

This is an Open Access document downloaded from ORCA, Cardiff University's institutional repository:<https://orca.cardiff.ac.uk/id/eprint/119386/>

This is the author's version of a work that was submitted to / accepted for publication.

Citation for final published version:

Qadrdan, Meysam , Fazeli, Reza, Jenkins, Nick , Strbac, Goran and Sansom, Robert
2019. Gas and electricity supply implications of decarbonising heat sector in GB.
Energy 169 , pp. 50-60. 10.1016/j.energy.2018.11.066

Publishers page: <http://dx.doi.org/10.1016/j.energy.2018.11.066>

Please note:

Changes made as a result of publishing processes such as copy-editing, formatting and page numbers may not be reflected in this version. For the definitive version of this publication, please refer to the published source. You are advised to consult the publisher's version if you wish to cite this paper.

This version is being made available in accordance with publisher policies. See <http://orca.cf.ac.uk/policies.html> for usage policies. Copyright and moral rights for publications made available in ORCA are retained by the copyright holders.



Gas and electricity supply implications of decarbonising heat sector in GB

Meysam Qadrdan^{1*}, Reza Fazeli², Nick Jenkins¹, Goran Strbac³ and Robert Sansom³

¹ School of Engineering, Cardiff University, Queen's Buildings, The Parade, Cardiff CF24 3AA, UK

² School of Engineering and Natural Sciences, University of Iceland, 101 Reykjavik, Iceland

³ Imperial College London, South Kensington, London, SW7 2AZ, UK

* qadrdanm@cardiff.ac.uk

Abstract – The increasing decarbonisation of the power and heat sectors in Great Britain poses numerous uncertainties about the future of the gas network. An optimisation model was developed for investigating the operation of future low carbon electricity, gas and heat supply systems. The model was employed to quantify the impacts on the operation of the gas network in Great Britain of transitioning to low carbon power and heat. The modelling results show that the decarbonisation of the power and heat sectors affects the operation of the high and low pressure gas networks differently. A highly electrified heat sector, only slightly changes the gas load duration curve for the high pressure gas transmission network, but significantly affects the load duration curve for low pressure gas distribution networks. In addition, in a future energy system with a large capacity of variable wind and solar generation, and highly electrified heat supply, although the annual volume of gas supply decreases, the peak gas supply during low wind and cold spells remains the same or even exceeds the current figure. This is mainly due to gas-fired power plants operating to their maximum capacity to complement the wind resource and also supply electricity for heat pumps.

Keywords – Decarbonisation of Heat Supply; Integrated Energy System; Renewable Energy

Nomenclature

Variables

Z	Objective function of the optimisation problem (£)
$P_{i,t}$	Power generation by power plant i at time t (MW)
Q_t	Gas supply flow at time t (MW)
$h_{j,t}$	Heat output from technology j at time t (MW)
$E_{j,t}$	Electricity consumption by heating technology j at time t (MWh)
G_t^{DHN}	Gas demand for CHP units connected to district heating networks at time t
G_t^L	Gas demand at low pressure gas networks (below 75 millibar) at time t
G_t^b	Gas demand for domestic boilers at time t
G_t^μ	Gas demand for micro-CHP units at time t
G_t^{HM}	Gas demand seen by high and medium networks (above 75 millibar networks) at time t
G_t^p	Gas demand for power generation at time t
P_t^{CHP}	Power generation from CHP at time t
P_t^μ	Power generation from micro-CHP at time t

Parameters

C^f	Fuel cost for power generation (£/MWh)
C^{vo}	Variable operating cost for power generation (£/MWh)
C^{em}	Emission cost for power generation (£/MWh)
C^g	Cost of gas (£/MWh)

H_t	Heat demand at time t (MW)
α_t	This multiplier was used to smooth the electricity demand for heating at every time step (t) and therefore accounts for thermal storage integrated with electric heating systems
HED_t	Historical electricity demand at time t
P_t^{Wind}	Power generation from wind at time t
P_t^{Solar}	Power generation from solar photovoltaic at time t
P_t^{Dem}	Power demand at time t excluding the demand for heating (MW)
\bar{P}_i	Maximum capacity of power plant i (MW)
A_i	Availability of power plant i during peak hours (%)
ΔP_i	Maximum change (i.e. ramp-up or ramp-down) in the power output of plant type i in two consecutive time steps (MW)
G_t^I	Gas demand for industries at time t
G_t^C	Gas demand for cooking at time t

1. Introduction

Power generation created 23% and buildings 16% of the total greenhouse gas emissions in 2014 and are amongst the CO₂ intensive sectors of the United Kingdom (UK) [1]. The emissions from buildings are mainly from the consumption of natural gas for heat supply. Decarbonisation of power and heat are perceived as strategic options for achieving the legally binding emission and renewable targets in the UK [1].

Although, future power generation in GB is expected to consist of a large capacity of wind, solar and gas-fired plants [2] and [3], there is significant uncertainty related to the future of the heat sector in GB [4]. According to Chaudry et al. [5], this uncertainty is mainly due to (i) lack of a clear long-term energy policy to incentivise and support low carbon heat supply, (ii) uncertainty in costs and performance of new technologies (e.g. heat pumps), and (iii) lack of understanding of decision making behaviour of consumers (references [6][7][8][9] provides more detailed discussion about the relationship between consumers behaviour and energy consumption in households).

The UK government has had various plans to reduce emissions from residential heating through improving the energy efficiency of the existing housing stock (e.g. Green Deal [10] which expired in 2015), and has supported market rollout of renewable heat technologies (e.g. through the Renewable Heat Incentives [10]-[11]). However the efficacy and the system wide impacts of these policy initiatives is uncertain.

During the last decade, natural gas has been responsible for supplying a substantial fraction of the energy used for heating and power generation, for example, in 2011 around 70% of heat, and 40% of electricity [12] were produced using natural gas. The current reliance of the British energy system on natural gas is a consequence of historically abundant natural gas supplies from North Sea, the availability of extensive gas transmission and distribution networks and the comparatively low upfront costs and high efficiency of gas boilers and Combine Cycle Gas Turbine (CCGT) generators [5].

The decarbonisation of heat and power sectors is anticipated to have a significant impact on the consumption of natural gas and therefore will introduce uncertainty in the future role of the gas network in a low carbon energy system. By improving energy efficiency and moving towards electrification of the heat sector, a significant drop in the total gas demand is anticipated.

Furthermore, given the increasing capacity of wind farms in the GB power system, and due to the variable nature of wind generation, balancing electricity demand and supply is becoming more

challenging. Owing to their flexible operating characteristics, gas-fired generating units will play a crucial role in compensating for wind variability. Consequently, the variation of the output of wind generation will be transferred to the gas demand [13]. It was shown by [14] that decarbonisation of heat and power will reduce the annual volume of gas demand but will not have a significant impact on peak gas demand. This will result in low utilisation of the gas supply infrastructure and therefore make it difficult to justify investment to expand and even maintain the gas networks.

2. Background and Literature Review

This section provides an overview of previous studies looking at decarbonisation of the heat sector in the UK. Author et al. [15] considered a range of decarbonisation scenarios and used a UK energy technology model MARKAL to assess the sensitivity of energy transition pathways to uncertainty over a range of drivers including resources, technology development, behavioral change and policy mechanisms. Their analysis shows that in order for the UK to achieve its GHG reduction target, no natural gas should be used for residential heating by 2050. Instead, heat pumps were expected to take the leading role for heating, accompanied by biomass and solar thermal.

Using a financial model, author et al. [16] constructed a UK supply curve for renewable heat. Based on this investigation although a mix of technologies are likely to be required, biomass boilers and heat pumps were found to offer significant potential, in some cases at relatively low cost. Later, they prepared a report [17] for DECC (Department of Energy and Climate Change) on Low-Carbon heat scenarios for the 2020s, in which several alternative scenarios are modelled and analysed to assess three options of electrification, bioenergy and district heating to support heating demand. The outcomes were tested for sensitivities to likely changes in discount rate, fossil fuel price, biomass availability and energy efficiency. The analysis provides interesting insights, e.g., significant emission abatement could be achieved at low or even negative cost; the most promising option for decarbonisation of space heating was found to be heat pumps, when accompanied by bioenergy for

high temperature heat. Risks to heat sector decarbonisation were found to be failure to promote energy efficiency or in the uptake of low-carbon technology over the next two decades.

Author et al. [18] analysed the role of district heating in future Renewable Energy Systems in Denmark. Authors have defined a scenario framework to achieve 100% Renewable Energy Sources (RES) in the year 2060 by decreasing space heating demands by 75%. Based on a comprehensive energy system analysis, the implications on fuel demand, CO₂ emissions and cost are estimated for multiple heating options, including district heating as well as individual heat pumps and micro CHPs (Combined Heat and Power). The study assumed that the conventional gas and oil boilers could be substituted by district heating or a more efficient individual heat source in around 25% of the Danish building stock. In such overall perspective, a gradual expansion of district heating and implementation of individual heat pumps in the remaining houses were found to be the best options [18].

A whole energy system cost-optimization model, RESOM (Redpoint Energy System Optimisation Model) was developed by Redpoint using DECC core assumptions, where the UK can purchase international emission credits, in order to meet the emission target [19]. According to the RESOM estimates, both peak and annual electricity demand could rise rapidly from 2030 onwards, demanding appropriate reinforcement. Besides, the model suggests that in order to tackle the seasonal and diurnal swings in demand, hybrid electric/gas heating and heat storage systems should be installed.

In [20], a scenario-based approach was employed to understand the implications of alternative mechanisms to decarbonise heat supply in buildings in the UK, during the 2030–2050 period. Starting from the Committee on Climate Change central scenario prediction for 2030 [16], three alternative scenarios¹ (‘policy extension’, ‘District Heating, constrained’ and ‘Electrification’) were explored to assess the technical potential for renewable or low carbon heat. With full exploitation of

¹ For detailed information on input assumptions of scenarios, see pages 6-7 of [20]

the technical potential of renewable heat, the 'policy extension' and 'DH, constrained' scenarios were found to be successful in decarbonising the UK's heating system by 2050. The results of resource cost² for the three scenarios, suggest that when evaluated at a social discount rate, the total resource cost of the 'electrification' scenario is significantly larger than the 'policy extension' and 'DH, constrained' scenarios. This is primarily due to the replacement of gas and oil boilers with heat pumps and direct electric heating.

In [21], the author reviewed how heat sector can be modelled in UK MARKAL, and recognised several limitations. He proposed a modified model to better estimate future heat demands and also to provide a consistent representation of all heat generation technologies. Besides, the model consists of a simplified housing stock model, to study decarbonisation pathways for residential heat demand. Disaggregating the residential sector by house type enabled the model to better represent the diversity of decarbonisation options and different consumer behaviour across house types.

Heat pumps seem to be essential element for decarbonising the UK's buildings sector as part of the Committee on Climate Change's (CCC) updated abatement scenario for meeting the UK's fourth carbon budget. Yet, the UK has one of the least developed heat pump markets in Europe. Therefore, [22] explored what lessons the UK might learn from Finland to achieve this aim considering that its current level of heat pump penetration is comparable with that outlined in the CCC scenario for 2030. Despite the differences between two countries, the author identified several policy-based lessons including: stimulating new-build construction and renovation of existing stock; incorporating renewable heat solutions in building energy performance standards; and bringing the cost of heat pumps in-line with gas fired heating via a combination of subsidies, taxes and energy RD&D.

² defined as the sum of the annualized capital costs of heating system installations together with annual fuel and maintenance costs

Author et al. [5] identified a great deal of uncertainty regarding the levels of deployment of low carbon heat technologies achievable by 2030. Concerning uncertainties in heat pump deployments, the study showed that lower SPF (Seasonal Performance Factor) values could increase emissions by 2 Mt CO₂ (at the uptake levels assumed by the CCC 4th carbon budget review) and the impact would be greater if the electricity grid does not decarbonise to an intensity of 50 g CO₂/kWh by 2030. They identified substantial concerns mainly focused around digging and laying of hot water pipes and high upfront capital costs for potential customers, which could affect the development in heat networks from 10 to 30 TWh by 2030, which is anticipated in the 4th carbon budget review.

Author et al. [23] provide a comprehensive review of academic literature and policy papers to identify the prevalent energy systems models and tools in the UK. The reviewed models and tools are studied based on the sectoral coverage and technological inclusion, as well as mathematical structure. The review highlights the advantages of different models to study the decarbonisation of heat sector in the UK.

More recently, Jalil-Vega and Hawkes [24] declared that many existing energy planning models have difficulty in comparing heat decarbonisation approaches because they don't consider trade-offs between heat supply, end-use technologies and network infrastructure at sufficient spatial resolution. Thus, [24] proposed an optimisation model that addresses these trade-offs. The results of applying the model for the UK, showed that electrification of heat is most cost-effective via district level heat pumps that supply heat networks, instead of individual building heat pumps. This is because the cost of reinforcing the electricity grid for installing individual heat pumps does not sufficiently offset heat infrastructure costs. Besides, the results emphasize the importance of spatial aspects as the authors found that the penetration of heat networks and location of district level heat

supply technologies depends directly on linear heat density and on zone topology. For different case studies, the authors identified linear heat density thresholds for heat network penetration.

Table 1 summarises the literature review provided in this section. As discussed above, a number of scenarios for decarbonising the heat sector in UK have been proposed. Electrification of heat sector through employing heat pumps was shown to be a key strategy for decarbonizing heat. In this paper we aim to analyse the impacts of two different heat decarbonisation scenarios on the operation of future gas and electricity supply systems in GB. In particular, this paper focuses on quantifying the impacts of heat pumps on the operation of whole energy system.

Table 1 - Summary of previous studies on heat sector

Focus of the studies	References
Heat decarbonisation pathways	[5][19][20][24][25][26]
Analysis of performance of low carbon heating technologies	[18][11][22]
Whole-system analysis of heat sector	[15][21]
Policy and socio-economic aspect of heat sector	[6][7][8][9]

3. Modelling methodology

3.1. Structure of the model

A linear programming optimisation model was developed to analyse the half-hourly operation of an integrated gas, electricity and heat supply system over a year. Energy flows and conversion technologies considered in the model are presented by Figure 1. Various power generation technologies including wind, solar and gas-fired were modelled using their detailed operational characteristics. For heat supply, list of current technologies (e.g. gas boiler) as well as plausible future technologies such as heat pumps and micro CHP were included in the model. The focus of the

model is to investigate the interactions between gas, electricity and heat supply systems under different decarbonisation scenarios for heat supply. Therefore, the coupling components that link different energy vectors were identified and their technical characteristics were modelled. Gas-fired power plants and CHP units that supply heat to district heating systems are connected to high and medium pressure gas networks respectively, while micro CHPs are linked to low pressure gas distribution networks. Table 2 shows the type of fuel used by coupling components as well as their energy conversion efficiency. Varying efficiency were considered for heat pumps to reflect their seasonal performance that is affected by outside temperature. The dispatch of electricity, heat and gas was simultaneously optimised over a time horizon of one year with half-hourly resolutions (17,520 time steps). Investigating the optimal operation of the integrated energy system with half-hourly time steps allowed the increasingly dynamic behaviour of the energy system caused by the large scale integration of wind and solar generation to be captured.

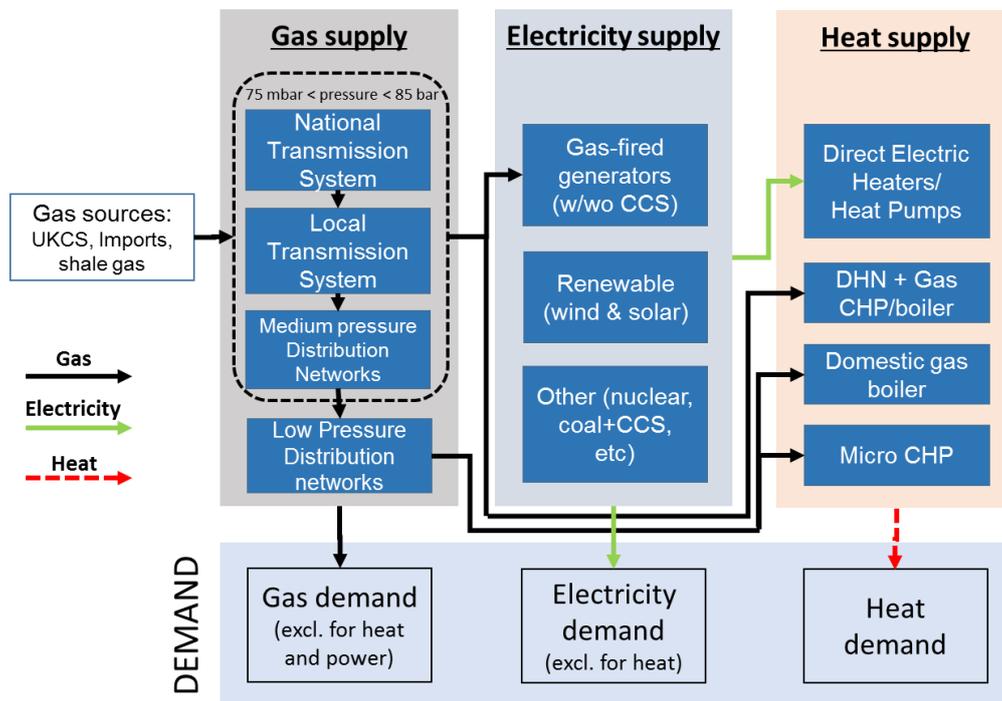


Figure 1 - Structure of the integrated gas, electricity and heat supply system

Table 2 - Input fuel and energy conversion efficiency of the coupling components

Fuel	Technology	Electrical efficiency	Thermal efficiency
Gas	CCGT [27]	60%	
	CCGT + CCS [27]	52%	
	OCGT [28]	35%	
	CHP [29]	30%	45%
	Boiler [30]		90%
	Micro CHP [31]	20%	70%
Electricity	Electric Heater [11]		100%
	Air Source Heat pumps [11]		120% – 400%
	Ground Source Heat Pump [11]		150% - 500%

3.2. Formulation of the model

The objective function of the optimisation model (Eq. 1) is to simultaneously minimise the costs of electricity generation, gas supply and the associated emissions. The contribution of different technologies to meet the heat demand was given to the model in the form of different scenarios and expressed as constraints. Therefore, heat outputs from different technologies are predetermined, and the fuel costs associated with heat supply are already reflected in the cost of electricity generation and gas supply.

$$Obj: \min Z = \sum_t \left[\left(\sum_i (C_i^f + C_i^{vo} + C_i^{em}) P_{i,t} \right) + (C^g Q_t) \right] \quad Eq. 1$$

Where, Z is the objective function, index i represents different types of power generation technologies, index t represents time steps, C^f is fuel cost, C^{vo} is variable operating cost, C^{em} is emission cost, $P_{i,t}$ is electrical energy produced by power plants, C^g is cost of gas, and Q_t is gas supply.

In this study, individual units of energy conversion technologies were not modelled explicitly, but the size of energy conversion technologies of the same type (e.g. gas boilers) were aggregated for the whole GB.

Heat Supply: The contribution of different technologies in supplying heat was given to the model as inputs. These were determined by various heat decarbonisation scenarios explained in section 4.1. Given the half-hourly heating demand and taking into account the efficiency of the heating technologies, the gas and electricity consumptions from the heat sector were calculated by the model. Equation 2 ensures that at every time step (t), the summation of heat outputs (h) from different heating technologies (j) is equal to the total heat demand (H). In practice, hot water tanks are used in many households that consume electricity to supply heat. This is to benefit from cheaper electricity price during nights to produce and store hot water, and then use the hot water during days when electricity price is higher. Therefore, the thermal storage tanks decouple the timing of heat demand and the electricity consumption for producing heat. In calculating the electricity demand for heating, thermal storage integrated with the heating technologies was modelled implicitly by smoothing the within-day electricity demand profile for heating. Equation 3 relates the electricity consumption (E) by heating technology (j) at time (t) to the heat output from the technology (and the thermal storage connected to it) at every time step ($h_{j,t}$). A constant multiplier (α_t) was used to smooth the electricity demand for heating and therefore accounts for thermal storage. The smoothing of the heat demand was conducted based on historical electricity demand (HED_t) data (Eq. 4). The integration of thermal storage with the heating technologies that consume electricity is to avoid extremely large peak electricity demand during cold periods.

$$\sum_j h_{j,t} = H_t \quad \text{Eq. 2}$$

$$E_{j,t} = \alpha_t \sum_{t=1}^{48} \frac{h_{j,t}}{\eta_j} \quad \text{Eq. 3}$$

$$\alpha_t = \frac{HED_t}{\sum_{t=1}^{48} HED_t} \quad \text{Eq. 4}$$

Electricity Supply: The core of the model is an optimal electricity dispatch module that determines, at every time step, the electricity generation from different types of power plants to meet total electricity demand including electricity for heating. Ramp rate limits of thermal power plants were taken into consideration to allow more accurate representation of the flexibility of the power generation technologies. Ramp rate values (% of capacity per minute) used in the model are Nuclear: 0.3; Coal & Biomass: 3.4; Gas-fired: 5) [32]. The links between gas and electricity supply systems were established through gas-fired power plants. Gas demand for power generation is an output of the electricity dispatch model and is calculated endogenously. Power generation from wind and solar are inputs to the model and were calculated based on historical power which was scaled up to represent the increased capacity for wind farms and solar PV in 2030. In this study, it was assumed that power generation and demand within every 30 minutes are constant.

Equation 5 ensures electricity balance at every time step. At every time step, the summation of electricity generation from different types of plants ($P_{i,t}$) in addition to electricity generation from wind (P_t^{Wind}) and solar (P_t^{Solar}), and electricity produced as by-product by large CHPs (P_t^{CHP}) and micro-CHPs (P_t^μ) is equal to summation of non-heating electricity demand (P^{Dem}) and electricity consumption by heating technologies ($E_{j,t}$) including air source heat pumps, ground source heat pumps and resistive heating.

$$\sum_i P_{i,t} + P_t^{Wind} + P_t^{Solar} + P^{CHP} + P^\mu = P_t^{Dem} + \sum_j E_{j,t} \quad \text{Eq. 5}$$

At every time step t , the power output from different power plants is equal or less than their de-rated capacity (Eq. 6). In this equation, \bar{P}_i is nominal capacity and A_i is availability of power plant i .

$$P_{i,t} \leq \bar{P}_i A_i \quad \text{Eq. 6}$$

The ramp up/down limits on power output from power plants were imposed using Eq. 7, where $P_{i,t}$ is electrical energy produced by power plant type i at time step t . ΔP_i is maximum change in the power output of plant type i from time step “ $t - 1$ ” to time step t .

$$|P_{i,t} - P_{i,t-1}| \leq \Delta P_i \quad \text{Eq. 7}$$

Gas Supply: A simplified two-node representation of the gas supply system was implemented in the model to distinguish the gas flows through high/medium pressure networks that operate above 75 millibar versus the low pressure networks that operate below 75 millibar. It was assumed that gas-fired power plants are supplied by the high/medium pressure gas network. The link between heat supply and high/medium pressure gas network is established via CHP plants. Heat supply also is connected to the low pressure gas network through Micro CHPs and domestic gas boilers (see Figure 1). It was assumed that the gas supply system is fully capable of meeting the total gas demand at every time step, therefore no hard constraint was used for the maximum gas supply limit.

As shown by Eq. 8, at every time step t , the demand seen by high/medium gas networks (G^{HM}) is equal to summation of gas demand for power generation (G^P), industry (G^I), CHP connecting to DHN (G^{DHN}), and the gas going through low pressure distribution networks (G^L).

$$G_t^{HM} = G_t^P + G_t^{DHN} + G_t^I + G_t^L \quad \text{Eq. 8}$$

As shown by Eq. 9, at every time step t , the gas flowing through the low pressure gas distribution networks (G^L) is equal to summation of gas demand for domestic gas boilers (G^b), micro CHPs (G^μ) and gas demand for cooking (G^c).

$$G_t^L = G_t^b + G_t^\mu + G_t^c \quad \text{Eq. 9}$$

Equation 10 was used to model the coupling components such as CHP, gas-fired generators and heat pumps that link different energy vectors. At every time step t , fuel consumptions by different types of conversion technologies ($Input_{k,t}$) are calculated via dividing their energy output (electricity or heat) ($Output_{k,t}$) by their efficiencies (η_k).

$$Input_{k,t} = \sum_i Output_{k,t} / \eta_k \quad \text{Eq. 10}$$

Hybrid heat pumps: In this study, it was assumed that the ASHPs will operate in conjunction with gas boilers as hybrid heating systems for domestic buildings. The share of the ASHP and the gas boiler to supply heating at different outdoor air temperature was modelled based on Figure 2.

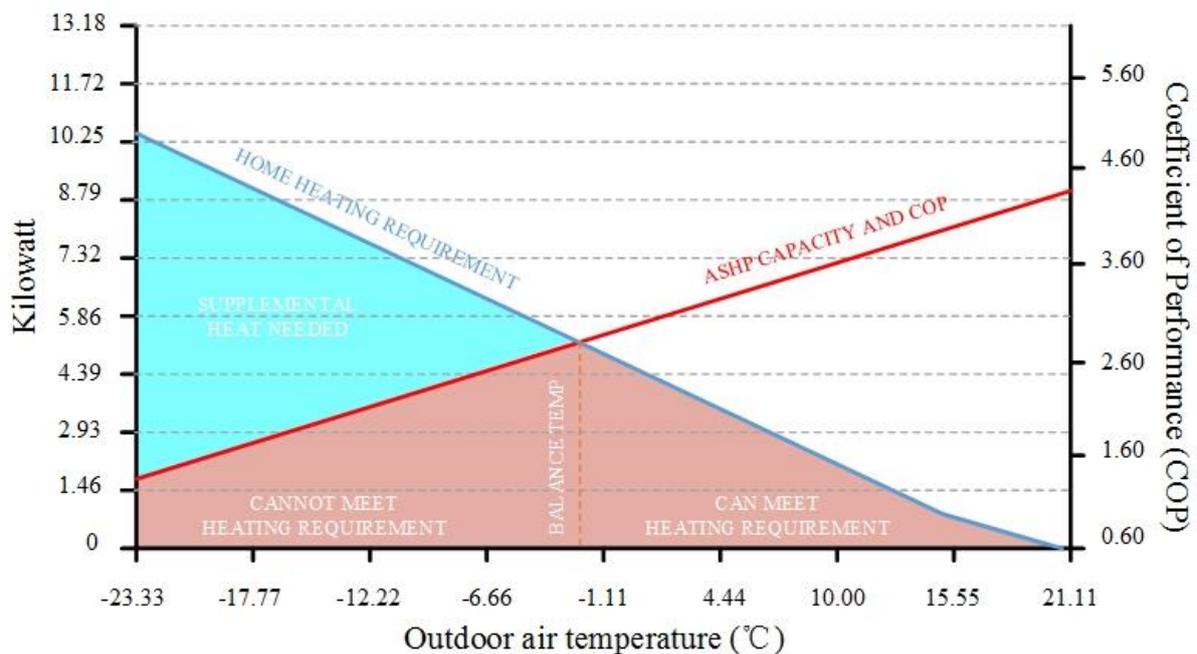


Figure 2 - Performance of a typical ASHP during heating seasons (adopted from [33])

The optimisation model was developed using Fico Xpress Optimisation Suite [34] and solved by Interior Point method in Xpress solver.

4. Case studies, assumptions and data

4.1. Case studies

Two case studies representing different shares of low carbon heat supply in 2030 were developed and the results were compared with a reference case in 2010. The narratives and rationale for different case studies are provided below:

2010-Ref: In order to calibrate the model and also compare the results of future scenarios, the GB electricity, heat and gas supply systems in 2010 were modelled as a reference case. The data for power generation mix and share of heat supply technologies to meet the heat demand are presented in Table 3 and

Table 4.

2030-CC: This case represents a future in which the share of technologies for supplying heat demand was determined based on economically rational consumers (

Table 4). The underlying assumptions for the heat supply scenario is explained in details in [25]. The power generation mix proposed in Gone Green Scenario [2] was used (Table 3).

2030-EH: In this case, a large contribution of district heating networks as well as a high level of electrification of heat sector were assumed [25]. Similar to 2030-CC, the generation mix proposed by the Gone Green Scenario was used.

Table 3 - Power generation capacity in different case studies

	Ref_2010 [35]	2030_EH and 2030_CC [2]
Nuclear	10800 MW	11300 MW
Coal	23000 MW	0
Coal+CCS	0	2000 MW
Gas CCGT	32200 MW	27600 MW
Gas+CCS	0	1900 MW
Wind	1800 MW	48000 MW
Solar	0	23300 MW
Hydro	4100 MW	1000 MW
Interconnector	3000 MW	17700 MW
Conventional Other	10800 MW	6800 MW
Renewable Other	200 MW	8400 MW

Table 4 - Share of different technologies in supplying heat [25]

	Ref_2010	2030_EH	2030_CC
DHN + Gas CHP	0	23%	7%
Gas Micro CHP	0	0	5%
Gas Boiler	80%	30%	60%
ASHP	0	25%	10%
GSHP	0	5%	0
Direct Electric Heating	10%	12%	15%
Oil Boiler	10%	5%	3%

4.2. Heat, electricity and gas demand data

Heat demand

The estimated half-hourly national heat demand for residential and commercial buildings in 2010 was taken from [26], and shown by Figure 3. The heat demand profile shows significantly large peak of 350GW in winter which is almost seven times larger than the peak for electricity. In addition, the substantial variations in heat demand throughout the year reflect the need for space heating in winter.

It was assumed that the heat demand for the year 2030 will be the same as the 2010. Although the efficiency improvement due to better insulation of the buildings is expected to reduce the heat demand per capita, the increased population as well as higher level of welfare were assumed to offset the effect of efficiency improvement in heat demand. This assumption is in line with the IPCC projection: *“Population growth, migration to cities, household size changes, and increasing levels of wealth and lifestyle changes globally will all contribute to significant increases in building energy use.”* [36].

Electricity demand

To derive the non-heating electricity demand, that is shown by Figure 3, the estimated electricity demand for heating in 2010 (as described by Eq. 2, Eq. 3 and Eq. 4) was deducted from the historical half-hourly electricity demand in 2010 for GB [37].

The non-heating electricity demand for GB in 2030 was derived by considering the additional electricity demand for electric vehicles [2]. The annual additional electricity demand of 14 TWh which will result in 1 GW increase in the peak electricity demand was added to the non-heating electricity demand in 2010.

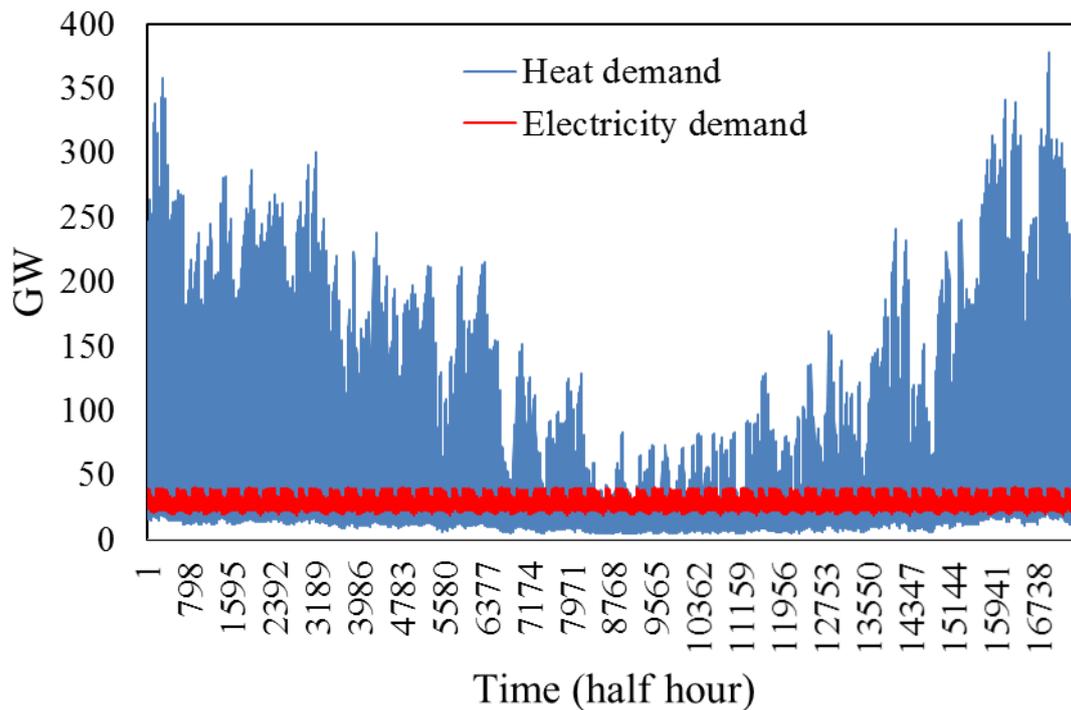


Figure 3 - Half-hourly demands for heat [26] and electricity (excluding electricity consumption for heat). The electricity demand profile shown in this figure excludes the electricity demand for heating, therefore, the maximum electricity demand over the year is fairly constant.

Gas demand

In 2010 roughly 80% of the total gas was used for heat and power generation. In this study, the gas demand for the heating and power sectors was calculated within the model. Gas demand for industry, which was around 90 TWh in 2010, was assumed to be distributed uniformly over a year. The half-hourly gas demand was used as input to the model. It was assumed that the gas demand excluding for heating and power (e.g. for cooking and industry) in 2030 and 2010 are the same. It

was assumed that the reduction in the gas demand in industry will be compensated by increase in gas demand for transport [2].

Wind generation

Real half-hourly aggregated wind generation data for GB over 2010 was taken from [38] and was normalised and used to represent power outputs from 3 GW installed wind in 2010 and 48 GW wind farms that is anticipated to be installed in 2030.

Solar generation

The half-hourly real data for total electricity generation from solar photovoltaic panels in GB in 2010 was used to calculate a normalised solar power generation profile. The normalised solar power generation profile was used in the 2030 cases to represent power outputs from 23 GW of PV.

The profile of normalised half-hourly solar power generation over different days in 2010 is shown by Figure 4, where dark blue means zero, and dark red means maximum power generation. A significant within-day as well as seasonal variation in the solar power generation is observed. One of the challenges of a large capacity of the solar PV is that the power output in evening of the winter days which is peak hours for electricity is zero, and therefore PV's contribution to meeting the peak electricity is zero.

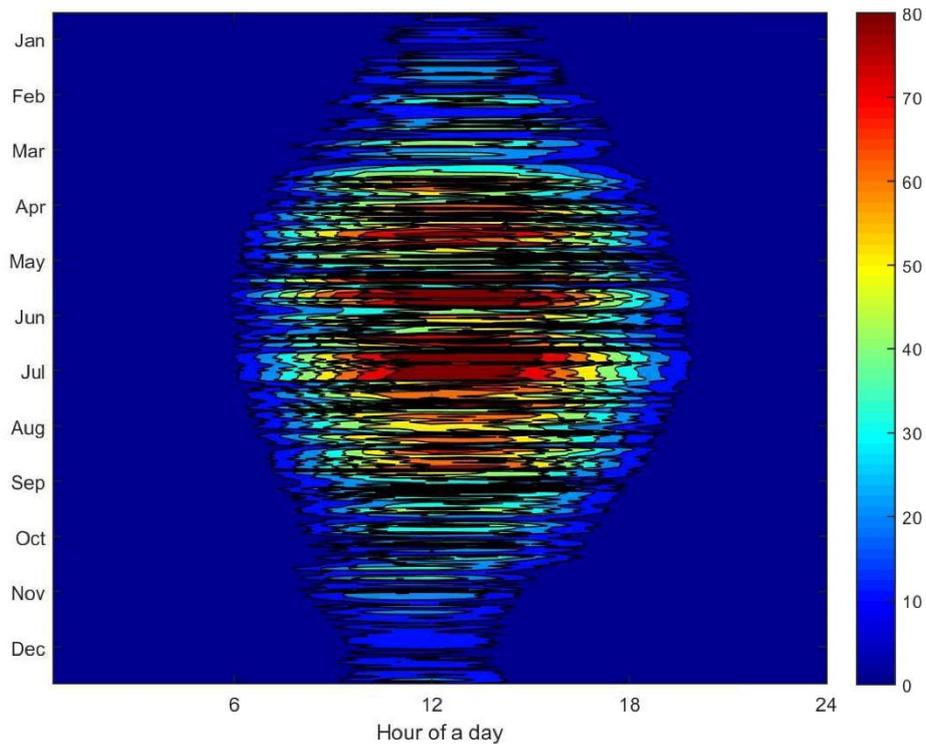


Figure 4 - Half hourly normalised solar power generation in GB in 2010. Dark blue colour shows zero, and dark red colour shows maximum power generation (% of capacity)

4.1. Generating hourly temperature values using daily maximum, minimum and average values

Considering the effect of outside air temperature on the performance of an air-source heat pump (ASHP), temperature data at half-hourly intervals is required. While the half-hourly temperature data was not available for 2010, a sinusoidal interpolation algorithm was applied to generate half-hourly temperature values using the daily maximum temperature T_{MAX} , and daily minimum temperature, T_{MIN} . To represent national average temperature in UK, the daily maximum and minimum temperatures for London in 2010, were obtained from [39].

The method developed by the Chartered Institution of Building Services Engineers (CIBSE) uses simply the daily maximum and minimum temperatures for generating hourly outdoor dry bulb

temperature [40]. This method relies on the times (t_{max} and t_{min}) at which T_{MAX} and T_{MIN} occur in the day, and uses two sinusoidal curves to fit the data. The preliminary algorithm produces data for one day only. However, in this study it is necessary to generate a year of data. Therefore, the T_{MAX} of any day was linked, using a sinusoidal curve, with the T_{MIN} of the following day, in order to produce a smooth transition between days.

The equation used for our calculation is given by Eq. 11.

$$T(t) = \left(\frac{Temp_{(next)} + Temp_{(prev)}}{2} \right) - \left[\left(\frac{Temp_{(next)} - Temp_{(prev)}}{2} \right) \times \cos \left(\frac{\pi(t - t_{(prev)})}{t_{(next)} - t_{(prev)}} \right) \right] \quad \text{Eq. 11}$$

where $Temp_{(next)}$ is the next known temperature value (T_{MAX} or T_{MIN}); $Temp_{(prev)}$ is the previous known temperature value (T_{MAX} or T_{MIN}); $t_{(next)}$ is the time for the next known temperature value; $t_{(prev)}$ is the time for the previous known temperature value; and t is the time. Further details can be found at [41].

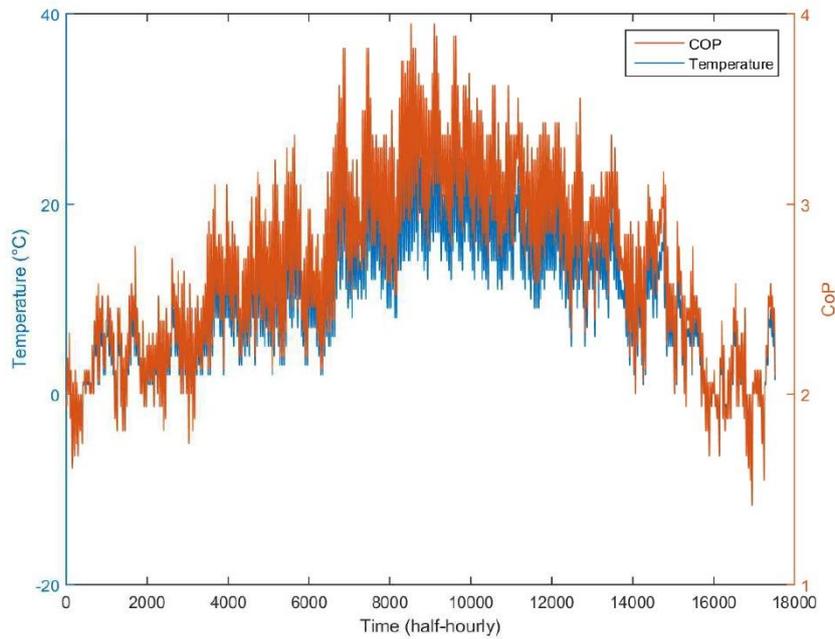


Figure 5 - Half-hourly temperature and COP of ASHP

3 [44] provides a list of suggested t_{max} and t_{min} for different months of the year

5. Results and Discussion

5.1. Electricity demand

Electricity demand load duration curves for different case studies are shown in **Error! Reference source not found.**. The different levels of electrification of heat supply assumed in *2030_CC* (25%) and *2030_EH* (42%) have significant impacts on peak and annual electricity demand. The peak electricity demand in *2030_EH* is 88 GW which is 28 GW (47%) higher than the electricity peak demand in 2010 (60 GW). The total annual electricity demand for *2030_EH* is 412 TWh from which 140 TWh is used by heat pumps and other types of electric heaters to supply heating. The peak electricity demand for *2030_CC* is 77 GW, and the annual electricity demand is 382 TWh. As the level of electrification of heat supply increases, the difference between maximum and minimum electricity demand over a year substantially increases (e.g. 39.6 GW in *Ref_2010* to 55.2 GW in *2030_CC* to 65.7 GW in *2030-EH*). This requires a large capacity of peaking plants to be installed to meet electricity demand during peak hours in cold seasons.

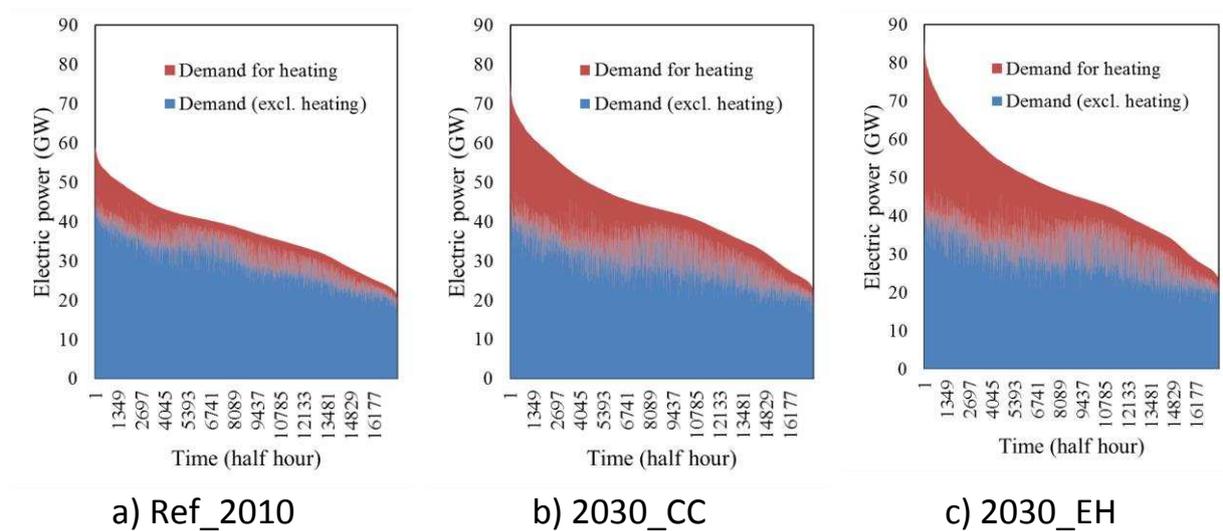


Figure 6 – Electricity demand load duration curve

It was assumed that the ASHP will operate in conjunction with a gas boiler as a hybrid heating system in dwellings. This allows the option of switching between gas and electricity for meeting domestic heat demand. From the costumers’ perspective, the rationale behind switching between gas and electricity in a hybrid heating system is primarily to minimise the energy bill subject to meeting the heat demand. From electricity system’s point of view, hybrid heat pumps can be operated in such a way to avoid an increase in the electricity peak demand and its associated system reinforcement costs. For instance, when electricity peak demand is about to exceed the existing peak value due to the additional electricity demand for ASHPs, the hybrid heating systems switch to gas to supply the heat demand. However, in this research, the performance diagram of a hybrid heating system (Figure 2) was used to determine the share of gas and electricity in hybrid heating system which only depends on the outside temperature.

The values of peak and annual electricity demand in the 2030 case studies shown in **Error! Reference source not found.** were derived considering that in domestic buildings that use an ASHP, a condensing gas boiler is used as a supplementary source of heating during low temperature periods. The analysis showed that if ASHPs were to meet the heating demand on their own, the peak and annual electricity demand increase as shown in Table 5. The employment of hybrid heating system does not significantly reduce the annual electricity demand (0.2 TWh in 2030_CC and 0.7 TWh in 2030_EH). This is due to the small number of hours at which the temperature drops below -2.7 °C and gas boilers supplement ASHPs (see Figure 2). However, the impact of hybrid heating system on reducing the peak electricity demand is considerable (600 MW in 2030_CC and 1500 MW in 2030_EH).

Table 5 - The impacts of hybrid heating systems (ASHP and gas boilers) on peak and annual electricity demand

Case study	Variants	Peak electricity demand (GW)	Annual electricity demand (TWh)
Ref_2010		60.2	329
2030_CC	ASHP only	77.4	382.5
	Hybrid heating system	76.8	382.3
2030_EH	ASHP only	89.2	412.5

	Hybrid heating system	87.7	411.8
--	-----------------------	------	-------

5.2. Power generation dispatch

The contribution of various generation technologies in supplying electricity is shown in Figure 7. In 2010 coal and gas power plants contribute equally to supplying 252 TWh (76%) of the total electricity demand in GB. Modelling results for 2010 suggest that the capacity factor is 40% for gas-fired, 56% for coal and 75% for nuclear plants. While the real capacity factor for these plants in 2010 were 61% for gas-fired, 40% for coal and 65% for nuclear plants. The differences between modelled and real capacity factors for gas-fire and coal power plants mainly originate from fuel price assumptions for coal and gas. In the optimisation model it was assumed that coal price is lower than gas price which generally is a valid assumption in long term (this caused lower capacity factor for gas-fired compared to coal plants in the model), however there could be some fluctuations in relative prices of gas and coal in short term that alter the marginal generation costs and consequently capacity factors for these plants [42]. In 2010, the gas price fell below coal price and therefore the capacity factor of gas-fired plants exceeded the capacity factor of coal plants. On the other hand, the relatively low real capacity factor for nuclear plants in 2010, compared to the modelling results, was due to maintenance outages at several stations (see Chapter 5 of [35]). These outages resulted in lower than average capacity factor for nuclear plants in 2010.

The electricity supply from unabated coal power plants reduced to zero by 2030 due to the phase out of these plants imposed by the Large Combustion Plants Directives (LCPD). Compared to 2010, electricity generation by gas-fired power plants (without CCS) reduced by 44.9 TWh in *2030-EH* and 25.6 TWh in *2030-CC*. This reductions are consequences of substantial increase in wind and solar generation capacity in 2030.

In both 2030 cases electricity supply by nuclear power plants increases by around 8 TWh compared to 2010 and reached around 74 TWh. Also CCS-equipped power plants will contribute to supplying 23 TWh of electricity demand.

One of the main changes in the electricity supply mix in 2030 is significantly larger share of wind and solar generation. While, the total electricity generation from wind and solar in 2010 is almost 5.7 TWh, it increased to 119 TWh in 2030-CC and 118TWh in 2030-EH.

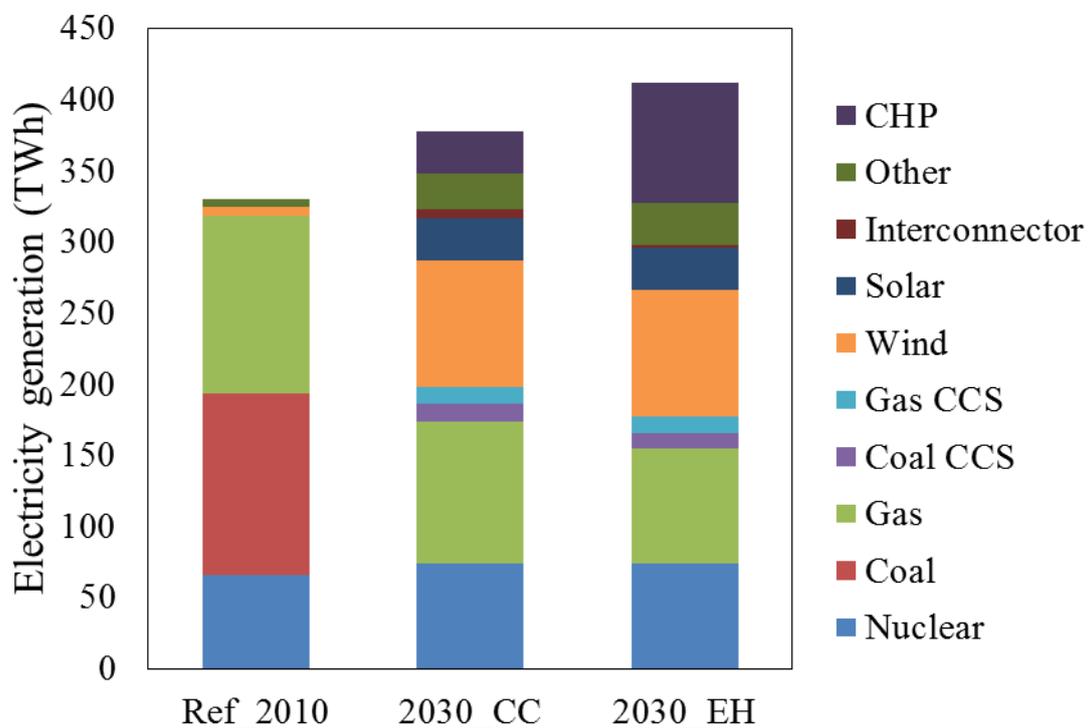


Figure 7 - Electricity generation by technologies for different case studies

Although the total electricity generation by gas-fired plants over a year (TWh) in 2030 cases was lower than in 2010, the maximum electric power generation by these plants (GW) slightly increases in the 2030 cases (Figure 8). This increase is a consequence of decommissioning of coal power plants that leaves the gas-fired plants to be the next cheapest option to complement variable renewable generation, in particular in occasions when low wind periods coincide with peak demand.

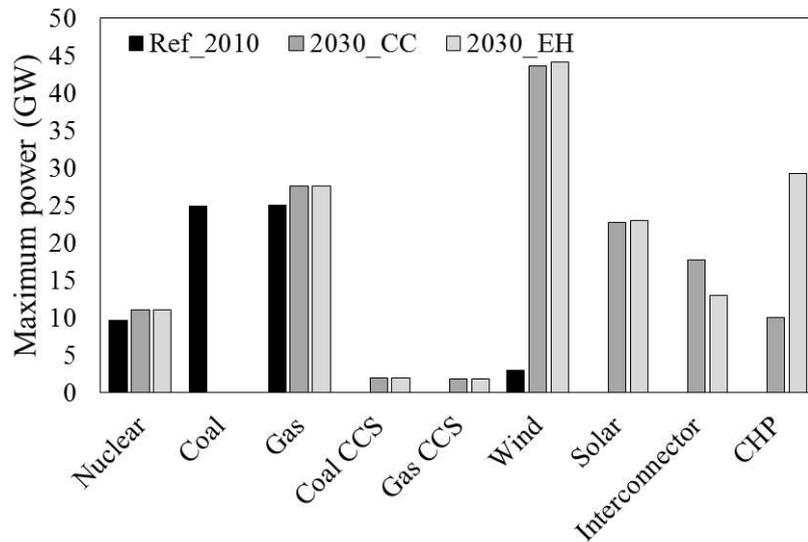


Figure 8 - Maximum power generation by different technologies

Power output from the gas-fired plants in 2030 cases fluctuates more frequently with larger magnitudes compared to 2010. The future role of gas-fired plants in balancing electricity supply and demand will result in lower capacity factor for these plants. The capacity factor of gas-fired plants in 2030_CC is 41% and in 2030_EH is 33%.

Analysis of wind and solar curtailment in 2030 showed that in 2030_EH, despite larger total electricity demand (including for heating), slightly more electricity is curtailed (9.7 TWh) compared to 2030_CC (9.3 TWh). This is due to the large capacity of heat-driven CHP plants and micro-CHP units in 2030_EH which supply 23% of the heat demand, and also generate electricity as by-product. As the heat-driven CHP plants do not provide flexibility to the power system, the combination of large capacity of variable renewable generation along with CHP plants leads to higher level of renewable electricity curtailment in 2030_EH.

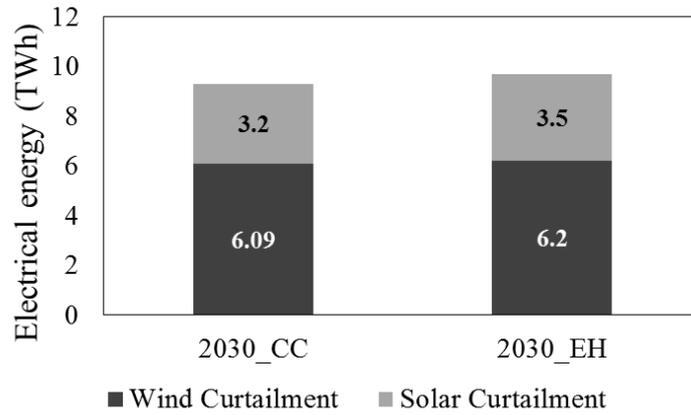
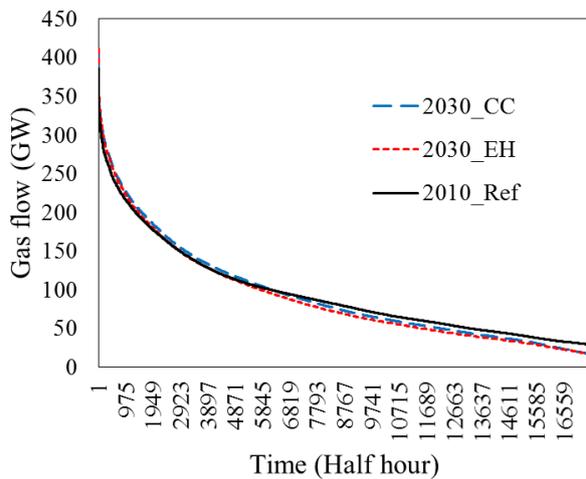


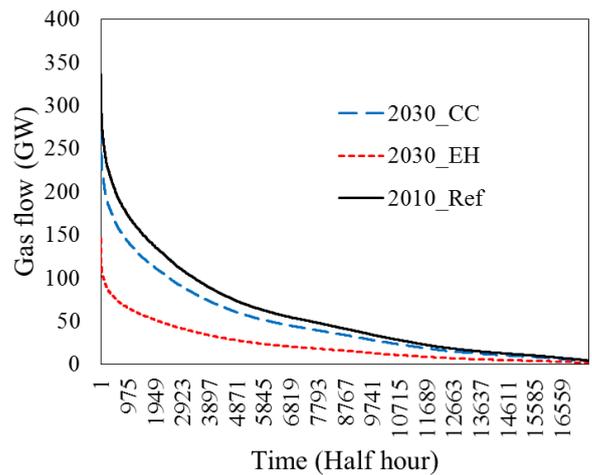
Figure 9 - Wind and solar curtailment

5.3. Gas supply

Gas supply duration curve for high and medium gas distribution networks (above 75 millibar) and low pressure gas distribution networks (below 75 millibar) are shown in **Error! Reference source not found..** In 2010, the total gas flowing through the high and medium pressure gas network is 835 TWh. This value for low pressure gas networks is 512 TWh.



a) High and medium pressure gas networks (above 75 mbar)



b) Low pressure gas distribution network (below 75 mbar)

Figure 10 - Load duration curves for gas demands on (a) High and medium gas pressure networks (above 75 mbar), and (b) low pressure gas distribution networks (below 75 mbar)

Electrification of heating reduces the annual gas supply through the low pressure networks by 92 TWh in 2030_CC and by 319 TWh in 2030_EH. This large reduction in the annual gas flowing through the low pressure networks is primarily because of the substantial reductions in the use of gas boilers to meet heat demand. The annual gas flow in the high/medium pressure networks also reduces in 2030 cases, however the changes are not as large as seen in the low pressure networks: 59 TWh reduction in 2030_CC and 190 TWh reduction in 2030_EH (Figure 11). The smaller reductions at high/medium pressure network compared to low pressure networks is a result of increase in gas demand for CHP plants that are connected to these networks (above 75 millibar).

Electrification of heat supply and moving towards larger penetration of district heating networks was shown to have major impacts on the low pressure gas networks. Substitution of domestic gas boilers with heat pumps and large CHP plants (which are connected to medium pressure gas network) significantly reduces the maximum gas demand in the low pressure networks, however, the maximum gas flow in the high/medium pressure networks is expected to increase. The maximum gas demand in the high/medium pressure networks in 2030 cases increased compared to the reference case in 2010. This is partly due to the reliance on gas-fired power generation plants to contribute to meeting peak electricity demand, and partly due to contribution of gas-fired CHP plants in supplying heat.

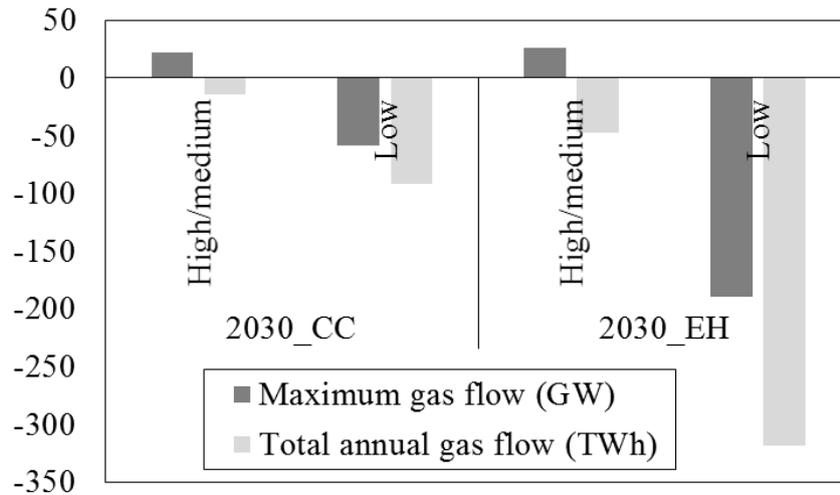


Figure 11 - Changes in Maximum and annual gas flow through different pressure tiers

Analysis of the half-hourly flow of natural gas through the GB high/medium and low pressure networks (Figure 12) shows that larger within-day changes in the gas flow, in particular in summer, occur in 2030-EH and 2030-CC compared to Ref-2010. This is mainly a consequence of reducing the share of gas-based power generation in meeting base load, but relying on gas generators to compensate for drops in wind and solar generation during peak hours. In order to manage the larger fluctuations in the gas demand, more flexibility needs to be made available either through adopting new operational strategy to maintain linepack, or by investing in physical assets such as fast-cycle gas storage and more flexible gas compressors.

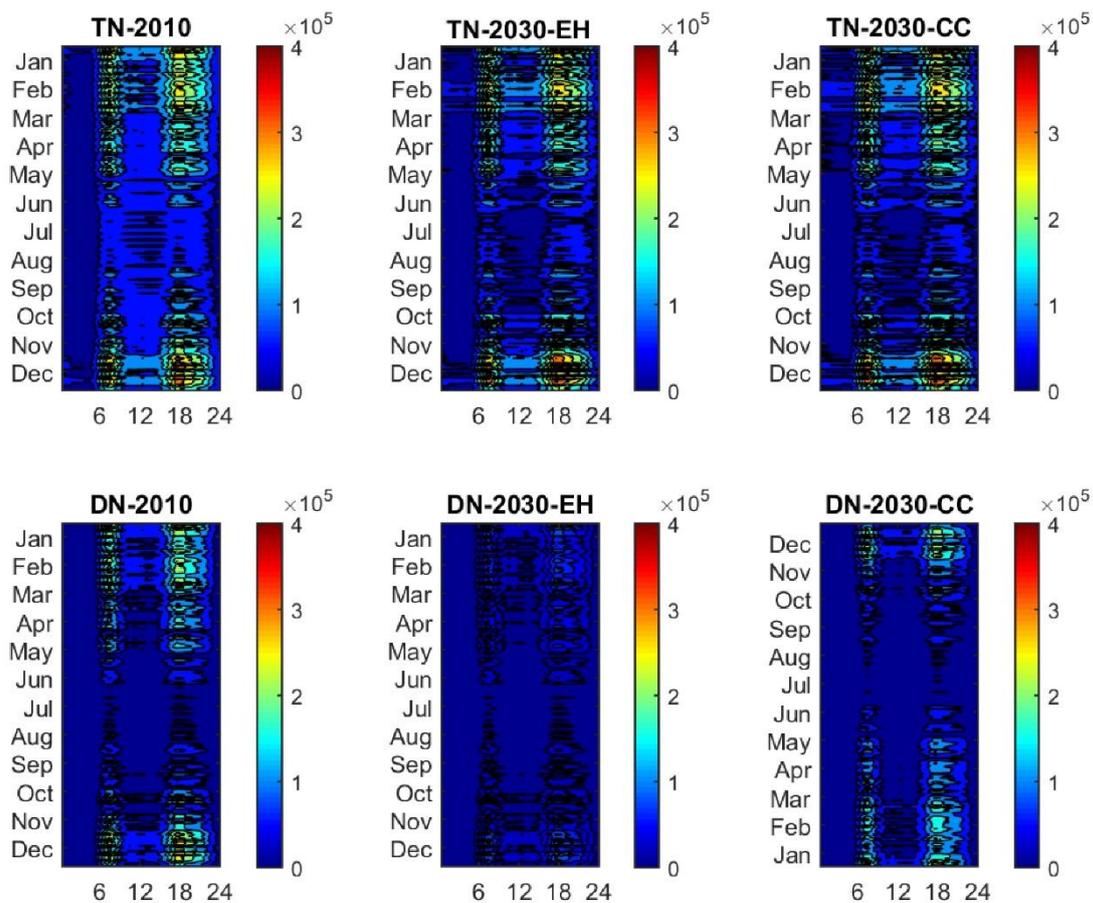


Figure 12 - Half-hourly gas demands on High and medium pressure gas networks (top), and (b) Low pressure gas networks (bottom) for 2010 and different scenarios in 2030. Dark blue colour shows zero, and dark red colour shows maximum gas flow (400 GW).

5.4. Hybrid heating system vs ASHP

The impacts of using hybrid heating systems (ASHP supplemented by a Gas boiler) instead of only ASHP on the peak and annual demand of gas were quantified for the 2030_CC and 2030_EH scenarios. Table 6 shows the annual and peak demand for gas for each heating scenario. Both annual and peak gas demand are reduced in all the cases in which a hybrid heating system was employed. The reduction in the annual and peak gas demand happened despite the larger share of gas in

supplying heat. This is due to the increased use of gas for power generation in cases in which ASHP is used. During peak hours when the temperature is low and wind generation is minimal, gas-fired plants operate to their maximum capacity to supply electricity demand for ASHP. The low CoP of ASHP during cold weather results in lower efficiency when gas is used in gas-fired plants and then ASHP used to produce heat, compared to using gas directly in a gas boiler to supply the same amount of heat. For instance, the efficiency of heat production through gas → CCGT → ASHP during cold weather is 72% which is lower than the 90% efficiency of a gas boiler.

Table 6 - The impacts of hybrid heating systems (ASHP and gas boilers) on peak and annual electricity demand

Case study	Variants	Peak gas demand (GW)	Annual gas demand (TWh)
Ref_2010		386	835
2030_CC	ASHP only	420	830
	Hybrid heating system	408	821
2030_EH	ASHP only	422	791
	Hybrid heating system	412	788

6. Conclusions and Policy Implications

This study investigated and quantified the impacts of decarbonising the GB power and heat sectors on the high/medium pressure and low pressure gas networks. The hypothesis behind this study was that the decarbonisation of heat in particular will impact both gas and electricity systems, and depending on decarbonisation pathways, the level of impacts and the infrastructure that will be influenced the most could be significantly different.

It was shown that the electrification of heat supply in GB will have a great impact on the low pressure gas distribution networks as a large fraction of gas for heating residential and commercial buildings will be replaced by electricity. At the transmission level, the electrification of heat supply mainly leads to lower annual gas flows and more fluctuations. However, in terms of the maximum instantaneous gas flows through transmission network, no reduction is expected due to the

increasingly crucial role of gas-fired generating units to compensate for variability of wind. This, in particular leads to a substantially large gas demand for power generation during cold winter peaks with low wind generation.

It was shown that electrification of the heat sector will substantially decrease the annual gas flowing through low pressure networks. This is because of widespread substitution of gas boilers by heat pumps. The reduced utilisation factor of the low pressure gas distribution network caused by electrification of the heat sector seems not to be in line with the nationwide programme of iron main replacement.

Although there is not an intrinsic and strong correlation between the availability of wind power and the level of heat demand, the provision of flexibility from the heat sector to support balancing energy demand and supply is a key feature that can be exploited through effective integration of heat and electricity sector in their planning and operation.

Also, a large contribution of air source heat pumps in supplying heat demand, questions the capability of heat supply system to meet peak demand during cold winters. This is due to the sensitivity of the coefficient of performance of ASHP's to temperature, which make these technologies struggle to produce high temperature heat during cold weather. This will require a backup heating technology to supplement the heat and consequently has cost implications.

The cost implication of frequent on and off cycling of the gas turbine power generating plants as well as their low capacity factors have been discussed for some time and policy makers recognise the issue as a factor that will affect the security and reliability of electricity supply. What has not been critically discussed was the cost implications on the gas distribution networks with lower utilisation factor. This requires a level of investment to maintain at least the current gas flow capacity, while the total gas demand is expected to decrease. The distribution of the network cost over the smaller number of customers means greater connection fee and greater gas network charges. All these question the economics of the gas network in future.

Acknowledgement

The first and third authors gratefully acknowledge the Flexible Integrated Energy Systems (Flexis) project for providing funding for this work. Flexis is part-funded by the European Regional Development Fund (ERDF), through the Welsh Government.

Appendix – Techno-economic characteristics of generation technologies

A. Generation cost

Costs of electricity generation are shown in table A.1.

Table A.1. Fuel and variable cost for different types of generators [28]

Generator type	Fuel and variable cost (£/MWh)
Nuclear	10
Coal	22
Coal+CCS	30
Gas CCGT	43
Gas+CCS	51
Interconnector	100

B. Plants availability

The availability of power plants were retrieved from [43] and are displayed in Table A.2.

Table A.2. Availability of different types of generators [43]

Generator type	Availability (%)
Nuclear	81
Coal with CCS	88
Gas w/wo CCS	87
Hydroelectric	84
Pumped Storage	97

References

- [1] Committee on Climate Change, “The Fifth Carbon Budget - The next step towards a low-carbon economy,” 2015.
- [2] National Grid, “Future Energy Scenarios,” 2015.
- [3] HM Government, “2050 Pathways Analysis,” 2010.
- [4] DECC, “Digest of United Kingdom Energy Statistics 2013,” 2013.
- [5] M. Chaudry, M. Abeysekera, S. H. R. Hosseini, N. Jenkins, and J. Wu, “Uncertainties in decarbonising heat in the UK,” *Energy Policy*, vol. 87, pp. 623–640, 2015.
- [6] R. V Jones, A. Fuertes, and K. J. Lomas, “The socio-economic , dwelling and appliance related factors affecting electricity consumption in domestic buildings,” Elsevier, 2015.
- [7] C. Carpino, R. Bruno, and N. Arcuri, “Statistical analysis of the heating demand in residential buildings located in Mediterranean climate and proposals for refurbishment,” in *Mediterranean Conference of HVAC; Historical buildings retrofit in the Mediterranean area*, 2017, pp. 16–27.
- [8] K. Gajowniczek and T. Zabkowski, “Data Mining Techniques for Detecting Household Characteristics Based on Smart Meter Data,” *Energies*, vol. 8, pp. 7407–7427, 2015.
- [9] A. Advani, P. Johnson, A. Leicester, and G. Stoye, “Household Energy Use in Britain : A Distributional Analysis,” 2013.
- [10] DECC, “Domestic Renewable Heat Incentive,” no. July, p. 34, 2013.
- [11] R. Lowe, “Renewable Heat Premium Payment Scheme: Heat Pump Monitoring: Cleaned Data, 2013-2015,” 2017.
- [12] Department of Energy and Climate Change, “The Future of Heating : Meeting the challenge,”

- Decc*, no. March, 2013.
- [13] J. Oswald, M. Raine, and H. Ashraf-Ball, "Will British weather provide reliable electricity?," *Energy Policy*, vol. 36, no. 8, pp. 3202–3215, 2008.
- [14] M. Qadrdan, M. Chaudry, N. Jenkins, P. Baruah, and N. Eyre, "Impact of transition to a low carbon power system on the GB gas network," *Appl. Energy*, vol. 151, pp. 1–12, 2015.
- [15] G. Anandarajah, N. Strachan, P. Ekins, R. Kannan, and N. Hughes, "Pathways to a Low Carbon Economy: Energy Systems Modelling," no. March, p. 109, 2009.
- [16] NERA and AEA, "The UK Supply Curve for Renewable Heat: Study for the Department of Energy and Climate Change," vol. 689, no. July, 2009.
- [17] NERA, "Design of the Renewable Heat Incentive Study for the Department of Energy & Climate Change Project Team," no. February, pp. 1–84, 2010.
- [18] H. Lund, B. Möller, B. V. Mathiesen, and A. Dyrelund, "The role of district heating in future renewable energy systems," *Energy*, vol. 35, no. 3, pp. 1381–1390, 2010.
- [19] Redpoint, "Modelling to Support - The Future of Heating : Meeting the challenge," 2013.
- [20] Element Energy and AEA, "Decarbonising heat in buildings 2030 - 2050. Summary report for The Committee on Climate Change.," 2012.
- [21] P. E. Dodds, "Integrating housing stock and energy system models as a strategy to improve heat decarbonisation assessments," *Appl. Energy*, vol. 132, pp. 358–369, 2014.
- [22] M. J. Hannon, "Raising the temperature of the UK heat pump market: Learning lessons from Finland," *Energy Policy*, vol. 85, pp. 369–375, 2015.
- [23] L. M. H. Hall and A. R. Buckley, "A review of energy systems models in the UK: Prevalent usage and categorisation," *Appl. Energy*, vol. 169, pp. 607–628, 2016.

- [24] F. Jalil-Vega and A. D. Hawkes, "Spatially resolved model for studying decarbonisation pathways for heat supply and infrastructure trade-offs," *Appl. Energy*, vol. 210, pp. 1051–1072, 2018.
- [25] Delta-ee, "2050 Pathways for Domestic Heat," 2012.
- [26] R. Sansom, "Decarbonising low grade heat for a low carbon future," Imperial College London, 2014.
- [27] Mott MacDonald, "UK Electricity Generation Costs Update," 2010.
- [28] BEIS, "Electricity generation costs," 2016.
- [29] U.S. Environmental Protection Agency and Combined Heat and Power Partnership, "Catalog of CHP Technologies," 2015.
- [30] Carbon Trust, "How to implement condensing boilers."
- [31] J. Harrison, *Micro CHP - The big picture*. Blurb, 2010.
- [32] E. Pean, M. Pirouti, and M. Qadrdan, "Role of the GB-France electricity interconnectors in integration of variable renewable generation," *Renew. Energy*, vol. 99, 2016.
- [33] D. Overbey, "Gauging the Seasonal Efficiency of Air-Source Heat Pumps," *Walls & Ceilings online*, Feb-2015.
- [34] FICO, "Getting Started with Xpress," 2017.
- [35] DECC, "Digest of UK Energy Statistics 2011," 2011.
- [36] E. Lucon O., D. Ürge-Vorsatz, A. Zain Ahmed, H. Akbari, P. Bertoldi, L. F. Cabeza, N. Eyre, A. Gadgil, L. D. D. Harvey, Y. Jiang and and M. V. V. Liphoto, S. Mirasgedis, S. Murakami, J. Parikh, C. Pyke, *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate*

- Change*. Cambridge University Press, 2014.
- [37] National Grid, "Historical Demand Data." [Online]. Available: <https://www.nationalgrideso.com/balancing-data/data-explorer>.
- [38] "Elexon," 2017. [Online]. Available: <https://www.elexon.co.uk/>.
- [39] "Weather Underground," 2017. [Online]. Available: <https://www.wunderground.com/>.
- [40] CIBSE, "Guide A2 Weather and Solar Data," 1982.
- [41] D. H. C. Chow and G. J. Levermore, "New algorithm for generating hourly temperature values using daily maximum, minimum and average values from climate models," *Build. Serv. Eng. Res. Technol.*, vol. 28, no. 3, pp. 237–248, 2007.
- [42] I. Pan, "Natural gas gains popularity with power generators," *Market realist*, 2013.
- [43] Ofgem, "Electricity Capacity Assessment Report 2014," 2014.
- [44] CIBSE, "Guide J Weather Solar and Illuminance Data," 2002.