November 2024

Developing a whole-systems approach to explore pathways to Net Zero

Assessing how a hydrogen market will operate alongside existing energy markets in the energy transition

centrica

FTI CONSULTING

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Foreword

Centrica is a multinational energy and services company whose activities span the production, processing, storing, trading and supply of energy. We live by our purpose — "*energising a greener, fairer future*"[1] - because we believe in providing energy and services to satisfy the changing needs of our customers and want to help them transition to a more sustainable energy future. This purpose naturally aligns with the concept of whole-systems thinking, especially within the UK context.

Whole systems thinking is crucial to the UK for several reasons:

- **Energy Transition** — The UK is committed to reducing its carbon emissions and transitioning towards more sustainable energy sources. Whole systems thinking allows for the integration of various energy sources, including both electrons and molecules, and technologies in a way that is efficient, sustainable, and responsive to changes in demand and supply.
- **System Efficiency** — This approach helps in optimising the entire energy system, reducing waste through integration of technologies such as renewable generation and demand response systems. These systems enable the balancing of supply and demand across the network, improving overall efficiency and lowering the system cost to consumers.
- **Resilience and Security** — Whole systems thinking is vital for enhancing the resilience of the energy system against disruptions. A comprehensive view helps identify vulnerabilities and interdependencies that may not be apparent when considering components in isolation.

The UK's energy policies and regulations are designed to encourage innovation and investment in cleaner energy technologies. A whole-systems approach ensures that policies consider all parts of the energy system leading to more coherent and effective investment framework.

Centrica through its purpose, recognises the importance of a systems-orientated approach to address these complex, interconnected challenges effectively. This allows us to improve our service and solutions offering but also contribute to the broader goal of a sustainable and secure energy future in the UK.

As we look to the future, Centrica has a crucial role in the energy transition, we've committed to investing between £600m to £800m a year until 2028 in renewable generation, security of supply, and our customers.

In doing so, we can add value for customers, colleagues, communities and shareholders alike.

Chris O'Shea

Group Chief Executive of Centrica

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1 See *Corporate Factsheet 2024*, Centrica (link).

Executive summary

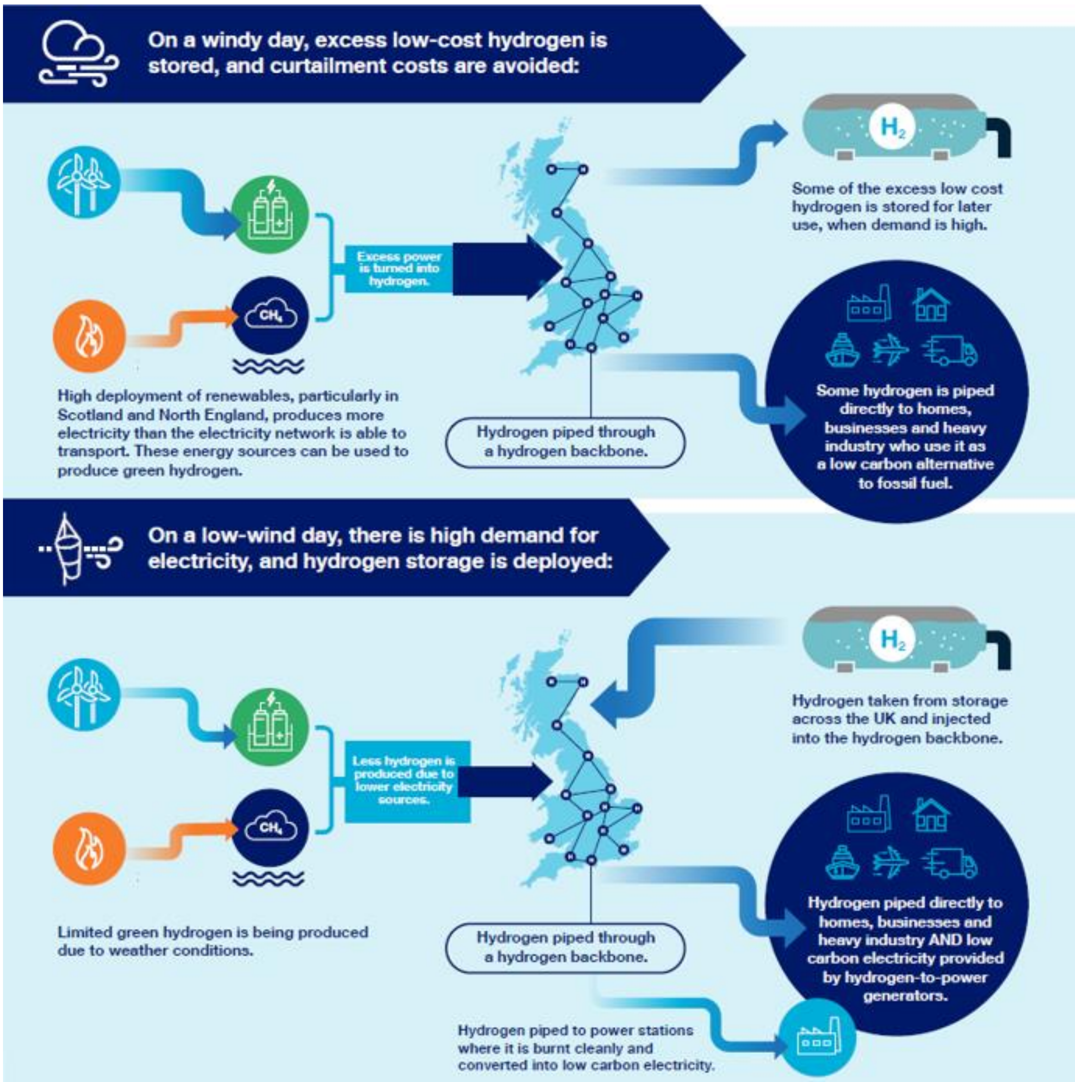
The UK has made significant progress on its decarbonisation journey towards net zero greenhouse gas emissions by 2050 and was the first major economy to halve its emissions compared to 1990 levels in 2022.

Despite this, many of the most challenging elements of the transition lie ahead, and a range of ambitious solutions will be required to deliver it in a timely, cost-effective manner. These elements include the decarbonisation of heavy, high-temperature-dependent industries, long-distance travel as well as securing electricity supplies so they are robust to extreme weather patterns.

Technological advances and reductions in the cost of renewables mean that electrification is likely to deliver the lion's share of change. However, the extent of electrification in a Net Zero world may be limited in some areas — for example in the provision of energy and feedstock in certain industrial processes. Additionally, a highly-electrified renewables system will lead to greater challenges in balancing the electricity system, given greater reliance on intermittent renewables, seasonal variations in demand (e.g. from electric heating), and scarcity in transmission network capacity. In this context, while the extent of a future hydrogen economy is still highly uncertain and subject to debate, many consider that hydrogen could complement the role of electrification in decarbonising the economy — providing an energy source for end users where other low-carbon alternatives may be limited, and bolstering the resilience of the electricity system itself.

Hydrogen is a gas of high calorific value which does not produce carbon dioxide when burned to generate energy. It can be produced in a low-carbon manner from electricity through electrolysis and from gas through methane reformation combined with carbon capture and storage. Once produced, it can then be transported by trucks (and in the future, through either new pipelines or repurposed gas pipelines) or stored in storage facilities such as salt caverns and depleted gas fields. Hydrogen could then be consumed in various ways, for example in industrial processes requiring very high temperatures, transport and electricity generation. Figure 1 below presents a stylised representation of such a hydrogen value chain.

Figure 1: Stylised hydrogen value chain



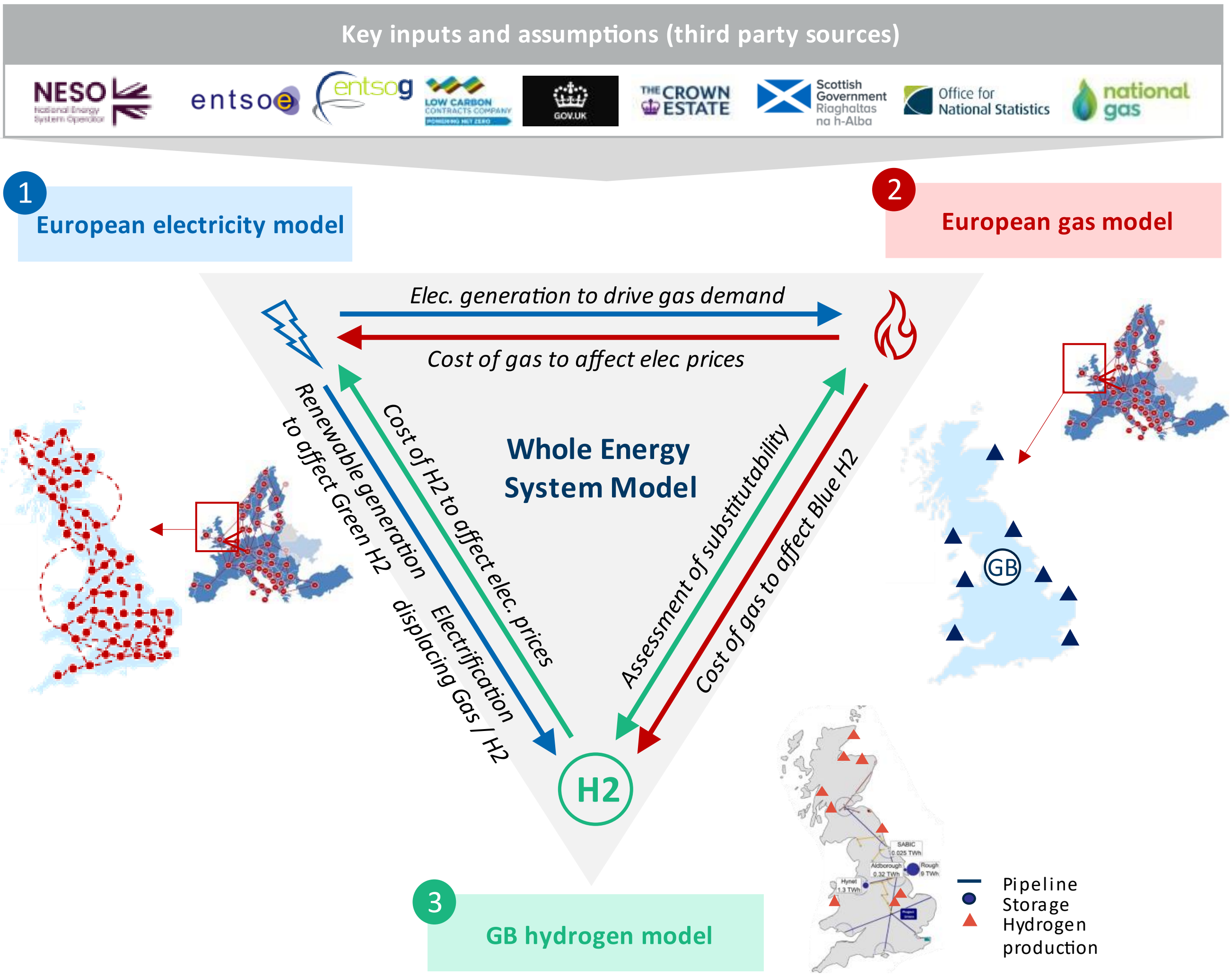
Sources: Centrica, FTI Consulting analysis.

Understanding the potential role of hydrogen, how it can be produced and deployed most cost-effectively, as well as how its production and usage might interact with other energy vectors, remains an uncertain, understudied area from an economic perspective. To support the critical conversations and decisions that will need to take place across industry, government and the wider policy environment, Centrica and FTI Consulting ("FTI") have worked together to develop a novel approach to analysing the energy system.

Our work has focused on exploring some of the key questions to which the answers depend most on the inherent interactions and interdependencies between hydrogen, electricity and gas. These include how the evolution of the renewable generation roll-out will affect hydrogen production costs and how hydrogen might be most cost-effectively produced; what role hydrogen-powered generation combined with hydrogen storage may play in the electricity generation mix; and what might gas price trends mean for the relative economics of hydrogen production from electrolysis vs methane reformation.

Our analytical approach builds significantly on the detailed and geographically granular electricity market model initially built by FTI Consulting to conduct our assessment of reforms to the GB electricity market for Ofgem. This electricity model sits alongside gas and hydrogen models, which incorporate key assets and sources of demand and supply in those markets (such as gas pipelines, electrolysers and hydrogen-to-power generating plants). The granular design of each of the market models, particularly that of the electricity market, enables us to assess them through a “whole-systems” approach, explicitly considering the key interactions such as electricity prices and hydrogen production from electrolysis, gas prices and hydrogen production from methane reformation, and electricity generation from hydrogen. Figure 2 shows a stylised depiction of our assessment approach.

Figure 2: Stylised depiction of our whole-systems model



Sources: FTI Consulting analysis.

For this report, we have modelled potential market outcomes under a particular scenario, developed in discussion with Centrica's energy experts. This model builds on overarching assumptions taken from the National Energy System Operator's Future Energy Scenarios and other public sources, with some adjustments made, for example to reduce the scale of hydrogen demand for home heating. This represents a scenario consistent with existing government policy, where hydrogen plays a significant role in several sectors, including heavy industry and transport, and where there is significant national hydrogen infrastructure including large-scale hydrogen storage and hydrogen transmission in the form of a national backbone.

We have also considered a second scenario, where we significantly reduced the capacity of hydrogen storage. This allows us to consider the impact on other parts of the energy system from a policymaking perspective regarding storage sites.

While our analysis so far focuses on these specific scenarios, there are some key insights that can be drawn to inform discussions and decisions regarding the shape of the UK's energy system and the role hydrogen may play:

1. **Hydrogen-fuelled electricity generation** is likely to be the only way to cost-effectively replace the balancing role currently fulfilled by unabated gas generation within a secure, decarbonised and renewables-dominated electricity system.

2. While the extent of a future hydrogen economy in the energy transition is unclear, the **value of hydrogen in both production and consumption will differ in GB across locations and time periods**.

3. The development of a **hydrogen transport network**, and sufficient large-scale **storage facilities**, will be necessary to establish a hydrogen market.

4. The build-out of flexible **green hydrogen production** would **complement the expansion of renewable generation capacity**, serving as a value-enhancing offtaker during times of excess renewable production.

5. Flexible **green hydrogen production** could play an even more important value-enhancing role **in regions of GB where intermittent renewable capacity will be greatest — most notably Scotland.**

6. Given the high fixed costs of hydrogen production facilities, significant external funding is likely to continue — **support mechanisms should incentivise the use of low cost electricity**, rather than maximum utilisation, to bring the overall cost of production down.

7. **Methane reformation (i.e. blue hydrogen)** may provide an **economically competitive source of hydrogen, if global conditions are conducive to lower gas prices** (falling demand, relatively stable supply)

Notably, the findings in Key Insights 1, 2, 4 and 5 emphasise that much of value of hydrogen is driven by how it complements the electricity sector — to be produced when it is "windy" and producing electricity when it is "not windy", helping to keep the Net Zero electricity system balanced. This is predicated on Key Insight 3, that having sufficient hydrogen transport and storage capacity is necessary for a hydrogen market to take advantage fully on the variability of electricity prices and system needs in different locations and time periods.

The key insights we have outlined above are predominantly based on our modelling outcomes, which are in part driven by key assumptions we have made for the analysis including within this report.[2] For example, we have had to make assumptions about the set-up of the GB gas market, how electrolyser and electricity generation siting decisions will be made, and how responsive to price-based market signals hydrogen assets will be — among other assumptions, each of which need to be considered further on a whole-systems basis.

As part of this, we also highlight three potential key areas to consider subsequent to this assessment: (1) the implications of a gas switchover to hydrogen when repurposing the gas network; (2) the potential substitutability of electricity transmission and hydrogen pipelines to relieve constraints on the electricity system; and (3) the implications of zonal electricity wholesale pricing on the hydrogen sector.

Ultimately, in the context of greater Net Zero deliverability challenges and uncertainties around the hydrogen economy, we envisage that the development and use of a whole-systems analytical tool would be useful to both policymakers and industry in exploring the different Net Zero pathways. We set out in more detail about our approach and findings our full report, where we explore the potential issues and solutions — and welcome further dialogue on the development of such an approach.

2 As this engagement was commenced in 2023, many of our input assumptions relied on data from 2022 or earlier. Some of these assumptions, particularly around technology cost estimates would likely have changed considerably since then, but we do not anticipate these to be material to our findings. We set out our key assumptions that drive the analysis of the report in Chapter 9.

1. Introduction

1.1. Achieving net zero greenhouse gas emissions ("Net Zero") by 2050 presents a significant delivery challenge for the UK. The UK has made considerable progress so far, but with the easier elements of decarbonisation achieved, the most costly and complex elements of the pathway still lie ahead.

1.2. The next stage will require continued technological advancement, as well as significant investment in new infrastructure and complementary policy from government and regulators.

1.3. Government decarbonisation strategies across the developed world, including the UK, have suggested that hydrogen will play a key role in the next stage of the energy transition and set out wide-ranging steps to develop a hydrogen economy.[3] This is because hydrogen is a gas of high calorific value, which can carry energy to hard-to-decarbonise sectors, releasing only water vapour when combusted.[4] While there is a broad consensus that hydrogen will play some role in the decarbonisation of the energy system, there is a wide range of views on the breadth of the role it will take.

1.4. It is in this context that Centrica and FTI Consulting ("**FTI**") have worked together to develop a whole-systems approach to modelling the future energy system. Our goal has been to develop an analytical tool that can be used to support evidence-based discussions with wider industry and policymakers on the potential costs and benefits of developing the future GB energy system to use hydrogen and various hydrogen assets across a range of uses. In this report, we (which refers to FTI Consulting in this report) set out the background and context to work, describe our analytical approach in detail, and summarise the key insights from our work so far, with particular focus on the role of hydrogen transportation and hydrogen storage in the future energy system.

1.5. In the remainder of this introduction, we briefly describe:

- the policy and industry background against which this work has been developed (**Section A**);
- the process followed in developing the analysis (**Section B**);
- some restrictions and caveats on the purposes and nature of the work (**Section C**);
- some limitations to the scope of our work (**Section D**); and
- the structure of the detailed report (**Section E**).

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[3] See, for example, the UK Government's Hydrogen Strategy, which was first launched in 2021. See *UK hydrogen strategy*, 2021, DESNZ (link).

[4] See **Chapter 2** for a more detailed discussion on the physical attributes of hydrogen.

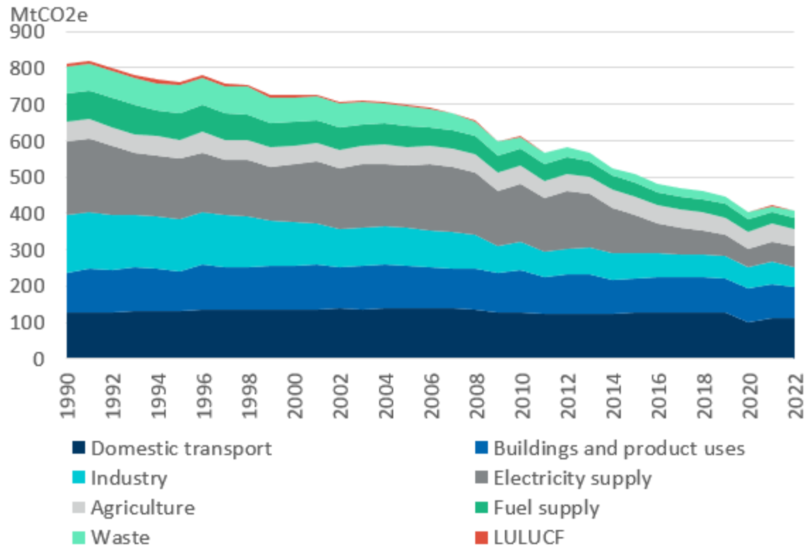
A. Background

1.6. The UK has recently become the first major economy to have cut its greenhouse gas emissions by 50% from 1990 levels.[5] There has been considerable success in the delivery of government commitments to reduce emissions, and according to the UK government, these have been cut *"faster than any other G7 country over the last decade"*.[6]

1.7. Figure 1-1 below shows the breakdown of net territorial UK greenhouse gas emission by sector from 1990 to 2022. In particular, it is noteworthy that:

- Total greenhouse gas emissions have reduced by c.50% from 1990 to 2022, with the electricity supply and industry sectors seeing a reduction of c.73% and c.63% in emissions, respectively. The waste and fuel supply sectors also made significant emissions reductions, reducing by c.74% and 60%, respectively.
- Historically, the electricity supply sector had the highest greenhouse gas emissions, but large reductions over the last decade means that since 2014, the domestic transport sector has had the highest emissions. The reduction in emissions from the electricity supply sector has been driven by changes in the mix of fuels and technologies used for electricity generation.[7]

Figure 1-1: UK GHG emissions by sector (MtCO2e), 1990 to 2022



Sources: DESNZ;[8] FTI Consulting analysis.
*Notes: Land use, land use change and forestry ("**LULUCF**") consists of emissions and removals from forests, cropland, grassland, peatland, and settlements.*

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5 See *UK first major economy to halve emissions*, 2024, UK government press release (link).
6 See *UK first major economy to halve emissions*, 2024, UK government press release (link).
7 Changes in the mix of fuels being used for electricity generation includes: the growth of renewables; greater efficiency as a result of technology improvements; and a shift from using Coal at power stations to Gas, which has a lower carbon content. See *2022 UK Greenhouse Gas Emissions, Final Figures*, 2024, DESNZ (link): Page 14.
8 See *2022 UK Greenhouse Gas Emissions, Final Figures*, 2024, DESNZ (link).

1.8. The remaining sources of emissions are concentrated in sectors and processes that are increasingly challenging to decarbonise. In particular, decarbonising long-distance transport, heavy (high-temperature dependent) industry and residential heating will require unprecedented committed from the energy sector and wider economy, working in tandem with government. A similarly challenging landscape is faced when it comes to delivering an electricity system that can operate securely and efficiently during protracted periods when the sun does not shine, and the wind does not blow.

1.9. Hydrogen, in either molecular form or as a derivative (such as ammonia-related compounds), could serve as a store of energy that can be used at different times or locations — without emitting carbon when produced from clean energy sources. Hydrogen's ability to store and convey energy has led many stakeholders to suggest that it may play an important role in addressing some of the biggest remaining decarbonisation challenges.[9] However, the extent and precise nature of the role of hydrogen in the future energy system remains highly uncertain, and so has become an important component of the discourse relating to decarbonisation worldwide. This is driven by factors relating to the potential for hydrogen on both the demand side and supply side, as well as the role of government policy. Several key factors are articulated below.

1.10. Firstly, the technological frontier for enabling decarbonisation across sectors is evolving rapidly. The extent to which hydrogen-based technologies will dominate specific sectors of demand in therefore uncertain. Examples of alternative technologies and solutions may include (non-exclusively):

- **Emerging electricity storage technologies**, which are currently undergoing research and development.[10] This includes gravitational storage, which uses excess electrical energy from the power grid to raise a mass (for example a concrete block) to generate gravitational potential energy; liquid and compressed air energy storage ("LAES" and "CAES") which use surplus electricity to liquify or compress air that can subsequently be allowed to regasify or decompress, powering generation turbines; and pumped heat storage which uses surplus electricity to power a heat pump, from which energy can be recovered to power a generator.[11]

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9 Currently, hydrogen is widely used in several sectors, predominantly in chemicals and refineries, but not for the power sector. In 2022, c.95Mt of hydrogen was consumed globally — almost all produced from fossil fuels, termed "**grey hydrogen**". See *Global Hydrogen Review*, 2023, IEA (link).

10 See *Future Energy Scenarios report*, 2023, NESO (link): Page 193.

11 See *What is renewable energy storage (and why is it important for reaching net zero)?*, 2023, NESO (link).

- **Flexible demand**, which can help manage the power sector during periods of stress by shifting electricity usage outside of peak demand periods. This includes the Demand Flexibility Service ("**DFS**") which was introduced in the winter of 2022 by the National Energy System Operator ("**NESO**"), then operating as the Electricity System Operator ("**ESO**"), and aimed to reward households and businesses for shifting their electricity use from peak times, thus supporting the NESO in balancing the power grid.[12]

1.11. Secondly, if hydrogen is to play a role in the decarbonisation of any future energy system, various new asset types will be required on the supply side. These assets will be essential to the production of low-carbon hydrogen, as well as its transportation and storage, and must be built into and around the existing core energy system given that various forms of hydrogen production will likely depend on another energy vector (i.e. producing hydrogen using electricity via electrolysis, or producing hydrogen using natural gas via steam methane reformation). The deployment and roll-out of these hydrogen assets will be largely dependent on key government policy decisions and the progress of emerging technological advancements.

1.12. In light of this, there is ongoing discussion on a range of important questions regarding the potential role of hydrogen, such as the sectors to which it will be most important; how it can be produced most cost-effectively; and what implications it will have for the electricity sector as the main energy vector in a decarbonised economy.

1.13. Government policy will also play a key role in enabling any decarbonisation solution in the future, such as hydrogen, due to the persistence of significant market failures associated with market nascency that will otherwise inhibit any developments. This is especially true given that, as discussed above, the production of hydrogen will depend on other energy vectors, and so a future energy system where hydrogen plays a significant role will be comprised of complex interactions across the energy vectors. More specifically:

- **electricity and gas[13] can both serve as potential alternatives to hydrogen**: including electricity storage, or using Carbon Capture and Storage ("**CCS**") to capture carbon emissions from various methods of electricity generation, such as unabated gas, biomass, or bioenergy sources; as well as

- **electricity and gas can both serve as potential sources for its production:** including using electricity and gas to produce hydrogen using various technologies, and potentially storing this hydrogen in storage facilities, which could play a key role as Long Duration Energy Storage ("**LDES**").

1.14. We discuss the interactions between hydrogen and the other energy vectors as outlines above in more detail in **Chapter 2B**.

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[12] See the NESO*'s Demand Flexibility Service*, NESO (link).

[13] In this report, we use the term "**gas**" as a shorthand reference to natural gas, unless specified otherwise.

1.15. Despite the complexity and uncertainty regarding the cross-vector interactions above, quantified assessments of the potential dynamics at play have so far been limited. In particular, there has been limited detailed quantified modelling of the operation of an energy system that examines the interactions, in demand, supply and also storage, between hydrogen and other energy vectors.

B. Process to produce this report

1.16. In this context, we have been commissioned by Centrica to develop a quantitative whole-systems approach to analysing the potential role of hydrogen in supporting GB's Net Zero ambitions, and how it might interact with the electricity and gas vectors. The purpose of this work is to facilitate better-informed discourse between policymakers and industry on the shape of potential future GB hydrogen economy and how to best deliver it.

1.17. This comprehensive whole-systems analysis builds on FTI Consulting's detailed analysis of the electricity system that underpins our quantitative assessments of locationally granular (nodal and zonal) market designs in GB, most notably our work for Ofgem that supported the UK Government's Review of Electricity Market Arrangements ("**REMA**"). As a baseline, the whole-systems analysis in this report includes an assumption that the *status quo* electricity market arrangements remain in place, that is it includes a uniform GB-wide wholesale electricity price. However, our whole-systems model is built on a granular representation of the electricity market, which enables us to study the geographical impact of a hydrogen market on other markets and vice versa. For example, the locational granularity of the model allows us to determine the optimal location to site electrolysers, considering a range of factors such as co-location with renewables, the topology of the electricity network, and planning constraints.

1.18. Given the uncertainties and complexities of the potential role of hydrogen as discussed above, we have been as transparent as possible in our approach in setting up our whole-systems model throughout this engagement.[14] Therefore, one of our aims of this report is to clearly explain our methodology, assumptions and overall approach to provide reassurance to stakeholders of the robustness of our findings and modelling outcomes. To this end, we have:

- used an industry-standard modelling tool, Plexos, to develop a whole-systems model which integrates the three energy vectors of electricity, gas, and hydrogen. In particular, we have augmented the FTI Consulting electricity nodal market model to explicitly incorporate hydrogen as a distinct energy vector, complementing and fully-optimising alongside the existing electricity and gas system models used elsewhere;

[14] The FTI Consulting expert involved in this report includes Jason Mann (link), and our recent energy system modelling experience includes our work for Ofgem on locational pricing: *Assessment of locational wholesale electricity market design options in GB*, 2023, FTI Consulting & Energy Systems Catapult (link).

- sought, wherever possible and appropriate, to use third-party publicly-available information as inputs into our modelling. In particular, we have used widely accepted industry-standard data produced by the NESO and the European Network of Transmission System Operators for Electricity ("**ENTSO-E**") for scenarios of the future evolution of generation, demand and transmission components across the energy system;
- made adjustment to projections of hydrogen demand and supply included in such third-party publicly-available information, specifically to various forecasts produced by the NESO in their Future Energy Scenarios ("**FES**") 2022 scenarios. This includes the extent to which hydrogen could be used in domestic heating (known as "**hydrogen for heating**"), as well as the development of hydrogen production and storage technologies;
- we have sought advice from industry stakeholders, including the NESO and National Gas, to build detailed discussions and conduct assumption testing; and
- presented our initial findings to key industry stakeholders, including DESNZ, the NESO, and various other stakeholders with potential investment in the hydrogen value-chain.

1.19. By setting out our whole-systems methodology and approach transparently, we hope this would provide stakeholders confidence on our key insights and recommendations in exploring future pathways to achieve Net Zero.

C. Restrictions

1.20. This report has been prepared solely for the benefit of Centrica, for use for the purpose described in this introduction.

1.21. FTI Consulting accepts no liability or duty of care to any person other than Centrica for the content of the report and disclaims all responsibility for the consequences of any person other than Centrica acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

D. Limitations to the scope of our work

1.22. This report contains information obtained or derived from a variety of sources. FTI Consulting has not sought to establish the reliability of those sources or verified the information provided.

1.23. No representation or warranty of any kind (whether express or implied) is given by FTI Consulting to any person (except to Centrica under the relevant terms of our engagement) as to the accuracy or completeness of this report.

1.24. This report is based on information available to FTI Consulting at the time of writing the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

E. Structure of this report

1.25. The remainder of this report sets out eight further chapters. These are:

- **Chapter 2** describes the background and context of this report;
- **Chapter 3** explores using a whole-systems approach to analyse the UK's Net Zero transition pathway, details our whole-systems modelling approach, and applies the whole-systems framework to critical policy and commercial questions;
- **Chapter 4** sets out our key inputs and assumptions underlying our whole-systems model relating to the electricity and gas markets;
- **Chapter 5** sets out our key inputs and assumptions underlying our whole-systems model relating to the hydrogen market and provides the relevant policy context to the future GB hydrogen economy;
- **Chapter 6** provides an overview of our modelling outcomes relating to the capacity build-out and wholesale pricing trends across the GB electricity, gas and hydrogen markets;
- **Chapter 7** provides an overview of the interplay between the three energy vectors towards Net Zero, and the implications for regulatory support for hydrogen production and hydrogen-to-power;
- **Chapter 8** sets out the role of hydrogen storage and transport in the future energy system, and provides an overview of the impact of reduced hydrogen storage; and
- **Chapter 9** sets out a summary of key insights.

1.26. A glossary to this report can be found in **Appendix 1**.

2. Background and context

2.1. Hydrogen has the potential to play several important roles in the delivery of Net Zero by 2050. This is because hydrogen is a gas of high calorific value which does not produce carbon dioxide when burned,[15] and can carry energy to hard-to-decarbonise sectors.[16, 17, 18] Hydrogen and its derivatives already play an important role in certain sectors of the economy - notably in petroleum refining and fertiliser production.[19] Moreover, given that it is inextricably linked to other energy vectors at various points of the value chain, well-informed policy and commercial decisions will need to rest on thinking and analysis that takes a "whole-systems" view.

2.2. In this context, Centrica and FTI Consulting have explored the application of such whole-systems thinking to detailed energy system analysis. To provide further background and context to this work, this chapter sets out:

- the scale of the remaining challenge for the UK to meet its decarbonisation objectives (**Section A**); and
- the potential role hydrogen can play in supporting how Net Zero can be achieved (**Section B**).

A. Scale of the Net Zero challenge

2.3. The UK has committed to Net Zero by 2050,[20] with the aim of limiting the negative impacts of climate change. As discussed in **Chapter 1,** the UK has so far made more progress towards this ambition than other major economies, with total greenhouse gas emissions falling by c.50% between 1990 and 2022.[21] This has primarily been achieved by the decarbonisation of electricity supply to existing sources of electricity demand, and reduced energy demand in some sectors as a result of improvements in energy efficiency.

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15 See *The role of hydrogen in achieving Net Zero*, 2022, House of Commons Science and Technology Committee (link). Hydrogen consumption can only be considered "clean" if the hydrogen is produced from clean energy sources.

16 Hydrogen gas (H_2) is a diatomic molecule which when burned in the presence of oxygen gas (O_2) forms water (H_2O) through a chemical reaction. See *Chapter 7 | An introduction to Chemical Reactions*, WebAssign (link).

17 Hydrogen has a high calorific value compared to other gases as measured by its heat value, the amount of heat released during combustion. Specifically, the heat values of various fuels are as follows: Hydrogen (H_2) = 120-142 MJ/kg; Methane (CH_4) = 50-55 MJ/kg; Petrol = 44-46 MJ/kg; Diesel = 42-46 MJ/kg; and Natural gas = 42-55 MJ/kg. See *Heat Values of Various Fuels*, 2020, World Nuclear Association (link). Throughout this report, we assume that the energy content of hydrogen is described by its Lower Heating Value ("**LHV**") rather than its Higher Heating Value ("**HHV**"), i.e. 33.33kWh/kg rather than 39.39 kWh/kg. The LHV is typically used if hydrogen is not burned directly. See *What is the energy content of hydrogen?*, Enapter (link).

18 Hydrogen is about 8 times lighter than natural gas. See *Hydrogen Compared with Other Fuels*, HydrogenTools (link).

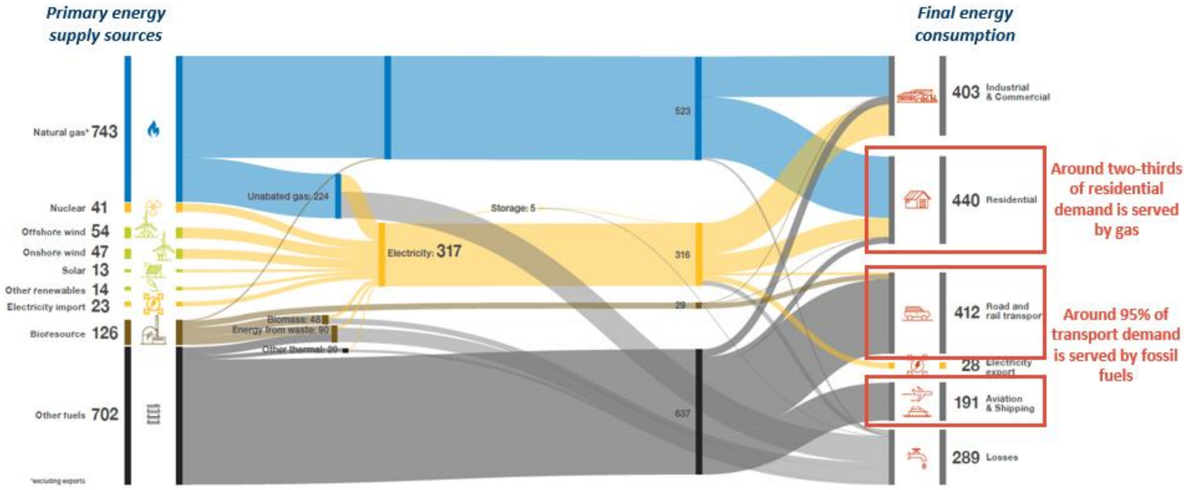
19 The end-uses of hydrogen include uses in its pure form, as well as uses from various derivative elements. See *Hydrogen*, International Energy Agency — Advanced Motor Fuels (link).

20 See *Net Zero Government Initiative*, 2023, DESNZ (link).

21 See *UK first major economy to halve emissions*, 2024, UK government press release (link).

2.4. Despite this substantial progress, Figure 2-1 below highlights the scale of the remaining challenge for the UK to overcome to achieve Net Zero by 2050.

Figure 2-1: Total energy supply and demand in the GB economy (TWh), 2022



Sources: NESO FES 2023.

2.5. Figure 2-1 shows that, in 2022:

- around 82% of the UK's primary energy supply came from fossil fuels;
- around 60% of energy demand from the industrial and commercial sector was served directly by fossil fuels;
- around two-thirds of energy demand from the residential sector (primarily domestic heating) was served directly by natural gas;
- around 95% of energy demand from the transport sector was served directly by fossil fuels; and
- of the remaining energy demand, 90% was served directly by electricity, some of which was generated from the use of fossil fuels.

2.6. To deliver Net Zero, the large components of energy demand that are currently reliant on fossil fuels will need to: transition to low-carbon energy sources, such as electricity generated from nuclear or renewables, i.e. "**electrification**"; directly adopt carbon capture technologies, known as Carbon Capture and Storage ("**CCS**");[22] or switch to alternative fuel sources such as low-carbon hydrogen. We note that of these solutions, electrification is one of the most important strategies for reducing carbon emissions, and involves replacing technologies or processes that currently rely on fossil fuels with electrically-powered equivalents. Such replacements are generally more efficient, and so reduce total energy demand and could help reduce carbon emissions as electricity generation is decarbonised.[23]

2.7. To facilitate the transition to low-carbon energy sources, many economists and other experts advocate the implementation of carbon pricing mechanisms. These policies are designed to effectively raise the cost of emitting carbon, with the intention of creating an incentive to move to low or zero emission alternatives. From a theoretical perspective, carbon prices could be set high enough to incentivise the delivery of net zero emissions across the economy.

2.8. In the UK, such carbon pricing mechanisms feature in the policy landscape, and are based around the Emissions Trading Scheme ("**UK ETS**"), a so-called "cap and trade" mechanism which applies across a range of sectors.[24] In the electricity sector, since 2013 the effective carbon price resulting from the UK ETS is combined with an additional cost from the Carbon Price Support ("**CPS**") scheme[25] to underpin a higher carbon price to incentivise greater investment in low-carbon power generation.

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22 We note that Carbon Capture and Storage ("**CCS**") is sometimes called Carbon Capture Utilisation and Storage ("**CCUS**"), with the view to re-use the carbon captured in various processes for a more efficient method of managing carbon emissions. See *What is carbon capture and storage?*, 2024, NESO (link).

23 See *Electrification*, International Energy Agency (link).

24 Historically the UK was included within the EU's similar Emission Trading System until the end of the Brexit transition period in January 2021).

25 See *Carbon price floor*, HM Revenue & Customs, (link).

2.9. Despite the potential role of carbon pricing in delivering decarbonisation, at this stage plans in the UK and other developed economies do not rely wholly on carbon pricing mechanisms to facilitate decarbonisation across the economy. This is reflected in currently forecasted carbon prices out to 2050 which would not, by themselves, be sufficient to deliver Net Zero across the economy. The Net Zero policy landscape includes, and will depend on, a range of other support measures because of the importance of policymaking considerations that go beyond the pursuit of theoretical efficiency. These include the distributional impacts of carbon pricing — including the risks of negative impacts on certain industries from overseas "carbon leakage"; the limitations to carbon pricing's efficacy in light of the need for system transformation, rather than optimisation, on the pathway to Net Zero; and the myriad of co-ordination problems that policy must therefore seek to overcome.[26] We discuss carbon prices in more detail, and our modelling assumptions regarding commodity prices in **Chapter 4C**.

2.10. As such, the UK's transition pathway to Net Zero will require a host of other decarbonisation solutions, especially given the potential stresses on the power sector if electrification is to play a critical role. For example, in any scenario there is likely to be a significant amount of additional electricity demand from various sources, as much of the transport sector (particularly cars through the adoption of Electric Vehicles ("**EVs**")) and the residential sector (through the adoption of electrified heating systems such as heat pumps) may decarbonise by electrification.

2.11. We emphasise that there is much debate on the extent that electrification would be needed to achieve Net Zero, and whether this role can be substituted by alternative technologies. This applies to sectors such as shipping or domestic heating, but is more apparent in particular sectors where industrial processes require very high-temperature heat or require hydrogen, or a derivative, directly.

[26] While there is not universal consensus among experts and economists, a wide range of challenges in relying on carbon pricing or similar as the sole policy instrument for delivering timely decarbonisation have been identified. For an example discussion, see *Why carbon pricing is not sufficient to mitigate climate change—and how "sustainability transition policy" can help*, 2020, Rosenblum et. al (link).

2.12. The extent of electrification in decarbonisation also brings forward questions on how this can be delivered. In particular, despite the potential energy efficiency improvements, wide-scale electrification will inevitably result in much greater electricity demand. Therefore, there will be a growing and costly challenge on how to deliver the necessary renewable electricity generation as well as the electricity transmission investments on the power grid needed to convey renewable generation from more remote areas, where much renewables generation is typically sited, to demand centres.[27] Aside from the cost, a high electrification scenario might give rise to greater security of supply challenges, both in terms of significant peak periods, and also short-term hourly and longer-term seasonal volatility.

2.13. Given the practical, economic and technological challenges to the electrification of hard-to-decarbonise sectors, there is significant discussion of the extent to which hydrogen could serve as an alternative low-carbon fuel to complement electrification in the Net Zero transition. While hydrogen is a potential store of clean energy, it is still currently expensive to produce at scale from clean energy sources, often requiring costly electricity or gas inputs, making it much less competitive than energy provided by electricity or gas themselves.[28] Additionally, there are engineering challenges associated with hydrogen when compared to natural gas, in terms of its storage and transportation such as those arising from its lower energy density and risks of pipeline corrosion and embrittlement.[29,30]

2.14. Part of this debate is therefore attempting to identify where hydrogen might have a comparative advantage, over other clean vectors of energy, in decarbonising the economy across certain sectors.[31]

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27 We note that FTI Consulting's current estimates, which take into account the NESO's recent *Beyond 2030* report, forecast that around £114bn of investment is required for transmission reinforcements on the power network by 2037. See *Beyond 2030*, 2024, NESO (link).

28 DESNZ, in their Hydrogen Production Delivery Roadmap, concluded that achieving an ambitious deployment of hydrogen production will be "*subject to affordability and value for money*", and that the roadmap will "*rise to the challenge of demonstrating significant cost reductions as the UK hydrogen sector takes off*". See *Hydrogen Production Delivery Roadmap*, 2023, DESNZ (link).

29 Hydrogen's low energy density presents issues related to its compression and liquefaction, as well as developing safe and efficient transport methods. See *Hydrogen Engineering Revolution: Leverage Rishabh Engineering's Multidisciplinary Approach*, Rishabh Engineering (link).

30 Hydrogen is the smallest molecule, and can fit into spaces in certain steel alloys where gas cannot, weakening the metal and making it more likely to crack or corrode. See *Can we use the pipelines and power plants we have now to transport and burn hydrogen, or do we need new infrastructure?*, 2023, Climate Portal (link).

31 One example of a more sceptical assessment on the potential use cases of hydrogen is set out by Michael Liebreich, see *Hydrogen Ladder Version 5.0*, 2023, Liebreich Associates (link). In this assessment, there are some activities that are considered highly challenging to decarbonise using alternative means apart from hydrogen such as fertilisers or long-duration energy storage, while other activities such as smaller scale transport vehicles could utilise more competitive low-carbon energy sources.

2.15. Overall, the ongoing contentious debate about the potential use of hydrogen illustrates both the varied views on different paths to Net Zero, and also emphasises the scale of the challenge in the energy transition — both of which require coordinated assessments and efforts.

B. The emerging role of hydrogen in a decarbonising energy system

2.16. While electrification is likely to be the primary mechanism through which sectors and processes are decarbonised, hydrogen seems likely to have a critical, complementary role in delivering Net Zero. Specifically, hydrogen has the potential to support decarbonisation by playing two broad roles:

- providing security of supply within a decarbonised whole-energy system; and
- directly replacing fossil fuels as a low-carbon alternative fuel.

2.17. These are discussed in more detail in the sections below.

Providing security of supply and support to the decarbonisation of the electricity sector

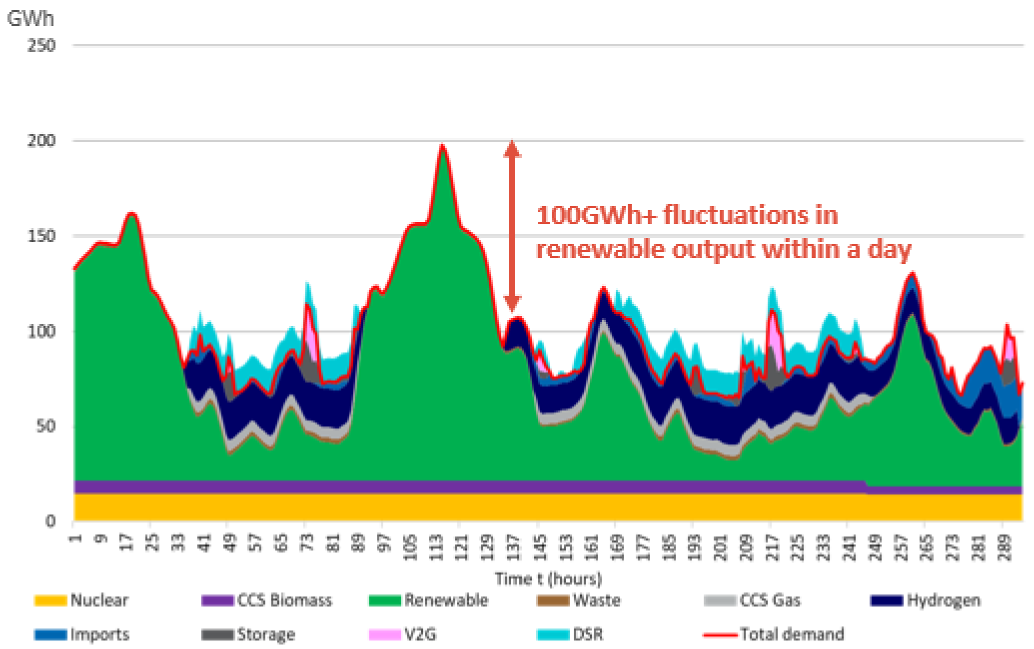
2.18. The UK's transition to Net Zero will require a continued move away from gas-fired generation and a significant increase in generation from renewable sources. As an electricity sector dominated by renewable technologies will be characterised by high volatility (both over- and under-supply) and potentially a supply and demand mismatch, this may present risks related to the security of supply, as well as managing peaks in electricity demand.[32] Figure 2-2 below from NESO shows the modelled hourly generation stack for an example stress period in 2050, known as a "**Dunkelflaute period**",[33] assuming the electricity sector is dominated by renewables in line with the NESO's modelling assumptions.[34]

[32] See *Future Energy Scenarios report*, 2023, NESO (link): Page 116.

[33] A Dunkelflaute period, named after the German compound word combining "dark" and "lull", is an extreme but rare extended period of low solar and wind generation. These periods can last for up to several weeks and so presents security of supply risks. See *Future Energy Scenarios report*, 2023, NESO (link): Page 117.

[34] See *Future Energy Scenarios report*, 2023, NESO (link): Page 213.

Figure 2-2: Modelled electricity generation stack (GWh), 19th February to 3rd March 2050



Sources: NESO FES 2023 (Consumer Transformation scenario).

2.19. As illustrated in the NESO's analysis presented in Figure 2-2 above, the future electricity system may be subject to large swings in renewable generation within a day. Therefore, to meet total demand during such periods where there is limited generation from offshore wind, other sources of electricity will be required. This potentially includes hydrogen-fuelled generation (referred to as "**hydrogen-to-power**" or "**H2P**" in the remainder of this report), as well as demand-side response ("**DSR**"), energy storage generation, dispatchable thermal generation and interconnector flows.

2.20. The NESO's analysis in Figure 2-2 shows fluctuations in renewable output reaching over 100 GWh per hour within a 24-hour period (a fluctuation of approximately 100%),[35] and considerable excess supply for sustained periods of time. In these periods of high renewable generation, the hydrogen system could play an important role — excess electricity can be used to produce hydrogen through electrolysis ("**green hydrogen**") at low cost, stored in long-term storage facilities ("**hydrogen storage**"), and subsequently used to generate electricity through H2P assets when renewable generation output is low. Notably, the biggest contributor of system flexibility during these periods of low renewable generation, as modelled by NESO, was in fact from H2P, especially during the second stress period which last approximately 5 days.[36]

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35 See the 32-hour period between hours 99 and 130 in the Dunkelflaute example in Figure 2-2 above.

36 See the approximate 5-day period between hours 137 and 257 in the Dunkelflaute example in Figure 2-2 above.

2.21. This demonstrates the potential for hydrogen to balance the system, particularly in the future where unabated gas-fired generation can no longer be used to meet peak demand and fill in the gaps. Achieving this is likely to require the development of appropriate market signals for hydrogen producers to use electricity when it is abundant (and electricity prices are low), for that hydrogen to then be stored for use ultimately when power is relatively scarce. The importance of the development of such a market is discussed further in **Chapter 7**.

2.22. This potential role of hydrogen to help alleviate stress periods in the power sector, and in turn enhance energy security is unlikely to be fully served by other sources of electricity storage. This is because these other sources typically operate efficiently over shorter durations, with batteries typically discharging for up to 2 hours (with potential to discharge for 4 to 8 hours, or multiday for pumped hydro).[37] As such, these non-hydrogen storage sources are well-placed to provide the flexibility required due to within-day or daily fluctuations in demand and supply, as well as to provide very short-term reserve, or help manage real-time network operability.[38] However, on the basis of current technologies hydrogen storage appears to be better suited to long-term or inter-seasonal storage, given it can:

- effectively store electricity at potentially very large volumes,[39] and so can provide months or years of energy storage;[40] and
- cycle the energy stored less frequently due to relatively low storage costs per unit of storage capacity.[41]

2.23. An alternative to hydrogen storage and H2P as low-carbon flexibility technologies is gas-fired generation combined with CCS (referred to as "**CCS Gas**"), which could serve as dispatchable capacity in the power sector. CCS technology involves capturing carbon emissions before it can reach the atmosphere, and then storing these emissions underground. The UK may have a unique strategic advantage in this space due to geological factors, as well as access to space under the North Sea for up to 78 billion tonnes of carbon emissions.[42]

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37 See *Long duration electricity storage consultation*, 2024, DESNZ (link): Page 23.

38 For example during the first stress period in the Dunkelflaute example in Figure 2-2 above, the approximate 3-day period between hours 31 and 93, total electricity storage operates constantly till it becomes empty, and only recharges once the stress period is over. See *Future Energy Scenarios report*, 2023, NESO (link): Page 214.

39 See *Future Energy Scenarios report*, 2023, NESO (link): Pages 192 to 194.

40 See *Large-scale electricity storage*, 2023, The Royal Society (link): Page 61.

41 We note that technologies with high capital costs per unit of capacity, such as batteries, must cycle the energy stored frequently in order to recover investment costs. This may present additional challenges related to such high cycle rates, for example the lifetime of batteries degrades as battery chemistry changes with use, and so battery capacity decreases. See *Large-scale electricity storage*, 2023, The Royal Society (link): Page 56.

42 See *New vision to create competitive carbon capture market follows unprecedented £20 billion investment*, 2023, DESNZ (link).

2.24. However, while CCS technology is likely to be critical in the Net Zero transition as a form of reducing emissions through carbon capture, it may not provide the necessary system flexibility to the power sector that is required on its own. This is due to several reasons:

- The high capital expenditure ("**Capex**") of CCS Gas compared to unabated gas or H2P plants means it has higher capital-intensity, and so for CCS Gas to be economic it must be generating for significant periods of time throughout the year. This potentially makes CCS Gas less suited for power generation under low capacity factors, which is likely to be the case in a renewables-dominated energy system where peaker plants typically operate infrequently.[43]
- The cost of CCS Gas is likely to be comparatively high, given that it involves the capture of low concentrations of carbon emissions. Specifically, there is no single cost for CCS technologies and the cost varies depending on the source of carbon captured: "pure" or highly concentrated sources of carbon emission (such as ethanol production or natural gas processing) are cheaper to capture; while low concentrations (such as capturing emissions directly from the air) are very expensive to capture. CCS Gas has a relatively low concentration of carbon emissions, and so its associated CCS capture costs are likely to be high.[44]
- The potential issues with surrounding the scalability of CCS technology, as specific geological conditions are required for storage sites meaning there are limited viable storage locations.[45] We note that similar locational, scalability and geological restrictions apply to hydrogen storage.
- CCS Gas typically does not capture 100% of carbon emissions, as most CCS projects target 90% efficiency as CCS technology costs get more expensive as it approaches 100% efficiency.[46] Therefore, CCS Gas will require negative emissions from other generation technologies on the system to reach Net Zero, such as bioenergy with carbon capture and storage ("**BECCS**") and direct air capture ("**DAC**"), but these technologies are unproven and may be limited by fuel supply.[47]
- CCS Gas still relies on natural gas to generate power, which could present several supply-side challenges, including:

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[43] DESNZ concluded that their modelling suggests "any flexible plants will be required for system security purposes, but that they are likely to be running at relatively low load factors. Given its lower capital-intensity, H2P is likely to be more cost-effective in this role than gas CCS". See *The Need for Government Intervention to Support Hydrogen to Power*, 2023, DESNZ (link).

[44] See levelised cost estimates for 'Power generation' *Is Carbon capture too expensive?*, 2021, International Energy Agency (link).

[45] The carbon capture storage sites are typically required to be 1km or more below ground. See *What is carbon capture and storage*, 2024, National Grid (link).

[46] See *How efficient is carbon capture and storage*?, 2021, Climate Portal (link).

[47] See *Policy Mechanisms for Supporting Deployment of Engineered Greenhouse Gas Removal Technologies*, 2021, Element Energy (link).

— the availability of gas may be limited in an energy system where key gas infrastructure assets, such as the transmission network or terminals are phased out; and

— CCS Gas generators in the UK may become increasingly dependent on global gas markets (as a result of limited domestic gas production), which carries the risks of input price volatility and supply disruptions.

2.25. Overall, our discussions above demonstrate that, in the absence of other technologies, hydrogen is likely to have a significant role in providing security of supply as the UK transitions to Net Zero. This is because the energy sector will be dominated by renewables which have volatile generation profiles that are subject to different weather patterns. Such volatility would be even more pronounced with a greater extent of electrification on the pathway to Net Zero, highlighting the potential need for hydrogen to balance the electricity sector in the future as well as directly replacing fossil fuels as a low-carbon alternative fuel.

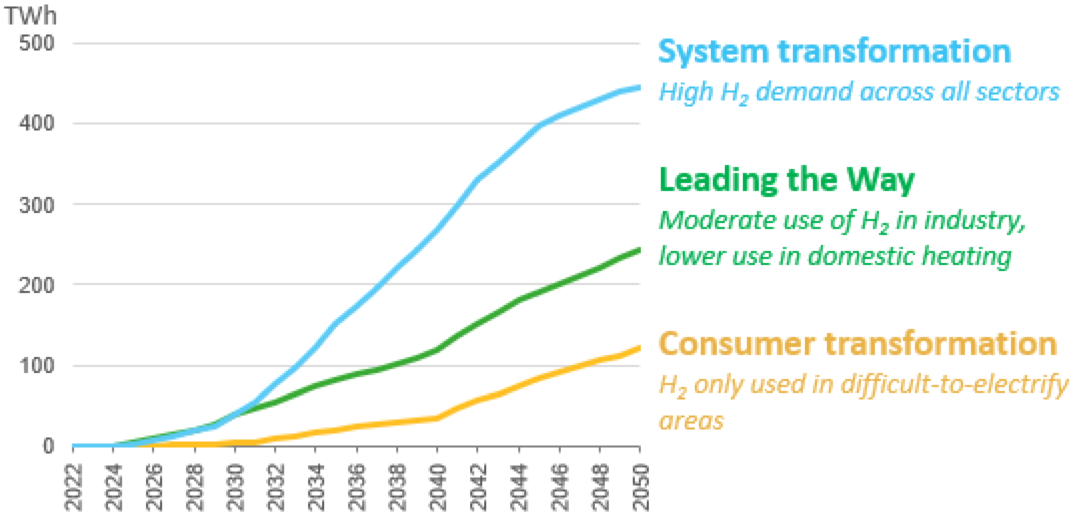
2.26. As indicated above, there is a lack of consensus regarding the extent to which hydrogen will be used as an alternative low-carbon energy fuel for end users. In theory, low-carbon hydrogen could play a role a wide range of sectors, including:

- **Power generation:** hydrogen, or a derivative such as ammonia, can fuel electricity generation. This generation technology would be dispatchable, meaning it can readily be turned-on, and ramped up and down, at relatively short notice to counter variations in renewables supply.
- **Industry**: hydrogen can provide the raw chemical input and/or be used to create the high temperatures required for some industrial processes.
- **Transport:** hydrogen in liquid, compressed or derivative form can be carried on board vehicles and used to power vehicles over long distances. Hydrogen is generally considered to be most useful to larger vehicles where batteries are less viable, such as Heavy Goods Vehicles ("**HGVs**"), aircraft, and ships.[48]
- **Heating:** hydrogen can be used as a direct alternative to natural gas for heating residential homes and commercial buildings.

2.27. However, it is still very unclear to what extent hydrogen and/or its derivates will become a viable low-carbon alternative fuel in such sectors, and will ultimately depend on its feasibility, and whether or not full electrification will be feasible and cost-effective. This is uncertainty is illustrated by the varying projections of total hydrogen demand produced by the NESO across the FES 2023 Net Zero scenarios, shown in Figure 2-3 below.

48 See *Hydrogen has a key role to play in decarbonising transport*, Hydrogen UK (link).

Figure 2-3: Hydrogen demand projections across the FES (TWh), up to 2050



Sources: NESO FES 2023.

2.28. As Figure 2-3 shows, the large variation in total hydrogen demand forecasts across the FES emphasise there is significant uncertainty surrounding the extent to which hydrogen will be used across various sectors. For example, the **System Transformation scenario** forecasts the highest level of hydrogen demand, with the greatest scope for hydrogen across all sectors, including residential and commercial demand (comprised mostly of hydrogen for heating), industry demand, and transport demand (comprised of shipping, aviation, and road transport). The **Leading the Way scenario** forecasts a moderate level of hydrogen demand, with reduced scope for hydrogen across all sectors, and the **Consumer Transformation scenario** forecasts even lower levels of hydrogen demand, with scope for hydrogen focused mostly in the transport sector.

2.29. The variation in total hydrogen demand across FES 2023 scenarios are largely the result of the assumed speed and manner of decarbonisation, and the type of societal change across different sectors of society, i.e. changes in consumer behaviour.

The hydrogen value chain

2.30. In order for hydrogen to fulfil its role in decarbonisation as discussed above, or indeed its role in any future energy system, various new asset types will be required and must be built into and around the existing core energy system. These assets are essential to the low-carbon hydrogen production, transportation, storage and use of hydrogen.

2.31. The most significant hydrogen assets are:[49]

- **Electrolysers:** produce so-called “green hydrogen” via the process of electrolysis and using electricity from renewable energy sources.

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[49] For a description of the “hydrogen colour spectrum”. i.e. the different types of hydrogen production technologies, see *The hydrogen colour spectrum*, 2023, NESO (link).

- There are two broad types of electrolysers which differ in their method of electrolysis: **Proton Exchange Membrane** ("**PEM**") electrolysis (which uses an acidic electrolyte solution and is often used to produce high-purity hydrogen); and **Alkaline** electrolysis (which uses a basic electrolyte solution, is less expensive, and typically produces hydrogen of lower purity).[50] While PEM electrolysis is more costly at this stage, one potential advantage is the ability to ramp production up and down relatively quickly in response to electricity prices or constraints on the electricity network.[51] Both of these technologies are currently commercially available, although innovative and more economic methods at scale are still being developed.[52]
- Furthermore, green hydrogen encompasses both grid-connected electrolysis, which are electrolysers connected to the power network, and non-grid-connected variants, which are electrolysers connected to dedicated renewables generators. These renewable electricity generating plants are not connected to the main power grid and are dedicated solely to the production of hydrogen.
- We note that there are other forms of electrolysis that can be used to produce hydrogen. For example, hydrogen could also be produced using electrolysis powered by nuclear energy using high temperatures from nuclear cogeneration processes (known colloquially as "**pink hydrogen**").[53] In addition, Solid Oxide electrolysers, which have not yet been demonstrated by scale, are fed by steam which can lead to greater efficiency than alkaline electrolysis and have the major advantage that they could in theory be used reversibly, i.e. to produce electricity from hydrogen.[54]

- **Methane reformation technologies:** use natural gas to produce so-called "**blue hydrogen**" through steam methane reforming ("**SMR**") or autothermal reforming ("**ATR**").[55, 56] Given that carbon dioxide is a by-product of the reforming reaction, blue hydrogen must be attached to CCS facilities to capture and store these emissions. Blue hydrogen production is more technically and economically challenging to change the level of output (i.e. to "ramp up" and to "ramp down") than PEM electrolysis.

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50 See *PEM vs Alkaline electrolysers*, Hydrogen Newsletter (link).

51 See *Electrolyser technologies: PEM vs Alkaline electrolysis,* Nel Hydrogen (link).

52 See *Large-scale electricity storage*, 2023, The Royal Society (link): Page 36.

53 See *The hydrogen colour spectrum*, 2023, NESO (link).

54 See *Large-scale electricity storage*, 2023, The Royal Society (link): Page 37.

55 The difference between SMR and ATR relate to how heat is used to activate the reforming chemical reaction. Specifically, in SMR the catalyst used is contained in tubes that are heated by an external burner, while in ATR a portion of the gas is burned to raise the temperature of the process gas before it contacts the catalyst. SMR is typically the more expensive production method, but ATR is less efficient than SMR. See *Cost and Performance Comparison Of Stationary Hydrogen Fueling Appliances*, 2002, Directed Technologies (link).

56 SMR is already applied across refinery and chemical facilities, known as grey hydrogen, if not combined with CCS facilities. ATR emerged as a lower-carbon solution to the traditional SMR, however, CCS is still needed to achieve blue hydrogen production. See *Debunking the myths of SMR vs ATR hydrogen technology*, 2021, Wood (link).

- **Hydrogen storage facilities:** hydrogen can be withdrawn from these facilities (supplying the system) or be injected into their facilities (withdrawing hydrogen from the system), helping to bridge potential supply-demand gaps. In the UK, there is just one currently operational hydrogen storage site, which operates underground and has a capacity of 0.025 TWh.[57] Though hydrogen can be stored either above or below ground, underground hydrogen storage sites can provide larger storage capacity, and includes salt caverns, which use water to dissolve an underground space in a seam of rock salt before piping hydrogen to be stored there; and depleted gas fields.[58] Centrica's offshore Rough storage facility is an example of a depleted gas field, as we will discuss further in **Chapter 3**.
- **Hydrogen pipelines:** this could comprise a national GB hydrogen transmission (high-pressure pipelines) network, connecting hubs of hydrogen supply and demand, and in particular areas of high industrial demand, known of industrial clusters. The current GB plans for such a network are often referred to as the "**hydrogen backbone**":
  - The National Infrastructure Commission, in their recent report on the future of GB's gas networks, concluded that "*the evidence indicates that a hydrogen backbone at transmission levels to be a crucial piece of infrastructure required early to enable the transition* […] *as a means of ensuring a competitive market for hydrogen*".[59]
  - The future hydrogen backbone could be comprised of repurposed existing gas pipelines as well as new infrastructure, and there are currently studies under way to explore its technical feasibility.[60]
  - We will discuss initiatives focused on the development of a hydrogen backbone in more detail in **Chapter 5B**.
- **Hydrogen-fired electricity generators:** use hydrogen to produce electricity, also known as hydrogen-to-power ("**H2P**"). More specifically, H2P uses a similar power generation technology as some existing thermal units, which use natural gas to fuel gas turbine power plants. However, H2P uses hydrogen to fuel gas turbine power plants, and in doing so does not emit any carbon during combustion.[61]

2.32. Figure 2-4 below depicts the interactions between key hydrogen assets across the hydrogen value chain, focusing specifically on the role of hydrogen on a windy day and a low-wind day.

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[57] See *Hydrogen Transport and Storage Analytical Annex*, 2022, Department of Business, Energy & Industrial Strategy (link): Page 5.

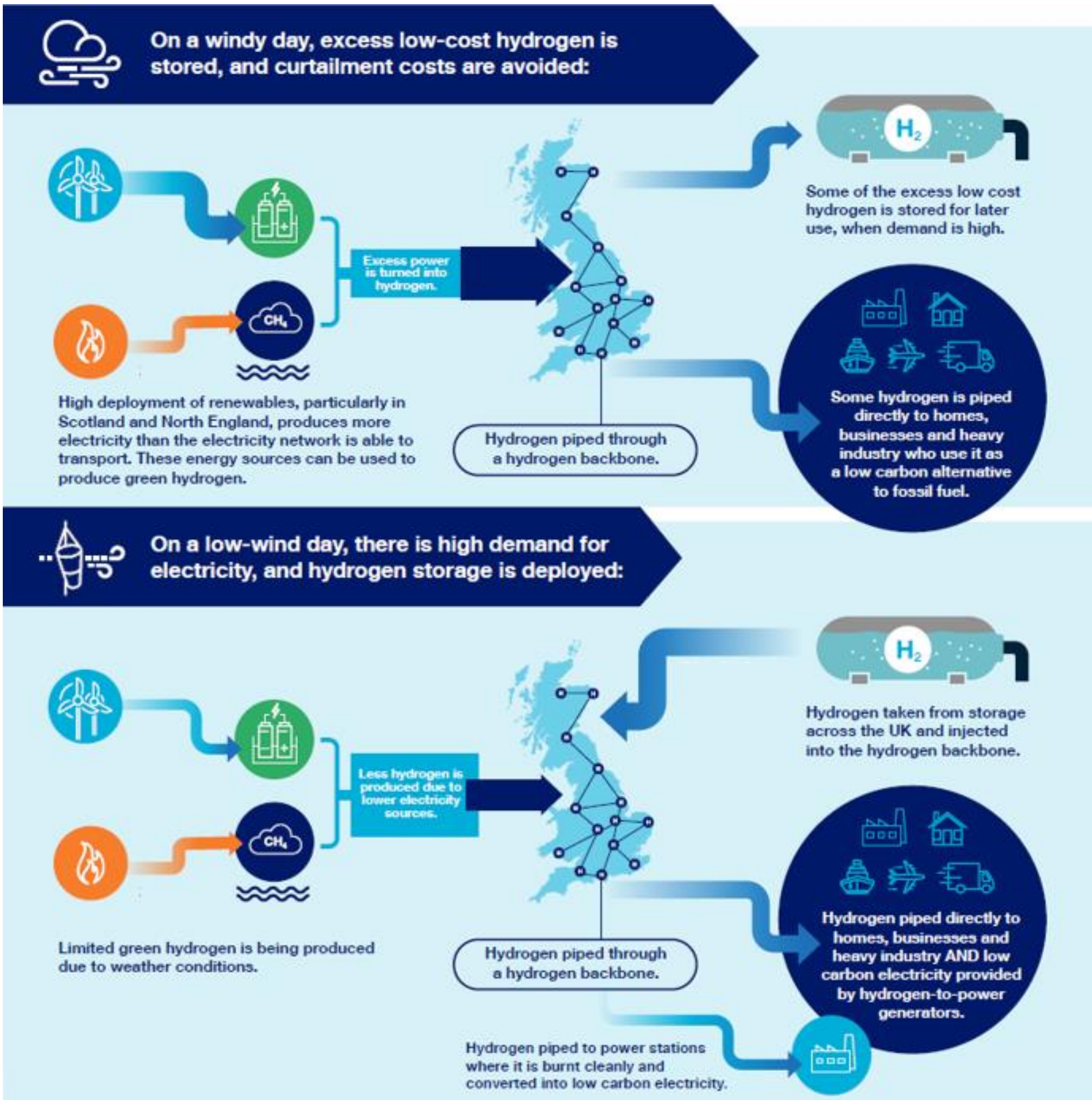
[58] See *Hydrogen Transport and Storage Analytical Annex*, 2022, Department of Business, Energy & Industrial Strategy (link): Page 5.

[59] See *Future of Great Britain's Gas Networks*, 2023, ARUP (link): page 9. There may also be road-based transport solutions, such as tube trailers.

[60] See *Future of Great Britain's Gas Networks*, 2023, ARUP (link): page 34.

[61] See *Hydrogen Power Generation Handbook*, Mitsubishi Power (link).

Figure 2-4: Stylised depiction of the hydrogen value chain



Sources: Centrica

2.33. The hydrogen value chain can be segmented into three key stages: production, transport and usage, with storage serving as a “bridge” between periods of production and periods of usage. We provide two detailed illustrated examples of the hydrogen value chain based on our modelling outcomes in **Chapter 8A**.

2.34. Figure 2-4 highlights several potential interactions between the hydrogen value chain and other energy vectors. Some of the key interactions include:

- Starting with hydrogen production, we set out the two primary methods of hydrogen production: green hydrogen, for which electricity is the key input, and blue hydrogen, which relies on gas with CCS technology.
  - Both the functioning of the electricity and the gas market therefore affects the cost of hydrogen production, as well as the competitiveness against each other.

   - Additionally, while there currently is a single uniform national price of wholesale electricity (in each half-hour), and price of wholesale gas (in each day), there is potential for a difference in the *locational value* of electricity and gas due to potential congestion on the networks. One impact of this is that the *true system cost* of producing hydrogen in areas with surplus electricity generation, such as northern GB, may be much lower than the cost of producing hydrogen in areas with surplus electricity demand (as the former would reduce electricity constraint management costs but the latter would increase it).[62]

- The hydrogen produced would then be injected into the hydrogen pipeline and transported to either immediate usage points or, on *a windy day* - when electricity production is greater than electricity demand, transported into storage facilities for later utilisation. As the hydrogen pipelines may in part consist of repurposed gas pipelines, there may be a transitional impact where increasing the capacity of hydrogen pipelines *reduces* the capacity of gas pipelines. This is especially pertinent in the earlier stages of a potential hydrogen economy, where natural gas demand is still high, thereby requiring two sets of parallel networks — one for hydrogen and one for natural gas.
- The transport of hydrogen using pipelines also offers alternative means of transporting energy from more remote areas with surplus energy sources to high-demand centres. For example, given the highly congested electricity transmission networks connecting high-renewable areas in Scotland from demand centres, hydrogen pipelines offer the opportunity to transport energy through a hydrogen vector, rather than transporting the electricity directly through transmission wires.
- At the other end of the value chain, hydrogen could then be used directly for end-user hydrogen demand, such as hydrogen for heating or industrial processes. Hydrogen could also be used for H2P where hydrogen is used to generate electricity, especially on *a low-wind, high-demand day* when there is reduced renewables generation. In a competitive electricity generation market, H2P would then compete with other dispatchable generators, such as unabated thermal generators, or other emerging technologies such as CCS Gas or BECCS.

[62] The lack of locational pricing in a wholesale electricity market would mean that green electrolysers would not be exposed to the locational value of electricity when choosing siting decisions, or on how to operate. This would also affect the revenues received by electrolysers as well as the number of subsidies they might require to be in the money. There are likely also further complexities in how green electrolysers might participate in the Balancing Mechanism.

2.35. The development of a hydrogen value chain, with the varied interactions with other energy vectors, may benefit from (if not necessitate) the development of a *hydrogen market*. Within such a market, price signals would help coordinate the matching of the competitive production of hydrogen with the willingness-to-pay of hydrogen consumption (i.e. via voluntary bids and offers). This matching of supply and demand would conceivably set a *market-clearing price* for hydrogen reflecting the prevailing market conditions when the marginal unit of hydrogen produced matches the marginal unit of hydrogen consumed.[63] The market price would vary by a predefined time period (e.g. half-hourly such as in the electricity market, or perhaps more likely daily, such as in the gas market, given physical characteristics). Similarly, the price could conceivably be set uniformly across GB, based on a virtual hub concept (as with GB's gas National Balancing Point ("**NBP**") based system), or vary by location as a physical hub price as in the US, where prices are typically set with reference to a specific physical location, the Henry Hub.

2.36. Similarly to the electricity market, the market price for hydrogen would influence outcomes in two broad respects. First, it would provide short-term operational signals, i.e. for hydrogen to be produced or consumed. For example, a higher market price (relative to input costs) would incentivise more hydrogen to be produced and injected into the system from storage, and also incentivise less hydrogen to be consumed and withdrawn from the pipeline network into storage. Second, the hydrogen market price could also affect the pattern of upfront investment in hydrogen assets, with expected prices providing a signal for investments that are likely to be economic over time (and reducing any required supporting subsidies).

2.37. Ultimately, the development of hydrogen as a potential new energy vector consists of a distinct value chain that is *interdependent* with the electricity and gas vectors. Likewise, a new hydrogen market to coordinate hydrogen supply and demand would be interdependent with other markets given the use of electricity and gas inputs, and electricity as an output (with gas as a potential substitute in some cases). With the objective of decarbonising the energy system securely and at least cost, compounded with the contentious nature of debates on electrification and hydrogen, this means that each vector cannot be assessed in isolation.

63 Specifically, a market-clearing price might set at the lowest hydrogen production offer needed to supply an incremental unit of hydrogen demand in each period (and location, if applicable).

3. Using a whole-systems approach to analyse the UK's Net Zero transition pathways

3.1. The development of hydrogen as a third energy vector has the potential to affect market dynamics across the whole system. As discussed previously, the successful integration of hydrogen will require the evolution of some existing assets and build-out of a range of new asset types. There will be critical interactions between this emerging hydrogen system and the rest of the energy system, in demand as well as supply.

3.2. As such, analyses of the role of hydrogen, and the ways in which it may be produced and used, need to reflect these whole system realities. Similarly, analyses of other markets, particularly the electricity sector, will benefit significantly from incorporating their potential interactions with hydrogen.

3.3. In this context, in this chapter, we set out the high-level approach we have taken to integrate an emerging hydrogen economy into the wider energy system within our modelling framework. More specifically, it sets out in detail:

- our highly-granular electricity market modelling framework which enables our whole-systems approach to be undertaken (**Section A**);
- the ways in which the model is integrated across electricity, gas and hydrogen and the questions this allows us to explore (**Section B**);
- our overall whole-systems modelling approach (**Section C**); and
- how we apply the whole-systems framework to critical policy and commercial questions (**Section D**).

A. FTI Consulting's pan-European electricity market model

3.4. To undertake quantitative assessments related to the energy transition, we often utilise our in-house power market model, developed using the Plexos software platform.[64] Plexos is a dispatch optimisation software which models electricity market outcomes in every defined period and location, given a predefined set of assumptions. This modelling approach, and the Plexos platform, is widely recognised and utilised by regulators, system operators, market participants, investors, and their advisors worldwide. We use this model in many of our studies of the energy transition, for example, in our previous work for Ofgem assessing locational wholesale electricity pricing as part of REMA.[65]

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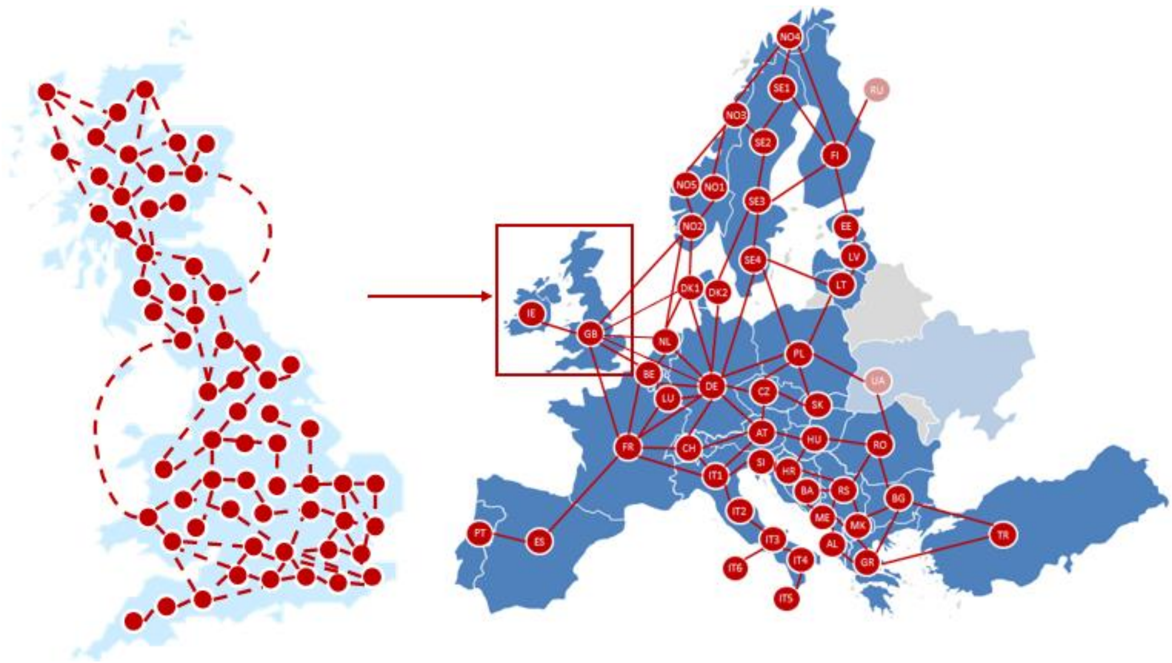
64 This software was developed and licensed by Energy Exemplar. See *PLEXOS The Energy Analytics and Decision Platform for all Systems*, Energy Exemplar (link).

65 See *Assessment of locational wholesale electricity market design options in GB*, 2023, FTI Consulting & Energy Systems Catapult (link).

3.5. To undertake robust assessments of the electricity markets, we have built a detailed representation of electricity generators, transmission networks and demand across Europe. Figure 3-1 depicts a high-level representation of the geographical set-up of our electricity market model.

Figure 3-1: Overall schematics of geographical set-up of FTI Consulting's electricity market model



Sources: FTI Consulting analysis.

3.6. As illustrated in Figure 3-1, the electricity market in GB is represented on a nodal basis where every major electricity injection and offtake point (mostly based on transmission substations) is a node. In total, this consists of c.1,200 nodes, aligning very closely to the actual current and expected topology of the GB transmission network.

3.7. Our GB nodal electricity market model is integrated with our pan-European market model to form a Europe-wide market model. While we have set up the GB market on a nodal basis, the rest of Europe, covering power markets across 49 countries, is set up on a zonal basis. This allows us to assess the GB electricity market at a highly granular level, while also capturing the dynamic interconnector flows between GB and neighbouring countries.

3.8. Even though the current wholesale market arrangements in GB are based on a *single, uniform* national wholesale price in each settlement period, having a *nodal* representation of the transmission network within our modelling framework plays a critical role in our assessments. This is because regardless of the market arrangement, the *physical flows* of electricity must adhere to the physical limits of the transmission network. In the context of GB's Net Zero ambitions, greater renewable generation in some parts of GB, combined with limited transmission networks would lead to escalating congestion costs, and in turn, greater challenges to decarbonising the power system securely and at least cost.[66]

3.9. The potential evolution of a hydrogen market, and its role in using electricity for production in some regions and in some periods, and serving electricity demand in other regions and other periods, would therefore require consideration of the precise topology of the power system.[67]

3.10. We set out how we consider the interactions of gas and hydrogen markets with the electricity market, and analyse outcomes on a whole-systems basis below.

B. Incorporating whole-systems dynamics into energy system analysis

3.11. Considering a detailed representation of the intra-GB electricity market and interconnection with Europe is important in the context of modelling the hydrogen market, due to the crucial interactions between the hydrogen, electricity, and gas, discussed briefly above.

3.12. In this context, we have worked with Centrica to develop a whole-systems model, combining our pan-European electricity market model with a pan-European gas market model and a GB hydrogen market model. Figure 3-2 below shows a stylised representation of our whole-systems modelling approach, and the interactions across the three energy vectors.

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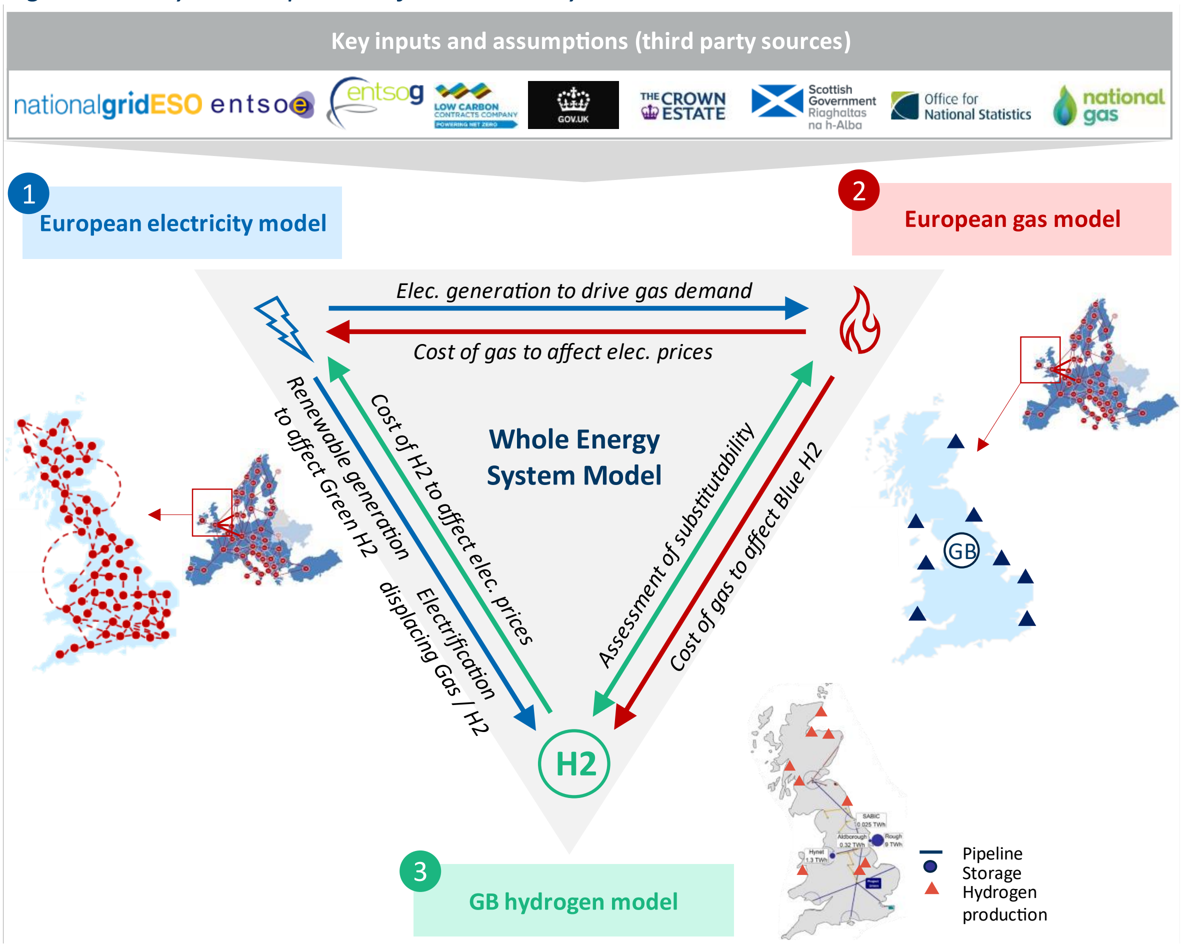
66 For clarity, while our model is set up with a nodal representation of the network, we have modelled power market outcomes in this assessment using the *status quo* market design of a national market.

67 The set-up of our nodal model has also been subject to critical challenge and scrutiny over an 18-month period in our engagement with Ofgem. In our many public workshops, and subsequent publication of our detailed report, see *Assessment of Locational Wholesale Pricing for GB*, 2023, Ofgem (link).

Figure 3-2: Stylised depiction of our whole-systems model



Sources: FTI Consulting analysis.

3.13. As Figure 3-2 illustrates, the interdependencies between the natural gas and electricity market are well-established: the supply of power generation needs to match the demand in electricity market, thereby influencing gas demand. Conversely, the cost of gas influences the short-run marginal costs ("**SRMC**") and competitiveness of gas-fired power stations against other technologies in the merit order in the power generation market.[68] As a consequence, gas-fired power generators, as a dispatchable capacity, often provide the marginal unit of electricity production, setting wholesale electricity prices.

[68] As defined by the NESO, the merit order in the power market "*determines which generation sources will be brought onto the system, starting with the options than can generate the modest electricity for the lowest price*". See *Electricity markets explained*, NESO (link).

3.14. While many market assessments focused on the electricity sector use future gas price profiles as an external input assumption, we have developed a distinct pan-European gas market model to evaluate gas market outcomes. This models gas flows and wholesale prices internally, rather than adopting an external assumption to input into the electricity model, which is necessary to capture the intricate interactions across the three vectors. In particular, this applies to the economics of blue hydrogen production, and the potential substitutability of gas-fired and hydrogen-fired thermal generators. Although not considered in this assessment, having a gas market model in GB would also enable us to study constraints in the GB gas market in the future, particularly during a period of switching-over from gas pipelines to hydrogen pipelines.

3.15. Introducing hydrogen as a third vector adds further dynamics for us to consider in the whole-systems analysis. For example, we consider:

- First, there are interactions on the demand side between the electricity, gas and hydrogen markets, where electricity and hydrogen could potentially serve as low-carbon alternatives to gas.
- Second, electricity and gas (with CCS) can be used for hydrogen production, with the cost of electricity and gas affecting wholesale hydrogen prices.
- Third, both gas (with and without CCS) and hydrogen could be an input into power generation, where changes to wholesale gas (with carbon prices) and wholesale hydrogen prices can affect the merit order of electricity generation.

3.16. To address these dynamics, which may differ both temporally and in different locations across GB, we have developed our GB hydrogen market model, setting out the different components of the hydrogen value chain, and our market model.

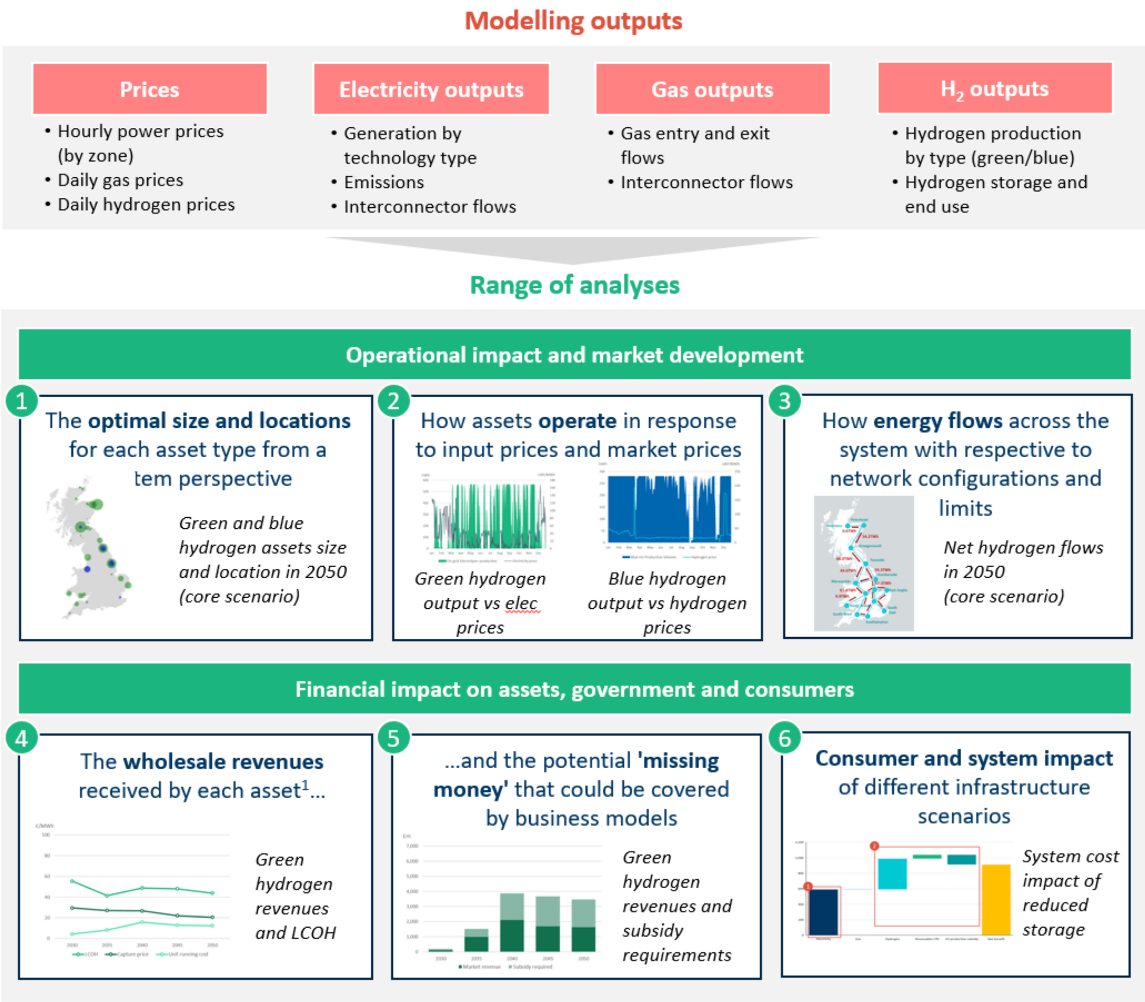
3.17. Overall, the development of our whole-systems model is a product of our key inputs and assumptions across the electricity, gas and hydrogen markets, which we will set out in **Chapters 4** and **5**. With these three distinct market models for each of the energy vectors built, we then integrate them into a single whole-systems model which captures the inter-vector dynamics identified above. This enables us to study the potential evolution of energy markets, as well as financial impacts across various assets and consumers. It has therefore been designed with a range of core features to assess a range of market, commercial and policy questions. These features include:

- **Capturing the key interactions across energy vectors** allows us to evaluate the cost-effectiveness of alternative hydrogen production technologies and their overall operating profile, the role of H2P, and the role of hydrogen storage in combination with these production technologies.

- **Assessing outcomes with a granular time period**, as hour-by-hour modelling of the electricity market and daily gas and hydrogen market modelling allows us to explore the optimal operational patterns of specific assets as well as replicating wholesale prices of each vector.
- **Assessing outcomes with high locational granularity** allows us to explore efficient siting decisions for generators, energy flows around the system and network and/or pipeline bottlenecks for the electricity and hydrogen transmission networks.

3.18. Figure 3-3 below shows the key modelling outputs and the range of analyses our whole-systems model enables us to study.

Figure 3-3: Key modelling outputs and range of analyses enabled by our whole-systems model



Sources: FTI Consulting analysis.

3.19. As shown in Figure 3-3 above, our model enables a range of analyses, which will help inform ongoing policy debates, as well as support investment and other strategic decisions for stakeholders across the hydrogen value chain. Though in our work with Centrica we covered the entire range of analyses outlined above, in this report we focus on analyses related to **operational impacts, market development**, and the effects of hydrogen storage capacity.

C. Overall whole-systems modelling approach

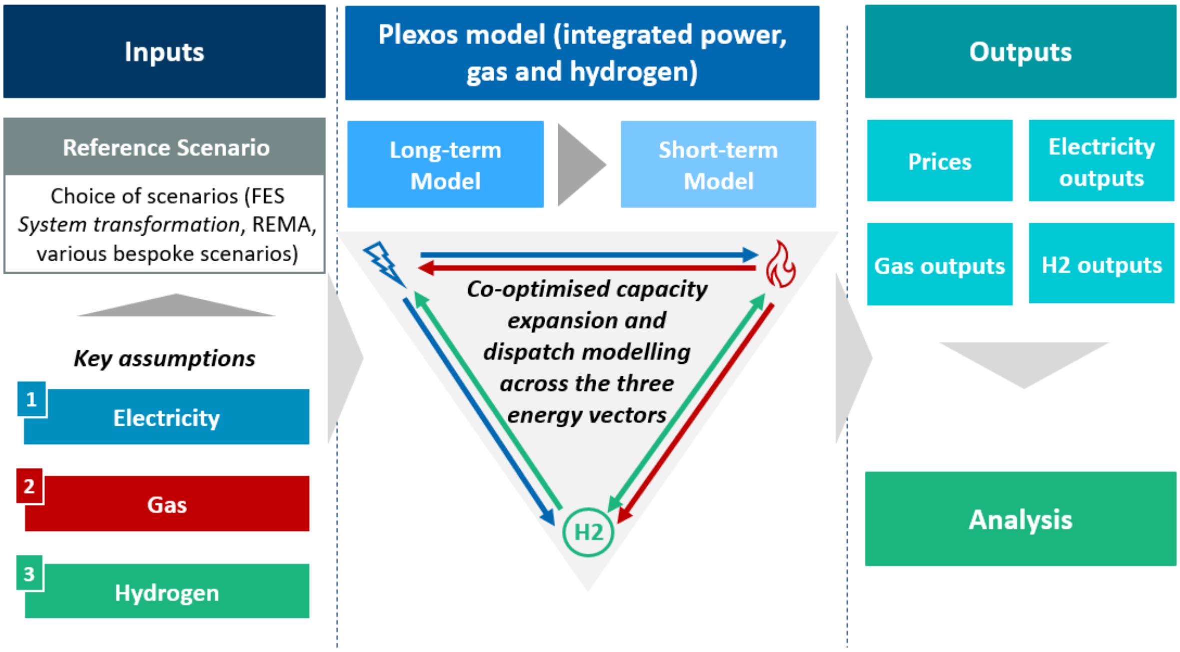
3.20. As described in the section above, to develop our whole-systems model we have developed three market models:

- a detailed representation of the wholesale market supply and demand fundamentals of the European electricity market, including GB;
- a representation of the European gas market, including GB; and
- a representation of the future GB hydrogen market.

3.21. The energy market models determine the least-cost development and dispatch of generation and demand-side resources to meet demand at all times and locations — that is on how the market can develop optimally, subject to various limits and constraints. This considers, among other factors, the technical characteristics and limitations of both the different energy vectors and of each generating unit across all locations modelled, in order to forecast the least-cost generation profile and from this the clearing price in each market, in each relevant period (e.g. hour for electricity, day for gas), at each location on the whole energy system.

3.22. Figure 3-4 below shows a simplified overview of how our whole-systems modelling fits into our overall analysis and approach.

Figure 3-4: Overview of our whole-systems modelling approach



Sources: FTI Consulting analysis.

3.23. As shown in Figure 3-4 above, our whole-systems modelling approach covers three key phases. Firstly, we set up the key inputs and assumptions of the model across the three energy vectors. We will discuss this in more detail in **Chapters 4** and **5**.

3.24. Following this initial set-up, we run the model in two stages:

- **First, a long-term expansion model:** this determines the optimal evolution of generation capacity to meet electricity and hydrogen demand at least cost. This optimises the investment decisions of certain new generation and storage assets, i.e. their locations and quantum, based on the key input assumptions, such as the capital cost of each technology, certain locational and supply chain constraints, the local climate profile and electricity transmission and hydrogen transmission build across both networks.
  - For this engagement we fixed the capacity evolution of certain generation technologies, including fixing nuclear capacity, CCS Gas capacity until 2030, blue hydrogen production capacity and hydrogen storage capacity. We do this in light of the fact that the future capacity evolution for some assets is generally considered not to be strongly influenced by wholesale price dynamics, as opposed to government policy decisions, or geological and other physical constraints.

  - An exception for this is our assumptions relating to electricity storage, which we have fixed in this engagement due to the computational intensity of modelling the optimisation of its build-out, given the short duration of their charging cycle and the resulting granularity required to set up a long-term optimisation model.[69]
  - For other assets whose capacity evolution is likely to be sensitive to wholesale prices, such as the renewables roll-out, H2P generation capacity and grid-connected hydrogen production capacity (electrolysers that are connected to the power grid), we optimise their location and capacity within our modelling framework, based on input assumptions.
  - We will discuss our assumptions on the capacity build-out of different generation technologies in more detail in **Chapters 4A** and **5B**.

- **Second, a short-term dispatch model:** this takes the capacity from the long-term model as an input, and determines the (i) least-cost electricity generation dispatch on an hourly basis, and (ii) least-cost gas production and hydrogen production on a daily basis, based on any defined network and generation and/or production constraints.
  - It also estimates transmission flows of electricity (including across interconnectors), gas, and hydrogen, as well as generation costs, wholesale prices, hydrogen storage utilisation, among other factors.
  - Specifically, the short-term dispatch model estimates wholesale prices for each energy vector. For the **hourly electricity market**, prices are a direct output of the optimisation process, and are equal to the shadow price on the net injection constraint in each hour.[70] For the **daily gas and hydrogen markets**, prices are the settlement price for gas/hydrogen, which is equivalent to the shadow price for gas/hydrogen.[71]

3.25. The final step of our analysis involves generating the modelled outputs, with which to produce a range of analyses. We provide an overview of the key modelled outputs and analysis in **Chapters 4** to **5**.

3.26. We have explicitly modelled the period from 2030 to 2050 using five-year increments. This is intended to capture changing dynamics from the early stages of the new low-carbon hydrogen economy through to longer-term outcomes as decarbonisation of a wider range of sectors takes place. We have not explicitly modelled beyond 2050.

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69 Our assumption was that batteries will have limited impact on the hydrogen market as batteries operate on more frequent cycles (e.g. 8-hourly) compared to H2P, and thus is not generally considered a close substitute to H2P.

70 Net injection constraints are the constraints on the net exports of electricity from nodes on the electricity network, including flows on lines and transformers.

71 Shadow prices are the value to the system of the next/last unit of gas or hydrogen supply to each market. We note that for the hydrogen market, shadow prices are often set by hydrogen storage, and reflect the value to the system of the next/last unit of hydrogen in storage.

D. Applying the whole-systems framework to policy and commercial questions

3.27. To apply and test our whole-systems modelling approach, we then developed an initial scenario with Centrica. This scenario, and the related analysis, is not intended to set out a *specific forecast* of the energy markets, but rather as *one potential pathway* to Net Zero, that includes the development of a relatively substantial hydrogen market.

3.28. In this section, we briefly discuss the scenario we have used to test the whole-systems approach in this report. We also set out potential ways of extending this framework to explore other analytical questions of interest using scenario analysis.

Scenario modelled

3.29. The initial stage of our work has focused on the development of one Net Zero scenario, formulated and developed based on discussions with Centrica, as well as feedback from various industry stakeholders.

3.30. The resulting scenario incorporates an assumed and relatively sophisticated hydrogen economy, comprised of various hydrogen assets across the value chain, from supply, transmission and storage, to demand from end-users and power generators, i.e. H2P. As such, this scenario assumes that hydrogen will indeed play a material role in the UK's decarbonisation efforts.

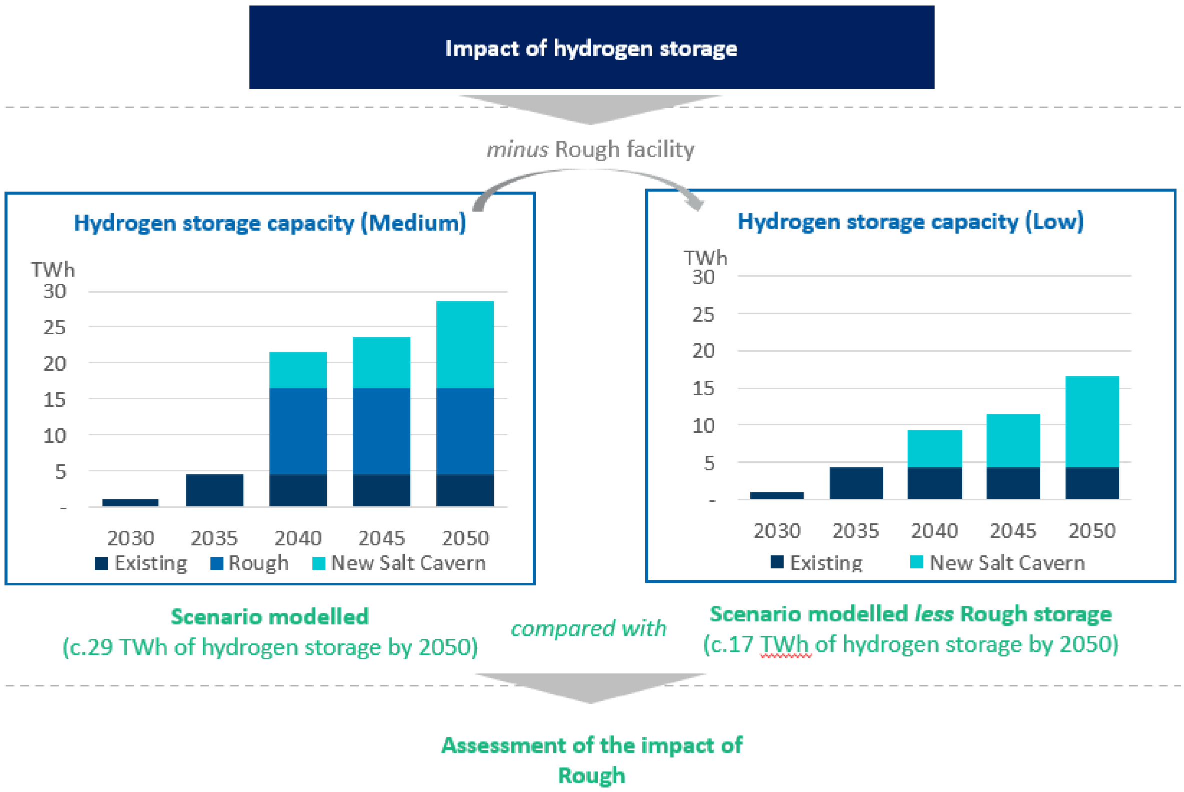
3.31. To craft this scenario, we started with the FES 2022's System Transformation scenario which is a Net Zero scenario with relatively high hydrogen demand. Following stakeholder feedback, we then adjusted several assumptions. The key adjustments, which are set out in detail in **Chapters 4 and 5**, are:

- building out a more granular representation of the hydrogen sector, centred around clusters, and a gradual formation of pipelines to connect the clusters;
- reducing hydrogen storage capacity from c.56 TWh as assumed in the FES System Transformation by 2050 to c.29 TWh;
- reducing hydrogen for heating demand by c.66% (which is the equivalent to assuming approximately 4 million homes in the UK use a hydrogen boiler) with a commensurate upward revision in heat pump demand to reflect greater electrification of heating accordingly;
- optimised the build-out of renewables and green hydrogen production to explore the complementary interactions between them;
- optimised the build-out of thermal generation capacity to explore the competitive effects to serve peakier electricity demand; and
- assumed that blue hydrogen plants can operate with some, but limited, flexibility rather than as a "must-run" asset, to explore hydrogen dispatch and pricing outcomes. This is based on our understanding of the technical features of these plants based on our discussions with industry.

3.32. By making these amendments, this scenario allows us to analyse the interactions between the three energy vectors that would occur across the whole energy system. An overview of the outcomes modelled in this scenario is set out in **Chapter 6**, with specific key outcomes and implications discussed further in **Chapter 7** and **Chapter 8**.

3.33. Separately, we also test the impact of reducing hydrogen storage. In this sensitivity, we keep the level of hydrogen storage broadly equivalent to the volume and location of existing natural gas storage sites, but assume that the Rough facility *is not* redeveloped as a hydrogen storage facility. This reduces the level of hydrogen storage from c.29 TWh in 2050 to c.17 TWh. Figure 3-5 below sets out our hydrogen storage assumptions in more detail.

Figure 3-5: Assessing the impact of reduced hydrogen storage



Sources: FTI Consulting analysis.

3.34. By comparing these two outcomes, we can then assess two interrelated items; (i) an assessment of the impact of Rough on both the energy system and consumer costs, as well as (ii) the additional cost and strain on balancing the electricity system, particularly during peak hours. We set out the outcomes of this sensitivity tested in **Section 8D**.[72]

[72] Throughout the engagement, we have also tested various other sensitivities including the (i) impact of a disjointed hydrogen network — leading to locational wholesale hydrogen prices, (ii) allowing more unabated gas-fired generators to be built in the 2040s against Net Zero ambitions, and (iii) assuming blue H2 production is a "must-run" technology, which ends up supressing wholesale hydrogen prices and increasing the amount of out-of-market regulatory support. We have not published the results of these sensitivities in this report, although they have been useful in developing and stress-testing different aspects of the analysis.

3.35. While we have only tested and applied the whole-systems framework in one specific scenario, the outcomes of this assessment mean that other scenarios can test a range of hypotheses to answer policy and commercial questions. It is both Centrica and FTI Consulting's intention to share our approach to other stakeholders, and for others to potentially adopt such a framework and contribute to the ongoing energy transition debates.

Potential extensions to the analysis

3.36. Given the uncertainty, and policy dependency of large aspects of the future energy system, industry and/or policymakers may wish to test various other scenarios, representing different sets of assumptions and views of the evolution of the energy sector. Such alternative scenarios may set out different views around the hydrogen market, for example different demand assumptions, production Capex assumptions or views on the build-out of a potential hydrogen network.

3.37. Assessing different scenarios would also enable us to evaluate and test specific questions of hypothesis. In particular, by comparing two or more scenarios, we can calculate the differences in consumer benefits of system costs between them. This may be useful for evaluating specific topics such as:

- the different pathways to Net Zero by 2050, for example with different capacity mix, demand assumptions, or assumptions around the hydrogen market development;
- the impact of a specific policy, for example different support mechanisms for specific assets, such as hydrogen production; and
- the impact of a specific asset or portfolio, for example a green electrolyser investment in Scotland to be co-located with wind assets.

3.38. Within each scenario, different sensitivities can also be undertaken by amending a single input assumption — such as levels of hydrogen storage capacity as discussed above.

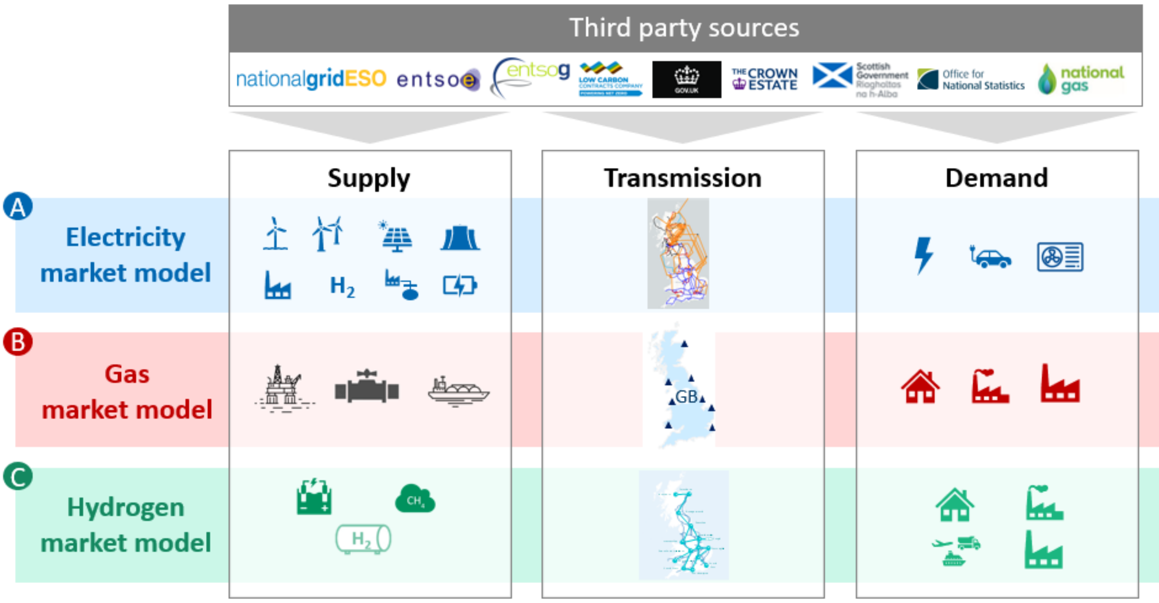
3.39. We explore and discuss our key inputs and assumptions underpinning our scenario modelled in detail in the following chapters, focusing on the electricity and gas markets in **Chapter 4**, and the hydrogen market in **Chapter 5**.

4. Our key inputs and modelling assumptions — Electricity and Gas

4.1. As discussed in the previous chapter, our analysis incorporates a representation of the electricity, gas, and hydrogen markets across the value chain, from supply, transmission and storage, to demand, and the key cross-vector interactions are explicitly modelled. This is because our modelled scenarios assume that hydrogen will play a material role in the UK's decarbonisation efforts, as per our set of assumptions agreed with Centrica.

4.2. In general, we calibrated the whole-systems model based on FES 2022 projections,[73] current UK government policy, Project Union,[74] and various third-party sources. Figure 4-1 below briefly depicts our whole-systems model set-up for Supply, Transmission and Demand inputs and assumptions across the three energy markets, as well as the data sources relied upon during this process.

Figure 4-1: Whole-systems model set-up process across the three energy markets



Sources: FTI Consulting analysis.

4.3. This chapter sets out the key inputs and assumptions underlying our model regarding the electricity and gas markets. More specifically, it sets out in detail the key underpinning inputs and modelling assumptions that form the basis of our:

- Electricity market model (**Section A**);
- Gas market model (**Section B**); and
- Commodity price assumptions (**Section C**).

[73] FES 2022 was the latest edition of the NESO's Future Energy Scenarios at the start of the engagement.
[74] Project Union is discussed in more detail later in this Chapter.

A. Electricity market modelling assumptions

4.4. We set up the electricity model with a nodal representation of the entire GB transmission network and locations for each asset, offering detailed insights and flexibility regarding the modelled areas and potential redispatch modelling.[75] We model hourly outputs for the electricity market, which production technologies such as electrolysers could respond to.

4.5. We note that in this report, we have assumed that as per the current market design, the GB electricity market follows a uniform national pricing regime, and so there is a single national wholesale electricity price at every modelled hour.

4.6. Figure 4-2 below outlines the key inputs and assumptions for the electricity market used in our analysis.

Figure 4-2: Key inputs and assumptions for the electricity market

Demand	• **GB Demand: based on FES System Transformation, adjusted to be consistent with the electrification supply assumptions** • **EU Demand: based on ENTSO-E**
Generation capacity	• **Exogenous assumptions: nuclear, CCS until 2030, various other renewables** • **Optimised by model: renewables, H2P, thermal generation**
Storage	• **Exogenous components: capacity and location of batteries, based on FES System Transformation; capacity and location of pumped storage, based on existing and planned sites** • **Endogenous components: daily operational pattern optimised in the model**
Transmission capacity	• **Intra-GB network: HND with 5-year delay** • **Interconnectors: twenty interconnectors based on FES System Transformation, with a Pan-EU set-up**

Sources: FTI Consulting analysis.

4.7. As shown in Figure 4-2 above, generation capacity, storage, demand and transmission capacity are key inputs and assumptions for the electricity market. We discuss these assumptions in more detail below.

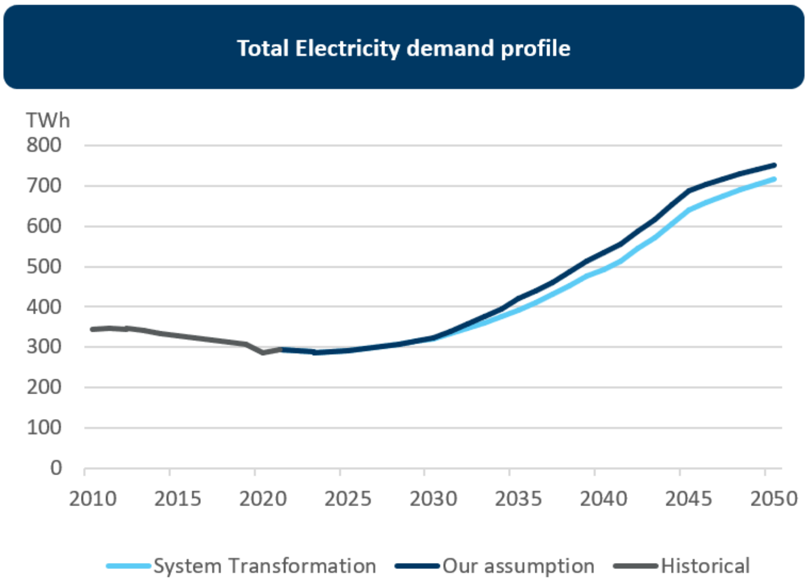
[75] The aim of redispatch modelling is to simulate the role of the System Operator ("**SO**") in balancing supply and demand in the GB wholesale power market at a national level subject to certain constraints, thus mirroring the current dynamics of the balancing market mechanism. See *What is the Balancing Mechanism*, NESO (link).

Demand

4.8. We have included in our analysis both GB demand for electricity and European demand, which is a crucial determinant of interconnector flows between GB and Europe.

4.9. For **GB demand**, we have assumed domestic electricity demand broadly follows the FES 2022 System Transformation scenario, but with an upward revision in heat pump demand to reflect greater electrification of heating, and reduced scope for hydrogen for heating.[76] Figure 4-3 below shows the historical and future evolution of total GB electricity demand as per the System Transformation scenario, and our assumptions. In addition, Figure 4-4 below shows the breakdown of total GB electricity demand by the different types of demand included in our model.

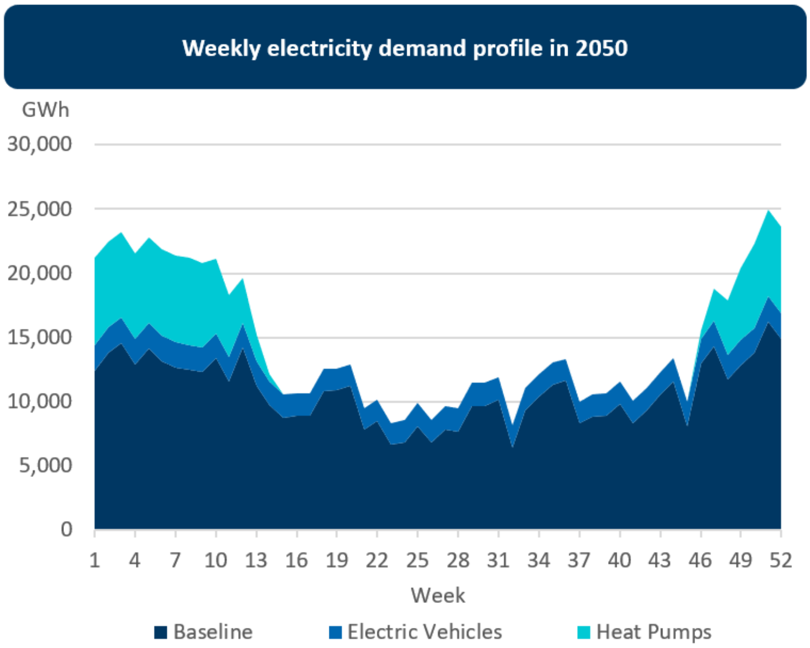
Figure 4-3: Total Electricity demand, historical and projections (TWh), up to 2050



Sources: FES 2022.
Notes: The demand profile of 'Our assumption' above is illustrative and does not reflect total electricity demand as per our modelling outcomes, but rather reflects our upwards adjustment to electricity demand from heat pumps.

[76] GB demand includes flexible forms of demand, including Demand Side Response ("**DSR**") which serves to decrease demand at certain price levels, as well as "**Smart Demand**" which is mostly from EVs and to a lesser extent heat pumps. We assume Smart Demand has a fixed amount of electricity demand that must be met throughout the day, but that the hours in which this is done is flexible meaning demand can be met in cheaper hours, within certain constraints regarding hourly consumption. We have assumed that the capacity of DSR and the share of Smart Demand from EVs and heat pumps follows the FES 2022 System Transformation scenario.

Figure 4-4: Total Electricity demand, historical and projections (TWh), up to 2050



Sources: FES 2022.

Notes: We do not include demand for electricity from electrolysers connected to the power grid, as this is optimised in our modelling.

4.10. As shown in Figure 4-3 and Figure 4-4 above, there is an increase in total GB electricity demand over the modelling period as per our assumptions. This reflects increased industry electrification, increased demand from datacentres, increased demand from EVs, and increased demand from heat pumps as heating is increasingly electrified, in line with decarbonisation ambitions.

4.11. Within the year, weekly electricity demand by 2050 is volatile, with large variations in baseline and heat pump electricity demand in particular. Weekly electricity demand is also highly seasonal, driven by much greater heat pump demand for electricity in the winter periods and greater demand for heating.

4.12. For **European demand**, we have assumed European electricity demand profiles are based on Ten-Year Network Development Plan ("**TYNDP**") from European Network of Transmission System Operators for Electricity ("**ENTSO-E**").

Generation capacity

4.13. We have calibrated electricity supply side assumptions based on the FES 2022, and modelled individual generators based on their inclusion in the FES.

4.14. However, we have made adjustments based on assumptions on supply chain constraints, and also optimised the build-out of certain generation technologies as follows:

- **Fixed, external assumptions:** we follow the nuclear build-out and retirements as per the FES 2022 System Transformation scenario[77], as well as the generation capacity of CCS Gas generators until 2030 and various other technologies including:[78] Hydro, Waste, and various non-Combined Heat and Power ("**CHP**") technologies.[79] These are set for technologies that are largely determined by government strategy and require significant government support.

- **Optimised assumptions:** we optimise the build-out of a number of generation technologies that are potentially more sensitive to the wholesale electricity price on the basis of assumed Capex and subject to locational and supply chain constraints. Specifically, the optimal evolution of generation capacity across the modelling period is determined by the long-term model, and subject to certain technological and locational constraints.[80] The generation capacity of the following technologies is optimised in our analysis:
  - Renewables, including offshore wind, onshore wind, solar;[81]
  - H2P, including Combined Cycle Hydrogen-fuelled Gas Turbines ("**CCHT**"), Open Cycle Hydrogen-fuelled Gas Turbines ("**OCHT**");
  - Thermal generation, including Combined Cycle Gas Turbines ("**CCGT**"), Open Cycle Gas Turbines ("**OCGT**"). See Box 4-1 below for more detail; and
  - Various other technologies, including Biomass, BECCS, and CCS Gas.[82]

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[77] This scenario includes nuclear generation capacity reaching a low of 2.47GW in 2026 before rising, reaching 4.5GW in 2030 and 12.92GW by 2045.

[78] We have assumed that CCS Gas generation capacity across the locations of Peterhead, Keadby, and Humber (which are "**CCS clusters**", see **Chapter 5A** for more detail), are aligned to the FES 2022 System Transformation scenario. This is because we consider that CCS assets will largely be determined by UK government policy in the medium term, rather than wholesale electricity prices.

[79] This includes the following technologies, as described in the FES 2022: Non-renewable CHP, Micro CHP, Renewable Engines, Non-renewable Engines (non-CHP), Biomass & Energy Crops, and Waste Incineration.

[80] We locate these selected new-build technologies in locations that are optimal to the electricity network, i.e. at ensuring the electricity network is balanced at all locations and times at minimum cost, subject to certain constraints to reflect real-life technological and geographical constraints. This assumes therefore a perfect central planner.

[81] We have assumed the capacity build-out of offshore wind, onshore wind and solar is limited to levels forecasted in the FES 2022 System Transformation scenario. In addition, we note that the build-out of offshore wind capacity beyond 2035 is optimised subject to seabed lease availability, and supply-chain constraints.

[82] We have assumed that all BECCS and CCS Gas plants are built in "**CCS clusters**" (see **Chapter 5A** for a description of CCS clusters).

Box 4-1: Our implementation of a cessation in new gas peakers from 2040 onwards

As part of our modelling for this report, we have assumed there is no new build of unabated gas generation capacity (CCGTs and OCGTs) from 2040 onwards, i.e., a "**cessation in new gas peakers**". This is because given our assumptions, and in particular our assumptions regarding future carbon prices which we discuss later in this section, it is likely that unabated gas generation would remain less costly than H2P when comparing the input costs of natural gas with wholesale hydrogen prices — but at a cost of greater emissions. Therefore, in view of Net Zero objectives, we have assumed there is a government policy of no new build of unabated gas from 2040 onwards.

4.15. For renewables, we have assumed that inputs on climate profiles for intermittent renewable generators are based on the Pan-European Climatic Database ("**PECD**"), which provides the hourly capacity factor for each technology across different GB regions, divided into five onshore and twelve offshore zones.[83] Each intermittent renewable generator included in the FES 2022 is matched to the relevant geographic zone.

4.16. For new generators, we have based our assumptions across technologies regarding costs (Capex, fixed operating and maintenance, variable operating and maintenance) and technical parameters (efficiency, emissions rate) on the EC 2020 Reference Scenario and the TYNDP 2022.[84] We also assume that H2P has production efficiency of 54% and 38% for CCHTs and OCHTs, respectively. This means that for every 100 MW of hydrogen used, 54 MW and 38 MW of electricity is generated, respectively.[85]

Storage

4.17. Electricity storage is modelled using a combination of technologies with location and capacity evolution set exogenously in our analysis based on the FES 2022 System Transformation scenario. The types of electricity storage technologies include:

- Pumped hydro storage;
- Batteries: 1h Batteries (with 1-hour duration), 4h Batteries (with 4-hour duration), Domestic Batteries (with 4-hour duration);
- Vehicle-to-Grid ("**V2G**") (with 1-hour duration); and
- Compressed Air Energy Storage ("**CAES**") (with 5-hour duration), and Liquid Air Energy Storage ("**LAES**") (with 4-hour duration).[86]

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83 We have used the Climatic year 2009 for each time horizon, which represents a relatively stressful Dunkelflaute case. See TYNDP 2022 Scenario Building Guidelines, 2022, ENTSOE (link): Page 43.

84 See *EU Reference Scenario 2020*, European Commission (link) and *TYNDP*, European Network of Transmission System Operators for Electricity (link).

85 Our technical assumptions for H2P production efficiency are based on information from Mitsubishi Heavy Industries, see *H-25 Series Gas Turbines*, Mitsubishi Power (link).

86 We use duration figures as implied by *FES 2022 Databook*, NESO (link).

4.18. For the modelling scenarios carried out in this engagement, we have fixed the capacity of electricity storage as described above, due to the modelling computational intensity required to optimise electricity storage build-out. Specifically, a very granular long-term model (with temporal blocks of short duration) is required to meaningfully optimise electricity storage capacity across technologies as they typically cycle frequently and are of low duration.

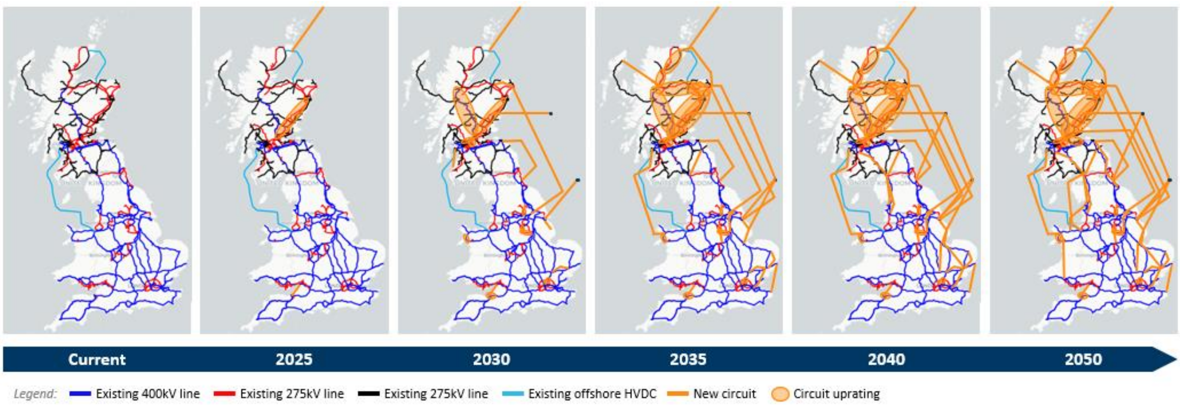
4.19. However, by fixing the build-out of electricity storage, one downside is that the potential substitutability between electricity storage and hydrogen assets are not fully captured. However, our hypothesis is that this would have limited effect as electricity storage and hydrogen assets are more effective in balancing the electricity sector in different ways — the former in balancing shorter-term variations (within-day, daily, and weekly), and the latter in balancing longer-term variations (monthly and seasonally).[87] As such, to balance the trade-offs between computational intensity and substitutability of electricity storage and hydrogen, we have at this stage decided not to optimise electricity storage capacity — although we can consider doing so in future modelling runs.

Transmission capacity

4.20. Transmission capacity refers to both the intra-GB power network, and GB's interconnection with Europe:

- **Intra-GB power network**: in our analysis, the GB power transmission network broadly aligns to Holistic Network Design ("**HND**"), but with an approximate 5-year delay to account for ongoing transmission challenges. Figure 4-5 below depicts the evolution of the network over the modelling period.

Figure 4-5: Electricity transmission network build-out over modelling period, FTI Consulting reference scenario



Sources: ETYS 2022; NOA 2021/22 Refresh; HND; and FTI Consulting analysis.

[87] Electricity storage such as batteries, typically operate on more frequent cycles (for example 8-hourly cycles) compared to hydrogen-fuelled generation technologies including H2P.

— As Figure 4-5 shows, we assume there are still significant increases in transmission reinforcements compared to historical levels outlined in the NESO's network plans, but that some of these reinforcements would be delayed.[88]

— We do this by adjusting the commission dates of onshore and offshore transmission reinforcements, and by delaying some transmission projects expected to take place during the middle of the modelling period.[89] As a result, this extends the timeline for the development of the transmission network, as the NESO expects the major developments to take place over c.15 years, while we have assumed they take place over c.25 years.

— By the mid-2040s, the power network in our analysis converges with the NESO's plans, when GB wind capacity is expected to reach its peak.[90]

- **Interconnectors**: to model interconnector flows with Europe, we have opted to use our Pan-EU model.

  — This network is based on the projected interconnector capacity of those interconnectors we considered were most viable at the time of developing our model. As per these internal in-house assumptions, this means by 2050 GB's interconnection network is comprised of twenty interconnectors, with a total capacity of c.24 GW.

  — Including this representation as part of our electricity market model balances the complexity and accuracy of interconnector flow modelling in the electricity market.

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88 We note that the NESO's latest network plans at the time our model was created assumed several large-scale transmission investments to come online between 2025 and 2030, to accommodate the Government's 50 GW offshore wind generation capacity target, as well as during the 2030s, albeit at a slower pace. Specifically, these investments included: (**2025-2030**) four point-to-point bootstraps linking Scotland with England, two co-ordinated offshore links linking windfarms in Scotland, Wales, and England, three bootstraps across local boundaries, more than 2000 km of new 400 kV onshore transmission circuits, and an uprating of over 1500 km of existing transmission circuits to 400 kV; (**2030-2040**) two point-to-point bootstraps between north-west England and north Wales, new onshore circuits between Scotland and north England, new onshore circuits between Lincolnshire and south England; (**post 2041**) no official publications are available on the electricity transmission build-out post 2041, but there is only limited expansion expected from the 2040 network presented in the NOA 21/22 Refresh, as this network is already set to accommodate a significant amount of wind generation capacity. See *Electricity Ten Year Statement*, 2022, NESO (link); *Pathway to 2030*, 2022, NESO (link); and *Network Options Assessment* ("**NOA**") *2021/22 Refresh*, 2022, NESO (link).

89 Our assumptions more closely align with the Transmission Owners' ("**TOs**") earliest in service dates ("**EISDs**"), and with the timelines of historical projects and supply-chain constraints. We assume the remaining transmission reinforcements expected to come online by 2030 under HND and NOA 2021/22 Refresh are completed between 2030 and 2040, which leads to steadier transmission build-out over the 2025 to 2040 period.

90 We note that the NESO's recently published report on network plans, which provides a national blueprint for a decarbonised electricity system in GB, was not available at the time of our study. See *Beyond 2030*, 2024, NESO (link).

B. Gas market modelling assumptions

4.21. We have modelled the GB gas market model with seven entry nodes and, for simplicity, one exit node with pipeline transmission currently unconstrained. This mimics the design of the current GB gas market, which sets a single national gas wholesale spot price for each day at a virtual hub referred to as the National Balancing Point ("**NBP**"), assuming no constraints on the GB National Transmission System ("**NTS**").[91] The outputs of the gas market are produced on a daily basis as per current market design.

4.22. Figure 4-6 below outlines the key inputs and assumptions for the gas market used in our analysis.

Figure 4-6: Key inputs and assumptions for gas market

Demand	• **Exogenous components: end-user demand from domestic heating and industry based on FES System Transformation, adjusted to adapt for hydrogen transition** • **Endogenous components: natural gas demand from power plants and blue hydrogen generators**
Supply	• **Domestic production: optimised based on cost of production and max production rate** • **Import: optimised based on costs, pipeline capacity, etc.**
Storage	• **Exogenous components: capacity and location based on existing gas storage sites** • **Endogenous components: daily injection and withdrawal patterns optimised in modelling**
Interconnectors	• **Interconnectors: five interconnectors based on data from ENTSOG**

Sources: FTI Consulting analysis.

4.23. As shown in Figure 4-6 above, demand, production capacity, storage and gas interconnector capacity are key inputs and assumptions for the gas market. We discuss these assumptions in more detail below.

Demand

4.24. We have included different components of GB demand for gas, some of which are external demand profiles and others which have optimised demand profiles.

[91] GB gas spot prices are determined at the so-called National Balancing Point, a "*virtual point on the UK gas supply system through which all gas passes in accounting and balancing term*". While national gas demand has fallen considerably from historical peaks, indicating excess capacity in some areas of the NTS, congestion do occur on occasion, requiring balancing actions from National Gas, see *End-to-end balancing guide*, 2017, National Grid (link).

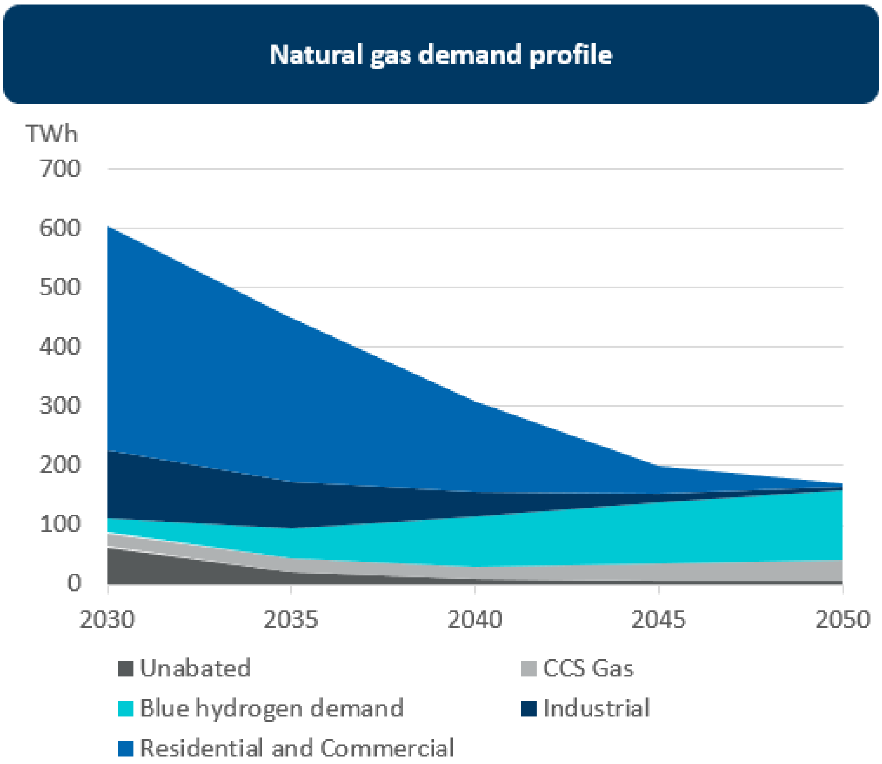
- **Exogenous external components:** end-user demand is externally fixed, and is comprised of natural gas for residential and commercial demand (most of which is heating) and industrial demand. We have assumed that demand at the GB level follows the FES 2022 System Transformation scenario, and derive demand at the regional level based on current regional shares of gas demand, as well as the region-specific pace of the hydrogen transition for industrial demand:
  - Current regional shares of gas demand follow historical data on natural gas consumption across GB local authorities as per the subnational gas consumption data produced by DESNZ;[92]
  - The phase-out of gas demand is determined by the pace of heat pump, hydrogen heating roll-out and industry adoption of electrification and hydrogen in each region and we have assumed this broadly follows assumptions in the FES 2022. We have adjusted industrial demand by regionally distributing demand profiles to ensure that the hydrogen roll-out is prioritised around localised areas where hydrogen is likely to play a role in decarbonisation, known as "**industrial clusters**".[93]
- **Optimised components:** comprised of natural gas demanded by power plants (i.e. unabated gas generators and CCS Gas which are used to produce electricity) and demand from blue hydrogen production plants (used to produce hydrogen). We optimise the operating profiles and gas consumption of these plants based on their technical characteristics and on the hourly or daily wholesale power, hydrogen and gas prices. As such the total demand from these sources is an output of the modelling.

4.25. Figure 4-7 below shows the natural gas demand profiles we have assumed in our analysis.

92 See *Sub-national gas consumption data*, 2024, DESNZ (link).

93 We do this by considering whether this region is part of the future GB hydrogen economy at each point in time, i.e. whether the region is fully connected to the hydrogen backbone at each point in time.

Figure 4-7: Demand profile for natural gas (TWh), 2030-2050



Sources: FES 2022; and FTI Consulting analysis.

4.26. As shown in Figure 4-7 above, there is a very material decline in natural gas demand over the modelling period, in line with GB's Net Zero ambitions:

- **Industrial**, and **Residential and Commercial** demand for gas (end-user demand) declines by c.95% and c.98% respectively;
- Demand for **unabated gas for power plant demand**, which is optimised endogenously, declines by c.92%, which is in line with the decline of unabated gas-powered generation capacity;
- **CCS Gas** demand for gas, which is power plant demand that is optimised endogenously, increases by c.52%, though remains relatively low compared to historic gas demand; and
- **Blue hydrogen** demand for gas increases by 3.6 times between 2030 and 2050, which is in line with the assumed roll-out of blue hydrogen production facilities. It becomes the single largest source of gas demand by 2045. As with the gas consumption of power plants, the annual consumption of gas from blue hydrogen and its pattern is optimised.

Supply

4.27. We have calibrated the gas supply based on a variety of sources depending on the type:

- **Domestic production in the UK and Continental Europe**:[94] Gas production in the UK and Continental Europe is optimised based on the assumed cost of production, maximum annual and daily production rates. These assumptions were developed for each country according to site specific assumptions from a third-party provider.[95]
- **Pipeline imports to Europe**: Assumptions on import volumes through pipeline from countries not covered under the point above (Azerbaijan and Algeria) were developed based on long-term contracts in place at the time of the calibration of the model. The volume of imports from Russia were set to zero.
- **Liquified Natural Gas ("LNG") imports**: The global LNG price was developed based on a mixture of forward prices and long-term benchmarks as described in **Section C** below where we discuss our commodity price assumptions. The volume of LNG imports is optimised, albeit subject to constraints on LNG terminal capacity.[96]

Storage

4.28. The location, capacity and technical parameters of gas storage sites in GB and across Europe are exogenously set based on existing sites.[97] The operational profile of the storage sites is subsequently optimised by our model.

Gas interconnector capacity

4.29. The topology and technical parameters of gas interconnectors in Europe is based on existing projects and data published on them by European Network of Transmission System Operators for Gas ("**ENTSOG**"). Figure 4-8 depicts the gas interconnectors linking GB to Continental Europe and Ireland, as well as terminals, where LNG and domestic supply enters the GB system.

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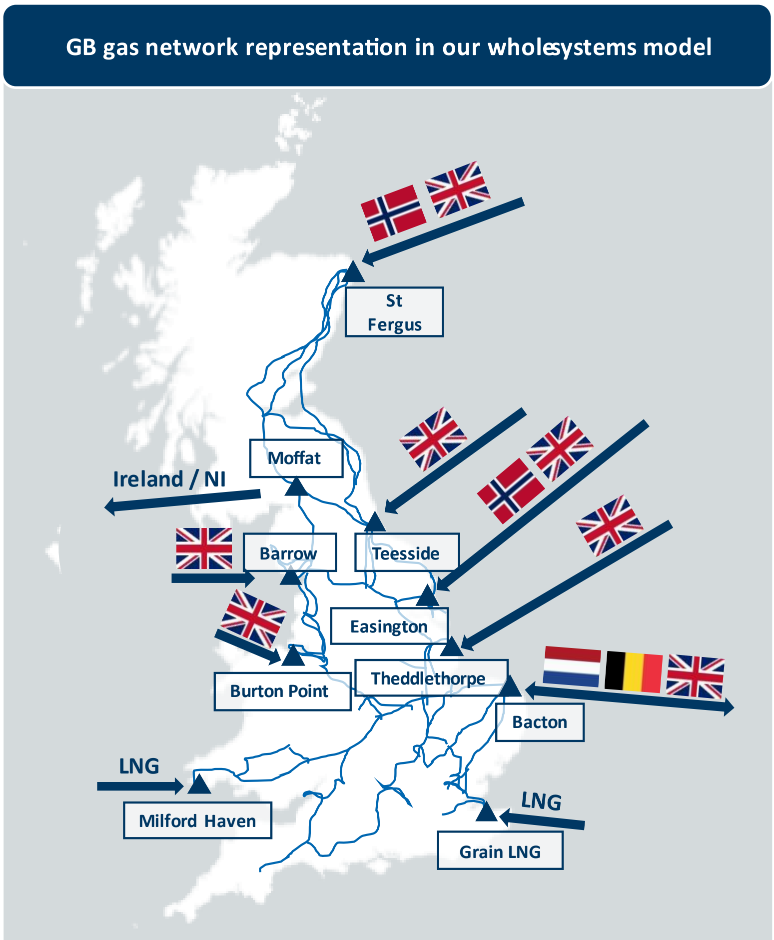
94 Domestic production is modelled for the EU-27, UK, and Norway.

95 Developed from data provided by Rystad Energy.

96 As per *LNG Database,* 2022, Gas Infrastructure Europe (link).

97 As per *Storage Database*, 2021, Gas Infrastructure Europe (link).

Figure 4-8: GB gas network representation in our whole-systems model



Sources: ENTSOG; and FTI Consulting analysis.

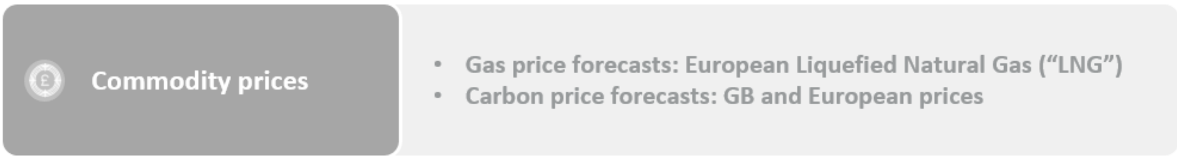
4.30. Figure 4-8 summarises GB's supply and interconnection with the rest of Europe. It shows:

- two interconnectors connecting the NTS (at Bacton) to the European continent via Belgium and the Netherlands
- two interconnectors and a pipeline connecting the NTS (at Moffat) to Ireland and Northern Ireland;
- multiple pipelines which bring production onto the NTS from production sites on the UK and Norwegian Continental Shelves; and
- three LNG regasification terminals, two connected to the NTS at Milford Haven and one at Isle of Grain.

C. Commodity prices

4.31. Commodity price forecasts include forecasts of global LNG prices, and European and GB carbon prices, as shown in Figure 4-9 below.

Figure 4-9: Key inputs and assumptions for commodity prices



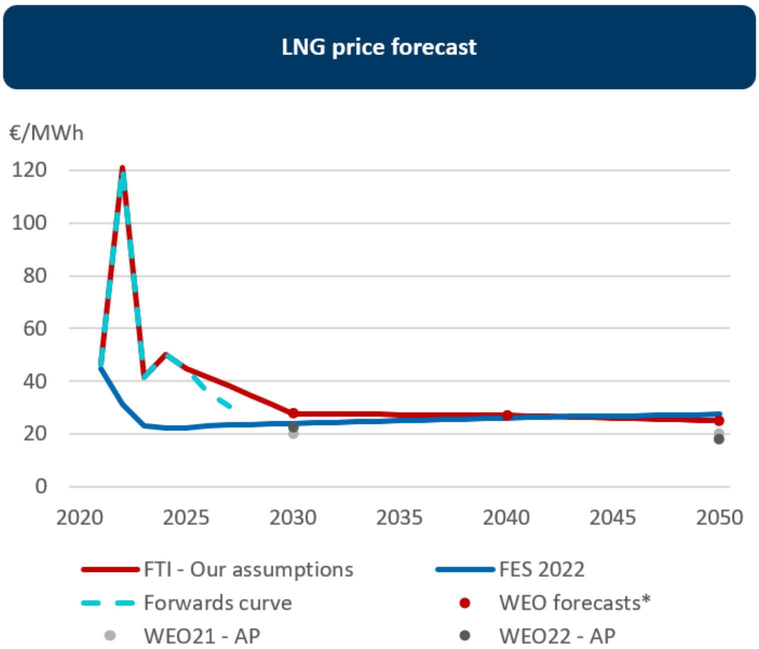
Sources: FTI Consulting analysis.

4.32. These commodity prices are a key determinant of the gas price in our modelling and in turn have a substantial effect on the power and hydrogen price, as LNG is the price setter in European gas markets (including GB) for long periods of the modelled years. We discuss this in more detail in **Chapter 6B**.

4.33. For these assumptions, we have relied on a combination of the relevant forwards curves and external long-term benchmarks produced by the International Energy Agency ("**IEA**") in their World Economic Outlook ("**WEO**").[98] Specifically, we combine these sources using linear interpolation to bridge the gap between the future curves, which were available up to 2027, and long-term benchmarks to 2050.

4.34. Figure 4-10 below shows the sources we have relied on, and our assumptions for LNG price forecasts.

Figure 4-10: LNG price forecast (€/MWh)



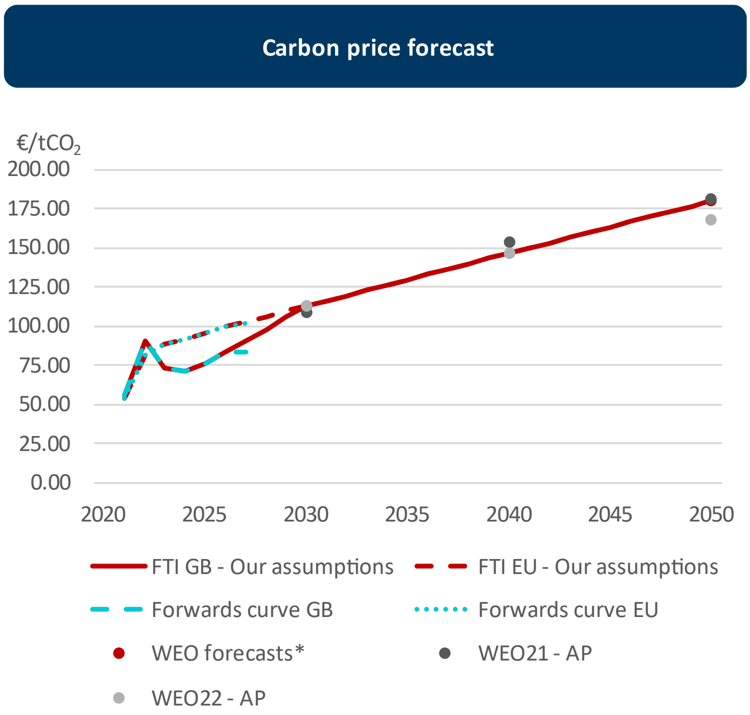
Sources: IEA's WEO; Bloomberg, FES 2022; and FTI Consulting analysis.
*Notes: WEO forecasts as based on WEO scenarios. The WEO scenario Announced Pledges ("**AP**") for 2021 and 2022 is shown in the figure.*

[98] We have selected the WEO long-term benchmarks based on the TYNDP, which uses the same set of benchmarks.

4.35. As shown in Figure 4-10, our LNG price assumptions follow the forward curves up to 2025, and then follow the IEA's WEO long-term forecasts from 2030. The movement in the gas price forecast between the forwards curves and the IEA's WEO long-term forecasts are linearly interpolated. This results in a gas price forecast that peaks between 2020 and 2025, reflecting trends in the LNG forwards curve and significant gas price spikes during the global energy crisis following Russia's invasion of Ukraine in 2022. After 2025, the gas price forecast declines until 2030 and stabilises for the remainder of the modelling period, which is in line with expectations of falling European gas and LNG demand through 2030 as per decarbonisation objectives.[99]

4.36. Figure 4-11 below shows the sources we have relied on, and our assumptions for carbon price forecasts.

Figure 4-11: Carbon price forecast (€/tCO_2)



Sources: IEA's WEO; FES 2022; and FTI Consulting analysis.

4.37. As shown in Figure 4-11, our GB and EU carbon price assumptions follow the relevant forwards curves up to 2025, converge by 2030, and follow the IEA's WEO long-term forecasts from 2030. The movement in the carbon price forecast between the forwards curves and the IEA's WEO long-term forecasts are linearly interpolated.

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99 See *Tidal wave of new LNG supply to flood market amid demand uncertainty*, 2024, IEEFA (link).

5. Our key inputs and modelling assumptions — Hydrogen

5.1. As discussed in **Chapter 3**, our analysis incorporates a representation of the electricity, gas, and hydrogen markets across the value chain, and our modelled scenarios assume that hydrogen will play a material role in the UK's decarbonisation efforts, as per the assumptions that we agreed with Centrica. The previous chapter outlined the key inputs and assumptions for each of the electricity and gas markets.

5.2. In this chapter, we now focus on the hydrogen component of our whole system model, describing the relevant policy context (including various UK government initiatives, industry projects), possible subsidy hydrogen schemes, and the key inputs and assumptions underpinning our model. More specifically, this chapter sets out:

- the policy context of the future potential GB hydrogen market (**Section A**); and
- the key underpinning inputs and modelling assumptions that form the basis of our hydrogen market model (**Section B**).

A. The policy context of the future potential GB hydrogen market

5.3. Our approach to modelling the future hydrogen system is aligned to UK government strategy and policy on the evolution of the future GB hydrogen market:

- We align the timing and location of hydrogen demand and supply with geographically localised areas where hydrogen is likely to play a role in decarbonisation, often referred to as "**CCUS clusters**" or "**industrial clusters**".[100] These clusters, which reflect areas of concentrated industrial activity that needs to be decarbonised, generally form the basis of government policy related to hydrogen and carbon capture and storage.
- We assume that a new GB hydrogen network, known as the "**hydrogen backbone**",[101] would be established through repurposing existing gas assets and the construction of new infrastructure with potential hydrogen blending capabilities, as per the ambitions of the hydrogen initiative known as "**Project Union**".[102]
- Our assumptions regarding both demand and supply in the hydrogen market are a mix of exogeneous assumptions and endogenous model optimisation, which are discussed further in the subsequent section.

[100] More specifically, DESNZ defines a CCUS cluster as a Transport and Storage ("**T&S**") network (a set of onshore pipelines, offshore pipelines and an associated offshore storage facility, which is capable of transporting CO_2 to the storage site for safe and permanent storage), and an associated first phase of at least two CO_2 capture projects. See *Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-1*, 2021, BEIS (link).

[101] We note that DESNZ also refer to a "**core network**", which is a transport infrastructure that would provide transmission of hydrogen both within and between "**regional networks**". See *Hydrogen Transport and Storage Networks Pathway*, 2023, DESNZ (link): Page 14.

[102] See later on in this section for a detailed description of the Project Union initiative.

Industrial clusters and cluster sequencing

5.4. Our hydrogen model assumes a structure and timeline of "**cluster sequencing**" policy, which underpins the policy pathway for CCUS, that affects hydrogen demand and blue hydrogen production capacity. We also consider the structure and timeline of the development of the hydrogen backbone, which is assumed to connect the clusters over time.

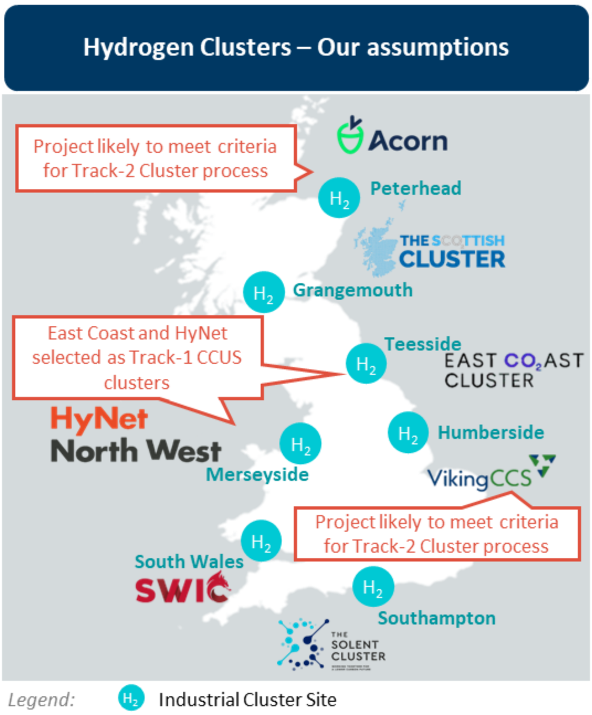
5.5. We have assumed that the future hydrogen economy will be structured around industrial clusters and cluster sequencing:

- **Industrial clusters** — are areas identified as having many industrial sites and high carbon emissions, and so are likely to deploy local Transport and Storage ("**T&S**") networks and CO_2 storage capture projects in order to facilitate decarbonisation.
- **Cluster sequencing** — aims to deploy hydrogen infrastructure and technology sequentially to those industrial clusters that are "*best suited*" first,[103] so as to support industrial decarbonisation while still maintaining security of supply. The UK government has outlined its intention to use a 'Track' process to cluster sequencing, prioritising the operationality of those industrial clusters and/or hydrogen-related projects in earlier Tracks. However, the timeline of cluster sequencing remains uncertain.

5.6. Figure 5-1 below shows the location of the UK industrial clusters and our assumptions relating to industrial clusters.

[103] See *Cluster Sequencing for Carbon Capture Usage and Storage Deployment: Phase-1*, 2021, BEIS (link).

Figure 5-1: Industrial clusters and cluster sequencing on maps



Sources: FTI Consulting analysis.

5.7. As shown in Figure 5-1, we have calibrated our GB hydrogen model based around the cluster sequencing process, which involved:

- aligning major hydrogen supply and demand centres to the identified cluster opportunities (i.e. the CCUS / industrial clusters: East Coast Cluster, HyNet Cluster, Scottish Cluster, South Wales Cluster, and Solent Cluster);
- calibrating hydrogen and gas demand profiles and blue hydrogen production capacity accordingly; and
- establishing timeline of cluster sequencing based on expected operational dates of Track-1 and Track-2 industrial clusters.

5.8. Overall, this approach results in hydrogen demand located primarily in industrial clusters. We will discuss the key inputs and assumptions underlying our hydrogen model in more detail in **Section B** of this chapter.

Project Union and the hydrogen backbone

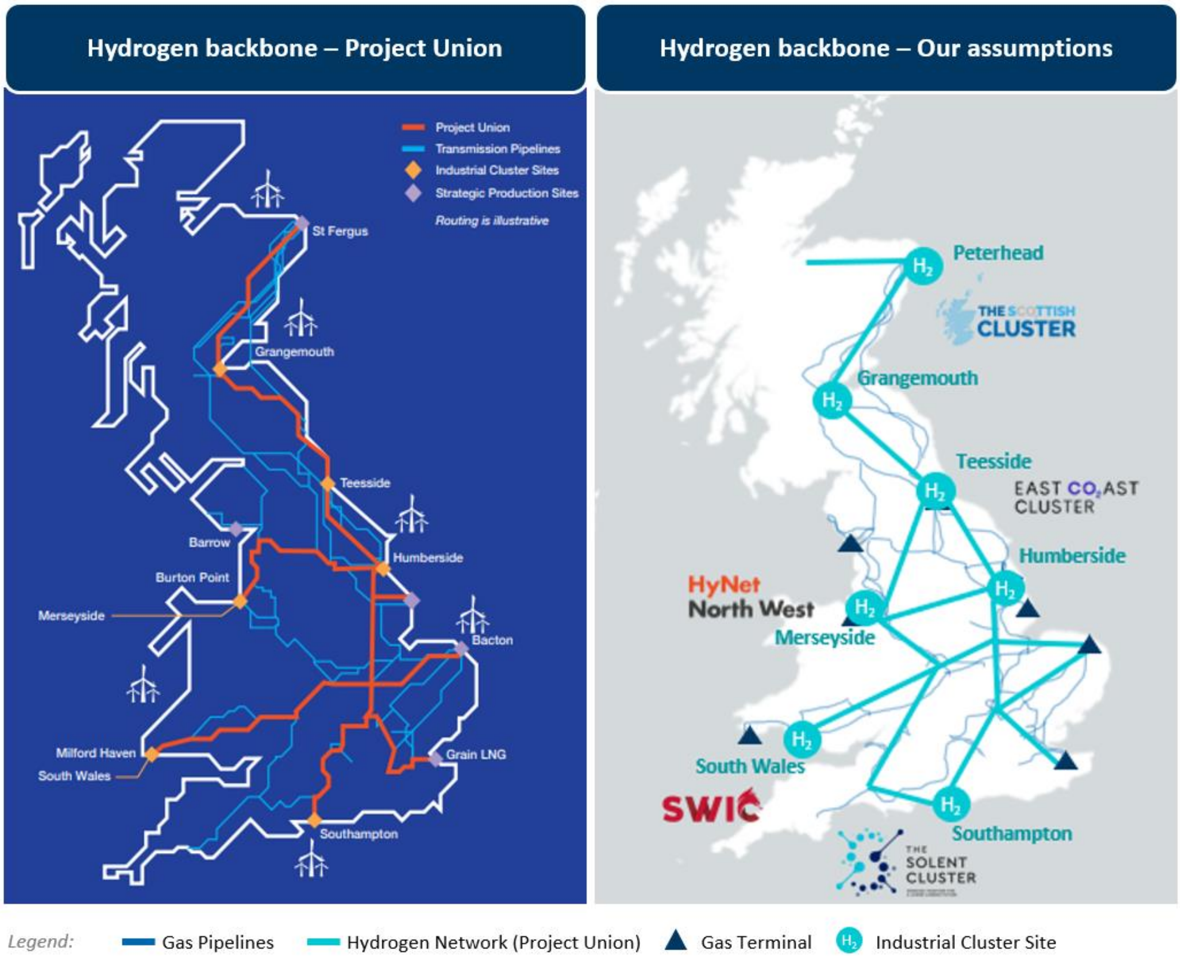
5.9. Project Union intends to create a hydrogen transportation system (or backbone) by 2030 by repurposing c.25% of existing assets related to the gas NTS, and by building new infrastructure.[104] Although there is uncertainty regarding the extent of the new infrastructure required, we assume for the purposes of our analysis that the future hydrogen backbone would follow a similar route as the existing gas transmission network. In addition, the development of the hydrogen backbone will depend on the timing and roll-out of the hydrogen economy across industrial clusters. Therefore, we have established the structure of the hydrogen backbone based on the following approach:

- We align the geographical extent of the "full" hydrogen backbone to that of the existing gas transmission network.
- We align the development of the hydrogen backbone to the cluster sequencing process and the Energy Network Association's latest report.[105]
- We test hydrogen network flows against historic gas flows and technical characteristics regarding pipeline capacities.[106]
- At this stage and for modelling simplicity, we have not considered the market impact and policy implications of the transition period where gas pipelines are switched over to hydrogen pipelines. However, our model is set-up with the capability to do so, and we consider this to be a key area to be explored further on the implications of parallel networks to serve both gas and hydrogen demand.

5.10. The hydrogen backbone plans within Project Union and the corresponding assumptions within our model are illustrated in Figure 5-2 below.

[104] See *Project Union: Launch Report 2022*, 2022, National Grid Gas Transmission (link).
[105] See *A hydrogen vision for the UK*, 2023, Energy Networks Association (link).
[106] We compare our modelling outcomes regarding hydrogen network flows against historic gas flows in **Chapter 8B**.

Figure 5-2: Project Union and hydrogen backbone on maps[107]



Sources: Project Union; and FTI Consulting analysis.

Hydrogen business models and fixed cost recovery

5.11. To support delivery of the UK government's Hydrogen Strategy, a range of asset-specific support policies are currently under development. These mechanisms are referred to as "business models" designed to support investment in the key assets of the future hydrogen system, against a backdrop of market nascency and potential market failures.

5.12. At present, the various asset-specific business models are at various stages of development. This includes:

- **Hydrogen Production Business Model** ("**HPBM**") which is a contractual business model for hydrogen producers to incentivise the production and use of low-carbon hydrogen through the provision of ongoing revenue support.

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[107] We depict the build-out of the hydrogen transmission network over modelling period, as per our assumptions in Figure 5-3 below.

— The HPBM revenue support scheme aims to bridge the cost disparity between low-carbon hydrogen and high carbon alternative fuels. Approved projects will receive support over a 15-year period and enter into the Low Carbon Hydrogen Agreement ("**LCHA**").[108]

— The ambition is to have up to 1 GW of electrolytic hydrogen production capacity in construction or operation by 2025, and to deliver up to 10 GW of low-carbon hydrogen production capacity by 2030 (up to 4 GW will be allocated to CCS-enabled hydrogen, and up to 6 GW will be allocated to electrolytic production).[109]

— Approved projects will be selected through the government funding mechanism Hydrogen Allocation Rounds ("**HARs**"), and at the time of this report the first allocation round "**HAR1**" has been completed. DESNZ selected 11 projects, totalling 125 MW capacity, to be offered contracts at an agreed weighted average strike price of £241/MWh.[110] HAR1 is expected to provide over £2 billion of revenue support, and the parallel Net Zero Hydrogen Fund has also allocated over £90 million to support the construction of such approved projects. The first projects are expected to become operational from 2025.

— In addition, eligible CCS-enabled low-carbon hydrogen projects may apply for revenue support via the Cluster Sequencing Process. The Track-1 project list was published in August 2022, including eight projects selected through the Cluster Sequencing Process, and is set to proceed to negotiations for forming the first two CCUS clusters located in HyNet and the East Coast Cluster.[111] Subsequently, DESNZ has launched Track-2 of the CCUS clusters sequencing process to establish two further CCUS clusters.[112]

- **Hydrogen Storage Business Model** ("**HSBM**"), which intends to support hydrogen storage projects to become operational at the earliest opportunity and to enable whole energy system benefits, including security of supply. In December 2023, DESNZ set out an intention to support up to two hydrogen storage projects to be operational or under construction by 2030, with potential to scale up as the hydrogen economy grows. The initial focus of support will be geological storage (the definition of which includes salt caverns and depleted gas fields such as Rough), delivered through a private law contract lasting at least 15 years. DESNZ's minded-to position for the design of the HSBM is a revenue "floor" in order to mitigate the demand risk for storage providers.

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108 See *Hydrogen Allocation Rounds*, 2024, DESNZ (link).
109 See *Hydrogen Production Delivery Roadmap*, 2023, DESNZ (link).
110 The weighted average strike price is weighted by the total expected hydrogen volume produced by each project over the lifetime of its contract. The subsidy will vary depending on changes in the reference price (the natural gas price). See *Hydrogen Production Business Model / Net Zero Hydrogen Fund*, 2023, DESNZ (link).
111 See *Cluster sequencing Phase-2: Track-1 project negotiation list*, Match 2023, DESNZ (link).
112 See *Hydrogen Net Zero Investment Roadmap*, 2023, DESNZ (link).

- **Hydrogen Transport Business Model** ("**HTBM**"), which has a near-term focus of supporting large-scale, regional and shared pipelines that transport hydrogen as a gas, as well as aiming to build regional networks to connect early hydrogen production and hydrogen demand to storage at scale. The initial focus of the HTBM will be on large-scale pipeline infrastructures, though smaller-scale, more limited transport infrastructures may be included in future allocation rounds. DESNZ's mind-to position for the design of the HTBM is a Regulated Asset Base ("**RAB**") framework and revenue support contract, similar to the current regulatory approach applied to the existing gas transportation network, i.e. the NTS.[113]
- **Hydrogen-to-power** ("**H2P**"), which has the potential to be a low-carbon flexible generation source and could provide a decarbonisation pathway, replacing unabated gas generation to support the decarbonisation of the power sector while ensuring security of supply.
  - DESNZ have consulted on the potential need for, and design of, market intervention to support H2P. Their minded-to position is to design a support mechanism based on elements of the CCUS Dispatchable Power Agreement ("**DPA**").
  - The DPA aims to incentivise the availability of low-carbon flexible generation capacity through providing investment certainty and supporting H2P's dispatch ahead of unabated gas generation, for example by including a variable payment that shifts H2P ahead of unabated gas in the merit order.
  - However, DESNZ have not yet decided on the design and manner of such a mechanism, nor if they will proceed with such market intervention.[114]

B. Hydrogen market modelling assumptions

5.13. As discussed above, the architecture of our hydrogen model has been set-up to reflect a future GB hydrogen market, based on how the government and industry envision its potential evolution. It models the five major industrial clusters, with national pipeline transmission currently unconstrained.[115] The outputs of the hydrogen market are produced on a daily basis, mirroring the granularity of the current gas market, which serves as the closest comparable market presently available.

5.14. Figure 5-3 below outlines the key inputs and assumptions for hydrogen market used in our analysis, and discussed in further detail in the remainder of this section.

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[113] See *Hydrogen Transport Business Model: Market Engagement on the First Allocation Round*, 2023, DESNZ (link).

[114] See Hydrogen to Power: Consultation on the Need, and Design, for a Hydrogen to Power Market Intervention, 2023, DESNZ (link).

[115] For computational reasons, we have not, at this stage, accounted for compressor usage or losses across hydrogen pipelines in our current modelling approach, but this can be included in subsequent modelling work. We complete a cross-check of our modelling outcomes regarding hydrogen network flows by comparing them with historic gas flows in **Chapter 8B**.

Figure 5-3: Key input and assumptions for hydrogen market

Demand	• **Industry & Transport demand: exogenous assumption based on FES System Transformation** • **Hydrogen heating demand: exogenous assumption based on FES Leading the Way** • **Power generation demand: endogenous, optimised in model**
Production capacity	• **Exogenous assumptions: Blue hydrogen** • **Optimised in model: Green hydrogen**
Storage	• **Salt caverns: exogenous assumptions based on existing sites and planned projects** • **Depleted gas field: repurposing Rough**
Transmission capacity	• **"Hydrogen backbone" by repurposing the existing National Gas network, alongside new infrastructure**

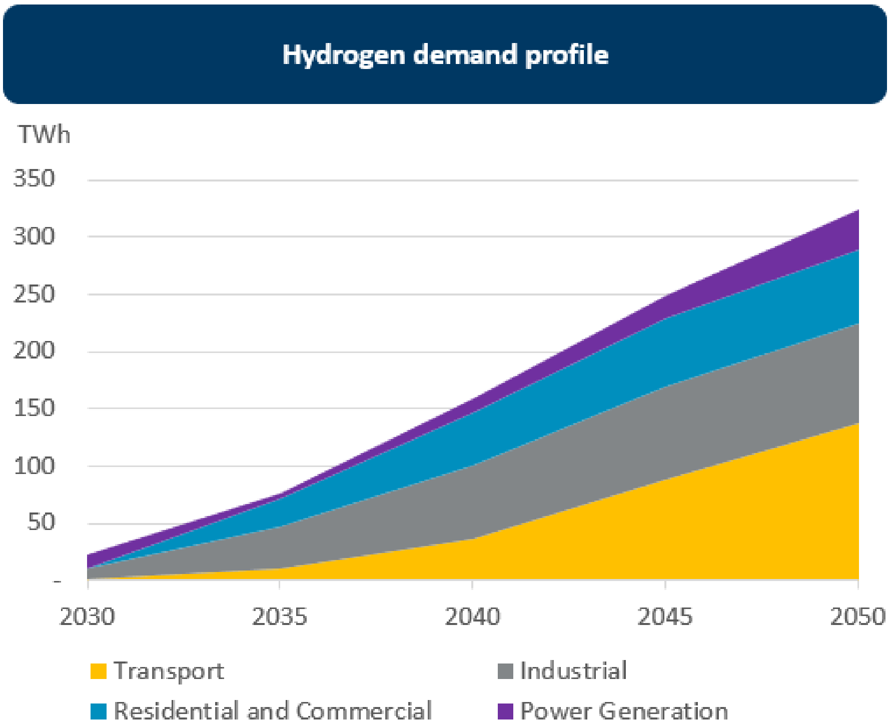
Sources: FTI Consulting analysis.

Demand

5.15. Given the extent of uncertainty in the scope and scale of hydrogen demand in future, our model has been set up to explore market patterns through the lens of overarching scenarios, which reflect a particular potential trajectory towards decarbonisation.

5.16. For the scenario set out in this report, we have adapted hydrogen demand assumptions from a variety of sources, depending on the use case. Figure 5-4 below shows the evolution of four different types of hydrogen demand in our analysis over the modelling period: transport, industrial, residential and commercial, power generation.

Figure 5-4: Hydrogen demand profile up to 2050 (TWh)



Sources: NESO FES; and FTI Consulting analysis.

5.17. As shown in Figure 5-4 above, this scenario includes a very material increase in hydrogen demand over time, with total Hydrogen demand increasing by over 13 times during the modelling period (albeit from a very low base). This increase in demand occurs across all types of hydrogen demand. Recognising the uncertainty in growth patterns, we describe each of these components and the assumptions we have made to incorporate them in detail below.

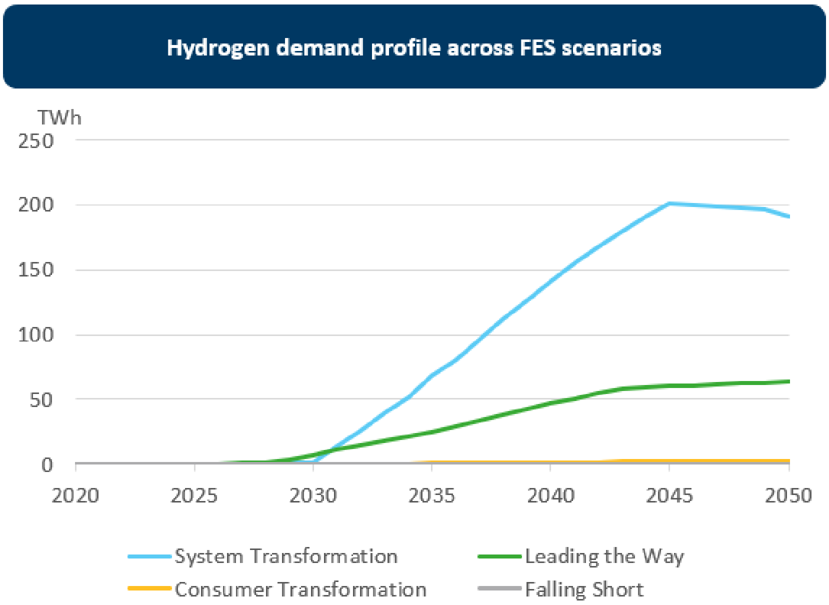
- **Transport hydrogen demand** is set exogenously and comprised of demand from aviation, shipping, rail and road transport, and are based on FES System Transformation. As FES produces hydrogen demand projections at the GB level, we have regionally distributed demand profiles for consistency with the timing and location of cluster sequencing.[116]
- **Industrial hydrogen demand** is set exogenously, and we assume is based on FES System Transformation. Similar to our adjustments to transport demand mentioned above, we have regionally distributed demand profiles for consistency with the timing and location of cluster sequencing.[117]

[116] We do this using various sources of historical data across GB local authorities, including data on: Aviation passenger volume, Shipping freight tonnage traffic, Rail Passenger journeys, Licensed Vehicles data.

[117] We do this using historical data on natural gas consumption across GB local authorities, and so use the historical regional distribution of gas consumption as a proxy for the future regional distribution of industrial demand for

- The final type of hydrogen demand included in the model is **Power Generation hydrogen demand**, which is determined endogenously and comprised of hydrogen demand from H2P generations that generate electricity. We optimise the capacity and operating profile of H2P depending on interactions between wholesale electricity, hydrogen and gas prices and H2P's relative competitiveness. Therefore, the key drivers are the level of other hydrogen demand among end-users, and the level of hydrogen storage.[118]
- **Residential and Commercial hydrogen demand** is set exogenously, and is based on FES Leading the Way. Relative to System Transformation, this includes substantially less use of hydrogen for heating, given the particular uncertainty and contentiousness of this topic within the policy debate. For example in 2050, Residential and Commercial demand is assumed to be c.64 TWh, in line with Leading the Way, and c.66% lower than the c.191 TWh assumed in System Transformation.[119] Figure 5-5 below shows the evolution of GB residential and commercial hydrogen demand (most comprised of hydrogen for heating) across different FES scenarios.

Figure 5-5: Residential and Commercial Hydrogen demand projections across FES scenarios (TWh), up to 2050



Sources: FES 2022.

hydrogen. We further consider whether regions are part of the future GB hydrogen economy at each point in time, i.e. whether regions are fully connected to the hydrogen backbone at each point in time.

118 We will discuss in more details about the interplay of the three markets in **Chapter 7**.

119 We note that this reduction in hydrogen for heating demand is offset by an upward adjustment in heat pump demand (i.e. electricity demand). We describe this adjustment in more detailed later on in this section.

5.18. As shown in Figure 5-5, by 2050 the System Transformation scenario forecasts residential and commercial demand of c.191 TWh (reflecting a roll-out of hydrogen boilers across approximately 11 million homes), with hydrogen heating anticipated to be evenly distributed across GB regions. Achieving this roll-out would require a low pressure hydrogen distribution pipeline build-out, as well as widespread public acceptance for hydrogen heating. This also implies a greater reliance on blue hydrogen production, and so greater blue hydrogen capacity, as well as reduced scope for electrification, and so reduced electricity demand from heat pumps.

5.19. Instead, we have calibrated our model to align with the less (but still quite) ambitious aggregate profile outlined in Leading the Way scenario, which forecasts a hydrogen heating demand of c.64 TWh (approximately 4 million homes). To do this, we have made the following adjustments:

- Firstly, as the FES formulates hydrogen demand projections at the GB level, we have regionally distributed residential and commercial demand profiles for consistency with the timing and location of cluster sequencing.[120] More specifically, we have based the regional distribution on the FES 2022 spatial heat model,[121] concentrating demand in relatively dense urban areas (identified based on housing stock profile data)[122] close to industrial clusters, to account for the fact that households located close to major hydrogen supply centres are more likely to adopt hydrogen boiler technology.

- Then, we reduced blue hydrogen capacity and maximum hydrogen storage volumes relative to the System Transformation scenario to reflect the reduced need for hydrogen production technologies. Figure 5-6 below shows these reductions, respectively.

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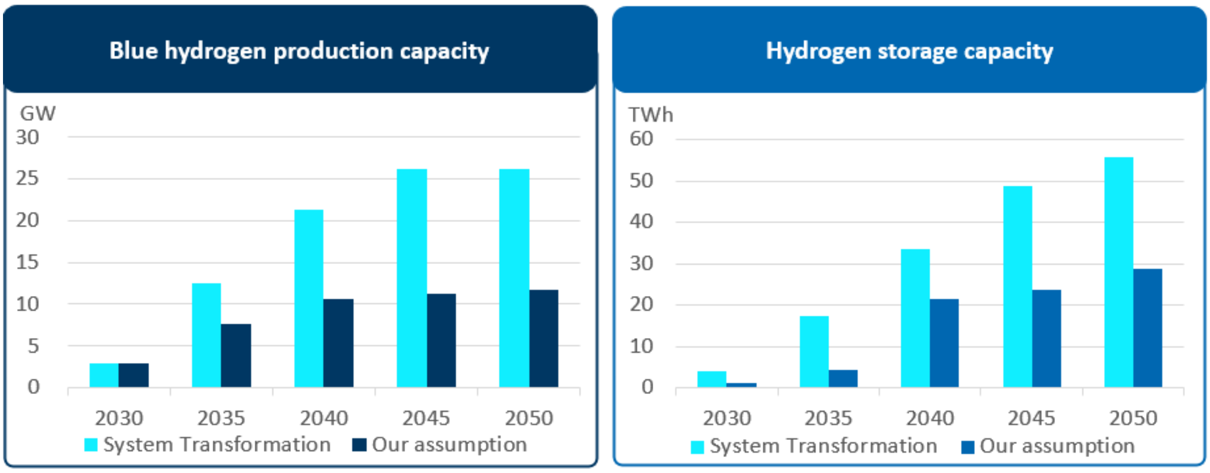
[120] We note that the NESO have produced a more granular breakdown of future heating demand projections. The FES 2022 Spatial Heat model, which is based on a building stock of c.30 million buildings, forecasts the stock (number of buildings) of heating technologies by local authority area from 2025 to 2050 across FES scenarios. For example, for the System Transformation scenario, the model forecasts an even roll-out of hydrogen for heating (buildings with hydrogen boilers) across GB local authorities by 2050, due to the NESO's assumption of a very well-developed hydrogen network in this scenario. In contrast, for the Leading the Way scenario, the model forecasts that hydrogen for heating is mostly rolled-out in the South of England, due to the NESO's assumption that hydrogen networks develop in regional hubs, but outside of these, hydrogen is not available for heating in this scenario. See *Local Authority Level Spatial Heat Model Outputs (FES)*, NESO (link); and *Regional modelling in FES*, 2021, NESO (link).

[121] We use the FES 2022 Spatial Heat model to estimate residential and commercial hydrogen demand by GB region based on the NESO's forecasts of the number of hydrogen boilers in the System Transformation scenario, and the considering the two factors described above, i.e. proximity to industrial clusters and rural and urban areas.

[122] See *English Housing Survey data on stock profile*, 2020, UK government (link), and the *Scottish House Condition Survey*, 2021, Scottish Government (link).

Figure 5-6: Our adjustments to blue hydrogen capacity and hydrogen storage relative to the FES System Transformation scenario

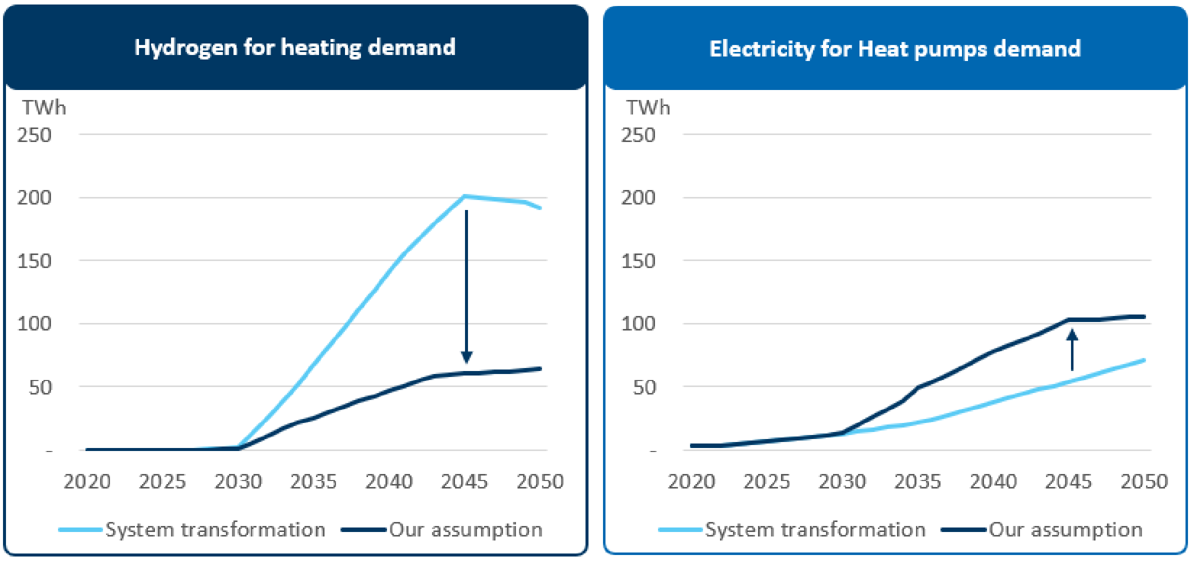


Sources: FTI Consulting analysis.

- As shown in Figure 5-6 above:
  - For blue hydrogen, we have reduced capacity to directly reflect reduced hydrogen heating demand. As a result, we assume c.12 GW of blue hydrogen production capacity in 2050, compared to c.26 GW in FES System Transformation.
  - For hydrogen storage, we have reduced volumes by aligning the maximum available storage volumes to exclude speculative storage sites.[123] As a result, we assume c.29 TWh of hydrogen storage production volume in 2050, compared to c.56 TWh in FES System Transformation.
- Finally, we have increased heat pump demand to reflect a greater need for electrified heating, assuming that heat pumps and hydrogen boilers are direct substitutes, and considering that heat pumps are a more efficient technology. Figure 5-7 below shows these adjustments to demand, respectively.

[123] According to the FES System Transformation scenario, hydrogen storage levels are expected to be quite substantial. In order to meet these levels, speculative 'dummy storage sites' must be created over and above storage levels across all known and existing storage sites. For example in 2050, c.24TWh of capacity from dummy storage sites is required to meet System Transformation forecasts of c.53TWh.

Figure 5-7: Our adjustments to hydrogen for heating demand and electricity demand for heat pumps relative to the FES System Transformation scenario



Sources: FTI Consulting analysis.

- As shown in Figure 5-7 above:
  - We have converted the reduction in hydrogen demand for heating into an increase in electricity demand for heat pumps. This increase in demand is smaller than the reduction in hydrogen demand as a result of the greater efficiency of heat pump technology compared to hydrogen boilers.[124]
  - Notably, the largest reduction in hydrogen for heating when comparing our assumptions to System Transformation occurs in 2045, a reduction of c.141 TWh.
  - This corresponds to an increase in electricity demand for heat pumps of c.49 TWh, demonstrating the greater efficiency of heat pumps relative to hydrogen boilers.

Production capacity

5.20. We have assumed there are two primary hydrogen production technologies in our analysis.[125] Firstly, we have included **blue hydrogen** in our analysis, which we assume is produced by SMR with CCS using natural gas as its main input, and so the marginal cost of blue hydrogen production is proportional to the wholesale natural gas price.

- As per the FES 2022, blue hydrogen is only assumed to play a significant role under the System Transformation scenario, with a rapid expansion in blue hydrogen after 2030, and production capacity surpassing 25 GW by the mid-2040s.

[124] We have based our efficiency assumptions for heat pumps and hydrogen boilers on the FES 2022.

[125] As described in **Chapter 1**, throughout this report we have assumed that the energy content of hydrogen is described by its lower heating value rather than its higher heating value, i.e. 33.33kWh/kg rather than 39.39 kWh/kg. This lower heating value is typically used if hydrogen is not burned directly. See *What is the energy content of hydrogen?*, Enapter (link).

- In our analysis, we have adjusted downwards blue hydrogen capacity to reflect the reduced roll-out of hydrogen for heating as discussed above.
- We assume blue hydrogen has a production efficiency of 76%, meaning that for every 100 MW of gas used, 76 MW of hydrogen is produced.[126]
- In addition, we have made several assumptions regarding the technical and operating characteristics of blue hydrogen plants, following discussions with stakeholders. The general assumption we have made is that blue hydrogen production is less flexible than green hydrogen production, but not entirely inflexible. This includes assuming that blue hydrogen generators:
  - can somewhat adjust production levels in response to price signals from a hydrogen wholesale market, ranging from minimum stable level (70%) to maximum capacity; and
  - can be completely shut down for a minimum shut-down period of one week. We have assumed that this shut-down would occur in response to economic signals.[127]

5.21. Secondly, we have included **green hydrogen** in our analysis, which we assume is produced by electrolysers through the process of PEM electrolysis, using electricity generally generated from renewables as its main input, and so the marginal cost of green hydrogen is proportional to the wholesale electricity price. We assume green hydrogen has a production efficiency of 69%, meaning that for every 100 MW of electricity used, 69 MW of hydrogen is produced.[128]

5.22. In our analysis, we have assumed there are two types of green hydrogen:

- **Grid-connected electrolysis**, which are electrolysers connected to the GB power transmission network (we will refer to them as "**on-grid**" electrolysers in this report), and so form part of the wholesale electricity market;[129] and

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[126] See *Hydrogen production from natural gas and biomethane with carbon capture and storage — A techno-environmental analysis*, 2020, Antonini, C. et al. (link): Table 3.

[127] We have included these indicative restrictions to reflect key aspects of flexibility that may evolve in blue hydrogen production. In the absence of these limited allowances for flexibility, uneconomic hydrogen market dynamics would likely arise, as blue hydrogen plants would continue generating despite wholesale hydrogen prices being very low, causing excess hydrogen supply and very low wholesale hydrogen prices.

[128] See *Scottish Hydrogen Assessment*, 2020, Arup (link).

[129] Note that we have not modelled other forms of electrolysis, such as nuclear-powered hydrogen electrolysis explicitly. To the extent that this technology becomes an established form of hydrogen production, it would be considered in our assessment to be similar to grid-connected electrolysis (albeit may have different costs and operational characteristics such as production efficiencies and ramping rates).

- **Non-grid-connected electrolysis**, which are electrolysers connected to dedicated renewables resources (we will refer to them interchangeably as **"off-grid"** or "**dedicated**" electrolysers in this report). We assume off-grid electrolysers are not connected to the electricity transmission network, and so are "fed" electricity solely from the renewable farm they are connected to, which are either dedicated offshore wind or dedicated onshore wind farms.[130]

5.23. We have assumed that in contrast to blue hydrogen generators, the operating capability of green hydrogen is more flexible. This is because we have assumed that electrolysers in our analysis use PEM technology and so, as discussed in **Chapter 2B,** they can respond quickly to wholesale electricity prices or weather patterns through their ramp up and ramp down capability and wide operating range of 0-100%.[131] More specifically:

- On-grid electrolysers can adjust production in response to wholesale electricity price signals; and
- Off-grid electrolysers adjust production in response to weather patterns, as their operating profile is directly proportional to the output of the dedicated renewables generators they are connected to, and so are determined by the climate.

5.24. The Capex and cost assumptions for different hydrogen production technologies are still currently very uncertain, with a wide range of estimates. In recent months, analysis have shown these cost estimates increasing, reflecting financing challenges and challenges within the sector.[132] As a starting point, at the date of this analysis being undertaken, we agreed to assume that hydrogen production costs are in line with those provided by external third-party sources. This includes the following assumptions:

- **Green hydrogen**: electrolyser build costs are based on the EC 2020 Reference Scenario, and TYNDP 2022, and their main input costs (for electricity) is the hourly wholesale electricity at the point of consumption which is endogenous in our analysis.[133]

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[130] We have assumed that a maximum of 20 GW of dedicated onshore wind, and 60 GW of dedicated offshore wind generation capacity could be built across GB and that these wind farms are not connected to the electricity transmission network. We chose these capacity limits as they provide sufficient scope to investigate the optimal co-location of renewable assets dedicated to electrolysers, while not being unreasonable relative to the renewables capacity figures provided by the FES 2022.

[131] See *Electrolyser technologies: PEM vs Alkaline electrolysis*, 2021, Rob Cockerill (link).

[132] See *Lex in depth: how the hydrogen hype fizzled out*, 2024, Camilla Palladino (link).

[133] See *EU Reference Scenario 2020*, European Commission (link) and *TYNDP*, European Network of Transmission System Operators for Electricity (link). We note that for off-grid electrolysers, we also include the build costs of onshore or offshore wind generators across each of the cost components, which are similarly sourced from the EC 2020 Reference Scenario, and TYNDP 2022.

- **Blue hydrogen**: blue hydrogen fixed and variable operating and maintenance costs are based on DESNZ estimates for Hydrogen Production Costs, and blue hydrogen generators' main input costs (for gas) is the daily wholesale gas price at the point of consumption which is endogenous in our analysis.[134]

5.25. For the avoidance of doubt, for each of the hydrogen production technologies, we have not included the cost of transmission or transport infrastructure within the cost of production. In particular, the production cost assumptions do not include the cost of hydrogen pipelines or CCUS transport and storage technologies required for blue hydrogen production.

5.26. We understand that some of these cost assumptions may be different from the assumptions used by other stakeholders. This can be amended for future modelling iterations, to update for latest data and/or to test for different sensitivities.

Storage

5.27. Hydrogen storage acts as both a consumer of hydrogen (when injecting into the storage facility) and as a producer of hydrogen (when withdrawing from the storage facility), helping to balance the hydrogen market based on arbitrage of the wholesale hydrogen price across the year.

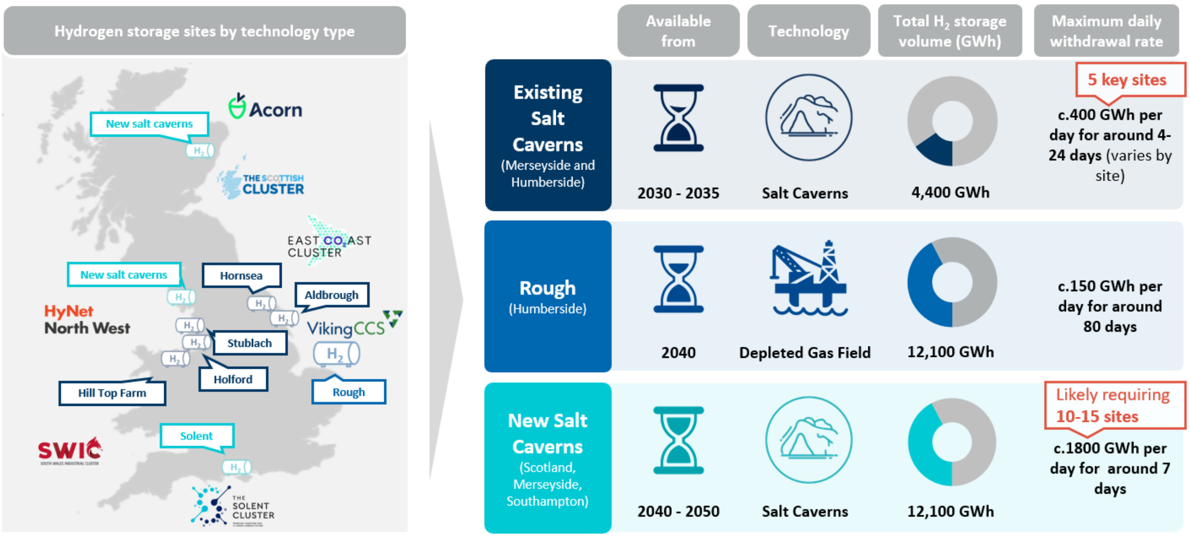
5.28. In addition, through its interaction with electricity supply and demand, hydrogen storage provides further system flexibility and can help to stabilise the power grid. For example, when electricity supply is dominated by intermittent renewables generation any excess supply of electricity can be used to produce hydrogen through electrolysis, which can be stored in hydrogen storage sites for various future uses. Alternatively, when electricity demand is at its peak, or renewables generation is low, H2P can be used to meet electricity demand using stored hydrogen, depending on the relative competitiveness of H2P generators. This supply stability can therefore be facilitated by hydrogen storage, the physical and economic features of which allows for longer-duration storage than other technologies, such as batteries.

5.29. Our model contains a representation of hydrogen storage sites based on existing and prospective salt cavern projects, as well as a redeveloped Rough.[135] Figure 5-8 below shows the location of existing hydrogen storage sites and the key technical assumptions regarding hydrogen storage used in our modelling for this engagement.

[134] See *Hydrogen Production Costs*, 2021, BEIS (link).

[135] We note that by "existing" projects, we are referring to known and existing storage sites that have been used as a gas store, though they may not be currently operational.

Figure 5-8: Key assumptions related to hydrogen storage across storage sites



Sources: FTI Consulting analysis; and technical input data from Centrica.

5.30. As Figure 5-8 illustrates, salt caverns and Rough differ in several aspects.

- From a technological perspective, as shown by our assumptions for the maximum daily withdrawal rates, salt caverns allow for faster injection of hydrogen into their storage facility, and withdrawal of hydrogen out of their storage facility compared to Rough in relation to size.
- From a physical perspective, as shown by our assumptions on total storage volumes and the number of sites, salt caverns are of much smaller volume than Rough which is anticipated to have up to 12,100 GWh of hydrogen storage capacity in the future.
- From a timing perspective, we have assumed that existing salt caverns are repurposed for hydrogen storage and are first operational by the early 2030s, followed by new salt caverns which are first operational by 2040, and that Rough is first operational by 2040.[136]

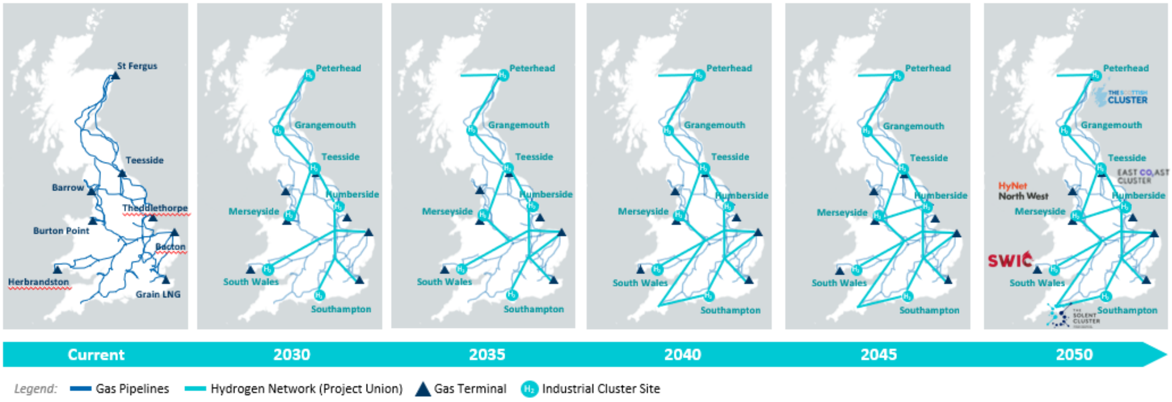
5.31. The differing technological characteristics leads to slightly different use cases for salt caverns and Rough. Salt caverns are expected to serve short-term hydrogen storage and supply solutions, whereas Rough could act as a seasonal storage site, meeting winter demand for example.

[136] We note that we have assumed existing salt caverns are operational earlier on as their size and location are more certain than the various new salt cavern projects we have researched. However, given that we have assumed salt caverns have a 15% withdrawal rate across all sites and that the hydrogen transmission network is unconstrained, the timing of existing versus new salt cavern projects is likely to have an immaterial impact on the modelled hydrogen storage utilisation profile.

Hydrogen transmission capacity

5.32. Transmission capacity refers to the Intra-GB hydrogen network, i.e. the hydrogen backbone. Figure 5-9 below depicts the assumed evolution of the hydrogen transportation network over the modelling period.

Figure 5-9: Hydrogen transmission network build-out over modelling period, FTI Consulting reference scenario[137]



Sources: National Gas; Project Union; Energy Network Association; and FTI Consulting analysis.
Notes: Gas Pipelines and proposed hydrogen backbone are illustrative only. Locations of Gas Terminals and Industrial Cluster Sites are also illustrative.

5.33. As Figure 5-9 shows, for the purposes of this modelling exercise:

- We have assumed that the hydrogen backbone is more or less complete by the early 2030s, with all major hydrogen supply and demand centres connected;
- In 2035, the hydrogen backbone extends to include connections between Merseyside and the West Midlands as well as a connection to Inverness, and similarly in 2040 to include connections to the South-West; and
- By 2045, the hydrogen backbone is fully complete with a connection between Merseyside and Humberside.

5.34. At this stage, we have not accounted for compressor usage or losses across hydrogen pipelines in our modelling. In addition, we do not explicitly model hydrogen blending, which involves blending hydrogen into the existing GB gas network. Also at this stage, we have not modelled hydrogen imports or exports into and out of the GB hydrogen economy, as there is currently very little certainty regarding the potential for a future international hydrogen network via pipelines or shipping — we note that this may affect our results materially. However, these assumptions can be included in subsequent modelling work.

137 For sources, see *Network route maps*, National Gas (link); *Project Union: Launch Report 2022*, 2022, National Grid Gas Transmission (link); and *A hydrogen vision for the UK*, Energy Network Association, April 2023 (link).

6. Overview of modelled GB electricity and hydrogen market outcomes

6.1. In the previous three chapters, we explained our modelling approach and the key inputs and assumptions which form the basis of the scenario modelled.

6.2. In this chapter we present the key physical and financial outcomes in the three energy vectors for this scenario, which represents one of many potential pathways to Net Zero. In particular, this includes:

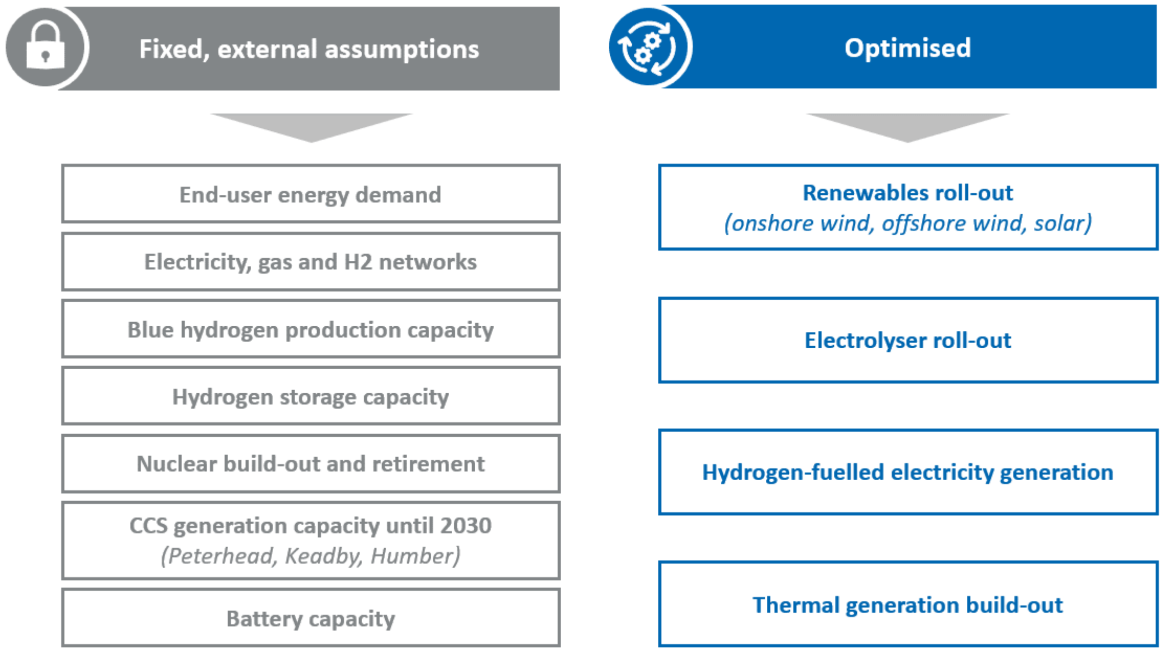
- physical outcomes, with a focus on the evolution of electricity generation capacity and geographical location of key assets over the course of the modelled period (**Section A**); and
- the resulting wholesale price trends in the electricity, gas, and hydrogen markets (**Section B**).

A. Capacity build-out

6.3. In this section, we provide an overview of our modelling outcomes relating to capacity build-out in our analysis, which are a product of our input assumptions detailed above. In this particular assessment, this capacity build-out reflects the optimal build (i.e. at minimum cost) to meet energy demand on a whole-systems basis, based on the set of key inputs and assumptions and subject to certain technical, locational and transmission constraints, as we discussed in **Chapters 4** and **5**.

6.4. As described in **Chapter 3C**, the capacity of certain generation technologies (such as nuclear) is based on fixed, external benchmarks. Figure 6-1 below summarises our approach to different generation technologies.

Figure 6-1: Capacity build-out treatment for different technologies in our analysis



Sources: FTI Consulting analysis.

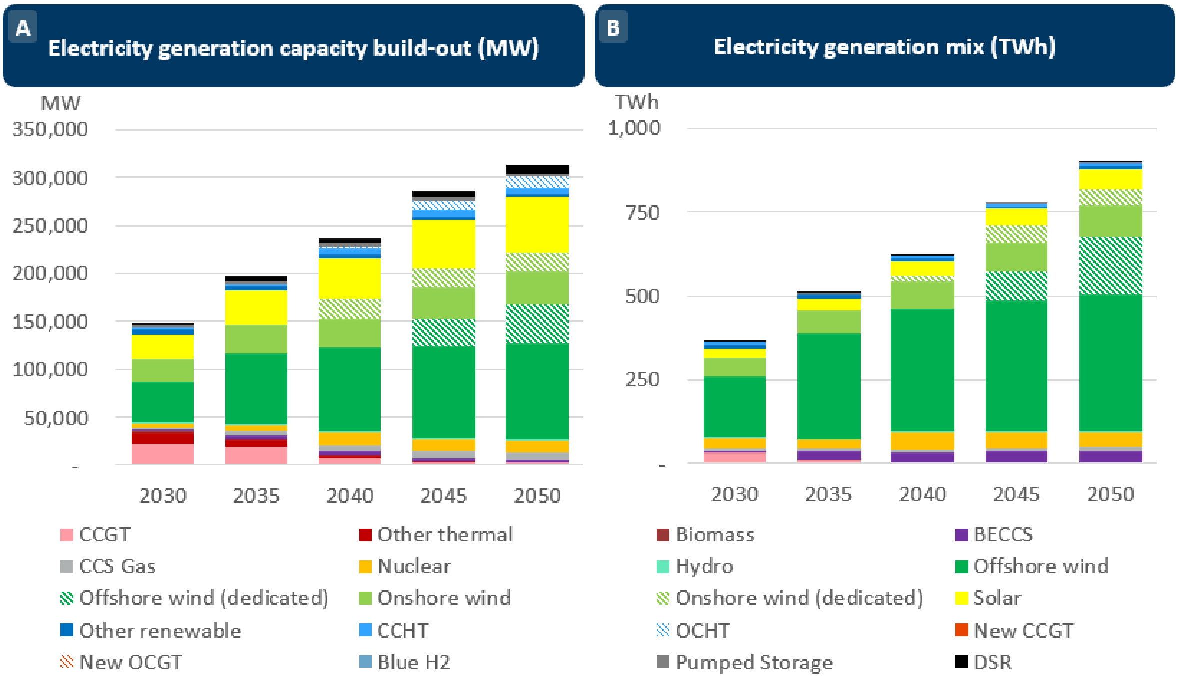
6.5. As outlined in Figure 6-1 and discussed in **Chapter 4**, we have assumed a fixed evolution of capacity build-out for assets whose build-out decisions are not likely to be driven by wholesale prices (with batteries as the exception due to modelling computational intensity, as discussed previously), and to optimise the capacity build-out of other technologies. This allows us to observe the intertwined development of the electricity and hydrogen markets, and in particular:

- the complementary build-out (both in location and size) between renewables and electrolyser capacity as the GB energy system decarbonises; and
- the different roles played by technologies across the whole energy system, such as H2P and thermal generators.

Electricity generation capacity in GB

6.6. Figure 6-2 below shows the electricity generation capacity build-out and the generation mix in GB projected in our modelled scenario, categorised by different generation technologies.

Figure 6-2: A) Electricity generation capacity build-out and B) generation mix in GB



Sources: FTI Consulting analysis.

6.7. With regard to capacity build-out, as Figure 6-2-A shows:

- Nuclear and CCS Gas generation capacity is expected to increase, with capacities in 2050 reaching c.13 GW and c.6 GW respectively as per our fixed, external assumptions.
- Renewable generation capacity is expected to increase rapidly until 2050, especially wind generation capacity:
  - Offshore wind and onshore wind generation capacity (that is connected to the electricity transmission grid) reaches over 100 GW and 34 GW respectively, though this expansion is limited by the capability of the electricity grid;[138] and
  - Dedicated offshore wind and onshore wind generation capacity (that is not connected to the electricity grid, but to off-grid electrolysers) reaches c.39 GW and 20 GW, respectively. As dedicated offshore and onshore wind farms are connected to off-grid electrolysers and so to the production of hydrogen, the generation capacity evolution in later modelling years is driven by the need for additional hydrogen supply and constraints on the electricity grid, which limit the build of wind capacity that is connected to the main electricity grid.[139]

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[138] As discussed in **Chapter 4A**, we have assumed that the capacity build-out of offshore wind and onshore wind is limited to levels forecasted in the FES 2022 System Transformation scenario.

[139] As discussed in **Chapter 5B**, we have assumed that a maximum of 20 GW of dedicated onshore wind, and 60 GW of dedicated offshore wind capacity could be built across GB, with these capacity limits being chosen based on the scope for co-location of dedicated renewables and off-grid electrolysers as well as reasonableness compared to FES

- From the 2040s, unabated gas generators are gradually phased out as they reach the end of their operational lives in line with Net Zero objectives, as per our assumptions based on the FES 2022. Furthermore, no new gas generators are built during the entire modelling period, largely as a result of our assumption of a cessation in the build of new gas peakers from 2040 onwards.

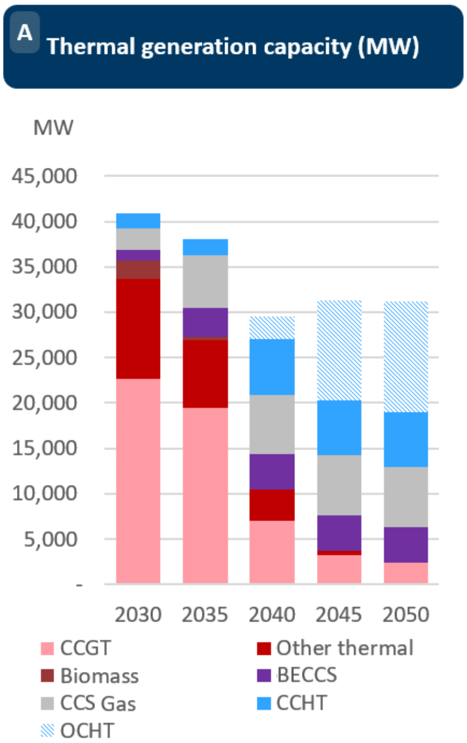
6.8. Regarding the generation mix, as Figure 6-2-B shows:

- Offshore wind becomes the largest source of electricity generation across the modelling period, providing c.426 TWh of on-grid generation (representing nearly 60% of total electricity generation on-grid), and c.177 TWh of off-grid generation by 2050.
- Generation from low-carbon thermal sources, such as nuclear, CCS Gas and BECCS reaches c.99 TWh in total by 2050 (representing nearly 14% of total electricity generation on-grid).
- In contrast, unabated gas generation decreases to below 5 TWh by 2040, as the technology is phased out in line with Net Zero objectives.

6.9. We also assess the extent to which different dispatchable capacity will play a role in providing flexibility to balance a peakier, more volatile Net Zero electricity market. Figure 6-3 below provides further details on dispatchable thermal generation capacity, including gas powered generators (CCGTs and OCGTs), CCS Gas, BECCS, Biomass, H2P generators (CCHTs and OCHTs), and other thermal generators.

2022. These wind farms are not connected to the electricity grid, but to off-grid electrolysers. The onshore capacity constraint is binding by 2050 in the scenario modelled.

Figure 6-3: A) Thermal generation capacity and B) Technical assumptions



B Technological assumptions

Technology	Capex	Efficiency	Lifetime
CCHT (200MW) H_2	565 €/kW	54%	20 yrs
OCHT (50MW) H_2	300 €/kW	38%	20 yrs
CCGT	565 €/kW	54%	20 yrs
OCGT	300 €/kW	38%	20 yrs
CCS Gas	2,000->1,750 €/kW	44%	30 yrs
BECCS	2,000->1,750 €/kW	33%	30 yrs

Sources: FTI Consulting analysis informed by Technical assumptions from EC 2020 and TYNDP 2022.

6.10. As Figure 6-3 shows:

- Unabated gas generation capacity (CCGTs and other thermal) falls rapidly as existing plants retire.
- The capacity of generators using CCS technology, including BECCS, increases significantly over the same period, rising from c.3.5 GW in 2030 to c.10.5 GW in 2050.
- Finally, the capacity of H2P generators increases significantly, particularly from 2040 onwards, rising from c.8.5 GW in 2040 to c.18.3 GW in 2050.

6.11. Notably, the (enforced) lack of new gas peakers from 2040 onwards means that alternative low-carbon dispatchable capacity is required to balance the power system.[140] In our assessment, we observe an accelerated shift towards hydrogen-fuelled dispatchable generators in the later years, out-competing other technologies to deliver the lowest-cost development and dispatch of generation to meet power demand. This considers, among other factors, the technical characteristics of each technology including its assumed Capex.

[140] We have assumed that no new gas peakers are built in the 2040s, based on the premise that future carbon prices as per our assumptions will not be sufficiently high to displace them in full in a Net Zero scenario.

6.12. As such, we find that both OCGT and OCHTs become more favoured than CCS Gas generators to balance a more peaky, seasonal electricity system given they can operate more economically with a lower capacity factor (c.5-20%).

6.13. However, the cost-competitiveness and efficiency of H2P is also very sensitive to other whole-systems dynamics, specifically:

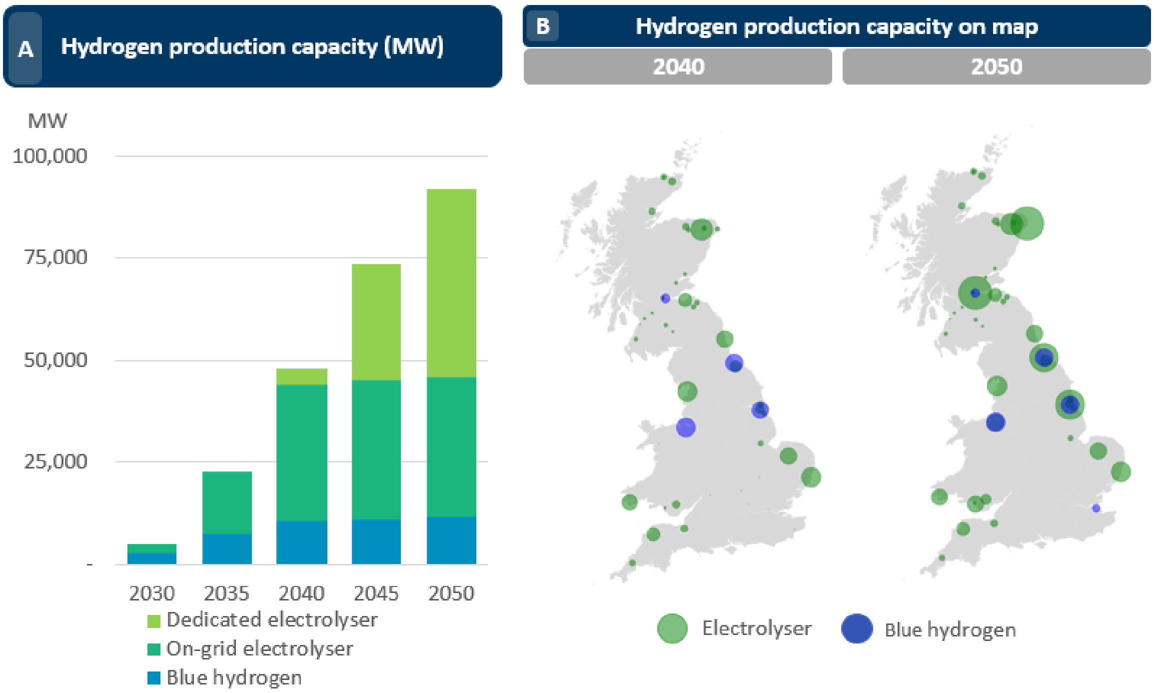
- hydrogen storage, which H2P generators rely on as a source of hydrogen fuel through withdrawals from storage sites;
- peak hydrogen demand, as increases in hydrogen demand will push up wholesale hydrogen prices influencing the competitiveness of H2P generators; and
- wholesale gas prices, which influences the economics of blue hydrogen production and so the hydrogen supply and wholesale price, as well as H2P competitiveness relative to thermal generators.

6.14. We explore some of these implications below in **Chapter 7** as we explore more of the potential interplay between the electricity and hydrogen markets further.

Hydrogen production capacity in GB

6.15. Figure 6-4 below shows the evolution of hydrogen production capacity across green and blue hydrogen on the left, and their corresponding build-out locations on the right.[141]

Figure 6-4: A) Hydrogen production capacity across green and blue hydrogen and B) Hydrogen production capacity on map.



Sources: FTI Consulting analysis.

[141] As discussed in **Chapter 4**, we optimise the size and location of on-grid and off-grid electrolysers, while we have assumed that the capacity of blue hydrogen plants is fixed.

6.16. As Figure 6-4 shows, hydrogen production capacity increases significantly over the modelling period:

- Blue hydrogen production capacity is expected to increase, with capacity in 2050 reaching c.12 GW as per our fixed, external build assumptions.
- There is a rapid expansion of on-grid electrolysers (that is electrolysers using electricity from the power transmission grid) in the 2030s with production capacity reaching c.33 GW in 2040. However for the remainder of the modelling period this growth stagnates. This is driven by trends in wholesale electricity prices, specifically:
  - the rapid growth of on-grid electrolysers in the 2030s is driven by their relatively favourable economics, as wholesale electricity prices are frequently very low due to large volumes of intermittent renewables generation; and
  - the stagnation in electrolyser growth thereafter is in line with average wholesale electricity prices stabilising, which is a result of the limited scope for further low-cost renewables to connect directly to the power transmission grid into the 2040, given our network build assumptions.
- Off-grid electrolysers start to be built in the 2040s to meet rising hydrogen demand, reaching c.46 GW of capacity by 2050. This shift in growth of on-grid electrolysers early in the modelling period versus growth of off-grid electrolysers later on reflects finite capacity on the electricity transmission grid, which ultimately limit the capacity of on-grid electrolysers.

6.17. In terms of the location of hydrogen production, as shown in Figure 6-4-B:

- By 2050, when the GB hydrogen economy has been fully rolled out, most electrolysers are located in Scotland, North-East England, and East Anglia. This is because we optimise electrolyser location such that electrolysers are located in areas where they are expected to provide the greatest benefits to the system, i.e. in areas with high offshore wind capacity where electrolysers help alleviate electricity transmission constraints.[142]
- In addition, blue hydrogen generators are located mostly in the Merseyside, and Teesside and Humberside regions as per our fixed inputs and the capacity of known blue projects in the Track-1 industrial clusters.

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[142] As mentioned previously, this assumes there is a "perfect central planner" entity that can support the optimal siting of electrolysers considering a range of factors such as co-locations with renewables, the topology of the electricity network, planning constraints, water supply, among others. We have assumed that there is no locational wholesale electricity pricing to convey the scarcity of transmission networks to incentivise greater co-location of electrolysers and renewables. However, we use "shadow" locational electricity prices (that we calculate) to guide the location of siting decisions.

6.18. Overall, when comparing our modelled outcomes related to electricity generation capacity in Figure 6-4-A and green hydrogen production capacity and the location of these electrolysers in Figure 6-4-B, there is a clearly a complementary relationship across the modelling period.

6.19. Furthermore, though the growth in electrolyser capacity throughout the modelling period is consistent, there is a clear shift in the growth of on-grid electrolysers early on, to the growth of off-grid electrolysers later. This is driven by congestion on the power network, meaning off-grid electrolysers and dedicated renewables must be built in order to meet the required growth in hydrogen production, which has usages across the whole system.

B. Wholesale price trends across the three markets

6.20. As discussed in **Chapter 3**, we forecast hourly or daily wholesale prices across the GB electricity, gas, and hydrogen markets. In this section we discuss wholesale price trends across the three markets, and dive into each in more detail in turn.

Wholesale price formation across the three vectors

6.21. The establishment of a hydrogen market, where competitively-produced hydrogen supply meets competitively-procured hydrogen demand, could help us to ascertain the "equilibrium" price level of hydrogen in a wholesale hydrogen market. As discussed in **Chapter 2**, this price would provide a market signal for dispatch, which would allocate scarce hydrogen production to demand. This price would also incentivise market participants to adjust the production and consumer of hydrogen in the shorter-term, and over time, may incentivise investments when economic to do so.

6.22. It is important to note that the *hydrogen wholesale price*, which is set by the market to facilitate supply and demand may be different from the *hydrogen production cost* (or Levelised cost of hydrogen ("**LCOH**")), which is the price of hydrogen required for the associated investment to be required. A hydrogen production cost that is higher than the hydrogen wholesale price indicates that external support (e.g. a subsidy or regulatory support mechanism) would be required to ensure commercial viability.

6.23. We have assumed that the formation of a hydrogen wholesale price would occur in a fully-competitive market where hydrogen producers provide *price offers* reflecting the marginal cost of hydrogen production for that asset. On the demand side, we have assumed that end-user demand, such as from industrial consumers, is set externally and so not price responsive, while demand for hydrogen from H2P and hydrogen storage is price responsive. Specifically, H2P is price responsive as it bids for hydrogen consumption (which determines its power generation) depending on its competitiveness in the power sector based on the prevailing wholesale hydrogen and wholesale electricity prices at the time. Hydrogen storage is price responsive as it optimises its withdrawal from storage (forming an offer of hydrogen supply to the system) and injections into storage (forming a bid for hydrogen consumption) depending on its state of storage, market conditions and the opportunity cost of acting in one period compared to future periods. The unit of the least costly supply offer which matches demand sets the wholesale hydrogen price — this ensures that hydrogen demand is met at the lowest cost possible.[143]

6.24. In effect, we have assumed that the formation of wholesale hydrogen prices occurs similarly to the so-called merit order of wholesale electricity prices.[144] In the electricity market, offers are stacked from lowest cost to the highest cost.[145] While the order may change from one period to another, this typically starts with "must-run" units such as some nuclear, followed by near-zero marginal cost renewables, biomass and other low-carbon technologies, and then thermal generation (with a carbon price) or battery storage.

6.25. The wholesale price level at which the electricity market clears might vary significantly across different time periods and levels of demand, for example electricity prices in a high wind generation period is expected to be low, while electricity prices in a low-wind period are expected to be higher. Similarly, the merit order for hydrogen follows the offer stack for production – for example, off-grid green electrolysers, on-grid electrolysers, blue hydrogen production, and storage withdrawals when relevant. This can be observed in Figure 6-5 below, which shows a hypothetical daily merit order for hydrogen supply and flows across the hydrogen value chain on a windy day in 2050.

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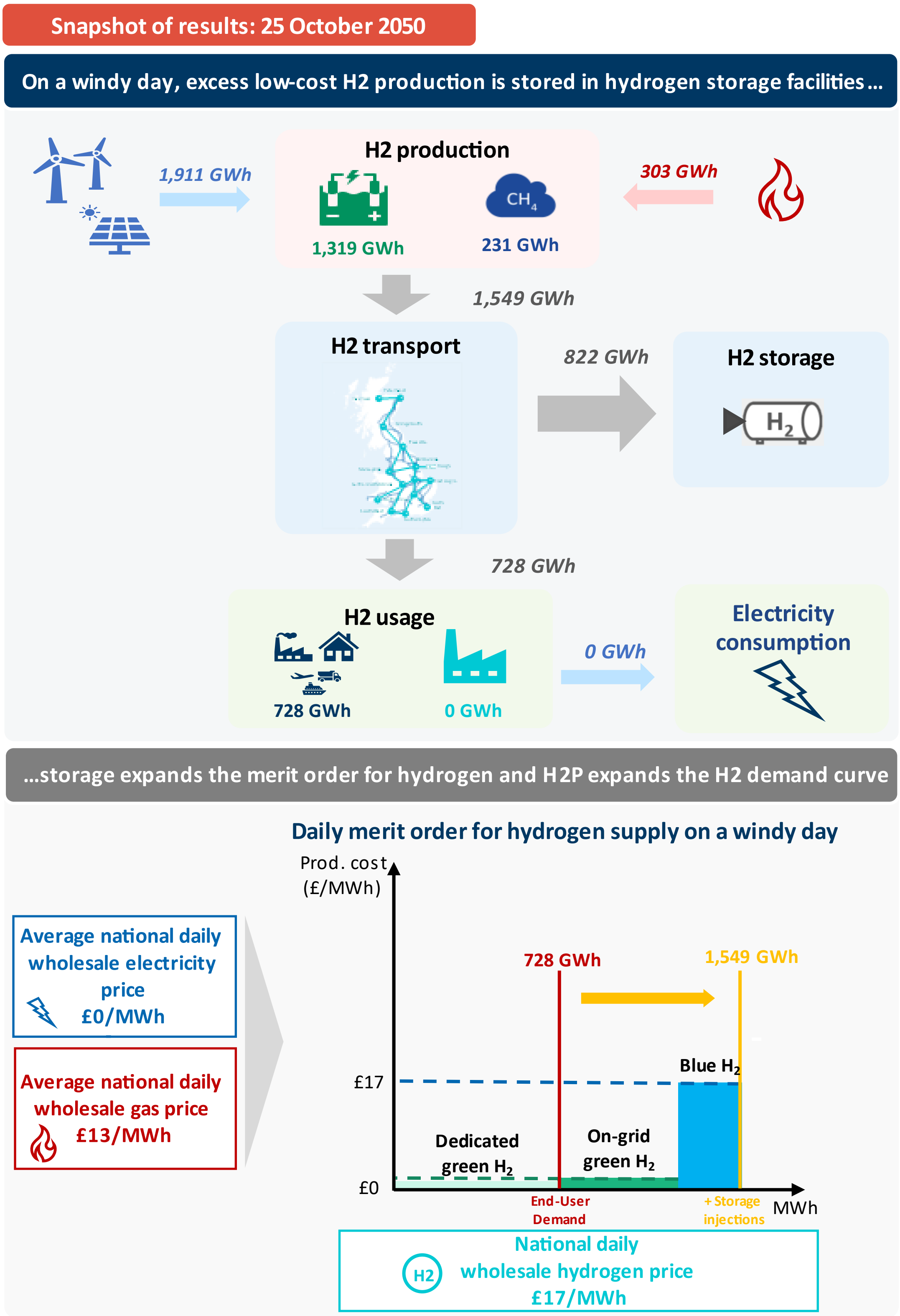
[143] We have assumed that market participants are incentivised to offer at marginal cost, i.e. there is no market power in the hydrogen market.

[144] In practice, merit-order in the GB wholesale electricity market is more obscured as most trades, and the scheduling of generation, occurs bilaterally. However, the merit order still applies — forward trades are still driven in anticipation of wholesale prices set by the marginal plant (typically based on the day-ahead price observed in an exchange such as the European Power Exchange ("**EPEX SPOT**")). In our modelling, in line with universally-accepted practice, we assume a centrally-scheduled pricing system where the merit order of the electricity market informs the marginal unit and price of electricity.

[145] There is a similar merit order for the GB gas wholesale market. This order typically starts as gas produced from the UK Continental Shelf, followed by Norwegian gas, gas storage withdrawals, LNG imports and lastly interconnectors.

Figure 6-5: Hydrogen flows and the daily merit order for hydrogen supply on a windy day in 2050

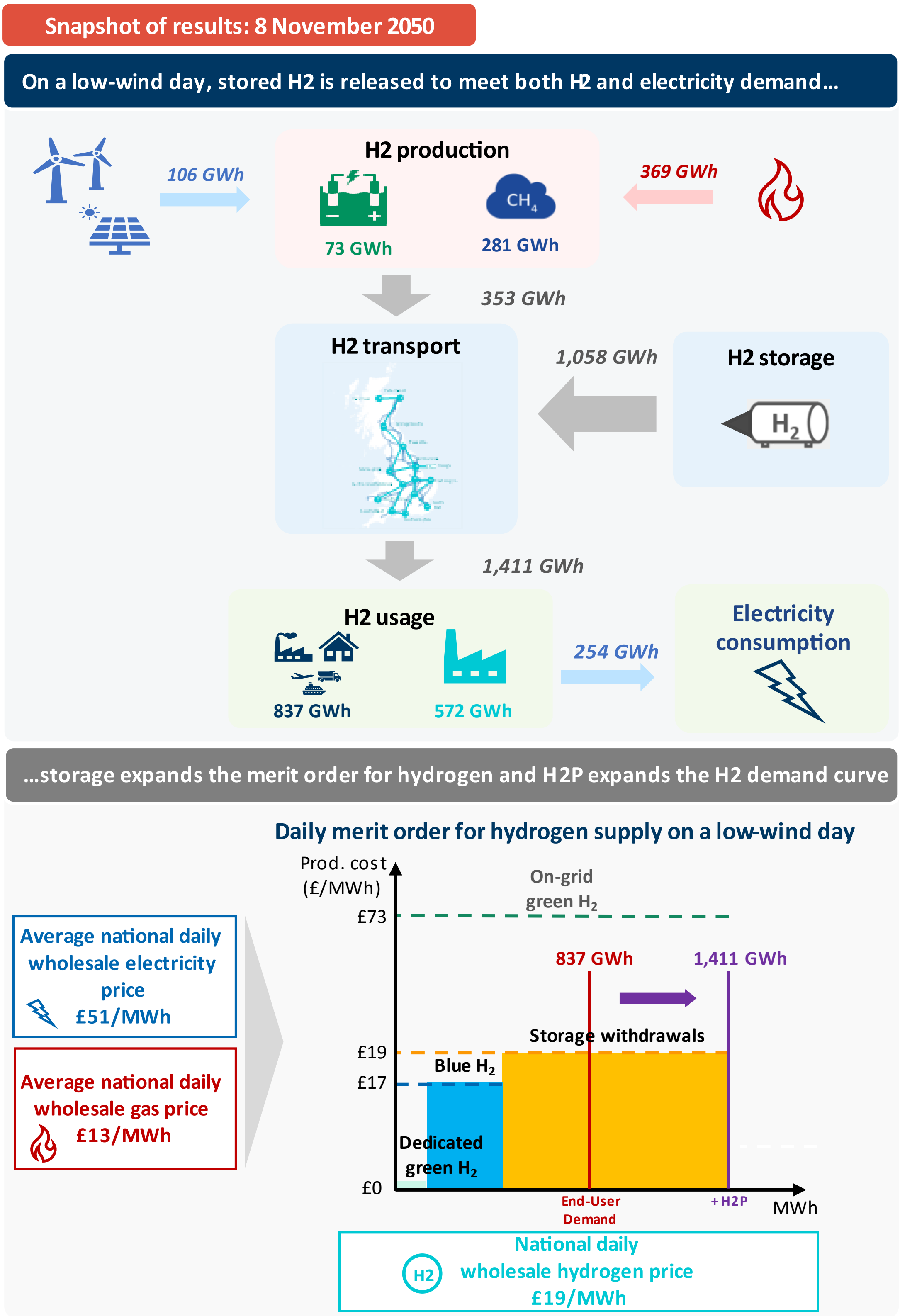


Sources: FTI Consulting analysis.

6.26. As Figure 6-4 above shows, on a windy day, in this case the 25th of October 2050, there is a large amount of wind generation leading to significant hydrogen production from green hydrogen. This is made up of a combination of off-grid electrolysers, as a direct result of the high wind generation, and on-grid electrolysers, due to the very low wholesale electricity prices. Overall, while green hydrogen production makes up a significant portion of supply to meet hydrogen demand, the wholesale price for hydrogen by blue hydrogen production to meet demand from hydrogen storage injections.

6.27. However, as hydrogen is produced from both electricity and gas inputs, the variations in wholesale electricity and gas prices may lead to very different merit orders in different days. Additionally, hydrogen could also be used as an input to generate electricity in periods of high wholesale electricity prices — effectively pushing on-grid electrolysers out of the merit order. As such, the hydrogen market may look very different in periods of excess renewable generation (driving wholesale electricity prices low, and in turn, green on-grid electrolyser production costs), which we showed above in Figure 6-5, compared to those periods of low renewable generation (driving wholesale electricity prices high, but also hydrogen demand to provide dispatchable power generation). Figure 6-6 below shows the daily merit order for hydrogen supply and flows across the hydrogen value chain on a low-wind day in 2050.

Figure 6-6: Hydrogen flows and the daily merit order for hydrogen supply on a low-wind day in 2050



Sources: FTI Consulting analysis.

6.28. As Figure 6-6 above shows, on a hypothetical low-wind day, in this case the 8th of November 2050, the lack of wind results in very little hydrogen production from green hydrogen. This is because off-grid electrolysers can only produce a little hydrogen as a direct result of the lack of wind; and on-grid electrolysers do not produce any hydrogen at all as on this day they are uneconomic, due to the lack of renewables generation driving up wholesale electricity prices. As a result, hydrogen storage withdrawals dominate the merit order for hydrogen, mostly to ensure that end-user hydrogen demand is fulfilled, which is afforded at higher wholesale hydrogen prices. Therefore, the wholesale price for hydrogen is driven by a combination of these storage withdrawals, as well as H2P, which serves to expand hydrogen demand in order to provide security of supply to the power sector through power generation, given that wholesale electricity prices increase significantly as a result of the lack of renewables generation.

6.29. Notably, we have made two key assumptions about the formation of wholesale hydrogen prices.[146] First, the wholesale hydrogen price is set daily — similar to wholesale gas prices.[147] Second, the wholesale hydrogen price is set GB-wide, i.e. through a virtual national hub such as the National Balancing Point ("**NBP**"), as we currently assume an unconstrained hydrogen network. If we tighten this assumption, it is conceivable that locational wholesale hydrogen prices might arise, perhaps varying in each industrial cluster — akin to gas wholesale prices in the US which vary across regional physical hubs, typically priced with reference to the Henry Hub.

GB wholesale electricity price outcomes

6.30. In general, hourly wholesale electricity prices within modelled years are highly volatile due to the dominance of intermittent renewable generation and relative lack of long duration electricity storage facilities. Figure 6-7 below shows hourly wholesale electricity price duration curves across our modelling period given the power generation fleet described in **Chapter 6A**,[148] as well as a more detailed look at wholesale electricity prices in 2050.

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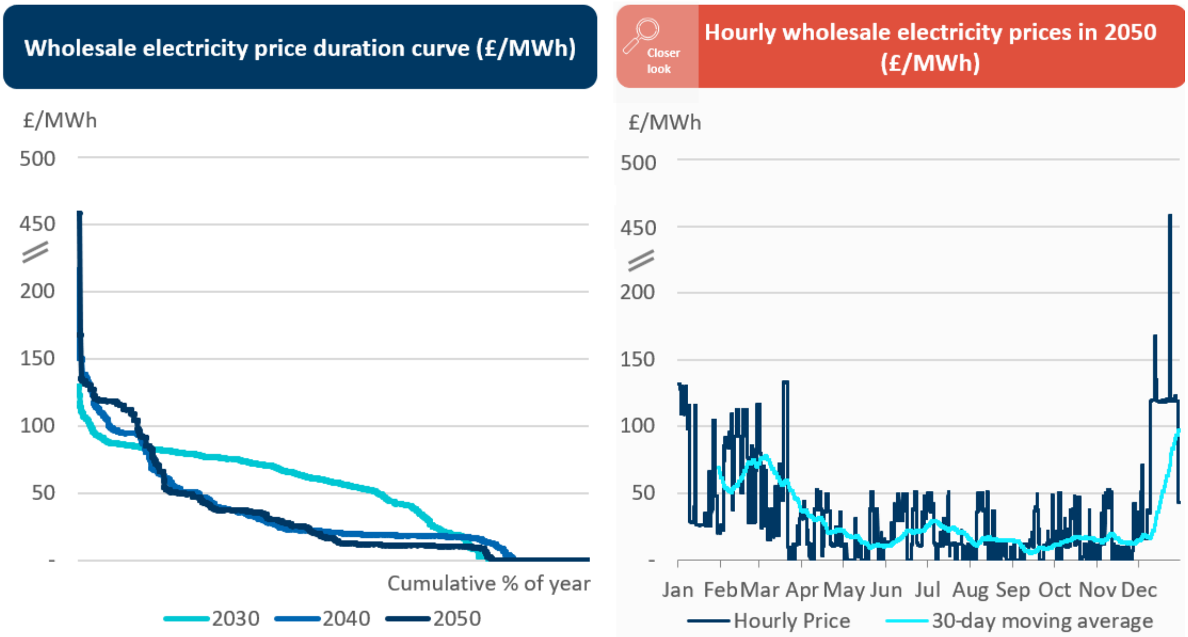
[146] We also assume that any form of H2 losses (through compressor use) do not affect the wholesale prices, and instead are recovered from H2 transportation tariffs akin to gas.

[147] Alternatively, policymakers may choose to set a more stable hydrogen price, such as over a monthly period. While this might provide a greater level of certainty, this would run counter to the variability of hydrogen production and demand, as well as limits to the future hydrogen network — leading to less efficient outcomes for market participants and consumers.

[148] The daily wholesale price duration curve orders daily wholesale prices within each year and orders them from highest to lowest.

Figure 6-7: Wholesale electricity price in 2030, 2040 and 2050



Sources: FTI Consulting analysis.
Notes: Average prices presented throughout this report are time-weighted by default, unless stated otherwise.

6.31. As Figure 6-7 illustrates, the proportion of hours with low wholesale electricity prices (defined as <£20/MWh) increases from c.27% in 2030, to c.45% in 2040, and then to over 52% by 2050. This is a result of the increasing prevalence of near-zero marginal cost renewable generation needed to decarbonise the energy system.

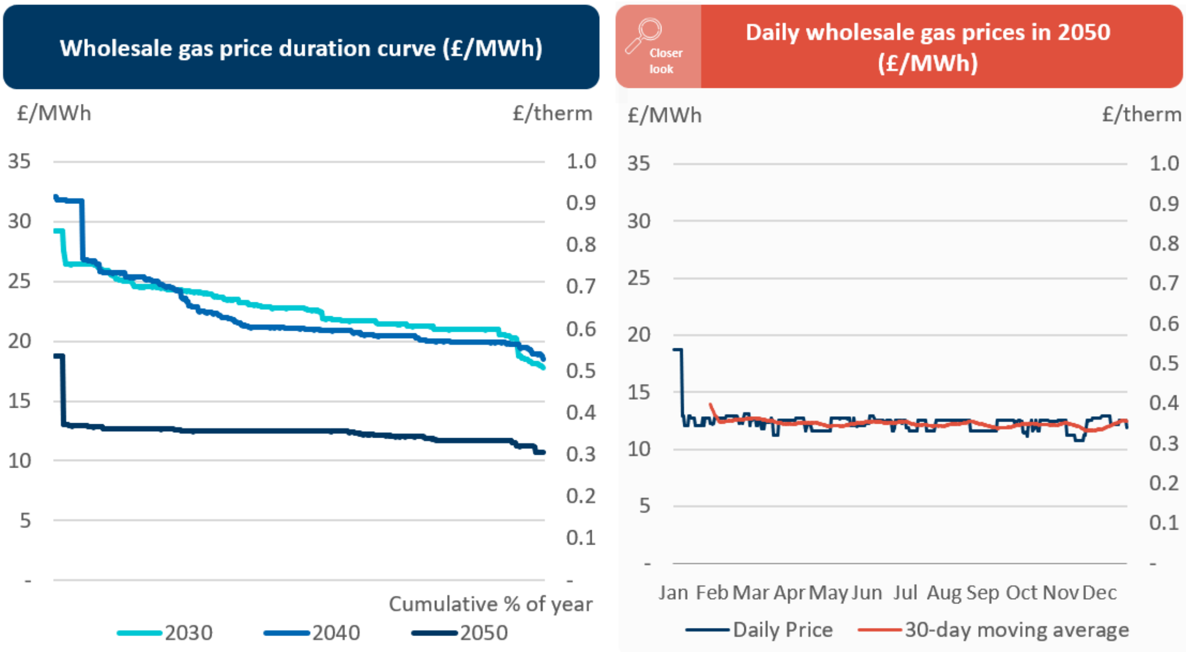
6.32. However, the volatility of wholesale electricity prices also rises across the period, as seen in the level of peak prices, which rise from c.£130/MWh in 2030 to over £460/MWh by 2050. With both of these peak prices occurring in the winter of each year this reflects the increase in peak power demand during the winter and the wide-scale electrification of heating. In addition, the increase in peak prices is driven by the fact that unabated gas generation, which is relatively low cost, has been phased out in line with Net Zero.

6.33. As more renewables come on the system, wholesale electricity prices become more seasonal, with higher winter peak prices. As Figure 6-7 shows, in 2050 prices fluctuate in the early months of the year during the winter, and then fluctuate at lower price levels during the spring and summer, and finally reach a peak of over £460/MWh during the final months of the year in the winter. These trends, as well as the substantial price volatility during the year, can be observed across all the later modelling periods, as a result of the greater roll-out of electrified heating and the fluctuations of electricity supply due to the intermittency of renewables generation.

GB wholesale gas price outcomes

6.34. Relative to wholesale electricity prices, wholesale prices in the gas market appear to be quite stable over the modelling period. Figure 6-8 below shows daily wholesale gas price duration curves across our modelling period, as well a more detailed look at wholesale gas prices in 2050.

Figure 6-8: Wholesale gas price in 2030, 2040 and 2050 (£/MWh)



Sources: FTI Consulting analysis.
Notes: We use the following conversion for £/MWh to £/therm: £1/MWh = £0.03/therm.[149]

6.35. As Figure 6-8 illustrates, wholesale gas prices decline significantly across the modelling period, declining from around £20/MWh to £33/MWh in the 2030s and 2040s, to around £10/MWh to £20/MWh by the 2050s, i.e. the shift downwards in the price duration curve in the 2050s. This clearly shows the decline in average wholesale gas prices, which is a result of an assumed substantial decline in GB gas demand and the move away from gas to electrification in line with Net Zero, combined with our assumption of a cessation in the build of new Gas peakers from 2040 onwards.[150]

6.36. Taking a more detailed look at wholesale gas prices by observing daily wholesale gas prices, there is a clear contrast to the large price volatility observed in the electricity market, with gas prices much more stable across the year. As Figure 6-8 shows, in 2050 there is very little variation in wholesale gas prices, which mostly stabilise around a relatively low wholesale price of £12/MWh throughout the year, reflecting the very low demand for gas, as per our assumptions.

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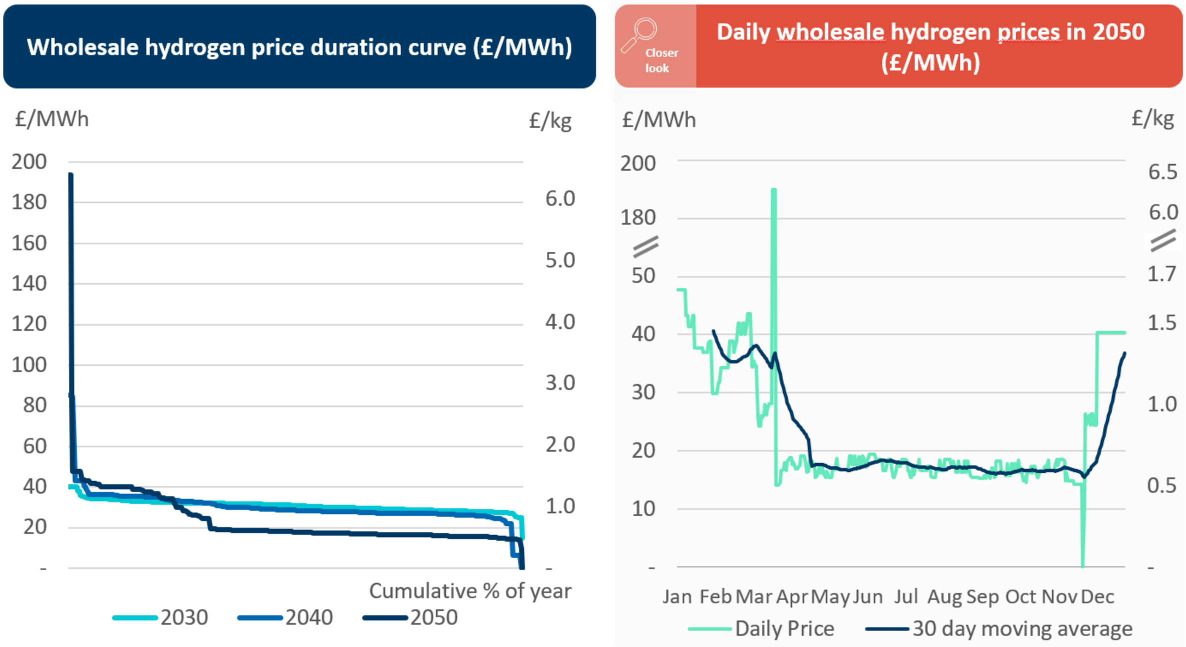
[149] See *UK Spark Spread*, ICE Futures Europe (link).

[150] This trend is broadly aligned with the gas price curves set out by DESNZ in their Fossil Fuel Price Assumptions 2023 (link).

GB wholesale hydrogen price outcomes

6.37. The wholesale hydrogen price is estimated by supply (electrolysers and blue hydrogen plants), and demand, especially types of hydrogen demand which do not have a fixed profile across the year (i.e. hydrogen for heating and H2P). Hydrogen storage also affects hydrogen supply and demand, through withdrawals from storage sites and injections into storage sites, respectively. Figure 6-9 below shows daily wholesale hydrogen price duration curves across our modelling period, as well as a more detailed look at wholesale hydrogen prices in 2050.

Figure 6-9: Wholesale hydrogen price in 2030, 2040 and 2050 (£/MWh)



Sources: FTI Consulting analysis.
*Notes: (1) As discussed in **Chapter 2,** we have assumed throughout this report that the energy content of hydrogen is described by its LHV, i.e. that hydrogen contains 33.33 kWh/kg, and so use the following conversion for £/MWh to £/kg: £1/MWh = £0.03/kg;*[151] *and (2) We display the last three weeks of wholesale hydrogen prices using the average price in January. This is because of certain hydrogen storage modelling assumptions which may exacerbate hydrogen price spikes on occasion.*[152]

[151] See *Hydrogen energy systems: A critical review of technologies, applications, trends and challenges*, 2021, Yue, M., et al. (link).

[152] In line with many modelling approaches, to avoid hydrogen storage sites from completely emptying during the end of the year, we assume that they must have similar storage levels at the end of the year to the start. However, this means that hydrogen storage units do not optimise across calendar years, and may act in an opposite manner to hydrogen prices during certain periods at the end of the year. Alternative assumptions can be considered for future modelling runs.

6.38. As Figure 6-9 illustrates, wholesale hydrogen prices remain relatively stable within each modelled year. In 2030, over 95% of the days have daily wholesale hydrogen prices between £25/MWh and £35/MWh. Moving towards 2050, we observe lower average prices outside peak hours due to increase hydrogen production capacity (as discussed in **Chapter 6A**). By 2050, over 60% of the year sees hydrogen prices within the range of £15/MWh to £20/MWh.

6.39. However, similar to wholesale electricity price trends and contrary to wholesale gas price trends, there is substantial variation in peak wholesale hydrogen prices, which rise significantly towards 2050. Peak prices increase from approximately £40/MWh in 2030, to around £85/MWh in 2040, and reach about £194/MWh by 2050. As also observed in the electricity market, these peak prices occur in the winter periods of each year and reflect the increase in peak hydrogen demand during the winter.

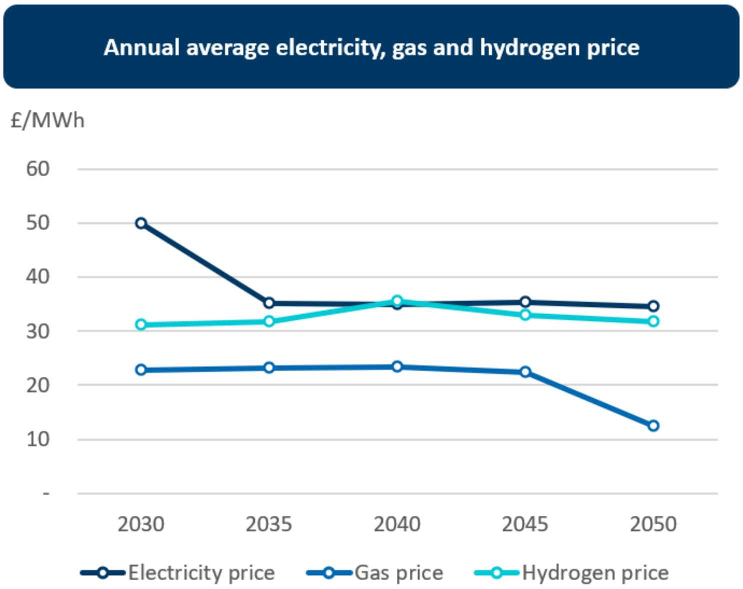
6.40. Daily wholesale hydrogen prices, shown in Figure 6-9, there is a similar seasonal price trend as seen in the electricity market, are lower in the summer months and higher in the winter. Some peaks are observed — similar to the current UK natural gas market occasionally has. As Figure 6-9 shows, there is a peak in prices earlier in the year at the beginning of spring of c.£194/MWh, driven by very low levels of hydrogen storage, as hydrogen storage has mostly been withdrawing to serve winter hydrogen demand at the beginning of the year. This means that when facing an unexpected short cold spell in the modelled period towards the end of winter, hydrogen storage has limited supply to meet excess demand as they are nearly empty, causing wholesale hydrogen prices to spike rapidly.[153, 154]

6.41. Overall, the wholesale price outcomes across the three markets across the entire modelling period are shown in Figure 6-10 below, which shows the annual average wholesale price across the electricity, gas and hydrogen markets.

[153] We note that We discuss hydrogen storage levels and utilisation across the year in much more detail later in **Chapter 8**.

[154] We note that in reality, proactive measures by system operators or regulatory bodies may play a crucial role in mitigating stress, thereby resulting in more conservative behaviour

Figure 6-10: Annual average wholesale electricity, gas, and hydrogen wholesale prices



Sources: FTI Consulting analysis.
Notes: Average prices presented throughout this report are time-weighted by default, unless stated otherwise.

6.42. As Figure 6-10 illustrates, **average wholesale electricity prices** are at the highest point during the beginning of the period, before declining sharply in 2035 and then stabilising for the rest of the modelling period, notably at a level slightly higher than average wholesale hydrogen and much higher than average wholesale gas prices. More specifically:

- average annual wholesale electricity prices are at a peak of c.£50/MWh in 2030 before declining sharply to c.£35/MWh in 2035, which is a reduction of c.30%. This sharp reduction is a result of the roll-out of zero marginal cost renewable generation capacity; and
- average annual wholesale electricity prices remain at about the same level for the rest of the modelling period, which is driven by higher winter peak prices resulting from electrified heating pushing up the average.

6.43. In contrast, **average wholesale gas prices** are mostly stable across the period, peaking in 2040 at c.£23/MWh. However, wholesale gas prices decline sharply at the end of the modelling period, from c.£22/MWh in 2045 to c.£12/MWh in 2050, which is a reduction of c.44%. This is driven by a number of factors, including:

- large reductions in gas demand in line with Net Zero, for example reduced demand from gas generators, and end-user industrial and residential and commercial demand; and
- gas demand beginning to fall behind total gas production, which is largely based in the UK and Norway.

6.44. As a result, by 2050 the gap between average wholesale gas and wholesale hydrogen prices widens.

6.45. Finally, **average wholesale hydrogen prices** follow a similar profile to average wholesale gas prices, and are relatively stable throughout the modelling period, peaking in 2040 at c.£36/MWh (or c.£1.17/kg).[155] The stability of wholesale hydrogen prices is due to the roll-out of the hydrogen economy, in particular the similar roll-out trajectories of hydrogen supply and demand, as well as the availability of significant hydrogen storage capacity. Average hydrogen prices and electricity prices are close on a £/MWh basis from 2035-2050. This is coincidental, with average annual hydrogen prices the result of a combination periods set by blue hydrogen production costs, storage shadow prices and green hydrogen production costs.

6.46. It is important to again note that the *hydrogen wholesale price* may be different to (and lower than) the overall *average production cost of hydrogen* (often represented as the LCOH) and also the *final cost of hydrogen* reflected in consumer bills. This highlights the challenges in designing and assessing the value of hydrogen production support mechanisms. We discuss some of the implications of these mechanisms in the next chapter.

[155] We have assumed throughout this report that the energy content of hydrogen is described by its lower heating value, and so use the following conversion for £/MWh to £/kg: £1/MWh = £0.03/kg. Therefore, £35.5/MWh is equivalent to £1.17/kg. See *Hydrogen energy systems: A critical review of technologies, applications, trends and challenges*, 2021, Yue, M., et al. (link).

7. Overview of the interplay between the three energy vectors

7.1. In the previous chapter, we set out our initial modelling results across the three energy vectors, covering capacity build-out, and wholesale energy price trends.

7.2. As discussed previously, there are significant interactions between the three vectors, with several energy system assets directly linking the hydrogen market with the existing gas and electricity markets. This chapter presents key insights from our analysis on the interactions between the three energy vectors, and with a particular focus on the role hydrogen is likely to play in overcoming the challenges of delivery a decarbonised electricity system.

7.3. In particular, it sets out:

- The operational patterns observed in hydrogen production (both green hydrogen and blue hydrogen) and its relationship to the electricity and gas markets (**Section A**);
- The operational patterns in H2P and the role of H2P in the wider electricity system (**Section B**); and
- The implications of our modelling results for regulatory support for hydrogen production and hydrogen-to-power (**Section C**).

A. Hydrogen production

7.4. The various hydrogen production methods display distinct dynamics, driven by variations in input price patterns and assumed technical characteristics. For example:

- green hydrogen is assumed to have greater production flexibility than blue hydrogen;
- production from off-grid electrolysers is not affected by wholesale electricity prices (unlike on-grid electrolysers) as their input electricity generation has no alternative use case, and so output is linked only to wind generation; and
- the production profile of blue hydrogen predominately relies on the consistently low gas prices derived in our model (and largely as a result of an assumed collapse in the demand for gas from other sources) and so operates with relative stability of outputs.

7.5. We provide further exploration of these dynamics in the following section.

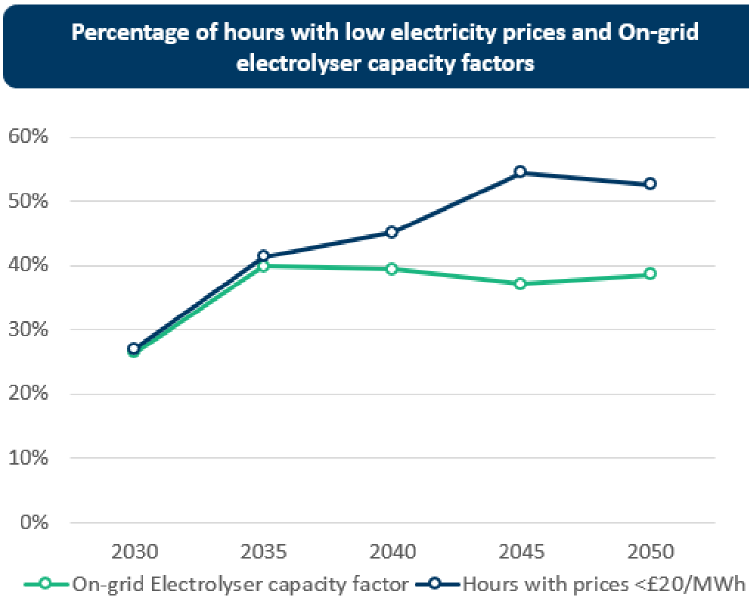
Green hydrogen

7.6. In our analysis, we have assumed there are two types of green hydrogen production from electrolysers.

On-grid electrolysers

7.7. On-grid electrolyser production closely follows trends in wholesale electricity prices, with its consumption of electricity (the main input into green hydrogen production) effectively limited to hours where low-cost renewables set a low or zero wholesale price. Figure 7-1 below shows annual average wholesale electricity prices and on-grid electrolyser capacity factors across our modelling period, and demonstrates the close relationship between on-grid electrolyser production and the proportion of low wholesale electricity priced hours in each year.

Figure 7-1: Percentage of hours with low electricity prices and On-grid electrolyser capacity factors

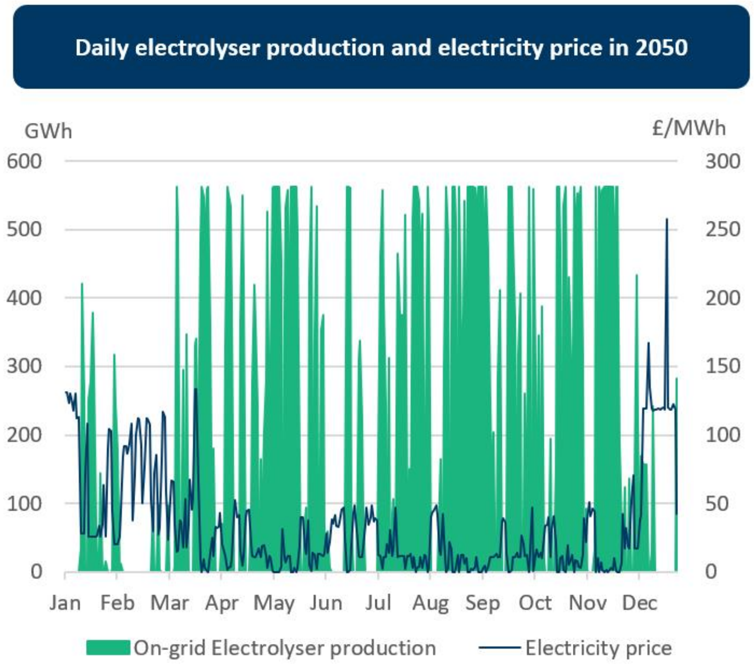


Sources: FTI Consulting analysis.
*Notes: We calculate capacity factors for electrolysers as **Annual Power Load** / (**Installed Capacity** (in terms of Max Load to be drawn) x **24-hours** x **365 Days**).*

7.8. As shown in Figure 7-1, in 2030 capacity factors are quite low at under 30%, but this increases to 40% by 2035. This is the result of a significant increase in the proportion of hours with low wholesale electricity prices, which rises in line with the roll-out of renewable generation capacity. Capacity factors remain relatively stable for the remainder of the modelling period hovering at around 40%, continuing to reflect the frequency of low wholesale electricity prices, the proportion of which remains around 50% each year.

7.9. To further illustrate the relationship between on-grid electrolyser production and wholesale electricity prices, Figure 7-2 below shows the relationship between daily on-grid electrolyser production and daily wholesale electricity prices in 2050.

Figure 7-2: Daily on-grid electrolyser production and wholesale electricity prices in 2050



Sources: FTI Consulting analysis.

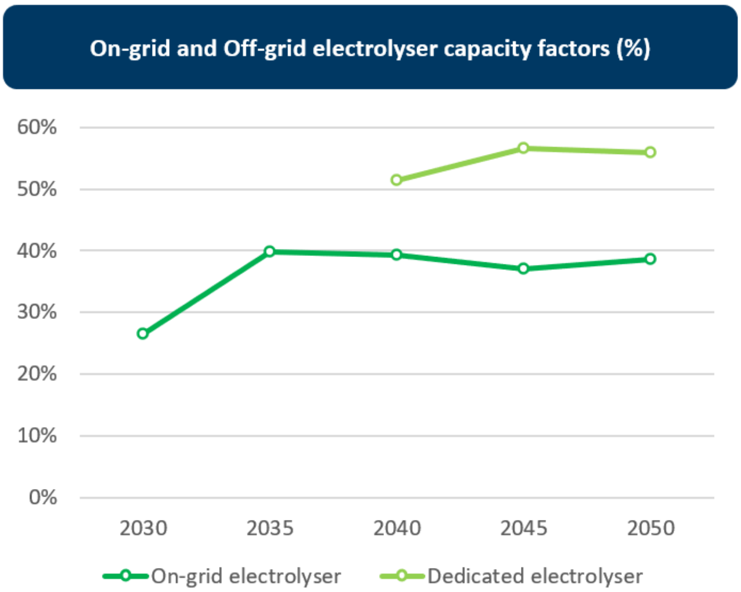
7.10. As Figure 7-2 shows, in 2050 on-grid electrolyser production fluctuates significantly throughout the year in response to changing wholesale electricity prices, as per our assumption that electrolysers in our analysis are exposed to these prevailing prices, and can ramp production up and down relatively quickly in response to lower or higher electricity prices. For approximately one-third of the year during 2050, there is no hydrogen production when wholesale electricity prices are sufficiently high so as to make the production of green hydrogen uneconomic. Conversely, during another c.14% of the year, electrolyser operations run at near full capacity when wholesale electricity prices are at or near £0/MWh. Overall, in 2050 the average wholesale price paid by on-grid electrolysers is c.£19/MWh, significantly below the annual average wholesale electricity price of c.£35/MWh in the same year.[156]

[156] The chart shows the relationship between electrolyser production and the *uniform national* electricity price. Without locational wholesale electricity prices, electrolysers in certain locations may not be operating efficiently, i.e. counter to the local value of electricity, once the limits of the transmission network are considered.

Off-grid electrolysers

7.11. In contrast, off-grid electrolysers, which are not connected to the main electricity grid, consume electricity generated from dedicated offshore and onshore wind farms. Therefore, off-grid electrolyser production is not affected by wholesale electricity prices, but rather the amount of wind generation at each point in time during the year. Unlike on-grid electrolysers, off-grid electrolysers can benefit from times when there are simultaneous spikes in wholesale hydrogen and wholesale electricity prices, which typically occur in the winter period due to peak demand for electrified and hydrogen heating. As a result, off-grid electrolysers have higher capacity factors than on-grid electrolysers. Figure 7-3 below compares on-grid and off-grid electrolyser capacity factors across the modelling period.

Figure 7-3: On-grid and off-grid electrolyser capacity factors



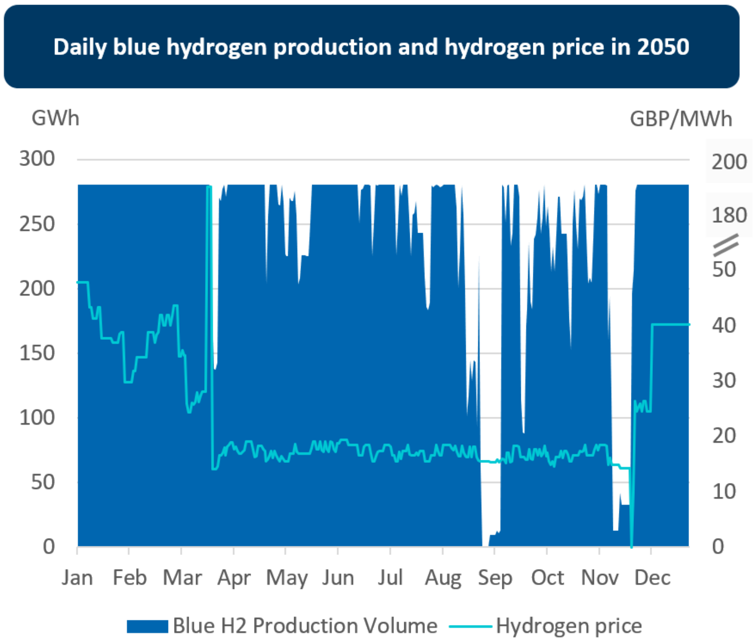
Sources: FTI Consulting analysis.
Notes: We calculate capacity factors for electrolysers as ***Annual Power Load*** */ (****Installed Capacity*** *(in terms of Max Load to be drawn) x* ***24-hours*** *x* ***365 Days****)*[157]

Blue hydrogen

7.12. Alongside green hydrogen production from electrolysers, blue hydrogen from methane (gas) reformation is expected to form part of hydrogen supply in the UK. Given their inputs, we assume blue hydrogen plants will make production decisions that reflect the differential between wholesale hydrogen and wholesale gas prices. Figure 7-4 below shows the daily operating profile across blue hydrogen plants, together with daily wholesale hydrogen prices in 2050.

[157] We note that the capacity factors for off-grid electrolysers shown in the figure exceed that of the typical capacity factors for the dedicated renewable wind farms they are connected. This is because the capacity of off-grid electrolysers is typically smaller than the dedicated renewable wind farms that they are attached to, which elevates their calculated capacity factor.

Figure 7-4: Daily blue hydrogen production and wholesale hydrogen prices in 2050



Sources: FTI Consulting analysis.

7.13. As Figure 7-4 illustrates, blue hydrogen production has been modelled based on the physical assumption that the production plants have some, but limited, flexibility which they can use in response to wholesale gas and wholesale hydrogen prices. Specifically, we have assumed that blue hydrogen producers can:

- Ramp production up and ramp down to a certain extent without shutting down (for example as they do during the months of September and October in Figure 7-4), in line with our detailed blue hydrogen production assumptions discussed in **Chapter 5B**.
- Shut down for a minimum period of one week, if blue hydrogen production would prove to be uneconomic (for example as happens during August in Figure 7-4). Such periods are likely to be driven by protracted periods of either low hydrogen prices (or indeed high gas prices).

7.14. Notably, in line with our assumptions set out in **Chapter 5B** blue hydrogen production is more stable than production from electrolysers. This is not only due to differences in its operational capability[158] but also differences in the price stability of gas as its key input when compared to the electricity used to produce green hydrogen across all modelled years. Figure 7-5 below shows daily wholesale gas and wholesale electricity prices in 2050, as shown previously in **Chapter 6B** Figure 6-7 and Figure 6-8.

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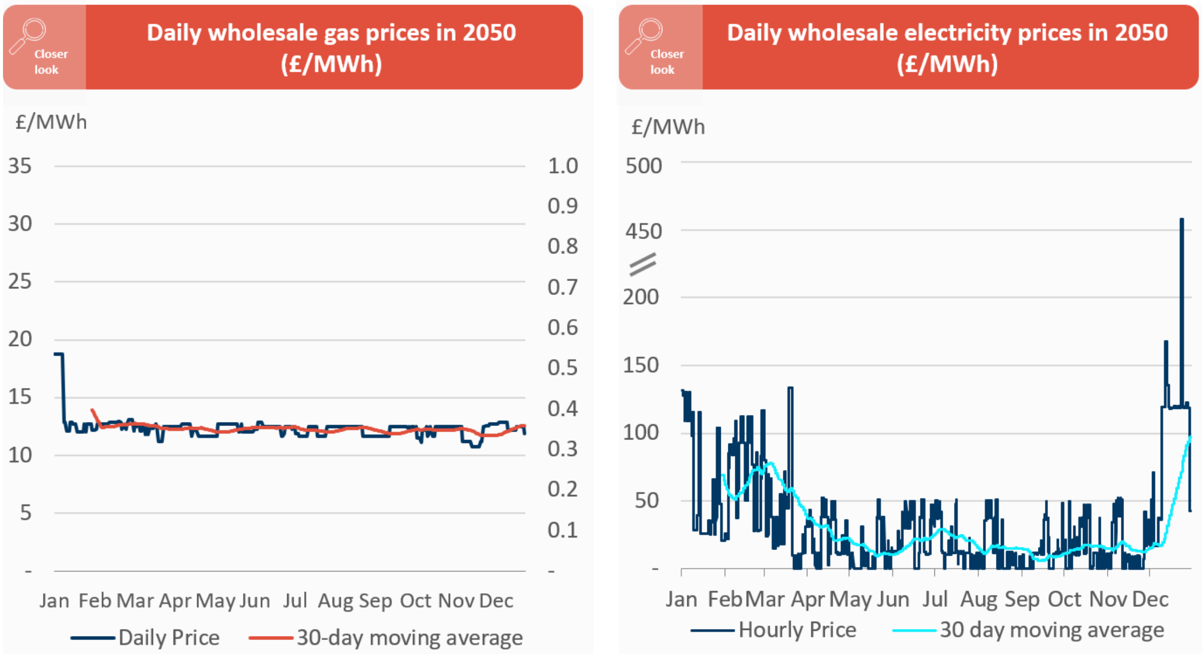
[158] See *Electrolyser technologies: PEM vs Alkaline electrolysis*, 2021, Rob Cockerill (link).

Box 7-1: Our assumptions and modelling approach for blue hydrogen

While we assume that blue hydrogen production has only limited flexibility, assessing blue hydrogen plants as a hydrogen baseload facility creates issues in a potential hydrogen wholesale market. This is because if blue hydrogen generators are assumed to operate in a similar manner to a nuclear plant, i.e. as if they were a must-run technology, blue hydrogen price offers would be zero (or negative) *regardless* of gas input prices. Given the prominence of blue hydrogen prices in the hydrogen market, this would *suppress* hydrogen wholesale periods across the system especially during periods where there was excess hydrogen supply leading to very low hydrogen prices.

To resolve this, we have assumed limited flexibility for blue hydrogen production, with limited ability to ramp up and down (for minimum periods and at a restricted pace). Blue hydrogen operators would then consider the cost of gas inputs against the expectations of hydrogen prices when considering their offers. This allowed us to factor in slow ramp rate assumptions and minimum shut-down period so that operators consider the *opportunity cost* of producing hydrogen from gas at a given time compared to future periods.

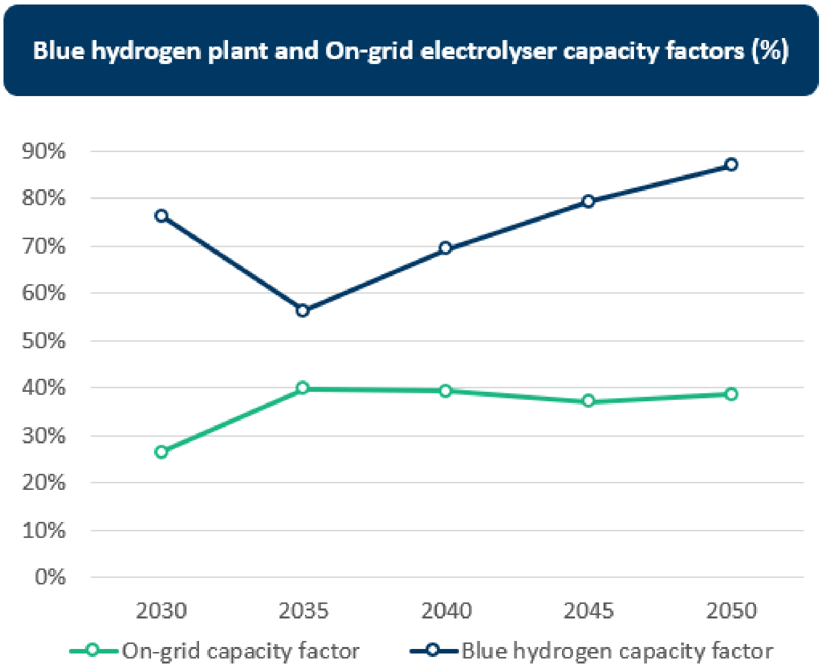
Figure 7-5: Daily wholesale gas and wholesale electricity prices in 2050



Sources: FTI Consulting analysis.

7.15. As shown in Figure 7-5 and discussed in **Chapter 6B**, wholesale gas prices are relatively low throughout the year. This is due to our assumptions on demand for gas, which by 2050 is c.72% lower than in 2030 given Net Zero ambitions (See Figure 4-7). Overall, the favourable economics for blue hydrogen plants as we saw in Figure 7-5 is mainly driven by the low wholesale gas price assumptions - which offers them a comparative advantage over on-grid electrolysers, even if they are unable to respond to wholesale price signals as quickly. This is illustrated by the comparison of the blue and green hydrogen production capacity factors such shown in Figure 7-6 below.

Figure 7-6: Blue hydrogen plant and On-grid electrolyser capacity factors



Sources: FTI Consulting analysis.
*Notes: (1) We calculate capacity factors for electrolysers as **Annual Power Load** / (**Installed Capacity** (in terms of Max Load to be drawn) x **24-hours** x **365 Days**). The capacity factor calculated using power load and hydrogen production are equivalent (as the difference would be the efficiency factor in both the numerator and denominator. (2) We calculate capacity factors for blue hydrogen as **Hydrogen Production** / (**Installed Production Capacity** x **24-hours** x **365 Days**).*

7.16. As Figure 7-6 shows, as a result of low wholesale gas prices, the capacity factor of blue hydrogen is relatively high throughout the modelling period. More specifically:

- blue hydrogen capacity factors fall to c.56% in 2035, due to the increase in blue hydrogen production capacity which rises by c.5 GW; and
- capacity factors then rise for the remainder of the modelling period, finally reaching around 80% to 90% by 2050, which is in line with the growth of blue hydrogen production and blue hydrogen production capacity stabilising.

7.17. The very high blue hydrogen capacity factors by 2050 reflect the improving economics of blue hydrogen. This is largely driven by falling wholesale gas prices and means that blue hydrogen is often setting the lower price bound for hydrogen across the market. The low and stable modelled wholesale gas prices are a result of our input assumptions (from the FES) regarding gas demand and supply. Specifically, that historically large gas demand begins falling behind total production in the UK Continental Shelf and the imports from Norway, and that LNG prices remain stable and decline slightly over the modelling period.

7.18. It is noteworthy that, in an alternative scenario with higher wholesale gas prices, for example one where global gas demand is higher than modelled in 2050, or supply lower, blue hydrogen production would be less economic (relative to green hydrogen production) and likely have lower capacity factors.

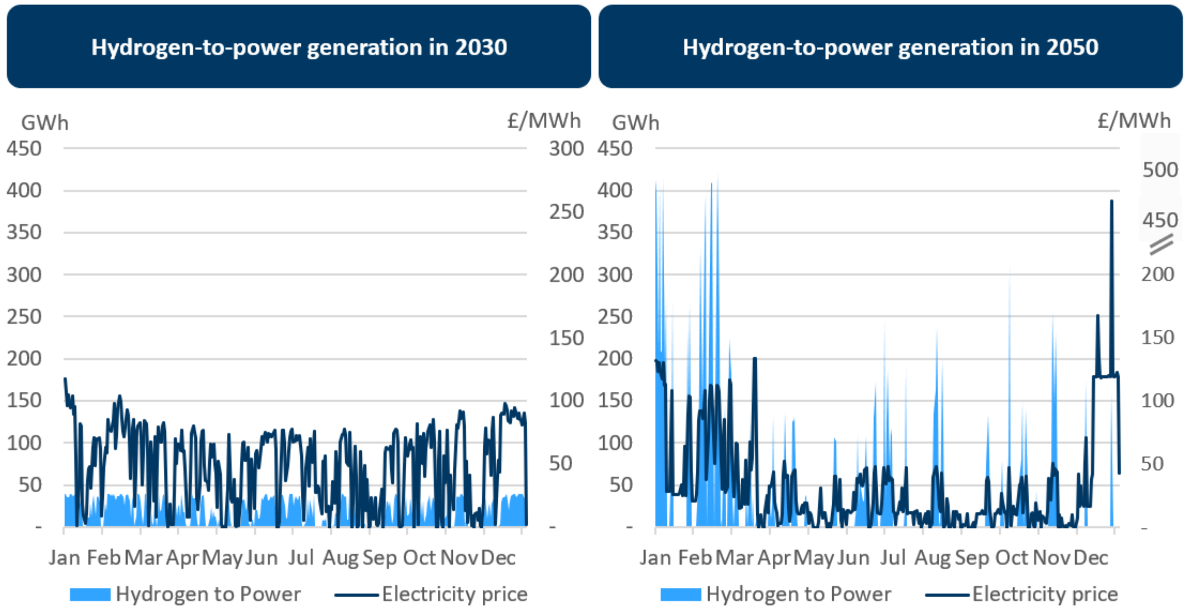
B. Hydrogen-to-power

7.19. As discussed earlier in **Chapter 4A**, we have modelled two types of hydrogen-fuelled electricity generators—CCHTs (combined cycle hydrogen-fuelled gas turbines) and OCHTs (open cycle hydrogen-fuelled gas turbines). These differ in their underlying economics. As with gas generators, combined cycle turbines have higher upfront costs, but are more efficient, while open cycle turbines have lower upfront costs, but are less efficient. As we showed previously in Figure 6-3-A, the outputs of our model on the capacity build-out of H2P generators suggests that:

- In 2030 and 2035, there is relatively limited operational CCHT, with c.2 GW of generation capacity.
- From 2035 onwards, there is an increase in H2P capacity in lieu of retired fossil fuel plants on the electricity grid and as part of Net Zero ambitions.
- By 2050, CCHT and OCHT generation capacity reaches a peak, of c.6 GW and c.12 GW respectively, reflecting too our assumption of the cessation of new gas peakers from 2040 onwards.

7.20. In our modelling, the economics of H2P generators mean they take on a role similar to that played currently by gas peakers, providing electricity to the system at times of high demand. Importantly, H2P is also the channel through which stored hydrogen can be transformed back into electricity when demanded by the system, doing so in response to higher electricity prices, resulting from high demand or low supply from other sources. Figure 7-7 below shows the interactions between H2P production and wholesale electricity prices in 2030 and 2050.

Figure 7-7: H2P generation and wholesale electricity price in 2030 and 2050



Sources: FTI Consulting analysis.

7.21. As Figure 7-7 illustrates, in 2030, the small amount of H2P generation capacity available (CCHTs only) is used relatively often due to the frequency of relatively high wholesale electricity prices across the year. By 2050, there is much more H2P capacity available, and so it is used less frequently throughout the year and is mostly used to respond to peak wholesale electricity prices. This is especially true in the early winter months of January and February, when power demand is at its highest and wholesale hydrogen prices are relatively low (the main input of H2P), due to high levels of hydrogen storage at the start of the calendar year when storage sites, such as Rough, are full.[159]

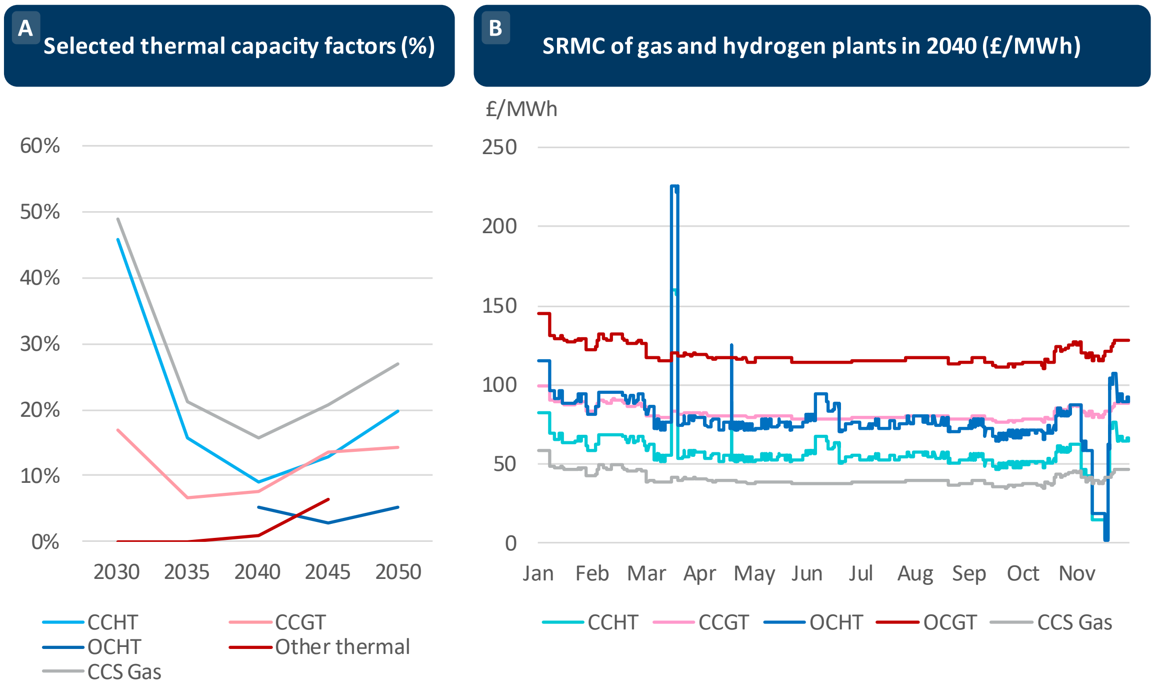
7.22. We note that, our modelling suggests that the correlation of hydrogen and electricity prices could potentially mitigate the benefits of H2P in the future. We observe such correlations during other modelled periods of peak wholesale electricity prices, such as December. This is mostly driven by our assumption that in the winter, there is higher demand for hydrogen as a result of hydrogen for heating:

- Higher demand for hydrogen in the winter puts upwards pressure on wholesale hydrogen prices, and so reduces H2P's competitiveness; and
- The increased stress on the hydrogen market puts pressure on the hydrogen supply, meaning that there may not be sufficient volumes of hydrogen available to fuel H2P.

159 We currently assume that hydrogen storage sites are relatively full (approximately 80% full) at the start of each modelling year, based on historical analysis over a longer-term which may not reflect the operation of hydrogen storage in each specific year.

7.23. H2P plants are relatively competitive compared to conventional OCGTs and CCGTs. Figure 7-8 below shows the capacity factors and SRMC of OCHTs and CCHTs comparing to other thermal generators.

Figure 7-8: A) Capacity factors (%) of selected thermal generation types[160]; and B) SRMC (£/MWh) of CCHTs, CCGTs, OCHTs and OCGTs in 2040[161]



Source: FTI Consulting analysis.
Notes: (1) We calculate capacity factors as ***Generation*** */ (****Installed Generation Capacity*** *x* ***24-hours*** *x* ***365 Days****); and (2) We do not present the last three weeks of data for the modelling year as the profile of daily wholesale hydrogen prices is in part driven by our assumption that hydrogen storage sites must end the year with storage levels that are similar to their initial storage level, leading to price spikes on occasion.*

7.24. As Figure 7-8 illustrates:

- The capacity factors for dispatchable thermal plants are high in 2030 due to the frequency of relatively high electricity prices across the year (shown in Figure 6-7 above). They fall sharply through the 2030s due to the roll-out of other generation technologies such as nuclear and renewable generation, which reduce the frequency of higher priced hours. Subsequently, thermal capacity factors rise moderately during the 2040s as electricity demand increases (as a result of increased electrification), and the growth of renewable technologies, such as solar, onshore wind and offshore wind, slows.

[160] 'Other thermal' includes OCGT and other small-scale oil and gas generators.
[161] SRMC calculated using input prices (gas and hydrogen) in the model, carbon prices where relevant, combined with technology-specific heat rates.

- Among dispatchable thermal technologies, CCS Gas has the highest capacity factors, as a result of its high fixed costs, relatively low operating costs and the lower short-run costs due to the saving on carbon prices — as shown in Figure 7-8-B — which makes it more competitive than unabated gas generators like CCGT and OCGT.
- Legacy CCGT plants have higher capacity factors than OCHTs in the 2040s because they are more competitive (despite our carbon price assumptions), which is driven by low wholesale gas prices and the correlation of wholesale electricity and wholesale hydrogen price spikes, which makes H2P less competitive. However, we note that this correlation may be reduced by increasing total available hydrogen storage capacity, or reducing alternative hydrogen demands that amplify price spikes. The correlation observed under our current model set-up is illustrated by Figure 7-8-B which shows similar patterns in the SRMC of the different thermal technologies in 2040:[162]
  - Across most of 2040, CCHTs are utilised more than CCGTs given the lower SRMCs of the former, despite our low modelled wholesale gas prices. This is driven by carbon prices, which adds up to 120% to the gas SRMC.[163]
  - There are periods where H2P is notably uncompetitive, such as the period in March in our 2040 example. This is because spikes in the wholesale hydrogen price, driven by very low wholesale hydrogen prices and an unanticipated (albeit relatively short) period of cold weather, temporarily reduce the competitiveness of H2P relative to gas peakers, who do not face such spikes in input prices.

7.25. The interplay between high electricity prices and hydrogen prices demonstrates the role of H2P generators to serve peak electricity demand. This is predicated on having sufficient hydrogen storage, which would store hydrogen predominantly during periods of low electricity prices.

C. Implications for regulatory support for hydrogen production and hydrogen-to-power

7.26. Currently, as industry and policymakers explore the scope and extent of the role which hydrogen can and will play in the future energy system, there is widespread consensus that regulatory support mechanisms will be required, at least initially. Most of these mechanisms are primarily targeted at hydrogen production technologies with the objective of lowering the cost of hydrogen over time through innovation and scale, which may otherwise not be provided by the market at pace.

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162 We note that the SRMC of each technology is a combination of our technological assumptions related to efficiency, carbon prices, and modelled wholesale gas and wholesale hydrogen prices.

163 We discussed our carbon price assumptions in **Chapter 4B**.

7.27. Notably, different jurisdictions have so far sought different types of regulatory support mechanisms for production technologies, ranging from a Contracts-for-Difference style contract in the UK, to a fixed premium support in the EU, and with a focus on loan guarantees and tax credits in the US.[164]

7.28. In addition to hydrogen production technologies, regulatory support mechanisms are also being developed in other areas of the hydrogen value chain, including storage, hydrogen transport, and hydrogen-to-power assets. Similar mechanisms are being developed for other parts of the necessary infrastructure for CCUS projects including CCS transport and storage.[165]

7.29. The purpose of this section is not to evaluate the existing support mechanisms, but to comment on the potential *implications of future support mechanisms,* in the context of an energy system with mature and highly integrated electricity, gas and hydrogen markets. We discuss the implications of the following hydrogen technologies below — green electrolyser production, blue hydrogen production and hydrogen-to-power.

Green electrolyser production

7.30. A potential challenge to the economics of green hydrogen production is that the input energy costs for electrolysers could be significant, due to relatively high electricity input prices, though there is much uncertainty surrounding this component of electrolyser costs. There have been many assessments into the economics of green hydrogen, including a recent study by McKinsey which found that clean hydrogen production costs have increased, driven by higher plant, financing and electricity costs.[166] Specifically, their study estimating the LCOH concludes that input energy costs contribute to almost half of the entire cost of electrolysers, based on an example from the US Gulf Coast.

7.31. However, in the context of a high-renewables scenario, the potential focus of green hydrogen production in certain periods and locations where the value of wholesale electricity prices is low offers an opportunity to reduce the input energy cost materially. For example, Figure 7-9 below shows the breakdown of electrolyser production costs, based on the McKinsey study mentioned above, and our modelling outcomes for on-grid electrolysers. Note that the two cost stacks are not directly comparable due to different cost and technical assumptions as well as different calculation approaches — nonetheless, we believe they serve as useful reference estimates to observe the relative size of each component.

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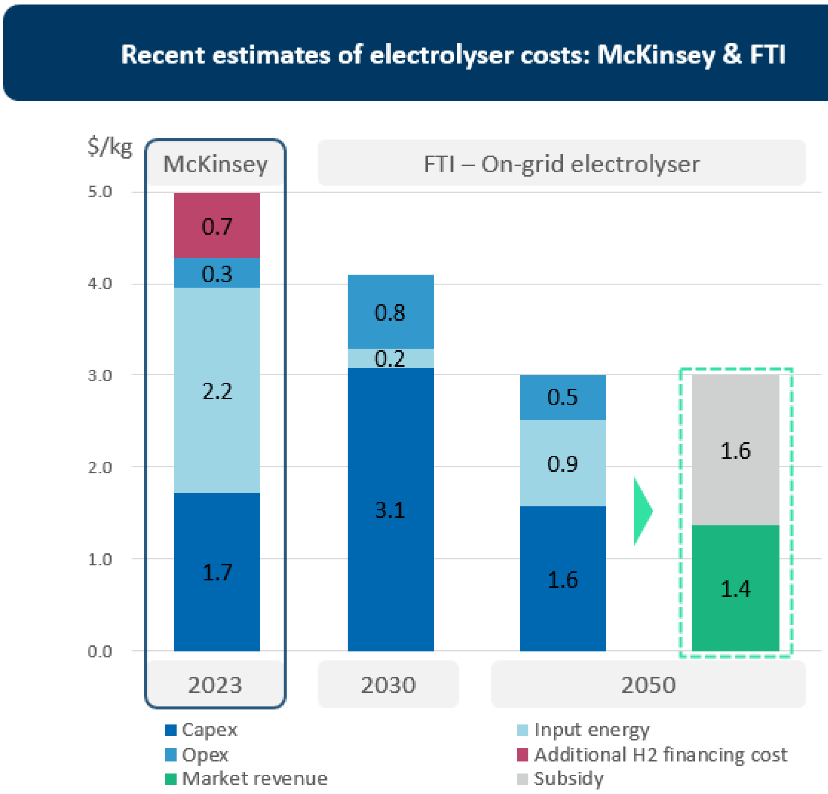
[164] See *Contracts for Difference*, 2023, DESNZ (link); *Commission launches first European Hydrogen Bank auction with €800 million of subsidies for renewable hydrogen production*, 2023, European Commission (link); *Clean Hydrogen Production Tax Credit (45V) Resources*, 2023, US Department of Energy (link).

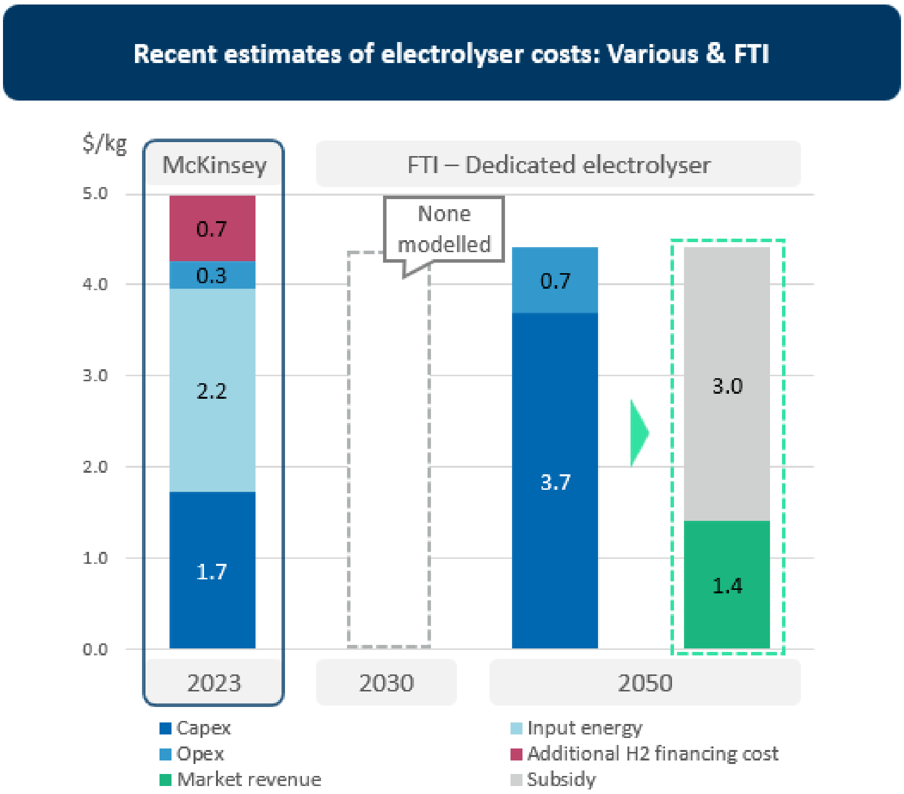
[165] See for example *The Carbon Capture and Storage Infrastructure Fund*, 2021, BEIS and DESNZ (link).

[166] See *Hydrogen Insights 2023: The state of the global hydrogen economy, with a deep dive into renewable hydrogen cost evolution*, McKinsey & Company & Hydrogen Council (link). We note that this study by McKinsey was included in a recent article in the Financial Times, see *Lex in depth: how the hydrogen hype fizzled out*, 20 May 2024, Camilla Palladino (link).

Figure 7-9: Breakdown of estimated electrolyser production costs[167]



[167] Our assessment considered input assumptions from 2022 which was the latest available at the time of the start of our assessment. We recognise that some cost estimates, particularly on electrolyser Capex (and associated financing costs) has increased significantly since then. These updates, which decreases the potential competitiveness of hydrogen technologies vis-à-vis other alternatives do not materially affect our assessment.



Sources: McKinsey; and FTI Consulting analysis.
Notes: McKinsey updated estimates based on 2023 US Gulf Coast data;[168] and FTI Consulting estimates are based on 2021 cost assumptions from DESNZ, inflated to 2023 using CPI and converted to USD.[169]

7.32. While the two figures are not directly comparable, due to different Capex and technical assumptions,[170] the chart above sets out a helpful reference on how the *relative size* of electricity costs could be reduced in a developed hydrogen market. For reference:

- As shown in Figure 7-9 above, McKinsey estimates the LCOH to be $5/kg, based on a US Gulf Coast example in 2023. McKinsey's estimates of Capex include the cost of capital for dedicated solar PV and wind capacity "behind-the-meter", which they assume feeds into the electrolyser. The additional H2 financing cost is driven by a 3-5 percentage point increase in the risk-free rate.[171]

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[168] See *Hydrogen Insights 2023: The state of the global hydrogen economy, with a deep dive into renewable hydrogen cost evolution*, 2023, McKinsey & Company & Hydrogen Council (link).

[169] Exchange rate used as of date: 1 GBP = 1.27 USD Source: *GBP-USD X-Rate*, 6 June 2024, Bloomberg (link).

[170] It is not entirely clear to us what McKinsey's detailed approach to calculating the estimates above is. For example, while McKinsey state they assume "*dedicated solar PV and wind capacity "behind the meter"* [feed] *into the electrolyser"*, it is not clear how the relevant Capex are represented in the cost stack, or what the electricity input cost component represents. Therefore, a direct comparison is not possible.

[171] See *Hydrogen Insights 2023: The state of the global hydrogen economy, with a deep dive into renewable hydrogen cost evolution*, 2023, McKinsey & Company & Hydrogen Council (link).

- Our 2030 estimate for the unit cost of green hydrogen production is around $4.1/kg, which is about 80% that of McKinsey's 2023 estimate of $5/kg. The Capex shown for our 2030 estimate in the figure only covers the cost of capital for on-grid electrolysers.[172]

7.33. A significant portion of the differences between cost estimates lies in the input energy (electricity) cost. Our 2030 estimates are based on on-grid electrolysers, which we have assumed optimise operations according to the prevailing wholesale electricity market conditions, benefiting from low-price hours to power green hydrogen production. Consequently, only c.5% of our total unit costs are attributed to input energy, compared to c.45% in McKinsey's 2023 estimate.[173]

7.34. Looking ahead to 2050, we anticipate an increase in input costs: as the wholesale hydrogen price rises due to increased hydrogen demand, the capacity factor of electrolysers rises (see **Chapter 7A**), and on-grid electrolysers start to operate in hours with slightly higher wholesale electricity prices given that wholesale hydrogen prices are even higher. As a result, the average input electricity costs for on-grid electrolysers rises to $0.9/kg, making up c.31% of total unit costs. In contrast, Capex is expected to decrease as the technology advances, leading to lower Capex per unit when combined with the higher capacity factor.[174]

7.35. In the last bar to the right of Figure 7-9, we also show the estimated revenue and subsidy breakdown next to the 2050 cost estimates, based on the expected market revenue for on-grid electrolysers relative to total production costs. Specifically, our modelling outcomes suggest that in 2050, c.46% of total unit costs for on-grid electrolysers could be recovered through market revenue, with the remaining portion requiring government subsidies at around $1.6/kg.[175]

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172 We use unit Capex and Opex cost assumptions for PEM electrolysers (High scenario) from *Hydrogen production costs 2021*, 2021, DESNZ (link).

173 The analysis in this report does not include the costs of any CfD supplier levy contributions from on-grid electrolysers.

174 See *Hydrogen production costs 2021*, 2021, DESNZ (link): Page 18.

175 Recent hydrogen production auctions for support in GB and EU also provide useful indications on the current LCOH. The GB HAR1 auction round held in 2023 implies an LCOH of c.£9.5/kg, of which about two-thirds will government funded (link, based on our calculations). On the contrary, the EU's first hydrogen bank auction results have set a much lower volume-weighted subsidy at c.£0.39/kg (link). While the latter may imply a much lower LCOH, some of the differences may be explained by greater risk being placed on the offtaker (through greater obligations on them), or the greater anticipation of *additional* support mechanisms (while the GB CFD regime restricts them). These indicators further highlight the challenges of a direct comparison but provide insights on the implications of the design of support mechanisms.

7.36. Furthermore, our current assessment at this stage does not capture any of the wider potential impacts of on-grid electrolysers on the energy system. Specifically, from an electricity system perspective, electrolysers could function as a *flexible demand technology*, which can be utilised to manage the network more effectively, for example, by consuming electricity that would otherwise be curtailed.[176]

7.37. One means of doing so is to allow electrolysers to participate in the Balancing Mechanism, which would both *reduce* the cost to electricity consumers by reducing constrained-off payments to renewables as well as to provide an *additional* revenue stream by bidding to consumed near-zero electricity that would otherwise be curtailed. This is likely to be more advantageous to electrolysers located in more remote, electricity export-constrained areas such as Scotland. In addition, locational electricity prices obviously also provide cost advantages to electrolysers located in lower-priced areas.

7.38. Incentivising the optimal use of electrolysers presents a series of challenges to industry and policymakers. Notably:

- On a commercial level, electrolysers that only operate when wholesale electricity prices are low, would mean a lower capacity factor overall. This might mean an overall lower reduction in total revenues, increasing the LCOH (i.e. the average cost over the lifetime of an asset on a cost per unit of hydrogen basis). Such a business model may not *prima facie* be viable to investors without greater “out-of-market” regulatory support to cover the investment cost.
- On a technical level, this would only apply to electrolysers that can respond quickly to electricity prices on a temporally granular basis. We understand that this currently favours PEM electrolysers over alkaline electrolysers, despite the latter having lower upfront costs.
- Additionally, the value of electrolysers in the energy system is also predicated on the extent of the hydrogen networks and level of hydrogen storage. An interconnected hydrogen network, and sufficient hydrogen storage, enables electrolyser to co-locate with more remote renewables assets more easily, as hydrogen produced in periods of excess generation could be stored, and then injected more easily into the system for future use. This would then provide a higher supply of hydrogen during periods of high electricity and hydrogen demand.

[176] We also understand that some emerging electrolyser technologies are *bi-directional*, i.e. can convert hydrogen to electricity. We have not considered this in our current assessment, although such technology could be even more beneficial to the electricity system (i.e. by operating as a *de facto* hydrogen-to-power asset).

- On a market and regulatory level, the *value* of electricity at a specific location may differ from the *price* of electricity which is set nationwide. This mismatch may lead to suboptimal outcomes from a consumer perspective — for example, electrolysers located in the south of GB might be consuming electricity in response to a low national price during periods of congestion, exacerbating congestion costs. Likewise, an electrolyser located in the north of GB might be facing higher electricity input costs than it should, given the benefits of using lower cost electricity. As such, without locational wholesale electricity pricing, electrolyser operators would need to be incentivised to respond appropriately in the Balancing Mechanism, or through an administrative scheme with a similar aim (such as under Section 13k of the German Energy Industry Act 2023, referred to as "use instead of curtail")[177] — but these likely carry their own set of challenges and potential policy inconsistencies.[178]
- The design of production subsidies themselves may distort the behaviour of facilities away from economically efficient production patterns. In particular, subsidies paid based on the volume of hydrogen produced (as opposed to on the basis of production capacity available) may over incentivise production, even at times when it is economically inefficient to do so, and may have detrimental consequences for the system (e.g. in pushing up electricity prices).

7.39. Therefore, policymakers face two broad challenges in designing a regulatory support mechanism to optimise the benefits of electrolysers. These are:

- First, to develop approaches to optimise the co-location of electrolysers to where they are best suited — either through central planning or market-based incentives. This would need to consider a set of trade-offs, namely the benefits of locating near areas with export-constrained renewables and the benefits of locating near areas of hydrogen consumption (e.g. near clusters).
- Second, to develop approaches to optimise the utilisation of electrolysers to produce when most beneficial to the electricity to do so (whether in response to locational wholesale prices, the Balancing Mechanism, or other regulatory interventions).

7.40. As such, the design and implementation of regulatory support mechanism should consider addressing these challenges, both in terms of how they are allocated to developers, and the incentives they might place in electricity dispatch. Relatedly, the regulatory support mechanisms for the required storage and transport infrastructure are discussed in the chapter below.

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177 See *Use instead of curtail*, Netztransparenz (link).

178 For example, an electrolyser located in the north of GB that may expect to be paid a greater amount to switch on in the Balancing Mechanism may choose to *withhold* electricity consumption in the wholesale market, while the lack of technological neutrality under Section 13k may introduce additional distortions across energy users.

Blue hydrogen production

7.41. In many ways, the optimal use of blue hydrogen production is more straightforward than green hydrogen production given that gas input prices are assumed to be lower, and the technology is likely to have limited ability to ramp up and down in response to prices, as well as greater restrictions in where they might be located.

7.42. However, the ability of blue hydrogen assets to ramp up and down, despite relatively inflexibility, is still potentially a useful feature, to serve seasonal or monthly swings in hydrogen demand (playing a role akin to that of hydrogen storage).

7.43. From a policy perspective, the benefits of green hydrogen production and blue hydrogen production differs in several ways in addition to the production cost itself. While green hydrogen production has the potential to be highly complementary with renewables optimising the use of electrolysers faces several challenges as highlighted above — not least the need for interconnected hydrogen pipelines and storage. On the contrary, blue hydrogen production may have a comparative advantage when there is a lack of such hydrogen infrastructure and where hydrogen demand is more localised (albeit requiring CCUS infrastructure to be in place). This may arise in the transitionary phase as the hydrogen backbone develops, or in a scenario where hydrogen demand is mostly baseload and centred around specific areas.

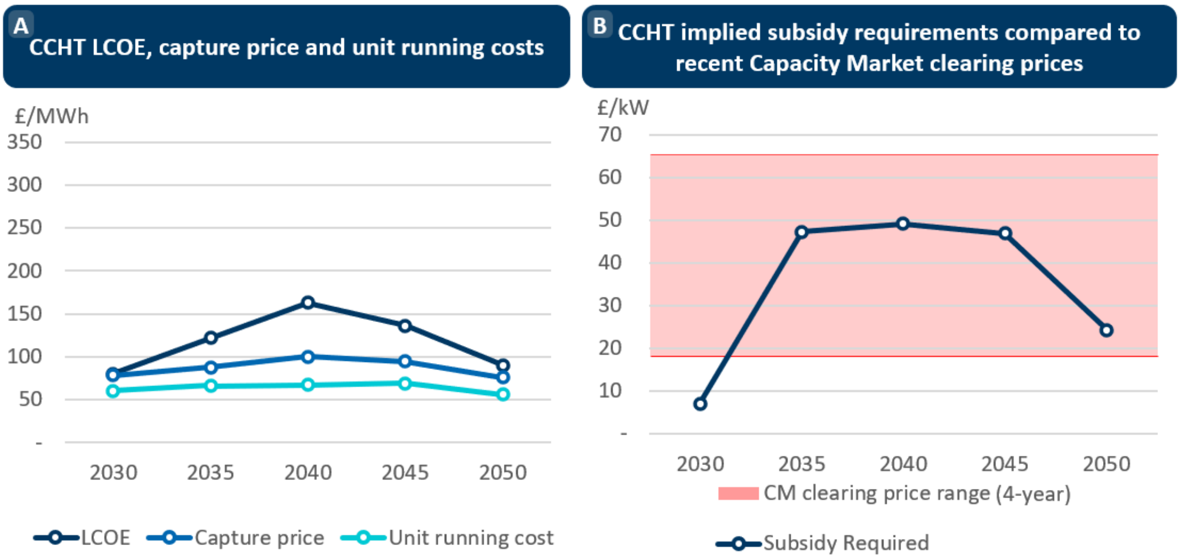
Hydrogen-to-power

7.44. As discussed above, while we have assumed that H2P assets have a similar cost to CCGTs and OCGTs, it is likely that the carbon price would not be sufficiently high to incentivise the market to switch to such assets without regulatory intervention. This is evident in our assessment where CCGTs were still the most economic dispatchable capacity available to meet very peaky wholesale electricity prices, as shown in Figure 7-8 in the 2040s, despite the prevailing, assumed, carbon price. However, when considering low-carbon alternatives to CCGTs, it is increasingly apparent that H2P may be the only viable technology currently available.[179]

7.45. To assess the implications for regulatory support for H2P assets, Figure 7-10 and Figure 7-11 below shows the unit running cost (based on wholesale hydrogen prices paid), capture prices (based on the wholesale electricity prices paid), and the levelised cost of electricity ("**LCOE**") (which includes the unit running costs, and the Capex and operational expenditure "**Opex**" of H2P generators), to determine the implied subsidy required for H2P assets (CCHT and OCHT, respectively). We also compared this subsidy required to recent Capacity Market auction results.

[179] We previously discussed that batteries tend to be limited by shorter duration and that CCS Gas power plant have cost structures that are less suited for peaker operational profiles, due to its high Capex.

Figure 7-10: A) CCHT LCOE, capture price and unit running costs (£/MW), and B) CCHT implied subsidy requirements compared to recent Capacity Market clearing prices (£/kW)



Source: FTI Consulting analysis; and National Grid NESO.[180]

7.46. As shown in Figure 7-10-A above, CCHT generators can recover all of its input energy costs as its unit running cost is always lower than its capture price.[181] This is akin to the existing “spark spread", i.e. an “H2 spark spread”.[182] However, given that CCHT’s LCOE always exceeds its capture price, CCHT generators can only partially cover its fixed costs. Overall, this means that the revenues CCHT generators make on the wholesale electricity market are only sufficient to cover its total costs partially, implying that subsidy payments would be required to support power generation for CCHTs.

7.47. We show this implied subsidy requirement in Figure 7-10-B, which is based on the revenue required to make up the shortfall between CCHT’s capture prices and LCOE, as well as its capacity size. Comparing these implied subsidy requirements to recent Capacity Market auction results suggests that CCHT generators are likely to be reasonably competitive in the capacity market, as the subsidy required lies within the range of recent clearing prices.

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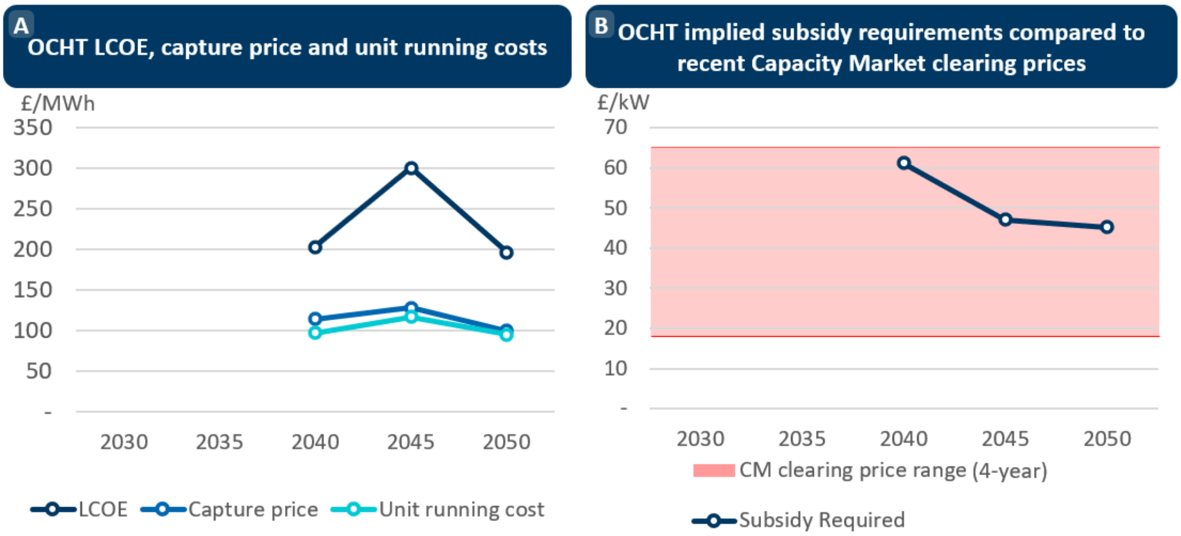
[180] We use the range of four years of T-4 Capacity Market auction results from 2020/21 to 2023/24. See National Grid NESO (link).

[181] Having unit running costs lower than the capture price means that the wholesale price at which CCHTs buy hydrogen is always lower than the wholesale price they receive from generating and selling electricity.

[182] “Spark spread” represents the theoretical gross margin of a gas-fired power plant derived from selling electricity having bought the natural gas to produce this electricity. See *UK Spark Spread — ICE*, Intercontinental Exchange (link).

Figure 7-11: A) OCHT LCOE, capture price and unit running costs (£/MW), and B) OCHT implied subsidy requirements compared to recent Capacity Market clearing prices (£/kW)



Sources: FTI Consulting analysis; and National Grid NESO.[183]

7.48. As shown in Figure 7-10-A above, the running costs of OCHT generators are only observable from 2040 onwards as no capacity is operational until 2040, as discussed in **Chapter 6A** and shown in Figure 6-3. Similar to the H2 spark spread observed for CCHT generators, OCHT generators also recover all of its input energy costs but only partially cover its fixed costs. However, unlike CCHT generators, the gap between OCHT's LCOE and capture prices is significant due to low capacity factors where typically generates in response to peak wholesale electricity prices, implying that subsidy payments would be required to support its power generation during periods of peak stress on the electricity system.

7.49. We show the implied subsidy requirements for OCHTs in Figure 7-10-B, which is based on the revenue required to make up the shortfall between OCHT's capture prices and LCOE, as well as its capacity size.[184] These implied subsidy requirements suggest that OCHT generators would require a capacity payment that lies within the range of clearing prices in recent Capacity Market auctions. This is especially true in the latter half of the modelling period, when OCHT capacity is expected to increase significantly, as shown in Figure 6-3-A.

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183 We use the range of four years of T-4 Capacity Market auction results from 2020/21 to 2023/24. See National Grid NESO (link).

184 We note that although the required subsidies for OCHT's may be large in absolute terms, the significant increase in OCHT capacity over the latter half of the modelling period reduces the subsidy size required on a per kW basis.

7.50. Overall, the subsidies required to support H2P assets in our analysis suggests that the implied subsidy required for H2P plants could be similar to the current level of prevailing capacity market payments. We note that this is especially true in the context of our scenario modelled, and our key modelling assumptions. As discussed in **Chapter 6A** and shown in Figure 7-8, H2P assets sometimes fall behind unabated gas-fired generators in the merit order due to both very low wholesale gas prices (which is driven by the FES assumptions that we have adopted on the declining use of gas, and seasonal wholesale hydrogen prices to meet high power demand).

7.51. The variability and seasonality of wholesale hydrogen prices means that hydrogen-to-power generation may change position in the electricity merit order regularly — sometimes displacing unabated gas-fired generation and in other times remaining at the highest end or the merit order. As mentioned in **Chapter 5D**, the development government policy on potential specific support investment for H2P is still in progress. Additionally, policymakers are considering whether any intervention is needed to influence the merit order of H2P in comparison to, for instance, unabated gas generation.[185]

7.52. Similarly, given the rapid development of technologies, and that peakier electricity periods may mean lower capacity factors of dispatchable generation capacity, policymakers may wish not to introduce any bias between larger CCHTs and smaller OCHTs in any policy support mechanisms.

7.53. Notably, the financial viability of hydrogen-to-power, and, in turn, the level of regulatory support required is significantly linked to the amount of hydrogen storage on the system. We discuss the role of hydrogen storage in supporting a Net Zero energy system in **Chapter 8** below.

[185] See *Hydrogen to power: market intervention need and design*, 2023, DESNZ (link).

8. The role of hydrogen storage and transport in supporting a Net Zero energy system

8.1. In the previous chapter, we explored the interactions between the three energy vectors further, and in particular the direct relationship between electricity and hydrogen through both on-grid electrolysers and H2P. One element of this is the intertemporal dynamics that arise in both markets, and notably both short and longer-term (e.g. seasonal) volatility.

8.2. In this chapter, we focus on the potential critical role of hydrogen network infrastructure to develop and deliver a hydrogen market to decarbonise the energy system. In particular, we explore:

- The complementary role played by hydrogen transport in a nationwide energy system (**Section A**).
- The hydrogen flows from our modelled scenario compared to historical natural gas flows for the purposes of comparison (**Section B**).
- The role of large-scale hydrogen storage, and its direct relationship to these intertemporal dynamics (**Section C**); and
- The impact of different volumes of hydrogen storage on the energy system (**Section D**).

A. Overview of the role of hydrogen networks

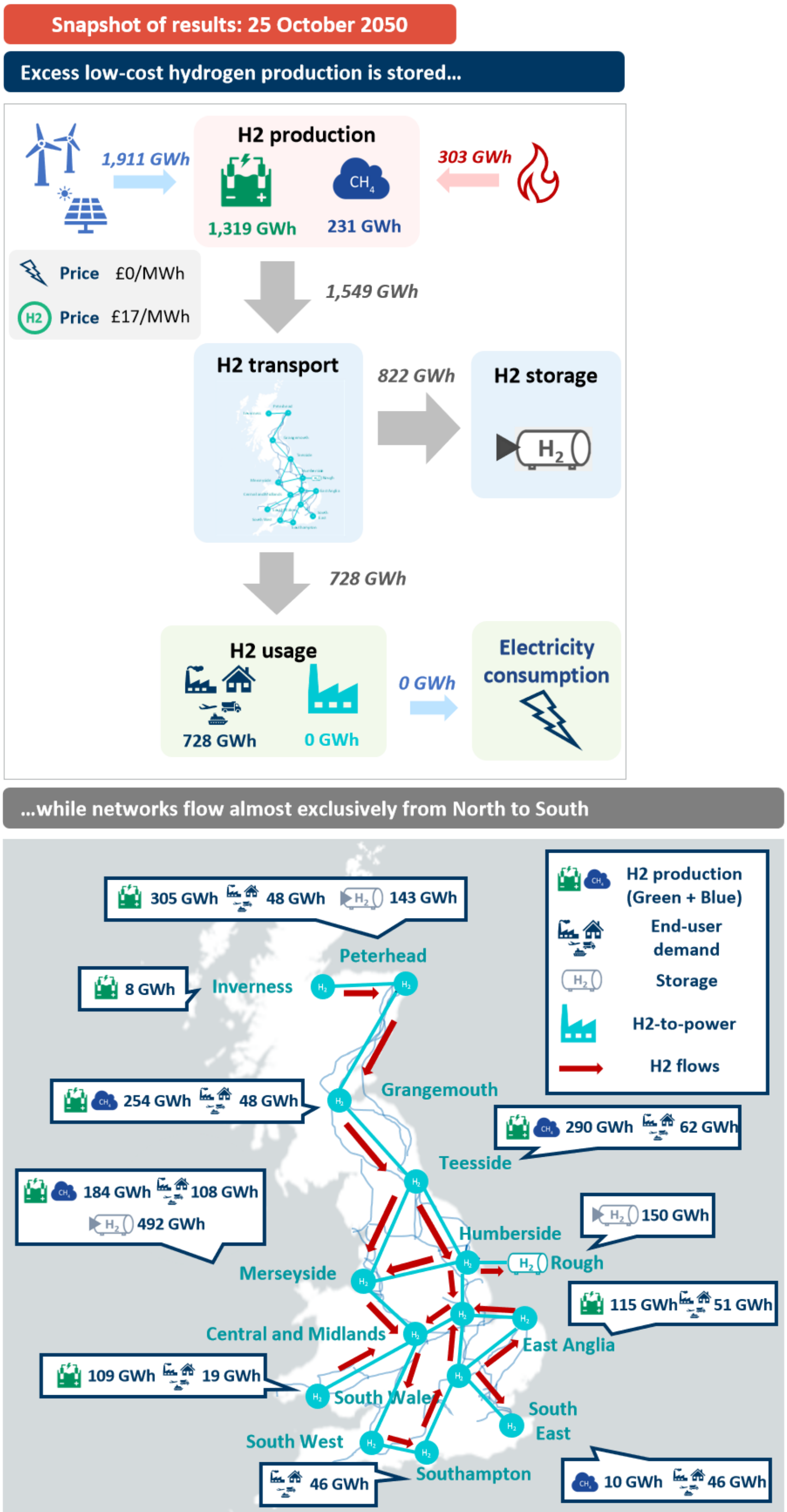
8.3. The hydrogen backbone is conceived as a vital part of the future hydrogen economy, facilitating the transport of hydrogen to and from supply and demand centres, and matching the *locational* variation in supply and demand.

8.4. The backbone is intended to be introduced to connect the various assets in the hydrogen value chain including hydrogen production assets, hydrogen storage assets and consumers of hydrogen including industries and power generation. The backbone therefore would improve the accessibility and ease to provide *offtake* for hydrogen production, currently one of the largest barriers to the hydrogen industry. Together with hydrogen storage, the backbone is envisaged to improve the ease for hydrogen to be produced and consumed when it is most economic to do so.

8.5. In the previous section, we discussed wholesale price trends across each market, and observed price volatility in the electricity and hydrogen market, as well as strong seasonal trends later in the modelling period. We demonstrate how the hydrogen backbone facilitates flows across the hydrogen value chain and, in turn with other energy vectors, under *different* weather conditions. Figure 8-1 and Figure 8-2 below show flows of hydrogen across the hydrogen backbone on a windy day and a low-wind day in 2050, respectively.

Example 1 — A windy day in 2050

Figure 8-1: Hydrogen flows on a windy day in 2050



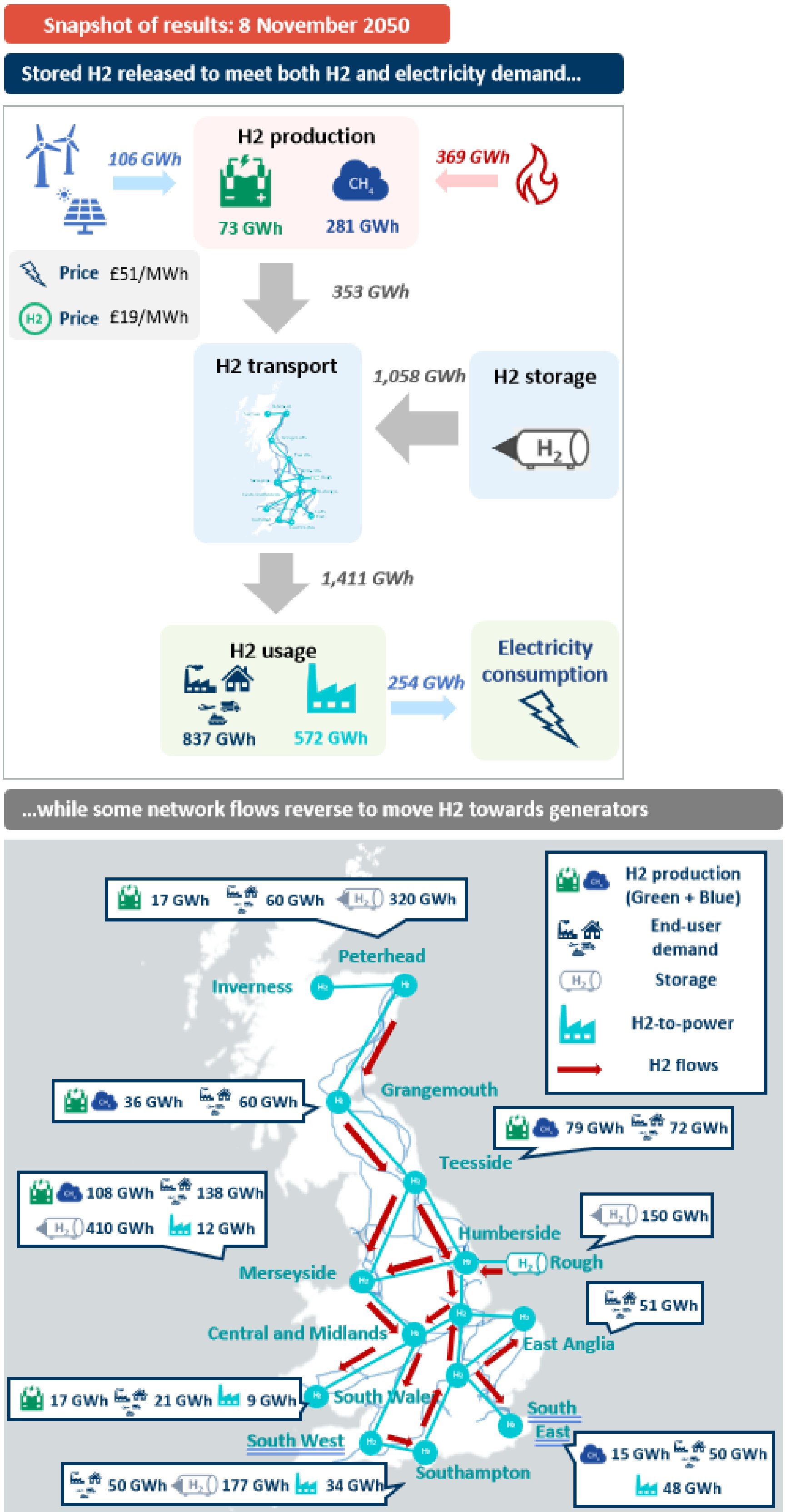
Sources: FTI Consulting analysis.

8.6. As Figure 8-1 shows, on a windy day, in this case the 25th of October 2050:

- Both the wholesale electricity and wholesale hydrogen prices are very low, at c.£0/MWh and c.£17/MWh, respectively.
- Wind farms generate electricity priced at near-zero, supporting large amounts of green hydrogen production along the coast of GB at very low input costs.
- The hydrogen produced serves local end-user demand and storage sites initially, then the excess hydrogen is transported from the North of GB to the South where much of hydrogen demand is located.
- Notably, on this day, H2P generation is not required despite the excess hydrogen supply. This is because given it is a windy day, low-cost renewable generation is very high, and can meet all GB electricity demand at low-cost (the marginal cost of wind generation is £0/MWh). Therefore, the national wholesale electricity price is close to £0/MWh and so H2P generators are uncompetitive.
- Overall, c.47% of hydrogen supply is consumed by industrial and consumer demand, the remaining c.53% is injected into hydrogen storage sites, in which market participants are assumed to buy hydrogen at low wholesale prices with a view to sell this later at times of relative hydrogen scarcity, and therefore higher wholesale hydrogen prices.

Example 2 — A low-wind day in 2050

Figure 8-2: Hydrogen flows on a low-wind day in 2050



Sources: FTI Consulting analysis.

8.7. As Figure 8-2 shows, on a low-wind day, in this case the 8th of November 2050:

- The wholesale electricity price rises to c.£51/MWh due to the lack of low-cost renewables generation.
- Green hydrogen production is largely suspended, as grid-connected electrolysis is not economic due to high wholesale electricity prices and non-grid-connected electrolysis is low due to low-wind, while blue hydrogen continues to operate as the wholesale gas price remains unaffected.
- In order to fill the supply gap for end-user demand, previously stored hydrogen across various storage sites is withdrawn. The storage withdrawals from hydrogen storage sites help to stabilise the wholesale hydrogen price, which is only c.£2/MWh higher than wholesale prices on the high wind day on the 25th of October, which is only 14 days earlier (see Figure 8-1).
- Crucially, this demonstrates the role of hydrogen in helping to provide flexibility and security of supply to the whole energy system, as hydrogen storage withdrawals support the competitiveness of H2P plants in electricity generation, ensuring that power demand is still served despite the lack of renewables power generation.

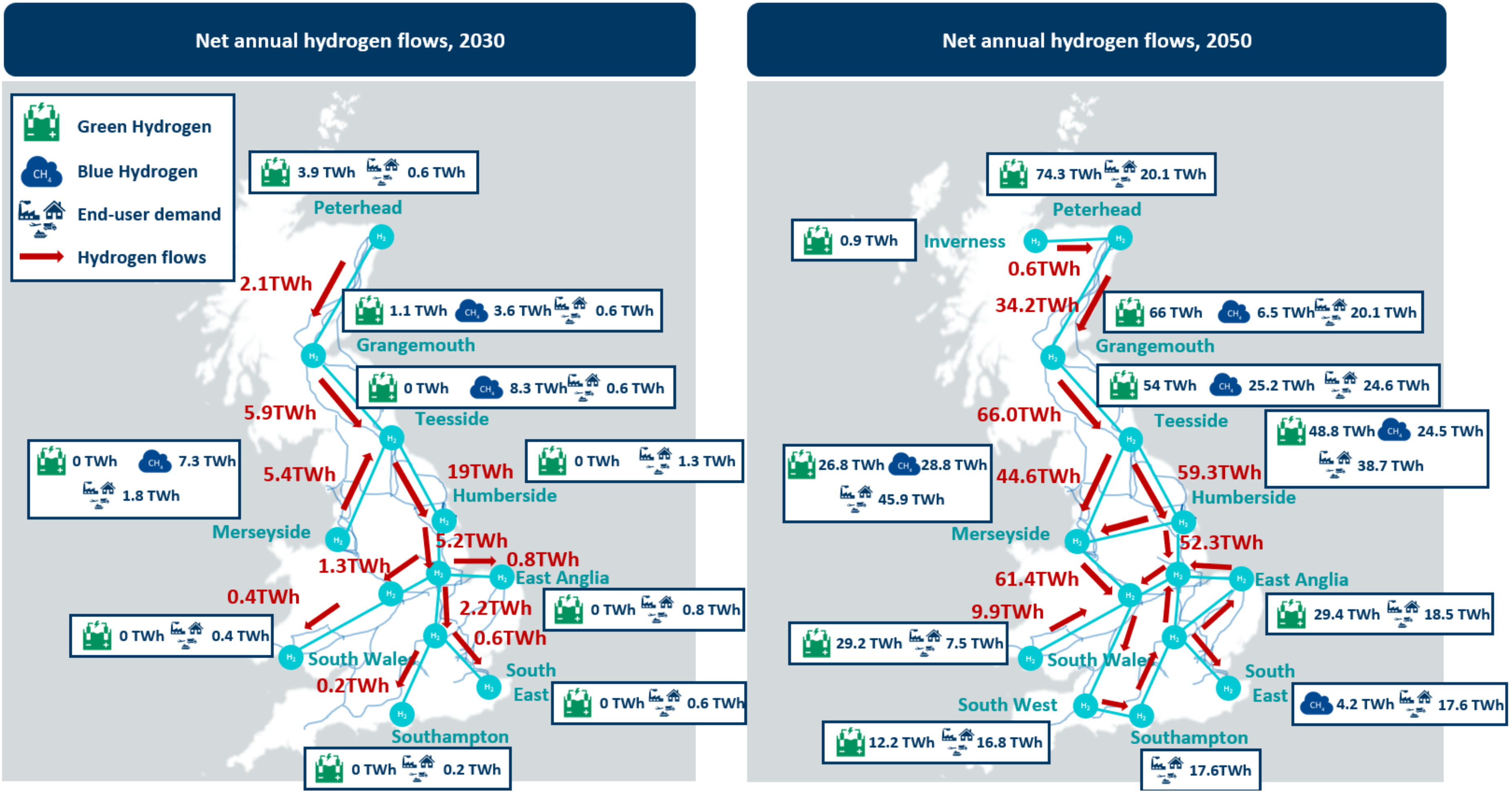
8.8. Overall, Figure 8-1 and Figure 8-2 above show that there are significant flows across the hydrogen backbone, and these generally flow in the direction of north to south. This is particularly true on a windy day in 2050, as large volumes of green hydrogen production in the north (where a large amount of wind capacity is assumed to site), flows to hydrogen demand located in the south, or large hydrogen storage sites located in the midlands. On a low-wind day in 2050, the direction of hydrogen flows is still largely north to south, though the direction of flow on certain sections of the network switches, such as on the South Wales to Central and Midlands section. This is a result of the need to flow hydrogen towards H2P generators, which, combined with significant withdrawals from hydrogen storage, act to provide security of supply to the power sector on a day with low renewables generation, and so ensure that energy demand across the whole energy system is served.

8.9. The clear patterns in the direction of hydrogen flows across the hydrogen backbone is due to the location of hydrogen demand and supply centres, as well as the whole-systems dynamics related to interactions between the hydrogen and electricity markets. We discuss these patterns in hydrogen flows in **Section B** below, by assessing hydrogen flows on an annual basis.

B. Hydrogen flows and comparison with historic gas pipeline flows

8.10. In our assessment, we observe significant north to south flows over the backbone, due to the locational mismatch of supply and demand and large volumes of green hydrogen production in Scotland. Figure 8-3 below shows modelled annual net hydrogen flows in the system, for 2030 and 2050, respectively.

Figure 8-3: Net annual hydrogen flows, 2030 and 2050 (TWh)



Sources: FTI Consulting analysis.

8.11. As Figure 8-3 illustrates, the largest modelled flows are between Grangemouth, Teesside, and Humberside — in order to move both green and blue hydrogen close to end-user demand and H2P demand. As we move towards 2050, there are increased net flows from Scotland to England to transport green hydrogen to the key hydrogen demand centres.

8.12. In addition, across time there are changes in the direction of flow between certain sections of the backbone. For example in 2030, there are annual net flows of c.0.4 TWh from West Midlands to South Wales; however by 2050, these flows reverse such that there are net flows of c.9.9 TWh from South Wales to the West Midlands.

8.13. This is driven by the increase in electrolyser capacity in South Wales, which results in greater green hydrogen production and so hydrogen supply out of South Wales, as shown by the increase in green hydrogen production from c.0 to c.29.2 TWh.

8.14. To assess the viability of this from a pipeline capacity perspective,[186] we compared daily hydrogen flows from our modelling outcomes to daily 2022 gas flows from the National Gas database.[187] This also serves as a cross-check of our modelled hydrogen flows to sense whether they appear reasonable compared to 2022 gas flows. Figure 8-4 below shows the cross-check we performed regarding modelled hydrogen flows across the hydrogen backbone based on our modelled scenario, through comparing modelled hydrogen flows with scaled 2022 gas flows.

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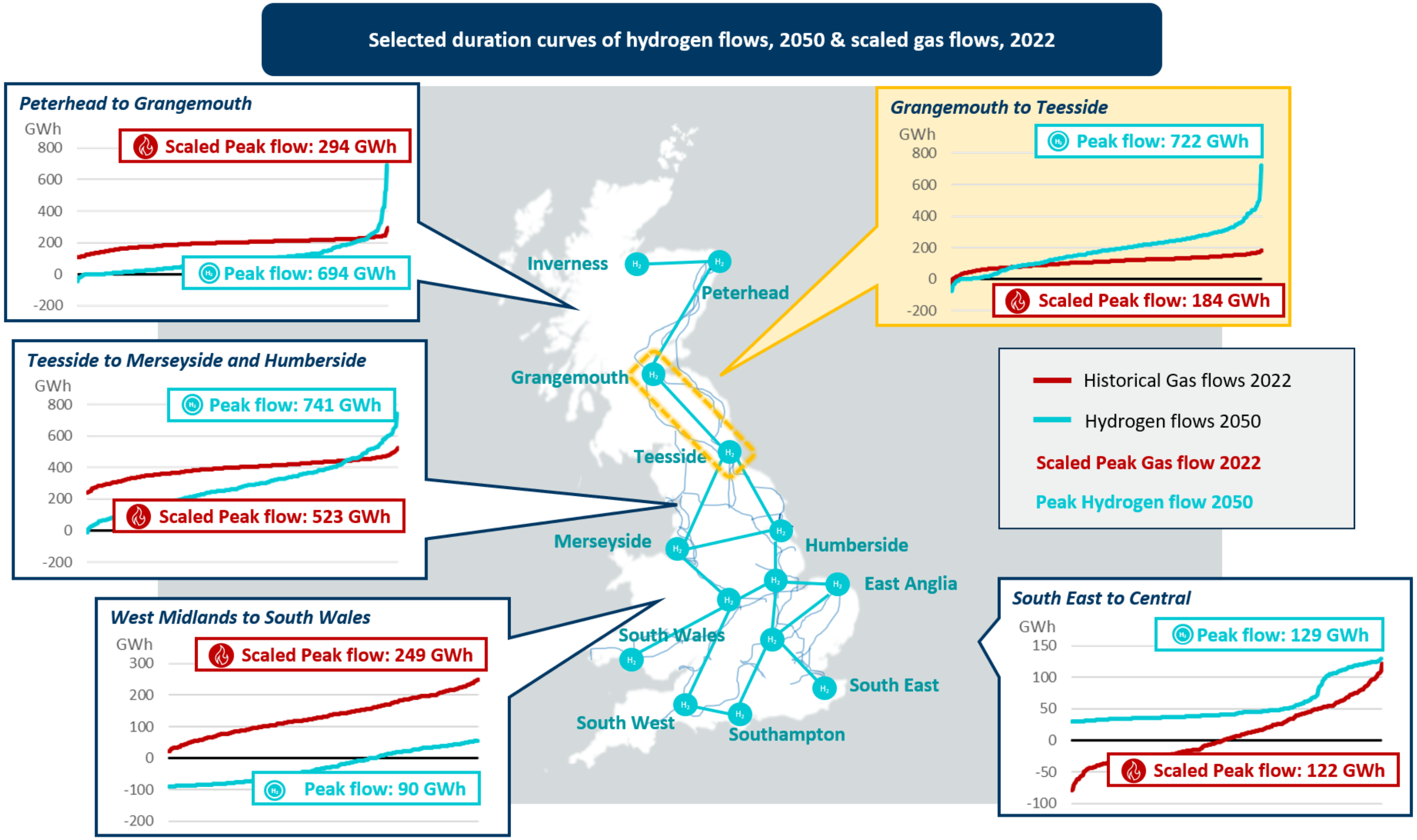
186 We note that a critical challenge regarding the hydrogen backbone and the Project Union initiative is how to facilitate the transition from gas to hydrogen. Specifically, if the hydrogen backbone is to repurpose existing gas assets, this will reduce the capacity of the existing gas transmission network. This is especially true during the early stages of the roll-out of the hydrogen economy, when natural gas demand is still high, and so the system will require two sets of parallel transmission networks — one for hydrogen and one for gas.

187 The data covers gas supply and demand at LNG ports, terminals, interconnectors, storage, industrial offtake, and Local Distribution Zone (“**LDZ**”) offtake. We allocate each of these data items to a node in our analysis and net off supply and demand to calculate net annual and daily gas flows between regions. Note that peak historical flows may not reflect maximum capacity.

Figure 8-4: Selected daily duration curves of hydrogen flows (GWh), 2050 & scaled daily 2022 gas flows (GWh), 2022



Sources: National Gas; and FTI Consulting analysis.

Notes: Scaled peak gas flows are calculated by summing daily excess supply (relative to daily demand) at each gas terminal on the NTS, to proxy daily gas flows between sections. We then divide this result by three for the purposes of comparison with modelled hydrogen flows, to account for the greater energy density of gas, which is approximately three-times that of hydrogen.

8.15. As Figure 8-4 illustrates, our modelled peak hydrogen flows fall below 2022 peak gas flows across most sections of the hydrogen backbone, indicating the plausibility, from a pipeline capacity perspective at least, of repurposing existing gas pipelines for the purpose of hydrogen transportation.

8.16. However, our modelled peak hydrogen flows do exceed historical peak gas flows in the Grangemouth to Teesside section, specifically for c.79% of year during 2050, which could suggest extra transmission infrastructure would be needed to support hydrogen flows across this section. Therefore, our modelling outcomes suggest that further investigation is required to fully investigate the extent of hydrogen transmission capacity required between Grangemouth and Teesside.[188]

8.17. We observe that the transport of hydrogen across the backbone, particularly from north to south GB, provides a supplementary mean to convey energy from lower-cost energy production areas (i.e. areas with high wind factors) to higher-demand areas. This means that hydrogen networks (with hydrogen storage) could be a potential *substitute* to electricity networks in the conveyance of energy — whether in the form of electricity or green hydrogen production.

8.18. We emphasise that peak daily gas flows in 2022 may not reflect actual maximum pipeline capacities, particularly with regard to the north to south flows if this section was under-utilised. Specifically, though a large portion of the NTS was designed to flow gas from the St Fergus terminal (in Scotland) to the south, with the decline of gas output from the North Sea area, this north to south gas flow has been somewhat lower in recent years. However, given that pipeline capacity still does affect historical peak flows, overall for most sections on the hydrogen backbone daily peak flows shown in Figure 8-4 appear to be reasonable, as per our modelled scenario.

8.19. In the context of significant transmission bottlenecks in the electricity system, which would seem to be exacerbated with greater renewables penetration, hydrogen networks offer the potential to alleviate some of this congestion. This is because transporting renewables-generated energy through hydrogen pipelines could be a substitute for transporting electricity through transmission wires, especially given the estimated costs of the likely reinforcements to the power transmission grid that will be required in the future.[189]

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[188] We emphasise that the scaled daily historical gas flows used in Figure 8-4 above is based on 2022 data on gas supply and demand across the NTS. Therefore, this data may be limited in its representation of historical gas flows across the NTS more generally. In addition, we have combined calculated flows across the Teesside to Merseyside and Humberside section as we could not distinguish gas flows to Merseyside and Humberside specifically, based on the data available.

[189] As discussed in **Chapter 2A**, FTI Consulting's current estimates forecast that around £114bn of investment is required for transmission reinforcements on the power network by 2037. See *Beyond 2030*, 2024, NESO (link).

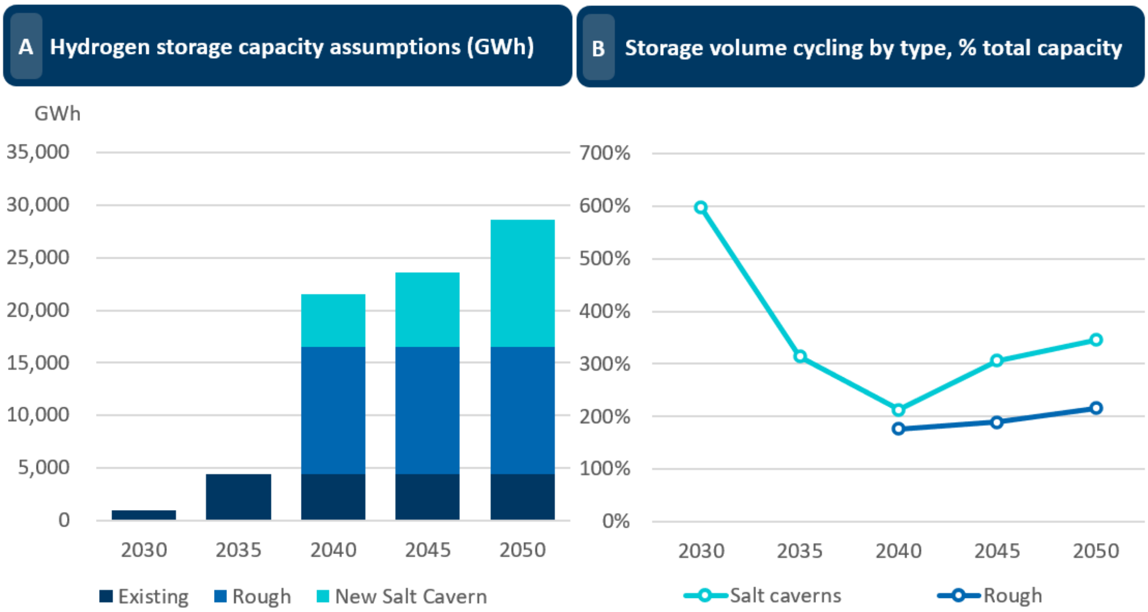
C. Role of hydrogen storage

8.20. As discussed in previous chapters, hydrogen storage facilities enable the withdrawal and injection of hydrogen into pipelines. This supports the matching of hydrogen supply and demand over longer periods, which in effect, can also match *electricity supply and demand* through the conversion of electricity to hydrogen and vice versa.

8.21. We consider two types of hydrogen storage sites: salt caverns and depleted gas fields (specifically the Rough storage facility). Based on third-party information and stakeholder feedback, we have assumed that salt caverns have higher withdrawal rates relative to their storage capacity, and so are able to inject and withdraw hydrogen more quickly compared to depleted gas fields. This means each type of hydrogen storage will have a different operating profile, which will impact its role in the whole energy system.

8.22. Figure 8-5 below shows the evolution of hydrogen storage capacity in our modelled scenario, as well as the annual cycling rates for the two types of hydrogen storage sites to give an indication of its operating profiles.

Figure 8-5: A) Hydrogen storage capacity (GWh) and B) cycling rates (%) in our modelled scenario, 2030 to 2050



Sources: FTI Consulting analysis.
Notes: We calculate volume cycling rates as total storage injections / storage capacity.

8.23. As illustrated in Figure 8-5-A, we have assumed that c.4.4 TWh of salt cavern hydrogen storage is available from 2035, which is equivalent to the current volume of existing natural gas storage. From 2040, we assume redeveloped Rough adds c.12 TWh of hydrogen storage capacity, while new salt cavern projects add a further c.5.0 TWh of storage capacity at the same time. Therefore by 2050, total hydrogen storage capacity reaches c.29 TWh by 2050.

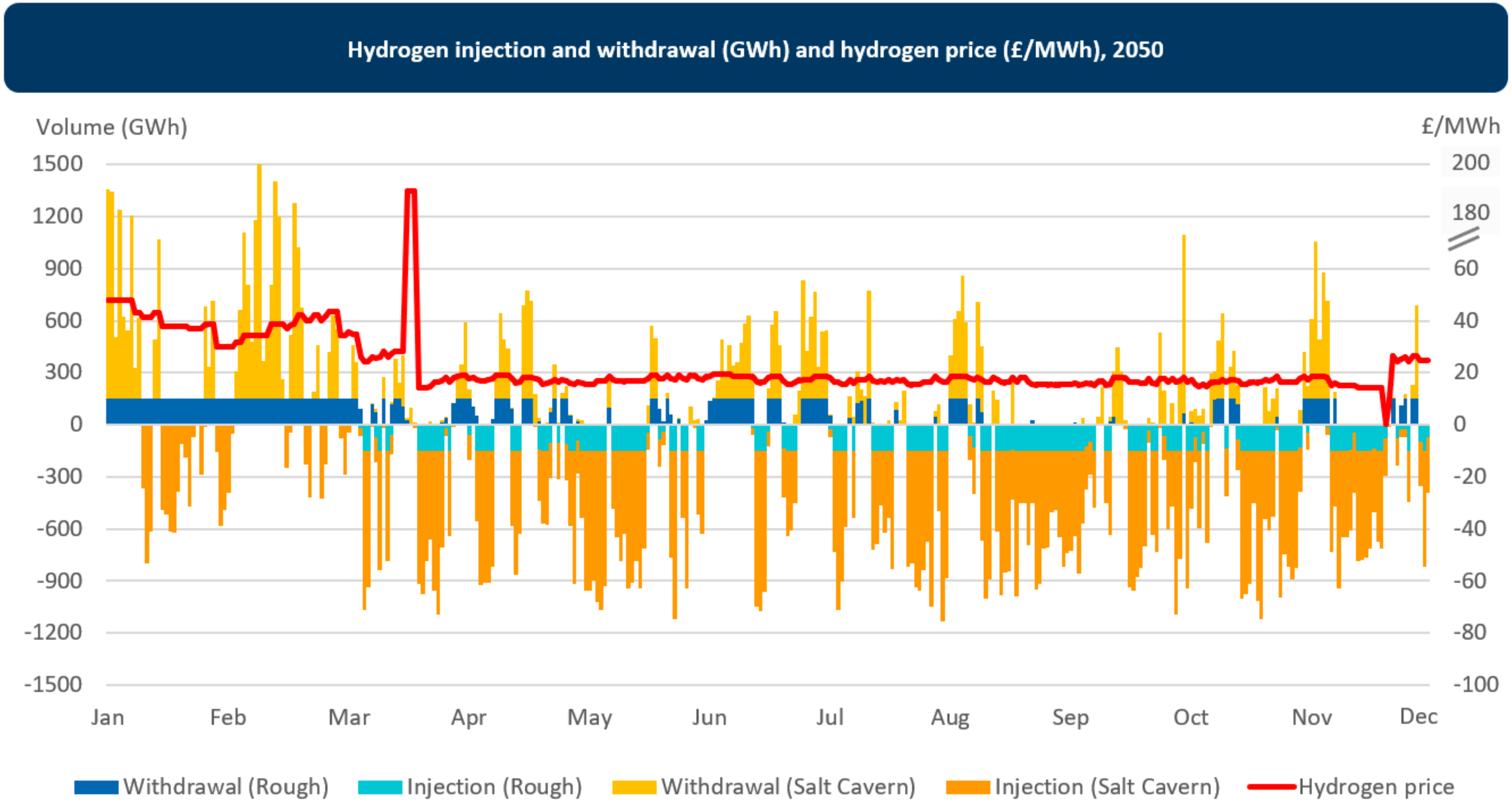
8.24. As shown in Figure 8-5-B, there is a clear difference between the volume cycling rates of salt caverns versus Rough, as salt caverns can cycle much faster than Rough. This mostly driven by technological factors, specifically:

- **injection and withdrawal speeds:** salt caverns have higher injection and withdrawal rates compared to Rough, and so fill and empty more quickly; and
- **maximum storage capacity:** salt caverns are typically of a much smaller size than Rough.

8.25. In 2030, salt caverns cycle through hydrogen volumes at c.6x their storage capacity. Thereafter, as more hydrogen storage is added to the system total utilisation of salt caverns falls to c.2x to c.3.5x their capacity. In comparison, in 2040, when Rough is assumed to come online, Rough has volume cycling rates of c.2x its capacity. This rises across the remainder of the modelling period, meaning that Rough becomes more utilised as the hydrogen economy continues to grow.

8.26. To provide a more detailed picture of the operating profile and dynamics of the hydrogen storage market, Figure 8-6 below illustrates hydrogen injection and withdrawal volumes together with the wholesale hydrogen price in 2050.

Figure 8-6: Daily hydrogen storage injections and withdrawals (GWh) and wholesale hydrogen price (£/MWh), 2050



Sources: FTI Consulting analysis.

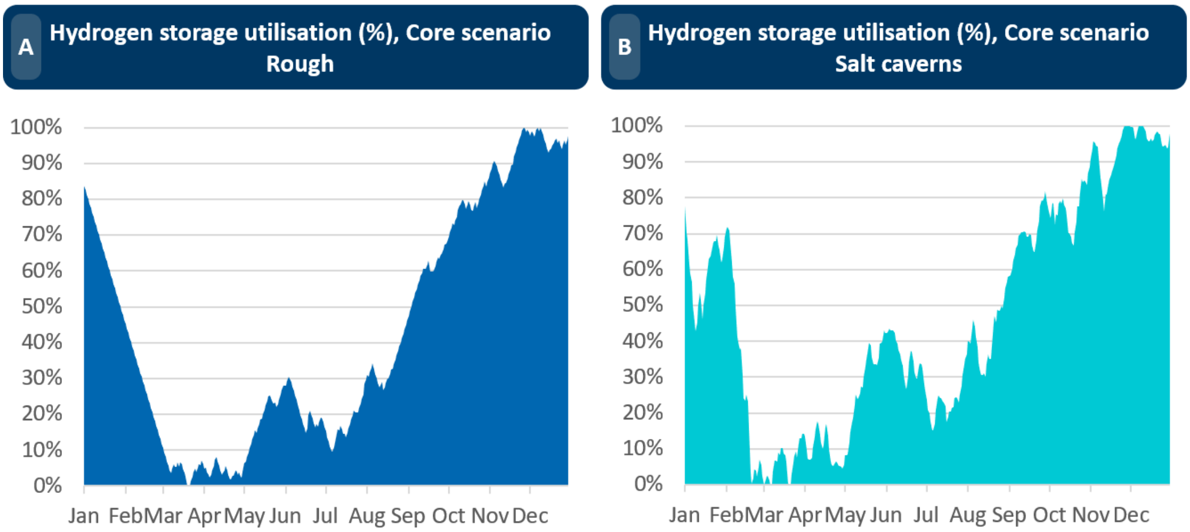
Notes: Negative volumes on the left-hand y-axis show injections into storage sites, while positive volumes show withdrawals into storage sites.

8.27. As Figure 8-6 illustrates, salt caverns can inject and withdraw a greater total volume of hydrogen across the year, due to faster injection and withdrawal rates as well as their greater total capacity when aggregated across all sites. Such fast cycling rates means that the role of salt caverns role is also more volatile, even over the course of winter.

8.28. In winter months (from January to March and from October to December), while Rough withdraws hydrogen continually, salt caverns inject significant volumes at times when the wholesale hydrogen price is relatively low. This allows salt caverns to refill, to some extent recycling the withdrawals from Rough, ready to offer faster withdrawal services during peaky higher-priced periods.

8.29. Finally, the role of hydrogen storage across the year is highly seasonal due to variation in demand for hydrogen. This is illustrated by the behaviour of Rough, during the winter months, 61% of Rough's operational activity is withdrawing to meet hydrogen demand — two times higher than it is in the summer months. The peak winter demand for hydrogen is due to end-user demand from hydrogen for heating, as well as from H2P, driven by high electrification of heat. To examine this seasonality in more detail, Figure 8-7 below shows the utilisation of hydrogen storage in our modelled scenario in 2050, for the two types of storage types.

Figure 8-7: Hydrogen storage utilisation (%) in our modelled scenario, 2050



Sources: FTI Consulting analysis.

8.30. As shown in Figure 8-7-A and Figure 8-7-B, hydrogen storage utilisation across both storage types shows strong seasonal trends, specifically:

- The utilisation of salt cavern storage capacity over time is more volatile than that of Rough, reflecting the greater rate at which hydrogen can be moved into and out of salt cavern facilities, relative to their total capacity, compared to a depleted gas reservoir on the scale of Rough.
- Hydrogen storage utilisation falls early in the year during the winter months, increases again during the spring and summer months, and reaches a peak in autumn.

- Storage utilisation then begins to fall at the end of the year as the winter period starts.

8.31. Such seasonal trends are clearly driven by the seasonality of hydrogen demand, as we discussed above. Hydrogen storage levels deplete during the winter when hydrogen demand is high and electricity demand and wholesale prices are likely to reach a peak. Then, hydrogen storage sites withdraw in order to provide extra supplies of hydrogen to the system, which acts to either meet hydrogen demand directly, or is used by H2P generators to generate electricity to support the power sector. Hydrogen storage levels then rise during the spring and summer, as hydrogen storage will inject when hydrogen demand and wholesale prices are relatively low.[190, 191]

D. Overview of the impact of reducing hydrogen storage

8.32. As discussed in **Chapter 3**, by comparing the modelling outcomes from our scenario modelled and the same scenario *less* Rough storage, we can assess the impact of Rough and reduced hydrogen storage more generally on the whole system.

8.33. We note that, for the purpose of this report, Centrica asked us specifically to consider the impact of removing the Rough storage site from the system, noting that Centrica have 100% ownership of Rough.[192]

8.34. Without Rough on the hydrogen system in the 2040s, the build of some energy assets is brought forward, or delayed. Figure 8-8 below shows the differences in generation capacity.

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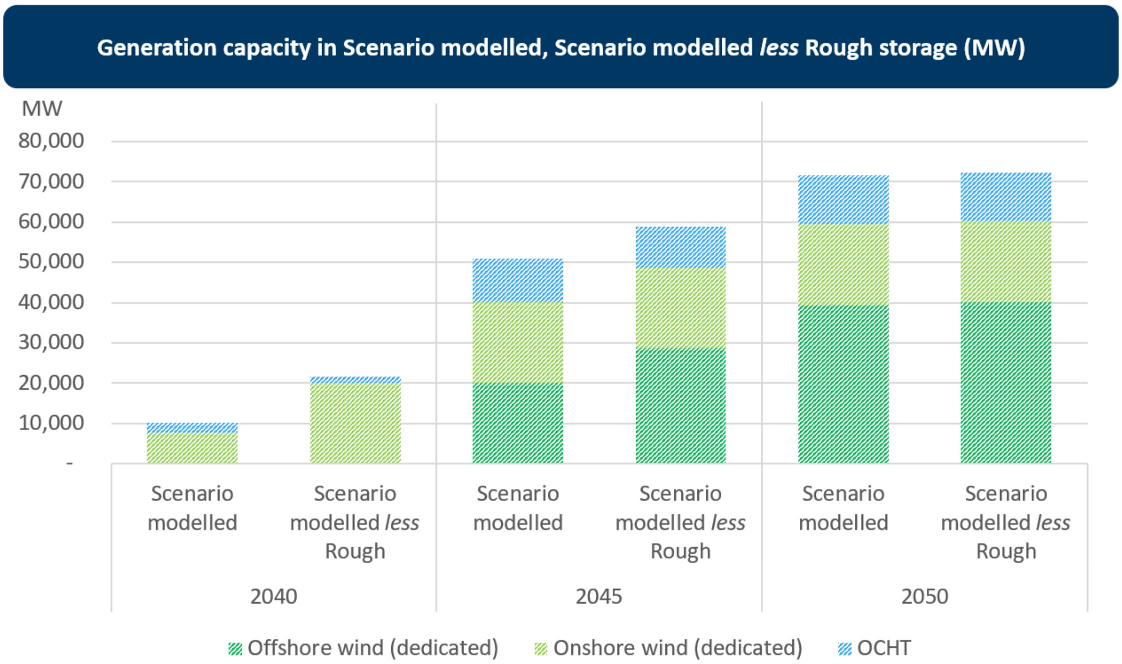
190 We note that in the FES 2022, the NESO shows a similar seasonal pattern of hydrogen storage utilisation in their System Transformation scenario. See *Future Energy Scenarios*, 2022, NESO (link).

191 We note that as shown in Figure 8-7-A and Figure 8-7-B above, hydrogen storage sites have quite high levels of storage at the beginning and end of the year. As noted in **Chapter 7**, this is driven by our assumptions that hydrogen storage levels are relatively full at the beginning of the year, and that hydrogen storage sites must end the year with storage levels that are similar to its initial storage level, which are limitations of our modelling.

192 See *Rough Gas Storage Facility, UK*, 2023, NS Energy (link).

Figure 8-8: Generation capacity in Scenario modelled, Scenario modelled less Rough storage (MW)



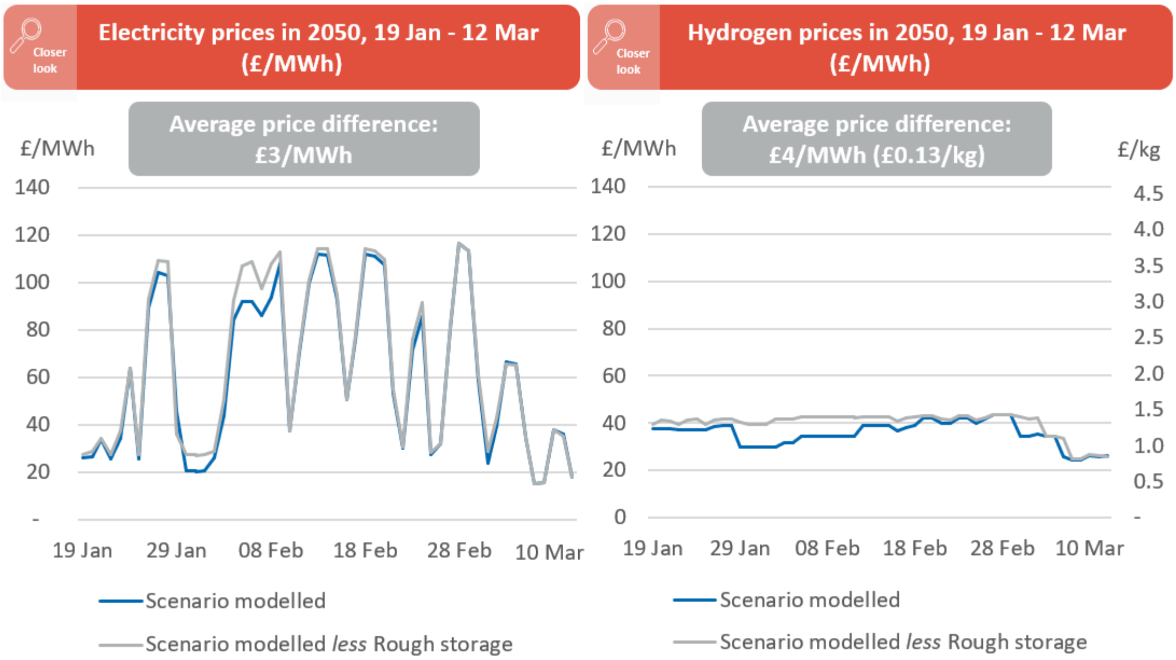
Sources: FTI Consulting analysis.
Notes: Showing generation categories with material differences between scenarios only.

8.35. As shown in Figure 8-8 above, reducing the volume of hydrogen storage results in three key impacts that stand out.

- **Need for additional assets in the 2040s:** an additional c.12 GW of dedicated onshore wind capacity and c.9GW of dedicated offshore wind capacity is built in the scenario modelled without Rough, which is 158% and 43% higher compared to our main modelled scenario, respectively. This is because with less hydrogen storage available, there is inadequate hydrogen supply during peak demand periods, leading to alternative hydrogen assets being built.
- **Reduced H2P capacity in the 2040s:** c.1 GW less OCHT capacity (a type of H2P generator) is built in the scenario modelled without Rough compared to our main scenario modelled. This is because with less hydrogen storage, there is lower withdrawal available for H2P limiting the useful capacity of OCHTs.
- **Limited difference in the capacity mix by 2050:** by 2050 there are no substantial differences in the generation capacity mix between the scenarios. This implies that the build of dedicated assets mentioned above were shifted forward to the 2040s, while the build of OCHTs is delayed to the 2050s.

8.36. With these impacts on the evolution of the system as a resulted of reduced hydrogen storage, lower levels of hydrogen storage may lead to increased system dispatch costs particularly in peak demand periods. Figure 8-9 below shows the profile of wholesale hydrogen prices and wholesale electricity prices in the winter months of 2050.

Figure 8-9: Wholesale hydrogen and wholesale electricity prices in 2050, 19 Jan to 12 Mar



Sources: FTI Consulting analysis.
Notes: the average price differences are calculated by comparing the average prices during the presented period between Scenario modelled and Scenario modelled less Rough storage.

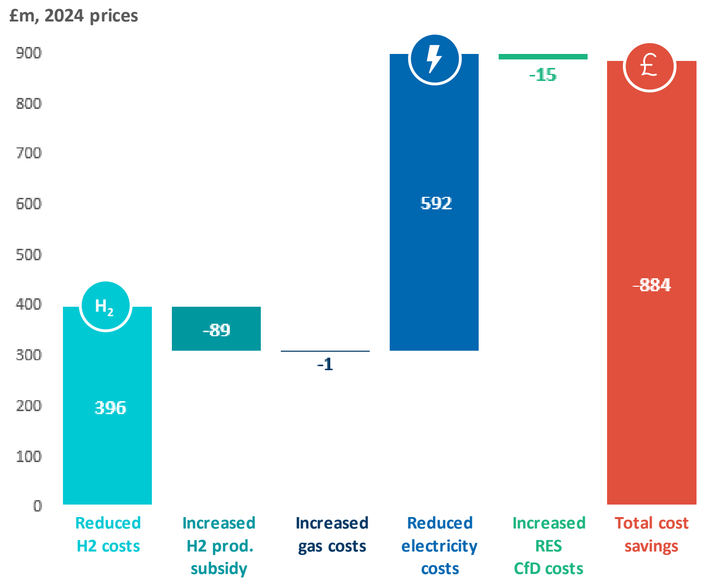
8.37. As shown in Figure 8-9 above, reduced hydrogen storage has an impact on hydrogen and electricity wholesale prices due to the increased scarcity and upwards pressure on system stress:

- **There are higher dispatch costs for hydrogen in 2050:** while wholesale hydrogen prices are relatively similar across scenarios, they are noticeably higher in the sensitivity modelled without Rough in the end of January through to March. Intuitively, reducing the levels of hydrogen storage creates a tighter system with less supply available, thereby increasing hydrogen wholesale prices. This is particularly pronounced during the winter months due to higher hydrogen demand.
- **There are higher electricity costs in 2050:** similar to the above, wholesale electricity prices are similar across scenarios apart from in the latter half of February, when wholesale prices are noticeably higher in the scenario modelled without Rough. This reflects the interactions between the hydrogen and electricity markets, as a higher wholesale hydrogen price pushes up the wholesale electricity price, as H2P are often setting wholesale electricity prices in winter months.

8.38. The combined effect is that reduced hydrogen storage leads to an increase in total system costs in 2050, the result of an increase of c.£396m in wholesale costs for hydrogen, and an increase of c.£592m in wholesale costs for electricity. From the perspective of energy consumers, these costs are partly offset by a reduction in implied H2 production subsidies and electricity CfD costs of c.£89m and c.£15m, respectively. This leads to an overall *increase in consumer costs from reduced storage* of c.£884m in 2050 under the scenario modelled.

8.39. As a corollary, assessing the impact of Rough by adding its capacity to our reduced storage scenario would produce an equal and opposite effect to the above, *reducing consumer costs*. This is shown in Figure 8-10 below.

Figure 8-10: Consumer cost savings as a result of increased H2 storage, 2050



9. Summary of key insights

9.1. While there is uncertainty in the scale required, there is some consensus that low-carbon hydrogen will play a key role in delivering decarbonisation of the UK economy.

9.2. In particular, low-carbon hydrogen is likely to form a significant part of the energy mix for some of the most challenging to abate sectors, where high-temperature heat is required, as well as providing an important feedstock in its own right in the chemical and fertiliser industries.

9.3. As discussed throughout this report, low-carbon hydrogen is inextricably intertwined with the other key vectors of the energy system — electricity and gas — when it comes to both production (supply) and usage (demand). A thorough analysis of hydrogen's potential role and its economics requires whole-systems thinking that reflects these interactions.

9.4. In this section, we set out some key insights from the whole-systems analysis presented in this report. Reflecting the interdependencies and uncertainties, these are not highly specific, but are instead intended to provide broad lessons for industry and policymakers as the UK considers the shape of its future energy system.

9.5. We also present a discussion of some of the key assumptions that sit behind our analysis, the impact they have on our results, and areas for further development.

A. Key insights

9.6. While our analysis is intended to explore dynamics and outcomes across the energy system for specific scenarios, against the backdrop of an uncertain market context, there are a range of important conclusions which can be drawn from what we have so far explored.

9.7. These conclusions, which fall across the different energy vectors and the variety of hydrogen system assets could have implications for policy and commercial discussions and decisions that are increasingly pressing.

***Key insight 1**: Hydrogen-fuelled electricity generation is likely to be the only way to cost-effectively replace the balancing role currently fulfilled by unabated gas generation within a secure, decarbonised and renewables-dominated electricity system.*

9.8. It is increasingly evident that a high-renewables and highly-electrified Net Zero electricity system will be highly challenging to balance without unabated gas generation.

9.9. Hydrogen-fuelled generation, as a low-carbon alternative to unabated gas peaking generation, can help overcome the intermittency problem associated with wind and solar generation. Combined with large-scale hydrogen storage, hydrogen-fuelled generation can make use of energy stored on a much larger scale over much longer durations than those that currently available alternative storage technologies (such as batteries) cannot cost-effectively match. This will be critical in a system where periods of low output from renewable generation may last for days, if not weeks — for example during '*Dunkelflaute*' weather patterns.

9.10. In addition, hydrogen-fuelled generation may be more economic to deploy than CCS gas for the purposes of solving intermittency, given their lower unit Capex. However, the extent of the competitiveness of hydrogen-fuelled generation depends largely on the availability of hydrogen storage and transportation that facilitates access to hydrogen supply during periods of low renewables production.[193]

Key insight 2*: While the extent of a future hydrogen economy in the energy transition is unclear, the value of hydrogen in both production and consumption will differ in GB across locations and time periods.*

9.11. The current expectations of a relative high cost of hydrogen assets (compared to alternatives such as electrification) means that hydrogen assets should be deployed where it is most valuable — but this differs by location and time periods.

9.12. For example, green hydrogen production would be more valuable to consumers if produced when and where the value of electricity is low — i.e. in locations and hours of surplus renewable generation. Likewise, apart from hard-to-abate industrial activities or where grey hydrogen is already used, hydrogen consumption would be more valuable to consumers if used when and where there is a shortage of electricity generation — for example during peak periods in demand centres.

Key insight 3*: The development of a hydrogen transport network, and sufficient large-scale storage facilities, will be necessary to establish a hydrogen market.*

9.13. Hydrogen transport and storage infrastructure would enable hydrogen to be produced when and where it is most economic to do so, and subsequently consumed when and where it is most valuable. In addition, these infrastructure assets would improve the ease of connecting hydrogen producers with offtakers.

9.14. A more established hydrogen economy, with the supporting infrastructure, may give rise to a hydrogen wholesale market — akin to the current gas NBP. In such a scenario, a hydrogen wholesale market would facilitate the financial and physical matching of hydrogen supply and demand through hydrogen wholesale prices — incentivising efficient operational and, potentially, investment outcomes.

Key insight 4*: The build-out of flexible green hydrogen production would complement the expansion of renewable generation capacity, serving as a value-enhancing offtaker during times of excess renewable production.*

9.15. By 2050, for around 15% of the year the volumes of electricity generated from renewables exceeds demand, even at the aggregate level, pushing prices down to £0/MWh. Electrolysers could provide a flexible source of demand, capable of creating a valuable resource, during these periods. Operating electrolysers flexibly, when power prices are low, will also reduce the costs of hydrogen production.

[193] As well as the coincidence of hydrogen and electricity peak demand, in that hydrogen stores can be used more readily for power production instead of direct consumption such as hydrogen heating.

***Key insight 5**: Flexible green hydrogen production could play an even more important value-enhancing role in regions of GB where intermittent renewable capacity will be greatest — most notably Scotland.*

9.16. In some areas of GB, most notably Scotland, the volume of electricity generated from renewables will exceed the demand it can serve (given transmission constraints) even more frequently, and earlier, than the 15% in 2050 discussed above. Flexible electricity demand from electrolysers sited in such areas could be even more valuable.

9.17. For example, our modelling sees c.55 GW of intermittent renewable generation capacity built in Scotland by 2050, compared to peak total (non-electrolysis) demand in Scotland of c.12 GW (and average demand of c.5 GW)[194] and transmission connections to the rest of GB of c.26 GW by the same date. In simplified terms, this implies that when output from renewable generation in Scotland exceeds around 70% of its capacity, there will be a surplus with no obvious means of consumption or transportation. In these circumstances, flexible hydrogen production, transportation and storage are likely to play a key role in avoiding curtailment — complementing the role of other forms of electricity storage that are most valuable over relatively short durations, such as batteries.

***Key insight 6:** Given the high fixed costs of hydrogen production facilities, significant external funding is likely to continue — support mechanisms should incentivise the use of low cost electricity, rather than maximum utilisation, to bring the overall cost of production down.*

9.18. Our modelling outcomes suggest that in 2050, market revenue could cover c.46% of the total unit costs for on-grid electrolysers. To ensure the viability and competitiveness of the technology, the government would need to provide subsidies at a rate of £1.3/kg ($1.6/kg) for the remaining costs.

9.19. So far, most large-scale subsidies in the energy system have been targeted at assets that have near-zero marginal costs (renewable generation from wind and solar) and which therefore come with limited risks from production-distorting incentivises (with the exception of the well-documented challenge associated with negative electricity prices).[195] In contrast, assets such as green hydrogen production have potentially highly variable marginal costs given the volatility of wholesale electricity prices. As such, significant care is needed in the design of production support mechanisms to ensure they promote efficient operations.

9.20. Therefore, support mechanisms should encourage (or rather, not discourage) efficient operations of hydrogen production — i.e. to produce hydrogen when the electricity price is low. This may have implications on the business model of electrolysers by affecting the Capex unit rate and offtaking agreements.

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194 Includes EV and heat pump demand.

195 See *Review of Electricity Market Arrangements: Options Assessment*, 2024, DESNZ (link).

***Key insight 7:** Methane reformation (i.e. blue hydrogen) may provide an economically competitive source of hydrogen, if global conditions are conducive to lower gas prices (falling demand, relatively stable supply).*

9.21. As decarbonisation progresses worldwide, the evolution of fossil fuel, including gas, demand and production is uncertain. Both will be significantly affected by policy decisions by governments across the world (for example on exploration and extraction licensing) as well as commercial considerations. In the scenario modelled for this report, gas demand in the UK reduces more quickly than readily available supplies, and wholesale gas prices fall significantly as a result. This means blue hydrogen production could be relatively cost-effective, especially if CCUS transport and storage infrastructure are already present. This pattern of falling gas prices is highly uncertain and contingent on specific supply and demand patterns. Gas prices that stay higher for longer — for example because of higher demand or more limited supplies that are readily available to the UK (e.g. from the UK and Norwegian Continental Shelves) — would have significant consequences for the economics of blue hydrogen.

B. Key assumptions that drive the analysis of this report

9.22. In our whole-systems analysis, we have made several key assumptions that affect the analysis of this report. For transparency, we have listed them out again below, together with a brief discussion on what we consider to be important for any future assessments.

9.23. These key assumptions are:[196]

1. our carbon price assumptions (see **Chapter 4C**);
2. our assumptions on the set up of the gas market (see **Chapter 4B**);
3. an unconstrained hydrogen network (see **Chapter 5B**);
4. a fixed build-out of electricity transmission (see **Chapter 4A**);
5. a perfect central planner (see **Chapter 4A**);
6. a fixed build-out profile for electricity battery storage (see **Chapter 4A**);
7. hydrogen assets operate accordingly to the hydrogen wholesale price signals it faces (see **Chapter 5B**); and
8. that green electrolysers would be exempt from renewable CfD funding costs (see **Chapter 7C**).

[196] We recognise that many of our cost input assumptions, based on 2022 data available to us at the start of this engagement may need updating. However, while varying many of these assumptions may change the scale of the findings, they are unlikely to affect the core implications relative to these seven key assumptions.

9.24. First, the **carbon price profile** used in our assessment is insufficient to incentivise a full switch away from unabated gas-fired generation to alternatives such as CCS Gas and H2P. As a consequence, we had to make an additional assumption that no unabated CCGTs and OCGTs would be built in the 2040s, in line with Net Zero ambitions. A higher assumed carbon price profile may alter the competitive dynamics between thermal dispatchable capacity in a whole-systems assessment.

9.25. Second, based on the **set-up of our gas market**, we find that our modelling outcomes for gas wholesale prices are low in this assessment, primarily because of a significant switch from gas consumption to electricity or hydrogen consumption across many sectors. An alternative set-up, for example with higher LNG prices, which produces higher gas wholesale prices, would alter some of the dynamics in our whole-systems assessment. Notably, this may lead to three effects:

- A reduction in the competitiveness of unabated CCGTs and OCGTs (together with a carbon price as discussed above), relative to alternative technologies.
- More costly blue hydrogen production, which affects the economics of blue hydrogen production relative to green hydrogen production (which in turn may also increase the amount of subsidy support required).
- Additionally, more costly blue hydrogen production would likely increase average hydrogen wholesale prices, as more costly gas is passed on to hydrogen consumers in the wholesale market.

9.26. Third, for simplicity, we have currently assumed an **unconstrained hydrogen network, with no losses**. Relaxing this assumption for future assessments would be necessary to further understand the cost and ability of hydrogen to balance both the hydrogen sector as well as power sector on a locational level (and the means of doing so — for example with a locational hydrogen wholesale price or balancing actions by a system operator). Additionally, given that we have assumed that the hydrogen and gas networks are constrained, our assessment does not consider the implications of a gas switchover to hydrogen and the potential issues and constraints that may arise from this. Policymakers are likely to need to consider this in more detail in the future.

9.27. Fourth, we have currently assumed a **fixed build-out profile for the electricity transmission network**, in part due to: (i) the availability of transmission cost information; (ii) the expected increase in computational times; and that (iii) optimising the build-out of the electricity transmission network may inadvertently mask whole system dynamics in other areas — for example the use of hydrogen to reduce electricity constraints. One potential area of a recommended future assessment is to consider the substitutability of electricity transmission and hydrogen pipelines in transporting energy from one area to another. This would test the hypothesis that hydrogen pipelines, to the extent they can be repurposed from existing gas pipelines, can serve to *reduce* the need for costly electricity transmission build.

9.28. Fifth, we have currently assumed a **perfect central planner**, in the siting of many electricity and hydrogen assets, in lieu of any electricity locational price signals in the wholesale market. This approach understates the amount of congestion in the electricity sector, as well as the potential challenges with balancing the electricity system, but may overstate the efficacy of hydrogen assets (as they are co-located with renewables).

9.29. Sixth, we have currently assumed a **fixed build-out profile for battery storage**, to simplify the computational intensity of our whole-systems assessment. Although we consider that optimising the build-out of battery storage is unlikely to affect the value of hydrogen storage (as they cycle over different time periods and last for different durations), these interactions may be considered in future analysis.

9.30. Seventh, we have assumed that **hydrogen assets operate in accordance with energy price signals** in each period. This applies to production, storage and H2P facilities. We assume therefore that regulatory support mechanisms *do not* affect these operational incentives in dispatch. This assumption is particularly critical for green electrolyser hydrogen production — as, despite its high Capex costs, on-grid electrolysers can take advantage of lower-cost electricity production when and where available. However, this would only be possible if the hydrogen and electricity price signals are aligned, without interference from a subsidy mechanism (e.g. a mechanism that encourages continuous production could create material distortions).

9.31. Eighth, we have assumed that **on-grid electrolysers will be exempt from funding renewable CfD costs** (through the CfD supplier obligation levy). However, off-grid electrolysers, which are served by a dedicated wind farm, will be required to make the investment on the wind farm whole, in effect providing the additional support payments a CfD would otherwise do.

9.32. It would be remiss of us when highlighting the importance of incentivising an efficient use of hydrogen assets without emphasising the potential benefits of locational electricity prices on the hydrogen sector. As described in our Key Insight #5, this is because a hydrogen sector that complements the electricity sector should both produce hydrogen, and use it to generate electricity, where it is most valuable to do so. While the Balancing Mechanism could be used to incentivise electrolysers to respond to locational factors, the idiosyncratic design of the mechanism may lead to unintended distortions, for example, by encouraging electrolysers to withhold electricity consumption in wholesale market. On the contrary, locational pricing would set more transparent and consistent price signals reflecting the local supply and demand conditions. This would lead to electrolysers benefiting from lower electricity wholesale prices in areas with excess supply, incentivising more efficient siting and operational outcomes, and may also improve the ease of contracting for power. As such, we consider implications and benefits of locational wholesale electricity pricing on the hydrogen sector to be explored further.

9.33. To develop this assessment further, we have intended for these assumptions to be taken forward by policymakers and other stakeholders to be stress-tested. To the benefit future assessments, we also wish to share our experience of several modelling challenges we have encountered given the complexity of the undertakings. We set some of them out in Box 9-1 below for those seeking to undertake similar assessments.

Box 9-1: Modelling challenges experienced during the development and process of this whole-systems assessment

We highlight the several key modelling challenges that we encountered during our whole-systems assessment for this report.

(1) **Modelling blue hydrogen** — As discussed in **Chapter 5B**, during our initial modelling iterations we modelled blue hydrogen plants on a must-run basis, given our understanding that such plants would operate on a near baseload basis. This meant that we assumed blue hydrogen production had a flat operating profile. However, this assumption resulted in hydrogen market dynamics that did not appear to make economic sense, as blue hydrogen plants would continue generating inflexibly, regardless of the profile of hydrogen wholesale prices. As a result, this caused an excess hydrogen supply which suppressed hydrogen wholesale prices, and so increased the implied amount of subsidy support required for all types of hydrogen production, especially for blue hydrogen plants which had very significant subsidy requirements given their very high utilisation.

Therefore, we decided to introduce a small level of flexibility to blue hydrogen production to address these issues. Specifically, we assumed that: (i) blue hydrogen plants can somewhat ramp up and down in response to wholesale price signals; and (ii) can shut down for a minimum period of one week. However, implementing this flexibility was highly computationally challenging, as the slow ramping rates and long minimum shut-down periods meant that operators of blue hydrogen plants had to consider the *opportunity cost* of flexing production in one period, relative to future periods. This was resolved by allowing foresight into the model, specifically allowing blue hydrogen producers to look ahead two weeks into the future when making operating, shut-down and start-up decisions.[197]

(2) **Hydrogen storage levels** — As discussed in **Chapter 8**, in line with common practice we have assumed that hydrogen storage sites would start the modelling year with relatively full levels of storage (at around 80%), and end the year at the same storage levels, subject to certain violation constraints. However, this assumption resulted in some hydrogen storage sites injecting hydrogen into storage (i.e. consuming hydrogen) during periods where hydrogen wholesale prices were relatively high. This was particularly true during the winter periods nearing the end of the modelling year, and as a result, drove hydrogen wholesale prices even higher. We recognise that this is a limitation of our modelling, however resolving this issue will

[197] Allowing foresight into the model means that operators of generators can better calibrate operating decisions based on not only current, but future market conditions. For example, suppose that hydrogen wholesale prices are currently relatively low, but that prices will rise to a much higher level in the near future. *Without foresight*, operators of blue hydrogen plants may ramp down now and shut down completely as a result of currently low wholesale prices. In contrast *with foresight*, operators of blue hydrogen plants will be able to consider that wholesale prices will rise in the near future, and so decide to ramp down only slightly now, but not shut down fully in order to capture the high hydrogen wholesale prices in the near future.

be very challenging from a modelling perspective. This is because it would require a multi-year optimisation modelling assessment (instead of our current approach where we model one year, every five years). Some potential solutions we can test in future modelling work include: (i) to change the modelling year to be April-to-March rather than January-to-December, so that our assumptions on hydrogen storage levels better reflect seasonal trends, as hydrogen storage are able to refill after the winter period has ended such that they are relatively full during spring; or (ii) to introduce a level of tolerance to allow hydrogen storage levels at the end of the year to deviate from the start, i.e. relax our end-of-year storage levels assumptions.

(3) **The optimisation of battery capacity build-out** — As discussed in **Chapter 4A**, we have fixed the capacity of batteries based on storage capacity forecasts in the FES 2022 System Transformation scenario. We did this due to the modelling computational intensity required to optimise electricity storage build-out in our long-term model. This is because batteries are typically of low duration and so have frequent cycling rates, meaning a very granular long-term model (with "temporal blocks" of short duration) is needed to meaningful capture these dynamics. We recognise that by fixing the capacity of batteries, we cannot fully capture the potential substitutability between electricity storage and hydrogen assets, which we discussed in **Chapter 1A**. Though we can optimise the build-out of batteries in future modelling work, we consider that this would have a limited effect on our overall modelling outcomes, as electricity storage and hydrogen assets appear to balance the power sector in different ways — batteries help to balance shorter-term variations in electricity demand versus supply, while hydrogen assets, such as H2P generators and hydrogen storage sites, appear to help balance longer-term variations.

9.34. Ultimately, we intend that the development of a whole-systems analytical tool would be useful to both policymakers and industry in exploring the different Net Zero pathways, including the challenges and solutions.

9.35. In particular, in the context of the hydrogen industry facing headwinds and uncertainty on its emerging role, a whole-systems assessment identifies and quantifies ways hydrogen assets could complement the electricity and gas sectors — especially in balancing the energy system.

9.36. We hope that this report, which sets out our assumptions, approach and findings would contribute quantitatively to the dialogue on the Net Zero transition, which we believe is much needed to achieve our Net Zero ambitions.

Appendix 1 Glossary

Term	Definition
AP	WEO Scenario Announced Pledges
ATR	Autothermal Reforming
BECCS	Bioenergy with Carbon Capture and Storage
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CCHT	Combined Cycle Hydrogen Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CHP	Combined Heat and Power
CPF	Carbon Price Floor
DAC	Direct Air Capture
DFS	Demand Flexibility Service
DPA	Dispatchable Power Agreement
DSR	Demand Side Response
EISD	Earliest In Service Date
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EPEX SPOT	European Power Exchange
ESO	Electricity System Operator
EU ETS	EU Emissions Trading System
EVs	Electric Vehicles
FES	Future Energy Scenarios
FOAK	First of a Kind
FTI	FTI Consulting LLP
H2	Hydrogen
H2P	Hydrogen-to-power
HAR	Hydrogen Allocation Round
HAR1	First Hydrogen Allocation Round
HGVs	Heavy Goods Vehicles
HHV	Higher Heating Value
HND	Holistic Network Design
HPBM	Hydrogen Production Business Model
HSBM	Hydrogen Storage Business Model
HTBM	Hydrogen Transport Business Model
IEA	International Energy Agency
LAES	Liquid Air Energy Storage
LCHA	Low Carbon Hydrogen Agreement
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LDES	Long Duration Energy Storage
LDZ	Local Distribution Zone
LHV	Lower Heating Value

LNG	Liquefied Natural Gas
LULUCF	Land Use, Land Use Change and Forestry
NBP	National Balancing Point
NESO	National Energy System Operator
NOA	Network Options Assessment
NTS	National Transmission System
OCGT	Open Cycle Gas Turbine
OCHT	Open Cycle Hydrogen Turbine
PPA	Power Purchase Agreement
PECD	Pan-European Climatic Database
PEM	Proton Exchange Membrane
RAB	Regulated Asset Base
REMA	Review of Electricity Market Arrangements
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SO	System Operator
SRMC	Short-Run Marginal Cost
T&S	Transport and Storage
TO	Transmission Owner
TYNDP	Ten-Year Development Plan
V2G	Vehicle-to-Grid
WEO	World Economic Outlook