A Game-Theoretic Framework for Hydrogen Integration to Accelerate Energy Transitions in Great Britain

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Abstract

The pathway towards net-zero emissions requires a clearly defined strategy that effectively integrates renewable energy, enhances system flexibility, and ensures economic viability. This paper develops a game-theoretic framework for integrated energy system planning in Great Britain (GB), aimed at addressing scalability and cross-sector policy interactions. The proposed framework captures competition among electricity, gas, and hydrogen systems within a multi-vector context. This framework is based on a bi-level optimisation structure that links long-term capacity investment decisions with short-term operational strategies, enabling the planning of integrated system dynamics under realistic constraints. Key contributions include the evaluation of hydrogen-based vector-coupling storage (VCS) as a flexible solution for enhancing system reliability and cost-effectiveness. Through this framework, the study explores how renewables, hydrogen systems, and infrastructure can synergise to support the United Kingdom's energy transition goals. The findings provide actionable insights for policymakers and industry stakeholders, offering tools to guide investment, infrastructure requirements, and decarbonisation efforts.

1 Introduction

Achieving net-zero emissions in Great Britain (GB) requires a well-structured decarbonisation pathway that integrates renewable energy sources, enhances system flexibility, and ensures economic feasibility. A holistic approach to energy planning is essential to balance competition across sectors, while emerging technologies such as hydrogen play a crucial role in the transition.

This paper presents a game-theoretic optimisation framework designed to address national-scale integrated energy systems, overcoming limitations in existing methodologies such as scalability and policy interaction. The model integrates multiple energy vectors, including electricity, gas, and hydrogen, providing insights for cost-effective decarbonisation pathways. The findings aim to guide policymakers in identifying optimal strategies and decision-making frameworks to ensure an effective transition towards a decarbonised energy system in GB.

1,1 Related Work

Strategic planning and optimisation are fundamental to addressing the challenges of decarbonising national energy systems. Recent studies have explored frameworks for decision-making in complex, multi-vector configurations. Hosseini et al. [1] systematically reviewed multi-vector energy networks, emphasising the importance of operational integration to achieve cost reductions and carbon mitigation targets. Fu et al. [2] developed a multi-energy systems optimisation model for Great Britain, assessing the integration of hydrogen across electricity, heating, and transport sectors under 30 Mt and 10 Mt carbon targets by 2050. Their findings highlight significant system-wide cost savings up to £14.2 billion annually, and underscore the strategic value of hydrogen pathways, particularly gas-to-gas (G2G), in reducing power capacity requirements, enabling wind integration, and shifting market shares in heat and transport technologies. Zhang et al. [3] developed a coordinated trading framework for hydrogen providers using a Stackelberg game-based mechanism, optimising interactions in electricity and hydrogen markets. Klatzer et al. [4] addressed integrated expansion planning for power, gas, and hydrogen systems, calling for holistic frameworks that accommodate hydrogen blending and infrastructure co-expansion.

Game-theoretic approaches have been applied to model strategic behaviours in energy systems. Andoni et al. [5] presented a Stackelberg-Cournot framework for investment analysis in renewables and storage, providing practical insights despite computational limitations. Similarly, Ma et al. [6] proposed a Nash bargaining-based framework for planning multi-agent wind-hydrogen-heat systems, demonstrating improvements in wind curtailment and system efficiency. In a related study from our research group, [7] introduced a bi-level game-theoretic optimisation framework for regional-scale multi-vector energy systems. This paper extends that formulation to the national level, capturing broader spatial coordination and systemic impacts.

Several review studies consolidate game-theoretic applications in integrated energy systems. He et al. [8] identified gaps in linking game theory with national-scale decarbonisation policies. Abapour et al. [9] and Marousi et al. [10] further classified methods across power and process systems, addressing challenges in resource allocation, pricing, and strategic investment.

Additionally, Xu et al. [11] discussed the role of distributed optimisation algorithms in enhancing system resilience and scalability, noting challenges in convergence and communication overhead, particularly relevant for large-scale energy system coordination. Zhang et al. [12] provide a comprehensive review of over 130 studies on hydrogen integration, highlighting modelling gaps across production, storage, and sector coupling. They emphasise the need for detailed cross-vector models capable of addressing hydrogen's evolving role in whole-system energy transitions. However, existing studies largely overlook the integration of game-theoretic optimisation with multi-vector hydrogen systems at a national scale, often relying on overly simplified operational models that fail to reflect the strategic complexity and context-specific realities of Great Britain's energy transition.

1.2 Research Objectives

This study aims to address several critical research questions:

- What are the optimal strategies for integrating hydrogen into existing energy systems in the GB?
- How can hydrogen contribute to decarbonisation in electricity, heating, and transportation in GB?
- What are the economic and technical challenges associated with hydrogen integration?
- How can game-theoretic optimisation models inform the development of effective decarbonisation strategies for GB?

The insights gained from this paper provide valuable guidance for policymakers, enabling them to make informed decisions on the adoption of hydrogen and other key technologies that are integral to achieving a decarbonised energy system.

2 Methodology

This section details the analytical methodology employed to investigate the strategic integration of hydrogen within Great Britain's future energy system towards the 2050 net-zero target. We present a bespoke bi-level optimisation framework designed to capture the complexities of multi-vector energy planning. This framework combines long-term investment decisions, modelled using a game-theoretic approach (GTM) to reflect stakeholder interactions in a liberalised market, with detailed short-term operational constraints evaluated through an optimal power and gas flow (OPGF) model. The subsequent subsections elaborate on the structure of this approach, the specific mathematical formulations of the GTM and OPGF components, and the iterative algorithm are used to ensure consistency between investment strategies and operational feasibility [7].

2.1 Framework Structure

The model is designed to facilitate interactions between various stakeholders, including electricity generators and energy storage systems (ESS) operators, particularly those utilising bidirectional hydrogen-based Vector Coupling Storage (VCS). Figure 1 displays the flowchart of the framework, which is presented in detail in this section.

2.2 Game-Theoretic Model (GTM)

A game-theoretic model is developed for decentralised competitive planning of the Integrated Energy System (IES), focusing on the interplay between gas and hydrogen networks within a liberalised market. The model integrates both long-term investment strategies and short-term operational considerations, enabling stakeholders to maximise their returns in a dynamic environment.

2.2.1 The Objective Function: The core objective of the investment model is to maximise the Net Present Value (NPV) of future cash flows from energy operations.

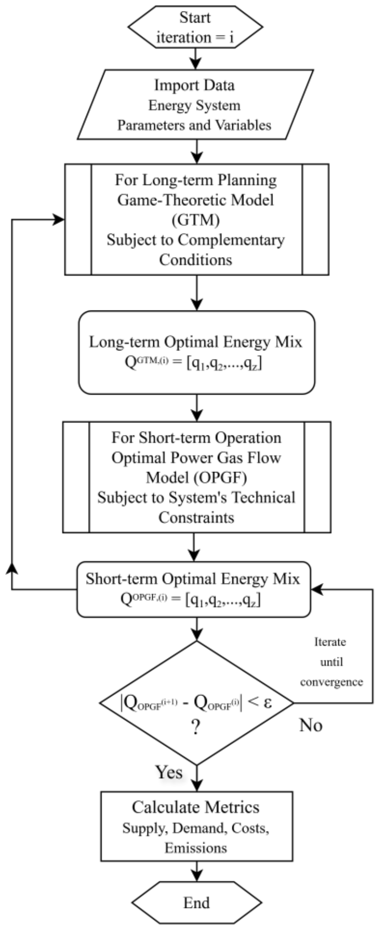


Figure 1 The framework flowchart.

The detailed NPV equation can be expressed as:

$$NPV = AF\left(\sum_{t=0}^{T}(R_t - C_t - CO_t) - FC\right) - NI \quad (1)$$

where:

- *AF* is the annuity factor

$$AF = ((1+r)^n - 1)/(r(1+r)^n) \quad (2)$$

r is the discount rate, and *n* is the economic lifetime of the technology.

- *Rt is the revenue from energy sales at time t,*

- C_t is the operational cost, which includes fuel costs, variable costs, and fixed costs related to technology z,

- CO_t is the carbon emissions cost at time t, calculated as:

$$CO_t = \sum_z q_z \cdot h_z \cdot c_{\text{emis}} \quad (3)$$

Where h_z is the emission intensity of technology z and c_{emis} is the cost per ton of emissions,

- FC represents the total fixed costs for the energy system, calculated as:

$$FC = \sum_{z \in Z} (\phi_z \cdot \varepsilon_z \cdot (K_z + I_z)) \quad (4)$$

where K_z is the total capacity of technology z at the end of the year, I_z is the investment in capacity for technology z, ε_z is the specific capital expenditure, and ϕ_z is the fixed cost fraction of the given technology,

- NI is the net investment outlay for all technologies, calculated as:

$$NI = \sum_{z \in Z} \left[\varepsilon_z \cdot I_z \cdot \left(1 - \frac{\lambda_z - n}{\lambda_z (1+r)^n} \right) \right] \quad (5)$$

where λ_z is the depreciation rate, r is the discount rate, and n is the technology's lifetime.

This expanded NPV equation considers operational profits and investment costs, while maximising returns across multiple periods.

2.2.2 The Complementarity Conditions: The objective function incorporates various cost components related to energy production, including operational costs and carbon emissions. The complementarity conditions for market clearing are represented as follows:

- *Generation Capacity:*

$$q_z \geq 0 \quad \perp \quad p_e - c_z(q_z) - \sigma_z \leq 0 \quad (6)$$

where the symbol $\perp$ denotes the complementarity condition. Specifically, the complementarity condition states that either:

$q_z > 0$ (positive generation), in which case
$p_e - c_z(q_z) - \sigma_z = 0$ (the constraint is active),

or $q_z = 0$ (no generation), in which case
$p_e - c_z(q_z) - \sigma_z \leq 0$ (the constraint is not active).

Thus, the condition ensures that either the quantity produced by technology z is positive, and the constraint on costs is active, or no production occurs, and the constraint is non-binding.
Where: q_z is the quantity produced by technology z, p_e is the market price of electricity, $c_z(q_z)$ is the cost function for technology z, often quadratic, represented as:

$$c_z(q_z) = a_z q_z^2 + b_z q_z + c_z \quad (7)$$

where a_z, b_z, and c_z are cost coefficients,

σ_z is the shadow price for generation capacity constraints.

- *Generation Investment:*

$$I_z \geq 0 \quad \perp - AF \cdot \phi_z \cdot \epsilon_z - \epsilon_z \cdot \left(\frac{1 - \lambda_z - n}{\lambda_z (1+r)^n} \right) + \sigma_z - \delta_z \leq 0 \quad (8)$$

where:

I_z is the investment in technology z. ϕ_z is the fixed cost fraction of technology z. ϵ_z is the specific capital expenditure for technology z. λ_z is the economic lifetime of technology z, r is the discount rate. n is the planning horizon. σ_z and δ_z are shadow prices representing the investment constraints for technology z.

These equations indicate that both the quantity produced, and the investments made must be non-negative and align with the Nash-Cournot equilibrium framework, ensuring profitability while adhering to market and capacity constraints.

- *Generation and Investment Limits:*

The complementarity conditions enforce the generation and investment limits for each technology:

Generation capacity limits:

$$0 \leq q_z \leq q_z^{\max} \quad \perp \quad \sigma_z \geq 0 \quad (9)$$

where $q_z^{\max}$ is the maximum generation capacity for technology z and σ_z is the shadow price associated with this constraint.

- *Generation investment limits:*

$$0 \leq I_z \leq I_z^{\max} \quad \perp \quad \delta_z \geq 0 \quad (10)$$

where $I_z^{\max}$ is the maximum investment allowed for technology

z and δ_z is the shadow price for investment constraints.

These complementarity conditions ensure that the generation and investment decisions are optimised within the capacity and financial limits of the system.

2.2.3 Market Clearing Conditions: the market clearing conditions for the electricity and gas markets can be expressed as:

$$q_e = \sum_z q_z \quad \text{(Electricity)} \,, \quad q_g = \sum_j q_j \quad \text{(Gas)} \tag{11}$$

where q_e is the total electricity supplied, and q_g is the total gas supplied.

2.3 Short-term Operational Model

The short-term operational model integrates the operational aspects of both the electricity and gas networks, ensuring optimal flow management. The optimal power and gas flow (OPGF) equations are represented as:

Electricity flow:

$$P_G - P_L - \sum_i |V_i||V_j|(G_{ij}\cos(\delta_i - \delta_j) + B_{ij}\sin(\delta_i - \delta_j)) = 0 \tag{12}$$

Gas flow:

$$\sum_j q_{j,in} - \sum_j q_{j,out} - q_{L,j} = 0 \tag{13}$$

where P_G and P_L represent the generated and load power, respectively, while $q_{j,in}$ and $q_{j,out}$ are the gas flows entering and leaving node j.

The model ensures that supply meets demand across the integrated system through the following balancing equation:

$$\sum_z q_z + \sum_j q_j = D \tag{14}$$

where D represents the total demand for energy, integrating contributions from all technologies.

The framework adopts a steady-state formulation for both electricity and gas networks, omitting network losses to streamline the analysis between both layers of the framework and focus on strategic interactions and investments.

2.4 Solution Algorithm

The solution algorithm, illustrated in Figure 1, iteratively aligns long-term investment with short-term operational feasibility. The key steps of the algorithm are outlined as follows:

1. Initialise system parameters and variables for iteration i.
2. Run the long-term GTM model to determine the optimal energy mix $Q_{GTM(i)} = [q_1, q_2, ..., q_z]$ under strategic and complementary conditions.
3. Use $Q_{GTM(i)}$ as input to the OPGF model to determine short-term feasible operation $Q_{OPGF(i)}$ subject to technical constraints.
4. Check convergence of energy mixes:
$$|Q_{OPGF(i+1)} - Q_{OPGF(i)}| < \varepsilon \tag{15}$$
5. If convergence is not met, update the GTM with OPGF outputs (capacity feedback) and repeat.
6. Upon convergence, calculate final metrics including supply, demand, costs, and emissions.

This approach ensures that long-term planning is iteratively adjusted to reflect short-term operational realities, using capacity alignment rather than cost-based convergence.

3 Case Study

The modelling framework employed in this paper represents the GB energy system as an interconnected multi-vector system, illustrated in Figure 3. This energy system integration approach captures the synergies and interactions between the electricity, natural gas, hydrogen networks. The data used to construct the model are available at: https://github.com/MohamedAbuella/GB_IES. The electricity network is supplied by conventional generation (e.g., nuclear), renewable energy sources (RES) such as wind and solar PV, and gas-fired power plants, potentially equipped with carbon capture and storage (Gas+CCS). Flexibility is provided by energy storage systems, including battery energy storage systems (BESS) and pumped hydropower stations (PHS).

The gas network, supplied by gas providers, meets direct gas demand and fuels gas-fired power generation. It also serves as a primary feedstock for hydrogen production via reforming technologies.

3.1 System Description

A key focus of this paper is the comprehensive integration of hydrogen as a flexible energy vector in the GB's energy system. The hydrogen network interfaces with the electricity network through multiple components:

- Hydrogen Production: The model incorporates diverse hydrogen production pathways:
  1) Green Hydrogen: Produced via electrolysis (Electrolyser), utilising electricity primarily from

RES or surplus grid power. This Power-to-Gas (P2G) route links the electricity and hydrogen networks.

2) Blue Hydrogen: Generated from natural gas using Auto Thermal Reformers coupled with Carbon Capture and Storage technology (ATR+CCS). This Gas-to-Gas (G2G) process utilises the existing gas infrastructure while mitigating associated CO_2 emissions.

Bio-energy Hydrogen: Produced through Biomass Gasification with Carbon Capture and Storage (BECCS), offering a potential negative emissions pathway by using biomass feedstock (implicitly linked via gas or dedicated supply).

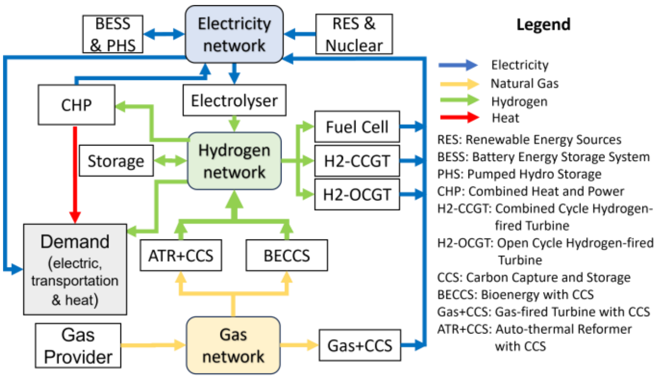
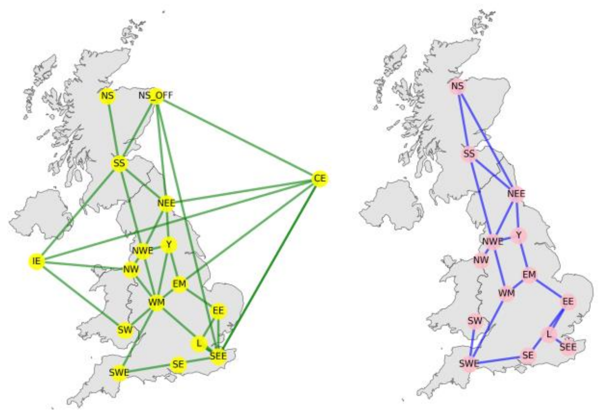


Figure 2 Integrated multi-vector energy system framework for GB, illustrating the coupling between electricity, gas, hydrogen networks, including various generation, conversion, and storage technologies.



(a) (b)

Figure 3 GB's energy system networks: (a) electricity network, (b) gas and hydrogen network.

- Hydrogen Storage: Dedicated hydrogen storage facilities (Storage) are included to buffer supply and demand mismatches, enhancing system flexibility and resilience.
- Hydrogen Utilisation: Stored or directly produced hydrogen can be utilised in several ways:
  1) Power Generation (Gas-to-Power, G2P): Hydrogen can be converted back to electricity using Fuel Cells, hydrogen-fired Combined Cycle Gas Turbines (H2-CCGT), or hydrogen-fired Open Cycle Gas Turbines (H2-OCGT), feeding power into the electricity network.
  2) Heating: The hydrogen network can supply energy to the heat demand, potentially through hydrogen boilers or combined heat and power (CHP) units.
  3) Direct Demand: Hydrogen can directly meet end-user demand in sectors such as transport and industry.

Finally, the model accounts for thermal energy provision, which may be supplied by hydrogen, electricity (e.g., heat pumps), or other sources, to meet heating demands.

The overall system model optimises investment and operation across these interconnected vectors to achieve decarbonisation objectives under technical and economic constraints.

3.2 Simulation

The simulation framework developed in this paper is designed to assess optimal decarbonisation strategies for GB's energy system, focusing specifically on the energy generation mix for peak demand in 2050. The simulations reflect system operation during a representative peak demand rather than a full day. This choice highlights strategic interactions, particularly for storage technologies, which would otherwise be masked by diurnal averaging, and provides an indication of infrastructure needs under maximum system stress.

Several key scenarios are considered to evaluate the potential impacts of various factors on the energy system, with a particular emphasis on hydrogen integration, as summarised in Table 1. The table outlines the assumed installed capacities for 2050 relative to the 2025 baseline across all scenarios. These scenarios reflect differing levels of renewable energy deployment alongside storage and hydrogen technologies in pursuit of decarbonisation targets. Specifically, the four investment scenarios are as follows: (i) a balanced capacity allocation across technologies (Uniform +25GW/Tech); (ii) high investment in renewables, BESS, and hydrogen infrastructure (High RES – High H_2); (iii) high investment in renewables and BESS with limited hydrogen deployment (High RES – Low H_2); and (iv) high investment in renewables and hydrogen with limited BESS deployment (High H_2 – Low BESS). These scenarios provide a foundation for analysing how alternative investment and planning pathways could influence system costs and emissions in the GB's energy system.

Table 1: Installed capacity settings for different investment scenarios in 2050, with 2025 baseline capacities. All values are in GW

Technology	2025	Scenarios for peak demand in 2050			
		Uniform +25 GW/Tech.	High RES–High H_2	High RES–Low H_2	High H_2–Low BESS
Nuclear	6.8	31.8	25	25	25
Wind (offshore, onshore)	31	81	100	100	150
Solar (PV)	17	42	70	70	150
BESS	3	28	60	60	10
Others	>25	>25	>25	>25	>25
G2P (H2-CCGT)	0	25	10	0.5	25
G2P (H2-OCGT)	0	25	10	0.5	25
G2P (Fuel Cell)	0	25	10	0.5	25
P2G (Electrolyser)	0.5	25.5	20	0.5	25
G2G (ATR+CCS, BECCS)	0	25	15	0.5	25

Table 2: Simulation results for 2050 peak demand under different capacity allocation scenarios. The electric peak demand is 102.17GWh, while hydrogen peak demand=14.27 GWh.

Metric	Uniform +25GW/Tech.	High RES–High H_2	High RES–Low H_2	High H_2–Low BESS
Total Demand [GWh]	152.51	158.1	117.75	182.75
Electric Demand [GWh]	119.2	136.22	103.1	149.44
Hydrogen Demand [GWh]	33.31	21.88	14.65	33.31
Total Energy Supply [GWh]	152.51	158.1	117.75	182.75
Total Operational Cost [£ million]	6.64	3.61	2.05	4.76
Total CO_2 Emissions [Tonnes CO_2 eq]	734	0	0	0
G2P / Elec. Peak Demand (%)	13.46%	5.38%	0.27%	13.02%
Utilisation of Wind & Solar = Allocated / Installed (%)	45.15%	64.82%	48.41%	43.22%

4 Results and Discussion

In this paper, the developed framework is applied to explore optimal allocations and analyse the strategic interactions within the energy sector. Figures 4–7 present the results of our framework simulation, which optimises the energy mix to meet peak demand in 2050 under four distinct investment scenarios, as shown in Table 1. Except for the Uniform +25 GW/Tech scenario, the installed capacities in each scenario are designed to reflect the most technically and economically feasible allocations to achieve the net-zero target by 2050.

Figure 4 illustrates that, in addition to a hydrogen demand of 14.27 GWh, a high dispatch from G2P (14 GWh) further increases hydrogen requirements. Although the G2G output reaches 11 GWh, the limited P2G dispatch results in hydrogen storage accumulating to 22 GWh to compensate. Meanwhile, Figure 6 depicts a scenario in which hydrogen storage is fully utilised to meet demand. In contrast, Figure 5 shows that when P2G output is high (16 GWh), leading to a lower level of hydrogen storage. In this case, the BESS level is also relatively low, at approximately 3 GWh.

Figure 7 illustrates a scenario in which battery storage is limited, thereby highlighting the vital role of hydrogen technologies as an alternative flexibility solution. In this case, hydrogen-based multi-vector units exhibit high levels of dispatch, with P2G reaching 20 GWh, G2P at 13 GWh, and G2G with CCS providing 10 GWh. This demonstrates how hydrogen can effectively compensate for constrained BESS capacity by offering both energy storage and dispatchable generation.

As the framework does not prioritise high capital investments, nuclear allocation was not favoured among the energy mix across the four scenarios.

Table 2 provides a comparative analysis of the outcomes from the framework across various scenarios and generation configurations for Great Britain's energy system in 2050.

As shown in Table 1, the High RES High H2 and High RES Low H2 scenarios have the same installed wind and solar capacity (170 GW) but represent cases with higher and lower hydrogen infrastructure capacity. Therefore, as presented in Table 2, the High RES–High H2 scenario achieves the highest renewable utilisation at 64.82% (i.e., 110.19 GW out of 170 GW), indicating reduced curtailment enabled by hydrogen production. Additionally, Table 2 shows that the High H2–Low BESS scenario supplies 13.02% of electric peak demand (i.e., 13.32 GWh from G2P to electric peak demand of 102.17 GWh), as illustrated in Figure 7. This highlights hydrogen's role in supporting system security.

The High H2–Low BESS scenario results in the highest total and electric demand, indicating a significantly increased load on the system, particularly from electrolysers (P2G), as shown in Figure 7. The scale of required energy generation highlights the need for major infrastructure investments.

The High RES–Low H2 scenario achieves the lowest operational cost (£2.05 million), reflecting reduced reliance on energy-intensive hydrogen production (P2G, G2G). In contrast, the High RES–High H2 scenario incurs a higher cost (£3.64 million), driven by hydrogen infrastructure operations (P2G, G2P and G2G+CCS). All scenarios achieve zero CO_2 emissions compared to the Uniform +25GW/Tech scenario (734 tonnes CO2 equivalent), which serves as a baseline scenario. This highlights the environmental benefit of high renewable and storage penetration.

The results show that strategic competition and varying infrastructure allocations can lead to significant differences in system operation: total operational costs range from £2.05 million in the High H_2–Low BESS to £6.64 million in Uniform +25GW/Tech scenario, while hydrogen dispatch varies from 0.5 GWh to over 33 GWh depending on P2G capacity and BESS availability.

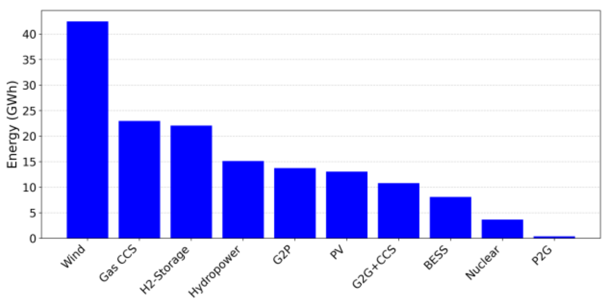


Figure 4 Simulated energy mix for 2050 peak demand under a balanced scenario with uniform 25GW allocated to each technology.

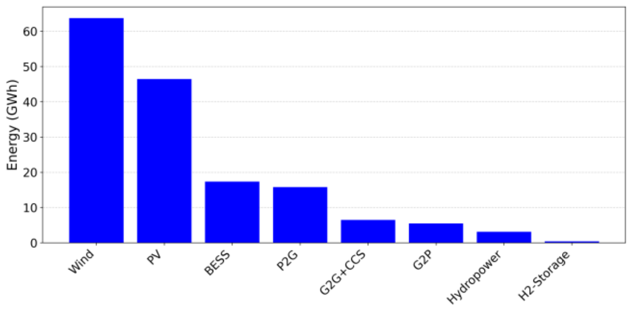


Figure 5 Energy mix for 2050 peak demand under a high-capacity investment scenario for renewables, BESS, and hydrogen infrastructure.

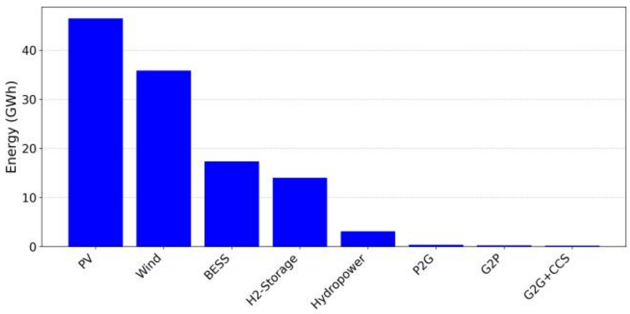


Figure 6 Energy mix for 2050 peak demand under high renewables and BESS deployment, with limited hydrogen capacity.

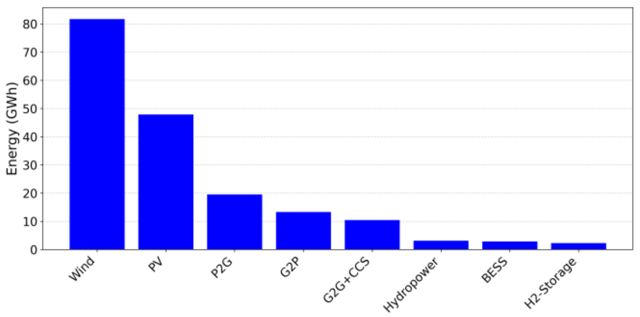


Figure 7 Energy mix for 2050 peak demand under high hydrogen with limited BESS capacity.

5 Conclusion

This paper presents a robust bi-level optimisation framework that integrates a long-term game-theoretic planning with a short-term operational power and gas flow, offering insights into decarbonised energy pathways.

Analysis of multiple scenarios demonstrates that hydrogen, through its multi-vector coupling units (P2G, G2G, G2P), can supply up to 13.02% of electric peak demand, significantly enhancing system flexibility and security by reducing renewable curtailment, achieving up to 64.82% renewable utilisation, and compensating for limited battery storage capacity. Hydrogen dispatch varies widely (0.5–33 GWh), reflecting its adaptability under different infrastructure allocations. Operational costs range from £2.05 million in low-hydrogen scenario to £6.64 million in high-hydrogen scenario. While hydrogen offers clear technical advantages as a flexibility vector, hydrogen feasibility remains the primary challenge, highlighting the necessity for policy support, such as subsidising electrolysers to boost green hydrogen.

These findings highlight the complex trade-offs between operational costs, infrastructure scale, and emission reductions, emphasising the need for integrated, policy-driven planning to optimise the energy mix, enhance system flexibility, and effectively meet decarbonisation goals.

Future research will extend this work by exploring a cooperative game-theoretic framework for generation expansion planning. By modelling coalition-based strategies, where players collaborate to optimise generation and storage investments, this approach could improve system efficiency, equity in resource allocation, and resilience, especially in hydrogen-intensive scenarios. A cooperative perspective would complement the competitive dynamics analysed in this study, offering a more comprehensive view of strategic planning for decarbonised energy systems.

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