75,000 units sold per year by 2012. A 70% growth rate would be unsustainable in the long term and a more realistic growth rate thereafter would be 50% annually.

27 We can assume that ASHPs would be a realistic option in smaller developments where site-wide heating schemes would not be available. By assuming that all developments with fewer than 50 homes install ASHPs, this equates to 48% of total new build (The Role of Onsite Energy Generation in Delivering Zero Carbon Homes, Element Energy, 2007) or nearly 100,000 homes per year.

introduced this would result in a total potential from new build alone of roughly 1 million units by 2022.

2.6.2. Potential in retrofit with no modifications to housing stock

At current costs and performance parameters and without any modifications, ASHPs are compatible with only a small percentage of existing homes (post-2000 homes) – this may account for roughly two million homes in the UK. The recent RAB energy efficiency study[28] modelled uptake of ASHPs in the existing domestic stock under a RHI and this predicted a cumulative uptake of one million units in the ***English*** owner occupied retrofit stock, equivalent to a total realistic ***UK*** potential in the equivalent population (without modifications) of roughly 1.2 million units by 2022.

2.6.3. Potential assuming all cavity walled stock achieves compatibility

Assuming all cavities are insulated by 2015, and assuming that various other relatively minor modifications (e.g. larger radiators, loft insulation, etc) are all that is necessary to ensure compatibility with ASHPs, this would increase the market size to all cavity walled houses – or 18 million homes in the UK[29]. This is likely to be the maximum number of existing homes which could be retrofitted with ASHPs at their current level of technological development, in view of the significant costs of insulating solid wall homes sufficiently to ensure compatibility with ASHPs.

By assuming that industry is capable of producing 75,000 units per year by 2012 (as discussed above) and assuming a maximum industry growth rate of 50 percent per year thereafter, up to a maximum of one million units per year (this is equivalent to the number of boilers sold to cavity walled houses annually[30]), this would lead to a total realistic potential for ASHP installations of roughly 6.5 million by 2022 (although this could have significant implications on grid capacity, as discussed in Section 2.7.3). Note however that this is an extreme case.

2.6.4. Potential assuming technological development

However, if ASHP technology develops sufficiently to allow them to run at very high flow temperatures whilst maintaining economical COPs, it is not inconceivable that the entire existing UK housing stock of 26 million homes could potentially be retrofitted with ASHPs.

Assuming the same industry growth rates as discussed above, up to a maximum of 1.56 million units per year (the current annual boiler replacement rate), this would lead to a realistic potential of some 8.4 million units by 2022 (although this would have significant implications on grid capacity, as discussed in Section 2.7.3). Note that this also is an extreme case.

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[28] The financial incentive components of major energy retrofit strategy for English homes: a Study, Element Energy and NERA Economic Consulting, 2009

[29] English House Condition Survey, 2005

[30] Assuming annual boilers sales of 1.56 million in 2006 (Purple Market Research, 2007) and an even distribution of sales between cavity and non-cavity housing.

2.7. Implications for Carbon Emissions

2.7.1. Discussion of impact of grid CO_2 intensity on CO_2 attributes of ASHP

Using standard CO_2 intensity assumptions for the UK (0.43 kg CO_2/kWh for marginal CCGT electricity, 0.185 kg CO_2/kWh for gas and 0.245 kg CO_2/kWh for heating oil)[31] and assuming a seasonal COP of 3, the following CO_2 savings (heating only) could be achieved by domestic air-to-water heat pumps, relative to the incumbent technologies:

- Off-gas homes: 47.3% (competing against condensing oil boilers @ 90% efficiency). For example in a relatively modern home (well insulated, smaller, relatively low heat demand) consuming 8,000 kWh/year, an oil boiler would emit 2.18 tCO_2 per year, whilst an ASHP would emit 1.15 tCO_2 per year, leading to a CO_2 saving of 1.03 tCO_2 per year.
- On-gas homes: 30.3% (competing against condensing gas boilers @ 90% efficiency). For example even in a less well insulated home with a heat demand closer to the national average at 14,000 kWh/year, a gas boiler would emit 2.88 tCO_2 per year, compared to emissions from an ASHP of 2.00 tCO_2 per year. This implies a CO_2 saving of 0.88 tCO_2 per year, which is less than the house described above, despite the much larger heat demand.

This illustrates the greater potential effectiveness of ASHPs at abating CO_2 in off-gas homes. However, over 35 percent of off-gas homes are old, solid wall homes[32] which are unsuitable for ASHPs.

Over time, if the CO_2 intensity of the UK electrical grid decreases, the CO_2 savings available from ASHP use in any given house would be expected to increase.

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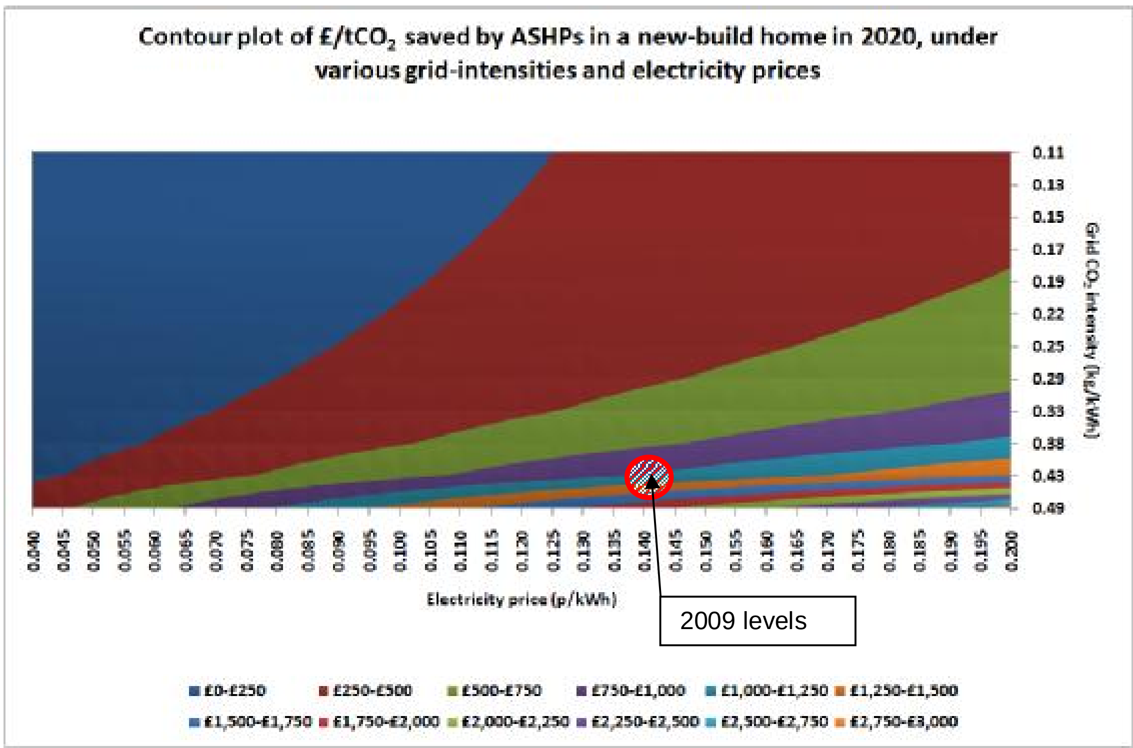
[31] Guidelines to Defra's GHG Conversion Factors, DEFRA, 2008. NB: 0.43kg/kWh is an estimate of future CO_2 intensity of marginal generation from CCGT.

[32] English House Condition Survey, 2005

2.7.2. Cost of carbon savings from ASHPs in residential properties

Figure 2.6 illustrates the cost of CO_2 savings using domestic air-to-water ASHPs in a modern, gas-connected home, which is very high compared to many other technologies (and compared to the shadow price of carbon).[33] The contour diagram illustrates the relationship between the grid CO_2 intensity and the electricity price, to give an indication of the price and grid intensity levels that would be required to make residential ASHPs a cost-effective means of reducing CO_2 emissions. Each contour band indicates where CO_2 abatement costs are within the cost range indicated in the legend at the bottom. The figure illustrates the reduction in abatement costs as grid CO_2 intensity decreases. Using current marginal CO_2 intensity assumptions (0.43 $kgCO_2$/kWh) and based on the assumptions set out in the footnote, the price of electricity would need to fall below 4.5 p/kWh to bring the abatement cost below £250/tCO_2.

Figure 2.6
Contour plot of abatement cost against grid CO_2 intensity and electricity price, modern home in 2020[34]



Note: The circled area indicates the region on the contour plot relevant to the current CO_2 intensity of marginal electrical capacity on the grid and current electricity prices.

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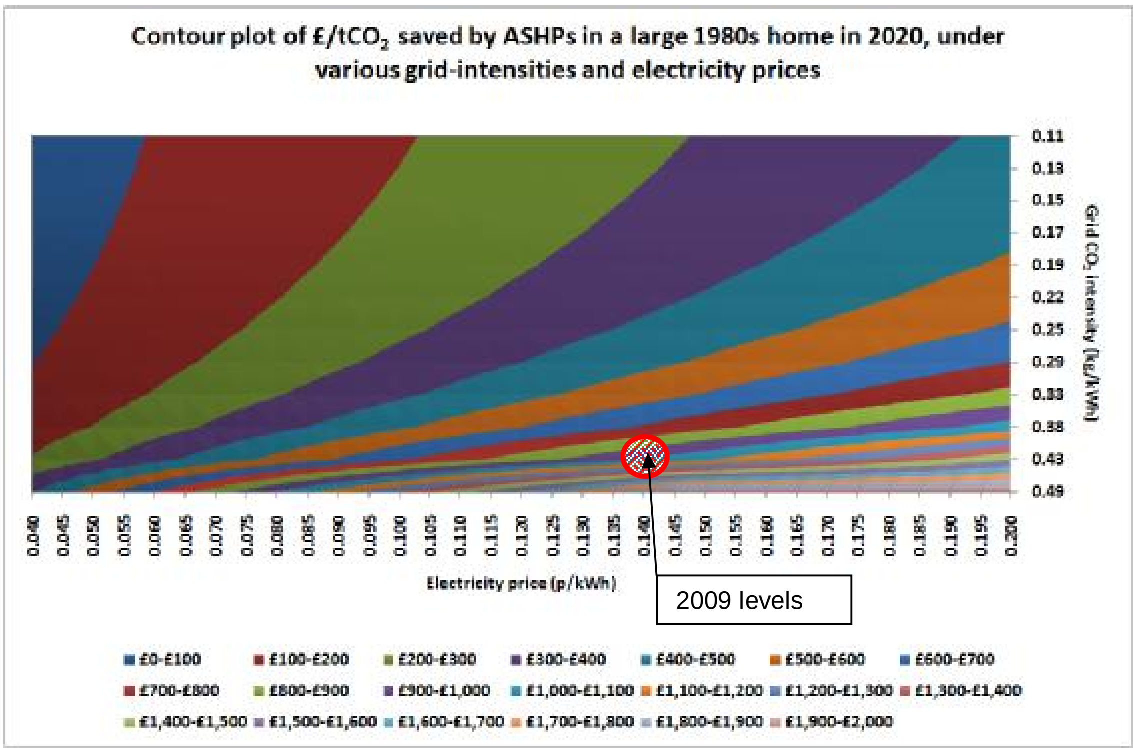
[33] www.defra.gov.uk/environment/climatechange/research/carboncost/step1.htm

[34] Assumes a mains gas CO_2 intensity of 0.185kg/kWh, a gas price of 4p/kWh, a capital cost of £6,000 for an 8kW ASHP and a maintenance cost of £88/year, a condensing gas boiler price of £2,500 and a maintenance cost of £88/year, a 3.5% discount rate, a COP of 3 and an annual heat and DHW demand of 8,000 kWh.

The costs in Figure 2.6 are for a modern, well insulated home, with a total heat demand of only 8,000 kWh/year.[35] Figure 2.7 illustrates the same costs for a 1980s home with 14,000 kWh/year total heat demand.[36] The carbon saving costs are significantly lower for the less efficient property, and this illustrates a difficulty with respect to domestic ASHPs: the larger the heat demand the more cost-effective the heat pump would be in saving CO_2 (because it offers more opportunity to take advantage of the relatively low running cost of heat pump systems) but the less compatible the heat pump will be with the characteristics of the property.

Figure 2.7
Contour plot of abatement cost against grid intensity and electricity price, large 1980s home in 2020[37]



Note: The circled area indicates the region on the contour plot relevant to the current CO_2 intensity of marginal electrical capacity on the grid and current electricity prices.

Despite illustrating the benefits of a larger heating demand on the cost-effectiveness of heat pumps, the costs illustrated in Figure 2.7 remain very high, in comparison to the shadow price of carbon of £26/tCO_2. This is largely due to the electricity to gas price ratio which is above 3

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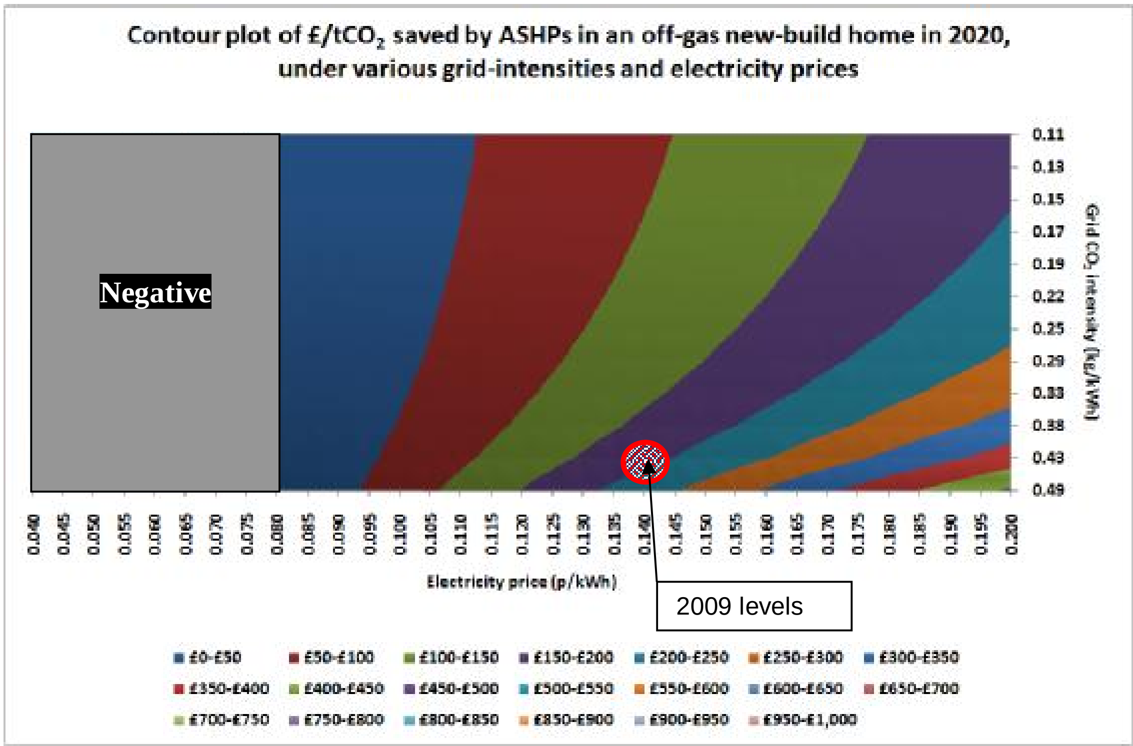
[35] This is a good estimate of heat demand (heating and hot water) for a part L 2006, 3-bed semi.

[36] Assuming a 1980s un-filled cavity-walled 3-bed semi-detached property.

[37] Additionally assumes a 14,000kWh/year heating and DHW demand.

and the lower CO_2 emissions of gas boilers compared to other conventional heating technologies. Figure 2.8 illustrates the cost of CO_2 savings in the same modern home in 2020, but for a home which is off-gas and whose incumbent technology is condensing oil boilers. The electricity to oil price ratio is only slightly above 2 and the CO_2 emissions from heating oil are approximately 30 percent higher than those from mains gas – this would be enough to bring the costs down to near £100/tCO_2 saved at today's grid intensity and electricity prices.

Figure 2.8
Contour plot of £/tCO_2 saved under various grid intensity and electricity price scenarios, for a new-build *off-gas* home in 2020[38]



Note: The circled area indicates the region on the contour plot relevant to the current CO_2 intensity of marginal electrical capacity on the grid and current electricity prices.

Figure 2.9 illustrates the cost of CO_2 savings when measured against an off-gas home that was previously heated by direct electric heating. In this extreme case, it is clear that ASHPs offer a distinct advantage over the incumbent technology at almost any grid intensity and electricity price.

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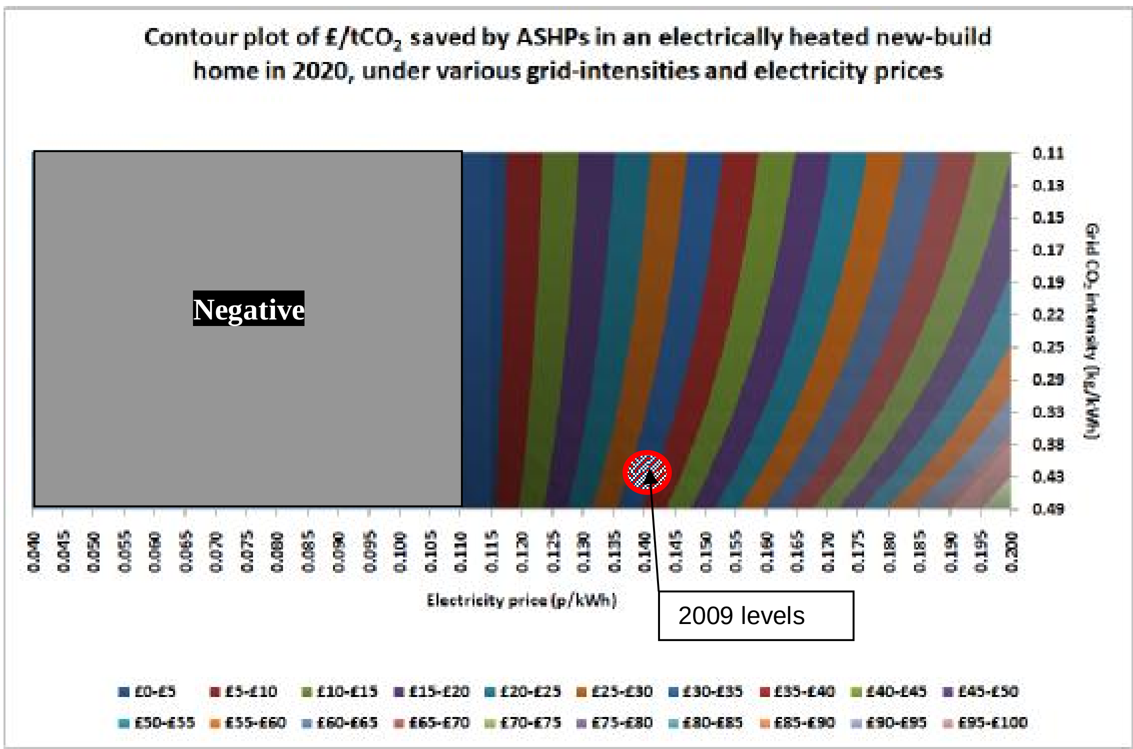
38 Assumes a heating oil CO_2 intensity of 0.25kg/kWh, an oil price of 6p/kWh, a capital cost of £6,000 for an 8kW ASHP and a maintenance cost of £88/year, a condensing oil boiler price of £2,500 and a maintenance cost of £88/year, a 3.5% discount rate, a COP of 3 and an annual heat and DHW demand of 8,000 kWh.

These graphs help to illustrate the differing competitiveness of ASHPs in various locations. The most cost-effective carbon savings from ASHPs would come from off-gas homes (which tend to be larger, older homes with higher heat demands and whose incumbent technology is oil fuelled, costing significantly more to run than gas fuelled heating), assuming they were compatible with these properties, whilst on-gas homes offer a far less attractive proposition (due to the lower cost of running gas-fuelled heating systems and the fact that many on-gas homes are more modern urban and suburban dwellings). Clearly if the characteristics of these homes were changed (e.g. if the older homes were well insulated, reducing their heating demands, or if the relative price of heating oil to gas varied), the economics of ASHPs in these properties would vary.

Figure 2.9
Contour plot of £/tCO_2 saved under various grid intensity and electricity price scenarios, for a new-build *off-gas, electrically heated* home in 2020[39]



Note: The circled area indicates the region on the contour plot relevant to the current CO_2 intensity of marginal electrical capacity on the grid and current electricity prices.

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39 Assumes an electric CO_2 intensity of 0.43kg/kWh, an electricity price of 14p/kWh, a capital cost of £6,000 for an 8kW ASHP and a maintenance cost of £88/year, an electric heater price of £2,000 and a maintenance cost of £88/year, a 3.5% discount rate and an annual heat demand of 5,000 kWh.

2.7.3. Discussion of the impact of mass deployment of heat pumps on the grid

Assuming a 50% market share for domestic ASHPs in new build only, from 2010, a total of 1 million units would be installed by 2020. Domestic ASHPs come in 5kW, 8kW and 14kW models, for flats, houses and large houses respectively, even assuming a modest 8kW peak thermal demand (and hence roughly 3kW electric) this deployment of 1 million units would result in an extra ***peak*** load on the grid of 3GW (the average would be considerably lower – however the peak would occur at normal peak electric demand times, i.e. mornings and evenings). This is equivalent to 4 percent of total UK grid capacity and illustrates the very substantial effect that even a relatively small quantity of ASHPs could have on the grid. If 50 percent of existing homes (26 million in 2005) were made compatible and fitted with ASHPs, this would require a huge additional peak load of 40 GW, corresponding to 50 percent to existing grid capacity.[40]

Although the load on the grid would benefit from a reduction in the number of electric heating systems, the primary market for heat pumps would be larger, more heat-demanding properties compared to the smaller, fairly energy-efficient homes which are currently electrically heated – as such the reduction in grid load from a smaller number of electric heating installations would be more than offset by any increase in heat pump use.

In the new-build only scenario, if the extra capacity were provided by CCGT, this would substantially increase grid CO_2 emissions; assuming annual heat + hot water demand in new build homes of roughly 8,000kWh and a seasonal COP of 3, this would result in an extra 1.1 $MtCO_2$ emissions per year, minus a saving of 1.5 $MtCO_2$ from a reduction in the number of gas boilers used, which would result in an overall CO_2 saving to the nation of 0.4 $MtCO_2$.

If the extra grid capacity were provided entirely by renewables, this would reduce total grid intensity to 0.41 kg/kWh and would save 1.5$MtCO_2$ from domestic heating. However, the requirement for additional grid capacity would make it more difficult to decarbonise the existing grid, unless significant quantities of nuclear were to be rolled out.

Any policy encouraging uptake of ASHPs will need to be supported by large-scale grid improvements. Even with an enlarged grid, safeguards will need to be taken to avoid grid instability caused by large spikes in demand at peak heating times.

2.8. Summary

Air-to-air heat pumps have reached commercial and economic maturity in the UK in the commercial sector.

Domestic ASHPs currently have very little market penetration, but have considerable potential in the UK. The technology in the past has suffered from poor performance (low COPs and unreliability), as well as a lack of awareness of the benefits of ASHPs and a lack of financial support to overcome the high capital cost barrier.

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40 Even taking into account the subset of homes currently using electricity for heating, some of which would be replaced under this scenario by heat pumps, the net increase in load would still be substantial, although it would not be as much as 40 GW.

Over recent years however, ASHP technology has been developed to maturity and ASHPs now offer competitive COPs and costs and good reliability. This has led to very rapid market growth in several major European markets over the last decade, aided by various state subsidies.

The technology has now been tailored to the UK market and offers a very attractive option to new-build properties. However, there remain several barriers to installation in existing homes, most notably the upper limit on flow temperature that is a feature of most UK models. Existing off-gas homes offer the most economically attractive locations for installing ASHPs, especially if they are currently heated electrically. However, these off-gas homes tend to be the oldest homes, which are least able to achieve low flow temperatures (and therefore economical COPs and compatibility with ASHPs), hence the overall potential in this section of the market may be limited. Economic competitiveness in existing on-gas homes is currently limited, due to the superior performance of modern gas boilers compared to oil boilers or electric heating.

There have been further recent technological developments on the continent which appear to have resolved the issue of low maximum flow temperatures, by allowing these to be significantly higher (up to 70°C), with only limited reductions in seasonal COP. If these technologies were to be marketed successfully in the UK, the number of existing homes that are compatible with ASHPs would be hugely increased. The introduction of the RHI could also drive improvements in the COP over time.

Additionally, a RHI is due to be introduced in 2011 and this could be designed to allow the economic barriers to be overcome in most (compatible) homes, leading to a technical potential equivalent to almost the entire UK cavity-walled housing stock (the solid-walled stock may still be unable to operate at flow temperatures below 70°C and may require further technological developments or expensive insulation measures such as solid wall insulation). However, UK industry starts from a low base. An ambitious scenario would be one where sales double for the first 2-3 years after the introduction of the RHI, and then grow at a rate of 50 percent per year. Sustained sales growth at this level would significantly exceed that achieved in other European countries, including ones where ASHPs have become a mass market technology, and would result in sales of some 400,000 units per year (corresponding to more than a quarter of total UK domestic boiler sales) and 1.6 million units installed by 2022. With sales growth of 30 percent, more in line with recent rates of growth observed in other EU countries, the potential would be much more modest, with sales of around 100,000 per year and 500,000 units installed by 2022. Given the barriers to installation, this may be a more realistic scenario.

The CO_2 savings from large quantities of ASHPs could contribute to the UK's CO_2 saving targets, albeit at (very) high abatement cost. Rapid grid decarbonisation would both increase the potential and help reduce the cost. However, installing large numbers of ASHPs in the UK would lead to significant increases in peak electricity demand and would require expansion of the grid and this in turn would make grid decarbonisation more difficult to achieve.

3. Ground Source Heat Pumps

3.1. Background

Ground Source Heat Pumps (GSHPs) use low level heat energy created by solar gain in the near surface layers of the earth to extract energy which can be used for space and water heating. In principle a GSHP uses a system much like how a refrigerator works to extract low temperature heat from one location (the 'source') and deliver higher temperature heat to another location (the 'sink') using electrical energy to drive the pumps. This operational principle can be used to produce heating as well as cooling energy. Heat pumps which use the ground, ground water and surface water as a heat source are called ground source or geothermal heat pumps.

The heat pump uses refrigerant gases and a compressor to absorb heat from the ground which in turn delivers heat to the target building. The compressor is usually driven by an electric motor. A heat exchanger, called an evaporator, is used to interface between the fluid from the buried pipes and the heat pump. GSHP systems use the gained energy to heat another fluid, through a heat exchanger, called a condenser that can be used to distribute the heat (at ~40-65ºC) in a building and return it to the heat pump at about 35ºC.

The effectiveness of heat pumps is measured by coefficient of performance (COP) which is the ratio of heat output to electrical power input. For an effectively operating heat pump, the COP should be always greater than one and is typically in the order of three/four meaning that for every unit of electricity used the equivalent of three/four units of energy are returned – hence GSHP being quoted with efficiencies in the order of 300%. Note, however, that seasonally adjusted COPs of this level may not be achievable, as discussed in the chapter on air source heat pumps.

The COP is very much dependent on the temperature of a heat source and the output temperature of the heat pump. The higher the heat source temperature and the lower the output temperature of a heat pump the better efficiency will be achieved. This means that the COP of a heat pump in winter can be different from the COP of the same heat pump in summer. "Seasonally adjusted" COPs account for these differences. It should be noted that the COP for heating is different from the COP for cooling. Modern ground source heat pumps can achieve COP of 4.5 for heating and COP of 6 for cooling.

3.2. Applications

GSHP can be used in domestic and commercial sectors for a number of applications including space and water heating, space cooling, heat recovery and humidification.

GSHPs are commonly used for space heating utilising water as a distribution medium. GSHP can use radiators to deliver heat into the space; however, they are particularly suitable and most efficient for low-temperature distribution systems such as under-floor heating. The system can be designed to deliver temperatures of 45°C to 55°C for a system with radiators and 30°C to 40°C for an under-floor heating system. A significant point to note is that the temperature of the fluid in the heat delivery system of a conventional central heating system leaves the boiler at about 80ºC and returns at about 60ºC. The lower output temperature from the GSHP system means that heat delivery systems designed for conventional central heating systems are not suitable for use with GSHP systems. GSHP systems are most efficient when all components of the system – heat collection, heat pump and heat delivery – are designed to be compatible. Similar considerations apply to GSHPs as apply to ASHPs with regard to compatibility with existing UK housing stock.

GSHPs can also be used for water heating, via a heat exchanger to hot water appliances. It is required to supply hot water with temperatures in a range of 55 - 60°C to prevent contamination of hot water system by legionella bacteria. Heating water to this temperature lowers the efficiency of GSHP systems, however.

Finally, it also is becoming more common to use GSHPs for space cooling. Space cooling can be provided in the same manner as space heating and usually GSHP are designed in such a way that they can provide cooling as well as heating which will maximise their performance. GSHP can efficiently supply cooling of 6 -7 °C however, for applications requiring greater temperature differentials the efficiency of the system will be lower.

3.3. System Design

GSHP are more efficient than air source heat pumps due to relative stability of ground temperatures all year round. However, efficiency of a GSHP system is very much dependent on a number of factors including system design and controls, heating/cooling loads, the temperature of the heat source and the output temperature and energy consumption of auxiliary equipment (e.g. fans, pumps). Thus, it is required to look not only at the stated COP of a GSHP but also at the overall operating performance of the system over a year.

GSHPs require ground loops or ground piles to be dug. Typically this requires access to external space, such as a garden for digging and installing the system. However, a new concept of 'thermo-piles' has been successfully used on the continent, whereby the ground heat exchange coils are installed inside the foundation piles at the time of construction. This technology is only available in new-build properties, but has been used in a limited number of locations in the UK, including the main offices of the Greater London Authority. There is the potential to design them into more construction sites.

Most GSHP systems have two loops: the primary loop in the appliance cabinet which exchanges heat with a secondary loop that is buried underground. The underground (secondary) loop can be classified as either open or closed, with closed loop systems typically sub-divided further into horizontal and vertical systems.

3.3.1. Open loop GSHPs

Open loop GSHPs either use ground borehole water or surface water of lakes / rivers as a heat source. The open loop system design may require an abstraction licence even if the water is returned to the source. The abstraction and recharge (return) of water should be separated by as great a distance as feasible within the site constraints to minimise the impacts of mixing (in the case of lake or river water extraction) or breakthrough between abstraction and recharge boreholds (in the case of a borehole water extraction). The implications of mixing warmer and cooler bodies can encompass environmental concerns but would also reduce the temperature differential over time and thereby reduce the efficiency of the system.

Open loop GSHP systems are cheaper and simpler to install and can operate successfully at the domestic level. However, since closed loop systems became more widely available these are typically specified as water pollution and increased maintenance of open loop systems can present some problems. In suitable areas open systems are still considered on a case-by-case basis, given the increasing focus on water both as a finite resource and as a resource impacted by climate change it is our view that most new GSHP systems are likely to be closed loop.

3.3.2. Closed loop GSHP

Closed loop GSHP systems are currently the most commonly used systems. In such systems, the secondary loop is installed either horizontally or vertically in the ground or surface water. When the ground is used as a heat source, the secondary loop can be installed either vertically using boreholes or horizontally using buried pipework (usually within 1.5-2 metres below the ground). If surface water is used as a heat source, the pipework should be installed horizontally as deep in the water as possible to minimise seasonal water temperatures variations. Typical systems work on a water to air or water to water basis. Choice of installation of a vertical or a horizontal loop depends on ground conditions, available land surface, local construction constraints and cost limitations.

The heat exchange can be achieved via either indirect or direct circulation system. An indirect circulation system uses water/antifreeze mixture fluid pumped around the loop to transfer energy to the heat pump refrigerant through a heat exchanger. A direct circulation system circulates refrigerant in a loop made of highly conductive material to directly to extract energy from the heat source.[41]

3.4. Resource and Regulatory Barriers

3.4.1. Resource issues

GSHPs utilise energy stored in the earth's crust. The temperature difference between the ground and circulating fluid in a closed loop system or the temperature of circulating water in an open loop system affect heat transfer thus it is vital to determine the temperature of the ground or the circulating water.

It is also important to understand ground characteristics such as type of ground and ground temperature as they affect heat transfer, determine choice of the system and influence installation costs of a GSHP. The characteristics of the ground influence configuration the secondary loop. For example, if the ground is rocky and soil cover depth is less than 1.5 metre it may not be possible to install a horizontal secondary loop[42].

Ground characteristics will determine configuration and design of GSHP systems and can create a number of problems such as:

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[41] [Some comments on suitability of ground and bedrocks will be added]

[42] Design and Installation of Closed Loop Systems – Good Practice Guide 339, Housing Energy Efficiency

- Precipitation of minerals, which results in scaling of heat exchangers and clogging of wells;
- Corrosion of piping and heat exchangers;
- Bio-fouling of the well intake area;
- Clogging of aquifer as a result of precipitation of minerals within the aquifer or transport of precipitation into the aquifer.

The problems can be avoided if considered at early stages of the system design.

It is also important to know ground water levels when considering design of a GSHP system. Understanding of ground water levels is required to establish required depth of boreholes. The deeper the borehole is the more pumping energy will be required, which can have considerable effect on overall efficiency of the system but will also influence the capital costs of the system.

It is important to consider not only resource availability but also resource quantity. To identify quantity of available water resource, it might be required to drill a test borehole to identify extraction flow rate. A permit should be obtained from the Environmental Agency before any borehole drilling.

3.4.2. Regulatory Issues

The Environment Agency (EA) controls water abstraction and discharges of pollutants and heat/energy to the environment. There are no specific requirements regarding the control of heat detailed in legislation or statutory guidance. The EA has the option to control discharges with a permit, where appropriate to avoid pollution or failure to achieve Water Framework Directive (WFD) objectives.

The EA strongly recommends designers of GSHP and especially open loop systems to contact them at an early stage to discuss options for the proposed design, its intended location and operation. This will help minimise delays in permit determination and/or potential system redesign.

The need to gain the required permissions, as described below, can be time consuming and add an element of delivery risk to designs thereby potentially resulting in a risk of non-delivery. In turn this perception could constrain the demand for systems and act as a constraint on the installed capacity.

3.4.2.1. Pollution prevention

Drilling through contaminated soil or ground poses a significant risk of pollution to groundwater and the EA will require evidence that these risks have been assessed and appropriate method statements are in place. Nevertheless shallow alluvial peats and silts are associated naturally high levels of ammonium and some gas. For both an open or closed loop system it will be necessary to prepare detailed borehole designs and drilling method statements to demonstrate that cross contamination of aquifer will not occur either during drilling or during the operation of the system. An EA permit is not required to construct or operate a closed loop system. Regardless of this the use of certain circulating fluids should be avoided where they comprise hazardous substances (List 1 under the Groundwater Regulations) and which will incur a Pollution Prevention Notice and a charge. This applies to all of the systems and configurations and is contingent on the substance being used as a circulating fluid.

3.4.2.2. Control of thermal changes

The EU Habitats Directive requires the EA to have specific regard to potential adverse effects on protected species and/or ecosystems when consenting a discharge of heat to controlled waters. The Groundwater Directive also states that energy/heat can cause pollution and that pollution should be prevented (although its application in UK law is not clear). This may limit the upper limit of any single cycle open loop cooling system that is discharged to surface water to around 30ºC and also limits the upper temperature of a closed loop system as this will affect shallow soil temperatures to a greater degree.

The EA recommends that the maximum area of influence on water quality and temperature arising from the proposed system operation is established. This should be reviewed to see if it adversely affects an existing GSHP system or other legitimate use of groundwater and if necessary the mode of operation and/or design altered. The driver for this is largely civil law.

3.4.2.3. Abstraction licences and discharge consents

For installation of an open loop system, the EA requires an investigation and consenting under the Water Resources Act as amended by the Water Act 2003. This process is currently taking about 12 months so needs to be run concurrently with the system design, drilling tender and investigation phases of any open loop system construction project.

This process is started by submission of an application for a Section 32-3 Groundwater Investigation Consent which is required before drilling can start. This application requires completion of a survey to identify other water abstractors and water features dependant upon groundwater which may be derogated by the proposed abstraction. The application will also require an outline of the proposed drilling programme, any pumping tests to be carried out, the discharge arrangements for those pumping tests and the proposed monitoring of groundwater levels. The EA may request changes to this programme and normally respond within 4 weeks.

A pumping test will always be required, normally between 7 days and 14 days duration and where returns are to be made to the aquifer, a recharge test of a similar duration. In certain cases the EA will permit these tests to be carried out without formal consents but will require evidence that the abstracted water does not contain any suspended solids from the drilling process or that the groundwater pumped will not cause pollution (e.g. from saline groundwaters). Accordingly some preliminary sampling of boreholes and a short programme of clearance pumping to land and, if necessary, the use of settlement tanks; is recommended. The EA have the powers to require formal applications for both temporary abstraction licences and discharge consents as prerequisites to carrying out these tests and have the powers to prevent these investigations. These applications take between 28 days (abstraction) and four months (discharge) and as the decision to require these is subject to local conditions this should be established at an early stage and an early application made to avoid project delays.

Following completion of the pumping and recharge tests and collation of monitoring data, the EA will require application for a full abstraction licence and in most cases a discharge consent for the return to the aquifer (if that has not already been obtained for the recharge test). The full abstraction licence application will require analysis of the monitoring data for the pumping test to demonstrate that adjacent water features and abstractors are not derogated in any way. There will be additional requirements in this case to demonstrate that saline intrusion is not caused and there is no derogation of other GSHP systems. In certain cases if the final system can be shown not to cause any deterioration of groundwater quality and no significant change in ground or groundwater temperature (i.e. a combined heating and cooling system), a discharge consent may not be required.

3.4.2.4. Infrastructure issues

As with any other form of ground investigations, particular care should be taken in avoiding damage to underground services and their potential safety hazards. It is required to obtain plans of all underground services including water mains, electricity cables, gas pipes, telecommunications as well as high pressure gas, National Grid and fuel/oil pipelines in the area of potential installation of a GSHP.

Where structures are to be constructed adjacent to river channels or other drains a Land Drainage Consent will be required.

The details of all boreholes should be notified to the British Geological Survey (Section 198).

3.4.2.5. Other issues and barriers

Apart from the aforementioned potential technical and regulatory issues, there are a number of other issues and barriers which slow down development of GSHP systems. Some of these issues and barriers are identified below as follows:

- Lack of trained installers and maintenance personnel
- Consumer confidence – can be easily eroded through media coverage of bad examples
- High up-front capital costs and poor payback periods (particularly if the system is designed incorrectly)
- Lack of understanding of these systems
- Disruptions due to digging boreholes or trenches is a barrier to retrofitting these systems
- Affordable heating requirements in legislation (the high cost of systems means they may be less attractive for affordable housing)
- Lack of borehole drillers[43]
- Lack of GSHP design engineers

Construction practice is centred on traditional trades providing electrical and plumbing skills, however, as GSHP systems are not yet so popular a specialist is required to deal with all of

[43] Barriers to Renewable Heat, Executive Summary

the problems of trades interfacing and planning activities in the construction phase. Historically there have been issues in getting suppliers to install complete systems (the heat collection, pump and delivery) although this has started to change and there are now complete systems available in the market. When linked with the potential lack of skills in the design of heat delivery from GSHP systems this can lead to less efficient systems which will impact on the overall installed capacity in the UK. As with solar thermal the potential lack of trained installers could act as a constraint on growth particularly if high growth rates are to be sustained to 2022.

Design of the systems need careful consideration with the available heat and required heat matched as far as practicable. A system should not take more heat than is gained (from solar activity) over an average annual cycle if it does, over time, the system will have to work harder to deliver the required heating which will increase the running costs and reduce the operational efficiency. As the temperature of the system is lower the heat delivery system needs to have a greater surface area to deliver the required heat and might also require the upgrading of insulation. This can increase the installation costs when retrofitting GSHP in replacement of conventional heating systems. In addition the installation of the below ground elements need to be carefully designed and sequenced in new builds to allow for installation and maintenance of other services and for existing with a consideration of access for maintenance. Where ground conditions and land availability do not allow for horizontal pipe-work then borehole/piled pipes are a potential solution although this adds to the costs. It is noted that some commercial applications have begun successfully incorporating pipes in the piled foundations, a method that can be used if deep piles are required for the new building. As before this design needs detailed planning as access will be limited when in service and repair virtually impossible. All these factors can impact on both costs of systems and the perception of reliability – which in turn can limit the overall installed capacity.

Lack of space to install collectors can be an issue that will constrain uptake. Given that there is a need to balance the available heat with the heat extraction/demand this can influence the size of collector both in horizontal/vertical cross-sections. The lack of experience and detailed understanding has also led to the over-design of many units which increases the costs and lengthens any payback periods. In addition, the design and installation of the large collection loops can add to complexity and therefore costs leading to potential delays, a potential reduction in operational efficiency and a cap on installed capacity.

The supply of electricity into domestic properties can have implications on the level of installed systems. The issues are two-fold. First the specification of the heat pump benefits from the availability of a three-phase electricity supply (most domestic supply is a single phase) because a three phase supply helps with the operation of the pump.[44] Second, the capacity of the local electricity supply networks may constrain developments without reinforcement.[45] While these impacts are not insurmountable they can lead to an increase in

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[44] Three phase motors are more efficient, less complicated and more reliable than single phase motors. Single phase motors are not easily available in sizes larger than about 10 horsepower. Three phase motors can be used with variable frequency drives (VFDs) to provide adjustable speed operation and controlling air or liquid flow by controlling the speed of a fan or pump is more efficient than using dampers or throttling valves.

[45] The capacity of electricity networks is a complex issue and one they is very much tied to specific location. To understand the restrictions on capacity in any detail would require discussions with the distribution network operators when specific plans/size/locations where available.

costs and therefore prevent/delay systems which has the knock-on potential impact of acting to constrain the installed capacity.

3.5. Market Status

The number of installed GSHPs in the UK some 15 years ago was very low. However, in recent years the market has shown a rapid growth and increasingly positive attitude towards heat pump technology and its use. According to information on the Department of Energy and Climate Change (DECC) website, there are currently around 250 ground-source heat pumps installed in the UK every year. In 2007 a report by the National House Builders Confederation (NHBC) estimated that between 500 and 700 GSHPs are being installed in the UK annually (the report focuses on residential properties).[46] It has been estimated that there are 1,550 large industrial sites in the UK where heat-pump systems could be installed, with an average size of 800 kilowatts of thermal power.[47] Note however that sites of this scale are not representative of the wider industrial market potential.

The GSHP industry is still being established with statutory industry guidelines yet to be fully established (good practice guidelines are currently emerging). This means that designers and installers have, in many cases, designed their own criteria. The GSHP industry is more developed in some European countries and in North America where industry-led codes are established. These codes can be very helpful but differences in climate, installation and ground conditions have to be taken into account. Such differences will significantly affect the efficacy of the system and the embedded length of the ground loops.

The overall heat pump market (including both GSHPs and ASHPs) has grown progressively in some European countries. While markets in Germany, Austria and Switzerland see large sales of GSHP, those in Norway and Finland are dominated by air-air heat pumps. This is due to a high percentage of houses equipped with direct resistance (electrical) heating. [48]

Most significant growth in 2007 was found in the larger markets of Italy (33%, or 30,000 units), France (30%, 70,000 units), Norway (+27%, 70,300 units), Finland (+25, 46,100 units) and Austria (+15%, 14,600 units) while the markets in Germany (+1.5%, 52,000 units), and Switzerland (17,000) are consolidating after strong historical growth. In most cases the balance of costs and incentives for installing GSHP relative to fossil fuel based systems have made these attractive options for these countries.

After years of growth, the Swedish market saw a decline of 23% in 2007 in comparison to 2006 although over 29,000 GSHPs were sold in 2006. This decline is the consequence of the market for residential heat pumps in single family houses being close to saturation. Heat pumps are by now the most common heating system in single-family houses in Sweden (approx. 34%). The existing opportunities of market development are likely to be found in the

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46 NHBC Foundation 2007, Ground Source Heat Pump Systems.

47 http://www.berr.gov.uk/energy/sources/renewables/explained/geothermal/current-use/page17515.html

48 This and subsequent paragraphs draw on *European Heat Pump Statistics Outlook 2008*, European Heat Pump Association, 2008.

segment of multi-family homes and commercial applications as well as in the segment for renovation. As noted, the market in Germany came to a halt 2007 with only 1.5% increase of sales. The slow down of the market is believed to be the consequence of an increase of the value added tax that came into force 1 January 2007.

Developing markets, like the UK, have seen steep increases in market size, albeit from a very small base. Historically the UK heat pump market has been dominated by ground source units, however, the current market trend has increased the importance of ASHP which may become more dominant as the market develops. The overall heat pump market is currently small in the UK with most of the growth being driven by the move to rapidly reduce emissions from new buildings. The UK heating market is dominated by gas and there is little economic argument for replacing heating systems in existing buildings.

3.6. Economic Performance

Table 3.1 below summarises the various costs associated with installing and maintaining a ground source heat pump system. Various assumptions have been made in order to determine these costs, including:

§ Individual house installations assume a horizontal ground loop, while community installations assume a borehole ground loop, based on the assumption that ground area will be limited;

§ A group of 5 dwellings is assumed per installation for the community schemes only (the fixed costs are spread equally between the dwellings);

§ Individual system maintenance assumes 0.5 day service every five years, while community systems maintenance assumes 1 day maintenance ;

§ Fixed costs include £2,000 per dwelling heat distribution costs;

§ System costs include a thermal store.

It is noted that the components have a long life-expectancy of approximately 20-25 years and up to 50 years for the ground coil.

Table 3.1
Ground Source Heat Pump Costs[49]

Year	Marginal Costs (£ / kW_{th})		Fixed Costs (£ / dwelling)		Maintenance Cost (£ / dwelling /yr)	
	Individual	Community	Individual	Community	Individual	Community
2009	£187	£1,121	£6,540	£3,495	£44	£18
2010	£181	£1,085	£6,330	£3,447	£44	£18
2011	£175	£1,051	£6,133	£3,402	£44	£18
2012	£170	£1,020	£5,948	£3,360	£44	£18
2013	£165	£990	£5,777	£3,320	£44	£18
2014	£161	£963	£5,618	£3,284	£44	£18
2015	£156	£938	£5,470	£3,250	£44	£18
2016	£152	£914	£5,334	£3,219	£44	£18
2017	£149	£893	£5,208	£3,190	£44	£18
2018	£145	£873	£5,092	£3,164	£44	£18
2019	£142	£855	£4,985	£3,139	£44	£18
2020	£140	£838	£4,888	£3,117	£44	£18

3.7. Support Mechanisms, Funding and Incentives

Under the Microgeneration Certification Scheme (MCS) a government grant of £1,200 against purchase of GSHP can be achieved in England and Wales. Only heat pumps that are certified and installed by a certified installer are eligible under this program. GSHPs must achieve a COP of 3.5 (GSHP at B0/W35). Scotland provides more generous support by granting up to £ 4,000 for heat pump installations.

3.8. Current Output Levels and Future Potential

According to AEA, a recent survey indicates that there is approximately 5 MW_{th} of installed GSHP in the UK, made up of around 600 – 700 units, providing around 30 GWh_{th} of heat.

We provide further estimates of future potential and constrained uptake in Appendix A.

3.9. Sustainability and Carbon Saving Potential

The carbon savings from heat pumps depend on the COP, the carbon intensity of grid electricity and the fuel that the heat pump is displacing (e.g., will vary depending on if

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49 Renewables Advisory Board, The Role of Onsite Energy Generation in Delivering Zero Carbon Homes, 2007. [Cost implications per household to be clarified.]

systems are installed in an electrically heated home or one heated by gas). The highest carbon savings will be achieved when systems are installed in electrically heated buildings.

4. Biogas Combustion and Injection

4.1. Background

Biogas is a renewable gas composed primarily of methane and carbon dioxide that is produced during the breakdown of organic matter by bacteria in the absence of oxygen (anaerobic conditions). As well as occurring naturally on a large scale, the process can be controlled and biogas harnessed for useful energy. Sources of biogas include landfills, sewage treatment processes and purpose built anaerobic digesters. The resultant gas is entirely derived from biological matter and so is considered carbon neutral when combusted.

Gas can also be created from solid biomass by heating it in a reduced oxygen atmosphere (gasification) or in the complete absence of oxygen (pyrolysis). The gas produced is called 'synthesis gas' (syngas) and consists primarily of hydrogen and carbon monoxide, so differs chemically from the biogas produced via anaerobic digestion.

Anaerobic digestion (AD) is suitable for biomass with high moisture content, including animal slurry, food waste, silage etc. It is often difficult to combust such feedstocks, and it is often preferable in terms of the overall energy balance (i.e. the efficiency of the process) to use anaerobic digestion to produce biogas. Anaerobic digestion is suitable for most biomass sources with total dry solids content below 30 percent. AD plants are usually small scale and installed near to the source of fuel, such as on farms or food production sites. It has also been successfully used for treating the organic fraction of Municipal Solid Waste (MSW) with the biogas used for energy production.

4.2. Biogas and Syngas Properties

Biogas produced in AD-plants or landfill sites is primarily composed of methane (CH4) and carbon dioxide (CO2) with smaller amounts of hydrogen sulphide (H_2S) and ammonia (NH_3). Trace amounts of hydrogen (H_2), nitrogen (N_2), saturated or halogenated carbohydrates and oxygen (O_2) are occasionally present in the biogas. Usually, the gas is saturated with water vapour and may contain dust particles and organic silicon compounds (e.g siloxanes). Typical compositions of different kinds of biogas and natural gas are shown in table Table 4.1. The raw gas is in all cases saturated with moisture.

The properties and composition of biogas depend on the feedstock and the type of digestion process. Typically the calorific value (CV) of biogas is around half that of natural gas, and so a greater volume is required to give the same energy output. It is possible to 'upgrade' the gas (remove non-combustibles) to increase the methane content and hence the CV. It is also necessary to remove impurities such as hydrogen sulphide (H_2S) before combustion. Syngas can have very variable properties depending on how it is produced. Table 4.1 compares typical properties of biogas, syngas and natural gas.

One very important factor in the utilisation of gas is the Wobbe index which is a combination of the energy content and the relative density of the gas. The heating value of biogas is determined mainly by the methane content in the gas. The methane number is a parameter that describes the gas resistance to knocking when used in a combustion engine. Methane has a methane number of 100 while hydrogen has a methane number of zero. Carbon dioxide increases the methane number because it is a non-combustible gas with a high knocking resistance.

Contaminants in biogases can present some difficulties either in combustion, corrosion or increased system costs due to the requirement for additional gas cleaning. Typical contaminants include:

§ Sulphur gases – Biogas and, especially, landfill gas can contain a variety of sulphur compounds, such as sulphides, disulphides and thiols. Oxidized sulphur compounds (sulphate and sulphite) are corrosive in the presence of water and therefore has to be removed in order to avoid corrosion in compressors, gas storage tanks and engines. The main sulphur compound in biogas is hydrogen sulphide. It is reactive with most metals and the reactivity is enhanced by concentration and pressure, the presence of water and elevated temperatures.

§ Halogenated compounds – Halogenated compounds (e.g. carbon tetrachloride, chlorobenzene, chloroform and trifluoromethane) are often present in landfill gas, however, only rarely in biogas from digestion of sewage sludge or organic waste. Halogens are oxidized during the combustion process. The combustion products are corrosive, especially in the presence of water and can cause corrosion in downstream pipes and applications. They can also initiate the formation of PCDDs and PCDFs (dioxines and furans) if the combustion conditions (temperature and time) are favourable. These gases are normally closely monitored and can cause significant public concern.

§ Siloxanes - Siloxanes are volatile silicones bonded by organic radicals. They occur in landfill gas and gas from digestion of sewage sludge. These originate from different kinds of consumer products (e.g. shampoo, detergents and cosmetics). Siloxanes are converted during combustion to inorganic siliceous deposits in downstream applications which can deposit on valves, cylinder walls and liners and cause extensive damage through erosion or blockage. Silicon compounds may also reach the lubrication oil requiring more frequent oil changes and thereby increasing operational costs.

§ Ammonia – High concentrations of ammonia are a problem for gas engines, and are often limited by manufacturers of gas engines. Normally up to 100 mg/nm^3 ammonia can be accepted. The combustion of ammonia leads to the formation of nitrous oxide (NOx) which is a problematic air pollutant subject to regulation.

§ Dust and particles – All biogas plants must be equipped with some kind of filter or/and cyclone for reduction of the amounts of particles in the gas.

Table 4.1
Typical Characteristics of Biogas, Syngas and Natural Gas

	Typical Composition	Typical LCV (MJ/m3)	Higher Wobbe Index (MJ/nm^3)	Methane Number	Yield	Typical Feedstock
Biogas (from controlled AD)	~60% CH_4, 40% CO_2	~20 MJ/m3	27	>135	0.25-0.35m3 CH4/kg COD[50]	Slurry, food waste
Syngas (from wood)	H_2, CO, N_2, (in variable proportions), some CO_2, CH_4	4 -12 MJ/m3 (for air gasification)	Highly variable - dependent on reactor conditions			Solid biomass (wood/straw/etc)
Natural Gas	~90%CH_4, some higher hydrocarbons	39	55	70	n/a	n/a

4.3. Anaerobic Digestion Process

AD occurs where complex organic matter is broken down by bacteria in a four stage process, the main output of which is biogas and a stabilised solid residue (digestate) which can often be used for soil treatment. The bacteria responsible for breaking down the material (methanogens) are strict anaerobes and will not survive unless conditions are suitable for growth such as temperature range, pH and nutrient content. In sub-optimal conditions the bacteria will not survive and no breakdown of the input will occur (and hence there will be no biogas production).

The anaerobic digestion process can either be maintained at mesophillic temperatures (around 35 – 37^oC), or thermophillic temperatures (above 55^oC). When carried out at mesophillic conditions digestion typically takes 10 – 30 days and the biogas produced has a lower methane yield. The process is quicker when carried out under thermophillic conditions with greater methane yield in the biogas, however in the UK climate achieving thermophillic temperatures requires a significant heat energy input so mesophillic reactors are generally used. It is essential to carefully control the temperature, pH and nutrients to ensure conditions in the reactor are optimum for microbial growth, and it is also important to ensure good mixing (to allow feedstock to come into contact with the microbes). The need for carefully controlled, stable conditions means reactors are sensitive to variations in throughput and biodegradable content, so ‘shock’ loads must be avoided.

There are numerous designs of digesters available, all suited to different feedstocks and varying in cost and complexity. A full review is not provided here but some of the more common types and suitable applications are provided in Table 3.2.

[50] COD is chemical oxygen demand, a measure of the organic (and hence degradable) proportion of the feedstock

Table 4.2
Anaerobic Digester Characteristics

Digester Type	Characteristics	Suitable Input
(Contact) Stirred Tank Reactor	Long residence time, suitable for difficult to digest waste, scale up simple	Feedstock with high suspended solids content including MSW, sewage sludge, agricultural slurries etc
Upflow anaerobic sludge blanket reactor	Suitable for feedstock with low solids content (typically 3% dry solids). Shorter residence times than STR	Dilute effluent such as wastewater with high COD including brewing and food production effluent (most common type for industrial effluent)
Anaerobic filter reactor	High loading rate possible but sensitive to changes in loading	Well suited to soluble effluent (very low suspended solids) such as certain food and drink effluent
Expanded granular sludge bed reactor	A combination of the above two reactors, high loading rate and high quality output but complex and relatively expensive	Industrial effluent (see UASB and filter)

The primary ways in which AD is applied to give a useful biogas output are described briefly in the sections below.

4.3.1. Landfills

Landfills produce methane by exactly the process described above, however as there is much less control over the conditions and the feedstock, the efficiency is much lower. Despite this it is possible, and indeed a requirement under Pollution Prevention and Control (PPC) legislation, to recover methane to limit release to atmosphere.

Landfill gas (LFG) currently makes a major contribution to renewable gas in the UK. There are currently 282 LFG generators with an installed capacity of 632 MW_e.[51] Generators are installed at the majority of large landfills where gas extraction is attractive economically (it is a requirement of the PPC permit to do so if financially viable), and so the remaining untapped potential is small. Almost all the biogas recovered from landfill sites is used for electricity generation with virtually none used for heating. This is because there is significant incentive to produce electricity (higher basic value and landfill gas is eligible for ROCs) and because landfill sites rarely are located close to sites with high heat demand, so to use the heat would require transporting either gas or hot water over significant distances at a high cost.

Landfills only produce gas for a limited period after closure, and there is a gradual reduction over time (depending on the size, waste constituents/structure and climatic conditions, however, indicatively approximately 50 percent of the emitted methane is economically recoverable over a degradation cycle of 100-150 years). The shift away from landfilling organic waste (driven by EU legislation) means in future this capacity will diminish. A proportion of this waste stream is likely to be diverted to dedicated anaerobic digesters, but a significant proportion may also be composted (aerobic digestion) or combusted in energy from waste plants, depending on the local authority waste management strategy. It is worth

[51] BERR, "Barriers to Renewable Heat: Analysis of Biogas Options", September 2008

noting that additional biogas production from AD of MSW will be at least be partly countered by the reduced production of biogas from landfills.

4.3.2. Sewage sludge

AD is widely used to process and stabilise sewage sludge. Raw sewage is first gravity-settled and then treated aerobically (which requires energy input). The resulting ‘activated’ sludge is then treated anaerobically. At larger sites, the quantities of biogas produced are sufficient to allow electricity to be generated. As digestion is an essential part of the stabilisation/treatment process the resulting biogas is a useful by-product rather than the main driver for installing such plant, however the gas is produced in sufficient volumes to heat the digesters and produce electricity to approximately meet the demands of the site. As such there is little scope for using sewage sludge as a significant source of renewable heat.

4.3.3. Industrial effluent

AD can be used for waste treatment where the effluent material has a high biodegradable content (measured in terms of Chemical Oxygen Demand, COD) and has low toxicity (including pathogens, biocides etc). AD is particularly well suited for the following industries:

- Starch/sugar processing – high COD;
- Brewing/distilling – high COD, neutral pH, very large volumes, ideal for AD;
- Vegetable processing – good but can be problems with pesticides/biocides;
- Farming and agriculture – slurry from cattle and pigs is well suited to treatment by AD; and
- Pulp/paper – more difficult to degrade but still reasonably well suited to AD.

Other industries produce effluent that is less well suited to AD but can still be used effectively to treat the waste, including:

- Dairy industry – often the best way to treat the large quantities of effluent produced, but high fat content of milk products means the degradation process is slow and relatively inefficient;
- Meat processing – by-products are difficult to degrade and pathogens can be a major hazard but AD can still be used in some circumstances;
- Textiles – also possible but can be very difficult to degrade.

The process can be batch, semi-continuous or continuous depending on the scale. The choice of reactor will depend on the suspended solids content, homogeneity of the material, how dilute the material is and so on (see Table 3.2 for an overview of common reactor types).

4.3.4. Municipal solid waste

The organic fraction of MSW can be treated in an AD plant. Ideally this requires separate collection of food waste, but it can also be recovered via a Mechanical Biological Treatment (MBT) process. For estimates of the resource available from food waste please refer to Table

A.5. There is debate as to the most appropriate way to treat this waste stream in energy recovery/lifecycle terms, although AD does offer advantages over incineration in terms of having no emissions to air (except exhaust from biogas combustion).

4.3.5. Planning issues

AD plants take up a large amount of land for the energy output, a typical small scale plant of around 5,000 tonnes per year will require in the region of 1,500m^2 for all necessary equipment (tanks, gas storage, CHP engines etc). Large facilities of around 40,000 tonnes per year (approx 1.5 to 2 MW capacity depending on feedstock) will need closer to 6,000m^2. Vehicle movements may be an issue particularly with larger plants where over 20 vehicles a day can be expected.

Odour can be a problem, and means sites must be located some distance away from sensitive locations such as residential areas. Plants are often located near the feedstock source in areas where odours are inevitable such as farms, sewage treatment works, industrial sites etc. The use of negative pressure systems can help to mitigate odours on larger facilities.

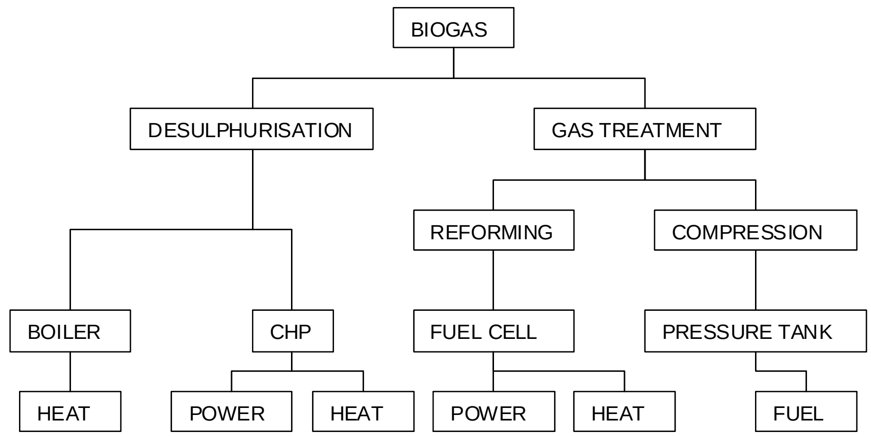
Noise and visual impact can also cause problems, but can usually be addressed by careful location of the site and including screening and acoustic attenuation in the engine room for example. Health and safety may become more of an issue as explosive gas production, storage and movement increases in scale.

Typically, however, regional and local planning authorities have been broadly supportive if AD facilities, partially in response to increased pressured for enhanced renewable deployment from central government and partially due to the need to divert biodegradable waste from landfills and the general lack of public support for energy from waste facilities.

4.4. Use of Biogas

The AD process produces gas with relatively low energy content from dilute energy sources, and hence significant volumes are required to produce a useful biogas output. In addition the fuel sources typically used (manure, slurry and food waste) tend to be scattered. Because of this AD plants tend to be relatively small scale, and even larger plants with on site electricity generation do not usually exceed a few MW of electrical capacity. A proportion of the heat is usually required to heat the digesters (to maintain mesophillic temperatures), but there is often a significant surplus that can be used for producing hot water. Given the relatively low output, AD plants must either be located close to heat demand, or the biogas must be transported to an offsite location by some means. It is possible to upgrade biogas to pipeline standard 'biomethane' for injection to the natural gas network; this is discussed further in below. Biogas can also be compressed and used as a renewable transport fuel. Biogas can be used in all natural gas appliances provided that upgrading of the gas quality is carried out. The main potential routes for biogas utilisation are depicted in Figure 3.1.

Figure 4.1
Biogas Utilisation (BERR 2008)



4.4.1. Heating

At industrial sites there will often be a heat and electricity customer located adjacent to the digester plant, although the potential for recovering heat is frequently neglected. Where there is a high demand biogas can be piped to the site and used directly for process heating, though the relatively low CV means that it may be unsuitable when high temperatures are required (e.g. furnaces). Given the higher value of electricity, particularly when incentives are taken into account, and the requirement for heating the digesters, the use of biogas directly for heating is limited and CHP is often used. At present only a small proportion of biogas is used for heating only.

4.4.2. CHP

Relatively high electrical efficiency even at small scale (with established technology) means biogas is usually used to generate electricity, often with CHP. A range of prime movers can be used for electricity generation, such as a modified internal combustion engine (spark ignition typically) and a gas turbine, though only at large scales (above approximately 10MW). Electrical efficiencies can be higher than biomass combustion (approximately 30%, but tend to be slightly lower than natural gas due to the lower CV. Heat can then be recovered from the engine exhaust, oil and cooling water and used for the production low to medium temperature hot water. The technology is proven, though impurities in biogas such as hydrogen sulphide and moisture mean that corrosion is more of a concern than in natural gas fired engines. Maintenance is typically required every 500 hours, for example to replace oil and spark plugs, and thorough overhauls will be required relatively frequently. It is also sometimes necessary to supplement the biogas with natural gas if the methane content falls below a certain threshold.

4.4.3. Fuel cells

Fuel cells have a potential to become the small scale power plant of the future although widespread commercial use is yet to be achieved. Fuel cells have a potential to reach very high efficiencies (>60%) and low emissions. Special interest for stationary biogas application is focussed on hot fuel cells operating at temperatures above 800°C particularly because the CO_2 does not inhibit the electrochemical process, but rather serves as an electron carrier. Two types of fuel cells are in an advanced stage of development: the solid oxide fuel cell (SOFC) for small applications of a few kW and the molten carbonate fuel cells (MCFC) operating in the range of 250kW and up.

4.4.4. Injection into existing gas network

When heating domestic properties an alternative to using biogas to produce heat for a district heating system is to make use of the existing gas distribution infrastructure and inject biogas into the network. This approach is already being used in several countries albeit only on a small scale at present. Biogas is well suited to this due to its high methane content; however it is possible to use syngas even where the methane content is very low if the gas is subsequently reacted to boost the methane content. However although technically feasible, it is not likely to be as economically viable an option as biogas, and in addition it is less well proven commercially. Hence the focus of gas production for grid injection is likely to be on AD.

In order to transport biogas with natural gas, it is necessary to upgrade the gas to almost pure methane. This is to reduce impurities that may damage pipes and increase emissions, and ensure a consistent quality. Upgrading is typically done using the 'pressure swing adsorption' process which removes the vast majority of CO_2, H_2O, H_2S, N_2, O_2 and other impurities, the resulting purified gas is known as 'biomethane'. The gas CV must closely match that of the natural gas in the network, if the quality is acceptable the gas is odourised, compressed and injected to the distribution network.

The key arguments in favour of biogas injection are:

§ Utilises existing infrastructure so does not require change in consumer behaviour or significant upgrade of infrastructure (pipeline network is a major cost element of large heating schemes)

§ Efficiency can be high as much of the gas will be used for heating rather than electricity generation (though some may be used in large gas fired electricity only plant)

§ Can increase production at a remote site and still store/utilise the gas effectively

§ Injection of biogas into the grid can improve local security of supply, an important factor in the UK.

Disadvantages and barriers are:

§ Most likely to be commercially viable on a large scale, but it is challenging to produce biogas on large scale at a single site, better suited to small scale at source.

§ At present not competitive with electricity generation or CHP, given current incentives on electricity generation—of course, in the context of new incentives for renewable heat, this balance could be changed.

§ Unlikely to be able to use the high pressure transmission network due to elevated oxygen content compared to natural gas

If these hurdles can be overcome it could be a useful way of expanding biogas distribution.

There are a number of small scale plants operating in Germany where new legislation means that gas network operators must prioritise biomethane injection over natural gas and contribute to infrastructure costs[52]

National Grid has recently reported on the potential that injection could offer.[53] The estimates are very optimistic, suggesting that as much as 18 percent of the total UK gas requirement could be met by renewable gas by 2020 (18.4bcm per year, equivalent to approximately 200 TWh per year). Figures include a high contribution from wood waste and energy crops which in practice would need to be gasified to produce syngas, which then requires further chemical conversion to methane in order for it to be injected into the natural gas network, so the true maximum contribution *from AD* may be closer to half that. The cost of delivered heat from biogas injection varies significantly depending on the source of biomass for digestion and the technology used.

However two other recent studies predict a lower contribution; a BERR study into biogas options[54] suggests a much lower potential from biogas injection equivalent to 1.6 percent of total demand and a recent NERA/AEA report[55] suggests a stretch growth scenario of 5.9 TWh, equivalent to only 1% of total demand. This compares with the NG report which suggests.5 to18 percent of total gas demand inform the baseline and stretch scenarios respectively

The NG report assumes that as well as using AD to produce biogas, wood waste and energy crops are used to produce syngas for subsequent upgrading and injection (a challenging and as yet commercially unproven process). Hence we consider the figures in the NG report to represent a very high uptake scenario, whereas the BERR and AEA studies are considered a more conservative estimate based on AD only and taking account of likely constraints on uptake.

There is no international technical standard for biogas injection but some countries have developed national standards and procedures for biogas injection (summarised in Table 1.4 – note all of the standards require upgrading of the biogas). MARCOGAZ, the technical association of the European Natural Gas Industry has adopted a recommendation concerning technical and gas quality requirements for delivery of non-conventional gases e.g. biogas into gas networks.

Injecting biogas into the gas grid sometimes raises concerns about the risk of transmitting disease via the gas. The Swedish Institute of Infectious Disease Control, National Veterinary Institute and the Swedish University of Agricultural Science have evaluated this risk ('Identification of the microbiological community in biogas systems and evaluation of microbial risk from gas usage'). The study concluded that the risk of spreading disease via

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52 Aufwind Schmack presentation

53 National Grid "The Potential for Renewable Gas in the UK", January 2009

54 BERR, "Barriers to Renewable Heat: Analysis of Biogas Options", September 2008

55 The UK Supply Curve for Renewable Heat, NERA/AEA, July 2009

biogas was judged to be very low; the number of micro organisms found in biogas was equal to the level found in natural gas.

Table 4.3
National Gas Standards

Country	Overview of standard
Sweden	In 1999 Sweden developed a national standard for biogas as vehicle fuel on request of the Swedish vehicle manufacturers as a design basis for fuel- and engine systems. The main parameters include a target bracket for the Wobbe index and restrictions on the levels of contaminants. In addition it specified a motor octane number which is a definition of the resistance to knocking. The Swedish standard is also applied when injecting biogas into the natural gas grid. Additional demands concerning the heating value are covered by the addition of propane to the gas.
Switzerland	Biogas is injected into the natural gas grid at several locations in Switzerland. Two different qualities are allowed in the Swiss regulations (G13): gas for limited injection and gas for unlimited injection. The restrictions for gas for unlimited injection are of course more severe than the restrictions for limited injection. The main parameters include a minimum level of methane content and restriction on moisture content and the levels of contaminants.
Germany	Germany has a standard for biogas injection (G262) that has been elaborated in cooperation between the German Water and Gas Association and the German Biogas Association. The standard is based on the German standard for natural gas, DVGW G260.The main requirements in the standard (for injection into natural gas grids with high heating value) include a target bracket for the Wobbe index and relative density of the fuel and restrictions on the levels of contaminants. The German standards allow injection of two types of gas, gas for limited injection and gas for unlimited injection. Unlimited injection of upgraded biogas in H-gas grids is possible if the cited concentrations are maintained. The German standard also requires the biogas producer to present at safety data sheet that describes any health hazards in connection to the handling of the biogas.
France	Gaz de France has in 2004 produced a de facto standard for gas injection into the national gas grid. While similar to Germany and Sweden in setting targeted ranges for the Wobbe Index the standard has more strict limits on oxygen than the other standards and also comprises a number of limits for heavy metals and halogens.

All of the above standards require gleaning of the gas to improve its energy content, fulfil requirements of the end user and to standardise the gas. The gas quality requirements depend strongly on the utilisation.

4.5. Syngas

Syngas is produced by heating solid fuel (such as wood) in the absence of oxygen or in a restricted oxygen atmosphere, known as pyrolysis and gasification respectively. The composition of the gas produced will vary depending on the feedstock, temperature, heating rate/residence time etc. Pyrolysis is an intermediate stage of gasification.

4.5.1. Gasification

The gasification process produces a gas consisting of hydrogen, carbon monoxide and a range of other non-combustible gases such as nitrogen. The gas has a low CV (typically around 4MJ/kg), a higher CV can be achieved by injecting oxygen (reducing inert N_2 present in air). Injecting steam increases the H_2 content by secondary reactions in the gasifier, known as the water gas shift reaction; this also increases the CV.

There are numerous types of gasifier available. Downdraught and updraught gasifiers are simple designs often used at smaller scales, and can be effective but require a reasonably homogenous material input. They cannot easily be scaled up. Downdraught gasifiers produce a clean but relatively low CV gas. Updraught gasifiers produce gas with a higher CV, but also higher in tars and significant gas clean up is required if it is used in an internal combustion engine, which increases the potential system operational costs.

Fluidised bed gasifiers are often used at larger scale. They can tolerate a larger range of particle sizes and moisture content, and most designs can be easily scaled up. The main downside is the increased cost, and the gas produced is not as clean as that from a downdraught gasifier so some cleaning is usually required if the gas is used in an internal combustion engine which again increases the system costs.

4.5.2. Pyrolysis

The pyrolysis process produces a gas with a similar CV to oxygen gasification (12 - 27MJ/m3), but also produces a solid component (char) and a liquid (bio-oil). The proportions of each phase depend on the conditions within the pyrolyser and the residence time. The higher CV is due to the lack of nitrogen as no air is used in the process. However the gas has very high levels of tar which condense on cooling. As a result if the gas produced is intended to be combusted directly, then gasification is typically employed as it produces a cleaner gas.

4.6. Costs

The costs of producing biogas are highly variable depending on the process used, feedstock, scale and end use to name just some of the variables. Reliable cost data for grid injection is particularly scarce given the limited operational experience and commercial confidentiality. A full assessment of biogas pricing is not possible here, but a summary of the capital and operational costs of AD for small- and large- scale systems provided in Table 4.4. A National Non-Food Crops Centre study[56] suggests typical ‘rule of thumb’ capital figures of £2,500 – £6,000 per kWe for the basic digestion apparatus (i.e. excluding auxiliary equipment such as grid connection). This significant range is due to the wide range of digesters and feedstocks.

Offsetting the capital and operational costs will be revenues from energy sales and a possible gate fee for the acceptance of the waste feedstock. It is likely that in most cases the energy sales will be the dominant revenue stream; the gate fee will depend on the source and type of waste and the alternative disposal options available. For example if the primary alternative is landfill, which carries a high fee and is subject to increasing taxation, then it would be possible to attract a higher fee than if there are competing options for the resource (such as other AD plants or use as animal feed for example). Hence the revenues will be highly site and project specific.[57]

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[56] A Detailed Economic Assessment of Anaerobic Digestion Technology and its Suitability to UK Farming and Waste Systems, Andersons for the NNFCC, April 2008

[57] For the purposes of this analysis, which focuses on the production of useful heat from renewable sources, we have not attempted to assess the GHG emissions implications of the waste and the waste disposal option represented by AD, as compared to other waste disposal options. In terms of GHG emissions from waste treatment and disposal, AD may have some advantages over landfill (which is becoming increasingly restricted by policy in any case), but may not be preferred to other forms of waste disposal.

Table 4.4
Typical Biogas Costs

Typical Scale	Electrical Output	Digester Volume	Capital Costs	Operational Costs
Small Farm	10 kWe	150 m^2	£60 – 70k	1 – 2% of CAPEX per year
Large Local/Regional Plant	1 MWe	10,000 m^2	£3 – 4M	1 – 2% of CAPEX per year

4.7. Support Mechanisms, Funding and Incentives

4.7.1. Support mechanisms

The RO mechanism provides support to electricity generation, but not for heat. There is a particularly strong incentive to generate electricity from renewable gas because unlike the combustion of biomass, many of the technologies are seen as emerging and in need of higher levels of support so are eligible for more than one ROC per MWh of generation (see Table 4.5). The exception to this is landfill gas and sewage gas, which are now considered mature. This has a negative impact on encouraging the use of biogas for heating, even though this can have higher overall efficiency and is the only close renewable alternative to natural gas. The introduction of the RHI may help to change the situation.

Feed-in tariffs are planned to support electricity produced from small generators below $5MW_e$, and as most AD schemes have an output below this the scheme may replace ROCs almost entirely.

Table 4.5
Summary of Relevant ROC Bandings

Generation Type	ROCs/MWh
Anaerobic Digestion	2
Landfill Gas	0.25
'Standard' Gasification (CV between 2 and 4 MJ/m^3)	1
'Advanced' Gasification (CV greater than 4 MJ/m^3)	2

In Germany new regulations have been passed that require gas network operators to contribute to the cost of biogas injection infrastructure and to treat this preferentially to natural gas. A similar system may be required in the UK in order to 'kick-start' the market for biogas injection, if this is judged to be a suitable method. The National Grid report (cited earlier) suggests overall costs of delivered energy from biogas injection are high, so support from an RHI scheme or similar is likely to be essential to encourage this technique in the UK (especially given that electricity generation using biogas receives subsidy under the Renewables Obligation).

4.7.2. Funding

Bioenergy capital grants are available for anaerobic digestion. Private Finance Initiative (PFI) credits are available for local authority waste management infrastructure, which includes AD in some cases and a number of authorities are currently considering this option as part of their waste management strategy. Other mechanisms providing support include: AD Demonstration Programme announced by Defra on 18th February 2008; €12.9 million (£10 million) from Environmental Transformation Fund capital grant for construction of new plants and enhanced capital allowances.

4.8. Market Status

4.8.1. Current status

There are over 100 small scale digesters producing electricity on sewage treatment works, and a relatively small number of installations on farms and food factories (approximately 60 in 2005).

There is currently only one operational plant in the UK that uses AD to treat MSW, located in Leicester. The plant at Wanlip is operated by Biffa and treats the organic fraction of MSW (which is produced by a novel ball mill MBT plant) in a wet AD process. The plant produces approximately 1.5MW_e, though residual heat is not exported.

Various other local authorities are considering AD as part of an integrated waste management solution. For example up to four AD plants could be built as part of the Greater Manchester Waste Disposal Authority PFI waste infrastructure project, treating a total of 200,000tpa of organic waste (approximately 10MW).

In the EU there were 2,429 commercial AD plants operating in 2005, 1,900 of which are in Germany[58]. There are many very small scale digesters in rural locations. Worldwide there are approximately 400 digesters treating effluent from food and drink manufacture; this is a very small proportion of the total sites that could employ this technology.

An overview of the current status of AD in the UK is provided in Table 4.6. Very few installations utilise the heat for purposes other than heating the digesters themselves, and hence only the electrical capacity has been included.

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[58] http://www.adnett.org/

Table 4.6
Current Status of UK Biogas Production

Type of Plant	Approximate Number of Operational Installations	Electrical Capacity
Landfill Gas	Unknown	632 MW (5,050GWh/y)
Sewage Treatment Gas	107 plants claiming ROCs (2006)	~80MW
Other AD[58]	Approximately 60 on farms. Small number on industrial plants (figure unknown)	~100MW
MSW	1 operational (Leicester), numerous others planned	1.5MW
Total		**~800MW**

4.8.2. Future potential

A recent report produced for BERR[59] considered the barriers to renewable heat, including the heating potential and investment required to overcome identified barriers. The report estimated the most optimistic total heat potential from biogas (from AD, excluding syngas) to be 27.8 TWh per year by 2020 (approximately 3% of total current UK heat demand). This assumes all biogas is used for heating so the true potential will be lower as much is likely to be used in CHP and electricity only applications, even where incentives for renewable heat exist.

To achieve the optimistic scenario will require considerable investment; the BERR report estimates a total of £2.9bn will be required to remove the barriers to allow the level of heat generation in Table 4.7.

Table 4.7
Biogas Potential by 2020

Method of Heating	Potential Heat Supply (TWh)			
	Landfill Gas	Sewage Gas	AD	Total
Heat recovered from existing facilities	3.2	1.0	0.0	4.2
Direct use (industry)	4.4	0.0	4.9	9.3
Injection to existing gas network	4.8	4.2	5.4	14.3

[59] BERR, "Barriers to Renewable Heat: Analysis of Biogas Options", September 2008

Despite the high infrastructure costs, the report also contains a review of the commercial performance of biogas, based on a generic 50t/day AD plant (approximately 1MW / 18,000 t per year). This suggests that, under some circumstances, electricity and CHP production from biogas could be cost-effective even without support mechanisms such as ROCs or an RHI scheme. The report also suggests that heat production through direct firing of biogas could be cost effective. However the production of biomethane for injection was less viable, the poorer economic performance potentially meaning increased support for this option will be required in order for it to be a valid commercial proposition. The economic performance will vary greatly on a case by case basis, particularly where heat is recovered from CHP generators since the heat distribution infrastructure is a major cost component (the distance required will have a critical impact in the economic performance). More generally, the favourable commercial assessment contrasts with the low levels of current production of biogas. Although more schemes are starting development, the generic commercial analysis may omit factors that tend to make biogas production less attractive in practice.

There also is a question of what proportion of biogas would be used for direct combustion, and what for grid injection. This depends on the balance of incentives for each. In general, a potential commercial advantage offered by biogas grid injection over its use in district heating systems is the higher load factor that can be achieved. The gas network is available all year round (limited only by off-peak demand levels), and it should be possible to ensure that all the biogas injected is used. By contrast, seasonal and daily variations in heat demand are likely to limit the load factor for district heating to substantially lower levels (although daily variations can be minimised by supplying mixed use developments, seasonal variation is more difficult to manage). There also is a wider question of what proportion of biogas would be used for electricity rather than heat production, as the electricity grid offers similar advantages of high load factors and may entail lower credit risk. Hence generation of electricity or injection into the gas network are relatively low risk options commercially, whereas the use of biogas to supply heat directly to specific sites carries a higher commercial risk

We provide further estimates of future potential and constrained uptake in Appendix A.

4.8.3. Barriers and opportunities

There are a number of barriers preventing the use of biogas for heating. As previously mentioned the current use of biogas for electricity is a key factor, but other barriers include:

- Lack of awareness and attitudes – from the demand side this relates particularly to district heating, from the supply side this concerns grid injection (not an issue on demand side as consumers would be largely unaffected other than price increases)
- Business risk – Investment in AD may be hit by current recession
- Technological risk – partly overcome by ensuring design is appropriate for application. Technology is generally mature and well understood, but can be operational problems. Grid injection is an emerging area however.
- Commercially simpler to generate and sell electricity than heat (particularly when supplying multiple customers)

- Lack of skilled installers and designers; while this is not currently a problem shortages could occur should the more optimistic scenarios be pursued
- Policy and most appropriate use – need clear direction as how best to use biogas in terms of carbon saving potential. In particular the best application of the fuel – e.g. vehicles or heating.
- Planning and odour issues
- Need to co-locate heat demand sources and supply of biogas unless using injection (or liquefaction)

A possible restriction on the use of biogas as a source of renewable heating fuel is its potential for use as a vehicle fuel. While the focus of this study is to consider the potential for renewable heat it would be remiss to gloss over the potential for biogas application in this sector. The transportation sector is a very difficult sector to address in terms of emissions and biogas can be upgraded and used in vehicles the same way that natural gas can. It is likely that the balance of incentives between electricity generation, heat generation and renewable transport fuels will dictate where the majority of gas use is likely to occur.

Planning consent will be required for most AD installations because AD is not considered within the agricultural planning guidelines, rather an industrial/waste treatment process. If the facility is going to use only feedstock from the farm and digestate will be spread only on the land of that farm, then it could be treated as permitted development (under part 6 of schedule 2 of the Town and Country Planning (General Permitted Development order 1995)) as long as the conditions can be met. In addition to likely planning permission requirements an AD plant will often have to obtain a waste management licence from the Environment Agency and may, depending on the input material, need to gain animal-by-products approval from the Animal Health Agency. In addition, depending on the disposal route for the residues additional duty of care will be required and perhaps the need to obtain biofertiliser land-use exemption from the Environment Agency.

However there are major benefits, such as security of supply and potentially more stable costs – depending on the fuel supply contacts in place.

4.9. Sustainability and Carbon Saving Potential

There is significant potential for production of biogas using AD. Only landfill and sewage gas has seen a high level of uptake at present, with limited use of AD for industrial effluent and food waste/MSW. A major expansion of AD is feasible which would greatly increase the level of biogas production providing the appropriate policies and, where necessary, financial support is put in place. However, the resource is limited by the availability of plant and the ability to economically gather resource together and even under optimistic scenarios there will be insufficient biogas to enable a full scale replacement of natural gas with biogas (less than 10% of current total usage). To increase the quantity of renewable gas further will require the production of syngas on a large scale, though the differing chemical composition means injecting into the gas network is much more challenging than for biogas, and is unlikely to be commercially viable in the short to medium term.

In purely physical terms, the most efficient use of a scarce biogas resource (for heat only applications, electricity only, CHP, or grid injection) will depend on the relative efficiencies of the conventional and biogas options, and on the CO_2 intensity of the counterfactual fuel being displaced. These factors will be site-specific. Assuming the efficiency of the biogas option is the same as the efficiency of the corresponding conventional option, it then becomes a question of the relative CO_2 intensity of the fuel being displaced. Moving from physical terms to cost-effectiveness, one needs to take into account the relative costs of the conventional fuels as well as the capex costs and the number of hours over which the capex can be spread (the load factor). For example, using an AD plant to provide on-site space heat may provide less cost-effective abatement than using the gas for grid injection or (at least in part) for electricity production, because heat demand is seasonal, whereas selling the gas or electricity on to the larger market afforded by grid access is likely to significantly reduce the impact of seasonality.

The use of anaerobic digestion in a controlled manner prevents the release of methane into the atmosphere. Given the high global warming potential of methane, this is an additional advantage (and one of the key reasons why landfill gas must be collected and combusted). When injecting into the existing gas network leakage must be minimised to prevent significant release of methane into the atmosphere which will reduce the carbon saving benefits.

In addition, the potential to use the digestate material as an alternative to conventional fertilisers offers the potential to reduce the use of fertilisers with higher CO_2 equivalent emissions over their lifecycle (including all relevant greenhouse gases).

On the negative side there is the potential for between 2-10 percent of biogas production to escape through leaks in the system, depending on plant construction quality. This gas includes methane which has a global warming potential around 23 times that of CO_2. Systems need to be designed and maintained such that they minimise the quantities of biogas that can escape to the atmosphere.

5. Biomass Boilers and CHP

5.1. Background

The term ‘biomass’ refers to any solid organic matter derived from plants (e.g. wood, straw). Energy can be released from direct combustion, or the material can be converted to gas or liquid for subsequent combustion or conversion to other products. This chapter considers the combustion of solid biomass only. Combustion of biomass is carbon neutral, assuming the production of the feedstock does not lead to net CO_2 emissions, either through land-use change, fertilizer input or change to harvesting frequency.[60]

Biomass as a fuel offers advantages over other renewables as it can be transported and stored and as such can offer a secure, reliable supply. Heat recovered from the combustion process can be used directly for heating, for generating electricity or both in a combined heat and power (CHP) plant. However, when compared to fossil fuels it is bulky and more difficult to transport and store which can present some difficulties in the uptake of this technology; all these issues are covered in this section.

There are many sources of solid biomass fuel, including specifically grown energy crops and residues from forestry management and arboriculture. In addition there is significant waste derived resource available, for example over half the content of typical municipal solid waste is biomass and much commercial and industrial waste wood is currently sent to landfill. This review also briefly considers the combustion of Municipal Solid Waste (MSW) in energy from waste (EfW) incinerators, though only the biodegradable fraction is classed as renewable.

This chapter presents a general overview of biomass combustion, including the technology, resource, policy and support mechanisms, current market situation and future potential.

5.2. Fuel Sources and Supply

When derived from a clean source biomass requires relatively little preparation for use as a fuel. Virgin wood has a high moisture content (typically around 50 percent) and it is advantageous, and for some applications necessary, to leave the wood to dry/season for several months (particularly if the fuel is to be stored for an extended period). The material is then formed into chips or pellets for use in a dedicated boiler or CHP unit.

The maximum economic transportation distance will be dependent on a number of factors such as the quantity supplied and source of fuel. At present, small- to medium- scale plants typically look for biomass supply within a 30 km radius.

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[60] As with most fuel sources, there are also emissions associated with transport, etc. Many biomass fuels are currently being assessed to determine their lifetime carbon balance, including issues of land-use change.

Plants combusting waste wood and other waste derived fuels (including animal by-products) must be compliant with the Waste Incineration Directive (WID), but there is a large resource available often at minimal cost as much of this material is landfilled at present.[61]

5.2.1. Fuel sources and existing resource

In recent years a number of studies have looked into the energy potential from biomass in the UK. The general conclusion is that there is a significant unused resource from arboriculture, forestry residues, waste wood and energy crops available now. Energy crops make up only a small proportion of the total figure but a major expansion is planned.

The UK Biomass Strategy published in 2007 suggested a total resource of 14.6M odt (oven dried tonnes) of solid biomass, excluding paper and card, the majority of which can be recycled.[62] A breakdown of the current UK resource is provided in Figure 5.1. If all of this resource was utilised it could provide approximately 18 TWh of electricity or 50 TWh of heat, equivalent to approximately 5 percent and 6 percent or more of current electricity or heat demand respectively.[63] To achieve higher levels will be dependent on a major expansion of energy crops and/or imports from abroad.

There are a large number of suppliers across the UK although many of these are very small and have a seasonal variation in output. Fuel brokerage companies (such as Forever Fuels) have formed to reduce supply risks and use back hauling to make delivery more efficient (important due to the low energy density of the fuel). Companies like this can aggregate the fuel in regional hubs which can make distribution simpler. The domestic production of wood pellets is currently small but is expanding.[64] Production may ultimately be constrained by the lack of raw materials, with the furniture board industry competing for forest waste and arboriculture arisings.

Pellet markets across the rest of Europe are increasingly mature with Sweden, Denmark, Austria, Germany and Italy leading the field. North America has a well-established market exporting large volume of pellets to Europe. China has stated a desire to increase pellet production both for domestic consumption and export.

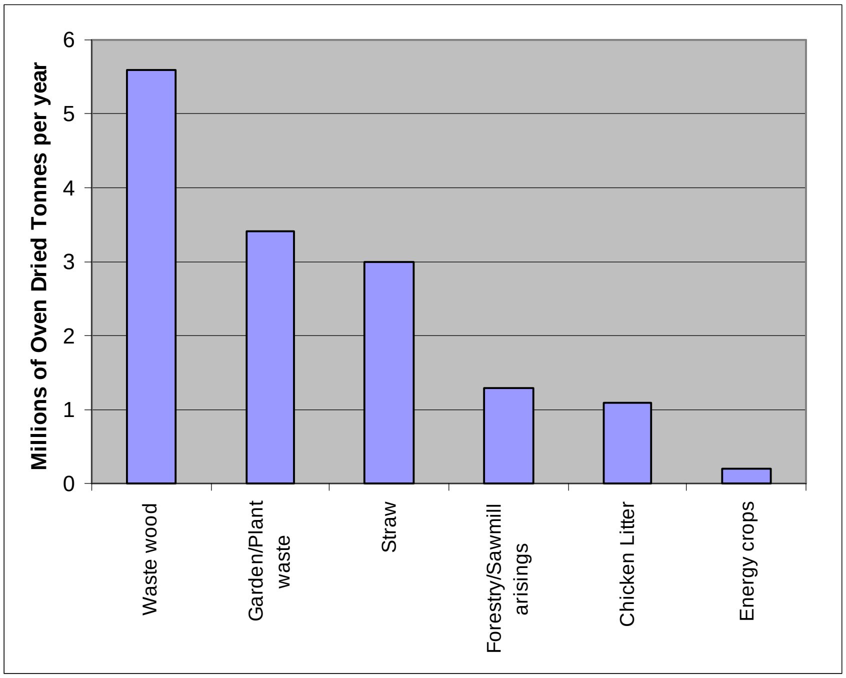
61 [Checking the cost of processing waste wood – e.g. for pellets – would be higher than similar costs for virgin wood? Or can waste wood not be used for pellets. Are there cleaning costs for waste wood – or is its applicability simply very restricted.]

62 UK Biomass Strategy, Annex A

63 The *Heat Call for Evidence* suggests that in 2005 the UK used 907 TWh of heat.

64 For example, Balcas currently is building a 100,000 tonne per annum pellet plant at Invergordon, Scotland.

Figure 5.1
Currently Available Biomass Resource



Source: UK Biomass Strategy 2007.
Note: Energy crops figure includes potential from land which has secured planting grants or has been approved for the purpose of growing energy crops.

5.2.2. Fuel types and characteristics

Woody biomass is generally processed into chips or pellets. Chips are produced using dedicated chipping machinery; pellets are usually made by applying pressure to fine particles or sawdust and extruding through a die. Logs and briquettes are also used but generally only in very small scale units. Ash content is low in all cases (in the region of 1-3 percent of the material). Pellets are generally more uniform and have lower moisture content than chips, but are more expensive. Pellets are better suited to small scale applications such as stoves and small boilers where consistent fuel is important for reliable operation, and where storage space is at a premium (usually domestic and small commercial and community systems) . Chips are generally used for medium and large scale applications as boilers tend to be less sensitive to the fuel specification and are able to easily handle a less homogenous fuel. Typical characteristics of chips and pellets are detailed in Table 5.1

The classification of some biomass fuel sources as waste has the potential to increase costs, prevent or delay projects thus restricting the potential installed capacity. If classified as a waste the differing regulations applied can impact on planning, storage, handling, transport and use of this material for heat production.

Table 5.1
Biomass Fuel Characteristics[65]

Type	Net Calorific Value (MJ/kg)	Moisture Content (%)	Typical Cost (£/tonne)	Typical Cost (p/kWh)	Approximate Particle Size	Bulk Density (kg/m^3)
Pellet	17	5 - 10%	200	~3-4	10mm	600 - 700
Chip	13 (@30% MC)	20 - 50%	80 (@30% MC)	~1.5-2.5	30mm	250

5.2.3. Transportation

The maximum economic transportation distance will be dependent on a number of factors such as the quantity of fuel supplied, type and storage capacity. The impact can be significant, for example transporting wood chip fuel a distance of 10 miles will add approximately £1 per MWh (around £4 per tonne) to the cost.[66] At present, fuel is typically not transported more than around 30 miles for small scale uses, unless the fuel store is particularly large and delivery intervals can be reduced.

5.2.4. Supply chain and potential restrictions

In some areas supply may be limited because of competition from very large biomass power plants. Large power stations have already created a significant demand for fuel for co-firing (1.4M odt per year in 2005), although only a small proportion of which comes from energy crops at present. For example this occurs at the 4GW Drax coal-fired power plant in North Yorkshire, where there are also plans for a very large scale biomass preparation plant on the site which could produce 1.5 million tonnes of biomass fuel per year for co-firing. In addition Drax has plans for an ambitious expansion of biomass energy production by constructing three separate 300MW power generation plants fuelled entirely by biomass, the first of which is scheduled to be operational in 2014 (potential requiring up to 1.5M odt of biomass). All of this is a major driver for biomass supply in the region; however it does mean that much of the home-grown fuel is likely to be contracted to supply Drax, potentially restricting the supply available to other users. As CHP is unlikely to be a feature of this plant the potential for renewable heat supply is low, and the overall biomass heating potential is reduced significantly as the available resource is reduced. Without a change in policy towards renewable heat this example is likely to be repeated in other regions, though not necessarily on such a large scale.

Conversely, as existing coal plants close in the future biomass resource may be released from those plants that currently co-fire. Reduced incentives for co-firing (as a result of changes to the Renewables Obligation) may also contribute to a shift in how biomass is used in future.

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65 The Biomass Energy Centre contains much more data relating to biomass fuel (http://www.biomassenergycentre.org.uk)

66 UK Biomass Strategy 2007 (Appendix A)

Overall, it seems likely that fuel supply will be restricted in some areas close to very large plants. Larger schemes therefore may need to source fuel from several different local suppliers, adding complexity. This situation may well change in the near future as the fuel supply market matures, and as imported fuel may become available.

It is also worth noting that the costs of clean biomass are likely to be significantly higher than waste derived fuels, though a plant handling only clean biomass will be less expensive than one handling waste and waste wood as the requirement for gas clean-up is much less stringent. Availability and price of fuel will have a major impact, currently both types of plant can be commercially viable propositions but there can be difficulties in securing adequate fuel supply contracts.

5.3. Non-Fuel Barriers

There are currently 2-3 developers of large scale plants in the UK with non-indigenous companies providing the turbines, boilers and turnkey plant construction (e.g., Alstrom, Siemens, Abengoa and Foster Wheeler). There are turnkey contractors in the UK who can fulfil the current demand for building and commissioning plant although there remains a risk of a lack of skills available to supply Engineering Procurement and Construction (EPC) and technology contracts which could delay and limit projects being installed, particularly if demand increases. In most cases the developer often takes responsibility for the operation and maintenance but relies on the equipment supplier to service the turbine, fluidised bed and boiler systems – there is no significant gap in this area.

The relatively limited availability of UK based manufacturers of high specification equipment is currently offset through imports, with Italy and Austria being important sources. If demand increases across Europe, or manufacturers fail during the recession, there is the potential for equipment supply to become constrained which could impact on the installation rates of plant thereby impacting on the overall installed capacity.

The installation and maintenance of new biomass heat plants requires skilled personnel, such as experienced engineers and plumbers. There currently are sufficient engineers to meet demand, however, if demand grows significantly there is a risk of a large skills gap that could lead to delays in projects, restriction on capacity being installed and sub-optimal operation of installed plant (i.e. not maintained correctly).

The installation of biomass systems in conjunction with district heating networks will require the installation of infrastructure which can be both costly and time consuming, and also cause significant disruption. The issues associated with installing district heating infrastructure can cause problems by delaying/preventing projects which in turn act as a constraint on the potential installed capacity. New build areas offer fewer obstacles for the installation of networks, both because of the higher density of occupation and because the disruption occasioned by the installation is lower than it is for retrofitting district heating to existing homes. On the other hand, the lower heating demand of new houses, and especially those with higher code levels under the Code for Sustainable Homes, combined with the high up-front costs of the networks can make district heating an unattractive proposition despite these advantages. However, the problems associated with retrofitting need not present an insurmountable barrier providing the heat density is sufficiently high, and retrofit projects have been undertaken or are currently underway in several cities, including Birmingham, Southampton, and Aberdeen. Often the development of heating networks is dependent on the will of the local authority to drive schemes forward, and this can vary dramatically from region to region.

The lack of an established and vibrant market (especially in the current economic climate) impedes the supplier development. Coupled with the complexity and increased costs of biomass systems there is a significant potential barrier to uptake – particularly in areas where natural gas is available. Gas replacement rates are in the order of 1.5 million units per year and given the current cost, fuel supply and availability of biomass units the displacement of gas is least likely. The lack of suppliers will also reduce the associated marketing, perceived availability and thereby limit supply of new systems. It also acts as a natural restriction on the number of customers that can be serviced and the geographical spread of services. In other words, there is not critical mass in the system which will impact on the installed capacity and potentially cause delays in the instalment of new systems.

Biomass plant require greater space in comparison to gas fired boilers and this additional space demand for fuel storage and vehicle access can restrict the application on certain sites. This can be a particular issue with retrofit heating sites that are currently gas fuelled although it poses far less of an issue for solid fuelled sites. The lack of adequate space has the potential to prevent biomass deployment and thereby restrict installed capacity.

5.4. Heat Only Biomass Plant

5.4.1. Overview

Biomass combustion is one the oldest sources of heat, though technology has evolved greatly with modern biomass heating systems being highly efficient with minimal emissions. There are concerns related to the potential localised air quality impact that could arise if biomass boilers were installed in sufficient numbers or where background levels of air quality are already poor.[67] Boiler plant can range dramatically in scale from individual wood stoves and boilers in homes to large industrial scale boilers serving process demand or heating entire neighbourhoods via a heat distribution network.

Typically wood chips or pellets are used. Pellets tend to be expensive but more uniform than chips and are often used in smaller applications. Chips can be significantly cheaper but are better suited to large boilers (several hundred kW and above) and are more bulky requiring more deliveries and/or increased storage capacity. Logs or briquettes can also be used for very small applications such as stoves.

Biomass boilers are much larger than their fossil fuel equivalent and require adequate fuel storage, the space requirement for storage may be as much or greater than for the boiler system itself. See Table 5.2 for typical boiler house footprints at differing scales. Biomass systems require an adequate storage facility and design with fuel specification often being high (for small systems) which means relatively expensive. In addition, the bigger plant size can therefore make these plants more expensive. There are significant economies of scale

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[67] See, e.g., AEA Technology 'Review of the Potential Impact on Air Quality from Increased Wood Fuelled Biomass Use in London', 2007

and the unit cost of heat from a small system will be much higher than a larger system. Part of this is due to the higher quality of fuel required in smaller systems in order to achieve high efficiency and reliability.

The efficiency of modern biomass boilers is high with up to 90 percent being achievable.[68] They can operate efficiently over a wide range of loads (typically between around 20 -100% of rated output), but they cannot respond to changes in demand as quickly as gas and oil boilers. In addition it is often best to use biomass boilers for base load operation to maximise the energy output and efficiency, and use top-up boiler(s) to meet peaks. Communal boilers supplying residential areas or mixed use developments are typically sized to meet 60 percent of peak load, and this is normally sufficient to supply approximately 90 percent of heat demand on an annual basis. Though it is possible to use biomass as top up it can be expensive to do this and for this reason, currently, gas or oil is often used. To minimise top up requirement accumulator tanks are often used to store hot water and smooth the demand profile allowing biomass to supply a higher proportion of the total.

Biomass systems can be compatible with other renewable heat options such as solar thermal and Ground Source Heat Pumps though it may not necessarily to do this economically, particularly if biomass is providing a relatively small proportion of the heat. There are examples of combined systems in Scandinavia that couple heat plant and solar thermal with a form of geothermal heat storage. Such systems require considerable land, are very expensive with the performance benefits remaining unclear.

5.4.2. Small scale

At domestic scale the systems used are wood burning stoves/heaters of a few kW output, and small biomass boilers rated from approximately 15 to 50kW, though these are suitable only for large houses. Heaters tend to provide background space heating (similar to an open fire but with significantly higher efficiency) and use small quantities of pellets or logs. Boilers almost always use pellets and feed a traditional wet heating system to provide space heating and hot water, but automated systems take up a much larger area than an equivalent gas or oil system and are often uneconomic in individual houses due to high capital costs.

At this scale fuel is expensive as ensuring high quality is crucial and comparatively small quantities are required, so discounts associated with bulk purchases are not available. Generally systems will cost more to run than gas, but can provide savings to properties heated by alternative more expensive fuels including oil and electricity. In addition grant funding is available (see Section 2.6) which may significantly improve the economic performance.

5.4.3. Medium scale

Larger boilers (ranging from 100kW to several MW) are appropriate for supplying heat to developments such as flats, small commercial and industrial sites and small community district heating schemes. Economies of scale mean that these systems are usually more economically viable than at domestic scale, and biomass boilers in flats can often compete with alternative communal heating systems in financial terms (fuel bills). Systems can either

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[68] On a Lower Heating Value (LHV) basis

be direct where hot water produced by the boiler is used directly in domestic heating systems, or indirect where the hot water from the boiler is passed through individual heat exchangers, which allow heat to be extracted only when required within individual properties.

A large number of schemes are currently operational in the UK including, Sheffield Road flats in Barnsley where an old coal boiler supplying social housing was replaced by two woodchip boilers with a combined capacity of 470kW. This was installed in 2005 and is one of the earliest such installations; since then many similar biomass heating schemes have been developed supplying homes, council buildings and industrial sites. An example of a boiler feeding multiple buildings is the Kielder village scheme in Northumberland, where a 300kW biomass boiler feeds various buildings connected by a village district heating network.[69]

5.4.4. Large scale

Large scale plants in the range of 10MW to 100MW or more can be used to supply single industrial sites or potentially for feeding large town-wide district heating networks. At this scale biomass CHP is often viable as traditional steam based electricity generation systems can be used. However, heat only systems can still be efficient and commercially viable enterprises.

There are many schemes of this type in Europe, but few large scale multi MW heat only schemes in the UK. Most large scale biomass and waste fuelled plant currently planned in the UK are either electricity only or CHP, largely due to economic incentives for electricity generation.

Table 5.2
Typical Plant Size – Heat Only

Applications	Rated Capacity (kW_{th})	Fuel Type	Fuel Requirement (tpa) [1]	Technology Type	Typical Footprint (Total Housing, ex Storage) [2]	Estimated Cost (plant only, (£/kWth)
Domestic	10 - 50	Log, pellet	90	Boiler	~10m^2	~£500
Flats, small industrial or commercial site	100 - 500	Pellet, chip	890	Boiler	~40m^2	~£300
Community district heating scheme	5,000	Pellet, chip	8,900	Boiler	~100m^2	n/a
Town-wide district heating scheme, large industrial site	50,000+	Chip	89,000	Boiler	~1000m^2	n/a

Notes: 1. Based on upper capacity bound
2. For fully automated system, based on upper capacity bound. Domestic biomass heaters will require minimal space, but systems producing hot water need significantly more.

69 http://www.energysavingtrust.org.uk/business/Publication-Download/?oid=349816&aid=1027931

5.4.5. System design

The design of biomass heating systems is generally more complex than fossil fuel systems. As well as increased space requirement for the boiler itself and fuel storage. Even for small scale boilers there will typically be a requirement for de-ashing, increased cleaning and maintenance, control systems (often incorporating remote monitoring for systems above around 100kW) and thermal storage in the form of hot water accumulators. Top up boiler(s) will also be necessary in many cases, particularly for larger systems, typically these will be gas fired (though can be biomass fuelled) and would be expected to provide in the region of 10% of total heat requirements. It is possible to avoid this requirement, for example if sufficiently large accumulators are installed or if the heat demand profile is relatively constant. District heating and the commercial issues associated with community heating schemes are considered in the district heating technology review in Appendix B.

5.4.6. Environmental issues

Biomass boilers and CHP plant fuelled by clean wood have very low emissions to air. Despite this they must comply with the Clean Air Act in smoke control areas, where a smoke control exemption is required and the boiler must be on an approved list of systems held by the relevant council. There should be very little smoke emitted from correctly operating plant, though releases can occur during start-up from cold. The ash produced from clean wood is non-hazardous and can be used as soil conditioner.

Despite this many projects have been delayed or abandoned on the basis of air quality concerns (NO_x and particulate matter typically), especially in areas where background air quality is already poor and the installation of a biomass plant(s) could lead to Air Quality Strategy Objectives being harder to attain or being exceeded. This can impact projects in two different ways: 1) biomass boilers may be required to meet stringent emissions standards (affecting the fuel and technology choice) and 2) may prevent their use in certain areas. The first impact would increase the cost of the project and potentially result in supply and skills constraints as the equipment and fuels may be less readily available. Coupled with the second element this may result in delays in projects seeking planning permission or act as a restriction on installed capacity

Where the fuel is waste derived the plant must comply with the requirements of the Waste Incineration Directive (WID) or Local Air Pollution Control, depending on the classification of the fuel. In both cases boiler and CHP plant must comply with all relevant PPC legislation. These requirements add costs to the plant design, build and operation with the costs associated with waste derived fuels being potentially more significant, although funding models for waste systems are fundamentally different given the potential for gate fees associated with the fuel. There are potential perception issues associated with ‘waste’ fuelled plant although with careful engagement with stakeholders these are easier to manage than those associated with mixed waste combustion.

Relatively small quantities of ash are produced and that obtained from clean wood is non-hazardous and can be used as soil conditioner; however the fly ash from waste wood is classed as hazardous and must be disposed of in a suitably licensed landfill.

5.4.7. Planning

For small wood boilers up to 50kW building regulations (Part J) apply (requirement J2). For larger boilers CIBSE Design Guide B and the local planning authority should be consulted. Permitted development rights apply to small biomass installations below a certain physical size (based on the boiler house footprint, but typically applicable to boilers with a rated output below 1MW), and so there will be no requirement for planning permission for many small scale systems. However, planning permission will be always required for larger installations. Planning could result in delays to implementation, prevention of installed capacity or changes to the systems being proposed all of this add to the potential costs, increase uncertainty and increase associated risks. Planning is typically dealt with at a local level and with increasing local requirements and targets for renewable energy barriers to renewables are being removed simplifying the consenting process. The risk of rejection of planning permission applications (related to lorry movements, visual impact, noise etc.) poses a significant barrier to the deployment of biomass heat (and CHP) plants.

For waste wood fuelled plant gaining planning permission can be challenging, particularly when heating residential areas as the plant should be as close as possible to minimise transportation. As well as the stringent air quality regulations, there may be significant local opposition which can be major barrier to the development of such schemes.

Planning permission delays can also impact on the ability to obtain finance with some lenders not willing to commit until full planning permission has been obtained.

5.5. Biomass Combined Heat and Power (CHP)

Generating electricity and then recovering the residual heat for useful purposes (such as space heating, hot water and process use) is known as combined heat and power (CHP) operation. In efficiency and carbon abatement terms CHP is always preferable to electricity only generation; for example the overall efficiency of an electrical only biomass plant is at most 30 percent, but the efficiency of a biomass CHP plant can exceed 80 percent.

At large scale, steam turbines are typically used for power generation with steam extracted from the turbine or heat recovered from the condenser for use on site or exported. This is proven technology with many operational biomass CHP plants, particularly in parts of Europe. Typically plants are sited on or near to large industrial sites or near residential areas (especially in Scandinavia and Germany), often with heat distributed to homes and businesses via a hot water district heating network.

At smaller scales the technology is less well established, though there are numerous examples of sub-MW systems in operation, again largely in Europe. A major constraint to development at small scale is that steam turbines are inefficient at small scales. In order to overcome this a variety of novel generators have been trialled, with varying levels of technical and commercial success.

For a CHP plant to be operated efficiently it is important the heat profile is suitable, ideally the heat demand should be as constant as possible. This is primarily because whereas any electricity surplus and shortfall can be imported or exported to the grid (albeit usually at additional cost), excess heat cannot and must be rejected to atmosphere[70]. Hence to maintain a high efficiency the level of heat rejection should be minimised. In order to be economic CHP plants should operate for a minimum of 4,000 hours per year as a 'rule of thumb', though the higher the running time the better.

Some rejection of heat is usually inevitable and is not necessarily a problem, but if the proportion of heat rejected becomes excessive there will be a fall in overall efficiency and the economic performance will suffer. Typical suitable sites include:

- Mixed use developments (residential and commercial)
- Hospitals
- Leisure centres
- University campuses
- Large hotels; and
- Industrial sites with process heat demand

In addition to the above, anywhere with a relatively high heat demand and smooth aggregate profile could be a potential candidate for a CHP system.

Given the current incentive structure in the UK heat recovery systems are often not fitted as this can impact of the efficiency of electrical generation and a corresponding reduction in incentive received. While this may be resolved with appropriate price signals and the establishment of a heat incentive the potential for it to restrict the installed capacity for heat recovery remains.

Table 5.3
Typical Plant Size - CHP

Potential Applications	Rated Capacity (kW)		Typical Fuel Type	Fuel Requirement (tpa)	Appropriate Technology Type	Estimated Cost (£/kWe) [71]
	Electrical	Thermal				
Small community scheme[72]	100	300	Pellet	750	Micro gas turbine	£5,000
Industrial site,	1,000	3,000	Chip	7,100	ORC turbine	£5,000

70 Although this can be partly mitigated by using thermal storage, discussed later

71 Estimates not provided for large scale systems as systems are not 'off the shelf' and there will be significant variation from project to project

72 The economic viability of biomass CHP is uncertain at this scale

Potential Applications	Rated Capacity (kW)		Typical Fuel Type	Fuel Requirement (tpa)	Appropriate Technology Type	Estimated Cost (£/kWe) [71]
	Electrical	Thermal				
Large community DH scheme, large industrial site	10,000	30,000	Chip	71,000	Steam turbine	n/a
Large DH system	50,000	100,000	Chip	270,000	Steam turbine	n/a

Note: The heat to power ratios shown are indicative of typical systems based on the likely maximum electricity output, but in practice CHP systems will be configured to meet the specific demands of the site. The maximum energy output is limited by the thermodynamics of the process, but the balance between heat and electricity can be varied. Site requirements, as well as overall plant size and technology choice will restrict flexibility. Government incentives available for renewable heat and/or electricity are likely to affect incentives to invest in equipment. Current incentives (in the absence of the RHI) favour the generation of electricity over heat.

5.5.1. Small scale biomass CHP

Steam turbines are inefficient at small scale (below a few MW) as the electrical efficiency falls rapidly and systems become uneconomic. A range of novel technologies have been trialled (see Appendix A for detail), with some commercial success, however systems are expensive and with the exception of Organic Rankine Cycle technology, most are still yet to be commercially proven. Proposed incentives for heat and small scale electricity generation may accelerate the deployment of these technologies, but it is too early to understand the potential impact of this.

5.5.2. Large scale biomass CHP

On a large scale biomass CHP plants, fuel is combusted to raise steam which is passed through a conventional steam turbine where electricity is generated. Steam can also be extracted for the turbine for heating, and there is potential to recover low grade heat from condensers. There are currently only a few examples of large scale biomass CHP plants in the UK, the largest being Slough Heat and Power with several others fuelled by waste (energy from waste incinerators at Nottingham and Sheffield for example).

Despite the lack of large CHP plant in the UK, there are several large electricity only biomass plants. One of the main barriers to the exploitation of CHP is the availability of appropriate heat demand coupled with the high additional cost of infrastructure, this often leads to the installation of electricity only facilities (particularly with the additional support these receive through the RO). One example of this is the recently commissioned plant at Steven's Croft near Lockerbie which has an electrical output of 44MW. This plant is not designed for CHP and is remote from heat loads, but there is no technical reason why it could not have been designed to recover heat. One of the main barriers to the exploitation of CHP is the availability of appropriate heat demand coupled with the high additional cost of infrastructure, as well as a support system favouring electricity generation over heat.

Elsewhere in Europe there are many biomass and EfW CHP schemes, particularly in Scandinavia and Germany. Changes in the support system (see Section 2.6) and increased awareness of the benefits of CHP and district heating may help to increase the take-up of this type of plant. In addition, the shift away from landfill is leading to a major expansion in EfW plants. Such plants are strongly encouraged by Government to make use of the available heat (often this is part of the planning conditions), and this has led to a number of EfW CHP schemes being developed or proposed.

5.6. Market Status

In many other European countries the focus has been on heating and large scale CHP systems, often in conjunction with district heating. The vast majority of plants use established and simple technologies, giving high efficiencies with associated economic and environmental benefits. In the UK the story has been different for large scale systems as the focus and support given to electricity generation has led to biomass power systems being developed in preference to simpler and often more effective boilers. Ambitious schemes to boost electrical efficiency such as the ARBRE project, an attempt at biomass gasification in a combined cycle have not been successful. The failure of this project and technical problems with small scale CHP dented confidence in the biomass sector, and has slowed uptake. The energy crop market has also struggled to expand as a consequence of perceived market uncertainty and the relatively long time-cycles of crops increasing uncertainty. However at smaller scales there are many examples of successfully operating biomass boilers, and the number is increasing (see section 4.6.1 for more detail). (Biomass CHP has also become more attractive recently as a result of the revision of the Renewables Obligation – see below.)

One of the key problems is securing fuel supply for projects, so it will be crucial to ensure a rapid expansion and high levels of quality control. This in-turn highlights issues regarding the source of the biomass, as many domestic fuel sources are not co-ordinated and carry a degree of uncertainty causing users to look to imports for secure supplies.

5.6.1. Heat only

Small and medium scale biomass boilers are now seen as a viable commercial proposition, particularly where grants are available and where fuel supply is reliable and relatively cheap (forested areas, near established suppliers etc). There are very few large scale heat only systems as it is usually preferable economically to generate electricity instead or as well as; an incentive for renewable heat may have a significant impact on this. In the commercial or industrial markets the increased cost of pelletised fuels may be unacceptable, and the large size and weight of straw bales makes them generally unattractive in most cases except on farms themselves. This leaves wood chip the most suitable fuel for the commercial and industrial sectors.

As noted above pelletised fuels are ideal to drive expansion of the residential market with the principal market for residential scale biomass heating being in rural and other locations not served by the gas grid (up to 4.4 million households). In addition approximately 1% of residential demand is assumed to be met through community/district heating – much of which is fossil fuel fired and therefore potentially a good target for biomass conversion.

Like the residential sector, the commercial sector is also constrained by physical space for boiler installations and by cost-effective access to biomass fuels. This again will likely favour greater development in rural locations although only a fraction of sites will have the space and access required to accommodate the larger size boiler and associated handling equipment needed for biomass. While the industrial sector may be less constrained in terms of space availability the most likely application will be to locations that are off the gas grid.

5.6.2. CHP

Biomass CHP at all scales is still very much an emerging technology in the UK. Large scale CHP systems in the UK are almost entirely fossil fuel powered (mostly gas). However, at large scales the technology is well proven and the market is mature in many parts of Europe

The reasons for the much higher level of deployment of biomass CHP in other parts of Europe include abundant resources (forestry), high heat demand (cool climate) and differing policies particularly towards district heating, which is usually used in combination with biomass CHP. There are few technical reasons why the UK could not see similar levels of deployment, with securing fuel supply being a key issue. The infrastructure requirements associated with district heating networks are also often considered a barrier with the laying of these incurring significant capital costs and the potential disruption that it can cause during construction. However, the infrastructure has a typical life of 50 years or more and therefore will benefit the community for some time.

At smaller scales the picture is more mixed. In the size range above approximately $500kW_e$ there is significant activity again in parts of Europe with some technologies relatively mature, such as that based on Organic Rankine Cycle technology (see Appendix A for a description). As an example, Italian manufacturer Turboden currently has 93 existing installations across Europe with a further 36 under construction, including one in the UK. These plants have an electrical output between 500 and 2,000 kWe, typical serving industrial sites and district heating networks.

In the UK there are a small number of Indirect Fired Gas Turbine (IFGT) systems in commercial operation (particularly Talbotts). Systems based on gasification have been plagued by technical problems at this scale and a lack of confidence in the technology hampers uptake in significant quantities. [73]

5.7. Support Mechanisms, Funding and Incentives

5.7.1. Support mechanisms

Until recently biomass heating projects in the UK have seen limited support, whereas several large electricity plants have been constructed (and co-firing in large coal power plants is now well established). The Renewable Obligation scheme incentivises electricity production from biomass over heat, a likely contributor to the decision to design most existing and planned large scale biomass plants for electricity generation only (e.g. plants at Lockerbie, chicken litter plants in the east of England).

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[73] [Further detail to be added about supply chain here -- installation expertise, skills, time required, potential rate at which plant / equipment is currently being built / manufactured.]

However in a bid to redress the balance towards heat, as of April 2009 biomass plants with CHP will be eligible for an additional 0.5 ROCs/MWh on the electricity generated (providing minimum levels of heat export are attained). There are also separate bands for co-firing and energy from waste. ROCs will provide an incentive for CHP to some extent, but it is the planned Renewable Heat Incentive (RHI) which may be of critical importance to the expansion of both heat only and CHP schemes as this may offer very significant revenues.

Table 5.4
Summary of Relevant ROC Bandings[74]

Generation Type	ROCs/MWh
Dedicated Biomass	1.5
Dedicated Biomass with CHP	2
Dedicated Energy Crops (with or without CHP)	2

The Energy Act also provides for funding from the RHI to come from fossil fuel suppliers, and costs are likely ultimately to be passed on to their consumers in the form of price increases (but unlike the Renewables Obligation where the funding ‘pool’ is fixed each year, the costs of the RHI scheme depend almost entirely on the uptake). Depending on the structure of the funding, the RHI subsidy may be used to offset the initial capital outlay (possibly restricted to small community scale schemes), a major barrier to the development of schemes even where the payback periods are reasonable.

In parallel to the RHI, a feed-in tariff for electricity generated from renewables with a rated capacity below $5MW_e$ is expected to be introduced in April 2010, which could replace the existing RO system for installations below 5MWe. This benefit will apply even to fairly large biomass CHP systems, hence this technology could be eligible for both RHI benefits on heat produced (when the RHI is introduced in April 2011) and feed in tariff benefits on electricity, as well as existing benefits such as Climate Change Levy Exemption Certificates (LECs)[75], so could become a very attractive commercial proposition. This depends any adjustments to RO or FIT support that may be made to account for the support offered to heat output through the RHI.

5.7.2. Funding

The Bioenergy Capital Grant Scheme provides funding for both heat and CHP projects for businesses and charitable organisations[76] covering all scales. The scheme, funded by the Department of Energy and Climate Change (DECC), is currently in its fifth round and up to £500,000 of funding is available for any single scheme.

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74 Full list can be found here: http://chp.defra.gov.uk/cms/roc-banding/

75 With the exception of ROCs as the feed in tariff is expected to replace this mechanism at small scale

76 http://www.bioenergycapitalgrants.org.uk/

Phase 1 of the Low Carbon Buildings Programme (LCBP) allows up to £1,500 grant funding to biomass boilers, or £600 off heaters or stoves.

Phase 2 of the LCBP[77] provides funding for non-profit community organisations, and this includes a range of microgeneration technologies including solar thermal and PV, GSHP, domestic scale biomass boilers etc. Grants are available to cover up to 50% of the capital cost, and a maximum £1M of funding is available per site (whether this funding is also available for larger scale communal systems is unclear, however).

The deadline for applying for both the above schemes is 2009, though there may be further rounds to follow. However it may be that in future the RHI will replace capital grants, so the continuation of these schemes cannot be relied upon in the long term.

Enhanced Capital Allowances (ECAs) allow businesses to write off the tax of certain low carbon equipment (including biomass boilers below 1MW rated capacity), and hence provide another benefit.

5.8. Current Output Levels and Future Potential

In 2005, biomass contributed some 0.6% of total heat UK supply (5,200GWh). Over six times this amount of electricity was generated from biomass, much of this from landfill gas and co-firing (1.4Mt biomass used for co-firing in 2005).

We provide further estimates of future potential and constrained uptake in Appendix A.

5.9. Sustainability and Carbon Saving Potential

5.9.1. Sustainability

The use of UK derived biomass from sources other than energy crops has few sustainability issues. There will be some CO_2 emissions associated with fossil fuel use during fuel preparation and transportation, which results in biomass having very low, though not zero, net CO_2 emissions. In addition its use as a fuel can prevent wood from being sent to landfill where it can degrade to methane (a potent greenhouse gas and particularly an issue with waste wood from industrial and commercial sources) and so it can often have a positive impact in additional ways other than reduced CO_2 emissions as a result of displacing fossil fuel combustion. At the current time there are no expected problems with competition from other uses yet (e.g. board manufacture, gardens etc).

UK grown energy crops can have an impact on food production (and costs) and biodiversity, but only likely to be significant at high coverage scenarios. In addition changes in land use leading to displacement of food crops have CO_2 emissions implications as well with "leakage" related to land use / agriculture / forestry remaining poorly understood.

Biomass fuel imported from overseas has higher transport emissions (and costs), but can still be a sustainable when the source is from properly managed forests for example. However

[77] http://www.lowcarbonbuildingsphase2.org.uk/

there can be major problems from energy crops (especially oils) displacing native forests in relation to biodiversity and increased greenhouse gas emissions from deforestation.

5.9.2. Carbon saving potential

Biomass is formally zero-rated for the EU ETS emissions registry. There are emissions associated with crop cultivation, fuel preparation and transportation, but it is otherwise carbon neutral. For the purposes of company reporting biomass can carry a nominal carbon emissions factor. There are various sources of CO_2 emission data, though actual emissions will vary depending on transportation distance.

In the case of energy crops displacing indigenous forests the net CO_2 emissions may be much higher, potentially exceeding that of fossil fuels, with an additional negative impact on biodiversity.[78]

Table 5.5
Based on Existing Woody Biomass Resource Only[79]

If all resource (14.4 MT/yt) used for:	Total displaced energy (MWh/year)			Carbon savings (tonnes CO_2/year)		
	Grid Electricity	Gas	Total	Grid Electricity	Gas	Total
Heat only	-	65,497,222	65,497,222	-	11,069,031	11,069,031
Electricity only	19,263,889	-	19,263,889	10,460,292	-	10,460,292
CHP only	19,263,889	38,527,778	57,791,667	10,460,292	6,511,194	16,971,486

78 [Source to be provided]

79 Currently assumed 14.4 Mt/y, source: UK Biomass Strategy 2007

6. Solar Thermal

6.1. Background

Solar thermal systems use the heat radiated by the sun to produce hot water via a solar collector. In their simplest form they consist of an absorber plate through which tubes containing water (or other fluid) is circulated. The water is heated as it passes through the collector and is then stored in a hot water cylinder.

Domestic scale solar collectors are generally used to preheat hot water, and typically contribute around a third to a half of the domestic hot water supply on an annual basis, though the heat generation is directly proportional to the collector area.[80]

Solar thermal systems perform best in direct sunlight, though they can produce useful amounts of energy even on cloudy days. A downside is that they produce the most energy in summer when the days are longer and the sun higher in the sky, but this is also usually also the time when heat demand is lowest, so supply and demand are not necessarily well matched.

Solar thermal systems currently have a relatively low take-up in the UK, currently around a very small proportion of existing homes. However it is an established and well proven technology with much higher levels of deployment in other countries (see Section 5.5).

6.2. Applications and System Design

6.2.1. Collector types

Three primary technologies dominate the domestic solar thermal market:

- Standard flat plate collector – uses a high absorption surface to absorb heat which is trapped in the collector by a low emissivity glass plate. Tubes embedded in the absorber plate carry water (or other fluid) to which the heat is transferred.
- Evacuated tube collector – uses the light from the sun to heat low-pressure liquids held in vacuum-sealed tubes. The heat from the vapour is then stored in a solar hot water tank. The vacuum within the evacuated tubes reduce convection heat losses.
- Unglazed collector – simple design typically used for heating swimming pools, very common in the USA but less so elsewhere.

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80 Although solar thermal is primarily used for small scale heating, there is increasing interest in using concentrating solar technology on a much larger scale, to produce much higher temperatures for electricity generation. This is done by using parabolic mirrors to focus the sun's rays to a central point, where either steam is raised and used in to power conventional turbines. A number of large scale 'solar towers' have been built and others are planned, where a large number of heliostats focus the sun to a point at the top of a tower where temperatures of several hundred degrees are achieved. Molten salt is often used as the heat transfer medium and is used to raise steam for use in a turbine. The molten salt can be stored to allow continued generation even at night. Plants can be designed to also recover and export heat in CHP mode, just like any other large scale thermal electricity generation plant.

Such systems offer definite potential in regions of the world, but given the very large areas and significant solar resource required they are unlikely ever to contribute significantly to UK energy supply.

Estimated yield in the UK can vary significantly, from 220kWh/$m^{2/}$year in high latitudes to 690kWh/m^2/year in low latitudes[81] on average (note the current government assumption is approximately 310kWh/m^2/year). The yield will vary on a daily and yearly basis depending on weather conditions, and is also highly dependent on the collector orientation and the technology used (evacuated tube designs have higher thermal efficiency).

A typical collector in the UK can produce around 0.3MWh of heat per m^2 per year when properly sited. For a typical domestic collector with an area of around 4m^2 the energy yield thus is approximately 1.2MWh per year. This is only a small proportion of the total heat requirement of an average UK house (less than 10%), but around a quarter of hot water demand. However new build properties, especially in future, will have significantly lower heat demand due to improved insulation, so solar thermal systems can supply an increased proportion of the total.

6.2.2. System design

Suitable properties need to have an adequate area of south-east to south-west facing roof space. The system must not be shaded as this will reduce the output. The optimal location and orientation in the UK for solar panels of any technology is on a south facing roof at an angle of around 30°. This is the optimum, but locating a panel on an incline of between 5° and 60° to the horizontal could still produce around 90% of the optimal yield[82]. The systems typically require checking (and cleaning if necessary) once a year by the owner and a more thorough check by a registered installer every 3 to 5 years. Although these maintenance requirements are modest, the low output of solar systems mean that they can be significant on a per-kWh basis. Systems are generally robust, especially flat plate collectors, but can be damaged by hail and direct systems can be damaged by frost.

Solar thermal systems require a relatively large storage tank. As lower water temperatures are preferred (allowing a higher proportion of heating from solar), a larger tank is required to achieve the equivalent energy storage capacity of a conventional system. The need for hot water storage means that solar thermal is incompatible with many combi-boilers. This may pose a significant constraint to expansion as the high efficiency of gas combi boilers have made them the preferred option for the majority of residential properties. Solar thermal is compatible with most other technologies that incorporate storage, including gas, biomass and electricity.

Direct systems circulate water from the storage tank through the collector (i.e. the water used for washing etc is circulated through the collector. Indirect systems keep the collector fluid separate from the domestic supply, and are recommended where temperatures routinely fall below freezing during the year as antifreeze must be added to the water, or an alternative liquid with a low freezing point used as the working fluid. Hence this type of system is usually installed in Europe (and indeed in many other parts of the world).

Passive systems use natural convection to circulate water, but tend not to be pressurised and are not generally used in cooler climates and more advanced heating systems. Active systems

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[81] Carbon Trust – Solar Thermal Technology

[82] Department of Trade and Industry active solar fact sheet

use a pump to circulate the fluid around the system, and are the standard type in Europe. The electricity requirements of the pump and thermal losses in indirect systems therefore make them inherently less efficient.

6.3. Barriers

6.3.1. Planning issues

The requirement to obtain planning permission when installing solar thermal panels has been eased by changes to the permitted developments rights in 2008. Permission is not required for any size roof mounted systems (providing panels protrude no more than 200mm from the roof), and standalone systems do not require permission if they are less than 4m high, $9m^2$ in area and less than 5m from property boundary. However, permission is still required in some circumstances, such as in Conservation Areas and World Heritage Sites.

6.3.2. Other potential barriers

The installation and maintenance of new solar thermal installations requires skilled personnel. At current levels of installation there is not a skills gap. However, at significantly higher rates of deployment a lack of skilled workers could be a significant constraint. Although training is relatively quick, there nonetheless a possibility that projects will be delayed (or avoided, if there is a perceived risk of maintenance service problems) which will impact on the installed capacity. In addition, high levels of deployment may require the use of sub-optimal siting or configuration which could reduce the efficiency of installed systems. The overall impact of this on energy saved from installed equipment is likely to be relatively small (<10%) in most cases, but could reduce efficiency by as much as 40% in extreme cases.

There can be some complexities in installing solar thermal units to existing roofs. Relevant considerations include the fit with the roof type, health and safety requirements, and maintaining the performance of the roof (as the roof fabric is penetrated but must remain water-tight). These complexities can add to costs and time required to fit solar thermal systems that may put potential consumers off or delay projects, both of which would tend to limit the installed capacity.

In addition to the potential incompatibility with combi-boilers introduced above, some other difficulties can arise when integrating solar thermal technologies with existing heating systems (for example, cylinders also may require replacement). This can add to the time and cost of retrofitted installation, which again could prevent or delay projects and would act as a restriction on installed capacity.

Equipment supply also may restrict the potential. The UK manufacturing base is small and the amount of high-quality collectors limited . The overall impact is likely to be small, as imports likely would be able to substitute for domestically produced equipment. As with other technologies the lack of a vibrant and growing market at the current time limits the desire to develop the UK manufacturing base and also restricts the current geographic coverage of some equipment suppliers – again impacting on the potential installed capacity rates.

6.4. Economic Performance

The total cost of a solar thermal system is lower than that of many microgeneration technologies, primarily due to their relative simplicity and maturity particularly in parts of Europe and China. However, the cost per unit output can be substantial.

The main cost elements are the collector, heat transfer system, a compatible hot water cylinder and installation costs. In addition some installations may only be feasible if the boiler also is replaced, and in such cases solar may be less attractive. The typical cost of an installed system is provided in Table 6.1.

Table 6.1
Solar Thermal System Indicative Costs

System Type	Specific Cost (£/m^2)	Cost per typical domestic installation (£)[83]
Flat Plate	500 – 750	2,000 – 3,000
Evacuated Tube	750 – 1125	3,000 – 4,500

6.5. Support Mechanisms, Funding and Incentives

The Low Carbon Buildings Programme (LCBP) is currently the key source of funding, Phase 1 for domestic buildings will continue until 2010. A maximum of £400 of grant funding towards the system cost is available[84]. Phase 2 for community buildings is only open until July 2009 but grants are available to cover up to 50% of the system cost.

The proposed RHI is likely to be very important from 2011 onwards. For small systems the output is likely to be deemed rather than metered, and may be used to cover the capital cost to increase the uptake, effectively making it a capital grant scheme. This may well replace the existing grant funding programmes. However, a very significant per-MWh subsidy would be required to cover the additional cost of solar systems. (As an indication, even at a low discount rate of 3.5 percent the cost of solar is on the order of £330 / MWh over a 20-year lifetime, as compared to perhaps £45 / MWh for the cost of using gas heating depending on gas prices.[85])

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83 Energy Savings Trust. Assumes a typical domestic collector 4m^2. Costs are indicative only and may vary significantly.

84 http://www.lowcarbonbuildings.org.uk/how/householders/

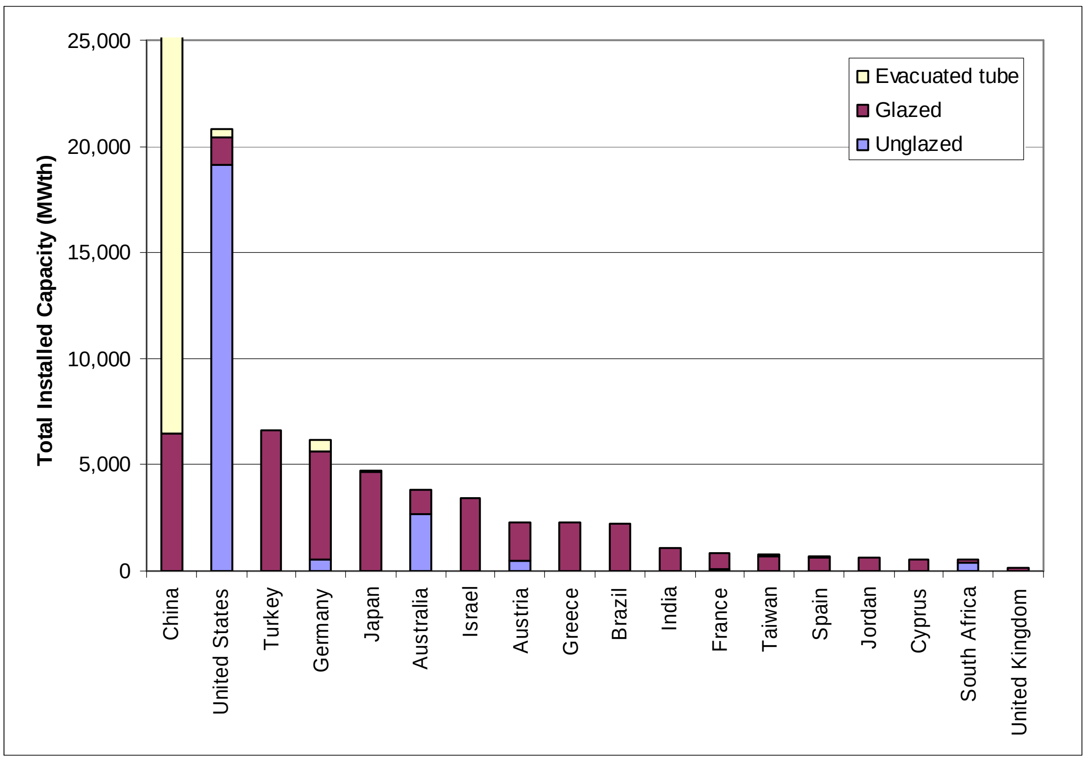
85 This calculation assumes yearly output of 1,100 kWh from a typical household 2.5 kW at a capex of £1,800/kW (corresponding to a cost of around £4,500 installed) , and also allowing for maintenance costs corresponding to £18/kW/year. The cost of solar increases significantly at higher discount rates. The cost of gas assumes a price of 3.5 p/kWh and a low boiler efficiency of around 75 percent. The capital and maintenance cost of the boiler is not included in the calculation as the use of solar thermal does not obviate the need for a boiler.

6.6. Current Output Levels and Future Potential

Solar thermal has a relatively low uptake in the UK and a number of other European countries have much higher installed capacity. For example, Germany has installed capacity of 6.3 GW_{th}, as compared with 0.2 GW_{th} in the UK, despite the similar sunshine resource in the two countries.[86] The US has a large number of simple, unglazed collectors used mainly for heating swimming pools but otherwise relatively few domestic type systems. China has by far the highest number of systems with an installed capacity of 65 GW_{th}, the vast majority of which are of the evacuated tube type. Reasons for higher uptake in other countries include less widespread gas infrastructure, greater support and more proactive policies, cheaper materials and installation, more expensive alternative fuels, and better solar resource. However, with appropriate support there is no reason why the UK installed capacity could not see a significant increase.

We provide further estimates of future potential and constrained uptake in Appendix A.

Figure 6.1
Worldwide Solar Thermal Uptake as at December 2006 [87]



[86] http://www.estif.org/fileadmin/estif/content/publications/downloads/Solar_thermal_markets_in_Europe_2007.pdf

[87] IEA Solar Heating & Cooling Programme, May 2008

6.7. Sustainability and Carbon Saving Potential

Although solar thermal could be used in a large number of premises its carbon saving potential is limited by the fact that it provides only a small proportion of heating needs (particularly where there is a high space heating demand), and by its unsuitability in properties with poor orientation, shading and limited space (including flats), and many non-domestic buildings where the contribution from solar thermal may be very low. In addition the requirement for electricity to power pumps in active systems reduces the net efficiency slightly.

The Energy Saving Trust estimates that an average domestic system reduces CO_2 emissions by 325kg per year when displacing gas[88]. Using this indicative performance number implies a best estimate of carbon saving potential of 2.5-3 $MtCO_2$ by 2020, with the low to high estimates ranging between 1-5 $MtCO_2$ / year.

[88] Energy Saving Trust, http://www.energysavingtrust.org.uk/Generate-your-own-energy/Solar-water-heating

7. Introduction to the Renewable Heat Model

This section provides a brief overview of the renewable heat model used to derive the marginal abatement cost curves.

7.1. Supply Curve Demand Segments

We use a cost curve model of renewable heat as the basis for estimating the marginal abatement cost curve. The cost curve is estimated in the following segments:

- Technology:
  - Air-source heat pumps,
  - Biogas district heating,
  - Biogas injection into the gas grid,
  - Biomass district heating,
  - Biomass individual boilers,
  - Ground-source heat pumps, and
  - Solar thermal.
- Consumer segment:
  - Domestic (residential)
  - Commercial / public
  - Industrial
- Consumer sub-segment:
  - Domestic: detached houses, flats, other houses (semi-detached, other)
  - Commercial public: small private, large private, small public, large public
  - Industrial: low-temperature process heat, 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:
  - Pre-1990, and
  - Post-1990 (including new build)

This segmentation results in around 250 distinct demand segments, each of which can be combined with five technologies (excluding biogas injection).

The analysis does not cover combined heat and power, which will be the subject of a separate project to be undertaken by AEA for DECC. The outputs of this work have not become available in time for incorporation into the modelling in this project. The analysis also does not cover biofuels, fuel cells, or (deep) geothermal heating.

7.2. Cost and Technology Characteristics

For each demand segment, we use estimates of technical and cost characteristics to develop an estimate of the cost of using each of the renewable heat technologies to serve the heat load. Specifically, we use estimates of the following quantities:

- Capital expenditure (including equipment costs, installation costs, auxiliary works, etc.);
- Fixed operational expenditure (chiefly maintenance)
- Lifetime
- Thermal efficiency
- Load factor
- Representative size

The technical data have been estimated by AEA Technology, relying on a range of sources. For a given technology, the various parameters can vary significantly between different demand segments. The demand segmentation therefore also translates into significant cost heterogeneity.

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 renewable heat as the difference between the levelised cost of each renewable heat technology and its relevant counterfactual fossil fuel or electric heating option.[89] The cost estimate optionally can include estimates of demand-side barrier costs, such as time costs or inconvenience associated with the use of renewable heat (see below for further discussion).

We calculate the cost of abatement 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

[89] In the case of biogas injection the relevant counterfactual is wholesale natural gas, and the wholesale price thus is used as the cost of the counterfactual.

emissions factors for fuel combustion and electricity to the energy input used by each counterfactual and renewable heat technology.[90]

7.3. Approach to Estimating Abatement Potential

Our approach to estimating abatement potential can be summarised in the following five steps:

1. Estimate maximum technical potential for each renewable heat technology, accounting for total heat demand and the suitability of different technologies to serve different types of heat load;
2. Estimate the market potential, accounting for the rate of replacement of heating equipment;
3. Estimate demand potential, accounting for interactions between the adoption of different technologies (which depends on their respective CO_2 abatement costs);
4. Estimate supply potential, accounting for constraints on overall resource and supplier capacity; and
5. Finally, estimate final potential accounting for the joint impact of all of the above factors.

The first step gives the technical potential. The next two reflect "demand-side" considerations, and the fourth step incorporates supply side constraints. The final step integrates all of these. We describe below how these factors are accounted for.

7.3.1. Technical potential

The starting point for an assessment of demand-side constraints is to identify the *technical potential*, defined as the heat demand that could feasibly be served by the respective renewable heat technologies. Technical potential is estimated individually for each technology, and based on two components. First, we use recent Updated Energy Projections from DECC estimating of total heat demand for each year until 2022.[91] The overall demand has been apportioned to the various demand segments using a range of sources on industrial, domestic, commercial and public heat demand, with main sources including the English Housing Condition Survey, the BRE Domestic Energy Factfile, data from the ENUSIM and BRE models, assessments by the Carbon Trust of commercial and public sector heat demand, and proprietary AEA data.

Second, AEA has assessed the suitability of each renewable heat technology for each demand segment. The assessment has accounted for a number of factors. One that applies to several technologies and heat loads is the ability of the technology to produce the quality of heat required. This is a consideration for industrial process heat, which cannot readily be served by any other renewable heat technology than biomass combustion, and in some cases may require fossil fuel or electric heating to achieve the required temperature or consistency. As

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

[91] See http://www.berr.gov.uk/energy/environment/projections/index.html

discussed in detail in section 2.4, the issue of heat quality it also can arise in the case of heat pumps in domestic settings, as the high-temperature output required in some cases either may not be achievable from heat pumps, or may significantly detract from heat pump performance.

Space requirements also may make renewable heat technologies unsuitable for some applications. For example, biomass boilers require bulky equipment as well as space for fuel delivery and storage; ground-source heat pumps or solar thermal installations require space for heat collectors; while several technologies require more space than is available in particular types of housing (notably, flats).

The compatibility with existing heating systems also may pose limitations. Examples of issues include the limited compatibility of domestic solar thermal with increasingly widespread combination boilers, or the requirement for low-temperature heating systems such as under-floor heating for the effective use of heat pumps. These issues have been accounted for partly by the assignment of suitable vs. unsuitable technologies, and partly by adjusting efficiency and capex assumptions to reflect the higher costs that may be required in unfavourable circumstances (e.g., the fresh installation of a wet heating system).

Another issue is the co-location of suitable heat loads with sites for heat production. This is a significant consideration for the production of biogas for heat, although less so for biogas injection. This consideration also is significant for CHP.

The suitability assessment also has accounted for some issues that may be considered "barriers", notably air quality constraints for biomass, limiting the proportion of urban heat load that can be served by this technology.

Overall these and other assessments have resulted in the exclusion of a large number of combinations of technologies and demand segments from the technical potential. Table 7.1 shows the technical potential in terms of heat and emissions abatement $MtCO_2$. Note that these are ***not*** additive, because there is overlap between the heat loads for which each technology is suitable.

Table 7.1
Technical Potential of Renewable Heat Measures

	Heat potential (TWh)			**Emissions abatement potential (MtCO2)**		
Technology	**Domestic**	**Non-domestic**	**Total**	**Domestic**	**Non-domestic**	**Total**
Biomass boilers	170	322	492	42	95	137
Biomass DH	160	101	260	40	28	67
ASHP	245	158	404	23	27	49
GSHP	143	100	243	19	19	38
Solar Thermal	21	3	23	4	1	5

Note: These potentials are ***not*** additive, because of overlap between the heat loads for which each technology is suitable.

7.3.2. Demand-side constraint 2: Market potential

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.

It may be possible to accelerate uptake above this level, at the cost of accelerated depreciation of still functional heating systems. We deem this an unlikely route to increasing potential, especially as the rate of replacement is not the binding constraint on overall potential in our central scenario. Even without accelerated depreciation, the size of the market potential exceeds supply potential for all technologies in the central case.

There are two main exceptions to the stock replacement approach to defining demand-side 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, assuming a representative size for each solar thermal installation.

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.

7.3.3. Demand-side constraint 3: Demand potential

The market potential defines an upper bound on the adoption of a *single* renewable 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. In the case of renewable 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 refer to the potential available once these interactions have been accounted for as the "demand potential", which we estimate through modelling.

7.3.4. 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 constrained. The model accounts for two main sources of such restrictions:

- Overall resource constraints: this is relevant to the biomass (biomass boilers, biogas combustion, and biogas injection) technologies. The total amount of biomass used is restricted not to exceed estimates of the total available suitable resource. These estimates, in turn, are derived from E4tech (2009) and additional estimates developed by AEA.
- Supply industry constraints: AEA also has developed scenarios for the feasible rate of expansion of the capacity to supply renewable heat technologies. There are several potentially relevant constraints on supply, including available expertise, infrastructure,

companies, institutions, and other elements of the supply chain required to deploy renewable heat.

7.3.5. Final potential

Modelling is required to calculate how the above considerations translate into a final abatement potential. Concretely, 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 renewable 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.

8. Modified Maximum Abatement Potential

This chapter provides summary results of the modified maximum CO_2 abatement potential available from renewable heat measures, and their associated costs. As noted above, the modified maximum potential (MMP) reflects various adjustments to the maximum technical potential (MTP), and represents a more meaningful quantity in the context of renewable heat. We therefore present results for the MMP in lieu of the MTP.

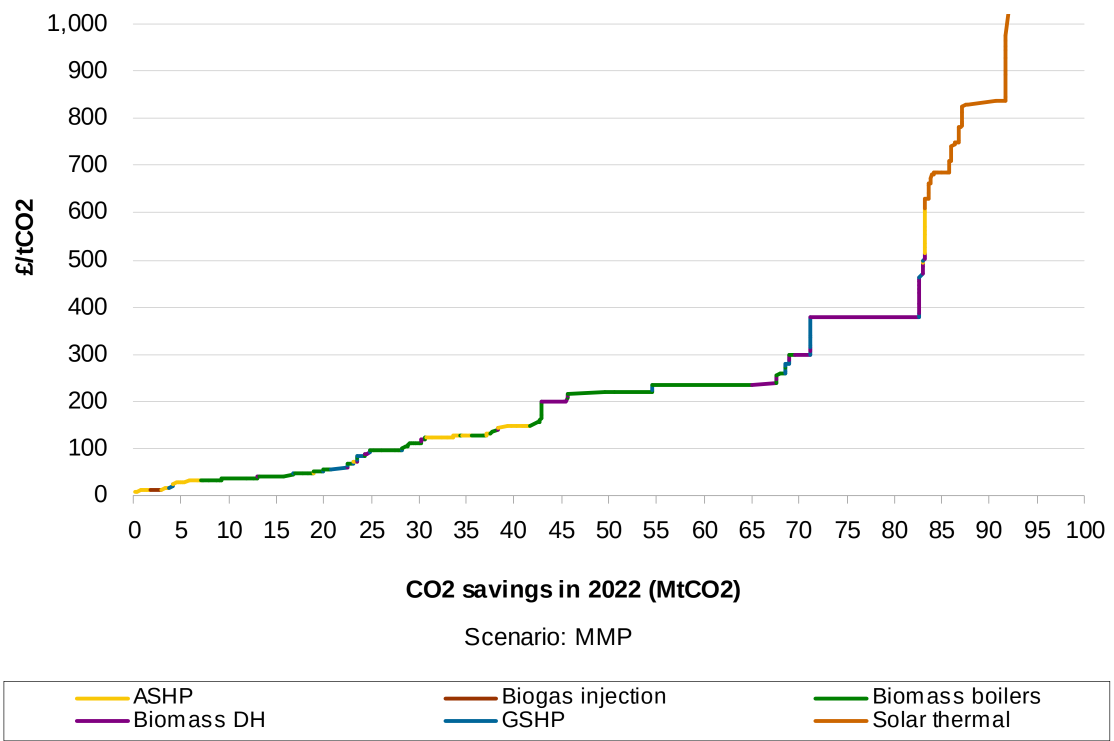
MMP is defined by the total size of the market for heating equipment in demand segments that could feasibly be served by the relevant renewable heat technologies. The MMP therefore reflects total heat demand, the suitability of renewable heat technologies to serve this demand, and the rate of replacement of heating equipment over time.[92] It also takes into account our abatement cost modelling, so that each segment is served by the renewable heat technology that has the lowest marginal abatement cost. In the spirit of defining an upper bound on the abatement potential, the MMP does not reflect any constraints on the growth of supply of renewable heat technologies. The MMP abatement cost curve thus shows the abatement that would be delivered if all heating equipment that is decommissioned between now and 2022 were replaced by renewable heating options.

Figure 8.1 shows the modified maximum CO_2 abatement potential in 2022 of the renewable heat technologies included in the model, categorised by technology. Emissions corresponding to just over 90 million tonnes of CO_2 ($MtCO_2$) could be abated by 2022 at costs up to £1,000 / tCO_2. Of this, 70 $MtCO_2$ are available at costs up to £300 / tCO_2. After this point the abatement cost curve rises steeply, reflecting the high abatement costs associated with solar thermal technology as well as some biomass district heating options.

Note that the cost curves presented below reflect the standard methodology used by the Committee on Climate Change with regard to the calculation of abatement costs. Important assumptions include the use of a 3.5 percent discount rate to levelised capital costs, and the exclusion of demand-side barrier costs and hassle costs (such as the cost of time or the inconvenience of any disruption associated with taking up a particular technology). We revisit these assumptions in Chapter 9, where we discuss some of the barriers to uptake, and in section 9.7, where we present further results that reflect the cost implications of alternative assumptions.

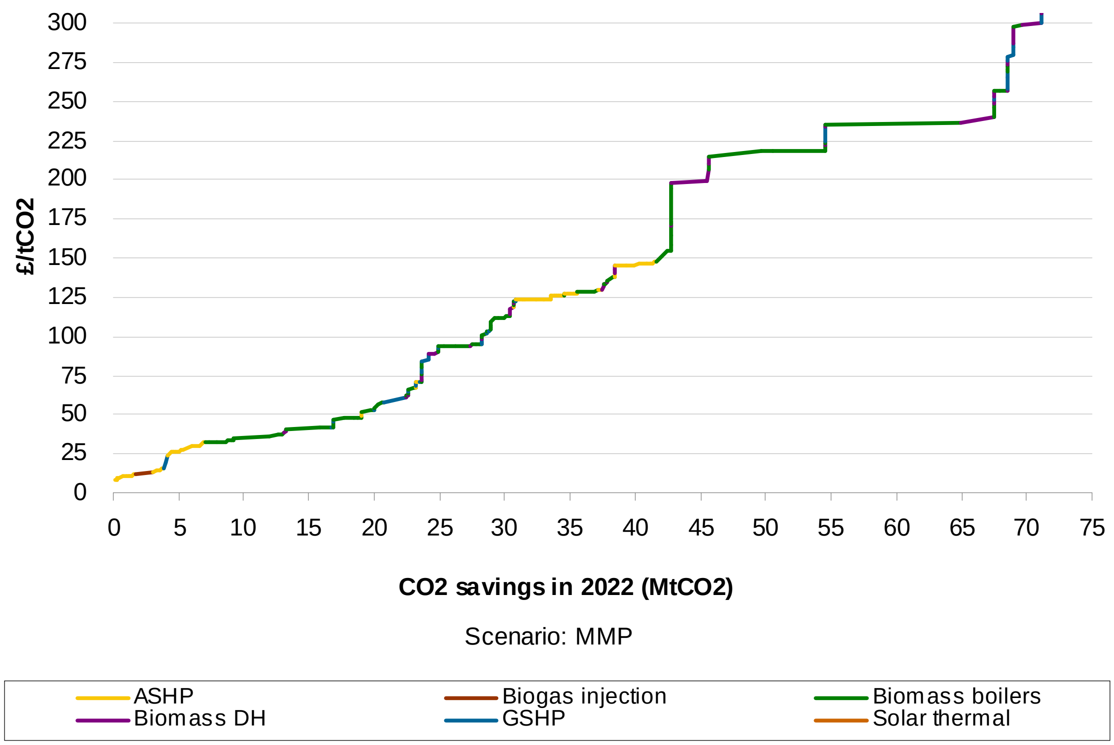
92 It would be possible to increase the potential by replacing existing heating equipment before the end of its useful life. However, because the overwhelming majority (>90 percent) of the existing heating stock anyway is expected to be replaced over the 2011-2022 modelling period, the additional abatement delivered by accelerated replacement would not be very great..

Figure 8.1
Modified Maximum Potential of Renewable Heat by Technology (2022)



To aid in the interpretation of the figures, we present MACCs on a different scale below, showing the abatement costs for measures that cost less than £300/tCO_2. The figures show the abatement costs by technology, consumer segment, and fuel counterfactual, respectively.

Figure 8.2
Modified Maximum Potential of Renewable Heat by Technology: Detail (2022)



The lowest abatement cost technologies, which have relatively limited abatement potential, are ASHPs (in the commercial / public sector) and biogas injection. Following these, by far the most significant technology represented on the MMP MAC curve are individual biomass boilers, indicating that these are the cheapest method to reduce CO_2 emissions for most of the heat demand segments. This reflects in part that biomass boilers can be cheaper than other renewable heat technologies on a per-MWh basis, but also reflects the fact that the net emissions abatement per MWh from other technologies is lower. Biomass accounts for over 20 $MtCO_2$ (nearly three quarters) of MMP abatement at costs below £100/tCO_2 in the figure.

Note that the MMP MACC should ***not*** be interpreted as indicating that there is little potential available from the other technologies. Rather, it reflects the fact that each consumer demand segment takes up the renewable heat source that reduces its CO_2 emissions at least cost. For any one segment, only one technology is selected. If biomass heat were not available (or were more expensive) there would be less biomass potential, but there would be increased potential from the other renewable heat technologies.

The maximum potential is divided among the domestic, commercial, and industrial sectors, as shown in Figure 8.3. Most of the relatively low-cost abatement potential (up to £50 / tCO_2) is found in the non-domestic sectors, with the majority accounted for by the use of biomass boilers for industrial process heat. As noted above, there is also a smaller but significant potential for ASHP in the commercial and public sectors—reflecting the fact that this technology is increasingly common even under a “business as usual” scenario. There is also abatement potential from ASHPs in the displacing gas in the commercial / public sectors, but this comes at abatement costs between £100-125/tCO_2.

Figure 8.3
Modified Maximum Potential of Renewable Heat by Consumer Segment (2022)

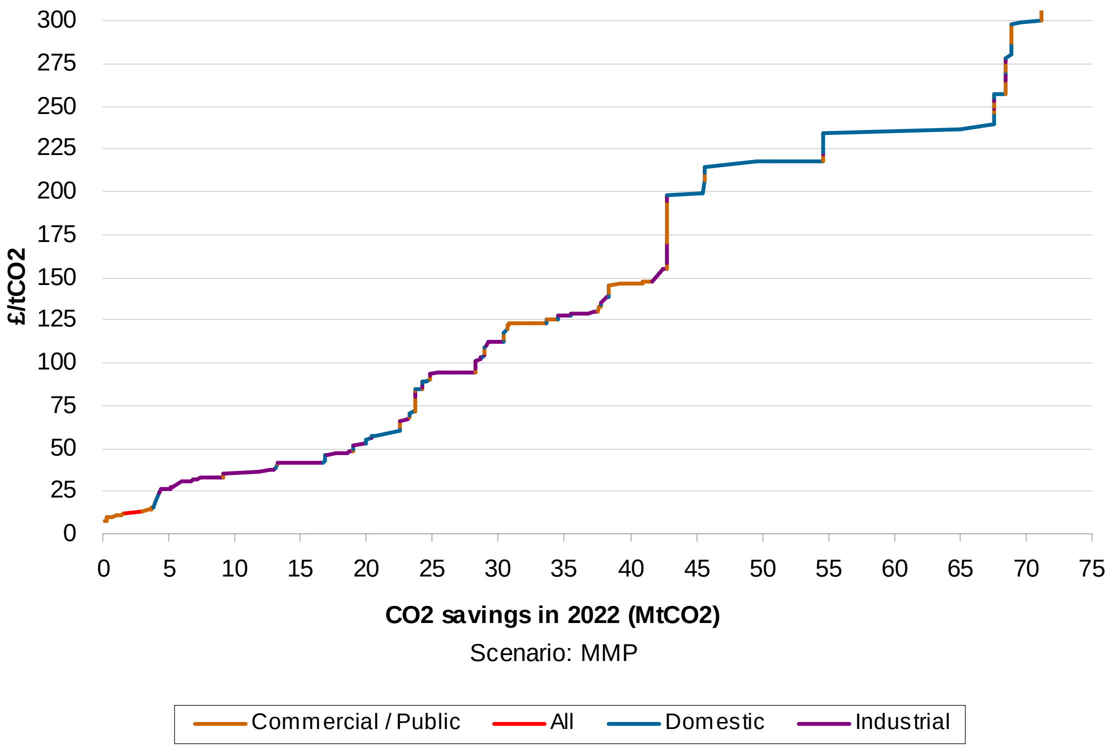
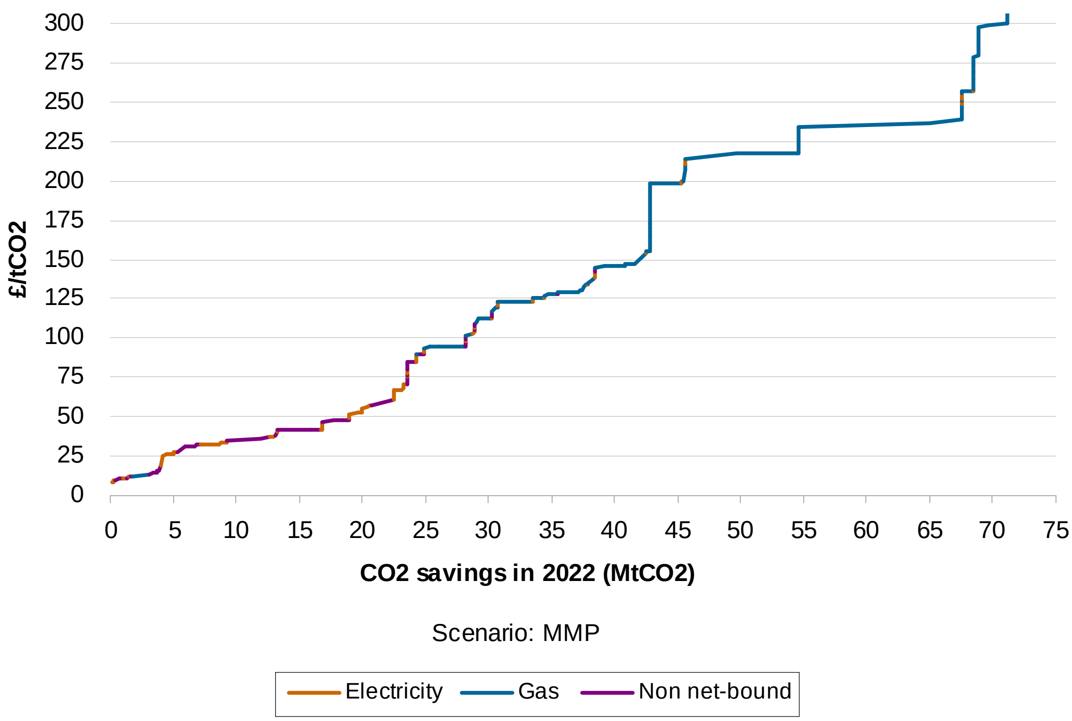


Figure 8.4
Modified Maximum Potential of Renewable Heat by Fuel Counterfactual (2022)



The domestic sector accounts for only a small proportion of the low cost abatement potential, with GSHPs off of the gas grid accounting for most of this.[93] The majority of domestic sector abatement potential comes at costs in excess of £200/tCO_2, and overwhelmingly involves biomass—primarily individual boilers, but also some district heating.

Figure 8.4 shows the MACC by fuel counterfactual (categorised as gas, non-net-bound fuels, and conventional electric heating). With the exception of grid injected biogas (and some industrial biomass boilers at just under £100/tCO_2), none of the abatement potential costing less than £100/tCO_2 involves gas as a counterfactual. The low-cost potential is split between non-net-bound fuel (oil, solid fuels, and liquefied petroleum gas) and electric heating, with non-net-bound fuels accounting for most of it. In contrast, the vast majority of abatement potential costing between £100-300/tCO_2 involves the replacement of gas as a heat source.

Figure 8.5 shows the MMP in 2022 alongside the MMPs in the years 2012 and 2017, by technology. The MMP increases each year in proportion to the number of heating systems replaced (up to the point where all systems have been replaced), so there is an approximately linear progression in the abatement potential. (There are also some reductions in cost over time.)

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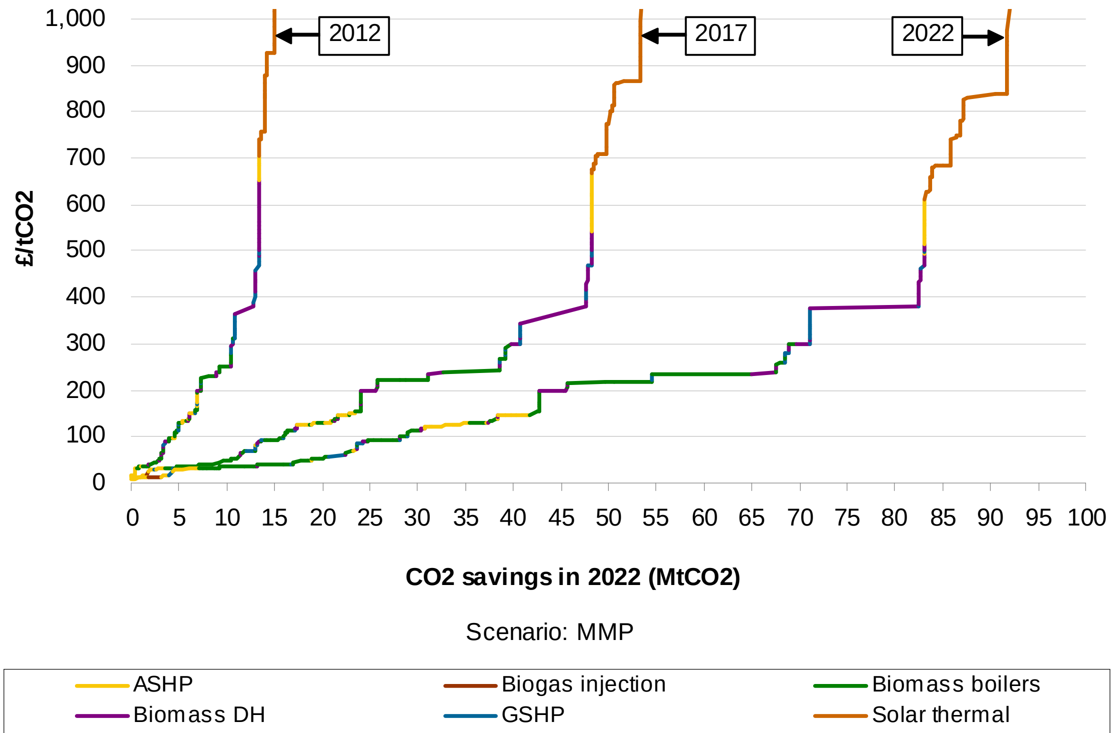
93 GSHP are more cost-effective than ASHP in the domestic sector primarily because for the relevant properties they are assumed to have a higher COP.

Figure 8.5
Modified Maximum Potential of Renewable Heat by Technology (2012, 2017, 2022)



9. Realistic Trajectories for Abatement

As noted, the MMP accounts for the suitability of technologies, and for the fact that heating equipment is replaced gradually over time, but does not account for other constraints. In this section we outline the additional constraints incorporated to arrive at more realistic estimates of the cost and potential for emissions abatement using renewable heat technology.

9.1. Demand-Side Constraints

9.1.1. Market size for heating equipment

As noted in section 7.3, we account for a number of demand-side considerations in the modelling of the potential market renewable heat market that underlies the MAC curve. The primary demand-side constraints are the following:

§ the suitability of the various technologies to serve different types of heat load;

§ the overall level of heat demand from demand segments where technologies are suitable for use;

§ the rate of heating equipment stock replacement; and

§ the overlap of technologies that potentially could serve the same load.

These together define the maximum size of the market for renewable heating equipment until 2022, and thus also the MTP and MMP.

9.2. Other demand-side barriers

9.2.1. Treatment of additional capital expenditure

We also account for various factors that in some analyses are classed as demand-side "barriers" that arise through the requirements for auxiliary engineering or equipment associated with the use of renewable heat. Examples include boreholes for ground-source heat pumps, the district heating pipe networks, fuel stores for biomass heating, conversions required to make pre-existing heating systems compatible with renewable heat technologies, and other major capital outline required for the use of renewable heating technologies.

These types of barriers are included directly through the estimated capital expenditure associated with the adoption of renewable heat technologies. The expenditure required in many cases depend on the properties of the demand segment, and the segmentation of the demand curve thus allows for many of the relevant effects to be captured. One example of this is that many renewable heating technologies require a wet heating system to function, so additional costs would be incurred in the conversion from electric heating. Other examples include the higher cost of district heating networks in urban areas compared to rural areas, stricter air pollution controls could be required in urban than in non-urban areas, or various higher costs associated with installation in older properties.

9.2.2. Implications of heat load characteristics

In addition to the impact on capital expenditure, the different characteristics of heat demand in different supply curve segments have several other impacts that determine the attractiveness of renewable heat for a given application.

One prominent effect is that the overall size of the load has a direct bearing on the cost of abatement through renewable heat technologies. Although smaller heat loads can have smaller fixed costs (e.g., a smaller heat pump or boiler), the up-front costs typically do not decline proportionately with the reduction in overall load. One effect of this is that smaller heat loads typically have a higher per-MWh cost over the equipment lifetime. Another is that a smaller heat load typically makes renewable heat technologies less attractive relative to fossil or electric heat, as up-front costs typically account for a higher proportion of the costs of renewable heat than of the relevant counterfactual heating system. As a result, for a given technology, the cost per tCO_2 abated is higher for smaller loads than for larger. The model accounts for these effects through variation in the size of the building or enterprise (large vs. small commercial / public and industrial; residential house type) and through the age of buildings (pre-1990 vs. post-1990 buildings). The effect also is pronounced where lower heat demand results in lower load factors (rather than just a reduction in capacity). For this reason, the use of renewables for (high load factor) industrial process heat typically has lower additional cost per tCO_2 abated than does (low load factor) space heating.

The characteristics of the heat load have an additional impact on the cost of abatement using heat pumps. The model captures the fact that, with current technology, the seasonal coefficients of performance can be significantly worse in older and / or larger properties with higher heat load requirements. As a result, the cost of abatement is higher for these categories of properties, both because running costs are higher and because the net abatement achieved per unit of heat output is lower.

9.2.3. Inconvenience, disruption, and time costs

Another category of cost that may be associated with renewable heat technologies is that they can entail additional time input, inconvenience, or disruption compared to the use of fossil or electric heating technologies. Some of the relevant time costs are discussed in Enviros (2008a), including estimates of costs of planning applications (as well as offering helpline and guidance support) and for the search ((finding the best technology option, installer, etc.), installation, and operation of renewable heat technologies. In Enviros's assessment, renewable heat technologies are likely to require additional time cost for all of these activities to varying extent.

Additionally, where technologies are adopted in response to policy intervention, there are likely to be administrative costs associated with participation in that policy. Potential activities could include learning about scheme rules, applications for support, documentation to establish eligibility, potential reporting of energy use, etc.

Another category of cost is the inconvenience or "hassle" associated with renewable heat technologies as compared to fossil or electric heating. Examples include the additional hassle of arranging for deliveries of and handling biomass fuel (as compared to net-bound fuels), and the inconvenience of having a garden dug up to fit a ground-source heat pump.

Element Energy (2008) sought to value some of the relevant factors in the household sector, using survey evidence and stated preference techniques. There are likely to be analogous costs in the non-household sector, including the cost of disruption to production upon installation, as well as the risk of further disruption or reduced performance if renewable heat technologies are less reliable or have more uncertain performance than do well-established conventional boilers or electric heating.

These costs have been reflected in previous analyses of renewable heat for Government, and various costs in these categories are included in forthcoming analysis for DECC (see NERA 2009, forthcoming). However, for this project the CCC has requested that we not include these costs in the cost of abatement using renewable heat. We understand that this approach is required for consistency with other models used by the CCC. We understand that the rationale for this methodology is the CCC's assessment that these costs do not represent relevant social costs in the context for which the CCC will use the relevant marginal abatement cost curves.

9.2.4. Informational, behavioural, and related demand-side barriers

Enviros (2008b) also identifies other barriers to the adoption of renewable heat including "inertia", lack of awareness of the relevant technologies, and lack of confidence in the technologies. These are similar to barriers often quoted in the context of energy efficiency (see NERA 2007[94], for a discussion). These barriers suggest methods for increasing the uptake of renewable heat, including demonstration programmes, marketing campaigns, and other mechanisms aimed at improving the state of knowledge.

One difficulty with these barriers is that their significance is very difficult to gauge. Another is that they may be transitory, as much of the initial resistance encountered by a new technology may be overcome as adoption becomes more widespread. The experience with many of the relevant technologies in other countries suggests that various "behavioural" sources of disinclination to adopt renewable heat technologies can be overcome to create a mass market – and even become the dominant heating technology – once a reliable supply industry and widespread adoption is underway.

9.2.5. Implied uptake rates

To avoid introducing arbitrary parameters that are not grounded in empirical assessments, we have not used "uptake rates" or similar parameters to explicitly reflect inertia or lack of awareness / confidence. However, we emphasise that the scenarios used in the modelling nonetheless are consistent with the existence of such barriers. For example, in the "central" plausible scenario (see below for details of the associated assumptions) the share of renewable heat in the total relevant market for new heating equipment remains below 12 percent until 2015, rising to 30 percent by 2022. In the more ambitious "high" scenario, the corresponding numbers are a 16 percent market share in 2015, rising to just over half in 2022.

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[94] NERA Economic Consulting 'Evaluation of Supplier Obligation Policy Options', report for DTI, 2007.

9.3. Supply-Side Constraints

As noted in the discussion of the various technologies above, there is a range of barriers that may impede the supply of renewable heat. We provide a brief summary for each technology below (please refer to the respective chapters, and to the discussion in Appendix A for more detailed discussion).

9.3.1. Biogas

Section 3 highlights several distinct barriers to the development of biogas supply. The availability of material suitable for digestion depends on several factors, including waste policy (notably, the introduction of waste separation), waste infrastructure development, and competing uses and pre-existing contracts (e.g., for EfW) for potential materials. Although supply potentially could be increased significantly through the digestion of biocrops, both AEA and Entec indicate that this is an unlikely development given the significantly higher cost and potential competing uses for this resource, such as direct combustion. The growth rates used are based on relatively ambitious increases in household waste separation and collection, as well as a substantially increased contribution from commercial and industrial sources (e.g., food waste) and farm wastes.

The other main constraint is the feasible rate of expanding digestion capacity. Currently there are less than 15 anaerobic digesters of the size envisaged under a scenario of large-scale expansion, whereas to achieve the market potential in the central scenario below implies the need for approximately 500 AD units of 2 MW capacity by 2022. This expansion would require the development of significant new supply industry. Entec's assessment shows growth constrained by the availability of expertise and skills required to build new capacity, as well as planning and other barriers.

9.3.2. Biomass boilers

The growth rate in biomass boilers is limited chiefly by the availability of supply companies and industry knowledge. Currently only a small number of companies are undertaking commercial and business biomass projects, with the public sector and private projects supported under the Bio-energy Capital Grants Scheme providing most of the demand. The growth rates underlying the scenarios are based on those achieved in other markets, including Sweden and Austria, where biomass use has increased significantly. These growth rates in turn reflect the various factors discussed in section 5.3, including equipment supply chains; the capacity of skilled installers; and likely feasible rates of growth of existing companies.

As highlighted in Chapter 5, the reliability and availability of fuel currently is a barrier to the uptake of biomass, although there would seem to be several reasons why these obstacles could be overcome. A recent project by E4tech (2009) suggests that there is little reason that fuel availability should be an absolute constraint on growth, with as much as 200 TWh of biomass fuel potentially available from domestic sources alone by 2020, and 320TWh by 2030. There also is significant potential to import biomass from more well-established markets where there already are commodity markets for wood chips and pellets. Nonetheless, making this fuel available would depend on the development of regional and local supply capacity, including infrastructure. Moreover, even if the resource is available in principle it is likely to be a challenge establishing fuel supply that matches the reliability of fossil fuels.

Air quality requirements could limit the feasible rate of expansion of biomass. This has been accounted for in the original assessment of what proportion of heat demand is suitable to be served by biomass boilers (for example, individual domestic biomass boilers are limited to houses in rural and suburban areas). AEA does not foresee any technical improvement that is likely to dramatically reduce emissions of nitrous oxides or particulate matter from smaller boilers over the period to 2022, although larger boilers offer more opportunities for emissions reductions. However, even given these restrictions, the amount of potential demand is likely to outstrip supply industry capacity by a large margin.

Biomass district heating faces another set of supply barriers, the most significant of which is the disruption associated with laying heating pipes. Availability of expertise in large-scale biomass projects also may be a factor. The growth rate restrictions on biomass district heating take into account past developments in community heating and the factors that previously have limited growth (including the need for coordination, planning, and significant capital outlay). It does not reflect the potential for CHP, which is a more likely way to power district heating than heat-only biomass boilers. Also, as highlighted in a recent report by Pöyry (2009), widely different trajectories for district heating are possible. If there were concerted effort to overcome current barriers higher rates of growth may be feasible.

9.3.3. Heat pumps

The growth rates for air-source heat pumps are significantly larger than for other technologies. This reflects the fact that this is a relatively mature technology, linked to the global refrigeration and air conditioning industry, whose production could be scaled up quite easily given favourable economic conditions. Compared to biomass and biogas, the supply chain is less complex, with fuel supply posing no constraints except in very high-growth cases where additional grid reinforcement may be required. The growth of ground-source heat pump supply capacity is more restricted than that of ASHPs. This reflects the greater complexity and more specialised skills required for this technology.

The growth rates in the central scenario are consistent with those achieved in other countries where heat pumps have become a widespread technology (e.g., France, Sweden and Switzerland).

9.3.4. Solar thermal

The solar thermal supply capacity is based on the availability of approximately 10,000 engineers working nearly exclusively to install 800,000 solar thermal systems by 2022. The total available potential is a significant downward revision of estimates by Enviros (2008a). This reflects in part a reassessment of the amount of output from typical solar installations, resulting in much lower estimates. The number of engineers assumed to be available to install solar thermal also is smaller.

9.3.5. Biomass CHP

As noted, the potential for renewable CHP is being assessed in a separate project for DECC that is still ongoing. The outputs from this work are not available, and therefore we have not been able to investigate to what extent the potential for renewable CHP is overlapping with (rather than supplementary to), the abatement potential presented in this report. Our understanding based on discussions of preliminary findings is that CHP could offer significant ***additional*** abatement potential, particularly among larger heat loads. To the extent the potential were overlapping, the technology most likely to be affected is biomass boilers.

9.4. Supply-side Scenarios

To reflect the above supply-side constraint, and to account for general constraints on industry growth, we make use of scenarios for the growth of supply capacity. These are based on the work carried out by NERA and AEA in work for DECC. This analysed each technology separately, accounting for the current state of the UK industry, growth rates observed in other countries, as well as the technology-specific factors discussed above. Please refer to NERA (2009) for a detailed description of the scenarios.[95]

As part of the current project, the scenarios have been separately cross-checked against additional analyses carried out by Entec and Element Energy, which are presented in more detail in section 9.4.3 and in Appendix A. Additionally, the trajectories have been extended to 2022.

9.4.1. Central scenario

The central scenario detailed growth rates and growth potential for each technology are shown in stylised form in Table 9.1, split by the domestic and non-domestic sectors.[96] As this shows, the total realistic potential in 2012 is relatively low, with a modest increase from the current baseline of around 6 TWh of renewable heat. By 2017, this grows significantly, to 31 TWh, a three- to four-fold increase on 2012 levels. This grows further to 86 TWh, or around 14 percent of total heat demand, by 2022. Of this, around two-thirds are in the non-domestic sector, reflecting the fact that the larger scale of projects in industry and commercial / public applications makes a ramp-up of supply capacity easier.

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96 The potential is shown in stylized form for 2012, 2017, and 2022 only, along with the implied growth rates. The underlying analysis and model for industry expansion varies by technology, and in several cases is based on three phases: a likely emerging phase for technologies that are not yet established; a rapid growth phase in early years; and then a more mature phase of stable expansion towards the end of the period. For a detailed description of the scenarios, please see NERA/AEA (2009) 'The UK Supply Curve for Renewable Heat', available at: http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/renewable_heat/incentive/supply_curve/supply_curve.aspx The "central" scenario corresponds to the "central" scenario in this analysis.

Table 9.1
Growth Rates and Growth Potential for Renewable Heat Technologies (TWh)
(Central scenario)

Technology	Sector	2012	2017	2022	Growth rate 2010-2015	Growth rate 2015-2020
ASHP	Non-domestic	0.7	4.2	16.3	45%	31%
ASHP	Domestic	0.2	1.4	5.4	45%	31%
Biomass boilers	Non-domestic	4.0	9.6	22.7	19%	19%
Biomass boilers	Domestic	0.1	1.8	7.2	67%	32%
Biomass DH	Non-domestic	0.6	0.9	1.7	9%	13%
Biomass DH	Domestic	0.6	0.9	1.6	9%	12%
GSHP	Non-domestic	1.1	6.1	15.6	40%	21%
GSHP	Domestic	0.4	2.0	5.1	40%	21%
Solar Thermal	Non-domestic	0.2	0.5	1.0	22%	17%
Solar Thermal	Domestic	0.5	2.7	6.2	38%	18%
Biogas injection		0.3	1.1	3.4	29%	26%
Total		**9**	**31**	**86**	**29%**	**23%**

The growth rates corresponding to these estimates are shown in the last two columns. These vary significantly by technology, reflecting the different extent of supply barriers. Heat pumps have the highest growth rates, whereas biomass and biogas technologies (and particularly for district heating) have lower rates of growth.

Note that these numbers are supply-side *inputs* to the modelling, showing the potential for industry supply growth. To obtain an abatement cost curve it is necessary to combine these inputs with the demand-side modelling of where potential is taken up, and at what cost.

9.4.2. Alternative scenarios

The achievable growth of supply capacity is a significant constraint in the modelling, and in the central case it constitutes a more significant limitation on abatement potential than does the market size of heating equipment to serve suitable heat loads. However, as indicated above, there are very significant inherent difficulties in predicting the likely development of supply industries, many of which currently are in their infancy. The significance of the barriers to increased supply is very uncertain, and it therefore seems important to consider scenarios with different growth of potential than in the central case. We present two such cases below.

9.4.2.1. High growth

The high growth scenario is detailed in Table 9.2.[97] This corresponds to a scenario where all industries simultaneously grow at rates as high as or exceeding rates achieved for individual technologies in other countries where financial, regulatory, and other conditions have been favourable for the various technologies. Nearly all technologies are mass market technologies in this scenario, with particularly high contributions from biomass boilers and heat pumps, and (again) the majority of capacity in the non-domestic sectors. Additionally, the scenario incorporates a significantly more optimistic scenario for district heating, on the lines projected by Entec. Overall, the output in 2022 is significantly higher than in the central case, reaching 149 TWh by 2022, or around 25 percent of total (non-electric) heat demand if all supply capacity were utilised.

Table 9.2
Growth Rates and Growth Potential for Renewable Heat Technologies (TWh) (High scenario)

Technology	Sector	2012	2017	2022	Growth rate 2010-2015	Growth rate 2015-2020
ASHP	Non-domestic	0.7	5.0	26.3	49%	39%
ASHP	Domestic	0.2	1.6	8.7	49%	39%
Biomass boilers	Non-domestic	4.0	11.2	37.3	23%	27%
Biomass boilers	Domestic	0.1	2.1	11.6	72%	40%
Biomass DH	Non-domestic	1.0	3.6	7.0	29%	14%
Biomass DH	Domestic	1.0	3.6	7.0	29%	14%
GSHP	Non-domestic	1.1	7.2	25.6	44%	29%
GSHP	Domestic	0.4	2.4	8.4	44%	29%
Solar Thermal	Non-domestic	0.2	0.6	1.7	26%	25%
Solar Thermal	Domestic	0.5	3.1	10.2	42%	27%
Biogas injection		0.3	1.3	5.6	33%	35%
Total		**10**	**42**	**149**	**34%**	**29%**

9.4.2.2. Low growth

The features of the low growth scenario are shown in Table 9.3. This corresponds to a scenario where barriers are more significant, which could ensue for a number of reasons. As represented in the table, the scenario is one where all barriers are more significant, resulting in lower supply capacity from all technologies, but other "low" scenarios also can be envisaged. One may be that a slow start means the significant growth of the central scenario is not feasible in the period to 2022; or, alternatively, that policy support is not sustained throughout the period, resulting in lower growth in the latter years where much of the

[97] This corresponds to an extension of the "higher" growth scenario in NERA/AEA (2009) 'The UK Supply Curve for Renewable Heat'.

potential is added in the central and high scenarios. Another possibility is that particular technologies do not develop, whether for policy or other reasons. A low scenario also may be connected to demand-side considerations, such as fossil fuel prices or carbon prices that are less favourable to renewable heat.

Table 9.3
Growth Rates and Growth Potential for Renewable Heat Technologies (TWh) (Low scenario)

Technology	Sector	2012	2017	2022	Growth rate 2010-2015	Growth rate 2015-2020
ASHP	Non-domestic	0.6	2.6	7.6	35%	24%
ASHP	Domestic	0.2	0.9	2.5	35%	24%
Biomass boilers	Non-domestic	3.4	5.8	10.4	11%	12%
Biomass boilers	Domestic	0.1	1.1	3.4	55%	25%
Biomass DH	Non-domestic	0.5	0.6	0.8	2%	6%
Biomass DH	Domestic	0.5	0.6	0.7	2%	5%
GSHP	Non-domestic	1.0	3.7	7.2	30%	14%
GSHP	Domestic	0.3	1.2	2.4	30%	14%
Solar Thermal	Non-domestic	0.2	0.3	0.5	14%	10%
Solar Thermal	Domestic	0.5	1.6	2.8	28%	12%
Biogas injection		0.3	0.7	1.6	20%	19%
Total		**7.6**	**19.1**	**39.7**	**20%**	**16%**

9.4.3. Additional growth scenarios

In addition to the above scenarios, Entec has undertaken a separate projection of the potential for renewable heat technologies in 2012, 2017, and 2022. This work has been carried out independently of the work presented above. A summary of Entec's best estimate of the potential for the various technologies (excluding ASHPs) are shown in Table A.1, and amounts to 79 TWh by 2022.

Table 9.4
Summary of Entec Renewable Heat Projections (TWh potential)

Technology	Sector	2012	2017	2022
Biogas	All	0.4	2.5	4.0
Biomass	Domestic	0.7	3.2	7.7
Biomass	Non-domestic	8.0	16.4	24.9
Biomass DH	All	0.7	3.3	9.0
GSHP	Domestic	0.9	4.7	9.8
GSHP	Non-domestic	0.9	4.7	9.8
Solar Thermal	Domestic	0.4	3.4	9.3
Solar Thermal	Non-domestic	0.4	3.2	4.1
Total	Total	12	41	79

The total potential of 79 TWh is more optimistic than the central scenario presented above, which shows 68 TWh of potential from the same technologies. The difference stems from higher potential for district heating (9 TWh rather than 3 TWh) and solar thermal (13 TWh rather than 7 TWh). By contrast, the potential for biogas, biomass boilers, and GSHPs is similar, even though the underlying two assessments have been undertaken separately.

These scenarios have been used as a sense-check on the main projections, and also to inform the extension of the main growth scenarios to 2022. They have not been used as direct inputs to the modelling. The detailed assumptions used to develop these scenarios are provided in Appendix A.

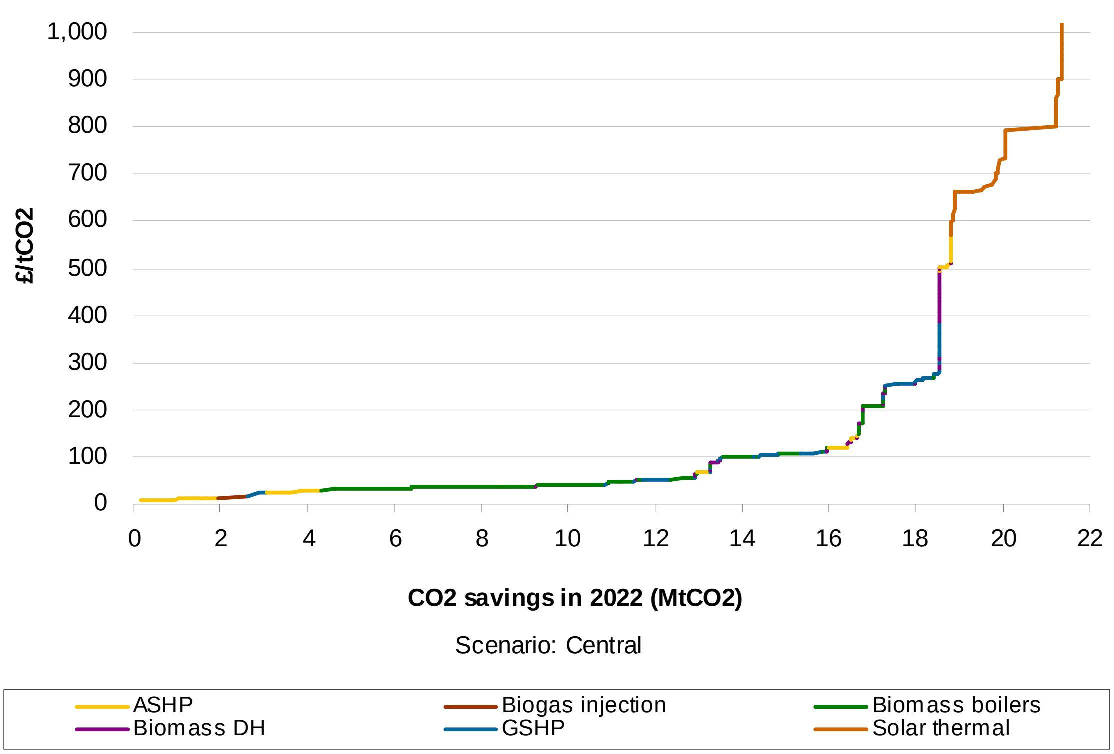
9.4.4. Realistic Abatement Trajectory Cost Curves

This chapter presents the results of our modelling after we take into account the constraints discussed in the preceding chapter. First we present a “central” case for renewable heat uptake, followed by results for a “low” and “high” case. Finally, we show the implications of using a cost methodology that differs from the standard one used by the CCC.

9.5. Central Realistic Abatement Trajectory

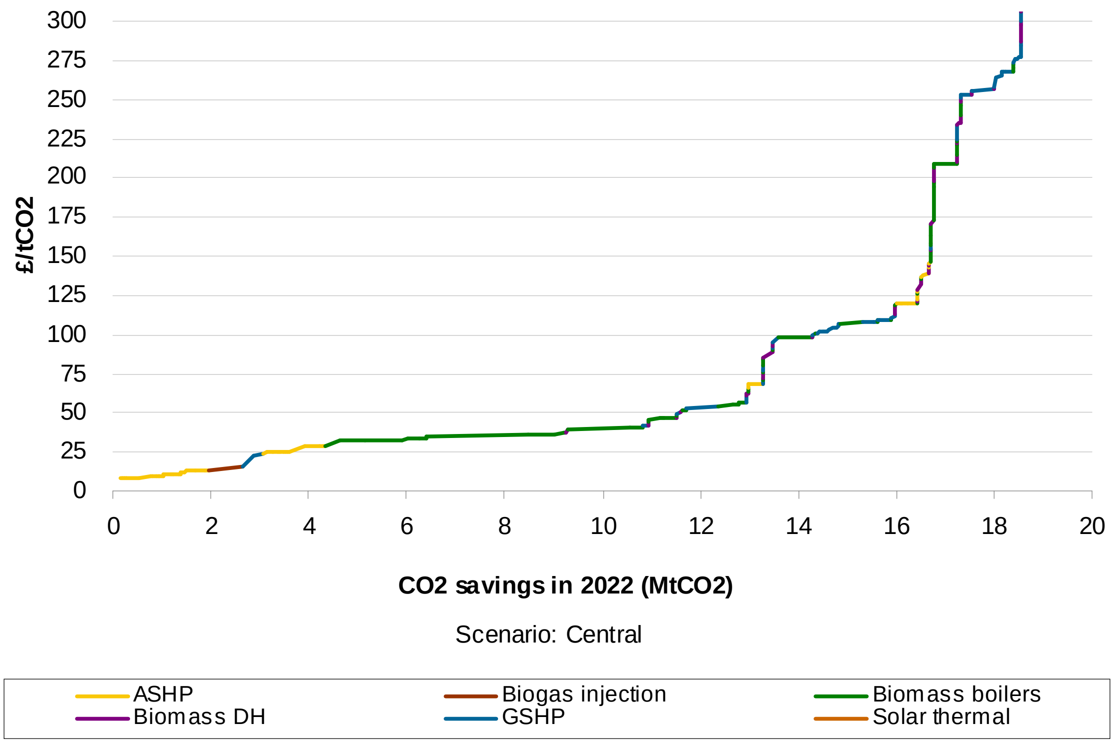
The figure below presents the outcome of our modelling when we impose a central set of supply- and demand-side constraints on renewable heat. The figure shows that as a result of the constraints, there is more diversity in the kinds of renewable heat technologies taken up for a given CO_2 price—primarily because the potential to supply biomass district heating and boiler equipment is more constrained.

Figure 9.1
Realistic Abatement Potential of Renewable Heat by Technology (2022)



The three figures below repeat the format followed above for the MMP, with costs above £300/tCO_2 excluded to make it easier to read the information. One significant implication of the constraint on the build rates for biomass equipment is that the realistic potential curve becomes steeper than the MMP curve as we approach the boundary of the figure. Otherwise, the characteristics of the realistic abatement potential are similar to the characteristics of the MMP. ASHPs, GSHPs and biogas injection again account for around one quarter of the abatement potential with a cost less than £100/tCO_2. Biomass boilers account for a slightly smaller proportion of this low-cost abatement potential—somewhat less than two-thirds, rather than the three-quarters we observe in the MMP case.

Figure 9.2
Realistic Abatement Potential of Renewable Heat by Technology: Detail (2022)



The low-cost realistic potential is again dominated by the non-domestic sectors, which account for 80-85 percent of the potential below £100/tCO_2. Nevertheless, there is some domestic potential (GSHP and biomass boilers) at costs around £50/tCO_2, and some additional domestic potential up to around £100/tCO_2 (biomass DH, ASHP, and biomass boilers).

Figure 9.3
Realistic Abatement Potential of Renewable Heat by Consumer Segment (2022)

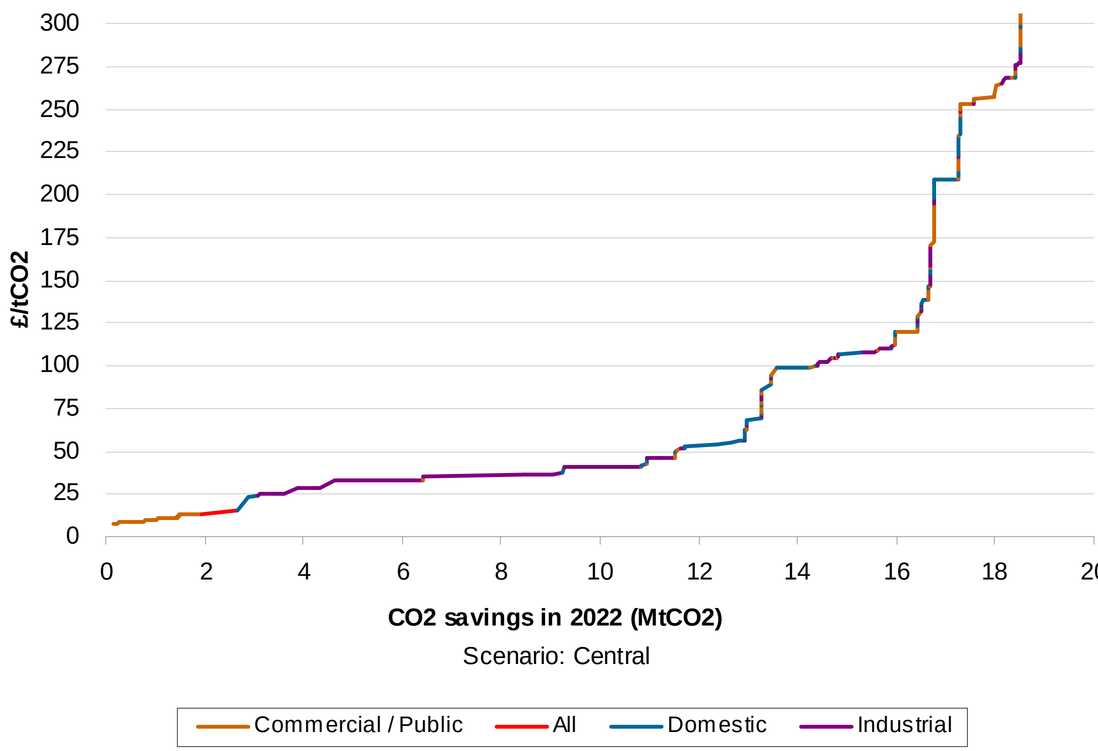


Figure 9.4 shows the central realistic potential MACC by fuel counterfactual. As in the case of the MMP MACC shown above, with the exception of grid injected biogas and a very small biomass segment, none of the abatement potential costing less than £100/tCO_2 shows gas as a counterfactual. Again, the low-cost potential is split between non-net-bound fuel and electric heating, with non-net-bound fuels accounting for somewhat more than electricity. Above £100/tCO_2 most of the potential is with users of gas, but unlike the MMP case, there is also some higher-cost potential involving the other fuel counterfactuals.

Figure 9.4
Realistic Abatement Potential of Renewable Heat by Fuel Counterfactual (2022)

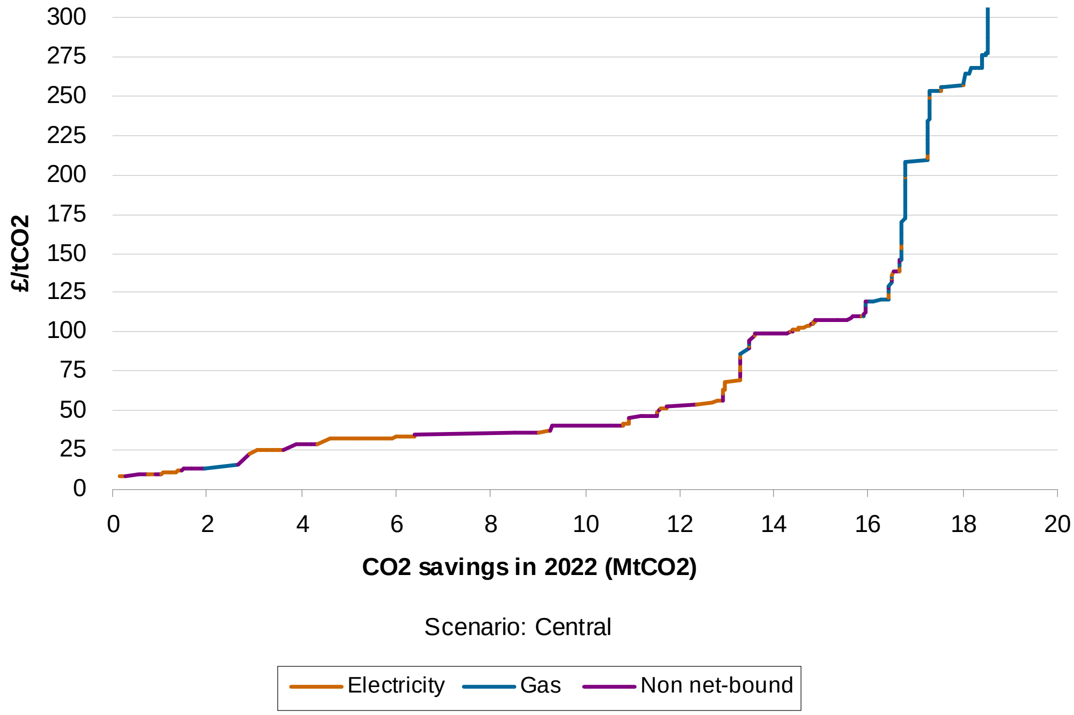


Figure 9.5 shows the realistic potential in 2012, 2017, and 2022. As the figure indicates, the bulk of the realistic potential is added in the final 5-year period, reflecting the assumption that growth in uptake and supply-side capacity will be more geometric than linear.

Figure 9.5
Realistic Abatement Potential of Renewable Heat by Technology (2012, 2017, 2022)

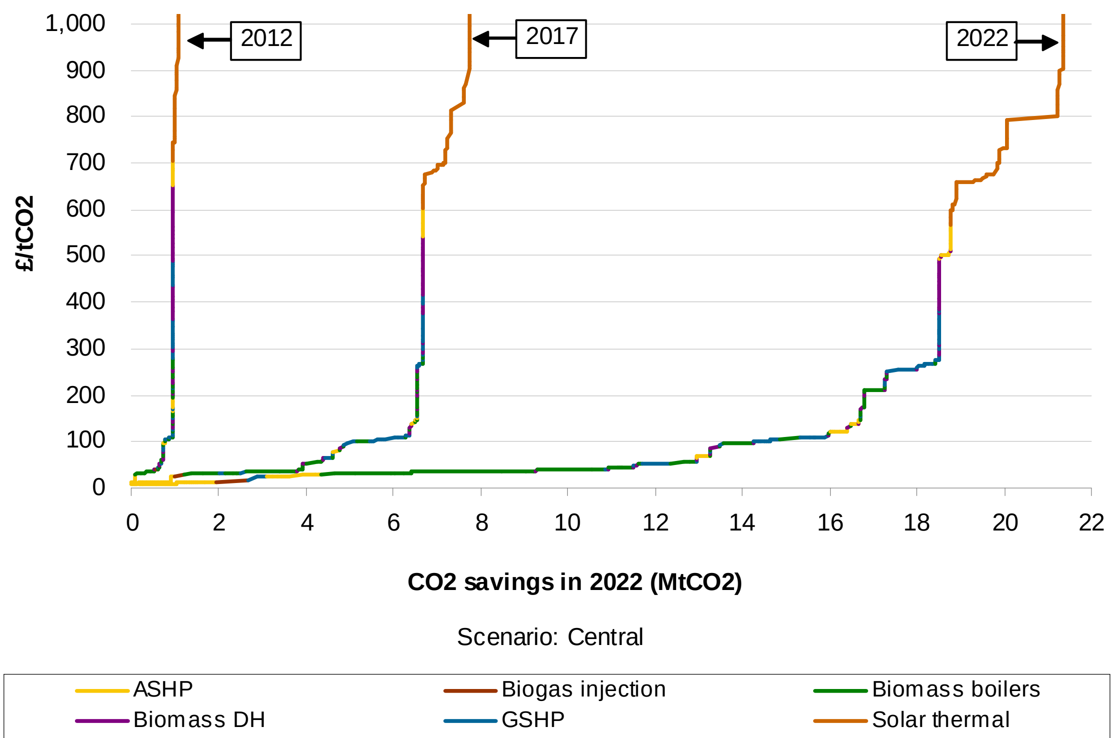


Table 9.5 shows the correspondence between CO_2 abatement, CO_2 abatement costs, and actual delivery of renewable heat – measured as output eligible to meet the UK's renewable energy target – in the central case. 60 TWh corresponds to approximately 10 percent of the overall heat demand relevant for the setting of a renewable heat target.[98] Because cost-effectiveness in delivering CO_2 abatement from renewable heat is not necessarily the same as cost-effectiveness in the delivery of renewable heat itself, the renewable heat potential available when optimising for CO_2 abatement is not the same as (and is significantly less than) the renewable heat potential available when optimising for renewable heat production.

[98] The target, and progress towards meeting it, is based on renewable heat input or output, depending on the technology.

Table 9.5
Renewable Output and Abatement Potential at Different Abatement Costs (Central – 2022)

Abatement Cost (£/tCO2)	CO2 Savings (MtCO2)	Output (TWh)
10	1	3
25	3	11
50	12	34
75	13	38
100	14	42
125	16	49
150	17	50
175	17	51
200	17	51
300	19	61

9.6. Alternative Realistic Trajectories for Abatement

As we discuss above, our model of renewable heat use is based on the assumption that once the "barriers" to the use of renewable heat (including financial and other barriers) are overcome via financial incentives, heat consumers will begin to take them up. The rate at which they can be taken up depends on consumer acceptance and on the various markets' ability to supply the relevant technologies. These rates are very uncertain. Thus, in addition to the central case whose results are presented above, we also model the two uptake rate sensitivity cases – one low and one high – that are described in Chapter 9.

The figures below present MACCs for 2022 corresponding to these alternative uptake scenarios.

Figure 9.6
Realistic Abatement Potential of Renewable Heat by Technology (2022; Low, Central, and High Uptake Scenarios)

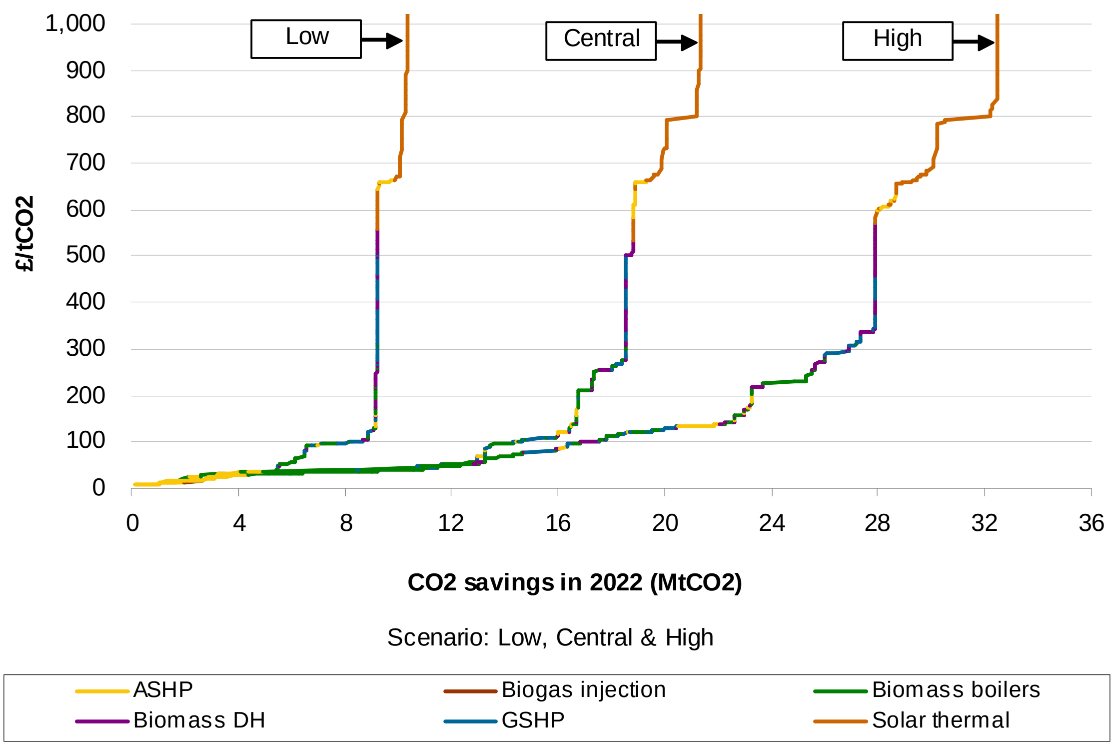
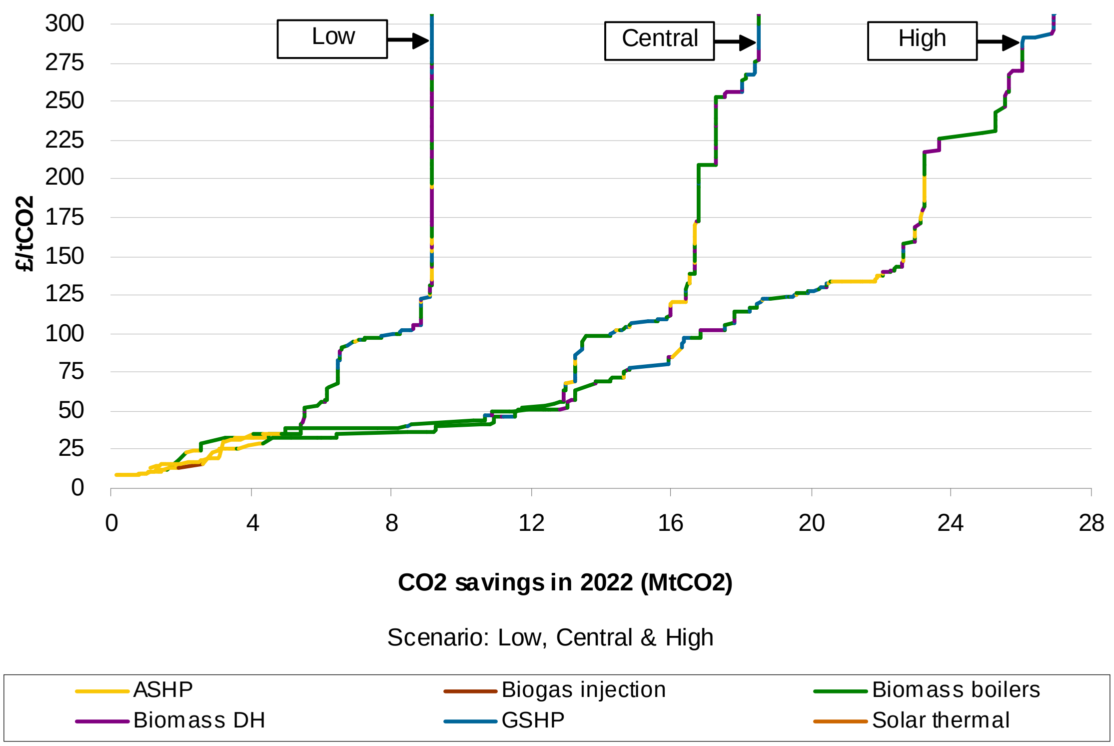


Figure 9.7
Realistic Abatement Potential of Renewable Heat by Technology; Detail (2022; Low, Central, and High Uptake Scenarios)



The comparison of the realistic trajectory scenarios shows that the potential expands significantly in the high growth scenario (and contracts significantly in the low growth scenario). The differences occur primarily in the moderate- and higher-cost abatement segments. There is more biomass district heating, more GSHPs, more commercial ASHPs (here displacing gas), and more biomass (in households displacing gas). The higher cost segments come into play because the importance of the supply-side constraints in the model tends to outweigh that of the demand-side constraints, so that customer segments take up technologies that are financially attractive if the supply is able to expand to meet demand.

As noted above, the central scenario MACC shows abatement potential of 20 $MtCO_2$ at a cost of £300/tCO_2 or less, and the corresponding heat output is 60 TWh. In the lower scenario, the corresponding abatement potential is 9 $MtCO_2$ from 26 TWh of heat output, while the high scenario MACC has 27 $MtCO_2$ of abatement potential from 96 TWh of heat. The high scenario corresponds to around one-sixth of heat demand.

9.7. Realistic Potential, Alternative Cost Methodology

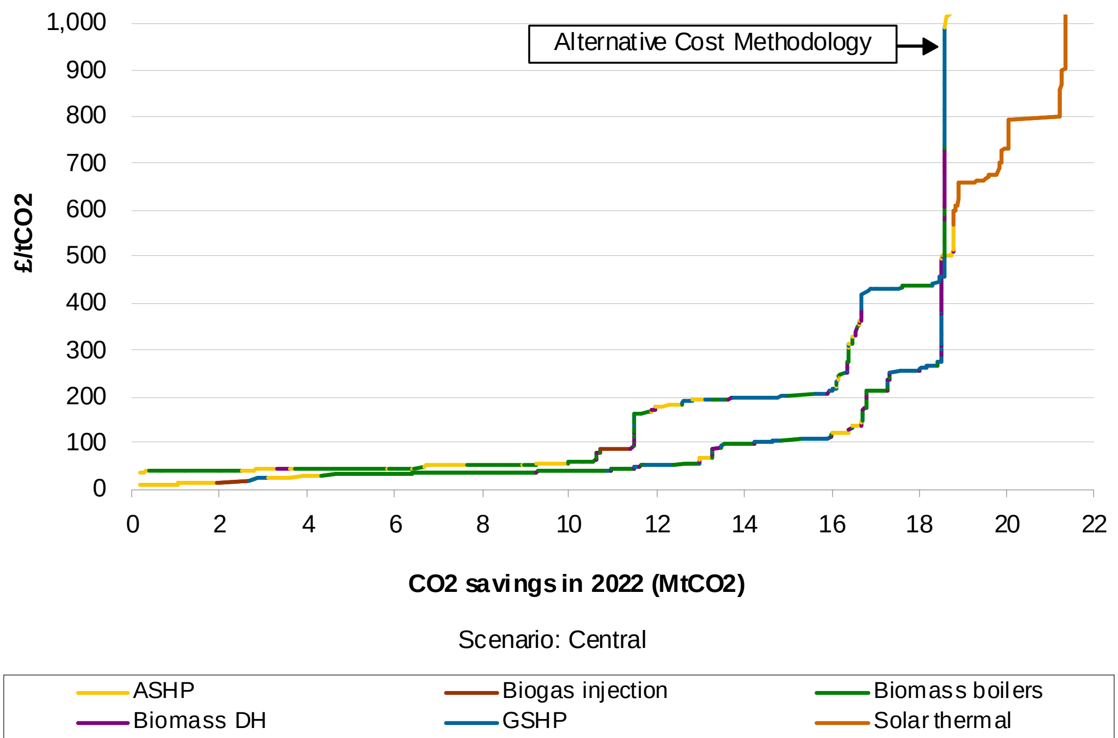
As noted in Chapter 8, the abatement costs presented in the preceding sections all reflect the CCC's preferred methodology, which applies a discount rate of 3.5 percent to calculate levelised costs, and which does not include financial estimates of various barriers and "hassle factors". For reference, we have constructed a renewable heat MACC curve that modifies these assumptions, as follows:

- Higher discount rates: we assume a 12 percent discount rate for the non-domestic sectors and a 16 percent rate for the domestic sector. This reflects the widespread assumption that organisations and households have higher discount rates than the social time preference rate used by Governments. Use of the higher discount rate to calculate levelised capital costs reflects an assumption that the higher rates reflect real costs to society, and not a form of irrationality among heat users. This assumption is in line with that used by the forthcoming NERA RHI study.

- Barriers and "hassle" costs: We include estimates of demand-side barriers and hassle factors in the costs associated with each renewable heat technology. These include several of the barriers noted in section 9.2.3, including available estimates of the time cost of search, installation and operation, as well as additional inconvenience associated with the use of renewable heat technologies. It does not include the administrative costs of policy, nor the costs associated with the risk of disruption or reduced performance.

We present the MACC under these alternative cost assumptions because we believe they represent an important complement to the methodology that the CCC generally uses.

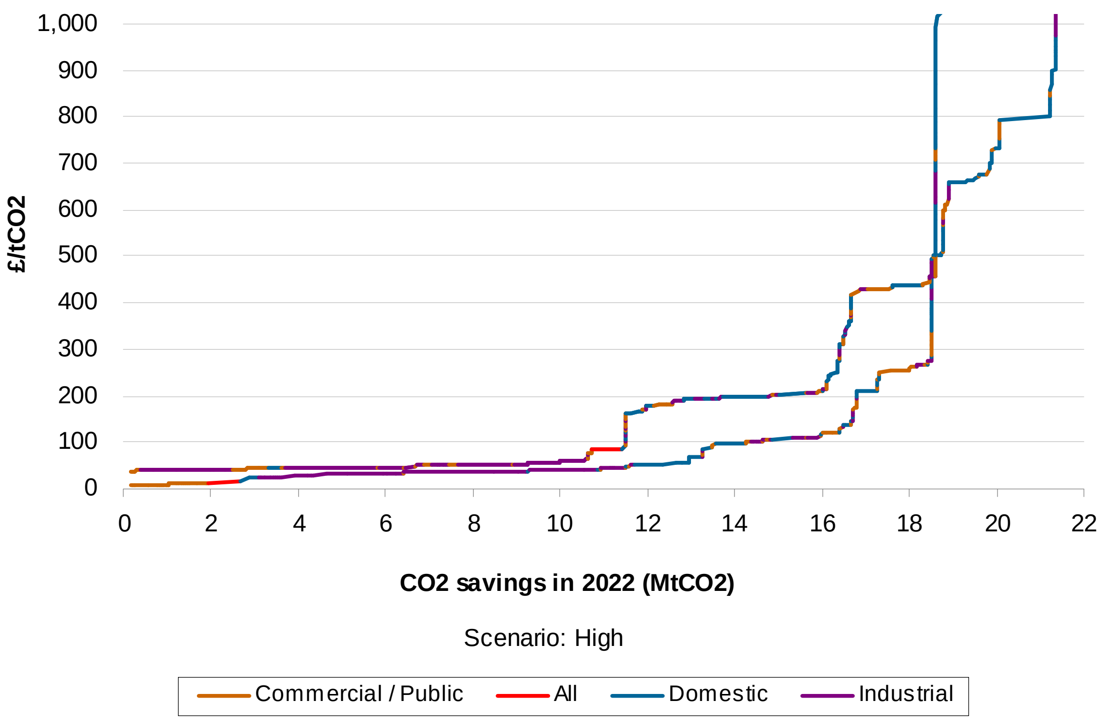
Figure 9.8
Comparison of Realistic Abatement Potential Using Standard and Alternative Methodologies (2022, by Technology)



The inclusion of these costs results in a re-ordering of the MACC. Biomass becomes a cheaper abatement option than heat pumps in many cases, reflecting mostly that capital expenditure forms a higher proportion of the overall cost of heat pumps than it does for biomass, but also the fact that the larger size of many biomass installations makes them less sensitive to fixed demand-side barrier costs.

Figure 9.9 shows the same MAC curves organised by the end-user sector. The higher cost methodology leads to some re-ordering of the demand segments. The most notable effect is the greater prevalence of industrial applications among the low-cost measures in the scenario with the higher discount rate and barrier costs. This is likely to reflect the higher load factor of industrial process heat as compared to space heating, as, other things being equal, higher utilisation leads to lower sensitivity to discount rate assumptions.

Figure 9.9
Comparison of Realistic Abatement Potential Using Standard and Alternative Methodologies (2022, by Sector)



The higher costs also mean that there is less abatement potential available for a given price per tonne of CO_2. Table 9.6 shows the cumulative abatement potential available at different cost levels under the two methodologies. For example, at £50 / tCO_2. the available abatement potential is reduced from 12 $MtCO_2$ to 7 $MtCO_2$. At £100 / tCO_2, the potential is reduced from 14 $MtCO_2$ to 11 $MtCO_2$.

Table 9.6
Comparison of Standard and Alternative Abatement Potentials

	Abatement Potential		CO2 Savings	
Abatement Cost (£/tCO2)	Standard CCC Cost Methodology (TWh)	Alternative Cost Methodology (TWh)	Standard CCC Cost Methodology (MtCO2)	Alternative Cost Methodology (MtCO2)
10	3	0	1	0
25	11	0	3	0
50	34	19	12	7
75	38	30	13	11
100	42	34	14	11
125	49	34	16	11
150	50	34	17	11
175	51	35	17	12
200	51	41	17	14
300	61	49	19	16
400	61	50	19	17

Table 9.7
Installations at Different Abatement Costs

	Abatement cost (£/tCO2)						
Sector and technology	£25	£50	£100	£200	£300	£1000	£1300
Residential							
ASHP	-	-	94	157	157	538	538
Biomass boilers	-	-	329	448	448	448	448
GSHP	-	420	420	420	420	420	420
Solar Thermal	-	-	-	-	-	1,761	5,065
Non-residential							
ASHP	29	32	32	36	36	36	36
Biomass boilers	-	2	2	2	2	2	2
GSHP	-	-	11	19	63	63	63
Solar Thermal	-	-	-	-	-	106	158

Note: The size of non-residential installations differs significantly by consumer segment and technology, and the total number of installations is not necessarily correlated with heat load or capacity installed.

9.8. Implications for Policy

All of the technologies analysed in the context of the MACC are likely to be supported under the Renewable Heat Incentive (RHI), due to be introduced in 2011. We briefly discuss below the relationship of this policy to the abatement potential identified and discussed above.

9.8.1. Impact of the RHI on CO_2 abatement

The deployment of renewable heat technologies under the RHI will lead to a reduction in CO_2 emissions. The amount of renewable heat that will result from the RHI is uncertain, however. The recent Renewable Energy Strategy suggests that the Government may aim for around 60 TWh of additional renewable heat output, resulting in emissions abatement of around 18 $MtCO_2$. However, the quantity depends on a number of uncertain factors, including the feasible expansion in supply capacity, as well as various conditions that influence the attractiveness of renewable heat technologies (such as fuel prices). The total amount of heat also depends on details of the policy that have not been finalised, most immediately the subsidy levels that will be provided under RHI.

The amount of CO_2 abatement that will be delivered by the RHI is also uncertain because the CO_2 abatement potential per MWh heat output varies significantly by technology and by counterfactual fuel. For example, an air-source heat pump with a low COP may reduce emissions only half as much as a biomass boiler. Replacing a gas-fired boiler with a renewable heat technology reduces emissions by half as much as replacing electric heating. As the RHI is denominated in terms of heat output, the technologies brought forward by the policy will not necessarily be those that reduce emissions at least cost.

Third, as a general observation, there is an interaction between the RHI and efforts to improve energy efficiency, another important method for emissions abatement. On the one hand, the subsidy of heating equipment or output is likely to result in an increase in heat demand. On the other hand, a levy on fossil fuel use to finance the RHI would have the opposite effect. The net effect on emissions is difficult to determine.

9.8.2. Impact of the RHI on barriers to renewable heat

The approach of the RHI is to stimulate demand for renewable heat technologies by making them financially no worse than conventional (electric / fossil-fuel fired) heating options. This implicitly relies on the market to overcome demand-side and supply-side “barriers” to renewable heat. For example, the subsidy will encourage marketing and other forms of awareness raising by suppliers; the reliability and applicability of technologies will become clearer as uptake is stimulated; the business opportunity created by the subsidy will provide incentives for training to acquire the required skills to install and maintain renewable heat projects and to develop the supply chains required for an expansion of capacity; etc. In this sense, many of the “barriers” to renewable heat are ones which are normal features of markets and which may be overcome to the extent it is financially advantageous to take the action required.

It is possible that supplementary policy may be able to accelerate uptake or overcome remaining barriers that are not easily overcome through the RHI alone. Many barriers were identified in sections 2-6 and summarised in sections 9.2 and 9.3. They often are specific to the individual heat technologies, sectors, and other localised situations, and detailed analysis would be required to identify potential policy interventions that could supplement the RHI.

One broad category of supplementary policy intervention is changes to regulations to facilitate the adoption of renewable heat. This could include exemptions from noise regulations, more favourable planning procedures, changes to waste policy (such as waste classifications of certain biomass fuels or requirements for digestate disposal), air quality regulations, modifications to gas composition standards to facilitate biogas injection, etc. A systematic review of regulatory barriers could complement the introduction of the RHI to facilitate the deployment of renewable heat technologies. However, many of these regulations have been introduced to safeguard other policy objectives, and in many cases it will likely be necessary to trade off the objective of promoting renewable heat against other considerations.

Another broad category of policy intervention is the coordination between authorities and market actors. Two examples where this is relevant include waste policy to facilitate the supply of materials for anaerobic digestion, and the implementation of district or community heating schemes. It remains to be seen to what extent these barriers will be significant once the RHI is in place – and the level of the RHI for specific technologies is likely to affect the importance of each barrier.

Finally, given that one of the barriers to uptake of renewable heating technologies is lack of familiarity and uncertainty about their performance, the creation of industry and regulatory standards and certification schemes could help signal the quality of renewable heat technologies and services to potential consumers. Such certification schemes are likely to arise via the impetus of private industry and stakeholder groups, but government may have a role in facilitating their agreement and adoption.

10. Conclusions

This report provides background on the renewable heat technologies that could contribute to meeting the UK's greenhouse gas emissions abatement and renewable energy targets. It also provides estimates of the cost and emissions abatement potential of these technologies, based on the marginal abatement cost model developed for the CCC.

The following are brief conclusions about the relevant technologies:

§ Biomass is the biggest contributor to CO_2 emissions abatement potential and provides much of the relatively low cost abatement potential (with costs below £50 or £100 / tCO2).

§ There are also very inexpensive ASHP options, primarily in the commercial and public sectors, where the technology is increasingly common even without subsidy.

§ Injection of biogas to the gas grid also appears to be an inexpensive abatement option, but its potential is limited by constraints on the number of digesters that could be built to supply the gas in the relevant time frame—as well as by the fact that a significant proportion of the gas is assumed (given the current policy framework) to be used to generate electricity.

§ There is only limited biomass district heating potential, because of the barriers to the construction of the necessary infrastructure, as well as the high cost of doing so.

§ Solar thermal technology is the most expensive, because it provides relatively little heat per installation, and involves a relatively high capital cost.

Most of the abatement potential with costs below £100 / tCO_2 is within industry, followed by the commercial / public sectors, and a small share in the domestic sector. Natural gas remains a relatively low-cost heating alternative even at CO_2 costs up to £100 / tCO_2, and therefore nearly all of the abatement potential involves replacing non-net-bound fuels or electric heating. The main exception to this is biogas injection.

If we use an alternative cost methodology that better reflects the costs perceived by heat consumers themselves, this leads to somewhat less low-cost abatement (below £50 / tCO_2), and moderate-cost abatement (below £100 / tCO_2).

The limited use of renewable heat technologies to date in the UK means that a number of important uncertainties remain concerning the technology costs and future cost developments, the suitability for the UK climate and housing stock, and feasible growth trajectories. As a consequence, the potential estimates presented here are relatively uncertain, and will need to be revisited as better information becomes available.

As noted, the model does not include abatement potential from biomass CHP because of the complexities associated with modelling this technology; the model has been designed to accommodate CHP data that are expected to become available at a later date as a result of a project currently underway for DECC.

Based on the modelling presented here, if the indicative contributions of renewable heat to the UK's renewable energy target (outlined in the Renewable Energy Strategy) are met by the

RHI, this will account for much of the realistic abatement potential identified in the MACCs presented above. The levels of subsidy under the RHI would need to be set high enough to make the relevant technologies financially attractive and also to overcome any remaining barriers to individual technologies and to stimulate high rates of growth for an extended period. If the various barriers are not overcome or growth in early years is not as fast as we have modelled, subsidy levels may need to be adjusted to ensure that the desired amount of renewable heat is delivered.

Appendix A. Additional Projections of Renewable Heat Potential

A.1. Summary and Comparison to Central Case

Entec has undertaken a separate projection of the potential for renewable heat technologies in 2012, 2017, and 2022, independently of the work underlying the central projection presented in section 9.4.1. The potential for the various technologies (excluding ASHPs) are shown in Table A.1, and amounts to 79 TWh by 2022.

Table A.1
Summary of Entec Renewable Heat Projections (TWh potential)

Technology	Sector	2012	2017	2022
Biogas	All	0.4	2.5	4.0
Biomass	Domestic	0.7	3.2	7.7
Biomass	Non-domestic	8.0	16.4	24.9
Biomass DH	All	0.7	3.3	9.0
GSHP	Domestic	0.9	4.7	9.8
GSHP	Non-domestic	0.9	4.7	9.8
Solar Thermal	Domestic	0.4	3.4	9.3
Solar Thermal	Non-domestic	0.4	3.2	4.1
Total	Total	12	41	79

As noted above in section 9.4.3, the total potential of 79 TWh is more optimistic than in the central scenario, which shows 68 TWh of potential from the same technologies. The difference stems from higher potential for district heating (9 TWh rather than 3 TWh) and solar thermal (13 TWh rather than 7 TWh). By contrast, the potential for biogas, biomass boilers, and GSHPs is very similar, even though the underlying two assessments have been undertaken separately.

The detailed assumptions for each technology are provided in the individual sections, below.

A.1.1. Comparison for air-source heat pumps

The potential for ASHPs is more difficult to estimate than for most of the other technologies. On the one hand, ASHPs may face fewer supply barriers than the other technologies, as the technology is linked to a large international market and installation is less dependent on specialised skills than are several other technologies. On the other hand, as the review in section 2.4 highlights, the suitability and performance of ASHPs in much of the UK housing stock is highly uncertain. It is possible that either significant modifications to houses or technological breakthroughs would be required to reach much of the potential market. The uncertainty about suitability, and therefore about the level of demand, would reasonably be assumed to deter some of the investment in supply capacity.

The discussion below sketches different scenarios, ranging from a steady-state capacity of around 100,000 units per year, to as much as one million units per year if the technology can be used for much of the housing stock and become the default technology replacing standard boilers. The lower case could ensue for a number of reasons, including slow take-up in early years and remaining uncertainty about performance and suitability. Balancing the various considerations, we have continued to rely for the central case on the projections previously developed by AEA, resulting in around 22 TWh of combined domestic and non-domestic ASHP output by 2022, with the majority of this capacity in the non-domestic sector. This scenario implies installation rates towards the end of the period of around 100,000 units per year for the combined domestic and non-domestic sectors.

A.2. Air-Source Heat Pumps

ASHPs have the potential to provide much of the UK's domestic heating requirements, under the right conditions. This section aims to predict the maximum and realistic potentials for installations of ASHPs by 2022, under various technological development and housing stock energy efficiency scenarios. The realistic potential scenarios assume:

§ Sufficiently generous financial support under an RHI (or other supportive policy) to encourage the predicted level of uptake.

§ Development of grid capacity to a sufficient extent to support the extra peak load required by large increases in the number of ASHPs.

A.2.1. Potential in new-build homes

All new-build homes can have ASHP compatibility built-in so as to achieve high seasonal COPs, i.e. with low temperature heating loops and very well insulated. Indeed, the majority of new build homes are already constructed based on low temperature heating systems suitable for condensing boilers. With the absolute number of new build homes in the UK being 213,700 in financial year 2005/6[99], this equates to roughly 2 million potential ASHP installations by 2022. Given current economic conditions, however, it is very difficult to arrive at reliable projections about the level of future house-building in the UK.

The UK has a similar number of properties as France, which was able to achieve significant industry growth to 100,000 units per year (from a low base of around 25,000) within two years of offering a subsidy (albeit with a history of other policies to encourage their uptake). Given the limited industry base in the UK today it may be realistic to assume that the UK could achieve sales of 75,000 units per year by 2012.[100]. If uptake could be ramped up to 100,000 units per year[101] in the new-build sector once the renewable heat incentive is

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99 Table 209 Housebuilding: permanent dwellings completed by tenure and country. CLG., www.communities.gov.uk/pub/313/Table209_id1511313.xls

100 France started from an industry base of 30,000 annual sales in 2005 (when the subsidy was introduced) and achieved nearly 90,000 by 2007 – this equates to a growth rate of roughly 70% per year. Assuming this growth rate can be achieved in the UK and assuming roughly 15,000 sold in 2009 (from manufacturer estimates), this would result in roughly 75,000 units sold per year by 2012. A 70% growth rate would be unsustainable in the long term and a more realistic growth rate thereafter would be 50% annually.

101 We can assume that ASHPs would be a realistic option in smaller developments where site-wide heating schemes would not be available. By assuming that all developments with fewer than 50 homes install ASHPs, this equates to

introduced this would result in a total potential from new build alone of roughly 1 million units by 2022.

A.2.2. Potential in retrofit with no modifications to housing stock

At current costs and performance parameters and without any modifications, ASHPs are compatible with only a small percentage of existing homes (post-2000 homes) – this may account for roughly two million homes in the UK. The recent RAB energy efficiency study[102] modelled uptake of ASHPs in the existing domestic stock under a RHI and this predicted a cumulative uptake of one million units in the *English* owner occupied retrofit stock, equivalent to a total realistic *UK* potential in the equivalent population (without modifications) of roughly 1.2 million units by 2022.

A.2.3. Potential assuming all cavity walled stock achieves compatibility

Assuming all cavities are insulated by 2015, and assuming that various other relatively minor modifications (e.g. larger radiators, loft insulation, etc) are all that is necessary to ensure compatibility with ASHPs, this would increase the market size to all cavity walled houses – or 18 million homes in the UK[103]. This is likely to be the maximum number of existing homes which could be retrofitted with ASHPs at their current level of technological development, in view of the significant costs of insulating solid wall homes sufficiently to ensure compatibility with ASHPs. By assuming that industry is capable of producing 75,000 units per year by 2012 (as discussed above) and assuming a maximum industry growth rate of 50 percent per year thereafter, up to a maximum of one million units per year (this is equivalent to the number of boilers sold to cavity walled houses annually[104]), this would lead to a total realistic potential for ASHP installations of roughly 6.5 million by 2022 (although this could have significant implications on grid capacity, as discussed in Section 2.7.3). Note however that this is an extreme case.

A.2.4. Potential assuming technological development

However, if ASHP technology develops sufficiently to allow them to run at very high flow temperatures whilst maintaining economical COPs, it is not inconceivable that the entire existing UK housing stock of 26 million homes could potentially be retrofitted with ASHPs.

Assuming the same industry growth rates as discussed above, up to a maximum of 1.56 million units per year (the current annual boiler replacement rate), this would lead to a realistic potential of some 8.4 million units by 2022 (although this would have significant implications on grid capacity, as discussed in Section 2.7.3). Note that this also is an extreme case.

48% of total new build (The Role of Onsite Energy Generation in Delivering Zero Carbon Homes, Element Energy, 2007) or nearly 100,000 homes per year.

102 The financial incentive components of major energy retrofit strategy for English homes: a Study, Element Energy and NERA Economic Consulting, 2009

103 English House Condition Survey, 2005

104 Assuming annual boilers sales of 1.56 million in 2006 (Purple Market Research, 2007) and an even distribution of sales between cavity and non-cavity housing.

10.1. Ground Source Heat Pumps

Table A.2
Domestic Ground Source Heat Pump Potential

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	260.2			260.2			260.2		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	0%	0%	0%	0%	0%	0%	0%	0%	0%
	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2	260.2
Site constraints	96%	92%	79%	96%	92%	79%	96%	92%	79%
	10.4	20.8	54.6	10.4	20.8	54.6	10.4	20.8	54.6
Planning constraints (inc visual, air quality etc)	5%	2%	-	5%	2%	-	5%	2%	-
	247.2	255.0	260.2	247.2	255.0	260.2	247.2	255.0	260.2
Conversion constraints (i.e. inconvenience and 'hassle factor')	15%	10%	5%	15%	10%	5%	15%	10%	5%
	221.2	234.2	247.2	221.2	234.2	247.2	221.2	234.2	247.2
Market Potential (of technical potential)	**3%**	**7%**	**20%**	**3%**	**7%**	**20%**	**3%**	**7%**	**20%**
Market Potential (TWh/y)	**8.4**	**18.4**	**51.9**	**8.4**	**18.4**	**51.9**	**8.4**	**18.4**	**51.9**
Infrastructure constraints - expansion of biogas injection	-	-	-	-	-	-	-	-	-
	8.4	18.4	51.9	8.4	18.4	51.9	8.4	18.4	51.9
Installation capacity constraints	96%	95%	97%	72%	73%	82%	39%	44%	61%
	0.4	0.9	1.4	2.4	5.0	9.5	5.1	10.4	20.3
Equipment availability constraints	-	-	-	5%	5%	10%	5%	5%	10%
	8.4	18.4	51.9	8.0	17.4	46.7	8.0	17.4	46.7
Total Realisable Potential (of market potential)	**4%**	**5%**	**3%**	**27%**	**26%**	**17%**	**57%**	**54%**	**35%**
TOTAL REALISABLE POTENTIAL (TWh/y)	**0.4**	**0.9**	**1.4**	**2.3**	**4.7**	**8.6**	**4.8**	**9.8**	**18.3**
Approximate Number of Domestic Systems	40k	90k	140k	230k	470k	860k	480k	980k	1,830k

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

The technical potential assumes of the 25.4 million domestic properties all are suitable for GSHPs providing 10MWh/year.[105] From this point the estimates are constrained on the basis of the following factors:

- Fuel Supply – electricity is the only fuel required and this is addressed under infrastructure issues below.
- Site Constraints – GSHPs will not be suitable in all properties, particularly where there is insufficient space, existing homes with gas central heating. Hence GSHPs are likely to be most suitable in new builds or existing electrically heated homes. Therefore the following assumptions have been made: Low assumes 25% of off grid properties suitable, best estimate assumes 25% off grid and 5% of other properties suitable, high assumes 50% off grid and 15% of other properties suitable (approx equivalent in number to all of the homes not heated by gas).
- Planning Constraints – GSHPs do not have significant visual, air quality or noise issues that other microgen technologies have. Hence planning should not prevent the vast majority of systems being installed. However, there are potentially problems with using aquifers, digging trenches for ground loop systems etc that may create issues in a small proportion of cases. Hence best estimate of 2% of systems prevented as a result of planning constraints, low of 5% and high of 0%, similar to solar thermal.
- Conversion Constraints – Conversion constraints are mostly associated with the difficulty of converting from gas to GSHP (especially given that cost savings may be small). However this has largely been accounted for in the site constraints, as only electrically heated homes are assumed to be suitable. However, a proportion of these properties will be difficult to convert particularly where significant disruption may be encountered, so the following constraint has been assumed - low 15%, best estimate 10%, high 5%.
- Infrastructure Constraints – No additional infrastructure such as district heating but when installed in weak grid areas upgrading of the electrical network may be necessary – however this is largely an economic constraint as it would be technically feasible to upgrade the network, so given that constraints associated with costs are disregarded it is assumed the constraint is 0% in all cases.
- Installation Capacity Constraints – Likely to be severe limitations on installers, particularly in the next 5-10 years. AEA have estimated the potential for capacity in 2010 (10,000/y), 2015 (35,000/y) and 2020 (55,000/y). AEA assumptions have been adopted for the BE scenario (adjusted for 2012, 2017 and 2022), however there may be potential to more rapidly increase the capacity, so high estimate assumes capacity increases at twice the rate in 2012, 2017 and 2022, and at half the rate for the low estimate. Low scenario, 5% in 2012, 10% in 2017 and 2022; best estimate 0% in 2012, 5% in 2017 and 2022, high scenario no constraint.

[105] [Citation required.]

Table A.3
Commercial and Industrial Ground Source Heat Pump Potential

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	70.0			73.8			77.5		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	0%	0%	0%	0%	0%	0%	0%	0%	0%
	70	70	70	73.75	73.75	73.75	77.5	77.5	77.5
Site constraints	60%	50%	40%	60%	50%	40%	60%	50%	40%
	28	35	42	29.5	36.875	44.25	31	38.75	46.5
Planning constraints (inc visual, air quality etc)	5%	2%	-	5%	2%	-	5%	2%	-
	66.5	68.6	70	70.0625	72.275	73.75	73.625	75.95	77.5
Conversion constraints (i.e. inconvenience and 'hassle factor')	-	-	-	-	-	-	-	-	-
	70	70	70	73.75	73.75	73.75	77.5	77.5	77.5
Market Potential (of technical potential)	38%	49%	60%	38%	49%	60%	38%	49%	60%
Market Potential (TWh/y)	26.6	34.3	42.0	28.0	36.1	44.3	29.5	38.0	46.5
Infrastructure constraints - expansion of biogas injection	-	-	-	-	-	-	-	-	-
	70	70	70	73.75	73.75	73.75	77.5	77.5	77.5
Installation capacity constraints	99%	97%	97%	91%	86%	78%	83%	73%	56%
	0.95	1.84	2.40	6.28	10.10	15.90	13.38	21.12	33.90
Equipment availability constraints	-	-	-	5%	5%	10%	5%	5%	10%
	70	70	70	70.0625	70.0625	66.375	73.625	73.625	69.75
Total Realisable Potential (of market potential)	**1%**	**3%**	**3%**	**8%**	**13%**	**19%**	**16%**	**26%**	**39%**
TOTAL REALISABLE POTENTIAL (TWh/y)	**0.4**	**0.9**	**1.4**	**2.3**	**4.7**	**8.6**	**4.8**	**9.8**	**18.3**
Approximate Number of Commercial Systems	7k	18k	29k	45k	94k	171k	97k	197k	366k

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

In defining the technical potential we assume average heat production of 50 MWh/yr per unit. This is then multiplied by the assumed number of C&I buildings existing (1.4 million) and the estimated construction of 150,000 new C&I buildings by 2022. This high level figure is then constrained by the factors outlined for domestic with the exception of:

- Site Constraints - Estimated that 50% of C&I sites have potential for GSHP. Low and high estimates 10% either side to account for uncertainty.

Installation Capacity Constraints - Based on same assumptions as domestic (same approach as AEA), but predicted to fall to 0% in all scenarios by 2017. However some constraint is still assumed beyond 2012 to account for the increased design and installation work required for larger commercial systems which may restrict the installation capacity (for 2017 and 2022 assumptions are low 20%, best estimate 10%, high 0%). AEA assumption that a different set of contractors will be used in this sector may be true to some extent but there is likely to be a good deal of crossover (with many companies offering both borehole and ground loop systems), and for many domestic installations both boreholes and ground loops will be suitable.

A.3. Biogas

The following table summarises the analysis for this report. A discussion regarding the basis of the assumptions follows the table.

Table A.4
Biogas Potential Grid Injection

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	13.9			13.9			13.9		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	60%	60%	60%	50%	50%	50%	40%	40%	40%
	5.6	5.6	5.6	7.0	7.0	7.0	8.3	8.3	8.3
Site constraints	10%	5%	0%	10%	5%	0%	10%	5%	0%
	12.5	13.2	13.9	12.5	13.2	13.9	12.5	13.2	13.9
Planning constraints (inc visual, air quality etc)	30%	20%	10%	30%	20%	10%	30%	20%	10%
	9.7	11.1	12.5	9.7	11.1	12.5	9.7	11.1	12.5
Conversion constraints (i.e. inconvenience and 'hassle factor')	0%	0%	0%	0%	0%	0%	0%	0%	0%
	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Market Potential (of technical potential)	**25%**	**30%**	**36%**	**32%**	**38%**	**45%**	**38%**	**46%**	**54%**
Market Potential (TWh/y)	**3.5**	**4.2**	**5.0**	**4.4**	**5.3**	**6.3**	**5.3**	**6.3**	**7.5**
Infrastructure constraints - expansion of biogas injection	95%	90%	85%	90%	50%	25%	50%	25%	0%
	0.7	1.4	2.1	1.4	7.0	10.4	7.0	10.4	13.9
Installation capacity constraints	0%	0%	0%	0%	5%	10%	0%	15%	20%
	13.9	13.9	13.9	13.9	13.2	12.5	13.9	11.8	11.1
Total Realisable Potential (of market potential)	**5%**	**10%**	**15%**	**10%**	**48%**	**68%**	**50%**	**64%**	**80%**
TOTAL REALISABLE POTENTIAL (TWh/y)	**0.2**	**0.4**	**0.8**	**0.4**	**2.5**	**4.2**	**2.6**	**4.0**	**6.0**
Indicative number of 2MWth plant required[106]	12	30	54	31	179	301	187	288	428

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

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[106] Some plants may be considerably larger.

Technical resource to assume only biogas from the anaerobic digestion of biodegradable matter, and does not include syngas or landfill gas. All biogas is assumed to be injected into the existing gas network (as opposed to being used in conjunction with district heating which is an alternative option). Certain types of feedstock will be difficult to collect for digestion in a centralised facility, as required for grid injection (need to be large plants in order to be economically viable). The key feedstocks are those where centralised collection is possible, such as food and green waste. It is possible to discount feedstocks for industrial effluent (best treated on site), sewage sludge (not sufficient biogas produced to economically use off-site), landfill and the majority of farm waste which would result in only food and garden waste feeding into the technical potential. However the following assumptions have been used to derive the technical potential.

Table A.5
Feedstock for Biogas Production and Energy Outputs

		Energy contained (TJ)		Energy contained (TWh)		
	Dry tonnes	**Low**	**High**	**Low**	**High**	**Mid point**
Poultry manure (30% DM)	369,000	2,546	4,981	0.71	1.38	1.05
Dairy cattle slurry (10% DM)	2,016,000	11,592	12,600	3.22	3.50	3.36
Pig manure (10% DM)	514,500	2,809	3,344	0.78	0.93	0.85
Food waste	25,000,000	22,410	39,841	6.23	11.07	8.65
Total	**27,899,500**	**39,357**	**60,766**	**10.93**	**16.88**	**13.91**

This technical potential has been reduced considering the following constraints:

§ Fuel Supply – Resource treated in alternative process - particularly food waste already secured in long term waste contracts (e.g. to EfW). Figure unknown at present but assumed to be 60% of total for all scenarios in 2012, falling to 50% in 2017 and 40% in 2022 as food waste collections increase, and increased collection and processing of farm wastes and industrial effluent . The majority of fuel is likely to arise from the food sector.

§ Site Constraints - Biogas supply uses existing gas infrastructure once upgraded so no constraint here. Small constraint on availability of sites for AD/gas treatment but not major. Assumed low – 10%, best estimate – 5%, high – 0%.

§ Planning Constraints - Planning for AD plants can be challenging, but far fewer sites required than for building integrated technologies. Assumed to be similar to community scale biomass: Assumed low – 30%, best estimate – 20%, high – 10%.

§ Conversion Constraints – Not an issue with injection to the existing gas network the issue of upgrading and cleaning is an economic consideration.

§ Infrastructure Constraints – Initially likely to be slow to develop (large plants will take several years to build, so potential for biogas grid injection likely to be close to zero by 2012)

§ Installation Capacity Constraints - Unlikely to a significant effect as relatively small number of centralised facilities required, however, as higher numbers of plant are potentially required to meet the more significant levels of recovery a small installation constraint related to skilled installers has been introduced. Lead times significant though but largely accounted for in infrastructure constraint.

§ Equipment Availability Constraints – Tied into the above.

The assessment currently gives no consideration to the conflicting demands for the biogas (e.g. electricity/transport fuel) this is considered further below.

10.2. Biomass boilers and CHP

Biomass combustion offers significant potential to contribute towards CO_2 emissions reductions. The potential uptake will depend on policy, support mechanisms for heat, a robust and stable fuel supply chain, fossil fuel and electricity price and removal of barriers to project development.

A potential constraint to the development of biomass energy will occur if the fuel supply chain is poor, and it is crucial that as biomass installed capacity increases, the fuel supply market responds accordingly to avoid fuel shortfalls. In the medium term there is no major constraint on available resource, the key issue is expanding the collection and processing of the raw material into useable fuel. In the long term as uptake increases energy crops will become an increasingly important source.

Ultimately it may not be possible to produce enough biomass in the UK to meet very high levels of demand (based primarily on land constraints), hence the importance of using it in the most efficient way, i.e. heat only or CHP plant.

An EEA report produced in 2007 estimated the land available for 'environmentally compatible potential bioenergy production' in the UK. Assuming the entire land area is planted with Miscanthus (with a typical yield of 13odt/ha/year giving approximately 63MWh/ha/year[107]), the potential contribution to UK renewable heat supply is summarised in Table A.6.

Table A.6
Energy Crop Potential

Year	Land area, MHa (% of UK total)[108]	Energy crop tonnage, Modt/y	Total heat energy, TWh/year[109]	Generation Capacity (MWth)
2010	0.8 (3.3%)	10.4	42.,8	4,890
2020	1.1 (4.5%)	14.3	58.9	6,724
2030	1.6 (6.5%)	20.8	85.7	9,781

[107] Biomass Energy Centre

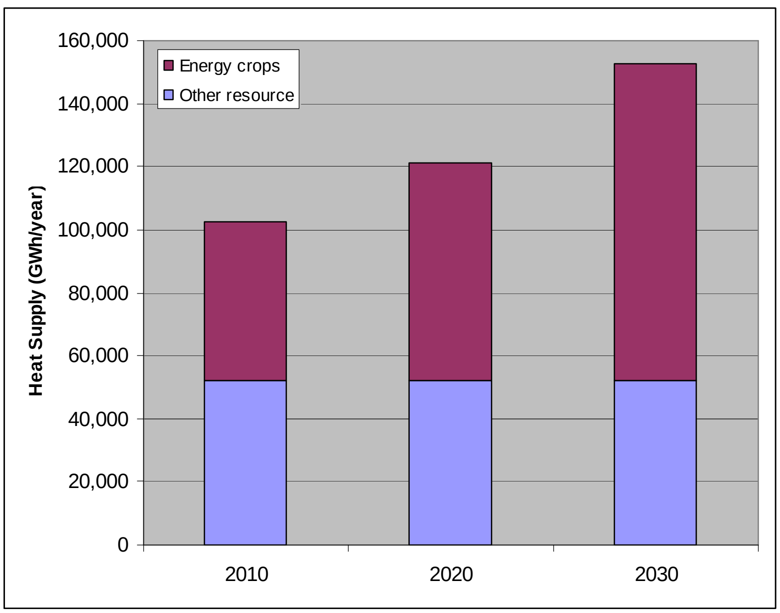
[108] http://reports.eea.europa.eu/eea_report_2006_7/en

[109] Assuming entire land area planted with Miscanthus and converted to useful heat at an efficiency of 85%

Table A.6 shows that a significant area of land is required to grow sufficient energy crops to contribute significantly to UK heating demand. An estimate of biomass potential for UK heat supply is provided in Figure A.1. The energy crop component assumes the entire compatible land area is planted with Miscanthus, the ‘other resource’ component assumes the existing resource in Figure 5.1 is used for wood chip production (less the energy crop figure of 0.2M odt), and that this remains relatively constant over the next 20 years. Note that the figures provide an indication of the upper limit of potential only, and such levels may not be achievable in practice (particularly the 2010 figure which is expected to be a small fraction of this realistically).

Regarding the non-fuel barriers while at the current market demands the import of skills and equipment is aiding the delivery of projects there is a significant capacity risk posed by the lack of high specification equipment, skilled contractors and the geographic coverage of the suppliers. Such elements can take time to develop and given the current confidence in markets a significant lag/gap in supply could emerge. Impacts of such a gap are dependent on the evolution of the biomass market in the UK and through Europe and are likely to be most significant on the medium term.

Figure A.1
Potential Heat Supply from Biomass



In terms of increasing capacity the Government’s recently published Heat and Energy Saving Strategy[110], outlines policy to encourage expansion of biomass schemes, in conjunction with CHP and district heating. Barriers such as a lack of accredited installers will need to be addressed.

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110 BERR ‘Heat and Energy Saving Strategy Consulation’, Feb 2009

Estimated potential for biomass related heat are provided in the following tables. The tables begin with the estimated total technical potential and then apply various constraints to estimate the proportion of this technical potential that should be excluded from the actual realistic potential. The table shows the projected potential for three reference years (2012, 2017, and 2022), and for a low, best estimate, and high potential scenario ("L", "B.E.", and "H", respectively).

Table A.7
Biomass Domestic (pellet boilers in individual dwellings)

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	163.6			156.6			146.6		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	0%	0%	0%	0%	0%	0%	0%	0%	0%
	163.6	163.6	163.6	156.6	156.6	156.6	146.6	146.6	146.6
Site constraints	70%	50%	30%	70%	50%	30%	70%	50%	30%
	49.1	81.8	114.5	47.0	78.3	109.6	44.0	73.3	102.6
Planning constraints (inc visual, air quality etc)	50%	25%	10%	50%	25%	10%	50%	25%	10%
	81.8	122.7	147.2	78.3	117.5	140.9	73.3	110.0	131.9
Market Potential (of technical potential)	**15%**	**38%**	**63%**	**15%**	**38%**	**63%**	**15%**	**38%**	**63%**
Market Potential (TWh/y)	**24.5**	**61.4**	**103.1**	**23.5**	**58.7**	**98.7**	**22.0**	**55.0**	**92.4**
Infrastructure constraints – expansion of district heating etc	0%	0%	0%	0%	0%	0%	0%	0%	0%
	24.5	61.4	103.1	23.5	58.7	98.7	22.0	55.0	92.4
Installation capacity constraints	98%	99%	99%	93%	95%	94%	82%	86%	84%
	0.4	0.7	1.2	1.7	3.2	6.2	3.9	7.7	15.2
Equipment availability constraints	0%	0%	0%	0%	0%	0%	0%	0%	0%
	24.5	61.4	103.1	23.5	58.7	98.7	22.0	55.0	92.4
Total Realisable Potential (of market potential)	**2%**	**1%**	**1%**	**7%**	**5%**	**6%**	**18%**	**14%**	**16%**
TOTAL REALISABLE POTENTIAL (TWh/y)	**0.4**	**0.7**	**1.2**	**1.7**	**3.2**	**6.2**	**3.9**	**7.7**	**15.2**
Approximate Number of Systems	20k	40k	60k	90k	170k	340k	210k	420k	820k

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

The assumptions on which the above estimates are based are as follows. The technical resource potential is assumed to cover all rural and suburban housing (excluding flats/apartments). Homes in urban areas and flats are assumed to be better suited to communal systems (i.e. biomass heat only or CHP with district heating). This high level demand figure is then reduced through the application of a number of constraints including:

- § Fuel Supply – We consider that there may be a constraint on uptake associated with poor or unreliable fuel supply; however this factor should be applied after determining the market/realisable potential and as such no constraint is applied here. The primary logic is that it can be assumed that the market will adapt to respond to demand. This may in the short term result in a greater level of imports but we consider that the market will to a large extend respond to the segment growth.
- § Site Constraints – Only a proportion of housing identified as technical potential is likely to be suitable for biomass heating. There needs to be adequate space for the boiler and possible thermal and fuel storage. Compatibility in homes with existing wet heating systems (gas fired) is good and unlike some renewable heat technologies do not require a low-temperature heating systems, so this is less of a significant constraint. This is a difficult factor to quantify, but have assumed a low estimate of 30%, best estimate of 50% and a high estimate of 70%.
- § Planning Constraints – Air quality is of particular concern with significant potential constraints on development primarily in urban areas. The majority of the areas that will have tighter air quality requirements will be urban areas. Given that the majority of heat demand is assumed to be in rural off-grid locations the impacts of this will be largely limited to the new homes developed.
- § Conversion Constraints – Given that biomass systems can operate at temperatures similar to existing domestic heating systems constraints on the installation due to complexity and system upgrades are small and much less significant than for other lower temperature technologies such as solar thermal and GSHP. This is effectively included in the site constraints factor.
- § Infrastructure Constraints – At the domestic level there is no need for heating infrastructure and the main physical constraint is likely to be the availability and size of fuel storage.
- § Installation Capacity Constraints – Likely to be severe limitations caused by a lack of trained and available installers, particularly over the next 5-10 years. AEA have estimated the potential for installation rates at 2010 (5,000/y), 2015 (10,000/y) and 2020 (20,000/y). The AEA assumptions seem to be quite a low estimate and as such have been adopted for the best estimate scenario (adjusted to the reference years for this study: 2012, 2017 and 2022). These installation rates have then been doubled and quadrupled for the best estimate and high estimate respectively.

Table A.8
Biomass Domestic (community and district heating)

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	149.4			143.0			133.8		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	0%	0%	0%	0%	0%	0%	0%	0%	0%
	149.4	149.4	149.4	149.4	149.4	149.4	149.4	149.4	149.4
Site constraints	60%	50%	40%	60%	50%	40%	60%	50%	40%
	59.8	74.7	89.6	59.8	74.7	89.6	59.8	74.7	89.6
Planning constraints (inc visual, air quality etc)	20%	10%	5%	20%	10%	5%	20%	10%	5%
	119.5	134.5	141.9	119.5	134.5	141.9	119.5	134.5	141.9
Market Potential (of technical potential)	**32%**	**45%**	**57%**	**32%**	**45%**	**57%**	**32%**	**45%**	**57%**
Market Potential (TWh/y)	**47.8**	**67.2**	**85.2**	**47.8**	**67.2**	**85.2**	**47.8**	**67.2**	**85.2**
Infrastructure constraints – expansion of district heating etc	20%	10%	5%	10%	5%	-	5%	-	-
	38.2	60.5	80.9	43.0	63.9	85.2	45.4	67.2	85.2
Installation capacity constraints	98%	99%	99%	93%	95%	94%	82%	86%	84%
	0.8	0.7	1.0	3.4	3.7	5.4	8.6	9.4	14.0
Equipment availability constraints	5%	-	-	10%	5%	-	10%	5%	-
	45.4	67.2	85.2	43.0	63.9	85.2	43.0	63.9	85.2
Total Realisable Potential (of market potential)	**1%**	**1%**	**1%**	**6%**	**5%**	**6%**	**15%**	**13%**	**16%**
TOTAL REALISABLE POTENTIAL (TWh/y)	**0.6**	**0.7**	**0.9**	**2.8**	**3.3**	**5.4**	**7.3**	**9.0**	**14.0**
Indicative number of systems required	N/A as there are major potential differences in terms of size.								

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

The basis of the above estimates is as follows. The technical resource potential assumes that all houses in urban areas and flats in all areas offer potential for connection to either a district heating network or the installation of a communal system (in apartment complexes for example). This high level demand figure is then reduced through the application of a number of constraints which are the same as described above for domestic pellet boilers with the exception of:

- Site Constraints – In terms of the work required within homes this is much less of an issue than for individual boilers, as just require a pipework connection and possibly a heat exchanger in the building (no larger than standard gas boiler). Few modifications are needed to internal heat distribution system in many cases. However there may be constraints to pipework to transfer the heat and some areas may not be suitable for installation of large biomass boilers. Difficult to quantify, but have assumed low estimate of 60%, best estimate of 50%, and a high estimate of 40% constraint.

- Planning Constraints – These are potentially less onerous than individual systems as there are fewer point sources with better dispersion possible, however, as many of the communal systems are located in urban centres there may be some increased issues from a planning perspective despite the general support for these developments within planning authorities. Assumed a low estimate of 20%, best estimate of 10% and high estimate of 5%.
- Infrastructure Constraints – District heating pipework is a mature technology but has low take up in the UK particularly for domestic schemes. This is primarily associated with the capital costs of laying the district heating network, the lower density of housing in newer developments and issues associated with the installation of the network. Where existing district heating systems are operational there are few problems. Only likely to be economically viable in regions where heat density exceeds $3000kW/m^2$ although many local authorities are supporting schemes in much lower density areas, and if sufficient levels of targeted grants or subsidies were made available a wider set of schemes could become viable. However, the installation rate is expected to be the dominant constraint and so only a small constraint has been applied.
- Installation Capacity Constraints – Larger projects are likely to be delivered by ESCOs and will have a lead time of several years to secure planning and design build etc. This presents major restrictions in the short term unless opportunities for the replacement of existing boilers can be realised. In addition potentially more lucrative schemes (city centre/industrial etc) likely to be perused initially due to the more favourable returns. The uptake rates for these are slower and this may result in project delays in realising district heating schemes. Due to a lack of firm data on installation capacity, and given the many variables involved the same assumptions as for domestic pellet boilers have been made.

Table A.9
Biomass (Commercial and Industrial)

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	336.9			346.3			350.1		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	0%	0%	0%	0%	0%	0%	0%	0%	0%
	336.9	336.9	336.9	346.3	346.3	346.3	350.1	350.1	350.1
Site constraints	90%	75%	60%	90%	75%	60%	90%	75%	60%
	33.7	84.2	134.8	15.7	39.2	62.6	14.7	36.7	58.6
Planning constraints (inc visual, air quality etc)	10%	5%	0%	10%	5%	0%	10%	5%	0%
	303.2	320.1	336.9	140.9	148.8	156.6	131.9	139.3	146.6
Market Potential (of technical potential)	**9%**	**24%**	**40%**	**9%**	**24%**	**40%**	**9%**	**24%**	**40%**
Market Potential (TWh/y)	**30.3**	**80.0**	**134.8**	**31.2**	**82.2**	**138.5**	**31.5**	**83.1**	**140.0**
Infrastructure constraints – expansion of district heating etc	90%	75%	60%	60%	50%	40%	35%	25%	15%
	3.0	20.0	53.9	12.5	41.1	83.1	20.5	62.4	119.0
Installation capacity constraints	50%	50%	50%	50%	50%	50%	50%	50%	50%
	15.2	40.0	67.4	15.6	41.1	69.3	15.8	41.6	70.0
Equipment availability constraints	30%	20%	10%	30%	20%	10%	30%	20%	10%
	21.2	64.0	121.3	21.8	65.8	124.7	22.1	66.5	126.0
Total Realisable Potential (of market potential)	4%	10%	18%	14%	20%	27%	23%	30%	38%
TOTAL REALISABLE POTENTIAL (TWh/y)	**1.1**	**8.0**	**24.3**	**4.4**	**16.4**	**37.4**	**7.2**	**24.9**	**53.6**
Approximate Number of 1MWth Systems[111]	200	1520	4620	830	3130	7120	1360	4750	10190

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

The technical potential is based on the total heat demand projections in the commercial and industrial sector. Both the AEA and E&Y studies (from DTI energy paper 68) assume a much lower technical potential, equivalent to 9% of the commercial market and only industrial sites not using gas as a fuel. This does not represent the true technical potential however, for example many industrial sites currently using gas could be suitable for conversion to biomass (indeed this could be an economic option), and so the figures in the aforementioned studies have not been used. In general the technical potential has been constrained by similar assumptions to those described above with the exception of:

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111 note in reality some plants may be considerably larger

- Planning Constraints –potentially less onerous than for individual systems as there will be fewer point sources, with better dispersion possible. Also sites are more likely to be located away from highly populated areas. Assumed low – 10%, best estimate – 5%, high – 0%.
- Site Constraints – Many commercial and industrial sites will be inherently unsuitable for biomass heating, or have insufficient space for equipment and deliveries. It is estimated that approximately 75% of all sites will not be suitable as a best estimate.
- Installation Capacity Constraints – as projects will be typically fewer in number but on a much larger scale than domestic systems, there is likely to be less constraint on installation capacity. Assumed a constraint of 50% in all cases, but this figure is a very high level estimate.

Equipment Availability Constraints – likely to be more of an issue than for smaller systems as larger equipment required and could result in projects being delayed (similar to that seen in the wind turbine industry recently). Assumed low – 30%, best estimate – 20%, high – 10%.

§

A.4. Solar Thermal

The following table provides estimates of potential and constrained uptake.

Table A.10
Solar thermal uptake – Domestic

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	32.5			33.0			33.4		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	0%	0%	0%	0%	0%	0%	0%	0%	0%
	32.5	32.5	32.5	33.0	33.0	33.0	33.4	33.4	33.4
Site constraints	50%	50%	50%	50%	50%	49%	50%	50%	47%
	16.3	16.3	16.3	16.5	16.5	16.9	16.7	16.7	17.6
Planning constraints (inc visual, air quality etc)	5%	2%	0%	5%	2%	0%	5%	2%	0%
	30.9	31.9	32.5	31.3	32.3	33.0	31.7	32.7	33.4
Conversion constraints (i.e. inconvenience and 'hassle factor')	15%	10%	5%	15%	10%	5%	15%	10%	5%
	27.6	29.3	30.9	28.0	29.7	31.3	28.4	30.1	31.7
Market Potential (proportion of technical potential)	**40%**	**44%**	**48%**	**40%**	**44%**	**49%**	**40%**	**44%**	**50%**
Market Potential	**13.1**	**14.3**	**15.4**	**13.3**	**14.5**	**16.1**	**13.5**	**14.7**	**16.7**
Infrastructure constraints - e.g. expansion of district heating	0%	0%	0%	0%	0%	0%	0%	0%	0%
	13.1	14.3	15.4	13.3	14.5	16.1	13.5	14.7	16.7
Installation capacity constraints	99%	97%	95%	87%	75%	56%	64%	33%	0%
	0.2	0.4	0.8	1.8	3.6	7.0	4.9	9.8	16.7
Equipment availability constraints	5%	0%	0%	10%	5%	0%	10%	5%	0%
	12.5	14.3	15.4	12.0	13.8	16.1	12.1	14.0	16.7
Total Potential (proportion of market potential)	**1%**	**3%**	**5%**	**12%**	**23%**	**44%**	**33%**	**63%**	**100%**
TOTAL - REALISABLE POTENTIAL	**0.2**	**0.4**	**0.8**	**1.6**	**3.4**	**7.0**	**4.4**	**9.3**	**16.7**
Approximate Number of Domestic Systems	200k	400k	600k	1,300k	2,700k	5,600k	3,500k	7,500k	13,400k

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

The total potential has been estimated based on the assumption that every rooftop is a potential site for solar thermal with a $4m^2$ system on average being installed collecting 1250kWh/year. This high level figure is then constrained by the following factors to provide the estimate of penetration:

§ Fuel Supply - No fuel requirements so not a constraint.

- Site Constraints – For existing properties 50% are assumed to be suitable for installation of a solar system based on assumptions in AEA (2007) which seems a reasonable high-level estimate. This assumption has been made for the low and best estimate scenarios. However, new build properties can be designed for solar thermal so for these properties the high scenario assumes 100% of new builds have potential for solar thermal, but only 50% for low and best estimate scenarios (though this has only a minor impact).
- Planning Constraints – Permitted development rights apply to domestic solar thermal systems i.e. providing certain criteria are met planning permission is not required (exception is properties in sensitive areas). Planning therefore should not affect the vast majority of potential systems. The best estimate scenario assumes that 2% of systems are prevented as a result of planning constraints (e.g. a proportion of those in conservation areas), while the corresponding assumptions for the low and high scenarios are 5% and 0% respectively. These numbers account for the fact that the site constraint already removes some of the situations where planning may be a restrictions.
- Conversion Constraints – Although technically feasible in many properties, where alternative systems exist solar thermal may not be appropriate or a reasonable option due to the hassle involved in converting to a new system (disregarding the financial viability and assuming there are no additional costs). Examples include properties with gas combi boilers, properties with limited space for hot water tanks, and homes that take up biomass or GSHP technologies and may not see the value of solar thermal. This restriction is difficult to estimate but is likely to be relatively small, and we assume the following: low 15%, best estimate 10%, high 5%.
- Infrastructure Constraints - No additional infrastructure required.
- Installation Capacity Constraints – Limitations on the number of trained installers could pose a significant constraint to realising the technical/market potential. The UK currently installs around 40,000 new systems each year so the jump in installation rate required for large-scale output is significant. Previous estimates by AEA suggested that under favourable market conditions capability to supply the retrofit demand could grow from 50,000 units per year in 2010 to 300,000 units per year in 2015 to 800,000 units per year in 2020. We assume a similar growth in installation rates for the best estimate case. This gives an 97% restriction in 2012, 75% in 2017 and 33% in 2022, and so this factor is by far the biggest constraint to uptake. The low scenario assumes the growth in capacity is half the best estimate (i.e. slower expansion of training) and the high scenario assumes the growth occurs twice the best estimate.
- Equipment Availability Constraints – As noted, equipment produced in the UK is unlikely to meet an ambitious growth scenario but imports would likely be available. Given the restrictions imposed by other constraints, equipment availability may not be binding, so only a small constraint has been assumed, increasing slightly in later years as the installation capacity constraint becomes less severe (low scenario, 5% in 2012, 10% in 2017 and 2022; best estimate 0% in 2012, 5% in 2017 and 2022, high scenario no constraint).
- Other Constraints – Factors such as costs and economic performance, competition with alternative low carbon technologies and policy will also have a significant impact on actual uptake. However these factors are not considered in this study.

Table A.11
Solar thermal uptake – Commercial and Industrial

	Uptake scenario								
	2012			2017			2022		
Total Resource - Technical Potential (TWh/y)	16.8			17.3			17.5		
Constraint	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**	**L**	**B.E.**	**H**
Fuel supply	0%	0%	0%	0%	0%	0%	0%	0%	0%
	16.8	16.8	16.8	17.3	17.3	17.3	17.5	17.5	17.5
Site constraints	50%	50%	50%	50%	50%	50%	50%	50%	50%
	8.4	8.4	8.4	16.5	16.5	16.5	16.7	16.7	16.7
Planning constraints (inc visual, air quality etc)	5%	2%	-	5%	2%	-	5%	2%	-
	16.0	16.5	16.8	31.3	32.3	33.0	31.7	32.7	33.4
Conversion constraints (i.e. inconvenience and 'hassle factor')	70%	66%	60%	70%	66%	60%	70%	66%	60%
	5.1	5.7	6.7	9.9	11.2	13.2	10.0	11.4	13.4
Market Potential (proportion of technical potential)	**14%**	**17%**	**20%**	**14%**	**17%**	**20%**	**14%**	**17%**	**20%**
Market Potential	**2.4**	**2.8**	**3.4**	**2.5**	**2.9**	**3.5**	**2.5**	**2.9**	**3.5**
Infrastructure constraints - e.g. expansion of district heating	-	-	-	-	-	-	-	-	-
	2.4	2.8	3.4	2.5	2.9	3.5	2.5	2.9	3.5
Installation capacity constraints	92%	84%	78%	-	-	-	-	-	
	0.2	0.4	0.8	2.5	2.9	3.5	2.5	2.9	3.5
Equipment availability constraints	-	-	-	10%	5%	-	10%	5%	-
	2.4	2.8	3.4	2.2	2.7	3.5	2.2	2.8	3.5
Total Potential (proportion of market potential)	**8%**	**16%**	**22%**	**90%**	**95%**	**100%**	**90%**	**95%**	**100%**
TOTAL - REALISABLE POTENTIAL	**0.2**	**0.4**	**0.8**	**2.2**	**2.7**	**3.5**	**2.2**	**2.8**	**3.5**
Approximate Number of Commercial Systems	60k	140k	240k	710k	880k	1,110k	720k	890k	1,120k

Note: L = lower bound; BE = best estimate and H = Higher or upper bound.

The total potential is based on approximately 1.4 million existing commercial and industrial buildings fitting sufficient solar thermal panels to meet 5% of the site energy demand. This technical potential is constrained in the same away as for domestic with the following exceptions

§ Conversion Constraints – Solar thermal may only make a small contribution to many C&I type sites, so conversion may not be an attractive option if it entails significant disruption. It has therefore been assumed that solar thermal will only be suitable for commercial sites and not industrial sites. Discounting industrial sites gives a 66% constraint (best estimate), with a low estimate of 60% and high estimate of 50%.

- Installation Capacity Constraints – Same assumptions on installation capacity as for domestic for 2012. Significant constraint initially with higher installation rates but diminishes rapidly (to 0% in all cases from 2017 based on the AEA installation rates, given the much lower market potential in the C&I sectors). However some constraint is still assumed beyond 2012 to account for the increased design and installation work required for larger commercial systems which may restrict the installation capacity (for 2017 and 2022 low 20%, best estimate 10%, high 0%).

Appendix B. Additional Technology Overview

This appendix provides additional technology overview of district heating and electric heating. Neither of these technologies is itself “renewable”, but they can be combined with renewable energy sources to provide heating. District heating often is powered by CHP, and the discussion here therefore supplements the discussion of CHP in the context of biogas and biomass district heating. It also is possible, although less common, to use district heating with other renewable heat technologies, including large-scale geothermal / ground-source heat pumps. Electric heating, meanwhile, could be a route to the use of renewables for heating if electricity generation from renewable sources were the main option for the addition of new generating capacity.

B.1. District Heating

B.1.1. Background

District heating is a critical part of the infrastructure in many medium and large scale communal heating schemes, as it allows the heat produced from plant to be distributed to homes and businesses. District heating approaches can be applied to a number of different renewable heating technologies, so we consider it in its own chapter. Hot water is the medium typically used, and it can be transmitted via modern pre-insulated pipework over considerable distances (many km) with low heat losses. Such pipelines can be directly buried in the ground and have low maintenance requirements, and are generally used in preference to steam for supplying residential, commercial and light industrial sites.

The heat from many thermal processes can be transferred via a heat exchanger to a district heating network, though normally this will be from a boiler or CHP plant. Any combustible fuel can be used as the source of heat, including biomass, waste and fossil fuels but it is also possible to use surplus heat produced from industrial processes and electricity generation.

The main drawback is that the capital cost associated with the installation of heating pipework and associated equipment is high. Costs vary with pipe size, insulation type etc, but often the most critical factors are the pipe lengths and the type of ground they are buried in (installing in urban areas is much more expensive than in soft ground and greenfield land).

Other barriers to the deployment of district heating include a general lack of awareness and understanding of the technology, planning issues, disruption on installation and the logistics and commercial problems associated with connecting many individual sites to a novel (at least in the UK) type of heating network.

Generally speaking, the larger the development and the higher the heat use, the more viable a connection is hence developments such as council buildings, hospitals, prisons and high-rise flats tend to be favoured over low density areas.

B.1.2. System design

District heating can be used to supply almost any site that requires hot water for heating. Only industrial sites requiring high temperatures and buildings with very low heating demand are technically unsuitable. In practice although there are few technical reasons why the majority of residential and commercial sites could not be supplied with heat via district heating the economic viability is much less certain and is the key constraint on uptake. In addition to the purely financial aspect, commercial issues of installation and operation are complex and can constrain the development of schemes.

B.1.2.1. Technical overview

Hot water is transported using either plastic or steel pipes, insulated with polyurethane foam and encased in corrosion resistant high density polyethylene or similar plastic. Large transmission pipes can be over a metre in diameter and typically carry hot water pressurised to as much as 25 bar. At this pressure water can be heated to 120^{o}C which increases the heat capacity.

Distribution pipework is usually all plastic and not pressurised significantly, carrying water at lower temperatures typically around 90^{o}C. Small networks will usually only consist of this type of pipework, with transmission mains usually restricted to larger town wide schemes.

Hot water pipes are smaller than equivalent steam pipes as despite the lower specific heat capacity (which may be around ten times less), water is several hundred times denser than steam and so a smaller volume is required to transport the same thermal energy.

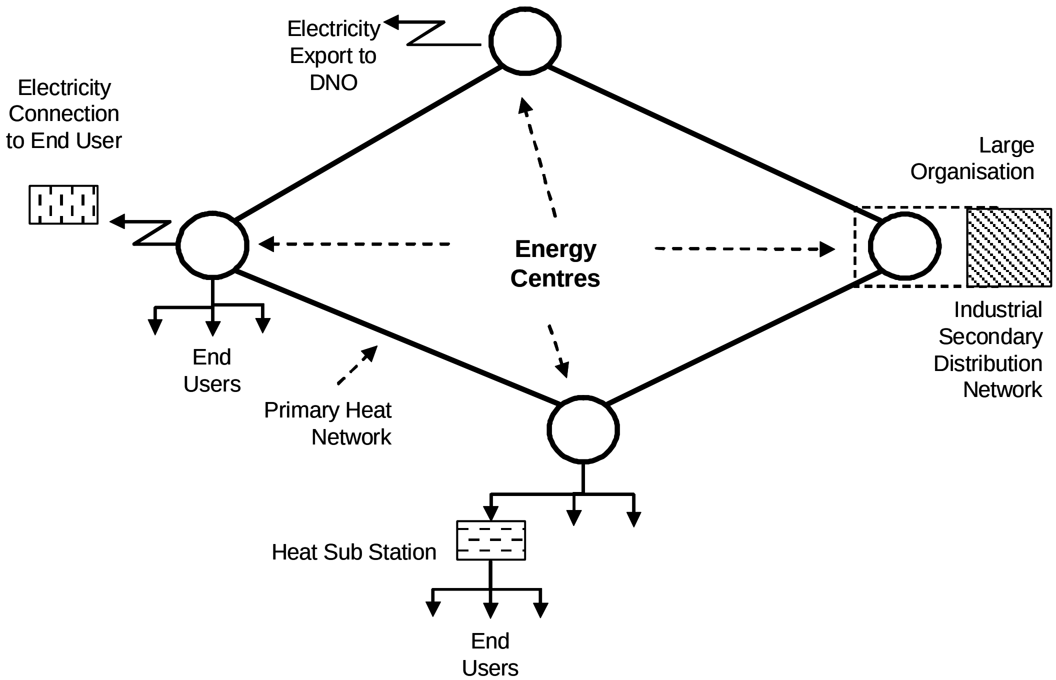
Heat is transferred from the source (usually a boiler or CHP unit) indirectly via a heat exchanger. The heated water is pumped around in a closed system, and heat is transferred to individual buildings again using a heat exchanger. In domestic properties these are roughly the size of a gas boiler, so space requirements are similar. Heat meters may be used to accurately record heat use, or fixed charges can be made in a similar way to water rates. Water is pumped back to the source at lower temperature, the lower the better from an efficiency point of view but typically between 40 and 60^{o}C.

Modern district heating systems are highly efficient, with large systems having total thermal losses well below 10% (c.f. similar steam based systems where losses may exceed 30%).[112]

The key elements of a community heating system are presented in Figure B.1. This shows different ways in which ‘energy centres’, typically CHP or heating plant can be connected to heat and electricity supply networks, such as coupled with an industrial site, or connected to the heating main and exporting electricity to the grid or via a private wire network.

[112] [Reference tbc]

Figure B.1
Key Elements of a Community Heating/CHP System



B.1.2.2. Infrastructure requirements and costs

The investment required in infrastructure is considerable. In a large scale heating network the infrastructure elements detailed in Table B.1 may be required. These costs are similar whether renewables or fossil fuels are used to generate the heat.

Table B.1
District Heating Infrastructure Components

Element of System	Description	Indicative Unit Cost
Transmission pipeline	Large steel pre-insulated pipe	£1,000 – £1,500 per metre (installed, buried)
Distribution pipeline	Smaller plastic pre-insulated pipe	£500 – £1,000 per metre (installed, buried)
Substations	Link transmission system to distribution system (typically include pumping and heat exchanger)	Variable depending on size and equipment required
Building heat exchangers	Heat exchanger for individual buildings. Replace gas boiler, similar space required	£1,000 – £1,500 per domestic unit (ex works)
Heat meter	Measure energy usage in buildings	£250 per domestic unit

In addition to the items listed in the above table, there will be significant project management and design costs, potentially including planning and legal fees.

For residential applications, a cost of district heating infrastructure of £6,000 per dwelling is a reasonable estimate for a new build development where piping is buried in soft ground, the housing is of moderate to high density and the heating pipework is installed in a common trench with other utilities. This figure includes the necessary supply pipework, domestic heat exchangers and heat meters at the property. This cost is in addition to the main transmission pipeline to the development. Note that the costs are sensitive to many factors including ground conditions, housing density, economies of scale and so on. The cost per dwelling may be more than twice that for a retrofit and/or for low density housing. Conversely, it may be less for flats where district heating is better suited.

Developing a district heating scheme in an established neighborhood can be a costly exercise which may require significant financial support from central or local government. Indicative costs could be of the order of £10,000 – £15,000 per home for connection to such a scheme, additional costs which primarily ensue from the requirement for laying the heat distribution pipes in existing roads through the neighborhood and connecting these pipes to the existing heating systems in individual homes.

Connection costs (pipework) are expected to be similar for commercial developments. It is therefore important to appreciate that the heat distribution infrastructure is likely to be a very significant cost element of a centralised heating or CHP scheme.

Comparing these costs with the capital costs of boilers which can be in the order of £250k to 300k (assuming a 800 kWth facility) a community scale system with a 1 km district heating loop which could be in the region of £0.75 to 1.3M, the costs are therefore potentially significant.

Planning, designing and building district heating infrastructure takes considerable time, particularly in built up areas. Obtaining wayleaves for pipelines can take significant time in built-up areas, as existing services must be identified. In all schemes may take several years from start to finish, so it is key that this is considered at an early stage.

B.1.2.3. Design and suitable applications

There are a number of ways in which a development can be designed, or suitable existing developments identified, to make the installation of district heating more straightforward from a technical viewpoint whilst also minimising costs. Some general principles are outlined below:

- New developments are easier and cheaper to connect than existing ones;
- The more densely packed the better to minimise pipe lengths (minimises capital expenditure and reduces heat loss and hence more efficient);
- A relatively constant heat demand is preferable to a highly variable one;
- The larger the development generally the better as costs fall and efficiencies tend to rise owing to economies of scale;

- The fewer the number of organisations, the simpler the commercial aspects (although the project risk can increase as the effect of a large organisation pulling out is more significant, and numerous partners helps to spread the risk);
- The establishment or employment of an Energy Services Company (ESCO) often simplifies matters and can avoid the need for large outlay upfront (if design, build and operate model used). For a large city-wide scheme this could be in partnership with the public sector; and
- Where pipes can be installed above ground significant cost savings can be made compared with burying, as much of the piping costs are attributed to civil works.

Table B.2 is a guide to the potential for installing district heating and centralised heat generation in different types of development. The table is based on technical, economic and commercial factors. This is not an attempt to cover all building types but rather to provide examples of the kinds of development better suited to district heating. In practice, district heating is often used in mixed developments, rather than in pure residential / commercial projects.

Table B.2
District Heating Potential

Suitability for District Heating Scheme	Example Developments		
	Residential	Commercial	Industrial
Very Good	New build flats/apartment complexes and mixed use developments	Large, high intensity users such as hospitals, prisons and mixed use developments	Large, energy intensive process operations requiring hot water rather than steam
Good	New build high density housing, existing flats/apartments complexes	New build large retail and offices, large educational facilities such as universities and secondary schools, leisure centres, hotels	Large manufacturing facilities, printing works, food production
Average	New build low/medium density residential, council owned existing housing	Small educational facilities, local healthcare, large existing offices, small new office developments	Light manufacturing and assembly works, business parks and trading estates
Poor	Privately owned low density existing housing (not already using district heating)	Storage facilities, small retail units	Warehouses, garages, buildings where wet heating systems are inappropriate

B.1.3. Cooling and trigeneration

Absorption chillers can produce chilled water from a heat source, such as hot water. This is a particularly efficient means of using heat from CHP plant in times of low demand such as in summer. Cooling water can be transferred via pre-insulated pipes in exactly the same way as hot water, and this can replace electric air conditioning systems. It may only be economic to do this in buildings with high cooling loads (public buildings etc rather than individual houses) and so this tends to be applied to localised areas (such as city centres, shopping centres etc). As the overall cooling load will normally be lower than the heating load in many UK buildings, fewer sites are likely to be economic than for heating so need to focus on areas of high demand.

B.1.4. Commercial issues

This section considers the commercial issues that will need to be addressed when installing a district heating scheme. The same issues apply to other community energy schemes (on-site electricity generation, biogas network etc)

The commercial arrangements for on-site generation of electricity and heat often differ greatly from the conventional energy supply model (electricity from the grid, heat from the gas network), particularly in the case of community schemes serving multiple homes and businesses via district heating and private wire electricity networks. The regulatory framework for such schemes is not yet fully developed, and it is often advantageous to engage the services of a specialist Energy Services Company to build and operate the necessary plant and distribution infrastructure.

At a very general level an ESCO is a company or organisation responsible for delivering energy in the form of electricity, heat or both to consumers. An ESCO may design and build the plant, be responsible for its operation, maintain the distribution network and generation plant, and meter and bill consumers—or it may be involved in some of these activities, but not all of them.

The export of heat differs from the export of electricity where an outlet for surplus electricity is almost always available, i.e. the National Grid. As no similar infrastructure exists for heat, there will be complex commercial issues to negotiate even where there is good technical potential for heat supply. One of the major obstacles occurs because the life of the installed plant may be in excess of 25 years, but few heat customers are willing to commit to a contract for this length of time. Given the high capital cost of the infrastructure a guaranteed income is often necessary, for significantly longer than the 5 years or so that the customer may be willing to sign up to.

As noted above, a district heating scheme with many consumers is a much more complicated arrangement than where there is just one, but the financial risk may be lessened due to the effect of having a large number of independent consumers, and the possibility of extending the scheme in future.

Hence though it is often technically simpler and cheapest in terms of capital cost to supply a single customer, this may be subject to the highest commercial risk.

In general, by relying on an ESCO, energy customers are able to:

- Simplify and consolidate the commercial aspects of the supply of heat and electricity into a single contract;
- Procure energy savings and emissions reductions; and
- Transfer much of the technical, and potentially financial, risk to a third party (the ESCO).

The consolidation of services and transfer of risk are prime reasons why the ESCO model is well suited to district heating networks all of which are evolving technologies not necessarily well proven with major operational experience at this scale, particularly in the UK. However, ESCOs are likely to be willing to take on significant risk only if adequately compensated. Where this results in higher charges it could lead to poor uptake/performance and a negative perception that may spill over to other potential schemes

Privately funded ESCOs will expect to see a profit from their operations. However, many public and charitable ESCOs do not, and these are often partly or wholly owned by the residents of the development they are serving. Thus ownership structure of the ESCO can have an impact on the price for its services.

One potential problem with ESCO provision is that customer may have no fallback option if charges for heat set by the ESCO are excessive, particularly where heating is only possible via a district heating network (e.g., no gas supply). One potential way to address this is to meter accurately and index the cost of heat to other relevant options (e.g., to other fuels). However, if the ESCO's own costs are not closely linked to fuels it may create too large a risk to the ESCO to be an attractive proposition.

If district heating networks become more widespread new regulation may be required to address the issue of competition. The Government's recently published Heat and Energy Saving Strategy[113] outlines possible options for such regulation.

B.1.5. Market status

B.1.5.1. UK

The use of district heating is currently limited in the UK. A number of small residential schemes exist, often fuelled by coal or oil (though increasingly these have/are converting to natural gas or biomass) and serving high density social housing.

A small number of relatively large scale schemes also exist. The largest is in Sheffield, primarily fuelled by the city's Energy from Waste plant. The scheme is a two-layer system of the type described previously consisting of a transmission pipeline and a number of substations feeding a distribution network to which many public buildings are connected. Southampton has a small network fuelled by geothermal energy (the only scheme of this type in the UK) and a much larger network is under construction that will supply approximately 4,000 council owned homes with heat sourced from a biofuel CHP plant.

Other schemes exist in Nottingham, London and Lerwick to name a few. Most are in cities where development is high density, with only a few schemes in more rural areas (such as the Kielder village biomass scheme).

A large network is planned in the Thames Gateway by London Development Agency[114], with first customers supplied by 2011. This network could supply as many as 120,000 homes and

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113 BERR 'Heat and Energy Saving Strategy Consultation', Feb 2009

114 See http://www.ltgheat.net/ for further information

other buildings with heat from a number of sources including surplus heat from Barking power station, potentially saving over 100,000 tonnes of CO_2 per year.

B.1.5.2. World

District heating is a very well established technology in some parts of the world, particularly in Scandinavia. For example in Denmark over 50% of all heating is supplied in this way. Copenhagen has a very large, city-wide heating system, the transmission network is operated by two companies (CTR and VEKS). The CTR system alone consists of a 54km long transmission pipeline, with heat transferred to a distribution network via 26 substations. Approximately 275,000 households are supplied by this network. The much greater use of district heating in Denmark than other countries is largely due to policies implemented by the Danish Government to reduce the reliance on imported energy following the 1970s oil crisis. Other large district heating systems exist in many other European cities such as Krakow and Munich. The US has numerous old steam-based heating networks (most famously in New York), although these are much less efficient and reliable than the modern hot water based systems. Many of theses are being replaced, and there are now a number of cities with large modern heating networks, an example being in St Paul in Minnesota where several hundred city centre buildings are connected. The system is fuelled by approximately 1,000 tonnes per day of biomass.

The use of steam is largely restricted to supply process heating demands, and has been entirely superseded by hot water systems for domestic and commercial purposes.

B.1.6. Potential and barriers

B.1.6.1. Potential

There is significant potential for district heating in the UK. and it could be an important part of a move to a low carbon economy for both new build but also in existing areas where the heat densities are appropriate. District heating using biomass boilers or biomass-fired CHP could be an important method for meeting the higher levels of the Code for Sustainable Homes (CfSH). Large scale schemes could form an important part of the infrastructure in many large new housing and commercial developments, including proposed ‘eco-towns’.

The carbon saving potential and investment required will depend on the uptake of heat generation technologies (e.g. biomass, biogas, use of waste heat). A discussion about the potential for district heating is provided in the biomass section.

B.1.6.2. Barriers to district heating

The dominant heating model has been a national gas distribution network for the last few decades. Technically and commercially the system is very well established and the vast majority of UK properties obtain heat in this way. This has created a number of significant barriers:

- Lack of awareness of district heating from the public and industry, and in some cases a negative perception based on older, less efficient systems;

- Increased complexity over conventional supply, as well as limited regulation can lead to a reluctance for householders and businesses to engage in schemes;
- Planning and obtaining wayleaves for pipelines;
- Existing heat supply contracts;
- Lack of flexibility and requirement to tie into contract can lead to reluctance to join scheme;
- Cost is an issue in existing developments, but for new builds with stringent sustainability targets this is often among the cheaper options; and
- Regulatory framework not established.

Other constraints may become an issue when the barriers above are overcome.

- Supply restrictions – at present almost all pre-insulated pipe is imported (mostly from Scandinavia), and there are few companies operating in the UK market. Will need to ensure supply chain is sufficient to cope with expected expansion, if locally manufactured this could reduce costs. It is anticipated that this will not be a significant issue with uptake, planning and construction being more pressing concerns.
- Competition with biogas injection to gas networks, there is debate as to the most appropriate use of biogas and reality a mix may be necessary.

B.1.7. Support mechanisms, funding and incentives

No grant funding is available for district heating infrastructure in isolation at present, but low carbon heating schemes incorporating this technology may be eligible for support from the new Community Energy Savings Programme (CESP). The appropriate technology chapters further discuss funding, resource and carbon savings potential of low carbon fuels that can be used in conjunction with district heating.

B.2. Electric Heating

B.2.1. Background

Electricity is used for heating in many domestic and commercial buildings. Around 12% of domestic buildings in the UK are heated electrically[115], and this figure has risen in recent years due to the relatively frequent use of electric heating in new-build flats and apartments. In addition to buildings heated entirely by electricity, many homes have electric fires and supplementary heaters (oil filled radiators and fan heaters for example). Almost all electricity used for heating is imported from the national grid, with very little sourced from on site generation such as solar photovoltaics and small scale wind turbines, which tend to be expensive and inefficient by comparison.

In the domestic sector electric heating is often used in flats, apartments and small houses (particularly social housing) as well as properties not on the gas network. In domestic applications storage heaters are typically used for space heating and immersion heaters for hot water. As electricity is much more expensive than gas, most is imported at off-peak times when the unit cost is lower, and the heat stored for use throughout the day.

Although electric heating is efficient at point of use, the overall conversion efficiency is low (<30%) due to high losses in the electricity generation and distribution process. The low overall efficiency coupled with the predominantly fossil-based fuel mix of grid electricity means electrical heating has high CO_2 emissions, significantly greater than gas or oil. The average grid carbon intensity currently is just over 0.5 $kgCO_2$ / kWh, but can vary significantly depending on the time of day and other factors. However, for assessment of the associated with additional electric heating it arguably is more appropriate to consider the emissions intensity of marginal new entrant generation capacity. The estimate typically used in policy assessment is 0.43 $kgCO_2$/kWh, representing a (relatively inefficient) CCGT plant. This is over twice the figure for heating from efficient natural gas boilers.

Despite these apparent drawbacks, electric heating potentially could become an option for long-term abatement if there were significant reduction of emissions associated with electricity production. A potential prospect for this may be through the use of carbon capture and storage, though it is questionable whether such a high cost product is an appropriate source of heat, even if carbon emissions are low.

B.2.2. Suitable applications

Conventional electric heating can have a role complementing a number of renewable heating technologies. This is true for both heat pump technologies, and conventional electric heating also may be combined with biomass and solar thermal technologies.

As noted above, given the characteristics of current likely new entrant generation capacity, electric heating is unlikely to reduce emissions at all, because the associated emissions intensity has a much higher average emissions factor than gas- or oil-fired heating systems.

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115 http://www.buildingtalk.com/news/ama/ama202.html

B.2.2.1. Buildings with low heat requirements

Electric heating can be particularly suited to small heat loads. Many commercial and industrial sites have a low demand for space heating and/or hot water. For example in the case of many warehouses which may have relatively high electrical load for lighting etc, but space heating requirements may be low and economically met by radiant electric heaters. There may be a small demand for instantaneous hot water, and it may be more cost effective to use immersion heaters for this purpose.

On the domestic front many modern/new properties are being designed and built with a much smaller energy demand which could be met through electric heating with environmental impact ratings (under SAP) of a similar order to gas-fired systems.

Buildings where a low ambient temperature is required (frozen foods, data rooms etc) may also have a very limited heating requirement, perhaps only in relatively small staffed areas, and electric heating may be attractive.

B.2.2.2. Remote properties

Properties not connected to the gas grid will generally have to use oil, electricity, LPG, or potentially biomass for heating. Where heat demands are low electricity may be the most cost effective option for providing heat, although the associated emissions may be higher than for other options.

B.2.3. Future contribution

As a rule of thumb typical heating capacity is designed at 100W per m^2. Historically electric heating has been installed in many off-grid areas and also in new developments where the developer is looking to make cost savings. It now is less likely that electric heating will be used without significant accompanying improvements in the building to reduce the required space heating. For example, we estimate that the designed heating requirement may fall to 60-70 W/m^2 in 2012; 40-50 W/m^2 in 2017 and between 5 and 40 W/m^2 in 2022, by which time many new homes will likely have very low heating requirements[116].

In the cases described in Section 1.2 electric heating may be a good option even where other renewable heating options exist. In general , however, other options (including gas) will be preferable both in terms of CO_2 emissions and overall cost.

The feasibility of grid decarbonisation will depend on a number of factors. One aspect of this is the aging or closure of existing power stations (e.g. coal in 2015/16), and long-planning times for replacement or expansion capacity. These factors will influence the average generation mix and therefore average carbon intensity, although it will likely take some time before the characteristics of marginal new entrant capacity change. Another relevant consideration is the creation of other potential electric loads, which could include increased use domestically, consumption by electric vehicles , and the production of hydrogen.

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116 Indicative floor areas for new properties include: studio 50-60m^2, 1 bed 60-80 m^2, 2 bed 80-110 m^2, 3 bed 110-160 m^2 and 4 bed 150 to 450 m^2.

Increased demand would add pressure to the system and our ability to decarbonise the grid over the next 12/13 years.

B.2.3.1. Future of electric heating – new build

The Government has decreed that all new housing must be zero carbon by 2016, and there are plans to extend this requirement to the non-domestic sector by 2019. The exact provisions for electric heating are yet to be finalised, but one proposal is that electricity will count as emissions free only if it is produced from renewable sources on site, or connected to the development through a private wire network. Any electricity used cannot be supplied via the grid, and ROCs cannot be claimed (if they were then the carbon benefits would be double counted, and the electricity supplied to the development therefore must not also be used to contribute to supplier obligations under the Renewables Obligation).

In some cases the use of large scale wind turbines may be feasible for electricity supply to some new developments. It is possible that there could be a significant net export; in this case it could be cheaper to simply heat the buildings electrically rather than using microgeneration or biomass heating.

This option is particularly attractive in very highly insulated buildings, such as houses designed to 'Passivhaus' standards (maximum heat demand of 15kWh/m^2/year which equates to between 1.2 and 1.6MWh/year for a 2 bedroomed property)**.** The very limited space heating requirements may mean connection to a district heating network is uneconomic as the investment required may not be recouped by low heat sales. Electric heating from a renewable source may then be a more attractive option.

B.2.3.2. Future of electric heating – existing buildings

The Heat and Energy Saving strategy proposes an outline plant to reduce carbon emissions to near zero by 2050. This includes consideration of appropriate efficiency measures and energy supply technologies (which could be on-site microgeneration or connection to a more centralised network) on a home-by-home basis. A possible strategy to ensure the appropriate use of electrical heating could be:

- Consider electrically heated homes as key targets for GSHP, ASHP and solar thermal (may be cheaper and have a higher positive impact on carbon)
- Maximise the use of alternative low-carbon sources and technologies such as solar thermal, biomass, biogas, gas/biomass CHP etc.
- At the point at which it becomes more cost effective to install renewable electricity generation capacity to use for heating (likely to be only at high uptake of renewable heat) this may need to be used more widely.

B.2.3.3. Impact on electrical generation capacity

The UK has set itself challenging targets for the proportion of energy sourced from renewable sources. Increases in electricity demand, including increased use of electric heating, would further increase the requirement for additional renewable capacity.

The RO scheme puts a premium on electricity generation, but places no restrictions on end-use. Hence electricity generated and then used for heating is still eligible for ROCs (noting the issues in the above section).

In addition to an increase in electricity for heating there may be other factors that further increase the overall demand and reduce the capacity of the system to provide low carbon heating. As noted, major developments may include an expansion in electric vehicles, and the use of electricity to produce hydrogen. Both of these could be important factors in the longer run.

B.2.4. Support mechanisms, funding and incentives

There is no direct support for electric heating, but when electricity is generated by renewable sources the support mechanisms for electricity generation apply, such as the Renewables Obligation scheme. Additionally a feed-in tariff for microgeneration is proposed from 2010, which is expected to apply to schemes with a capacity below $5MW_e$ (though specific details are not yet known).

B.2.5. Sustainability and carbon saving potential

As noted, the carbon impact of electric heating depends greatly on the source of electricity. In many situations, a more viable option for carbon savings may be to use other low carbon heating (except in the circumstances particularly favourable to electric heating noted above).

The contribution that electricity can make to a longer-term low carbon heat supply is difficult to quantify. It will depend on many factors including the uptake of other renewables and level that the resource is exploited, the cost of electricity and policies towards electric vehicles and hydrogen production. To meet the targets proposed in the Heat and Energy Saving Strategy of virtually no emissions from domestic sector by 2050, a contribution from electric heating sourced from renewable generation will likely be necessary in order to achieve low-carbon heating heat loads where other renewable heat is unsuitable or insufficient in the aggregate to meet demand.

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