Energy Conversion and Management 268 (2022) 115952

Contents lists available at ScienceDirect

Energy Conversion and Management

journal homepage: www.elsevier.com/locate/enconman

A whole-system approach for quantifying the value of smart electrification for decarbonising heating in buildings

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ARTICLE INFO

Keywords:
Smart electrification
Heat pump
Decarbonising heating
Electricity grid flexibility
Demand response
Energy system modelling

ABSTRACT

This paper uses a whole system approach to examine system design and planning strategies that enhance the system value of electrifying heating and identify trade-offs between consumers' investment and infrastructure requirements for decarbonising heating in buildings. We present a novel integrated model of heat, electricity and gas systems, HEGIT, to investigate different heat electrification strategies using the UK as the case study from two perspectives: (i) a system planning perspective regarding the scope and timing of electrification; and (ii) a demand-side perspective regarding the operational and investment schemes on the consumer side. Our results indicate that complete electrification of heating increases peak electricity demand by 170%, resulting in a 160% increase in the required installed capacity in the electricity grid. However, this effect can be moderated by implementing smart demand-side schemes. Grid integration of heat pumps combined with thermal storage at the consumer-end was shown to unlock significant potential for diurnal load shifting, thereby reducing the electricity grid reinforcement requirements. For example, our results show that a 5 b£ investment in such demand-side flexibility schemes can reduce the total system transition cost by about 22 b£ compared to the case of relying solely on supply-side flexibility. In such a case, it is also possible to reduce consumer investment by lowering the output temperature of heat pumps from 55 °C to 45 °C and sharing the heating duty with electric resistance heaters. Furthermore, our results suggest that, when used at a domestic scale, ground-source heat pumps offer limited system value since their advantages (lower peak demand and reduced variations in electric heating loads) can instead be provided by grid-integration of air-source heat pumps and increased thermal storage capacity at a lower cost to consumers and with additional flexibility benefits for the electricity grid. Lastly, our results show that, regardless of consumers' investment and operation decisions, the UK electricity grid can reliably accommodate close to 50% of the heating demand, but this can be increased to about 75% by implementing smart operation schemes at the consumer end.

1. Introduction

Decarbonising heating in buildings is one of the major challenges many countries face for meeting their emission mitigation targets [1]. The scale of the heat challenge differs significantly from state to state depending on a variety of factors, such as climate conditions, building stock, energy prices, the heating portfolio in buildings and the current structure of the energy system in a country. Some countries, such as United Kingdom (UK), the Netherlands and Germany, rely predominantly on the direct use of fossil fuels to provide heating in buildings, whereas other countries, such as Norway and Sweden, make little direct use of fossil fuels for heating in buildings [1,2]. In countries where the majority of the heating demand is met with the direct combustion of fossil fuels, the resulting dispersed emissions from heating comprise a large portion of their total emissions [1,3,4]. Decarbonising heating is therefore recognised as a policy priority for decarbonising the energy system and achieving the net-zero emission target. In these countries, reducing emissions from heating requires fuel switching and a shift away from direct use of fossil fuels for heating to low-carbon energy vectors such as electricity, hydrogen and district heating that do not produce CO_2 at the point of use. As a result, all pathways towards achieving a low-carbon heat system (particularly in countries that heavily rely on the natural gas grid for heating, such as the Netherlands and the UK) will, over time, involve a decisive break from established forms of supply and significant changes to their energy infrastructure [1,2,5,6].

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https://doi.org/10.1016/j.enconman.2022.115952
Received 6 April 2022; Received in revised form 28 June 2022; Accepted 29 June 2022
Available online 18 July 2022

Nomenclature

Abbreviation

ASHP	Air-source heat pump
ATR-CCS	Auto-thermal methane reforming with carbon capture and storage
BECCS	Bio-energy with carbon capture and storage
CCGT	Combined-cycle gas turbines
CCGT-CCS	Combined-cycle gas turbines with carbon capture and storage
CCS	Carbon capture and storage
COP	Coefficient of performance
GI	Grid-integrated heat pumps
GSHP	Ground-source heat pump
NGI	Not grid-integrated heat pumps
OCGT	Open-cycle gas turbines
SWDI	Shannon Weiner Diversity Index

Sets

a	Planning periods year
c	Days of each year day
gb	Type of gas boilers $gb \subset K$
h	Heating demand category
hp	Type of heat pump $hp \subset K$
i	Technologies in the electricity grid, $i \in I$ –
ic	Conventional electricity generating technologies, $ic \subset i$ –
ig	Electricity generating technologies, $ig \subset i$ –
ir	Variable renewable technologies, $ir \subset i$ –
is	Electricity storage technologies in the electricity grid, $is \subset i$ –
j	Gas productionstorage technologies $j \in J$ –
jc	Bio-methane production technologies $jc \in J$ –
jf	Hydrogen production technologies that use fossil fuels as fuel, $jf \subset jp$ –
jp	Hydrogen production technologies, $jp \subset j$ –
js	Hydrogen storage technologies, $js \subset j$ –
jus	Underground hydrogen storage, $jus \subset js$ –
k	All the heating technologies at the consumer side $k \in K$ –
l	Alternative low-carbon energy vectors $l \in L$ –
t	Time periods hour
v	Energy vectors used for heating, $v \in V$ –
zg	All the generation technologies in electricity and gas grids, $zg = ig \cup js$ –
zn	All the technologies in electricity and gas grids, $zn = i \cup j$ –

Parameters & Variables

ΔT	Weighted average temperature increase required at the consumer side °C
$\lambda(h, v, a)$	Conversion efficiency for each energy vector v for each demand group h at year a –
ρ	Density of water kg/L
$b(z, a)$	Number of new built units of technology z in year a –
c_p	Specific heating capacity of water J/kg K
C_{dcg}	Cost of decommissioning gas grid £/MWh
CAC	Cost of avoided CO_2 £/t_{CO_2}
$CAPEX(zn)$	Capital expenditure of technology zn £/MW
$CI(v, a)$	Carbon intensity of the energy vector v at year a t_{CO_2}/MWh
CM	Capacity margin %MW
$COP(hp, c, t)$	Coefficient of performance for heat pump type hp –
$d_{BM}(a, c, t)$	Demand for bio-methane MWh
$d_{ev}(h, v, a)$	Demand for primary energy vector v used directly for supplying demand group h at year a MWh
$d_e(a, c, t)$	Total electricity demand MWh
$d_g(gb, a, c, t)$	Demand for gas from boiler gb MWh
$d_{H_2}(a)$	Total annual demand for hydrogen at year a MWh
$Disc(a)$	Discount factor in year a £
$DP_{heat}(c, t)$	Normalised demand profile for heating in buildings –
$DT(zg)$	Minimum down time requirements of technology zg h
$e_{AD}(jc)$	Emission rate of bio-methane production from anaerobic digestion t_{CO_2}/MWh
EUC	Fuel switching over the planning horizon-excluding the cost of fuel £
$F_{outMax}(jus)$	The maximum discharging rate from each underground storage unit MW
$hd(k, a)$	Average heating demand from each household in year a MWh
$Ins(k)$	Installation cost share for heating technology k –
$m_{in}(k, a, c, t)$	Water inflow to the tank integrated with heating technology k kg
$m_{out}(k, a, c, t)$	Water outflow from tank integrated with heating technology k to demand kg
$m_{tank}(k, a, c, t)$	Hot water stored in the tank integrated with heating technology k kg
$n(zn, a, c, t)$	Number of units of technology zn –
$NC(zg)$	Nominal capacity of technology zg MW
$NC_{HP}(a)$	Nominal thermal capacity of heat pump installed in year a kW
$NC_s(jus)$	Storage capacity of underground gas storage technologies jus MWh
NL	Gas network losses %
NRF	Network reinforcement factor for transmission and distribution networks
$o(zs, a, c, t)$	Number of units of storage technology zs –
OM	Operating margin requirement in the gas grid
$OPEX(a)$	Total operational costs in year a £
$p_{BM}(jc, a, c, t)$	Bio-methane production from anaerobic digestion MWh
$p_e(ig, a, c, t)$	Electricity generation from technology ig MWh
$p_{H_2}(jg, a, c, t)$	Hydrogen production from technology jg MWh
$p_{hp}(hp, a, c, t)$	Electricity to heat pump hp MWh
$pd_e(ig, a, c, t)$	Electricity to demand from technology ig MWh

$pd_{H_2}(jg,a,c,t)$	Hydrogen to demand from generation technology jg MWh
$PL_e(a)$	Peak electricity load in year a MWh
$PL_{H_2}(a)$	Peak load of hydrogen demand in year a MW
$q_{backup}(k,a,c,t)$	Heat output from electric resistance heater integrated with heating technology k MWh
$q_d(h,v,a)$	Heat demand supplied by energy vector v for demand group h at year a MWh
$q_{lc}(l,h,v,a)$	Heating demand supplied by alternative low-carbon energy vectors l replacing energy vector v for demand group h at year a MWh
$q_{out}(k,a,c,t)$	Heat output from the thermal storage tank for each heating technology k MWh
$q_s(h,v,a)$	Heat delivered by energy vector v to demand group h at year a MWh
$r_e(ig,a,c,t)$	Reserve capacity provided by technology ig MWh
$RD(zg)$	Maximum ramp down rate of technology zg %
RM	Absolute reserve margin %MW
$RU(zg)$	Maximum ramp up rate of technology zg %
$S_{Cush}(jus)$	Minimum storage inventory level of underground storage-cushion gas %MWh
$s_e(is,a,c,t)$	Effective state of charge of technology is MWh
$s_{H_2}(js,a,c,t)$	Inventory level in storage technology js MWh
$S_{Max}(is)$	Maximum storage inventory level %MW
$S_{Min}(is)$	Minimum storage inventory level %MW
$sd_e(is,a,c,t)$	Electricity from storage to demand from technology is MWh
$sd_{H_2}(js,a,c,t)$	Hydrogen to demand from storage technology js MWh
SI	Minimum system inertia demand MWs
SM	Supply margin requirement in the gas grid
$sr_e(is,a,c,t)$	Reserve capacity provided by technology is MWh
$T_{air}(a,c,t)$	Air temperature °C
$T_{soil}(a,c,t)$	Soil temperature °C
$TE(i,*)$	Features of technology i, where $*$ is: (various)
$Pmin$	Minimum output %MW
$Pmax$	Maximum output %MW
Ems	Emission rate t_{CO_2}/MWh_e
$Cmax$	Maximum capacity provision %MW
RP	Reserve potential %MW
IP	Inertia provision potential Mws/MW
$TF(j,*)$	Features of technology j, where $*$ is: (various)
$Pmin$	Minimum output %MW
$Pmax$	Maximum output %MW
Ems	Emission rate t_{CO_2}/MWh_{H_2}
TL	Losses in transmission network %
TSC	Total system cost £
TSE	Total system emission t_{CO_2}
$u(zg,a,c,t)$	Number of units of technology zg starting up –
$UC(gb)$	Unit cost of gas boiler gb £
$UC(hp)$	Unit cost of heat pump hp £
UC_{SM}	Cost of grid integration for each heat pump unit £
UC_{tank}	Unit cost of hot water storage tank £
$ug_{H_2}(a,c,t)$	Unmet Hydrogen demand-gas shedding MWh
$up_d(a,c,t)$	Unmet electricity demand-load shedding MWh
$UT(zg)$	Minimum up time requirements of technology zg h
V_{tank}	Hot water tank storage capacity integrated with technology k L
$w(zg,a,c,t)$	Number of units of technology zg shutting down –
WFA	Annual weighting factor –
WR	Dynamic reserve for wind electricity generation %MW
$x(z,a)$	Number of units of technology z operational in year a, cumulative –

While there are uncertainties regarding the extent to which heating in buildings can be practically decarbonised and the mix of future low-carbon heating technologies, electrification of heating using heat pumps is widely accepted as an essential element of all decarbonisation pathways [5,7,8]. Extensive accessibility of electricity, maturity and high efficiency of heat pumps and the growing low-carbon electricity supply promote electrification using heat pumps as an immediate option for decarbonising heating in many regions [3,4,9–12]. However, transferring a large volume of variable heating demand to the electricity network would increase the peak electricity demand and its temperature dependency, and, therefore, the overall throughput requirements of the electricity system [3,13,14]. When planning for widespread electrification of heating, it is also important to consider the effect of additional electric heating loads on the emissions from the generating sources that will serve this load. Therefore if heating is to be decarbonised primarily through electrification, it is imperative to coordinate the infrastructure planning for decarbonisation of the electricity and heat sectors through whole system analysis and explore the impacts of electrifying heating at scale on emissions, the technology mix, and reinforcement requirements of the electricity (and gas) system over the long term [7]. Such a coordinated approach to decarbonising electricity and heating is essential for identifying synergies and complementarities between the two sectors, as well as identifying measures and strategies that can enhance the system value and emission reduction benefits of electrification.

1.1. Challenges and opportunities of electrifying heating in buildings

Electrifying heating using heat pumps is primarily motivated by moving away from combustion for generating low-temperature heat in buildings for two main reasons: avoiding the dispersed emissions from burning fossil fuels at the consumer end and improving the whole energy system efficiency by adopting more efficient conversion processes for generating low-temperature heating. In boilers, combustion takes place at temperatures above 1000 °C, which is much higher than the temperature required in buildings for water and space heating applications (about 55–70 °C) and thus introduces thermodynamic inefficiencies to the system [7,15]. In addition to enabling the heating sector to benefit from the rapid decarbonisation of the electricity grid [7], electrifying heating will also decouple the heating provision from the fuel source and therefore provides the opportunity for diversifying the resource mix and reducing long-term fuel security risks.

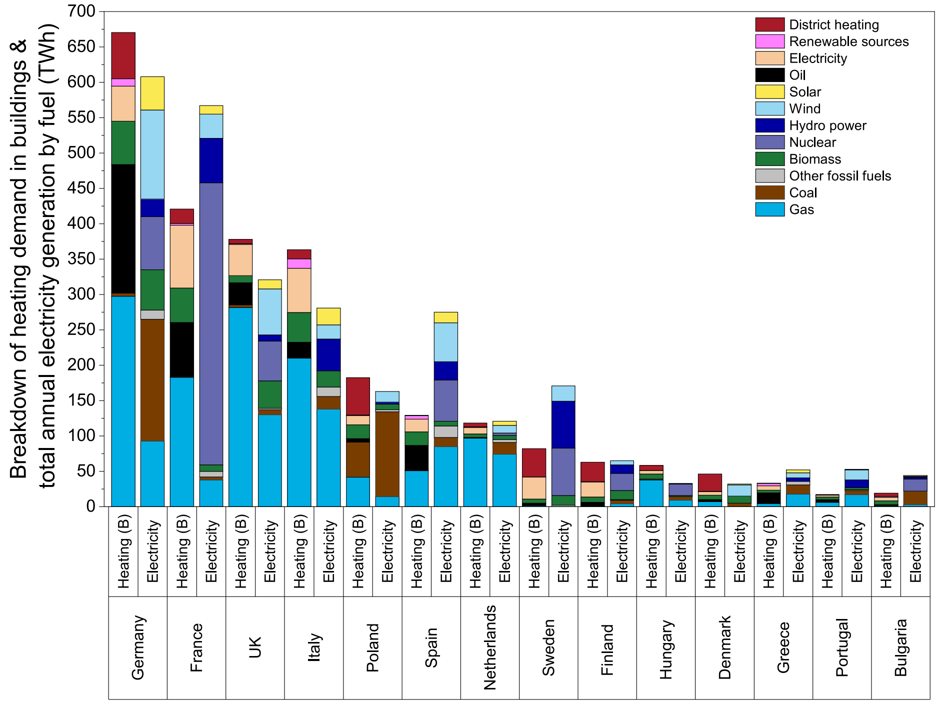

Fig. 1. Breakdown of heat demand (space heating and hot water) in buildings and the total annual electricity generation by fuel in selected countries. The data are for 2019 and derived from Refs. [11,20–22]. Note that in the *x*-axis (B) indicates buildings.

Widespread electrification of heating, however, poses challenges on both the supply and demand sides. Unlike electricity, which is largely generated centrally at the grid level and distributed to the users, heat is typically generated within the home by a gas or oil boiler, solid fuel stove or electric resistance heater. Therefore, decarbonising heat will not only entail changes 'upstream' from consumers but also involve a shift away from familiar heating systems towards alternative heating systems that are currently unfamiliar to most consumers. Therefore, consumer engagement is key to decarbonising heating in buildings since they have a greater potential influence through the choice of heating technologies and their associated energy vectors.

The upfront cost of installing heat pumps is higher than that of existing fossil fuel heating technologies without providing a much higher level of service (especially in low-insulated buildings) from the consumers' perspective. Furthermore, the much lower price of fossil fuels in comparison to alternative low-carbon energy carriers such as electricity and hydrogen [16,17] is another barrier to decarbonising heating in buildings and raises concerns that fuel switching might increase rates of fuel poverty [18,19]. Hence, the cost of switching to electric heating is a key factor in ensuring consumer engagement and achieving the fuel-switching rates needed for meeting the net-zero emission target.

On the supply side, extensive electrification of heating poses two major challenges to the electricity network. Firstly, supplying additional load from the electrifying heat will require a potentially large increase in low-carbon electricity generation. Secondly, accommodating high variable electric heating loads and the need to instantaneously balance rapid changes in supply and demand requires enhancing the system flexibility on both a daily and seasonal basis [13,23]. The scale of these challenges is context-specific and directly attributed to the current structure of the heating and electricity sectors resulting from how these sectors have developed over time, based on the available resources, policies, and growth paths in a country.

Fig. 1 shows the breakdown of heat demand in buildings and the total annual electricity generation by fuel in some selected countries in 2019. In some countries with a cold climate, such as Germany, the UK, the Netherlands, Poland, Italy, Hungary and France, there is a major imbalance between the heat demand that is currently met by the direct burning of fossil fuels and the electricity generation capacity, both in terms of scale and flexibility requirements. Even though the regular electricity demand (excluding thermal loads from both cooling and heating) varies throughout the day, it generally follows a regular pattern and remains relatively stable throughout the year [24,25]. On the other hand, weather dependency and seasonality of heating demand, as well as rapid changes over peak hours, require flexibility in the supply. For example, in the UK, peak heating demand is more than six times greater than the peak electricity demand during the cold winter days [26]. These countries mostly rely on the flexibility of the existing fossil fuel supply chain to balance variations in heating demand. On the other hand, due to the low use of electricity for heating in these countries, the electricity generation capacity is typically quite small in comparison to the scale of heating demand, and the electricity grid lacks the flexibility mechanisms required to respond to highly fluctuating and seasonal heating loads. Countries such as the Netherlands and the UK, and Italy rely heavily on their extensive natural gas network for supplying a substantial part of their heating demand [27]. The flexible operation of the gas network, as well as the lower cost of gas storage and transport, make it a reliable option for supplying large variations within daily and seasonal heat demand. For instance, in the UK, on cold winter days, daily gas demand can be around 4.7 TWh, more than five times the energy delivered by the electricity grid on an average winter day [28–30]. Therefore, to accommodate large amount of electric heating loads, the electricity system should be developed in a way that it can deliver low-carbon electricity at such scale and flexibility and also at an affordable cost while maintaining stable and secure operation.

System flexibility is a key enabler for an efficient and cost-effective transformation to a future low-carbon electricity system [31]. The electricity system flexibility refers to "the ability of the system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales" [32]. This is the ability of an electricity system to maintain a reliable balance between demand and supply (subject to network operating constraints) in the event of rapid, large, expected, and unexpected imbalances [24]. The electricity system's flexibility is generally evaluated over three timescales [24,25,33,34]:

- **Stability and resilience:** The ability of a system to recover instantaneously from disruptions and imbalances in supply and demand and maintain operating reserves and inertia.
- **Balancing and operational security:** The ability of a system to retain the balance of supply and demand, also known as load following. It includes real-time, intra-day, and day-ahead balancing.
- **Adequacy:** The ability of a system to meet long-term capacity requirements and meet peak and aggregated electricity demands at all times.

The three forms of flexibility are complementary to each other, and they are fundamental to an efficient transition to the future low-carbon electricity system [31,34] and effective widespread electrification of heating.[1]

The current electricity system is primarily built on inflexible demand and dispatchable generation, with electricity system operators adjusting supply to match the electricity demand. Therefore, the flexibility in the electricity system is traditionally associated with dispatchable thermal plants [24]. However, there is a high emission effect associated with the flexibility provided by these generators; therefore, their service becomes more expensive with tightening emission targets and rising carbon prices. On the other hand, as the share of variable renewable sources increases, the supply side becomes less flexible [24]. Therefore, to successfully decarbonise the electricity grid by taking maximum advantage of renewable electricity generation while reliably and cost-effectively accommodating a high degree of electrification, electric heating loads will need to be flexible [23]. There has been a lot of attention paid to flexibility options within the electricity grid [31,35], but considering the scale of heating demand, if electrification takes place in a way that is manageable and controllable, the electric heating demand could become an invaluable source of low-carbon flexibility for the electricity grid [36]. Harnessing this flexibility entails moving from traditional flexibility sources to more active flexibility provision and demand management.

The goal of demand management is to shift or curtail consumer demand and transition towards a system in which demand can be tailored to match electricity supply [24,25]. The growing electricity demand from electrifying heating provides the opportunity to embed flexibility measures in the electrified heating loads and take advantage of the inherent flexibility of heating demand [23,31,36,37]. This could be achieved through smart-enabled technologies and system-informed operation schemes to mitigate the impacts of electrification on the electricity grid and also reduce the cost to consumers. Smart demand-side management schemes can redistribute electric heating loads and engage demand-side resources for system balancing without compromising the quality of service to customers [7,36,37].

The successful decarbonisation of heating requires a coordinated effort across many areas, including buildings, heating systems, the electricity sector, and the existing fuel supply infrastructure such as the gas grid [7]. There have been many studies over the past decade investigating the value of demand-side management [38,39]. In the literature, most studies on assessing the role of electrification for decarbonising heating use an abstract representation of heating technologies [8,14,40–44]. Therefore, the value of flexible operation of electric heating technologies and demand-side management for decarbonising heating and its impact on the cost competitiveness of electrification compared to other options such as hydrogen pathway is not well understood. On the other hand, in many studies that examine the potential of electrified domestic heating for demand response, the system boundary is either set at the household level or an abstract representation of the electricity grid is implemented [37,38,45–49]. Most of the modelling work in this area assesses the short-term operation of the electricity grid, with less focus on how this affects infrastructure investment planning and the value of other heat decarbonisation pathways, including hydrogen and other low-carbon gases [36,38,47,50,51]. Therefore, these studies do not provide much insight into how investment and operational set-ups at the consumer-end affect the role of electrification for decarbonising heating and how they impact the short- and long-term operation and investment planning of both the electricity and gas grids. There is a lack of an integrated approach that considers coordinated planning of fuel switching for decarbonising heating with electricity and gas grids operation and capacity planning. As a result, the trade-offs between consumer investment decisions and infrastructure requirements for cost-effective decarbonisation of heating are not well defined.

1.2. Contribution of this study

In this paper, we use a whole system integrated approach to examine the interactions among the electricity grid, the gas grid and heating systems to quantify the value of smart electrification strategies for decarbonising heating. In this context, the term smart electrification refers to system-informed strategies and integrated approaches aimed at enhancing the system value and emission reduction benefits of electrifying heating in buildings and mitigating the reinforcement requirements of the electricity grid [7]. The term heating in this paper refers to both hot water and space heating in buildings. Our study investigates smart electrification from two perspectives: (i) from a system-planning perspective, regarding the extent and timing of electrification of heating under different system-wide constraints, and (ii) from a demand-side perspective regarding the operation and investment schemes on the consumer side aimed at mitigating the impacts of electrification on the electricity system, enhancing its system value and reducing consumers' costs.

In order to investigate smart electrification schemes, we developed an integrated multi-scale capacity planning and unit commitment model of heat, electricity and gas systems, HEGIT, and integrated that with techno-economic models of heat pumps. Incorporating the performance and cost characteristics of different heating technologies and set-ups into the whole system model allows to capture the impacts of smart electrification schemes at both the consumer and energy-system levels and is key for identifying cross-system solutions and trade-offs between consumer investment decisions in heating technologies and infrastructure requirements.

The main contributions of this work are the following:

(a) Examining different pathways for decarbonising heating through electrification from both energy-system planning and demand-side perspectives. First, we explore different scenarios regarding the scope, complementary options and timing of electrification of heating to evaluate the system-wide implications of different planning strategies for electrification of heating, considering the energy security and environmental constraints. Then, we analyse the system value of different investment and operation schemes on the consumers' end to identify those that reduce consumers' investment, mitigate the reinforcement requirements and enhance the system value and emission reduction benefits of electrification. This involves a comparative assessment of different scenarios based on the combination of the following decision factors: (i) standalone or grid-integrated heat pumps; (ii) installing hot water storage tanks with different capacities; (iii) investment in air-source heat pumps (ASHPs) or ground-source heat pumps (GSHPs); (iv) reducing the output temperature of heat pumps and load sharing between heat pumps and electric resistance heaters. To the authors' best knowledge, this is

[1] The system operators usually use different mechanisms to procure these flexibility services such as: short-term operating reserve, fast reserve and frequency response.

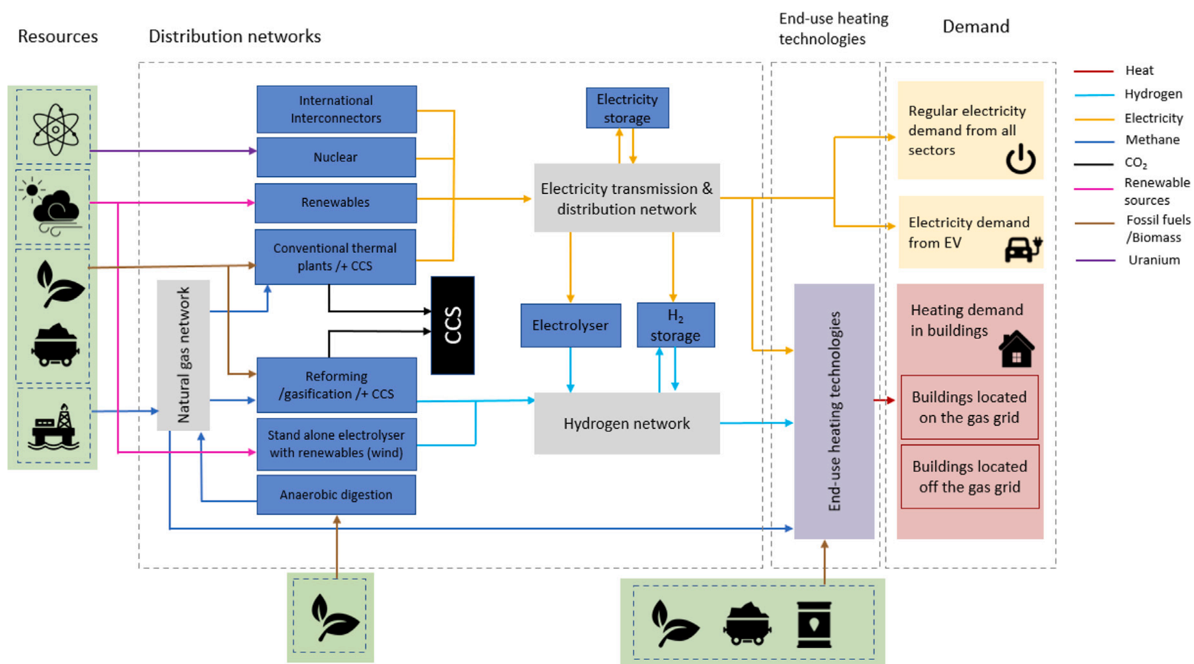

Fig. 2. A simple schematic of the HEGIT framework. HEGIT is a Mixed Integer Linear Programming multi-scale capacity planning and unit commitment model of combined heat, electricity and gas systems. The framework has four main parts: (i) demand, (ii) heating technologies at the consumer end, (iii) distribution networks and (iv) resources. All the parts are combined into a single decision making framework.

the first attempt to provide a comparison of investment and operation decisions at both the energy system and end-user levels.

(b) Conducting an integrated assessment (incorporating demand-side schemes into different system planning scenarios) to investigate the value of smart electrification schemes at the consumer end for accelerating electrification (timing) and enhancing the cost-effective and reliable level of electrification of heating (scope).

We use the UK as an example of a country with a high dependency on fossil fuels for heating in buildings, low use of electricity for heating, and an ambitious net-zero emission target [52]. In the UK, heating in buildings contributes more than 35% of the final energy consumption and is estimated to account for 23% of the UK's greenhouse gas emissions. The emissions are primarily a result of the direct burning of fossil fuels for heating and split between 17% in homes, 4% commercial buildings and 2% in public buildings. Approximately 74% of the UK's heating and hot water demand in buildings is supplied by natural gas, and 10% by petroleum and only less than 9% by electricity [10,41,53].

The remainder of the paper is structured as follows: Section 2 presents the modelling framework, the methodology and the key assumptions used in this study. Section 3 provides descriptions of scenarios examined in our analysis. The results are discussed in Section 4. Section 5 presents the sensitivity analysis and discusses the study limitations and future work. The conclusion follows in Section 6.

2. Methodology and modelling framework

We developed HEGIT (Heat, Electricity and Gas Infrastructure and Technology) model for studying the coordinated planning of electricity, gas and heat systems in order to assess the impacts of different policies and pathways for decarbonising heating on the operation and long-term planning of the gas and electricity grids [54]. In this study, the HEGIT framework is used to examine different scenarios for electrification of heating in buildings. HEGIT is an integrated multi-scale heat, electricity and gas system capacity planning and unit commitment model based on Mixed Integer Linear Programming. The model co-optimises the investments and operations of electricity and gas grids as well as end-use heating technologies while maintaining the security of supply. The outputs are the cost-optimal heating portfolio and heating technology mix in buildings as well as the optimal technology mix, the dispatch profiles and transition over the planning horizon for both electricity and gas grids, subject to different environmental, operational and system-wide constraints. Such a coordinated approach enables us to better understand how major components of the system interact and are affected by one another and to identify cross-system solutions and trade-offs between heating technologies at the consumer end and infrastructure requirements.

Fig. 2 shows a simplified structure of the framework. The model consists of four main parts that are combined into a single decision-making framework. In the following subsections we will broadly describe some of the main constraints in the model. The modelling methodology supplementary document provides a detailed description of the HEGIT model, its formulation, and assumptions.

2.1. Heating demand from buildings

On the demand side, the main constraints are balances between service demand for heating q_d and demand supplied by the energy vectors v in the present system q_s & demand supplied by alternative low-carbon energy vectors l (replacing energy vector v) q_{lc} in each planning year a. Demand for conventional energy vectors for heating d_{ev} is calculated using the average conversion factor of existing heating technologies λ (Eqs. (1) & (2)).

$$q_s(h,v,a) + \sum_l q_{lc}(l,h,v,a) = q_d(h,v,a) \qquad \forall\ h,v,a \qquad (1)$$

$$d_{ev}(h,v,a) = q_s(h,v,a)\ /\ \lambda(h,v,a) \qquad \forall\ h,v,a \qquad (2)$$

Our study incorporates the building heating demand profile for general cold weather proposed by Sansom et al. [55]. Since the full hourly version of the model takes a long time to run we used the k-means clustering method with an "energy-preserving" approach as proposed in Refs. [56,57] to identify 12 representative days and a peak-demand day for our analysis.[2] The methodology proposed by Eyre et al. [42] is used to project the heating demand over the planning horizon. The planning period is from 2020 to 2050 with 5-year planning steps. Furthermore, it is presumed that fuel switching will occur only when the demand for heating is met by direct combustion of fossil fuels. Therefore, if demand is already met by low-carbon energy vectors such as biomass, electricity or renewable sources, fuel switching will not be enforced. Further details about the demand modelling is available in Section **A** of modelling methodology supplementary document.

2.2. Heating technologies

This part includes the operating constraints and specifications of different heating technologies and operation set-ups. The heating technologies translate the heating demand to load curves for different energy carriers. Therefore, their operation and performance characteristics affect the operation and transformation of both the electricity and gas grids and eventually the cost of low-carbon energy vectors used for heating. In this work, we assume that fuel switching for electrification will take place using ASHPs and GSHPs with electric resistance heaters as backup. Also, hydrogen boilers were assumed to be the main alternative to heat pumps for decarbonising heating.[3]

Heat pump is the key technology for electrifying heat in buildings mainly because of its high efficiency in converting electricity to heat [58] and the fact that, with appropriate design, it can be used for both space heating and hot water applications. For residential applications, the most common types are air-source heat pumps, which use outside air as the heat source and ground-source heat pumps, which extract heat from the ground. A heat pump's performance can be measured using a metric known as the coefficient of performance (COP), which is the ratio of the delivered heat to the input electricity of the compressor. While most boilers have an efficiency of approximately 90%, heat pumps can achieve high COPs between 2 to 5 depending on their design, application and operation conditions [59]. The COP can be enhanced by reducing the temperature difference across which heat is transferred. Due to its low thermal conductivity, the ground maintains a more stable temperature than the outside air throughout the year. As a result, GSHPs offer a higher COP than ASHPs, especially during winter, when demand for heating is higher. Fig. 3 shows how the COP of a GSHP and an ASHP varies outside temperature during two consecutive years (in the UK 2009–2011). As shown, the COP of the ASHP closely follows outside temperature variations and ranges between about 1.8 and 4 from winter to summer. On the other hand, the GSHP demonstrates a more consistent performance and maintains a COP of approximately 3.5 throughout the year. Moreover, GSHPs do not require defrosting cycles, which is necessary to maintain the system performance of ASHPs and can often cause disruptions in their operation [60]. On the other hand, GSHPs have higher specific costs at small capacities and higher upfront installation costs. Moreover, ground heat requires time to be replenished, and this can become a limiting factor in highly populated areas [61].

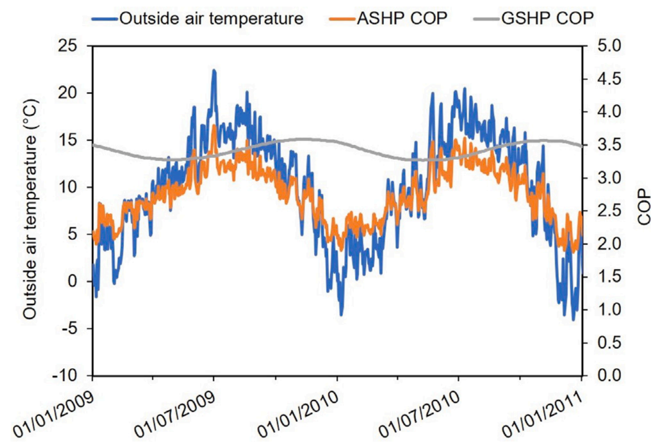

Fig. 3. ASHP and GSHP COP variation over time with outside air temperature for a heat sink temperature of 55 °C.

Unlike boilers, whose performance is independent of weather conditions, heat pump performance can vary significantly with the outside temperature. The common practice in system modelling and capacity planning is to either use a single average value for representing performance and cost characteristics of technologies [14,62], or to use simplified linear relationships [43,63]. These approaches lack detail at the component level and fail to capture variations in cost and performance for different operating conditions and capacities, which are particularly important for technologies such as heat pumps. As a result, small changes in model assumptions can lead to very different results; therefore, such results provide limited reliability. Additionally, manufacturers do not get insights into how to improve their designs to align better with the system's requirements.

In this study, to account for variations in heat pump performance with outside temperature, we soft-linked HEGIT with the techno-economic models proposed by Olympios et al. [64] which capture the cost and performance characteristics of small-scale commercial heat pumps. This involves the use of cost and performance curves of different heat pumps based on an extensive analysis of domestic and commercial technologies available on the market [65] to validate the results from techno-economic modelling of heat pumps. Fig. 4 summarises the cost per unit of thermal power for different sizes of ASHPs and GSHPs. The data correspond to single-stage compressor units without extra features and do not include tax or installation costs. In most buildings, the range of capacities used varies between 5–25 kW, depending on the type of household and the number of residents. Although the unit price of a GSHP is not significantly higher than that of an ASHP, it has a much higher installation cost which can reach up to 500–800 £/kW [66,67]. In this study, the average household size in the UK is used for sizing the heat pumps and installation is assumed to add 20% and 60% to the total capital cost of ASHPs and GSHPs, respectively [68].

A hot water tank should be integrated with the heat pump to reserve hot water for immediate use. Fig. 5 shows the specific cost of a hot water storage tank based on market research for about 20 domestic heat pump tanks. The tank is an expensive component, so its cost should not be neglected when estimating the total investment cost. Hot water tanks are often sized to store about 50 L of water per person per day [69]. Hot water in domestic applications is required at a minimum of 55 °C to prevent the growth of harmful bacteria [70]. Although most newly designed heat pumps can reach these temperatures (except in extreme conditions), their performance drops considerably when the difference between condensing and evaporating temperatures increases. The majority of hot water tanks come with a small electric resistance heater of about 3–9 kW (and if not, it can be added at a small

[2] The full hourly version of the model takes between 34 to 76 h depending on the investigated scenario and activated constraints. The solution error in the objective function value ΔTSC (Total System Cost) was about 1.8–2.7% for 13 representative days compared to the full hourly version of the model, while our running time was reduced to 8–45 min.

[3] The HEGIT model implements six alternative low-carbon heating technologies to replace conventional fossil fuel boilers: ASHPs with electric backup, GSHPs with electric backup, hybrid heat pumps with natural gas boilers, solar thermal, hybrid heat pumps with hydrogen boilers, and hydrogen boilers. To limit the scope of this study, air-source/ground-source heat pumps with electric resistance heater backups were considered as main options for electrifying heating and hydrogen boilers as an alternative option for determining the optimal level of electrification. We discuss other hybrid heat pump options in the Ref. [54].

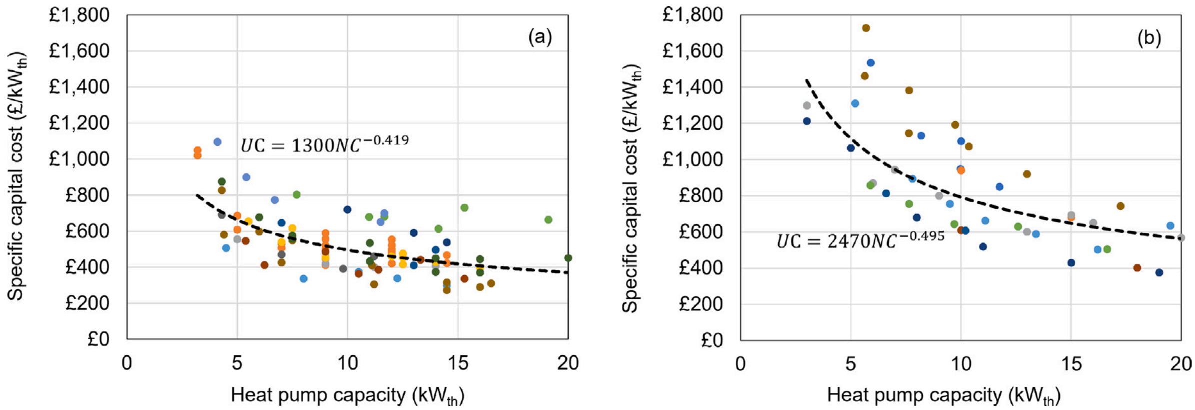

Fig. 4. Specific capital cost as a function of thermal output for small-scale: (a) ASHPs; and (b) GSHPs. Tax and installation costs are excluded. Different colours represent different manufacturers.

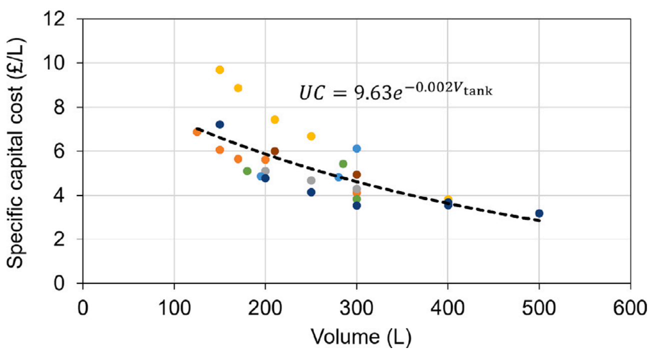

Fig. 5. Hot water storage tank cost as a function of its capacity. All data corresponds to units compatible with low-temperature domestic heat pumps. Tax and installation costs are excluded. Different colours represent different manufacturers.

cost of about £100 [71,72]) that can be used as a backup when the heat pump's output is not enough to meet the demand, especially when the heat source temperature drops below the bivalent temperature.[4] Alternatively, many manufacturers recommend that the heating duty can be divided between electric resistance heaters and heat pumps, so the heat pump heats up the water to a certain temperature (*e.g.* 45 °C), and the electric resistance heater then increase the temperature to the desired output temperature (55 °C). In this way, it is possible to install a smaller heat pump unit, and it also operates more efficiently [71]. Fig. 6 compares the COP of different ASHPs and GSHPs at two different heat sink temperatures of 55 °C and 45 °C. While electric resistance heaters offer a more reliable performance (since their performance does not depend on outside temperature) and have an efficiency of almost 100%, they are still much less efficient than heat pumps.

For each heating technology k, the main constraints are the heat supply and demand balance (Eq. (3)), as well as the mass and energy balances for the hot water tank in each building at each time period t, day c and planning year a (Eqs. (4) to (6)). The thermal output of each heat pump type hp at each time step is constrained by their installed capacity NC_{HP} and their coefficient of performance $COP(hp,c,t)$ at that time step (Eq. (7)).

$$q_{out}(k,a,c,t)+q_{backup}(k,a,c,t) = DP_{heat}(c,t)\ hd(k,a) \qquad \forall\ k,a,c,t \quad (3)$$

$$\Delta_t\ m_{tank}(k,a,c,t) = m_{in}(k,a,c,t)-m_{out}(k,a,c,t) \qquad \forall\ k,a,c,t \quad (4)$$

$$m_{out}(k,a,c,t) \le m_{tank}(k,a,c,t) \le \rho\ V_{tank}(k) \qquad \forall\ k,a,c,t \quad (5)$$

$$q_{out}(k,a,c,t) = m_{out}(k,a,c,t)\ c_p\ \Delta T \qquad \forall\ k,a,c,t \quad (6)$$

$$m_{in}(hp,a,c,t)\ c_p\ \Delta T = COP(hp,c,t)\ p_{hp}(hp,a,c,t) \le NC_{HP}(a) \qquad \forall\ hp \subset k,a,c,t \quad (7)$$

We use the correlation shown in Figs. 6 to calculate the performance of heat pumps as a function of the outside air and ground temperatures at each time step in different scenarios. The unit cost of heat pumps *UC(hp)* and their integrated hot water tanks UC_{tank} as a function of their installed capacity in each scenario are calculated using the equations shown in Figs. 4 and 5. For the gas boilers, single cost and performance estimation from market research and literature are considered [16,65]. Hydrogen boilers are assumed to have a unit cost of 2950 £,[5] with an average efficiency of 90%. The total fuel switching investment by consumers (EUC) is calculated as the sum of the heat pump and hot water tank cost, cost of gas boilers *UC(gb)*, grid integration via smart meters UC_{SM} and the installation cost *Inst(k)* as shown in Eq. (8) (variable *b(k,a)* indicates the number of installed technologies in year *a*). Since the cost of low-carbon fuels is calculated endogenously in the model, their costs are not included in the fuel-switching cost.

$$\begin{aligned} EUC = \sum_a \Big(& \sum_{hp} b(hp,a)\ NC_{HP}(1+Ins(hp))\ UC(hp) \\ & + \sum_{hp} b(hp,a)\ UC_{tank}\ V_{tank}(hp) \\ & + \sum_{hp} b(hp,a)\ UC_{SM} + \sum_{gb} b(gb,a)\ UC(gb)\ (1+Ins(gb))\Big)/Disc(a) \end{aligned} \quad (8)$$

2.3. Electricity and gas networks

An integrated unit commitment and capacity expansion problem is developed for the coordinated operation and planning of the gas and electricity grids. The combined network planning problem will determine the optimal investment strategy in both networks for different scenarios. In this section, only the main operating and balancing constraints related to gas and electricity networks' unit commitment

[4] The bivalent temperature is the temperature below which the heat pump's capacity is lower than its nominal capacity.

[5] Assuming 1500 £ for the hydrogen boiler, 500 £ for changing the internal piping, and 950 £ for installation cost [16,65].

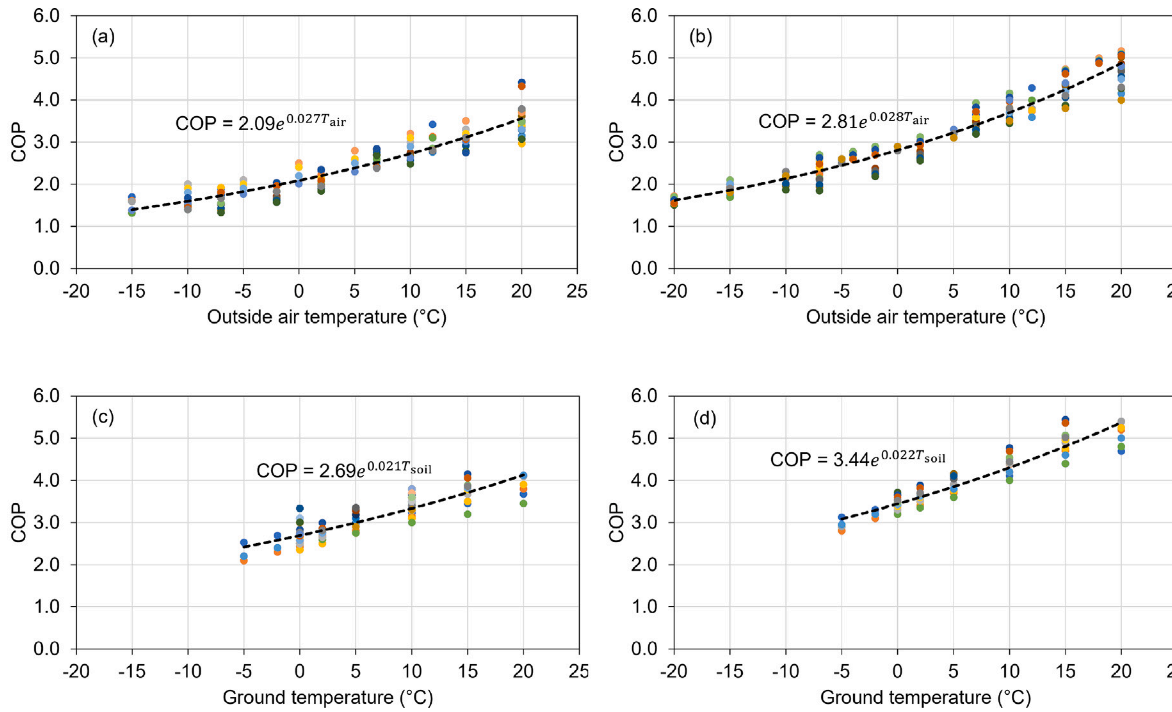

Fig. 6. Heat pump COP as a function of heat source temperature as collected from manufacturers for: (a) ASHP and heat sink temperature of 55 °C; (b) ASHP and heat sink temperature of 45 °C; (c) GSHP and heat sink temperature of 55 °C; and (d) GSHP and heat sink temperature of 45 °C.

problem are presented. Section **C** in the modelling methodology supplementary document provides a detailed representation of equations for this part. Eqs. (9) and (11) show the balances between the demand and supply of each energy vector and ensure that the output from generation $p_{e,H_2,BM}$ and storage sd_{e,H_2} units would be sufficient to meet demand $d_{e,H_2,BM}$ at each time step over the planning horizon.

$$\sum_{ig} pd_e(ig,a,c,t) + \sum_{is} sd_e(is,a,c,t) = d_e(a,c,t)\ (1+TL) - up_d(a,c,t) \qquad \forall a,c,t \tag{9}$$

$$\sum_{jp} pd_{H_2}(jp,a,c,t) + \sum_{js} sd_{H_2}(js,a,c,t) = d_g(H_2boiler,a,c,t)(1+NL) - ug_{H_2}(a,c,t) \qquad \forall a,c,t \tag{10}$$

$$\sum_{jc} p_{BM}(jc,a,c,t) = d_{BM}(a,c,t) \qquad \forall a,c,t \tag{11}$$

The main security and operation constraints for the electricity and gas networks are presented in Eqs. (12) to (15). Eq. (12) ensures the minimum reserve capacity *CM* in the system at each time step is enough to meet peak electricity demand PL_e and demand forecast errors. Eq. (13) ensure compliance with reserve buffer requirements and the operating reserve in the electricity grid at each time step to make up for the loss of renewable generation output and disruptive events. Eq. (14) enforces compliance with the minimum level of inertia required in the electricity grid *SI* and ensures enough units with inertia provision are online at every time step. Eq. (15) denotes the operating *OM* and supply margin *SM* requirements (to account for 1 in 20 demand and n-1 condition [28]) in the hydrogen network. In this case, operating margins are provided by hydrogen storage facilities, linepack, and production units.[6]

$$\sum_{i} x(i,a)\ NC(i)\ TE(i,Cmax) = PL_e(a)\ (1+CM) \qquad \forall a,c,t \tag{12}$$

$$\sum_{ig} r_e(ig,a,c,t)\ TE(ig,Rp) + \sum_{is} sr_e(is,a,c,t)\ TE(is,Rp) \geq PL_e(a)\ RM + \sum_{ir} pd_e(ir,a,c,t)\ WR \qquad \forall a,c,t \tag{13}$$

$$\sum_{ig} n(ig,a,c,t)\ NC(ig)\ TE(ig,Ip) + \sum_{is} o(is,a,c,t)\ NC(is)\ TE(is,Ip) \geq SI \qquad \forall a,c,t \tag{14}$$

$$\sum_{jf} x(jf,a)\ NC(jf)\ TF(jf,P_{max}) + LP_{H_2}\ d_{H_2}(a) + \sum_{jus} x(jus,a)\ F_{outMax}(jus) \geq PL_{H_2}(a)\ (1+OM) + SM \qquad \forall a \tag{15}$$

The outputs of generating plants are limited by the minimum and maximum capacity of each unit *TE(*,Pmax,min)* and *TF(*,Pmax,min)* for electricity and gas generation plants, respectively (Eqs. (16) to (18)). In the case of variable renewable generation units, the upper and lower bounds are multiplied by the renewable sources' availability.

$$p_e(ig,a,c,t) + r_e(ig,a,c,t) \leq n(ig,a,c,t)\ NC(ig)\ TE(ig,Pmax) \qquad \forall\ ig,a,c,t \tag{16}$$

[6] It is assumed that all hydrogen will be produced domestically, and hydrogen imports are not considered. Electricity generation via hydrogen turbines is also not considered here. Although both options might become available in the future and enhance hydrogen network flexibility, it is prudent not to rely on them for strategic infrastructure planning [73].

$$p_e(ic,a,c,t) \geq n(ic,a,c,t)\ NC(ic)\ TE(ic,Pmin) \qquad \forall\ ic,a,c,t \tag{17}$$

$$n(j,a,c,t)\ NC(j)\ TF(j,P_{min}) \leq p_{H_2,BM}(j,a,c,t) \leq n(j,a,c,t)\ NC(j)\ TF(j,P_{max}) \qquad \forall\ j,a,c,t \tag{18}$$

The state of operation of each generating unit in both the electricity and gas networks is given in Eqs. (19) to (21). Separate variables are used for units that are shutting down *w(zg,a,c,t)* or starting up *u(zg,a,c,t)* as expressed in Eqs. (19) to (20) to maintain the linearity of the model (*UT* and *DT* represent the minimum up time and down time for each technology, respectively). The ramping constraints for all generating units are also denoted in Eq. (21) where *RU(zg)* and *RD(zg)* represent the ramping up and down constraints for each technology, respectively.

$$\Delta_t n(zg,a,c,t) \leq u(zg,a,c,t) \leq n(zg,a,c,\tau) \quad \forall\ zg,a,c,t,\tau = t+t'-1,\quad t' \leq UT(zg) \tag{19}$$

$$-\Delta_t n(zg,a,c,t) \leq w(zg,a,c,t) \leq x(zg,a) - n(zg,a,c,\tau) \quad \forall\ zg,a,c,t,\tau = t+t'-1,\quad t' \leq DT(zg) \tag{20}$$

$$-n(zg,a,c,t)\ NC(zg)\ RD(zg) \leq \Delta_t\ p_{H_2,e,BM}(zg,a,c,t) \leq n(zg,a,c,t)\ NC(zg)\ RU(zg) \qquad \forall\ zg,a,c,t \tag{21}$$

Eqs. (22) and (23) describe the minimum and maximum state of charge of each storage unit. In case of gas storage units, withdrawal and injection flows from each gas storage unit are constrained by maximum inflow and outflow of each gas storage unit at each time step.

$$o(is,a,c,t)\ S_{Min}(is) \leq s_e(is,a,c,t) \leq o(is,a,c,t) S_{Max}(is) \qquad \forall\ is,a,c,t \tag{22}$$

$$o(jus,a,c,t)\ S_{Cush}(jus)\ NC_s(jus) \leq s_{H_2}(jus,a,c,t) \leq o(jus,a,c,t)\ NC_s(jus) \qquad \forall\ jus,a,c,t \tag{23}$$

2.4. Objective function and key performance metrics

The objective function of the optimisation model is the total transition cost *TSC* of the system over the planning horizon (2020 to 2050) as represented in Eq. (24). It includes the total capital investment required in the electricity and gas grids, the cost of decommissioning the gas grid, the cost of fuel switching at the consumer side EUC and the operating cost over the planning horizon in both electricity and gas networks *OPEX(a)*. The latter cost includes the fixed and variable operating cost of electricity generation and gas production plants, the start-up cost, the emission cost, the cost of imported electricity, the cost of primary energy vectors used for heating and the maintenance cost of heating technologies at each year.

$$TSC = \sum_{zn,a} b(zn,a)\ WFA(zn)\ CAPEX(zn)\ NC(zn)\ NFR/Disc(a) + EUC + \int_a OPEX(a)\ da + \sum_{\substack{a,h,v=gas\\ l=electricity}} C_{dcg}(\Delta_a\ q_{lc}(l,h,v,a)/\lambda(h,v,a))/Disc(a) \tag{24}$$

The cost of avoided CO_2 is an estimate of the costs incurred under each scenario for each tonne of avoided CO_2 emissions. This is calculated as the ratio between changes in total system cost, in this case the difference between the total system cost in the net-zero emission scenarios (Net0) and the business as usual (BAU) scenario, to the total avoided emissions (Eq. (25)). The business as usual is defined as a scenario in which there is no emission reduction target for heating, and transformation of the gas and electricity grids is driven by changes in demand and decarbonisation targets for electricity. TSE indicates the total system emissions and is calculated as expressed in Eq. (26).

$$CAC(\pounds/t_{CO_2}) = \frac{TSC_{Net0} - TSC_{BAU}}{TSE_{BAU} - TSE_{Net0}} \tag{25}$$

$$TSE = \int_a \Big(\sum_{ig,c,t} p_e(ig,a,c,t) TE(ig,Ems) + \sum_{jp,c,t} p_{H_2}(jp,a,c,t)\ TF(jp,Ems) + \sum_{h,v} d_{ev}(h,v,a)\ CI(v,a) + \sum_{jc,c,t} p_{BM}(jc,c,t)\ e_{AD}(jc) \Big)\ da \tag{26}$$

The Shannon Weiner Diversity Index (SWDI) is a measure of the diversity of a set, and a higher index value indicates a more diverse mix [74,75]. SWDI is widely used in long-term energy planning and supply security analysis. This paper uses the Shannon index to evaluate the diversity of the primary energy vectors used for supplying electricity and heating. Eq. (27) is the general equation for the Shannon index with y(n) representing the proportion of each category.

$$SWDI = -\sum_i y(n)\ \ln y(n) \tag{27}$$

3. Scenario description

There are different aspects to smart electrification, including technological, operational, financial, system design and planning and policy aspects. In this study we will first examine how different pathways for decarbonising heating in buildings will impact the operation, technology mix, and transformation of the electricity grid and then we will look at how different investment and operational schemes on the consumer end could impact the system value and system-wide implications of electrifying heating in buildings. In all scenarios discussed, we assume that the commitment to achieving net-zero emission by 2050 [52] will be maintained. Furthermore, in all scenarios, we assume that the installation of new oil and coal boilers in buildings will cease after 2025 [53].

3.1. System planning for electrification of heating

In this part, we examine two sets of scenarios based on the level of direct emissions from heating at the consumer side at the end of the planning horizon in 2050.

3.1.1. No direct emissions from heating in buildings in 2050

In this case, we assume that meeting the net-zero emission target in 2050 will require eliminating all direct emissions from heating in buildings by 2050. We study three scenarios in this case:

(a) 100% electrification of heating in all buildings (Sc1.EL): This scenario analyses the case in which decarbonising heating takes place by switching from fossil fuel boilers to ASHPs (with electrical resistance heater as backup) in all buildings. As a result, the low and medium pressure gas grid used primarily for heating in buildings will be abandoned in this scenario [76,77]. The timing of fuel switching in this scenario is determined based on the electricity grid's available capacity and operating constraints at each planning year.

(b) Accelerated electrification of heating in buildings (Sc2.AEL): This scenario also involves switching to ASHPs in all buildings, however in this case, we assume minimum fuel switching rate targets in different planning years. Consequently, we assume that the annual rate of switching from fossil fuel boilers to heat pumps will reach 600.000 in 2028 (as envisaged by the UK government) [78], and should remain constant up until 2050 till heating in all buildings is fully electrified.

Table 1
Summary of system planning scenarios for electrification of heating.

Scenario	Direct emissions in 2050 from heating (Mt_{CO2})	Technologies for fuel switching	Internal fuel switching targets
Sc1.EL	0	ASHPs	No
Sc2.AEL	0	ASHPs	Yes
Sc3.EL-H2	0	ASHPs and hydrogen boilers	No
Sc4.Em5	5	ASHPs	No
Sc5.Em10	10	ASHPs	No
Sc6.Em-UNL	Unconstrained	ASHPs	No

(c) Availability of hydrogen for heating in buildings (Sc3.EL-H2): This scenario uses hydrogen as a complementary option to electrification for decarbonisation of heating in buildings connected to the gas grid. In this case, no constraint on the degree of electrification or switching to hydrogen is set. Rather, the model evaluates the cost-optimal balance between the two options to decarbonise heating in all buildings. The Sc3.EL-H2 scenario is based on the idea of re-purposing the existing gas network infrastructure and also benefiting from the storage potential and flexibility mechanisms offered by the gas grid [79–82]. Unlike electrification, the use of hydrogen for heating is a novel and unprecedented experiment, and there is much uncertainty and debate about the viability of hydrogen network and the use of high-value hydrogen for low-temperature heating [73,82]. Nevertheless, we assume that there will not be any significant technical challenges in converting the gas grid to deliver hydrogen, and all the safety measures will be in place for using hydrogen for heating in buildings.

3.1.2. Partial decarbonisation of heating in buildings

In this set of scenarios, the requirement for zero direct emissions from heating in buildings to obtain the net-zero emission target is relaxed. Using these scenarios, we explore the impact of different levels of residual emissions from heating (different degrees of fuel switching) on the value proposition of electrification for decarbonising heating in buildings. We examine three levels of residual emissions from heating in buildings:

(d) 5 Mt_{CO_2} ($Sc4.Em5$)
(e) 10 Mt_{CO_2} ($Sc5.Em10$)
(f) $\text{No constraint on residual emissions from heating (Sc6.Em} - \text{UNL)}$

It is important to note that ultimately, the level of residual emissions depends on how future carbon budgets are planned, the emission reduction targets set for different sectors and the availability and scale of negative emission technologies for carbon offsetting in different countries. In all the scenarios studied in this paper, bio-energy with carbon capture and storage (BECCS) is the only negative emission technology considered. Table 1 provides a summary of system planning scenarios for electrification of heating.

3.2. Investment and operation schemes at the demand side

In all the six system planning scenarios discussed in the previous section, the electric heating loads were transferred to the electricity grid as given by consumers' demand for heating. The electricity grid should then respond to this additional and generally fluctuating electric heating demand. However, if the electrification is implemented smartly and based on system requirements, electric heating loads could be manageable and more flexible than regular electricity loads and can be transferred to the electricity grid in a way that is beneficial to the electricity grid and provide flexibility services.

Electrification of heat using distributed heat pumps involves four main investment and operational trade-offs at the consumer end. Different combinations of these decision factors will result in different electricity demand profiles and different fuel switching costs to consumers. Therefore the following scenarios have been developed based on different combinations of these decision factors:

(i) Grid-integrated (GI) vs. not grid-integrated (NGI) heat pumps: Here, we examine the impact of grid integration of heat pumps via smart meters on the operation and reinforcement requirements of the electricity grid. If heat pumps are integrated into the electricity grid via smart meters, they can interact with the electricity grid and adjust their operation based on the price and availability signals from the grid [23].
(ii) Varying shares of installed ASHPs versus GSHPs in buildings: The share of ASHPs in total installed heat pumps in buildings is varied between 60% and 100%. The share of GSHPs consequently changes between 40% and 0%. The 40% upper limit for GSHP installations is set to represent the fact that many types of UK households are not suitable for GSHP installation due to lack of space and the unsuitability of the ground[7] [83].
(iii) Sharing the heating load between the heat pump and the direct electric resistance heater: As discussed in Section 2.2, the smaller is the temperature difference between the heat source and sink of a heat pump, the higher its COP will be. This effect is examined through two cases of heating duty division between the heat pump and the electric resistance heater. In 55 °C scenarios, the heat pump heats the water to 55 °C (which is the desired temperature considered for both hot water and space heating in this study), and the electric resistance heater is only used as a backup. In this scenario, the annual average COP of the heat pump is around 2.07. In 45 °C scenarios, however, the heating duty is shared between the heat pump and electric resistance heater, so the heat pump raises the water temperature to 45 °C and the electric resistance heater then further raises it to 55 °C. Therefore, in the 45 °C scenario, a smaller heat pump can be installed, and the annual average COP of the heat pump is around 2.8.
(iv) Size of thermal storage tank: We vary the buffer hot water storage capacity between 50 L and 200 L per person in order to evaluate the impact of thermal storage at the consumer end on the electricity grid operation and reinforcement requirements. A minimum fixed reserve capacity of 50 L is considered for immediate hot water use in all the time steps. Therefore, in the 50 L per person scenario for a household with two residents, the thermal capacity of the hot water tank would be about 150 L. The focus here is on buffer capacity, and other values can be used for fixed reserve capacity. Additionally, it is worth noting that the specified volumes are based on storing water at 55 °C. If a higher storage temperature is chosen, the size of the hot water tanks could be smaller.

Table 2 provides a summary of investment and operation scenarios on the demand side.

[7] Another important consideration for the installation of GSHPs is that the ground should recover the heat extracted through solar or geothermal gains. As such, installing a large number of GSHPs in a block may gradually lower the ground temperature [66].

Table 2
Summary of investment and operation scenarios on the demand side.

Fuel switching decision factors at the consumer end	Trade-offs	From consumers perspective	From electricity system perspective
Interactions with the electricity grid	Grid integrated (GI) **vs.** not grid integrated (NGI) heat pumps	Requires small additional cost	Provides demand-side response
Heat pump type	GSHP **vs.** ASHP	GSHPs are more expensive than ASHPs but have lower operating cost	GSHPs have a higher and more stable COP than ASHPs, which means less variations in electric heating demand and lower peak and aggregated electricity demand
Heat pump output temperature	55 °C **vs.** 45 °C	Reducing heat pump's output temperature to 45 °C and load sharing with resistance heater improves heat pump's COP. So a smaller heat pump unit can be installed and the fuel switching cost is reduced but it can increase the operating cost	Less variations in the electric heating demand but peak electricity demand could increase in the 45 °C scenario
Capacity of thermal storage	50 L/person to 200 L/person	Increasing thermal storage capacity increases fuel switching cost and requires more space but it can reduce the operating cost	Enhances the load-shifting and flexibility services enabled through grid integration of heat pumps

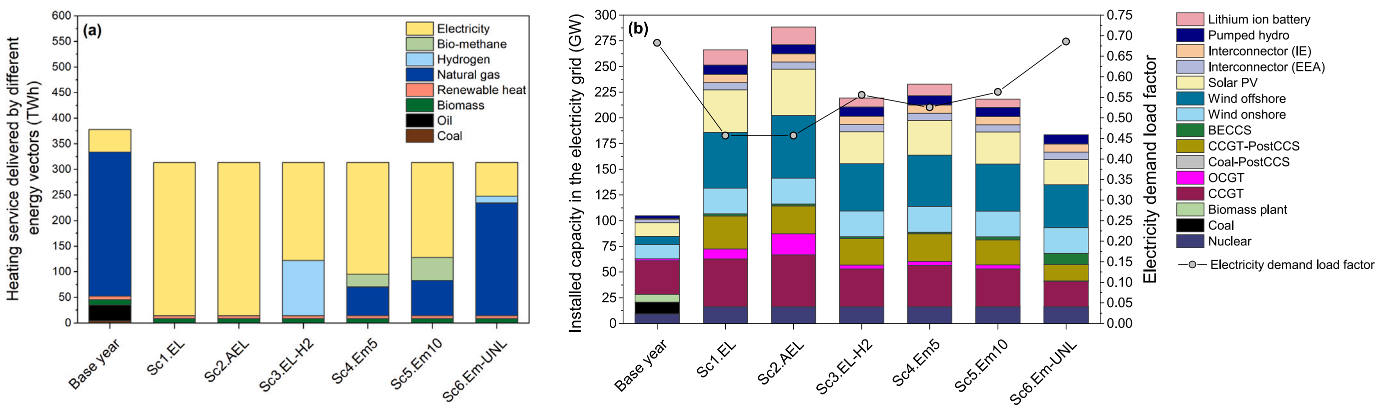

Fig. 7. (a) Breakdown of the energy vectors used for providing low and zero-carbon heating in each electrification planning scenario at the end of the planning horizon (2050), compared to the base year (2020). (b) Required installed capacity and technology mix in the electricity grid in 2050 for each scenario. The dotted line represents the electricity demand load factor in each scenario.

4. Results and discussion

4.1. Long-term planning for electrification of heating

Fig. 7(a) shows the breakdown of energy vectors used for providing heating in buildings in 2050 for different electrification planning scenarios. Fig. 7(b) shows the required installed capacity and technology mix in the electricity grid in 2050 for each scenario. In both Sc1.EL and Sc2.AEL scenarios, nearly all of the heating in buildings will be supplied by electricity using heat pumps. This will have three major impacts on the electricity demand profile in the UK. First, the total annual electricity demand will increase from 296 TWh in the base year to 533 TWh in 2050. Secondly, the instantaneous peak electricity demand will increase substantially from 49 GW in the base year to 133 GW in 2050. This will significantly increase the rate and range of ramping in demand during peak hours, which necessitates a very steep ramping requirement in the system. Third, the seasonality and temperature dependency of heating demand will reflect in the electricity demand profile, increasing the variability of electricity demand with outside temperature.[8] Our results show that this reduces the electricity demand load factor[9] from 0.68 in the base year to 0.45 for the complete electrification of heating scenarios.

Accommodating the additional and highly variable load (both diurnally and seasonally) with elevated peaks from electrifying heating requires a substantial expansion and reinforcement of the electricity grid as well as the transmission and distribution networks. In the case of the Sc1.EL scenario, about 253 GW of installed capacity will be required in the electricity grid up from 105 GW in the base year. Electricity demand growth, however, provide the opportunity for the deployment of low-carbon renewable electricity generation. In the Sc1.EL scenario, the total wind offshore and solar PV capacity increase about 3 and 5.5 fold, respectively. In addition to decarbonising the electricity grid, this will also facilitate resource diversification (SWDI increases compared to the base year as shown in Fig. 8), reduce demand for fossil fuels mainly natural gas here,[10] and reduce the vulnerability to volatility in fossil fuel prices. However, delivering the necessary scale of renewable generation requires a sustained expansion of wind and solar PV capacities [84].

Increasing the share of renewable energy in the system will not completely solve the energy security problem but will change the nature of security risks from long-term availability risks to short-term reliability risks that need to be managed. The increased variability and intermittency on the supply side, as well as the high diurnal variations and seasonality on the demand side with elevated peak demand, will significantly increase the grid's flexibility requirements. So, in order to maintain stable and secure operation, substantial investment will be needed to enhance the system's flexibility. We observe that in the

8 Due to the low use of electricity for heating in the UK, these effects are minor in the base year.

9 The electricity demand load factor refers to the ratio between the average electricity demand over a year and the peak electricity demand during that year.

10 In the case of the UK, since domestic natural gas production is projected to decline, reduced demand for natural gas means less dependence on imports.

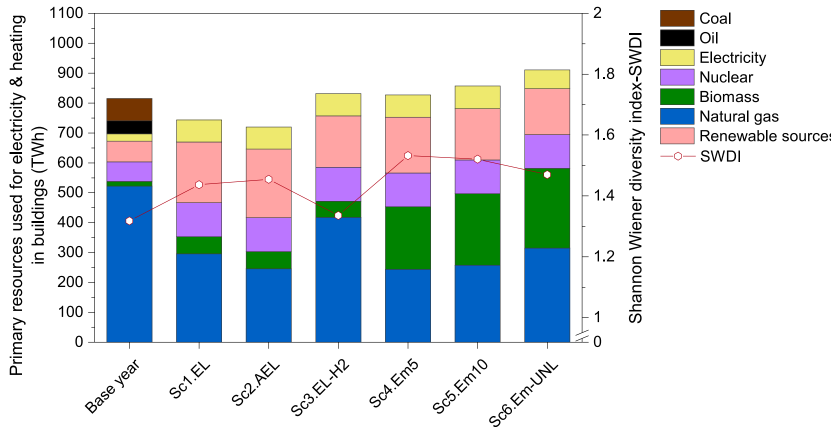

Fig. 8. Breakdown of demand for resources in different scenarios at the end of the planning horizon in 2050 compared to the base year, 2020. The dotted line shows the Shannon-Wiener index (SWDI) as an indicator of diversity of the fuels mix. The higher value of the SWDI index represents a more diverse fuel mix.

Sc1.EL scenario, a considerable capacity of peak/reserve dispatchable thermal generators is used to balance large volumes of variable renewables and ensure the security of supply under unforeseen events such as a sustained period of low wind. Our results indicate that while the total installed capacity of dispatchable thermal generators increases from 54 GW in 2020 to 94 GW in 2050 in the Sc1.EL scenario, the average capacity factor of these generators.[11] drops from 37% in the base year to about 23% in 2050. This means these capacities have to run at higher cycling rates. In addition, due to the high carbon intensity of fossil-based reserve/peak capacity, variations in demand will be associated with increased emissions. Therefore, meeting the increased ramping requirements by fossil-based generation could be more expensive in the future due to the increased number of start-ups, efficiency losses from part-load operation (which also increases the CO_2 emissions rate of these plants), and the increasing carbon tax [31]. Considering the low capacity factor, inefficient operating pattern and high operating costs of fossil fuel-based reserve generators, it may be difficult to attract investment for these plants, especially at such large scales, since wholesale market revenues are likely to be too low and risky to justify the investment.

The substantial expansion of the electricity grid and the build-up of underutilised capacity will make the decarbonisation of heating more expensive in the complete electrification scenario. Fig. 9 shows the average cost of avoided CO_2 in different scenarios and how this value will change with variations in fuel prices and carbon tax rate. The average cost of avoided CO_2 for Sc1.EL and Sc2.AEL scenarios are about 121 and 144 £/t_{CO_2}, respectively. We observe that while both scenarios have a lower level of vulnerability to changes in fuel prices and carbon taxes, they have a higher average abatement cost compared to other scenarios.

4.1.1. Timing of electrification

Fuel switching and achieving zero and low-carbon heat will undoubtedly be costly and require consumers to engage with new technologies, products and services. Fuel switching and consumer engagement are slow and time-taking processes [23]. In the Sc1.EL scenario, the fuel-switching rate and timing were driven by the available capacity and operational constraints in the electricity grid. In that scenario, the bulk of heating decarbonisation occurs after 2035, mainly due to the availability of more low-carbon flexibility options in the electricity grid, such as carbon capture and storage (CCS) integrated thermal plants and grid-scale battery storage. This is also because of the prospect of lower heating demand due to energy efficiency measures and, therefore a lower cost of fuel switching. However, given the very short time frame to 2050 (from 2035), achieving zero-emission heat in this scenario would require a high fuel switching rate of more than two million households per year. The scale and complexity of this transition increase the risk of missing emission mitigation targets for heating in buildings. Therefore, if a country aims to supply a substantial share of its heating demand in buildings by electricity, it is sensible to start earlier [23,84]. Thus, the question of the timing of electrification of heating arises. Would it be better to wait until low-carbon flexibility options such as combined-cycle gas turbines with carbon capture and storage (CCGT-CCS) and cheaper grid-scale battery storage become available at scale before introducing widespread electrification of heating? Or is it better to start earlier to avoid the risks of slow fuel switching rates and missing emission targets in the future and reinforce the electricity grid accordingly?

In the case of the UK, given the ambitious plans set by the UK government to significantly reduce greenhouse gas emissions of the electricity grid by 2035, the coordinated timing of decarbonisation and expansion planning of the electricity grid and electrification of heating is key. Therefore in the Sc2.AEL scenario, we looked into implications of accelerated electrification of heating and achieving 600,000 heat pumps installation rate (per year) by 2028 and continued uptake of heat pumps afterwards to 2050 [78]. As noted in Fig. 9 the cost of avoided CO_2 in this case is about 23 £/t_{CO_2} higher than Sc1.EL scenario. There are two reasons for this rise in the mitigation cost in the Sc2.AEL scenario. Firstly, in the accelerated electrification scenario, the cost of fuel switching will be higher due to early adaptation of more expensive heat pumps; this part is inevitable and is necessary to reduce the risks of missing the net-zero target. Secondly, the accelerated electrification of heating impacts the operation, transformation and technology mix of the electricity grid. As shown in Fig. 7 the installed capacity required in the case of Sc2.AEL is 16 GW higher than the Sc1.EL scenario. Fig. 10 shows the fuel-switching trend and the transition of the electricity grid for both Sc1.EL and Sc2.AEL scenarios. The main difference between the two scenarios is observed between 2025 to 2040. In the Sc2.AEL scenario on the demand side, the increased demand from accelerated uptake of heat pumps increases the flexibility requirements of the electricity grid. On the supply side, planned reductions in the carbon intensity of electricity will constrain the operation of flexible unabated thermal generation units while necessitating the expansion of variable renewable generation capacity. The electricity grid would therefore have to deal with the additional fluctuating electricity demand from electrifying heat, the increasing uptake of renewables and limitations on the operation of traditional flexibility and balancing sources at the same time around the 2030s. The problem could be exacerbated as this would coincide with the expected retirement of a large nuclear fleet

[11] The average value reported is for all the thermal dispatchable generation including combined-cycle gas turbines (CCGT), open-cycle gas turbines (OCGT), combined-cycle gas turbines with carbon capture and storage (CCGT-CCS), BECCS, Coal plants and Biomass plants.

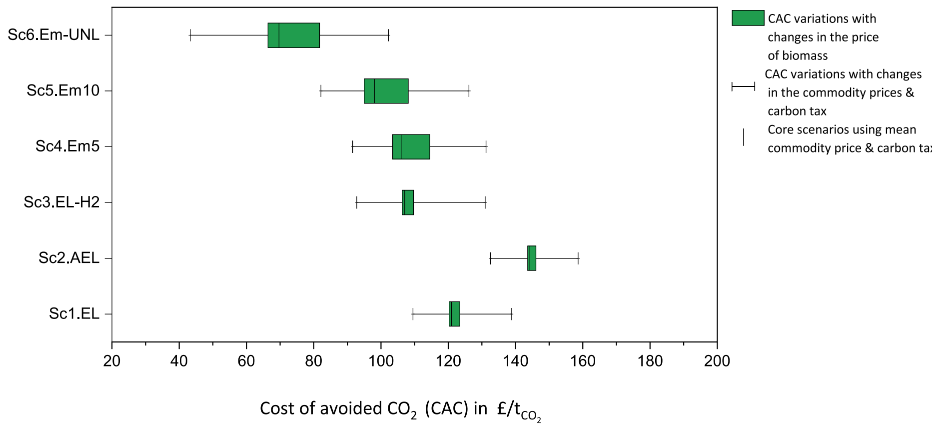

Fig. 9. Variations in the cost of avoided CO_2 from changes in commodity prices and carbon tax.

in 2030–2035 in the UK.[12] Therefore to maintain a reliable supply, the system is oversized by investing in additional renewable generation capacity as well as additional peak/reserve generators (mainly open-cycle gas turbines (OCGT) and combined-cycle gas turbines (CCGT)), as well as installing grid-scale battery storage earlier. However, this has the disadvantage that the flexibility services provided by unabated generation plants to meet these near-term flexibility requirements would become less valuable and more expensive with an increase in the carbon tax and the availability of other flexibility sources such as low-carbon gas-CCS and increased grid-scale battery storage down the planning horizon. Therefore over the long term, this will negatively impact the capacity factor of these plants and lead to oversizing the system. An oversized system will increase the cost of transition, which will ultimately be passed on to the consumers' bills. However, this effect is not inevitable, and in the next section, we will discuss how implementing demand-side management and smart electrification schemes at the consumer side could facilitate accelerating electrification.

4.1.2. Complementary options to electrification of heating

The Sc3.EL-H2 scenario examines the case in which the low and medium pressure gas grid is partially retained. To comply with the zero direct emissions from the heating target in 2050, in this scenario, hydrogen boilers are selected to supply part of the heating demand in buildings connected to the gas grid. The cost-optimal level of electrification in this scenario is found to be around 50%,[13] while the remainder of the heating demand will be supplied by hydrogen. The electricity grid's required capacity in this scenario reduces to about 199 GW versus 253 GW in the Sc1.EL scenario. It is noteworthy that the electricity demand load factor increases to about 0.55 (compared to 0.45 in the Sc1.EL scenario), which can be attributed to the lower peak demand and less variations in the electricity demand due the lower degree of electrification of heating. Thus, fewer idle peak/reserve generators will be required in the electricity grid, and the average capacity factor of thermal generators increases by about 10% in this scenario compared to Sc1.EL. Among the possible hydrogen production technologies, the model selects auto-thermal methane reforming with carbon capture and storage (ATR-CCS), mainly due to the lower cost and higher operation flexibility reported for this technology. In light of this, we observe a higher demand for natural gas in this scenario compared to electrification scenarios. The combination of this with the lower penetration of renewable generation in the electricity grid (due to lower growth in electricity demand[14]) will reduce the diversity of the system's resource mix in this scenario (SWDI decreases).

Another option would be to partially remove direct emissions from heating in buildings and rely on technologies that deliver negative emissions, such as bio-energy combined with carbon capture and storage (BECCS) to achieve the net-zero emission by 2050. The residual emission budget for heating in 2050 was examined under three constraints of 5 Mt_{CO_2}, 10 Mt_{CO_2} and unconstrained budgets in Sc4.Em5, Sc5.Em10 and Sc6.Em-UNL respectively. These scenarios offer the benefit of avoiding fuel switching in some regions or for some consumer groups. This could allow the gas grid to operate partially and continue supplying natural gas to the remaining consumers. In both the Sc4.Em5 and Sc5.Em10 scenarios, bio-methane injection to the gas grid is selected to reduce the carbon intensity of the gas delivered via the gas grid, as shown in Fig. 7. In both scenarios, BECCS is used to offset emissions from both heating and electricity generation, resulting in a 10%–15% increase in its capacity factor compared to the Sc1.EL scenario (in Sc1.EL scenarios, BECCS is mainly used to offset emissions from electricity generation). As a result, the biomass resources are partly allocated to BECCS plants for negative emissions and partly directed to bio-methane production to reduce the carbon intensity of the gas grid. This would enable the use of biomass for heating and improve the diversity of the heating portfolio as well as the whole system resource mix. In both cases, the electricity load factor is also improved (0.52 and 0.56 respectively for Sc4.Em5 and Sc5.Em10 scenarios) over the Sc1.EL scenario since less variable heating load is transferred to the electricity grid. This reduces the grid's capacity and flexibility requirements. The effect is most noticeable on grid-scale storage and peak/reserve generator capacity in these scenarios compared to Sc1.EL (Fig. 7). In terms of cost, both scenarios lead to reduced mitigation costs compared to the Sc1.EL scenario, primarily due to lower fuel switching costs and less idle capacity in the electricity grid. A noteworthy observation is that despite different infrastructure and resource requirements, the cost of avoided CO_2 in the Sc4.Em5 scenario is relatively close to the Sc3.EL-H2 scenario. Their cost, however, has different characteristics. While in the Sc3.EL-H2 scenario, the mitigation cost is more susceptible to changes in natural gas prices, in the Sc4.Em5 scenario, despite the reduced vulnerability to gas prices, the mitigation cost is more susceptible to changes in biomass prices.

In the Sc6.Em-UNL scenario, the constraint on direct emission budget from heating is relaxed, and the only driver for fuel switching at the consumer end is the carbon price and commodity prices. As shown in Fig. 7 the system avoids fuel switching in buildings connected to

[12] This is based on the lifetime of 50 years assumed for nuclear plants in our analysis. Therefore, a sizable capacity of nuclear plants is expected to retire due to ageing between 2030–2035, which is consistent with data reported by the World Nuclear Association [85].

[13] Please note that no constraint on scale of electrification is set in this scenario and the model evaluates the cost optimal degree of electrification based on operating and system-wide constraints. If hydrogen is selected, the model builds the whole supply chain for supplying hydrogen to buildings.

[14] This will also reduce the flexibility requirement of the electricity grid.

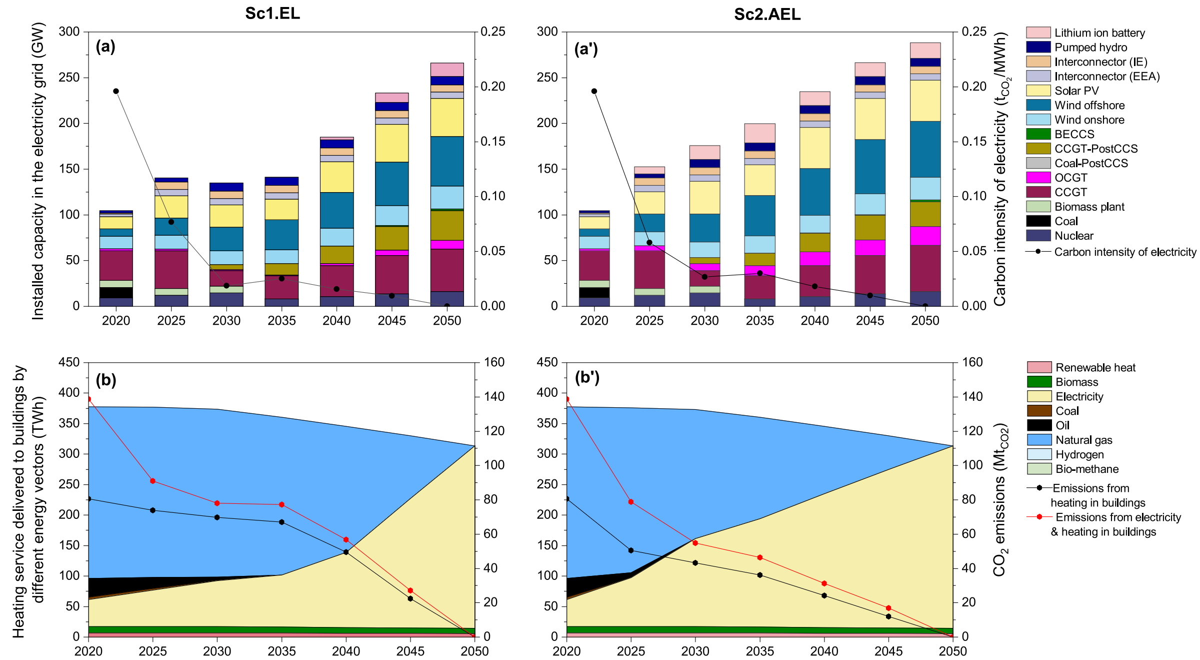

Fig. 10. Top: The required installed capacity in the electricity grid in (a) Sc1.EL scenario as compared to (b) Sc2.AEL scenario. Bottom: Heating service provided by different energy vectors over the planning period in (a′) Sc1.EL scenario as compared to (b′) Sc2.AEL scenario.

the gas grid. Instead, it uses BECCS capacity in the electricity grid to provide further emissions space for heating. Therefore, in this scenario, a higher capacity of BECCS will be required, and the plants will also run as a base generator with a capacity factor of about 85%. In addition, part of the biomass in this scenario is allocated to reduce the carbon intensity of gas supply through controlled injections of bio-hydrogen into the gas grid (up to 20% by volume). In this scenario, bio-hydrogen is used to reduce the carbon intensity of the gas grid because it has a higher carbon removal potential compared to bio-methane, making it a more cost-effective option for allocating biomass resources given the scale of residual emission from the gas grid in this scenario.[15] Although this approach could reduce the mitigation cost significantly, it has some major disadvantages. Firstly, in this case, the system will be locked in high demand for both biomass and natural gas and therefore more exposed to volatility in commodity prices, as shown in Fig. 9. The implications of this in terms of energy security could vary from region to region, depending on the country's endowments and access to global commodity markets. In the case of the UK, since domestic natural gas production is projected to decrease in the next decades, higher demand for natural gas as well as quite significant dependence on biomass increases long-term availability risks in the system. On the other hand, a lower degree of electrification means lower growth in electricity demand. This limits the potential for the deployment of indigenous renewable sources. Furthermore, as shown in Fig. 8, the whole system will become less efficient compared to the Sc1.EL scenario and approximately 26% more resources will be needed to meet the same demand.

Overall, both hydrogen and partial carbon offsetting, despite having different infrastructure requirements, are valuable options to complement electrification and reduce the electricity grid's reliability risks and flexibility requirements and moderate the idle reserve capacity required in the grid. Therefore, reducing the costs and reliability risks of decarbonising heating. However, the availability of both options and the extent to which they can be used depends on various factors such as the availability of carbon capture and storage, the present infrastructure in a country, countries' endowment, access to global commodity markets and consumer engagement for fuel switching.

4.2. Electrification schemes at the consumer end

The previous section discussed how widespread installation of heat pumps could pose reliability risks to the electricity grid, especially during cold winter days. This led to the requirement for a substantial expansion and reinforcement of the electricity grid. In all the scenarios discussed in the previous section, electric heating demand was transferred to the electricity grid as given by consumers' demand for heating and, the system relied solely on flexibility mechanisms within the electricity system (such as flexible generation and electricity storage) to balance variations in demand and supply. However, heating in buildings offers considerable potential for load shifting and demand-side management. In fact, if the electrification of heating is implemented smartly, it can be used to provide flexibility services to the electricity grid and moderate its reinforcement requirements. In this section, we discuss how consumers' investment and operation set up choices could affect the cost of fuel switching for them as well as the implications of electrifying heating at scale on the operation and transformation of the electricity grid. Note that the Sc1.EL scenario described in Section 3.1 is used as the reference case for the analysis in this section.

The projected peak electricity demand plays a critical role in electricity grid capacity planning, and the grid should be configured to securely supply electricity during extreme events [37]. Electricity grid operators often turn to fossil-based dispatchable generations, which are the traditional sources of flexibility in the system and have high response rates, to meet the ramping rate required during peak hours. This results in an increase in the carbon intensity of electricity during these periods. Fig. 11 shows the peak electricity demand in 2050 for different consumer end operations and investment scenarios considering complete electrification of heating. The black dashed line represents the peak electricity demand in 2050 without additional load from heating.

[15] The carbon intensity of bio-methane could vary between −0.050 to 0.450 kg_{CO_2}/kWh depending on the biomass source, the upgrading process and the availability of CCS [86]. In our analysis, we assume the carbon intensity of bio-methane produced from anaerobic digestion to be 0.0004 kg_{CO_2}/kWh compared with 0.2049 kg_{CO_2}/kWh for natural gas [86,87]. In the case of bio-hydrogen, the carbon intensity could vary significantly depending on the type of gasifier and the biomass source. We have used the average value of −0.36 based on the data reported in Antonini et al. [88,89].

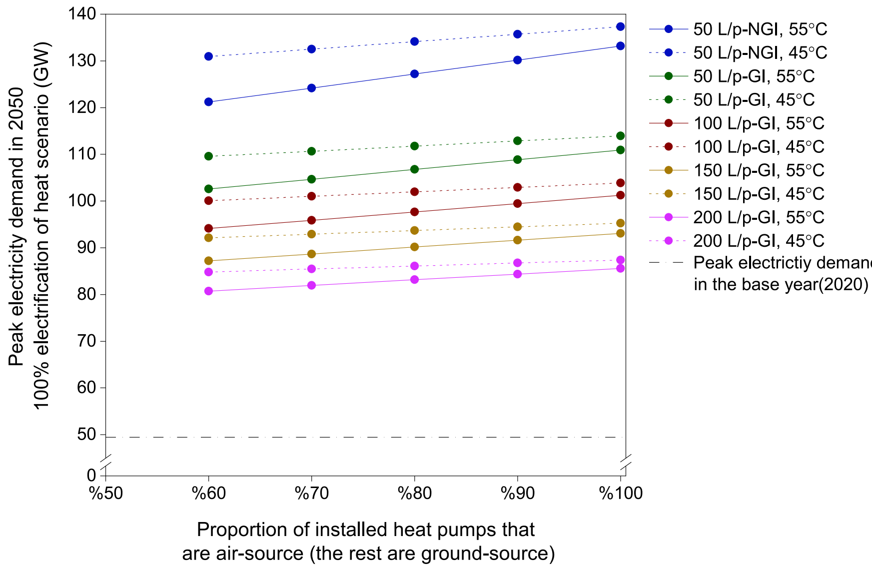

Fig. 11. Changes in the peak electricity demand for different fuel switching and operation schemes at the consumer end. The black dashed line represents peak electricity demand in 2050 without additional load from heating. All the scenarios assume that heating in buildings is completely electrified. In the legend, NGI refers to not grid-integrated heat pumps and GI refers to grid-integrated heat pumps.

Four distinct trends can be identified in Fig. 11. First, grid integration of heat pumps via smart meters could reduce peak electricity demand by up to 21 GW compared to the case of not grid-integrated heat pumps. Grid integration of heat pumps would allow them to adjust their output based on availability and price signals from the grid and fill the hot water storage tank during hours when there is excess generation on the grid, mainly from renewable sources. This way, they can also provide reserve and frequency response services to the electricity grid. However, the load shifting potential, in this case, will be limited by the capacity of the hot water storage tank integrated with heat pumps. It should be noted that both smart meters and a cost-reflective electricity pricing scheme are crucial to enable load shifting and demand response [23].

Second, the peak electricity demand could be reduced by about 27 GW by increasing the buffer thermal storage capacity from 50 to 200 L per person. Installing a larger thermal storage capacity boosts the load shifting potential enabled by the grid integration of heat pumps. Therefore, larger flexible electric heating loads can be spread over time to off-peak hours and the periods when there is abundant electricity generation in the grid. By doing so, it enhances the system's ability to absorb the output from variable renewable technologies. Fig. 12 illustrates this effect more clearly. It compares the electricity dispatch profiles for the scenario of complete electrification of heating without grid integration of heat pumps and buffer thermal storage capacity of 50 L per person (Fig. 12(a)) with the case of electric heating with grid integration of heat pumps and buffer thermal storage capacity of 150 L per person (Fig. 12(b)). Fig. 12(a) shows how inflexible additional electric heating loads affect the peak, ramping rate, and ramping range of electricity demand when compared to the electricity demand profile without additional load from heat pumps (the dashed line). During peak hours, the rapid variations in demand increase the ramping requirements of the system, which is primarily supplied by unabated dispatchable thermal generators and more expensive sources such as grid-scale battery storage. The other balancing challenge in this scenario will be during periods of low demand and high renewable output (highlighted for day 3). Such conditions pose a challenge for the system's operation since solar PV and wind do not contribute to system inertia and cannot provide frequency response to the system. Therefore, a sufficient number of synchronous thermal power plants need to be kept operating at the minimum stable generation level to maintain the reliable operation of the system. This will result in over-generation in the system, thereby limiting the system's ability to absorb the output of renewable generation.

Fig. 12(b) shows that when demand flexibility is enabled through grid integration of heat pumps and larger thermal storage capacity, the electricity grid can use the additional thermal storage capacity to redistribute the heating loads and align them with the availability of renewable resources in the grid. It can also reduce the electricity draw from the heat pump during the evening and morning peak demand periods and shift it to off-peak periods. This way, it reduces the rate, range and frequency of variations in the net load[16] therefore, reducing the supply side ramping rate and storage requirements. The effect is highlighted for two example periods on representative days 3 and 11. On day 11, the electric heating demand is shifted to midday when the solar PV output is high. Therefore the solar PV output is used to fill the storage tanks that will then be used to supply heating in the evening. By doing so, the system avoids evening peak demand and also does not need to reduce thermal generator output to absorb solar PV output. On day 3, load shifting and increasing demand during periods of high wind availability mitigate over-generation and facilitate more efficient utilisation of the assets. For example, our results show that, for a mid-merit generator such as CCGT-CCS, the capacity factor increases by 13% in the scenario shown in Fig. 12(b) as compared to Fig. 12(a).

However, the flexibility and load shifting that domestic thermal storage can provide is limited. The system value of the flexibility offered by thermal storage decreases with increasing storage capacity, as shown in Fig. 11. Due to their relatively small capacity, domestic hot water storage tanks can only be used for diurnal load shifting and cannot contribute to balancing over extended periods, such as between seasons or prolonged periods of cold weather [37]. Therefore the system value of additional thermal storage decreases after a certain level. Another issue is that although a recent report published by Energy system catapult [90] shows that all buildings in the UK are suitable for installing heat pumps, installing storage tanks could be challenging in many buildings due to space limitations. The degree of flexibility and responsiveness in electric heating demand is primarily determined by the space available in households for installing hot water storage

[16] Net load is electricity demand after accounting for the variable renewable output and is a key characteristic an electricity system. The ramp rates and ranges in the net load, can be higher than the variations in the electricity demand and renewable generator output [24].

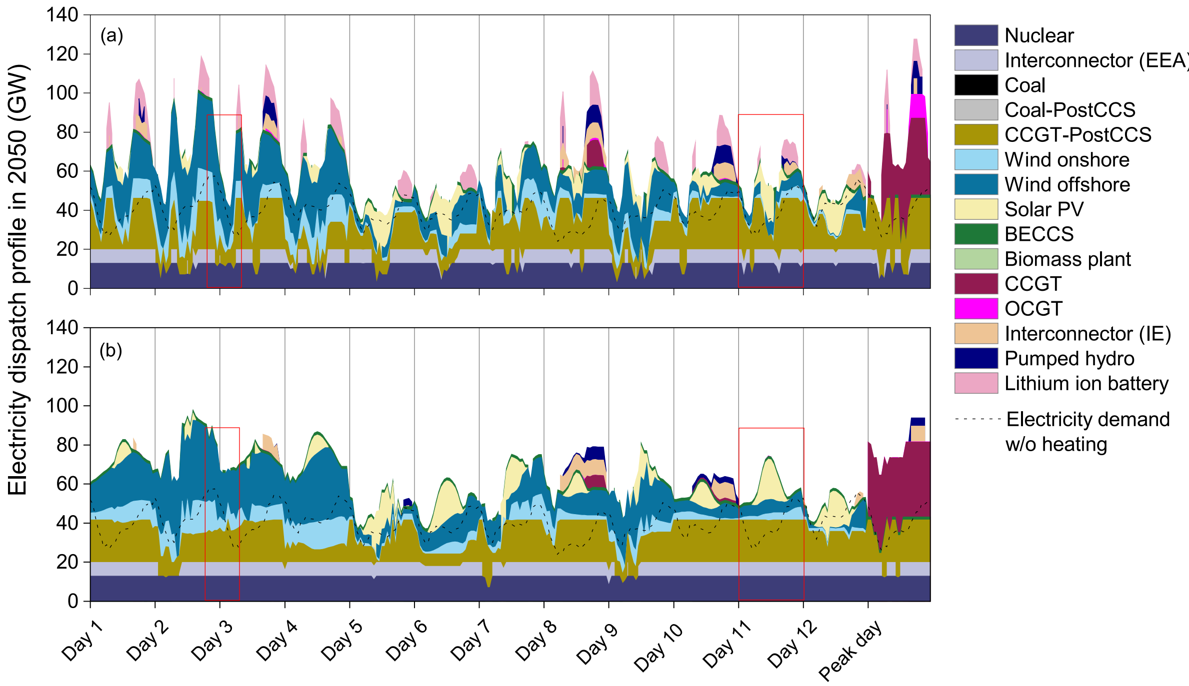

Fig. 12. The electricity grid dispatch profile in 2050 if heating is completely electrified using: (a) not grid-integrated heat pumps with thermal storage capacity of 50 L per person, and (b) grid-integrated heat pumps with thermal storage capacity of 150 L per person.

tanks and the consumer's willingness to install them and participate in demand response. On the other hand, consumers participating in demand response may have different sized storage tanks and heating demands and may be located in different zones. Another challenge of enabling demand response is coordinating loads of different sizes to achieve the required response rates or capacity reductions. One way of increasing responsiveness is to aggregate demand from various end-users and form a larger demand block that participates as one unit in the market [24,91,92].

The third effect shown in Fig. 11 is that peak electricity demand increases as the share of installed ASHPs increases. This is because, unlike GSHPs, which have a relatively stable performance throughout the year, ASHPs' COP drop significantly during cold winter days when heating demand is high. As a result of the mismatch between ASHPs performance and demand for heating, ASHPs have a higher electricity demand than GSHPs, especially during cold periods. Lastly, we find that peak electricity demand is higher in the 45 °C scenarios and that the gap between 45 °C and 55 °C scenarios widens as the proportion of installed ASHPs increases. In the 45 °C scenarios, the electric resistance heater provides a fixed share of the heating demand, therefore the electric demand variability with outside temperature will be reduced. Our results indicate that the total annual electricity demand for both cases is relatively similar[17] because the improved heat pump COP in the 45 °C scenario balances the lower efficiency of electric resistance heaters. During cold winter days, however, the drop in heat pumps' COP along with the less efficient electric resistance heaters increase peak electricity demand in the 45 °C scenario as compared to the 55 °C scenario. It is noteworthy that the effect of both increasing the share of installed ASHP and the 45 °C scheme on the peak electricity demand becomes less significant as thermal storage capacity increases.

As opposed to the first two schemes (grid integration via smart meters and increasing thermal storage capacity) that require additional consumers' investments, installing ASHP and implementing the 45 °C schemes will reduce the upfront cost of electrification for consumers. In Fig. 13, we presented the total capacity required in the electricity grid (Fig. 13(a)) and the total system cost over the planning horizon and the total consumers' investment in each scenario (Fig. 13(b)) to provide a holistic view of the system value offered by these investment and operation schemes at the consumer end. Fig. 13(a) shows similar trends as Fig. 11. Grid integration of heat pumps and increasing thermal storage reduce the required installed capacity in the electricity grid, and the savings from reduced installed capacity in the electricity system outweigh the additional investment required by consumers, reducing the total system cost. For example as shown in Fig. 13(b), 5 b£ additional investment in grid integration of heat pumps and additional thermal storage in the 55 °C 100 L/p-GI scenario can reduce the total system transition cost by about 22 b£ compared to the case of relying solely on supply-side flexibility in the 55 °C 50 L/p-NGI scenario. However, it is noticeable that as we move to larger thermal storage capacities, the system value of additional storage capacity decreases and the total system cost increases. On the other hand, the total installed capacity increases by increasing the proportion of ASHP installations and by sharing heating duty between heat pumps and electric resistance heaters (45 °C). However, this effect is reduced as the thermal storage capacity increases. In both cases, savings from reduced consumer investment outweigh the additional investment required in the electricity grid, and the effect persists even as thermal storage capacity is increased. For instance, reducing the heat pump output temperature to 45 °C in 45 °C 100 L/p-GI scenario will further reduce the total transition cost by about 7.5 b£ (compared to 55 °C 100 L/p-GI) through reducing the consumers' upfront investment. Overall, our results suggest that investing in demand flexibility via grid integration of heat pumps and additional storage is a more valuable investment than GSHPs that has a more stable performance throughout the year. This is because the load shifting and demand flexibility enabled by increased thermal storage capacity and grid integration of heat pumps can be used to mitigate the disadvantages of cheaper low-performance heating systems (45 °C scheme and ASHPs).

[17] For example the total annual electricity demand in 2050 for the case of grid integrated 100% ASHP with 100 L per person thermal storage capacity, is 532 TWh in the 55 °C compared to 535 TWh in the 45 °C scenario.

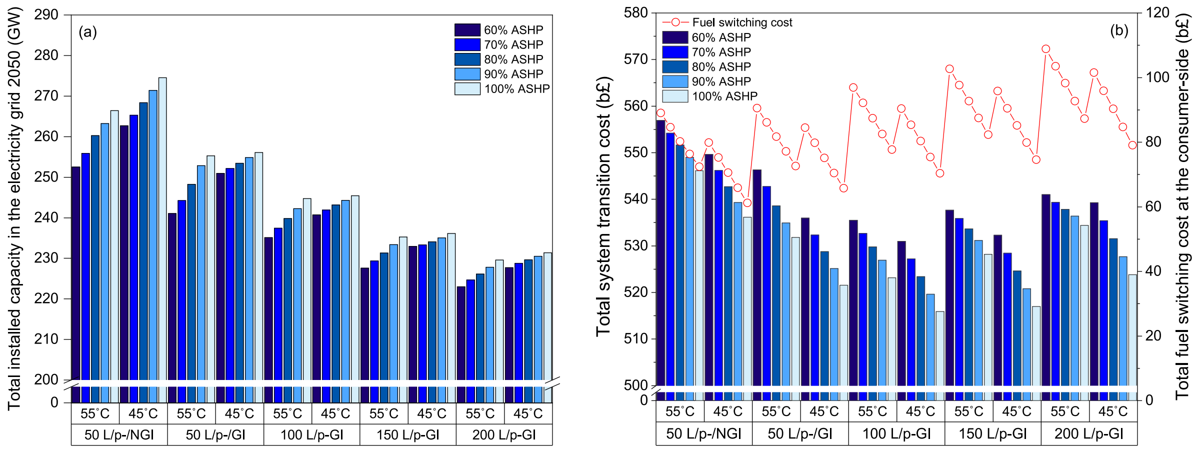

Fig. 13. (a) Total installed capacity required in the electricity grid for different fuel switching and operation strategies at the consumer side. (b) Total system cost for different fuel switching and operation strategies at the consumer side. The dotted red line represents the total cost of fuel switching for consumers. All the scenarios assume that heating in buildings is completely electrified. In the horizontal axis, NGI refers to not grid-integrated heat pumps and GI refers to grid-integrated heat pumps.

4.3. Coordinated planning of electricity and heating decarbonisation

4.3.1. Value of demand flexibility in accelerating electrification

In Section 4.1.1 we discussed the importance of accelerating electrification in order to reduce the risk of missing emission mitigation targets for heating. However, it was shown that if the early uptake of heat pumps is not well planned (i.e., adding heat pumps at scale to a system with inadequate flexibility mechanisms as shown in the Sc2.AEL scenario around 2030), then this could pose reliability risks to the electricity grid and result in adopting short-term stop-gap flexibility measures and therefore oversizing the system. In this section, we discuss how smart electrification schemes on the consumer side could facilitate the early adoption of heat pumps. Fig. 14 compares the technology mix and the transformation of the electricity grid over the planning horizon in the Sc2.AEL scenario and a smart scenario with accelerated electrification where heat pumps are integrated into the electricity grid, thermal storage is increased to 100 L per person, and the heating load is shared between the heat pump and electric resistance heater (heat pump output temperature is set to 45 °C). Through demand flexibility and load shifting enabled in the smart scenario, the rate and range of variation in net load can be reduced, thereby reducing the requirement for supply-side flexibility (such as unabated dispatchable generators and grid-scale storage) for early accommodation of electricity for heating and increasing the proportion of variable renewable sources around 2030. Our results indicate that the total installed capacity in 2050 for the smart scenario is about 245 GW, down from 268 GW for the Sc2.AEL scenario, due to a reduction in grid-scale battery storage and peak reserve thermal dispatchable capacity. These system cost reductions, along with the lower fuel switching cost on the consumer side in the smart scenario, could reduce the total cost of transition by up to 30 b£ compared to the Sc2.AEL. Another noteworthy observation in Fig. 14 is that the solar PV installed capacity in 2050 is about 11 GW higher in the smart scenario than in the reference scenario, whereas it remains the same for wind. Heating demand flexibility has created a greater value for solar PV since short-term load shifting via thermal storage in domestic buildings is better suited with solar PV availability than wind, which requires load shifting over a more extended period.

4.3.2. Can smart operation strategies boost the cost competitiveness of electrification?

Lastly, we examined how incorporating smart investment and operation schemes will affect the cost competitiveness of decarbonising heating via electric heat pumps versus using low-carbon gases (mainly hydrogen). Fig. 15 shows the cost-optimal degree of electrification for all operation and investment scenarios at the consumer end compared to the Sc3.EL-H2 (solid blue line-100% ASHP) as the reference case. In each case, the rest of the heating demand will be supplied by hydrogen boilers. The results show that the optimal degree of electrification lies between 47%–75% across all scenarios. Therefore it can be concluded that regardless of the investment and operation scheme adopted by consumers, the electricity grid in the UK can reliably accommodate at least half of the heating demand. The optimal degree of electrification lies between 47%–55% for all 55 °C scenarios as well as the not-grid-integrated 45 °C scenarios. However, we observe that switching to the 45 °C scheme and grid integration of heat pumps increases the degree of electrification to about 75%. The results show that both investment reduction strategies on the consumer side - heating duty sharing and increasing the installation of ASHPs - effectively boost cost-optimal degrees of electrification. Nevertheless, as shown, the effectiveness of these schemes for enhancing the optimal degree of electrification depends on grid integration of heat pumps and the availability of adequate storage capacity to embed flexibility in electric demand and avoid the elevated and carbon-intensive peaks caused by their lower performance on electricity grids.

5. Sensitivity analysis and study limitations

The study's core scenarios involve a number of key assumptions. This section conducts a sensitivity analysis to understand the potential changes in system-wide implications of electrifying heating in buildings when our assumptions are adjusted. We examine four different scenarios by altering our assumptions about achieving energy efficiency targets in buildings, the investment in onshore wind capacity and the availability of CCS. Moreover, in order to determine the value of smart investment and operation schemes under different conditions, we examine a smart scenario for each sensitivity case, in which we follow the same specifications for smart electrification as in Section 4.3.1 (i.e., (i) the heat pump is integrated into the electricity grid; (ii) the buffer thermal storage capacity is increased to 100 L per person; and (iii) the heating load is shared between the heat pump and an electric resistance heater by setting the heat pump output temperature to 45 °C)). The results are summarised in Fig. 16 and compared to the reference scenario Sc1.EL.

The results suggest that some of the assumptions significantly affect the cost of decarbonisation and system-wide implications of electrifying heating in buildings. Energy efficiency is an important low-cost option for decarbonising heating as it complies with key system planning objectives of energy security, mitigating emissions, and affordability [19,93,94]. Additionally, improving building's energy efficiency

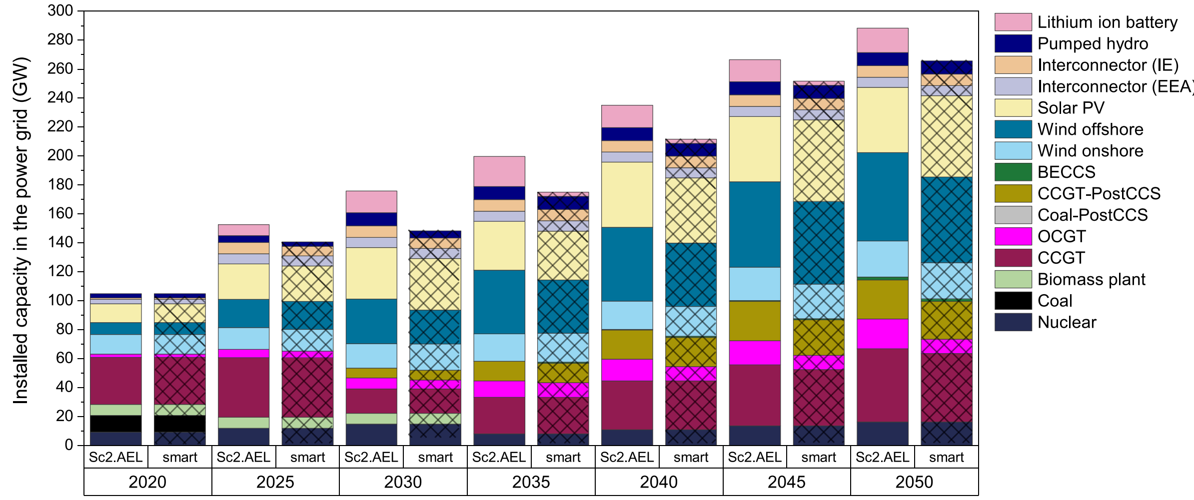

Fig. 14. Installed capacity and technology mix required in the electricity grid over the planning horizon with and without smart electrification of heating. Smart electrification here involves grid integration of heat pumps, increasing the thermal storage capacity to 100 L per person and setting the heat pump output temperature to 45 °C (the rest of the heating demand is covered by the electric resistance heater). All runs are based on the accelerated electrification scenario (Sc2.AEL).

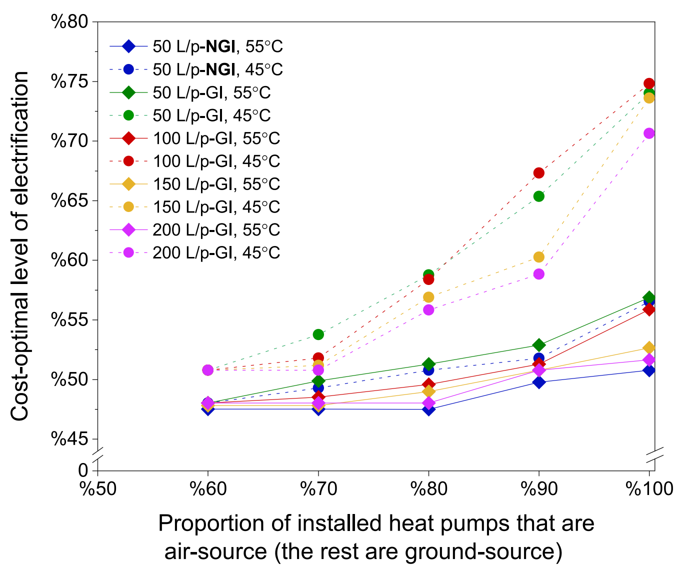

Fig. 15. Cost-Optimal degree of electrification in different operation and investment scenarios at the consumer-side. Sc3.EL-H2 is used as a reference scenario here and all scenarios assume hydrogen boilers are an alternative option for heating. In the legend, NGI refers to not grid-integrated heat pumps and GI refers to grid-integrated heat pumps.

allow for a more flexible and efficient operation of low-carbon heating technologies [7]. To project heating demand over the planning horizon and create a baseline for our analysis, we had previously assumed that as energy efficiency measures are gradually retrofitted into buildings, the demand for heating will reduce by approximately 8% until 2030 and then by a further 22% until 2050 [40,95,96]. Even so, there is a great uncertainty regarding how much retrofitting efficiency measures could contribute to reducing demand and carbon emissions in buildings, especially in regions with older building stock such as the UK and many EU countries [95]. Therefore, we examined a scenario in which energy efficiency improvement goals are not fulfilled. Our results show that without energy efficiency improvements, the annual electricity demand for electrifying heat could increase by about 40 TWh, and the peak electricity demand could also increase by about 19 GW compared to the Sc1.EL scenario. Therefore, an additional 23 GW capacity will be required in the electricity grid, which increases the total transition cost by about 43 b£.

In order to reflect on the recent decision of the UK government to stop subsidising onshore wind and planning constraints for this technology in the UK,[18] a maximum installed capacity constraint of 25 GW for onshore wind was considered in this study based on the values reported in the sixth carbon budget [41], and National Grid future energy scenarios [97]. In the wind onshore sensitivity scenario, the maximum installed capacity constraint was increased to 50 GW. The sensitivity analysis shows that if the onshore wind is deployed at scale, it has the potential to reduce the transition cost by approximately 25 b£ (16 £/Mt_{CO_2} reduction in abatement cost) when compared to the Sc1.EL scenario. While the UK government policy is focused on supporting offshore wind to meet the 40 GW of renewable capacity by 2030 [41], planning constraints and limited Contracts for Difference auctions on onshore wind are limiting the potential for deployment of this technology in the UK [84]. If the constraints on onshore wind persist, there will have to be a significant ramp up in new offshore wind construction to meet net-zero emission target.

[18] https://www.independent.co.uks/uk/politics/wind-power-onshore-policies-environmental-impact-government-collapse-a8334786.html.

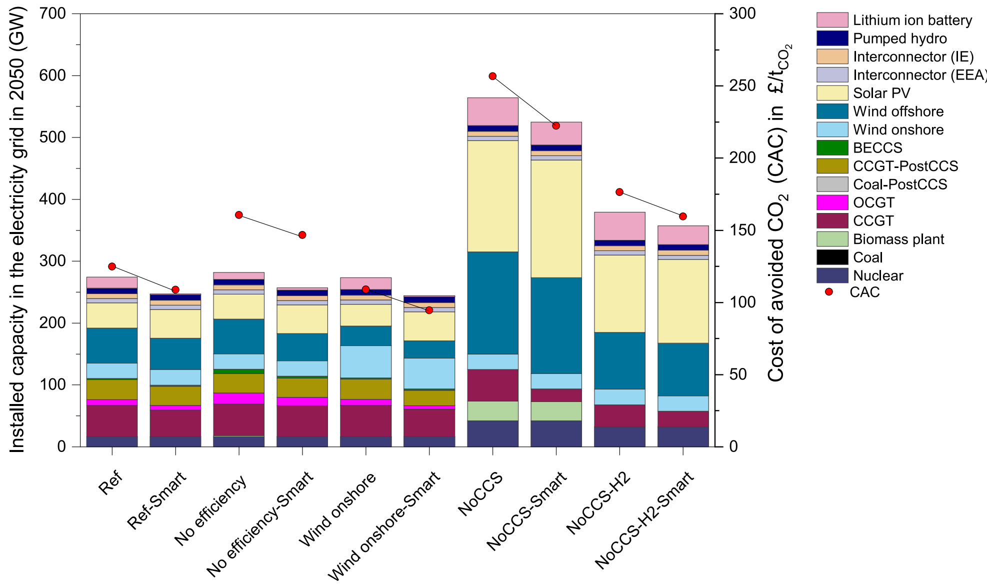

Fig. 16. Installed capacity and technology mix in the electricity grid and the cost of avoided CO_2 in four scenarios: (i) reference scenario (Sc1.EL), (ii) a scenario in which building energy efficiency improvement targets are not achieved. (iii) a scenario in which CCS is not available and all heating is electrified; and (iv) a scenario with no CCS where hydrogen for heating is available. All scenarios are tested when smart electrification is also implemented. Smart electrification here involves grid integration of heat pumps, increasing the thermal storage capacity to 100 L per person and setting the heat pump output temperature to 45 °C (the rest of the heating demand is covered by the electric resistance heater).

Another major assumption in our analysis is the availability of carbon capture and storage (CCS) after 2030. Across all scenarios, the level of dependency on CCS to decarbonise electricity and heating varies significantly, with the total amount of CO_2 captured and sequestered per year ranging from 48 to 91 Mt. Accordingly, this will affect the timing and required rate of the CCS infrastructure deployment. There is, however, much uncertainty regarding the availability, cost-competitiveness, social acceptance, and the rate of deployment of CCS, particularly within a short period of time. Fig. 16 shows the installed capacity required in the electricity grid for two cases in which CCS is not available: Complete electrification of heating (NoCCS scenario) and a case in which hydrogen for heating is available (NoCCS-H2 scenario). The NoCCS scenario has a very different technology mix portfolio than the reference case, which highlights the pivotal role of CCS in meeting climate mitigation targets. If CCS is not available (or is not deployed at the scale required), one of the system's main low-carbon options for providing flexibility services, CCGT-CCS, will not be available. Additionally, the absence of BECCS for carbon offsetting will not only eliminate the frequency response and operating reserve this generator can provide, but more importantly, it will limit the potential for using unabated fossil-based reserve/peak generations (CCGT and OCGT) to provide flexibility services. As a result, the system can only rely on interconnections, grid-scale storage, renewable sources, nuclear and biomass power plants to meet demand. Maintaining a secure and stable operation in such a system containing a high proportion of variable renewable generation, inflexible nuclear power, and high variability and uncertainty on the demand side from the electrification of heating is extremely challenging. As a result, we observe that the system is oversized, with a capacity of approximately 565 GW, which is more than five times the capacity of the base year and more than twice the capacity required in the reference scenario. The cost of abatement in this scenario increases to about 256 £/Mt_{CO_2}, mainly due to the low utilisation rate of assets, increased curtailment of the renewable and much higher cost of ancillary services resulting from the low inertia state and higher operating reserve requirements [98]. Such an expansion of the electricity grid over the considered planning horizon means that some of the critical technologies, including nuclear, should be built at a rate that is much higher than historical rates. Although an increased build rate for renewables is foreseeable, increasing nuclear capacity, especially at the scale required for this scenario (42 GW in 2050), would be very challenging. Demand-side management will be a valuable source of flexibility in the NoCCS-smart scenario and partially reduce strain on the electricity grid and reduce the abatement cost. However, demand response from buildings does not have the potential to replace the supply side flexibility provided by thermal generators, and significant expansion of the electricity grid will still be required.

In the noCCS-H2 scenario, hydrogen for heating is available, but CCS is not. Without CCS, the blue low-carbon hydrogen from fossil fuel and biomass reforming will not be available, and electrolysis will be the main technology to produce low-carbon hydrogen. In this case, grid-powered electrolysers are selected over stand-alone integrated renewable plant and electrolysers for hydrogen production and approximately 19 GW of grid-powered electrolysers and 12 TWh of underground gas storage is installed in the gas grid in this scenario. The reason is that hydrogen production via grid-integrated electrolysers can provide low-carbon flexibility and ancillary services to the electricity grid by adjusting their hydrogen production according to the availability of renewable generators and the balancing requirements of the electricity grid. In addition, if the hydrogen produced is used for heating in buildings connected to the gas grid, it would further reduce the stress on the electricity grid. Although the additional conversion step in this case (converting renewable electricity to hydrogen and use hydrogen for heating) will reduce system efficiency compared to generating heat via heat pumps powered by renewable electricity [73]. In this sense, grid-integrated electrolysers compete with other flexibility options, such as conventional thermal plants with/without CCS, demand response, and grid-scale electricity storage in providing flexibility and ancillary services to the electricity grid. In the Sc3.EL-H2 scenario, where CCS was available in the system, the model did not select electrolysers to produce hydrogen for heating because of their higher cost compared to ATR-CCS, lower efficiency due to the additional conversion step, lower flexibility requirements of the electricity grid, and also the availability of dispatchable CCS integrated thermal plants.

5.1. Study limitations

This study focuses on the technical and system-wide implications of the transition in the heat and electricity sectors. We recognise that there are some limitations to the analysis presented in this paper. Some of the key limitations are:

- In our study, only low-carbon gases (bio-methane, hydrogen or bio-hydrogen) are considered as alternative energy vectors to electricity for fuel switching for decarbonising heating. HEGIT uses a single-node representation of the system, so our analysis does not consider options such as district heating, which requires a spatially disaggregated representation of the energy system [99, 100]. Heat networks can not only supply part of the heating demand, but the flexible operation of centralised combined heat and power (CHP) and other heat-generation systems (*e.g.*, large-scale heat pumps) could provide flexibility and balancing services to the electricity grid [101–103]. Assessing the value of heat networks for decarbonising heating requires an assessment based on spatially disaggregated regional (sub-national) modelling approaches that identify demand clusters and match them with low-carbon waste heat availability and local non-site-specific constraints/sources, as well as taking into account the complexities regarding the impact of unit size and fuel source on the cost of heat networks,[19] which is outside the scope of this work.
- In our study, we used a central planner perspective, and we did not consider consumers' preferences for heating equipment. Our analysis assumes fuel switching is driven by the emissions mitigation target, commodity prices, carbon tax and the transformation of the electricity and gas grids over the planning horizon. Furthermore, we do not consider the suitability of different technologies for different building types in our analysis, such as space limitations for large storage tanks.
- This study considers the heating demand profile from buildings exogenously. Our model does not account for the impact of behavioural changes or energy efficiency measures on the heating demand load curve.
- For all of the technologies, we do not account for cost reduction by learning. We recognise that some technologies, such as batteries, can become more cost-competitive through learning by doing.

5.2. Future work

In this work, as described in detail in Section 2.2, heat pump performance and cost were obtained based on the characteristics of an average domestic heat pump available in the UK market. As shown in the extensive analysis of the market in the work of Olympios et al. [64], in practice, there is a wide range of possible heat pump designs. Thus, future work will involve using the HEGIT framework to investigate the impact of various heat pump design characteristics (e.g., working fluids, size and design of heat exchangers, compressor types) on the system-wide implications of electrifying heating. Such a system informed technology design analysis will provide valuable insights to policy makers for system planning and operation as well as to heat pump manufacturers about how to best design technologies based on their system value.

6. Conclusion

Extensive electrification of heating poses challenges on both the supply and demand sides, especially in countries where fossil fuel-based boilers are prevalent such as the UK, the Netherlands, Germany, and Italy. The purpose of this study is to examine planning strategies and integrated approaches for enhancing the system value and emission reduction benefits of electrifying heating using heat pumps in buildings and identify the trade-offs between consumers' investment and infrastructure requirements for decarbonising heating. We developed an integrated model of heat, electricity and gas system, HEGIT, to study the integrated transition of heat, electricity and gas systems and quantify the value of smart electrification schemes for delivering zero and low-carbon hot water and space heating in buildings. We examined the case study of the UK as an example of a country with a high dependency on fossil fuels for heating, limited current use of electricity for heating and an ambitious net-zero emission target.

Our study examined the system value of smart electrification of heating from two perspectives: system planning and demand side. There are two major aspects to planning for the electrification of heating: timing and scope. In this regard, we looked at two sets of scenarios based on the level of direct emissions from heating at the end of the planning horizon in 2050. For the case of a zero-emission target from heating in 2050, we examined complete electrification of heating (Sc1.EL), accelerated electrification of heating (Sc2.AEL), and using hydrogen as a complementary option to electrification (Sc3.EL-H2). Also, we examined three scenarios based on different levels of residual emissions from heating in 2050: $5\ \mathrm{Mt_{CO_2}}$ (Sc4.Em5), $10\ \mathrm{Mt_{CO_2}}$ (Sc4.Em10) and no constraint on residual emissions from heating (Sc6.Em-UNL).

Our results indicate that in the case of the UK if all heating demand were electrified (Sc1.EL), peak electricity demand would increase from 49 GW in the base year to 133 GW while the electricity demand load factor would decrease from 0.68 to 0.45, which result in a 160% increase in the installed capacity required in the electricity grid. Even though the growth in electricity demand in this scenario offers the opportunity to deploy indigenous renewable generation in the electricity grid and increase the diversity of resources, the mismatch between variable renewable output and demand leads to inefficient and costly integration of these resources. It was shown that uncontrolled transfer of heating demand and relying only on electricity system flexibility mechanisms (such as fossil fuel-based reserve and peak generation and grid-scale storage) in the Sc1.EL scenario increases the emissions effects of variations in net load, reduces the utilisation rates of assets and therefore increases the average abatement cost to about 121 $£/\mathrm{t_{CO_2}}$. Therefore, there could be significant technical challenges and risks associated with this scenario. The problem could be exacerbated if plans for accelerating electrification of heating are not coordinated with decarbonisation and expansion planning of the electricity grid, and heat pumps are adopted at a time when the electricity grid lacks sufficient low-carbon flexibility mechanisms. Our results show that this could lead to an oversizing of the system (16 GW increase in the required installed capacity) in the Sc2.AEL scenario and further increase the abatement cost of complete electrification by about 23 $£/\mathrm{t_{CO_2}}$.

Both hydrogen and partial emission offsetting, despite having different infrastructure requirements, were shown to be valuable options to complement electrification, reducing the electricity grid's expansion

[19] Recent studies by the UK government [53,104] shows that heat networks could be a key option in areas of high-density heat demand and where there are large low-carbon heat sources, covering up to 20% of the total heat demand. However, these studies stress that this is an upper bound and that the actual potential is likely to be significantly lower due to local constraints and the fact that many projects based on waste heat sources may prove to be uneconomic in the future. Another recent study on alternative low-carbon heating technologies in the UK [105] shows that district heating systems could be an economical option for domestic consumers in areas where this option is available. However, the study notes that reported costs are based on existing gas-fired CHP systems, and delivering low/zero-carbon heating via heat networks may require higher investments. Installing these networks in less suitable regions could also cause a further increase in the price of the heating service provided by heating networks. Furthermore, the specific cost of CHP systems largely depends on their size [106], and the latter depends on the size of each district heating network. Based on these complexities, the authors believe that using single cost estimates of heat network systems in our model without proper modelling of the effect of heat density or network size would have introduced significant uncertainties to the results; therefore, we have not included these options in our analysis. Examples of such regional (sub-national) analysis for the UK can be found in contributions by Vega et al. [99,100,107], which demonstrate the trade-offs between different infrastructure decisions using a spatially resolved model of regions in the UK. However, their analysis does not extend to the national scale and is limited to some specific regions.

and flexibility requirements and facilitating more efficient use of assets. Despite the uncertainties surrounding the use of hydrogen for low-temperature domestic heating, it has the advantages of retaining the value of the existing gas network assets, lower space requirements and consumers' familiarity and satisfaction with central gas heating. Our results suggest that, for the core scenarios, when hydrogen is an available option in the model, the cost-optimal degree of electrification is about 50%, and the rest of the heating demand is supplied by hydrogen. Partial carbon offsetting also allows avoiding fuel switching in some regions or for some consumer groups. Additionally, it facilitates the efficient use of biomass resources for heating in the form of bio-methane, bio-hydrogen, and bio-electricity. On the other hand, the lower growth in electricity demand in both cases reduces the potential for deployment of renewable generation.

If implemented smartly, electric heating demand can be more flexible and manageable than regular electricity demand. In order to identify cost-effective practices for managing electric heating demand and identify trade-offs between consumer investment and infrastructure requirements, we examined four investment and operation trade-offs on the demand side: (i) stand alone vs. grid integrated heat pumps; (ii) investment in GSHP vs. ASHP (iii) reducing the output temperature of heat pumps and load sharing with electric resistance heater (45 °C vs. 55 °C) (iv) increasing hot water storage tank buffer capacity. The combination of these factors results in different electric heating demand profiles with different levels of flexibility and up-front investment costs for consumers. Our results indicate that grid integration of heat pumps combined with additional thermal storage at the consumer end can unlock significant potential for diurnal load shifting, therefore, reducing the peak electricity demand and ramping rate requirements of the electricity grid. For example, our results show that 5 b£ additional investment in such demand-side flexibility schemes can reduce the total system transition cost by about 22 b£ compared to the case of relying solely on supply-side flexibility. It is also possible to reduce the consumer investment by sharing the heating duty between electric resistance heaters and heat pumps by lowering the output temperature of heat pumps (and thus installing smaller size heat pumps). Although this would increase the peak electricity demand, the impacts could be offset by grid integration of heat pumps and installing sufficient thermal storage capacity. Furthermore, our results show that, when used at a domestic scale, GSHPs offer limited system value. This is because the benefits of GSHPs (lower peak demand for electricity and reduced variations in electric heating demand with outside temperature) can instead be provided by grid integration of heat pumps and increased thermal storage capacity at a lower cost to consumers and with additional flexibility and balancing benefits for the electricity grid.

The results of our integrated assessment show that coordinated system expansion and decarbonisation planning is key for accelerating electrification (time) and enhancing the cost-effective and reliable level of electrification of heating (scale). Smart electrification can reduce the supply side flexibility requirements for early deployment of electric heating and accommodating a higher proportion of renewable generation around 2030. Therefore, rather than investing in sub-optimal stop-gap flexibility solutions (such as OCGT), the system will have time to expand its flexibility portfolio and invest in other low-carbon flexibility options with greater long-term value. Lastly, our results also show that, regardless of the investment and operation schemes adopted by consumers, the electricity grid in the UK can reliably accommodate almost half of the heating demand. This level can be further enhanced to about 75% by implementing smart operation and investment schemes at the consumer end.

Overall, our results suggest that if policy and investment decisions at both the electricity grid and demand-side levels are made based on the whole system value, system capacity requirements and consumer costs can be reduced. Decarbonising heating through electrification can be done more rapidly, at a lower cost to consumers, and with greater system benefits if a smart and coordinated approach is implemented.

CRediT authorship contribution statement

Pooya Hoseinpoori: Conceptualization, Methodology, Programming and data collection, Writing – original draft. **Andreas V. Olympios:** Methodology, Data collection, Writing – review & editing. **Christos N. Markides:** Methodology, Reviewing and editing. **Jeremy Woods:** Reviewing and editing. **Nilay Shah:** Supervision, Methodology, Reviewing and editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

All data used in this study are included within the article and the supplementary file.

Acknowledgements

This work was supported by the UK Engineering and Physical Sciences Research Council (EPSRC) [grant numbers EP/R045518/1 and EP/S032622/1]. For the purpose of Open Access, the authors have applied a CC BY public copyright licence to any Author Accepted Manuscript version arising from this submission.

Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.enconman.2022.115952.

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