System-driven design of hybrid electricity- and hydrogen-based systems for domestic heat decarbonisation

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ABSTRACT

This paper explores various combinations of electric heat pumps (EHPs), hydrogen boilers (HBs), electric boilers (EBs), hydrogen absorption heat pumps (AHPs) and thermal energy storage (TES) to assess their potential for delivering cost-efficient low-carbon heat supply. A technology-to-systems approach is adopted in the paper based on comprehensive thermodynamic and component-costing models of various heating technologies, which are integrated into a whole-energy system optimisation model to determine cost-effective configurations of heating systems that minimise the overall cost for both the system and the end-user. Case studies presented in the paper focus on two archetypal systems that differ in terms of heat demand and availability profiles of renewables (North and South). Modelling results indicate a preference for a portfolio of low-carbon heating technologies including EHPs, EBs, HBs and TES, while AHPs are not chosen for investment due to their high investment cost. Capacities of the four heating technologies are found to vary significantly depending on system properties such as the volume and diversity of heat demand and the availability profiles of renewable generation. The bulk of heat (83-97%) is delivered through EHPs, while the remainder is supplied by a mix of EBs, HBs and TES. The results also suggest a strong impact of heat demand diversity on the cost-efficient mix of heating technologies, with higher diversity (i.e. lower coincidence factor) favouring less EHP and more of the other, less capital-intensive heating options. Finally, if only a subset of heating technologies is available for investment, the modelling suggests that coupling EHPs with TES is the second best solution in the North system, while in the South it was the combination of EHPs and EBs.

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KEYWORDS

Heat pumps, thermal energy storage, hybrid heating systems, hydrogen boiler, energy system modelling, system-driven design.

INTRODUCTION

The achievement of net-zero carbon emissions targets by 2050 represents a key commitment for many countries and organizations around the world [1]. The residential energy sector accounts for more than one-third of the global carbon emissions, and half of these emissions are associated with the demand for space heating and hot water [2]. A net-zero carbon heating provision requires the adoption of clean and emission-free technologies or a full offset of the emissions that may occur when using fossil fuel resources [3].

Natural gas boilers currently dominate the heat supply in the residential sector, while the most implemented alternative options include electric heat pumps (HPs) [4], solar thermal heating or biomass (sometimes coupled with district heating). Other options, such as hydrogen boilers (HBs) or hydrogen absorption heat pumps (AHPs) [5,6] appear promising but strongly rely on the hydrogen infrastructure and on the possibility to generate green hydrogen from renewables or low-carbon blue hydrogen from gas reforming with carbon capture, utilisation and storage (CCUS).

Electric vapour-compression HPs are a mature technology [7] with a higher energy efficiency and longer lifetime than gas boilers, but also a much higher investment cost. The key performance indicator of electric HPs (EHPs), the Coefficient of Performance (COP), is greatly affected by the outdoor environmental conditions, which opens up opportunities for integration with thermal energy storage (TES) assets and demand response solutions to increase the flexibility of energy systems [8].

The "Net Zero" report from the UK Climate Change Committee (CCC) highlights heat electrification as a crucial step to decarbonisation [3]. However, this requires the availability of renewable or other low-carbon electricity to supply a continuous increase of electricity demand, which could pose issues for the security of supply and grid reinforcement [9]. For these reasons, it is broadly recognised that the decarbonisation of heat via electrification will require the adoption of a portfolio of flexibility measures to reduce daily peak demands, including energy efficiency, demand-side response (DSR) and change of end-user consumption habits, as well as the utilisation of various energy storage technologies.

It has been shown that a cost-effective approach to decarbonise both heat and electricity supply requires coordination between heating and electricity systems to capture benefits from unlocking cross-vector flexibility and support the integration of low-carbon generation technologies [10]. Coordinated design of heat and electricity supply systems generally results in a lower low-carbon transition cost compared to a "silo" approach that addresses the two supply systems separately.

Cost-efficient decarbonisation of energy supply through integrating high penetrations of variable renewables such as wind or solar PV will require a wide variety of flexibility options to provide grid support, balancing, and security of supply [11]. These technologies include various forms of energy storage, DSR, expansion of interconnection capacity and deploying more flexible generation technologies, but also the options providing cross-vector flexibility or sector coupling, such as hydrogen production and conversion technologies [12,13].

Hydrogen has been shown to represent a promising option for integration within a wider energy system, providing opportunities for flexible interactions between electricity, heat and transport sectors in the UK [5,14]. Hydrogen could efficiently complement heat electrification in an integrated low-carbon energy system, as shown in [15]. There are different options to pursue a sustainable transition from existing natural gas to hydrogen-based infrastructures, as proposed in [8], which concluded that the most cost-effective hydrogen-based heat supply would involve deploying ATR (auto-thermal reforming) with CCUS and negative emission technologies (NETs).

Another option to decarbonise heating are AHPs, which use thermal energy instead of electricity to extract heat from a low-temperature heat source (e.g., ambient air) and transfer it into a high-temperature sink. Absorption systems are gaining increased attention for heating applications, despite being mainly adopted for refrigeration. Scoccia et al. [16] used experimental data to show that in countries where electricity prices are much higher than gas prices, gas-driven AHPs can economically outperform EHPs. Lu et al. [17] conducted a thermo-economic analysis of a gas-fired AHPs for high-temperature hot water application, reporting average payback period in south China of 3 years. Garrabrant et al. [18] reported a COP for AHPs in the range of 1.44-1.63, while Wu et al. [19] predicted values between 1.43 and 1.55.

A comprehensive techno-economic comparison of electric and hydrogen-driven heating technologies has been proposed in [6], proposing thermodynamic and component-costing models of a vapour-compression EHP, a standalone HP and an AHP driven by heat from a hydrogen boiler. Relative competitiveness of different heating technologies greatly depends on the cost of electricity and hydrogen.

This paper aims to scale up the assessment of residential low-carbon heating technologies from the homeowner's perspective to the system-level perspective, addressing the added value that these technologies could offer in terms of enhanced flexibility of energy systems, and consequent potential reduction of energy supply costs. For this purpose, this work aims to integrate the developed technology models within the Whole-electricity System Investment Model (WeSIM), a model of the whole UK energy system [20], which has recently been used to provide evidence to the government on heating decarbonisation [21]. WeSIM is here used to identify future heating technology mix in the UK that minimises total system cost that consist of investment and operation cost at both supply and demand side.

The remainder of the paper is organised as follows. Section 2 provides a description of the whole energy system model used in the paper, also setting out key assumptions used in the modelling and describing the thermodynamic and component-costing models of the heating technologies under investigation. In Section 3, the results of the portfolio optimisation for low-carbon heating operations are presented, while the concluding remarks are provided in Section 4.

METHOD

This section presents the formulation of the energy system model used for identifying cost-efficient portfolios of low-carbon heating technologies, followed by the description of the techno-economic models of heating technologies used in the energy system model, and the summary of key assumptions used in the analysis.

Energy system model with decarbonised heating

The model presented here represents a modified version of the WeSIM model [20]. This version integrates the cost and technical features of hydrogen production, storage and imports, as well as the features of end-use low-carbon heating technologies in order to minimise the overall cost of delivering heat and electricity to end-consumers. Certain elements of the model that are not central for this paper have been omitted from the formulation for brevity reasons.

Objective function. The objective function minimised by the model represents the total system cost, which contains terms associated with: a) investment in electricity generation and storage and the associated operation cost, b) investment in hydrogen production and storage with associated operation cost including, if relevant, hydrogen import cost, and c) investment cost in end-use low-carbon heating technologies:

$$\min z = \varphi_{\mathrm{el}} + \varphi_{\mathrm{H2}} + \varphi_{\mathrm{heat}} \tag{1}$$

The electricity sector cost includes investment cost of generation assets and battery energy storage systems (BESS) as well as generators' operating cost:

$$\varphi_{\mathrm{el}} = \sum_{g=1}^{G} \pi_g^{\mathrm{gen}} \mu_g^{\mathrm{gen}} + \sum_{s=1}^{S} \pi_s^{\mathrm{bs}} \mu_s^{\mathrm{bs}} + \sum_{t=1}^{T} \sum_{g=1}^{G} c_{g,t}^{\mathrm{gen}} \tag{2}$$

The hydrogen sector cost consists of investment and operation costs of electrolysers, reformers and hydrogen storage, plus the cost of hydrogen imports:

$$\begin{aligned}\varphi_{\mathrm{H2}} = {} & \sum_{e=1}^{E} \pi_e^{\mathrm{elH2}} \mu_e^{\mathrm{elH2}} + \sum_{r=1}^{R} \pi_r^{\mathrm{ref}} \mu_r^{\mathrm{ref}} + \sum_{u=1}^{U} \pi_u^{\mathrm{hs}} \mu_u^{\mathrm{hs}} \\ & + \sum_{t=1}^{T} \left[\sum_{i=1}^{I} F_i^{\mathrm{imp}} \xi_{i,t}^{\mathrm{imp}} + \sum_{e=1}^{E} A_e^{\mathrm{elH2}} \xi_{e,t}^{\mathrm{elH2}} + \sum_{r=1}^{R} \left(A_r^{\mathrm{ref}} + F_{\mathrm{gas}} L_r^{\mathrm{gas}} \right) \xi_{r,t}^{\mathrm{ref}} \right]\end{aligned} \tag{3}$$

The investment cost of end-use heat technologies includes the investment costs of: EHP, EB, HB, AHP and TES assets:

$$\varphi_{\mathrm{heat}} = \pi^{\mathrm{EHP}} \mu^{\mathrm{EHP}} + \pi^{\mathrm{EB}} \mu^{\mathrm{EB}} + \pi^{\mathrm{HB}} \mu^{\mathrm{HB}} + \pi^{\mathrm{AHP}} \mu^{\mathrm{AHP}} + \pi^{\mathrm{TES}} \mu^{\mathrm{TES}} \tag{4}$$

Energy balance constraints. The power balance constraint is formulated for each time interval t stipulating that total electricity supply needs to match total demand across various categories, which include electrified heating but also other non-heat segments:

$$\sum_{g=1}^{G} p_{g,t}^{\mathrm{gen}} + \sum_{s=1}^{S} \left(p_{\mathrm{dch},s,t}^{\mathrm{bs}} - p_{\mathrm{ch},s,t}^{\mathrm{bs}} \right) = \sum_{k=1}^{K} d_{k,t}^{\mathrm{el}} + p_t^{\mathrm{EHP}} + p_t^{\mathrm{EB}} + \sum_{r=1}^{R} L_r^{\mathrm{el}} \xi_{r,t}^{\mathrm{ref}} + \sum_{e=1}^{E} L_e^{\mathrm{el}} \xi_{e,t}^{\mathrm{elH2}} \tag{5}$$

Non-heat demand segments relate to baseline, appliance and EV demand, and also generally include the effect of DSR for each segment k.

Hydrogen balance requires that hydrogen supply from electrolysers, reformers and imports matches total hydrogen demand at every time interval t, including non-heat demand for hydrogen, demand from HBs and AHPs, consumption of hydrogen power generators and net hydrogen storage operation:

$$\sum_{r=1}^{R} \xi_{r,t}^{\mathrm{ref}} + \sum_{e=1}^{E} \xi_{e,t}^{\mathrm{elH2}} + \sum_{i=1}^{I} \xi_{i,t}^{\mathrm{imp}} = \sum_{u=1}^{U} \left(\xi_{\mathrm{ch},u,t}^{\mathrm{hs}} - \xi_{\mathrm{dch},u,t}^{\mathrm{hs}} \right) + \xi_t^{\mathrm{HB}} + \xi_t^{\mathrm{AHP}} + \xi_t^{\mathrm{gen}} + \Xi_t^{\mathrm{ext}} \tag{6}$$

Generation, battery storage, and hydrogen production and constraints. Standard constraints for conventional and variable renewable generators are also included in the model, but are omitted here due to space considerations. These constraints refer to maximum allowed new capacity of generation technologies, unit commitment and output constraints, operating cost constraints including no-load cost, variable cost and start-up cost, annual output limits and dynamic constraints (ramping, start-up, reserve, response and inertia). More details on this part of the formulation can be found in Ref. [20]. Similarly, standard constraints on hydrogen production and storage facilities are also implemented in a similar manner as in Ref. [13].

Constraints on end-use heating technologies. General heat balance includes the output of all heat technologies, which needs to meet the heat demand at time t:

$$p_t^{\mathrm{EHP}}\eta_t^{\mathrm{EHP}} + p_t^{\mathrm{EB}} + \xi_t^{\mathrm{HB}}\eta^{\mathrm{HB}} + \xi_t^{\mathrm{AHP}}\eta_t^{\mathrm{AHP}} + h_{\mathrm{dch},t}^{\mathrm{TES}} - h_{\mathrm{ch},t}^{\mathrm{TES}} = X_t \tag{7}$$

Upper bounds on heat technology outputs take into account the heat demand coincidence factor J (note that all heat technology capacities are expressed as heat output rates):

$$p_t^{\mathrm{EHP}}\eta_t^{\mathrm{EHP}} \le J\mu^{\mathrm{EHP}}, p_t^{\mathrm{EB}} \le J\mu^{\mathrm{EB}} \tag{8}$$

$$\xi_t^{\mathrm{HB}}\eta^{\mathrm{HB}} \le J\mu^{\mathrm{HB}}, \xi_t^{\mathrm{AHP}}\eta_t^{\mathrm{AHP}} \le J\mu^{\mathrm{AHP}} \tag{9}$$

$$h_{\mathrm{dch},t}^{\mathrm{TES}}, h_{\mathrm{ch},t}^{\mathrm{TES}} \le J\mu^{\mathrm{TES}} \tag{10}$$

TES balance and energy limit constraints are implemented as follows:

$$q_t^{\mathrm{TES}} = q_{t-1}^{\mathrm{TES}} + \left(\eta_{\mathrm{ch}}^{\mathrm{TES}}\, h_{\mathrm{ch},t}^{\mathrm{TES}} - \frac{1}{\eta_{\mathrm{dch}}^{\mathrm{TES}}} h_{\mathrm{dch},t}^{\mathrm{TES}}\right) \cdot \Delta \tag{11}$$

$$q_t^{\mathrm{TES}} \le J\mu^{\mathrm{TES}}\tau^{\mathrm{TES}} \tag{12}$$

Note that the operating cost of low-carbon heating technologies is implicitly considered through electricity and hydrogen balance equations.

System-wide carbon constraint. Total carbon emissions in the energy system result from the operation of thermal generators and methane reformers. An annual system-wide carbon emission target is implemented as follows:

$$\Delta \sum_{t=1}^{T} \left(\sum_{\substack{g=1 \\ g\in TG}}^{G} \left(\alpha_g^{\mathrm{gen}} n_{g,t}^{\mathrm{gen}} + \beta_g^{\mathrm{gen}} p_{g,t}^{\mathrm{gen}}\right)\epsilon_g^{\mathrm{gen}} + \sum_{r=1}^{R} L_r^{\mathrm{gas}} \xi_{r,t}^{\mathrm{ref}} \epsilon_r^{\mathrm{ref}} \right) \le \Phi_{\mathrm{CO_2}} \tag{13}$$

System reliability constraints are also included in the model as in [20].

Techno-economic models of end-use heating technologies

In order to compare end-use heating technologies from a whole-energy system perspective, techno-economic models are presented in this section for EHPs, AHPs, EBs and HBs. These models are used to capture how the technology design and operating conditions affect the performance and cost of these options, which may affect the design of the energy system and cost-optimal heat decarbonisation pathways.

EHPs in small-scale applications involve four main components: a compressor, a condenser, an expansion valve and an evaporator. The HP process involves heat being extracted from a source (e.g., air, ground) and transferred to the working fluid (i.e., the refrigerant) in the evaporator. The working fluid, which leaves the evaporator in vapour form, is raised to a higher pressure and temperature by an electrically driven compressor. It is then condensed, rejecting heat to hot water for domestic use. Following the condenser, the working fluid passes through the expansion valve, where its temperature and pressure are reduced, and it then flows back to the evaporator.

Three of the four main components of an EHP are the same in an AHP, but instead of an electrically-driven compressor, an absorption cycle is used to raise the temperature and pressure of the working fluid. The absorption system requires two fluids: a refrigerant and an absorbent. The refrigerant coming out of the evaporator is in this case absorbed by the absorbent to form a liquid solution, which is pumped to a higher pressure and temperature in a process that requires a negligible amount of electricity. The main source of energy input in an AHP comes from a high-temperature source in the generator, which is needed to desorb the refrigerant from the liquid solution.

Validated spatially-lumped thermodynamic models of an EHP and an AHP have been developed in previous work by the authors [6,8]. Both models assume that all components operate at steady-state conditions and that there are negligible losses in pipes and heat exchangers. Component-costing correlations are used to identify the costs of different HP components, which is further validated using manufacturer data for HPs available in the UK market. Although the data available on AHPs is limited, the absorption HP model was validated in Ref. [6] by comparing its performance against the relevant literature. The authors have also developed a thermodynamic model of a hydrogen boiler in [6], while the efficiency of an EB was assumed to be close to 100%, and therefore no specific thermodynamic model has been developed.

Operating conditions of HPs, such as the outdoor temperature, will impact their performance. The COP of an EHP represents the ratio of the heat output from the condenser and the compressor electricity input [8]:

$$COP_{\mathrm{EHP}} = \frac{\dot{Q}_{\mathrm{cond}}}{p_{\mathrm{comp}}} \tag{14}$$

The COP of an AHP on the other hand represents the ratio of the sum of the heat output from the condenser and absorber and the sum of the pump electricity input (which is often neglected) and the heat input in the generator:

$$COP_{\mathrm{AHP}} = \frac{\dot{Q}_{\mathrm{abs}} + \dot{Q}_{\mathrm{cond}}}{p_{\mathrm{pump}} + \dot{Q}_{\mathrm{genr}}} \tag{15}$$

The EB efficiency (η_{EB}) and HB efficiency (η_{HB}) represent the ratios of the heat output over the electricity input (p_{EB}) and fuel input ($\dot{Q}_{\mathrm{fuel}}$), respectively:

$$\eta_{\mathrm{EB}} = \frac{\dot{Q}_{\mathrm{EB}}}{p_{\mathrm{EB}}}, \eta_{\mathrm{HB}} = \frac{\dot{Q}_{\mathrm{HB}}}{\dot{Q}_{\mathrm{fuel}}} \tag{16}$$

Using the thermodynamic and component-costing models of these end-use technologies, simple relationships are developed here that capture how the COP of EHPs and AHPs is affected by the outdoor temperature (Figure 1a) and how the specific price of all options is affected by their nominal heat output (Figure 1b). R32 is chosen as the working fluid for the electric HP, while for AHP ammonia and water are chosen as the refrigerant and absorber, respectively. The hot-water delivery temperature is assumed to be fixed at 55 °C, which is the minimum required for domestic hot water and space heating.

Specific prices in Figure 1b are calculated in GBP and include a value-added tax (VAT) of 20%. The prices of EHPs and AHPs are calculated using the developed component-costing models. For the EBs, a best-fit line based on power regression is found using the cost data for more than 25 commercially available units within the investigated heat output range (5-15 kW_{th}). Lastly, the price of HBs is expected to be similar to natural gas boilers for domestic consumers [22], so the HB cost is obtained from the average price of over 50 commercially available natural gas boilers [23].

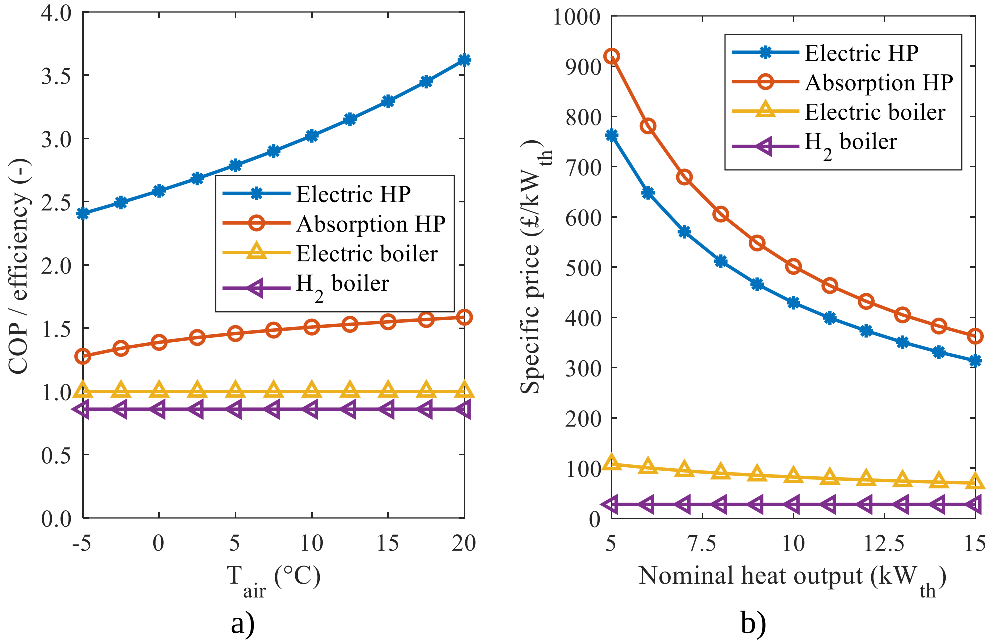


Figure 1. Cost and performance of different end-use heating technologies: (a) COP/efficiency as a function of air temperature (for a hot-water delivery temperature of 55 °C); and (b) specific price as a function of nominal heat output. The specific price excludes installation costs.

Note that natural gas boilers on the market are typically oversized, and the range of nominal heat output for which data was collected is 24-30 kW_{th}. No significant relationship was identified between the specific price and the size of a gas boiler in this range, and therefore the average specific price is plotted in Figure 1b for comparison purposes. Installation costs, which are excluded from Figure 1b, are assumed to be £2,200 for HPs and £1,400 for boilers [24].

System scenarios and assumptions

In order to study the impact of system characteristics on cost-efficient portfolios of low-carbon heat technologies, two generic geographic systems have been assumed: North and South. Both systems have been sized to broadly match the size of the UK electricity system with an annual demand of 400 TWh_{el}. The two systems differed in two main ways:

1. North system is characterised by colder climate conditions, which is reflected in a much higher residential heating demand (185 TWh_{th}) to be supplied by low-carbon sources than in the South system (36 TWh_{th}). Peak heat demand was also much higher in the North than in the South, as illustrated in the heat Load Duration Curves (LDCs) for the two systems in Figure 2. At the same time the electricity demand for cooling is several times higher in the South (40 TWh_{el}) than in the North (6 TWh_{el}).

2. RES potential is assumed to differ between the two systems so that the available wind utilisation factors in the North were much higher than in the South (58% vs. 35%), while for solar PV generation the utilisation factor is assumed to be lower in North than in the

South (11% vs. 24%). This resulted in the Levelised Cost of Electricity (LCOE) of wind and PV in the North of £43/MWh and £56/MWh, respectively, while in the South the same LCOEs were £39/MWh and £25/MWh.

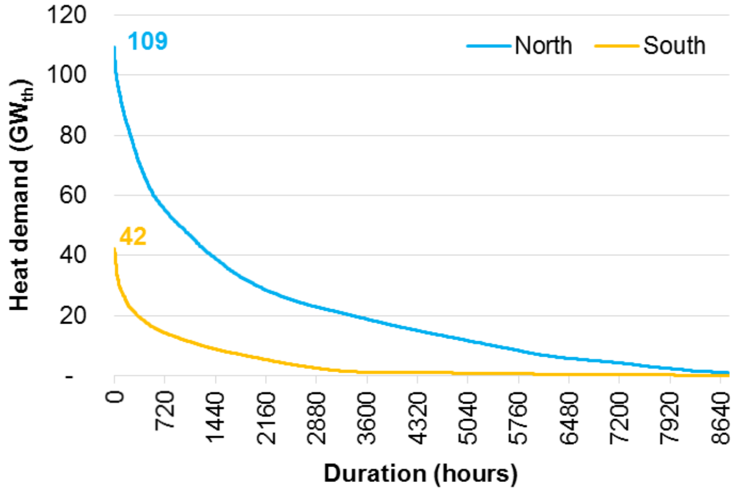


Figure 2. Load duration curves (LDCs) for hourly heat demand in North and South systems.

In all studies both systems are optimised to reach net zero carbon emissions, which could be achieved by investing in a range of zero-carbon and positive-carbon technologies as well as carbon offsets in the form of electricity generators using Bioenergy with Carbon Capture and Storage (BECCS). Energy systems have been modelled in hourly resolution as single node systems, i.e., ignoring any transmission, interconnection or distribution networks.

The model was used to cost-optimise the supply of low-carbon heat to 15 million residential customers by investing in a portfolio of available technologies including EHPs, AHPs, EBs, HBs and TES. In addition to any hydrogen demand for residential heating (which was subject to optimisation in the model), it was also assumed there was a hydrogen demand of 97.5 TWh per year to meet the requirements in the industry and transport sectors.

The assumed costs of low-carbon heat options were based on the analysis presented in the previous section and on typical asset sizes, as follows (note that these figures include both the component costs from Figure 1 and the relevant installation cost):

- EHP: £578/kW_{th}
- AHP: £638/kW_{th}
- EB: £139/kW_{th}
- HB: £98/kW_{th}
- TES: £75/kWh_{th}

In addition to initial investment it was assumed that all assets also incur an annual maintenance cost of £35/kW_{th}/yr except for TES, where this cost was £20/kW_{th}/yr. Asset lifetime was assumed to be 20 years for EHPs and AHPs and 15 years for EBs, HBs and TES. A 5% interest rate has been assumed for all heating technologies to convert overnight cost into annualised values required by the model. The assumed duration of TES (the ratio between energy capacity and heat discharge rate) was 3 hours.

The cost of gas available for power generation and H_2 production in reformers was assumed to be £21.8/MWh, although it is acknowledged this is far lower than gas prices seen during recent spikes in energy prices. Hydrogen import was also assumed to be available at the relatively high price of £100/MWh. Note that for simplicity reasons District Heat Networks (DHNs) are not included in the scope of this analysis, although it is understood that they could make a significant contribution to the UK's future low-carbon heat sector [25].

In addition to the baseline system scenarios for the North and South systems, the quantitative analysis presented in the paper also includes the following sensitivity studies:

- Impact of higher investment cost of BESS (50% above baseline).
- Sensitivities on heat demand coincidence factors: in addition to the default value of J = 1, the analysis also looked at values of 0.75, 0.5 and 0.25.
- Impact of restricting which low-carbon heat technologies are available for investment in the model: 1) EHP only, 2) EHP+TES, 3) EHP+EB, and 4) EHP+HB.

Diversity of energy demand is critically important for planning and studying energy supply and distribution infrastructure. It is based on the well-known fact that the timings of peak energy use for a larger group of customers will not coincide exactly, so that the aggregate peak demand of the group will be lower than the sum of individual customer peaks. This allows for network components to be sized to meet aggregate (diversified) peak demand rather than the total of individual customer peaks, which are extremely unlikely to occur at the same time. Diversity is typically quantified using the coincidence factor J, which is defined as the ratio between diversified and non-diversified peak per customer [26].

With respect to the restricted availability scenarios that do not include any TES (EHP only, EHP+EB and EHP+HB), it has to be noted that EHPs in domestic systems are generally not used to supply domestic hot water demand directly (unlike space heating). In a typical application the EHP charges a hot water cylinder, and DHW demand is met by drawing water from that cylinder. Therefore, for a fully accurate evaluation should also account for additional cylinder cost in those three scenarios. This issue will be addressed in future work.

RESULTS

This section presents the results of system modelling aimed at establishing cost-efficient portfolios of low-carbon heating technologies for a variety of system conditions and scenarios. The case studies presented in this section address the following aspects:

- Impact of system geography, reflected in the volumes of heating (and cooling) demand and in the availability of wind and solar PV resources
- Impact of higher cost of competing flexibility options such as battery energy storage systems (BESS)
- Impact of diversity of heat demand, i.e., of the ratio between diversified (aggregate) and non-diversified (household-level) peak heat demand
- Impact of availability of various low-carbon heat technologies

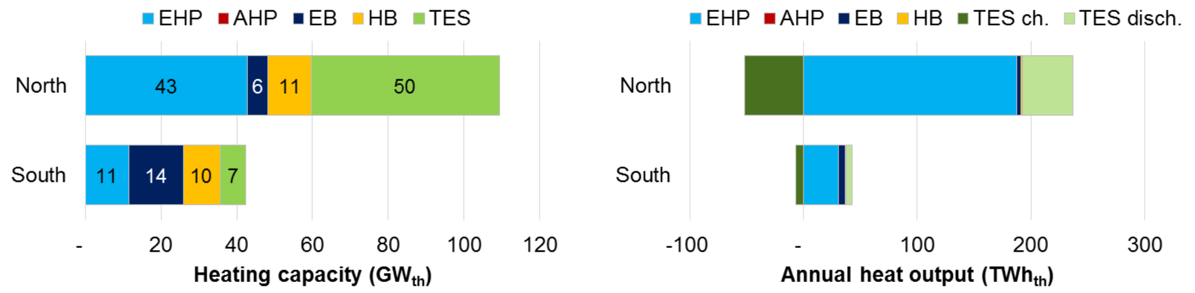
Key quantitative modelling results used to discuss the solutions presented in this section include the capacity mix of low-carbon heating technologies and their annual volumes of supplied heat.

Cost-efficient portfolios of end-use heat technologies for baseline scenarios

Cost-efficient portfolios of low-carbon heating options, optimised from the system perspective, are presented in Figure 3 for North and South systems. Figure 3a presents the breakdown of peak heat capacity in GW_{th} across different technologies.

Several key observations can be drawn from the results. First, AHP does not get chosen as part of the cost-efficient low-carbon heat portfolio in any system. Its assumed investment cost is approximately double that of H_2 boilers, and even higher than the cost of EHP per unit of heat output capacity, while its efficiency is inferior to the COP of EHP, and the cost of producing hydrogen significantly higher than the cost of producing electricity from low-cost renewables. All of these factors, in addition to the fact that EHPs are assumed available for investment in all investigated scenarios, combine to make AHPs an unattractive proposition under these cost assumptions. All other heating options get chosen (in various proportions) as part of the cost-optimal heating capacity mix.

Second, the compositions of the cost-optimal low-carbon heat portfolios differ significantly between the North and South systems. As expected, the total combined heating capacity of all options corresponds to the peak heat demand level of a given system, as depicted in Figure 2, i.e., 109 GW_{th} in the North and 42 GW_{th} in the South. Nevertheless, because of the much longer and more intense heating season in the North, its heat portfolio is much more dominated by EHPs, with 39% of total capacity, and TES with 45% of total capacity. Respective contributions in the South system are 27% for EHPs and 16% for TES. Share of EBs and HBs in the heat portfolio for the North system are relatively minor (5% and 10%, respectively), while in the South they represent a larger share of heat capacity: 34% for EHBs and 23% for HBs.



a) b)

Figure 3. Cost-optimal configurations of low-carbon heating portfolios for North and South systems: a) heating capacity in GW_{th}, b) annual heat output in TWh_{th}.

Although the relative contribution of EHPs to the heat capacity mix is only between about a quarter and two-fifths, their contribution to the annual energy output is substantially higher, as shown in Figure 3b. This is not surprising given that EHPs have the typical features of a baseload technology, with relatively high investment cost but low operating cost, driven by relatively low cost of electricity and high operating efficiency (i.e., COP). The observed shares of EHPs in total annual heat supply are 97% in the North and 83% in the South.

Although both TES charging and discharging are plotted in Figure 3b, their net effect at an annual level is a relatively small amount of additional heat demand caused by TES roundtrip losses. Nevertheless, the contribution of TES to heat supply is significant, with 24% of heat supplied from TES discharging in the North and 15% in the South (acknowledging that this energy was stored using the heat output from EHP, EB or HB at other times).

Annual energy contributions from EBs and HBs are marginal in the North (below 3% of total heat supply when combined), while in the South there is a sizeable contribution from EBs (around 15%) but marginal from HBs (below 1%). This is driven by the availability of low-cost solar PV resources in the South, which combined with high PV utilisation factors allow electricity to be produced at a relatively low cost, making EBs a relatively more attractive option or providing peak heat than HBs, when compared to the North system.

Impact of high battery storage cost and heat demand diversity

This section investigates the impact of increasing the cost of BESS on the cost-efficient heating portfolio, while also quantifying the effect of various levels of diversity in heat demand on the cost-optimal portfolio. Figure 4 shows the cost-optimal heat portfolios in the North and South systems for cases with high BESS cost and a range of coincidence factors that are lower than one (0.75, 0.50 and 0.25). All of these cases are plotted alongside the baseline North and South scenarios to allow for identifying key differences and similarities.

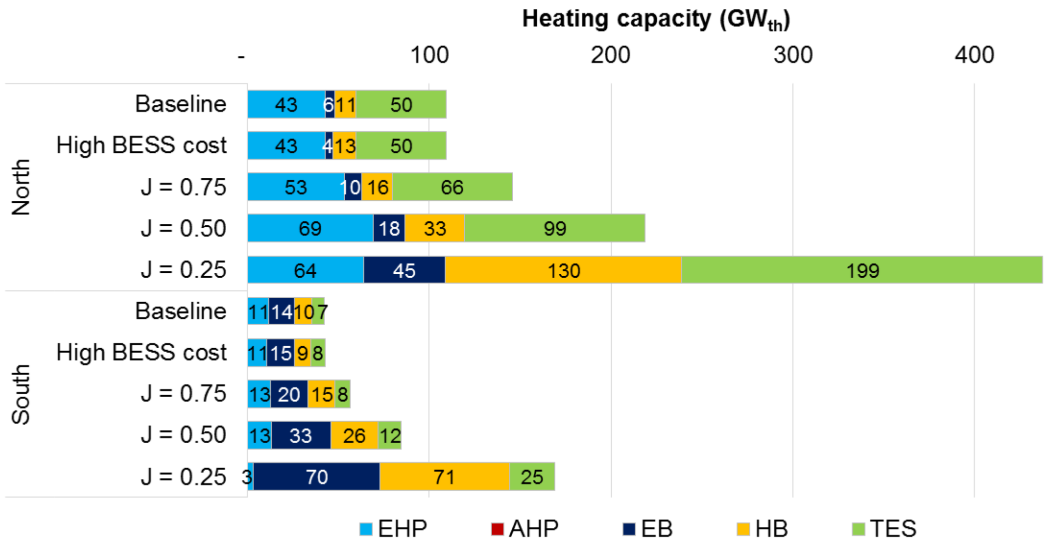


Figure 4. Cost-optimal heating capacities of low-carbon heating portfolios for high BESS cost and various diversity scenarios in North and South systems.

The effect of higher BESS cost on the cost-efficient heat portfolio is relatively minor. Increasing the cost of BESS by 50% has a notable impact on the portfolio of electricity generation technologies, by reducing the volumes of BESS and PV generation and increasing the capacity of wind and peaking thermal generation. However, there is a relatively minor impact on the capacity of heat technologies. EHP capacity is unaffected both in the North and South. Some of the EB capacity (about 2 GW$_{th}$) in the North shifts to HB, while in the South there is an opposite shift at the level of around 1 GW$_{th}$. TES capacity in the North does not change, while in the South it increases by about 1 GW$_{th}$, as high PV capacity in the South requires more flexibility, and with high BESS cost some of the flexibility is provided through installing additional TES capacity.

On the other hand, the impact of lower coincidence factors (J) on the heat capacity mix is substantial. This is not surprising given that reducing coincidence factors from 1 to 0.75, 0.50 and 0.25 effectively implies that the installed heating capacity needs to be 1.33, 2 and 4 times higher than diversified peak heat demand, respectively, as the non-diversified peak that needs to be met through heat technologies also increases by the same amount. It is interesting to note that as non-diversified peak increases to four times the baseline amount, the cost-efficient volumes of heating technologies do not scale up proportionately to peak increase. An exception to this is the TES volume in the North system, where it increases almost exactly in proportion to the increase in non-diversified peak demand, from 50 to 200 GW_{th}.

In the North, the EHP capacity initially increases with lower coincidence factors, however it reaches a ceiling at J = 0.50 given that its investment cost is the highest amongst all heating options (other than AHP that is never chosen), and is therefore inefficient to scale up given that its investment cost effectively increases in proportion to the increase in non-diversified peak demand. Its share of capacity drops from 39% in the baseline scenario to only 15% in the J = 0.25 scenario. At the same time, the missing heat capacity is made up by EBs and HBs, whose capacity increases by 8 and 11 times, respectively, as non-diversified peak increases 4 times.

Similar trends are also observed in the South system, where EHP drops from 13 to 3 GW_{th} as coincidence factor reduces from 0.50 to 0.25. To compensate for that, the EB and HB capacities in the $J = 0.25$ scenario increase to 5 and 7 times higher levels than in the baseline, respectively.

Figure 5 shows the effect of high BESS cost and various diversity factors on annual supply of heat from low-carbon heating technologies. In the high BESS scenarios there is very little change in the annual volumes of heat output from different low-carbon heat sources. In both North and South systems there is a slight increase in the utilisation of TES (reflected in higher volumes of both TES charging and discharging), which results from lower system flexibility due to reduced installed BESS capacity driven by its higher cost.

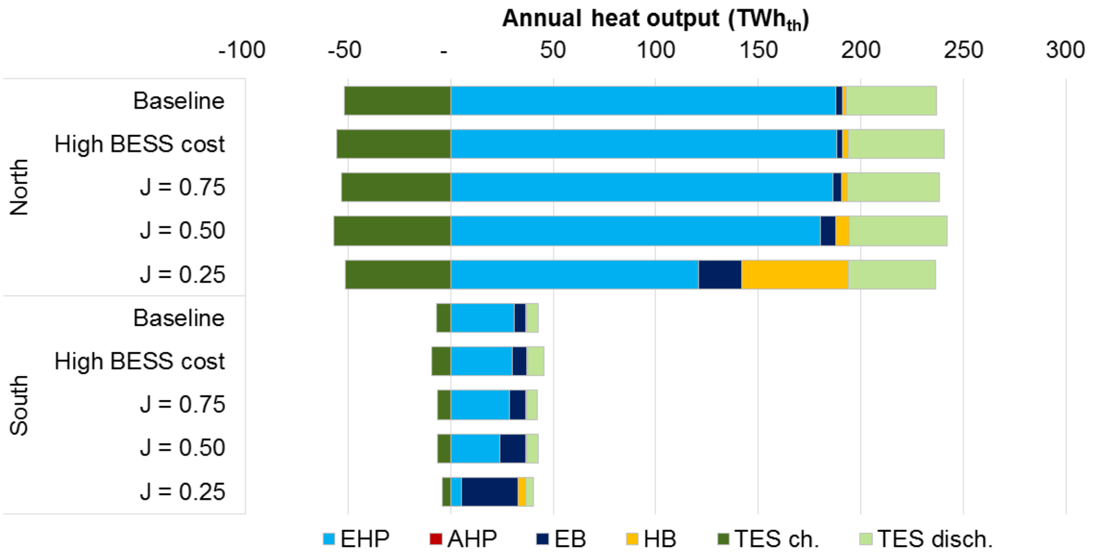


Figure 5. Annual heat outputs of low-carbon heating technologies for high BESS cost and various diversity scenarios in North and South systems.

Similarly to the capacity diagram in Figure 4, the share of EHP in annual heat supply declines for lower values of coincidence factor, although this reduction is proportionately much slower than the reduction in capacity. In the North, the share of EHPs in heat supply drops from 97% in the baseline to 93% in the $J = 0.50$ scenario and 62% in the $J = 0.25$ scenario. At the same time, the combined contribution of boilers (EB and HB) increases from 3% (baseline) to 7% ($J = 0.50$) and 38% ($J = 0.25$). A similar, although even more extreme trend is observed in the South, where the share of EHPs reduces from 83% in the baseline to just 15% in the $J = 0.25$

scenario. Note that most of the heat displacing EHP output in the North is provided by HBs, while in the South this is supplied from EBs; this follows from a very low cost of electricity produced by solar PV generators in the South.

Impact of restrictions on availability of low-carbon heating technologies

The main aim of this section is to study the changes in the cost-optimal portfolio of low-carbon heating options if not all of the technologies were available for investment in the model. The following combinations of availability are covered by the case studies presented here:

- Baseline (all heating options available for investment)
- EHP only
- EHP and TES
- EHP and EB
- EHP and HB

Figure 6 describes how the cost-efficient portfolios change in the presence of above constraints, and compares them to the portfolios obtained for baseline (unconstrained) North and South scenarios.

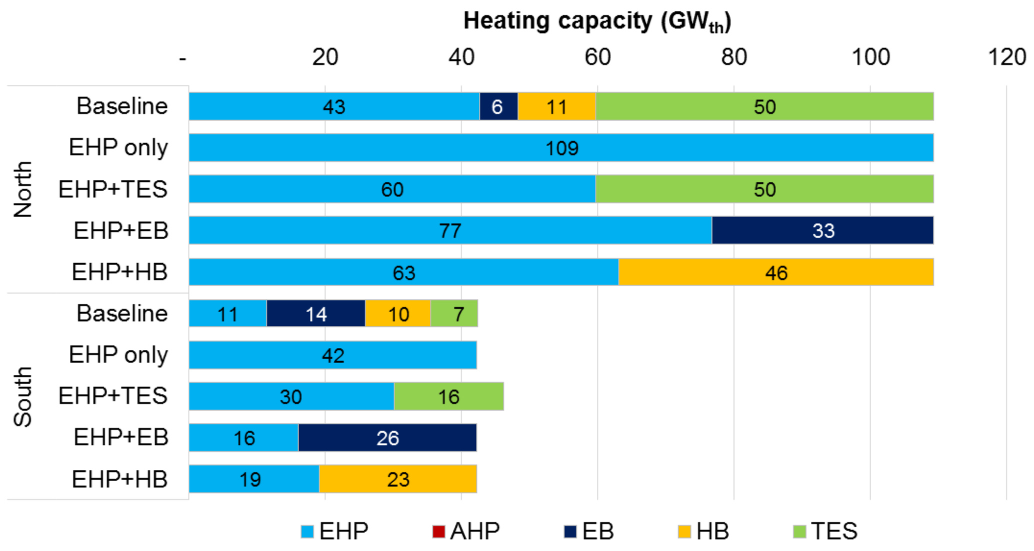


Figure 6. Cost-optimal heating capacities for various combinations of available low-carbon heating technologies in North and South systems.

In the “EHP only” scenarios the solution is trivial, with the installed EHP capacity exactly equal to the peak heat demand (109 GW_{th} in the North and 42 GW_{th} in the South), as no other heating technology was assumed to be available for investment. If EHPs are allowed to be combined with TES, the installed capacity of TES in the North is the same as in the baseline scenario (50 GW_{th}), while the remaining heating capacity (60 GW_{th}) is provided by EHPs. This is not the case in the South, where the TES capacity in the EHP+TES scenario is significantly higher than in the baseline scenario (16 vs. 7 GW_{th}), while the EHP capacity increases almost threefold from the baseline (30 vs. 11 GW_{th}).

If EHPs and EBs are the only options available, the cost-optimal portfolio in the North consists of 70% EHP and 30% EB capacity, while in the South, with lower heat demand levels and relatively cheap electricity from solar PV the split between EHP and EB capacity is 38% to

62%. Finally, when only EHPs and HBs are available for investment (being equivalent to "hybrid" HP solutions that include part standard EHPs and part hydrogen or even gas boilers), the model chooses a split of 58%:42% between EHPs and HBs in the North, and 45%:55% in the South.

The impact of restricted availability of low-carbon heating technologies on annual heat output is quantified in Figure 7. In all cases EHP was the dominant source of heat due to its favourable combination of cost and efficiency characteristics. In all cases the share of EHPs in heat supply remained above 95% in the North, and above 83% in the South.

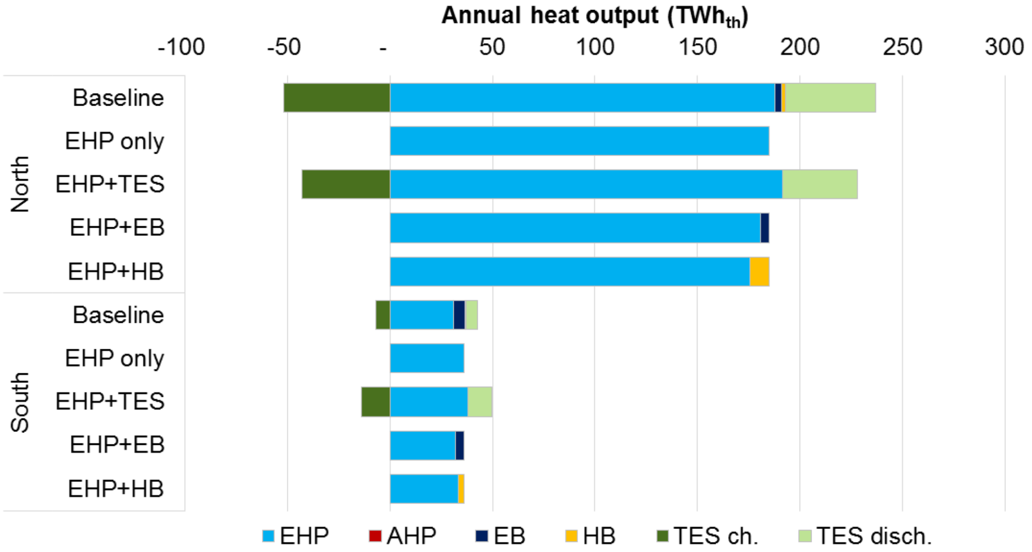


Figure 7. Annual heat outputs for various combinations of available low-carbon heating technologies in North and South systems.

As mentioned before, this analysis did not consider additional investment in hot water cylinders when EHP is used to supply domestic hot water; this issue will be addressed in future work.

DISCUSSION

The results of the energy system modelling suggest that the cost-efficient portfolio of low-carbon heating technologies would involve four different technologies: EHPs, EBs, HBs and TES. The only heating technology that was not chosen for investment by the model was hydrogen-fuelled AHP due to its relatively high investment cost compared to other options. The exact proportions of the four technologies in terms of both heating capacity and annual volume of heat were found to vary depending on system properties such as the availability of renewable generation and volume and diversity of heat demand.

In most cases EHPs were found to deliver the bulk of annual heat demand (97% in North and 83% in South baseline scenario), although their share of capacity was much smaller (39% in the North and 27% in the South) due to their relatively high cost per unit of heat output capacity and low running cost. Any residual peak heat demand was supplied by a mix of EBs, HBs and TES capacity in different proportions depending on the system characteristics: 5%, 10% and 45% in the North, and 34%, 23% and 16% in the South, respectively.

The main difference between cost-efficient portfolios of heat options obtained for North and South systems is in the volume of required heat capacity, which is significantly higher in the North due to higher volume of heat demand both in terms of energy and peak demand. In both systems the EHPs were the main source of heat, although in the South there was a significant share of heat provided by EBs (around 15%), enabled by relatively lower cost of electricity in the South available from inexpensive solar PV generation.

The results of the analysis quantify the cost-efficient heat technology mix at the level of the whole energy system. Obviously, it would not be feasible to simply scale this system-level solution down to the level of individual properties. Instead, the actual choice of individual heating system configuration would reflect the local circumstances for a given property. For instance, it may be efficient to install HBs in smaller properties that are subject to space constraints that prevent them to install EHP systems, or use boilers as part of hybrid EHP+HB solutions where there are constraints in the local electricity distribution network. Similarly, some of the TES capacity, which the modelling suggests would be an efficient option, could be installed at the individual property level, while in other cases TES might be best implemented as a common asset serving multiple properties (such as e.g. flats in multi-occupancy buildings). Nevertheless, the results strongly point to a balanced mix of heating solutions being the most efficient pathway, with most heat supplied through EHPs and other technologies used for supplying relatively infrequent, high-magnitude heat demand peaks.

When testing the sensitivity of the solution to variations in key assumptions, it was found that a 50% increase in the cost of battery storage had very little effect on the cost-optimal mix of heating technologies. The main change triggered by higher BESS cost was a slightly more intense utilisation of TES, given that the model decided to install less battery storage resources and therefore had less flexibility available in batteries.

Reducing the assumed level of coincidence factor for heat demand from 1 in the baseline scenarios to 0.25 expectedly resulted in an increase in installed heating capacity that was inversely proportionate to the reduction in coincidence factor (e.g. the coincidence factor of 0.25 meant that the system required 4 times more installed heat capacity to be able to meet peak demand). Nevertheless, the modelling results suggest that the increase in total heat capacity should not be simply achieved by proportional scaling of baseline heating portfolio.

Lower coincidence factors effectively change the relative proportion of investment vs. operation cost for different heating technologies, making EHPs with their high investment cost relatively less attractive. As the result, the share of EHPs reduces with lower coincidence factors. For instance, with a coincidence factor of 0.25 the share of EHP capacity in the North drops from 39% in baseline to 15%, and in the South from 27% to only 2%. In the North EHPs remain the largest source of heat even with low coincidence factors, although their share in annual heat supply drops to 62%, which is compensated by increased output of HBs and EBs. In the South system, on the other hand, the EHP output with the lowest coincidence factor drops to just 15% of annual heat supply, and the majority of heat supply is taken over by EBs.

The final set of case studies quantified the cost-efficient portfolios of heating technologies if only a subset of them was available for investment, i.e. if EHPs were the only available options or were allowed to be coupled with just one more technology (TES, EB or HB). The "EHP only" scenario resulted in the highest incremental cost for both North and South systems, as it required that high-cost EHP capacity matched the peak heat demand. In the North system the most favourable restricted combination of heating technologies was EHP+TES, resulting in only £0.5bn/yr cost increase relative to the fully optimised heat solution. In the South, with relatively cheap electricity available from solar PV resources, the most cost-efficient combination of two technologies was EHP+EB, although its cost penalty was only marginally lower than for EHP+TES and EHP+HB combinations.

Any changes in the volume and variability of heat demand, such as those driven by increasing global temperatures as a result of climate change or by improvements in building thermal insulation levels, would also likely change the cost-optimal portfolios of low-carbon heating options identified in this paper. Drivers such as climate change and insulation improvements can be expected to affect not just the installed volume of low-carbon heating options, but also their relative proportions in the portfolio. Nevertheless, for a more accurate assessment of the impact on heating technologies portfolio it will be necessary to conduct further analysis, which the authors intend to address in future work.

CONCLUSIONS

This paper proposed a quantitative energy system modelling approach to determine cost-efficient composition of integrated low-carbon heating solutions from the system perspective. The objective of the model was to minimise total energy system cost concurrently with the cost of investing into a portfolio of customer-level low-carbon heating technologies.

This technology-to-systems approach used comprehensive thermodynamic and component-level costing models of various heating technologies, which informed the whole-energy system optimisation model. This allowed for identifying cost-efficient system-driven designs of low-carbon heating systems based on electricity and hydrogen that result in lowest overall energy system cost when heat supply is optimised alongside electricity and hydrogen supply systems.

Case studies presented in the paper were based on two archetypal energy systems (North and South), which had different characteristics with respect to the volume of heat demand and the utilisation of renewable generation technology. Modelling results suggest that a cost-efficient solution for zero-carbon heating consists of a portfolio of low-carbon heating technologies including EHPs, EBs, HBs and TES, while AHPs were found to be less attractive due to their high investment cost. The capacities of the four heating technologies were found to vary significantly depending on key system characteristics such as the volume and diversity of heat demand and the availability profiles of renewable generation.

Future work in this area will focus on differentiating between different types of low-carbon end-use technologies trading off high-cost but high-efficiency solutions against low-cost and low-efficiency, as well as studying the impact of different TES durations. Impact of fuel price variations, as experienced recently for natural gas, will also be explored in more detail. More analysis will be required to adequately address the relationship between the installation sizes of different technologies and their investment cost per unit of capacity. Given the high sensitivity of the heat resource portfolio on the coincidence factor, more work will be needed to better understand the diversity of heat demand under different weather conditions including extremely cold spells. The necessary investment in hot water cylinders for HP-only systems needs to be investigated further. Attention will also need to be given to issues associated with electricity and hydrogen distribution grids and their costs. Finally, it needs to be established under which conditions conventional gas boilers could also be used as part of cost-efficient future heat portfolios if carbon offsets were available to compensate for their emissions.

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NOMENCLATURE

Subscripts/superscripts

abs	Absorber	genr	Generator (for AHPs)
AHP	Absorption heat pump	i	Hydrogen import source index
bs	Battery storage	H2	Hydrogen supply system
ch	Storage charging	HB	Hydrogen boiler
comp	Compressor	heat	Heat supply system
cond	Condenser	hs	Hydrogen storage
CO_2	Carbon dioxide emissions	k	Demand segment index
dch	Storage discharging	max	Maximum output
e	Electrolyser technology index	min	Minimum output
EB	Electric boiler	new	New capacity
EHP	Electric heat pump	r	Methane reformer technology index
el	Electricity	ref	Methane reforming
elH2	Electrolysis	RES	Renewable energy sources
ex	Existing capacity	s	Battery storage technology index
ext	External (demand)	t	Time interval index
g	Generation technology index	TES	thermal energy storage
gas	Natural gas	u	Hydrogen storage technology index

Symbols

α	No-load heat rate (MWh_{th}/hr)	H	Number of H_2 storage technologies
β	Incremental heat rate (MW_{th}/ MW_{el})	HG	Set of H_2-fuelled electricity generation technologies
Δ	Length of unit time interval (hr)	I	Number of hydrogen import sources
ϵ	Carbon emissions per unit of fuel (tCO_2/MWh)	J	Coincidence factor of heat demand
η	Conversion efficiency	K	Number of electricity demand segments
μ	Newly added capacity (MW)	L	Specific consumption per unit of H_2 output (MW/MW_{H2})
ξ	Hydrogen production or consumption variable (MW_{H2})	M	Maximum capacity (MW)
Ξ	Non-heat hydrogen demand (MW_{H2})	n	Number of generator units in synchronised operation
π	Annualised investment cost per unit of capacity (£/MW/yr)	p	Power generation or consumption variable (MW_{el})
τ	Storage duration (hr)	$\dot{Q}$	Heat output of end-use technology (MW_{th})
φ	Total system cost component (£)	q	Energy content of energy storage (MWh)
Φ	Annual emission limit (tCO_2/yr)	R	Number of methane reforming technologies
Ω	Maximum annual utilisation factor	RG	Set of renewable electricity generation technologies
a	Normalised availability factor for RES	S	Number of battery storage technologies
A	Variable operation cost coefficient (non-fuel) (£/MWh)	T	Number of time intervals in a year

c	Generator operation cost (£)	T_{day}	Set of time intervals belonging to the same day
d	Electricity demand after DSR (MW_{el})	TG	Set of thermal electricity generation technologies
D	Electricity demand before DSR (MW_{el})	U	Number of hydrogen storage technologies
E	Number of electrolyser technologies	w	Output curtailment (MW_{el})
F	Cost of fuel (£/MWh)	X	Heat demand (MW_{th})
G	Number of power generation technologies	z	Total system cost (£)
h	Heat input/output of TES (MW_{th})		

Abbreviations

AHP	Absorption Heat Pump	HB	Hydrogen Boiler
BECCS	Bioenergy with Carbon Capture and Storage	HP	Heat Pump
COP	Coefficient of Performance	HB	Hydrogen Boiler
DHN	District Heat Network	LCOE	Levelised Cost of Electricity
DSR	Demand-Side Response	LDC	Load Duration Curve
EB	Electric Boiler	NET	Negative Emission Technology
EHP	Electric Heat Pump	RES	Renewable Energy Sources
EV	Electric Vehicle	TES	Thermal Energy Storage

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