THE IMPACT OF FUTURE HEAT DEMAND PATHWAYS ON THE ECONOMICS OF LOW CARBON HEATING SYSTEMS

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***Abstract* - The demand for heat will have a fundamental influence on all the assets required from supply to delivery through to end-user consumption. Thus it is important to improve our understanding of heat demand and how it might change in the future as it will have a direct impact on the economics of low carbon heating systems such as heat pumps and district heat networks. To address this, a model was constructed which synthesises half hourly heat demand from actual data where available. The analysis presented in the paper uses the DECC 2050 Pathways with the focus on national peak heat demand and the implications for electricity demand. The results from this model are then used to explore the economics of heat decarbonisation with a transition scenario to 2030 followed by a decarbonisation scenario to 2050.**

Keywords: heat, demand, heat pumps, district heat, decarbonisation, low carbon heating, energy economics

1 INTRODUCTION

The demand for heat[1] will have a fundamental influence on all the assets required from supply to delivery through to end-user consumption. Heat demand forecasts are frequently presented annualised and although this is helpful for macro-economic analysis, without further refinement it is not possible to determine the assets required to meet short term variations in heat demand. For example, electrification of heat will have a direct impact on peak electricity and the capacity of the assets to meet this demand.

National heat demand modelling based on building simulation software is computing intensive, requires large amounts of data and incorporates a number of assumptions such as heating control settings and consumer behaviour. These can lead to errors when aggregated on a large-scale. Such models if based on typical day data can substantially underestimate peak demand. Calibrating these models to actual data is desirable but not possible as national heat demand data is not available other than in annualised format for heat consumption, e.g. gas, oil, solid fuels, etc., from DECC [1].

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

The first part of this paper describes a heat demand model and presents some results based on the DECC 2050 Pathways [2] for heat. The second part examines the economics of low carbon heating systems. A transition scenario to 2030 is first examined followed by a decarbonisation scenario to 2050. Finally the paper introduces an integrated heat and electricity model for further work which will examine the operational performance of the system.

[1] For the purposes of this report heat demand only includes low grade heat for space and water heating for commercial and domestic premises.

PART 1 – HEAT DEMAND

2 HEAT DEMAND MODEL

A representation of the model is shown in Figure 1.

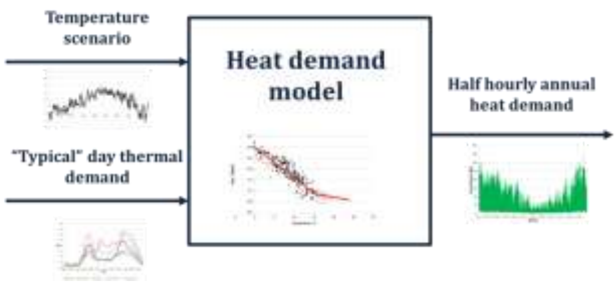

Figure 1 - Heat demand model

The demand for space heating is predominantly determined by external temperature, although there are other factors such as solar gain and wind chill [3]. Currently gas meets nearly 80% of UK heat demand, thus it is the good source of data from which to evaluate the relationship between heat demand and external temperature. Daily NTS (National Transmissions System) demand data are available from National Grid plc [4] and includes daily temperatures. These data include all gas demand, refer to Figure 2, and so gas for commercial and domestic space and water heating was extracted using data from DECC [1] to give daily demand data at NTS.

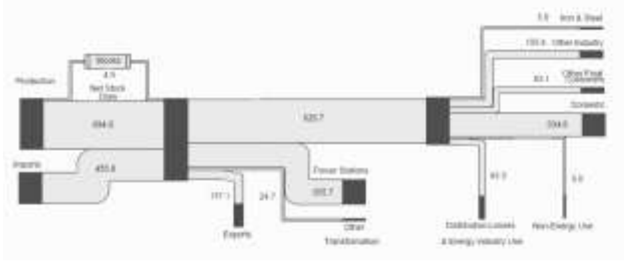

Figure 2 - Natural gas flow chart 2009 (TWh) [1]

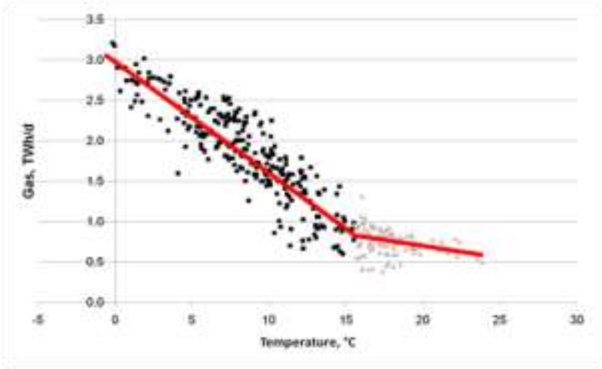

Figure 3 – Scatter graph of commercial and domestic daily gas demand against temperature – 2003

Gas demand is negatively correlated with external temperature [3]. This is illustrated in Figure 3 which is a scatter graph of commercial and domestic space and water heating gas demand against daily temperature. In the UK the cut-off temperature for space heating is 15.5°C. Hence above that temperature gas demand is predominantly for water heating.

A two stage linear regression model was constructed represented by the red line in Figure 3. This was repeated for each year for which actual gas demand data is available from [4], i.e. from 1998 to 2010, and gas duration and daily data derived using the regression models and compared with actual data. National Grid plc uses a similar approach for the production of gas demand forecasts. However, the regression is based upon a Composite Weather Variable (CWV) which includes other factors in addition to temperature such as wind chill, cold weather upturn and warm weather cut-off [3]. As a result the CWV is a better predictor of gas demand.

Table 1 displays the results for the three temperature scenarios described later in this paper. Below the space heating cut-off (15.5°C) the slope is similar for each year but the intercept is lower for 2010 than 2002 and 2003. An explanation for this might be due to a reduction in national gas consumption as a result of improvements in housing insulation and gas appliance efficiency [6]. All three sets of linear regressions have high R^2 which indicates how well the variability in data is accounted for by the models.

Year and temperature		Space heating cut- off <15.5°C	>15.5°C
	Slope	-0.15	-0.05
2002 "NORMAL"	Intercept	3.11	1.57
	R^2	0.88	0.11
	Slope	-0.14	-0.03
2003 "MILD"	Intercept	3.03	1.23
	R^2	0.79	0.10
	Slope	-0.14	-0.08
2010 "COLD"	Intercept	2.57	1.91
	R^2	0.88	0.08

Table 1 – Gas and temperature linear regression models

However, this is not the case for when temperatures are above the heating cut-off (15.5°C), as these have lower values of R^2 which indicate a much weaker relationship between gas consumption and temperature. This is because most of the gas consumption is for domestic hot water which is less affected by temperature.

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

Year and temperature	Regression model 2002	2003	2010
2002 "NORMAL"	98%	98%	97%
2003 "MILD"	97%	97%	97%
2010 "COLD"	97%	97%	97%

Table 2 - Correlation of gas demand with regression model

Figure 4 shows the comparison of "Actual" with "Derived" (from the regression model) for the duration curve and Figure 5 shows the comparison with daily annual demand. Visual inspection of both figures shows a reasonable match between "Actual" and "Derived", with an overall correlation of 97% and above for the daily annual demand. As expected the model's performance is better at higher demands, i.e. below space heating cut-off temperature.

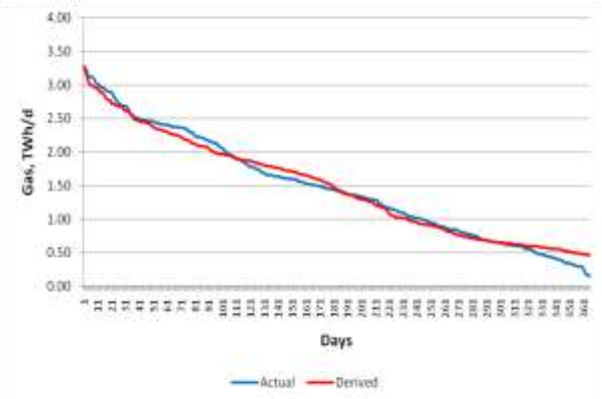

Figure 4 - "Actual" versus "Derived" gas annual duration curve

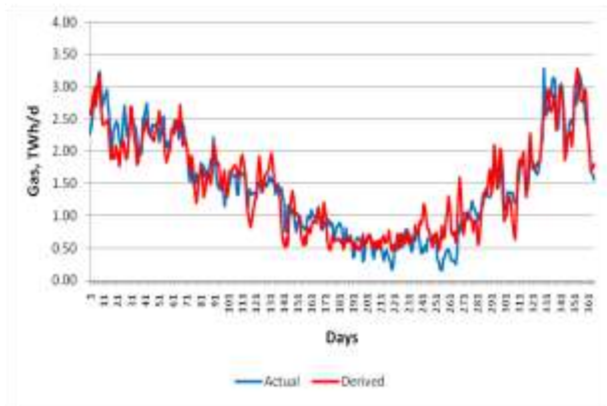

Figure 5 – "Actual" versus "Derived" daily gas demand

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

Annual external temperature scenarios

Energy demand is frequently normalised or temperature corrected as temperature has a dominant influence on consumption. For example, National Grid plc calculates seasonal normal gas demand based on the average weather from October 1987 to September 2004 [3], although this has recently been revised to include an adjustment to compensate for the effect of UK climate warming [7]. However, other methods may be used. For example DECC temperature corrects energy consumption based on the average from 1971 to 2000 [8]. As a consequence it was considered necessary to construct temperature scenarios so that the impact of temperature on heat demand can be evaluated.

The gas demand data for the years 1998 to 2010 [4] also include national average temperature data. Heating degree day[2] analysis using 15.5°C as the cut off for heating is shown in Figure 6. It can be seen that 2002 had the lowest and 2010 had the highest heating degree day and were subsequently classified as “Mild” and “Cold” respectively. The closest to Seasonal Normal Temperature based on National Grid’s definition [3] is 2003 and was classified as “Normal”.

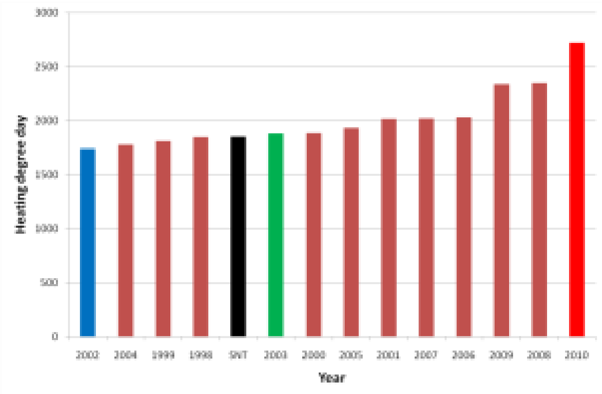

Figure 6 - Heating degree days 1998-2010 (15.5°C cut off)

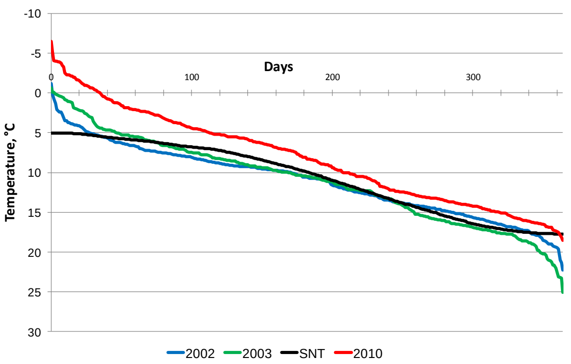

Figure 7 - UK daily temperature annual duration curves

In Figure 7 the corresponding daily temperature duration curves are shown. It can be seen that 2010 was noticeably colder than other years with peak cold temperature several degrees lower. The years 2002 and 2003 had similar peak cold temperatures but 2002 had slighter higher temperatures during the heating period, i.e. below 15.5°C. Also shown is the Seasonal Normal Temperature duration curve. It can be seen that this substantially underestimates peak cold temperatures and so demand modelling that uses typical days based on SNT must be used with caution.

[2] Heating degree day is a measure of the demand for space heating and is the number of degrees the daily temperature is below the threshold or cut-off temperature [3].

Heat demand profiles

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

Initially heat profile data were obtained by modelling different types of buildings along with assumptions on hot water consumption [9]. The main problem with this approach is that assumptions also had to be made in terms of other influencing factors such as occupancy behaviour, timer settings, thermostat settings including setback settings, individual radiator settings, etc. These assumptions are extremely important as they determine the level of diversity in heat demand and, in particular, the resultant Peak Coincident Factor (PCF) which will have a direct impact on the assets required to meet peak heat demand. For example a PCF of 50% means that the sum of the peak heat demand for each building can be reduced by 50% due to diversity. It was therefore considered important to use actual heat demand data if possible.

In 2007 the Carbon Trust published its interim report on its Micro-CHP Accelerator project [10]. The project as described by the Carbon Trust involved *“a major field trial of 87 Micro-CHP units in both domestic and small commercial environments as well as a corresponding field trial of 27 condensing system boiler installations to provide as a relevant baseline against which to compare Micro-CHP performance. The relative performance of these technologies is also being compared directly under controlled laboratory conditions.”*. Importantly *“an extremely rigorous methodology to ensure high quality data capture and to allow robust, independent assessments to be made. At each site up to 20 data parameters are measured at five-minute intervals throughout each day and around 33,000 days of system operation have been analysed so far.”*. These data included heat data.

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

- 81 domestic buildings constructed from 1650 to 2006 and comprising:
    - 52 Micro-CHP sites (11 kW_{th} to 13 kW_{th})
    - 19 Condensing boiler sites (20 kW_{th} to 30 kW_{th})
- Located in the Midlands, Northern Ireland, North West and East England.
- Comprising detached, semi-detached and terrace buildings.
- Data collected over the period from October 2006 to March 2007 at 5 minute intervals.

The heat data was converted from 5 minute to 30 minute intervals and then aggregated into weekday and weekend daily profiles. These are shown in Figure 8 and Figure 9 for sites with micro CHP and condensing boilers respectively. The following observations are made:

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

The figures also display the maximum diversified demand which is ~5kWth for the Micro-CHP sites and ~7kWth for the condensing boiler sites.

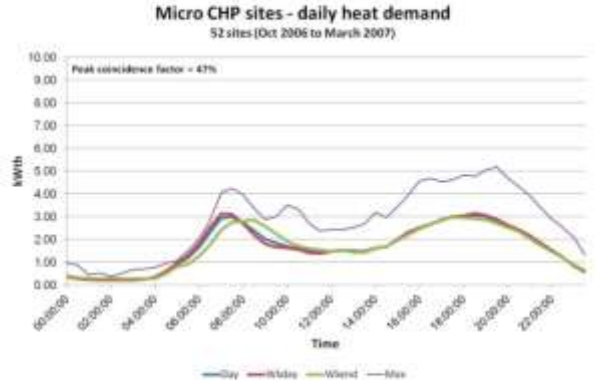

Figure 8 – Micro CHP daily heat demand

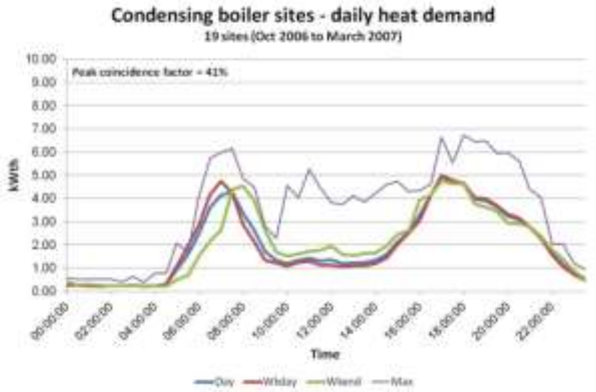

Figure 9 - Condensing boiler daily heat demand

Peak coincidence factor (PCF)
As mentioned previously PCF is very important as it directly impacts the aggregated peak heat demand and therefore the assets required. It can be seen from Figure 8 and Figure 9 that Micro-CHP sites have a higher PCF (47%) than condensing boilers (39%) and this is probably due to the lower thermal output of the Micro-CHP which results in lower and wider peaks.

Figure 10 shows a scatterplot of temperature and daily peak coincidence factor and it can be seen that PCF increases with reductions in temperature. This might be expected as heating appliances will need to be on for progressively longer periods to meet the increasing heat demand as temperature falls. As a consequence the diversity of heat demand will fall and PCF will rise. The winter of 2006/2007 was not particularly cold and the lowest temperature was minus 1.1°C (Central England Temperature daily average). This compares to minus 6.4°C for 2010 and as a consequence a higher PCF would be expected.

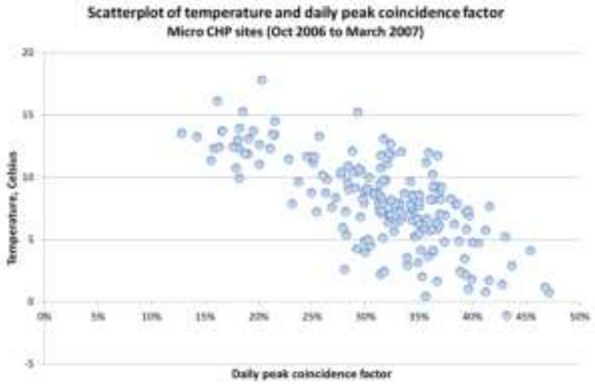

Figure 10 - Scatter plot of temperature and daily peak coincidence factor

The following sets of data profiles were used for domestic sites:

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

In the absence of actual heat demand data for commercial sites, comparisons were made between modelled data and data from the Micro-CHP trial. It was decided that it was better to use the domestic profiles for commercial demand rather than use modelled commercial demand as assumptions would need to be made on diversity. Commercial space and water heating represents less than 25% of total heat demand based on the DECC Pathways [2] and so the impact of this assumption on total heat demand will be reduced although caution must be exercised when examining commercial heat demand on its own.

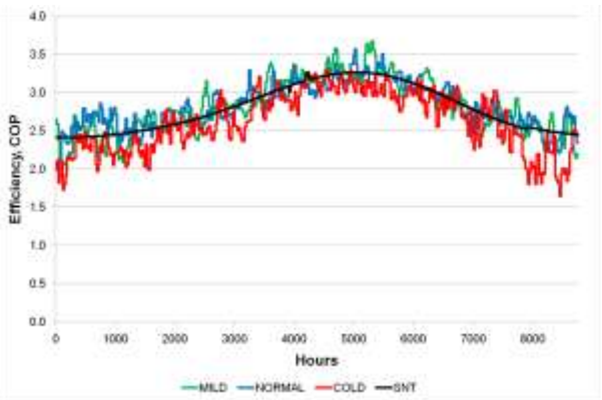

Figure 11 - ASHP hourly annual efficiency for temperature scenarios[3]

Electric heat demand
The heat demand synthesised represents the heat demand by the buildings. This demand can be converted to electric heat demand with assumptions made on the type of heating appliance, i.e. air source heat pump, ground source heat pump, direct heating as well as the percentage of heat demand that is assumed to be electrified. Electric heating appliances have a lower heat output than a condensing boiler and so the model selects the Micro-CHP heat profile as this is likely to be more representative. In addition as the

[3] Based on Mitsibushi Ecodan 8.5kW$_{th}$ ASHP efficiency performance at 55°C water flow [11]

heat output of an air source heat pump will vary with temperature, the model incorporates an adjustment to reflect these variations. Figure 11 illustrates this effect.

Results

Figure 12 displays the UK half hour heat demand for 2010. It can be seen that the peak demand was just above 330GW$_{th}$ and with a minimum demand of less than 30GW$_{th}$. (Note: this is the heat required by the building.) Heat demand load factor is ~17% which is substantially lower than electricity which is presently ~60%.

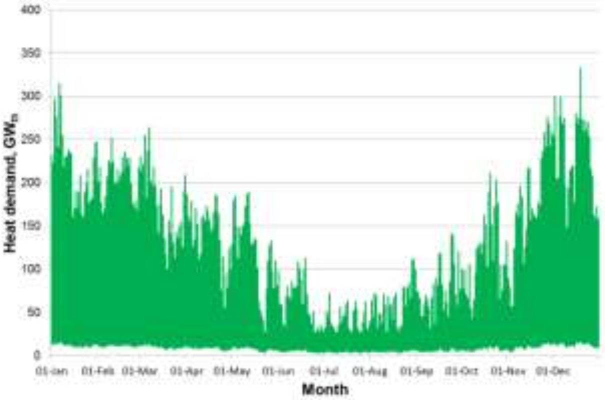

Figure 12 –UK half hourly heat demand 2010

The 2050 Pathways for UK peak heat demand (Normal temperature scenario) is shown in Figure 13 and it can be seen that there is a substantial variation in peak heat demand with Pathway 4 less than half of Pathway 1 in 2050. (Note: included within these pathways is an assumption that households increase from~27million to ~40million by 2050 [2].)

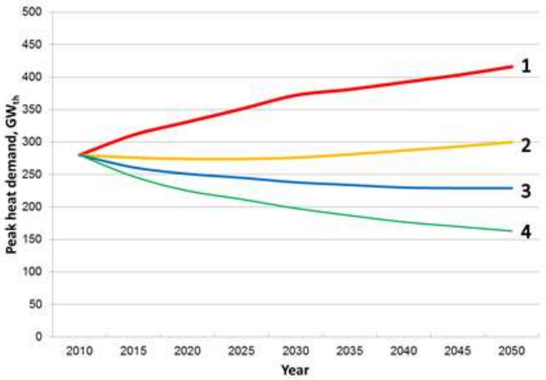

Figure 13 – 2050 Pathways UK peak heat demand

Figure 14 to Figure 17 present the peak electricity demand for pathways 1 to 4. This is the electricity demand at the consumer premises, i.e. before distribution and transmission losses. The solid black line shows the peak demand for Normal weather and the blue block is the range from the Mild to Cold temperature scenarios. The solid green line is the percentage of heat demand assumed to be electrified with Pathway 1 the lowest level followed by Pathway 2 and then 3 and 4 with the same levels of electrification.

An assumption is made that 65% of domestic heating appliances are air source heat pumps (ASHP) and 35% ground source heat pumps (GSHP). For commercial heating the reverse applies. The remaining 5% of heating appliances are assumed to be direct electric, i.e. resistive heating. ASHP performance is based upon that shown in Figure 11 and for GSHPs efficiencies of 350% and 400% are assumed for domestic and commercial appliances respectively.

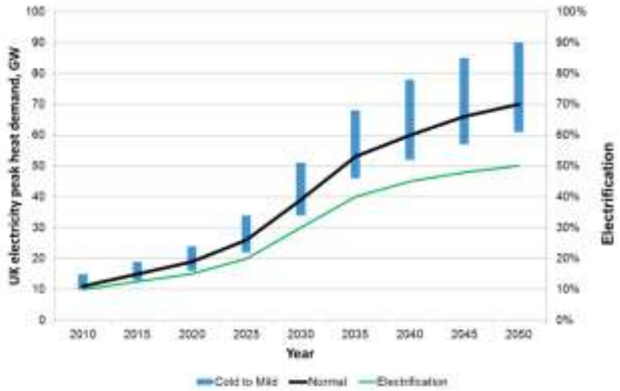

Figure 14 - UK electricity peak heat demand at consumer premises for Pathway 1

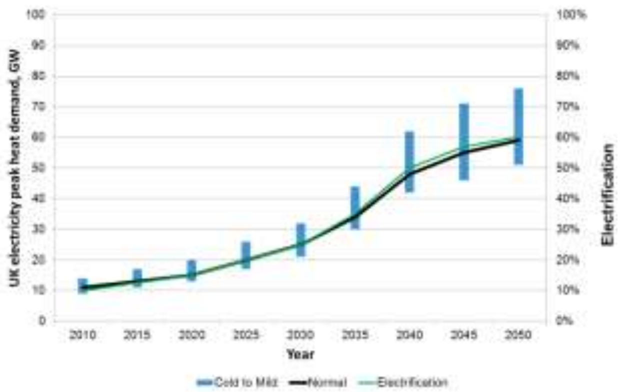

Figure 15 - UK electricity peak heat demand at consumer premises for Pathway 2

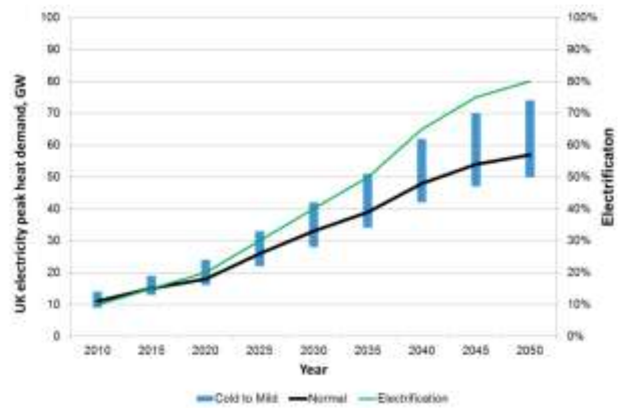

Figure 16 – UK electricity peak heat demand at consumer premises for Pathway 3

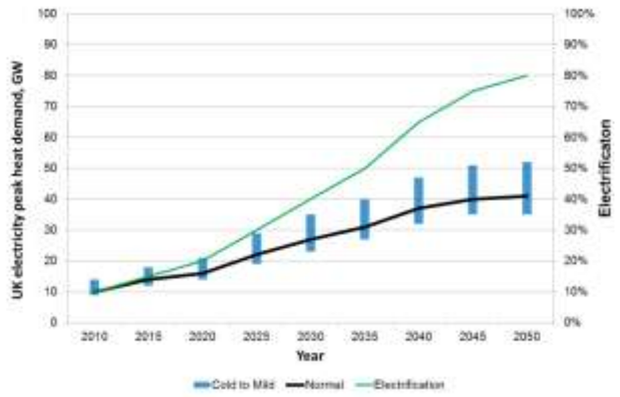

Figure 17 – UK electricity peak heat demand at consumer premises for Pathway 4

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

3 HEAT DEMAND CONCLUSIONS

A heat demand model has been presented that synthesises a half hourly demand profile and which incorporates actual data where available. The model can be used to investigate the impact of different heat demand pathways and temperature scenarios as well as the impact on electricity from heat electrification.

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

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

A further assumption is that the heat pump has been sized to meet the maximum demand required by the building. As temperature falls the heat output from an ASHP will be degraded and for very cold conditions supplementary resistive heating may be required to meet the occupants' requirements. This would further increase peak demand.

However, space and water heating do offer opportunities for demand side participation and so there may be opportunities to reduce peak demand.

Finally the results illustrate the increase in sensitivity to electricity demand from changes in temperature. For example the electricity peak heat demand for Pathway 3 in 2050 is 57GW for the Normal temperature scenario which would result in a near doubling of electricity peak demand. This will require a significant increase in generation capacity as well as substantial reinforcement of transmission and distribution systems. However, for the Cold temperature scenario electricity peak heat demand is further increased to an estimated 74GW, nearly 30% higher. To maintain the current level of supply security for heat, mostly provided for by gas would require additional investment in assets such as peaking plant and/or demand side management arrangements as well as further network reinforcement. Hence, consideration needs to be given to the impact on supply security standards arising from the electrification of heat.

PART 2 – ECONOMICS OF HEATING SYSTEMS

4 HEAT SCENARIOS

To explore the impact of heat demand on the economics of heating systems two scenarios were developed which each examine two case studies. The first is a transition scenario to 2030 and the second is a full decarbonisation scenario to 2050.

The focus of the economic analysis is to identify the asset investment requirements for each of the scenarios and case studies examined and the associated cost differences. As a consequence investments and other costs which are common to the case studies are not included. The analysis may be described as "high level" with a number of simplifying assumptions but from which further more comprehensive analyses can subsequently be performed.

The scenarios also do not assume any specific year for investment and instead make the assumption that the investments are made over the period to 2030 and then from 2030 to 2050. Finally the analysis focuses exclusively on the residential sector and throughout parameters are expressed on a per household basis with results presented in levelised terms, i.e. £/household/a. Cost and performance data is listed in appendix 1.

The scenarios and case studies are described as follows:

- **2030 Transition Scenario**

This scenario assumes the focus is on decarbonising electricity and improving building energy efficiency. Space and water heating continues to be dominated by gas condensing boilers and the penetration of heat pump technology remains low. The first case study, Case 1a, assumes power plant investment is nuclear supplemented by combined cycle gas plant (CCGT) in order to provide flexibility. However CCGT operation is constrained such that the overall carbon emissions are less than 100 g/kWh. The second case study, Case 1b, assumes power plant investment is gas based CHP CCGT connected to a district heat network and which includes thermal storage and network connected heat pumps to meet heat demand.

Included in Case 1a is the cost of gas condensing boilers as the term of the analysis (to 2030) exceeds the life of the appliance (15 years) and so most will be replaced over this period. However, if a direct comparison is made with district heating this would assume full avoidance of future gas boiler costs but take no account of past investment and any residual life of the boilers replaced. Although these are sunk costs, without an adjustment comparisons would be overstated. Hence a gas boiler residual life adjustment is added to Case 1b to compensate.

Heat networks are major investments. Implicit in the assumptions is that the heat network takes 15 years to construct and develop the heat load. Construction commences with "anchor loads" which are predominantly public and commercial buildings, social housing, etc., and these take about 5 years. The heat network is then expanded to include other households and rolled out on an area by area basis. The assumption made is that this takes 5 years before the area is commissioned, heat is supplied and network revenue received. Hence interest charges are incurred which have been added to the capital cost.

- **2050 Targets Met Scenario**

This scenario develops the 2030 Transition Scenario to 2050 with the full decarbonisation of both electricity and heat to meet the 2050 targets. The first case study, Case 2a, assumes the large-scale rollout of air source heat pump household appliances to meet space and water heating demand with additional investment in nuclear and new investment in carbon capture and sequestration (CCS) CCGT power plant. This is supplemented by open cycle gas turbine (OCGT) to meet the Cold temperature scenario electricity peak heat demand. The second case study, Case 2b, assumes the replacement of gas CHP CCGT with nuclear and CCS CCGT. Heat demand continues to be met by the heat network which is now exclusively supplied by network heat pumps.

Heat and electricity peak demand

As Pathway 1 has no improvement in energy efficiency, only heat pathways 2, 3 and 4 are examined. In the case of electricity it is assumed that there is no change in household consumption up to 2030 but up to 2050 (non-heat related) electricity demand reduces by a third. The data used is shown in Table 3.

	2030 Transition			2050 Target Met		
	Pathway			Pathway		
	2	3	4	2	3	4
Peak electricity, kW	1.0	1.0	1.0	0.7	0.7	0.7
Peak heat, kW_{th}	5.7	4.9	3.9	4.9	3.7	2.5

Table 3 – Peak heat and electricity demands

Peak heat demand is calculated from the heat demand model based on the Cold temperature scenario with 33million households in 2030 and 40 million households in 2050 [2].

2030 Transition Scenario

- **Case 1a**

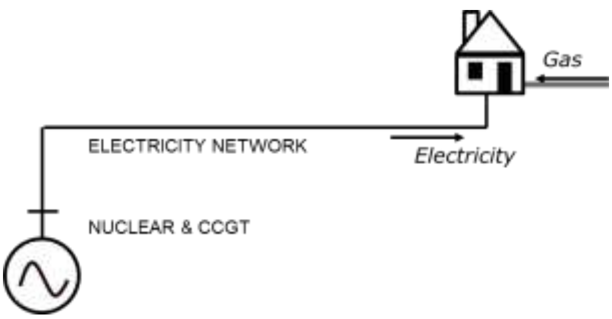

Figure 18 –Case 1a assets

Figure 18 illustrates Case 1a. The investment required is for the nuclear plant, CCGT and household's gas boiler. Peak electricity demand is 1kW/household, refer to Table 3, and it is assumed that the power plant capacity investment is 50% nuclear and 50% CCGT. The levelised costs are shown in Table 10 in appendix 2.

- **Case 1b**

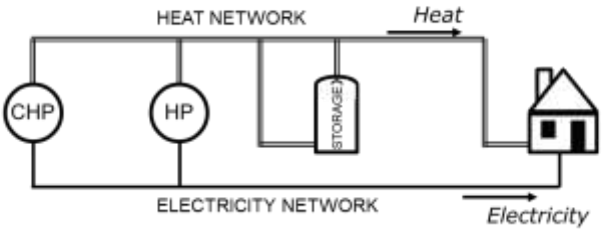

Figure 19 - Case 1b assets

Figure 19 illustrates Case 1b. The investment required is for the CHP CCGT, network heat pump, thermal storage, heat network and electricity network reinforcement. Peak electricity demand is 1kW/household plus the network heat pump. For Pathway 3, peak heat demand is 4.9kW_{th} and is met by the CHP plant, network heat pump and thermal storage. It is assumed that thermal storage output is the same as the heat pump and is 2kW_{th}/household. The remaining output of 0.9kW_{th}/household is met by the CHP plant. However, CHP CCGT electricity output is reduced when producing heat and so it is assumed that the CHP CCGT capacity is 1.6kW/household. The levelised costs are shown in Table 10 in appendix 2.

2050 Target Met Scenario

- **Case 2a**

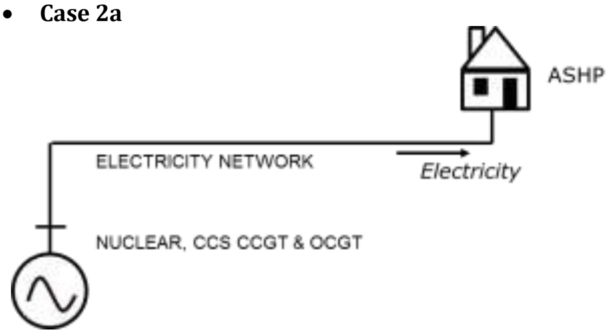

Figure 20 – Case 2a assets

- **Case 2b**

Figure 21 illustrates Case 2b. The investment required is for the nuclear, CCS CCGT and electricity network reinforcement. Peak electricity demand is 0.7kW/household plus the network heat pump. The peak heat demand for Pathway 3 is 3.7kW_{th}/household which is met by the storage and the network heat pump. The installed capacity (from 2030) is 4kW_{th}/household and so no additional assets are required. The network heat pump load is 2kW_{th}/household or 0.5kW/household assuming 400% COP. Hence the nuclear and CCS CCGT capacity required to meet peak demand is 1.2kW/household. Assuming 0.5kW/household is nuclear with the remaining 0.7kW/household CCS CCGT. The levelised costs are shown in Table 11.

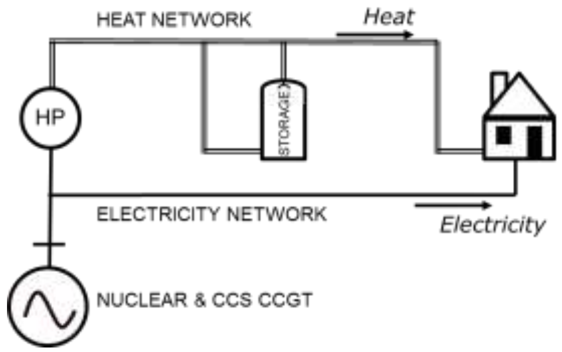

Figure 21 - Case 2b assets

5 RESULTS

The results of the analysis for pathways 2, 3 and 4 are shown in Table 4. (Note: the detail for Pathway 3 is shown in Table 10 and Table 11.) It is important to emphasise that the costs displayed do not include some common costs including gas costs and hence should only be used for case comparisons.

Results		
	2030 Transition Scenario	
	Case 1a	**Case 1b**
	£/household/a	*£/household/a*
Pathway 2	880	1111
Pathway 3	880	1092
Pathway 4	880	1051
	2050 Target Met Scenario	
	Cases 2a[1]	**Cases 2b[1]**
	£/household/a	*£/household/a*
Pathway 2	2042	1270
Pathway 3	1914	1224
Pathway 4 (see 2)	1457	1178

Notes
1. Includes any ongoing levelised costs from 2030 "Transition" scenario.
2. ASHP cost reduced to £5000.
3. Excludes some common costs such as gas costs

Table 4 – Summary of economic analysis of heating systems

It can be seen that for the 2030 Transition Scenario the levelised costs for Case 1a are less than Case 1b for all pathways. The impact of the pathways on levelised costs is relatively small for Case 1b because heat capacity is provided by low cost thermal storage and high efficiency network heat pumps. (Note: Case 1a is not affected by the pathways as the impact on gas infrastructure is not included in this analysis.) Gas consumption is the same for both cases and the CO_2 emissions will be similar. This is because Case 1b includes a network heat pump which recovers renewable heat substantially reducing the fossil fuel consumed for heating and offsetting the gas consumed by the CHP plant.

For the 2050 Target Met Scenario, the levelised costs include incremental investment made after 2030 and any on-going levelised costs. It can be seen that Case 2b has a much lower cost than Case 2a for all pathways. This is mainly due to the cost of the household ASHP appliance and the associated investment in power plant capacity to meet its demand. Consequently Case 2a is more sensitive to pathway or heat demand assumptions.

6 ECONOMICS OF HEATING SYSTEMS CONCLUSIONS

A “high level” economic analysis comparing heating systems has been presented. These comprise the continued use of household gas condensing boilers up to 2030 followed by their replacement with household ASHPs (cases 1a and 2a) with district heating (cases 1b and 2b). The analysis has shown that district heating has higher levelised costs for all the pathways examined up to 2030. This is mainly due to the cost of the heat network.

However, as heat is fully decarbonised to 2050 district heating has lower costs for all the pathways examined. This is mainly due to the cost of the household ASHP appliance and the additional power plant capacity to meet the demand requirements of the ASHP.

As might be expected the impact of the pathways has a greater impact on levelised costs for a heating system based on household ASHP. However, at the very low levels of heat consumption the high capital cost of household ASHP or district heating systems may not be competitive with lower cost heating systems such as storage heating for example.

7 FURTHER WORK

The economic analysis has been useful but further more detailed analysis is required to enable robust conclusions to be made. An integrated heat and electricity model has been constructed, refer to Figure 22, which incorporates half hourly heat and electricity demand and includes wind, CHP, thermal storage and thermal generating plant. The household heating systems include those connected to the district heat network as well as household heat pumps and electric storage heating systems. Investigations will enable the operational performance to be evaluated as well as other features such as system support from thermal and electricity storage and the management of wind intermittency.

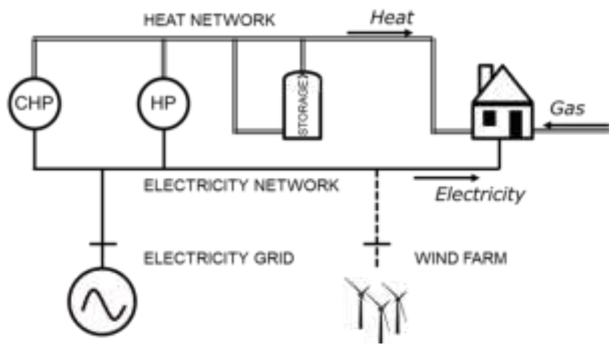

Figure 22 – Integrated heat and electricity model

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APPENDIX 1 – ECONOMIC ASSUMPTIONS

Financing		
Power plant		
Cost of capital	10%	
Term, years	40	
Annuity factor	9.8	
Home appliance		
Cost of capital	10%	
Term, years	15	
Annuity factor	7.6	
OCGT & other assets		
Cost of capital	6%	
Term, years	40	
Annuity factor	15	

Table 5 – Financing assumptions

Nuclear plant		
Nuclear plant NOAK		
Capital cost (High), £/kW	3538	
Construction period, years	6	
Interest during construction	35%	Based on flat profile of expenditure
Capital cost with IDC, £/kW	4772	
Levelised cost, £/kW/a	488	
O&M (Medium), £/kW/a	75	
Nuclear fuel cost, £/MWh	5	

Table 6 – Nuclear plant assumptions [12][13]

GAS PLANT		
CCGT plant NOAK		
Capital cost (Medium), £/kW	669	
Construction period, years	3	
Interest during construction	13%	Based on flat profile of expenditure
Capital cost with IDC, £/kW	755	
Levelised cost, £/kW/a	77	
O&M (Medium)£/kW/a	27	
CCGT CHP plant NOAK		
Capital cost (High), £/kW	758	
Construction period, years	3	
Interest during construction	16%	Based on flat profile of expenditure
Capital cost with IDC, £/kW	877	
Levelised cost, £/kW/a	90	
O&M (Medium)£/kW/a	27	
Heat to electricity ratio	70%	
CCGT CCS plant NOAK		
Capital cost (High), £/kW	1525	
Construction period, years	6	
Interest during construction	35%	Based on flat profile of expenditure
Capital cost with IDC	2057	
Levelised cost, £/kW/a	210	
O&M (Medium), £/kW/a	39	
OCGT		
Capital cost (Medium), £/kW	400	
Construction period, years	2	
Interest during construction	6%	Based on flat profile of expenditure
Capital cost with IDC, £/kW	424	
Levelised cost, £/kW/a	28	
O&M (Medium), £/kW/a	12	

Table 7 – CCGT plant assumptions [12][13]

Home appliances		
Condensing gas boiler cost, £	2500	
Condensing gas boiler cost, £/a	329	
Gas appliance maintenance, £/a	100	
ASHP cost, £	7500	Estimate
ASHP cost, £/a	986	
ASHP COP for peak heat	200%	

Table 8 – Home appliance assumptions [14]

Other assets		
Heat network assets		
Network heat pump cost, £/kWth	350	Estimate
Network heat pump cost, £/kWth/a	23	
Network heat pump COP	400%	Estimate
Network heat pump size/kWth	2	
Network heat pump peak, kW	0.5	
Heat network cost, £/household	6000	
Construction period, years	5	
Interest during construction	16%	Based on flat profile of expenditure
Heat network with IDC, £/household	6964	
Heat network cost, £/household/a	463	
House connection, £/household	2000	
House connection, £/household/a	133	
Thermal storage, £	100	Estimate
Thermal storage, £/a	7	
Electricity n/w reinforcement		
Above LV, £/kW	300	Estimate
Above LV, £/kW/a	20	
LV, £/household	400	Estimate
LV, £/household/a	27	
Gas infrastructure charges, £/a	100	

Table 9 – Other assets [14]

APPENDIX 2 – RESULTS

2030 Transition Scenario (Pathway 3)	Case 1a £/household/a	Case 1b £/household/a
Asset investment:		
Power plant	283	124
Condensing gas boiler (see 1)	329	148
Network heat pump	0	47
Thermal storage	0	7
Heat network	0	596
Electricity network (see 2)	0	10
Total assets	**611**	**930**
Operating costs:		
Gas, pa (see 2)	The same	The same
Gas boiler maintenance, pa	100	0
Nuclear fuel, pa (see 3)	12	0
O and M, pa	57	62
Total operating costs	**169**	**62**
Network costs:		
Electricity, pa	The same	The same
Gas, pa (see 4)	100	0
Heat network, pa (see 5)	0	100
Total network costs	**100**	**100**
Total levelised cost (£/household/a)	**880**	**1092**

Notes
1. Case 1b includes a gas boiler residual life adjustment.
2. Assumes CHP gas consumption is the same as household's gas boiler.
3. Assumes nuclear generation is 2.25MWh/household/a.
4. Based on gas tariff charges.
5. Estimate.
6. Excludes some common costs such as gas costs

Table 10 – Levelised costs for 2030 Transition Scenario

2050 Target Met Scenario (Pathway 3)	Cases 2a[1] £/household/a	Cases 2b[1] £/household/a
Asset investment:		
Power plant	730	391
Heat pump	986	0
Network heat pump	0	47
Thermal storage	0	7
Heat network	0	596
Electricity network (see 3)	63	10
Total asset investment cost	**1779**	**1050**
Operating costs:		
Gas, pa (see 2)	The same	The same
Gas boiler maintenance, pa	0	0
Nuclear fuel, pa	12	9
O and M, pa	123	64
Total operating costs	**135**	**73**
Network costs:		
Electricity, pa	The same	The same
Heat network, pa (see 3)	0	100
Total network costs	**0**	**100**
Total levelised cost (£/household/a)	**1914**	**1224**

Notes
1. Includes any ongoing levelised costs from 2030 "Transition" scenario.
2. Assumes CCGT CCS gas generation is the same for both cases.
3. Estimate.
4. Excludes some common costs such as gas costs..

Table 11 – Levelised costs for 2050 Target Met Scenario

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