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The Role and Value of Hydrogen in Future Zero-Carbon Great Britain's Energy System

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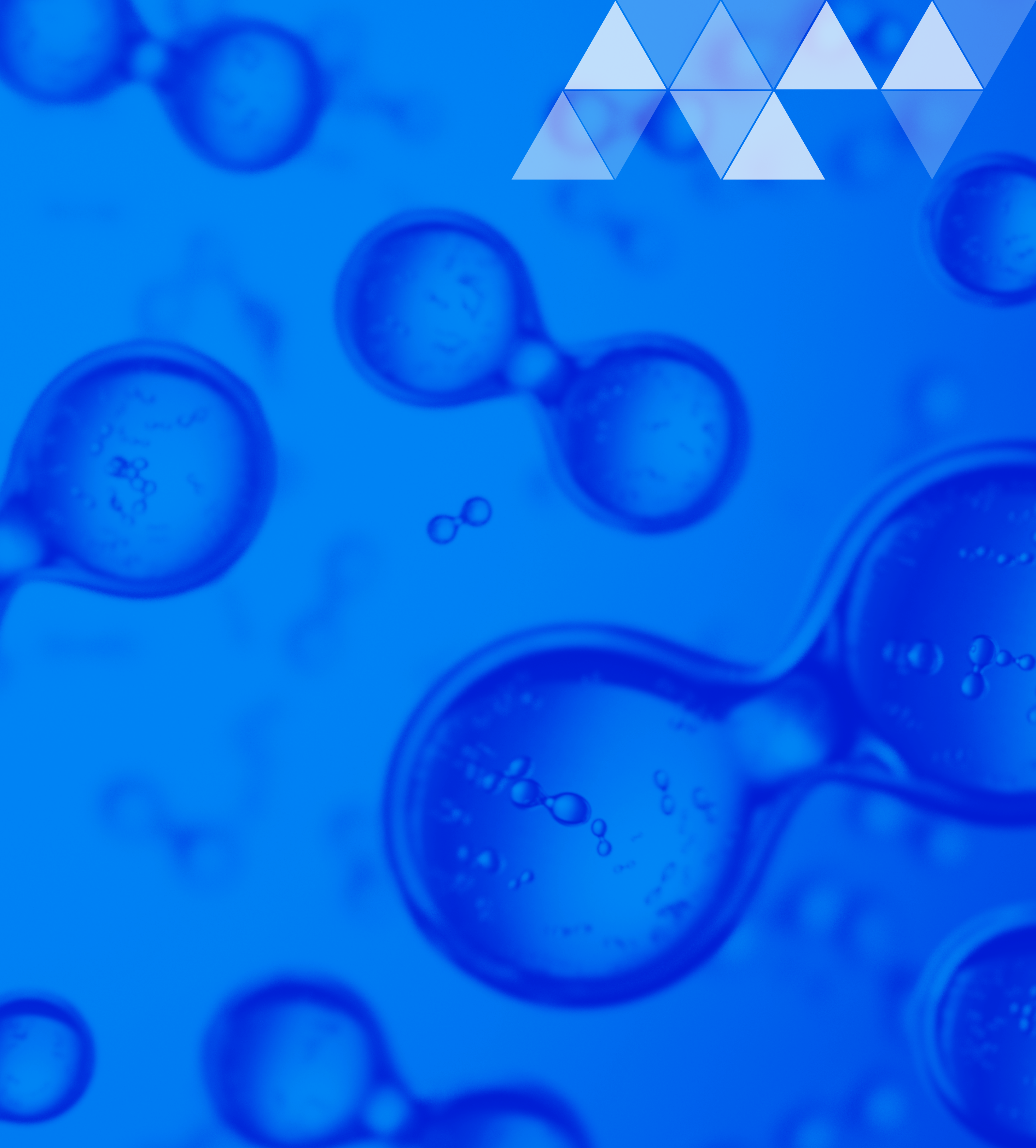

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Executive Summary

Context

Achieving the UK's long-term climate targets 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 key 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 of hydrogen's scale, applications, and economics and how hydrogen should be integrated to support cost-effective decarbonisation and energy system security.

Many studies have been related to the system benefits of hydrogen; however, many analyses consider 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, this analysis re-evaluates the value of hydrogen holistically by conducting a series of whole-system studies to provide fundamental and robust evidence about hydrogen's role and system benefits under different energy system scenarios.

How has the evidence been developed?

The analysis is based on detailed cost-minimisation of a 2050 energy system that meets the net-zero emissions target and resilience against extreme weather events, especially wind droughts during winter peaks and extreme cold conditions. Using sophisticated optimisation models of multi-energy systems (electricity, heat, hydrogen), we analyse the energy system portfolio to understand the hydrogen infrastructure capacity and operation needed for hydrogen production, transport and storage to meet demand under different scenarios. In the models, hydrogen technologies compete against other alternative technologies, and the optimisation models determine the least-cost solution. We analyse the hydrogen portfolio proposed by the models as part of the optimal solution.

Another critical question about hydrogen is its role in decarbonising heat. Many objections to hydrogen for heating are centred on heat pump applications offering higher energy efficiency and high cost of hydrogen. Therefore, we analyse the whole-system cost performance of two core scenarios: (i) the Hydrogen and (ii) the Heat Electrification pathways. The only difference between these scenarios is how gas-grid-connected customers' heat demand is decarbonised. The first scenario uses hydrogen boilers, and the second uses electric heating involving heat pumps and resistive heating. In addition, a range of sensitivity studies has been conducted to identify the sensitivity of the results from the core scenarios against different assumptions in the sensitivity scenarios from the whole-system perspective.

The key findings

Role of Hydrogen in Supporting Decarbonisation and Energy Security in a Net-Zero Energy System

In all scenarios, hydrogen plays a crucial role in energy decarbonisation, energy system balancing and providing energy security and resilience against extreme weather events. Hydrogen provides zero-carbon fuel for power generation, heating, transport, and industrial processes. Through the studies, we observe that hydrogen technologies have different roles:

- **Hydrogen power generation,** such as hydrogen Combined Cycle or Open Cycle Gas Turbines (CCGT or OCGT) and fuel cells, provides firm and dispatchable capacity, producing zero-carbon electricity, system balancing capability and reserve services. Hydrogen power generation improves energy resilience in coping with low renewable output and peak demand conditions.

- **Auto Thermal Reformers (ATR) with Carbon Capture and Storage (CCS)** produce blue hydrogen from efficient methane reforming processes with low residual carbon emissions (less than 5%). The production cost of blue hydrogen, depending on the natural gas prices, could be lower than that of green hydrogen. ATR with CCS also provides balancing and peaking capacity in the hydrogen supply system.

- **Electrolysers** produce hydrogen and enable lower-cost Renewable Energy Sources (RES) system integration by providing sector-coupling flexibility and ancillary services. It allows electricity to be converted to hydrogen to be stored efficiently or to supply hydrogen demand.

- **Hydrogen transmission and distribution** enable hydrogen to be transported from production sites to load centres. Hydrogen can also be stored in the pipeline; the hydrogen linepack provides intra-day flexibility to manage the challenges driven by renewable intermittency in the gas infrastructure. Flexibility from the hydrogen network should be operated in synergy with other flexibility technologies such as interconnectors, electricity storage and demand response technologies to support cost-efficient system operation and security.

- **Hydrogen storage** provides bulk energy storage with low losses, hydrogen supply capacity, and an alternative balancing source for the hydrogen system. Distributed hydrogen storage also helps manage the hydrogen pipeline operating pressures, managing the volume of hydrogen that can be delivered to meet demand. Whether harnessing excess green hydrogen produced during windy summer days or supporting the energy needs during cold winter days, hydrogen storage is the keystone for managing supply fluctuations. With the increasing integration of renewables and as the green hydrogen supply chain evolves, the role of hydrogen storage becomes even more critical in enhancing resilience.

- **Bio-energy with CCS (BECCS)** acts as a negative emission technology and provides a flexible option for biomass energy for electricity or hydrogen production.

- **Hydrogen boilers** act as zero-carbon heat appliances.

- **Hydrogen** is also a **zero-carbon fuel** for industrial processes and transport (ground, aviation, and shipping).

The studies demonstrate the cost-effective role of hydrogen as part of a holistic approach to improving resilience, energy decarbonisation and system flexibility. Hydrogen technologies should integrate and work in synergy with other low-carbon and smart technologies.

Hydrogen for heating is a viable option to decarbonise heat cost-effectively.

Although the overall efficiency of primary energy use in the Hydrogen pathway is 19% less[1] than that of Heat Electrification, the Hydrogen pathway costs **£5.4bn/year** less than the Heat Electrification pathway. *This study demonstrates that a system with higher energy efficiency will NOT always lead to a more cost-effective system.* The annual system costs of both pathways are shown in Figure E-1.

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 (including conversion cost)	**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

Figure E-1 Annual system costs of Hydrogen and Heat Electrification pathways

[1] *The efficiency calculation covers all energy demand including electricity, heat, and hydrogen.*

By comparing the cost figures of both pathways, the difference between the costs of the Hydrogen and Heat Electrification pathways can be identified and analysed. The results are shown in Figure E-2.

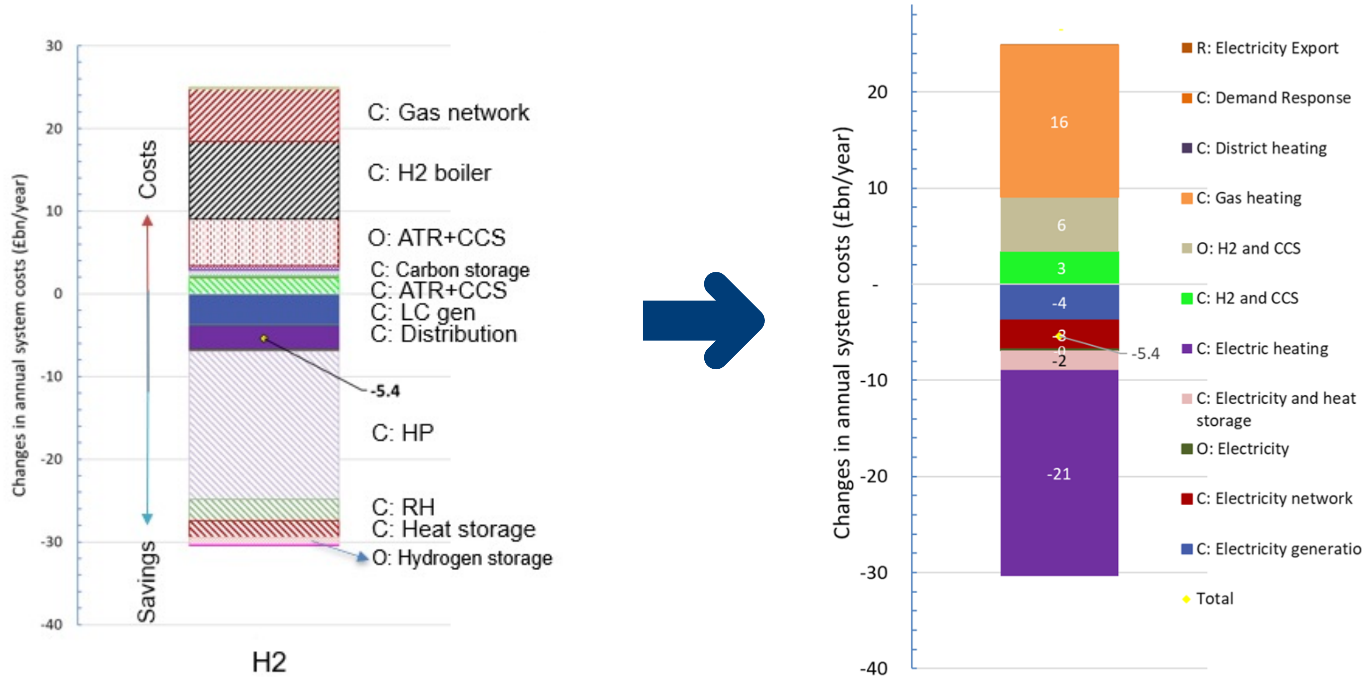


Figure E-2 Changes in annual system costs from Heat Electrification to Hydrogen pathway.

The savings obtained in the Hydrogen pathway are driven by several factors:

- The annuitised capital cost of hydrogen heating appliances is less than half that of heat pump systems. Even with the gas infrastructure costs, a gas heating system costs less than electric heating.
- Heat Electrification will lead to higher peak electricity demand and require greater energy infrastructure capacity, such as electricity distribution (Figure E-3), firm low-carbon generation capacity (Figure E-4), and energy storage, to be built for security purposes, mainly operating during peak times or when RES output is low.

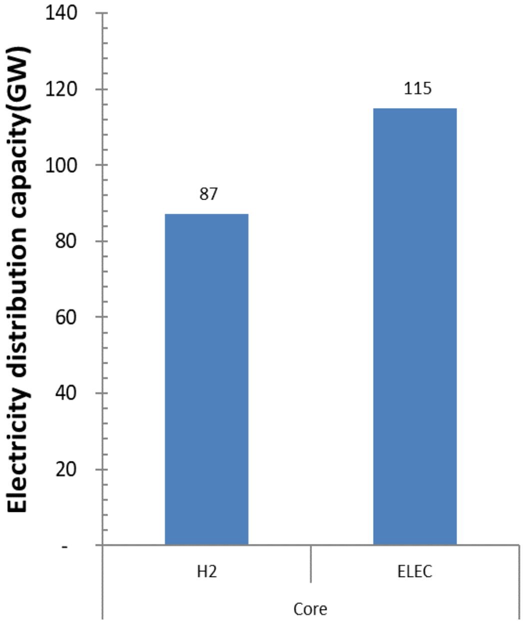
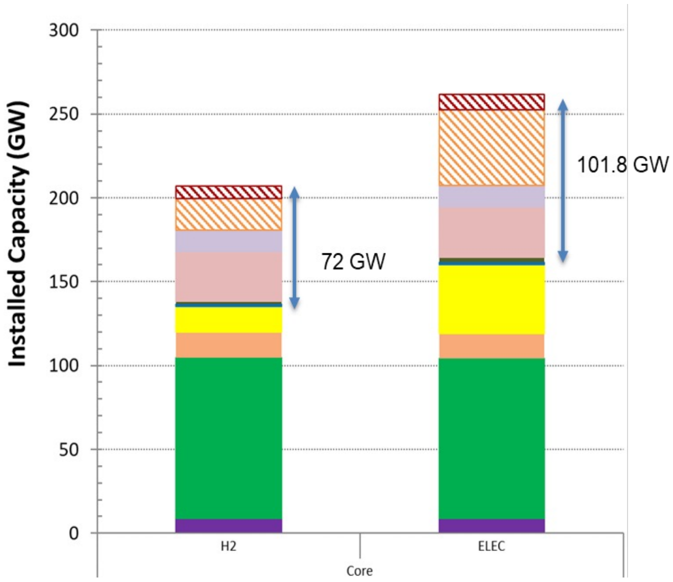


Figure E-3 Electricity distribution capacity of Hydrogen and Heat Electrification pathways

Figure E-3 shows that the Heat Electrification pathway will result in 28 GW more peak demand on the distribution network. Around 30 GW more hydrogen power capacity (Figure E-4) must be built to secure electricity supply during peaks and extreme weather events such as prolonged wind droughts during winter peaks.

Figure E-4 Optimal power generation portfolio in Hydrogen (H2) and Heat Electrification (ELEC) pathways



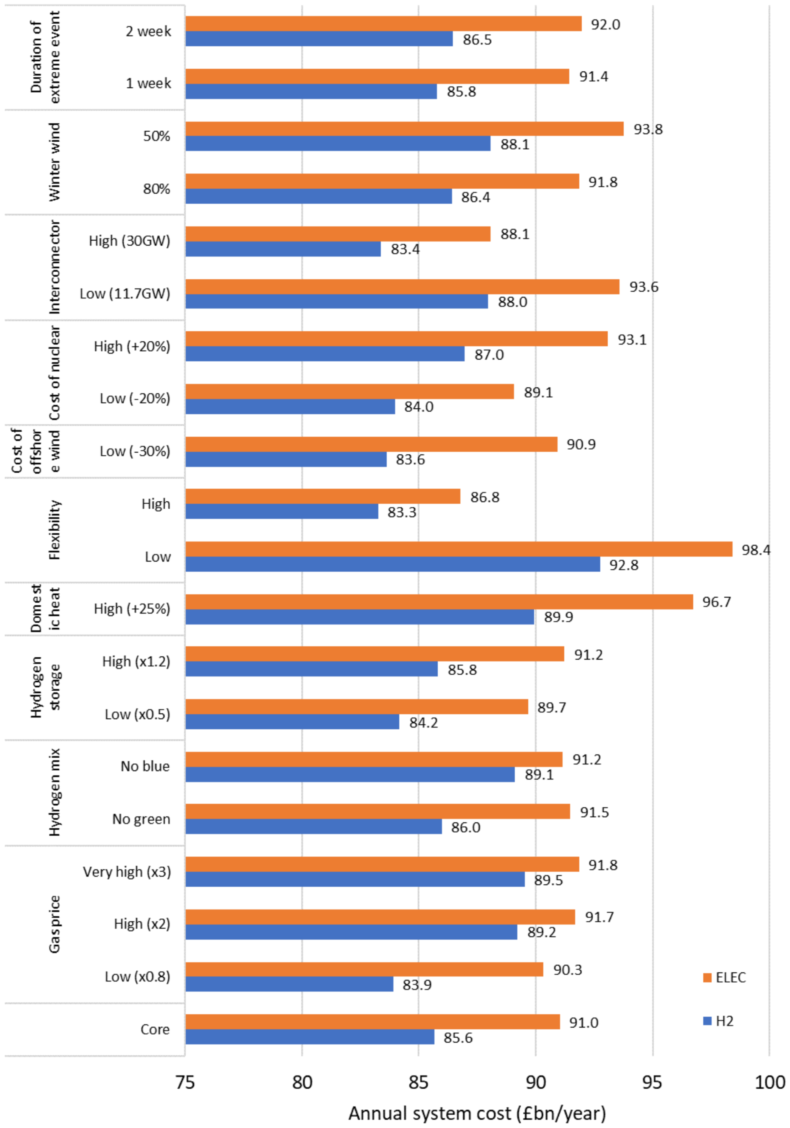
- There is a synergy for hydrogen assets supporting resilience, flexibility, and decarbonisation. The hydrogen system cost can be minimised by optimising hydrogen production technologies (reforming processes, electrolysis and biomass gasification) and other hydrogen assets, such as network and storage while optimising the power generation portfolio.
- Heat Electrification requires more flexibility and heat storage. Shifting demand and storing energy may increase energy losses.

Sensitivity studies on the economics of hydrogen

A range of sensitivity studies has been conducted to analyse the impacts of different assumptions of gas prices, hydrogen mix, cost of hydrogen storage, offshore wind and nuclear, system flexibility and interconnection capacity and also longer wind drought events on the conclusions that we derive from analysing the core (Hydrogen and Heat Electrification) scenarios. The studies identify the four key drivers for increased costs in the Hydrogen pathway: *high gas prices, low system flexibility, and high domestic heat demand due to less energy efficiency improvement.* However, the studies demonstrate that:

- The Hydrogen pathway can save **£2-7.3bn/year** compared with the Heat Electrification pathway across all scenarios considered in this study, as shown in Figure E-5.

Figure E-5 Changes in annual system costs from Heat Electrification to Hydrogen pathway.



- Even extreme gas prices do not make the Hydrogen pathway less cost-effective overall. Higher gas prices will shift hydrogen production from methane reforming processes to electrolysis. It will increase the cost of the Hydrogen pathway, but it can be limited by using an optimal portfolio of low-carbon power generation considering nuclear, RES, and gas CCS. Higher penetration of RES will increase its system integration cost, and at a certain point, this will encourage other low-carbon technologies to contribute more, capping the green hydrogen production cost. If the natural gas price is more than £70/MWh, the model will no longer use natural gas, so there is no further impact.

- Improving system flexibility through deploying demand response, energy storage technologies, and electricity interconnection between Great Britain and Europe is essential for both pathways as it is the most sensitive factor for overall 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.

- Reducing the annual and peak energy consumption through improving energy efficiency is important in all scenarios.

Increased duration of extreme weather events is not a significant issue if the system has sufficient firm low-carbon capacity from gas CCS, hydrogen, and nuclear power generation. The hydrogen production from ATR+CCS can be increased to support increased hydrogen demand due to prolonged low-wind conditions with a modest impact on the capacity requirement. Hydrogen storage and RES capacity can be increased as an alternative option if green hydrogen is preferred.

Sensitivity studies on hydrogen deliverability

Sensitivity studies have also been performed to u nderstand the hydrogen deliverability and the impacts on hydrogen network operations in different energy system scenarios, including a system with a high level of flexibility, high gas prices, different hydrogen production mixes, and the cost of hydrogen storage technologies, among others:

- The flexibility of an energy system, shaped by factors such as interconnection, electricity storage, and demand side response (DSR), significantly influences the degree of linepack swings. In scenarios where electricity-related flexibilities are limited, linepack swings tend to be more pronounced, particularly in the Heat Electrification pathway (24.2 mcm/day more compared to the Core scenario). This increased reliance on linepack flexibility to accommodate challenges from renewable energy sources underscores the importance of managing the linepack variability within the broader energy system.

- Low hydrogen storage cost facilitates more renewable energy sources into the overall energy system. As renewables increase, their inherent intermittency is shifted to the gas network, requiring more linepack flexibility. This effect is particularly pronounced in the Heat Electrification pathway, where more significant green hydrogen injection into the gas infrastructure results in a swing of up to 13.8 mcm/day (compared to the Core scenario) to ensure supply security.

- In the lower cost wind sensitivity, the investment in hydrogen compression can be reduced (up to 42% less in the supply and 10% less in the infrastructure), given the direct gas network compatibility of green hydrogen through PEM electrolysers as well as the broader distribution of electrolysers compared to fixed locations of ATR+CCS plants, which are built close to natural gas terminals.

- Hydrogen compression demand increases in the Heat Electrification pathway and the higher natural gas price sensitivity. This increase is attributed to the greater reliance on hydrogen-based CCGTs (H2-CCGTs) due to the increased costs of operating gas CCS plants. Despite the reduction in blue hydrogen production, the system sufficiently meets its needs through green hydrogen, primarily because the hydrogen demand is relatively low. However, the increased hydrogen demand for power generation necessitates a more extensive supply from BECCS, resulting in an 11% increase in the requirement for electricity to compress the hydrogen produced via BECCS. In contrast, in the Hydrogen pathway, the demand for electricity in hydrogen compression decreases by up to 45%. This reduction is driven by the reduced reliance on costly blue hydrogen production, which plays a substantial role in hydrogen supply in the Core scenario, as the system shifts its focus towards the increased utilisation of green hydrogen.

- In line with expectations, a similar trend to high natural gas prices emerges in the "No Blue" scenario, where blue hydrogen production is unavailable. This results in a 12% increase in the electricity needed for hydrogen compression in the Heat Electrification pathway and a 45% reduction in the Hydrogen pathway. Conversely, in the No Green scenario, marked by increased hydrogen supply through methods like ATR+CCS and BECCS, there is a significant 10% increase in electricity demand for hydrogen compression compared to the Core scenario.

- Reducing hydrogen storage costs by half can increase investments in storage facilities, boosting the gas system's flexibility to supply more hydrogen to hydrogen-based power plants. However, the system needs to weigh these storage savings against the financial impacts of increased blue hydrogen compression to maintain an efficient gas network operation.

- In temporary energy source shortages, i.e., the conditions that happen more frequently when blue hydrogen is unavailable or when nuclear power costs rise, the system relies more on linepack to support the system (up to 32 GWh/day energy supply). It acts as the buffer, underscoring the delicate interplay between various energy sources, keeping the supply and demand in harmony and ensuring system resilience.

- Both linepack and hydrogen storage are crucial components in the integrated operation of electricity and hydrogen systems. As evident during various scenarios, from wind energy affordability to limited electricity flexibility, their interplay helps to stabilise the system and ensures a consistent hydrogen supply.

In all sensitivity scenarios, the transportation of hydrogen within the existing infrastructure is made possible by various factors:

- The optimal allocation of green hydrogen supply sources to decrease the distance between supply and demand ensures seamless integration of hydrogen into the infrastructure..

- Optimal investments in hydrogen compression capabilities are crucial in facilitating hydrogen transportation, ensuring its availability when and where needed.

- The optimal allocation of distributed hydrogen storage facilities to bypass long-distance transport further enhances the infrastructure's ability to store and transport hydrogen efficiently.

- Linepack's capacity to provide intra-day flexibility to deal with the intermittencies adds another layer of adaptability to the system, enabling hydrogen transport within the gas infrastructure.

Key challenges

There are some challenges observed from the results of the studies; these are summarised here:

- The volume of energy and carbon infrastructure scale to be built within the next 30 years is high. Scaling up all infrastructure development and repurposing the existing gas infrastructure will be challenging. In the Hydrogen pathway, the distribution of infrastructure development is more balanced between electricity and hydrogen, providing more diversity in technology development, while the Heat Electrification pathway focuses more on the electricity sector. Both pathways will require substantial capacity for manufacturing, installing, operating, and maintaining all the assets. A sufficient workforce with appropriate skills must be developed.

- Many new technologies, such as hydrogen applications for heating, power, storage, industrial processes, transport, and hydrogen production technologies, are not yet mature.

- Both the Hydrogen and Heat Electrification pathways require CCS infrastructure, which does not exist in Great Britain today, to be deployed at scale to achieve net zero cost-effectively. The Hydrogen pathway requires more CCS infrastructure than Heat Electrification.

- The planning and operation across different energy sectors become more strongly coupled in all scenarios. Therefore, it requires a holistic approach to optimise the investment and operating decisions of the whole energy system. The planned transformation of the Electricity System Operator (ESO) to the Future System Operator (FSO) provides evidence that this issue has been recognised and the policy action is in the right direction.

- The future system with high renewables increases operational challenges for the NTS as the studies reveal that high swings in daily linepack (39% and 83% more compared to November 2021[2] in Heat Electrification and Hydrogen pathways, respectively) can happen to maintain the supply-demand balance (Figure E-6).

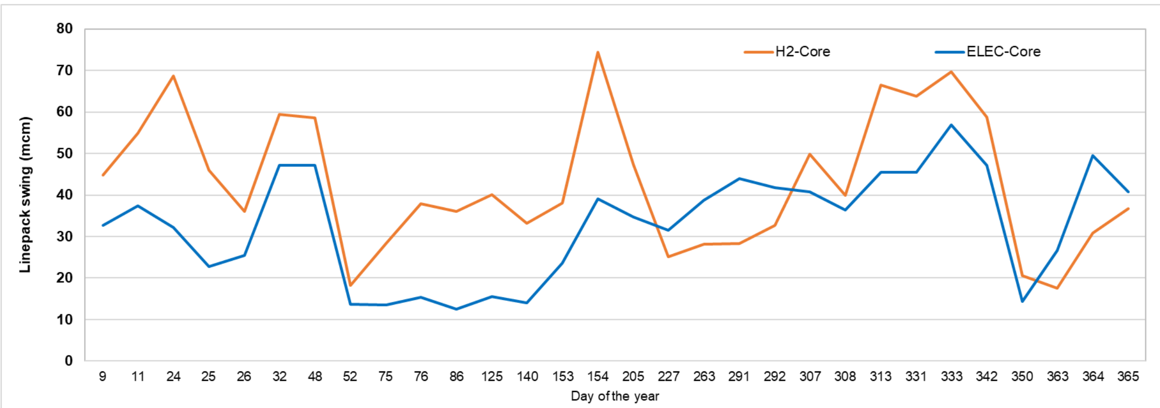


Figure E-6 Linepack swing during the year in Heat Electrification and Hydrogen pathways

[2] The NTS has recently experienced some days with significant swings in linepack. In November 2021 the NTS saw swings of ~41mcm over the course of the gas day (National Grid Gas Transmission (March 2022). GMaP: GB Gas Balancing Regime Review final report)

The linepack swing in the Hydrogen pathway is generally more significant than in the other pathway. This is mainly because the hydrogen must be supplied on time to meet heat demand, leading to significant linepack swings (maximum swing 74.4 mcm/day). In contrast, given that there is no hydrogen demand for heating in the Heat Electrification pathway, the system experiences less stress, and rapid fluctuations in linepack are less likely to occur. Consequently, the linepack swings in the Heat Electrification pathway are smaller (maximum swing 56.8 mcm/day), highlighting a more stable operation within this pathway. To deal with these large swings in the system operation, the primary strategy would rely on distributing hydrogen reserves throughout the system, consistently maintaining pressure standards, and proactively overseeing compressors to prevent shutdowns. Any unplanned outages could lead to potential systemic complications.

Policy recommendations

Based on the studies being conducted, the analyses and the discussions with relevant stakeholders, some policy recommendations are made and listed as follows:

- Review the approach to measure energy system resilience and security standards considering the integration of hydrogen technologies into the future system;
- Ensure that the current high levels of hydrogen production development commitment match hydrogen storage and network infrastructure development. Other supporting infrastructure, such as CCS infrastructure, should also be facilitated.
- Provide sufficient funding and incentives to speed up research, development and deployment of innovative hydrogen technologies;
- Establish a level playing field and fair market competition for all types of hydrogen technologies, including hydrogen from different energy sources (gas, electricity, biomass) and hydrogen for heating;
- Support demonstration of medium and large-scale innovative hydrogen projects;
- Provide a clear roadmap for hydrogen integration to support the transition and as part of the enduring solution for net-zero and sustainable energy systems;
- Develop appropriate hydrogen regulatory and market framework to ensure that the whole-system value of hydrogen technologies can be quantified and commercially remunerated via markets.
- Establish a coordination structure across all relevant energy system stakeholders to develop integrated strategies to improve energy system resilience and decarbonisation while ensuring optimal development and operation of the whole energy system across different energy vectors, including electricity, hydrogen and heating.

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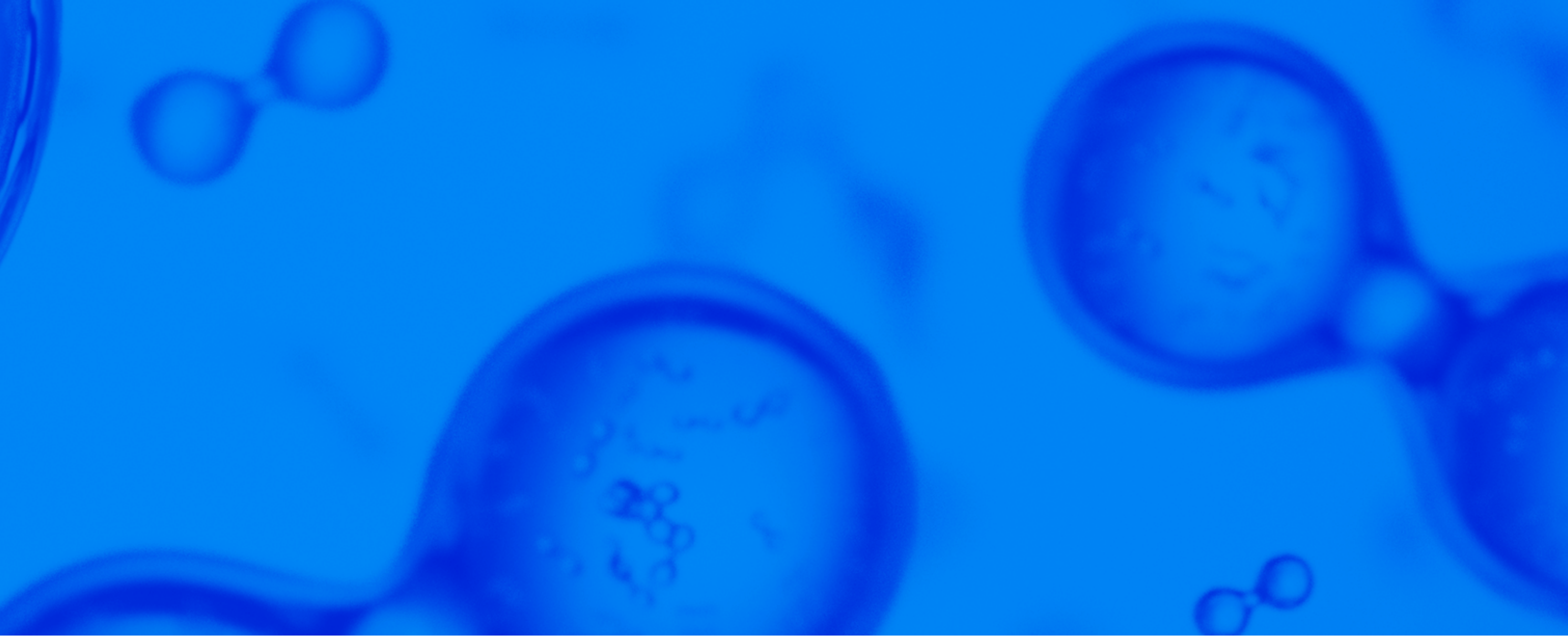


Abbreviation

ATR	Auto Thermal Reformer that produces hydrogen from natural gas
BECCS	Bioenergy plants with CCS. BECCS produces hydrogen or power
BEIS	Department for Business, Energy and Industrial Strategy
CCC	Committee on Climate Change (CCC)
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture, Utilisation and Storage, also called CCS
CE	Continental Europe
DACCS	Direct Air Carbon Capture and Storage
DNO	Distribution Network Operators
DSR	Demand Side Response
DH	District heating
ELEC	Heat Electrification pathway
EV	Electric Vehicle
Gas CCS	Gas-fired power generation with CCS
GB	Great Britain
H2	Hydrogen pathway
H2-CCGT	Hydrogen-based CCGTs
HGV	Heavy Good Vehicles
HP	Heat Pumps
IE	Ireland
IWES	Integrated Whole Energy System model
LCoE	Levelised cost of electricity
OCGT	Open Cycle Gas Turbine
OSW	Offshore Wind farms
PV	Photovoltaic
Reformer	Methane reformer (Auto Thermal) with CCS
RH	Resistive Heating
SA	Smart Appliances
UK	United Kingdom
WSHP	Water Source Heat Pump

Chapter 1. Introduction

1.1 Context

Achieving the United Kingdom's (UK) long-term climate targets will require *an integrated electricity, transport and heat decarbonisation strategy.* While transport accounted for 27% of UK emissions in 2020, heat in buildings and the industrial sector accounts for more than half of the UK's energy consumption and contributes to around a third of the total carbon emissions[3]. Defining heat decarbonisation scenarios simultaneously with electricity and transport decarbonisation will require a clear and holistic strategy for delivering the optimal portfolio of low-carbon electricity, gas and heat options based on an in-depth understanding of their techno-economic and environmental characteristics and integration with the broader energy system. The UK's decarbonisation strategy must be supported by sufficient and timely investment in low-carbon technologies like renewables, nuclear power, hydrogen, and bioenergy to displace fossil fuels gradually. Unabated power, reforming, and heating gas plants should be fitted with Carbon Capture, Utilisation, and Storage (CCUS) technologies. Moreover, Direct Air Carbon Capture and Storage (DACCS) can also help offset emissions from hard-to-decarbonise sectors to achieve net zero. All of these require optimal investment and operational coordination across multiple energy vectors, involving various energy storages and demand flexibility in parallel with improving system flexibility using innovative technologies.

Hydrogen as an energy vector has been on the periphery of energy policy discussions during the last two decades. Due to the UK's net-zero commitment for 2050 and the recent conflict between Russia and Ukraine, which created high energy price spikes and affected the affordability and security of energy supply in the UK, the potential role of hydrogen in supporting energy decarbonisation and resilience is becoming increasingly crucial. For instance, the Climate Change Committee (CCC) advises, "*Moving beyond an 80% target changes hydrogen from an option to an integral part of the strategy*"[4]. Hydrogen can support achieving the net-zero target through (i) decarbonising the heat supply, (ii) providing flexibility to the power system through electrolysers (i.e. to produce green hydrogen) and fuel cells (i.e., to generate carbon-free electricity), and (iii) facilitating the decarbonisation of industrial demand as one of the significant challenges in achieving the net-zero emission target.

[3] *Source: Department of Energy Security & Net Zero. 2022 UK Provisional Greenhouse Gas Emissions.*

[4] *Source: Climate Change Committee. Net Zero -The UK's Contribution to stopping global warming, 2 May 2019, p.181*

In terms of heat decarbonisation, *full electrification of heat using heat pumps may not be a sole perfect solution* due to:

1. the high investment cost of electric heating systems comprising heat pumps, resistive heating, and heat storage;

2. the requirement of new generation capacity and network reinforcement, driven by increased electricity peak demand;

3. increased resilience challenges in the system with high penetration of Renewable Energy Sources (RES) due to extreme weather events;

4. the limited flexibility of electric storage in large volumes.

In this context, as our analysis demonstrates, the employment of hydrogen in decarbonising energy systems, including heat to deliver a net-zero 2050 system, could provide up to **£5.4bn/year** savings by 2050 in annual system costs compared to a full electrification pathway.

Strong integration between hydrogen and electricity systems can also enhance flexibility. Excess electricity from RES can be converted into hydrogen, stored in bulk, or used to supply hydrogen demand. Gas decarbonisation with hydrogen may also enable large quantities of energy to be stored across the seasons cost-effectively, significantly reducing the system integration cost of variable renewable sources, expected to supply more than 75% of future demand. When needed, e.g., when RES output is low, hydrogen can generate zero-carbon electricity, supporting energy resilience and supply reliability.

In a net-zero/low-carbon energy system dominated by intermittent RES, the impact of extreme weather on energy security becomes more critical. Due to the variation of RES availability over time, there may be periods with prolonged low output (up to a few weeks) during cold-spell conditions (peak demand periods). These adverse events could lead to energy supply scarcity if not anticipated and planned for beforehand. To manage this risk and enhance system resilience, a significant volume of energy must be stored (e.g., the production of green hydrogen to be injected into the gas infrastructure or stored in storage facilities). The employment of hydrogen could also effectively enable trade and storage of renewable sources between different regions to overcome seasonal differences between supply and demand.

It is important to highlight that the benefits of hydrogen can only be realised when the whole energy system is considered, and hydrogen is efficiently integrated with the other energy vectors. Therefore, it is vital to maximise the synergies across different energy vectors (e.g., electricity, gas/hydrogen, and heat) and build flexibility and optionality into energy dispatch and supply by developing a resiliency-oriented multi-vector energy system operation mode. When hydrogen is deployed alongside electricity infrastructure, electricity can be converted to hydrogen and back or further converted to other fuels, making end users less dependent on specific energy resources and increasing the resilience of energy supplies. In this context, whole-energy system modelling is essential for capturing the complexities of different energy sub-systems and specific features of emerging energy conversion and storage technologies (e.g., fuel cells, electrolysers) that link energy vectors and provide flexibility. Analysing multi-vector energy systems at sufficiently detailed temporal and spatial granularity will be essential for assessing resilience in future net-zero energy systems.

1.2 What have previous studies said about the role of hydrogen?

The role of hydrogen in the future has been widely discussed in recent years as global efforts to combat climate change and transition towards sustainable energy sources continue to intensify. 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 (IEA, 2021; UK Parliament, 2022).

One of the primary aspects that previous studies have addressed is hydrogen's potential as an energy storage medium, particularly with the increasing penetration of renewable energy sources (RES) into power grids (IRENA, 2019; Yue et al., 2020). The intermittent nature of RES, including solar and wind power, necessitates energy storage solutions that can effectively manage supply and demand fluctuations over short and longer durations. Hydrogen, produced through electrolysis using excess RES, has been identified as a promising solution for long-term, large-scale storage applications (Kharel et al., 2018; Hydrogen Council, 2017). In this context, hydrogen can help mitigate the challenges associated with RES integration and contribute to grid stability (Maestre et al., 2021).

Another area of focus has been hydrogen's role in the transportation sector. Previous studies have highlighted the potential of hydrogen as a fuel source for various types of vehicles, including passenger cars, buses, and heavy-duty trucks (de las Nieves Camacho et al., 2022; Ajanovic et al., 2018). Hydrogen fuel cells have been suggested as an alternative to battery electric vehicles, particularly for applications requiring longer driving ranges, faster refuelling times, and heavier payloads (Li et al., 2022). As hydrogen production and fuel cell technologies continue to advance, these studies suggest that hydrogen could play a crucial role in the decarbonisation of the transportation sector.

The potential of hydrogen to contribute to the decarbonisation of industrial processes has also been investigated in the literature (Griffiths et al., 2021; Kazi et al., 2021). Many energy-intensive industries, such as steel and cement production, are responsible for a significant share of global greenhouse gas emissions. These industries are difficult to decarbonise using conventional methods due to process emissions, high-energy demands, economic constraints, lack of suitable green alternatives, and existing infrastructure limitations. Hydrogen, produced through low-carbon or carbon-free methods, has been identified as a potential solution for reducing emissions in these sectors by replacing fossil fuels as an energy source (IEA, 2021). Moreover, hydrogen has the potential to act as a feedstock in various industrial processes, further reducing the carbon footprint of such industries (Nicita et al., 2020).

While hydrogen's potential is evident, the literature acknowledges several challenges and barriers to its widespread adoption. These include high production costs, the need for extensive infrastructure development, and concerns regarding the efficiency and safety of hydrogen systems (IEA, 2021). Additionally, the current hydrogen production process predominantly relies on fossil fuels, raising questions about its environmental sustainability (Weidner et al., 2023). To address these challenges, the previous studies emphasise the importance of continued research and development, government support, and international collaboration in facilitating the transition to a hydrogen-based economy.

Another aspect investigated in the previous studies is related to hydrogen's inherent safety and health concerns associated with its production, storage, transportation, and utilisation. One of the primary safety concerns with hydrogen is its flammability, as it can form explosive mixtures with air in a wide range of concentrations (5% to 75% by volume) (Yang et al., 2021).

Addressing the challenges associated with hydrogen-based energy carriers, such as flammability, toxicity, storage, and consumption, necessitates the development of innovative devices and techniques that can enable their widespread adoption on a large scale (IPCC, 2022). Furthermore, developing codes, standards, and best practices for hydrogen systems and training and education programs for hydrogen professionals are crucial for ensuring hydrogen technologies' safe and widespread adoption (Barilo et al., 2021). In this context, as demonstrated in the Hy4Heat report (BEIS, 2022), the evaluation suggests that using 100% hydrogen for heating and cooking in specific house types such as detached, semi-detached, and standard construction terraced houses, which were examined in the study, could achieve a safety level comparable to that of natural gas.

Hydrogen is emerging as a significant option in the sustainable heating landscape. Unlike traditional fossil fuels, its combustion only produces water, making it a clean alternative. Clean hydrogen could play a significant role in reducing greenhouse gas emissions from the heating sector. However, there are challenges to its widespread adoption. First, current production methods for hydrogen, especially those that are cost-effective like steam methane reforming, still produce significant CO2 emissions unless coupled with carbon capture and storage (Jalil-Vega et al., 2020; Aunedi et al., 2022; Scheepers et al., 2022). Using electrolysis powered by renewables, green hydrogen production is an attractive option. However, the efficiency of this route to supply hydrogen to the boilers compared to direct electrification is lower (Cassarino et al., 2022; Sheikh et al., 2019; Element Energy, 2022; Matthes et al., 2021; ETC, 2021; Ueckerdt et al., 2021). Storage and transportation of hydrogen also present challenges, as it requires either high-pressure storage systems or cryogenic temperatures, adding to infrastructure costs. Additionally, there is the issue of retrofitting or replacing current infrastructure to handle hydrogen's unique properties, which includes being a smaller molecule that can lead to leakages (Ueckerdt et al., 2021; Giehl et al., 2023; Oshiro et al., 2022).

A prevalent limitation in the literature is associated with the lack of inclusion of extreme weather events, such as extended cold periods with low wind energy output (Kranzl et al., 2022; Jalil-Vega et al., 2020; Scheepers et al., 2022). Regarding the electricity system, underestimations are recurrent. Predominantly, the implications of increased heat demand due to electrification on electricity peak demand are often overlooked. Concurrently, the requirement and cost of power generation capacity and electricity distribution networks are not considered (Baldino et al., 2021a; Baldino et al., 2021b; Element Energy, 2022; Giehl et al., 2023). The lack of modelling depth, particularly in spatial and temporal aspects, can misrepresent capacity needs and be unable to capture asset utilisation of those mid-merit and peaking plants. Notably, the absence of hydrogen-based CCGTs, natural gas with CCS, or occasionally nuclear energy could result in a lack of synergy between heating, electricity, and hydrogen systems (Korberg et al., 2023; Röben et al., 2022). In hydrogen system modelling, there is a bias towards suboptimal hydrogen generation techniques. Specific research leans towards SMR or less efficient electrolysers, like PEM, neglecting superior methods such as ATR (Agora Energiewende, 2021). The exclusion of CCS technologies and negative-emission technologies (e.g., DACCS) in some models could curtail the broader adoption of blue hydrogen, inadvertently favouring the costlier green variant (Simon et al., 2022; Cassarino et al., 2022; Victoria et al., 2022; Röben et al., 2022). Furthermore, some studies do not see potential cost underestimations related to gas network adaptations for hydrogen transition (Baldino et al., 2020; Baldino et al., 2021c).

In summary, previous studies have highlighted the pivotal role that hydrogen could play in the future, particularly in decarbonising the energy storage, transportation, and industrial sectors. However, some studies projected a limited role for hydrogen in heat decarbonisation. Despite the existing challenges, ongoing research and development efforts, coupled with supportive policies and international cooperation, are expected to foster the widespread adoption of hydrogen in various applications, ultimately contributing to a more sustainable and low-carbon future.

1.3 What does this analysis add to the debate?

This study focuses on the role and value of hydrogen in decarbonising energy while maintaining the security of supply and enhancing system resilience in supporting net-zero energy systems. In contrast to the previous works, which were rooted in an assessment of an individual property, this study analyses the role and value of hydrogen using the whole-system approach, which can capture the complex interaction across investment and operating decisions of different technologies with sufficient temporal and spatial details.

The specific aims of the project are to:

- Investigate the role and costs of hydrogen against alternative pathways in heat decarbonisation.
- Quantify the role and value of hydrogen in providing energy system flexibility and supply capacity to enhance resilience against severe weather conditions;
- Assess the role of hydrogen linepack (linepack is the volume of hydrogen stored in pipelines and can be used to meet abrupt diurnal changes in hydrogen demand) when injected into the gas infrastructure to deliver resilience to the energy system.
- Analyse and provide the quantitative evidence to inform technical, economic and policy decision-making regarding the transition to a resilient, low-carbon heat energy future.

• 1.4 Overview of the scenarios and sensitivities assessed in this study

A broad spectrum of scenarios has been studied and analysed to meet the objectives and facilitate the investigation of the role and value of hydrogen, focusing on a 2050 GB' net zero-emission system. The energy system background and the key assumptions can be found in Appendix A. In summary, the scenarios are divided into core and sensitivity studies described as follows:

- **Core scenarios** evaluate and compare the cost performance of two heat decarbonisation scenarios. 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 (WSHPs) covering around 20% of heat demand and electric heating (heat pumps and resistive heating for the remaining customers. As we focus on the heat decarbonisation of on-gas grid customers, we call this scenario **the Hydrogen pathway (H2).** In contrast, the second scenario does not use hydrogen heating as all heat demand will be supplied using electric heating. We call this scenario **the Heat Electrification pathway (ELEC).**
- **Sensitivity scenarios** are used to assess the impact of various factors that may drive the cost performance of the Hydrogen and Heat Electrification pathways. These factors are:
    - **Natural gas price** – The natural gas supply shortage caused by the Russia-Ukraine war has created energy price spikes, triggering deep concern about the role of gas in supplying future energy. This concern will also affect people's opinion of hydrogen; however, hydrogen can be produced from different sources besides natural gas. So, this study aims to identify and quantify the impact of higher natural gas prices on the overall techno-economic performance of the Hydrogen

and Heat Electrification pathways with different assumptions on natural gas prices.

- **Different hydrogen production mix** – There is a need to understand the optimal production mix of different hydrogen production technologies (i.e. methane reforming, electrolysis, and biomass gasification). The core scenario assumes an optimal mix, while the sensitivity studies evaluate the cost and implications of having no blue or green hydrogen.

- **Cost of hydrogen storage** – Given the seasonal nature of heat-driven hydrogen demand and the variability of RES for green hydrogen production, the storage cost may be an essential factor. Therefore, sensitivities that vary the cost of such storage by -50% to +20% have been examined.

- **Level of energy efficiency improvement for domestic heat demand** – Different levels of domestic heat demand due to different energy efficiency improvements may influence the comparative cost performance of hydrogen and Heat Electrification. In the core scenarios, domestic heat demand is 222 TWh/year based on the FES 2022 Leading the Way energy demand scenario from National Grid ESO. Based on the System Transformation scenario, the sensitivity scenario assumes the domestic heat demand at 277 TWh/year.

- **Level of distributed flexibility** – The impact of different demand responses and distributed storage has been analysed here. Different heating decarbonisation strategies will impact local and national systems; therefore, understanding the impact of having different levels of distributed flexibility is crucial.

- **Levelised cost of offshore and nuclear** – Increased penetration of inflexible generation, such as offshore wind and nuclear, will affect the need for flexible low-carbon technologies such as hydrogen. Therefore, the sensitivity studies assume a lower Levelised Cost of Electricity (LCOE) of offshore wind to increase its penetration capacity and a higher or lower cost of nuclear to analyse their impacts.

- **Level of interconnection development** – Electricity interconnectors between Great Britain and Ireland, Great Britain and mainland Europe also provide flexibility supporting the Great Britain system balancing and supply capacity. The impact of a higher and lower total capacity of interconnectors on the Great Britain system has also been analysed.

- **Duration of extreme weather events** – Wind generation is expected to be the main supply for the future GB electricity system; however, as wind energy is variable and intermittent, its availability during peak demand periods cannot be guaranteed. Moreover, the Met Office indicated the possibility of having wind drought across large areas during icy weather conditions when energy demand is at its peak[5] - or called Winter-time wind-drought peak demand events. These conditions raise concerns about how the energy system should be designed and the role of hydrogen technologies in it. There are other adverse weather events, such as wind-drought summer peak demand and summer-time surplus generation events. While those events pose challenges in balancing the energy supply and demand, they are less severe regarding security issues than the Winter-time wind-drought peak demand events.

[5] *Source: Met Office (Tom Butcher and Laura Dawkins, et al.), "Adverse Weather Scenarios for Renewable Energy System Testing: Discovery Phase", June 2021*

1.5 Summary of the approach

1.5.1 Integrated Whole Energy Systems model (IWES)

We use the Integrated Whole Energy Systems (IWES) model to quantify the system impacts of different scenarios. IWES 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. IWES also optimises the deployment of flexibility technologies such as thermal energy storage (TES), electricity storage such as Pumped Hydro Energy Storage (PHES) and Battery Energy Storage System (BESS), hydrogen storage, demand response technologies (e.g. smart 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 peak demand with low renewable output. The model considers the energy system from the local district level to a national one and the interactions between the Great Britain (GB) 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. A more detailed description of the model can be found in Appendix B.

Annual system costs and the energy system infrastructure proposed by the model in different scenarios, e.g., in the Hydrogen and Heat Electrification pathways, and sensitivity scenarios described in the previous section can be analysed and compared to identify conditions that drive the value of hydrogen in the system. It is worth noting that the system proposed by the model will always be optimal (i.e. the least-cost solution) given all deterministic input provided and meet all the specified constraints, such as the 2050 net-zero carbon emissions and resilience against severe weather events.

1.5.2 Integrated hydrogen and electricity systems (IHES) model

As highlighted in recent publications (e.g., UKERC, 2019), the gas grid that transports 100% hydrogen would require detailed network analyses regarding the amount of linepack that existing and new pipelines should be designed to hold, including the levels of within-day flexibility of linepack (MacLean et al., 2021). Due to the lower energy density of hydrogen compared to natural gas, about three times more volume of hydrogen is required to supply the same amount of energy. Therefore, maintaining the security of supply will be more challenging in hydrogen networks, and hence, linepack will play a critical role.

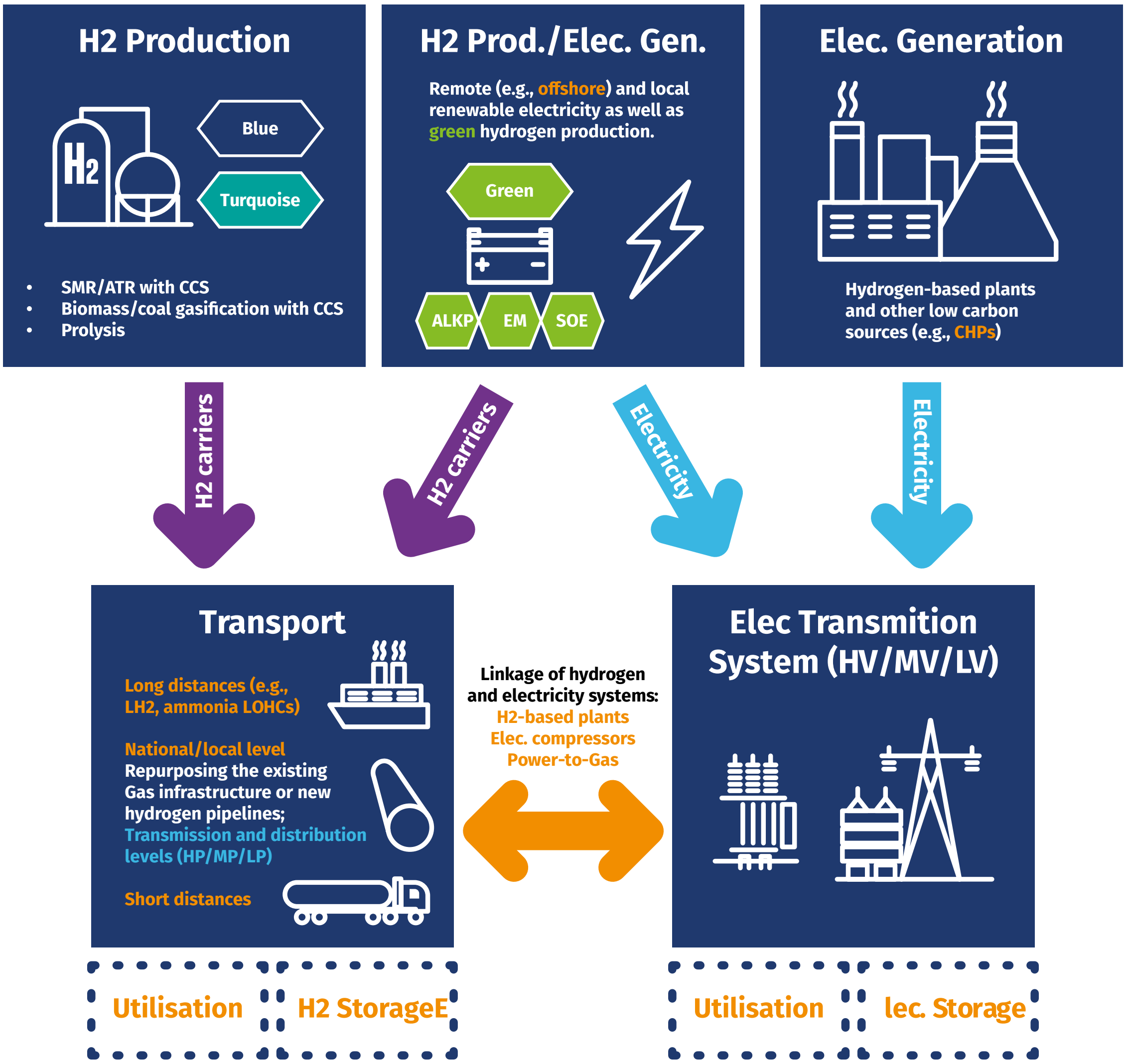


Figure 1-1 Integrated hydrogen and electricity systems components

In this context, the Integrated Hydrogen and Electricity System (IHES) model (Figure 2 3) has been developed to analyse hydrogen transport in the transmission system. This model will be applied to provide fundamental evidence regarding the ability of the existing gas transmission networks to deliver hydrogen and meet heat and hydrogen-based electricity generation demand while determining the locations and capacity of hydrogen storage and compressors needed to ensure the resilience of the hydrogen system. The model also facilitates system benefit analysis of the flexibility of heat and electricity infrastructure sources (e.g., interconnectors, electricity storage, thermal storage demand-side response) to enhance the energy system resilience and complement challenges in transporting hydrogen.

In summary, the strength of the IHES model for this project can be summarised as follows:

- Understanding the physics of hydrogen flow within the gas infrastructure at the transmission level
- Assessing the value of hydrogen linepack in delivering resilience to net-zero energy systems
- Quantifying the interaction between gas/hydrogen and electricity systems

Chapter 2. Role of Hydrogen in Supporting Decarbonisation and Security for a Net-Zero Energy System

This chapter presents and analyses the critical results of the core studies as defined in section 1.3. Before going into the details presented in subsequent sections, the key findings of the study are summarised as follows:

- In all scenarios, hydrogen plays a crucial role in energy decarbonisation, energy system balancing, and providing energy security. Hydrogen provides zero-carbon fuel for power generation, heating, transport, and industrial processes.

- Hydrogen technologies have different roles:

    - **Hydrogen power generation**, such as hydrogen Combined Cycle or Open Cycle Gas Turbines (CCGT or OCGT) and fuel cells, provides firm and dispatchable capacity, producing zero-carbon electricity, system balancing capability and reserve services. Hydrogen power generation improves energy resilience in coping with low renewable output and peak demand conditions.

    - **Auto Thermal Reformers (ATR)** with Carbon Capture and Storage (CCS) produce blue hydrogen from efficient methane reforming processes with low residual carbon emissions (less than 5%). The production cost of blue hydrogen, depending on the natural gas prices, could be lower than that of green hydrogen. ATR with CCS also provides balancing and peaking capacity in the hydrogen supply system.

    - **Electrolysers** produce hydrogen and enables a lower-cost RES system integration by providing sector-coupling flexibility and ancillary services. It enables electricity to be converted to hydrogen to be stored efficiently or to supply hydrogen demand.

    - **Hydrogen transmission and distribution** enable hydrogen to be transported from production sites to load centres. Hydrogen can also be stored in the pipeline; the hydrogen linepack provides intra-day flexibility to manage the challenges driven by renewable intermittency in the gas infrastructure. Flexibility from the hydrogen network should be operated in synergy with other flexibility technologies such as interconnectors, electricity storage and demand response technologies to support cost-efficient system operation and security.

    - **Hydrogen storage** provides bulk energy storage with low losses, hydrogen supply capacity, and an alternative balancing source for the hydrogen system. Distributed hydrogen storage also helps manage the hydrogen pipeline operating pressures, managing the volume of hydrogen that can be delivered to meet demand. Whether harnessing excess green hydrogen produced during windy summer days or supporting the energy needs during cold winter days, hydrogen storage is the keystone for managing supply fluctuations. With the increasing integration of renewables and as the green hydrogen supply chain evolves, the role of hydrogen storage becomes even more critical in enhancing resilience.
    - **Bio-energy with CCS (BECCS)** acts as a negative emission technology and provides a flexible option for biomass energy for electricity or hydrogen production.
    - **Hydrogen boilers** act as zero-carbon heat appliances.
    - **Hydrogen** is also a **zero-carbon fuel** for industrial processes and transport (ground, aviation, and shipping).

- The cost of the overall energy system can be minimised by maximising the synergy across all energy supply vectors and sectors of demand. All energy system investment and operation, especially for the power and hydrogen systems, should be optimised from the whole-system perspective, considering the complex interactions across all energy vectors and carbon storage and removal infrastructure.

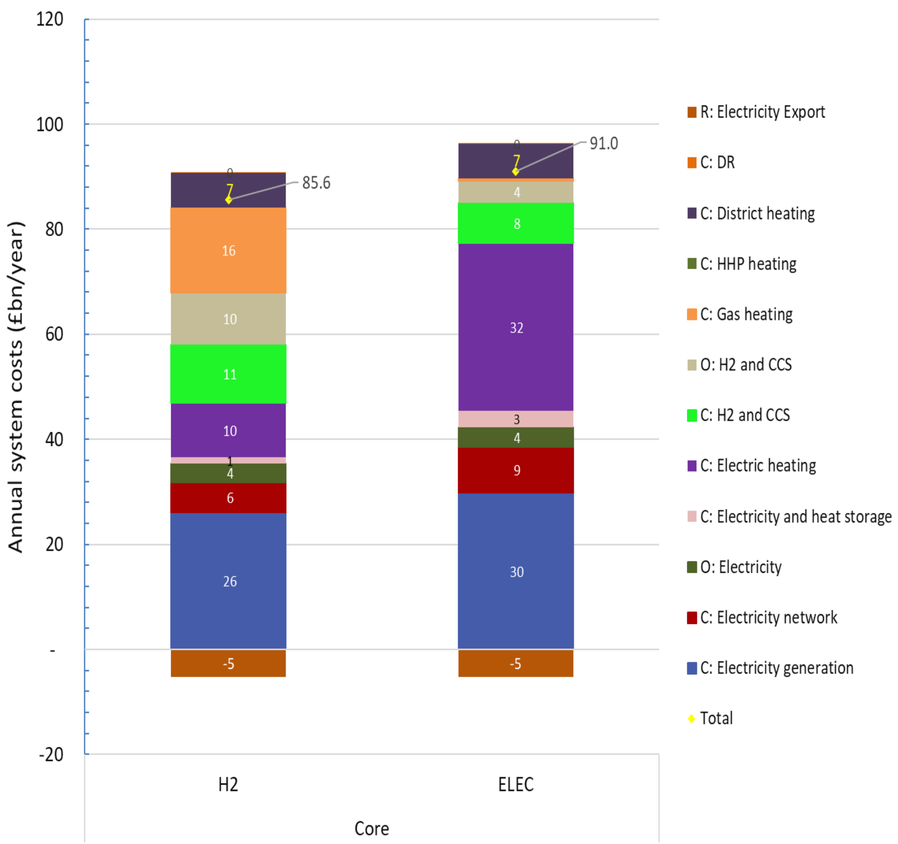
- Hydrogen is a competitive alternative for many types of energy decarbonisation, including heating and electricity, while contributing to energy security due to its diverse energy sources (electricity, natural gas, bioenergy). Our studies suggest that the cost of the Hydrogen pathway **(£85.6bn/year)** is **£5.4bn/year lower** than the cost of Heat Electrification **(£91bn/year)**. All annual cost figures are related to the 2050 cost but presented as real value in 2022.

- While Heat Electrification using heat pumps improves energy efficiency, the energy system cost of a deeply electrified system can be higher than the hydrogen alternative. These are driven by the following:
    - A higher heating appliance cost – the annual cost of heat pump systems is more than twice that of hydrogen boiler systems. Even with the gas infrastructure costs, a gas heating system costs less than electric heating.
    - A higher supporting energy system cost attributed to a higher electricity peak demand - Heat Electrification will require extra energy infrastructure capacity such as low-carbon generation, distribution, and hydrogen storage to be built for security purposes, mainly operating during peak time or when RES output is low.
    - The hydrogen system cost can be minimised since it uses most of the hydrogen assets needed to improve energy resilience to the electricity system. The hydrogen system cost can be minimised by optimising hydrogen production technologies from different sources (reforming processes, electrolysis, and biomass gasification) and other hydrogen assets such as network and storage while optimising the power generation portfolio.
    - While a heat pump system requires half or less primary energy to deliver the same heat unit compared to a hydrogen boiler, Heat Electrification requires more flexibility and heat storage. Shifting demand and storing energy may increase energy losses.

- The volume of energy and carbon infrastructure scale to be built within the next 30 years is high. Scaling up all infrastructure development will be challenging. Both Hydrogen and Heat Electrification pathways require CCS infrastructure to be built to achieve the net-zero carbon target cost-effectively.

2.1 Cost performance of the Hydrogen (H2) and Heat Electrification (ELEC) pathways

The modelling results (Figure 2-1) suggest that the cost of the Hydrogen pathway **(£85.6bn/year)** is **£5.4bn/year lower** than the cost of Heat Electrification **(£91bn/year).** The cost of converting the gas distribution network has been included in the Hydrogen pathway cost, and the cost of decommissioning gas distribution is included in the Heat Electrification pathway (see Appendix A for details). The results may surprise many as hydrogen for heating is seen as less efficient (in terms of energy) than Heat Electrification using heat pumps. 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. However, we will present the robustness of the conclusions from these results using the sensitivity studies in the subsequent chapter.



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 (including conversion cost)	**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

Figure 2-1 Annual system costs of Hydrogen and Heat Electrification pathways

To understand the differences between the cost of the Hydrogen (H2) and the Heat Electrification (ELEC) scenarios, we compare the cost components of the two pathways using the latter as the counterfactual. The results are presented in Figure 2-2; the left diagram provides detailed information on where the system costs would be changed between the two pathways. The right diagram shows a simplified version of the left diagram with a higher-level cost mapping, as in Table B-1 of Appendix B.

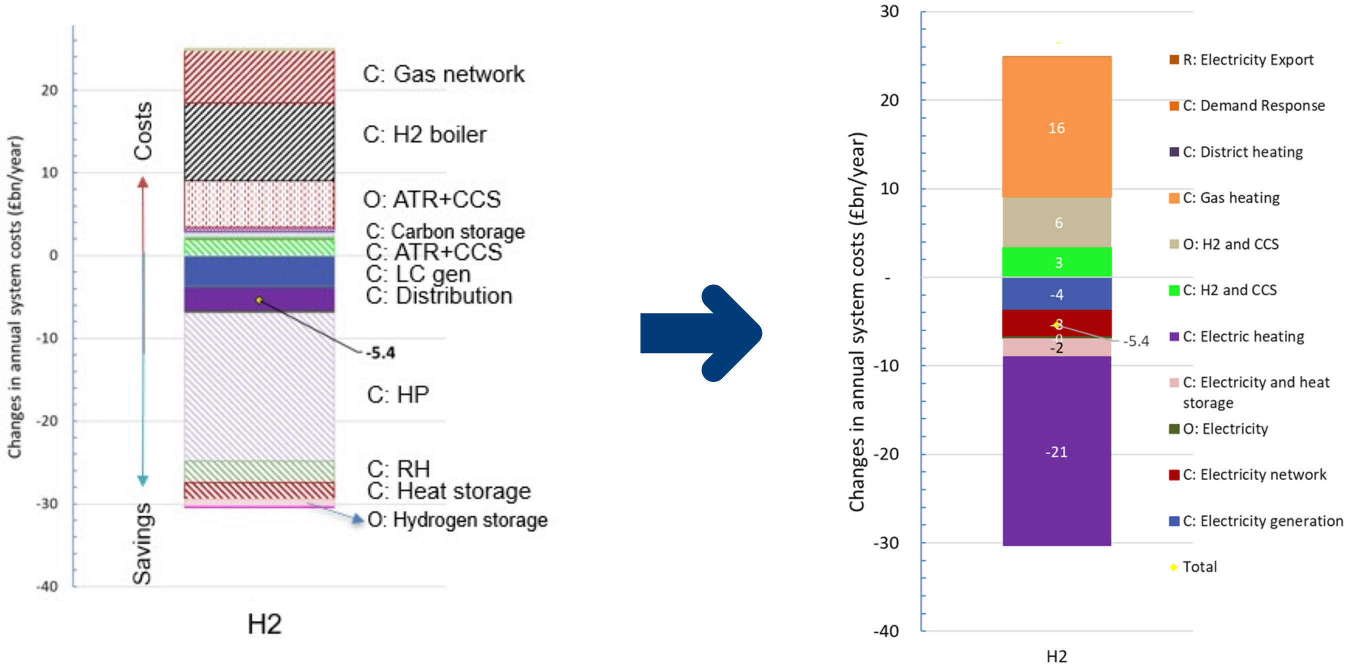


Figure 2-2 Cost differences between Hydrogen (H2) and Heat Electrification (ELEC) pathways

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**.

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[6]) 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 natural gas boilers.

[6] *The annual Capex of a hydrogen boiler system is around £350 including the annual maintenance cost; while the annual Capex and maintenance of heat pump system is around £750/year.*

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 instantaneous hot water supply. In contrast, heat pumps require thermal storage and resistive heating to meet peak heat demand. Resistive heating is typically used to boost the thermal output of the heat pump system.

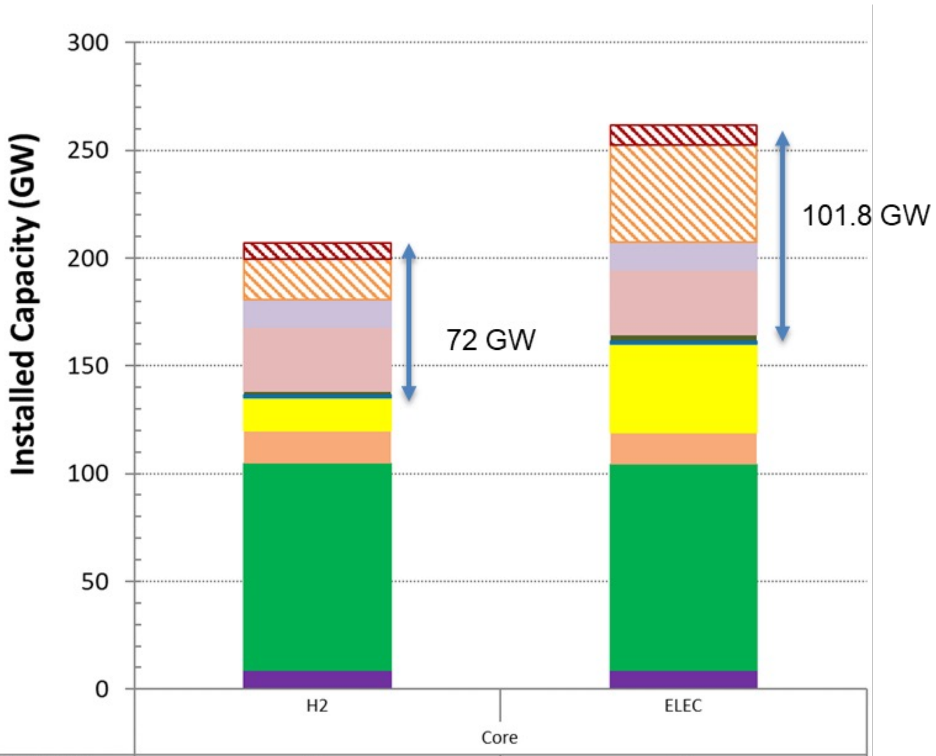
As the primary savings of the Hydrogen pathway are related to the heat pump costs, the results will be sensitive to the cost of heat pumps. In order to be on par with the Hydrogen pathway, the cost of heat pumps must be reduced by 30%, which will lead to 1.5 times the investment cost of hydrogen boilers. 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.

By dividing the whole energy system cost by the total annual energy consumed by end users, the Hydrogen pathway will cost, on average, **9.35p/kWh**, while ***Heat Electrification*** will cost ***9.94p/kWh.*** The cost in the Hydrogen pathway is 6% cheaper than in ELEC. The cost includes the Capex and Opex of the energy system considered in the IWES model.

2.2 Role of hydrogen in low-carbon power generation system

Figure 2-3 shows the optimal power generation mixes for the Hydrogen and Heat Electrification pathways. The mixes are optimised considering the total system costs, including those technologies' investment, operation and system integration costs. System integration costs are system-specific, reflecting additional infrastructure and operating costs needed to integrate the technologies into the system. The system integration costs are influenced by operating characteristics, e.g., controllability, availability, variability in energy sources, flexibility, and ability to provide ancillary services, locations, installed capacity, and emission performances.

The model picks hydrogen power generation alongside other low-carbon technologies: nuclear, wind, solar PV, and gas plants with CCS and electricity storage, indicating that hydrogen also plays essential roles in future low-carbon power generation systems. Two types of hydrogen power generation proposed here are Combined Cycle Gas Turbines (CCGTs) and Open Cycle Gas Turbines (OCGTs). CCGTs have a higher efficiency (around 58%) but are more expensive than OCGTs, which are less efficient. OCGTs are considered rapid units that can provide standing reserves, while CCGTs provide spinning reserves.



	H2	ELEC
H2 OCGT	7.7	9.2
H2 CCGT	18.5	45.2
Storage	12.7	12.7
CCS	29.9	30.0
Biomass CCS	1.7	3.2
Hydro	1.5	1.5
PV	15.2	40.8
Onshore Wind	15.0	15.0
Offshore Wind	96.0	95.4
Nuclear	8.9	8.8

Figure 2-3 Optimal power generation portfolio in Hydrogen (H2) and Heat Electrification (ELEC) pathways

The roles of hydrogen power generation and gas CCS are to provide:

- Firm capacity to meet the peak demand;
- Flexibility to support system balancing to deal with the variability of renewable output (wind, solar PV);
- Ancillary services to support system security.

It is worth highlighting that the firm capacity needed from dispatchable generation besides nuclear varies in the Hydrogen and Heat Electrification pathways. The Hydrogen pathway requires 72 GW, while the Heat Electrification pathway needs 101.8 GW, driven by a higher electricity peak load (discussed in section 2.3). Hydrogen power generation contributes to 26.2 GW of firm capacity in the Hydrogen pathway and 54.4 GW in the Heat Electrification pathway. Interestingly, the model optimisation demonstrates that the hydrogen power generation capacity needed in the Heat Electrification pathway is higher than in the Hydrogen pathway. The results suggest *a trade-off between hydrogen for heating and power generation investment*. If hydrogen is used for heating, it will reduce the total capacity required for hydrogen power generation since hydrogen heating does not increase electricity peak demand.

The optimal electricity generation mixes for the two 2050 scenarios are dominated by offshore wind production, followed by nuclear, onshore wind, solar PV, biomass, and the remaining supply comes from hydrogen generators, biomass and gas-fired power plants with CCS. Figure 2-4 shows the cost-optimal mix. Nuclear will continue its role as a baseload plant while hydrogen provides mid-merit and peaking power generation capacity to ensure the adequacy of firm generation. As shown in the previous figure, the volume of electricity production from hydrogen-fuelled power generation is relatively small. Low utilisation of these hydrogen power plants and gas plants with CCS indicates that these technologies only provide energy for peak or when the variable RES output is low. The main roles of those technologies are to provide firm and controllable capacity for system security and energy resilience against weather variation and to provide ancillary grid services such as balancing and other grid ancillary services.

Figure 2-4 Optimal electricity production mixes in Hydrogen (H2) and Heat Electrification (ELEC) pathways

Although the utilisation level of hydrogen power generation and gas with CCS is relatively low, their capacity could not be displaced by variable RES capacity. Hence, the capacity cost of those generators will be part of the security costs that need to be paid by the customers. The capacity of thermal plants with a low utilisation factor in the Hydrogen pathway is 56 GW, lower than the 84 GW deployed in Heat Electrification. In this context, the cost of providing thermal capacity in the Hydrogen scenario is considerably less than in the Heat Electrification scenario.

2.3 Impact of hydrogen for heating on electricity demand

Heat-led electricity demand is lower in the Hydrogen pathway (51 TWh/year) than in the Heat Electrification pathway (117 TWh/year), as some customers use hydrogen for heating, as shown in Figure 2-5. Off-gas-grid customers use electric heating in both scenarios. However, the reduction in heat-led electricity load is offset by increased electricity demand due to hydrogen production processes via electrolysis and reforming, which reduces the difference between the total annual electricity demand in the Hydrogen pathway (585 TWh/year) and the Heat Electrification pathway (618 TWh/year). Electricity loads such as industrial, commercial, and residential, including smart appliances and EVs, are fixed in all cases.

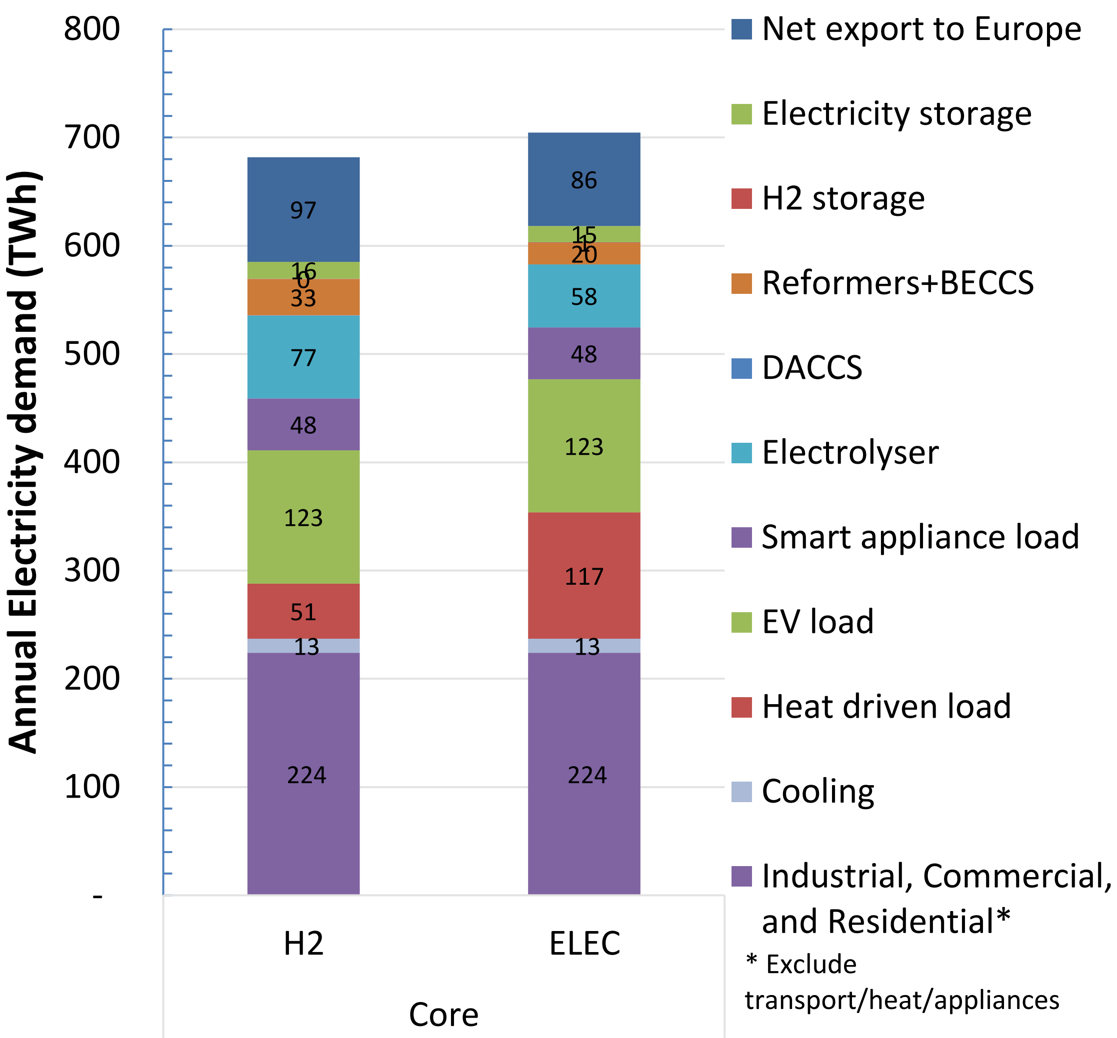


Figure 2-5 Annual electricity demand in Hydrogen and Heat Electrification pathways

Due to a lower heat-led electricity load, the peak of electricity demand at distribution systems in the Hydrogen pathway is 28 GW smaller than in the Heat Electrification scenario (ELEC). Figure 2-6 shows the electricity distribution network capacity driven by the peak demand.

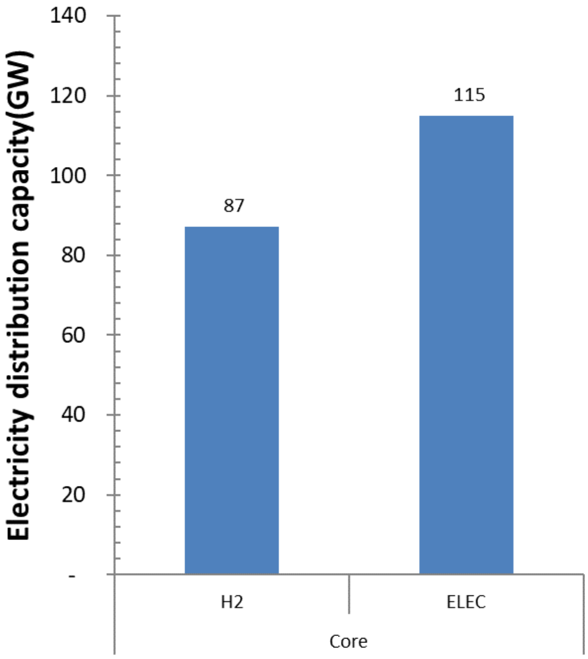


Figure 2-6 Electricity distribution capacity of Hydrogen and Heat Electrification pathways

Thus, in the Hydrogen pathway, the system will require much less electricity infrastructure, including network capacity and the firm thermal generation capacity, to secure peak demand or to meet demand when the RES' output is low, as discussed in section 2.2. In this study, electrolysers and all hydrogen production technologies are connected to the transmission, and, therefore, it does not affect electricity peak demand at distribution.

In both the Hydrogen and Heat Electrification pathways, the electricity peak demand will increase from the current peak (50–60 GW)[7] due to electrification in heat and transportation. As considered in this analysis, the impact of electrification on peak demand can be minimised using energy storage and demand flexibility (load shifting). As the peak demand in the Hydrogen pathway is smaller than for Heat Electrification, the distribution network reinforcement will be lower.

Larger distribution network capacity in the Heat Electrification pathway also increases the system cost, and the utilisation factor of the distribution systems is lower than in the Hydrogen pathway scenario. This issue is similar to the low-capacity factor problem of thermal generation systems (excluding nuclear) in the Heat Electrification scenario. This cost contributes to the overall higher cost of the Heat Electrification scenario.

In both cases, the optimal system will deliver supply to meet all energy demands required by the end users without compromising the comfort level even under Winter-time wind-drought peak demand events. There would be no planned load curtailment as the energy infrastructure capacity will be sufficient to meet the peak demand. The annual heat demand from domestic and non-domestic space and water heating, including the low-heat temperature processes, is around 360 TWh/year[8]. Figure 2-7 shows how various heating technologies in Hydrogen and Heat Electrification pathways supply the heat demand.

[7] *Source: Statista, Peak hourly electricity load in the United Kingdom (UK) from January 2016 to June 2021. Available at* https://www.statista.com/statistics/1342528/peak-hourly-electricity-load-uk-by-month/

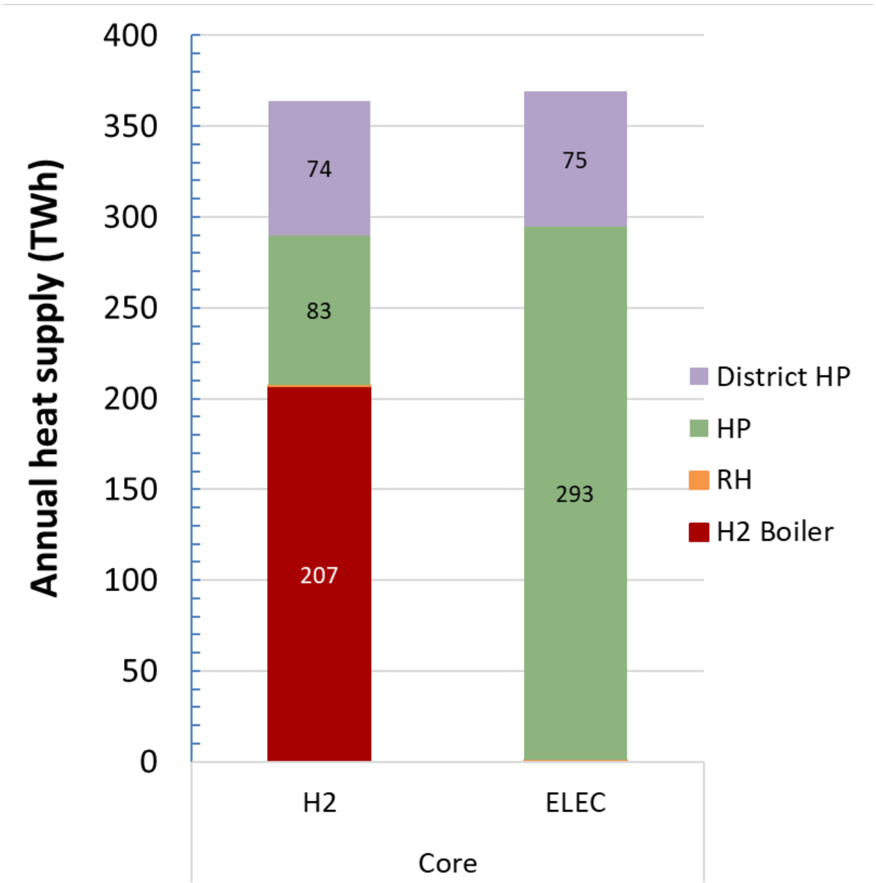


Figure 2-7 Annual heat supply from different heating technologies (HP: Heat pumps, RH: Resistive Heating, H2: hydrogen)

The results already include some heat losses considered in thermal storage. As the efficiency of thermal storage is high, the losses are relatively modest, i.e. between 4-9 TWh thermal per year. The losses in Heat Electrification are higher than in the Hydrogen pathway due to more thermal storage involved in heat pump systems.

2.4 Primary energy usage

The main argument for supporting electrification to decarbonise heat centres on its high energy efficiency. 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 modelling results (Figure 2-8) also demonstrate that 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 considered.

[8] *Currently, around 434 TWh of heat demand goes toward space and water heating requirements. Source: Ofgem, Future Insights Series: The Decarbonisation of Heat.*

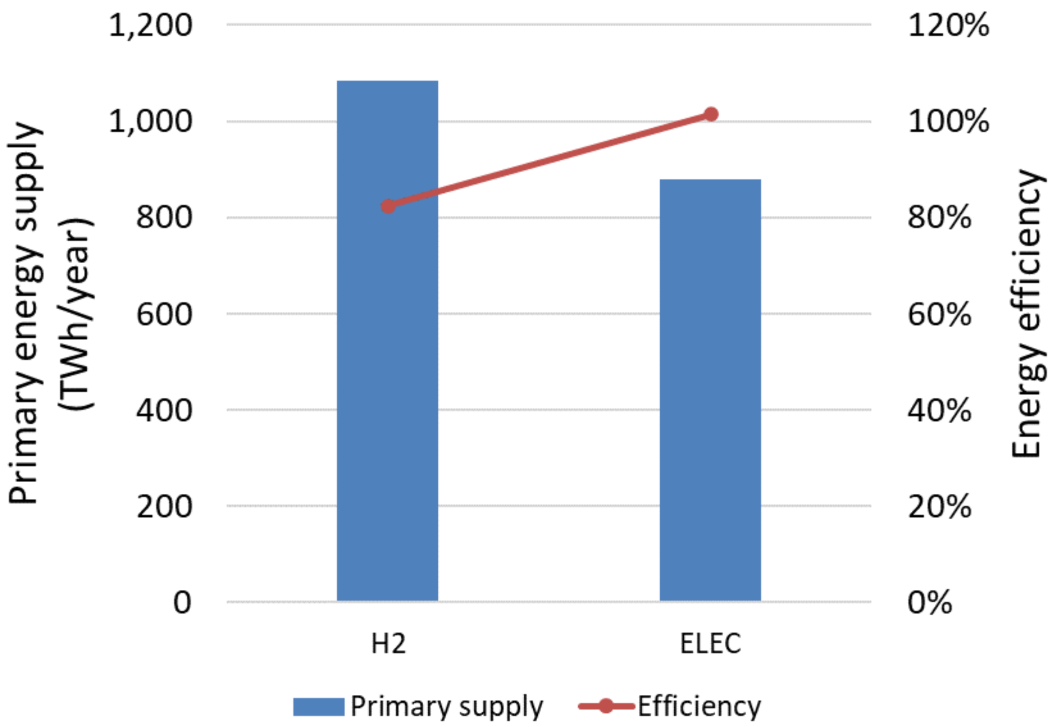


Figure 2-8 Annual primary energy supply and average energy efficiency for Hydrogen (H2) and Heat Electrification (ELEC) pathways

Although Heat Electrification is more efficient in using primary energy, its system cost is higher than the cost of the Hydrogen pathway, as demonstrated in section Figure 2-1. *This study demonstrates that a system with higher energy efficiency will NOT always lead to a more cost-effective system*. Many aspects must be considered, e.g., the cost and portfolio of technologies, supporting infrastructure, and investment efficiency.

2.5 Hydrogen demand, supply, and storage systems

In both Hydrogen and Heat Electrification pathways, optimal hydrogen systems are required. The system consists of hydrogen production, networks, and storage facilities. So besides hydrogen for heating, the hydrogen system plays an essential role in power generation (as discussed in section 2.2), but also to meet demand and decarbonise some industrial processes, shipping, heavy goods vehicles (HGVs) and agriculture.

2.5.1 Hydrogen demand

Figure 2-9 shows the annual hydrogen demand from different sectors. The total demand for hydrogen from those sectors is around 390 TWh and 162 TWh per year in the Hydrogen and Heat Electrification pathways, respectively. This 2050 hydrogen demand will be a significant increase from the current hydrogen demand, i.e. below 50 TWh/year. Hydrogen is used in the oil refining and chemical industries. Hence, scaling up hydrogen production will be one of the major challenges, especially in the Hydrogen pathway.

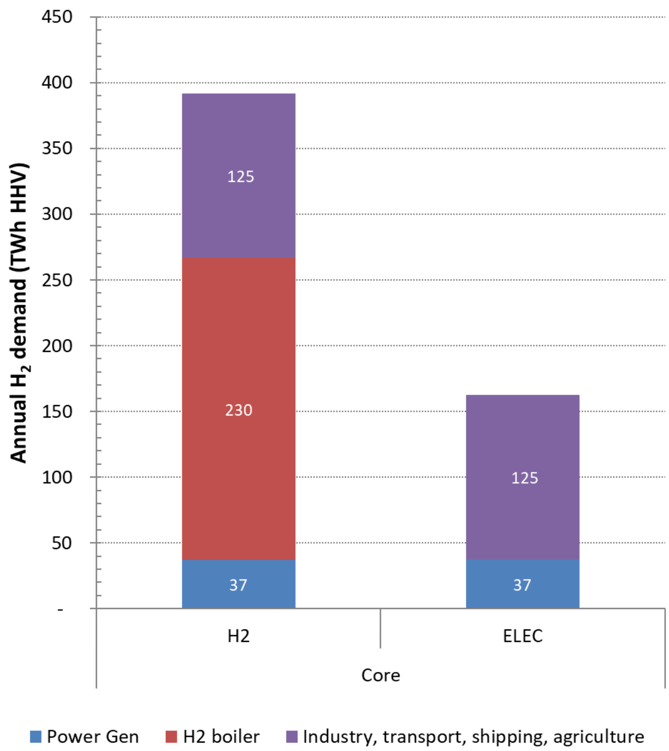


Figure 2-9 Annual hydrogen demand in the Hydrogen and Heat Electrification pathways

Hydrogen for heating is the main driver of hydrogen demand in the Hydrogen pathway. Hydrogen demand for power generation is the same, indicating that hydrogen power generation is needed in both pathways' optimal power generation mixes. Another 125 TWh/year of hydrogen will be required for industry, transport, shipping, and agriculture[9].

2.5.2 Hydrogen supply

Three low-carbon hydrogen production technologies, i.e. (i) Auto Thermal Reformer with CCS (ATR+CCS), (ii) electrolysers, and (iii) biomass gasification with CCS (BECCS), are used in the studies to meet hydrogen demand. Figure 2-10 shows the annual production of blue hydrogen from reforming processes through ATR+CCS, green hydrogen from electrolysis, and hydrogen from BECCS. One of the key criteria used in the system optimisation model is that Great Britain must have sufficient hydrogen production capacity to meet the hydrogen demand.

[9] *This is input data to the modelling, and therefore, the number is fixed across all scenarios.*

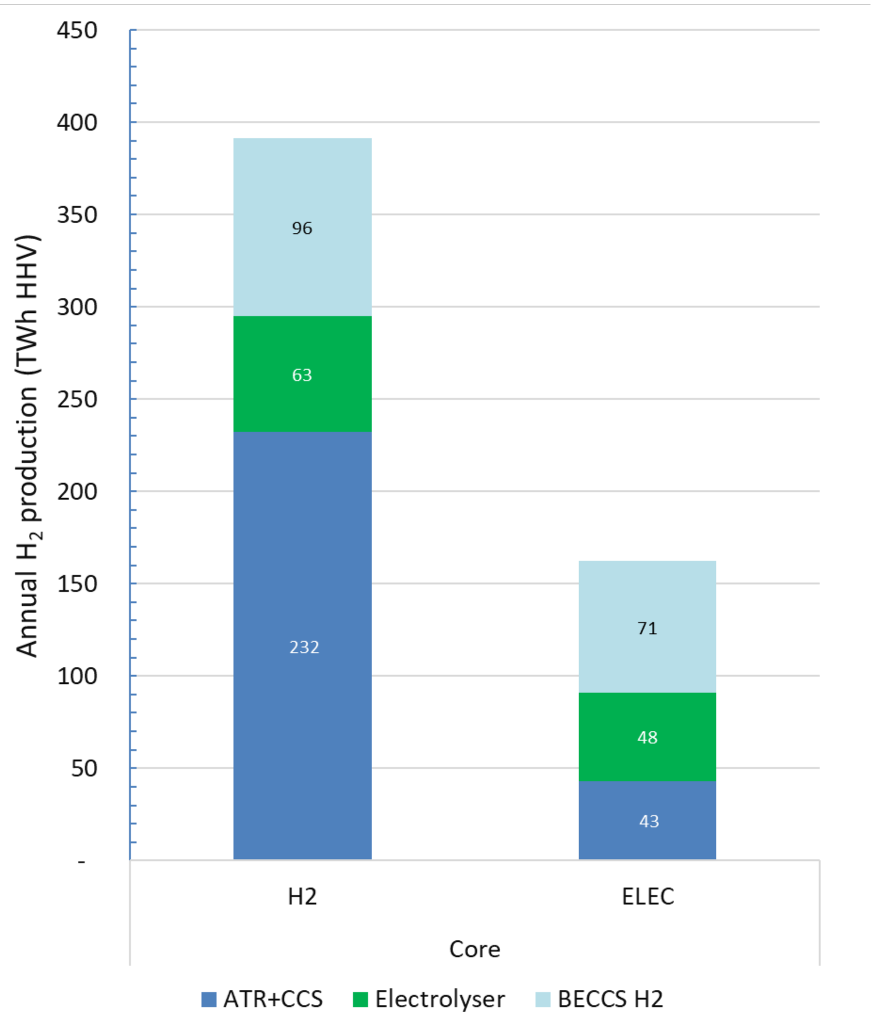


Figure 2-10 Annual system costs of Hydrogen and Heat Electrification pathways

It is worth noting that even if the production cost of green hydrogen is higher than blue hydrogen, given the benefits of the electrolysers that provide sector-coupling flexibility to the electricity system, the optimal production mixes will contain some green hydrogen. Electrolysers increase the flexibility in the electricity system by following the RES output while providing balancing and ancillary services such as frequency control and reserve services. These benefits are recognised in the model and provide cases to deploy electrolysers in the system to reduce the system integration cost of RES. The bulk of the hydrogen supply in the Hydrogen pathway still comes from ATR+CCS , indicating that the hydrogen production cost from ATR+CCS[10] is lower than the green hydrogen production cost. However, this is not the case in Heat Electrification, as the volume of blue and green hydrogen is relatively similar. The modelling results indicate that electrolysers' flexibility in the Heat Electrification scenario is essential.

[10] *The residual carbon emissions of ATR+CCS are relatively small and the impacts are discussed later in section 2.6.*

BECCS also contributes to both hydrogen and electricity generation. The model optimises the mix between biomass for power and hydrogen within the available biomass resource limit (e.g. 177 TWh/year)[11] to minimise the overall system costs. BECCS plays an essential role in the net zero emission system as it is considered a negative emission technology as the carbon dioxide captured during the plant's lifetime is accounted for, and the carbon produced by the gasification process is captured and stored.

Figure 2-11 shows the capacity of ATR+CCS, electrolysers, and BECCS technologies. While hydrogen demand in the Hydrogen pathway is 2.4 times higher than in the Heat Electrification scenario, the hydrogen production capacity in the Hydrogen pathway is just 1.6 times higher. The results indicate a higher utilisation factor of the investment in hydrogen production capacity in the Hydrogen pathway than in Heat Electrification.

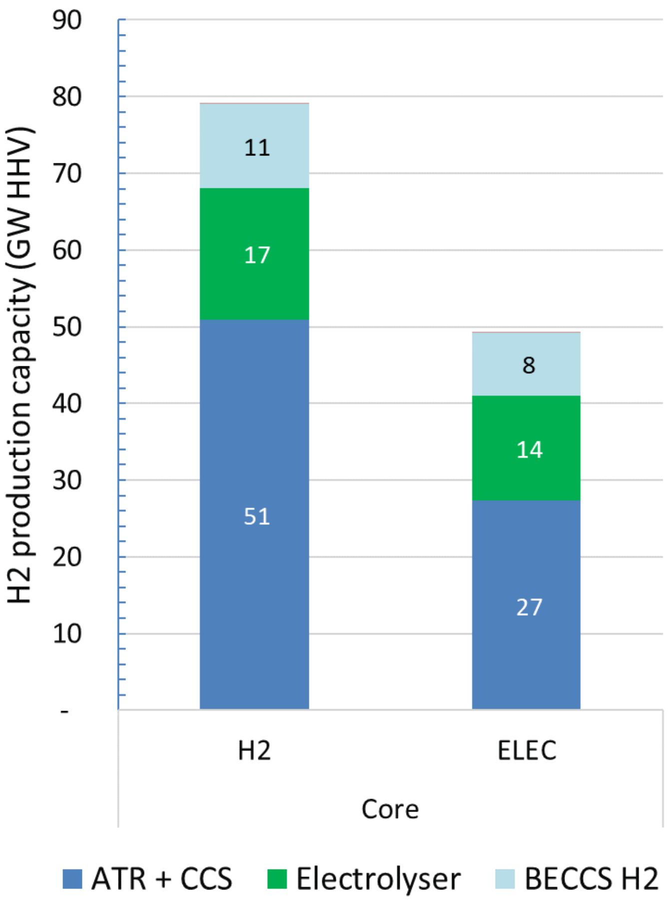


Figure 2-11 Optimal hydrogen production mixes in the Hydrogen and Heat Electrification pathways

[11] *Source: National Grid, FES 2022 – 2050 Leading the Way scenario.*

The modelling results show that the capacity factors of electrolysers and BECCS are around 40% and 100%, respectively, in the Hydrogen and Heat Electrification pathways. However, the capacity factor of ATR+CCS in the Hydrogen pathway is much higher (i.e. around 52%) than in the other pathway (18%). Figure 2-12 shows the capacity factor of different hydrogen production technologies in both pathways.

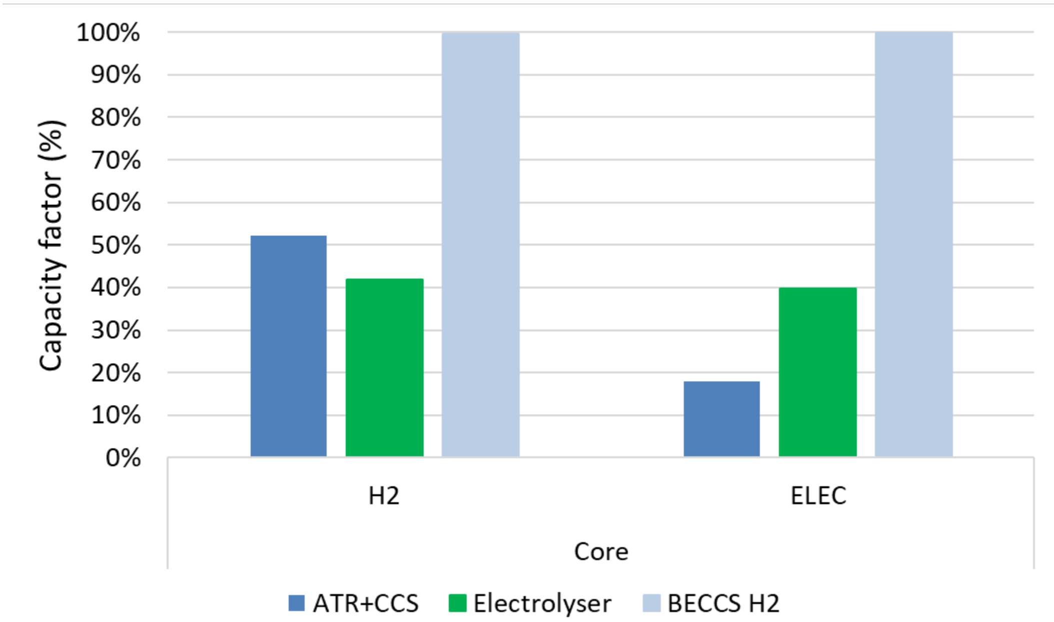


Figure 2-12 Capacity factor of different hydrogen production technologies in the Hydrogen and Heat Electrification pathways

Based on these results, we conclude that different hydrogen technologies play different roles, as summarised below:

- ATR+CCS provides balancing and acts as mid-merit and peaking capacity in the hydrogen supply system
- Electrolysers produce hydrogen when electricity cost is low during high RES output with lower electricity demand, enabling lower-cost RES system integration by providing sector-coupling flexibility and ancillary services.
- BECCS acts as a negative emission technology and provides options for deploying biomass energy for electricity or hydrogen production. BECCS also acts as baseload hydrogen production plant.

2.5.3 Hydrogen storage

Mismatches between hydrogen production and demand can be balanced by hydrogen storage. Hydrogen production from electrolysers varies depending on the availability of low-cost electricity (driven by high-RES output and low-demand conditions). On the other hand, hydrogen demand also varies in time depending on the usage of hydrogen power generation and hydrogen boilers. As heating demand is strongly seasonal, the hydrogen demand is also seasonal, especially in the Hydrogen pathway. Moreover, the use of hydrogen for power generation is also seasonal, as the peak demand occurs in winter, and the minimum demand occurs in summer. We assume the hydrogen demand from industry, transport and agriculture is uniformly constant across the year.

Figure 2-13 shows the capacity of underground (salt caverns) and overground (medium pressure vessels) hydrogen storage deployed by the model in both pathways. Underground storage is much cheaper but less flexible than overground storage. The amount of hydrogen that can be extracted from underground storage is limited to around 10% of the energy stored to maintain hydrogen-well stability. For the overground storage, that constraint is not needed. Both pathways require around 6 TWh of hydrogen storage. Overground storage is around 10% - 20% of total hydrogen storage. The model has not considered using ammonia or Liquid Organic Hydrogen Carriers (LOHCs) to store or transport hydrogen and is subject to further research and modelling development.

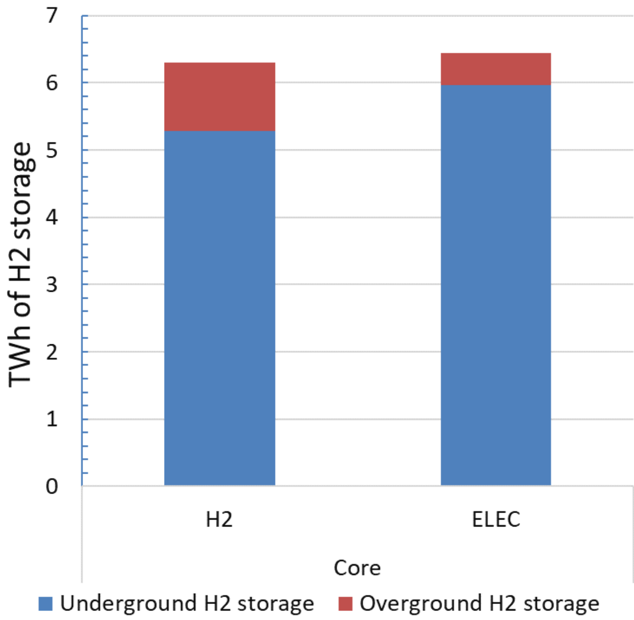


Figure 2-13 Optimal hydrogen storage mix in Hydrogen and Heat Electrification pathways

The seasonal character of the hydrogen storage utilisation is shown in Figure 2-14.

The number of cycles of hydrogen storage is, on average, between 6 and 11.5 times. These numbers represent the annual volume of discharged hydrogen divided by the total storage capacity. The result demonstrates that the storage is not fully cycled regularly, which means that the storage is used more towards medium or long-duration storage than short-term storage. Medium-pressure overground storage and linepack of the hydrogen network can contribute to the short-term balancing of the hydrogen system, while salt-cavern storage acts as long-duration storage. The results also demonstrate that hydrogen storage utilisation in the Hydrogen pathway is higher than in the Heat Electrification pathway.

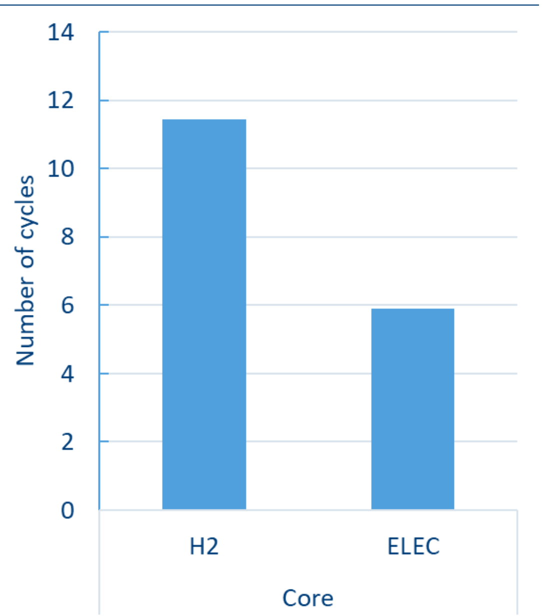


Figure 2-14 Hydrogen storage's number of cycles in the Hydrogen and Heat Electrification pathways

2.6 Carbon emissions performance

Both Hydrogen and Heat Electrification pathways can achieve net-zero emissions; the residual emissions and carbon offsets from different sectors are shown in Figure 2-15.

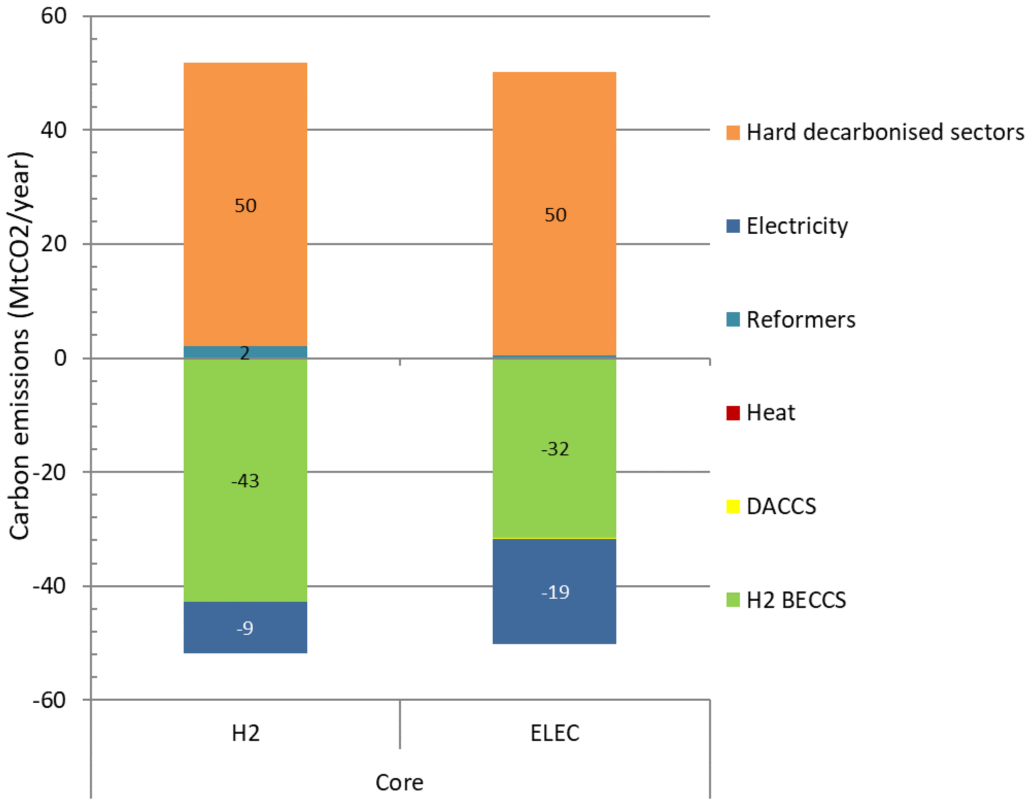


Figure 2-15 Carbon emissions and offsets in Hydrogen and Heat Electrification pathways

In all cases, there will be 50 $MtCO_2$/year emissions from hard-to-decarbonise sectors and residual emissions from power generation and reforming processes in ATR; these emissions are relatively small because of the CCS applications and most of the electricity production already comes from zero-carbon sources (RES, nuclear, hydrogen). As biomass with CCS is used for power and hydrogen production, the net emissions of those sectors can become negative and offset the positive emissions, enabling net zero emissions.

In these two studies, the carbon offsets come from BECCS for power and hydrogen production. As biomass resources are limited (177 TWh/year), the allocation of those resources needs to be optimised. In the Hydrogen pathway, most biomass is used in hydrogen production; in the Heat Electrification pathway, a higher volume of biomass is allocated to the power sector. These results indicate that strategic resource allocation planning needs to be guided to maximise the synergy between power and hydrogen sectors to achieve net zero overall.

These cases also demonstrate the importance of CCS to achieve net zero and the role of hydrogen with all other low-carbon technologies to reduce residual emissions in the power and hydrogen production sectors. In these cases, other high-cost carbon removal technologies, such as Direct Air Carbon Capture and Storage (DACCS), are not needed. However, if the system does not have sufficient biomass resources, DACCS can be an alternative solution to offset the residual emissions. It is worth highlighting that the cost of removing carbon in power, hydrogen and other processes increases when a stringent emission performance is applied and to a certain extent, alternative technologies such as BECCS and DACCS can become options to minimise the cost of removing carbon from the air.

Carbon storage facilities have to be built for both pathways. However, the volume of carbon sequestration in the Hydrogen pathway (111 $MtCO_2$/year) is higher than in the Heat Electrification pathway (68 $MtCO_2$/year). The Hydrogen pathway requires around eleven times the carbon storage that sites like Acorn CCS[12] or Viking CCS[13] , which will inject 10 $MtCO_2$/year by 2030. In comparison, the Heat Electrification pathway needs around seven of those facilities. The contribution of hydrogen BECCS, ATR+CCS, and CCS in the power sector (including biomass for power generation) is shown in Figure 2-16.

[12] Acorn CCS, the project operated by Storegga, aims to develop a CO2 storage site off the coast of Scotland, with a capacity to inject 5-10 MtCO2/year by 2030. Source: Reuters.

[13] Viking CCS, a project led by Harbour Energy, aims to store up to 10 MtCO2/year by 2030 at the depleted Viking gas fields in the southern North Sea. It plans to start injecting CO2 in 2027, initially at a rate of 2 MtCO2/year, ramping up to 10 MtCO2/year by 2030 and 15 MtCO2/year by 2035.

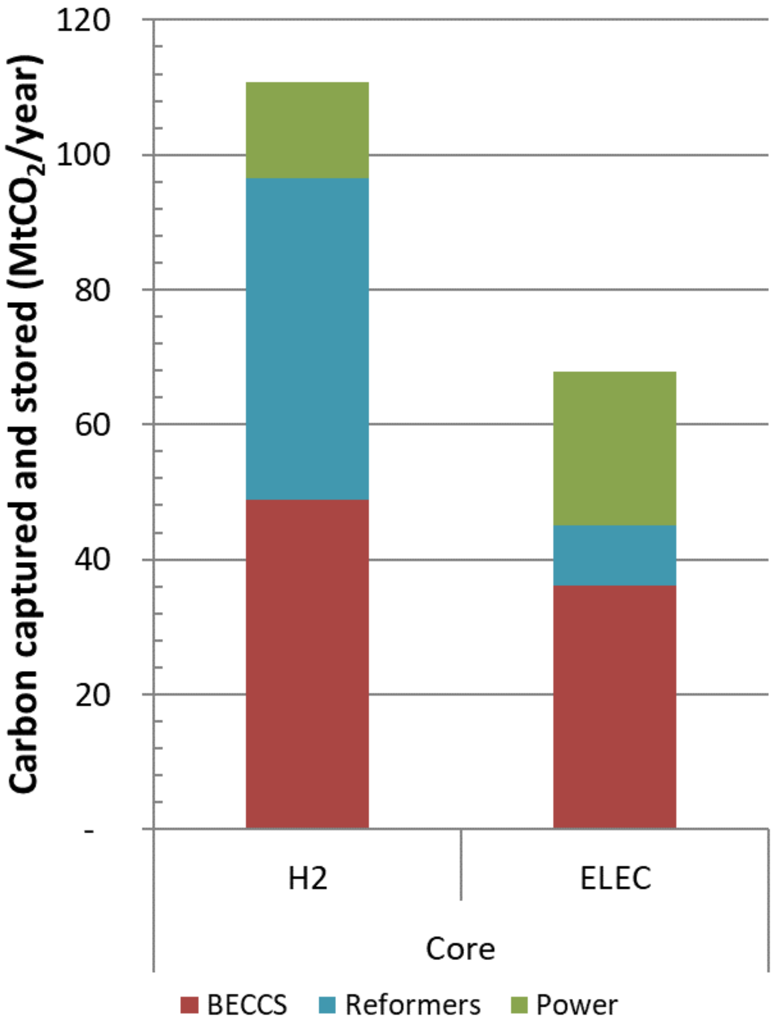


Figure 2-16 Volume of annual carbon sequestration for Hydrogen and Heat Electrification pathways

2.7 Transport of hydrogen within the existing infrastructure

This section investigates the feasibility of hydrogen transport via pipelines and the role of linepack. Efficient hydrogen transport and linepack management form a 'Virtuous Circle'[14] based on three key pillars: flexibility, efficiency, and cost-effectiveness (Figure 2-17). The studies are conducted using the integrated analysis of hydrogen and electricity systems. In this context, the Circle can be formed based on hydrogen transport within the existing infrastructure, as linepack (the hydrogen storage within the pipelines) is the critical element in this approach. Before going to the details, here is the summary of the approach as follows:

[14] *A 'virtuous circle' is a complex, self-sustaining chain of events where each positive action or result leads to another, creating an ongoing cycle of positive outcomes.*

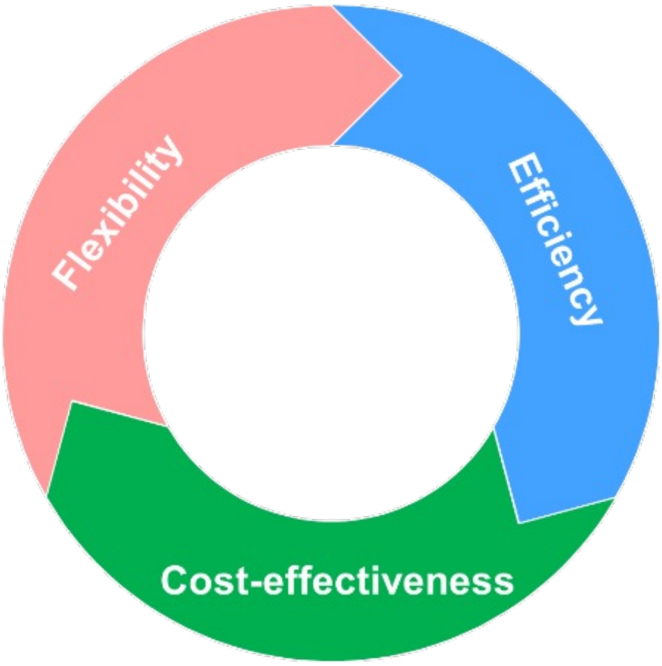


Figure 2-17 Flexibility, efficiency, and cost-effectiveness Virtuous Circle

1. *Flexibility:*

- Definition: The capacity of an energy system to adapt to dynamic conditions, including shifts in demand, supply interruptions or new energy source integration.
- Implications in the energy sector: With the advent of renewable energy sources, which are often intermittent (e.g., solar or wind power), flexibility becomes critical. Systems must be able to adapt to changes in energy supply quickly. Through injecting green hydrogen (produced via electrolysers) into the gas infrastructure, the excess energy can be stored in storage facilities and within the pipelines and converted back into electricity when needed. In this realm, the inherent linepack flexibility in the gas pipelines plays an important role in enabling hydrogen to be delivered to the demand centres.
- Contribution to the Circle: Hydrogen-related flexibility can harness peaks in renewable energy output and optimal usage of resources, laying the foundation for improved efficiency.

2. *Efficiency:*

- Definition: The ratio of useful energy output to the total energy input, indicating how well energy resources are utilised.
- Implications in the Energy Sector: A more efficient energy system minimises energy loss, whether in transmission, storage, or end-use. For instance, reducing renewable energy curtailment by converting excess energy to green hydrogen using electrolysers and storing it in the gas infrastructure improves the utilisation of energy resources.
- Contribution to the Circle: Improving efficiency conserves valuable resources and drives down operational costs, paving the way for cost-effectiveness.

3. *Cost-Effectiveness:*

- Definition: Achieving desired outcomes or benefits at the lowest possible cost.
- Implications in the Energy Sector: An energy system that combines flexibility and efficiency inherently reduces energy losses. This results in lower operational and maintenance costs. When renewables operate at their highest efficiency and storage systems like hydrogen are deployed to balance the grid, the costs associated with energy production and distribution diminish.
- Contribution to the Circle: By keeping costs low, investments can be redirected into further enhancing system flexibility for higher integration of renewables.

In summary, the interplay between these three pillars is as follows: flexibility provided by electrolysers and linepack (to transport the hydrogen within the existing gas infrastructure) ensures that energy systems can adapt to changing conditions, leading to increased efficiency in energy use. This increased efficiency, in turn, reduces losses and operational costs, translating to greater cost-effectiveness. Subsequently, as systems become cost-effective, more capital is available to invest in technologies and infrastructure that further boost flexibility. Thus, the circle feeds into itself, ensuring that advancements in one pillar bolster the others, leading to a continually evolving, improving, and self-sustaining energy ecosystem.

2.7.1 Case study and core assumptions

The IHES model is applied to comprehend the mechanisms of hydrogen transportation within the gas infrastructure. This model is applied to the Great Britain network, which includes an 85-node National Transmission System (NTS) and a representative 47-node electricity network, depicted in Figure 2-18 and Figure 2-19, respectively. The model also includes a simplified offshore network. The primary assumptions, including those related to investment decisions for electricity generation and hydrogen supply, are derived from the IWES model and subsequently input into the IHES model. Furthermore, the IHES model also incorporates the fundamental scenarios of heat decarbonisation presented earlier, ensuring a comprehensive and aligned energy system analysis.

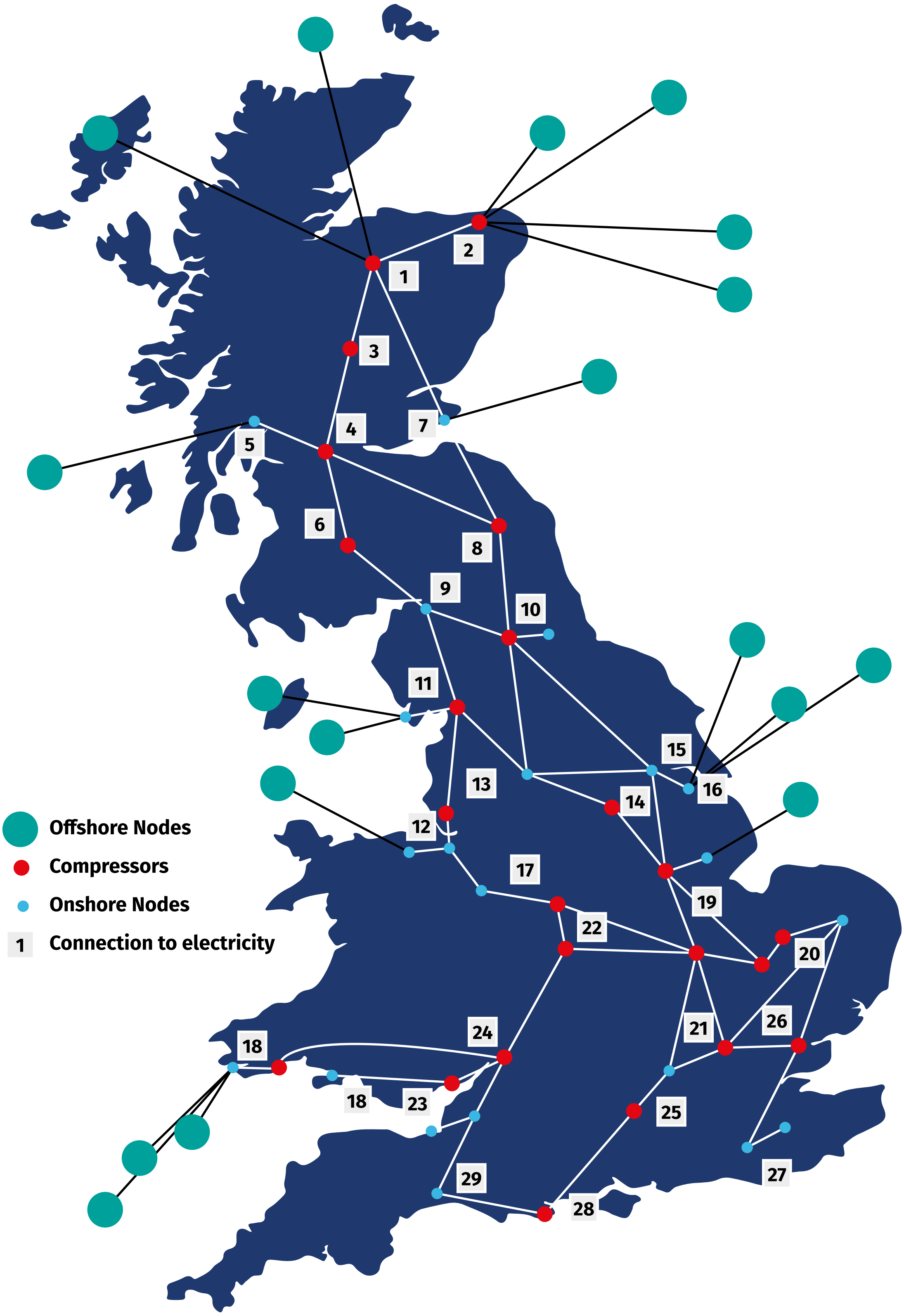


Figure 2-18 A Simplified Great Britain 85-node gas network

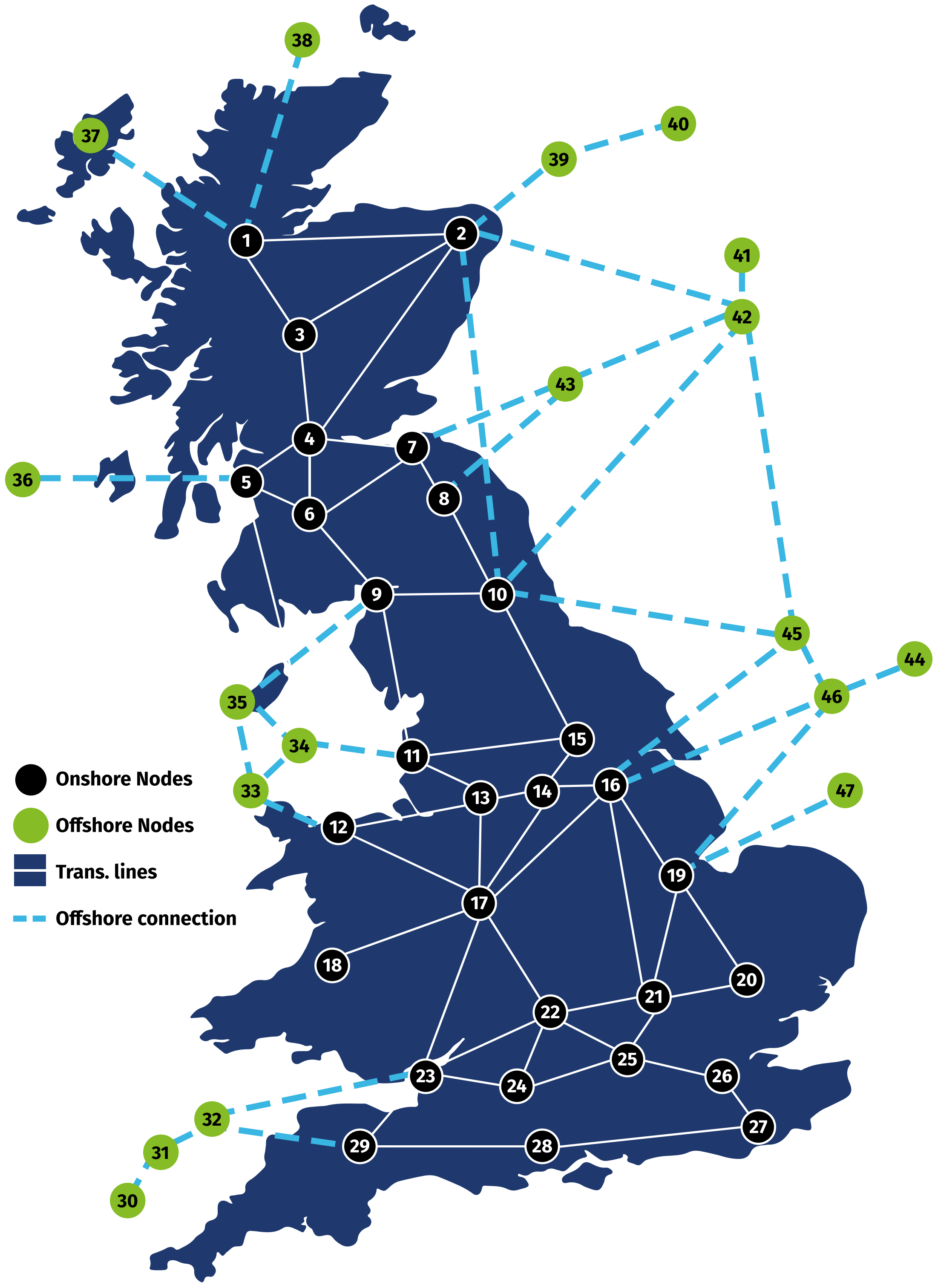


Figure 2-19 A 47-node representative Great Britain electricity network

2.7.2 Role of linepack in supporting the energy system

This section investigates the role of linepack as a means of flexibility to support the energy system. The IHES model is applied to investigate the virtuous circle formed through electrolysers (for green hydrogen production) and hydrogen-based power generation as the links between hydrogen and electricity systems. As depicted in Figure 2-20, the integration of RES into the system is significantly enhanced, particularly in the Hydrogen pathway. This pathway exhibits a substantial 43% decrease in RES curtailment compared to the Heat Electrification (ELEC) pathway, equivalent to a saving of 4.5 TWh/yr. This flexibility is primarily facilitated by the widespread deployment of electrolysers, which produce green hydrogen that supports the heat demand in the Hydrogen pathway. By injecting more green hydrogen into the gas infrastructure, an increase in linepack is achieved, delivering 'free' flexibility, maintaining the load factor on RES, and reducing curtailment. This is reflected in the hydrogen system, serving as a flexible means of maintaining supply-demand equilibrium within the hydrogen system, manifesting as a range of swings in linepack, reaching up to 56.8 mcm/day and 74.4 mcm/day in Heat Electrification and Hydrogen pathways, respectively. The 'free' storage within the pipes can be valued[15] at £0.71m/day and £1.06m/day in Heat Electrification and Hydrogen pathways, respectively. The active role of linepack is particularly necessary due to the added stress on the system imposed by the demand for hydrogen for heating applications, which is served via boilers.

Moreover, hydrogen transport in the Hydrogen pathway is emphasised as being more critical, further highlighting the importance of the linepack's role. The additional system stress highlights the necessity for reinforcement within the gas infrastructure, such as through enhanced hydrogen storage facilities. In this context, the linepack plays an indispensable role in maintaining the security of the hydrogen supply within this highly active, stress-prone Hydrogen pathway.

Any surplus hydrogen supply by electrolysers is redirected into hydrogen storage facilities. These facilities exhibit high utilisation during extreme events such as cold winter days, offering cost-effective supply to support resilience. The support for these findings is further provided in the form of hourly operational data for both electricity and hydrogen supply, covering different decarbonisation pathways and scenarios, including windy summer days and cold winter days. This data effectively illustrates the efficiency, flexibility, and resilience of these integrated energy systems.

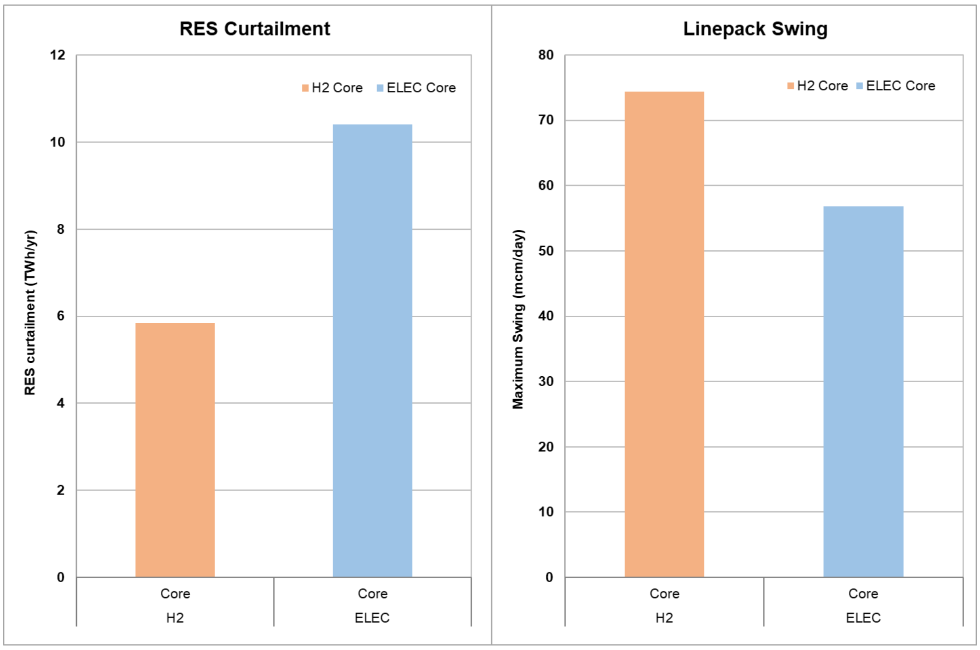


Figure 2-20 RES curtailment and linepack swing in different decarbonisation pathways

[15] *Speirs J., Jalil Vega F., Cooper J., Gerber Machado P., Giarola S., Brandon N. and Hawkes A. The flexibility of gas: what is it worth?; Sustainable Gas Institute, Imperial College London. July 2020.*

Figure 2-21 illustrates the impact of renewable intermittency on the operation of the gas network, manifesting as a range of swings in linepack, reaching up to 74.4 mcm/day (83% more than November 2021[16]). High swings in linepack of such scale can pose operational challenges for the NTS. The primary strategy would then revolve around evenly distributing hydrogen reserves throughout the system, consistently maintaining pressure standards, and proactively overseeing compressors to prevent shutdowns. Any unplanned outages could lead to potential systemic complications. The figure underscores the dynamic role played by the linepack in the Hydrogen pathway, serving as a flexible means of maintaining supply-demand equilibrium within the hydrogen system. It highlights the variance in swings between the Hydrogen and Heat Electrification pathways. The linepack swing in the Hydrogen pathway generally appears more significant because the demand for hydrogen for heat must be supplied promptly, leading to significant variations in linepack levels to meet these time-sensitive requirements.

In contrast, the Heat Electrification pathway exhibits smaller swings in linepack. This is attributable to the fact that there is no hydrogen demand for heating in the Heat Electrification pathway. With smaller demand, the system experiences less stress, and rapid fluctuations are less likely to occur. Consequently, the linepack swings in the Heat Electrification pathway are noticeably smaller, highlighting a more stable operation within this particular pathway. Overall, Figure 2-21 details how different energy pathways handle renewable intermittency and the subsequent impacts on the operational stability of the gas network.

Figure 2-21 Linepack swing during the year in Heat Electrification and Hydrogen pathways

In conclusion, as indicated in Figure 2-17, the whole system approach through integrating hydrogen and electricity systems can result in the formation of a 'virtuous circle' based on three key pillars: flexibility, efficiency, and cost-effectiveness:

- *Flexibility:* The large-scale deployment of electrolysers facilitates hydrogen production, which can act as a versatile energy carrier. As we expand the use of hydrogen for heating and other applications, the resultant flexibility in energy storage and distribution grows in value. This adaptability ensures the energy network's stability, as linepack variability offers inherent 'free' flexibility.

- *Efficiency:* A more flexible energy system is inherently more efficient. With the increasing integration of RES, maintaining their load factor becomes crucial to optimise their output. As the energy system becomes more adaptable, curtailing or wasting excess energy produced by renewables is minimised if not completely avoided. This ensures that energy is utilised more efficiently and sustainably, benefiting both the environment and the economy.

[16] The NTS has recently experienced some days with significant swings in linepack. In November 2021 the NTS faced swings of ~41mcm over the course of the gas day (National Grid Gas Transmission (March 2022). GMaP: GB Gas Balancing Regime Review final report).

- *Cost-Effectiveness:* Efficiency directly correlates with cost savings. As the energy system operates at higher efficiency levels, the levelised cost of renewables is kept low, ensuring more affordable energy prices. Furthermore, the flexibility achieved ensures that energy storage solutions are utilised optimally. During extreme events when energy demand spikes, these storage solutions can provide a cost-effective supply, preventing potential energy crises and stabilising consumer energy prices.

In summary, the virtuous circle of flexibility, efficiency, and cost-effectiveness emphasises the interconnected nature of hydrogen and electricity systems. By investing in electrolysers and integrating them into the energy system to produce green hydrogen to be injected into the existing gas infrastructure, an energy future that is both sustainable and economically viable could be achieved. This interconnected cycle fosters resilience and stability in the decarbonisation of the energy system.

2.7.3 Temporal analysis of electricity and hydrogen systems in extreme events

This section presents and analyses the key results of the critical role of hydrogen in bolstering grid resilience. The key findings of the study are summarised as follows:

- In the Hydrogen pathway, abundant summer renewables are utilised to produce and store hydrogen, ensuring system resilience and fulfilling heating demands, whereas the Heat Electrification pathway prioritises storage.

- In cold winter conditions, hydrogen storage and linepack provide crucial flexibility and resilience to the energy system, addressing both electricity and heating demands amidst reduced renewable availability.

- Hydrogen-based CCGTs generate approximately 21% of energy to compensate for the renewable deficit during low-RES periods.

- In scenarios where electricity from hydrogen-based CCGTs is low (due to high demand for heating), nuclear and gas CCS step in, supplying a significant 809 GWh/day. Hydrogen storage facilities then become pivotal, contributing approximately 475 GWh/day, marking a 35% increase compared to the Heat Electrification pathway, showcasing the crucial role of stored hydrogen during high-demand periods.

This section investigates the critical role of hydrogen in bolstering grid resilience. In this context, Figure 2-22 and Figure 2-23 depict two distinct scenarios designed to shed light on this matter. These extreme events provide contrasting conditions in terms of demand and renewable supply, enabling a comprehensive understanding of hydrogen's role across diverse operating conditions:

- Figure 2-22 represents the "Windy Summer" days scenario. In this scenario, the available renewable generation is high, reaching up to 110 GW in the Heat Electrification pathway, while the peak electricity demand is notably low. Under these circumstances, the hydrogen demand in the Heat Electrification pathway is less compared to the Hydrogen pathway. This is primarily due to the excess renewable generation, which can be effectively utilised to meet the demands of the Hydrogen pathway.

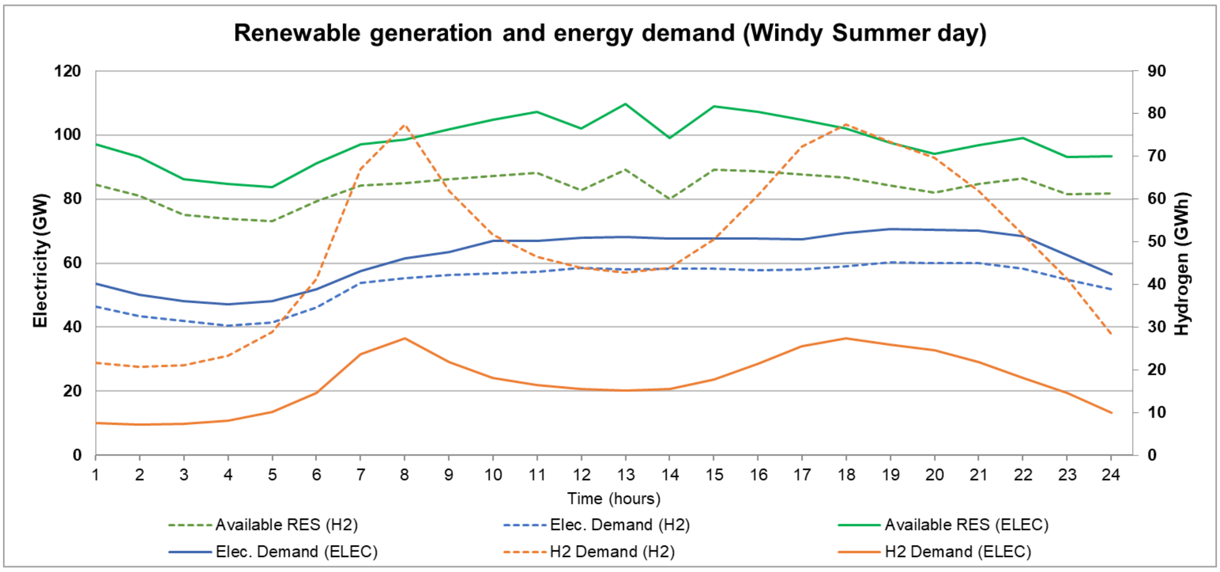


Figure 2-22 Representative Windy Summer day in different decarbonisation pathways

- Figure 2-23, on the other hand, portrays the representative “Cold Winter” days scenario, where the available renewable generation is significantly low, not exceeding 20 GW, and the electricity and hydrogen demands are concurrently high. This scenario provides insights into the operational complexities of balancing supply and demand under resource constraints, demonstrating the critical role that hydrogen can play in mitigating the challenges associated with renewable intermittency and demand fluctuations.

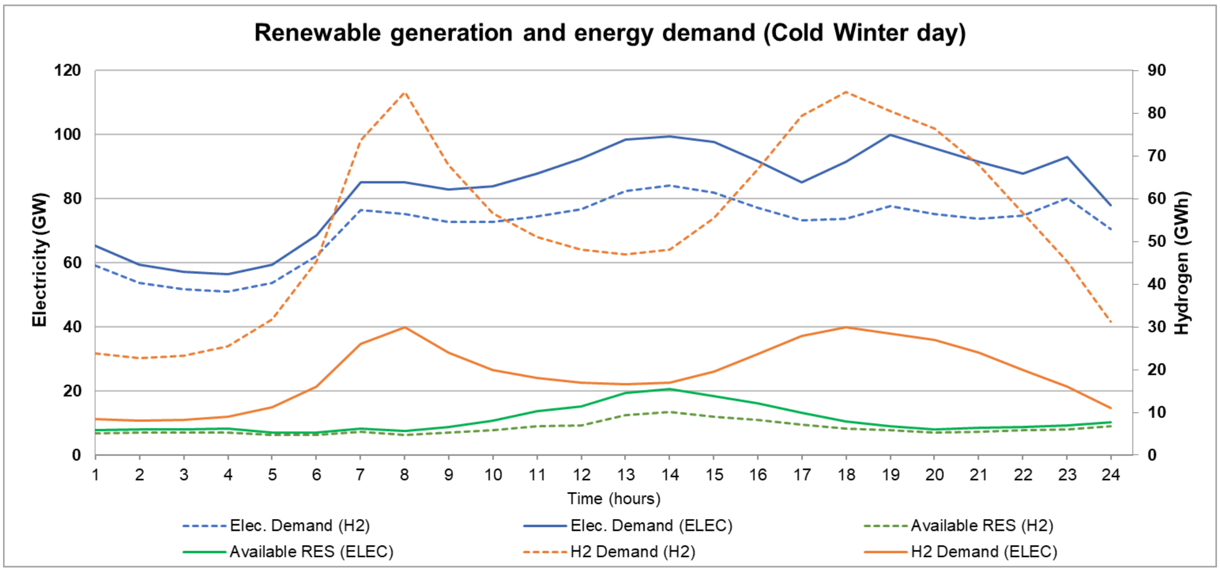


Figure 2-23 Representative Cold Winter day in different decarbonisation pathways

The insights derived from Figure 2-24 offer a compelling analysis of various energy pathways and their interactions with different weather conditions and demand profiles.

During the windy summer days, the dominance of RES, including offshore and onshore wind, solar, and others in the electricity supply is notable. This observation aligns with expectations, considering the high availability of wind and solar resources during this period. The Hydrogen pathway scenario depicts a lower electricity demand than the Heat Electrification pathway. This difference leads to increased production of green hydrogen (330 GWh/day as opposed to 268 GWh/day), which is then injected into the gas infrastructure. Consequently, the electricity demand in the Hydrogen and Heat Electrification pathways remains roughly identical. The hydrogen demands in the Hydrogen pathway are predominantly met by a combination of green hydrogen and Blue+Bio H2 (i.e., ATR+CCS and biomass gasification). Excess hydrogen is stored in dedicated facilities to bolster system resilience during extreme events. However, the heating demands in the Hydrogen pathway require increased supplies of Blue+Bio H2 and green hydrogen. As a result, less hydrogen is stored in the facilities (251 GWh/day), contrasting with the Heat Electrification pathway that stores up to 430 GWh/day.

In contrast, RES availability dwindles during the cold winter days, representing extreme weather conditions. Therefore, most of the electricity demand is met by other generation plants (nuclear and gas CCS) and hydrogen-based CCGTs, as presented in Figure 2-24. Significant flexibility measures, including electricity storage and interconnections, are necessitated to address the variability associated with RES during this period. In these winter days, the flexibility of long-duration hydrogen storage facilities is invaluable, as it enhances the system's resilience to cope with extreme weather events. It is demonstrated that in the Hydrogen pathway, they supply up to 475 GWh/day, meeting hydrogen demand for the base, electricity generation and heating. Conversely, due to the increased electricity demand in the Heat Electrification pathway to supply heat, a more significant proportion of electricity (77%) must be supplied by hydrogen-based CCGTs. Lastly, it is worth noting the role of linepack as the intra-day storage for hydrogen. By providing flexibility to counter the intermittency introduced by a significant penetration of renewables, linepack ensures a balanced hydrogen system. The hourly operation depicts the negligible sum of linepack over a day, as the system operator aims to balance the available linepack at the end of the day.

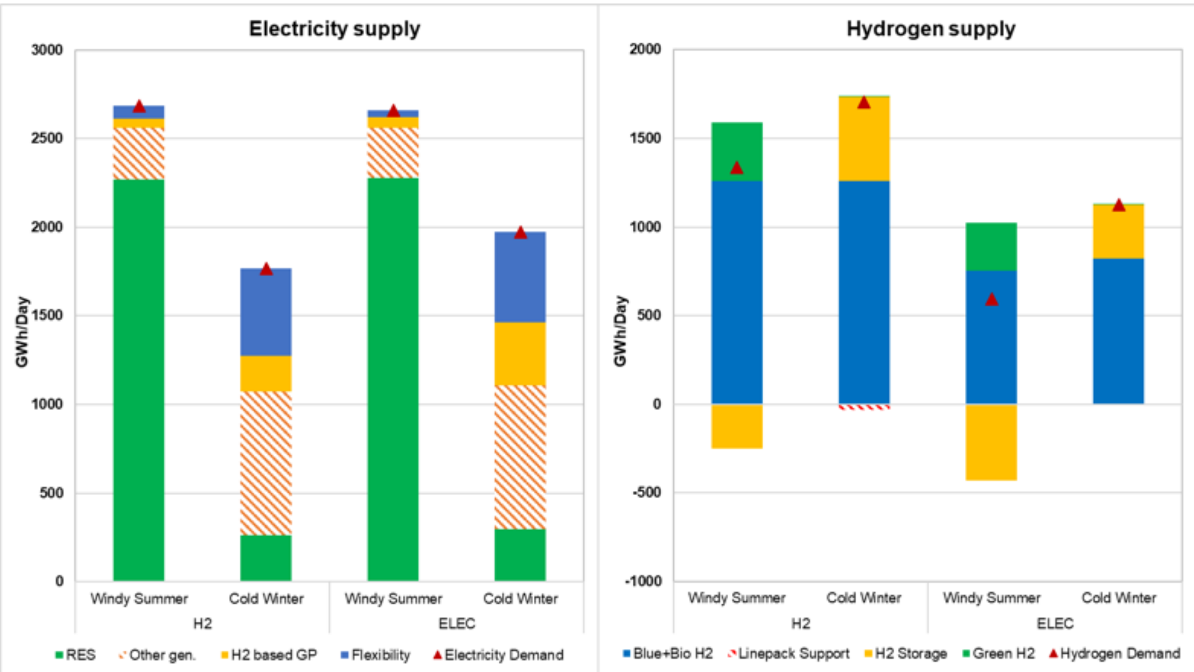


Figure 2-24 Energy supply during two extreme weather events

Figure 2-25 and Figure 2-26 provide valuable insights into how renewable energy can be optimally used for electricity provision and green hydrogen production, thereby ensuring energy security during prolonged periods of low wind availability. As depicted in Figure 2-25, during periods of high renewable availability, most of the electricity demand is met directly by these renewable sources, minimising dependence on non-renewable sources. It contributes to sustainable energy use and reduces carbon emissions associated with conventional electricity generation. Figure 2-26 demonstrates the potential of using this abundant renewable energy to produce green hydrogen. It indicates how excess renewable electricity can be converted into green hydrogen through electrolysis when renewable sources are abundant. This green hydrogen is then injected into storage facilities, creating a reserve that can be tapped into during extreme events such as prolonged periods of low wind. On this specific day, the model suggests that approximately 430 GWh/day of hydrogen is injected into the storage facilities, creating a significant buffer against fluctuations in renewable generation. This highlights the dual benefit of renewable energy availability: direct provision of electricity and the production source of green hydrogen for future use. This strategy ensures resilience and flexibility, supporting intermittent renewable generation and contributing to long-term energy security and sustainability.

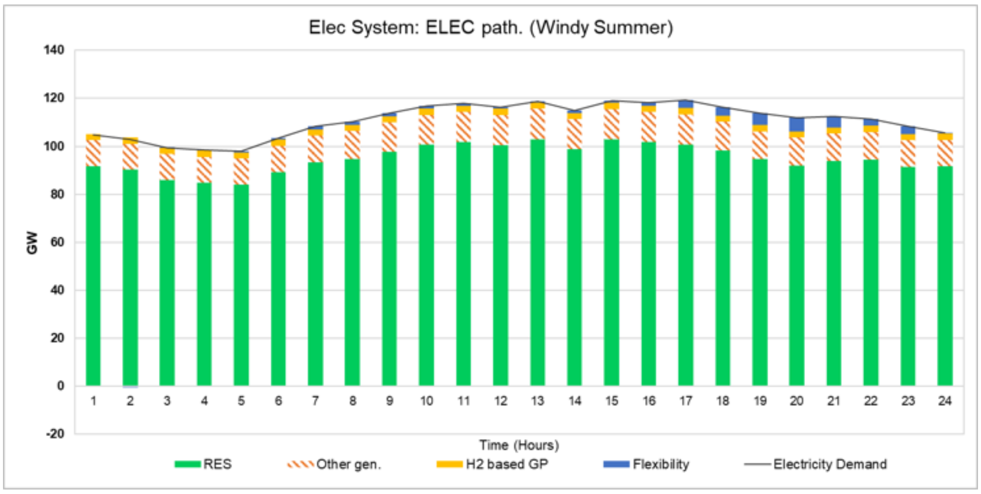


Figure 2-25 Electricity system operation on the Windy Summer day: Heat Electrification pathway

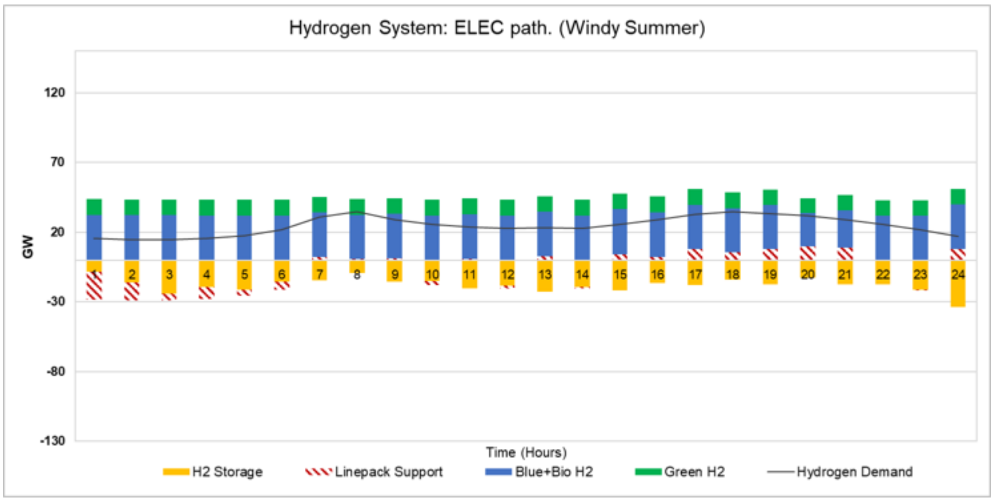


Figure 2-26 Hydrogen system operation on the Windy Summer day: Heat Electrification pathway

The Hydrogen pathway presents a different scenario, primarily due to the additional hydrogen demand for heating (Figure 2-27 and Figure 2-28). As depicted in Figure 2-28, this increased demand necessitates a larger share of the produced green hydrogen to be directed immediately towards meeting the demand at the consumption centres. Despite this increased demand, a substantial amount of hydrogen is still injected into storage facilities to enhance system resilience during extremely low renewable events. The model suggests that under the Hydrogen pathway, around 250 GWh/day of green hydrogen is stored, which, while less than the amount stored under the Heat Electrification pathway, still provides a significant cushion for maintaining the system's stability during low-renewable events. It is demonstrated that even when hydrogen is in high demand for heating, strategic planning and management allow for adequate reserves to be maintained, thereby ensuring system resilience during periods of renewable scarcity. This insight underlines the importance of efficient resource distribution and the strategic role of green hydrogen in managing renewable intermittency.

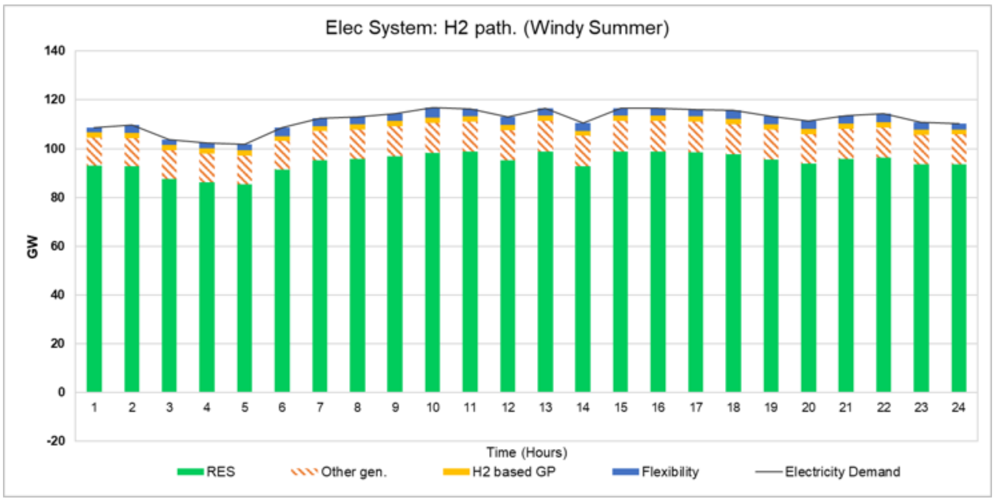


Figure 2-27 Electricity system operation on the Windy Summer day: Hydrogen pathway

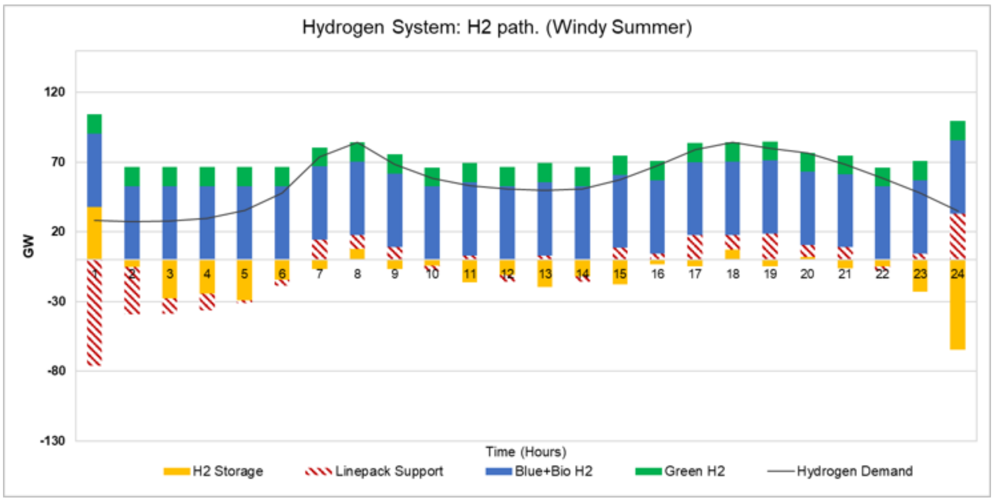


Figure 2-28 Hydrogen system operation on the Windy Summer day: Hydrogen pathway

Figure 2-29 presents a scenario characterised by low RES availability. In this circumstance, the crucial role of hydrogen-based CCGTs in supplementing the lack of renewable generation becomes abundantly clear. Approximately 350 GWh/day (21%)[17] of electricity is generated by these hydrogen-based CCGTs to make up for the renewable deficit. This situation necessitates a more active role for both linepack and hydrogen storage facilities to maintain the security of supply, as illustrated in Figure 2-30. An important observation here is that the usual constraint mandating the linepack capacity at the end of the day to be the same as at the start of the day is relaxed, indicating the flexibility and adaptability of the system under stress conditions. The low availability of RES leads to a reduced supply of green hydrogen, further emphasising the value of the stored hydrogen and its strategic role in supporting grid resilience during low-RES periods. It also underscores the vital function of hydrogen storage facilities and flexible linepack management in ensuring continuous energy supply in periods of renewable intermittency.

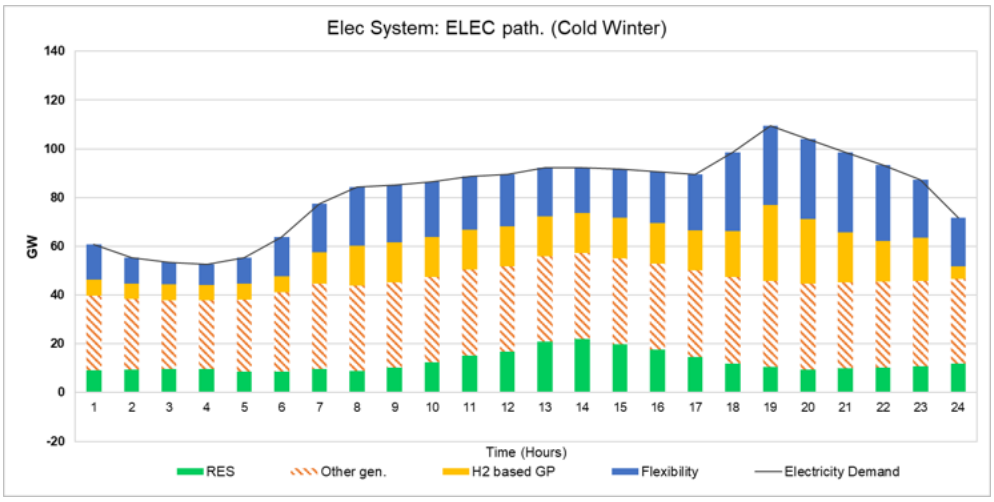


Figure 2-29 Electricity system operation on the Cold Winter day: Heat Electrification pathway

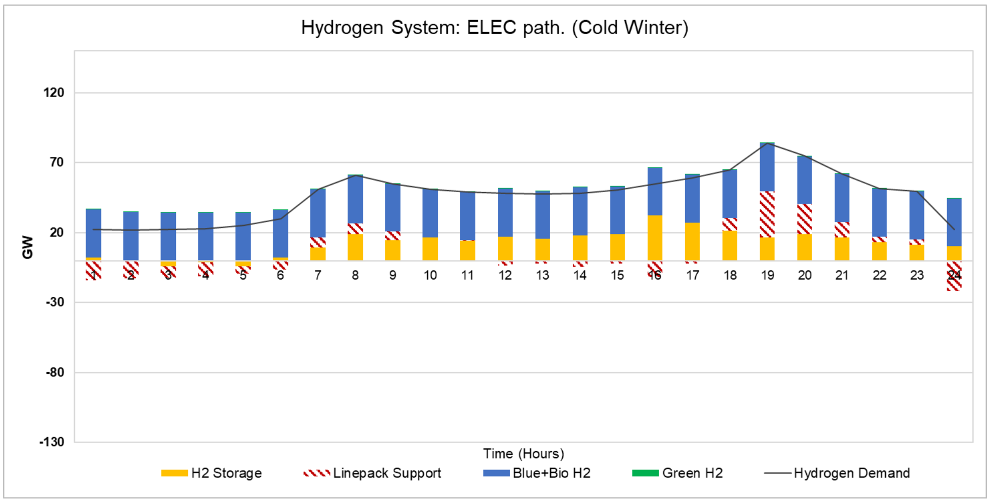


Figure 2-30 Hydrogen system operation on the Cold Winter day: Heat Electrification pathway

[17] *The electricity demand (without the demand for electrolysers) is 1704 GWh/day in the Cold Winter day.*

Figure 2-31 highlights a scenario characterised by low electricity generation by hydrogen-based CCGTs. This is primarily due to the high demand for heating, leading to increased reliance on other generation plants for electricity supply. In such circumstances, nuclear and gas CCS are responsible for supplying a significant energy load of approximately 809 GWh/day. In this high-demand scenario, the role of hydrogen storage facilities becomes even more crucial in ensuring the security of the energy supply.

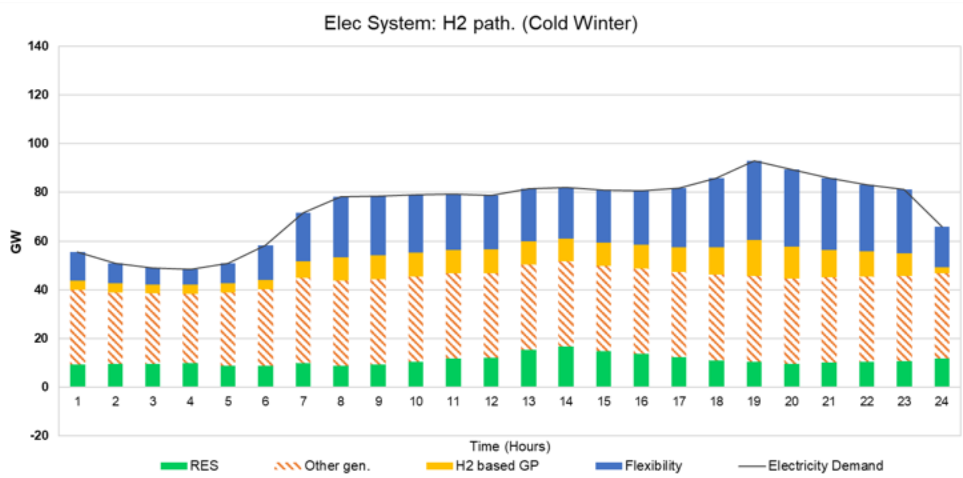


Figure 2-31 Electricity system operation on the Cold Winter day: Hydrogen pathway

As Figure 2-32 demonstrates, the energy contribution from these storage facilities amounts to approximately 475 GWh/day. This represents a substantial 35% increase compared to the energy provision in the Heat Electrification pathway, thus emphasising the pivotal role of stored hydrogen in maintaining the reliability of energy provision, especially during periods of heightened demand.

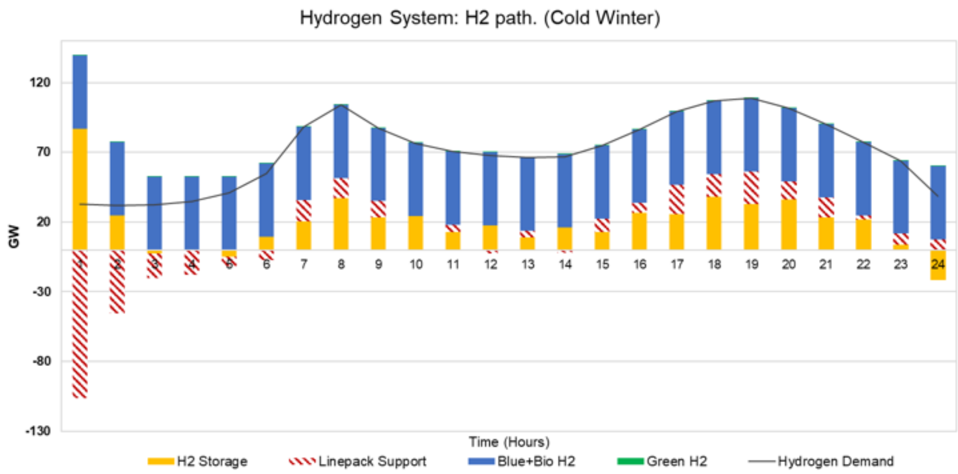


Figure 2-32 Hydrogen system operation in the Cold Winter day: Hydrogen pathway

Chapter 3. Comparison between Hydrogen and Heat Electrification Pathways under Different Future Developments

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 discussed in the previous chapter. All our modelling results meet 2050 net-zero carbon and achieve energy system resilience against extreme weather events. Before going to the details of the studies, the key findings of our sensitivity analysis can be summarised as follows:

- The hydrogen pathway costs less than the Heat Electrification pathway across all the scenarios. The savings are between **£2–7.3bn/year.** Even extreme gas prices do not make the Hydrogen pathway less cost-effective overall.
- Improving system flexibility through deploying demand response, energy storage technologies, and electricity interconnection between Great Britain and Europe is important for both pathways as it is the most sensitive factor that drives system costs up or down. 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.
- Reducing the annual and peak energy consumption through improving energy efficiency is important in all scenarios.
- All hydrogen production technologies should be considered and optimised to minimise the overall system costs while providing diversity in hydrogen supply to improve energy security and resilience against extreme weather events.
- Increased duration of extreme weather conditions is not a major issue if the system has sufficient firm low-carbon capacity from gas CCS, hydrogen, and nuclear power generation. Hydrogen production from ATR+CCS can be increased to support higher hydrogen demand due to prolonged low-wind conditions with a small impact on the capacity requirement. Hydrogen storage and RES capacity can be increased as an alternative option if green hydrogen is preferred.

3.1 Description of scenarios used in the sensitivity studies

The case studies discussed in section 1.4 are summarised in Table 3-1, with the key parameter changes being studied. The parameters are selected to represent the key drivers of uncertainty in future system conditions that may affect costs. Variables range across assumptions about the level of heat demand depending on the level of energy efficiency improvement achieved by 2050, technology costs, fuel costs, especially gas prices, hydrogen production policies, e.g. green hydrogen only, weather conditions, constraints in energy infrastructure development such as interconnectors, and deployment of distributed flexibility resources.

Table 3-1 List of sensitivities being studied.

Parameters	Core / Baseline	Sensitivity scenario tested	Rationale
Gas price	£23.67/MWh[18]	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[19].

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

Parameters	Core / Baseline	Sensitivity scenario tested	Rationale
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.

3.2 Key results of the sensitivity studies

The sensitivity studies show that the Hydrogen pathway is more cost-effective than the Heat Electrification pathway in all cases, even when the gas prices are set to be three times the gas price in the core scenario. The annual energy system costs of Hydrogen and Heat Electrification pathways under different scenarios are summarised in Figure 3-1. Figure 3-2 and Figure 3-3 show the difference between the system costs in different scenarios with the core scenario for Hydrogen and Heat Electrification pathways, respectively.

Key findings from the sensitivity analysis are:

- The modelling results (Figure 3-1) demonstrate that 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, as it will increase the hydrogen production cost, while the maximum difference is when the gas price is low.

- The four key drivers for increased costs in the Hydrogen pathway are *low system flexibility, high domestic heat demand due to less energy efficiency improvement and high gas prices*. A policy choice to avoid the deployment of blue hydrogen adds cost in the hydrogen scenario.

- In comparison, the four main drivers for increased cost in the Heat Electrification pathway are *low system flexibility, high domestic heat demand, low winter wind and low development of interconnectors.*

- A higher level of domestic heat demand will increase the cost of Hydrogen and Heat Electrification pathways due to increased system capacity requirements and operational costs. The results indicate that reducing the annual and peak energy consumption through improving energy efficiency is important in any scenario.

- **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.

- **Hydrogen Storage:** A high hydrogen storage cost sensitivity has less impact as there are other alternative flexibility solutions, such as increasing the production capacity of reformers. However, a lower cost of storage sensitivity can reduce overall system costs.

- **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.

- **Cost of Low-carbon Generation:** Changes in the cost of key low-carbon technologies such as nuclear and offshore wind will also affect the system costs in both pathways. While offshore wind costs continue to decrease, there is significant uncertainty on the cost of nuclear, given that the wide range of financing costs for this technology influences its cost.

- **Interconnection:** Development of electricity interconnection capacity is also important for both pathways. Interconnection improves system flexibility and the ability to exchange and trade energy, capacity, and grid services with interconnected regions.

- **Wind output uncertainty during winter:** The risk of low wind output during periods of peak winter demand increases the system costs of both pathways, considering that wind supplies more than 75% of the annual electricity demand in both pathways. The results indicate the need for other energy sources, such as natural gas, pump hydro, biomass, geothermal, marine, and nuclear to diversify the energy mix and ensure energy security for GB.

- **Longer Peak Winter Wind Droughts:** Increasing the duration of extreme weather events is not a major issue, given that the optimal system in the core scenario already includes a 3-day extreme weather event. The system has sufficient firm low-carbon capacity from gas CCS, hydrogen, and nuclear power generation to mitigate extended supply constraints. The hydrogen production from ATR+CCS can be increased to support increased hydrogen demand due to prolonged low-wind conditions with a small impact on the capacity requirement. Hydrogen storage and RES capacity can be increased as an alternative option if green hydrogen is preferred.

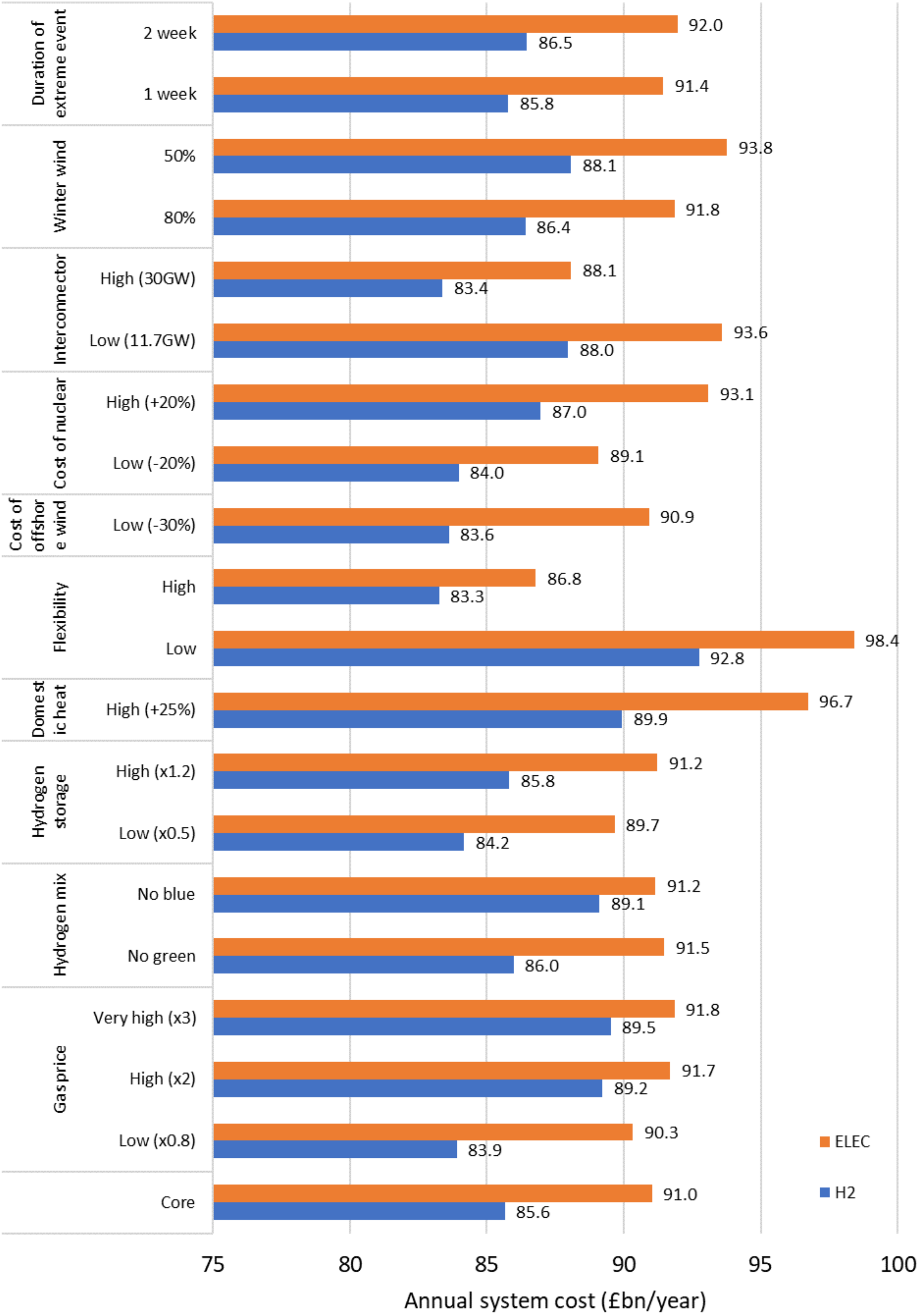


Figure 3-1 Changes in annual system costs from the Heat Electrification to the Hydrogen pathway.

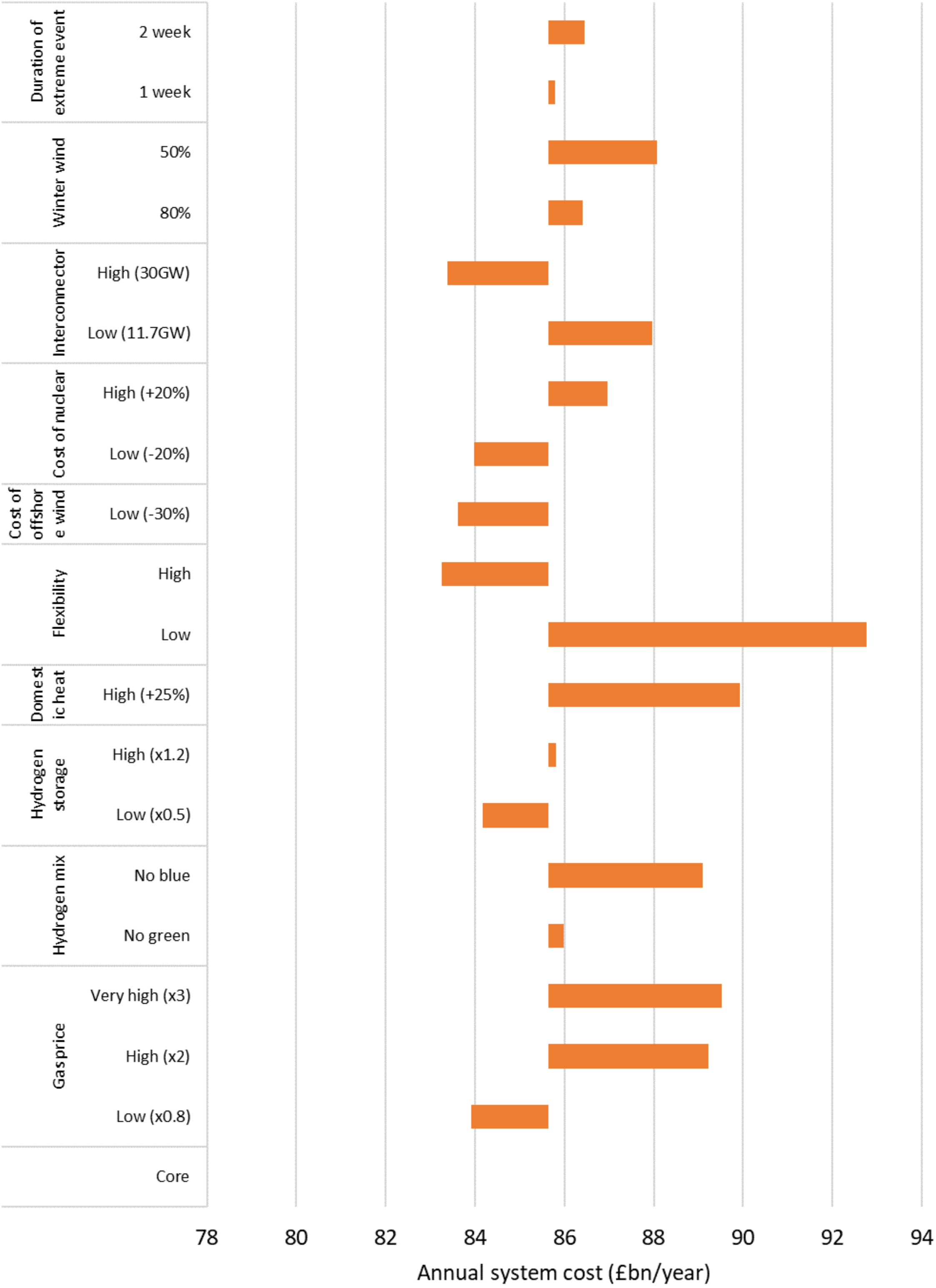


Figure 3-2 Annual system cost changes in the Hydrogen pathway due to different assumptions. The core scenario is the reference.

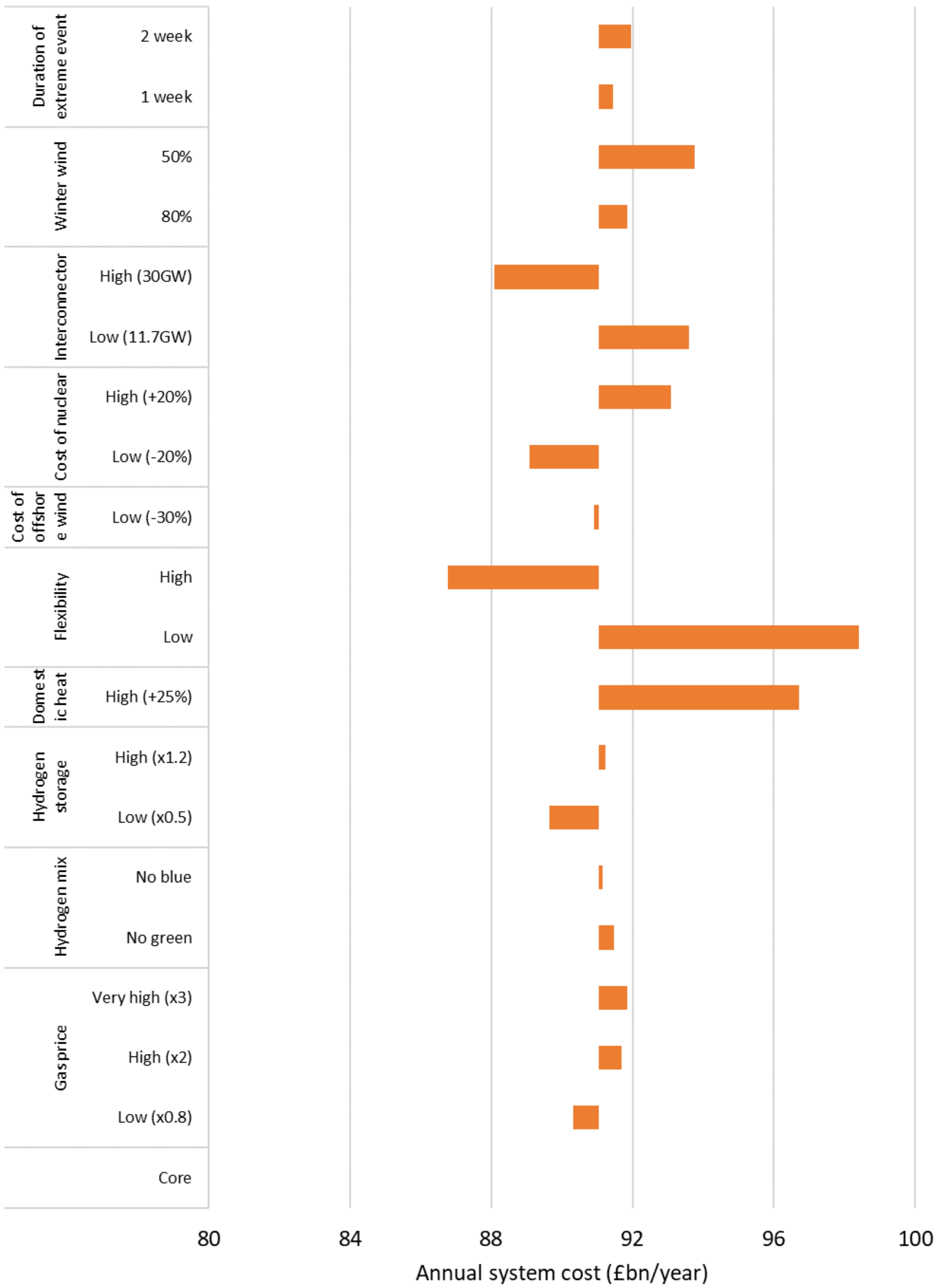


Figure 3-3 Annual system cost changes in the Heat Electrification pathway due to different assumptions. The core scenario is the reference.

Selected key factors influencing the system costs are identified and analysed in more detail based on the results above. Those factors are:

1. Gas prices
2. System flexibility
3. Optimal hydrogen mix
4. Development of electricity interconnection with Europe
5. Level of heat demand
6. The impact of prolonged extreme weather events

3.3 Impact of higher gas prices

The natural gas supply shock caused by the Russia-Ukraine war has created energy price spikes - with the peak level at more than 10x pre-war prices and increased price volatility, triggering deep concern about the role of gas in future energy supply. This concern may affect decision-makers' views about hydrogen applications. However, hydrogen can be produced from different sources besides natural gas. So, this study aims to identify and quantify the impact of different assumptions of natural gas prices on the overall techno-economic performance of the Hydrogen and Heat Electrification pathways. The range of gas prices used in the study is between 80% and 300% of those used in the core scenario (£23.67/MWh). Figure 3-17 shows the impact of gas prices on the supply and demand of natural gas.

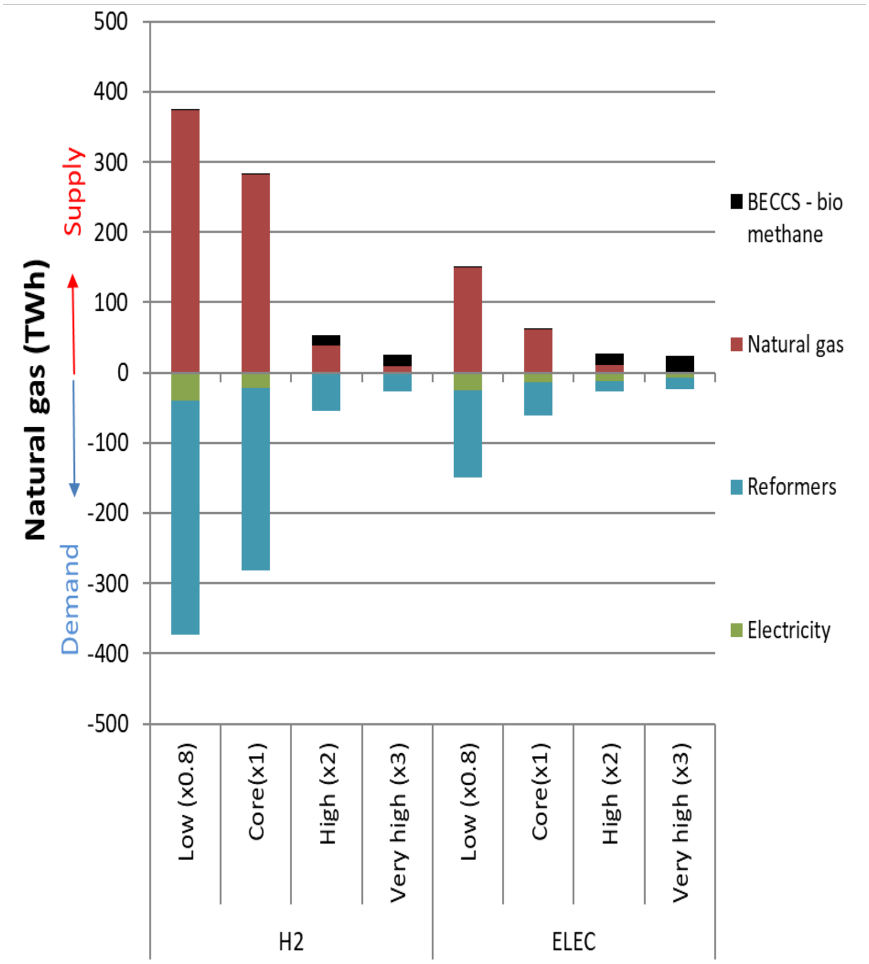


Figure 3-4 Impact of gas prices on the supply and demand of natural gas

The modelling results suggest the following:

- In the Hydrogen pathway, if the gas price is £23.67/MWh, natural gas will still supply around 280 TWh/year. The volume increases by 33% to 373 TWh/year if the price is reduced by 20%. If the gas price is doubled, the natural gas demand reduces to 38.40 TWh/year and drops further to 9 TWh/year if the price is tripled. It shows that the results are very sensitive to the gas price assumption, and the impact is non-linear.

- Most methane is needed for blue hydrogen production, and less than 10% is for electricity generation.

- When gas prices are doubled, methane produced from biomass gasification with CCS can be an alternative source. However, as the volume of biomass is limited and the production cost is high, the volume of bio-methane produced is still relatively small.

- Even with tripled gas prices, a small amount of methane is still reserved for reforming processes. The results indicate the importance of ATR+CCS (which requires methane) for balancing and meeting the hydrogen peak demand.

The impacts of different gas price assumptions on the system cost compared to the core scenario are shown in Figure 3-5.

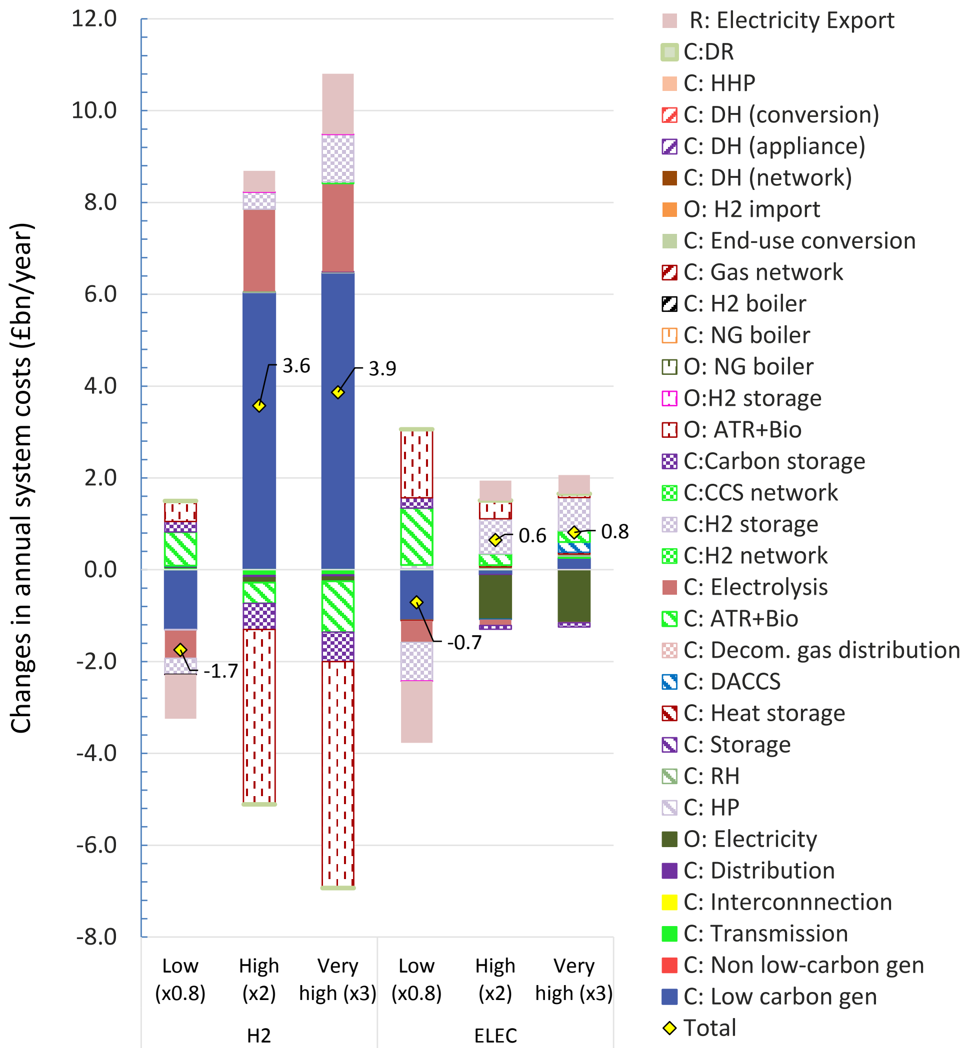


Figure 3-5 The difference between annual system costs of scenarios with different gas prices with the core scenario as the reference. (C: Capex, O: Opex – more detailed descriptions can be found in Appendix B)

The modelling results indicate that:

- With a lower gas price, more blue hydrogen will be produced. It requires additional investment in ATR+CCS and increased natural gas consumption, leading to increased carbon storage costs. On the other hand, it reduces the demand for low-carbon generation technology, electrolysers and hydrogen storage. A lower gas price also increases the business case for hydrogen heating as the savings to Heat Electrification increase to £6.4bn/year (Figure 3-6).

- With a higher gas price, the impact is reversed. It requires more investment in low-carbon technologies, electrolysers, and hydrogen storage to reduce the blue hydrogen infrastructure (reformers, carbon storage) and natural gas consumption. Those investments could be the economic rationale response to mitigate the risk of higher international gas prices.

- It is important to highlight that higher gas prices also affect the Heat Electrification scenario as the use of gas in power generation (gas CCS) and hydrogen production needs to be reduced. However, the increased cost in the Heat Electrification scenario due to higher gas prices is modest **(£0.6–0.8bn/year)**.

- The Hydrogen pathway is more exposed to the gas price assumption than the Heat Electrification pathway but remains more cost-effective, although the cost difference between the two pathways becomes smaller, as shown in Figure 3-6. This figure provides evidence from the modelling that the total cost of additional low carbon generation, hydrogen production, hydrogen boiler and gas network infrastructure in the Hydrogen pathway when the gas prices are high is still £2bn/year lower than the cost of distribution network, electric heating and storage in the Heat Electrification pathway.

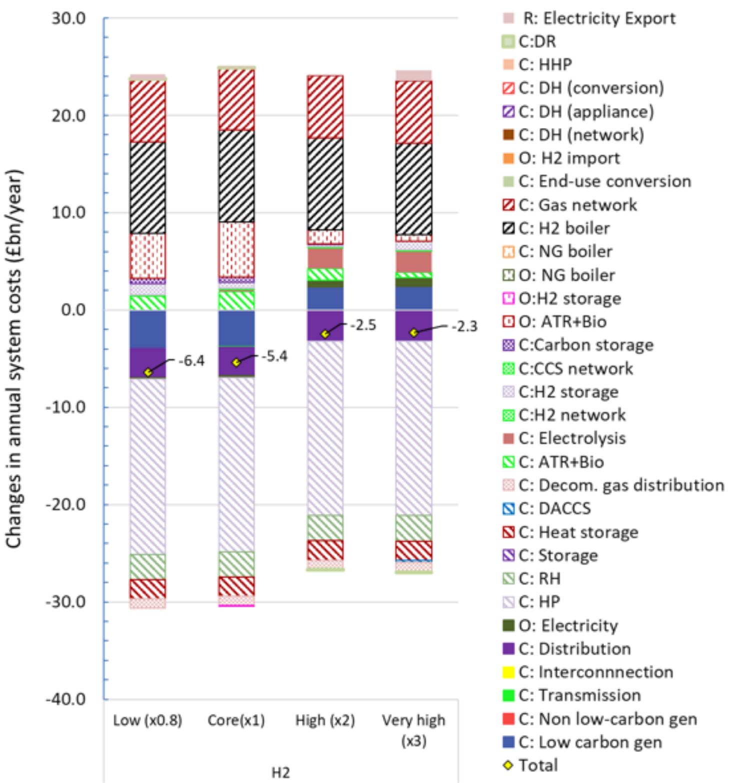


Figure 3-6 The difference between the Hydrogen and Heat Electrification's (as a reference) annual system costs with different gas prices

- The optimal mixes of annual hydrogen production in different scenarios are shown in Figure 3-7, providing evidence of the shift of blue to green hydrogen in both pathways when gas prices increase. A small volume of blue hydrogen is produced from synthetic methane.

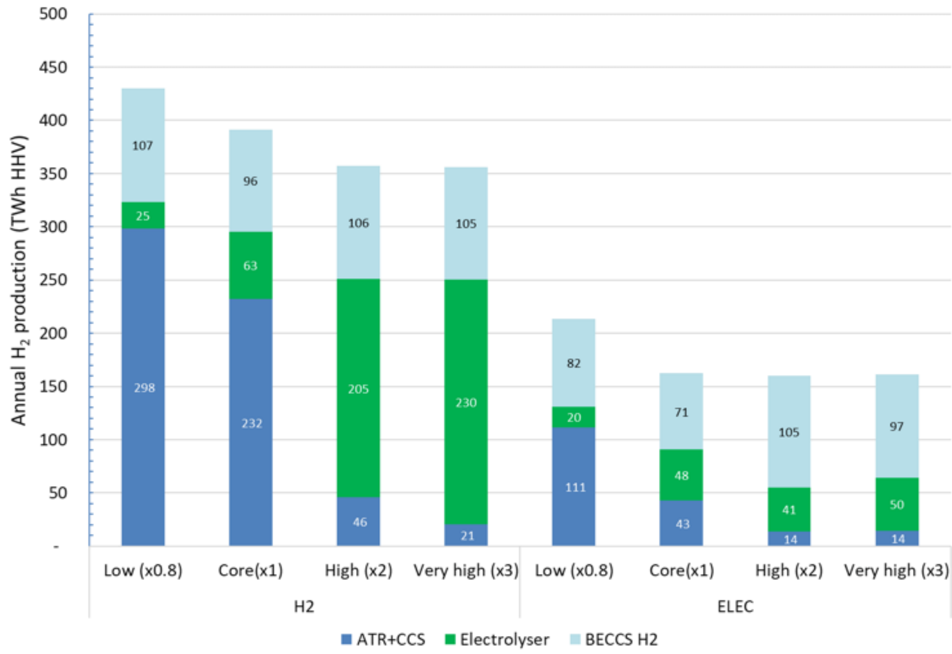


Figure 3-7 Optimal mixes of hydrogen production in scenarios with different gas prices

Higher gas prices also reduce the volume of hydrogen production needed, driven by less demand for hydrogen for power generation in the Hydrogen pathway while hydrogen is still used for generating power in the Heat Electrification scenario. These modelling results are shown in Figure 3-8. The results also show that lower gas prices will increase the utilisation of hydrogen for generating electricity.

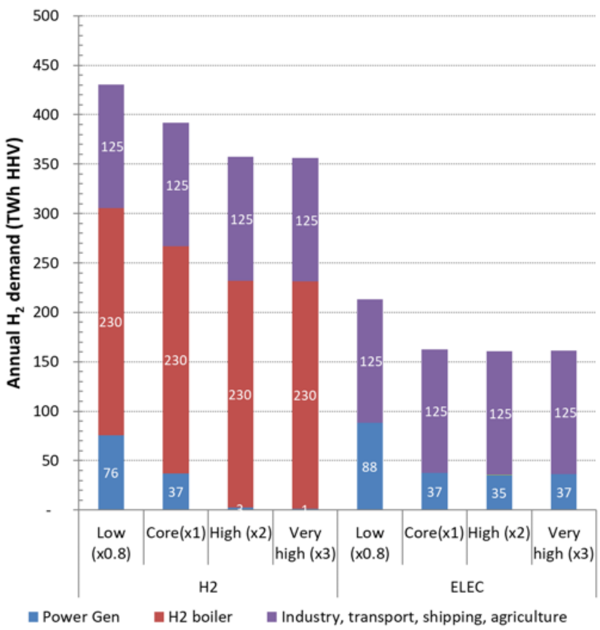
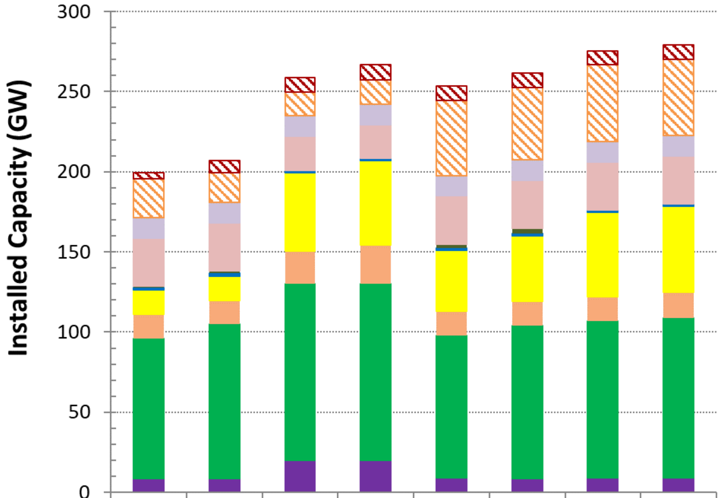


Figure 3-8 Annual hydrogen demand in scenarios with different gas prices

Higher gas prices also increase demand for low-carbon electricity, driving increased capacity of installed renewable energy capacity (wind and solar PV) in both pathways for facilitating green hydrogen production. As the model optimises the power generation mixes, nuclear capacity[20] increases to 20 GW in the Hydrogen pathway when the gas prices increase to 2x and 3x. The use of nuclear limits the cost of low-carbon generation as the system integration of RES increases as a function of its installed capacity. Figure 3-9 shows the optimal power generation portfolio in scenarios with different gas prices.



	H2				ELEC			
	Low (x0.8)	Core(x1)	High (x2)	Very high (x3)	Low (x0.8)	Core(x1)	High (x2)	Very high (x3)
H2 OCGT	3.7	7.7	8.9	9.4	9.2	9.2	8.8	9.0
H2 CCGT	24.4	18.5	14.8	15.0	46.6	45.2	47.9	47.7
Storage	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
CCS	30	30	21	21	30	30	30	30
Biomass CCS	1	2	0	0	2	3	0	0
Hydro	1	1	1	1	1	1	1	1
PV	15	15	49	53	38	41	53	53
Onshore Wind	15	15	21	24	15	15	15	16
Offshore Wind	87	96	110	110	89	95	98	100
Nuclear	9	9	20	20	9	9	9	9

Figure 3-9 Optimal power generation portfolios in scenarios with different gas prices

3.4 Importance of improving system 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. Figure 3-10 shows Great Britain and Europe's demand response capacity, electricity storage, and interconnection in different system flexibility scenarios. Improving system flexibility reduces electricity peak demand and enables better integration of low-carbon technologies. In the "Low flex" scenario, it is assumed that no demand response and new storage could be deployed, and the interconnection capacity is constrained to 12 GW. In the "Core" scenario, only 25% maximum potential demand response and 10 GW new distributed storage are available. The interconnection capacity can be developed to 20 GW. In the "High flex" scenario, all demand response potentials can be accessed, and we assume no limit on the capacity of new distributed storage. The maximum capacity for interconnectors is still 20 GW.

[20] *Assuming the LCOE of nuclear is £60/MWh.*

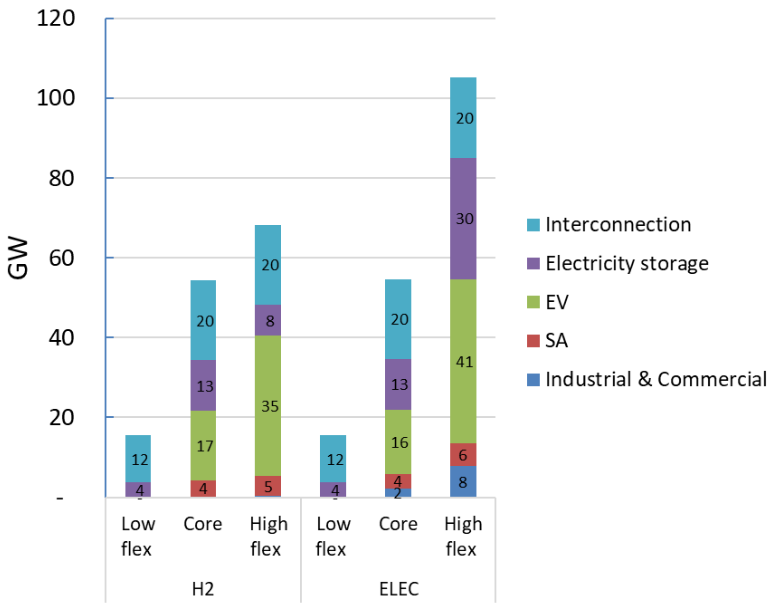


Figure 3-10 Demand response, electricity storage and interconnection capacity in different system flexibility scenarios

The modelling results show that both pathways require significant investment in flexibility technologies such as interconnector capacity, demand response and distributed energy storage technologies; however, Heat Electrification in the "High flex" scenario needs 37 GW more than the Hydrogen pathway. The requirements are met by having more demand responses from different customer types and distributed electricity storage, e.g., batteries. It indicates that hydrogen for heating also reduces some flexibility requirements that otherwise would be needed if heat is deeply electrified.

Figure 3-11 shows the difference between the cost of Low Flex and High Flex with the cost of the Core scenario with medium flexibility.

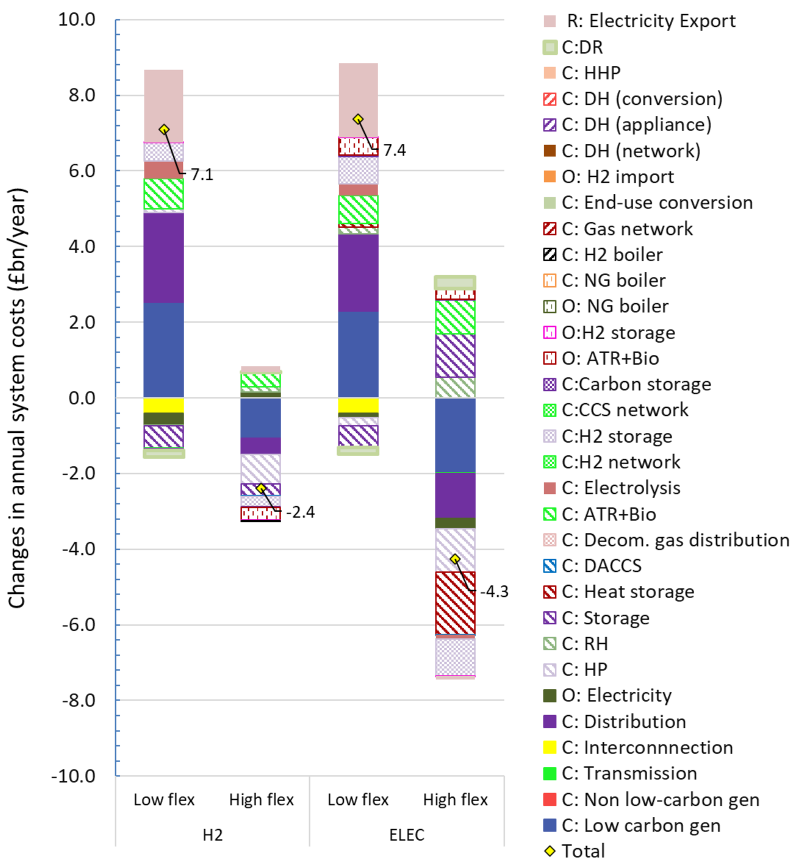


Figure 3-11 The difference between annual system costs of Low flex and High flex scenarios with the core scenario as the reference

The costs of insufficient flexibility are around **£7bn/year**, and the benefits of improving flexibility from the core scenario are **£2.4bn/year** in the Hydrogen pathway and **£4.3bn/year** in the Heat Electrification pathway. The value of flexibility is higher in the Heat Electrification pathway, indicating more flexibility demand to support electrification. Most savings are in reducing the Capex of low-carbon generation, electricity distribution, and hydrogen infrastructure such as ATR+CCS, electrolysers and hydrogen storage.

3.5 Impact of higher heat demand

In this study, the heat demand is increased by around 55 TWh/year (thermal), aligned with the National Grid's Future Energy Scenario (FES) 2022 System Transformation (ST) scenario. The results are compared with the core scenario based on the Leading the Way (LW) scenario. The modelling results are shown in Figure 3-12.

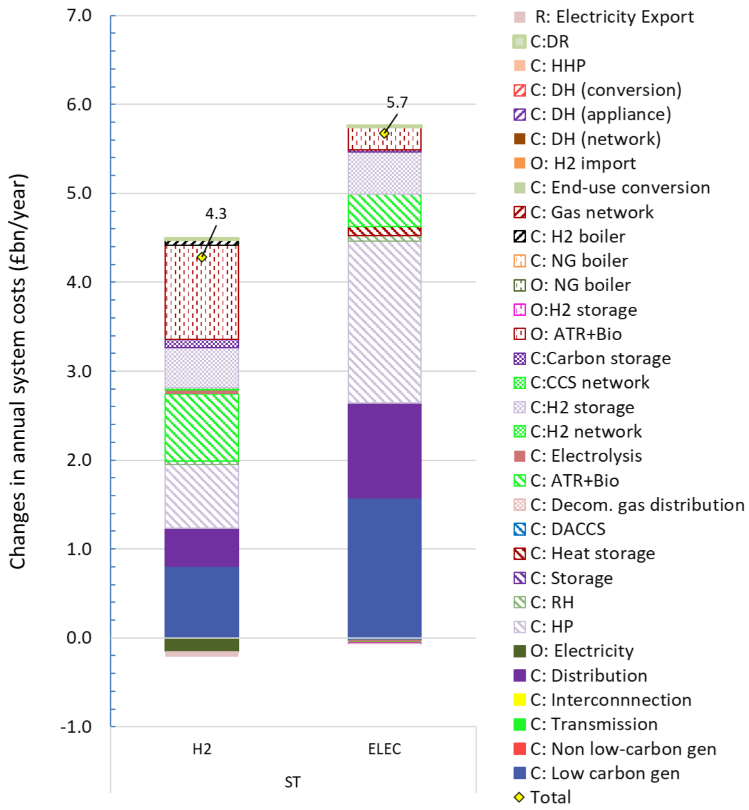


Figure 3-12 The difference between annual system costs of the ST cenario with the core scenario as the reference

The results demonstrate:

- The Heat Electrification pathway is more sensitive to the increased heat demand than the Hydrogen pathway. The cost of increasing 55 TWh is **£5.7bn/year** in the Heat Electrification pathway but costs only **£4.3bn/year** in the Hydrogen pathway.

- Increased heat demand leads to a higher energy and peak demand of heat. It affects the sizing of heat pumps and the associated Capex, while the impact is much less for oversized hydrogen boilers (e.g. 24kW on average domestic), designed to deliver instantaneous hot water.

- It also affects the sizing of other energy infrastructure. In both pathways, additional investment in low-carbon generation capacity, distribution network capacity, higher capacity heat pump systems; and cost of hydrogen production, hydrogen storage, and Opex of the hydrogen system. However, the proportion of those costs varies depending on the pathway. In the Hydrogen pathway, more than 50% of the increased costs are related to the Capex and Opex of the hydrogen system, while in the Heat Electrification scenario, 80% of the increased costs are in the electricity system.

3.6 Optimal hydrogen mix

The study with different gas price assumptions also indicates the importance of optimising the hydrogen production mix. In this study, we analyse three different technology scenarios: (i) no green hydrogen, (ii) optimal mix, and (iii) no blue hydrogen. Figure 3-13 shows the optimal hydrogen mix of those scenarios. It is worth reiterating that all our modelling results meet the net-zero carbon and energy system resilience against extreme weather conditions.

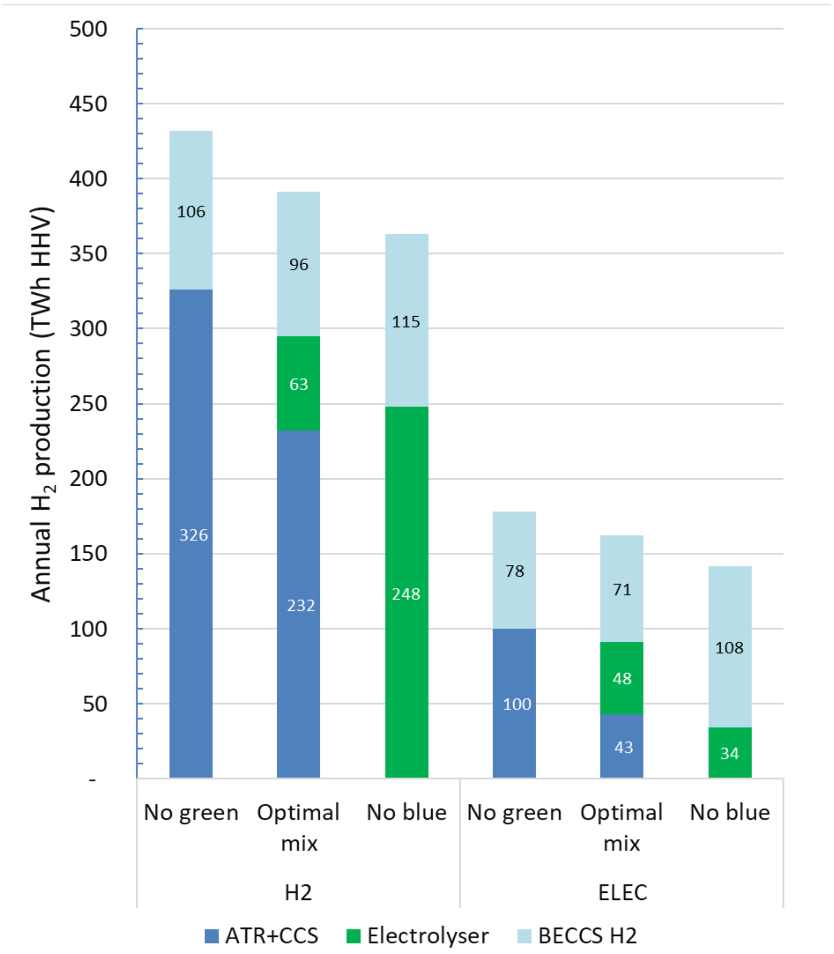


Figure 3-13 Optimised hydrogen production mixes based on technology scenarios for the Hydrogen and Heat Electrification pathways

The results demonstrate:

- Three main technologies will be used in future to produce hydrogen: (i) ATR+CCS, (ii) electrolysers, and (iii) BECCS.
- Without green hydrogen, the annual hydrogen production is higher than in the system with green hydrogen. Electrolysers provide flexibility. Without it, other flexible technologies must be available, e.g. hydrogen power generation, which will increase hydrogen demand, as shown in Figure 3-14. Hydrogen demand for power generation decreases with increased green hydrogen production in the system.

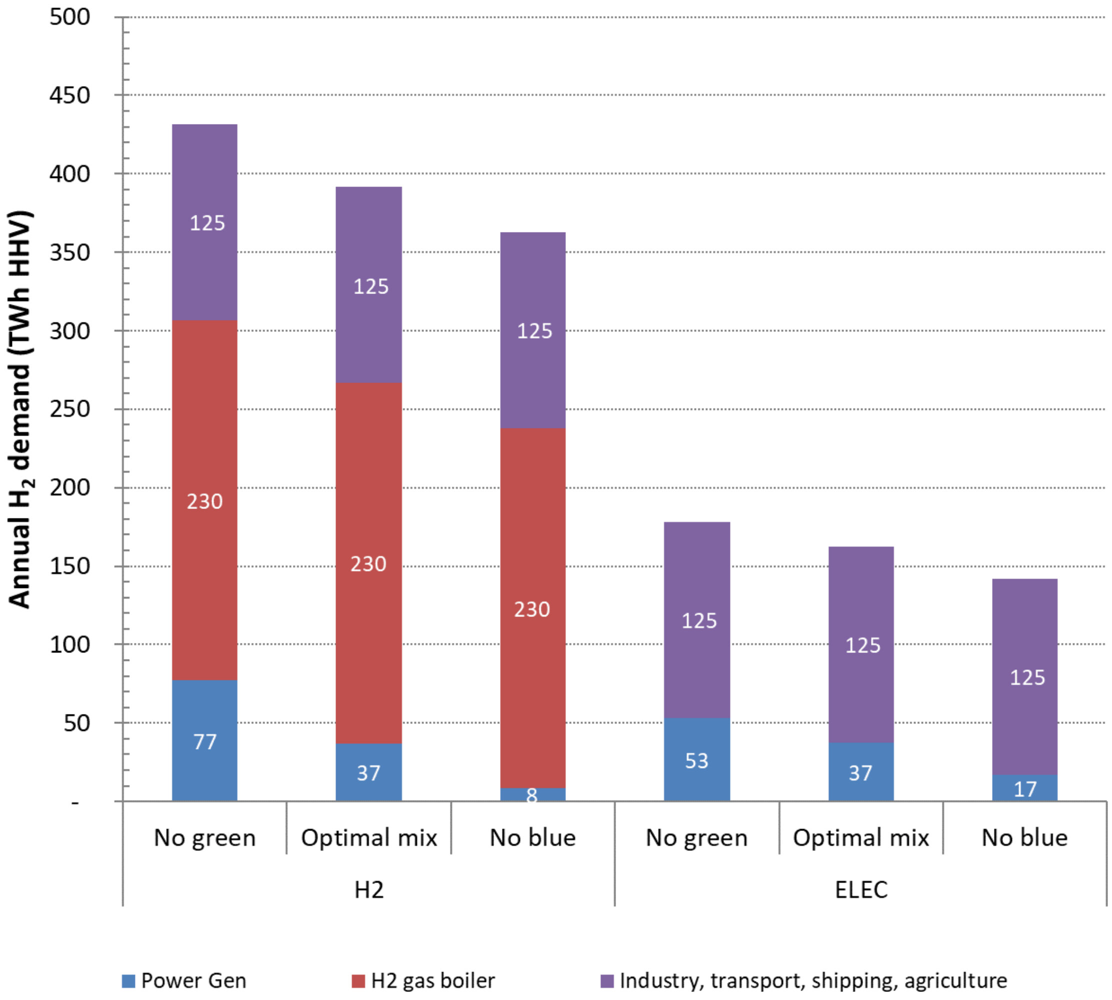


Figure 3-14 Hydrogen demand of different hydrogen mix scenarios

- Because of the flexibility that it can provide, green hydrogen from electrolysis processes should be part of the hydrogen production mix. Although the production cost of green hydrogen is higher than blue, it has a system value in improving energy system balancing, reducing the system integration cost of renewable energy sources (wind and solar PV) and curtailment. For example, electrolysers can convert excess wind-generated electricity to hydrogen during high wind-low demand conditions. Hydrogen can be stored or directly used for heating, generating electricity, industrial processes, and transport. Electrolysers can also play a role in network management and provide ancillary services to support the electricity system operation.

- Without ATR+CCS capacity in the "No blue hydrogen" sensitivity, the volume and capacity of hydrogen production from BECCS increases, indicating a shift from using biomass for power generation to hydrogen.

Figure 3-15 shows the impact of having different hydrogen production mix scenarios with the results from the core scenario as the reference.

Figure 3-15 The difference between annual system costs of scenarios with different hydrogen production mixes with the core scenario as reference.

The results demonstrate that:

- Mitigating blue hydrogen increases system costs under the hydrogen scenario, especially when the blue hydrogen production cost is lower than the cost of green hydrogen.

- Without green hydrogen, the system must have a higher blue hydrogen capacity (ATR+CCS). It also increases the fuel (natural gas) cost for hydrogen production and carbon storage costs. On the other hand, the system requires less investment in low-carbon technologies (mainly wind and PV) and electrolysers and reduces electricity Opex.

- The condition reverses when the system does not have blue hydrogen. It can save the cost of blue hydrogen infrastructure and Opex and reduces carbon storage cost. Except in Heat Electrification, additional hydrogen storage is used to replace the role of ATR+CCS.

- The impact of different hydrogen mixes is much larger in the Hydrogen pathway than in the Heat Electrification pathway.

3.7 Impact of electricity interconnection development

Electricity interconnection development is also crucial for both pathways. Interconnection improves system flexibility and the ability to exchange and trade energy, capacity and grid services with interconnected regions. In this study, the total capacity of the Great Britain interconnectors is constrained to (i) 11.7 GW, (ii) 20 GW (core scenario), and (iii) 30 GW. Currently, the total interconnector capacity is 6 GW, which includes 3 GW to France, 1 GW to the Netherlands, 1 GW to Belgium, and 1 GW to Ireland. The first case, 11.7 GW, reflects the firm interconnector capacity by 2030 from Ofgem[21] and assumes no further development till 2050. The second case aligns with the government policy to deliver at least 18 GW of interconnection by 2030[22].

In comparison, 30 GW reflects the level of interconnection expected to be available in 2050, indicated by the BEIS model[23]. As the development of interconnectors is lengthy, 20 GW is assumed in the core scenarios. Figure 3-16 displays the impacts of low and high interconnection development scenarios on the annual system costs; the impacts are analysed by comparing them to the core scenario results.

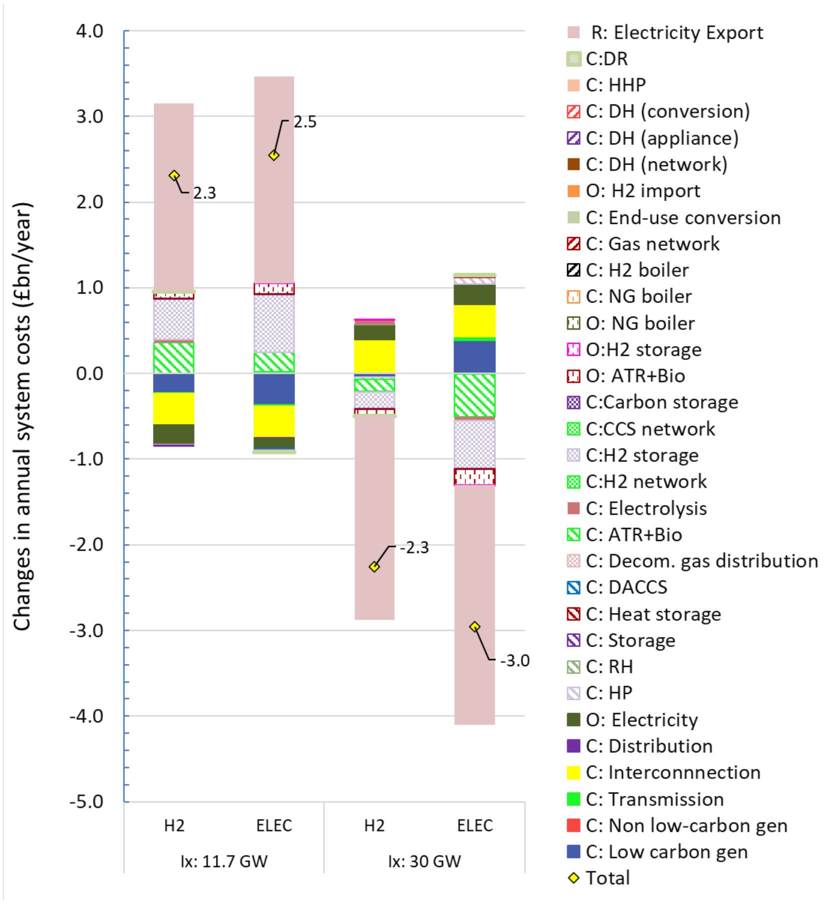


Figure 3-16 Impacts of low and high interconnection development on the system costs

[21] *Source: Ofgem, 2020. Available at https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors*

[22] *Source: Energy white paper: Powering our net zero future from GOV.UK*

[23] *Source: BEIS, Transitioning to a net zero energy system: Smart Systems and Flexibility Plan 2021*

From analysing the modelling results, we observe the following:

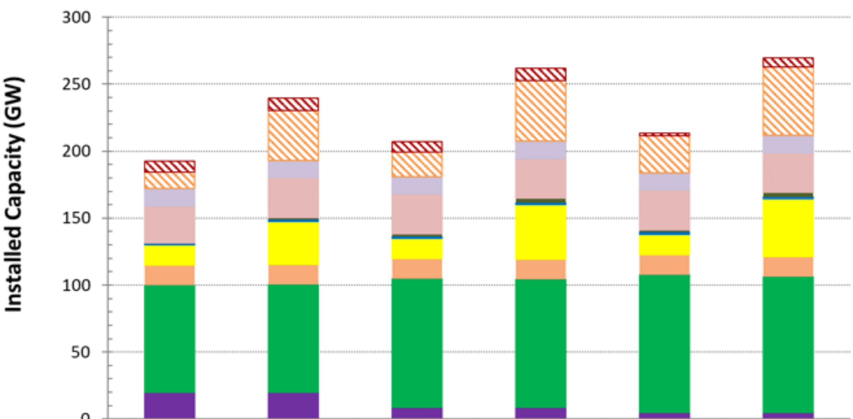
- Energy export should be facilitated by developing sufficient interconnection capacity as Great Britain's energy mix will rely on variable renewable energy sources such as wind power. Without that capacity, there will be less energy that can be traded between Great Britain and Europe.

- Lack of interconnection development will increase the need for hydrogen production capacity and storage to support the system and operating costs and reduce the amount of low-carbon technology that can be integrated.

- Since interconnection is one of the flexibility technologies, the impact of having more or less flexibility will be more prominent in the Heat Electrification than in the Hydrogen pathway.

3.8 Cost of nuclear power generation

Changes in the cost of key low-carbon technologies such as nuclear and offshore wind will also affect the system costs in both pathways. While offshore wind costs continue to decrease, there is significant uncertainty in the cost of nuclear power generation due to the risk associated with the technology and market. In this context, we analyse two sensitivity scenarios, i.e. (i) Low-cost scenario where the cost of nuclear is reduced by 20% and (ii) High-cost scenario where the cost of nuclear is increased by 20%. In all scenarios, the minimum nuclear capacity is assumed to be 5 GW. The core scenario assumes the levelised cost of nuclear is £60/MWh[24]. The optimal generation portfolios for those three scenarios are shown in Figure 3-17.



	Low		Central		High	
	H2	ELEC	H2	ELEC	H2	ELEC
H2 OCGT	8.2	9.2	7.7	9.2	1.5	6.9
H2 CCGT	12.4	37.4	18.5	45.2	27.8	51.0
Storage	13	13	13	13	13	13
CCS	28	30	30	30	30	30
Biomass CCS	0	1	2	3	2	3
Hydro	1	1	1	1	1	1
PV	15	32	15	41	15	43
Onshore Wind	15	15	15	15	15	15
Offshore Wind	80	81	96	95	103	101
Nuclear	20	20	8.85	8.82	5.00	5.00

Figure 3-17 Optimal generation portfolios in different nuclear cost scenarios

[24] *The current LCoE of nuclear is around £90–100/MWh.*

The impacts of reducing or increasing the cost of nuclear power are as follows:

- Nuclear capacity will increase to 20 GW if the cost is low. On the other hand, it goes to the minimum capacity of 5 GW when the cost is 20% higher. The results indicate that nuclear capacity can swing widely depending on cost.

- Higher nuclear capacity reduces RES capacity, especially offshore wind, baseload biomass CCS and mid-merit thermal plants such as hydrogen CCGT. The opposite happens with lower nuclear capacity. The capacity of offshore wind and hydrogen CCGT increases with the reduction in nuclear capacity. While offshore wind provides renewable and zero-carbon energy, hydrogen CCGT provides flexibility and capacity to support system operation, security, and resilience against extreme weather conditions.

Figure 3-18 shows the changes in the system costs responding to lower or higher nuclear costs.

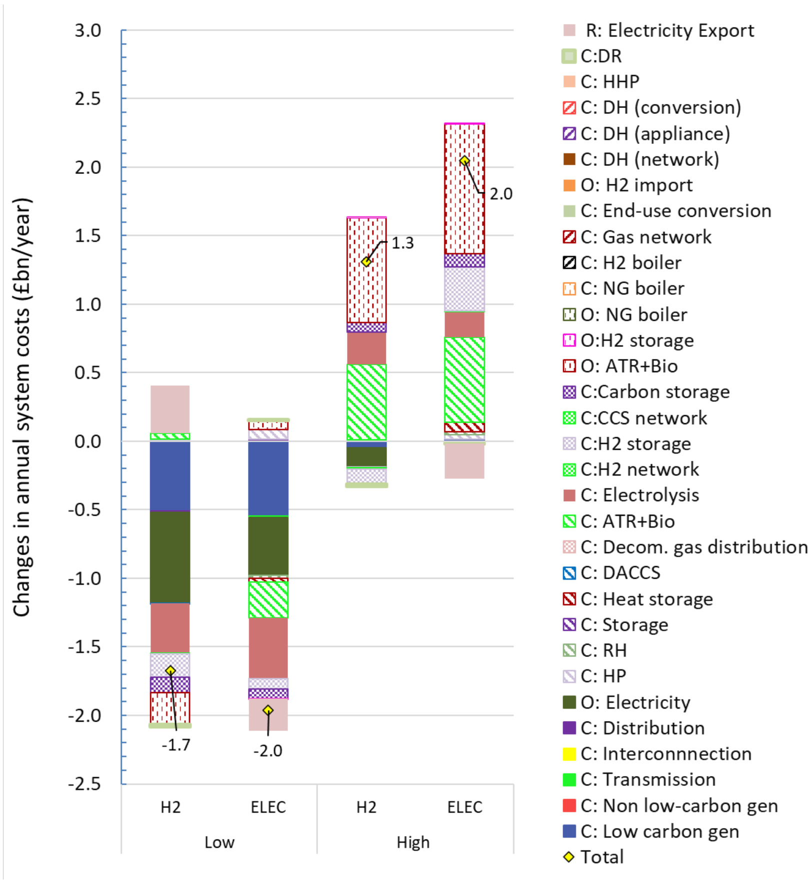


Figure 3-18 Impacts of low and high nuclear costs on annual system costs

The modelling results suggest the following:

- High nuclear costs will drive investment in hydrogen production capacity (ATR+CCS and electrolysers) and increase the natural gas consumption for hydrogen production. Consequently, it also increases carbon storage costs. Increased hydrogen production capacity is needed to support additional hydrogen power generation when the nuclear power generation capacity is reduced to the minimum.

- Lower nuclear cost will reduce the investment cost of low-carbon technology overall and electricity opex due to less gas usage and reduce the need for electrolysers, hydrogen storage, and hydrogen production fuel cost. It also reduces the carbon storage costs.

In this study, we investigate the impact of having 50%–80% lower Winter Wind (50% WW and 80% WW) output and 1 and 2 weeks of winter wind draught peak demand events (1wk WD and 2wk WD) in contrast to the assumption in the core scenarios, i.e. three days. The Met Office[25] studies indicate that around two weeks of such events happen once every 20 years. Thus, the recurrence for three 3-day events will be expected to be regular. Increased duration of extreme weather conditions (1 and 2 weeks) is found to have a modest impact considering that the core scenario system has been designed for dealing with a 3-day extreme weather event, i.e. very low wind during an extremely cold winter week. Therefore, the system already has sufficient firm low-carbon capacity from gas CCS, hydrogen, and nuclear power generation. Hydrogen production from ATR+CCS can then be increased to support increased hydrogen demand due to prolonged low-wind conditions with a small impact on the capacity requirement. Hydrogen storage and RES capacity can be increased as an alternative option if green hydrogen is preferred. Figure 3-19 shows the impacts of extreme weather events on the system costs.

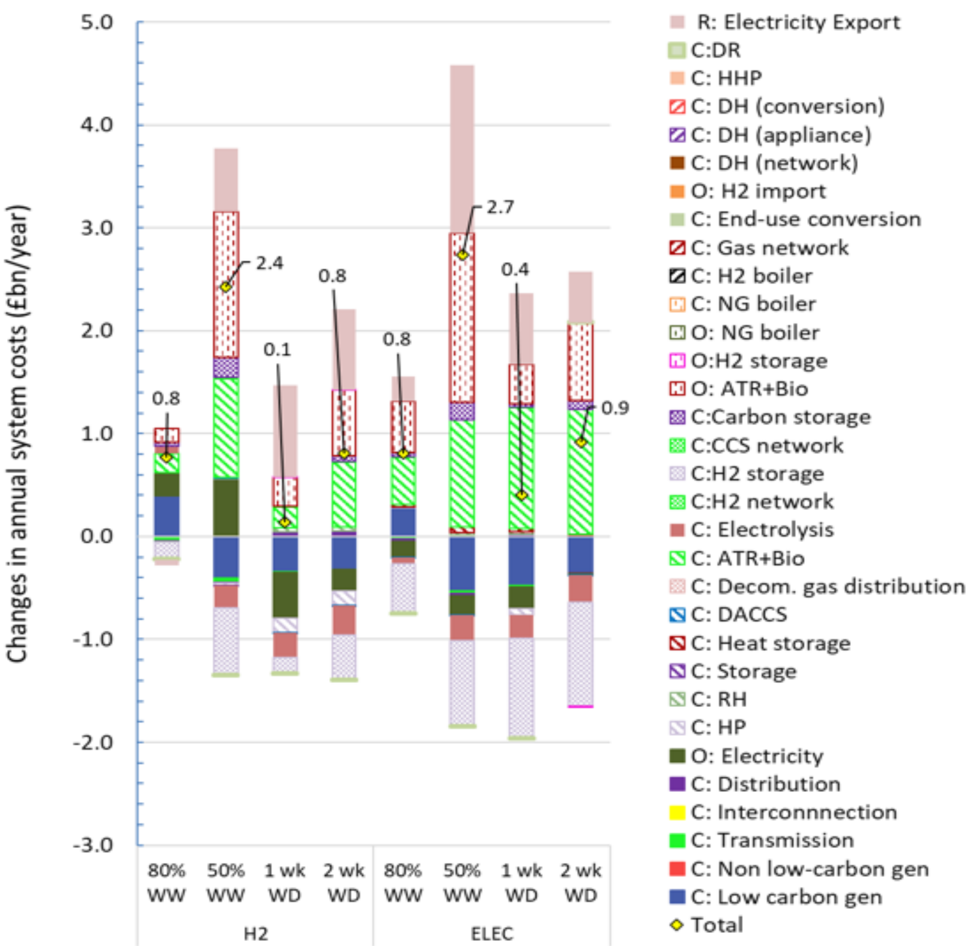


Figure 3-19 Impact of extreme weather events on the system costs of Hydrogen and Heat Electrification pathways

[25] *Source: Met Office (Tom Butcher and Laura Dawkins, et al.), "Adverse Weather Scenarios for Renewable Energy System Testing: Discovery Phase", June 2021.*

- Low wind conditions require additional investment in blue hydrogen production capacity (ATR+CCS) and higher blue hydrogen production. The production is shown in Figure 3-20. The highest increased production is in the 50% winter wind scenario. Consequently, the increased blue hydrogen production also increases the cost of carbon storage.

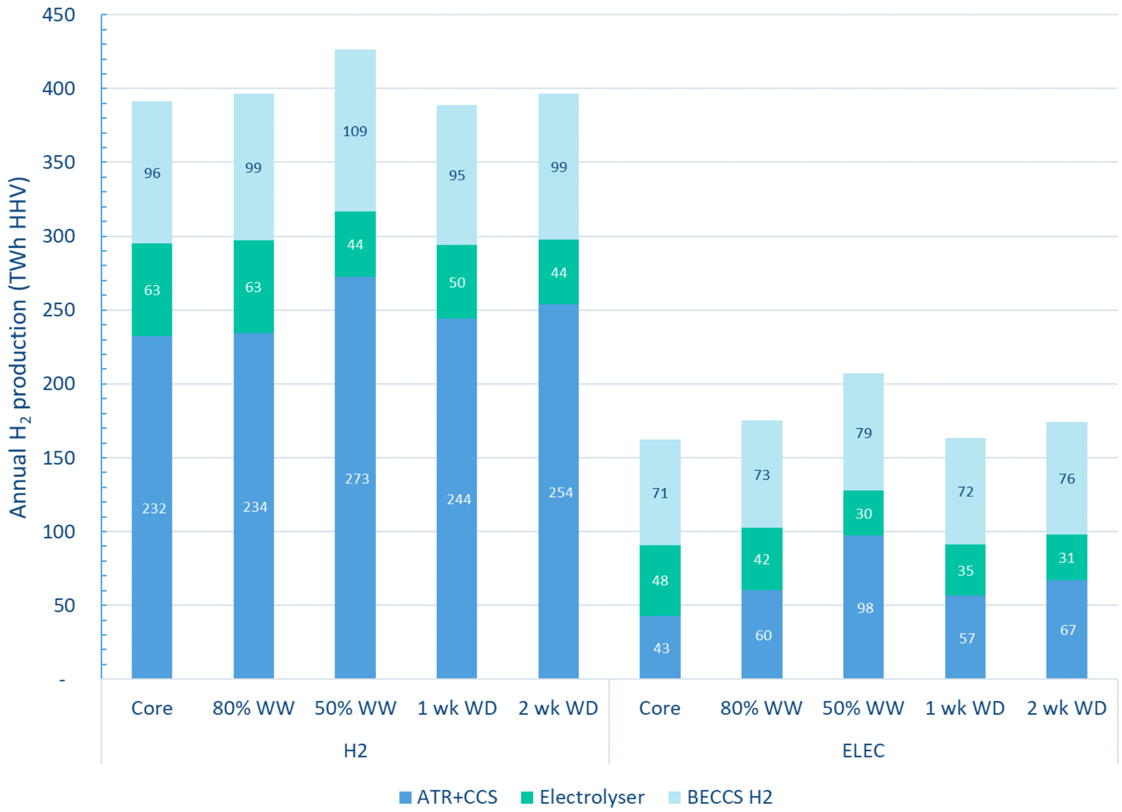


Figure 3-20 Annual hydrogen production in different extreme weather scenarios in the Hydrogen and Heat Electrification pathways

- The results highlight the importance of diversifying energy sources for hydrogen production. It indicates the role of natural gas in supporting resilience against extreme weather conditions.

- Uncertainty in wind availability may reduce the value of wind power and, therefore, the capacity proposed for that technology. In this study, the reduction in proposed wind power capacity is relatively marginal.

- The low availability of wind power will reduce electrolysers and hydrogen storage requirements. There is a shift from using electrolysers to ATR+CCS as the latter is not a weather-dependent technology.

3.10 Transport of hydrogen within the infrastructure in different future scenario developments

The IHES model has been employed to scrutinise the complexities of hydrogen transport across diverse scenarios. Before the in-depth exploration of these studies, the key findings derived from our analyses can be summarised as follows:

- Significant aspects of system flexibility, encompassing interconnection, electricity storage, and DSR are instrumental in managing linepack variations. These can escalate up to 1.2 mcm/day and 24.2 mcm/day more linepack swing in Hydrogen and Heat Electrification pathways, respectively. This situation underscores the requirement for enhanced flexibility to manage the increased intermittency driven by RES within the gas network, thereby safeguarding supply security.
- The requirement for hydrogen compression is subject to variations in wind and natural gas prices. Lower costs associated with wind energy translate to a decreased requirement for hydrogen compression, while escalating natural gas prices drive up the demand for this process.
- Price shifts concerning natural gas and hydrogen storage exert a substantial influence on the energy system. In scenarios where natural gas prices reach extreme highs, the production of blue hydrogen may decline, correspondingly decreasing the need for hydrogen compression. A drop in hydrogen storage costs may stimulate the demand for hydrogen compression due to the increased installation of hydrogen storage facilities.

3.10.1 Flexibility provided through linepack

The variations in linepack swing relative to the Core scenario are illustrated in Figure 3-21. The key points from Figure 3-21 are as follows:

- The degree of flexibility within the system - such as that provided by interconnection, electricity storage, and DSR - significantly influences these swings, given that linepack, as another source of flexibility, should complement these other forms of adaptability. As demonstrated in Figure 3-21, in scenarios with lower electricity-related flexibilities (i.e., Scenario Ix: 11.7 GW, and the Low Flex scenario), linepack swing is higher than in the Core scenario (up to 24.2 mcm/day), while in higher flexibilities, the linepack swings are lower (up to 18.6 mcm/day). This occurs because the support from linepack flexibility is more heavily relied upon to handle challenges in gas network operations induced by renewable energy sources. The changes in the linepack swings are higher in the Heat Electrification pathway, as the impact of the level of electricity-related flexibility is more on the electricity system operation.
- It is demonstrated that if hydrogen storage becomes a more economical option, more renewable energy sources are integrated into the energy system. Consequently, the increased intermittency associated with these sources is transferred to the gas network, necessitating additional flexibility from the linepack. This is highlighted in the Heat Electrification pathway as more green hydrogen is injected into the gas infrastructure, which increases linepack variability by 13.8 mcm/day (compared to the Core scenario) to maintain supply security.
- In other sensitivities, the deviations in linepack swing compared to the Core scenarios are not significant. These fluctuations can be influenced by various elements, such as the level of RES integration, the scale of firm blue hydrogen supply, and the establishment of hydrogen storage facilitates.

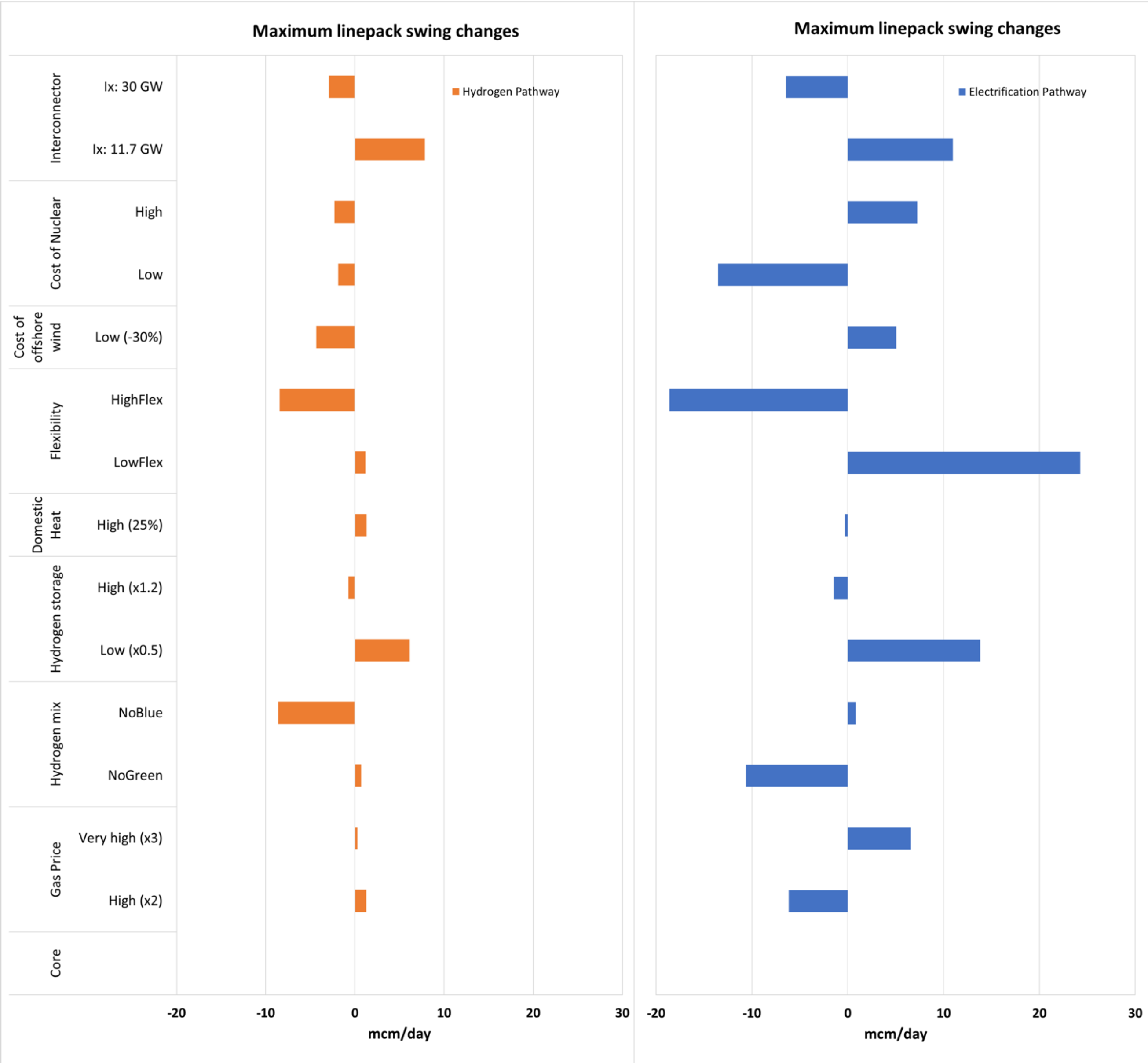


Figure 3-21 Change in maximum linepack swing compared to the Core decarbonisation pathways in different scenarios

3.10.2 Required electricity demand for hydrogen compression

In Figure 3-22, the electricity demand for hydrogen compression is presented. A comprehensive description of the compression required for hydrogen production through ATR+CCS and BECCS is provided In Appendix B. The necessary compression within the infrastructure for hydrogen transportation is also elaborated. The key findings from the analyses are summarised as follows:

- In a low cost of wind sensitivity, the requirement for hydrogen compression in the supply points, specifically in the Hydrogen pathway, reduces 42%, due to more green hydrogen supply compared to the Core case. Furthermore, hydrogen compression in the gas network infrastructure is reduced by 10%. This is attributed to (i) the assumption that green hydrogen produced, primarily via Proton Exchange Membrane (PEM) electrolysis, can be directly injected into the gas network, and (ii) electrolysers are distributed across a wider geographical area compared to the concentrated locations of ATR+CCS plants, which are typically situated in proximity to natural gas terminals.

- The demand for hydrogen compression increases in a sensitivity study with high natural gas prices and the Heat Electrification pathway. This increase is because the energy system relies more on H2-CCGTs due to the higher cost of operating gas CCS plants. As the hydrogen demand is low in the Heat Electrification pathway, the majority of supply is realised through green hydrogen. Although blue hydrogen production is reduced (i.e., due to natural gas price increase), however, due to the increased hydrogen demand for power generation, more hydrogen supply from BECCS is required. Consequently, there is greater demand (11% more) for electricity to compress the produced hydrogen via BECCS. In contrast, in the Hydrogen pathway, the electricity demand for hydrogen compression decreases, as the system does not rely on costly blue hydrogen production (i.e., plays a major role in supplying hydrogen in the Core scenario) and hence pivots significantly toward green hydrogen supply. As a result, the electricity demand for hydrogen compression is reduced significantly (up to 45%).

- As anticipated, a similar pattern to high natural gas prices is observed in the "No Blue" scenario, where Blue hydrogen production is absent. In this case, an increase of 12% in electricity required for hydrogen compression in the Heat Electrification pathway and a decrease of 45% in the Hydrogen pathway are noted. Conversely, in the "No Green" scenario, characterised by increased hydrogen supply through methods such as ATR+CCS and BECCS, a noticeable 19% increase in electricity demand for hydrogen compression is observed compared to the Core scenario.

- With low hydrogen storage costs, the increased installation of hydrogen storage facilities enhances the system's flexibility. More hydrogen can be supplied to H2-CCGTs, necessitating more blue hydrogen, resulting in greater electricity demand for hydrogen compression.

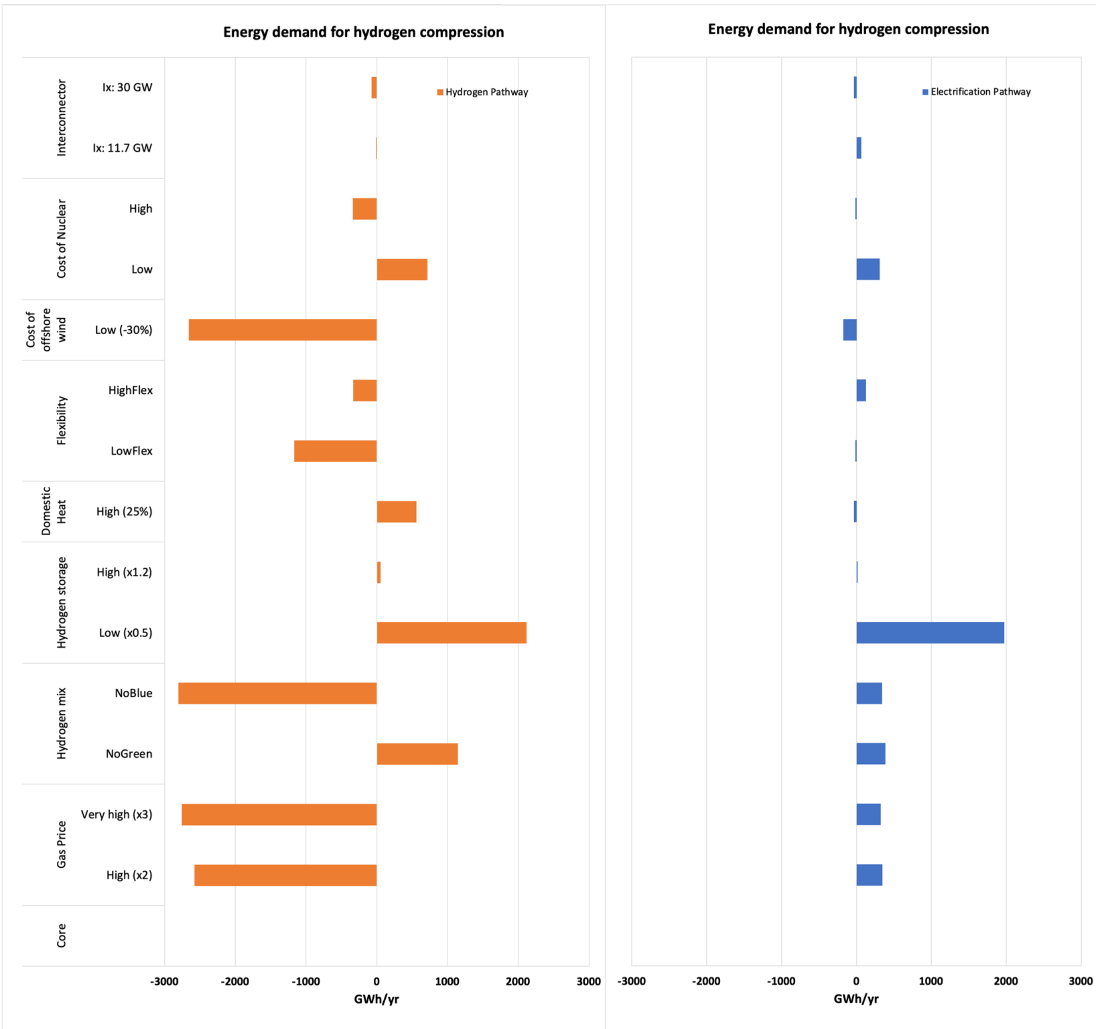


Figure 3-22 Change in electricity required for hydrogen compression compared to the Core decarbonisation pathways in different scenarios

Impact of higher natural gas prices

Figure 3-23 demonstrates the predictable reduction in blue hydrogen production because of higher natural gas prices. The system compensates in response to this decrease by producing up to 620 GWh/day[26] more green hydrogen in the Hydrogen pathway compared to the Core case. On Cold Winter days, the system faces significant stress due to the simultaneous conditions of green hydrogen unavailability and costly blue hydrogen production.

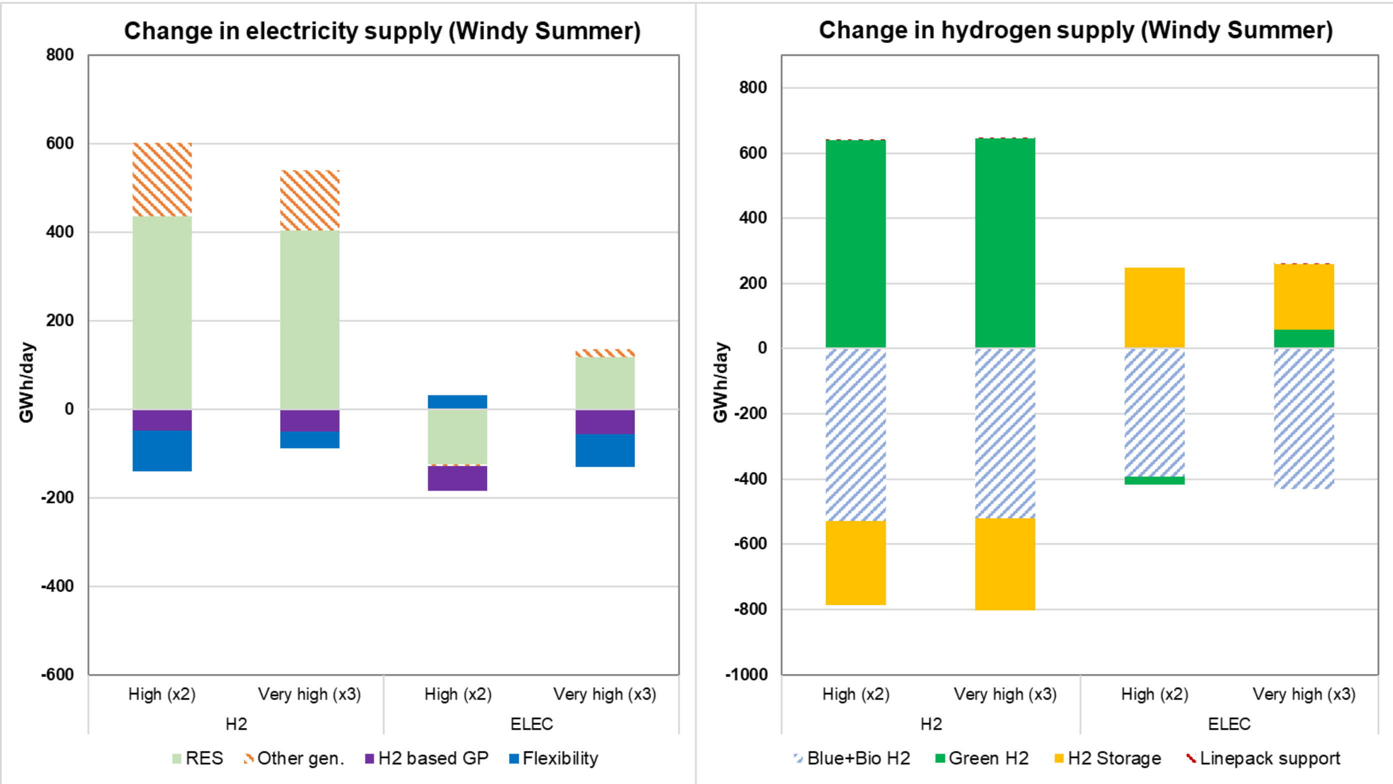


Figure 3-23 Impact of natural gas price on the energy supply compared to the Core: Windy Summer day

As illustrated in Figure 3-24, the system draws more electricity from other generation energy sources (Nuclear and gas CCS) to ensure a steady supply of green hydrogen, particularly in the Hydrogen pathway. Furthermore, more hydrogen is withdrawn from the storage facilities to maintain the security of supply. The linepack plays a critical role in maintaining the supply-demand balance when natural gas prices are high, highlighting its importance in the overall resilience and flexibility of the system. This approach further demonstrates the interdependent and dynamic relationships between different energy sources and technologies and the role of flexibility and linepack in mitigating the impact of high gas prices, which result in lower blue hydrogen production.

[26] *The hydrogen demand (without the demand for electricity generation) is 1179 GWh/day in the Windy Summer day.*

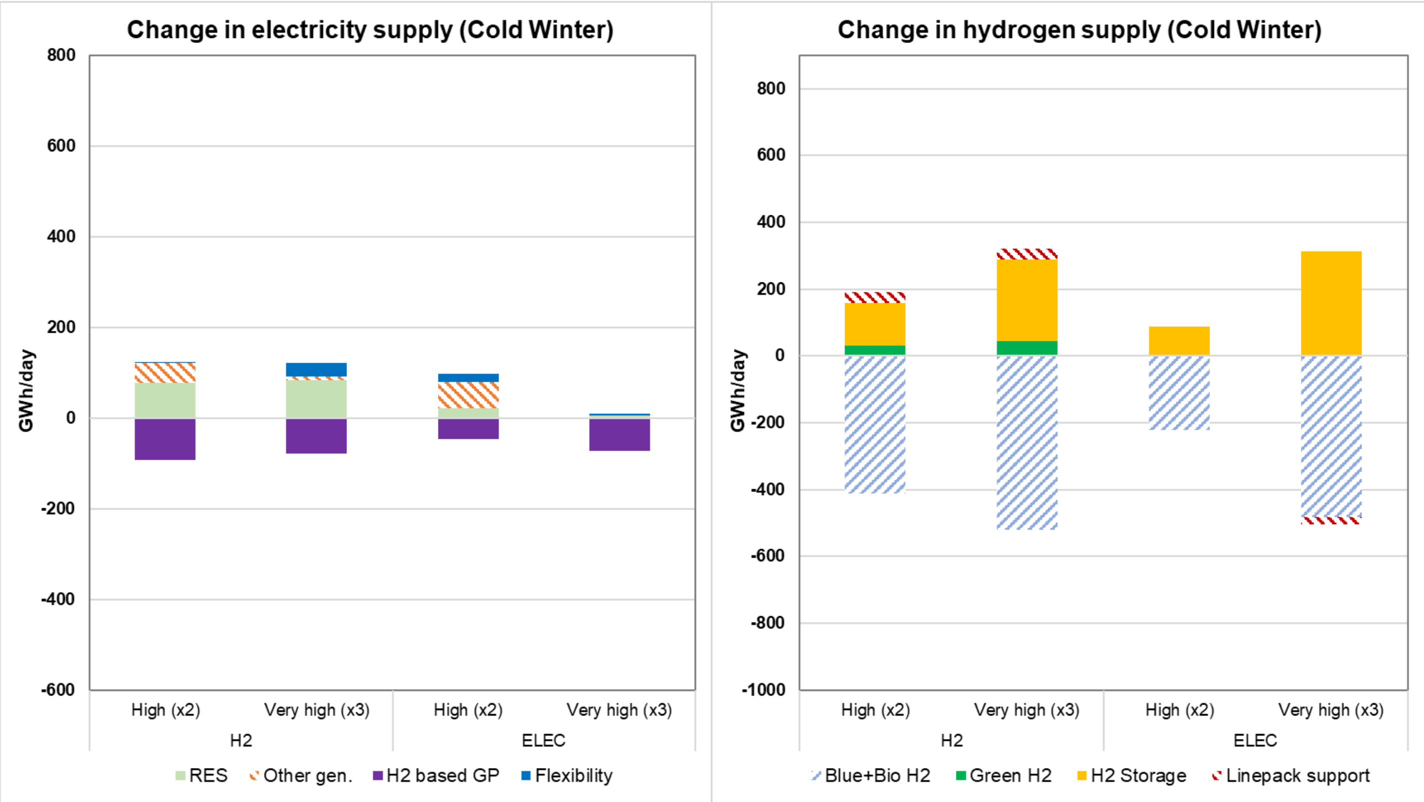


Figure 3-24 Impact of natural gas price on the energy supply compared to the Core: Cold Winter day

Hydrogen production mix

As shown in Figure 3-25, on Windy Summer days, particularly within the Hydrogen pathway, the efficient utilisation of renewables for significant green hydrogen production becomes more pronounced. The produced green hydrogen is then stored in dedicated facilities to ensure its availability during prolonged periods of low wind availability. Conversely, during Cold Winter days, particularly in instances where blue hydrogen is not an available option (*"No Blue"* cases), the system becomes more reliant on other firm electricity generation (e.g., nuclear and gas CCS) to meet the increased green hydrogen supply demands. In both scenarios, hydrogen storage emerges as an integral element in the system's flexibility, specifically when green hydrogen supply is abundant. This active role of hydrogen storage assists in addressing the challenges associated with the intermittency of renewable energy sources, as indicated in Figure 3-25. Meanwhile, Figure 3-26 illustrates an expected reduction in electricity generation from H2-CCGTs during *"No Blue"* cases, due to the unavailability of blue hydrogen as a firm supply source to the gas plants. The reduction in generation can reach up to 60 GWh/day[27] in the Heat Electrification pathway, highlighting the critical interplay between hydrogen supply and demand, as well as the impact of supply constraints on overall system operation and resilience.

[27] *The electricity demand (without the demand for electrolysers) is 1490 GWh/day in the Windy Summer day.*

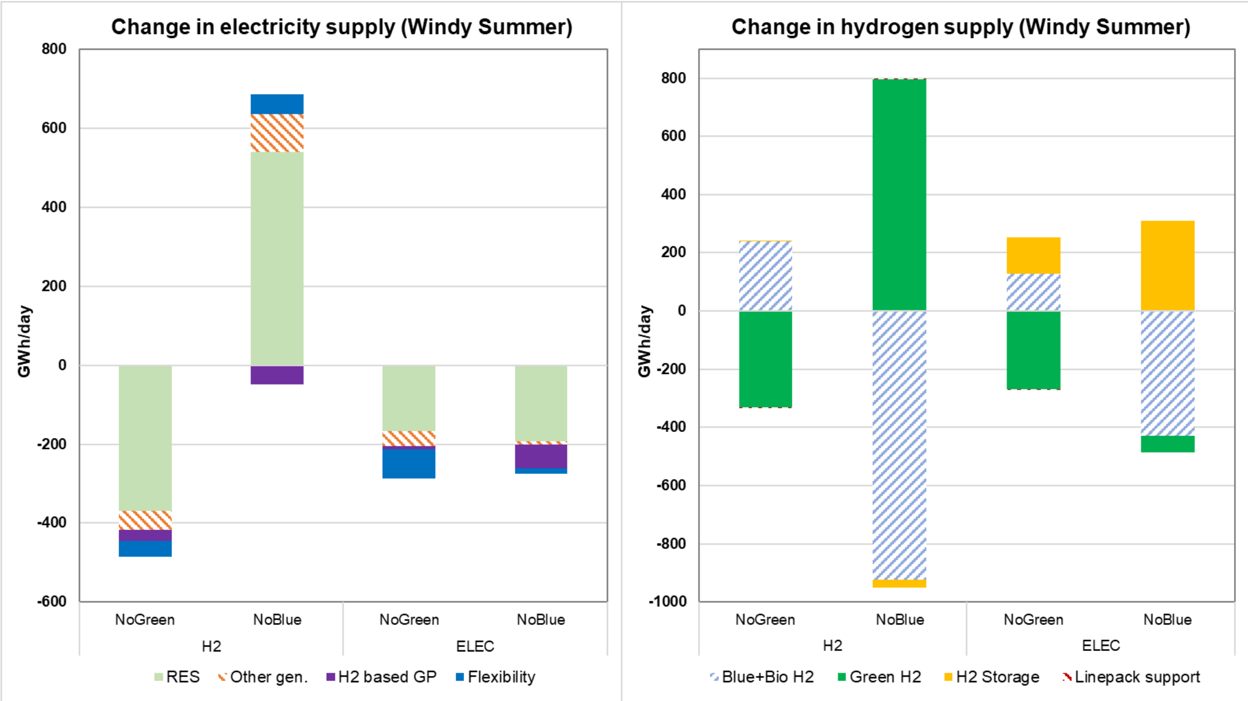


Figure 3-25 Impact of different hydrogen production technologies on the energy supply compared to the Core: Windy Summer day

Figure 3-26 Impact of different hydrogen production technologies on the energy supply in compared to the Core: Cold Winter day

It is important to note that the sum of electricity supply changes across all sensitivities does not equate to zero. This discrepancy arises from variations in electrolyser demand for green hydrogen production, contingent on the specific sensitivity setup. Similarly, in hydrogen supply, the difference can be attributed to varying hydrogen demands for electricity generation.

Importance of system flexibility

Figure 3-27 illustrates how the level of installed electricity storage and DSR (as indicated in Table 3-1 List of sensitivities being studied) can significantly influence the way the integrated electricity and hydrogen supply portfolio meets demand. As depicted, the role of electricity storage is particularly crucial in dealing with extreme events, demonstrating its vital contribution to overall system resilience. Furthermore, as illustrated in Figure 3-27 and Figure 3-28, the degree of flexibility in electricity storage and DSR can substantially influence the overall state of hydrogen storage and linepack utilisation.

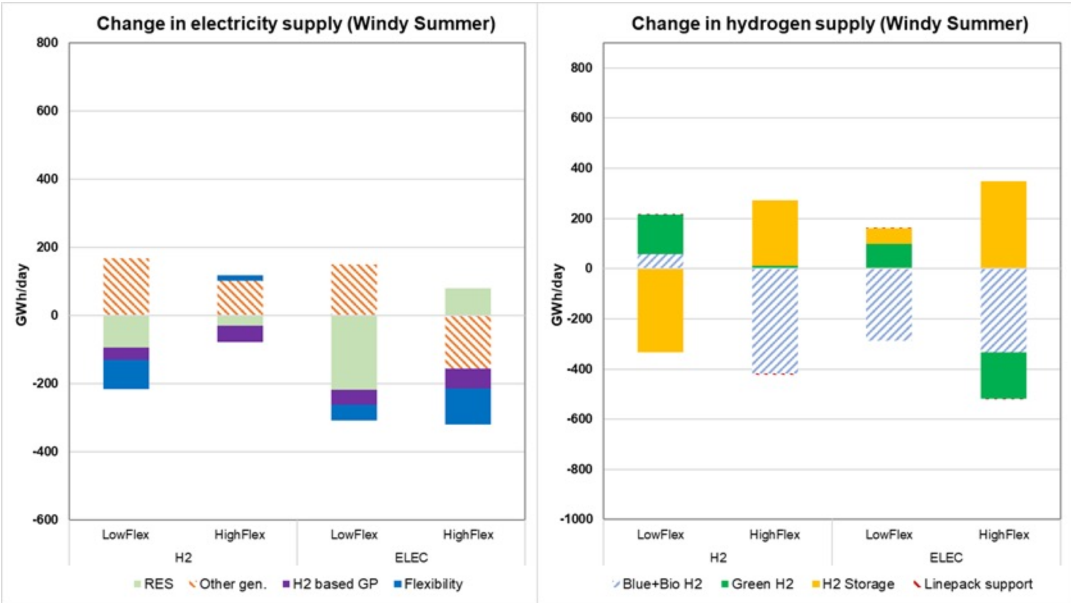


Figure 3-27 Impact of the level of flexibility on the energy supply compared to the Core: Windy Summer day

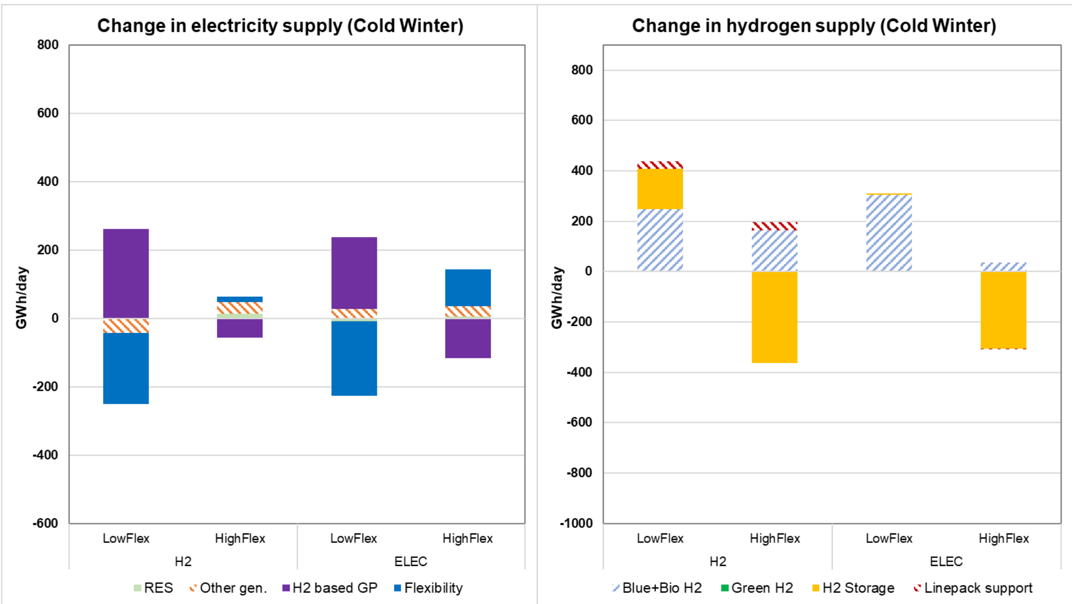


Figure 3-28 Impact of the level of flexibility on the energy supply compared to the Core: Cold Winter day

This is due to the fact that such flexibility can effectively manage the challenges associated with extreme weather events. Thus, a more flexible system can leverage its capabilities more effectively, ensuring a steady hydrogen supply even during low RES periods (Figure 3-28). Conversely, when flexibility related to electricity is limited, there is increased generation of electricity from H2-CCGTs (260 GWh/day[28]) to maintain a balance between supply and demand during cold winter days. This leads to a greater supply of blue hydrogen, along with increased contributions from linepack and hydrogen storage facilities. This dynamic underlines the interplay and mutual dependency between various flexible technologies in the integrated operation of electricity and hydrogen systems.

Impact of low wind price

As depicted in Figure 3-29, in sensitivities where the price of wind energy is reduced, higher utilisation of renewable energy sources can be observed. This increased utilisation also leads to an increase in the production of green hydrogen, which can be stored in hydrogen storage facilities for later use. A reduction in wind energy prices results in a decrease in the need for blue hydrogen supply (up to 350 GWh/day[29]) during both extreme Windy Summer and Cold Winter days. This relationship between wind energy prices and blue hydrogen supply is illustrated in both Figure 3-29 and Figure 3-30. The analysis reveals that when wind energy is lower cost, greater integration of renewable energy sources occurs in the energy system, and thus, more green hydrogen is injected into the gas infrastructure (570 GWh/day) in the Windy Summer days. This effect is particularly pronounced in the Hydrogen pathway, in addressing situations of low renewable energy availability, providing around 20 GWh/day more 'free' flexibility than the Core scenario (Figure 3-30). This illustrates the critical role of the linepack in maintaining a balance between supply and demand, thus contributing to overall system resilience during periods of low renewable energy production.

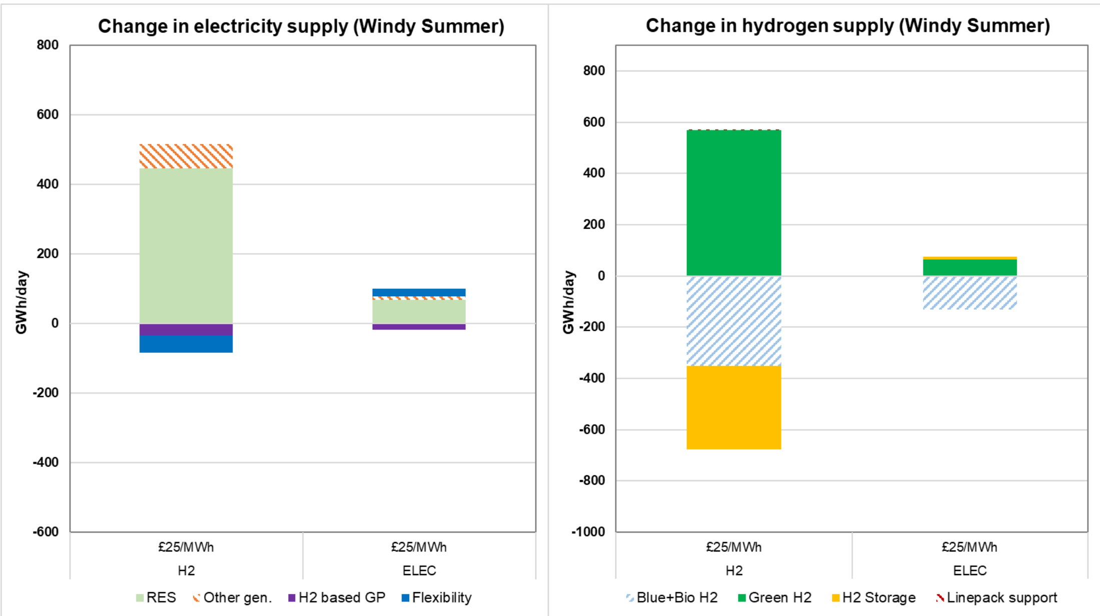


Figure 3-29 Impact of wind price on the energy supply compared to the Core: Windy Summer day

[28] *The electricity demand (without the demand for electrolysers) is 1704 GWh/day in the Cold Winter day.*

[29] *The hydrogen demand (without the demand for electricity generation) is 1179 GWh/day in the Windy Summer day.*

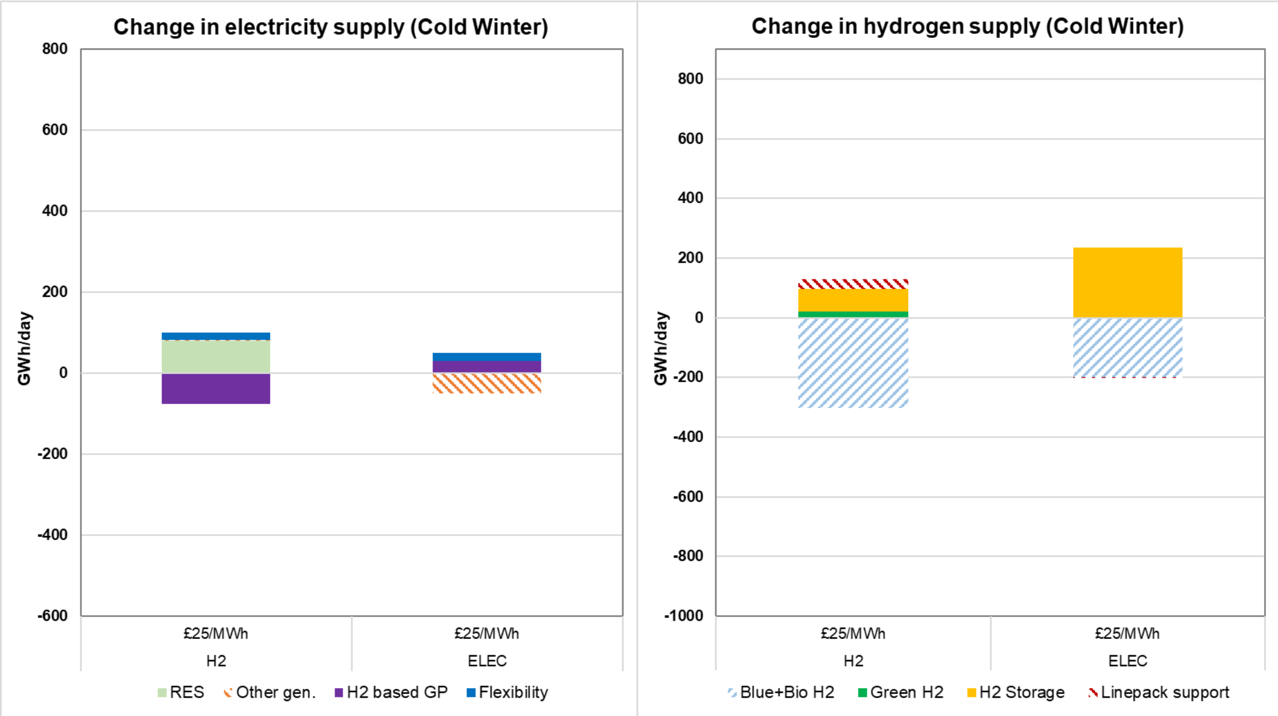


Figure 3-30 Impact of wind price on the energy supply compared to the Core: Cold Winter day

Cost of nuclear power generation

Figure 3-31 illustrates that when the cost of nuclear power is low compared to the Core case, it leads to a higher reliance on nuclear energy (as part of the Other gen. in the figures), and consequently, the electricity from RES, H2-CCGTs, and flexibility (i.e., interconnectors and battery storage) is decreased in both Windy Summer and Cold Winter days (up to 395 GWh/day[30]). As a result, there is a reduction in the amount of green hydrogen supplied on the specific day, as a significant amount of hydrogen is stored in the storage facilities across the year due to an increase in firm electricity generation from nuclear plants. Vice versa, when the cost of nuclear power is high, there is greater reliance on linepack (32 GWh/day[31]) to flexibly support the demand for H2-CCGTs in the Hydrogen pathway and maintain the supply-demand balance, as shown in Figure 3-32. This highlights the linepack's integral role in maintaining the system's stability, particularly when specific power sources are high-cost.

[30] The electricity demand (without the demand for electrolysers) is 1490 GWh/day in the Windy Summer day.
[31] The hydrogen demand (without the demand for electricity generation) is 1294 GWh/day in the Cold Winter day.

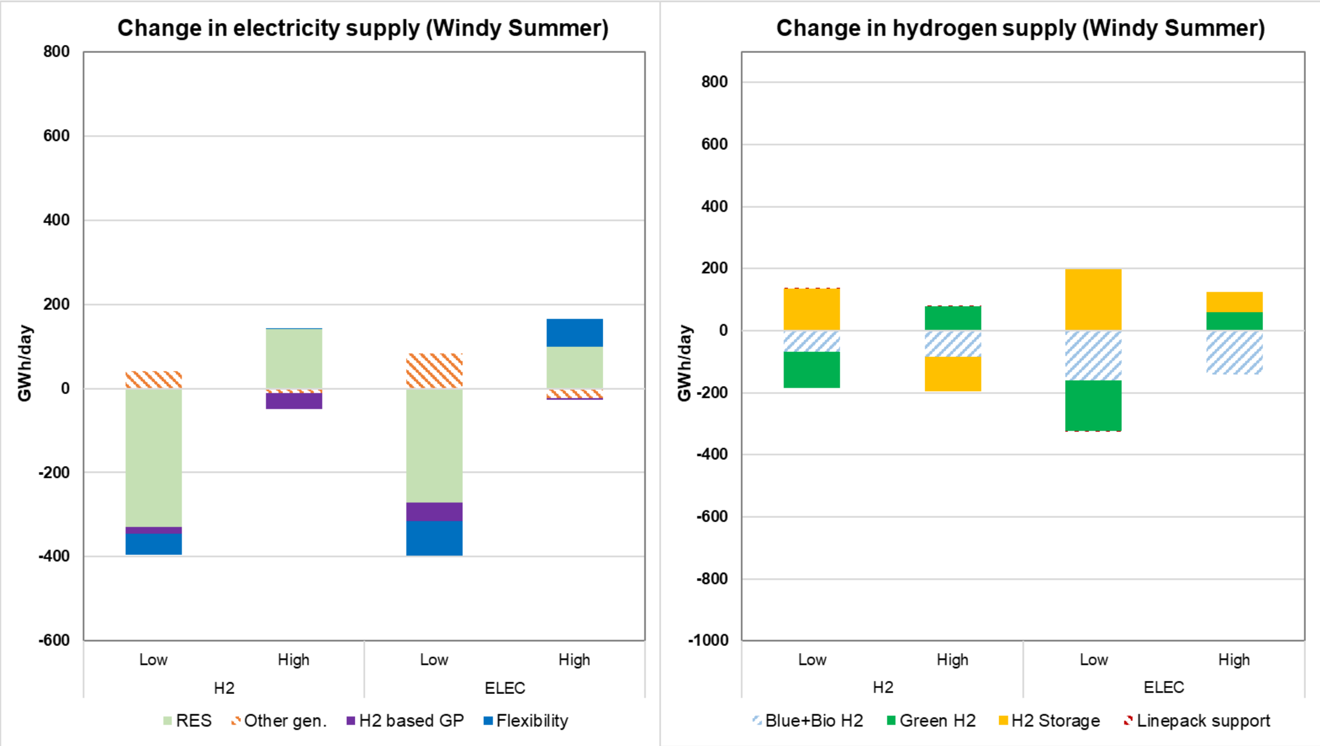


Figure 3-31 Impact of nuclear price on the energy supply in compared to the Core: Windy Summer day

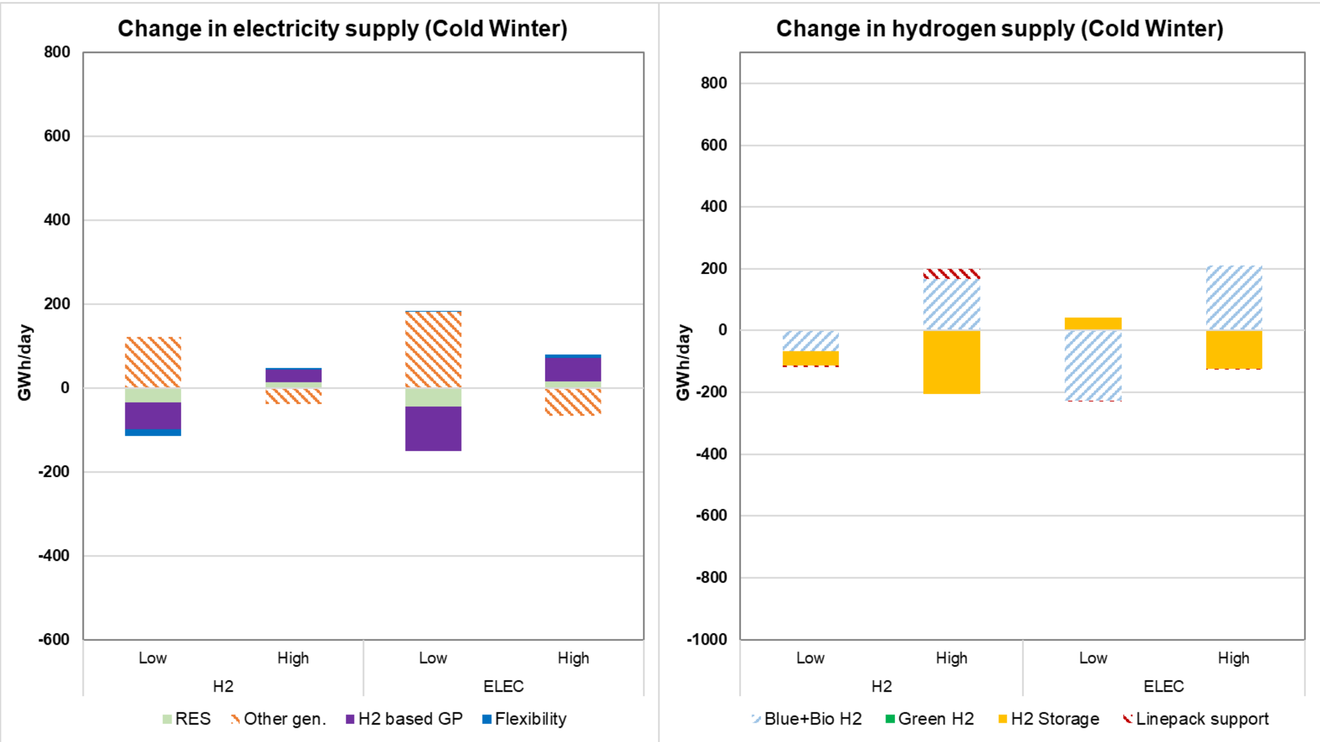


Figure 3-32 Impact of nuclear price on the energy supply in compared to the Core: Cold Winter day

3.10.4 Summary of the key findings

The system's flexibility, determined by elements including interconnection, electricity storage, and DSR, plays a pivotal role in managing the gas network's response to the intermittent nature of renewable energy. When electricity-related flexibility is lower, the system relies more on linepack flexibility, resulting in higher swings. If the cost of hydrogen storage facilities is low, more renewable sources can be integrated, shifting some intermittency management onto the gas network, especially when more green hydrogen is incorporated.

In sensitivities where the cost of wind energy is lower than in the core scenario, the need for hydrogen compression diminishes as the green hydrogen, primarily sourced from PEM electrolysis, can be directly fed into the gas network. High natural gas prices increase electricity demand for hydrogen compression in the Heat Electrification pathway due to greater reliance on H2-CCGTs as the electricity production cost of gas CCS plants becomes expensive. Green hydrogen supplies meet demand, but higher hydrogen demand for power generation leads to increased electricity consumption for compression via BECCS. In a high gas price sensitivity for the Hydrogen pathway, reduced dependence on costly blue hydrogen production significantly lowers electricity demand for hydrogen compression. In the "No Blue" scenario, there is an increase in electricity demand for hydrogen compression in the Heat Electrification pathway and a decrease in the Hydrogen pathway. In contrast, in the "No Green" scenario (with increased hydrogen supply through methods like ATR+CCS and BECCS), there is a noticeable increase in electricity demand for hydrogen compression compared to the Core scenario. Furthermore, when hydrogen storage costs are lower, there is a spike in hydrogen storage facility installations, boosting system flexibility. This amplifies the hydrogen supply to H2-CCGTs, increasing the demand for blue hydrogen compression electricity.

The summary of the key findings on the role of hydrogen (e.g., green hydrogen supply, linepack, and hydrogen storage) in representative extreme weather days are as follows:

- Higher natural gas prices reduce blue hydrogen production, prompting the system to boost green hydrogen production. During cold winter days, the system relies on other energy sources, such as nuclear and gas CCS, due to green hydrogen shortages and blue hydrogen's high cost. The system also taps into stored hydrogen to ensure supply. Linepack's role becomes pivotal in these scenarios, underscoring the interplay between different energy sources and the need for flexibility to address challenges from higher gas prices.

- During windy summer days, especially in the Hydrogen pathway, there is an emphasis on harnessing renewables for substantial green hydrogen production, which is then stored for periods of low wind. However, during colder winter days, especially when blue hydrogen is not accessible, the system leans heavily on other dispatchable electricity sources, such as nuclear and gas CCS, to fulfil the green hydrogen supply. Hydrogen storage is pivotal in ensuring flexibility, particularly when green hydrogen supply peaks, helping mitigate challenges posed by renewable energy intermittency. When blue hydrogen is unavailable, there is a notable decrease in electricity generation from H2-CCGTs, spotlighting the link between hydrogen supply and demand and its effect on system resilience.

- Installed electricity storage and DSR greatly affect the integrated electricity and hydrogen supply's response to demand. Electricity storage is pivotal during extreme events, ensuring system resilience. The flexibility of these systems influences hydrogen storage and linepack use, especially during extreme weather. A highly flexible system consistently supplies hydrogen even in low RES periods. However, with limited electricity flexibility, there is a rise in H2-CCGT electricity generation during Cold Winter days, increasing the need for blue hydrogen and more storage. This underscores the interconnection of flexible technologies in the integrated operation of electricity and hydrogen systems.

- In scenarios where wind energy is lower cost, there is a notable rise in its use and an increase in green hydrogen production for storage. With lower wind costs, the demand for blue hydrogen supply decreases during extreme weather conditions. The cost-effectiveness of wind energy leads to more integration of renewables in the system, resulting in more green hydrogen being injected into the gas infrastructure, especially on Windy Summer days. The Hydrogen pathway offers significant flexibility during low renewable availability, further highlighting the importance of linepack in balancing supply and demand, ensuring system resilience during periods of low renewable energy output.

- When nuclear power is lower cost, the system relies more on nuclear energy, leading to a decrease in electricity derived from RES, H2-CCGTs, and other flexibility sources during both Windy Summer and Cold Winter days. Consequently, the green hydrogen supply for that day diminishes, with a notable amount being stored throughout the year due to consistent electricity generation from nuclear plants. However, when nuclear power costs are higher, the system relies more on the linepack to support the H2-CCGTs demand, emphasising the linepack's vital role in ensuring system stability, especially when specific power sources are financially unfavourable.

Chapter 4. Summary

A set of multi-energy system studies have been conducted to analyse the role and value of hydrogen in supporting decarbonisation and providing resilience in net-zero energy systems. The studies are based on the 2050 energy system backgrounds where the capacity and operation of electricity, gas (natural gas and hydrogen), heating, carbon capture and storage (CCS) systems are optimised holistically using an integrated whole energy system model to minimise the whole-energy system cost. The studies compare the techno-economic performances of two mainstream heating decarbonisation pathways, i.e., the Hydrogen pathway, which uses hydrogen boilers and the Heat Electrification pathway, which uses heat pumps and resistive heating. Sensitivity studies have also been performed to analyse the impacts of different assumptions, such as varying levels of heat demand, different hydrogen mix scenarios, cost uncertainty of hydrogen storage, gas prices, offshore wind and nuclear power generation, interconnection development, level of system flexibility that will be available in future, and duration of extreme weather conditions. The last refers to the system conditions without RES output during peak energy demand.

4.1 Key findings

The key findings can be summarised as follows:

Role of Hydrogen in Supporting Decarbonisation and Energy Security in a Net-Zero Energy System

- In all scenarios, hydrogen plays a key role in energy decarbonisation, energy system balancing, and providing energy security. Hydrogen provides zero-carbon fuel for power generation, heating, transport, and industrial processes.

- Hydrogen technologies have different roles:

    - Hydrogen power generation (CCGT and OCGT) provides firm and dispatchable capacity, producing zero-carbon electricity, system balancing capability and reserve services. It enables hydrogen to be converted to electricity.

    - Auto Thermal Reformers with CCS produces blue hydrogen from methane reforming processes with very low carbon emission; it also provides stable supply, balancing and peaking capacity in the hydrogen supply system.

- Electrolysers produce hydrogen and enable lower-cost RES system integration by providing sector-coupling flexibility and ancillary services. It allows electricity to be converted to hydrogen to be stored efficiently or to supply hydrogen demand.

- The transmission and distribution of hydrogen play a crucial role in its transport from production sites to areas of high demand. Moreover, hydrogen linepack is vital for managing the challenges driven by the intermittent nature of renewable energy sources within the gas infrastructure. The flexibility offered by the hydrogen network must be seamlessly integrated with other technologies, such as interconnectors, electricity storage, and demand response systems to ensure the cost-effective and secure operation of the overall energy system.

- Hydrogen storage offers a versatile solution for bulk energy storage with minimal losses, providing substantial hydrogen supply capacity and serving as an alternative source to balance the hydrogen system. Distributed hydrogen storage also plays a significant role in regulating the operating pressures within hydrogen pipelines, thereby optimising the volume of hydrogen that can be delivered to meet demand. Whether it involves harnessing surplus green hydrogen generated during windy summer days or fulfilling energy requirements during cold winter periods, hydrogen storage is fundamental in effectively managing fluctuations in supply. As renewable energy integration continues to grow and the green hydrogen supply chain matures, the significance of hydrogen storage further increases, notably in enhancing the overall resilience of the energy system.

- BECCS acts as a negative emission technology and provides a flexible option for biomass energy to be applied for electricity or hydrogen production.

- Hydrogen boilers act as zero-carbon heat appliances.

- Hydrogen is also a zero carbon fuel for industrial processes and transport (ground, aviation and shipping).

- Hydrogen integration can minimise the total cost of the overall energy system. All energy system investment and operation, especially for the power and hydrogen systems, should be optimised from the whole-system perspective, considering the complex interactions across all energy vectors and carbon storage and removal infrastructure. A silo'd approach to managing electricity and hydrogen systems will produce suboptimal results.

- Hydrogen is a competitive alternative for many types of energy decarbonisation, including heating and electricity, while contributing to energy security due to its diverse production options (electricity, natural gas and bioenergy).

- While Heat Electrification using heat pumps improves energy efficiency, its energy system cost can be higher than the hydrogen alternative. These are driven by the following:
    - A higher heating appliance cost.
    - A higher supporting energy system cost attributed to higher electricity peak demand - Heat Electrification will require additional energy infrastructure capacity to be built for security of supply purposes. These will operate at low load factors, infrequently operating, e.g. only during peak time or when RES output is low, and drive high cost per unit of output energy.

    - While a heat pump system requires half or less primary energy to deliver the same heat unit compared to a hydrogen boiler, Heat Electrification requires more flexibility and heat storage. Shifting demand and storing energy may increase energy losses.

- Several key factors enable effective hydrogen transportation within the existing infrastructure:

    - By optimal allocation of green hydrogen supply sources closer to demand centres, reducing the need for long-distance transport.

    - Crucial investments in hydrogen compression capabilities play a pivotal role in facilitating hydrogen transportation, ensuring its availability precisely when and where it is required.

    - The optimal distribution of hydrogen storage facilities further enhances the infrastructure's efficiency by minimising the necessity for long-distance transport, effectively storing and transporting hydrogen where needed.

- The role of linepack as the inherent flexibility in the gas infrastructure for the transport of hydrogen sets the stage for a 'virtuous' cycle built on three foundational pillars: flexibility, efficiency, and cost-effectiveness:

    - *Flexibility:* As hydrogen's application broadens through ramped-up employment of electrolysers, linepack variability offers inherent 'free' flexibility to deal with the challenges associated with more utilisation of renewable energy sources.

    - *Efficiency:* A system with adequate flexibility inherently operates more efficiently. With the integration of renewable sources, harnessing their full potential becomes essential. Enhanced flexibility means the unnecessary curtailment of surplus renewable energy is reduced to produce green hydrogen to be injected into the gas infrastructure, ensuring energy is utilised optimally to the advantage of both the environment and the economy.

    - *Cost-Effectiveness:* As the energy system operates at higher efficiency levels, the levelised cost of renewables is kept low, and hence, more investment can be made on flexibility. The inherent flexibility ensures that energy storage solutions are selected optimally, supplying cost-effective energy during extreme events when energy demand spikes, thereby enhancing the energy system resilience and preventing potential energy shortfalls.

Comparison between Hydrogen and Heat Electrification Pathways with a Range of Sensitivities

- The hydrogen for decarbonising heat pathway is more competitive than the Heat Electrification pathway across all the scenarios. The savings are between **£2–7.3bn/year.** Even extreme gas prices do not make the Hydrogen pathway less cost-effective overall.

- Improving system flexibility through deploying demand response, energy storage technologies, and electricity interconnection between Great Britain and Europe is very important for both pathways as it is the most sensitive factor that drives system costs up or down. 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.

- Reducing the annual and peak energy consumption through improving energy efficiency is important in any scenario.

- All hydrogen production technologies should be considered and optimised to minimise the overall system costs while providing diversity in hydrogen supply to improve energy security and resilience against extreme weather events.

- Increased duration of extreme weather conditions is not a major issue if the system has sufficient firm low-carbon capacity from gas CCS, hydrogen, and nuclear power generation. Hydrogen production from ATR+CCS can be increased to support higher hydrogen demand due to prolonged low-wind conditions with a small impact on the capacity requirement. Hydrogen storage and RES capacity can be oversized as an alternative option if green hydrogen is deployed to limit UK exposure to international gas prices.

- The flexibility inherent in an energy system, influenced by factors like interconnection, electricity storage, and DSR, plays a pivotal role in determining the extent of linepack fluctuations. In low flexibility scenarios, more pronounced linepack swings are observed, particularly in the Heat Electrification pathway, where swings can be as high as 24.2 mcm/day compared to the Core scenario. This increased reliance on linepack flexibility to manage challenges derived from renewable energy sources demonstrates the critical need for effectively handling linepack variations within the broader energy framework.

- The cost-effectiveness of hydrogen storage has a direct impact on the integration of renewable energy sources into the energy system. As renewables deployment is increased, the inherent intermittency is shifted onto the gas network, demanding greater linepack flexibility. This effect is particularly prominent in the Heat Electrification pathway, where increased injection of green hydrogen into the gas infrastructure results in more linepack swings of up to 13.8 mcm/day (compared to the Core scenario) to ensure the security of supply.

- In scenarios characterised by lower cost wind energy, investments in hydrogen compression have the potential to be reduced, with up to 42% reduction in supply (in the Hydrogen pathway) and a 10% reduction in infrastructure. This reduction is due to the direct compatibility of green hydrogen with the gas network through PEM electrolysers and the wider distribution of electrolysers compared to the fixed locations of ATR+CCS plants, which are typically located near natural gas terminals.

- In scenarios with high natural gas prices, an increase in the need for hydrogen compression is observed in the Heat Electrification pathway. This heightened demand stems from the system's greater reliance on H2-CCGTs, given the increased costs associated with gas CCS plants. While blue hydrogen production is reduced, the primary supply source shifts to green hydrogen due to lower hydrogen demand. However, to meet the rising hydrogen demand for power generation, more hydrogen supply from BECCS is required. Consequently, there is an 11% increase in electricity demand for compressing the hydrogen produced via BECCS. Conversely, in the Hydrogen pathway, electricity demand for hydrogen compression decreases as the system transitions away from high-cost blue hydrogen production, favouring green hydrogen supply instead. This shift substantially reduces electricity demand for hydrogen compression (up to 45%).

- As expected, a similar trend to high natural gas prices is observed in the "No Blue" scenario. In this situation, there is a 12% rise in the electricity needed for hydrogen compression in the Heat Electrification pathway, and a substantial 45% reduction is witnessed in the Hydrogen pathway. Conversely, in the No Green scenario, marked by increased hydrogen supply via methods like ATR+CCS and BECCS, a noticeable 19% increase in electricity demand for hydrogen compression is observed compared to the Core scenario.

- A 50% reduction in hydrogen storage costs can stimulate investments in storage facilities, enhancing the gas system's flexibility to supply more hydrogen to hydrogen-based power plants. Nevertheless, the system must balance these storage cost reductions against the financial implications of increased blue hydrogen compression to maintain the efficient operation of the gas network.

- During unplanned energy source shortages, such as the unavailability of blue hydrogen or an increase in nuclear power costs, the system places more reliance on linepack to supply the energy demand (up to 32 GWh/day). Acting as a buffer, linepack highlights the complex interplay between various energy sources, ensuring the harmonisation of supply and demand while enhancing system resilience. Linepack's ability to provide intra-day flexibility to manage intermittencies adds an additional layer of adaptability to the system. This flexibility plays a crucial role in facilitating hydrogen transport within the gas infrastructure, contributing to its overall efficiency and reliability.

- Both linepack and hydrogen storage are integral components in the integrated operation of electricity and hydrogen systems. As observed across various scenarios, spanning from the affordability of wind energy to constraints in electricity flexibility, their synergy improves system flexibility, enabling efficient hydrogen transport to meet hydrogen demand across GB.

4.2 Key challenges

There are some challenges observed from the results of the studies; these are summarised here:

- The volume of energy and carbon infrastructure scale to be built within the next 30 years is high. Scaling up all infrastructure development and repurposing the existing gas infrastructure will be challenging. In the Hydrogen pathway, the distribution of infrastructure development is more balanced between electricity and hydrogen, providing more diversity in technology development, while the Heat Electrification pathway focuses more on the electricity sector. Both pathways will require substantial capacity for manufacturing, installing, operating, and maintaining all the assets. A sufficient workforce with appropriate skills must be developed.

- Many new technologies, such as hydrogen applications for heating, power, storage, industrial processes, transport, and hydrogen production technologies, have not been developed maturely.

- Both the Hydrogen and Heat Electrification pathways require Carbon Capture and Storage (CCS) infrastructure, which does not exist in Great Britain today, to be deployed to achieve net zero cost-effectively. The Hydrogen pathway requires marginally more CCS system than Heat Electrification.

- The planning and operation across different energy sectors become more strongly coupled in all scenarios. Therefore, it requires a holistic approach to optimise the investment and operating decisions of the whole energy system. The transformation of ESO to the Future System Operator (FSO) provides evidence that this issue has been recognised, and the policy action is in the right direction.

- The transition to a future energy system characterised by high renewable energy sources presents notable operational challenges for the NTS, especially when hydrogen is injected into the gas infrastructure. The study demonstrates that a significant increase in daily linepack fluctuations (83% higher than those observed in November 2021) can occur as a consequence of efforts to maintain the supply-demand equilibrium. To address this situation, the primary operational strategy entails the optimal distribution of hydrogen reserves across the system, along with the upkeep of pressure standards and proactive monitoring of compressors to avoid shutdowns. It is crucial to emphasise that any unanticipated outages in this context could potentially give rise to systemic complications, underscoring the importance of proactive management and adaptability within the NTS.

4.3 Policy recommendations

Based on the studies being conducted, the analyses and the discussions with relevant stakeholders, some policy recommendations are made and listed as follows:

1. Review the approach to measure energy system resilience and security standards considering the integration of hydrogen technologies into the future system;

2. Ensure that the current high levels of political commitment to hydrogen production development are matched with hydrogen storage and network infrastructure development. Other supporting infrastructure, such as CCS infrastructure, should also be facilitated.

3. Provide sufficient funding and incentives to speed up research, development and deployment of innovative hydrogen technologies;

4. Establish a level playing field and fair market competition for all types of hydrogen technologies, including hydrogen from different energy sources (gas, electricity, biomass) and hydrogen for heating;

5. Support demonstration of medium and large-scale innovative hydrogen projects;

6. Provide a clear roadmap for hydrogen integration to support the transition and as part of the enduring solution for net-zero and sustainable energy systems;

7. Develop appropriate hydrogen regulatory and market framework to ensure that the whole-system value of hydrogen technologies can be quantified and commercially remunerated via markets.

8. Establish a coordination structure across all relevant energy system stakeholders to develop integrated strategies to improve energy system resilience and decarbonisation while ensuring optimal development and operation of the whole energy system across different energy vectors, including electricity, hydrogen, and heating.

4.4 Future work

The work described in this report flags several areas that need to be studied in more detail in future, including:

- The value and role of emerging small and medium scales hydrogen technologies (electrolysers, fuel cells, hydrogen storage) for domestic and local community applications and integrated net-zero energy hubs to improve energy efficiency and security;

- The economic performance of alternative hydrogen transport and storage technologies like ammonia and Liquid Organic Hydrogen Carriers (LOHCs);

- Optimisation of North Sea gas/hydrogen and electricity network infrastructure to support cost-effective integration of marine renewable resources.

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Appendix A Energy system background and key assumptions

The data below are used for the 2050 system studies. Most of the data are taken from established studies, including:

1. CCC studies (2018) – "Analysis of Alternative UK Heat Decarbonisation Pathways", available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf

2. Carbon Trust (2021) – Flexibility in Great Britain, available at: https://publications.carbontrust.com/flex-gb/analysis/

3. National Grid ESO (2022) – https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Data from the above studies were usually the results of consultations with key industry stakeholders, CCC, BEIS and research organisations.

The key input data and assumptions are summarised in the following table.

<table>
<tr><th>Category</th><th>Key input data and assumptions for central scenarios</th></tr>
<tr><td>Carbon emissions</td><td>Net-zero on an annual basis (GB system)
Need to offset emissions from “hard to decarbonise” sectors: 50 MtCO_2/year
Include emissions from electricity and hydrogen systems</td></tr>
<tr><td>Energy demand</td><td>All figures are in TWh/year*
7% losses are included in the electricity demand to account for transmission and distribution losses.

Domestic
• heat demand: 222 TWh (heat)[32]
• 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 (heat)
• 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. The energy system infrastructure and operation in IWES are optimised to meet the annual energy demand and net-zero emissions requirements. The Great Britain is assumed to be energy positive at the annual level (total annual demand is less or equal to annual production), and the interconnectors are used for short-term energy/power exchanges with adjacent countries.</td></tr>
<tr><td>Bioenergy</td><td>177 TWh (biomass input)[33]</td></tr>
<tr><td>Negative emission technologies</td><td>BECCS for power, hydrogen, methane
DACCS with electricity and hydrogen heating</td></tr>
<tr><td>CCUS</td><td>Carbon storage and CCUS network are available and optimised by the model
Cost of storing carbon: £15/tCO_2
All CCUS technologies (except BECCS) are developed in regions with carbon storage terminals (Scotland, North East England, North Wales, East Midlands, East England)</td></tr>
<tr><td>LCoE of power generation in 2050</td><td>Renewable and nuclear technologies
<table>
<tr><th>Technology</th><th>LCOE (£/MWh)</th><th>Max. capacity by 2050 (GW)*</th></tr>
<tr><td>Offshore</td><td>35</td><td>110</td></tr>
<tr><td>Onshore</td><td>30</td><td>50</td></tr>
<tr><td>Solar PV</td><td>44</td><td>100</td></tr>
<tr><td>Nuclear</td><td>60</td><td>20</td></tr>
</table>
*rounding up to the nearest 10GW from FES 2022 capacity</td></tr>
</table>

[32] Derived from Leading the Way 2050 in FES 2022 by National Grid ESO. It is based on the underlying heat demand provided by electric and hydrogen heating (Table EC.R.06 and EC.R.08 in FES 2022 workbook)
[33] Bioresource in 2050 Leading the Way Fes 2022

Category	Key input data and assumptions for central scenarios

LCoE of power generation in 2050

Other technologies

Technology	CAPEX £/kW (2050)	Fixed Cost (£/kW) (2050)	Hurdle rate	Lifetime	Annuitised cost (£/kW p.a.)
H2 CCGT	611	31	7.50%	25	82.44
H2 OCGT	578	31	7.50%	25	79.73
Gas CCS - CCGT	1,203	61	7.50%	25	160.90
Nuclear - Large	3,870	78	9.50%	40	423.29
Biomass with CCS	3,308	33	10%	25	364.67

No unabated natural gas-fired power generation in 2050

Electricity interconnectors to Europe

Baseline capacity: 11.7 GW

Countries	GW
France	5.4
Ireland	1.5
Netherlands	1
Norway	1.4
Belgium	1
Denmark	1.4

The Maximum additional capacity that can be built by 2050 is 8.3 GW, bringing the maximum potential capacity to 20 GW.

Distributed storage

Technology: Li-Ion (grid scale >50MW). CAPEX: £55/kWh (in 2050). WACC:6.5%, Lifetime: 10 years

Heat decarbonisation

Few possible pathways for on-gas-grid customers:

1. Electrification (a combination between ASHP and resistive heating)

2. Hydrogen boiler

District heating networks (DHNs) supply 20% of heat demand.
DHNs are in urban areas only and supplied by G/WSHP with a flat COP (3).
The heat demand of off-gas-grid customers is supplied by electric heating. Around 10% of domestic and 20% of non-domestic customers are off-gas grid.
ASHP needs at least 2kWh thermal storage. DHN storage is around 20kWh/household.

The model optimises additional thermal storage.

Category

Key input data and assumptions for central scenarios

Hydrogen technologies

Three main hydrogen production technologies:

- Auto Thermal Reformers(ATR) with CCUS – ATR supersedes Steam Methane Reformers (SMR) due to their higher energy efficiency.
- Electrolysis (Proton Exchange Membrane, Alkaline, and Solid Oxide)
- BECCS (gasification)

Technology	Capex (£/kW)	Fixed Opex (£/kW/year)	Efficiency (%)	CO^2 Capture Rate (%)
ATR + CCUS	364	24.4	89%	96%
Solid Oxide Electrolyser	700	50.0	84%	
Alkaline	455	29.3	82%	
Proton Exchange Membrane	340	29.3	82%	
Biomass Gasification + CCUS (H2 BECCS)	1,173	103.4	69%	95%

Unless otherwise stated, the study also assumes that hydrogen production in the Great Britain should be sufficient to meet the hydrogen demand.

Hydrogen storage

Two technologies:

- Underground storage (Cheshire Basin, East Yorkshire, East Irish Sea and Wessex)
- Overground storage – around 350 GWh distributed storage is needed to enable meeting hydrogen peak demand. Only medium pressure storage is considered to be feasible.

Cost and volume available for underground storage are defined below[34]

Site	Capex £/GWh Stored	Fixed OPEX (£/GWh stored)	Variable Opex (£/GWh)	Losses	Lifetime (y)	WACC	Annuitised Cost (CAPEX + Fixed OPEX) [£/GWh stored]
Cheshire Basin	1,763,946	67,298	419	0.84%	40	10%	187,261.94
East Yorkshire	1,403,377	79,570	637	0.42%	40	10%	151,645.29
East Irish Sea (offshore)	1,763,946	100,965	419	0.84%	40	10%	190,704.71
Wessex	1,763,946	67,298	419	0.84%	40	10%	187,261.94

Cost of overground hydrogen storage (medium pressure) is defined below

	Capex £/kWh Stored	Fixed OPEX (£/kWh stored)		Losses	Lifetime (y)	WACC	Annuitised Cost (CAPEX + Fixed OPEX) [£/GWh stored p.a.]
Medium pressure	11.45	0.34	0	0%	40	10%	1,205,638.50

[34] *Element Energy. Hydrogen Supply Chain Evidence Base. November 2018*

Category	Key input data and assumptions for central scenarios
Hydrogen network	The natural gas National Transmission System will be repurposed and hydrogen compatible.[35] Gas distribution will be hydrogen-compatible in 2050. Cost of gas distribution conversion £1,665 million/year (source: Element Energy - Cost of Gas Network Hydrogen Conversion Update, November 2021)
Gas price	£23.67/MWh
Demand flexibility	Maximum potential flexibility: • 20% of Industrial and Commercial customers • 40% of smart appliances • 80% of smart EV Heat storage is used to modulate the heat-led electricity demand. Flexibility services include load-shifting for arbitrage, capacity, network congestion, and ancillary services (frequency response and reserves)
Optimisation approach	Whole-system approach – all system components are optimised to reduce the system costs.
Distribution network cost	The cost function is derived using representative fractal networks considering Great Britain distribution network characteristics for urban and rural systems with different customer densities. 14 DNO regions are modelled.

In the Heat Electrification pathway, the annual cost of decommissioning the gas distribution network is £957 million/year (source: DNV - Decommissioning the GB Gas Networks: Discussion paper, 26 November 2021).

[35] *Note: the transition to the fully hydrogen NTS is not part of the analysis.*

Appendix B Modelling approach

To study the interaction between multi-energy vectors and analyse the impacts of alternative decarbonisation strategies on the UK energy infrastructure in 2050, a range of scenarios can be simulated and optimised using the Integrated Whole-Energy System (IWES) model. The IWES model incorporates detailed modelling of the electricity system and heating options, including district heating, heat network, heat pumps (air/ground source, Hybrid), and hydrogen infrastructure. IWES models the complex interactions across those energy vectors, as shown in Figure B-1.

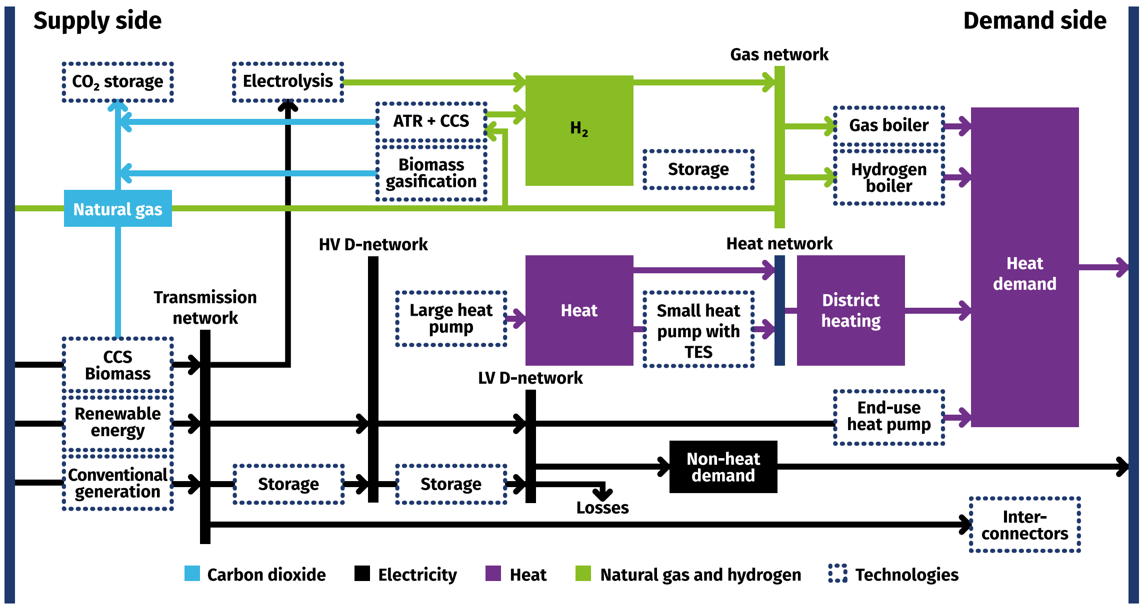


Figure B-1 Interaction between gas, heat, and electricity systems

In IWES, the multi-energy system's short-term operation and long-term investment decisions are optimised simultaneously to minimise the overall system costs by maximising synergies in system expansion planning and operation within agreed constraints, such as a specified carbon target. The model covers both local district and national/international level energy infrastructure details, including energy-flow interactions with mainland Europe via interconnectors, as illustrated in Figure B-2. This functionality is essential since those aspects are complexly intertwined and must be analysed simultaneously in the whole-energy system context.

The Great Britain energy system is divided into 14 regions following the distribution network areas to provide sufficient spatial granularity to capture the regional characteristics. Each region has two (or more) different representative district characteristics (e.g. urban and rural systems). IWES also considers the interactions between the Great Britain energy system, Ireland, and continental Europe, cross-border energy exchange, and sharing capacity and flexibility.

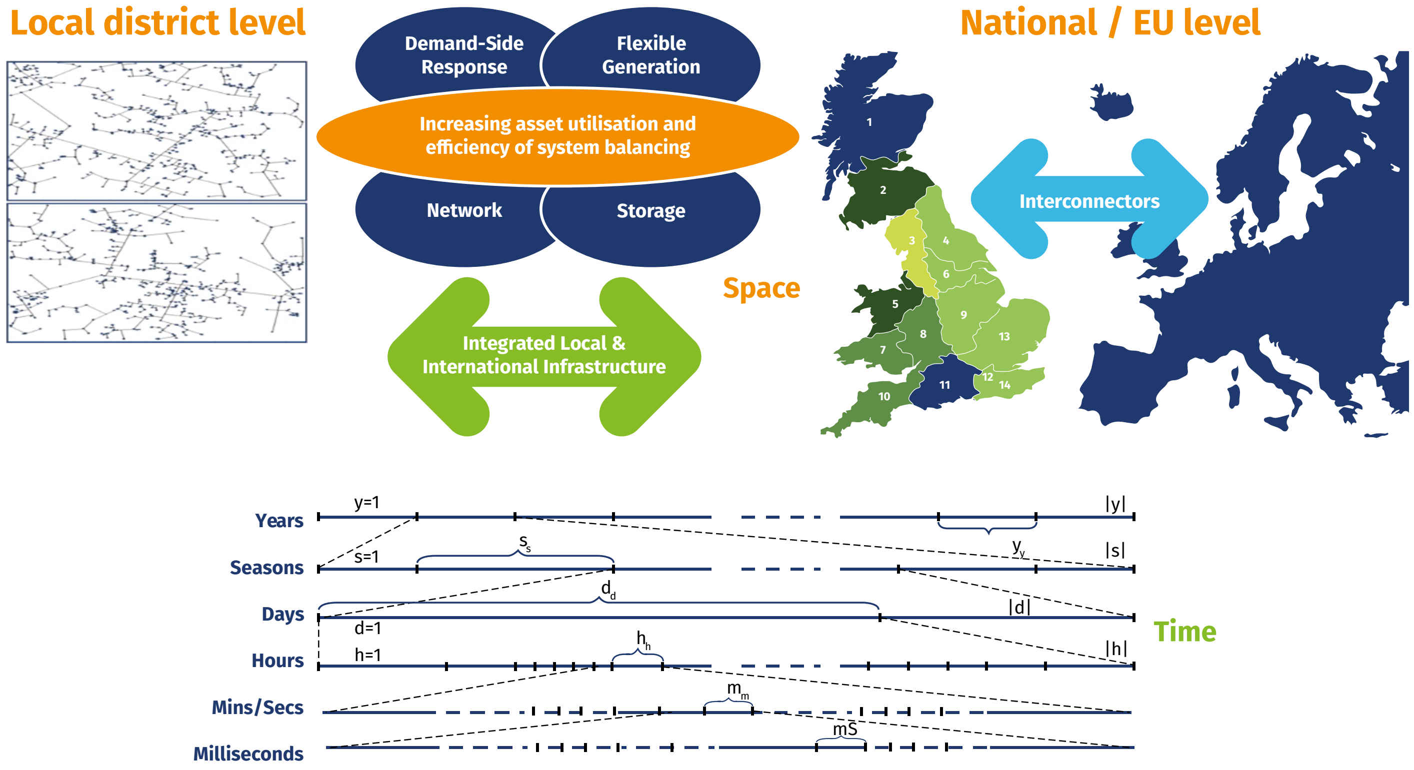


Figure B-2 Coordinated decisions across various timeframes and location interactions in the integrated modelling of low-carbon systems

IWES optimises the energy supply portfolio, transmission and distribution infrastructure, and energy storage simultaneously to capture system components' interactions. For example, a more extensive distribution capacity may be needed to enable end-users' flexibility to follow renewable output. IWES also optimises the technical needs for real-time supply and demand balancing, including frequency regulation and balancing reserve (seconds and minutes time-scale) while considering critically essential changes in the system inertia (which is vital for zero-carbon energy system) while reflecting on the dynamic parameters and technical limitations of the selected portfolio of energy sources and flexibility technologies. The benefits of system flexibility provision can be analysed across various energy vectors.

IWES model has been applied to investigate the value of system flexibility[36], evaluate the performance and system implications of different heat decarbonisation pathways[37], quantify the benefits of hydrogen and electricity integration involving electrolysers and hydrogen-fuelled power generation, identify the role of carbon removal technology for net-zero, understand the impact of local versus whole-system optimisation and the importance of ESO-DSO coordination, identify the system integration cost of renewables[38], and the value of long-duration energy storage[39].

[36] Carbon Trust, G.Strbac, D.Pudjianto,"Flexibility in Great Britain," May 2021 – Available at: https://publications.carbontrust.com/flex-gb/analysis/

[37] G.Strbac, D. Pudjianto, et al,"Analysis of Alternative UK Heat Decarbonisation Pathways", a report to the Committee on Climate Change, June 2018. Available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf

[38] G. Strbac, M. Aunedi, D. Pudjianto, F. Teng, P. Djapic, R. Druce, A. Carmel, and K. Borkowski, "Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies," Imp. Coll. London, NERA Econ. Consult., 2015.

[39] D.Pudjianto, Luis Badesa, G.Strbac," Whole-system value of long-duration energy storage in a net-zero emission energy system for Great Britain," a report for SSE Renewables, Feb 2021.

The IWES model considers more than 30 different cost categories. However, for simplicity, the annual system costs are presented and grouped into fewer high-level cost categories, including eleven Capital expenditure (C), two Operating costs (O) and one Revenue (R) categories described as follows:

Table B-1 Detailed and higher-level cost categories

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitised[40] and operating costs are annual)
C: Low carbon gen	C: Electricity generation	Capital cost of wind, PV, hydro, nuclear, gas CCS, power BECCS, and H2-based generation.
C: Non low-carbon gen	C: Electricity generation	Capital cost of traditional fossil-fuel-based generation such as CCGT, OCGT and CHP.
C: Transmission	C: Transmission and interconnection	Capital cost of the Great Britain transmission network, including onshore and offshore (but not interconnection).
C: Interconnection	C: Transmission and interconnection	Capital cost of Great Britain interconnectors.
C: Distribution	C: Distribution networks	Capital cost of reinforcing electricity distribution network.
O: Electricity	O: Electricity	Fuel cost, no-load cost and start-up cost of power generation. The cost of hydrogen as a fuel is excluded here[41] but included in the Capex and Opex of hydrogen.
C: HP	C: Electric heating	Capital cost of heat pump devices, installation cost and the annual fixed operating and maintenance cost.
C: RH	C: Electric heating	Capital cost of resistive heating devices, installation cost and the annual fixed operating and maintenance cost. RH is not used in this study, but it is part of the IWES model.
C: Storage	C: Electricity and thermal storage	Capital cost of electricity storage in the system; it includes the cost of pumped hydro and battery energy storage system.

[40] *The annuitisation of capital cost considers hurdle rates and payment periods.*

[41] *Carbon Trust, G.Strbac, D.Pudjianto,"Flexibility in Great Britain," May 2021 – Available at: https://publications.carbontrust.com/flex-gb/analysis/*

Table B-1 Detailed and higher-level cost categories

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitised[40] and operating costs are annual)
C: Heat storage	C: Electricity and thermal storage	Capital cost of domestic and district heating thermal energy storage.
C: DACCS	C: Hydrogen and CCS	Capital cost of DACCS[42].
C: Decom. gas distribution	C: Electric heating	this cost occurs only in the Electric scenario as most of the gas distribution network is no longer used, and therefore, it should be decommissioned. The cost is estimated at £1bn/year. A small proportion of gas distribution connected to large customers (e.g. industry) and BECCS to hydrogen is maintained.
C: ATR+Bio	C: Hydrogen and CCS	Capital cost of building ATR with CCS and the biomass gasification with CCS for hydrogen production.
C: Electrolysis	C: Hydrogen and CCS	Capital cost of various electrolysers: Proton Exchange Membrane (PEM), Alkaline, Solid Oxide Electrolyser (SOE).
C: H2 network	C: Hydrogen and CCS	Capital cost of building a national hydrogen transmission network. It is assumed that the national gas transmission is retained.
C:H2 storage	C: Hydrogen and CCS	Capital cost of both underground and overground storage.
C: CCS network	C: Hydrogen and CCS	Capital cost of building the CCS network.
C: Carbon storage	C: Hydrogen and CCS	Cost of storing carbon captured by CCS. It is assumed that the carbon storage cost is £15/tCO_2.
O: ATR+Bio	O: Hydrogen and CCS	Fuel cost used by ATR with CCS and BECCS to produce hydrogen[43].
O:H2 storage	O: Hydrogen and CCS	Operating cost of hydrogen storage.
O: NG boiler	O: Hydrogen and CCS	Cost of natural gas used by the boilers.
C: NG boiler	C: Gas heating	Cost of natural-gas-based boilers, installation, and the annual fixed operating and maintenance costs.
C: H2 boiler	C: Gas heating	Cost of natural-gas-based boilers, installation, and the annual fixed operating and maintenance costs.
C: Gas network	C: Gas heating	Cost of retaining the present gas distribution network. It is applied to the H2 and Hybrid pathways.
C: DH (network)	C: District heating	Cost of district heating networks, including the operating and maintenance cost.

[42] The cost information on DAC is based on the 2018 report by the US National Academies titled "Negative Emissions Technologies and Reliable Sequestration: a research agenda."

[43] Operating cost of electrolysers is part of the power sector costs.

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitised[40] and operating costs are annual)
C:DH (appliance)	C: District heating	Cost of household heat infrastructure needed for the district heating system, e.g. metering, heat control, and connection to the main heat network.
C:DH (conversion)	C: District heating	Cost of decommissioning natural-gas appliances including replacing the gas hob and gas oven with an electric hob and oven and adding the hot-water storage system.
C: HHP	C: HHP heating	Capital cost of heat pump, natural gas or hydrogen boiler, control system and the fitting cost.
C: DR	C: Demand response	Capital cost of demand response technologies.
R: Electricity Export	R: Electricity Export	Estimated revenue from electricity export (calculated based on the average electricity cost).

The energy required for hydrogen compression for injection into the gas infrastructure used in the IHES model:

The energy needed to compress hydrogen from P1 bar to P2 bar relies on various factors, including the volume of hydrogen undergoing compression, the compression technique employed, and the efficiency of the compression process. However, we can approximate the energy required for compression by applying the ideal gas law and assuming an isothermal compression process. Assuming that the volume of hydrogen being compressed remains constant, the energy required for compression in Joules/mole can be calculated as follows[44]:

$$E_{comp} = RT * ln\left(\frac{P_2}{P_1}\right) \quad (1)$$

where P1 is the initial pressure and P2 is the final pressure, R is the gas constant, and T is the temperature.

Assuming standard temperature and pressure (STP) conditions, the volume of 1 kg of hydrogen is 495.05 moles and to convert the energy to kWh and assuming an efficiency for the compressor, the formula is modified as follows:

$$E_{comp} = RT * l\,n\left(\frac{P_2}{P_1}\right) * 0.000138/\eta \quad (2)$$

Regarding hydrogen production intended for injection into a distribution network at lower pressures, typically below 7 bar, compression may not be necessary. Most CCUS-enabled technologies typically produce hydrogen at approximately 20 bar, while electrolysis is assumed to yield hydrogen at around 30 bar for PEM electrolysis. Therefore, most technologies would involve compression expenses if they were to directly inject hydrogen into a transmission network. It is assumed that only larger facilities would directly connect to a transmission network. Additionally, as compressor CAPEX and fixed OPEX costs decrease significantly with increased scale, they are unlikely to constitute a substantial portion of the overall levelised cost. For instance, at a 300MW site producing hydrogen at a constant or high load factor throughout the year, compressor costs would contribute roughly £1/MWh[45]. Therefore, depending on the heat decarbonisation pathway, we need hydrogen compression for the hydrogen produced from ATR/SMR and BECCS. In this study, it is assumed that the majority of the produced green hydrogen will be directly connected to the transmission system, and there is no requirement for additional compression.

[44] *Felderhoff, M., Weidenthaler, C., von Helmolt, R., & Eberle, U. (2007). Hydrogen storage: the remaining scientific and technological challenges. Physical Chemistry Chemical Physics, 9(21), 2643-2653.*
[45] *https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf*

It is reasonable to consider that the operational pressure limits in the Great Britain NTS, range from approximately 38 to 85 bar. In this context, we assume that the pressure of blue hydrogen production is 20 bar, while biomass gasification operates at 10 bar. Additionally, the pressure required for injection is assumed to be similar to the gas terminal injection in the network, which is 80 bar. The energy required for compression from 20 bar to 80 bar (assuming 80% compressor efficiency) for injection into the gas infrastructure can be calculated as follows:

$$E_{comp,blue} \approx 0.6 \text{ kWh/kgH2}$$

$$E_{comp,bio} \approx 0.9 \text{ kWh/kgH2}$$

The second aspect involves calculating the energy needed to compress hydrogen within the NTS to maintain the pressure within operational boundaries and compensate for pressure losses due to friction in the pipelines. To achieve this, compressor units are installed. The necessary power for the compressor's prime mover, whether electrically or gas-driven, can be calculated using equation (3). In the case of gas-driven compressors, it's essential to convert the energy consumption into the equivalent natural gas volume that would be injected into the compressor. The ratio of discharge pressure to suction pressure is constrained by equation (4).

$$P_{c,t}^{comp} = \frac{\beta . Q_{c,t}^{comp} . p_{c,t}^{suc}}{\gamma} . \left[\left(\frac{p_{c,t}^{dis}}{p_{c,t}^{suc}} \right)^{1/\beta} - 1 \right] \qquad (3)$$

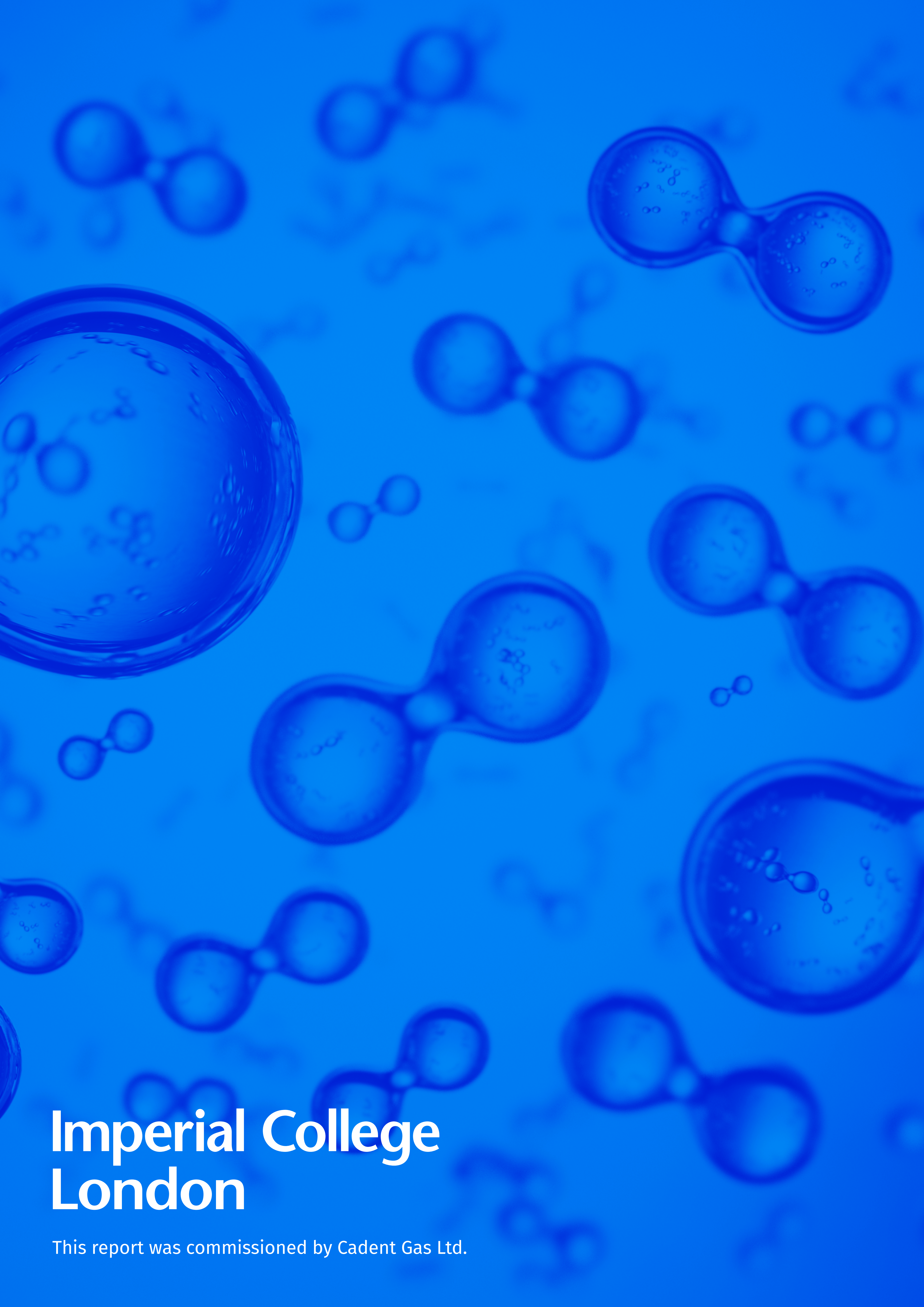
$$1 \leq \frac{p_{c,t}^{dis}}{p_{c,t}^{suc}} \leq CR^{max} \qquad (4)$$

$$E_{comp,inf} = \sum \sum P_{c,t}^{comp} \qquad (5)$$

where β is the polytropic exponent of a gas compressor, γ is the efficiency of compressor units, and CR_{max} is the compressor pressure ratio.

Hence, a rough estimation for the calculation of the energy required for the compression of hydrogen in the case of 100% injection of hydrogen to the NTS is as follows:

$$E_{comp,tot} = E_{comp,inf} + E_{comp,blue} + E_{comp,bio} \qquad (6)$$



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