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Abstract

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Keywords heat electrification, energy systems optimisation, carbon capture and storage, heat pumps, unit commitment, investment planning

JEL Classification C31, C61, C63, L94, L95, Q42, Q48

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The case of 100% electrification of domestic heat in Great Britain

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Unlike power sector decarbonisation, there has been little progress made on heat, which is currently the biggest energy consumer in the UK, accounting for 45% of total energy consumption in 2019, and almost 40% of UK GHG emissions. Given the UK's legally binding commitment to "Net-Zero" by 2050, decarbonising heat is becoming urgent and currently one of the main pathways involves its electrification. Here, we present a spatially-explicit optimisation model that investigates the implications of electrifying heat on the operation of the power sector. Using hourly historical gas demand data we conclude that the domestic peak heat demand is almost 50% lower than widely-cited values. A 100% electrification pathway can be achieved with only a 1.3-fold increase in generation capacity compared to a power-only decarbonisation scenario, but only, by leveraging the role of thermal energy storage technologies without which a further 40% increase would be needed.

Introduction

Energy use and emissions from residential heating and cooling are increasingly important in many leading countries in their race to net-zero[1,2]. Recent studies on 1.5°C- compliant scenarios indicate considerably less flexibility in options available to decarbonise the residential sector highlighting the necessity to act now[3–6]. Decarbonising heat in particular is often conceived as a daunting task as natural gas serves between 60-80% of the domestic heat sector in countries like the UK, the Netherlands and United States with high consumer satisfaction[7,8]. By 2019, the UK managed to reduce its greenhouse gas (GHG) emissions by 36% compared to 2008 levels, driven by power sector emissions, which fell by 67%.[9]. While there has been steady progress in decarbonising the power sector, mostly through deploying renewable energy and replacing coal with gas generation, decarbonising the heat sector remains an unsolved riddle on the energy agenda. In 2019, heat was the single biggest energy consumer in the UK, accounting for 45% of total energy consumption and 40% of UK's territorial emissions[10].

The carbon intensity of the heat sector is driven by the incumbent gas-dominated system which serves almost 80% of demand across residential, commercial and industrial sectors[10]. Given the high operational efficiency and low cost of the gas system, decarbonising the heat sector will require judicious decision making and high levels of policy intervention.

Full electrification of the heat sector and replacing natural gas with hydrogen and hybrid systems including district heat networks and cogeneration technologies are the main heat decarbonisation pathways being advanced[11–14]. Each pathway is characterised by distinct trade-offs and a high degree of uncertainty related to the end cost for heating as well as the efficiency and security of the resulting low-carbon system. To date, most research has examined the problem of heat decarbonisation by considering aggregate representations of the spatial and temporal scales of the problem on a national level[15] and the impact of operational and security constraints on the resulting energy infrastructure has been neglected. In its 2018 overview publication, the UK Department of Business, Energy & Industrial Strategy (BEIS), outlined developments and policy initiatives on the topic of heat decarbonisation arguing that no single technology can prevail as dominant so far[16]. Electrification, biomass and hydrogen were advanced as the three main pathways whereas in its 2013 publication electrification was proposed as the dominant pathway[17]. Concerns over electrification often centre on expected pressures on the power grid and the perceived need for a very significant increase in generation capacity by as much as three-fold[18].

We use modelling and optimisation to elucidate the implications of decarbonising the domestic heat sector in Great Britain (GB) through electrification and present for the first time a high-resolution regional analysis. A key contribution of our study is the derivation and modelling of region-specific domestic heat demand profiles across the 13 local distribution zones (LDZs) of the GB gas network. The goal of our study is two-fold: (i) provide a systems-based examination on the implications of electrifying domestic heat in GB and (ii) identify the factors that act as barriers and enablers in the cost-optimal pathways for domestic heat decarbonisation.

Analysing the domestic heat sector in GB

Almost 80% of British households are connected to the gas grid while the remaining 20%, amounting to approximately 3.5 million households, are off-grid. Of the off-gas grid prop-

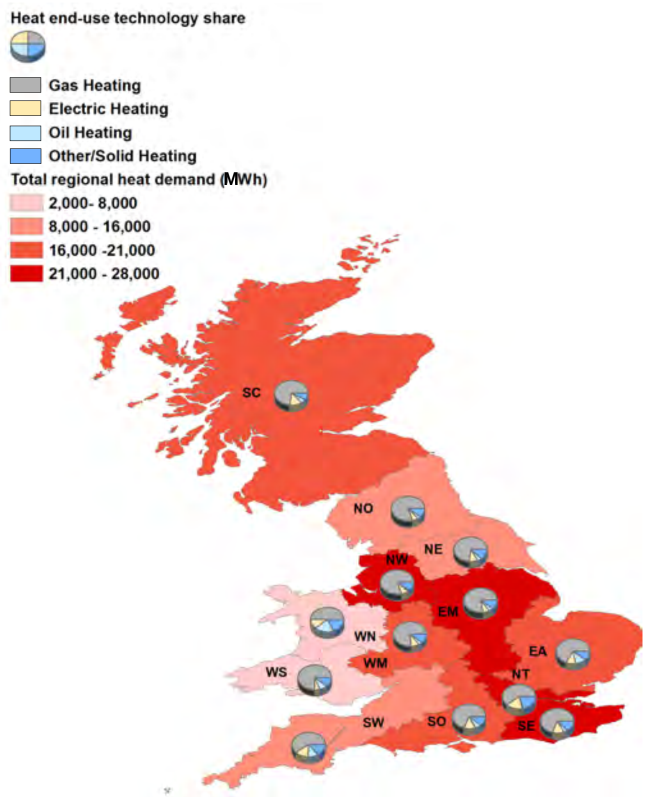


Figure 1. Regional analysis of the share of installed heating systems across the different regions in GB along with the total regional heat demand (MWh, given in red shading. Abbreviations: East Anglia (EA), East Midlands (EM), North East (NE), North (NO), North Thames (NT), North West (NW), Scotland (SC), South East (SE), South (SO), South West (SW), West Midlands (WM), Wales North (WN), Wales South (WS).

erties, 36.6% use some form of electric heating (mostly in the form of storage heaters), 40.8% utilise solid fuels (e.g. biomass, coal) and 22.4 % use oil burners[19]. Other forms of heating technologies such as district heat networks, ground-source heat pumps (GSHPs), air-source heat pumps (ASHPs) and micro combined heat and power systems (micro-CHP), all of which constitute viable options but to date have experienced limited adoption and taken together represent less than 2.6% of domestic heating systems in the UK[16]. In terms of incumbency, as indicated by Fig. 1 , the regions in the North of England (NO, NE, NW) have the lowest share of electric heating technologies while the South of England (SW, SE, NT) have the largest share. Interestingly in Wales, there is a significant divergence between the two regions, WS and WN, which can be attributed to 50% of WN properties not being connected to the gas grid and hence there are large shares of both electric and oil heating. In Scotland, more than 26% of domestic properties are not connected to the gas grid (13.5% electric heating and 13% oil/solid fuel).

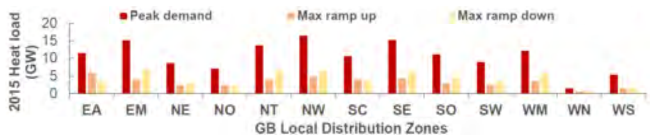
Regional domestic heat demand in GB

Deciphering the impact of heat electrification in GB is explicitly dependent on the underlying heat demand characteristics of the different regions. Compared to non-heat- related electricity loads, heat demand is both highly volatile (in terms of ramp-rate changes) and seasonal. To date, one key challenge has been the lack of heat demand data at high temporal and spatial resolution. In GB, gas consumption data over the 13 different local distribution zones is only publicly available by National Grid with daily resolution[20] which impedes any analysis on the operational implications for the power system. Only a handful of studies make use of (half) hourly heat demand data[15,21,22] to examine heat decarbonisation in GB. However the aforementioned time series suffer from three shortcomings: (i) they are based on a limited number of smart-meter trials[23,24], thus generalising to the actual building stock can be problematic, (ii) the same demand profiles are applied uniformly across regions, thus neglecting differing socioeconomic and climactic factors that affect consumer behaviour and (iii) scaling-up individual profiles on a regional scale is subject to several assumptions about after diversity maximum demand (ADMD) which directly affects the sizing and performance of the resulting energy system infrastructure. ADMD accounts for non-coincident factors that explain the phenomenon under which the actual observed demand from a collection of households is less than the direct summation of their respective loads[25].

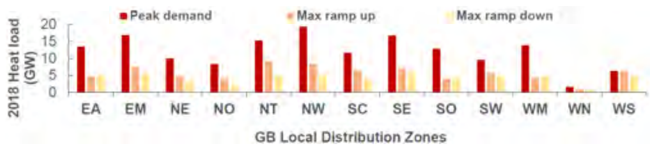
To this end, we obtained hourly gas consumption data over a number of years from all British gas network operators (GNOs) and analysed time series so as to develop hourly and region-specific domestic heat demand data. Further details on the data and methodology are given in the Methods section. Noting that previously estimated values cover the year 2010 which based on BEIS' official heating degree days analysis was 20% colder than 2018 and 22% than 2015[26], our analysis indicates that the domestic peak heat demand in GB can be up to 149 GW which is up to 53% less than previously estimated values[27,28] while the maximum hourly increase in heat demand was found to be 54 GW[21]. The importance of taking into account actual regional heat demand characteristics is underscored by Figs. 2(a)-2(c), which highlight the variations in peak load and maximum ramp rate.

Given the striking divergence from previously estimated heat loads, a sliding-window correlation analysis across the spatial and temporal scales was performed to visualise and quantify the importance of region-specific and actual heat demand profiles. As shown by Fig. 3, overall heat demand is as expected strongly dependent on ambient temperature and hence we identify high coincidence in neighbouring regions. Nonetheless, in comparing regions that are not spatially proximal, e.g. NW and SE, we see that their temporal heat map is not uniform (across the x-axis of each square) and hence even though both regions exhibit high heat demand peaks (Fig. 3), the overall peak diverges due to non-coincidence. Of course, non-weather phenomena, such as social factors or differences

(a) Comparison GB-wide peak heat demand and ramp-rates



(b) Regional estimates of peak heat demand and ramp-rates for 2015.



(c) Regional estimates of peak heat demand and ramp-rates for 2018.

Figure 2. Comparison of estimated GB heat demand characteristics for different years and with previous estimates.

in building stock, can affect hourly heat demand, which can be seen when comparing the heat demand synchronicity in adjacent regions such as SE and NT, WN and WS or NO and NE. These neighbouring-region pairs experience similar hourly weather patterns so it would be natural to expect high levels of correlation across temporal scales. Instead, we observe significant variation on an hourly basis, which in turn can explain the reduction in heat peak and ramping estimates. The differences are revealed more clearly, once we perform a regression analysis on a daily and hourly basis. After aggregating our historical data on a day-by-day basis, a segmented linear regression explains well the dependence of heat demand on temperature. However, replicating the analysis using a finer (hourly) temporal scale, reveals that the relationship between heat demand and temperature is highly nonlinear, indicating the importance of other factors aside from weather (see Supplementary note 2).

In terms of regional diversity, the largest regions such as North West (NW), East Midlands (EM), NT and SE exhibit peak demand of up to 19 GWh for 2018, which represents the extreme year in our analysis, whereas the smallest regions such as the two Welsh LDZs have peak demand of less than 5 GWh. Focusing on the time series for 2018, while the GB-wide peak domestic heat demand occurs on 1 March between 18:00-19:00, this is not the case in every region. Specifically, while indeed the peak is synchronised with the regions EM, NE, NO, NW, SW and WM; in Wales (WN, WS) peak demand was on the same day but between 17:00-18:00 and 07:00-08:00 respectively, the southern regions (SE, SO) and EA exhibited a morning peak between 07:00-08:00 while the NT and SC regions' peak was the day before (28 February) between 18:00-19:00. Such instances, highlight the necessity of using regional data to evaluate decarbonisation strategies, since their peak occurs at distinctly different days and/or times

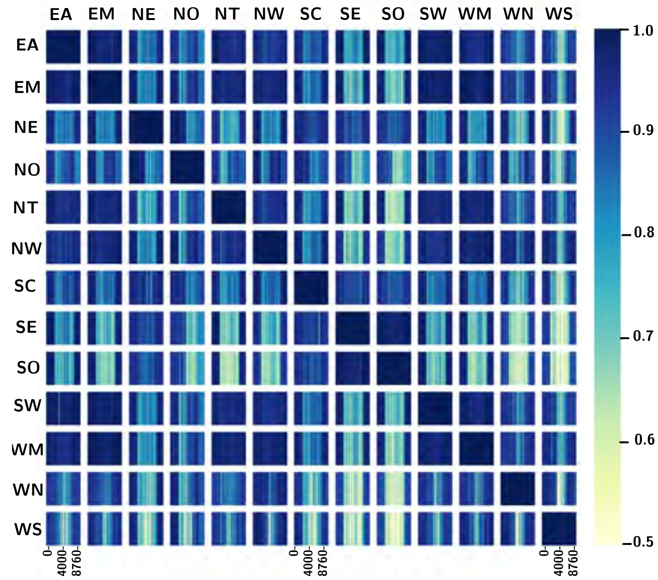


Figure 3. Temporal and spatial heat map of sliding window correlation analysis. Each square block represents the temporal synchronicity of heat demand pattern between two regions. Darker areas indicate synchronous demand pattern while light areas indicate greater divergence.

(see Supplementary note 2).

Scenarios and system description

To accomplish our twin goals of providing a systems-based study of GB heat electrification and drivers of cost-optimal pathways, we propose a new spatially-explicit multi-period mixed integer model (OPHELIA) that simultaneously optimises capacity expansion (on a five-year basis) and operational decisions (on an hourly basis). Final electricity demand is endogenously computed and is divided into heat-driven and non-heat related demand. Assuming that the effects of population growth and improved welfare will be counterbalanced by energy efficiency improvements, which result in reduced demand per capita, future heat demand were derived based on 2015 and 2018 respectively[28]. For non-heat electricity demand, we follow the projections of the GB system operator[29] and consider annual energy requirements of 307TWh (excluding losses) and GB-wide peak demand of 57GW (excluding losses). A detailed overview of the mathematical formulation of OPHELIA along with the list of assumptions is provided in Supplementary note 3. Additional information on the derivation of regional electricity demand as well as the techno economic data is provided in Supplementary note 4.

To analyse the impact of different system assumptions on cost-optimal electrification we consider four main scenarios. In our base scenario "Elec", we assume heat is electrified by deploying ASHPs that are fully flexible and can be used in conjunction with termal energy storage (TES). Scenario "ASHPFlex" differs from "Elec" in that ASHPs are considered to have constrained flexibility and can only ramp-up/ramp-down up to 70% of their nameplate capacity[30]. To quantify the role

Table 1. Impact of heat electrification on capacity and generation by 2050 for different scenarios

	NoHeat	Elec2015	Elec2018	Elec NoTES (2015 heat data)	Elec NoICPeak (2015 heat data)
Nuclear (GW)	6	14.4	16.8	23.4	15.6
CCGT (GW)	18	18.5	18.5	20.5	18.5
CCGTCCS (GW)	19	21.5	21.5	23.5	21.5
Biomass (GW)	7.7	11.2	12.9	13.3	13
BECCS (GW)	1.5	1.5	3	7	4
WindOn (GW)	35	39.6	50	55	46.7
WindOff (GW)	12	38.7	41.9	44.5	42.5
Solar (GW)	26.2	19.3	38.4	45	28
GridStorage (GW)	16	17	19	32.9	20
Total Capacity(GW)	141.4	181.7	222	265.1	210
Total Generation (TWh)	353	530	593	570	563

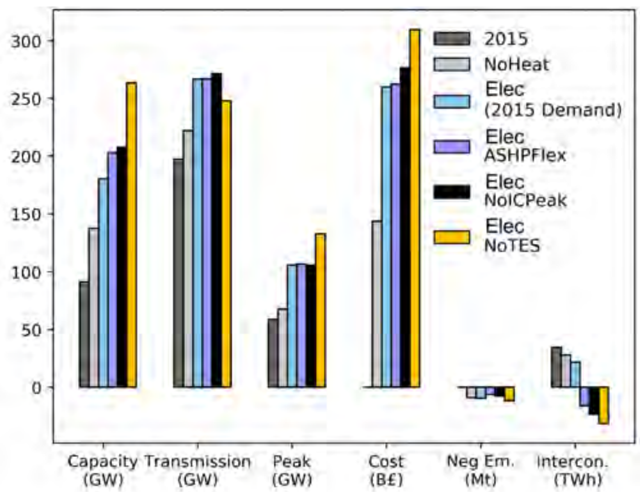


Figure 4. Overview of system-wide impact of domestic heat electrification under different scenarios. NoHeat: Scenario of only power sector decarbonisation. Elec: Base scenario of power and heat decarbonisation through heat electrification. In this scenario, ASHPs are assumed to have full flexibility and TES can be deployed. ASHPflex: Same as the Elec scenario, but ASHPs can ramp up/down only up to 70% of nameplate capacity each hour. NoICPeak: Same as Elec scenario but no interconnection is allowed on the peak heat demand day. NoTes: Same as Elec scenario, but no deployment of TES is considered.

of TES in electrifying heat, we study the scenario "NoTES" in which case electrification is only achieved through ASHPs. The "NoICPeak" scenario is similar to our base "Elec" scenario but no power imports or exports are allowed through interconnection on the peak heat day. Finally, to assess the incremental effect of heat electrification, we consider a "NoHeat" scenario where the power sector is fully decarbonised by mid-century but not heat.

As end-use heating technologies we consider: (i) ASHPs, (ii) TES and (iii) gas boilers. Although GSHPs and resistive heaters (RH) are also suitable electrification technologies, the latter were not considered due to their inferior performance compared to ASHPs and the former would require information on the regional building stock and space availability, two factors that are out of the scope of the present study. As TES, we consider generic insulated hot water tanks. Finally, for the off-gas grid properties we consider full electrification of all related heat requirements (i.e., ASHP adoption).

System-wide implications of 100% heat electrification

Overall, comparing the "NoHeat" and "Elec" scenarios, for 2015 heat demand, electrification could be achieved through a 33% increase in generation capacity and 18% increase in transmission capacity between regions to meet a system-wide peak demand that increases by 56% (106GW vs 68GW). An additional £100bn in capital investments would be needed to deliver sufficient power generation capacity to ensure system security and adequacy under the increasingly seasonal load that a future power sector would have to face under a 100% electrification scenario. A summary of the system-wide changes for the different scenarios is found in Fig. 4.

These differences intensify when system planning is performed under more extreme years, such as 2018, when heat demand data captures the weather variability of a European cold wave (the so-called ‘Beast from the East’ plus Storm Emma). Specifically during 1 March 2018, gas demand in the distribution networks reached nearly 360 mcm which was higher than the 1-in-20 peak demand forecast that was published as part of GB’s gas transmission operator’s Ten Year Statement[31]. In "Elec2018", the total system peak reaches 113 GW (a 67% increase compared to the "NoHeat" scenario) while a further 10% increase in TSC is observed compared to the "Elec2015" scenario, with 28% generation capacity (mostly in the form of Nuclear, BECCS and offshore wind) and 4% additional investments in transmission capacity.

Considering only power sector decarbonisation, as shown by Table 1, the optimised generation capacity is dominated by renewable generation technologies (52%), with onshore wind accounting for 25% of the capacity mix. The deployment of combined cycle gas turbines with post combustion carbon capture and storage (CCGT-CCS) begins in 2033 and steadily grows to reach 21.5GW capacity by mid-century, while 1.5GW of of bioenergy with carbon capture and storage (BECCS) is deployed to provide negative emissions. Relative to our central scenario ("Elec") using 2015 (2018) heat demand, the most notable changes are the increase in Nuclear capacity by a factor of 2.4 (2.8) and in offshore wind capacity by a factor of 3.3 (3.6). For the "Elec2018" scenario, aside from those changes, the value of CCS is further highlighted as a source of flexibility in extreme years - BECCS capacity doubles to 3GW and CCGT-CCS capacity increases by 1GW. Electrification of heat also impacts the timing and spatial deployment of CCS technologies, with investments in

CCGT-CCS technologies taking place a half-decade earlier for the "Elec" scenario compared to the "NoHeat" scenario. As an illustration of differences on a regional level, 1GW of CCGT-CCS is deployed in the NT region in the "NoHeat" scenario, but when heat electrification is taken into account, final capacity in the region is increased by a factor of 4.5. As seen in Fig. 2(b), this can be attributed to the high heat demand peak in NT.

Overall, as Table 1 indicates, a potential 100% electrification of heat would require an almost 2-fold increase of firm generation capacity (Nuclear, Biomass) in the best case ("Elec2015") while in the worst case ("NoTES") a direct electrification with limited flexibility would require a 3-fold increase. From a renewable generation perspective, heat electrification appears to favour investments in wind rather than solar generation due to issues related to synchronicity on the availability of solar vs heat demand patterns. Finally, another interesting aspect is the potential competition between grid-level storage technologies and TES as either can be used for absorbing RES intermittent generation (cf. "Elec", "NoTES" scenarios).

Regional drivers and adoption rates

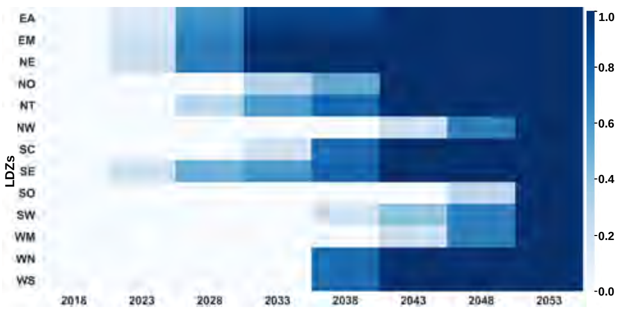
In this section, we delve into the spatio-temporal evolution of the GB energy system towards 100% heat electrification. As indicated by Fig. 5(a), in our base scenarios where no adoption rates constraints are imposed, there is great disparity in regional electrification rates. Eastern regions (EA, EM, NE and SE) appear to be early and steady adopters throughout the planning horizon whereas other regions such as NW, WM, SO and Wales only become electrified towards the end of the time horizon based on very high adoption rates. When adoption rate considerations are not taken into account, the eastern regions can exhibit electrification rates ranging from 35% to 56% over a 5-year period, which far exceeds any previous electrification rollout, and so might be viewed unrealistic[32]. To this end, and to shed light on key barriers/enablers for early electrification, we explore different scenarios whilst imposing a requirement that regional adoption rates lie within either: (i) 10%-20% or (ii) 15%-30% over a 5-year period. The results of these runs are presented in Figs. 5(b)-5(c). It is interesting to note that the 10-15% adoption rate case reflects the UK's government's ambition to install 600,000 heat pumps annually from 2028 following its recent "Ten point plan for a green industrial revolution"[33].

To guide our analysis, let us focus on SE and SO, which, though neighbouring regions, follow completely different paths to electrification, as seen in Figs. 5(a)-5(c). These two regions are also interesting because, apart from similar weather conditions (which affect ASHP performance), they also exhibit very similar heat demand patterns as shown in Fig. 3. In the base scenarios, the SO region is a net importing region while SE is a net exporter, mostly to the NT region. When adoption rates are constrained, however, power flows are reversed in both regions. For example, when adoption rates are constrained, SE exports on a net basis to SO but is a net importer from NT, which, in turn, reduces the electrification rate in NT. The general trend indicates an increase in firm generation, mostly through more nuclear and some biomass power plants, with subsequent reduction in the regional share of intermittent renewable energy sources. This trend is particularly apparent during the early periods (2023-2038) before the uptake of CCS technologies (BECCS or CCGT-CCS). For instance, comparing generation capacities in SO during 2028 we identify an increase of 0.7GW in biomass capacity and 1.5GW in grid-level storage capacity in both constrained scenarios versus the unconstrained case. The same trend is identified in the SW region where solar capacity declines by 1GW in the case of 10-20% and by 2GW when 15-30% rates are imposed. In both scenarios 2.4GW of nuclear capacity is deployed in SW in 2028 whereas in the unconstrained case no nuclear capacity is installed. By contrast, 3GW of additional nuclear is expected in EA by 2033 in the unconstrained case but when adoption rates are constrained, additional installed capacity reduces to 1.8GW and 1.2GW for the 10-20% and 15-30% adoption rate scenarios respectively. Nonetheless, overall RES capacity does not decline in order to meet the decarbonisation targets but instead is complemented in regions with investment in peaker plants (CCGTs, OCGTs) and grid storage. That is the case for NT, where full heat decarbonisation is delayed by a decade in the constrained adoption rate scenario, but both solar power plant capacity (+3GW) and CCGT (+3GW) increase in 2033. Similar insights are derived by examining the NO and NW regions, where firm generation and grid-level storage both increase when adoption rates are constrained (see supplementary note 5).

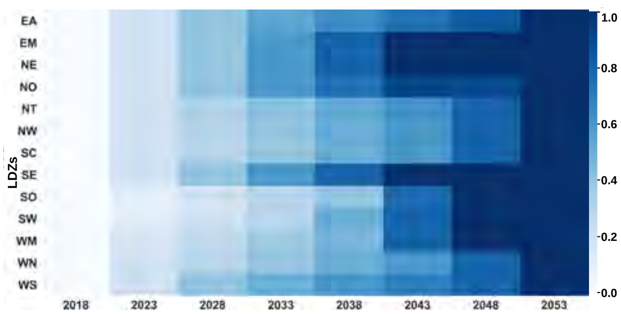
The cost of reduced flexibility in heat electrification

Sources of flexibility become crucial in alleviating the challenges of direct electrification of heat. In particular, we identify and study three different factors: (i) the use of thermal energy storage (NoTES), (ii) the operational flexibility of ASHPs (ASHPflex) and (iii) the ability to import/export power during peak heat demand days (NoICPeak). A decarbonised system without TES deployment requires a total capacity of almost twice that needed for decarbonising the power sector alone due to the doubling in the overall peak the system has to meet (132 GW vs 68 GW). The reduced flexibility due to the absence of TES results in a 35% increase in total system cost (TSC) and leads to asset under-utilisation, with the average utilisation factor for CCGT-CCS dropping to 36% in the "NoTES" from 69% ("Elec" scenario) for the case of 2018 heat demand.

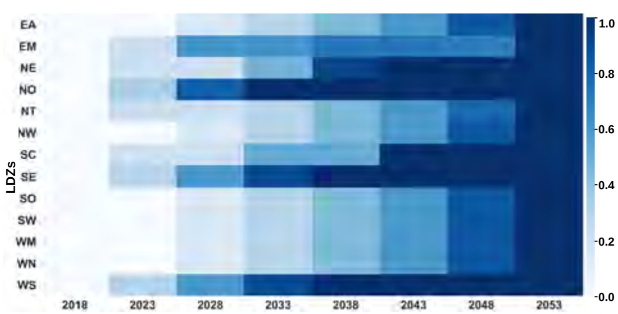
In the "ASHPflex" and "NoICPeak" scenarios, generation capacity increases by 50% compared to the "NoHeat" case, while the absence of interconnection during the peak heat day results in a 22% increase in cross-region transmission capacity utilised to counterbalance the lack of interconnection in coastal regions. In both cases, an additional £10bn and £18bn increase is inflected in the TSC while GB ends up being a net power exporter by mid-century mostly to Norway and Denmark due to the increased generation by onshore and offshore wind power plants. Nonetheless, the interconnection flows rely upon future price projections based on European Network of Transmission System Operators for Electricity's Ten-Year Network Development Plan according to their "Global Climate Ambition" (GCA) (or deep-decarbonisation) scenario[34].



(a) Spatio-temporal progress of domestic heat electrification with no constraints on the deployment of ASHPs.



(b) Spatio-temporal progress of domestic heat electrification with adoption rates ranging between 10-20%.



(c) Spatio-temporal progress of domestic heat electrification with adoption rates ranging between 15-30%.

Figure 5. Domestic heat electrification rates under the "Elec" scenario of on-gas grid properties across different regions in GB, following different scenarios for ASHP adoption rate. Progressively darker shades indicate a higher percentage of electrified properties in each region at each time step.

Conclusions

Full electrification of heat will be challenging for many reasons apart from the demands placed on the electricity system. Reaching high sustained adoption rates will require significant government incentives and will involve engaging not just early adopters but will require a shift away from gas in large commercial establishments and amongst late adopters and laggard domestic consumers, who will be sceptical of the technology and/or daunted by the capital expense. The economics of maintaining the existing gas infrastructure in the transition to full electrification with ever-smaller volumes of gas is also challenging. Moreover, there are numerous important questions that remain such as how to maintain gas in the system for hybrid heat pumps and what the basis should be for sizing a fully-electrified system. From a carbon reduction perspective in the short run such complications may not be insurmountable, but in the long run they can lead to deadlocks due to the mixed market signals being sent, e.g. on the future of natural gas, as well as undermining a smooth policy-driven transition to low-carbon heat. Future research should build on spatially explicit and multi-period modelling to explore integrated capacity expansion planning and operational optimisation of the integrated heat and power system, particularly in the context of the role negative emissions might play in decarbonising the heat sector. While there is no silver bullet to decarbonise heat, we have shown in the present study that electrification of heat in conjunction with smart operation of thermal energy storage constitute a viable candidate without needing unreasonably rapid growth in overall system capacity. Although we have demonstrated that electrification is not as daunting as some have claimed, this is only one part of the heat puzzle and the potential role for hydrogen and biomass need to be investigated in similar detail so as to decipher the underlying synergies and this constitutes ongoing research within our group.

Methods

OPtimising Heat ELectrificatiOn regIonaL strAtegies (OPHELIA) model description

OPHELIA simultaneously minimises the power and heat system costs to satisfy the related loads on an hourly basis subject to technical constraints for evaluating the impact of domestic heat electrification on the power and gas systems in Great Britain (GB). It is a spatially explicit multi-period model where GB is discretised into the 13 local distribution zones (LDZs) of the gas network. Given existing and projected power generation capacities in GB, the model optimizes: (i) new power generation and storage capacity locations; (ii) hourly dispatch decisions; (iii) power transmission flows within the considered GB regions; (iv) interconnection flows with third countries;(v) hourly upward and downward reserve requirements and commitment; (vi) heat generation and storage capacity investments and location; (vii) hourly heat generation and storage operational decisions. Other key outputs of OPHELIA include: (a) regional share of heat-end use technologies (gas boilers, air-source heat pumps and heat storage); (b) separate monitoring of electricity and heat generation emissions; (c) regional hourly gas flows; and (d) regional hourly marginal cost of electricity. To account for system's flexibility requirements the the ramp-rate constrained unit commitment conditions are employed: (i) minimum up time and down time requirements for thermal generation plants; (ii) thermal generation ramping constraints during the different modes of operations (start-up, committed, shut-down). For the representation of renewable energy sources, we collect hourly availability data as provided by the renewables.ninja platform[35]. The hourly availability reflects the percentage of the installed nameplate capacity that would be generated at a given hour. To capture the variability in RES availability within each region, for solar and onshore wind we sample different spatial intraregional availability and the average of those is used as the final regional availability factor, whilst for the case of offshore wind generation points were considered up to 50km from the shore. While more detailed representations of RES have been presented in recent studies[36], we opt for this approach as our main focus here is the impact of heat electrification and not the integration of renewables in the grid, although our model can readily consider such detailed cases as input data. In terms of reserve requirements, we model upward short-term operating reserve as a function of the forecasting errors in wind generation, electricity demand and the capacity of the largest generator to simulate N-1 security criteria considerations[36]. Downward reserve requirements are modelled as a percentage of the upward requirements[37]. Distribution losses are modelled as a percentage of the resulting regional demand, while transmission and interconnection losses are endogenously calculated as proportional to the transmitted power and distance between the different regions[38]. Transmission corridors between different regions is modelled following the transshipment models conventions which does not account for Kirchhoff's voltage law[39]. One strong point of OPHELIA is the high-fidelity regional demand considerations across the different LDZs. To date, in past studies of heat decarbonization, models have employed the same hourly heat demand patterns and a limited number of representative days when regional decarbonisation strategies are examined[40]. Moreover, we differentiate between emissions reduction requirements for the heat and the power sectors to enable the examination of sector- specific budgets and their impact on heat decarbonisation policies. The overall model is formulated as a mixed integer linear program and is implemented in GAMS and AIMMS. A more detailed description of the model's data, equations and key assumptions can be found in Supplementary notes 3-4.

Deriving regional domestic heat demand data

Understanding and preserving the spatial and temporal variations on heat demand is vital for deriving realistic decarbonisation insights and strategies. In principle, heat demand profiles are determined by a range of aspects such as behavioural, building stock and weather conditions. A primary concern regarding the decarbonisation of heat through electrification is the resulting load variability that the grid operator would face. To this end, a limited amount of works have been presented in the literature that employ half-hourly/hourly heat demand profiles[15,21]. The shortcoming of these previous studies is that the derived heat demand profiles come from either a 2007 Carbon Trust Micro-CHP Accelerator project with 71 domestic buildings[21] or from the Energy Demand Research Project (EDRP) that was carried out between 2007-2010 with around 6000 participants[41]. While these data sets and the resulting heat demand profiles constitute a significant step in the desired direction, using them to evaluate the impact of decarbonisation in a spatial manner for the UK runs into difficulties because of the limited representation of the regional characteristics of heat as well as the end regional heat load is subject to after diversity peak demand considerations which are key in designing the future grid. To this end, in the present work we employ regional hourly gas demand data as a proxy for heat demand that were collected from the GB Gas Distribution Network Operators (DNOs) spanning from 2015-2018. In these time series, gas demand comprises daily metered (DM) demand (associated with large industrial premises) and non-daily metered (NDM) demand (associated with domestic, commercial and medium sized industrial premises). The reader interested in the specific definitions of this components in referred to National Grid's methodology[42] for a comprehensive review. To then derive the related domestic demand from the time series the following methodology was devised by using gas standard load procedures by German Federation of the Gas and Water Industry (BGW)[43] as well as the German Association of Local Utilities (VKU)[44]. Using their methodology, characteristic hourly and temperature-dependent gas demand profiles are presented for a range of different domestic, industrial and commercial units. In conjunction with these profiles, regional hourly temperature data[35], sub-national gas consumption data from BEIS (that also non-gas properties using solid using fuels for heat) in the different regions across GB[45] were employed. Domestic demand is derived then as follows. First, using the gas standard load profiles the daily metered demand as reported in[43,44] is scaled down on an hourly basis for all the LDZs. The resulting hourly DM demand was subtracted from the DNO time series leaving gas demand related to NDM customers. Then, using sub-national gas consumption data statistics about regional domestic and non-domestic percentages together with the master temperature-dependent profiles for non-domestic customers we scale down on an hourly basis the NDM consumption data available from[46]. By subtracting the hourly non-domestic NDM component together with the related DM component from the original time series the domestic hourly gas consumption demand in the different LDZs is retrieved. Finally, for the cases where negative values where encountered in the final time series we interpolated between the neighbouring data points to preserve continuity. It should be noted that for the Welsh regions (WN, WS) we employed existing regional domestic half-hourly data for heat demand[47] because of complications in accounting for different gas flows in those regions. Finally, to derive non-electric heat demand for the proportion of off-gas grid properties within each region, we use the data about household heating technologies as presented by[19] and assume an average of 80% efficiency for both biomass and oil burners. Further assumptions that are employed for the derivation of regional heat demand profiles include: (i) the gas-heated domestic demand is taken as representative for the whole building stock within each region and (ii) the gas boiler demand reflects directly the underlying heat demand. Further to these assumptions, with the regards to the applicability and validity of the German gas suppliers methodology we can expect to have some deviations from the ground-truth heat demand but as indicated by Ruhnau et al.[48] using these standard profiles for the UK results in high consistency between modelled and historic behaviour of the heat sector.

As indicated by Fig.2(a), compared to existing works on estimating the GB heat demand, we are on a national scale, we are in good agreement with the results of Watson et al.[41] with 4% higher estimated peak demand (177GWh) with a larger deviation is observed at 20% for the maximum ramp up in heat demand (72GWh vs 60GWh). Compared to Sansom et al.[24] we derive a significantly lower peak demand (36%) and almost 45% lower maximum ramp up. With regards to the regional aspects of gas-related heat demand, as shown in Figs.2(b)-2(c) the regions EM and NT have the largest contributions to the national peak demand (around 25GW each) while for the case of Wales the profiles derived from Knight et. al[47] indicate a rather interesting behaviour with the scale of peak demand and ramp up, ramp down requirements being quite close especially for WN as indicated by Figs. 2(b)- 2(c). Apart from WN, the smallest heat peak demand is found to be in the NO region (11.3GW) and SW region (12.4GW) and such region-specific insights are useful when deciding regional rollout of electrifying heat as it may be preferable to electrify first those regions where their peak heat demand component is not prohibitively large.

Representative days selection

we use data clustering techniques. In particular, we employ K-Medoids clustering to agglomerate days of the year that exhibit similar patterns with respect to regional demand of electricity and gas, RES availability, interconnection prices and average temperature across the 13 LDZs. To preserve peak electricity and gas demand days, the original time series are pre-processed and these two days are excluded from the clustering and are added at the final stage. Once clustering is completed, an average day is computed and then the representative day is chosen such that it has the minimum geometric distance from that day. While clustering techniques have been widely applied to energy systems models[49,50] the resulting representative days are generally not placed in chronological order. However, for the case of heat decarbonisation preserving the chronological order is important due to the inherent seasonality of demand. To this end, once representative days are selected for each cluster, they are organised in chronological order.

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Conceptualization: DMR, KC and VC; Data curation: DMR and VC; Formal Analysis: VC and MF; Funding acquisition: DMR; Investigation VC and MF; Methodology VC, DMR, KC and MF; Project administration: DMR; Visualization: VC and MF; Writing - original draft: VC; Writing - review & editing: VC, DMR, KC and MF.

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