Discussion Paper

Low Carbon Heat Foresighting

DISCUSSION DOCUMENT
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Scottish Enterprise

Abstract

This Paper evaluates heating (and cooling) in Scotland and the UK, with the aim of understanding the key technologies and drivers which will enable the sector to transition to meet emission reduction targets of 80% by 2050. It explores the main regulatory drivers and incentives, and how various modelled heat scenarios foresee technology development and heat delivery evolving over the coming decades. Energy efficiency measures and behaviours will be key to ensuring the transition to a low carbon economy, whilst providing affordable heat to householders and business. Low carbon heat technologies are identified and ranked in this analysis in terms of their ability to meet Scotland's heat targets, their cost of energy, the presence of Scottish competitive advantages, and the feasibility of the technology for large-scale deployment. Estimates of current and future deployment rates are given.

This analysis will allow SE and other stakeholders to develop an overall strategic approach, and provide evidence for companies to encourage investment and supply chain development of low carbon heat technologies. Opportunities for SE to stimulate economic growth in the low carbon heat sector are recommended.

Work completed by Scottish Enterprise relevant to this paper:

- "Analysis of the Scottish Company Base and Market Opportunities", Innovas report commissioned by SE;
- "The International Opportunity for the Scottish Low Carbon Heat Sector", Delta EE report commissioned by SE;
- The Smart Grid Action Plan.

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Acronyms

AD	Anaerobic Digestion
ADE	Association of Decentralised Energy
ASHP	Air Source Heat Pump
BT	Balanced Transition
BtG	Biomethane to Grid
CIBSE	Chartered Institute of Building Services and Engineers
CoE	Cost of Energy
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CPF	Carbon Price Floor
DECC	Department for Environment and Climate Change
DH	District Heating
DHN	District Heating Network
DNO	Distribution Network Operator
EfW	Energy from Waste
ENA	Energy Networks Association
FIT	Feed in Tariff
GI	Government Intervention
GSHP	Ground Source Heat Pump
GVA	Gross Value Added
HPSM	Heat Pathways Scenario Model
HGPS	Heat Generation Policy Statement
HUI	Hydraulic Unit Interface
LPG	Liquefied Petroleum Gas
LTS	Local Transmission System
MSW	Municipal Solid Waste
NTS	National Transmission System
PPC	Pollution Prevention and Control
PV	Photovoltaic
RHI	Renewable Heat Incentive
SE	Scottish Enterprise
SEPA	Scottish Environment Protection Agency
SG	Scottish Government
SHCS	Scottish Housing Condition Survey
WSHP	Water Source Heat Pump

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EXECUTIVE SUMMARY

Renewable heat targets and market drivers

Scotland has ambitions to hold a leading market position in the wider low carbon market, including the delivery of 11% of non-electrical heat demand from renewables in 2020. Currently heat accounts for around 55% of Scotland's total energy consumption[1,2], more than transport and electricity combined. Supporting the UK's low carbon heat ambitions is the Renewable Heat Incentive (RHI) operated by the Department for the Environment and Climate Change (DECC), which is the world's first long-term financial support programme for renewable heat[3].

Scotland's heat sector statistics

Domestic, commercial and industrial heat in Scotland is currently primarily delivered by natural gas (61%) followed by petroleum products (31%)[4]. Just under 80% of Scottish domestic properties are currently heated by individual grid-connected gas boilers. Deployment of District Heating Networks (DHN) has been limited to date in Scotland, although the Scottish Government has draft targets for 40,000 homes to be connected to a DHN by 2020. In 2012, 3.0% of Scotland's non-electrical heat demand was delivered from renewable sources, primarily (80%) from biomass[2].

Scottish heat scenarios to 2030 and 2050

Three heat scenario studies have been explored in detail in this study:

1. DECC's heat pathways to 2050[5]
2. Scottish Government's Heat Generation Policy Statement (HGPS)[1]
3. Energy Network Association's gas future scenarios project[6]

All three studies indicate that measures currently in place are expected to reduce emissions arising from the heat sector by roughly 50% by 2050, due to reduced heat demand from thermal efficiency improvements through retro-fit and new build, and improved heating system efficiencies. The Scottish Government has a goal to diversify the sources of heat to support a resilient heat supply and reduce the pressure on household energy bills, in particular supporting the fuel poor; reducing heat demand through energy efficiency and behaviour change are considered key in ensuring that the transition to a largely decarbonised heat system is affordable.

While current measures are predicted to deliver significant progress, in order to meet the 2050 emissions reduction target of 80% (baselined to 1990), several main themes emerge in one or more of the three studies:

- A substantial reduction in the role of natural gas for heat; a gradual phasing out of gas towards 2050, but out to 2030 the mains gas network remains the dominant source of heat supply across domestic, commercial and industrial sectors.
- Towards 2050, any end-use of natural gas is increasingly expected to utilise Carbon Capture and Storage (CCS) – which would only be feasible for large consumers & heat networks;
- Increasing electrification of the heat sector (via air and ground source heat pumps), powered by low carbon electricity;
- Increasing uptake of hybrid boilers (a gas boiler and Air Source Heat Pump (ASHP)) is forecast by a 2013 DECC study[5] as conventional boiler units are refreshed, and by 2030 hybrid gas boilers could become the standard heat source for the UK's gas-grid connected properties;
- An increase in District Heat Networks (DHN): the Scottish Government has a 2020 draft target of 40,000 homes and 1.5 TWh supplied by DHNs[1], <2% of Scotland's total number of homes and heat demand. This draft target will require the installation of around 30 new DHN projects of the scale of the Commonwealth Games DHN[7] over the next 5 years. DHNs can be effective from a carbon and cost perspective and offer flexibility of source; however retrofit installation can be disruptive.
- The potential for biomass (wood products) to play a substantial role in meeting heat targets. Biomass is currently the most widely used low carbon heat resource in Scotland (~80% of low carbon heat supply), is a

relatively mature low cost source, and can be adapted to suit many building types with suitable fuel storage space.

- Renewable biomethane from feedstocks traditionally considered waste (e.g. sewage, food waste, animal slurry, and agricultural waste) could provide around 20-25% of Scotland's 2030 gas demand[8], via the existing gas-grid. The Zero Waste (Scotland) landfill ban of biodegradable waste in 2020 represents a major short-term feedstock opportunity. Less certain in any of the scenarios is the role synthetic gas (hydrogen and methanation) could play in the heat sector, and any increased role will be dependent on regulatory changes on the levels of hydrogen permitted for injection to the gas grid, as well as the availability of affordable low carbon electricity to facilitate electrolysis.

Average Scottish gas consumption per household has fallen by 28.7% since 2005[2]. DECC's model[1] suggests that building and heating efficiency improvements, coupled with a move to other heat sources, may lead to a further 40% reduction in total UK domestic gas demand (over 2011-50).

Recommendations for Scotland's low carbon heat sector

Low carbon technologies for gas-grid connected heat users:

- <u>Renewable gas</u>: Biomethane (biogas) is a low carbon resource which can utilise the existing gas network with minimal disruption for the end-user, potentially at a low cost. Penetration is limited by finite feedstocks to 20-25% of the total expected future heat demand[8]. SE should support activity in the biomethane sector in Scotland, such as maximising economic opportunities arising from Zero Waste Scotland's initiatives to divert organic waste from landfill. The role of synthetic gas (e.g. hydrogen from electrolysis, and methanation) needs further analysis but could become an additional low carbon gas resource.
- <u>Hybrid gas boilers</u>: SE should support trials of smart enabled hybrid boilers and (if successful) subsequently develop the supply chain for their widespread deployment. Early indigenous adoption may provide opportunities for Scottish manufacturing (e.g. Mitsubishi in Livingston). The UK could require millions of units under DECC scenarios.

District Heat Network renewable technologies:

- <u>A large-scale heat pump demonstrator</u>: Scottish company Star Refrigeration has demonstrated a Water Sourced Heat Pump (WSHP) system in a Norwegian fjord which provides for around 6,000 properties via a heat network (at >300% efficiency)[9]. Across Central Scotland there are existing heat networks in close proximity to *rivers* and *flooded former mines* which may provide ideal sites for a Scottish project.
- <u>A large-scale heat energy storage demonstrator:</u> SE should consider supporting a large underground water store (like the 70,000m^3 pit heat storage in Marstal, Denmark[10]). Heat storage allows efficient operation of heat networks and can accept any available heat source (e.g. solar, Combined Heat and Power (CHP), and waste heat) for use on demand.
- <u>A large-scale solar farm demonstrator:</u> to demonstrate seasonal renewable heating (summer to autumn) for the first time in Scotland. Whilst individual domestic solar heating is a relatively expensive option due to high installation costs, conversely large Danish solar plants have demonstrated energy costs on a par with natural gas (£35/MWh)[10].

- <u>Biomass</u>: Biomass fuel costs are comparable to natural gas, it is a mature technology and a widely used renewable heat resource. Indigenous feedstock estimates are ~3.5 TWh p.a. (5% of Scotland's 2020 demand)[11]. SE should support activity to explore maximising indigenous biomass feedstock quantities and associated supply chain.

- <u>Renewable heat costs</u>: More generally, SE should explore how targeted support could reduce the cost of energy of low carbon heat technologies to increase uptake; e.g. measures to reduce cost of energy of biomass and larger biomethane plants. Also explore and support sources of potentially low cost low carbon heat for DHNs, including industrial by-product heat, geothermal and solar.

1. HEAT TRENDS, SCENARIOS AND TECHNOLOGIES

1.1 Market drivers: regulations and incentives

Scotland has ambitions to hold a world leading market position in the wider low carbon market. In 2009, the Scottish Parliament set Scotland's ambitious climate change targets, including:

- A minimum 80% reduction in greenhouse gas emissions by 2050, and;
- A world leading 42% reduction in greenhouse gas emissions by 2020, relative to a 1990 baseline.

The Scottish Government has linked carbon reduction targets for 2020:

1. An energy efficiency target to reduce total final energy consumption (including transport, electricity and heat) in Scotland by 12% against a baseline of the average final energy consumption in 2005-7:
   - The most recently published data (2012) states a 11.8% reduction[2];
2. Delivery of 11% of non-electrical heat demand by renewable sources:
   - Latest data (2012) indicates renewables provided 3.0% of heat[2];
3. 100% equivalent of Scotland's electricity demand from renewables:
   - In 2013, 44% of Scotland's electricity was supplied by renewables[2].

The renewable heat targets currently only apply to non-electrical heat due in part to the difficulty determining the end-use of electricity, and also to avoid "double counting" of renewables in terms of Scotland's updated Renewables Routemap commitment to an overall renewable energy target of 30% by 2020.

In terms Scottish heat supply, the Scottish Government's HGPS outlines a heat hierarchy pyramid, Figure 1.1 with the following ambitions:

- Firstly, and most importantly, to reduce the demand for heat. This will include ensuring buildings are well insulated via new build regulations and retrofitting existing buildings, and also taking advantage of passive heating and cooling to reduce demand for energy (and consequently the cost to the consumer). Scotland's heat demand has been reduced by 15% since 2005[2].
- Secondly, supply heat efficiently. Some efficiency improvements can be made within individual buildings, while other opportunities for efficiency depend on the relationships between buildings. Using the same source to heat several buildings, such as in a district heating network, can often lead to a more efficient heat supply. An important theme is to deliver heat at least cost to the consumer to minimise the impact on energy bills and *mitigate fuel poverty*.
- Lastly, in addition to reducing heat demand and improving heating efficiency, the use renewable and low carbon heat resources should be implemented where possible.

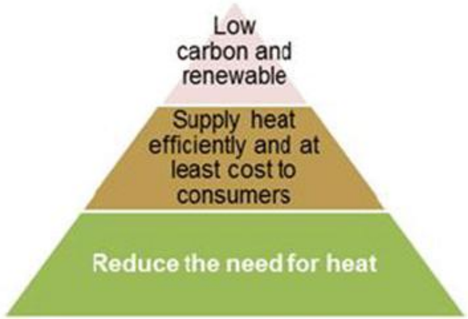

Figure 1.1. Heat hierarchy in the Scottish Government's HGPS.

Currently heat accounts for around 55% of Scotland's total energy consumption[1], approximately the same as the energy consumed by the transport and electricity sectors combined. Around 80% of domestic and commercial heat is delivered by natural gas via the National Grid, 15% is supplied electrically and the remainder from oil and solid fuel[1].

The most recently published figures indicate that in 2012 renewable heat supplied 3.0% of Scotland's heat demand (2.6% for the whole UK). The EU average is 15.6%, and several countries (Sweden, Finland, Estonia and

Latvia) obtain over 40% of their heat demand from renewable sources[2]. Scotland and the UK are at the very bottom of EU table in terms of heat from renewables, Figure 1.2.

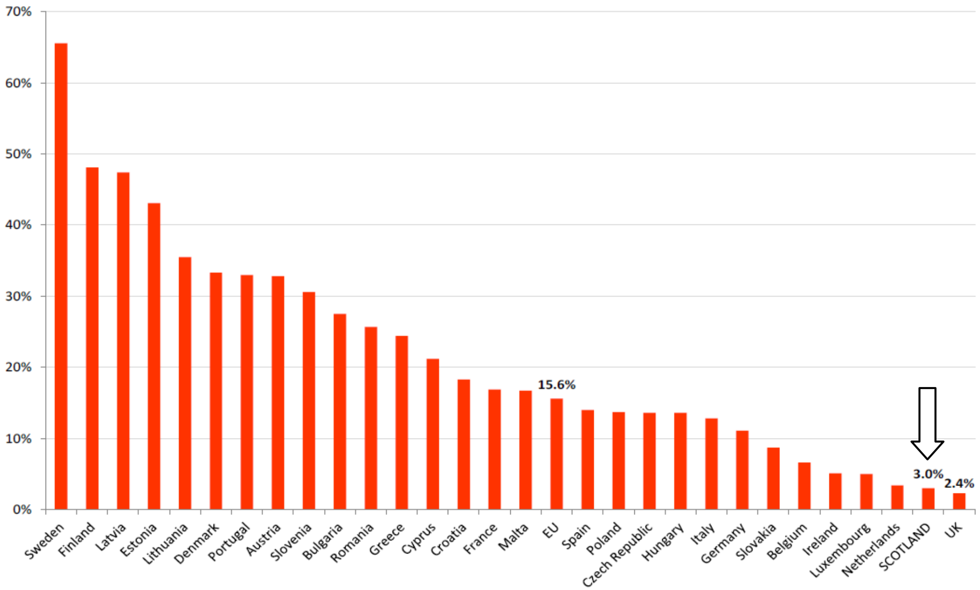

Figure 1.2. Percentage of heat generated from renewable sources across Europe in 2012[2].

Although there was little formal attention to heat as an explicit component within overall energy policy before 2009 (so that unlike electricity, it has not been a regulated commodity), domestic heating has a very substantial organisational and material history in the UK. Under national ownership between the 1940s and 1980s, UK heating was governed by corporate arrangements between the UK Government and the Gas Council, while in the post-privatised period, the regulation of gas investment and consumer protection has resided with the industry's statutory regulator Ofgem.

Under these governance arrangements, UK domestic heating went through a major transition over the last half-century, from municipal 'town gas' to a natural gas national grid and domestic boilers. More recently, the last decade has seen a major programme of technology transition with the conversion to thermally efficient condensing gas boilers. UK domestic heating is atypical in the European context, being dominated by a national gas network feeding over 20 million individual household boilers (around 80% of all UK households); the UK is the world's biggest market for domestic gas boilers, supported by mature and extensive manufacturing, supply chain and installer and maintenance bases. For the majority of UK citizens, this transition has offered a secure, cheap and clean source of domestic heating since the 1970s - and a major improvement (environmentally and socio-economically) on earlier forms of domestic heating. Whereas electricity generation has been very much in the public focus through various evolutions including nuclear and then renewables, heat has largely been overlooked as part of energy policy in the UK over this longer timescale, at least in the eyes of the media and the general public; perhaps due to the fact that UK domestic heating became a rather hidden and taken-for-granted success due to relatively low cost natural gas from the North Sea and the existence of the national gas grid.

However, more recently the UK has developed an import-dependency for natural gas, after decades of self-sufficiency, coinciding with a period of geopolitical instability and (until very recently) dramatically increasing wholesale gas prices. Environmental concerns exerted more gradually, such as through the Climate Change Act, imply a near-wholesale shift away from unabated natural gas as a domestic heating by 2050. The combined effect has been the rather sudden emergence of a heat policy 'trilemma' (echoing the wider energy policy trilemma) with concurrent but divergent concerns over the cost, security and environmental sustainability of UK domestic heating.

Renewable Heat Incentive (RHI)

Supporting Scotland and the UK's low carbon heat ambitions is the Renewable Heat Incentive (RHI) operated by DECC, which is the world's first long-term financial support programme for renewable heat[3]. It is designed to bridge the gap between the cost of fossil fuel heat installations and renewable heat alternatives, and also to help sustain and build the supply chains required to deliver renewable heat targets for 2020 and beyond. By increasing the generation of heat from renewable energy sources, the RHI helps the UK reduce greenhouse gas emissions and meet targets for reducing the effects of climate change.

There are two parts to the RHI:

- Domestic RHI – launched April 2014;
- Non-domestic RHI – launched November 2011.

The non-domestic RHI scheme is open to commercial, industrial, public sector, not for profit organisations and heat networks, Table 1.1. It provides a subsidy, payable for 20 years, to eligible non-domestic renewable heat generators and producers of biomethane for injection based in Great Britain.

The domestic RHI scheme is a financial incentive scheme designed to encourage uptake of renewable heating among domestic consumers. DECC state that the domestic RHI is targeted at, but not limited to, homes off the gas grid. Those without mains gas have the most potential to save on fuel bills and decrease carbon emissions. The scheme covers single domestic dwellings and is open to homeowners, private landlords, social landlords and self-builders. It is not open to new properties other than self-build.

Scotland has a higher than population share of the accredited RHI schemes in the UK: 15.5% of domestic and 17.6% of non-domestic RHI schemes.

Tariff name	Eligible technology	Eligible sizes	Tariffs p/kWh
Small commercial biomass	Solid biomass including solid biomass contained in waste	<200 kWth Tier 1 <200 kWth Tier 2	6.8 1.8
Medium commercial biomass		>200 kWth & <1MWth Tier 1 >200 kWth & <1MWth Tier 2	5.1 2.2
Large commercial biomass		1MWth and above	2
Solid biomass CHP systems (commissioned on or after 4 December 2013)	Solid biomass CHP systems	all capacities	4.1
Water/Ground-source heat pumps	Ground-source heat pumps & Water-source heat pumps	all capacities Tier 1 Tier 2	8.7 2.6
Air-source heat pumps (commissioned on or after 4 December 2013)	Air-source heat pumps	all capacities	2.5
Deep geothermal (commissioned on or after 4 December 2013)	Deep geothermal	all capacities	5
All solar collectors (accredited on or after 21 January 2013)	Solar collectors	Less than 200 kWth	10
Biomethane injection	Biomethane	First eligible 40,000 MWh Next eligible 40,000 MWh Remaining eligible MWh	7.5 4.4 3.4
Small biogas combustion	Biogas combustion	<200 kWth	7.5
Medium biogas combustion (commissioned on or after 4 December 2013)		>200 kWth & <600 kWth	5.9
Large biogas combustion (commissioned on or after 4 December 2013)		>600 kWth	2.2

Table 1.1. Latest non-domestic RHI tariffs (January 2015).

The domestic RHI will pay the following tariffs, Table 1.2, per kWh unit of heat generated for seven years and is intended to enable low carbon heat technologies to compete financially with mains gas prices of around 4 p/kWh. The tariffs have been set at a level that reflects the expected cost of renewable heat generation over 20 years.

Technology	Tariff
Air-source heat pumps	7.3p/kWh
Ground and water-source heat pumps	18.8p/kWh
Biomass-only boilers and biomass pellet stoves with integrated boilers	12.2p/kWh
Solar thermal panels (flat plate and evacuated tube for hot water only)	19.2 p/kWh

Table 1.2. Current domestic RHI tariffs (as of December 2014).

The upper limit of DECC's models suggests the RHI will incentivise the following renewable heat capacity at a UK level:

- Domestic RHI: 3.3 TWh/year of low carbon heat output by 2020 (around 380,000 installations).
- Non-domestic: around 5,000 non-domestic installations and an additional 6.4TWh of renewable heat output by the end of 2015/16.

Other relevant regulatory drivers

Other regulations relevant to Scottish emissions include:

- The EU Emissions Trading Scheme puts a cap on the carbon dioxide emitted by business and creates a market and price for carbon allowances. It covers 45% of EU emissions, including energy intensive sectors and approximately 12,000 installations. Related to this is the UK's Carbon Price Floor (CPF).
- The CRC Energy Efficiency Scheme, and the Energy Savings Opportunity Scheme (ESOS), are regulations for assessing and reducing larger energy consumers with the aim of emission reductions and cost savings.
- Scotland's Pollution Prevention and Control (PPC) regulations only allow recovery of energy from waste for which all reasonably practicable measures have been taken to recover materials for recycling, and that the recovery of energy takes place with a high level of energy efficiency.

1.2 Detailed Scottish heat statistics

Demand for heat in the UK varies during each day, at weekends and holidays, and the demand for space heating is significantly higher during winter months. This periodically fluctuating annual and daily pattern of heat electrical demand is highlighted in Figure 1.3 (using analysis by the University of Sheffield). It shows that during the winter gas demand can be as much as five times the demand for electricity, and demonstrates the challenges faced by the heat network in meeting demand:

- Peak capacity on cold winter days. The UK heat network must have the capacity to provide heat on the coldest winter days (with the economic challenge of potentially low overall utilisation throughout the year). The challenge therefore for any low carbon heat infrastructure of the future is to be able to meet the peak winter heat demands without expensive duplication or under-utilisation of assets.
- Heat demand varies more than electrical demand. Heat demand has a significantly more fluctuating profile than electricity throughout the year, indicating one challenge of opting to transition to low carbon renewable electricity heating systems – that of matching electricity supply with heat demand. Many low carbon heating fuels such as biomethane and biomass can be stored to meet future heat demand when required. Similarly, fossil fuel derived electricity can also be generated to meet demand. However renewable electricity cannot currently be stored at utility scale for re-use as electricity, other than via several hours of pumped hydro electrical storage.
- Renewable electricity supply and heat demand. On a short-term basis (minutes to possibly hours), smart enabled electrical heating systems

may be able to operate at varying output levels to match renewable electrical supply with the heat demand for buildings.

- Heat storage for smoothing heat demand. Heat (typically hot water) can be stored on a *daily* basis domestically, and a few utility scale *seasonal* heat storage pilot schemes have been demonstrated globally in tandem with district heat networks. Heat storage is therefore a potentially important technique for smoothing the heat profile and shifting heat from times of excess supply (e.g. from industrial by-product heat, solar, or excess variable renewable electricity) to meet periods of heat demand, both daily and seasonally.

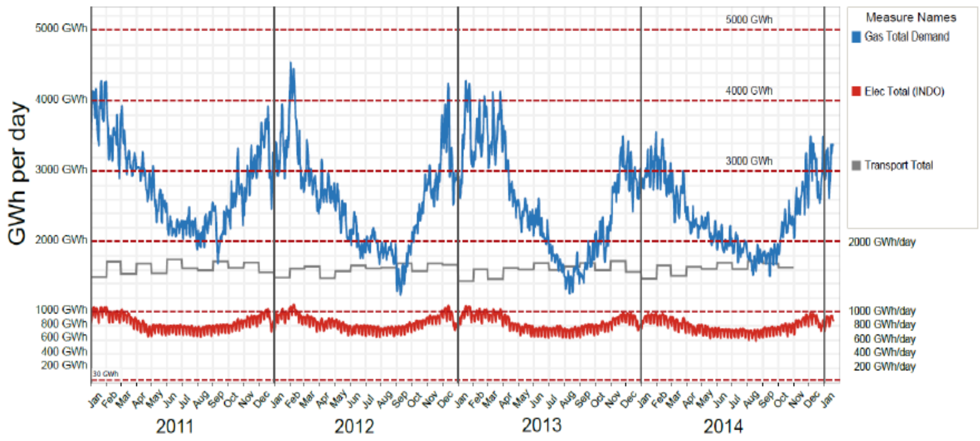

Figure 1.3. Daily and seasonal fluctuations in gas (blue plot) and electricity demand (red plot) from 2011-2014 (data from Sheffield University and reproduced in Ref [2]).

The Scottish Government has a target for 11% of non-electrical heat demand in Scotland to come from renewable sources by 2020. The Energy Saving Trust measures progress against this target via a database of renewable heat installations which records installations known to be operating and those currently in various stages of development, and contains data on their capacity and yearly heat output. Previous work measuring renewable heat penetration by the Scottish Government was based on a predicted 2020 non-electrical heat demand of 60.1 TWh[12]. However after stakeholder consultation a new methodology of "% of Renewable Heat Output (annually)" has been implemented which provides an estimate of progress based on the current level of heat demand as opposed to a projection for 2020. Progress is being made towards 11% of heat supply from renewables by 2020, although this remains a challenging target[2], Figure 1.4 & Table 1.3.

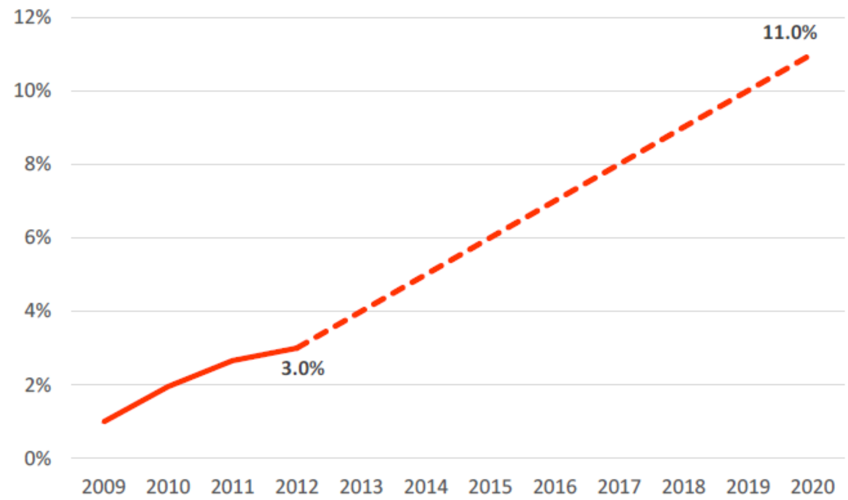

Figure 1.4. Share of renewable heat in Scotland's non-electric heat demand 2008/9-2012 (sources: EST, DECC, Scottish Government).

The Energy Saving Trust noted that large renewable heat installations (>1 MW) produce higher outputs per unit of installed capacity than medium and micro units[16], reflecting the longer running hours and in some cases higher efficiencies realised in large installations. In addition, the large installation category includes installations which are primarily using renewable heat to provide process heat, as a product of CHP, or for waste disposal, which are activities which continue year round. The challenge is to ensure that as much of the useful heat available is used productively. Small to medium, and micro installations, are more likely to be used to provide seasonal space heating and building hot water.

	2008/09	2010	2011	2012	2013
Renewable Heat (GWh)	845	1,696	2,263	2,481	2,904
Heat Demand (non-electrical, GWh)	85,039	87,123	85,328	82,722	-
% Renewable Heat	1.0%	1.9%	2.7%	3.0%	-

Table 1.3. Renewable heat target statistics for Scotland 2008-2013.

Heat in Scotland is currently primarily delivered by fossil fuels, with natural gas the prominent fuel (61%) followed by petroleum products (31%)[4] (based on 2010 data, Figure 1.5). While total fuel sales/delivery can be reliably accounted for through metering and taxation, the end-use of these fuels can be less certain for many sectors. The total energy consumption for applications excluding transport and electricity, i.e. heat, published by DECC for Scotland in 2010 was 87 TWh, and this has decreased 5.0% to 82.7 TWh by 2014[2]. To provide a comparison for the size of the heat sector demand, electricity consumption for 2010 was 27 TWh, which is 18% of total Scottish energy consumption or roughly one-third of the heat consumption.

The largest 3 chart segments on Figure 1.5 represent 87% of the 2010 total Scottish heat demand: domestic gas, industrial and commercial gas, followed by petroleum products (oil and LPG) for industry. Coal, bioenergy and domestic oil make up the remainder.

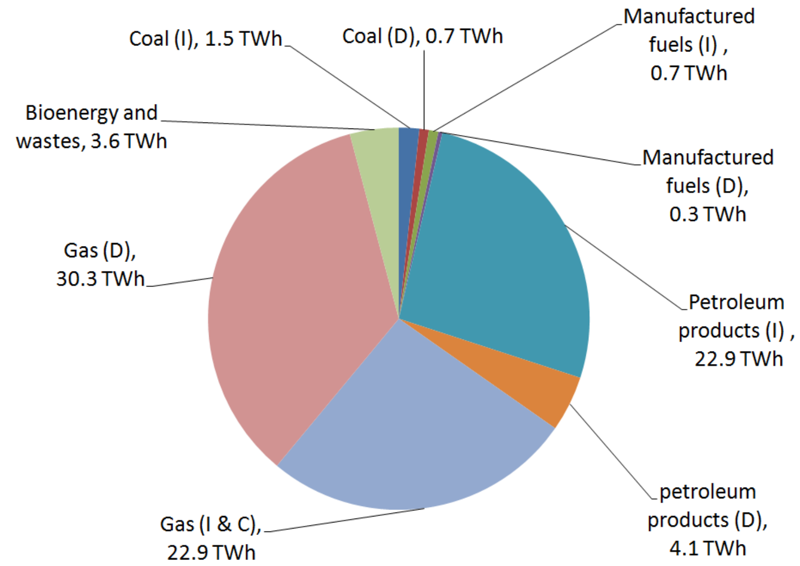

Figure 1.5. DECC heat consumption statistics (TWh) for Scotland for 2010, by fuel type. Key: (I) = industry, (D) = domestic, (C) = commercial.

The Heat Pathways Scenario Model (HPSM) developed for the Scottish Government by ARUP provides a total heat consumption for 2010 in Scotland of 99.9 TWh[13]. The data for 2010 was selected as the baseline primarily due to relatively good levels of overlap in the available datasets. It should be noted that other baselines, such as those for total national emissions, are normally compared to 1990 data. It should also be noted that 2010 was a particularly cold winter, which will most likely have had an effect on total heat emissions performance; a significant peak in residential emissions in particular was recorded for this year[13].

The HPSM, Figure 1.6, includes: all heat use and generation within Scotland associated with the use and occupation of buildings, including space heating, hot water supply, cooking. It also includes industrial process heat. Cooling is included in the non-domestic sector data.

There currently exists no direct means of verifying Scottish electrical heat consumption using published data (in future smart metering and devices may begin to facilitate this). Modelled figures for domestic electrical heat demand are likely to be a reasonable estimate, as they are based on Scottish Housing Condition Survey (SHCS) information, and they are considered to be within a plausible range[13]. A crude estimate of 4.2 TWh of domestic electric heating demand can be determined by assuming the average Scottish annual domestic gas demand (of 14.3 MWh in 2013) is comparable to the average domestic electrical heat demand, and the knowledge that 13% of 2.3 million homes rely on electrical heating. For the non-domestic and industrial sectors there is less certainty due to the more limited information available[13], although public sector non-domestic sector estimates are based on real meter readings. Corresponding carbon emissions due to heat generation in Scotland in 2010 were 26.6 MtCO2e. Modelling suggests that heat was responsible for 47% of Scotland's total carbon emissions in that year. This includes traded and untraded emissions.

As mentioned, the renewable heat targets currently only apply to non-electrical heat due to the difficulty determining the end-use of electricity, and also to avoid "double counting" of renewable heat and electricity.

For this SE Foresighting paper, ARUP's figure of 99.9 TWh of Scottish heat consumption in 2010 is taken as the baseline. This is based on the DECC published figures of 87 TWh for non-electrical fuel consumption and a further 12 TWh of electrical heat (arising from 13% of Scottish domestic properties which are electrically heated and from industrial electrical process heating).

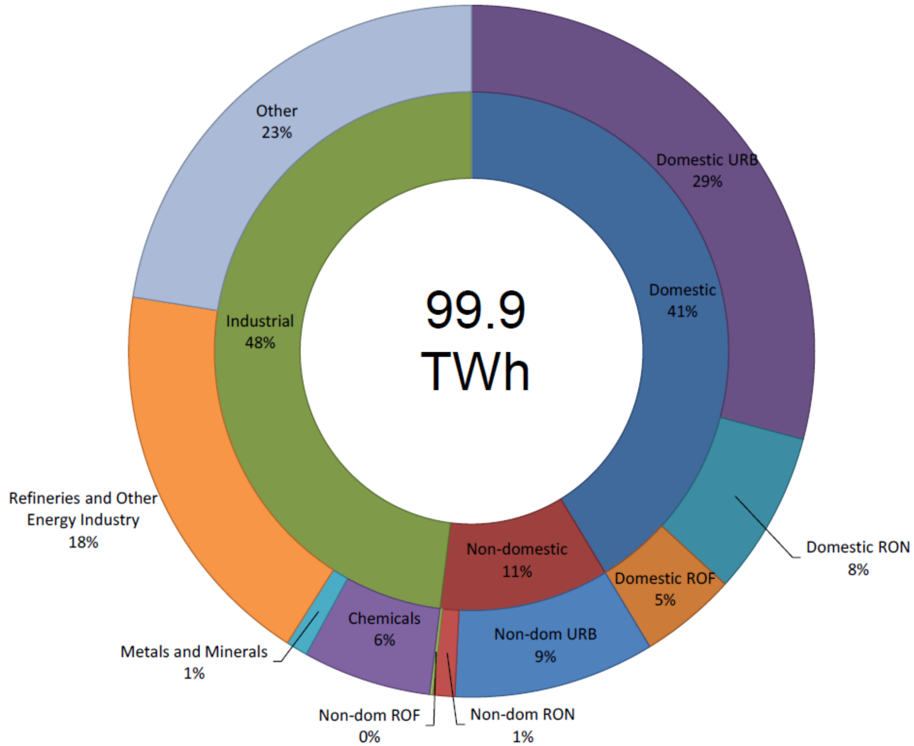

Figure 1.6. The 2010 Scottish Heat Consumption of 99.9 TWh divided into industrial, domestic and non-domestic sectors (inner ring), and sub-sectors (outer ring).
Key: URB = Urban, RON = Rural On-Gas Grid, ROF = Rural Off-Gas Grid.

Figure 1.7 shows that domestic gas consumption ***per consumer*** has decreased in Scotland by 28.7% between 2005 and 2013[2]. Rising gas prices and improved energy efficiency in homes and boilers are quoted by the Scottish Government as contributing factors to this trend. The gas data are weather corrected; that is, the consumption figure is revised downward in cold years and upwards in hot years, to isolate changes in demand that are not due to year-to-year weather variation.

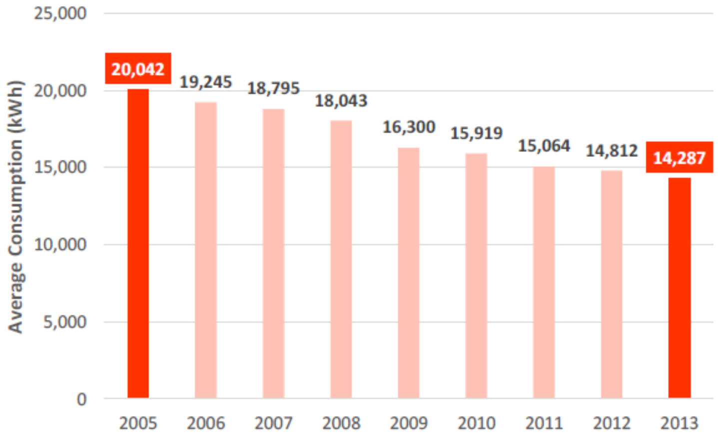

Figure 1.7. Domestic gas consumption per consumer in Scotland, 2005 to 2013, weather corrected, showing a 28.7% fall in demand over 5 years.

Scotland's current renewable heat sector composition

In 2013, 2.904 TWh of heat was produced from renewable sources, from an installed capacity of 0.662 GW. The 2009 Renewable Heat Action Plan set a target of delivering 11% of Scotland's projected heat demand from renewable sources. In 2012 (2013 figures not yet published), renewable heat generation equated to 3.0% of Scotland's non-electrical heat demand, up from 2.7% in 2011.

It is assumed all current renewable heat installations will still be operating by 2020. Biomass installations using primary combustion or CHP accounted for around 80-90% of renewable heat capacity and output (2.05 TWh) in Scotland in 2013[16], Table 1.4 & Figure 1.8. The remainder is supplied by Energy from Waste (EfW), solar thermal and heat pumps.

A Scottish study[11] estimates an annual indigenous solid biomass (wood) resource of 700k to 1M oven dried tonnes, which could provide up to 3.4 TWh of heat, which may equates to around 5% of the expected 2020 Scottish demand. Additional biomass can be imported, at the expense of a 60% increase in carbon emissions due to increased transportation to ~50 kg CO_2 per MWh[17], still >75% lower than emissions from natural gas (220 kg CO_2 per MWh). Therefore imported biomass still realises significant carbon savings compared to gas and other fossil fuels.

Geothermal resources from flooded former mineworks, may represent a significant Scottish heat resource of as much as 12 TWh[18]; full exploitation would require the construction of national heat distribution networks.

Renewable technology	Renewable heat capacity (MW)	Renewable heat capacity (%)	Annual Output (MWh)	Annual output (%)
Biomass	290	44%	1,198,051	41%
Biomass CHP	261	39%	1,419,400	49%
EfW	16	2%	120,811	4%
Heat Pump	64	10%	151,162	5%
Solar Thermal	30	5%	14,654	0.5%
Total	662	100%	2,904,078	100%

Table 1.4. 2013 renewable heat output and capacity in Scotland.

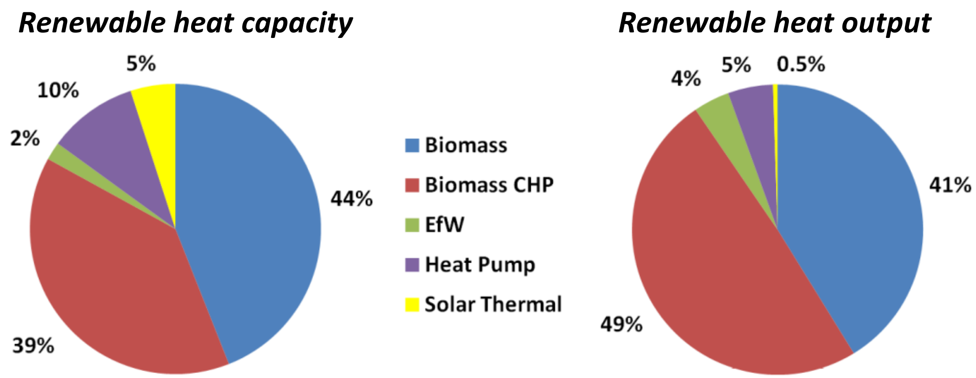

Figure 1.8. 2013 renewable heat capacity and actual output in Scotland.

Scotland's available excess heat

Many industrial processes and commercial buildings generate heat as a by-product. The unused excess heat is often rejected as waste and can involve expenditure and infrastructure to cool (e.g. returning water to a river). Excess heat is not currently eligible for RHI support.

A 2011 study for the Scottish Government[19] estimated 40 TWh energy losses from Scotland's four coal and gas fired electricity generation at that time. The scale of the excess heat identified, equivalent to around 40% of Scotland's total heat demand for that year, demonstrates the significant opportunity in the future for appropriately designed co-located power stations and heat networks (Cockenzie has closed since 2011 and Longannet in particular has a very limited remaining lifespan).

A 2014 study for DECC[20] developed databases describing "archetypal" characteristics of the waste heat sources and heat sinks at 73 of the largest UK industrial sites. Overall the databases identify 48 TWh/yr industrial waste heat sources, around one sixth of overall UK industrial energy use. The DECC model further identifies a *technical* potential of 11 TWh/yr (2.2 MtCO2/yr emission reduction) from around 250 UK potential individual combinations of heat sources, heat sinks and heat recovery technologies including heat exchangers, heat pumps and heat-to-power technologies. Based on industry feedback, a narrower "commercial" potential is also defined as those projects which provided simple payback within two years of investment. This *commercial* potential is identified as 5 TWh/yr, saving 1.1 MtCO2/yr, and derives mostly from use of heat exchangers to connect heat sources and heat sinks at the same site.

Scotland's Heat Map[21] provides the location of heat sources, such as cooling towers, and aims to link heat demand with excess heat, albeit currently without data quantifying the potential heat resources. The Scottish Government is encouraging industry to provide information on excess heat through a voluntary section of the Scottish Pollution Release Inventory and to agree to this data being made widely available.

1.3 Scottish heat infrastructure

1.3.1 National gas grid and renewable biomethane

The National Transmission System (NTS) is the network of gas pipelines throughout the United Kingdom that supplies gas to 40 power stations from natural gas terminals situated on the coast, and also gas distribution companies which lead indirectly to homes. North Sea Gas was first brought ashore in the UK in 1967, stimulating the building of the NTS. Prior to this gas came locally from municipal gasworks. Most of the NTS was built in the 1970s and early 1980s. The gas distribution network (to homes) is not part of the NTS. Companies that own part of this gas network, also known as the Local Transmission System (LTS), are known officially as Gas Transporters. Gas to this network enters via the NTS through a pressure reduction station to the twelve gas distribution zones in England, Scotland and Wales within eight distribution networks. In total, there are 275,000km of gas pipelines within this network.

Around 80% of Scottish domestic properties are connected to the gas grid[22] and domestic gas consumption totalled 28.8 TWh in 2012, with a further 21.8 TWh of consumption by the non-domestic sector[23], Table 1.5.

	Total consumption (TWh)
Domestic	*28.8*
Non-domestic	*21.8*

Table 1.5. Total annual gas consumption in Scotland 2012 (DECC).

Techniques for decarbonising the existing gas grid such as renewable gas injection (via biomethane, hydrogen or methanation) inherently decarbonise both the domestic and non-domestic sectors without any additional end-user infrastructure or equipment modification.

One of the most significant advantages of upgrading biogas for biomethane injection to grid, rather than producing electricity and heat from the biogas at source via a Combined Heat and Power (CHP) plant, is the efficiency of the energy production and utilisation process. If all or most of the heat from a CHP unit is effectively utilised then the argument for biomethane production is significantly reduced. However, where little or none of the heat from the CHP unit is used to good effect (apart from the sacrificial heat load on the digester) then the efficiency of energy conversion will be around 30-40%. By comparison, most modern natural gas appliances have very high efficiencies (~85%) and therefore biomethane to grid makes efficient use of the feedstock resource.

Many AD plants are sited in locations remote from major heat users, and it is not at all unusual for it to be impractical or extremely expensive to construct a heat distribution network to the nearest heat users. If those users are domestic properties then the demand for heat is far from constant. Under these circumstances it may be worth considering the feasibility of converting all or part of the biogas to biomethane.

There are, however, significant constraints in developing a gas-to-grid project and these constraints need to be considered very early in the project's conception phase. Gas-to-grid cleaning and injection technologies are expensive, with some elements of the cost accelerating very little with increased scale. Although piping gas is not as expensive as piping heat, there are limits to economic viability in terms of distance to the gas grid.

DECC's 2014 tariff review states that biomethane injection to grid is a key RHI technology, projected to generate approximately 15% of the UK's total renewable heat deployment under the RHI by 2015-16[24]. DECC states it is important that the UK ensures the sustainability of this emerging market.

A 2009 study by National Grid states that with the right government policies in place, renewable biomethane could contribute of the order of 5%-18% of the UK's total gas demand[8], which corresponds to biomethane providing up to 175 TWh of the UK's predicted 970 TWh 2020 demand. A scenario where biomethane is not used for electricity production or transport, and electricity is produced by other low carbon methods (e.g. wind, nuclear and fossil fuel thermal plants with Carbon Capture and Storage (CCS)), indicates that up to 50% of residential gas demand could be met with renewable gas in the "Stretch" scenario using feedstocks which are typically considered waste[8]. Techniques include Anaerobic Digestion (AD) of animal slurry, sewage, food waste and agricultural waste, and pyrolysis or gasification of Municipal Solid Waste (MSW), Table 1.6.

The "Baseline" figures in Table 1.6 considers the scenario where a significant proportion of waste still goes to landfill, is not sorted appropriately or is still used for electricity generation – rather than being used for renewable gas production. The "Stretch" scenario indicates what could be achieved if policies are put in place to ensure that all waste is directed towards renewable gas production and that the most appropriate (high yielding) technology is used for each type of waste.

In terms of the cost to the UK of delivering renewable gas, National Grid estimated that the marginal cost (i.e. that over and above the cost of the waste infrastructure which must be built anyway in the UK to deal with reducing landfill capacity) would be in the region of £10bn. These costs include the Anaerobic Digester (AD) plants, gas upgrade equipment and associated civil works required at a national scale.

	2020 (baseline) million m³	2020 (stretch) million m³
Sewage / waste water	270	629
Manure - dairy and cattle	254	507
Agricultural waste	234	967
Food waste	729	1,333
Biodegradable waste	1,042	8,328
Wood waste	1,253	2,697
Miscanthus	1,845	3,971
Total	**5,625**	**18,432**
As % total UK gas demand (~97bcm)	**5%**	**18%**
As % residential gas demand (~35bcm)	**15%**	**48%**

Table 1.6. Upgraded biomethane[8] production scenarios.

1.3.2 Electrical grid and smart metering

Scotland has a target of 100% equivalent electricity demand from renewables by 2020, which has the potential to offer a route to very low carbon heat generation for appropriate well insulated properties, such as combining heat pump operation with renewable electricity. Wind, solar and marine renewables are inherently variable in nature and may operate at high output when demand is low (although in general wind and hydro energy production are both higher in winter when heating demand is also increased).

Due to the lower operating temperatures than conventional gas boiler systems, electrical heat pump systems are not considered well suited for poorly insulated draughty properties[32], if the heat is to be kept affordable to households and businesses.

The installation of smart meters for every electricity end-user is anticipated to be completed by 2020, and potentially offers better dynamic control of electricity demand to help smooth supply and demand. The Scottish Government's Smart Grid Action Plan[25] states the potential synergy between the electricity and heat sectors:

- Smart metering and aggregation;
- Integration of different energy forms;
- Actively managing the network: including electric heat pumps.

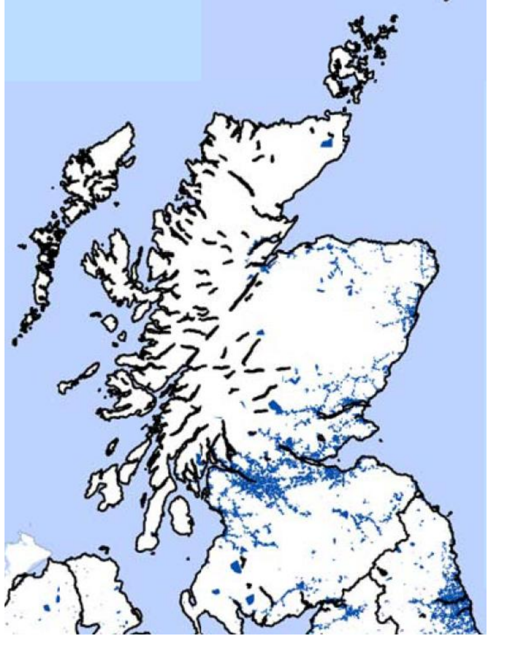

Figure 1.9. Scottish gas grid connections, indicated by a blue dot, primarily across the Central Belt and the cities on the East Coast. Note large swathes of Scotland without access to a gas grid connection.

Whilst around 80% of domestic properties are connected to the gas grid in Scotland, Figure 1.9, conversely the remaining circa 500,000 domestic properties in Scotland rely on other fuels to provide their primary heat source. In urban areas this is typically in the form of electric heating systems, which have a particularly high penetration throughout Glasgow Housing Association properties such as tower blocks. Rural properties may have access to local biomass supplies, or instead rely mainly on expensive supplies of tanker delivered LPG or oil. Electrical heat supply may be particularly attractive to these off-gas grid properties with the advent of smart metering aggregation and attractive commercial models.

1.3.3 District Heating Networks (DHN)

Well designed and maintained heat networks operating at high utilisation throughout the year can help to reduce carbon emissions compared to other forms of heating, reduce fuel bills and tackle fuel poverty, as well as contributing to energy security.

The 2014 draft Scottish Heat Generation Policy Statement (HGPS)[1] states an ambition to have 40,000 homes connected to District Heating Networks (DHN) by 2020. Recent figures indicate Scotland has of the order of 2.4 million domestic dwellings[26], i.e. the draft 2020 target equates to less than 2% of Scottish dwellings.

The Scottish Government estimates that Scotland currently has just over 9,000 properties connected to a DHN, with a further 14,000 homes in planning or under consideration for connection to a DHN (i.e. 23,000 in total). It also estimates that around 10% of homes connected to DHNs are small-scale renewable networks in rural areas. The Wyndford Estate DHN in Glasgow supplies around 2,000 homes, the Commonwealth Games Village DHN around 700 and Aberdeen Heat and Power in total supplies around 2,000 homes. Therefore the draft target of 40,000 homes connected to a DHN scheme is ambitious, requiring the financing, planning and build by 2020 of around 30 new projects of the scale of the larger existing Scottish DHNs.

In the UK, it was estimated that in 2009 around 70,000 dwellings and 11M m^2 of commercial space were heated by DHNs, providing only 0.3% of national heat demand[27]. A later 2012 study for DECC[28] included some larger schemes which had not been included in the earlier study and estimated that around 200,000 dwellings (out of 27.1 million) in the UK may be heated by a DHN (0.7% of all dwellings). Detailed modelling for DECC by Pöyry estimated the maximum potential penetration levels of DHN in the UK, examining the best-case scenario whereby there is an active policy regime supporting DHNs, a regulatory technology discount rate is applied, and capital cost reductions occur over time. In the most ambitious case with favourable regulation and cost reductions and wide scale acceptance of the technologies, it was estimated that in the UK 7.9M households and 26.3M m^2 could be financially viable for connection to a DNH scheme; this would provide a maximum penetration of 14% of the UK's total heat demand by DHNs[27], Table 1.7.

	2009 UK installed DHN	UK potential financially viable DHN projects
Number of dwellings	70,000	7,900,000
Commercial floor space	11 million m^3	26.3 million m^3
% of UK total heat demand from DHNs	0.3%	14%

Table 1.7. Actual heat demand provided by DHN in 2009 and projected maximum financially viable DHN penetration in the UK assuming cost reductions, suitable regulation and technology discounts.

It is important to note that District Heat Networks are not necessarily a low carbon heat solution; they are a method of distributing heat from a central location to many end-users, and carbon emissions depend directly on the heat source.

DHNs are often powered by Combined Heat and Power (CHP) plants which can be much more efficient when electricity generation is also included in the total emissions analysis. For example, the average efficiency of older fossil-fuelled electrical generation power plants is 33%, meaning that two-thirds of the energy in the fuel is vented off and lost as heat[29]. After using waste heat recovery technology to capture the heat produced in a CHP plant, a DHN can then distribute this heat which would otherwise be wasted, achieving total CHP system efficiencies of 60-80% for the combined production of electricity and heat. In order for the CHP plant to operate with optimal efficiently throughout the year, the DHN should be designed to include appropriate heat demand (or storage) during all periods of electricity production.

Other heat source options for DHNs include biomass (used by many of the small networks in rural Scotland), by-product heat from industrial processes (for example glass works or cement works), and other technologies including large-scale water sourced heat pumps, geothermal resources and large-scale solar thermal. A major benefit of DHNs is that they can be used to successfully facilitate the distribution of low carbon heat from many sources which would otherwise be infeasible to use at the point of the heat demand (e.g. waste industrial heat piped to domestic properties). For many DHN scenarios, it can be a challenge in summer to balance heat supply and demand, when domestic heat demand is reduced. Therefore a mixed profile of heat demand users is often preferred to optimise heat demand and supply for a DHN. Alternatively large-scale seasonal storage may offset the variation in seasonal heat demand.

Heat losses of the order of 10% have typically been reported from source to end-user through heat networks[30]. In order to minimise heat losses, the Chartered Institute of Building Services and Engineers (CIBSE) and Association of Decentralised Energy (ADE) are finalising Codes of Practice for heat networks, which were published for consultation in 2014.
In terms of installation, DHNs are particularly attractive where new large-scale developments are undertaken, such as new hospitals, schools or new housing estates, as it allows the heat pipe infrastructure to be installed during construction and avoids costly and disruptive retrofit. An interactive heat map is available on the Scottish Government website[21] which aims to allow assessment of heat demand and heat sources, and how these can be connected in an efficient way to reduce the cost of heat supply and the carbon intensity of heat generation. It aims to allow users to identify where opportunities for decentralised energy projects across Scotland exist and where there are opportunities for DHNs.

1.3.4 Carbon emissions by fuel type

In the UK, electricity is generated from a variety of sources including coal, gas, nuclear and renewables and so the average carbon emissions per MWh of electricity varies with time, depending on the specific generation mix. The latest[31] (August 2014) life-cycle CO_2 emissions for gas, oil and electricity (including production) are:

- Natural gas 227 kg per MWh
- Oil 314 kg per MWh
- Electricity (UK grid - delivered) 470 kg per MWh

Therefore in order for electrical heating to generate lower carbon emissions than a natural gas powered boiler it must have a Coefficient of Performance (COP) of 2.1 or higher (470/2.1 = 223 kg per MWh), which is a practically achievable goal for heat pumps based on UK trials by the Energy Saving Trust[32]. In future as electricity production is increasingly decarbonised through higher renewable penetration, and potentially CCS is installed on thermal electricity plants, heat pump carbon emissions will become increasingly lower than from equivalent natural gas boilers.

1.4 Cost of Energy of low carbon heat technologies

The SE Foresighting Team, and separately Ricardo-AEA[33], compared the unsubsidised Cost of Energy (CoE) of various heating technologies in terms of the lifetime cost of capital and operating expenditures (CAPEX and OPEX) and total lifetime fuel costs. As discussed in Section 1.1, the Renewable Heat Incentive (RHI) is intended to provide a subsidy to compensate for the higher CoE for most low carbon heat technologies in comparison to mains gas. In this way the RHI helps the UK reduce greenhouse gas emissions and meet targets for providing renewable heat, but also aims to increase market uptake of low carbon heat options, improve supply chains and provide economies of scale, with the intention of leading to longer term reductions in the overall costs of low carbon heat technologies.

For Figure 1.10, the domestic CoE was calculated over a 20 year period based on a typical annual Scottish household heat demand of 15 MWh and typical CAPEX and OPEX costs as discussed in Ref [33].

- Mains gas is supplied domestically at £42/MWh and electricity is typically £140/MWh, which includes network costs. Industrial users would expect to obtain lower rates when buying in larger quantities.
- The Energy Savings Trust have performed detailed trials of various heat pump configurations in various building types in the UK[32]. COPs of 2.73 for ASHPs and 3.21 for GSHPs were observed on average, providing electrical running costs of £51 and £43 per MWh respectively.
- Capital expenditures for typical UK installations are provided on the Energy Savings Trust website, and elsewhere.

The CoE heat delivered by DHNs is more complicated:

- DHN components: The costs for district heating comprise the heating source, the heat distribution network, each individual property's wet radiator system, and a Hydraulic Unit Interface (HUI) and heat metering system for each end-user.
- CAPEX sub-component costs: DECC quote £0.5M-£1M per km for the heat-pipe installation, and the HUI connection to each end-user as £2k[33]. DECC provides estimates for the cost of CHP plants on their website. Therefore, the heat source is only one component of a DHN, and for lower density schemes the pipework at £0.5M-£1M per km may dominate the CAPEX.
- CAPEX Cost of Energy: The CAPEX £/MWh of a "typical" district heating scheme is calculated as varying between £33-49/MWh over a 20 year period assuming 100% utilisation. In this case a "typical" DHN was assumed to consist of 200 flats in tower blocks powered by a CHP scheme (comparable to Aberdeen Heat and Power's Hazlehead Energy Centre scheme). A median figure of £40/MWh over 20 years was assumed as a representative CAPEX.
- DHN gas prices: District heating operators benefit from lower gas prices than domestic users due to long-term contracts and purchasing substantially higher volumes, so there is a trade-off for gas fuelled DHNs of higher CAPEX against lower fuel costs, when compared to individual domestic gas boilers.
- DHN heat source options: This analysis considered the "typical" DHN scenarios of (1) a gas powered CHP powered scheme and (2) a biomass CHP scheme, as multiple examples exist in Scotland. A DHN based on gas CHP is reproducible across urban Scotland due to access to the gas grid and relative ease of plant installation, allowing reliable costing based on published CHP costs. Other DHN heat sources exist including geothermal (not enough data found to reliably evaluate costs for this study), and co-product heat from industrial processes (discussed below). The long lifespan of the heat network (40+ years), allows for

fuel switching in future and for low carbon sources to be connected at source to deliver benefits across the network rather than replacing all individual boilers.

- Co-product heat CAPEX: By-product heat opportunities from industrial processes will often be specific to the individual site and often the heat recovery and DHN solution will require bespoke design, making reproducible CAPEX analysis more challenging for these heat sources. While there may be similarities for different sites within a sectors (e.g. distilleries), different industrial sectors offer vastly different heat co-product opportunities (for example compare distilleries and cement kilns) and therefore co-product heat DHNs have not been costed for this report.
- Co-product heat fuel: Fuel costs will almost certainly be lower – in many cases "free" - although the DHN may require back-up fossil fuel powered boilers depending on the heat source profile.

Figure 1.10 demonstrates that the RHI subsidised Cost of Energy (red columns and red horizontal cost comparison lines) significantly reduce the disparity in cost with mains gas, oil boilers and direct (resistive) electrical heating for all low carbon heat technologies, although solar thermal costs remain high compared to fossil fuel alternatives even with RHI subsidies.

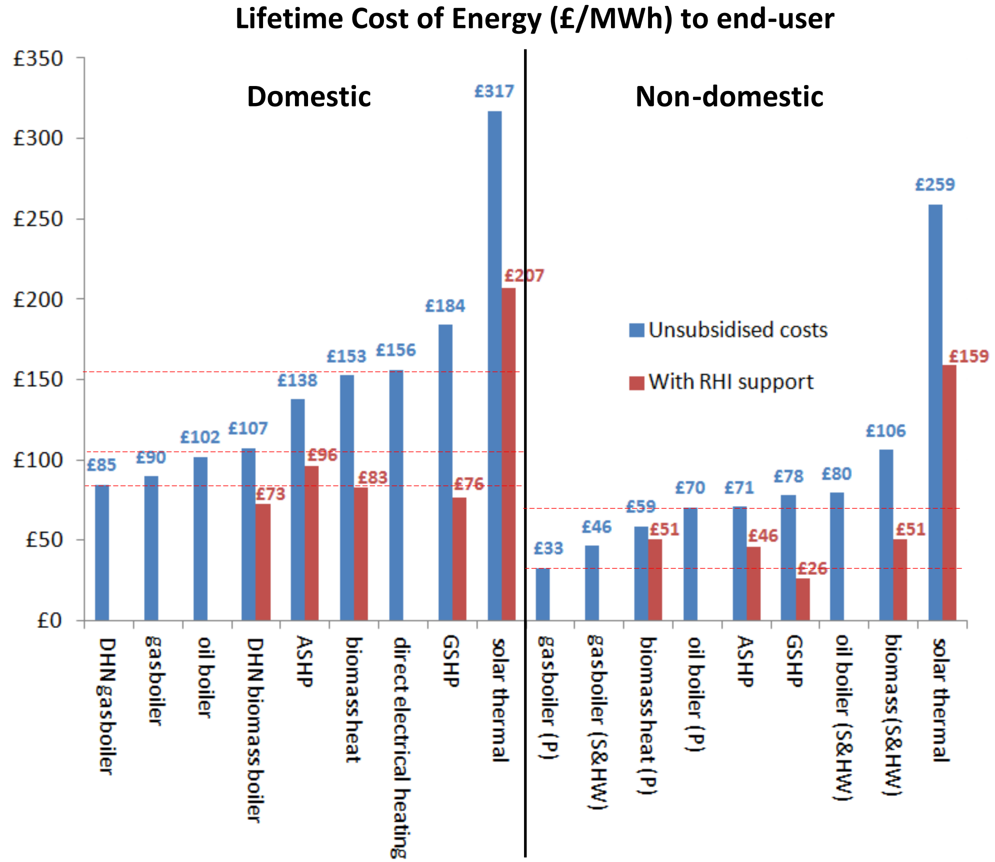

Figure 1.10. Comparison of the Cost of Energy (CoE) in £/MWh for various fossil fuel and low carbon heating options: this the lifetime capital, operating and fuel costs for both domestic and non-domestic customers.
***Blue**: actual cost of energy without any subsidies*
***Red**: delivered costs for technologies eligible for RHI subsidies*
Dotted lines: allow comparison of RHI subsidised costs against the conventional heating forms of gas, oil and electrical.
Key: P = industrial process heating
S&HW = space and hot water heating

Domestic cost of energy conclusions

Calculated over 20 years for a typical 15 MWh/annum property:

- Mains gas domestic boilers and DHNs are the cheapest form of unsubsidised heating at around £85-90/MWh (fuel, CAPEX and OPEX).
- Including RHI subsidies, biomass DHNs are the cheapest domestic heating option at £73/MWh including RHI (£107/MWh unsubsidised).
- Without subsidies, air source and ground source heat pumps are approximately 60% and £120% more expensive respectively over a 20 year period than mains gas.
- Solar hot water heating is by far the most expensive option at over £300/MWh. This is due to the high CAPEX of £3-5k and a relatively low heat provision of around 1-2 MWh per annum (e.g. equivalent of £40-80 of gas savings per annum).

Non-domestic cost of energy conclusions

- Non-domestic costs are significantly lower than the domestic costs for a given heat technology, very crudely 50% lower for most technologies, reflecting lower wholesale fuel prices, longer running hours and in some cases higher efficiencies realised in large installations.
- The CoE of non-domestic technologies analysed in this section (before subsidies) ascends in the same order as the domestic technologies: mains gas, biomass, heat pumps, solar thermal. Note that co-product industrial heat and geothermal heat sources have not been costed, as explained in the DHN cost analysis earlier in this section.
- After subsidies, GSHP is the cheapest heating option, followed in ascending order by natural gas, ASHP, and biomass.

DHN costs

DHNs can provide a Cost of Energy to the domestic user which is marginally lower than that of individual gas boilers. DHNs are clearly economically advantageous to the end-user when replacing direct (resistive) electrical heating systems, as electrical heating is a particularly expensive form of heating at £156/MWh and in dense urban areas the length of expensive heat network (up to £1M per km) is kept to a minimum. For locations where waste heat provides very low cost "fuel", or a biomass source is available, this may make the case for a district heating scheme more compelling, both economically and in terms of carbon reductions. DHNs can vary significantly in topology (e.g. supplying a university campus, an industrial estate, or multiple tower blocks), and each proposed scheme has to be evaluated on a case-by-case basis in terms of economic viability and practicalities of installation. The modelling here has assumed the installation of a new network – an extension to an existing network may benefit from lower CAPEX costs arising from an existing heat source if the system was front-loaded to future proof later expansion – however this does not affect the overall Cost of Energy of the DHN.

Biomethane production costs

Without subsidies, current biomethane production costs for a typical UK pilot plant such as Poundbury are of the order of 4-fold the unit cost of producing wholesale natural gas; however forecasts suggest that biomethane production costs may reach parity with natural gas as biomethane plant size increase and technology matures[24]. Importantly, the production of biomethane for energy provides significant carbon savings arising both from the displacement of fossil fuels and from avoiding landfill decomposition of waste streams, such as sewage and food waste which have few other applications outside of the energy sector. The methane in biogas is 20 times more potent a greenhouse gas than carbon dioxide and if left to decompose in landfill, biodegradable waste would emit methane to the atmosphere. Instead it is preferable that the processed biomethane is burnt for heat to release less harmful carbon dioxide post combustion, whilst also displacing natural gas.

Based on existing UK plant examples (Poundbury) and DECC figures from commissioned research by SKM Enviros[35], analysis determines a

Biomethane to Grid (BtG) injection cost of £80/MWh, versus £21/MWh wholesale price for natural gas, Figure 1.10. Note that for both natural gas and biomethane, transmission and distribution costs add another ~£20/MWh onto these costs for the end-users.

When RHI tariffs are included, biomethane producers can achieve production and injection costs below the £21/MWh for natural gas, down to only around £5/MWh, Figure 1.11. The current RHI biomethane injection tariff was most recently reviewed in December 2014 by DECC following representations from other technology suppliers that there was a risk of overcompensation for large BtG plants. Under the current RHI tariff, the first 40 GWh per annum of eligible BtG injection currently receives £75/MWh, the next eligible 40 GWh receives £44/MWh, and any further eligible biomethane injection to grid receives £34/MWh. Typical current BtG plants of around 1 MW capacity, running at 70% utilisation rates throughout the whole year, would produce 42 GWh, so almost all of its output would receive the highest RHI tariff of £75/MWh.

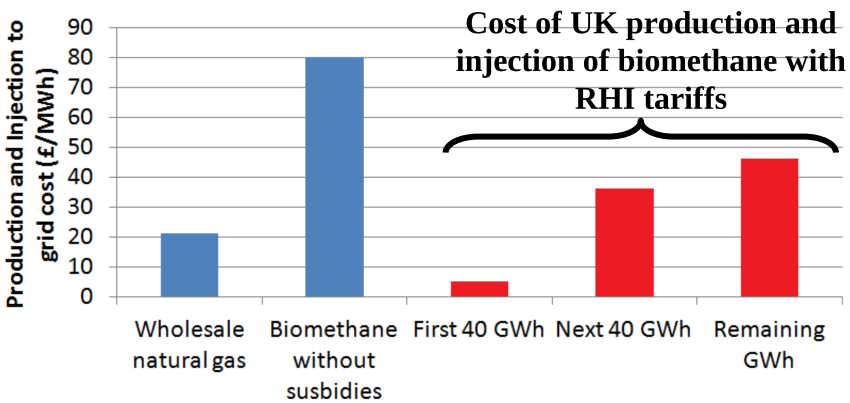

Figure 1.11. Production and injection to grid costs of natural gas and biomethane (blue columns); cost to the producer of the biomethane to grid injection including RHI subsidies (red columns). These figures do not include the gas network costs, which are an additional ~£20/MWh to the end-user.

DECC modelling suggests substantial cost reductions with increasing plant size, Figure 1.12. This suggests the first 40 GWh RHI biomethane to grid tariff (£75/MWh) is sufficient to compensate waste plants of around 2-3 MW (depending upon the gate fee assumed) and biocrop plants of 3-4 MW. Importantly, production costs are expected to fall with increasing plant size to around £5-50/MWh for 15 MW plants depending on the input feedstocks and gate fees (£25-41/tonne), shown as the three different plots on Figure 1.12. This may allow biomethane to achieve parity with natural gas (currently ~£20/MWh), or if natural gas prices increase significantly in future then biomethane from large plants (10-15MW) may even become economically more favourable than wholesale natural gas. Cost reductions can also arise from linking many AD plants to one single biomethane upgrading plant, as demonstrated at various sites in Germany.

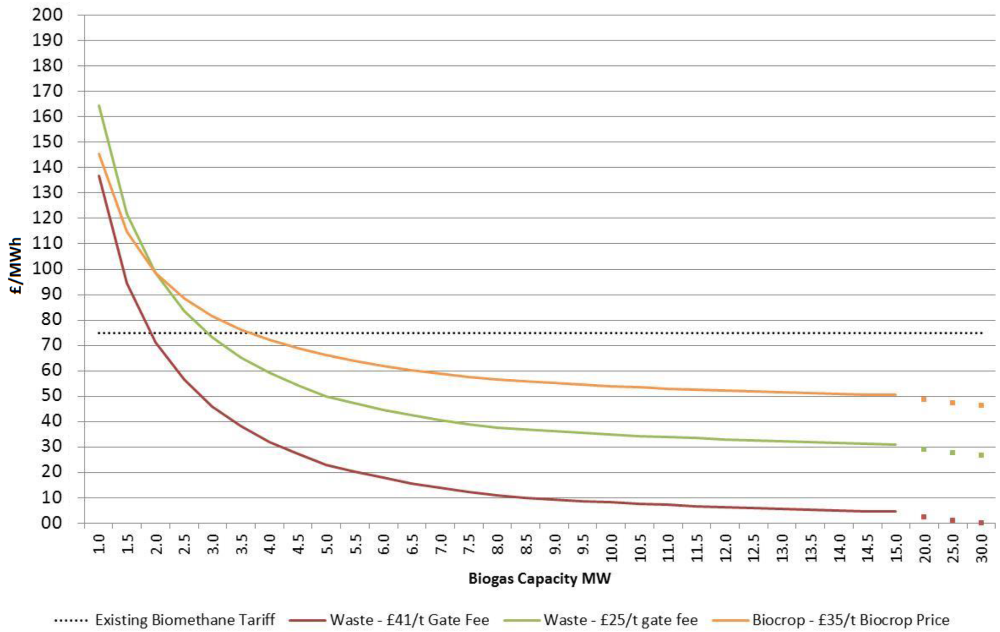

Figure 1.12. Required RHI tariff to provide a 12% internal rate of return (DECC, 2014)[24].

1.5 Summary of key Scottish heat sector facts and figures

Renewable (non-electrical) heat targets and penetration in Scotland:
- Scottish 2020 target of 11% of heat from renewable sources;
- Heat from renewables in Scotland in 2012 was 3.0% of demand;
- 2020 target to be achieved through both heat demand reduction and increased renewable heat sources.

Electrically generated heat is not included in data sets due to uncertainty measuring end-use of electricity, and to avoid “double counting” renewable electricity and electrical renewable heat under the total renewable target (20% by 2020 and 30% by 2030).

Other renewable targets relevant to heat:
- A 2020 energy efficiency target to reduce total final energy consumption (including transport, electricity and heat) in Scotland by 12% against a baseline of the average final energy consumption in 2005-7 (already at 11.8% in 2012);

Total Scottish consumption:
- (Non-electrical) heat consumption in 2010 = 87 TWh[4];
- Electricity consumption in 2010 = 27 TWh[4];
- Non-electrical heat consumption roughly 3 x electricity consumption.

Scotland’s residential sector heating:
- Accounted for 51% of Scotland’s total heat emissions in 2010;
- Accounted for 15% of Scotland’s total carbon emissions in 2010 (including all heat, transport and electricity);
- Residential gas consumption decreased by 28.7% over 2005-2013;
- 78% of Scottish domestic properties on the national gas grid.
- 13% of domestic properties primarily heated electrically;

Scottish renewable heat figures:
- 2.904 GWh of renewable heat installed in 2013;
- 82% renewable heat output from biomass and biomass CHP in 2012;
- Remainder from Energy from Waste (EfW), solar and heat pumps.

Scottish gas consumption figures:
- Domestic gas consumption in 2012 = 28.8 TWh;
- Non-domestic consumption in 2012 = 21.8 TWh;
- National Grid[8] suggest 5-18% of UK gas demand in 2020 could come from biomethane from sewage, food waste and Municipal Solid Waste (MSW).

2020 renewable electricity targets:
- 100% equivalent electricity demand in Scotland from renewables;
- Every electrical end-user to have a smart meter by 2020;
- Potential synergy between heat and electricity domains after 2020 (heat pumps in particular utilising variable renewable electricity with a COP of >3 times the input electrical power[32]).

District Heating Networks (DHN):
- 2020 goal of 40,000 domestic dwellings on DHNs by 2020 (<2% of Scotland’s 2.4 million dwellings);
- In 2009, DHNs provided only 0.3% of UK heat demand;
- Study for DECC[27] suggests maximum economically feasible penetration of DHNs in the UK of 14% of total heat demand.

2 Detailed analysis of projected heat scenarios to 2050

The development of low carbon heat solutions will be dependent on future trends in heat use and the wider development of low carbon and renewable technology. Since the Climate Change Act (2008), various studies have provided forecasts and projections for low carbon heat use and technology development in the UK, as discussed in Ref. [34], often without with different conclusions on the likely dominant technologies.

Three heat scenario studies and their implications for the Scottish heat sector have been explored in detail by the SE Foresighting team:

1. DECC's heat pathways to 2050[5]
2. Scottish Government's Heat Generation Policy Statement[1]
3. Energy Network Association's gas future scenarios project[6]

2.1 DECC 2050 Pathways

DECC's scenarios for the UK heat sector are dominated by the UK's 2050 target to reduce greenhouse gases by 80% relative to 1990 levels[5]. By 2050, DECC anticipate virtually no role for natural gas in the domestic market due to the greenhouse gas emissions associated with combustion in the domestic setting. Instead, under DECC's Carbon Plan it is anticipated that the UK will shift from using natural gas for domestic heating to low carbon electrical forms of heat. The low carbon electricity is to be generated from renewables and nuclear, but critical to the scenarios is the successful implementation of Carbon Capture and Storage (CCS) to enable continued use of fossil fuel electricity generation.

The 2050 Pathways document was first published in 2010 and was most recently revised in 2013[5]. In 2012 DECC performed additional modelling[36] of seasonal and daily heat demand to include heat networks with storage and new building-level technologies including gas absorption heat pumps, hybrid systems (gas boilers with an electric heat pump), micro-CHP and domestic hydrogen boilers.

Figure 2.1 shows that DECC anticipates *conventional* gas boilers to be phased out by 2030, with *hybrid* gas boilers becoming the most common domestic heating source. By 2050, DECC suggests that heat pumps will supply the vast majority of domestic heating (>80%) with the remainder coming mainly from heat networks, although there may still be a limited role for gas to meet peaks in demand on the coldest days of the year.

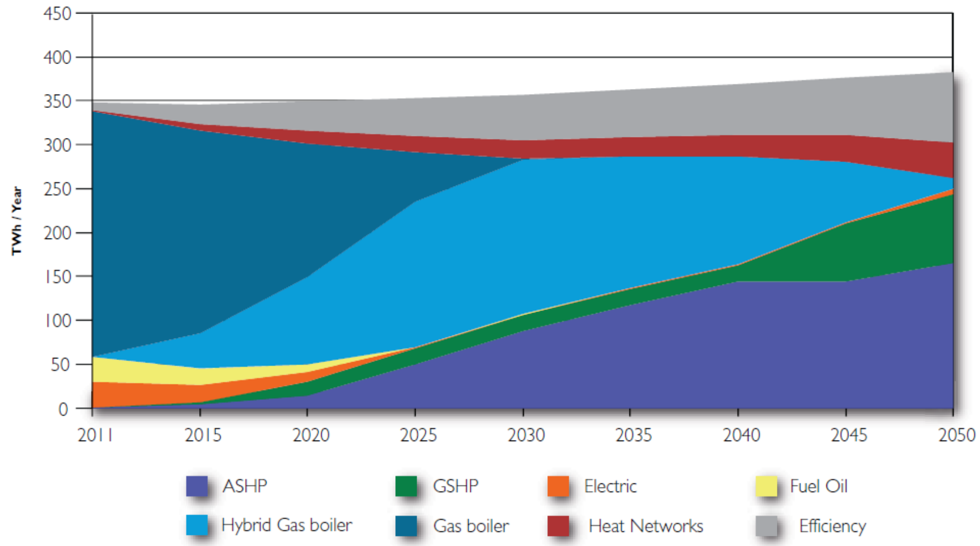

Figure 2.1. DECC's 2050 Pathways modelled UK domestic heat supply (space and water), by technology.

DECC's modelling suggests around 60 TWh of heat delivered by heat networks by 2050. Figure 2.2 shows that gas is expected to provide about two thirds of the energy supply for heat networks in 2030, along with contributions from biomass and large heat pumps. Moving beyond 2040, district heating gas systems are expected to be fitted with CCS technology to minimise the greenhouse gas contributions from heat networks.

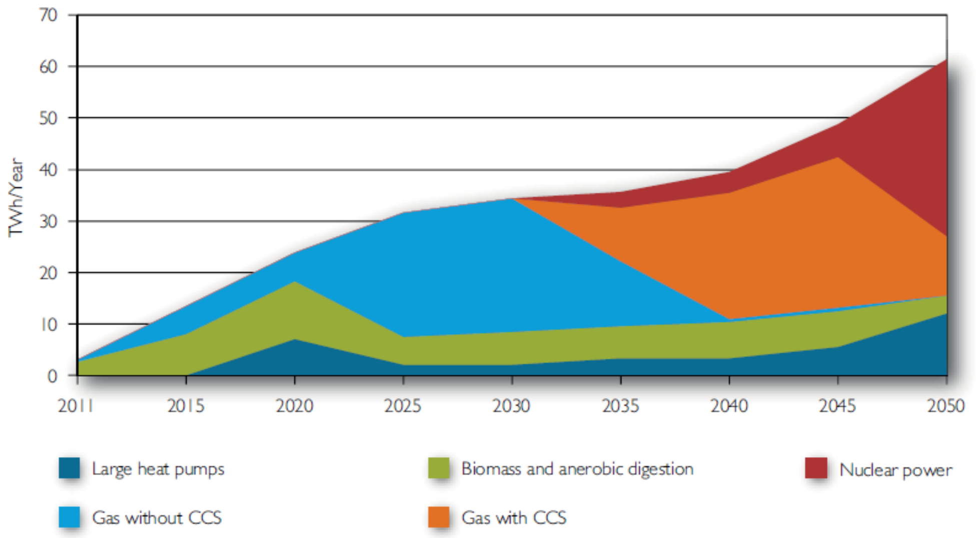

Figure 2.2. DECC's projected deployment of building level district heat networks in the UK.

Throughout DECC's heat strategy towards 2050, natural gas is expected to be used in conjunction with CCS and will therefore not contribute significantly to emissions, whether used for heat networks or for generating electricity (for uses including heat pumps). The substantial and obvious risk with the entire DECC scenario planning is that CCS cannot be implemented on such a large scale, due to technical or economic reasons. The UK is currently only just building its first CCS demonstrator (White Rose near the current Drax power station) and only one plant is operational worldwide (Boundary Dam, Canada, commissioned in 2014).

DECC's models discuss biomethane's role in space heating in the short to medium term, as well as in high-temperature process heating in the longer term: around 20 TWh of biogas from the expected total gas demand of 550 TWh could be sourced from gasification of biomass, anaerobic digestion and landfill gas - only around 3.5%. Hydrogen is noted for its potential for providing heat for buildings and industry but DECC states further work is needed to fully understand its role in the energy system and infrastructure costs.

The high-level conclusions from this study were that overall gas demand will fall by 40% by 2050 (compared to 2011) and there will be a reduction of around 90% in the use of gas for directly heating buildings, Figure 2.3. The remaining gas use will be in conjunction with CCS for heat networks and large industrial users. DECC forecast a greater role for district heating networks, in part because of their storage potential and the functionality this allows in terms of balancing production and use of energy.

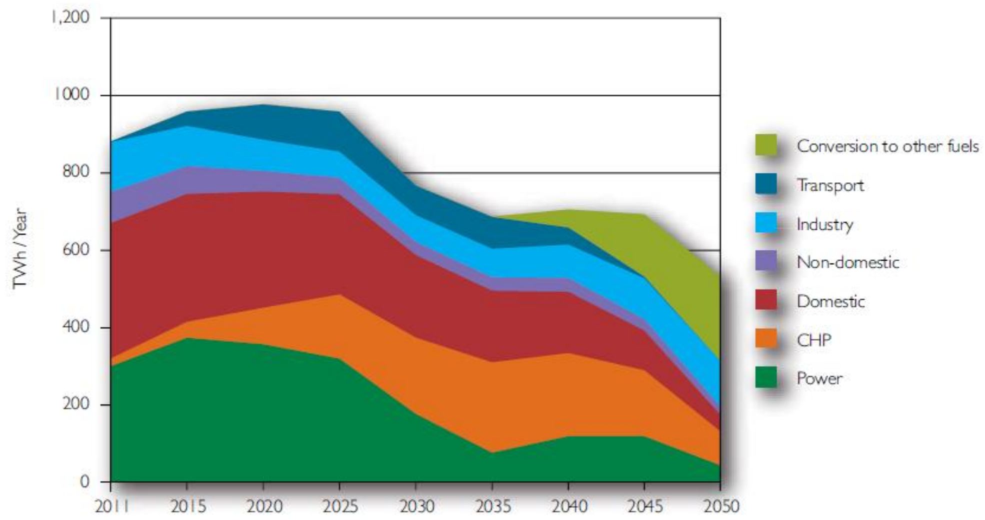

Figure 2.3. DECC's predicted end-use of natural gas towards 2050. Note the decline in domestic use from over 300 TWh to around 20 TWh.

There are some notable uncertainties in DECC's strategy. DECC discusses the possibility of a limited role for natural gas as a backup to meet peaks in demand on the coldest days of the year. This is considered to be more cost effective than full electrification of the peak seasonal demand which would require large amounts of additional generation capacity and upgrading the distribution network to meet only occasional use. The most cost effective solution may be to maintain some gas in buildings, for use in hybrid gas appliances for example.

In summary, in the medium term, by 2030 gas is still the dominant heat provider for heat networks and individual domestic properties, with hybrid gas boilers replacing conventional boilers (hybrid boiler = gas boiler and electric air source heat pump). Longer term, DECC's target to meet 80% reductions in greenhouse gases by 2050 results in the phasing out of the national gas grid as a provider of domestic heat as it is inherently not a low carbon solution. DECCs preferred scenario is the electrification of the heat sector using heat pumps, with the electricity sourced from gas powered CHP and thermal plants fitted with CCS, renewable and nuclear. Large industrial heat users will be expected to fit CCS at the point of use in order to continue to use natural gas. This whole strategy relies on the successful and economic implementation of large-scale CCS and massive deployment of heat pumps, all of which will require regulatory intervention due to economic and technology obstacles. DECC discuss that further work will need to be performed to consider the necessary upgrade and running costs of the gas and electricity networks as the heat sector shifts from gas to electricity and the implications of a partially used gas grid coupled with increases in electrical capacity and transmission.

2.2 Scottish Government Heat Generation Policy Statement (HGPS)

The Scottish Government has developed the Heat Generation Policy Statement (HGPS, 2014)[1], which includes a forward projection model prepared by Arup to explore scenarios and pathways for largely decarbonising the heat system in Scotland up to 2050. The model brings together all heat use and generation within Scotland associated with the use and occupation of buildings, including space heating and cooling, hot water supply, cooking, and industrial processes. The model explores different pathways of heat decarbonisation by altering two key drivers – the level and nature of '**Government Intervention**' (GI) and the '**Uptake**' of new measures.

GI represents action by the Scottish, UK and local governments either to mandate or incentivise uptake of measures to reduce energy demand and to increase switching to lower carbon supply technologies. Examples of GI included in the model are:

- Building regulations requiring certain energy efficiency standards of new buildings or existing buildings that are modified;
- Subsidies/grants to incentivise uptake of demand reduction measures such as insulation;
- Ensuring that consumers perceive and react to the true costs and benefits of their heating choices (including the carbon cost).

'Uptake' represents a change in the attitude of individuals and businesses which results in a greater willingness to overcome barriers and adopt lower carbon demand and supply measures and behaviours. This increased willingness to adopt new technologies, uptake retrofit measures and adjust demand for heat may be influenced by peers, company business models and action and leadership by the public sector.

Figures 2.4 and 2.5 (also reproduced in Appendix B in a larger format to aid analysis) show the four scenarios (of Uptake and GI) for the domestic and non-domestic sectors in Scotland. Table 2.1 shows the total heat emissions ($MtCO_2e$) for the four scenarios compared to a reference scenario which attempts to reflect the continuation of existing policies[37]. The reference scenario provides an indication of the costs of a heat system in which no further action is taken to decarbonise above what is already in place. Importantly, for the reference case emissions still fall by 50% by 2050 from the 2010 levels (from 27 $MTCO_2e$ to 12 $MTCO_2e$) due to current energy efficiency and heat policies.

Table 2.1, Figures 2.4 & 2.5 contain a substantial amount of information for penetration levels of various different heating technologies, for each decade from 2010 to 2050, both for domestic and non-domestic demand.

Scenario		Emissions 2050 ($MtCO_2e$)	2050 Emissions Reductions Compared to 2010	40 Year Costs Relative to Reference Case (£M)
Government Intervention	Uptake			
High	Low	8.45	68%	15,260
Low	Low	15.05	43%	6,110
Low	High	8.31	69%	639
High	High	5.05	81%	-1,470

Table 2.1: Scottish Government's heat emissions and costs in 2050 by scenario. Note that the High GI and High Uptake scenario is predicted to lower costs compared to the reference case over a 40 year period, whereas the other three scenarios increase costs.

In summary:

- The Low GI and Low Uptake scenario (bottom left, Figures 2.4 & 2.5) sees a reduction of carbon emissions of 43% to 2050. Low Uptake, in part, stems from a low level of mandated or incentivised uptake of measures; consumers demand familiar means of heat supply and assess new technologies based only on their cost and not on their emissions abatement potential. Emission reductions are primarily driven by fabric retrofit measures and the installation of more efficient gas boilers and low level use of heat pumps and district heating. In the non-domestic sector, the demand for heat rises marginally, however biomass and heat pumps progressively supply a greater share of the demand.

- The Low GI and High Uptake scenario (bottom right, Figures 2.4 & 2.5) demonstrates a 69% reduction in heat emissions to 2050. Demand for heat declines in both the domestic and non-domestic sectors, driven by consumer uptake of retro-fitting improving the energy efficiency of building stock. The domestic sector experiences a fall in the contribution of gas boilers from around 73% in 2010 to 37% in 2050, replacing them with heat pump solutions and a growing role for district heating. In the domestic sector, by 2050 around 60% of heat is supplied by low carbon solutions, mainly from biomass heating, heat pumps and district heating networks.

- The High GI and Low Uptake scenario (top left, Figures 2.4 & 2.5) demonstrates a 68% reduction in heat emissions to 2050. Despite high levels of Government Intervention to mandate and incentivise uptake and reduce demand, consumers still demand existing familiar means of heat supply and reduction techniques. In this scenario technology selection is based only on cost and not on emissions abatement potential. In existing domestic and non-domestic building stock, this combination leads to significant uptake of electric storage heating due to its low installation cost and low carbon performance due to an increasingly decarbonised electricity network.

- The High GI & High Uptake (top right, Figures 2.4 & 2.5) results in an almost complete move away from on-site combustion gas boilers (as in the DECC scenario). In the domestic scenario modern electric heating technologies such as heat pumps play a very significant role, providing 58% of all heat. In non-domestic buildings biomass gains a substantial share of the heat supply market, supplying around 46% of all heat by 2050. District heating plays a notable role in supplying low carbon heat to both domestic and non-domestic users. This scenario sees an 81% reduction in emissions by 2050.

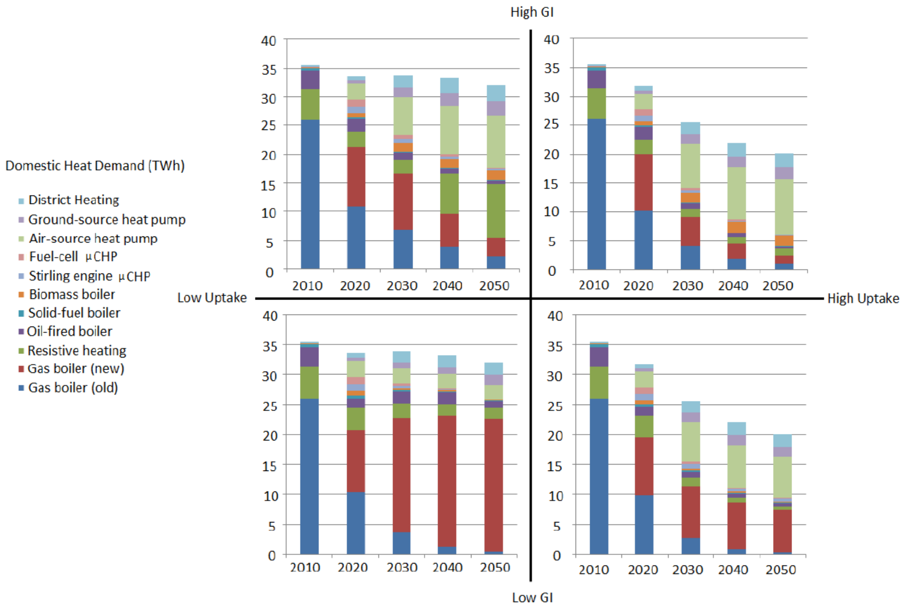

Figure 2.4. Scottish Government's domestic annual projected heat demand (TWh) to 2050, based on 4 different Uptake and Government Intervention (GI) scenarios (note a larger version in reproduced Appendix B).

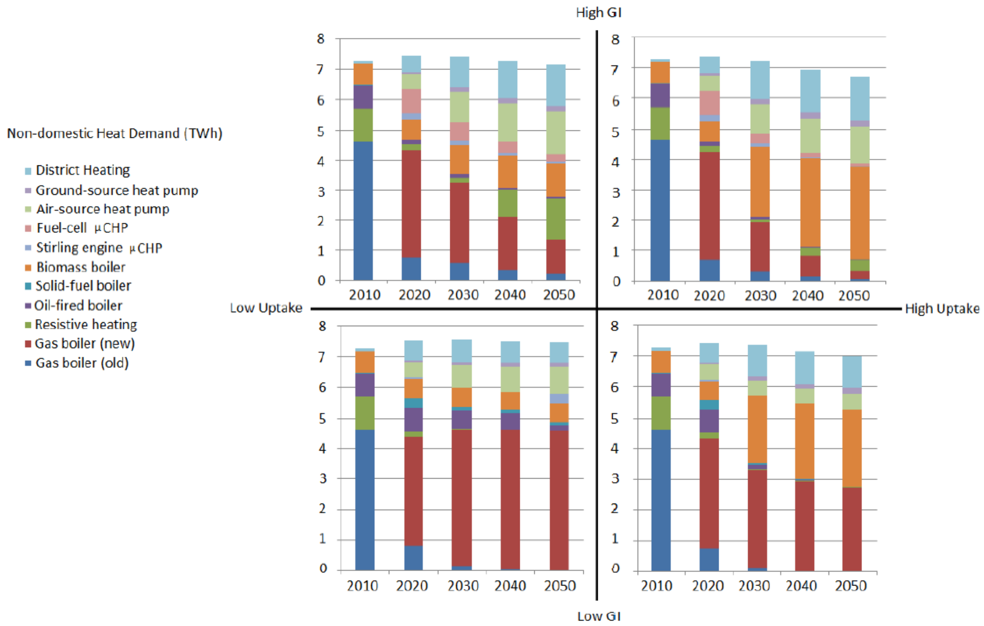

Figure 2.5. Scottish Government's non-domestic annual projected heat demand (TWh) to 2050, based on 4 different Uptake and Government Intervention (GI) scenarios (note a larger version in reproduced Appendix B).

The overall predicted costs of delivering each of the 4 scenarios varies depending on the levels of heat demand, energy efficiency technologies and behaviour change, and the heat technologies used. The resulting costs presented in Table 2.1 are associated with the whole heat system and its capital and operating costs for each scenario.

In one of the four scenarios - High Government Intervention and High Uptake - it is possible to reduce both the carbon intensity of heat and lower costs relative to the measures currently in place, Table 2.1. These results are driven by savings in operating costs resulting from increased adoption of new technologies, reductions in demand for increasingly expensive fossil fuels, and widespread adoption of energy efficiency and demand management measures.

In both scenarios where the *uptake* of low carbon heating solutions is *High*, the difference in costs compared to the reference case is relatively small per year, Table 2.1 (£639M and -£1,470M in total respectively over 40 years, or £16M and -£37M p.a.). The most costly scenario is where the Government Intervention is High but uptake is Low, i.e. a lot of resources and investment attempts to subsidise and regulate the market to drive uptake, which doesn't then materialise. Specifically, under this scenario heat demand remains high and the penetration of resistive heating is high, with associated high fuel costs, leading to an additional cost of £15B over 40 years (£375M p.a.), emphasising that heat interventions must be successfully delivered to avoid costly failure.

The Scottish Government's HGPS states that the patterns of electricity demand, and peak demand in particular, are important factors to consider when assessing options and trade-offs in the use and generation of heat. It is suggested that further modelling is required to understand the impacts of peak electricity demand and the overall cost implications of providing sufficient generating capacity. It references DECC's scenarios and modelling discussed in Section 2.1, repeating DECC's comments that full decarbonisation of heat through electrification might be more costly, as this would require additional generation capacity and further reinforcement of the electricity grid to meet peak heat demands. The HGPS notes that the DECC model only included a simplified representation of the gas and electricity grids and their associated costs, and therefore the DECC model does not necessarily factor in all the implications of keeping a system of gas boilers and associated infrastructure that are used only occasionally. It notes that further work is required to understand the practical implications of a partially-used gas grid, including the technical feasibility and the implications for network costs. It follows that whether gas or electricity is used to meet occasional peaks in heat demand, some expensive redundancy in the systems could be involved.

2.3 Energy Networks Association: 2050 Pathways for Domestic Heat

In 2012, Delta-EE were commissioned by the Gas Futures Group of the Energy Networks Association (ENA) to provide a study on the optimal appliance technology pathways[6]. This study focuses on the UK domestic space and water heating requirements to 2050. It was performed by domestic property type, based on known and emerging heating technologies, highlighting the impact on consumers and the potential load changes on the gas and electricity distribution networks out to 2050.

A residential heat model was developed, including:

- A housing stock model, segmenting the UK housing stock into 35 segments according to fuel availability and use, age, and building type. For each segment the thermal demand is defined, and how this changes decade by decade to 2050;
- A technology performance model, forecasting costs and performance covering various different low carbon heat technologies;
- A customer choice model, incorporating physical fit of different technologies with different parts of the housing stock; customer uptake based on payback and upfront cost; and customer attitudes.

The ENA study notes that around 80% of carbon emissions from residential heating in the UK are from on-gas properties, mainly in suburbia. The slow turnover of housing stock means these properties remain 'the challenge' in 2050. It references that DECC's target is full decarbonisation of residential heat by 2050, however it is noted in the ENA report that growth in biomethane and reducing thermal demand alone cannot meet this target. A major change in the heating appliance mix is therefore required.

The study identifies that:

- There are many potential low-carbon heating appliance options – but technologies & markets are, in most cases, very immature today;
- There are no examples, globally, of large-scale switches away from gas boilers for existing buildings – although some smaller-scale switches are emerging in a few markets. Volumes of low carbon heating appliances are, in nearly all cases, very low (and therefore costs are high);
- There are massive opportunities for learning and innovation in retrofitting low carbon heating technologies to existing UK homes.

Where gas is available, the study states that gas boilers are an excellent fit with customer 'wants', including low capital cost, reliability, low maintenance, high efficiency & low-cost fuel (DECC forecasts relatively stable future gas costs), compactness, excellent fit with UK heat distribution systems (high temperature radiators) and easy to use with instantaneous hot water. Therefore large-scale switching away from gas boilers will be challenging and require strong interventions.

The ENA study uses the Redpoint 'Green-Gas' Scenario[38]: by 2050, 75 TWh of biomethane is predicted to be available for use domestically (60% of the estimated 125 TWh total biomethane production by 2050) as more plants are built, with production limited by finite feedstock availability, Figure 2.6. This equates to ~25% of domestic gas demand being met by biomethane in the model's Base Case scenario and 66% under the Balanced Transition scenario.

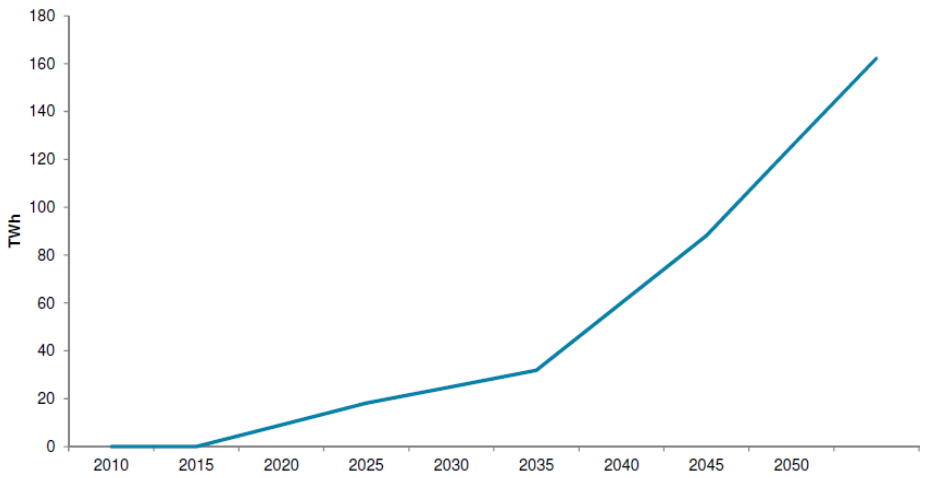

Figure 2.6. ENA predictions of UK biomethane production, of which 75 TWh would be available for domestic use by 2050.

This residential heat model was then used to determine the future appliance mix under three scenarios:

1. Customer Choice (CC)

- Without any intervention, customers chose gas appliances, with less than 1% of gas customer switching to an alternative fuel;
- Carbon targets are missed;
- Impacts on customers and the wider energy system are low.

For existing homes, gas heating appliances offer low to moderate upfront costs, and low running costs, Figure 2.7. Micro-CHP grows on the back of product maturing and electricity prices rising substantially faster than gas prices. Gas heat pumps mature but gain minimal market share. There is some switching away from oil. New build is dominated by heat networks and electric heating (driven by regulations).

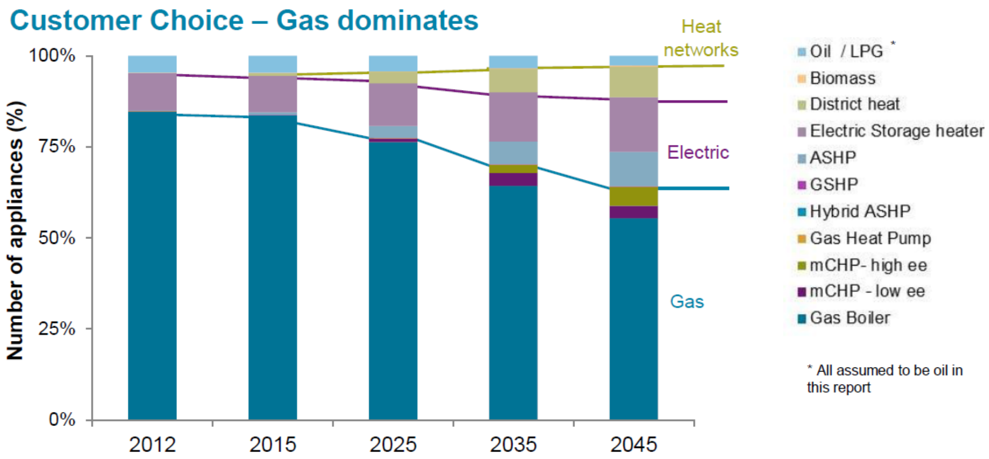

Figure 2.7. ENA's Customer Choice domestic heating predictions to 2050.

Carbon reductions of 46% are realised compared to the 2010-20 baseline, from growth in biomethane (biomethane provides 75 TWh out of 327 TWh of UK domestic demand, or 23% of total gas consumption for residential heat), reduction in thermal demand and some growth in lower carbon appliances. There is some growth in peak demand on the electricity system from growth of heat pumps (in new build and off-gas grid properties), but this only amounts to 8 GW. Heat networks grow but nearly all in new build.

2. Electrification and Heat Networks (E&HN)

- Delivers carbon targets but at high cost to customers;
- Significant interventions will be required to shift customers away from gas appliances and onto either electric heating or heat networks;
- Similar to the DECC heat strategy, which sees a massively reduced future role for gas in the domestic sector, and almost completely decarbonises heat via electrification.

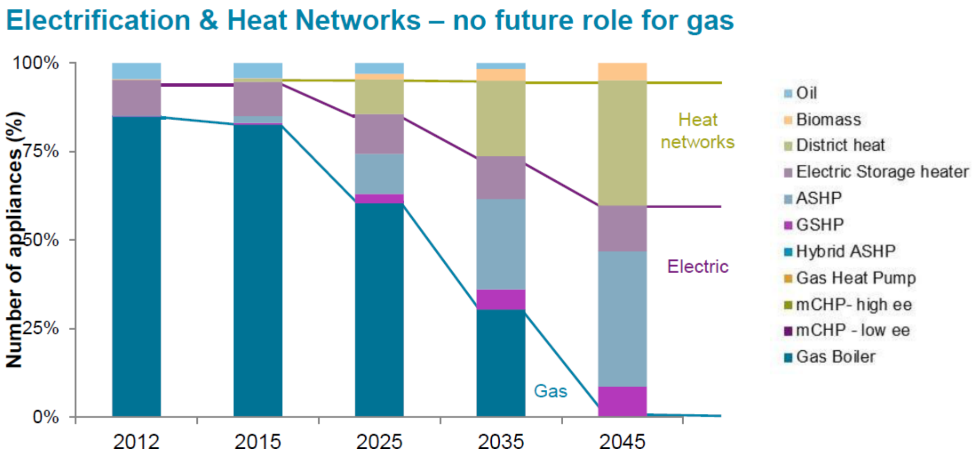

Figure 2.8. ENA's Electrification and Heat Networks domestic heating predictions to 2050.

All customers are moved to electric heating and heat networks. Although this delivers on carbon targets (96% reduction) it imposes high costs on customers, involves challenging retrofit issues, a major roll out of heat networks, and results in major impacts on peak electricity demand. There is significant growth in peak demand on the electricity system from growth of heat pumps – an additional 48GW of electrical capacity will be required, along with major upgrading of the distribution network (costing £16-£28bn to 2050, including electric vehicles and PV), and the shut-down of all gas networks. Significant growth in heat networks is required – even into areas with less dense housing (including all urban, and some suburban homes).

3. Balanced Transition (BT)

- Achieves significant carbon reductions whilst minimising impacts on the customer and the energy system;
- Very strong growth in heat networks and electrification of heating – but with gas still playing a significant role in suburban homes;
- Ambitious decarbonisation and fuel switching needs to occur – but the hardest to switch homes are able to stay on gas (or gas-electric hybrids).
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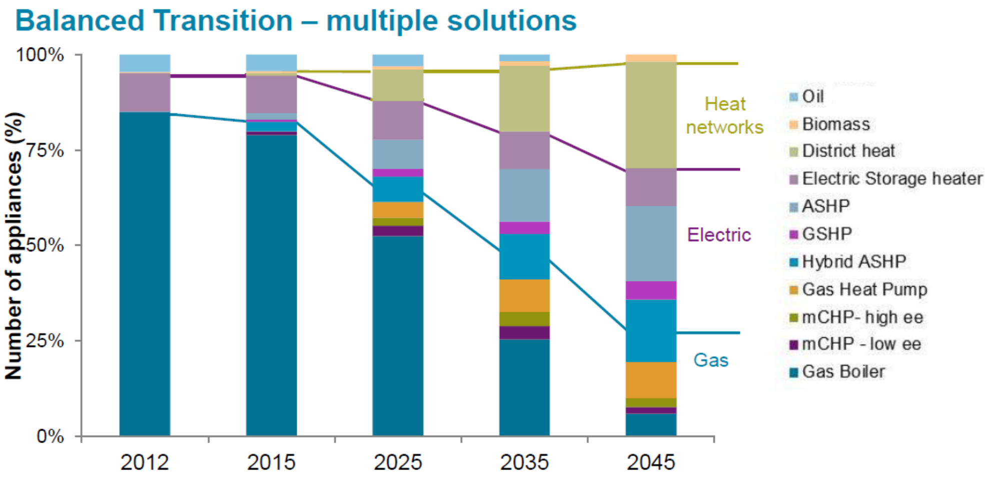


Figure 2.9. ENA's Balanced Transition domestic heating predictions to 2050.

The Balanced Transition scenario imposes higher costs on customers than the Customer Choice scenario, but for certain customer groups (primarily suburban customers currently on the gas network) these costs are lower than in the Electrification and Heat Networks scenario. It offers a wider range of technologies to make retrofit less challenging and delivers significant carbon savings (90% reduction), but this is dependent on

75TWh of biomethane being available. There is growth in peak demand on the electricity system – an additional 24GW of UK capacity will be required, along with upgrading parts of the distribution network (costing £8-14bn to 2050, including that for electric vehicles and PV) and the shut-down of parts of the gas networks. Significant growth in heat networks is required – but only into dense urban housings. Suburban on-gas homes can opt for gas or hybrid technologies.

Summary of ENA model

The ENA study identified that success in the E&HN and BT scenarios depends on achieving the following challenges:

1. Reduce thermal demand – the model has assumed 21% reduction in thermal demand from current buildings – interventions such as the ‘Green Deal’ will be required.
2. Development and widespread expansion of district heating - growth of district heat will require major intervention under both scenarios (more so under E&HN). It will require a new regulatory framework (potentially mandating that customers connect).
3. A need for technology, product & supply chain development - to ensure efficient appliances are brought to market & can be successfully retrofitted to homes (including efficient gas appliances under BT).
4. Decarbonisation of electricity grid, decarbonised heat supply for district heating and biomethane growth (for BT) are all required.
5. Major energy system upgrades & additional peak electrical generating capacity - on both the electricity side, and on decommissioning the gas grid, will be required.

There are various uncertainties in the model, including: the penetration levels of biomethane into the grid (the model assumes 125 TWh per annum by 2050, of which 75 TWh is available for domestic use), the improvements in COP of heat pumps towards 2050, and also the deployment rate of technologies.

While the study discusses in significant detail projected costs for individual heating system technologies in the context of the variety of different housing types out to 2050, it does not comprehensively cover the total costs for national (UK) deployment of each scenario, which would seem to be a major omission. It discusses the cost implications of upgrading the electricity grid for each of the 3 scenarios to 2050, Table 2.2, ranging from £3bn-£28bn depending on which scenario is deployed. It also states a figure of £4bn under the E&DH scenario to decommission the gas network by 2050.

Scenario	**Carbon reduction** (2040-50, compared to 2010-20)	**Electricity system impact**	**Gas system impact**
Customer choice	46%	£3-6 bn upgrade costs to 2050	Gas plays the significant role in domestic heating, supplying around 80% of the UK requirement in 19 million homes
Electrification and heat networks	96%	52 GW of additional peak electricity demand Upgrading most of the UK’s electricity distribution network £16-28bn upgrade costs to 2050	No role for gas network for domestic homes Cost of £4bn to exit gas network
Balanced transition	90%	23 GW of additional peak electricity demand Upgrading part of the UK’s electricity distribution network £7-14bn upgrade costs to 2050	12.5 million UK homes still use gas for some or all of their heat (50% of total number of homes)

Table 2.2. Summary of the carbon reductions and implications for electricity system for ENA’s three heat sector scenarios over 2010-2050.

2.4 Summary of Scottish and UK heat scenarios to 2050

All three heat study scenario studies (DECC, SG and ENA) suggest that measures currently in place will see carbon emissions from the heat sector reduce by roughly 50% by 2050, from the 2010 baseline, due to reduced demand for heat stemming from thermal efficiency improvements through retro-fit and new build, and improved heating system efficiencies.

One conclusion from the three studies and various scenarios detailed within them is simply the enormous uncertainty and lack of agreement over which fuel types will dominate towards 2050.

- Gas is presently the UK's dominant source of heat for both industrial and domestic users (around 80% penetration), and without any intervention both the SG and ENA studies suggest that domestic customers will continue to overwhelmingly choose gas boilers as the preferred form of heating.
- However with successful intervention leading to high uptake rates of low carbon heating, the highly desirable outcome of both greenhouse gas reductions and cost savings are possible out to 2050, according to the SG's HGPS. A move from gas to a combination of electrification (heat pumps), heat networks and biomass is considered likely.
- High intervention with little uptake from heat users may achieve carbon reductions of 69%, at a high cost.

In order to meet UK 2050 emission reduction targets of 80% (baselined against 1990), several main themes emerge across the three studies in terms the way heat is delivered in the UK and Scotland. These are:

- A substantial reduction in the role of natural gas for heat.
- Managing the emissions from the remaining gas contributions via CCS - only economically feasible for large consumers or heat networks.
- Increasing electrification of the heat sector (particularly using air and ground source heat pumps), powered by low carbon electricity.
- An increase in district heating scheme capacity. DECC's model indicates a 10-fold increase in UK heat network output by 2030 (to 30 TWh). The HGPS discusses a draft target of 1.5 TWh total DHN output in Scotland by 2020, with >1 TWh non-domestic output by 2030.
- The potential for (solid) biomass to play a substantial role in non-domestic heat sector. The Scottish Government indicate of the order of 50% of non-domestic heat from biomass under optimistic scenarios.

Natural gas:

- DECC envisages gas continuing to supply industrial heat (and also generate electricity), used in conjunction with CCS at point of use. The major risk with this policy is that CCS may not be implemented on a large-scale due to technical or financial reasons.
- DECC anticipate a move to gas hybrid boilers by 2030 and the phasing out of gas altogether for domestic heating by 2050 (since it is not possible to capture emissions at a domestic level).
- The SG and ENA studies also envisage a change to either hybrid or new boilers by 2030 coupled with a 25-50% reduction in gas demand, with continued reduction in gas consumption to 2050 and a general phasing out of domestic gas use.

Biomethane:

- DECC indicate around 20 TWh of biogas from the expected total UK gas demand of the 550 TWh in 2050 may be sourced from gasification of biomass, anaerobic digestion and landfill gas (i.e. only around 3.5%).
- ENA are more optimistic stating 125 TWh of biomethane by 2050, of which 75 TWh out of 327 TWh is available for use as UK domestic demand, or 23% of total gas consumption for residential heat.
- A 2009 National Grid report states that with the right government policies in place, renewable biomethane could contribute of the order of 48 to 145 TWh (5% to 18% of total UK gas demand of around 970 TWh in 2020)[8].

- The wide variation in predicted volumes of biomethane for heat supply, ranging from 20 TWh by DECC up to 145 TWh by National Grid, can be explained by DECC's comments that whilst there are significant benefits in injecting biomethane into the grid, there may be uses for biomass in other parts of the economy where low carbon alternatives are absent or less cost-effective (such as transport or electricity generation).
- In summary, assuming the finite feedstocks are not used for other purposes, biomethane can provide up to (but not more than) around 25% of predicted gas demand due to the limited availability of feedstocks.

Hydrogen and methanation renewable gases:

- Hydrogen's role in the future of heating is uncertain in all of the scenarios reviewed and is only briefly mentioned, with DECC stating that further modelling and consideration is required. Methanation, where hydrogen is combined with CO_2 to produce synthetic gas, was not mentioned in any of the scenarios, despite being commercially demonstrated in Germany for example. The conclusion is that renewable hydrogen (and methanation) is unlikely to play a major role in Scottish and UK heating towards 2030.

Electrical heat:

- The domestic sector will have to significantly electrify heating under all scenarios if carbon targets are to be met.
- Low carbon electricity can be sourced from fossil fuel generation plants using CCS (DECC favours gas), nuclear or renewables.
- Heat pumps can boost the efficiency of electrical heat (COPs>3)[32].
- Heat as an end-use is well suited to variable renewable electrical generation as instantaneous heat delivery and constant supply is not essential for many heat applications.

Meeting heat demand on the coldest winter days:

- One challenge of transitioning to a largely electrical heat supply system is meeting the heat demand on the coldest winter days - UK heat demand fluctuates much more significantly on a daily and seasonal basis than current electricity demand (Figure 1.3 in Section 1); therefore complete electrification (if even possible) may involve expensive generation and network upgrades that will be largely under-utilised for much of the year (52 GW extra capacity costing £28 billion under the ENA model[6]).
- Given that the UK has an existing gas grid with high penetration (supplying ~80% of domestic properties), the use of gas powered heat pumps and hybrid boilers may allow some of the peak winter demand to be met using natural gas on the coldest days, whilst decarbonising the heat network compared to current conventional boiler use for most of the year. In particular, hybrid boilers may provide significant carbon savings if the heat pumps are the dominant heat provider for the majority of the year (running on renewable electricity).

To conclude, the heat challenge cannot be fully solved in isolation from the electricity question, the storage question and the infrastructure question – the heat sector is inextricably linked to the overall energy system. The coming decade may well be a preparatory period, with many different technologies being trialled and evaluated in preparation for mass deployment in the late 2020's onwards.

3 TECHNOLOGY ANALYSIS

This section discusses current and potential levels of renewable heat deployment in Scotland, and summarises each low carbon heat technology, or enabling technology, in a one page overview which aims to capture the Scottish deployment potential, CO_2 savings, Cost of Energy (CoE), innovation potential, and any issues related to practicalities of widespread deployment in Scotland. GVA and potential job creation analysis was performed by Ricardo-AEA for renewable gas and energy storage (see Appendix A). Further work would be required to determine these figures for the other low carbon technologies if required.

3.1 Current renewable heat deployment levels

DECC publish RHI statistics on the number of registered renewable heat installations. The Scottish RHI deployment levels as of October 2014[39]:

- 2,054 accredited domestic systems;
- 1,113 accredited non-domestic systems;
- 1,933 heat pump and biomass RHPP vouchers redeemed (RHPP was the predecessor to RHI).

There does not yet appear to be a Scottish specific breakdown of the non-domestic systems by technology. As discussed in Table 1.3, around 80% the total capacity and output of renewable heat in Scotland currently comes from biomass and CHP biomass. Table 3.1 shows the domestic breakdown.

	On grid	Off grid
Air source heat pump	169	359
Ground source heat pump	76	209
Biomass systems	213	655
Solar thermal	157	216

Table 3.1. Accredited Scottish domestic RHI installations by technology.

3.2 Renewable heat deployment estimates for 2020

DECC estimates an upper bound of 380,000 UK domestic renewable heat installations supported by the RHI by 2020[40]. 2014 statistics regarding Scotland's share of UK RHI installations: 18% of non-domestic and 16% of domestic installations. This suggests an upper bound of 60,800 domestic renewable heat installations in Scotland by 2020, as a ratio of current RHI deployment. Across the UK, DECC estimate realistic installation numbers by 2020 are: 100,000 heat pumps and an additional 24,000 biomass installations. In the absence of specific Scottish figures, and assuming Scotland maintains its current % share of UK RHI installations, this suggests 18,000 heat pump and 4,300 biomass installations in Scotland by 2020.

Heat pumps. There are ~20,000 heat pump installations per year in the UK, primarily of domestic ASHPs[41]. The Climate Change Committee estimated 13 TWh p.a. heat pump output by 2030 (coming from 0.7M installations), mainly ASHPs, or 14 TWh by 2030 and 1.0M UK installations[41] when including hybrid boilers. Assuming a uniform installation rate across the UK, this gives the following Scottish heat pump installation figures:

- Up to 2020: 3,800 a year, total of 18,000 by 2020;
- 2020-2030: 10,000-15,000 a year, total of 105,000-150,000 by 2030.

DHN: Meeting the Scottish Government's draft target of 40,000 homes connected to DHNs by 2020 (from the current level of just over 9,000), will require the installation of around 30 projects of comparable size to Glasgow's Commonwealth Games DHN[7] (704 homes, 120 bed care home and a velodrome). This appears ambitious over a 5 year time-scale in terms of securing finance, planning consent and the required civil works.

Biomass: DECC estimates 6,500 industrial and 55,000 commercial and public sector biomass installations across the UK[42] by 2020. Given Scotland's relatively high penetration of biomass and availability of feedstock, this equates to *at least* 1,300 industrial and 11,000 commercial and public sector biomass systems under RHI by 2020. The mean boiler size in industrial and commercial applications is 175 kW[42], although this may change in future if RHI tariffs are revised. The HGPS scenarios estimate increasing penetration of biomass over 2020-2030, with a tripling of both domestic and non-domestic capacity in some scenarios.

- Up to 2020: 1,300 industrial and 11,000 commercial and public sector installations (130 and 1,000 installations p.a. respectively);
- 2020-2030: 3,000 industrial and 15,000 commercial and public sector installations (300 and 3,500 installations p.a. respectively).

Solar thermal: There is no evidence to suggest any future increase in uptake rates of solar thermal from the current rate of <100 installations per year unless regulations or incentives change. Introducing incentives, or tightening regulations on new builds, may increase the uptake.

Table 3.2 summarises the 5 low carbon heat technology deployment figures discussed in this section.

Technology	Deployment to 2020 p.a.	Installations by 2020	Deployment 2020-2030 p.a.	Installations by 2030
Heat pumps	3,800	18,000	10,000-15,000	105,000-150,000
DHN	-	30 DHNs (of 1,000 homes)	-	-
Biomass (industrial)	260	1,300	300	1,500
Biomass (commercial and public sector)	2,200	11,000	3,000	15,000
Solar thermal	<100	<500	<100	<1500

Table 3.2. Possible Scottish deployment rates of new systems and total number of new installations of low carbon heat technologies to 2020 and 2030, based on DECC and industry body analysis.

3.3 Individual low carbon heat technology breakdown

This section provides a 1-page summary of the following technologies from a Scottish perspective in terms of deployment practicalities, deployment issues, innovation potential, CO_2 benefit, and relative costs:

- Biomass
- Geothermal
- Solar thermal
- Solar photovoltaics (PV)
- Heat pumps
- Hybrid boilers (conventional boiler plus air source heat pump)
- Renewable gas (biomethane, hydrogen, methanation)
- Smart (electrical) grid
- Heat storage
- District heating

Solid biomass (typically wood products)

Overview: Correctly managed, woodlands are a sustainable resource and it is possible to offset the carbon emissions from burning them against the carbon uptake of the trees during the growth of the crop. Woodfuel provides a potential market for wood residue and arboricultural debris which would otherwise be disposed of at landfill sites. Wood pellet boilers automatically feed the heating system and require little input from the user. Wood chip or logs require more user input but are generally slightly cheaper as the fuel requires less processing to manufacture. Solid biomass fuel costs are typically similar to mains gas prices at around £40-50/MWh. Suitable domestic and non-domestic systems are eligible for RHI.

Practicalities: Relatively straightforward to install on domestic and commercial//industrial properties, although it does require storage space for the biomass which might be a limit on small properties and flats - a communal wood fuel boiler can provide heat to several properties which can alleviate this problem. Scottish studies[11] estimate an indigenous wood fuel resource of 700,000 to 1 million oven dried tonnes per year, which would provide between 1.5 and 3.4 TWh of heat, or up to around 5% of the expected 2020 Scottish heat demand of 60 TWh. Additional biomass can be imported, which increases the carbon footprint from 34 kg to 52 kg CO_2 per MWh, still well below fossil fuel alternatives (220 kg CO_2 per kg for mains gas) and significantly lower than for imported coal (*at least* 410 kg CO_2 per MWh).

Deployment: By far the most popular technology in terms of the registered RHI scheme, with 5,494 small schemes, 567 medium and 29 large non-domestic schemes installed in the UK, with a combined heat capacity of 651 MW, 330 MW and 103 MW respectively. The domestic RHI has not been running long-enough for the statistics to be meaningful. To be eligible for RHI the systems needs to heat a liquid for distributing the heat (i.e. a conventional wet radiator system) - there will be many more log burners installed which are not RHI eligible. Limits to domestic feedstock availability may place an upper limit on total deployment. Most practical for rural estates with own biomass supply.

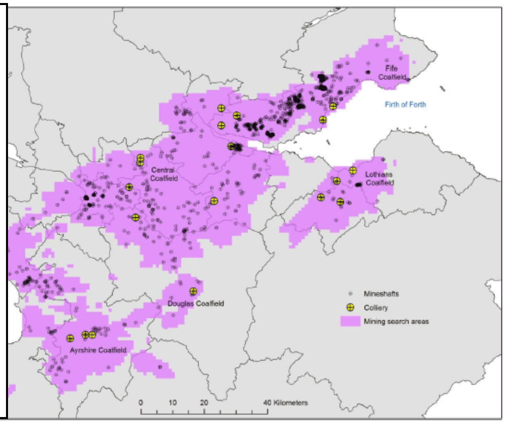
Innovation: Mature technology with limited scope for efficiency improvements in heating systems. SE and the Woodfuel Association are currently (2014) evaluating if indigenous production can be increased, particularly from forest floor residues after forestry clearances.

CO_2 benefits: The Woodfuel Association state biomass has life cycle emissions of between 20 to 80 grams of CO_2 per kWh which is associated with supply chain activity, at least a 90% reduction on fossil fuel alternatives.

Costs: Biomass is a lower cost heating option, fuel costs of £40-50 per MWh rival mains gas prices even without subsidy.

Geothermal

A recent independent study investigated the potential for deep geothermal energy in Scotland and the steps necessary for commercialisation[18]. In Scotland the average temperature of water in former mines is around 17°C (with a general range of 12 to 21°C). Flooded mine workings could be used as a low temperature heat resource by using heat pumps to extract this ambient heat which could then used as the heat source for district heating schemes. It is estimated that some 2.5MW/km^2 could be obtained on average using open-loop ground source heat systems in the mined areas of Scotland. Multiplying this value by the area covered by former mine works gives a very approximate estimate of the maximum accessible heat resource of 12GW, potentially a significant resource. Additional sources of geothermal heat may be found in hot sedimentary aquifers (expected to be mainly found in Central Scotland) or by deep drilling into rocks (typically 3-5km deep) and injecting water.



Practicalities: The geothermal heat resource beneath Scotland can be considered in terms of three main settings: (1) abandoned mine workings (low temperature); (2) hot sedimentary aquifers (low and possibly relatively high temperature); and (3) hot dry rocks (relatively high temperature). Of the three options, abandoned flooded mine-works appear to offer the most accessible and practical source of heat in the short-term.

- Central Scotland has a substantial network of abandoned mines (as shown in purple on the map).
- Aquifers are bodies of permeable rock that can conduct significant quantities of groundwater. The largest and most conductive aquifers generally occur in sedimentary strata, in general, down to depths of around 4km, and most will yield water in the temperature range 20 to 80°C.
- Heat can be extracted from rock at significant depth by injecting water into the hot fractured rock, and extracting the resulting hot water.

Deployment: Two mine water installations exist in Scotland: in Shettleston and Lumphinnans. Both are small schemes, serving less than 20 dwellings, and have been operating since approximately 2000. A much larger-scale scheme has been developed utilising water in abandoned mine workings at Heerlen in the Netherlands, funded by the European Commission, and mine water is used for sustainable heating and cooling within the town.

Innovation: Currently only a handful of pilot schemes have been demonstrated, and therefore significant innovation opportunities exist in terms of site evaluation and exploration, drilling techniques, environmental monitoring techniques, system optimisation and modelling and technology development.

CO_2 benefits: Relatively high input temperatures (15-20°C) mean high heat pump performance factors should be achieved. The low operating energy requirements coupled with the potential to utilise low carbon renewable electricity offer the potential for very low carbon heating.

Costs: Not enough examples to properly quantify costs. There is a significant differential in technological, risk and costs uncertainty between relatively shallow heat-only developments and deeper primarily electricity-generating developments. It is anticipated that experience gained from demonstrator project(s), and progressively deeper schemes will increase developer and investor confidence, reduce costs and thereby encourage development.

Solar thermal (solar water heating)

Overview: Solar water heating systems, also known as solar thermal, use heat from the sun to produce hot water, alongside a heat storage tank, for domestic and non-domestic purposes. A conventional boiler or immersion heater can be used to top-up the hot water temperature when the solar energy does not meet demand. It is an established technology and works alongside the majority of existing heating systems including biomass boilers and heat pumps and requires no change in user behaviour. The Energy Savings Trust state it can provide roughly 50% of a UK domestic property's annual hot water (1-2 MWh per annum, with seasonal variability). Eligible for RHI.

Practicalities: Relatively straightforward to install in properties with existing hot water tank, most suited to south facing roofs, requires only a few m^2 of roof space. Not suitable for properties without the space for a hot water tank and more expensive if a new dual coil hot water tank is required (often existing tanks will have to be replaced with a dual coil tank).

Deployment: Mature UK market with 1,000s sales/year. Not particularly mentioned in the DECC, SG or ENA scenarios, so solar thermal is only expected to play a limited niche role in meeting Scottish/UK heat targets.

Innovation: Solar thermal is a developed market globally. Key future uncertainties: the price of raw components, potential competition with PV due to limited roof space on some properties, and also more favourable financial model for solar PV than solar thermal under current UK Feed in Tariff (FIT) and RHI rates. Potential for mutually increased efficiency and reduce overall Cost of Energy by combining solar thermal and PV into one unit: PV efficiency decreases at higher temperatures, so PV electrical output would be increased by solar thermal lowering the PV panel temperature on sunny days; also, shared installation costs may reduce overall Cost of Energy. Potential for solar thermal to increase heat pump performance by raising input temperatures of heat source. Cost reductions will be small to 2050 - technology is mature and highly commoditised. In terms of providing heat, the technology works, providing 1-2 MWh per annum of domestic hot water, but its Cost of Energy is currently expensive.

CO_2 benefits: The Energy Saving Trust state that for a typical installation on a UK domestic property providing 1800 kWh/year, carbon savings per year compared to fossil fuels are: gas 275kg, coal 610kg, electricity 490kg, oil 350kg, LPG 325kg.

Costs: Small-scale system costs are very high, the most expensive technology at >£300 per MWh for domestic installations. Domestic installation costs about £2-4k and can generate up to about 1.8 MWh heat per year in Scotland, displacing fossil fuels. Note 1.8 MWh of domestic gas costs £75, so the annual saving for an on-mains gas property is £75 on a CAPEX of **at least** £2k, with a payback of **at least** 26 years without RHI. Conversely, large-scale solar farms have reported significantly lower costs, such as £35/MWh in Denmark, making large-scale solar potentially one of the cheapest low carbon heat source[10] - large-scale solar thermal will require a co-located direct heat user or DHN with heat storage facility to operate efficiently. Fuel costs are zero, so the cost savings arise from reduced capital installation costs in comparison to fitting panels and plumbing to individual houses. Installation on new-builds is preferable to avoid retrofitting costs and minimise Cost of Energy.

Solar photovoltaics – for heating

Overview: An appropriately installed 4 kW domestic photovoltaic (PV) system can typically produce of the order of 3.2 MWh of electricity per year in Scotland (source: Energy Saving Trust website). Low-cost commercially available monitoring systems allow automatic monitoring of domestic electricity consumption, and when PV output exceeds the instantaneous domestic consumption the excess electricity can be diverted to a specified appliance, e.g. the hot water cylinder. In the simplest case the hot water can be heated by direct resistive heating, or via a heat pump to realise higher efficiencies. For households largely unoccupied during the day (i.e. with low electrical consumption during the day), this PV system can provide several MWh of hot water throughout the year, particularly in summer but also on days of high pressure in winter; a large water cylinder heated in this way may provide the majority of the annual hot water depending on the specific load for that property.

CO_2: Given the higher carbon content of current UK electricity versus natural gas (470 kg versus 227 kg per MWh), from a carbon reduction viewpoint surplus PV generated electricity should be transmitted to the grid rather than displace gas hot water heating. However, for **off-gas grid** properties (and also as the electricity grid is increasingly decarbonised) domestic PV may be a suitable low carbon option for providing the majority of a domestic property's annual hot water requirements. A conventional oil or LPG boiler or electricity from the grid can provide back-up when required.

Practicalities: Suitable for properties with large south-east to south-west facing roofs. Particularly suitable for properties with existing immersion cylinders, thus avoiding hot water cylinder installation costs.

Deployment: DECC's Feed in Tariff (FIT) sub-regional statistics show that Scotland had 37,187 existing domestic PV installations by the end of 2014 (1.5% of all homes). Any of these properties with space for a hot water cylinder would be suitable. Future PV installations may be encouraged by the possibility of "free" hot water, particularly off gas grid properties.

Innovation: A mature technology which has seen rapid fall in prices in recent years, as reflected by the fall in the FIT from 37.8 p/kWh in 2011 to 12.94 p/kWh in 2015.

CO_2 benefits: Carbon reduction depends on the fuel source being displaced. If the surplus electricity drives a heat pump then the system should realise carbon savings over all alternatives. If using direct resistive heating then carbon savings may not be realised over conventional gas boilers due to the current UK electricity carbon footprint being higher than that of natural gas - increasing decarbonisation of UK electricity will narrow this gap.

Costs: The PV system is primarily installed to provide electricity and is eligible for FIT payments. The additional benefit of several MWhs of annual hot water is achieved for less than £400 if the property already has a hot water cylinder and only requires the monitoring and switching unit.

Heat pumps

Overview: Air Source Heat Pumps (ASHP) absorb heat from the outside air, ground source (GSHP) from pipes buried in the ground, and water source heat pumps (WSHP) from rivers, lochs, aquifers, mine-water and the sea. “To-water” systems distribute heat via a wet central heating system, “to-air” systems produce warm air which is circulated by fans. Heat pumps work much more efficiently at lower output temperatures than gas boilers, making them more suitable for underfloor heating systems or larger radiators (providing lower temperatures over longer periods of time). Ground/water source heat pumps circulate a mixture of water and antifreeze around a loop of pipe, which is buried in the ground or submerged in water. Heat is absorbed into the fluid and then passes through a heat exchanger into the heat pump. The ground/water stays at a fairly constant temperature throughout the year, unlike the air, meaning more uniform seasonal performance for ground/water versions. In all cases, heat is absorbed at low temperatures into a fluid which then passes through a compressor which raises it to a higher temperature. Heat pumps require energy input to drive the pump and compressor, and typically have a Coefficient of Performance (COP) providing 2-5 times more heat output than input energy. Heat pumps are typically powered by electricity but can also be gas powered, offering the potential for additional forms of gas heating on the coldest winter days.

Practicalities: Requires behaviour change to “trickle” heat rather than rapidly heat water and space; best suited to well insulated properties. ASHPs are easier to install than GSHPs which require trenches or pile-driving, but they have lower COPs. Normally a ground loop is laid flat or coiled in trenches about 2m deep, but if there is not enough space a vertical loop can be inserted down into the ground to a depth of up to 100m for a typical domestic home. Heat pump systems typically require an outdoor unit, a water tank and some modifications to the existing system which will not be practical in every property. Electric storage heaters (COP = 1) may be a more practical solution for homes with very small thermal demands or limited space. For large heat demand properties (>18 kWth) a three-phase electrical connection is required. Significant installation process is a key barrier for GSHP.

Deployment: Currently in the UK: ASHP ~12,000/yr, GSHP ~4,000 installs p/yr (source: Delta-EE). The SG’s HGPS scenarios suggest by 2030:

ASHP: 2-8 TWh domestic (100,000-500,000 units) and 0.5-1 TWh non-domestic (depends on size but likely to be 25,000-50,000 units)

GSHP: 0.5-2 TWh (25,000- 100,000 units) and 0.5-1 TWh non-domestic (number of units depends on size, but likely many 1,000s)

Innovation: Mature technologies - no single breakthrough expected however heat exchanger design, compressor efficiency, & new refrigerants are possible improvements. Performance improvements may include system design, installation quality & improved controls. Hybrid ASHP-gas boilers and gas powered heat pumps may offer development opportunities: however gas related emissions still arise, albeit at a reduced level to conventional boilers.

CO_2 benefits: >90% carbon reductions longer term (2030+) for electric heat pumps compared to gas boilers, if electricity network is decarbonised.

Costs: The economic proposition for heat pumps is highly dependent on electricity price. Even with a heat pump COP of 3, higher installation costs and lower gas prices (domestically, electricity is over 3 times the gas unit price) currently result in domestic Costs of Energy which are ~50% (ASHPs) to ~100% (GSHPs) higher than for mains gas boilers. Future smart metering may allow aggregated users to utilise excess intermittents at lower fuel costs.

Note on heat pump performance factors

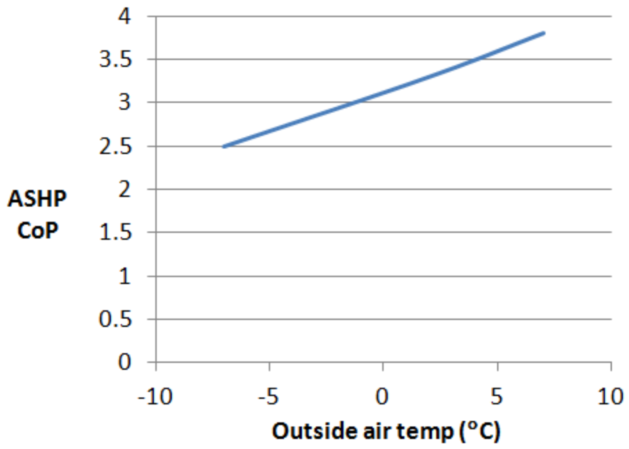
Lower performance of ASHPs in colder weather

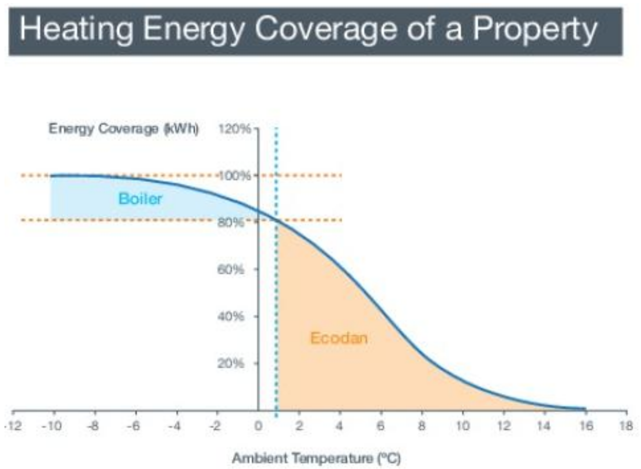
The amount of work (or energy) required to raise the temperature of the heat pump output to a set room temperature depends on the input temperature.

The Coefficient of Performance (COP) is the ratio heat supplied to (or removed from) the reservoir versus the work done.

The right-hand plot shows how an ASHP's CoP decreases as the outside air temperature decreases, from a COP of ~3.5 at 7°C to a COP of ~2.5 at -7°C (source: Worcester-Bosch).

In contrast, GSHPs encounter a relatively constant ground temperature throughout the year.





Hybrid boiler

A hybrid boiler can be optimised to use the ASHP when the outside temperature is warm enough to realise a high enough CoP to make it cheaper to run than the conventional boiler.

Additionally, a smart-enabled heating system could take advantage of cheaper off-peak electricity tariffs irrespective of temperature.

Image source: Mitsubishi Ecodan

The Energy Saving Trust ran year-long UK trials on properties heated only by a heat pump system with the following results:

GSHP: average CoP = 2.82 (21 trial systems)
ASHP: average CoP = 2.45 (15 trial systems)

Hybrid boiler (gas + ASHP)

Overview: Hybrid heat pump systems combine an outdoor air source electric heat pump with an indoor gas boiler. The aim is that the heat pump will operate most of the time, with the gas boiler as an additional backup heat source on the coldest days and nights of the year. The continuous low-grade heat supply from the heat pump is intended to maintain an adequate ambient temperature, with the backup security of the existing natural gas network when required. Hybrid boilers feature heavily in both DECC and Scottish Government's scenarios towards 2025-2030 and are complementary with the decarbonisation of the electrical grid, the roll-out of smart metering and the smart grid. The reduced gas demand resulting from heat demand shifting to the electrical domain via heat pumps allows for higher penetrations of renewable gas in the gas grid. Also, being connected to the gas grid provides security of heat supply on the coldest winter days.

Practicalities: Additional disruption can be minimised if the hybrid boiler is installed when the current boiler is being upgraded. On new builds the installation of a wet radiator system and a gas boiler are common procedures, with only the additional work of fitting the heat pump required. The heat pump has to be situated outside either wall or ground mounted, so installation should be suitable for most building types including flats (with the possible exception of listed buildings). A hybrid gas boiler is most suitable for the 80% of domestic properties connected to the gas mains.

Deployment: DECC have suggested all domestic boilers being replaced by hybrid boilers in the UK by 2030, so the market is potentially 1.8 million homes in Scotland (80% of the 2.3 million domestic properties) and 10 times that number across the UK. ASHPs do not typically provide enough heat for poorly insulated or large properties so other solutions may be required for these buildings.

Innovation: Innovation potential exists in the design and manufacture of integrating existing heat pumps and boilers into this new form of heating. More advanced innovation includes: smart-enabling and optimising the overall system performance, and optimising the installation process to minimise disruption as much as possible.

CO_2 benefit: if the UK electricity grid has largely decarbonised by 2030, then hybrid boilers can realise better than 90% carbon savings when operating in heat pump mode only without the gas boiler. Trials will be required to determine typical operating performance in Scotland (an SE opportunity) – in particular the amount of heat demand required by the gas boiler for various property types.

Costs: ASHPs have typical UK COPs of 2.7[32], although this figure is for stand-alone ASHPs running as the sole heat provider, whereas the heat pump on the hybrid boiler will more typically run when the outside temperature is above freezing so the COP for the hybrid boiler's heat pump should be higher. A flexible smart enabled tariff, with reduced ASHP at peak times, could provide parity between ASHP running costs and mains gas costs.

Renewable gas (biomethane, hydrogen, methanation)

Overview. The UK has a mature gas network, supplying around 80% of Scotland's domestic properties, and around 60% of Scotland's total heat supply across all sectors. Renewable gas injection offers a route to decarbonising the UK heat network, and requires no change in technology or behaviour by the end-user. **Biomethane** can be generated from the cleaned outputs (methane and CO_2) from Anaerobic Digestion (AD) of feedstocks which otherwise are typically considered waste (manure, sewage, crop residues, food waste, MSW). The resulting methane can be upgraded and injected to the gas grid, while the CO_2 can be used (e.g. by the food industry) or stored (CCS). **Hydrogen** can be cleanly generated by the hydrolysis of water using decarbonised electricity. **Methanation** is the use of chemical or biological processes to create methane by combining CO_2 and hydrogen from a range of sources (e.g. H_2 from hydrolysis, CO_2 from AD).

Practicalities: Finite feedstocks means that the UK could in theory produce around 140 TWh p.a. of biomethane (which equates to ~15% of current UK consumption). Hydrogen is currently limited by UK regulations to only 0.3% by volume, although studies suggest 10-20% by volume could be possible without implications for end-users[43]. In theory methanation production is only limited by the availability of decarbonised electricity, and the economics of this solution when compared to other energy options. Instead of upgrading biogas to biomethane, the biogas from AD plants is often burnt to produce electricity and heat in a CHP plant - however, if a suitable local heat load does not exist to efficiently utilise the CHP heat output then biomethane injection to the grid may be more appropriate depending on issues including proximity to the gas grid.

Deployment: Several small-scale biomethane plants have been built in the UK, with one plant commissioned in Scotland (Coupar Angus, December 2014). Various hydrogen injection studies have been explored in Scotland and the UK[44], with a £10m demonstrator proposed by Scotia Gas Networks for part of the Scottish network or one of the discrete Scottish gas networks, although this was withdrawn. Methanation plants have been built in Germany and Denmark, but to date only studies have been performed in the UK[44]. National Grid and the Energy Networks Association separately estimate that about 140 TWh of biomethane could be produced in the UK, limited by the finite availability of feedstocks. This could replace about 15% of today's 970 TWh UK gas demand, or up to 25% of the predicted UK 2050 demand of 550 TWh. Hydrogen deployment is uncertain, and DECC say further analysis and modelling is required. Discussion of the potential role for methanation is notably absent from the scenarios.

Innovation: Breakthroughs in electrolyser costs and performance would strengthen the economic argument for hydrogen and methanation projects.

CO_2 benefit: The EU details GHG calculations for biomethane from various feedstocks[45]. Notably, biogas from AD of manure avoids methane emissions, with GHG savings of over 100% if the methane is subsequently burnt as a fuel to emit CO_2. The EU considers it good practice for existing bioenergy installations to achieve GHG savings of at least 70%. The EU note that GHG targets for biomethane may be set post-2020.

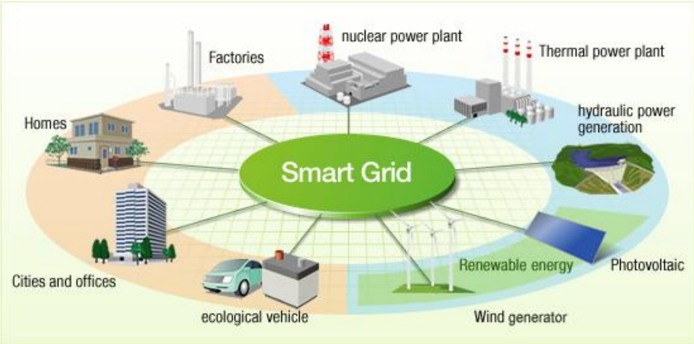
Costs: Biomethane to grid ~£80/MWh for current few MW capacity plants, larger plants will see cost reductions (wholesale natural gas ~£25/MWh).

Smart Grid (enabling technology for low carbon heat)

Overview

A low carbon future in Europe will require a more dynamic electricity system. A decarbonised grid - with high penetration of intermittent wind and inflexible nuclear – will require balancing of generation and demand. Demand may need to be shaped to meet available generation and the energy system of the future will have to deal with increasing supply and demand imbalances and increased congestion on the distribution grid (in part due to increasing electrification of transport and heat).

There are several ways to shape demand: time of use price signals, home energy management systems, and turning off 'smart' refrigerators and washing machines. However, with their relatively large electrical consumption, heat pumps (and to a lesser extent direct hot water and electrical heating systems) offer attractive opportunities to help match supply and demand and usefully utilise intermittent electricity.



Practicalities: Relatively little user disruption, as operation will be automated after installing smart meter and setting initial parameters. Customer should benefit from lower fuel costs due to optimally using lower tariffs when excess electricity is available and reducing consumption when demand exceeds supply, and also improved efficiency from energy management information and device control. Users may wish to set minimum temperatures for given times of the week irrespective of electricity tariffs – leading to higher costs. Potentially intermittent smart enabled electrical heating will be best suited to well insulated, air tight properties which lose little heat during periods when the heating is not operating.

Deployment: Smart meters due to be installed for every domestic and commercial property in the UK by 2020.

Innovation: Tremendous innovation opportunities on many levels, from individual heating system device and technology development, ICT and sensor developments, through to customer aggregation and business model development.

CO_2 benefit: Heat pump systems with COPs of >2 already have lower carbon emissions than natural gas with the UK's current mix of coal, gas, nuclear and renewable sources[31]. Heat pumps powered by excess renewable electricity would be significantly lower still, with DECC stating onshore wind has a footprint of 20 kg CO_2 per MWh. Direct electrical heating (e.g. hot water storage, storage heaters and direct heating) would realise a carbon reduction of the order of 90% if smart metering ensures the heating only operates using renewable electricity.

Costs: Dependant on future variable tariffs; electrical heating users should benefit from lower tariffs utilising excess electrical production, when compared to properties not operating a smart heating system.

Heat storage

Overview: Heat storage allows the capture of off-peak or off-season energy which would otherwise be lost, for use over a period of hours to months later, at capacities ranging from domestic through to district heating scales. Storage mediums include: water, earth or bedrock accessed with heat exchangers, deep aquifers contained between impermeable strata, lined pits filled with gravel and water, and phase-change materials. Summer heat from solar collectors can be stored inter-seasonally for use in winter (successfully demonstrated in Denmark[10]). Other suitable input sources include heat (or cold) produced from direct electrical elements or heat pumps, ideally with excess renewable electricity. Further heat sources include CHP power plants and waste heat from industrial processes. Domestic storage for hot water is dominated by hot water storage tanks, which are a cheap and mature technology. Typically hot water accounts for of the order of 20% of the domestic heat load and is required all year round, so is a practical use of excess low carbon renewable electricity. Domestic space heat storage is dominated by storage heaters and modern versions have improved in terms of reduced heat loss and usability.

Practicalities: Domestically, fitting hot water storage is straightforward for all properties with sufficient space. Large-scale storage involves pipework and large ground excavations or tank installation, both of which can be intrusive. Large-scale storage requires access to a DHN, so there are only limited sites at present in Scotland.

Deployment: Domestically, unless fitted with a combi-boiler, properties will already have a hot water tank. Retro-fit opportunities may exist for storing hot water when replacing the boiler, such as if fitting a hybrid boiler (either a hot water tank, or phase change material and heat exchanger). Existing hot water storage can be upgraded by fitting solar heating and/or smart enabling the tank which would facilitate the use of excess low carbon electricity for use when required later in the day. There are 2.3 million domestic properties in Scotland so potentially this could be a big opportunity.

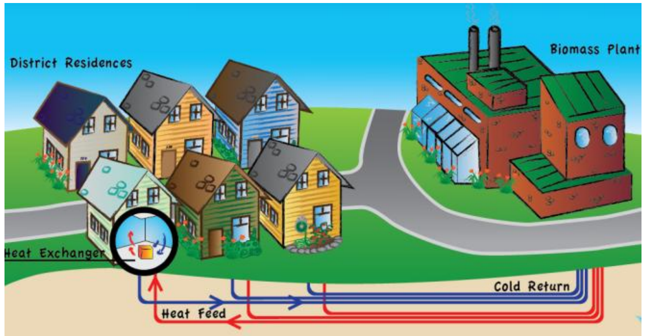
Innovation: Aggregated domestic heat storage in conjunction with smart metering has been identified as a potential Scottish opportunity using excess renewable electricity. Improvements in reducing tank size and increasing capacity, such as using phase change materials instead of water, would increase the attractiveness of heat storage assuming capital costs were favourable.

Carbon savings: Storage of energy which would otherwise be wasted such as industrial waste heat, excess intermittent renewable electricity, and solar hot water all displace the need for heating at the time of demand (saving 220 kg CO_2 per MWh for gas and 480 kg CO_2 per MWh for UK grid electricity).

Costs: Domestically - low CAPEX (few £100s) so a low cost option. Large-scale - medium pay back (few years) from efficiency savings.

District heating

Overview: A District Heating Network (DHN) uses insulated pipes used to deliver heat from the point of generation to an end user. Distribution networks can be up to hundreds of kilometres long, although a few km is more typical. DHNs can provide heat across our cities, smaller communities and industrial areas. DHNs enable heat energy which could not be captured otherwise, and which is currently often wasted such as in power generation or industrial processes, to be harnessed and delivered to a point of use. They allow for economies of scale, as the generation of heat in one large plant can often be more efficient than production in multiple smaller ones. Heat networks can also be supplied with heat from multiple diverse sources, including waste heat, solar thermal, CHP and electric heat pumps.



Practicalities: Ideally there will be a flat heat demand on the DHN throughout the year which means having an end-user such as a swimming pool, industrial process or retirement home can help the economic feasibility of the scheme. Installing the heat pipe network can be hugely disruptive (and costly) if retro-fitting in an urban area, but more practical when installed while building a new housing estate or industrial estate.

Deployment: The Scottish Government has draft targets of 1.5 TWh capacity and 40,000 homes connected to DHNs by 2020. The Scottish Government's modelled future scenarios sees around 1 TWh out of 7 TWh of industrial heat delivered by DHNs by 2030 in the more optimistic scenarios.

Innovation: DHNs are a mature technology in countries such as in Denmark and Sweden. Developing a Scottish supply and installation chain is a possible opportunity.

CO_2 benefit: Carbon savings depend on (1) the heat source for the DHN and (2) the heating system it is replacing. If a gas CHP DHN replaces domestic gas boilers, then after heat pipe losses are included, the overall carbon emissions may be minimal. However the carbon advantage for DHNs is that they allow low grade waste heat, Energy from Waste (EfW), and other heat sources to be captured which could not otherwise be used for heating, and so carbon savings can be significant, especially in the case where it is replacing direct electrical heating. Aberdeen Heat and Power state carbon (and individual fuel bill) savings of 50% for their system which replaced electric heating in tower blocks.

Costs: The cost of retrofitting heat network pipe work in urban areas can be very expensive, DECC quote £0.5-1 million per km, and the cost of connecting each end-user to the network via a Hydraulic Unit Interface (HUI) is of the order of £2k per user. Specific costs vary depending therefore on the heat source, fuel type, heat pipe network length, density of end-users and heat load throughout the year. Work performed for SE by Ricardo-AEA and work done internally by the SE Energy Team estimate a cost of the order of £85-115/MWh for a domestic property on a "typical" DHN[33].

4. CONCLUSIONS AND RECOMMENDATIONS

Gas and petroleum products currently provide 92% of heat generated in Scotland across all domestic, commercial and industrial sectors[4] (gas 61% and oil 31%). Longer term, ***towards 2050***, fossil fuels can only be combusted to supply heat if the resulting carbon emissions are abated through Carbon Capture and Storage (CCS), if the UK is to meet carbon reduction targets of 80%. However, CCS is not compatible with the current widespread use of individual domestic gas boiler heating systems and therefore over the longer term, unabated gas will be gradually phased out as the primary domestic heat source (with DECC indicating a possible 90% reduction in domestic heating by gas by 2050).

Towards 2030, improvements to the energy efficiency of buildings and heat equipment are expected to lead to a 35% reduction in domestic gas demand across the UK. Average domestic gas consumption per household in Scotland has already seen a 28.7% reduction in demand since 2005, and this trend is expected to continue as the housing stock is refreshed. In DECC's model, hybrid gas boilers replace conventional gas boilers as older units are replaced and upgraded, and by 2030 DECC considers that they may be the standard heat source for the ~80% of Scotland's domestic properties connected to the gas grid. This would allow end-users to use domestic heating systems which can operate and provide heat in the same way as current gas boiler systems, but with the introduction of ASHPs which will take advantage of smart metering and low carbon electricity to partially decarbonise heating towards 2030. This will ideally aid acceptance of heat pump performance, leading to further uptake of ASHPs, and to a lesser extent GSHPs, after 2030.

Renewable biomethane from feedstocks traditionally considered waste (e.g. sewage, food waste, animal slurry, and agricultural waste) may provide up to 20-25% of Scotland's 2030 gas heat demand if not used elsewhere (such as for transport or electricity production). Less certain is the role hydrogen could play in the heat sector, and any increased role will be dependent on regulatory changes on the levels of hydrogen permitted for injection to the gas grid, as well as the availability and economics of low carbon electricity to facilitate electrolysis. Methanation (combining CO_2 with H_2) has been omitted from the UK and Scottish scenarios, but in theory the only limit to production of synthetic natural gas is the economic availability of low carbon electricity, making it potentially compatible with Scotland's target of 100% equivalent renewable electricity.

Figure 4.1 captures three key transitions anticipated by one or more scenarios for Scotland's heat sector towards 2025-2030:

1. Domestically, a transition from conventional boilers to hybrid boilers incorporating ASHPs to partially electrify the heat network;
2. An increase in the penetration of renewable gas for the remaining portion of the gas delivered;
3. Where appropriate, transition from individual heat sources to District Heat Networks (DHNs), e.g. dense areas of aggregated social housing.

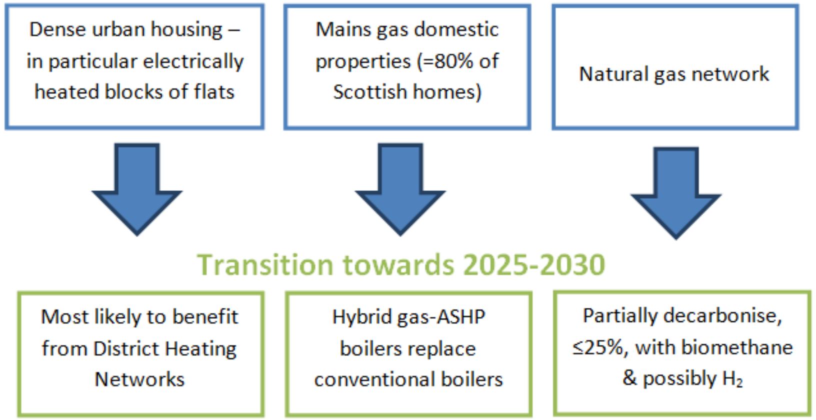


Figure 4.1. Summary of key options which may facilitate Scotland's transition to a low carbon heat sector towards 2025-2030.

Figure 4.2 provides a summary of the key low carbon technologies considered relevant in terms of delivering Scotland's low carbon heat. It summarises and qualitatively compares, for each technology:

1. Cost of Energy;
2. Disruption involved in installation and impact on end-user;
3. Potential penetration levels in the Scottish heat sector;
4. Technology maturity;
5. Scottish capability – research, and commercial supply chain.

Fuel/technology type	Solid biomass	Gas	Gas + electricity	Electricity	Sun	Enabling technologies	
Technology	Wood products	Renewable gas	Hybrid boiler (gas + ASHP)	Heat pumps	Solar thermal	District heating	Energy storage
Cost of Energy (£ per MWh)	Low	Low	Low-Medium	Low-Medium	High	Low	Low
Disruption (upheaval)	Low	Low	Low	Medium	Low	High	Low
Potential penetration	High / Medium	Medium	High	Medium-High	Low	Low-Medium	Low-Medium
Maturity	High	Medium	Low-Medium	Medium	High	Medium	Low / High
Scottish capability / Supply chain	High	Medium	Medium	Medium	Medium	Low - Medium	Low / High

Figure 4.2. Summary of Scotland's key low carbon heat technologies.

Comments on Figure 4.2:

- Wood products: Low cost; relatively straight-forward to implement and run; penetration levels of 5% of total heat demand with indigenous supply, and in theory much higher if feedstocks are imported (emissions still 75% lower than natural gas even for imported biomass); mature supply chain with Scottish pellet manufacturing facilities.
- Renewable gas: Biomethane costs are currently higher than natural gas but predictions are that parity may be possible with larger scale plants in future; no disruption to end-users as completely compatible with existing gas grid; biomethane could supply up to 25% of future gas demand, limited by finite feedstocks; a few pilots plants exist in the UK with more being planned (1 built and 1 under construction in Scotland).
- Hybrid boilers: Operating costs depend on ratio of gas to electricity fuel consumption and future smart enabled tariffs but are expected to be largely comparable to current gas boilers; no significant extra disruption compared to standard boiler installation; potentially suitable for 1.8 million gas-grid connected homes in Scotland; opportunities for R&D, manufacture and installation.
- Heat pumps: Relatively high installation costs, especially GSHPs; ASHPs can be fitted in around a day, GSHPs require substantial groundwork; 100,000 units may be installed by 2030; mature technology although limited deployment in Scotland and limited supply chain.
- Solar thermal: Although an effective method of generating low carbon heat, overall energy costs are very high due to installation costs; low disruption, installation takes about a day; mature technology with existing Scottish supply chain. A step-reduction in installation costs, or increased regulation/incentives, could make it an attractive option but otherwise uptake will be limited.
- District heating: Once installed a well designed system will provide low cost energy to the end-user; installation can be extremely invasive in urban areas (reduced if installed while building new estates) – most cost effective when replacing electrical heating (in which case individual properties will require installation of wet systems; potential penetration of up the order of 10% of total heat demand as only cost effective in areas of dense end-users; mature technology in other countries but limited supply chain in Scotland.
- Energy storage: Low cost of energy – large-scale storage can improve efficiencies of DHNs; low disruption both domestically (a day to install) and large-scale (single site with no public access); wide-spread deployment domestically, limited penetration of large-scale storage; domestic hot water mature but only couple of large-scale prototypes.

To conclude, the heat challenge cannot be fully solved in isolation from the electricity question, the storage question and the infrastructure question – the heat sector is inextricably linked to the overall energy system. The coming decade will be a preparatory period, with many different technologies being trialled and evaluated in preparation for mass deployment. Given that Scotland and the UK has a mature gas network connected to ~80% of domestic properties, natural gas sourced heating may be necessary to meet peak heat demand on the coldest winter days.

Recommendations for the Scottish low carbon heat sector:

- **Renewable gas**: Renewable biomethane gas from wastes and residues satisfies many targets: reducing waste, increasing national energy security and substantially reducing greenhouse gas emissions (this can be over 100% depending on feedstock). SE should look to support activity in the biomethane sector in Scotland.
- **Hybrid gas boilers**: SE should consider (1) supporting a pilot scheme to evaluate performance of aggregated hybrid boilers in tandem with smart metering, and (2) subsequently supporting the supply chain for widespread uptake of hybrid gas boilers if successful. Early adoption in Scotland may lead to first mover advantage and the opportunity to support manufacture in Scotland. Tens of millions of units will need to be deployed across the UK under DECC scenarios. Scotland has some relevant manufacturing capability, for example Mitsubishi Electric Air-Conditioning Europe in Livingston manufactures several hundred thousand air conditioning units annually for export and has an R&D facility which develops air to water heat pumps.
- **Large-scale heat pump demonstrator** project in Scotland. The Scottish company Star Refrigeration has successfully demonstrated a 15 MW WSHP system in a fjord in Norway which has a COP>3 and provides 90°C output to around 6,000 properties via a heat network. There are existing heat networks in close proximity of rivers and flooded mine works which would provide ideal test sites, or alternatively a new heat network could be developed next to deep sea/loch site.
- **Large-scale heat energy storage demonstrator** project(s), such as a large underground water store (e.g. 70,000m^3 pit heat storage in Marstal, Denmark). Heat storage allows more efficient operation of heat networks and can accept any available heat source (e.g. solar, waste heat, CHP) for use at times of higher demand. CHP for example may generate electricity at times of low heat demand – this heat could be usefully stored in a large-scale heat storage system rather than simply being wasted, and could also be augmented with local waste heat sources. There may be benefits in retro-fitting an existing heat network with an energy storage system to allow analysis of system performance improvements with storage.
- **A large-scale solar farm** in tandem with a large-scale heat storage system, would demonstrate seasonal renewable heating from summer to autumn for the first time in Scotland. Solar farms have been successfully demonstrated in northern Europe (e.g. Marstal is one of the many installed in Denmark) with 20 year energy costs of around £35/MWh, i.e. showing parity with mains gas in the UK[10] Whilst domestic solar thermal is very expensive, dominated by installation costs, large scale farms can benefit from economies of scale to realise low energy costs and should be considered for development for both economic and carbon saving reasons.
- **Cost of Energy**. Heat system costs for low carbon heat technologies are typically higher than for natural gas, although it is predicted that biomass and biomethane in particular may achieve parity. DECC's RHI ambitions are to incentivise the addition low carbon heat capacity to meet the Scottish 11% renewable heat target. Potential areas for development to help stimulate the uptake of low carbon heat technologies in Scotland include projects utilising co-product waste heat and projects developing geothermal resources which offer long-term cost reduction opportunities for DHNs.

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Appendix A: ECONOMIC IMPACTS

Ricardo AEA were commissioned by SE[44] to evaluate the economic impacts for Scotland for three specific areas of low carbon heat: renewable gas, energy storage and electrification of heat using smart metering.

A.1 Renewable Gas: Economic Impacts

This section estimates the potential employment and GVA impacts of renewable gas in Scotland by 2020, focusing on biomethane and hydrogen production and injection to the gas grid. The methanation of biogas is not included in this analysis as it is still in very early stages of development and cost data is scarce.

Direct employment impacts are assessed following a simple methodology:

- Estimate capital and operating costs for an average facility under each technology drawing from publicly available research and existing projects.
- Estimate the potential number of facilities in Scotland and derive the total construction and operational expenditure from this investment.
- Estimate gross direct construction and permanent jobs from this expenditure using standard turnover to job ratios.

The net direct impacts on Scotland's labour force and indirect impacts on the supply chain and the local community cannot be quantified without looking at specific examples and collecting more data. However, qualitative analysis drawing from literature provides some information on the type and scale of impacts which may be expected, in particular in terms of the range of sectors which may benefit.

This assessment only provides high level figures for each technology's possible impacts. It should only be seen as an indication of scale under given assumptions. In order to deliver a robust assessment, much more detailed data would be needed on the likely mix of facilities in terms of size and scenarios would need to be built to explore their deployment over time, linked to Scotland's energy market.

Cost assumptions

The unit cost assumptions for a biomethane to grid and a hydrogen to grid facility are presented in Table A.1.

Capital costs for biomethane to grid include: digester, clean-up and upgrading, boiler, biomethane injection and metering. For the purpose of this assessment, simple cost assumptions are made for one reference facility. In the next section, this is then multiplied by the number of such facilities which could be supported in Scotland in order to produce a total capital investment figure.

Capital costs for hydrogen injection include: the electrolyser, the hydrogen store and the gas and electricity grid interfaces. Apart from the power grid interfaces these are new systems, not in volume manufacture. The cost of electrical grid connection will vary by site. These factors mean that the level of uncertainty over the costs of hydrogen injection are much higher than the uncertainties over the costs of biomethane.

The cost information found will not reflect the variability in the site development / pre-development costs which can be significant. Operating costs include: maintenance, electricity, labour, insurance, landfill.

	Biomethane	Hydrogen
Capacity	5MW (gas)	1 MW
Unit capital costs (£ million)	13.2	1.9
Operating costs (£k/year)	1,960	32

Table A.1. Capacity and cost assumption per technology, source: DECC (2014) and ITM Power.

Direct economic impacts

In Ricardo-AEA's analysis[44], there is a significant growth potential for biomethane and hydrogen to grid. This section provides initial and high level estimates of what this potential might represent in terms of expenditure, employment and gross value added during both the construction and operational phases.

Biomethane is a growing market in the UK and Europe generally and significant growth is expected over the next decades. Scotia Gas Networks indicated that a number of biomethane plants had approached them for connections in Scotland. This is expected to continue. For 2015 it is assumed 2 biomethane plants in Scotland (Coupar Angus + one other) and an arbitrary assumption of a total of 15 biomethane plants in Scotland by 2020.

Hydrogen is an emerging market in Europe (mostly in Germany) but has not yet started to develop in the UK. The ITM Power study sets out some outline proposals for a UK pilot but no funds have been committed to this.

Based on the estimated number of facilities by 2020 and the unit costs presented above, total expenditure for both biomethane and hydrogen by 2020 is calculated in Table A.2. From this, it is then possible to derive gross direct construction jobs (from capital investment) and permanent jobs (from operational costs) supported by this expenditure. These in turn are used as the basis to estimate GVA impacts on Scotland. More specifically:

- Construction job years are estimated by dividing capital costs by construction output per job (in Great Britain as data was not found at Scotland level).
- Full time equivalent construction jobs are then estimated by applying a standard 10 man-years to 1 permanent job ratio.
- Operational jobs are estimated by dividing operational costs by overall output per job in the UK.
- Finally, GVA per construction job and GVA per job in Scotland are applied to construction and operational jobs respectively in order to estimate the GVA impact of these investments.

	Biomethane	Hydrogen
Potential no. facilities by 2020 in Scotland	15	10
Total capital expenditure (£m)	£186	£15.15
Total construction jobs	337	27
Total GVA during construction	6.7	0.5
Total operating expenditure per year (£m/yr)	29.4	0.27
Total operational jobs	911.3	8.4
Total GVA per year during operation	18.2	0.17

Table A.2. Potential expenditure and jobs from renewable gas technology.

A.2 Heat Storage: Economic Impacts

This section provides initial and high level estimates of what the potential for heat storage in Scotland might represent in terms of expenditure, employment and gross value added during both the construction and operational phases.

Based on the potential number of facilities and the unit costs presented in the previous section, total expenditure for heat storage is calculated in Table A.3 and Table A.4 as well as employment and GVA impacts using the same method as in Section A.1.

	No. facilities	Total capital expenditure (£m)	Total construction jobs	Total GVA during construction (£m)
Tank storage – domestic	385,000	496	897	17.9
Tank storage – commercial	6,200	34	61	1.2
Cavern storage	0	0	0	0.0
Pit storage	3	2	3	0.1
Aquifer Thermal Energy Storage	3	18	32	0.6
Boreholes	20	10	18	0.4
Electric resistance	37,000	19	34	0.7

*Table A.3. Investment, employment and GVA potential from **construction** of heat storage facilities in Scotland by 2020.*

	No. facilities	Total operating expenditure (£m / year)	Total permanent jobs	Total GVA during operation (£m)
Tank storage – domestic	385,000	13.2	409	8.2
Tank storage – commercial	6,200	0.9	28	0.6
Cavern storage	0	0.0	0	0.0
Pit storage	3	0.1	3	0.1
Aquifer Thermal Energy Storage	3	1.8	55	1.1
Boreholes	20	0.5	15	0.3
Electric resistance	37,000	1.0	30	0.6

*Table A.4. Investment, employment and GVA potential from **operation** of heat storage facilities in Scotland by 2020.*

A full economic assessment would need to explore the proportion of these construction and operational jobs which would leak outside of Scotland or result from a displacement of activity from other parts of the country in order to determine the net new number of jobs resulting from this new investment in biomethane and hydrogen to grid by 2020.

While data is not available to do this at this stage, Ricardo-AEA believe it is likely that construction jobs would largely benefit the local Scottish workforce – unless it mostly requires specialist skills - as would operational jobs so leakage would probably be quite small. As for displacement, it is difficult at this point to determine whether investment in heat storage basically replaces other forms of investment in Scotland.

Appendix B: HGPS SCENARIO PLOTS

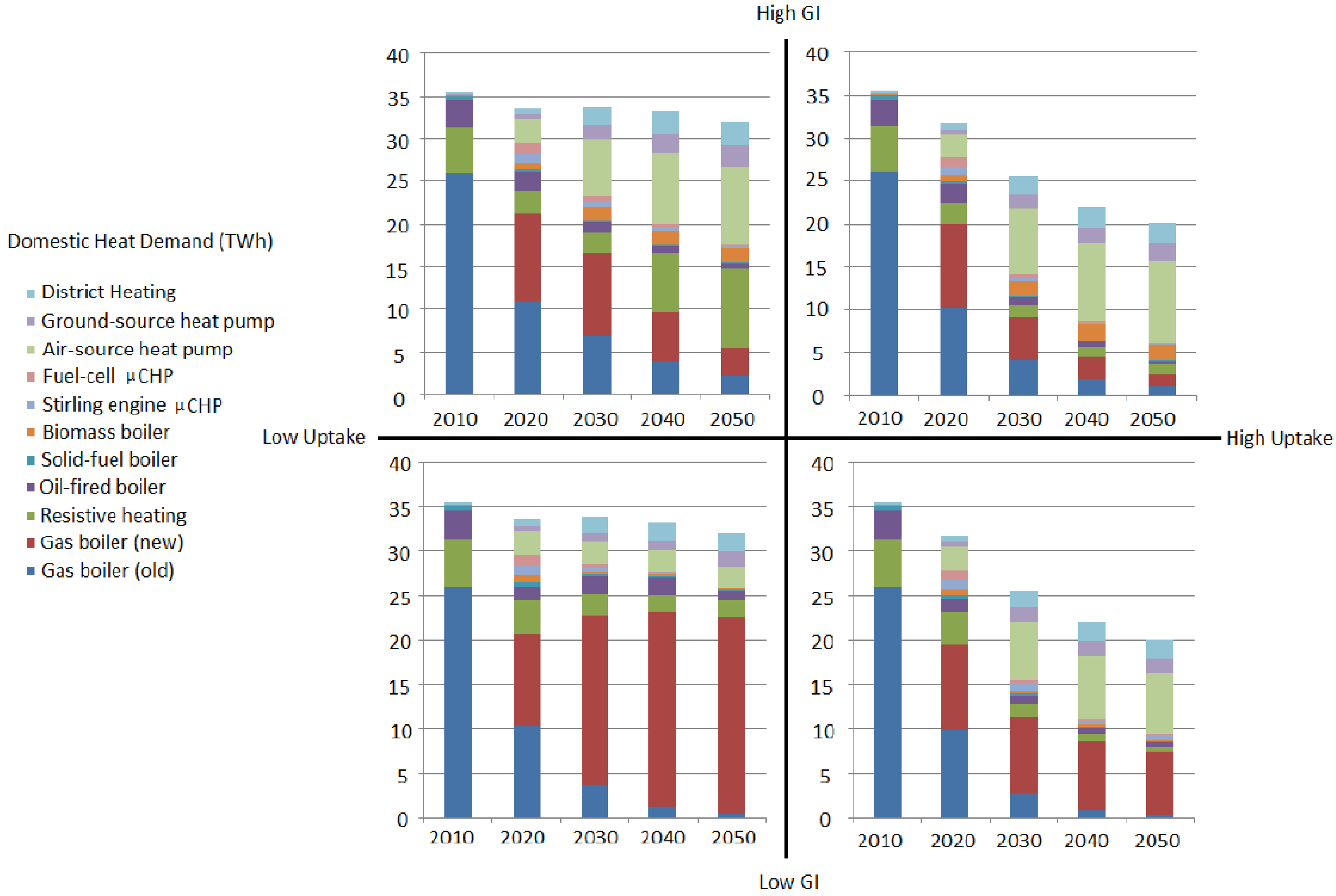

Figure B1. Scottish Government's domestic annual projected heat demand (TWh) to 2050, based on 4 different Uptake and Government Intervention (GI).

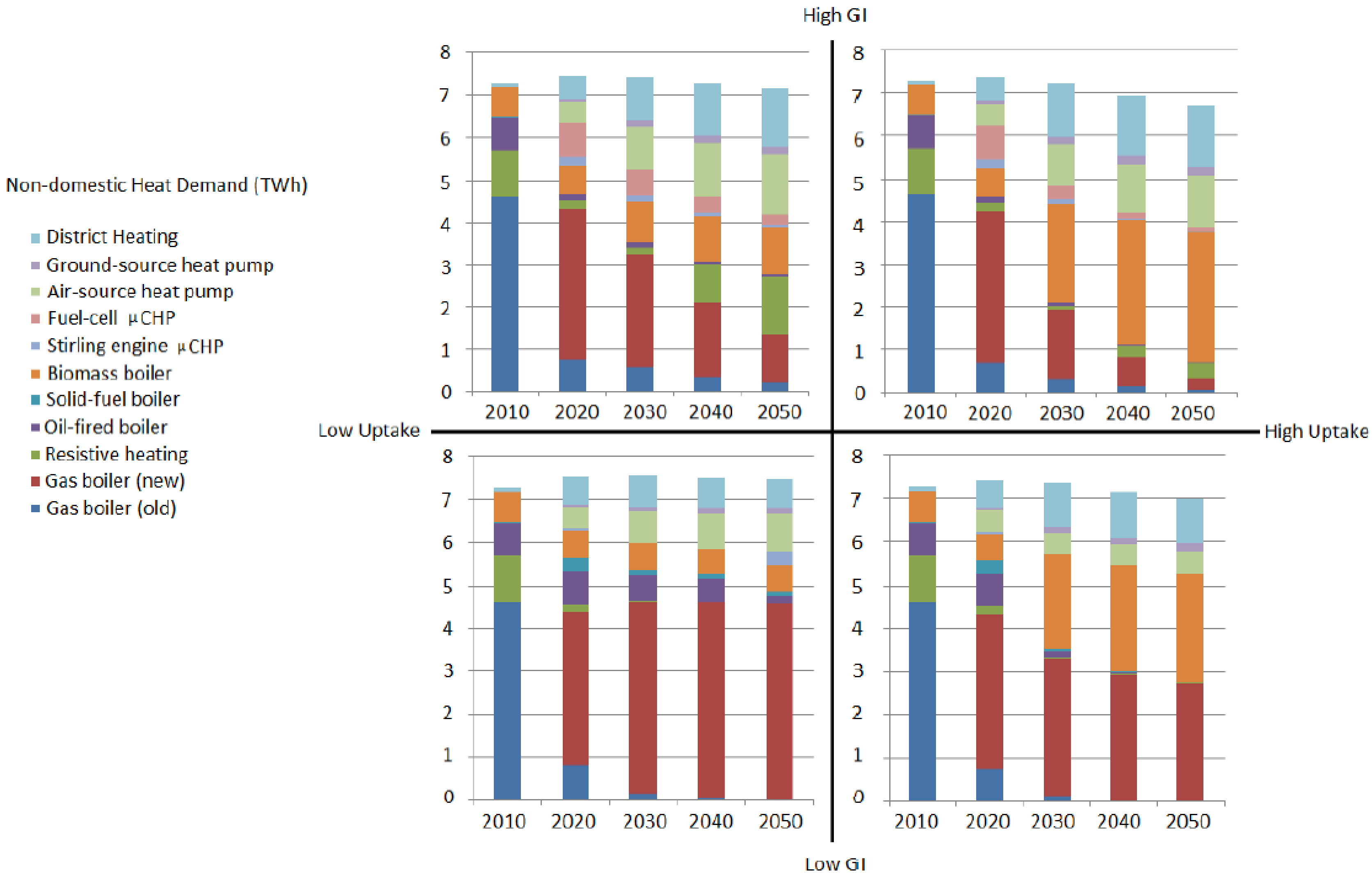

Figure B2. Scottish Government's non-domestic annual projected heat demand (TWh) to 2050, based on 4 different Uptake and Government Intervention (GI).