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A Holistic Approach to Empower Hydrogen Supporting Net-Zero

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ABSTRACT

The lack of clarity and uncertainty about hydrogen's roles, demand, applications, and economics has hindered hydrogen development. This paper presents an integrated whole energy system (IWES) model to optimise the planning and operation of an energy system; the model is used to identify the role of hydrogen technologies in decarbonising energy systems, improving system flexibility and enhancing energy system security and resilience against extreme weather. The studies were conducted on the future (year 2050) Great Britain's energy system to understand the hydrogen infrastructure capacity needed and their utilisation from the production, transport, storage, and demand under different scenarios. In the models, hydrogen technologies will compete against other alternative technologies, and the optimisation models will determine the least-cost solution. The studies demonstrate that hydrogen is essential for providing flexibility, energy system security and resilience against extreme weather. Synergy across hydrogen assets reduces the cost of hydrogen heating, which can be cost-competitive against the heat electrification approach.

Keywords: decarbonisation, flexibility, hydrogen, optimisation, resilience, whole-system

NOMENCLATURE

Constants

α_d	The ratio of flexible electricity demand to total demand
α_d^{rsp}	The proportion of flexible loads that can be interrupted to provide frequency response
α_d^{res}	Proportion of flexible loads that can be interrupted to provide operating reserves
α_s^{rsp}	Proportion of storage charging that can be interrupted to provide frequency response
$(\alpha, \beta)_{L,n}$	Linear coefficient and constant term for the n-th piecewise linear approximation of LOLP function
η_d	Demand-Side Response (DSR) efficiency [%]
η_{eh}	Electric heating efficiency [%]
η_{hb}	Hydrogen boiler efficiency [%]
$\eta_s[\eta_{sh}]$	Electricity[hydrogen] storage efficiency [%]
$\overline{\mu}$	Number of existing generating units
$\pi_{\widehat{dn}}$	Distribution network reinforcement cost per unit
$\pi_{\hat{f}}$	Transmission network reinforcement cost per unit
π_g	Generation operating cost per unit
$\pi_{\hat{\mu}}$	Generation investment cost per unit
π_{nl}	Generation no-load-cost
$\pi_{\hat{s}}$	Storage investment cost per unit
π_{st}	Generation start-up cost
τ	Total time horizon [h]
c^6	Carbon emissions per unit energy produced [kgCO$_2$/MWh]
d	Electricity load [MW]
dh	Hydrogen load [MW]
$\overline{dn}$	Peak load that can be accommodated without network reinforcement
$\overline{f}$	Existing transmission network capacity [MW]
$\underline{g}$	Minimum stable generation [MW]
$\overline{g}$	Power rating of a generating unit [MW]
LF	Load factor of a generator
r_{dn}	Ramp-down limit [MW]
r_{up}	Ramp-up limit [MW]
$\overline{rsp}$	Maximum response limit [MW]
$\overline{s}$	Existing storage capacity [MW]
sc	Number of hours that storage can produce electricity at maximum power (i.e. storage duration)
$\underline{srp}$	System frequency response requirement
$\underline{srs}$	System operating reserves requirement
$\underline{Dn}$	Minimum downtime [h]
$\underline{Up}$	Minimum uptime [h]

Variables

μ	number of units in operation
$\hat{\mu}$	Number of additional generating units installed
d_+	Increased electricity load due to DSR [MW]
d_-	Reduction in electricity load due to DSR [MW]
ds	number of generating units being de-synchronised
e	Electrolyser load [MWh]
eh	Electric heating load (MWh)

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$es[esh]$	Energy content of electricity[hydrogen] storage [MWh]
$\hat{f}$ $[\widehat{fh}]$	Additional electricity[hydrogen] transmission network capacity [MW]
g	Electricity production [MW]
ghr	volume of carbon emissions removed [kgCO_2 p.a.]
h	Hydrogen production [MW]
hb	Hydrogen boiler [MWh]
res	Spinning reserve provided by generators [MW]
rsp	Frequency response provided by generators [MW]
$s_+[sh_+]$	Electricity[hydrogen] generated by storage [MW]
$s_-[sh_{h-}]$	Electricity[hydrogen] consumed by storage [MW]
$\hat{s}[\widehat{sh}]$	Additional electricity[hydrogen] storage capacity [MW]
st	number of generating units being synchronised
$tes_{-,+}$	Charging (-)and discharging (+) of thermal storage [MWh]
CM	Capacity margin [MW]
$LOLP$	Estimated Loss of Load Probability (LOLP)
Functions	
$C_g(\cdot)$	Generation operating cost function
$F(\cdot)$	Power flows function
Sets	
D $[Dh]$	Set of electricity [hydrogen] demand
E	Set of electrolysers
$F[Fh]$	Set of electricity [hydrogen] transmission corridors
G	Set of generators
H	Set of hydrogen production technologies
N	Set of nodes
$S[Sh]$	Set of electricity [hydrogen] storage devices
Q	Set of heat demand
T	Set of operating snapshots

1. INTRODUCTION

Achieving a net-zero energy system will require holistic strategies for decarbonising electricity, transport and heat while maintaining energy security and minimising system costs. Low-carbon electricity and green gases, including hydrogen, will be the crucial energy vectors driving decarbonisation. While there has been substantial growth in the development of low-carbon electricity in the past decade, the hydrogen system has been less developed due to the lack of clarity and uncertainty about hydrogen's roles, demand, and economics and how hydrogen should be integrated to support cost-effective decarbonisation and energy system security.

Several studies have explored the potential applications of hydrogen and its capacity to transform various sectors, ranging from energy storage and transportation to industrial processes [1]. Techno-economic characteristics of key hydrogen technologies have been reviewed in [2], suggesting that although hydrogen can play an essential role in supporting the decarbonisation of various sectors, the current status of the system capital cost and hydrogen production cost are still not competitive for the hydrogen's wide deployment and therefore a variety of progress in research, development, and trial of hydrogen technologies is strongly demanded.

The potential of hydrogen to contribute to the decarbonisation of industrial processes has also been recognised since many energy-intensive industries, such as steel and cement production, are still responsible for a significant share of global greenhouse gas emissions [3]-[4]. Other applications are in transport sectors (buses, heavy-duty trucks) [5]-[6], and the benefits of hydrogen transport integration were discussed in [7]. Hydrogen is also emerging as a significant option in the sustainable heating landscape and has become an alternative to heat electrification [8]-[9]. However, hydrogen for heating is frequently seen to be less favourable because of its much lower energy efficiency than heat pumps.

While there have been many studies evaluating the applications of hydrogen; however, many of the analyses considering the hydrogen applications in silos and, therefore, overlook the synergy of hydrogen assets in improving energy security, resilience against extreme weather events, and system flexibility while decarbonising energy systems. In this context, the contributions of this paper are twofold: (i) It provides an analytical framework to identify the role of various hydrogen technologies, and (ii) it presents a series of whole-system studies to provide fundamental and robust evidence about hydrogen's role and system benefits under different energy system scenarios.

The structure of the paper is as follows: the analytical model used to optimise the energy system is described in Section 2, followed by the results of the studies in the subsequent section. The final section describes the summary of the paper.

2. INTEGRATED WHOLE-ENERGY SYSTEM MODEL (IWES)

2.1 Overview of the model

The Integrated Whole Energy Systems (IWES) model is a least-cost optimisation model that minimises long-term investment and short-term operating costs across multi-energy systems (electricity, heating, hydrogen) from the supply side and energy network to the end customers while meeting the required carbon targets and system security constraints. The interactions across different energy components in IWES are illustrated in Fig. 1.

IWES also optimises the deployment of flexibility technologies such as thermal energy storage (TES), electricity storage such as Pumped Hydro Energy Storage (PHES) [10] and Batteries Energy Storage System (BESS), hydrogen storage, demand response technologies (e.g. intelligent electric vehicle charging system with and without vehicle-to-grid capability, industrial and commercial sector demand response), interconnection with Europe, electrolysers, and generation flexibility to ensure adequate generation capacity during the peak demand with low renewable outputs.

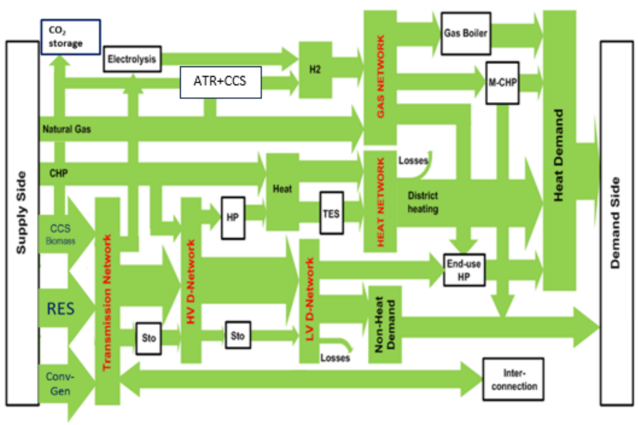


Fig. 1 Energy system components modelled in IWES.

IWES also optimises the deployment of flexibility technologies such as thermal energy storage (TES), electricity storage such as Pumped Hydro Energy Storage (PHES) and Batteries Energy Storage System (BESS), hydrogen storage, demand response technologies (e.g. intelligent electric vehicle charging system with and without vehicle-to-grid capability, industrial and commercial sector demand response), interconnection with Europe, electrolysers, and generation flexibility to ensure adequate generation capacity during the peak demand with low renewable outputs.

The model considers the energy system from the local district level to a national one and the interactions between the UK and European energy systems. IWES also considers the system's operational requirements, such as frequency response and reserves (which has a timeframe of milliseconds to minutes), dispatch problems (hours, days or seasons), and long-term investment problems (years) simultaneously.

2.2 Problem formulation

The objective function (1) minimises the overall system cost, consisting of annuitised investment costs associated with various energy production, network and storage assets, and the annual operating cost for electricity (2), cost of hydrogen systems (3) and heating systems, plus the cost of greenhouse gas removal to meet the carbon target. The investment cost includes (annuitised) the capital cost of new energy production capacity, storage units, and additional energy network capacity. Various types of investment costs are annuitised using the appropriate weighted average Cost of Capital (WACC) and the estimated economic life of the asset. These parameters are provided as inputs to the model for each technology.

$$Minimise\ \varphi = C_e + C_h + C_{heat} + C_{ghr} ghr \tag{1}$$

where

Cost of electricity system:

$$\begin{aligned} C_e = \sum_{i=1}^{G} \pi_{\hat{\mu}_i} . \hat{\mu}_i + \sum_{i=1}^{S} \pi_{\hat{s}_i} . \hat{s}_i + \sum_{i=1}^{F} \pi_{\hat{f}_i} . \hat{f}_i \\ + \sum_{t=1}^{T} \sum_{i=1}^{G} C_{g_i}^{t} (\pi_{g_i}, g_i^t, \pi_{nl_i}, \pi_{st_i}, \mu_i^t) \end{aligned} \tag{2}$$

Cost of hydrogen system:

$$\begin{aligned} C_h = \sum_{i=1}^{H} \pi_{\hat{h}_i} . \hat{h}_i + \sum_{i=1}^{E} \pi_{\hat{e}_i} . \hat{e}_i + \sum_{i=1}^{Sh} \pi_{\widehat{Sh}_i} . \widehat{Sh}_i + \sum_{i=1}^{Fh} \pi_{\widehat{fh}_i} . \widehat{fh}_i \\ + \sum_{t=1}^{T} \sum_{i=1}^{H} C_{h_i}^{t} (\pi_{h_i}, h_i^t) \end{aligned} \tag{3}$$

Cost of heating system:

$$C_{heat} = \sum_{i=1}^{N} \pi_{\widehat{hb}_i} . \widehat{hb}_i + \sum_{i=1}^{N} \pi_{\widehat{hp}_i} . \widehat{hp}_i + \sum_{i=1}^{N} \pi_{\widehat{TES}_i} . \widehat{TES}_i \tag{4}$$

Electricity system operating cost is the total annual generation cost that consists of (i) variable cost, which is a function of electricity output, (ii) no-load cost, which is a function of synchronised units, and (iii) start-up cost, while hydrogen system operating cost is associated with the hydrogen production cost from gas.

There are a set of equality and inequality constraints that the model takes into account while minimising the overall cost. All constraints are applied for each time interval within the optimisation time horizon ($\forall t \in T$). These include:

Power system constraints

Power balance constraints (5) ensure that supply and demand, considering storage and DSR, are always balanced.

$$\sum_{i=1}^{G} g_i^t + \sum_{i=1}^{S}(s_{+i}^{\ t} - s_{-i}^{\ t}) - \sum_{i=1}^{D}(\mathrm{d}_i^t + d_{+i}^{\ t} - d_{-i}^{\ t}) - \sum_{i=1}^{E} e_i^t - \sum_{i=1}^{N} eh_i^t = 0 \tag{5}$$

Generator operating constraints include (i) Minimum Stable Generation (MSG) and maximum output constraints (6); (ii) ramp-up (7) and ramp-down (8) constraints; (iii) minimum up (9) and downtime (10) constraints; (iv) available frequency response and reserve constraints (11); maximum response constraints for each generation technology (12); annual load factor constraints (13); and the maximum number of synchronised units (14). Constraints (6)-(14) are applied to all generators $(\forall i \in G)$.

$$\mu_i^t . \underline{\mathrm{g}}_i \le g_i^t \le \mu_i^t . \overline{\mathrm{g}}_i \tag{6}$$
$$g_i^t - g_i^{t-1} \le \mu_i^t . \mathrm{r}_{up_i} \tag{7}$$
$$g_i^{t-1} - g_i^t \le \mu_i^{t-1} . \mathrm{r}_{dn_i} \tag{8}$$
$$\sum_{k=t-\underline{\mathrm{Up}}_i}^{t-1} st_i^k \le \mu_i^t \tag{9}$$
$$\mu_i^t \le \overline{\mu}_i + \hat{\mu}_i - \sum_{k=t-\underline{\mathrm{Dn}}_i}^{t-1} ds_i^k \tag{10}$$
$$\mu_i^t . \underline{\mathrm{g}}_i \le g_i^t + rsp_i^t + res_i^t \le \mu_i^t . \overline{\mathrm{g}}_i \tag{11}$$
$$rsp_i^t \le \mu_i^t \cdot \overline{\mathrm{rsp}}_i \tag{12}$$
$$\sum_{t=1}^{T} g_i^t \le \mathrm{LF}_i \cdot \tau \cdot (\overline{\mu}_i + \hat{\mu}_i) \cdot \overline{\mathrm{g}}_i \tag{13}$$
$$\mu_i^t \le \overline{\mu}_i + \hat{\mu}_i \tag{14}$$

The model optimises the quantity and the location of new generation capacity for various generation technologies. If required, constraints can be put in place to limit the investment in particular generation technologies at given locations. Annual load factor constraints (13) limit thermal generating units' utilisation level, e.g., to account for the effect of planned annual maintenance on plant utilisation.

Storage operating constraints include maximum power rating constraints for storage charging (15) and discharging cycles (16), constraints associated with the amount of energy that can be stored (17), and the storage energy balance (18). The model considers new investments in energy storage by optimising its location and capacity to minimise the overall cost (1). Constraints (15)-(18) are applied to all storage units $(\forall i \in S)$.

$$s_{+i}^{\ t} \le \overline{\mathrm{s}}_i + \hat{s}_i \tag{15}$$
$$s_{-i}^{\ t} \le \overline{\mathrm{s}}_i + \hat{s}_i \tag{16}$$
$$es_i^t \le (\overline{\mathrm{s}}_i + \hat{s}_i) \cdot \mathrm{sc}_i \tag{17}$$
$$es_i^t = es_i^{t-1} - s_{+i}^{\ t} + \eta_{s_i} \cdot s_{-i}^{\ t} \tag{18}$$

Demand-side response constraints include constraints for various specific types of loads. Different demand categories are associated with different levels of flexibility. Flexibility parameters associated with various forms of DSR are obtained using detailed bottom-up modelling of different types of flexible demand. A set of generic DSR constraints is presented below. These include the demand reduction constraints (19) and the energy balance for demand shifting (20), potentially considering losses driven by a temporal shifting of demand (as shifting demand may increase the overall energy requirements), quantified through the efficiency η_d. Constraints (19)-(20) are applied to all electricity loads $(\forall i \in D)$.

$$d_{-i}^{\ t} \le \alpha_{\mathrm{d}_i}^{\ t} \cdot \mathrm{d}_i^t \tag{19}$$
$$\sum_{t \in D_x} d_{-i}^{\ t} \le \eta_{d_i} \cdot \sum_{t \in D_x} d_{+i}^{\ t} \tag{20}$$

Operating reserve constraints include various forms of fast and slow reserve constraints. The operating reserve and frequency response requirements are calculated exogenously as a function of uncertainty in variable generation and demand across various time horizons. Deterministic renewable energy profiles and a predefined forecast error level (e.g. 5%) for additional operating reserve requirements due to variable renewable sources are used. In contrast, the frequency response requirement is calculated based on the impact of the most extensive loss of infeed in different system inertia conditions [11]. The model distinguishes between two fundamental types of balancing services: (i) frequency regulation (response), which is delivered in the timeframe of a few seconds to 30 minutes, and (ii) reserve, typically split between spinning and standing reserve, with delivery occurring within the timeframe of half an hour to several hours after the request. Wind output forecasting errors directly drive the need for these services, which will significantly affect the ability of the system to absorb wind energy. The reserve and response requirements calculation for a given level of intermittent renewable generation is carried out exogenously and fed into the model.

The frequency response and reserve constraints are formulated in (21) and (22), respectively, stating that the contribution of all generators to response (rsp) and reserve (res), combined with the contributions from storage and DSR, needs to satisfy the system-level requirements for the two services.

$$\sum_{i=1}^{G} rsp_i^t + \sum_{i=1}^{S}(\alpha_{s,i}^{rsp} \cdot s_{-i}^{\ t}) + \sum_{i=1}^{D}\{\alpha_{d,i}^{rsp} \cdot (\mathrm{d}_i^t + d_{+i}^{\ t} - d_{-i}^{\ t})\} \geq \underline{\mathrm{srp}}^t \quad (21)$$

$$\sum_{i=1}^{G} res_i^t + \sum_{i=1}^{S}(\overline{s}_i + \hat{s}_i - s_{-i}^{\ t}) + \sum_{i=1}^{D}\{\alpha_{d,i}^{res} \cdot (\mathrm{d}_i^t + d_{+i}^{\ t} - d_{-i}^{\ t})\} \geq \underline{\mathrm{srs}}^t \quad (22)$$

The amount of spinning, standing reserve, and response is optimised ex-ante to minimise the expected cost of providing these services.

Power flow constraints (23) limit the energy flowing through the transmission system, respecting the total installed capacity as the upper bound. The model optimises the location and capacity of new transmission investment to minimise the objective function. Power flows are calculated as a function of net power injection, network topology and parameters.

$$-(\bar{\mathrm{f}}_i + \hat{f}_i) \leq F(G,S,D)_i^t \leq \bar{\mathrm{f}}_i + \hat{f}_i \quad \forall i \in F \quad (23)$$

Power flow is a function of power injections by generation, load and storage, network topology and parameters. A linear expression of the power flow is given below (24).

$$F(G,S,D)_i^t = \sum_{j=1}^{N}\left(\partial F_i/\partial P_j \cdot \left[g_j^t + s_{+j}^{\ t} - s_{-j}^{\ t} - d_{+j}^{\ t} - d_{+j}^{\ t} + d_{-j}^{\ t}\right]\right) \quad \forall i \in F \quad (24)$$

Where $\partial F_i/\partial P_j$ is the sensitivity of the flow at corridor i to power injection at node j.

Given their location, expanding transmission and interconnection capacity is vital for facilitating the efficient integration of large intermittent renewable resources. Interconnectors provide access to renewable energy and improve the diversity of demand and renewable output on both sides of the interconnector, thus reducing the short-term reserve requirement. Interconnection also allows for the sharing of reserves, reducing long-term capacity requirements.

The model can reinforce existing transmission links and add new capacity between previously unconnected regions (where the user allows). The model will reinforce both existing and new corridors if economically justified.

Reliability constraints ensure sufficient generating capacity in the system to supply the demand with a given level of reliability and estimate the Loss of Load Expectation (LOLE). Constraints (25) are used to approximate the LOLP, and the sum of LOLP across the year should meet the reliability criterion as defined by $\overline{LOLE}$ (26).

$$\begin{aligned} LOLP_i^t &\geq \alpha_{L,1} CM(\cdot) + \beta_{L,1} \\ &\dots \\ LOLP_i^t &\geq \alpha_{L,n} CM(\cdot) + \beta_{L,n} \end{aligned} \quad (25)$$

$$\sum_{t=1}^{T} LOLP_i^t \leq \overline{LOLE}_i \quad (26)$$

Hydrogen system constraints

The hydrogen power balance constraint (27) ensures that hydrogen supply and demand, considering storage, are always balanced.

$$\sum_{i=1}^{H} h_i^t + \sum_{i=1}^{Sh}(sh_{+i}^{\ t} - sh_{-i}^{\ t}) - \sum_{i=1}^{Dh} \mathrm{dh}_i^t + \sum_{i=1}^{E} e_i^t = 0 \quad (27)$$

Constraint (27) limits the hydrogen production to be less or equal to the installed capacity. If needed, the model can reinforce the hydrogen production capacity.

$$h_i^t \leq \bar{\mathrm{h}}_i + \hat{h}_i \quad (28)$$

Hydrogen storage constraints (29)-(32) are modelled the same way as for electricity storage (15)-(18).

$$sh_{+i}^{\ t} \leq \overline{\mathrm{sh}}_i + \widehat{sh}_i \quad (29)$$

$$sh_{-i}^{\ t} \leq \overline{\mathrm{sh}}_i + \widehat{sh}_i \quad (30)$$

$$esh_i^t \leq (\overline{\mathrm{sh}}_i + \widehat{sh}_i) \cdot \mathrm{sch}_i \quad (31)$$

$$esh_i^t = es_{hi}^{t-1} - sh_{+i}^{\ t} + \eta_{sh_i} \cdot sh_{-i}^{\ t} \quad (32)$$

Hydrogen transport constraints (23) limit the hydrogen energy flowing through the hydrogen transmission system, respecting the total installed capacity as the upper bound. The model optimises the location and capacity of new hydrogen transmission investment to minimise the objective function. Hydrogen flows are calculated as a function of net hydrogen injection, network topology and parameters.

$$-(\overline{\mathrm{fh}}_i + \widehat{fh}_i) \leq Fh(H,Sh,Dh)_i^t \leq \bar{\mathrm{f}}h_i + \widehat{fh}_i \quad \forall i \in Fh \quad (33)$$

Heat system constraints

The heat supply-demand balance constraint dictates that the output of all heat technologies always meets the heat demand.

$$\eta_{eh_i} \cdot eh_i^t + \eta_{hb_i} \cdot hb_i^t + tes_{+,i}^t - tes_{-,i}^t = Q \quad (34)$$

Their capacities limit the thermal power of those heating appliances, as defined in (35)-(37).

$$\eta_{eh_i} \cdot eh_i^t \leq \widehat{hp}_i \quad (35)$$

$$\eta_{hb_i} \cdot hb_i^t \leq \widehat{hb}_i \quad (36)$$

$$tes_i^t \leq \widehat{TES}_i \quad (37)$$

The energy stored in thermal storage is constrained as follows (38).

$$qtes_i^t = qtes_i^{t-1} + \eta_{TES_i} tes_{-,i}^t - tes_{+,i}^t \quad (38)$$

Carbon emission constraints

Equation (33) ensures that the annual carbon target is met by limiting the sum of residual emissions from electricity and hydrogen systems.

$$\sum_{t=1}^{T}\sum_{i=1}^{H} c_{hi}^{6} h_i^t + \sum_{t=1}^{T}\sum_{i=1}^{G} c_{gi}^{6} g_i^t - ghr \le Carbon\ target \quad (39)$$

The optimisation problem defined in (1)-(39) has been implemented and solved using the FICO Xpress optimisation tool[12]. A comparison between IWES and other heat decarbonisation modelling approaches in the UK can be found in [13].

3. CASE STUDIES

3.1 Core scenarios

In Great Britain, almost half of the final energy consumed is to provide heat – more than used to produce electricity or transport. Therefore, there is an essential question about the role of hydrogen in decarbonising heat in Great Britain. In this context, two core scenarios have been developed. The first scenario is to use hydrogen heating for around 2/3 of domestic customers (i.e. 20 million dwellings) as their primary heating appliances. These customers are connected to a gas (hydrogen) grid. Other customers who are off-gas grid are supplied by district heating using Water Source Heat Pumps (WSHP), covering around 20% of heat demand and electric heating (heat pumps and resistive heating for the remaining customers. As the focus is on the heat decarbonisation of on-gas grid customers, the first scenario is called the Hydrogen pathway (H2). In contrast, the second scenario does not use hydrogen heating as all heat demand will be supplied using electric heating, and therefore, this scenario is defined as the Heat Electrification pathway (ELEC).

The studies were conducted on the 2050 GB net-zero energy system based on the National Grid ESO's Future Energy scenario, "Leading the Way" [14]. The energy system demand is defined as follows.

- Domestic heat demand: 222 TWh (heat)
- Domestic appliances: 48 TWh (electricity)
- Road transport: 123 TWh (electricity)
- HGV, shipping, aviation, non-heat industrial hydrogen process: 88 TWh (hydrogen)
- Non-domestic
  - electricity (non-transport/heat): 224 TWh
  - space and water heating: 81 TWh (heat)
  - industry low-temperature heating: 57 TWh
  - industry high-temperature heating: 37 TWh (hydrogen)
- Cooling (electricity): 12 TWh (electricity)

Electricity demand from electrolysis, hydrogen production, energy storage, DACCS, and interconnectors is excluded in this table. Those will be calculated in the model directly.

3.2 Optimal portfolio of hydrogen technologies

In all pathways, Hydrogen and Heat Electrification, hydrogen technologies are proposed by the model, indicating the competitiveness and value of those technologies to support efficiency and reliable net-zero energy systems. The capacity of hydrogen infrastructure and their utilisation is shown in Table 1. The utilisation of hydrogen storage is expressed in cycles instead of percentages.

Table 1 Optimal portfolio and utilisation of hydrogen technologies

Hydrogen portfolio	**Capacity**		**Utilisation**	
	H2	**ELEC**	**H2**	**ELEC**
H2 CCGT (GW)	18.5	45.2	13.3%	5.5%
H2 OCGT (GW)	7.7	9.2	0.2%	0.2%
ATR+CCS (GW)	50.9	27.3	52.1%	18.0%
Electrolysers (GW)	17.2	13.7	41.8%	39.7%
H2 BECCS (GW)	11.0	8.2	99.6%	99.7%
H2 storage (TWh)	6.3	6.4	11.4	5.9

In addition to those technologies, there is a hydrogen network with linepack management and hydrogen boilers in the Hydrogen pathway. Different technologies have specific roles but should work in synergy to maximise their value and benefits to the system.

Hydrogen Combined and Open Cycle Gas Turbine (CCGT and OCGT) provides firm and dispatchable low-carbon power generation to support energy system resilience against peak demand, extreme weather (low RES output), and system balancing. Auto Thermal Reformer with CCS provides firm capacity and balancing for hydrogen supply and demand in the hydrogen system. Electrolysers provide sector-coupling flexibility between hydrogen and power systems. Hydrogen from gasification of biomass energy with CCS (BECCS) offsets emissions, allowing low-cost but non-zero carbon technologies to be deployed to minimise system costs. Hydrogen storage provides low-loss, short to long-duration energy storage.

The capacity of hydrogen power generation in Heat Electrification is much higher than in the Hydrogen pathway driven by a higher electricity peak demand. The utilisation of hydrogen assets in the Heat Electrification is also lower than that in the Hydrogen pathway. Nevertheless, those assets are still proposed, indicating their importance and competitiveness against other alternatives.

Fig. 2 shows the role of the hydrogen and gas CCS power generation to meet peak demand during low RES output events (day 16th – 18th), while electrolysers support the system balancing during high wind periods (day 19th – 20th) while most thermal generators are off.

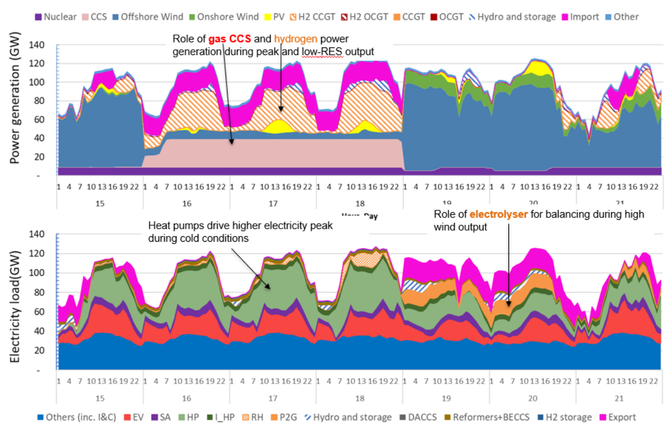


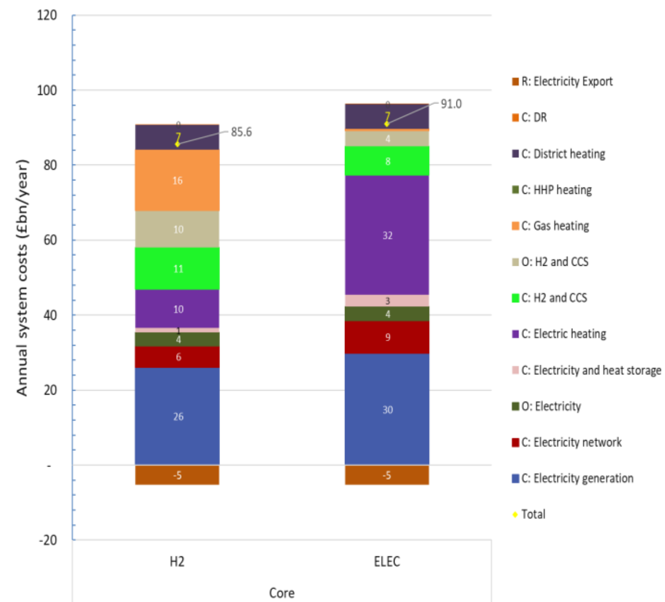
Fig. 2 Electricity supply-demand profile during a winter week

Demand flexibility and storage also play a significant role in system balancing and provide ancillary services such as reserves and frequency response.

3.3 Cost performance of the Hydrogen and Heat electrification pathways

The modelling results (Fig. 3) suggest that the cost of the Hydrogen pathway (£85bn/year) is £4.4bn/year lower than the cost of Heat electrification (£91bn/year). All Capex and Opex of the energy system involving electricity, heat, hydrogen, CCUS, and flexibility technologies are included in this analysis. As in all energy-system cost minimisation studies, the results are system-specific and subject to the scenarios' assumptions.

The results may surprise many as hydrogen for heating is seen as less efficient (in terms of energy) than Heat electrification using heat pumps. With the heat pump's coefficient of performance between 2 and 4.5, the system will require less than half of the energy needed to supply the heat demand than the hydrogen boiler system. The energy efficiency of the Heat Electrification scenario (101%) is substantially higher than the efficiency in the Hydrogen pathway (82%). Considering all other energy conversion losses occurring in the system, the primary energy used in the Hydrogen pathway (1,083 TWh/year) is substantially higher than in the Heat Electrification pathway (880 TWh/year). The primary energy supply consists of energy from nuclear, wind, solar PV, biomass, hydro, and natural gas. All energy conversion losses, storage efficiency losses, and energy usage to support electricity, hydrogen, CCS, and carbon storage infrastructure are accounted for.



Legend:

R: Electricity Export	Revenue from electricity export	**C: DR**	Capex of Demand Response
C: District heating	Capex of district heating system	**C: HHP heating**	Capex of hybrid heating
C: Gas heating	Capex of gas heating system	**O: H2 and CCS**	Opex of hydrogen and CCS system
C: H2 and CCS	Capex of hydrogen and CCS system	**C: Electric heating**	Capex of electric heating system (HP and resistive heating)
C: Electricity and heat storage	Capex of electricity and heat storage system	**O: Electricity**	Opex of electricity
C: Electricity network	Capex of electricity network (transmission, distribution, interconnection)	**C: Electricity generation**	Capex of electricity generation

Fig. 3 Energy system components modelled in IWES.

The cost components of the two pathways are compared to understand the differences between the cost of the Hydrogen (H2) and the heat electrification (ELEC) scenarios. The results are presented in Fig. 4. The negative numbers represent the savings in the Hydrogen pathway, while the positive numbers represent additional costs in the Hydrogen pathway compared to the Heat electrification pathway. The total savings are slightly above £30.4bn/year, consisting of savings in electric heating appliances (heat pumps, resistive heating, heat storage), followed by savings in distribution network costs and investment in low-carbon generation. There are other small savings in hydrogen storage. However, the Hydrogen pathway will require investment in hydrogen heating systems (boilers and hydrogen distribution network) and hydrogen production capacity (ATR+CCS).

The additional cost of the Hydrogen pathway also includes the increased Opex of ATR+CCS for blue hydrogen production and increased carbon storage costs. The total additional cost for the Hydrogen pathway is around £25bn/year. Hence, the net savings of the Hydrogen pathway are £5.4bn/year.

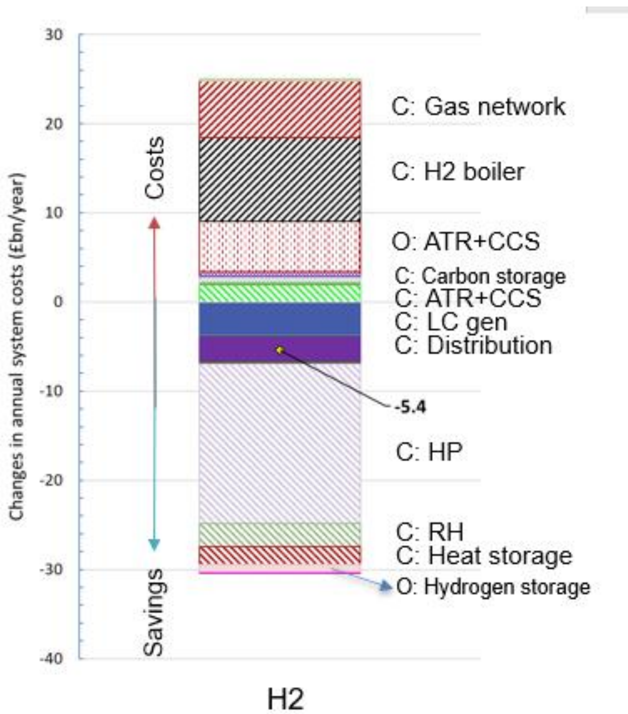


Fig. 4 Annual energy system cost differences between the Hydrogen and Heat Electrification pathways

While the energy used for heating in Heat electrification is less than in the Hydrogen pathway, the investment cost is higher as heat pumps are more expensive than hydrogen boilers. In this study, the annuitised Capex of heat pumps (including fixed O&M) is 2.1 times the annual Capex of hydrogen boilers. It is worth mentioning that the study already assumes the future reduction cost of heat pumps due to its mass scale deployment. The cost of hydrogen boilers is assumed to be similar to that of traditional boilers.

The rating of hydrogen boilers (20 kW or more) is much higher than heat pumps, so boilers can deal with the peak of heat demand and provide an instantaneous hot water supply. In contrast, heat pumps require thermal storage and resistive heating to meet the peak heat demand. Resistive heating is typically used to boost the thermal output of the heat pump system.

As the primary savings of the Hydrogen pathway are related to the heat pump costs, the results will be sensitive to the cost of heat pumps. In order to be on par with the Hydrogen pathway, the cost of heat pumps must be reduced by 30%, which will lead to 1.5 times the investment cost of hydrogen boilers. This study assumes that the annual Capex and fixed operating and maintenance cost for a 24 kW hydrogen boiler is £350/year, and for a 10 kW heat pump system is £750/year. The operating cost of those heating appliances is calculated inherently by the model.

3.4 *Sensitivity studies*

Several sensitivity studies have been undertaken to test the robustness of the key findings from the techno-economic comparison between Hydrogen and Heat Electrification pathways. All the modelling results meet the 2050 net-zero carbon and energy system resilience against extreme weather conditions. The sensitivity scenarios are summarised in Table 2, with the key parameter changes being studied.

Table 2 List of sensitivities being studied

Parameters	Core / Baseline	Sensitivity scenario tested	Rationale
Gas price	£23.67/MWh[1]	Very High: x3, High: x2; Low: - 20%	Recent high spikes in gas prices
Hydrogen production technologies	An optimal mix between blue hydrogen using ATR+CCS, green hydrogen (electrolysers), BECCS	No blue hydrogen No green hydrogen	Different views on how the low-carbon hydrogen should be produced
Hydrogen storage	As defined in the core assumptions	High: +20%, Low: -50%	Uncertainty in hydrogen storage costs
Domestic heat demand	222 TWh (Leading the Way)	277 TWh (System Transformation) * It includes improvement in energy efficiency from today's.	Uncertainty in the level of energy efficiency improvement achieved by 2050
Distributed flexibility	Medium: 25% maximum potential demand response and 10 GW new distributed storage. Maximum interconnection capacity of 20 GW	Low flex: no demand response, new energy storage (except mandatory, e.g., thermal storage for heat pump), and maximum interconnection capacity of 12 GW. High flex: maximum demand response and no constraint on new energy storage. Maximum interconnection capacity of 20 GW	System flexibility has been identified as an important aspect of future energy systems[2].
LCOE of offshore wind	£35/MWh	Lower cost: £25/MWh	Rapid reduction in the cost of offshore wind
LCOE of nuclear	£60/MWh	High: +20% Low: - 20%	Uncertainty in financing the nuclear costs
Interconnectors	Up to 20 GW	High: up to 30 GW Low: up to 11.7 GW	Uncertainty in the new interconnection capacity that can be deployed by 2050
Duration of wind lulls during peak demand	Three days	Low wind (50%,80%) for six winter weeks 1 and 2 weeks of no wind during winter peak	Increased dependency of the energy system on wind raises questions about the system's resilience against low wind output during peak demand.

[1] Source: National Grid FES 2022, the projected gas price in 2050
[2] Carbon Trust and Imperial College, Flexibility in Great Britain.

Due to limited space, only selected results from Fig. 5 are highlighted. Some of the key findings include:

- The whole-system cost of the Hydrogen pathway is lower than the Heat electrification pathway across all the scenarios. The savings are between **£2–7.3bn/year**. The minimum is found in the Very High Gas Price scenario, while the maximum is when the gas price is low.

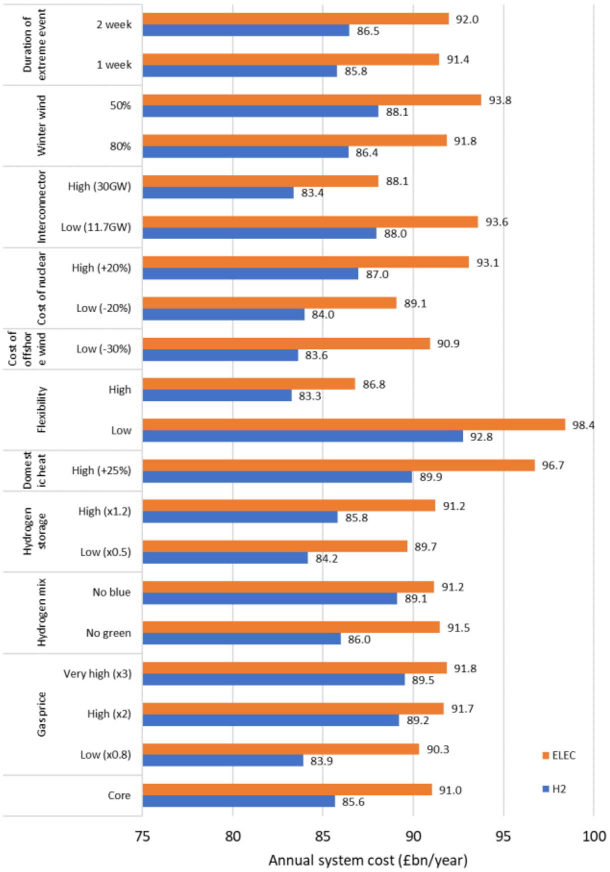


Fig. 5 Annual system cost performance of hydrogen and Heat electrification pathways in the sensitivity studies

- **Gas prices:** Even with very high gas prices or no blue hydrogen (which means that only electrolysers and BECCS produce hydrogen), the cost of the Hydrogen pathway is still lower than the cost of the Heat electrification pathway. However, the annual system cost of the Heat electrification scenario is less sensitive to variability in gas prices as the volume of natural gas used in this pathway is much less than in the Hydrogen pathway.
- **The role of blue hydrogen:** This is important in the Hydrogen pathway, depending on the gas price assumption. If the blue hydrogen production cost is lower than green hydrogen, the investment in blue hydrogen should be justified. Furthermore, producing hydrogen from different sources will improve energy security and resilience against the shock due to the temporal lack of availability of one source.
- **Flexibility:** *Improving system flexibility through deploying demand response and energy storage technologies is very important for both pathways* as it is the most sensitive factor that drives up or down the system costs. The costs of insufficient flexibility are around **£7bn/year**, and the benefits of improving flexibility from the core scenario range between **£2.4–4.3bn/year**. The value of flexibility is higher in the Heat electrification pathway, indicating more flexibility demand to support electrification.

4. CONCLUSIONS

The modelling results demonstrate that hydrogen technologies play a crucial role in energy decarbonisation, energy system balancing, and providing energy security and resilience against extreme weather events, e.g. low RES outputs during winter peaks in all scenarios. The hydrogen portfolio, including various sources of hydrogen (e.g. blue, green), must be optimised using the whole-system approach to maximise synergy across low-carbon technologies. This study also demonstrates that a system with higher energy efficiency will not always lead to a more cost-effective system. Although the overall efficiency of primary energy use in the Hydrogen pathway is 19% less than that of Heat Electrification, the Hydrogen pathway costs £5.4bn/year less than the Heat Electrification pathway due to lower Capex of heating appliances and supporting system costs due to more efficient use of assets. The competitiveness of using hydrogen to decarbonise heat in GB is robust against many parameters, including high gas prices, different hydrogen production mixes, and system flexibility levels.

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