Socio-Technical, Electrification, and Hydrogen-Driven Pathways for Residential Heating Decarbonisation in the North of Tyne

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***Abstract*—Decarbonising domestic heating remains a major challenge, particularly in gas-dependent and fuel-poor regions. This paper investigates hydrogen-based and alternative decarbonisation pathways for residential heating in the North of Tyne (NoT) region, UK. A multi-system perspective (MSP) framework—combining qualitative scenario analysis with quantitative energy system modelling—evaluates the effects of socio-technical interventions (STIs), technology adoption (heat pumps and hydrogen boilers), and hydrogen blending on energy demand, CO_2 emissions, and system costs to 2050. Monte Carlo simulations capture behavioural uncertainties, while a game-theoretic investment model supports long-term planning. Results show that while STIs significantly reduce demand, they cannot alone achieve net zero. Hydrogen blending offers limited short-term benefits, whereas heat pumps deliver the lowest operational costs and emissions, representing the most efficient pathway under full electrification. Hydrogen boilers, though cost-intensive and less efficient operationally, show high long-term net present value (NPV £318–624 million), suggesting potential economic payoff over time. By 2050, with full CCS deployment and high renewable penetration, operational emissions are nearly eliminated across all scenarios. The findings highlight the importance of integrated planning, investment coordination, and social engagement to deliver a resilient and cost-effective low-carbon heating transition.**

***Index Terms*—Residential Heating, Decarbonisation, Hydrogen, Electrification, Socio-technical Interventions.**

I. Introduction

The heating sector's decarbonisation is pivotal for achieving net-zero greenhouse gas (GHG) emissions [1]. Residential heating accounts for a substantial portion of energy consumption and CO_2 emissions in many countries, particularly those with colder climates and fossil fuel-based heating systems [2]. The UK faces a significant challenge, with approximately 85% of homes heated by natural gas, contributing around 14% of the UK's total carbon emissions [3].

The North of Tyne (NoT) region in North East England epitomises these challenges. With diverse consumption patterns, high fuel poverty, and significant reliance on natural gas for heating, the NoT is a complex case. The region consumed 17.3 TWh of gas in 2018, 1% of UK total energy consumption, with the domestic sector being a major contributor [4]. Transitioning to low-carbon alternatives requires careful consideration of technology, economics, social acceptance, and infrastructure.

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A. Related Work

Various pathways for heating decarbonisation are being explored, including electrification (e.g., heat pumps), district heating, and low-carbon gases like hydrogen and biomethane [5]. Hydrogen, produced via electrolysis (green) or from natural gas with Carbon Capture and Storage (CCS) (blue), is gaining traction as a potential direct replacement or blend for natural gas [6]. Recent analyses suggest up to 20% volumetric hydrogen blending is feasible without major network impacts, though higher shares pose significant challenges [7]. Broader system-level studies highlight hydrogen's benefits across electricity, heating, and transport [8], while multi-model analyses point to the cost-effectiveness of combining heat pumps and hydrogen boilers [9]. However, hydrogen's role, production costs, infrastructure implications, and integration with other solutions remain debated [10]. Additionally, social interventions, such as insulation upgrades and behavioural changes, are vital for reducing energy demand [11], [12].

B. Objectives and Contributions

This study addresses key questions for decarbonising residential heating in the NoT. Objectives include:

1) Evaluating the impact of social interventions.
2) Assessing stakeholder willingness to adopt technologies and behaviours.
3) Determining required investment in hydrogen production and renewable energy.
4) Optimising heating setpoint adjustments, insulation, heat pumps (HP), and hydrogen boilers (HB) for efficiency and emissions.
5) Identifying strategies to promote stakeholder acceptance, considering affordability and comfort.

This paper develops a novel Multi-System Perspective (MSP) modelling framework, soft-linking qualitative scenario development with quantitative energy system modelling to evaluate decarbonisation pathways up to 2050. It provides insights into technical, economic, and societal implications, aiming to inform policy and investment in the NoT and similar contexts.

II. Methodology

This study employs an MSP framework to model hydrogen-based decarbonisation strategies for NoT residential heating. The methodology integrates qualitative scenario development with quantitative energy system modelling, drawing on a game-theoretic optimisation framework for stakeholder interactions in multi-vector energy systems [13].

A. Modelling Framework

The core of the study is a high-level resources–technology model, representing an integrated multi-vector energy system (Figure 1). The model considers energy resources from electricity (Ele.), natural gas (NG), hydrogen (H_2), and renewable energy sources (RES) such as wind, solar, and bioenergy with carbon capture and storage (BECCS), along with their respective networks. It incorporates conversion and storage technologies such as electrolysers, auto–thermal reformers with CCS (ATR+CCS), fuel cells (FC), and hydrogen storage. The system meets residential heat demand through technologies including natural gas boilers (HNG), heat pumps (HP), and hydrogen boilers (HB), alongside social and technological interventions (STI) such as smart controls and insulation retrofitting.

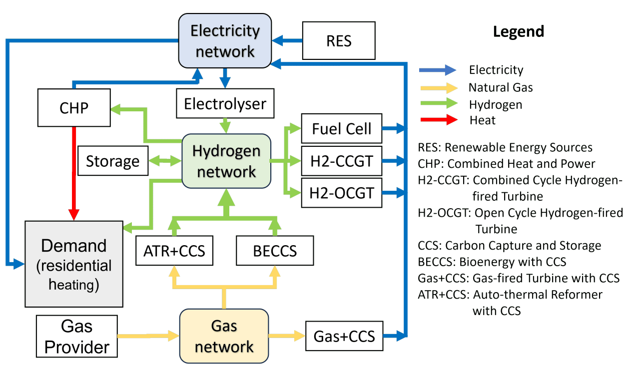

Figure 1: Integrated multi-vector energy system framework for NoT.

B. Electric Network Modelling

The electricity network is represented by nodal power balance equations, ensuring active and reactive power injections match demands at each bus, respecting network constraints. This provides a steady-state snapshot, crucial for integration with hydrogen systems. Pandapower [14] solves the power flow equations.

1) Active Power Flow:

$$P_{G_i} - P_{L_i} - \sum_j |V_i||V_j| \big(G_{ij}\cos(\delta_i - \delta_j) + B_{ij}\sin(\delta_i - \delta_j)\big) = 0 \tag{1}$$

2) Reactive Power Flow:

$$Q_{G_i} - Q_{L_i} - \sum_j |V_i||V_j| \big(G_{ij}\sin(\delta_i - \delta_j) - B_{ij}\cos(\delta_i - \delta_j)\big) = 0 \tag{2}$$

where variables are standard electrical engineering terms.

C. Hydrogen Blending in the Gas Network

Hydrogen injection into the natural gas network reduces carbon emissions by utilising existing infrastructure. Pandapipes [15] simulates gas mixtures. This study considers hydrogen blending in the NoT's low-pressure natural gas network, analysing its impact on flow, pressure, and gas quality. Hydrogen fraction, $\alpha_{H_2} \in [0, 1]$, defines the molar proportion of hydrogen. Mixture properties, including density, viscosity, compressibility, and gross calorific value (GCV), are calculated using established mixing rules:

$$\rho_{\text{mix}} = \sum_{i \in \{\text{NG}, \text{H}_2\}} w_i \, \rho_i \tag{3}$$

$$\mu_{\text{mix}} = f(\mu_i, M_i, x_i) \tag{4}$$

$$Z_{\text{mix}} = \sum_i x_i Z_i \tag{5}$$

$$\text{GCV}_{\text{mix}} = \frac{\sum_i x_i \, \text{GCV}_i}{Z_{\text{mix}}} \tag{6}$$

where w_i, M_i, x_i are mass fractions, molar masses, and molar fractions.

The gas flow in each branch is:

$$q_k = \pi \sqrt{\frac{R_{\text{air}}}{8} \frac{T_n}{p_n}} \sqrt{\frac{(p_i^2 - p_j^2) D^5}{f S_{\text{mix}} L T Z_{\text{mix}}}} \tag{7}$$

with nodal balance ensuring mass conservation:

$$\sum_j q_{j,\text{in}} - \sum_j q_{j,\text{out}} - q_{L,j} = 0 \tag{8}$$

Power-to-Gas (P2G) units couple with the electricity system, converting electrical energy into hydrogen injected into the network:

$$q_{\text{H}_2} = \frac{\eta_{\text{P2G}} P_{\text{P2G}}}{\text{GCV}_{\text{H}_2}} \tag{9}$$

This formulation accounts for blending effects on network pressures, energy content, and operational feasibility.

D. Socio-Technical Interventions and Demand Modelling

Six socio-technical interventions (STIs) were identified and quantified based on established literature [11], [12], [16]. These six interventions, listed in Table I, represent behavioural and technological measures that can reduce residential heating demand through efficiency and behavioural change. Each intervention's estimated impact on gas and electricity demand was parameterised to reflect realistic household responses.

The six STIs were subsequently used as input parameters in a Monte Carlo simulation (Section III.D) to generate probabilistic gas and electricity demand profiles for a representative cold day. These simulated demand profiles are then used as input scenarios in the case study analysis to evaluate the overall system-level impacts of socio-technical adoption.

E. Socio-Technical Interventions and Demand Modelling

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F. Monte Carlo Simulation of STI Demand Profiles

A Monte Carlo simulation generates gas and electricity demand profiles for a representative cold day, accounting for STI uncertainties. Let G_0 and E_0 be baseline hourly demands. Adjusted demands G and E are:

$$G = \frac{1}{n}\sum_{i=1}^{n}\left(G_{0,i} \times \sum_{j=1}^{N} \Pr(I_j)\cdot R_j \cdot X_j\right) \tag{10}$$

$$E = \frac{1}{n}\sum_{i=1}^{n}\left(E_{0,i} \times \sum_{j=1}^{N} \Pr(I_j)\cdot K_j \cdot Y_j\right) \tag{11}$$

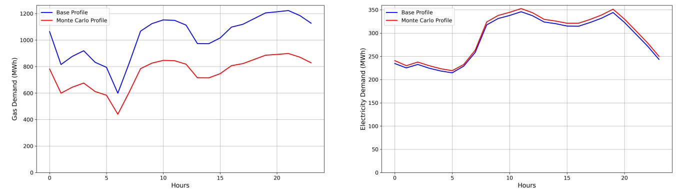
where n is iterations, $N = 6$ interventions, $\Pr(I_j)$ is intervention probability, R_j and K_j are adjusting factors, and $X_j \sim \mathcal{N}(\mu_{R_j}, \sigma_{R_j})$ and $Y_j \sim \mathcal{N}(\mu_{K_j}, \sigma_{K_j})$ are random variables for uncertainty.

The six STIs (Table I) were used as input parameters in this Monte Carlo simulation to generate probabilistic demand profiles. Figure 2 presents the simulated hourly gas and electricity demand profiles under the STI scenario for a representative cold day.

These simulated profiles are then employed as input to the STI scenario in the case study, linking behavioural and technological measures to energy system outcomes.

G. Game-Theoretic Model Framework

A game-theoretic investment planning model (GTM) captures strategic interactions between stakeholders (e.g., electricity generators, hydrogen storage operators) in a competitive multi-vector energy system [13]. It integrates long-term investment (for 6 discrete years: 2025, 2030, 2035, 2040, 2045, 2050) and short-term operational decisions to maximise



(a) (b)

Figure 2: Simulated residential energy demand profiles under socio-technical interventions (STIs) for a cold day, showing (a) gas demand and (b) electricity demand.

stakeholder returns under technical and market constraints. Investments include generation technologies (gas turbines, CHP, wind, solar, biomass) and hydrogen production (electrolysers, H2 reformers) to meet heating demands and decarbonisation targets. The objective is to maximise Net Present Value (NPV):

$$NPV = AF\left(\sum_{t=0}^{T}(R_t - C_t - CO_t) - FC\right) - NI \tag{12}$$

where AF is annuity factor, R_t revenue, C_t operational cost, CO_t carbon cost, FC fixed costs, and NI net investment. This jointly optimises investment and operational decisions. Generation and investment are subject to capacity constraints and market clearing, formulated as complementarity conditions for a Nash-Cournot equilibrium. The GTM is solved iteratively with a short-term Optimal Power and Gas Flow (OPGF) model (Figure 3):

1) Initialise system parameters.
2) Run GTM for optimal investment and generation under strategic constraints.
3) Use GTM outputs in OPGF for short-term operational feasibility under network constraints.
4) Compare results; if convergence not met, update GTM with OPGF feedback.
5) Upon convergence, compute metrics.

III. Case Study: The North of Tyne Region

This section details the MSP framework and game-theoretic model implementation in the NoT. It illustrates how integrated electricity and gas networks, with hydrogen blending and STIs, can achieve decarbonisation.

1) System Description: The NoT region (Newcastle upon Tyne, North Tyneside, Northumberland) has 833,000 people in 360,000 households [4]. It relies heavily on natural gas for residential heating. In 2018, NoT consumed 17.3 TWh of gas (1% of UK total), with domestic use contributing significantly. Natural gas for domestic consumption was 75% of total domestic energy demand, electricity 20%. The region produced 1146 GWh of renewable energy in 2019, with 837 MW capacity [4]. Fuel poverty and ageing housing stock add complexity, making NoT a pertinent case study. Techno-economic parameters (Table II), are from [8], [17], [18]. For the analysed demand day, prices are 24-hour averages: electricity at £125/MWh, natural gas at £37/MWh.

Table I: List of six socio-technical interventions (STIs) and their estimated impact on residential heating demand.

STI ID	Intervention Description	Effect on Gas Demand	Effect on Electricity Demand
STI-1	Decreasing heating set point by 2 °C	20% decrease	No effect
STI-2	Improving whole building insulation (Passivhaus-like)	77% decrease	No effect
STI-3	Delaying start of heating season (October to November)	5.5% decrease	No effect
STI-4	Use of radiator valves (in unoccupied rooms)	4% decrease	No effect
STI-5	Adoption of heat pumps (HP) for 10% of heat demand	10% decrease (gas)	14% increase (elec.)
STI-6	Adoption of hydrogen boilers (HB) for 10% of heat demand	10% decrease (gas)	No effect

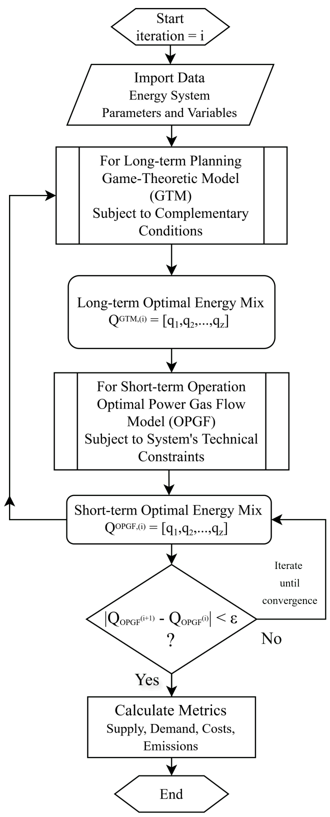


Figure 3: GTM framework for integrated energy system planning.

Hydrogen production costs are endogenously determined. The model data and scripts are available at: https://github.com/MohamedAbuella/Heating_Decarb_NoT.

Table II: Techno-economic parameters for NoT energy system.

Type	CapEx (£/MW)	OpEx (£/MWh)	Fx.Cost FC (ϕ)	Life (yrs)	Emissions (tCO_2/MWh)
GT	1,500,000	85	0.0251	25	0.444
Biomass	3,400,000	205	0.0348	25	0.0892
CHP	4,600,000	135	0.0274	15	0.1839
Wind	1,500,000	46	0.0251	25	0
Solar	400,000	44	0.0123	35	0
Electrolyser	1,158,630	42	0.1043	30	0
ATR-CCS	1,500,000	85	0.1000	30	0

2) Heating Scenarios: To assess decarbonisation pathways, four residential heating scenarios are considered in the case study:

1) Socio-Technical Interventions (STI) only: Demand reduction strategies including setpoint adjustments, insulation improvements, radiator valve usage, and partial adoption of heat pumps and hydrogen boilers. The six STIs (Table I) are simulated via Monte Carlo to generate probabilistic gas and electricity demand profiles used as model inputs.
2) 50/50 Heat Pumps and Hydrogen Boilers (Hybrid): Half of the heating demand is met by heat pumps, half by hydrogen boilers. This scenario captures a transitional pathway combining electrification and hydrogen use.
3) 100% Heat Pumps (HP): Full electrification of heating demand via heat pumps, representing a pathway focused on minimal fossil fuel reliance and reduced system carbon intensity.
4) 100% Hydrogen Boilers (HB): Full reliance on hydrogen boilers to meet heating demand, representing a hydrogen-centric pathway, either via blue hydrogen with CCS or green hydrogen from electrolysis.

These scenarios are evaluated under different hydrogen blending ratios (0%, 20%, 100%) and CCS deployment assumptions to explore techno-economic and system-level impacts across 2025–2050.

3) Evaluation Metrics: Decarbonisation pathways are assessed using the following indicators:

- CO_2 Emissions (tonnes/day): Total CO_2 emissions from energy generation and consumption.
- Operational Cost (£/day): Daily operational expenditure required to meet residential heat demand under peak conditions.
- Net Present Value (NPV, £): A measure of the long-term economic performance of investment strategies, as defined in Section II-G.

IV. Results and Discussion

Tables III and IV summarise the simulation results for heating pathways in 2035 and 2050, selected to represent a peak demand day under contrasting CCS scenarios: 2035 without CCS deployment and 2050 with full CCS deployment. Figures 4 and 5 illustrate energy mixes and investment planning for extreme blending cases (0% and 100% hydrogen) on the peak day over six discrete years between 2025 and 2050.

In 2035, as shown in Table III, without CCS, all scenarios of heating and hydrogen blending cases retain residual CO_2 emissions due to fossil-fuel-based sources such as gas turbine (GT) operation and reformer-based hydrogen production. Heat pumps remain the most cost-effective option (£0.76–0.80 million) with low emissions (1475–1553 tonnes) and moderate NPV (£124–186 million). Hydrogen boilers are the most expensive (£1.92–2.81 million) and carbon-intensive (2578–2789 tonnes), though their higher NPV (£254–307 million) reflects long-term investment potential. Mixed pathways and STIs fall in between, offering a trade-off between operational cost, emissions, and NPV.

Table III: Operational cost (Opex, million £/day), emissions (tonnes CO_2/day), and net present value (NPV, million £) for peak demand in 2035 (without CCS).

H_2 blending (%)	0% H_2			20% H_2			100% H_2		
Scenario / Metric	Opex	Emis	NPV	Opex	Emis	NPV	Opex	Emis	NPV
STI	0.80	1510	194	0.87	1471	152	2.46	1190	274
50/50 HB & HP	1.28	2454	194	1.30	2269	166	1.52	598	154
100% HP	0.76	1553	157	0.80	1475	124	1.44	663	186
100% HB	1.92	2789	307	1.95	2578	278	2.81	1597	254

By 2050, with full CCS deployment and high renewable penetration, operational emissions are near zero in nearly all scenarios. However, small residual emissions (8–9 tonnes CO_2) persist in the mixed HP–HB pathways, due to incomplete carbon capture in blue hydrogen production. Heat pumps generally offer the lowest operational costs (£0.60–0.65 million) under blended hydrogen conditions with substantial NPV (£316–419 million). STIs maintain moderate costs (£0.64–2.03 million) across blending levels, reflecting the impact of socio-technical interventions while retaining high NPV (£324–486 million). Mixed HP–HB pathways exhibit intermediate costs (£0.82–1.10 million) with minor residual emissions, indicating a balanced trade-off between operational expenditure and flexibility. At 100% hydrogen, operational costs range from £1.10 million for mixed HP–HB pathways, but also have the lowest NPV (£253 million), to £2.03 million for STIs with the highest NPV (£323 million), illustrating the trade-off between operational cost and long-term economic value across the scenarios.

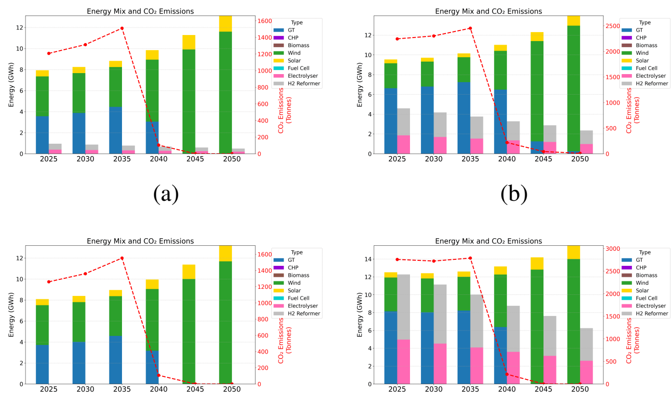
Table IV: Operational cost (Opex, million £/day), emissions (tonnes CO_2/day), and net present value (NPV, million £) for peak demand in 2050 (full CCS deployment).

H_2 Blending (%)	0% H_2			20% H_2			100% H_2		
Scenario / Metric	Opex	Emis	NPV	Opex	Emis	NPV	Opex	Emis	NPV
STI	0.64	0	486	0.67	0	384	2.03	0	323
50/50 HB & HP	0.82	9	518	0.83	8	411	1.10	0	253
100% HP	0.60	0	419	0.65	0	316	1.95	0	323
100% HB	1.16	0	624	1.19	0	519	1.93	0	318

Collectively, the results highlight the trade-offs between short-term operational costs, CO_2 emissions, and long-term economic returns (NPV), providing insights for strategic planning of decarbonisation pathways under varying hydrogen blending levels.

Energy mix outcomes are shown in Figures 4 (0% blending) and 5 (100% blending). Across all scenarios, wind and solar capacity expand substantially, reflecting their role as backbone technologies.

In the 0% hydrogen blending case (Fig. 4), pathways diverge markedly by 2050. Heat pumps (c) require no hydrogen, achieving the lowest total demand (12 GWh) and representing the most-efficient option. Hydrogen boilers (d) increase demand to 13.5 GWh and necessitate significant hydrogen production. Hybrid HP–HB pathways (b) occupy an intermediate position in terms of hydrogen use and overall demand, unlike the STI scenario (a), which maintains low hydrogen production.



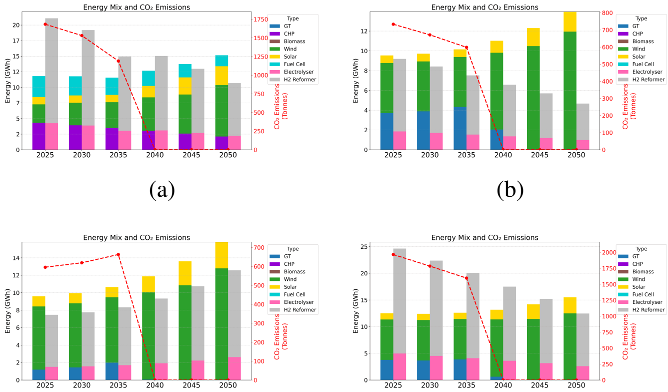
(a) (b) (c) (d)

Figure 4: Investment planning (0% hydrogen blending, CCS from 2040) for: (a) Socio-technological interventions (STI), (b) 50% heat pumps (HP) and 50% hydrogen boilers (HB), (c) 100% HP, (d) 100% HB.

In the 100% hydrogen blending case (Fig. 5), total energy demand varies notably across pathways by 2050. The hybrid heat pump–hydrogen boiler (HP–HB) pathway achieves the lowest total demand (13 GWh), reflecting the benefits of combining efficient electrification with flexible hydrogen use. In contrast, the 100% heat pump (HP) scenario exhibits the highest demand (15.5 GWh), primarily due to the large electricity requirements for heat generation. The 100% hydrogen boiler (HB) and the Smart Thermal Integration (STI) pathways show intermediate results: both require high hydrogen production, but overall demand remains lower than in the HP case owing to efficiency gains and demand-side measures.

By 2040, with full CCS deployment, direct CO_2 emissions are effectively eliminated across all cases, although emissions persist beforehand from unabated fossil-fuel sources, particularly reformer-based hydrogen production.

The results demonstrate a robust transition towards a low-carbon energy system by 2050, primarily driven by the significant integration of renewable energy, including extensive deployment of CCS from 2040. While the overall decarbonisation trajectory is broadly consistent across different intervention strategies and hydrogen blending levels, the 100% hydrogen scenarios require substantial investment in electrolysers and reformers, which, based on the NPV, appear likely to pay off in the long term. Whereas heat pumps rely predominantly on direct grid electricity and remain the most



(a) (b)

(c) (d)

Figure 5: Investment planning (100% hydrogen blending, CCS from 2040) for: (a) Socio-technological interventions (STI), (b) 50% heat pumps (HP) and 50% hydrogen boilers (HB), (c) 100% HP, (d) 100% HB.

efficient option in terms of operating costs and overall energy efficiency.

V. Conclusions

This study assessed hydrogen-based and alternative decarbonisation strategies for residential heating in the North of Tyne region to 2050, considering operational costs, CO_2 emissions, and long-term economic performance (NPV).

By 2035, without CCS, only 100% hydrogen scenarios achieve zero operational CO_2. Heat pumps remain the most cost-effective option (£0.76–0.80 million) with low emissions (1475–1553 tonnes) and moderate NPV (£124–186 million). Hydrogen boilers are the most expensive and carbon-intensive (£1.92–2.81 million), though they offer higher long-term NPV (£254–308 million). Mixed pathways and socio-technical interventions (STIs) provide intermediate trade-offs between cost, emissions, and NPV.

By 2050, with full CCS deployment and high renewable penetration, operational emissions are near zero. Heat pumps offer the lowest costs (£0.60–0.65 million) and substantial NPV (£316–419 million), while STIs maintain moderate costs (£0.64–2.03 million) and high NPV (£324–486 million). Hybrid HP–HB pathways exhibit intermediate costs (£0.82–1.10 million). At 100% hydrogen, operational costs range from £1.10 million for mixed HP–HB pathways, but also with the lowest NPV (£253 million), to £2.03 million for STIs with the highest NPV (£323 million), illustrating the trade-off between operational cost and long-term economic value across the scenarios.

Overall, the findings emphasise that a resilient, low-carbon heating future relies on a combination of demand reduction, large-scale electrification via heat pumps, CCS, and renewable expansion, with hydrogen providing additional flexibility and support.

Acknowledgements

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