Net Zero Power and Hydrogen: Capacity Requirements for Flexibility

A report to the Climate Change Committee

MARCH 2023

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AFRY Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and bio-based industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to European energy markets. Our energy team of over 250 specialists offers unparalleled expertise in the rapidly changing energy markets across Europe, the Middle East, Asia, Africa and the Americas.

Executive Summary

The UK's legal commitment to deliver Net Zero emissions by 2050 will require transformative changes across the energy system

As part of its wider commitment to meeting legally-binding "carbon budgets" and reaching Net Zero emissions by 2050[1], the Government has pledged to decarbonise the electricity system by 2035[2] subject to ensuring security of supply. To achieve this the power system of the future will undergo a drastic transformation, with variable wind and solar energy playing a pivotal role in shaping a low-carbon generation system. This shift will take place against the backdrop of an increasing demand for electricity, as the electrification of key sectors, such as transport and heating, underpins wider economy emission reductions.

Ensuring the seamless integration of new low-carbon technologies into the GB energy system is crucial in meeting our growing energy demand while reducing carbon emissions. Key challenges in this integration include:

- balancing of supply and demand over different time horizons;
- addressing locational constraints; and
- adapting to a low inertia system.

Addressing the integration challenges will require significant investment in flexible solutions. At present there are a range of technologies that can, in principle, provide solutions to the issues identified above including flexible generation, demand side response (DSR), network solutions and energy storage. The future mix of technology solutions is highly uncertain, with numerous competing options available in each pathway. The precise blend of these solutions will depend on various factors, including the rate of technological innovation, outturn costs, supply chain constraints and infrastructure delivery.

This report builds upon the CCC's prior work, updating and expanding a set of tracking indicators for flexibility within the power and hydrogen sectors

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[1] HM Government, Climate Change Act 2008, November 2008
[2] HM Government/BEIS, Net Zero Strategy: Build Back Greener, October 2021

The purpose of this report is to examine the necessary scale and range of flexibility options required to balance a low-carbon and weather-dependent electricity system in 2035, incorporating key interactions with the hydrogen sector. The findings of this investigation have been synthesised into a comprehensive indicator framework that can be used to track progress towards this goal.

This builds upon the Climate Change Committee's (CCC) 2021 'Report to Parliament: Progress in Reducing Emissions'[3], which presents a comprehensive evaluation of progress towards meeting the Sixth Carbon Budget[4] through the lens of sector-specific indicators. This report updates and expands on the sub-set of indicators associated with the provision of flexibility solutions in the power and hydrogen sectors. The newly proposed indicators are divided into two categories: technology and development (please see Exhibit 0.1).

Exhibit 0.1 – Technology indicators

Indicator	Unit	Definition
Power sector		
Dispatchable low-carbon percentage of generation	%	Dispatchable low-carbon generation (Gas CCS and hydrogen-fired plant) as a fraction of total domestic generation
Dispatchable low-carbon generation capacity	GW	Dispatchable low-carbon capacity (Gas CCS and hydrogen-fired plant)
Output capacity of grid storage	GW	The sum of maximum discharge capacities of grid storage technologies (Batteries, CAES, LAES, and Pumped Storage)
Grid storage capacity	GWh	The total amount of energy that can be stored in grid storage technologies (Batteries, CAES, LAES, and Pumped Storage)
Active demand response as percentage of total demand	%	The fraction of total domestic demand that is shifted or avoided
Hydrogen sector		
Low-carbon hydrogen production	TWh/yr	Low-carbon hydrogen production (Electrolysis, ATR CCS, and Biomass Gasification CCS)
Low-carbon hydrogen production derated capacity	GW	Low-carbon hydrogen production derated capacity (Electrolysis 50% LF, ATR CCS 90% LF, and Biomass Gasification CCS 95% LF)
Hydrogen storage capacity	TWh	Total amount of hydrogen that can be stored in storage technologies (Salt Caverns and Tanks)
Economy-wide		
Volume of CO_2 cumulatively captured	$MtCO_2$	The economy-wide volume of CO_2 cumulatively captured from CCS-enabled technologies

The technology indicators capture the target contributions from different technologies. To complement this, a set of development indicators have been created to ensure sufficient flexible capacity is 'in development' or 'under

[3] Climate Change Committee, Progress in Reducing Emissions, Report to Parliament, June 2021
[4] The Sixth Carbon Budget, The UK's path to Net Zero, December 2020

construction'. The development indicators were selected for technology groups and infrastructure types that have long lead times:

- dispatchable low-carbon capacity;
- low-carbon hydrogen production derated capacity;
- hydrogen storage capacity; and
- carbon capture and storage (CCS) capacity.

Keeping track of the capacity levels at each stage of development is crucial in anticipating potential problems caused by delays in infrastructure deployment and insufficient project pipelines.

A scenario-based modelling approach was taken in order to inform a range of outcomes for each indicator

Constructing a robust set of indicators is challenging due to the complicated and ever-evolving nature of energy systems. To manage this unpredictability, a scenario-based modelling approach was taken in order to inform a range of outcomes for each indicator at any point in time, as well as over time. The analysis involved the creation and evaluation of 3 core scenarios and 12 sensitivities[5]. From this pool, the CCC carefully selected[6] specific scenarios and sensitivities to inform the range of indicators. To effectively account for the complex and interconnected nature of energy systems, the selection process concentrated on key assumptions with high levels of uncertainty, while also taking into account a diverse set of outcomes that recognises the uncertainty in how the system will ultimately deliver the Net Zero transition.

Energy market modelling was performed using AFRY's proprietary software, BID3, a multi-market dispatch model that uses advanced mathematical techniques to model the hourly dispatch of supply and demand, market prices, capacity evolution, and all other important features of energy markets.

The scenarios and sensitivities were constructed using the most current and relevant data. Key assumptions included power and hydrogen demand outlooks, which were informed by scenarios outlined in the CCC's Sixth Carbon Budget, specifically the "Balanced Pathway," "Widespread Innovation," and "Headwinds" scenarios. Additionally, the deployment of renewables was guided by the ambitions outlined in the British Energy Security Strategy[7] (BESS). These inputs, along with technology costs, commodity prices, carbon prices, and system constraints, were developed in

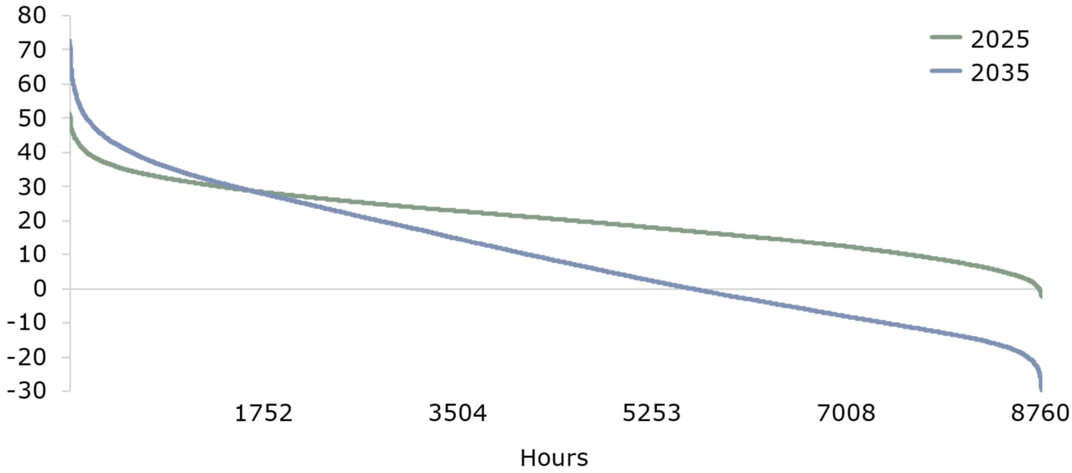
[5] This report presents the results of 3 core scenarios and 9 sensitivities, while the remaining 3 sensitivities are included in a supporting document, Net Zero Power and Hydrogen – Additional Sensitivities.
[6] The indicator ranges were based on the 3 core scenarios and 4 sensitivities. These include the Central, Low, and High scenarios, and the Low RES/Nuclear, Biomass Gasification, Low Wind Year, and Grid Storage sensitivities.
[7] HM Government, British Energy Security Strategy, April 2022

collaboration with the CCC and a Steering Group comprising key stakeholders[8].

The shape of residual demand will become increasingly variable and extreme

Residual demand, defined as final consumption minus renewable generation, represents the load that must be met by non-renewable sources, such as power plants, interconnector flows, energy storage, or DSR. The volume and shape of residual demand are crucial determinants of the capacity and combination of flexible solutions required to balance an electricity system.

Exhibit 0.2 – Duration curves for hourly residual demand (GWh)



Notes: Central scenario and 2012 weather patterns
Source: AFRY Analysis

Growing demand for electricity, combined with the expansion of renewable energy, significantly alters the nature and scale of residual demand:

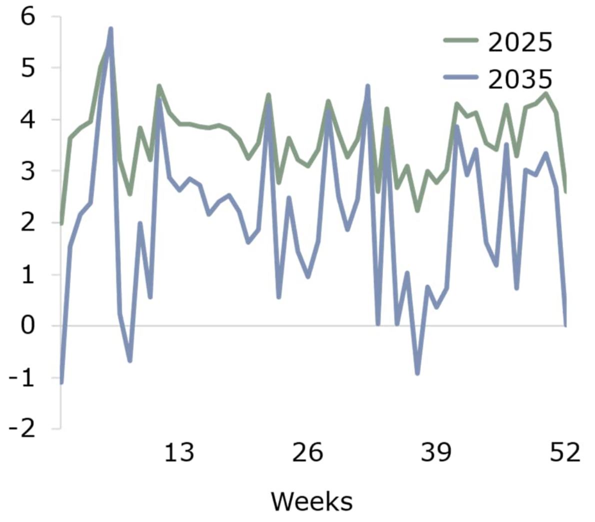
- by 2035, there will be more extreme residual demand levels to manage, including both the highest and lowest hours of residual demand (see Exhibit 0.2);
- the residual demand pattern will become more variable, with extended periods of high and low residual demand, and more challenging fluctuations from week-to-week (see Exhibit 0.3); and
- future residual demand will deviate more significantly hour-to-hour (Exhibit 0.4).

The challenges of balancing the electricity system are poised to intensify. To effectively address these issues, a range of flexible solutions will be required, each tailored to meet specific demands. During system stress events, there must be sufficient dispatchable capacity to meet these demands. Rapidly

[8] The Steering Group included representatives from the Department for Business, Energy & Industrial Strategy (BEIS) and the National Infrastructure Commission (NIC).

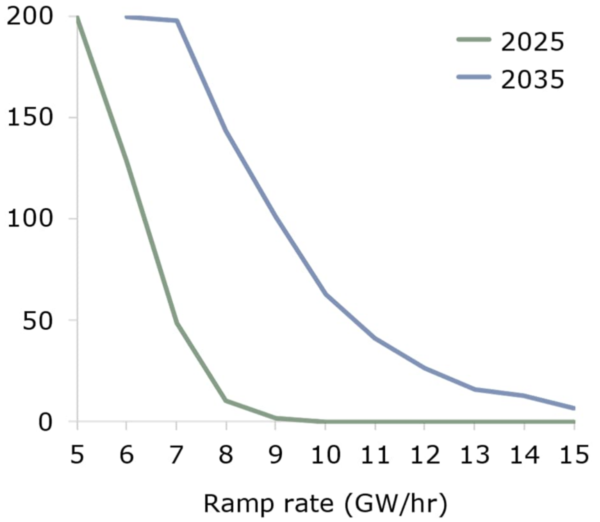
responding capacity will be necessary to address the most extreme ramping requirements. And overall, there must be enough flexibility to balance supply and demand over both short and long timeframes, from adjustments needed to align intraday deviations, to the longer-term solutions required to balance the prolonged ups and downs of weather-driven renewable energy sources.

Exhibit 0.3 – Weekly net total residual demand (TWh)



Notes: Central scenario and 2012 weather patterns
Source: AFRY Analysis

Exhibit 0.4 – Frequency of >5GW/hr residual demand ramp rates (hr/year)

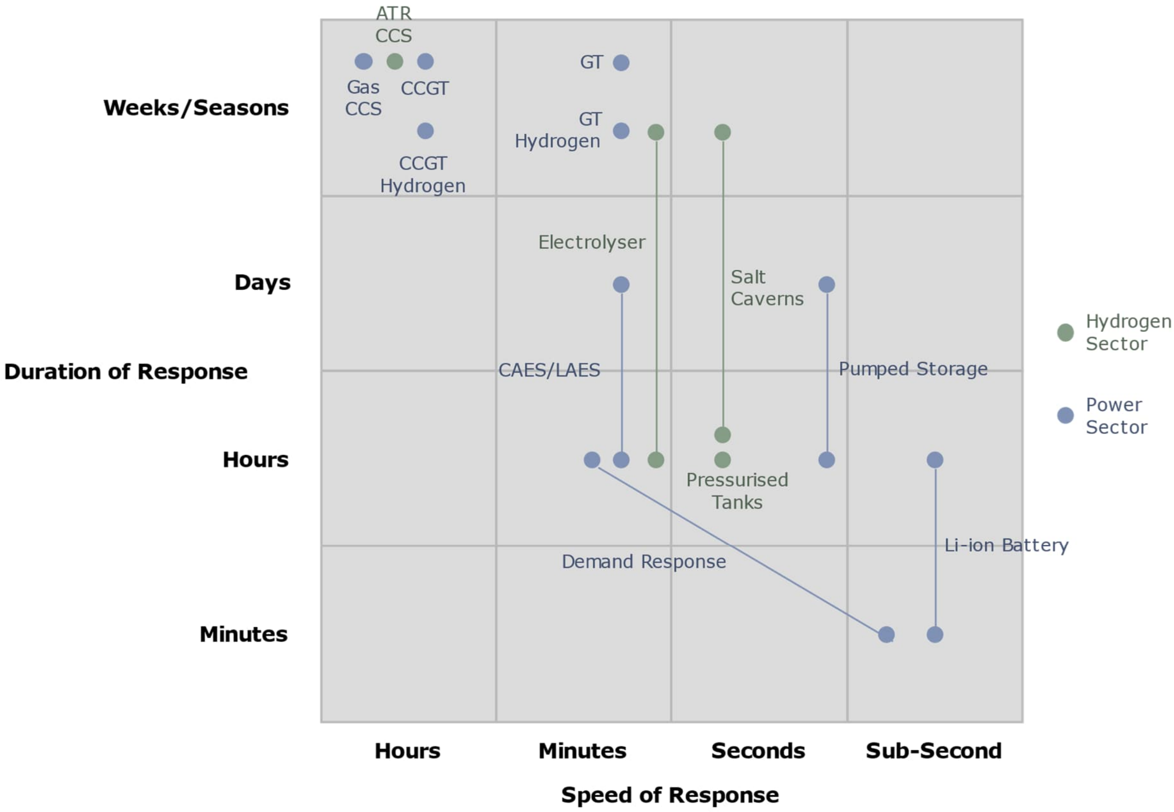


Notes: Central scenario and 2012 weather patterns
Source: AFRY analysis

A variety of solutions are available to meet the diverse flexibility requirements of an energy system

A low-carbon and weather-driven electricity system will need both fast responding, and long lasting, flexibility solutions. The diverse nature of flexibility requirements is mirrored by a similarly diverse set of technological solutions. Each type of flexibility resource offers different types of flexibility, at different timeframes, and in different combinations are more, or less, suited to meeting the flexibility requirements of a Net Zero system. This study encompasses a wide spectrum of solutions with different operational characteristics; Exhibit 0.5 displays an example set of solutions and their specific flexibility metrics, including response time and duration.

Exhibit 0.5 – Flexibility matrix for sample set of technologies (illustrative)

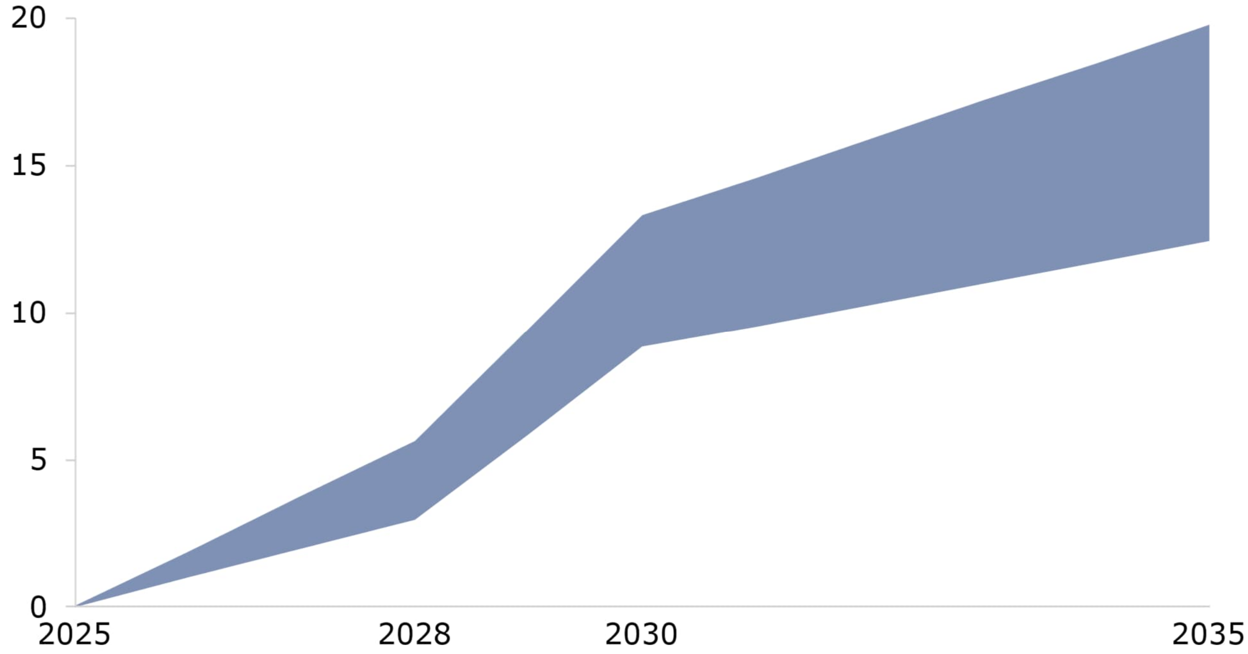


Notes: This analysis also takes into account network solutions with passive features that do not fall within the matrix.

The mix of dispatchable generation capacity will undergo a transformative shift and become indispensable in delivering long-duration flexibility

Low-carbon generation technologies that can be dispatched to balance the fluctuations of renewable energy are critical for decarbonising the power system while ensuring long-term flexibility. As the electricity system becomes increasingly reliant on renewables, the need for flexible capacity that can respond to prolonged periods of low energy production becomes more important. Renewable energy sources, like wind and solar, can face long stretches of low power generation that can last multiple weeks. Flexible solutions such as DSR, energy storage, and network solutions may not be able to address these low output periods. During these times, it will be crucial to have low-carbon generation technologies that can operate continuously to maintain reliable system operation.

Exhibit 0.6 – Indicator for dispatchable low-carbon generation capacity (GW)



Notes: Dispatchable low-carbon generation capacity comprises Hydrogen CCGT/GT and Gas CCS.

The current reliance on unabated gas as the sole source of dispatchable generation is incompatible with emission targets. By 2035, there will be a marked shift in the dispatchable generation technology mix, transitioning away from unabated gas to incorporating a substantial capacity of Hydrogen Combined Cycle Gas Turbine/Gas Turbine (CCGT/GT) and Gas with Carbon Capture and Storage (Gas CCS). Exhibit 0.6 indicates that the capacity of flexible low-carbon generation technologies will need to rise from zero to 12-20GW by 2035[9].

These tracking indicators should not be considered prescriptive, but rather a plausible range of future needs. The exact scale and optimal mix of hydrogen-fired plants and Gas CCS is highly uncertain. Peripheral developments in the wider energy system will influence deployment, such as the shape of residual demand (particularly dimensioning metrics like the peak hour and highest continuously accrued volume of residual demand), delivery risk of enabling infrastructure, competition from alternative solutions (e.g. DSR and energy storage), and national and international policy. In addition to this, low-carbon generation technologies that can be dispatched as needed are still in their early stages of development and will require Government support initiatives, which may experience delays or face uneven priorities and funding.

In this study, a sizable tranche of unabated gas capacity remains on the power system in 2035 despite the high assumed cost of carbon, though it

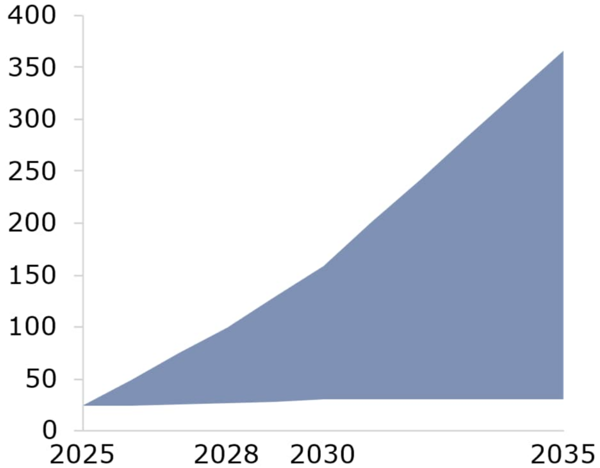
[9] Each indicator range displayed in this report includes the lower and upper limits of the selected scenarios/sensitivities.

accounts for only 2% of generation. Running at low load factor[10], these plants can provide valuable flexibility, including intra-day balancing and support during extended periods of generation deficit. The future of unabated gas plants remains uncertain, and this will have a major effect on the necessary implementation of alternative low-carbon flexible technologies.

The use of grid storage and DSR is expected to rapidly grow, providing efficient and effective means of balancing short-term residual demand

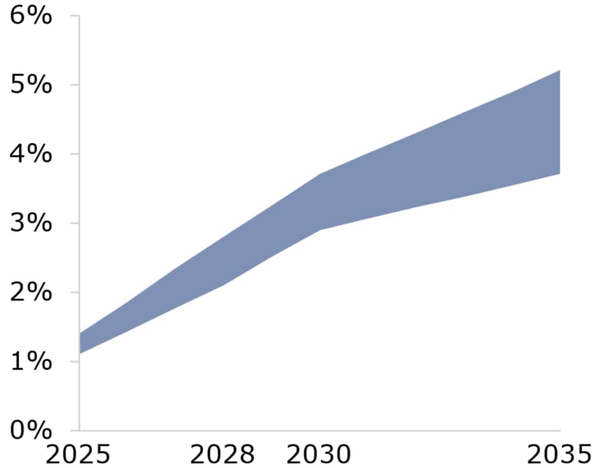
The operational parameters of grid storage and smart DSR are well-suited to enhance short-duration system stability. Both flexible resources can be used to smooth out fluctuations in electricity demand and supply, which can help manage extreme ramping, shift load during surplus generation, and balance intra-day volatility.

Exhibit 0.7 – Indicator for capacity of grid storage (GWh)



Notes: The total amount of energy that can be stored in grid storage technologies (Batteries, CAES/LAES and PS).

Exhibit 0.8 – Indicator for active DSR as percentage of total demand (%)



Notes: The fraction of total domestic demand that is shifted or avoided.

Exhibit 0.7 and Exhibit 0.8 depict the tracking indicators for grid storage capacity and the demand that is actively shifted/turned down, respectively, both demonstrating growth. It is expected that the cumulative capacity of DSR and grid storage will rise sharply in response to the increasingly extreme and volatile patterns of residual demand. The exact combination of short-term flexible solutions is unclear, but the DSR assumptions made in the analysis (provided by the CCC) anticipate that a substantial proportion of the new demand for electricity from transportation and heating is flexible and can readily be accessed by the system to address short-term flexibility needs.

[10] In the Central scenario for 2035, the 2% of the total energy generation from unabated gas plant implies a fleet average load factor of around 10%.

The analysis considered grid storage technology configurations with durations ranging from 1 hour to 3 days. The findings showed that chemical batteries play a crucial role in short-term intraday balancing, with a projected growth in batteries with 1-2 hour capacity until 2030 and 4-6 hour capacity thereafter. This is due to the increasing need for extreme residual demand balancing, leading to higher arbitrage spreads, although the frequency of charge-discharge cycles remains similar. The deployment of grid storage was limited by the availability of DSR. If the expected DSR capacity does not materialise, it is likely that higher levels of grid storage will be required.

The GB transmission network will experience a significant expansion to accommodate growing renewable generation and enhance the stability of the power system

By 2035, the capability of transmission network boundaries must approximately double from 2025 levels to integrate the growing penetration of renewables

The electrical transmission network must undergo significant strengthening to support the Government's ambitions for renewable energy capacity. This study assessed the transmission needs of various regions by dividing GB into 11 distinct zones. Regardless of the scenario or sensitivity, there is a pressing need for substantial boundary reinforcement. By 2035, the capability of transmission network boundaries must approximately double from 2025 levels to integrate the growing penetration of renewables. Despite the presence of secondary factors, such as the advancement of longer-duration storage and expedited development of alternative transmission vectors, the proliferation of renewable energy sources and the growth of electricity consumption remain the paramount factors in determining the expansion rate of the transmission network.

Alongside the growth of its national transmission network, GB is poised to see an increase in interconnectivity with neighbouring energy markets. The outlook for interconnector capacity was predetermined in this analysis and factored in several uncertain factors such as country specific congestion rent. The study expects that the GB net flows will reverse from net import prior to 2030, to net export by 2035. This shift is brought about by the rapid expansion rate of renewables in GB under the BESS compared to other markets that are decarbonising at a slower pace. Significant interconnection capacity paired with uneven rates of decarbonisation between connected markets can lead to unexpected, but nonetheless important, outcomes: for example, exceeding current Government ambitions for renewable capacity may result in a substantial portion of the additional renewable energy produced being exported. However, there may be alternative options to address periods of negative residual demand (surplus generation), such as further green hydrogen production, if new interconnection does not materialise or policy designed to incentivise domestic usage is enacted.

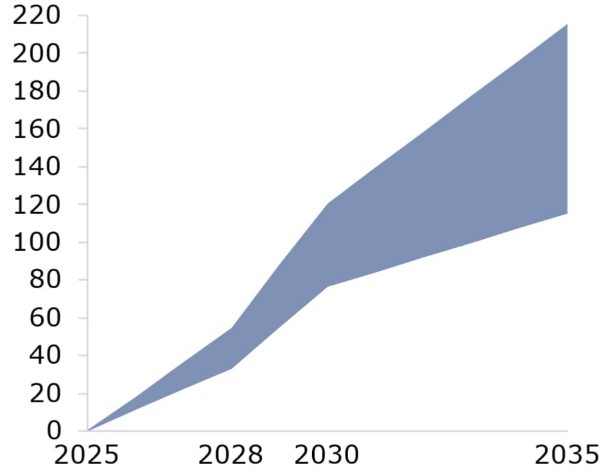
Interconnectors play a crucial role in the transfer of electricity between energy markets, especially during instances of divergent system needs. This allows for a more efficient distribution of electricity, reducing the need for curtailment and overproduction. However, widespread weather events often result in a positive correlation of residual demand positions across interconnected energy markets. This means that interconnectors can worsen imbalances and cannot be relied upon to ensure Great Britain's energy security during extended periods of high residual demand (generation deficits). Therefore, the interconnector flows impact the utilisation rate of flexible technologies, but not necessarily the cumulative capacity, which is dimensioned against extreme residual demand patterns that are not reliably met by interconnectors.

Hydrogen-based solutions have the potential to play a crucial role in the decarbonisation of the power sector and wider economy

The rapid increase of low-carbon hydrogen production technologies in the modelling are presented in Exhibit 0.9 and Exhibit 0.10.

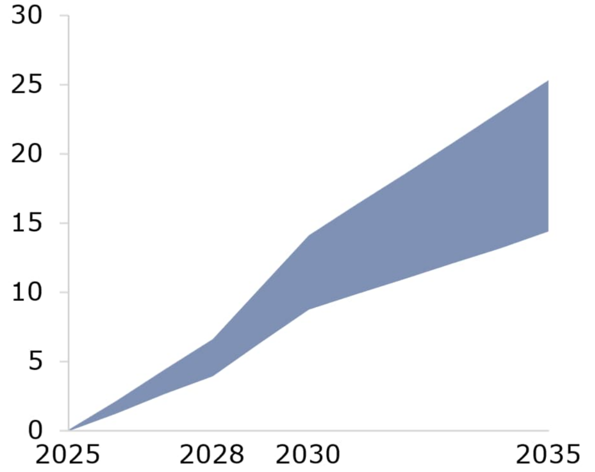
The expansion of low-carbon hydrogen production is a response to the growing demand for hydrogen in the power sector and throughout the wider economy. The non-power demand[11] for hydrogen is a fixed assumption based on the scenarios outlined in the CCC's Sixth Carbon Budget, while the power demand for hydrogen is optimised within the modelling. As the hydrogen economy is still in its early stages, the demand for hydrogen will depend on the success of policies and regulations supporting the adoption of hydrogen-based solutions. The integration of these solutions into the energy mix and the extent to which they will replace fossil fuels will depend on various unknown factors, including the timely development of necessary infrastructure, economic conditions, and consumer preferences.

Exhibit 0.9 – Indicator for low-carbon hydrogen production (TWh/yr)



Notes: Low-carbon hydrogen production from electrolysis, ATR CCS, and Biomass Gasification CCS.

Exhibit 0.10 – Indicator for low-carbon hydrogen production capacity (GW)



Notes: Derating load factor for each technology - electrolysis 50%, ATR CCS 90%, and Biomass Gasification CCS 95%.

Hydrogen can be produced through various technologies and the indicators are impartial to the method used. The modelled scenarios favour blue hydrogen up to 2035 due to the limited volumes of excess generation that

[11] Non-power hydrogen demand is divided by sector, specifically Removals, Surface Transport, Aviation, Shipping, Residential Buildings, Non-Residential Buildings, Agriculture, Manufacturing & Construction, Fuel Supply, and Waste.

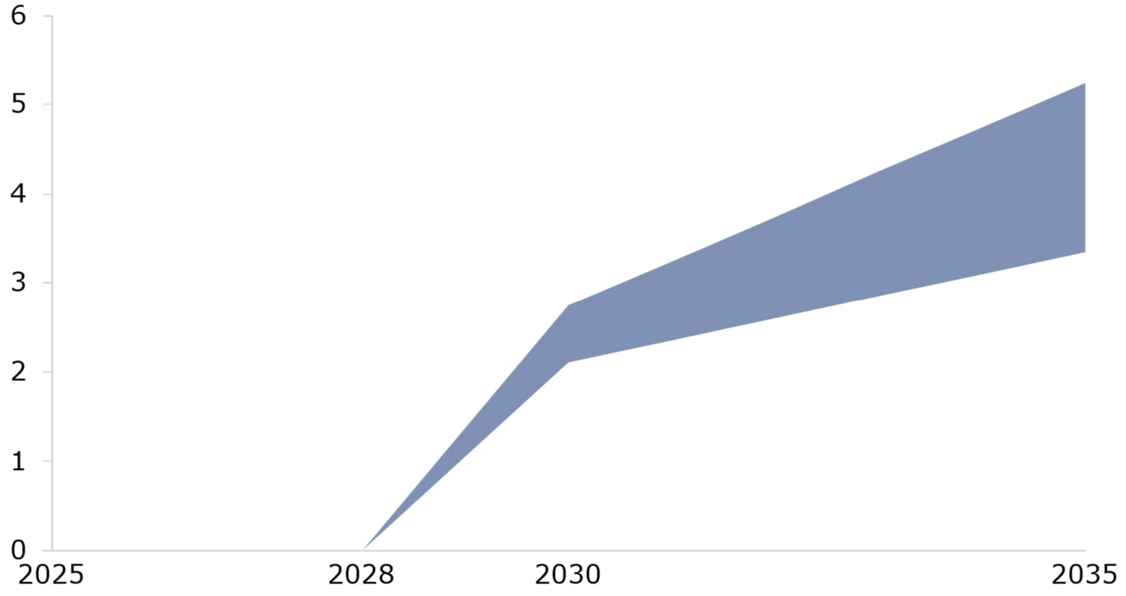
can be electrolysed after more cost-effective means of balancing are taken into account (e.g. exporting via the interconnector or load shifting with DSR/grid storage). Moreover, CCS-enabled technologies are well-suited to meet the projected stable demand profiles from most non-power sectors[12].

The growth of the hydrogen market is contingent on the timely establishment of hydrogen infrastructure

The success of hydrogen as a vector for decarbonising the power sector and wider economy is dependent on the timely development of infrastructure. Hydrogen pipelines are crucial for transporting hydrogen from production sites to demand centres, typically spanning the North-South divide. Salt cavern hydrogen storage was found to be the most cost-effective solution for storing large amounts of energy. This aided in balancing supply and demand and provided energy reserves during prolonged periods of generation deficit in the power sector, from which they were ultimately dimensioned.

Exhibit 0.11 presents the considerable growth of hydrogen storage in the indicator range, which rises from nothing in 2028, to 3-5TWh by 2035. In actuality there is significant delivery risk due to uncertain factors, including the availability of the necessary funding and legislative support, as well as the ability of alternative solutions (e.g. interconnectors, grid storage, DSR) to compete.

Exhibit 0.11 – Indicator for hydrogen storage capacity (TWh)



Notes: The total amount of hydrogen that can be stored in Salt Caverns and Pressurised Tanks.

[12] Excluding Residential Buildings and Non-Residential Buildings which account for heat variation (i.e. seasonality).

The updated set of indicators are derived from the outputs of the core scenarios and selected sensitivities

Exhibit 0.12 – Technology indicators

Indicator	Unit	2025	2028	2030	2035
Power sector					
Dispatchable low-carbon percentage of generation	%	0%	5%-9%	7%-13%	4%-12%
Dispatchable low-carbon generation capacity	GW	0	3-6	9-13	12-20
Output capacity of grid storage	GW	7	8-9	10-11	10-19
Grid storage capacity	GWh	24	26-100	30-159	30-366
Active demand response as percentage of total demand	%	1%	2%-3%	3%-4%	4%-5%
Hydrogen sector					
Low-carbon hydrogen production	TWh/yr	0	33-55	76-121	115-216
Low-carbon hydrogen production derated capacity	GW	0	4-7	9-14	14-25
Hydrogen storage capacity	TWh	0	0	2-3	3-5
Economy-wide					
Volume of CO_2 cumulatively captured	$MtCO_2$	1	20-34	60-96	242-361

Exhibit 0.13 – Development indicators

Indicator	Unit	Phase	2025	2028	2030	2035
Dispatchable low-carbon generation capacity	GW	Operational	0	3-6	9-13	12-20
		Under Construction	3-6	7-8	2-4	2-8
		In Development	8-11	2-5	3-7	2-7
Low-carbon hydrogen production derated capacity	GW	Operational	0	4-7	9-14	14-25
		Under Construction	4-7	6-9	3-7	3-8
		In Development	8-12	4-8	3-6	5-15
Hydrogen storage capacity	TWh	Operational	0	0	2-3	3-5
		Under Construction	1-2	2-4	1-2	1-2
		In Development	2-4	1-2	2-3	2-3
CCS storage capacity	$MtCO_2$	Operational	1	20-34	60-96	242-361
		Under Construction	39-64	113-168	146-212	168-271
		In Development	207-304	207-312	256-405	274-467

Key findings that arise from the results and indicators:

- The indicators show a range of possible outcomes, which underlines that there are competing technology solutions in any pathway. Future uncertainty is driven by factors such as the cost competitiveness of different technologies, the availability of supply chains and infrastructure, and the evolution of residual demand. The latter, in particular, is subject to significant uncertainty and depends on factors such as the level of electricity demand, the deployment of renewable energy sources, and the progression of the nuclear fleet.

- There are interdependencies across competing solutions. The flexible capacity options are interdependent, meaning the presence or absence of one solution can affect the need or utilisation of another solution. For instance, a high deployment of Hydrogen CCGT may reduce the need for Gas CCS as both provide similar flexibility services. Similar relationships can be observed between electrolysers and CCS-enabled technologies for hydrogen production, as well as between grid storage and DSR for the provision of short-duration flexibility.

- The hydrogen and power sectors are closely connected and one sector's failures can impact the other. For instance, if the development of hydrogen infrastructure lags, the power sector may have to rely more on CCS and grid storage to make up for the deficit. The relationship between these sectors should also be considered when developing policy to avoid skewed or inefficient co-development.

- The lower bound of the indicators requires significant investment and effective Government support policies for implementation. To maintain progress towards Government targets, the indicators suggest the energy system must have at least 9GW of dispatchable low-carbon generation capacity, 10GW of grid storage, 76TWh/yr of low-carbon hydrogen production, 2TWh of hydrogen storage, and 60MtCO_2 of cumulatively captured and stored emissions by the end of this decade.

- The urgency to act is amplified by the protracted development and construction times for these emerging technologies and their supporting infrastructure. Concurrent progress across the hydrogen supply chain (i.e. supply, transport and storage) and the establishment of CCS infrastructure is crucial to meet Government targets. Due to lead times extending up to 10 years, immediate action is crucial. By 2025, the indicators suggest the energy system must have underway the construction of at least 3-6GW of low-carbon dispatchable generation capacity, 4-7GW of low-carbon hydrogen production, 1-2TWh of hydrogen storage, and 39-64Mt of CO_2 storage space.

Monitoring implementation, particularly for solutions facing coordination challenges with infrastructure, will be vital

Achieving the Net Zero objectives in the power sector and beyond requires a significant increase in investment. To support this, a range of policy measures have been proposed or implemented, with additional initiatives being considered as part of the Review of Electricity Market Arrangements (REMA) process[13]. There are some areas where significant challenges arise in terms of coordinating infrastructure, such as networks and storage infrastructure that enable emerging hydrogen and CO_2 capture technologies. Due to the urgency of meeting these targets, it will be crucial to closely monitor the implementation and effectiveness of these policies.

[13] BEIS, Review of Electricity Market Arrangements, October 2022

1 Introduction

A core duty of the CCC under the Climate Change Act is to publish periodic reports to Parliament monitoring progress towards meeting Carbon Budgets. In the CCC's 2021 Report to Parliament 'Progress in Reducing Emissions'[14], a set of sector-specific Indicators were developed to assess the underlying progress to meet the Sixth Carbon Budget.

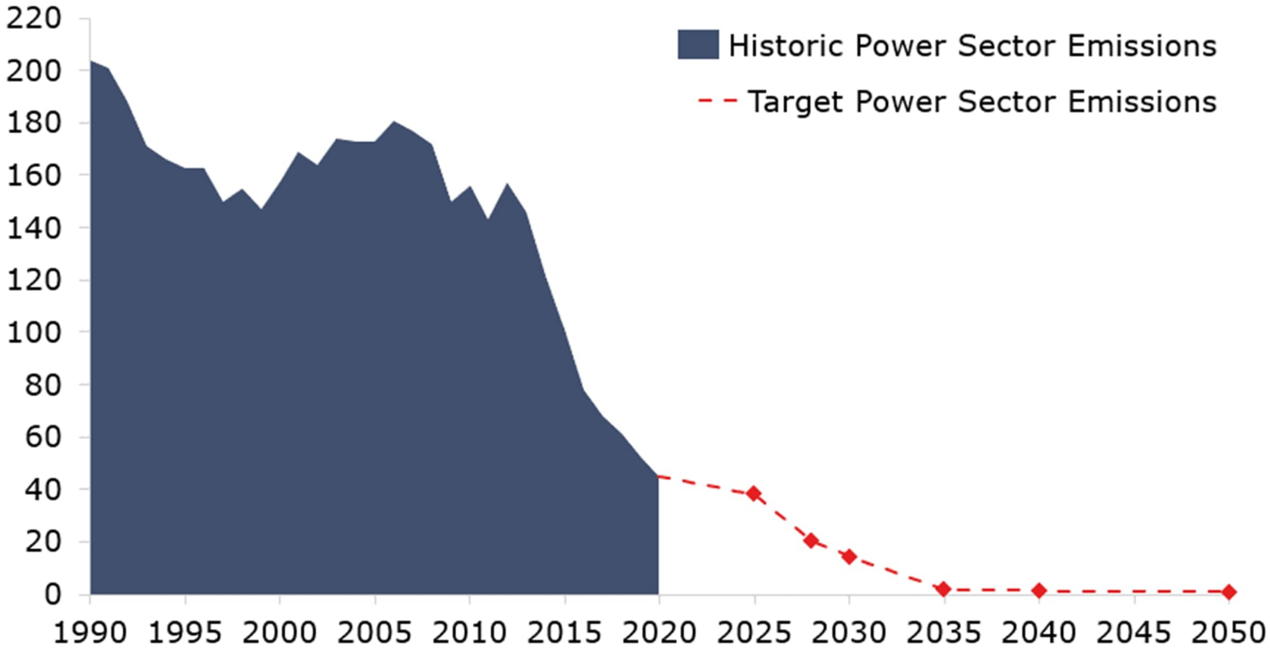
As part of the CCC's directive to develop deeper metrics of progress and consider a better dashboard of Indicators, this report presents a set of updated tracking Indicators for low carbon flexible capacity in the power and hydrogen sectors. The indicators established in this project will allow the CCC and other parties to track the progress of flexible capacity deployment, which will be central to delivering a cost-effective, decarbonised energy system. The outputs of this project will form part of the evidence base for a refreshed set of economy-wide tracking indicators.

1.1 Background

The UK's legal commitment to deliver Net Zero emissions by 2050 will require transformative changes across the energy system. Key steps towards Net Zero include the Government's commitment to meet Carbon Budgets and to achieve decarbonisation of the power sector by 2035 (see Exhibit 1.1).

[14] Climate Change Committee, Progress in Reducing Emissions, Report to Parliament, June 2021

Exhibit 1.1 – Gross power sector emissions, historic values and future targets in the CCC Balanced Pathway ($MtCO_2e$)



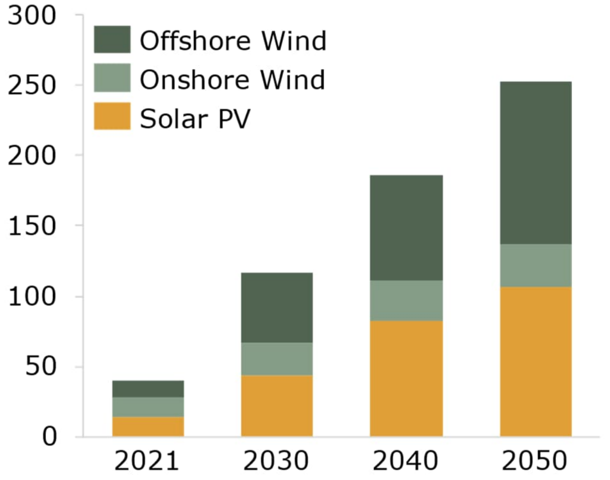
Source: BEIS, CCC

The invasion of Ukraine by Russia has provided a greater impetus for the UK Government to transition towards clean energy. The BESS, published in April 2022, sets out the dual ambition of reducing international dependence on Russian fossil fuels whilst pivoting towards clean sources of energy. This is considered central to reducing Britain's reliance on expensive and volatile fossil fuels, whose prices set by international markets, and boosting energy security in the long-term.

While there are various perspectives on the pathways to decarbonising the power sector, there is a general consensus that the electricity system's generation and demand mix will be fundamentally different from the present day:

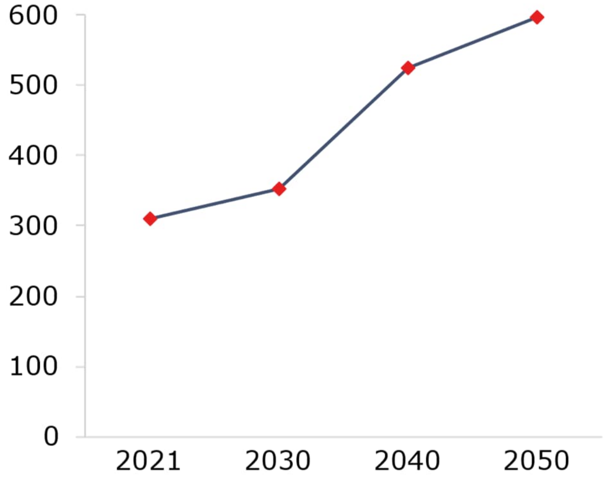
- the backbone of a low-carbon generation mix will be renewables, predominantly intermittent wind and solar resource, which, as shown in Exhibit 1.2, are projected to exceed 250GW by 2050; and
- electrification of heating, transport and some industrial processes may result in final electricity consumption being double current levels by 2050, as is shown in Exhibit 1.3.

Exhibit 1.2 – Outlook for renewable capacity (GW)



Source: CCC, BEIS, BESS

Exhibit 1.3 – Electricity demand in the CCC's Balanced Pathway (TWh)



Source: CCC

The BESS outlines ambitious targets set by the UK Government, including the delivery of 50GW of offshore wind power by 2030, 70GW of solar energy by 2035, progressing up to 24 GW of nuclear capacity by 2050, and deploying 10GW of hydrogen by 2030. The successful integration of these technologies into the GB energy system is crucial to ensure sufficient low-carbon power is available to meet the country's energy needs.

Key challenges in this integration include:

- balancing of supply and demand over different time horizons;
- addressing locational constraints; and
- adapting to a low inertia system.

Flexibility can be defined as the ability to shift in time or location the consumption or generation of energy

Flexibility can be defined as the ability to shift in time or location the consumption or generation of energy. The increasing importance of renewables in the generation mix introduces greater variability in generation patterns, reflecting underlying weather conditions, and leads to more variation in the residual demand position (i.e. the demand to be met net of renewable generation). As such, an adequate provision of flexibility will be central to delivering a cost-effective and secure power system as we decarbonise out to 2035.

There are a range of solutions that can address differing system flexibility needs. The precise combination of solutions remains uncertain, as there are competing technologies and the exact mix will be dependent on factors such as out-turn costs, supply chain constraints, and infrastructure availability.

1.2 Aims and objectives

The purpose of this report is to investigate the necessary scale and range of flexibility options required to balance a low-carbon and weather-driven electricity system that will be decarbonised by 2035. This analysis will form the basis of a new set of flexible capacity indicators, which will be used to monitor the progress of the energy sector towards the Sixth Carbon Budget and wider Government targets.

The project is structured around three primary objectives:

OBJECTIVE 1: Characterise the scale and range of low-carbon flexible capacity required to decarbonise the power and hydrogen sector by 2035

OBJECTIVE 2: Develop a comprehensive set of indicators for flexible capacity

OBJECTIVE 3: Identify high level policy milestones necessary to enable delivery of these indicators

1.3 Approach to the analysis

To conduct this analysis, a scenario-based energy modelling methodology was used to examine the flexibility requirements of the future GB energy system. The model generated various combinations of technologies necessary to provide the system flexibility required to achieve decarbonisation across a range of plausible future pathways up to 2050. Details on the energy modelling can be found in section 2.3.

Key metrics, or indicators, of the energy system associated with flexibility were identified as proxies for measuring progress towards decarbonisation in the power and hydrogen sectors. Based on the modelled results of the scenarios and sensitivities, a range was compiled for each progress indicator for the years 2025, 2028, 2030, and 2035[15].

The indicators were then compared against the existing energy policy and legislation, which helped to identify policy gaps that need to be addressed to support the adequate deployment of flexible capacity in line with the modelled decarbonisation pathways. This included any dependencies on enabling infrastructure, such as electricity, hydrogen, and CO_2 networks.

Throughout the course of the study, the CCC formed a Steering Group consisting of relevant stakeholders[16] who participated in regular discussions. This group guided the energy market modelling and development of the indicators.

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[15] Despite the focus in the near term, the modelling extends out to 2050.
[16] The Steering Group included representatives from the Department for Business, Energy & Industrial Strategy (BEIS) and the National Infrastructure Commission (NIC)

1.4 Structure of this report

This report is structured as follows:

- Executive Summary provides an overview of the main points of the report;
- Chapter 1 provides the background, aims and objectives of this report alongside setting out the structure and conventions practised;
- Chapter 2 explains the modelling approach adopted for this analysis;
- Chapter 3 sets out the scenarios and sensitivities explored in this project;
- Chapter 4 shows the key results from the modelling and draws the scenario and sensitivity results together;
- Chapter 5 presents the modelled outputs as a set of progress indicators and comments on potential policy gaps to meet these indicators.

Alongside the main report, there are several supporting annexes:

- Annex A provides further detail on the modelling methodology;
- Annex B reports the Central Scenario results for 2050; and
- Annex C presents a glossary of terms used this report.

1.5 Conventions and sources

Please note the standards practised in this report:

- all monetary values quoted in this report are in GB Pounds Sterling in real 2020 prices, unless otherwise stated;
- annual data relates to calendar years running from 1 January to 31 December, unless otherwise stated;
- scenario results are the average of the five modelled weather years unless stated otherwise;
- acronyms and abbreviations are defined on their first use and included in the glossary; and
- footnotes serve the dual purpose of providing references and supplying extra context and information to enhance the main body of the text.

Unless otherwise attributed, the source for all tables, figures and charts is AFRY Management Consulting.

2 The need for flexibility

This chapter highlights how the need for flexibility will evolve as we transition to Net Zero: balancing supply and demand over multiple time frames, offering system stability, and managing locational constraints. The range of flexibility solutions that can provide differing system needs is discussed. Finally, a summary of the modelling methodology is presented.

2.1 The need for system flexibility as we transition to Net Zero

In order to understand the importance of flexibility, it is necessary to consider the operational needs of a reliable, secure and resilient electricity system. The amount of electricity fed into the grid must be equal to the amount consumed; the tolerance for imbalance is small and excessive deviation can result in costly damage to electrical equipment and supply interruption or failure (e.g. brownouts, blackouts). In addition to energy balancing needs, ancillary features of an electricity system (e.g. inertia, voltage, thermal constraints) must also be managed to maintain stability.

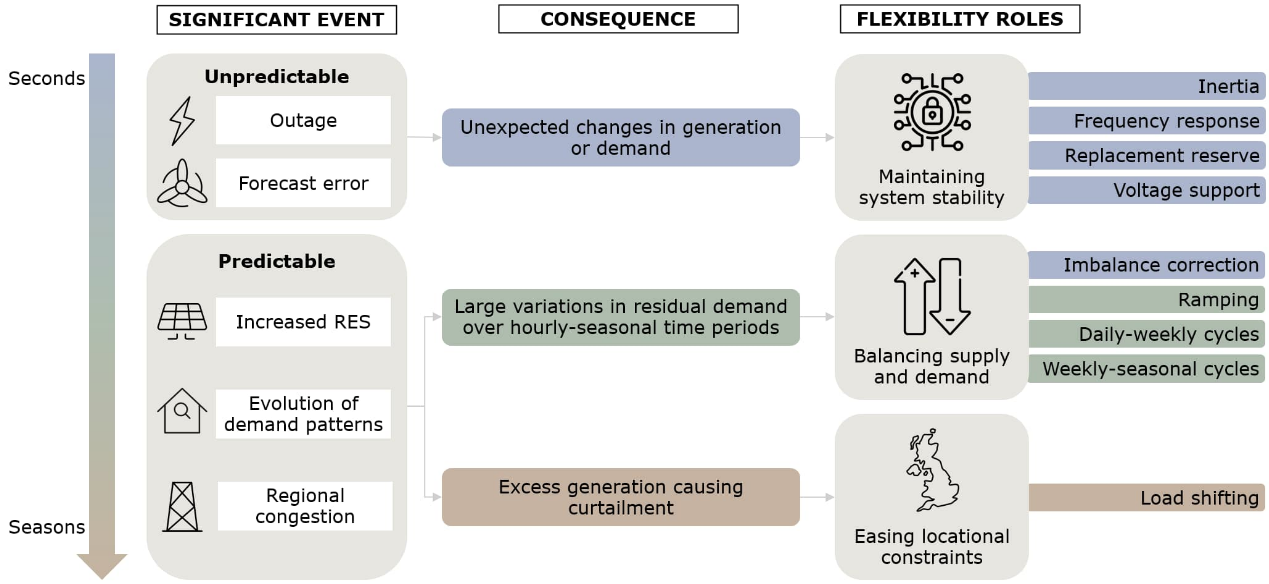
Residual demand is defined as final consumption, excluding electrolysis, minus renewable generation

Rapid electrification and a heavy dependency on intermittent renewable generation sources will amplify the operational needs required to maintain a reliable, secure and resilient electricity system. Relative to today, the levels and type of future flexibility required will develop in response to three key trends:

- increasingly variable residual demand patterns on the electricity system (residual demand is defined as final consumption, excluding electrolysis, minus renewable generation);
- higher proportion of non-synchronous generation as the penetration of renewable generation increases; and
- increasingly dispersed location of generation relative to demand in response to the distribution of renewable resource (wind and solar) relative to demand.

Exhibit 2.1 presents the events that drive these trends, as well as the system flexibility roles this will create.

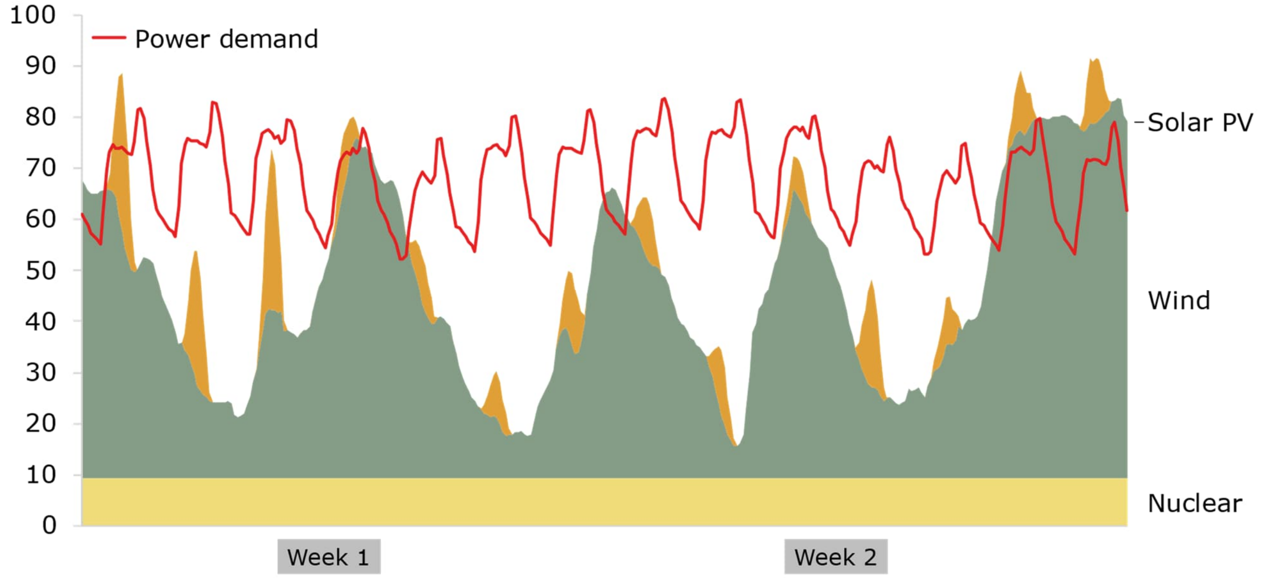
Exhibit 2.1 – Drivers of flexibility and system balancing roles required to manage



2.1.1 Balancing supply and demand will become more challenging across multiple time scales

As the penetration of intermittent renewables and inflexible nuclear increases, greater system flexibility will be required in order to balance supply and demand. The challenge of balancing a low-carbon, weather-driven electricity system is illustrated in Exhibit 2.2 for a sample two-week period in 2035. This displays simulated electricity demand, intermittent renewable generation, and baseload nuclear output on an hourly basis.

Exhibit 2.2 – Generation and demand gap over two-week sample period in 2035 (illustrative)



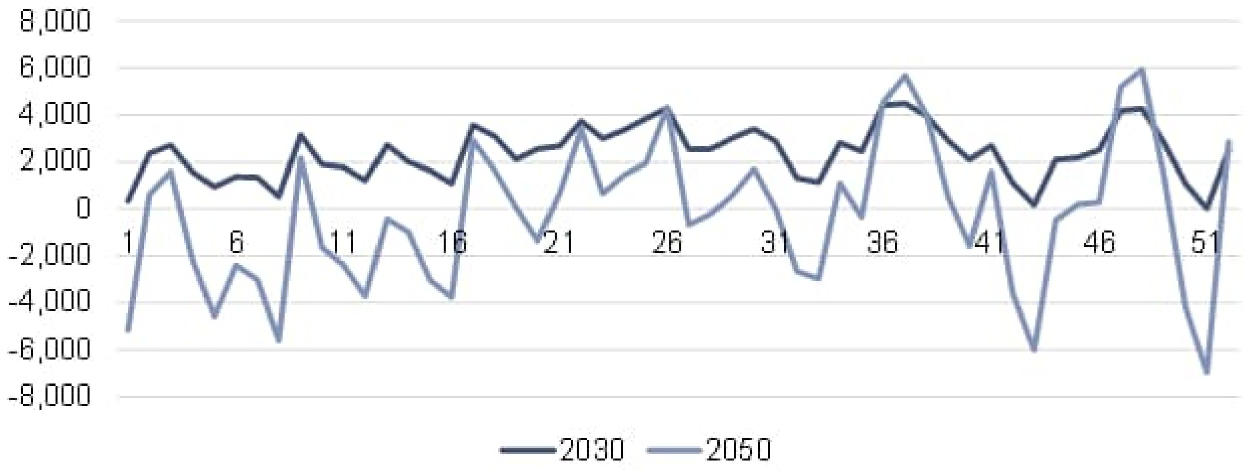
Notes: AFRY analysis using CCC assumptions. For this modelling exercise, 2012 weather patterns were used[17].

Intermittent renewables result in periods of both excess and shortfall of generation relative to demand. In this example fortnight there is a 5-day period (in week 2) of continuous generation shortfall amounting to 3TWh. Furthermore, there are hours with up to 26GW of generation in excess of demand and, conversely, 67GW of generation shortfall to demand.

As we move towards a Net Zero system, the balancing issues intensify with both more extreme residual demand positions to manage and greater volatility across time. Exhibit 2.3 shows how, by 2050, in addition to weeks with higher residual demand, the system of the future is also likely to feature weeks with high excess renewable output.

[17] The weather year 2012 has been commonly used to present hourly system behaviours in this report; it was randomly selected from the 5 historical weather patterns (2012, 2014, 2015, 2017, and 2018) used in this analysis – however the same patterns are observed across all weather year.

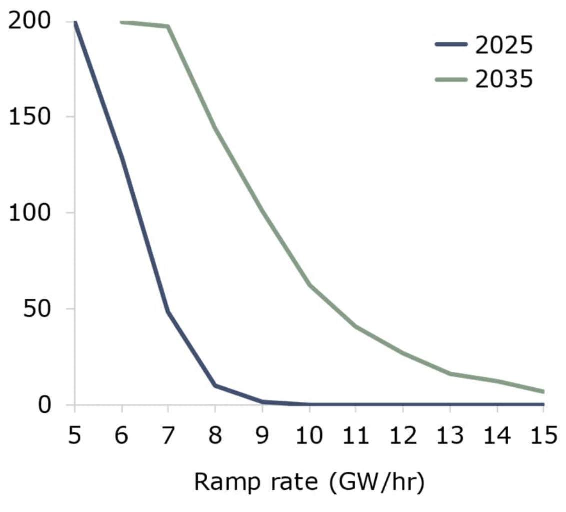
Exhibit 2.3 – Weekly net total residual demand variability (GWh) (illustrative)



Notes: Residual demand defined as final consumption, excluding electrolysis, minus renewable generation. Positive values indicate a deficit and negative values indicate a surplus of generation.

The patterns of residual demand will drive the need for flexibility over different time frames; from hourly and daily cycles, to monthly and seasonal balancing of supply and demand.

Exhibit 2.4 – Frequency of >5GW/hr residual demand ramp rates (hr/year)



Notes: AFRY analysis using CCC assumptions. For this modelling exercise, 2012 weather patterns were used.

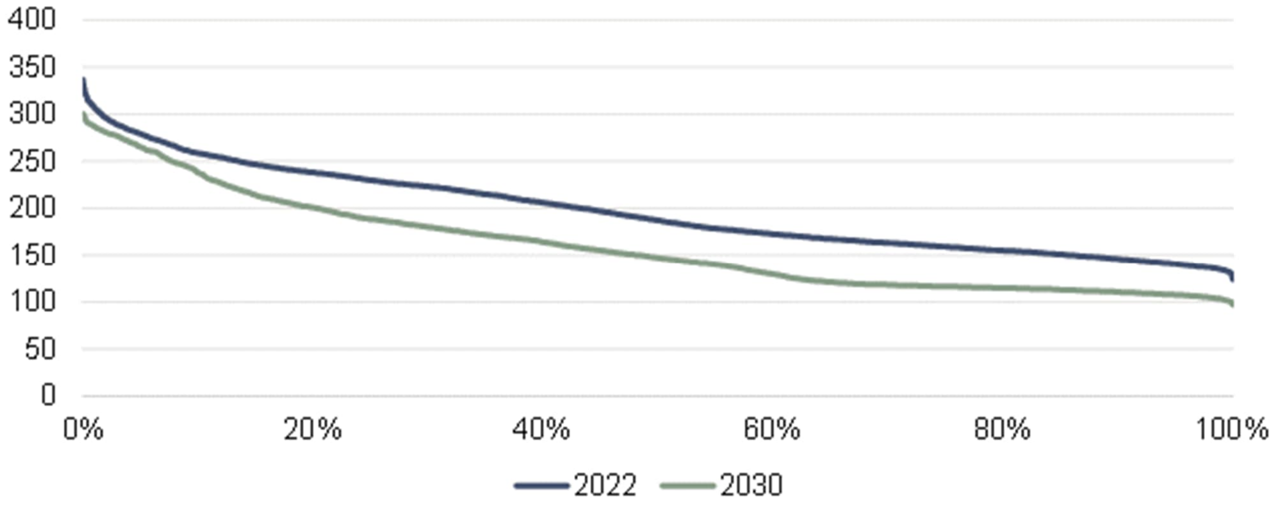
In addition to balancing more extreme supply and demand positions over time, future residual demand will deviate more significantly hour to hour. This is illustrated in Exhibit 2.4, which shows that hourly changes in residual demand are not forecast to exceed 10GW/hr in 2025, however this threshold will be surpassed for over 50 hours of the year by 2035.

Steeper hourly deviations in residual demand will drive the need for sufficient flexible capacity to provide the necessary upward and downward ramping capabilities.

2.1.2 Implications for system stability

The proportion of non-synchronous generation is set to increase as we transition to Net Zero. This will reduce the levels of inertia on the system and make secure operation of the system more complex. The falling levels of inertia are illustrated in Exhibit 2.5.

Exhibit 2.5 – Duration curve of modelled half hourly inertia (GW.s) (illustrative)



Notes: AFRY analysis using CCC assumptions. For this modelling exercise, 2012 weather patterns were used.

Voltage stability will need to be maintained as the penetration of non-synchronous, distributed renewables increases. Voltage stability is needed in order to ensure that power is transferred across the network. With more renewables, power transmission lines are likely to be lightly loaded more frequently, leading to reduced voltage stability. This will drive the need for voltage support (typically reactive power absorption).

Accurately forecasting output from generation will be harder as the amount of energy generated from wind and solar increases; this is due to the inherent uncertainty in weather forecasts[18]. Larger forecast errors from weather-driven renewables are likely to lead to a need to manage larger imbalances at short notice.

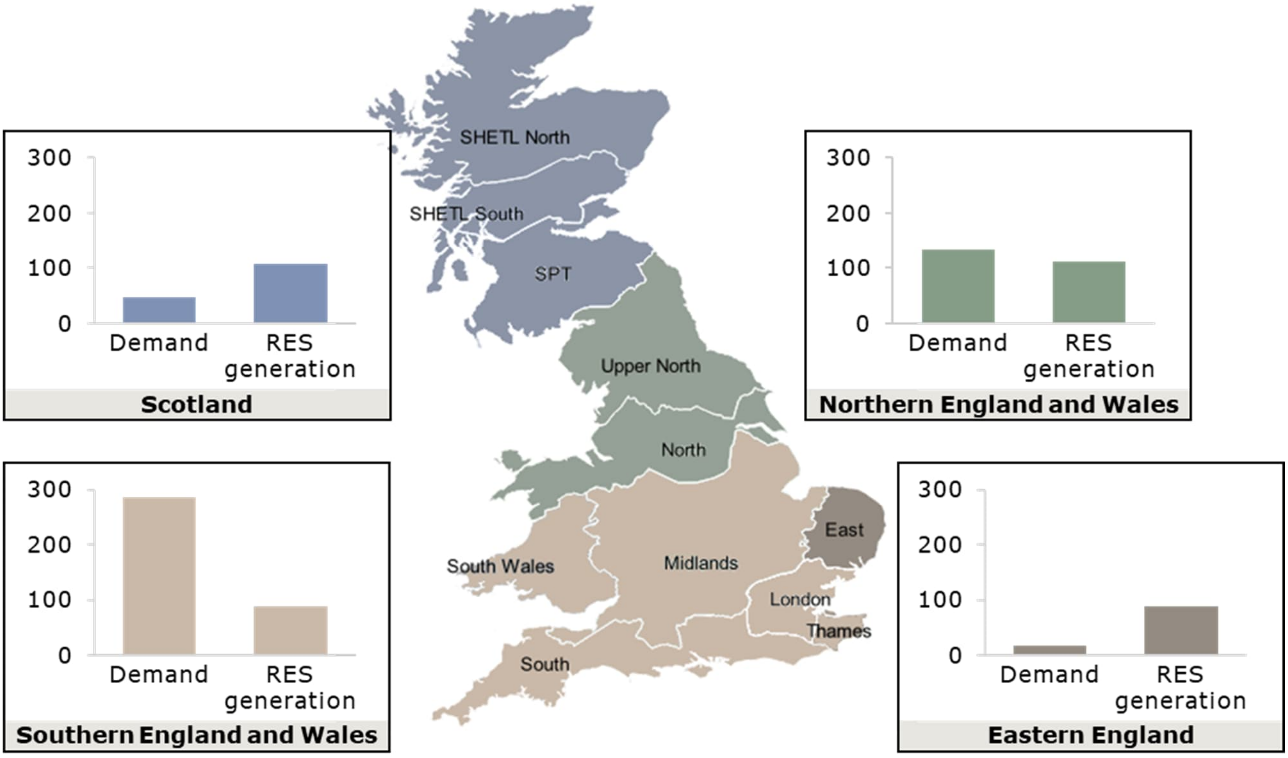
2.1.3 Utilising geographically diverse wind and solar resource will increase power network congestion

In addition to the temporal need for flexibility, there will also be a greater need for locational flexibility. Wind and solar resources are not typically distributed close to demand, but rather sited based on available network connections, land value, geographic topography, and, most importantly, renewable resource (high wind speeds and to a lesser extent solar irradiation). In order to maximise the potential of these technologies, growing quantities of generation will be located further from demand centres.

Exhibit 2.6 illustrates how wind and solar generation in Scotland and East England is proportionally higher than their regional demand requirements. In Scotland, renewables alone are forecast to generate 60TWh surplus generation relative to total regional demand in 2035.

[18] Big data and artificial intelligence have great potential to improve weather forecast accuracy – this may counterbalance forecast error growth from increased renewable penetration.

Exhibit 2.6 – GB regional annual demand and RES generation in 2035 (TWh)



Notes: AFRY analysis using CCC assumptions. For this modelling exercise, 2012 weather patterns were used.

Limited capability to transmit power to the major demand centres, particularly in the South of England, results in forced wind curtailment and activation of replacement generation at uncongested parts of the network. This results in wasted renewable output and potentially increased emissions from activated replacement generation, all at significant additional cost. This practise is likely to continue as more dispersed renewable capacity is deployed.

National Grid Electricity System Operator (NG ESO) and the Transmission System Operators (TSOs) are tasked with cost-effectively integrating rapidly growing levels of renewables onto the network, weighing up the cost of redispatch against reinforcement of transmission capability or use of storage technologies, in order to soak up excess generation. More fundamentally, it is important that the cost of connecting generation and load to the network should be reflected in their respective revenues and costs, in order to promote efficient geographic investment.

2.2 There are a range of solutions that can provide differing system flexibility needs

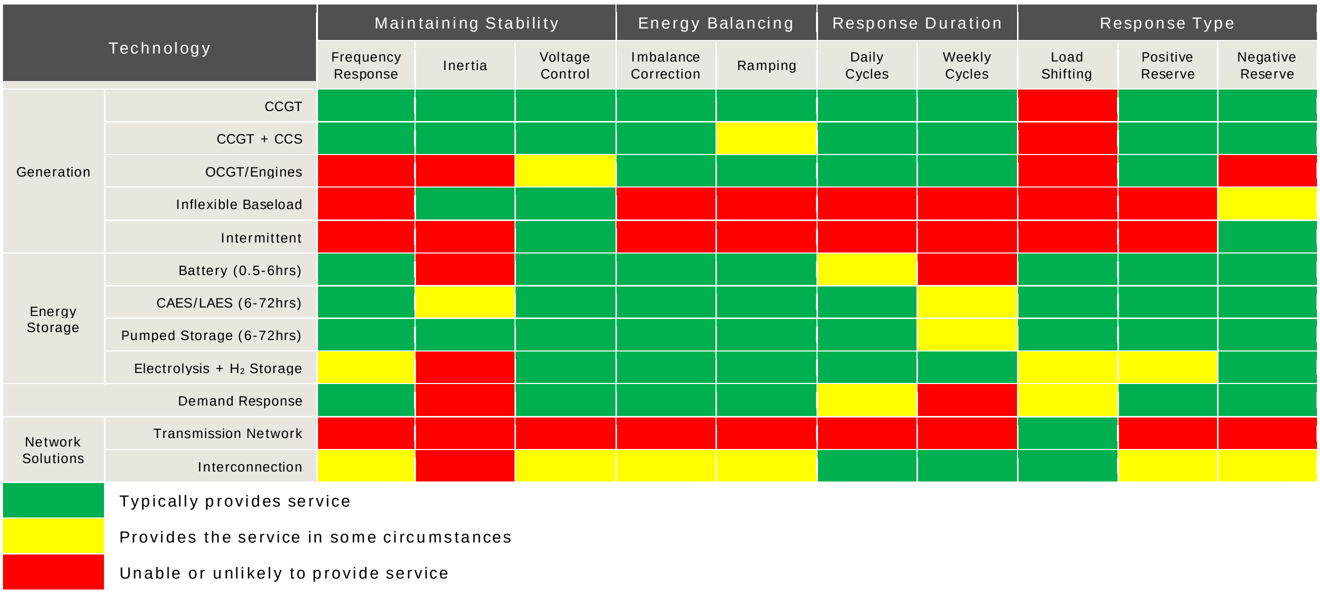
Electricity system flexibility today is almost entirely delivered on the supply side. The provision of existing flexibility is dominated by gas-fired generation. CCGTs and OCGTs form the backbone of system flexibility. In recent years, growing numbers of fast responding reciprocating engines (gas and diesel) have come onto the system. This is supplemented by a limited quantity of Pumped Storage plant and almost 2GW of short duration Li-ion battery storage at present. Alongside this, levels of interconnection and demand response have also increased.

The diverse nature of flexibility requirements is mirrored by a similarly diverse set of technological solutions

However, the status quo cannot persist. The role of unabated thermal capacity must be restricted by emission constraints and new flexible solutions will need to be deployed to manage the changing pattern of residual demand.

As we move towards Net Zero, the electricity system will need both fast responding, and longer lasting, flexibility solutions. The diverse nature of flexibility requirements is mirrored by a similarly diverse set of technological solutions that can be grouped into four broad categories – flexible generation, energy storage, demand response and network solutions (see Exhibit 2.7).

Exhibit 2.7 – Flexibility capabilities of different technologies



Each category of flexibility resource offers different types of flexibility, at different time frames, and in different combinations and are therefore more, or less, suited to meeting the flexibility requirements of a Net Zero system. For example, many types of flexible generators can offer longer duration response services but cannot offer the same load shifting capability of many energy storage technologies.

2.3 Modelling methodology

The primary objective of this project is to investigate the necessary scale and range of flexibility options required to balance a low-carbon and weather-driven electricity system that will be decarbonised by 2035. To conduct this analysis, a scenario-based energy modelling methodology was used to examine the flexibility requirements of the future GB energy system.

2.3.1 BID3 model

Energy market modelling was performed using AFRY's proprietary software, BID3. BID3 is AFRY's multi-market dispatch model that uses advanced mathematical techniques to model the dispatch of supply and demand, market prices, capacity evolution, and all other important features of energy markets.

For the purpose of this research, features of the BID3 platform included:

- the 'Auto Build' module, which was used for scenario creation with optimal least-cost new-build, retrofitting, retiral and mothballing;
- sophisticated treatment of demand response and energy storage, allowing simulation of flexible load such as electric vehicles and heat, and detailed modelling of various energy storage technologies;
- hydrogen and power sector coupling including hydrogen production, storage, transmission between zones, and consumption;
- geographic resolution, which allows BID3 to give proper representation to the spatial constraints within the GB power and hydrogen sectors; and
- co-optimisation of energy and ancillary services, including frequency response, regulating reserve and short-term operating reserve (STOR).

The energy modelling for each scenario/sensitivity includes 6 snapshot years up to 2050, with a focus on the near-term (i.e. 2025, 2028, 2030, 2035, 2040, and 2050). Each future year is simulated under 5 historical weather patterns (2012, 2014, 2015, 2017, and 2018), to reflect a range of possible outcomes for uncertain, weather-driven features of power systems[19]. This includes demand for power, as well as production from wind and solar.

For a detailed description of the modelling methodology, please see Annex A.

2.3.2 Input assumptions

The scenarios and sensitivities were constructed using the most current and relevant data. Key assumptions included power and hydrogen demand outlooks, which were informed by scenarios outlined in the CCC's Sixth Carbon Budget, specifically the "Balanced Pathway," "Widespread Innovation," and "Headwinds" scenarios. Additionally, the deployment of renewables was guided by the ambitions outlined in the BESS. These inputs, along with technology costs, commodity prices, carbon prices, and system constraints, were developed in collaboration with the CCC and a Steering Group comprising key stakeholders.

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[19] The analysis does not incorporate changing climate/weather patterns that could be expected in future.

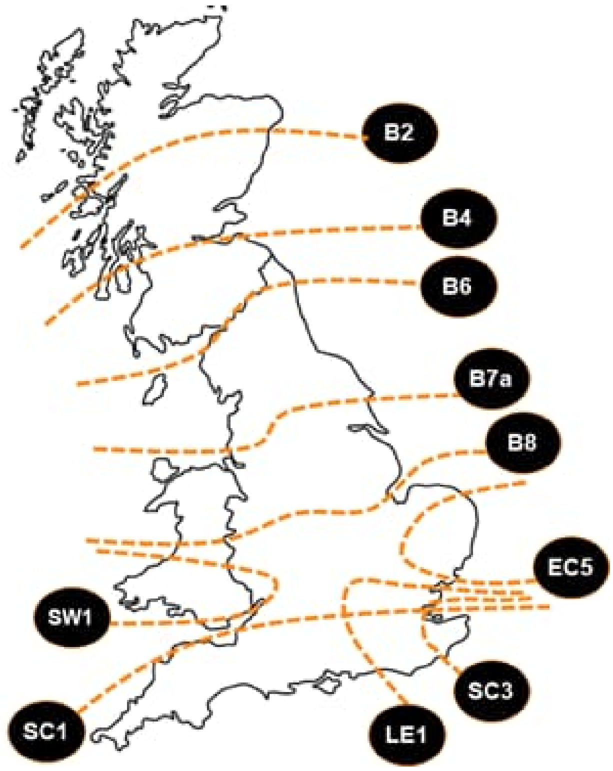
AFRY supplemented input assumptions where required and converted high level assumptions into granular modelling data (e.g. hourly shaping of demand, geographic distribution of future renewable capacity).

2.3.3 Modelled constraints

A series of constraints were imposed on the model runs, including security of supply standards (for power and hydrogen), ancillary service requirements (e.g. frequency response and replacement reserve), and build resource limits.

In order to assess locational flexibility needs and to incorporate the cost of transporting power and hydrogen, the modelling considered GB as 11 separate energy zones determined by constraints in the power transmission network at present.

Exhibit 2.8 – Boundary map

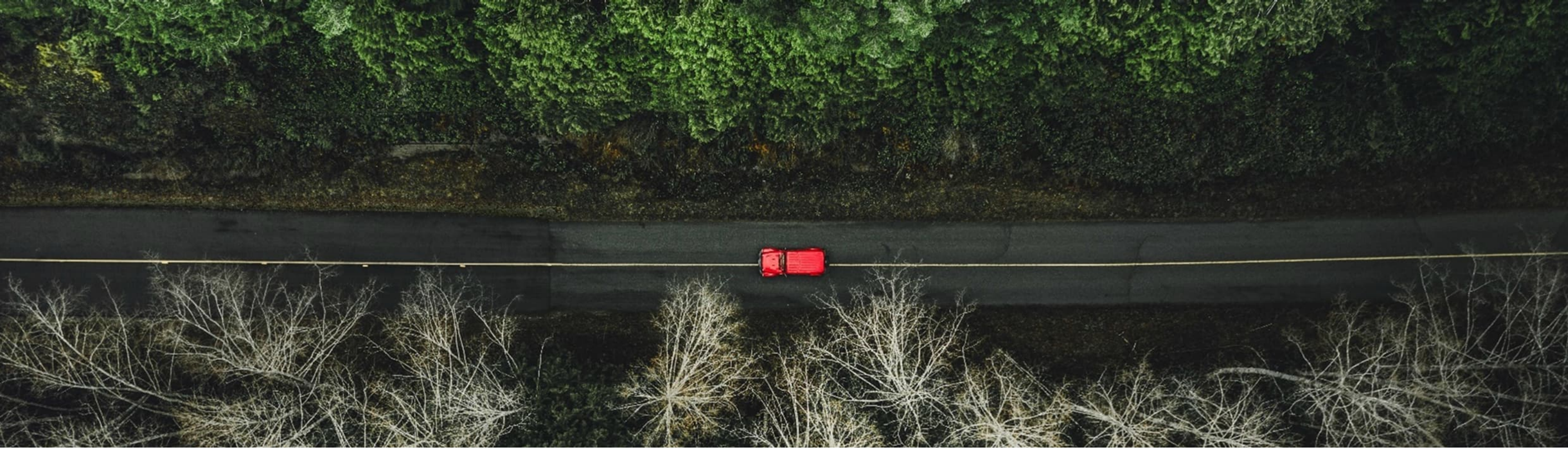


Notes: Each of the 10 boundaries are subject to transmission limitations for power and hydrogen.

Exhibit 2.9 – Energy zones

Notes: Supply and demand must be balanced for power and hydrogen in each of the 11 zones.

The viability of deploying CCS and utilising salt caverns for hydrogen storage were zonally assigned in order to better understand the locational feasibility of different technologies. Furthermore, constraints on the build rate and earliest deployment year were applied to reflect the fastest possible development of these emerging technologies.



3 Pathways to decarbonise the GB power system by 2035

This Chapter presents a summary of the modelled scenarios and sensitivities. This includes an explanation of the design process, particularly with regard to the technologies that were fixed and optimised. Finally, a brief synopsis of the sensitivities is provided, outlining the narrative and modelling approach adopted.

The complexity of present and future energy systems, and their uncertain and changeable characteristics, creates challenges for energy market analysis and developing a robust set of tracking indicators. To manage this unpredictability, a scenario-based modelling approach was taken in order to inform a range of outcomes for each indicator at any point in time, as well as over time. The analysis involved the creation and evaluation of 3 core scenarios and 12 sensitivities[20].

From this pool, the CCC carefully selected specific scenarios and sensitivities to inform the range of indicators. To effectively account for the complex and interconnected nature of energy systems, the selection process concentrated on key assumptions with high levels of uncertainty, while also considering a diverse set of outcomes that recognises the uncertainty in how the system will ultimately deliver the Net Zero transition.

3.1 Scenarios

The CCC defined 3 core scenarios to reflect a range of demand outlooks for both power and hydrogen. These were guided by demand projections from scenarios developed for the CCC's Sixth Carbon Budget[21], namely the 'Balanced Pathway', 'Widespread Innovation', and 'Headwinds'; Exhibit 3.1 describes the key characteristics of the 3 core scenarios.

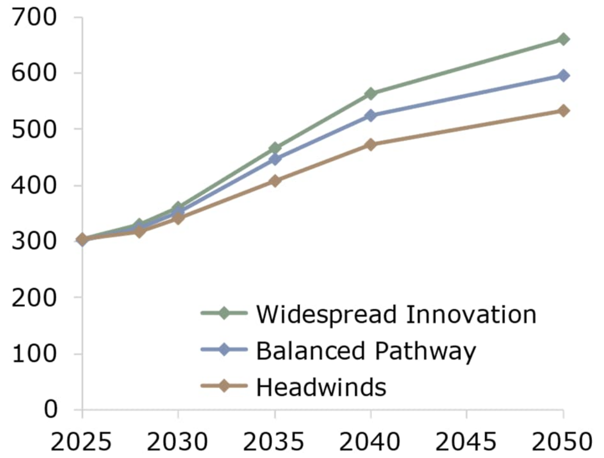
[20] This report presents the results of 3 core scenarios and 9 sensitivities, while the remaining 3 sensitivities are included in a supporting document, Net Zero Power and Hydrogen: Capacity Requirements for Flexibility – Additional Sensitivities.
[21] Climate Change Committee, The Sixth Carbon Budget – The UK's path to Net Zero, December 2020

Exhibit 3.1 – Scenario descriptions

Scenario	Description
Central	Power and hydrogen demand projections based on the CCC's Balanced Pathway. This scenario has the midmost power demand of the 3 scenarios and lowest hydrogen (non-power) demand from 2030 onwards.
High	Power and hydrogen demand projections based on the CCC's Widespread Innovation exploratory scenario. This scenario has the highest power and hydrogen (non-power) demand of the 3 scenarios from 2035 onwards.
Low	Power and hydrogen demand projections based on the CCC's Headwinds exploratory scenario. This scenario has the lowest power demand of the 3 scenarios and midmost hydrogen (non-power) demand from 2030 onwards.

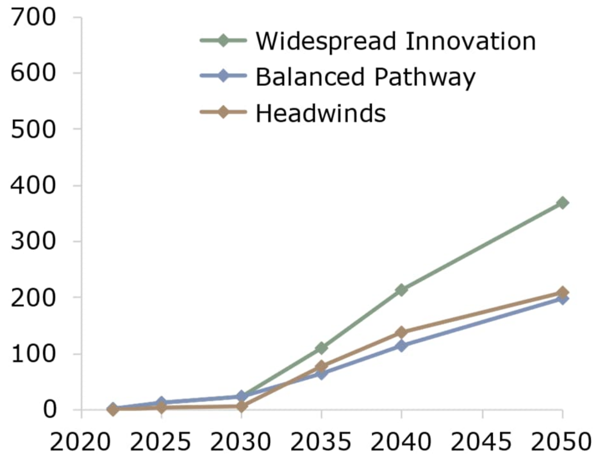
Balanced Pathway was designed to drive progress through 2020s, while creating options in a way that seeks to keep the exploratory scenarios open (i.e. Headwinds, Widespread Engagement, Widespread Innovation, and Tailwinds). This uses electricity efficiently and seeks to limit hydrogen demand to only to where it's needed.
Widespread Innovation is built on the premise that the costs of low-carbon technologies fall further than other scenarios, and technology efficiencies improve. New technologies play a larger role, such as autonomous vehicles and high temperature heat pumps.
Headwinds assumes that policies only manage to bring forward societal/behavioural change and innovation at the lesser end of the scale. This exploratory scenario uses more hydrogen than the Balanced Pathway, with commensurately less electrification (e.g. building heat).
Notes: Hydrogen (non-power) demand projections are not uniformly distributed across the scenarios (please see Exhibit 3.3).

Exhibit 3.2 – Electricity demand by scenario (TWh)



Source: CCC

Exhibit 3.3 – Hydrogen (non-power) demand by scenario (TWh)



Source: CCC

The scenario names (Central, High, and Low) make reference to the level of projected electricity demand, not hydrogen (non-power) demand, out to 2050 (see Exhibit 3.2 and Exhibit 3.3). In addition to the differences in absolute power and hydrogen demand, the fraction of demand allocated to each sub-division[22] drives spatial and load profile variations across the scenarios.

Within the scope of this analysis, the demand for hydrogen is divided into various components. While the non-power hydrogen demand was held as a fixed assumption, the demand for hydrogen in the power sector was part of a cross-sector co-optimisation process. With this objective in mind, the energy modelling had the potential to expand the scope of hydrogen utilisation within the power sector, provided it proves to be the most economically viable option for satisfying the electricity demand.

The Government have committed to decarbonise the power system by 2035, subject to security of supply[23]. In this study, decarbonisation in the energy modelling was driven by a 'value of emissions avoided' (modelled as a carbon price[24]) rather than an explicit emission limit constraint or the simulation of regulatory instruments that ban unabated fossil fuel technologies. The outcomes of all the scenarios and sensitivities were all sense-checked and resulted in gross emissions of below around 10MtCO_2 in the power and hydrogen sectors together which, in discussions with CCC, were considered reasonable accounting for the potential for negative emissions and interpretation of the security of supply provision in the Government commitment.

3.1.1 The energy modelling comprises a fixed capacity outlook for certain technologies

To streamline the modelling process, the scenarios and sensitivities are situated within a future that is more precisely contextualized, where capacity assumptions have been established for specific technologies. These assumptions cover the potential of renewable and nuclear capacity, the degree of smart demand response, and the interconnection with neighbouring markets. By incorporating these assumptions, together with the foundational demand outlooks, the analysis establishes a framework for optimising the capacity and operation of flexible technologies in the system.

3.1.1.1 Fixed generation capacity

The analysis of the energy system is built upon the premise that a significant level of renewable and nuclear capacity will be deployed in accordance with the expectations set out in the BESS. This forms a critical foundation for the analysis of the system, as the deployment of significant renewable and nuclear capacity will have a significant impact on the potential for energy system optimisation and the role of flexible capacity in meeting demand.

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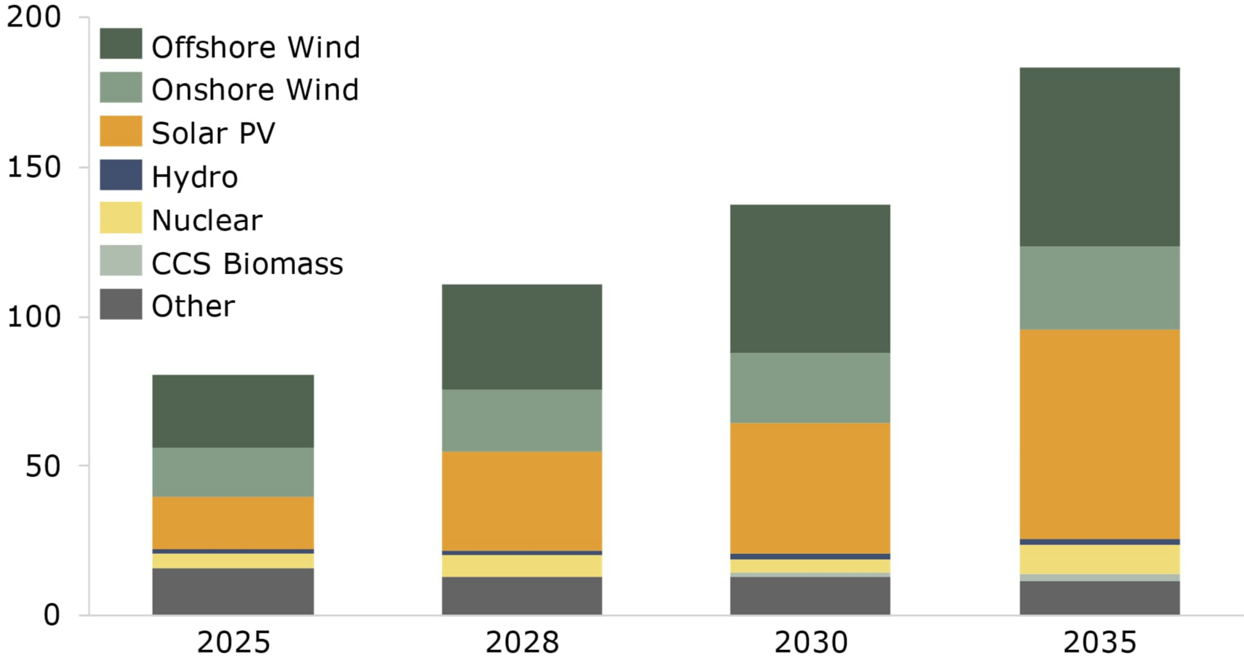
[22] Power demand is divided nationally (England, Scotland, and Wales) and by consumption group (Base, EV, and Heating). Hydrogen (non-power) demand is divided by sector, specifically Removals, Surface Transport, Aviation, Shipping, Residential Building, Non-Residential Building, Agriculture, Manufacturing & Construction, Fuel Supply, and Waste.
[23] HM Government/BEIS, Net Zero Strategy: Build Back Greener, October 2021
[24] The assumed carbon price is £260/tCO_2 in 2025, rising in a linear fashion to £378/tCO_2 by 2050 (see Annex A for more details).

Exhibit 3.4 – Fixed generation capacities in the power sector (GW)



Biomass CCS capacity was back-calculated from biomass feedstock assumptions (baseload operation).
Other technologies include Biomass, Energy for Waste, Combined Heat and Power, and Reciprocating Engines.
Notes: Demand side response is an input assumption, however it is a function of demand (fixed fraction) and therefore differs across the scenarios.
Source: AFRY, CCC

The fixed capacity projections for generation technologies utilised in this analysis are presented in Exhibit 3.4. These projections were established in consultation with the CCC and are grounded in declarations made by the UK Government, availability forecasts for biomass feedstock, economic analysis, and expert assessment.

This includes[25]:

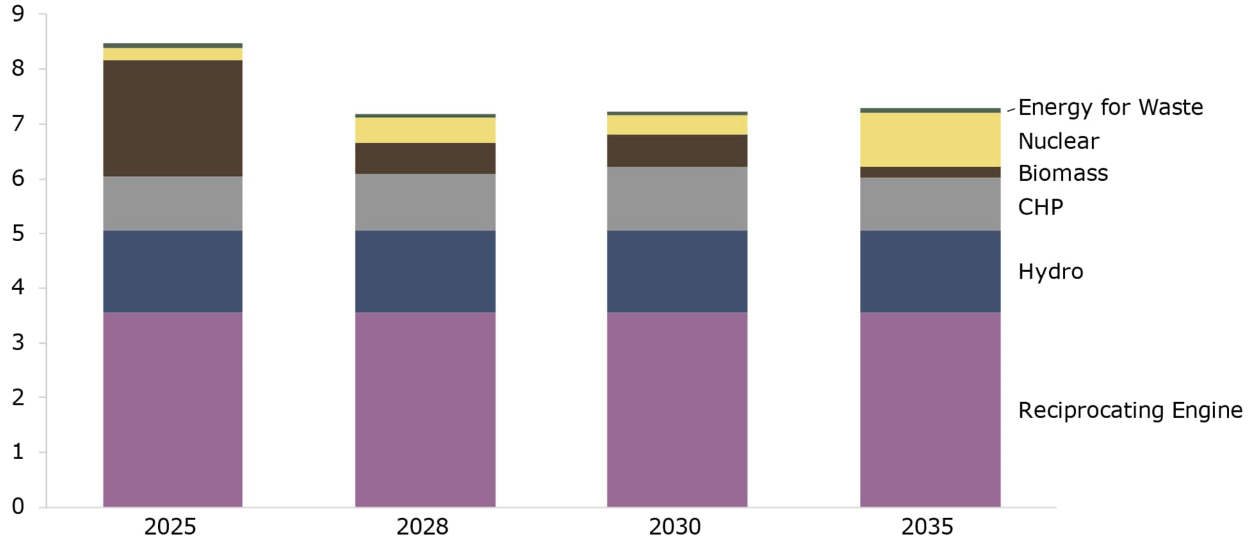
- Wind and Solar PV: Guided by BESS stated ambitions, including delivering 50GW of Offshore Wind by 2030 and 70GW of Solar PV by 2035.
- Hydro: Existing hydro plants comprising both run-of-river and reservoir hydro technology types.
- Nuclear: BESS stated ambition for up to 24GW of nuclear capacity by 2050.
- Biomass CCS: Incremental conversion of existing large biomass plants.

[25] Detailed capacity assumptions can be found in the accompanying results Excel workbook.

- Other:
  - Biomass: Only one operational unabated plant post-2030.
  - Combined Heat and Power (CHP): Gas CHPs are assumed to retrofit to hydrogen by 2035. Small-scale CHPs which undergo retrofit are considered as non-power hydrogen demand.
  - Energy for Waste and Reciprocating Engines: AFRY analysis based on capacity data is from the Capacity Market Registers and Renewable/CHP Register.

For the purpose of this analysis, the capacities of these technologies were fixed and not available in the optimisation of future plant capacity. However, the hourly economic dispatch did consider the intrinsic flexibility of each technology – this was restricted by the operational parameters and monthly availability (adjusting for temperature, water levels, outage schedules) of each technology type (see Exhibit 3.5).

Exhibit 3.5 – Embedded dispatch flexibility of fixed capacity technologies (ramping capability in GW/hr)



Reciprocating Engine: Capability to fully ramp up and down.
Hydro: Capability to ramp down to approximately 10% of capacity.
Biomass: Capability to ramp down to approximately 50% of capacity.
CHP: Capability to ramp down to approximately 80% of capacity.
Nuclear: Capability to ramp down to approximately 90% of capacity.
Energy for Waste: Capability to ramp down to approximately 90% of capacity.

Most of the dispatch flexibility from the fixed capacity technologies is derived from Reciprocating Engines and Hydro, amounting to 5GW/hr over the modelled period. While Biomass offers significant dispatchability in 2025, it is mostly phased out by 2035 due to its integration with CCS capability, which is assumed to remove operational flexibility in this study. The rest of the flexibility is offered by Nuclear, CHP, and EfW, which have limited ability to adjust generation responsively from their respective maximum export limit (MEL).

3.1.1.2 Fixed DSR capacity

Demand Side Response (DSR) is a method used on the demand-side to balance the system. It encourages consumers to modify their energy usage patterns to help balance the grid. This can be achieved by shifting or reducing consumption in response to changing market conditions, such as supply shortages manifesting as price spikes.

Exhibit 3.6 – Output capacity of DSR by type (GW)

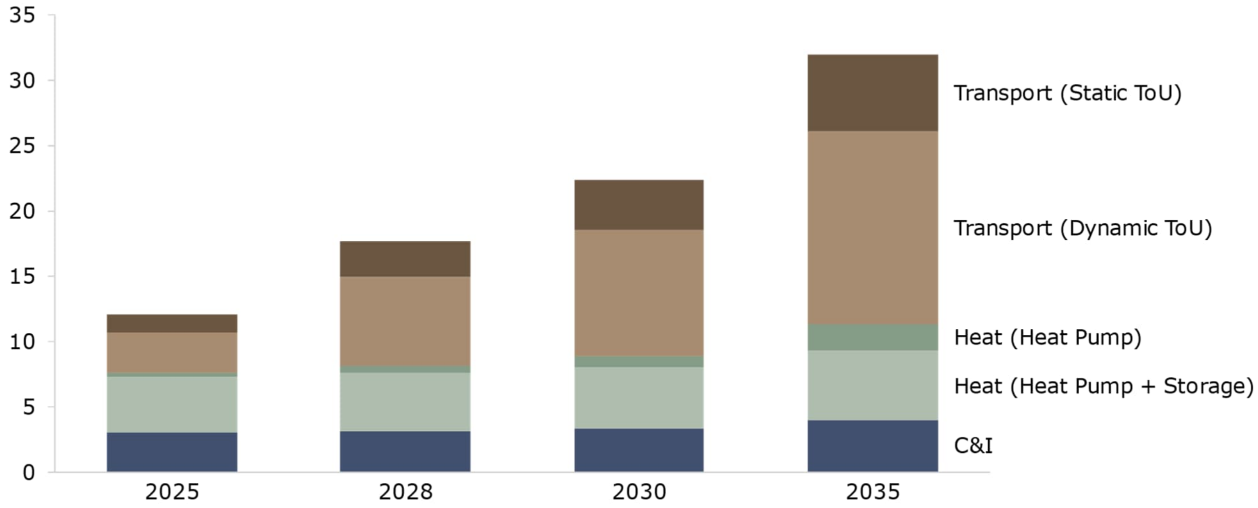


Exhibit 3.6 shows the modelling of different categories of DSR in this study, the capacity and operational parameters of which are fixed. The emergence of this responsive demand is predicated heavily on the electrification of transport and heat (i.e. adoption rates for electric vehicles and heat pumps), as well as consumer engagement in these areas. Additionally, it assumes that consumers will have access to the necessary technology and infrastructure to take part in DSR programs, and that they will be motivated to do so through pricing and other means.

The energy modelling incorporates the different categories of DSR in distinct ways:

- Transport DSR modelling is bifurcated into two representative consumer types, namely: Static Time of Use (ToU) and Dynamic ToU tariff users:
  - For Static ToU, the demand profile is tailored to exhibit a smoother profile than that of inflexible electric vehicle consumers.
  - Dynamic ToU consumers follow a more complex optimisation process based on hourly prices, while being limited by time and charge level constraints.
- Heat DSR comprises two types of representative electrical heating configurations, namely heat pump in isolation (capable of shifting

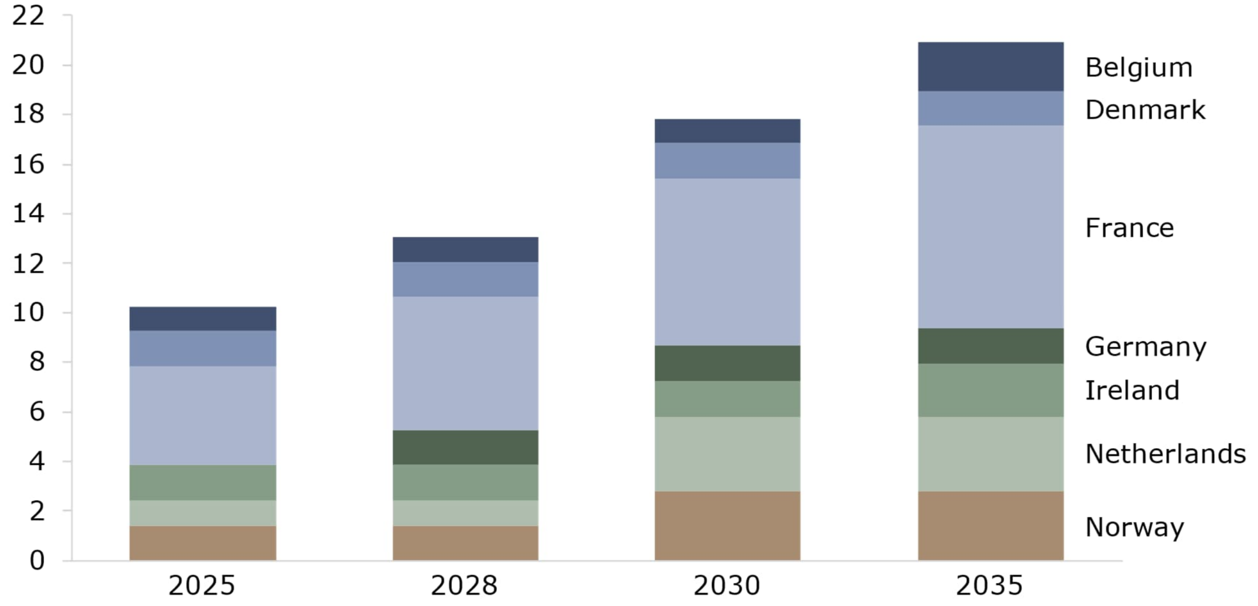
demand by 4 hours) or heat pumps with heat storage (capable of shifting demand by 8 hours).

- Commercial & Industrial (C&I) DSR is the only reduced consumption DSR (i.e. ‘turn-down’) considered in this analysis. This could theoretically run continuously, however is limited to capacity provision due to the prohibitive activation cost at £500/MWh.

3.1.1.3 Fixed Interconnector capacity

The outlook for interconnector capacity (see Exhibit 3.7) was predetermined in this analysis and factored in several uncertain factors such as country specific congestion rent. Please note that the outlook is consistent with the interconnector capacity projections in the NG ESO Future Energy Scenarios[26].

Exhibit 3.7 – Outlook for GB interconnector capacity (GW)



Notes: The outlook is consistent with the projections in the NG ESO Future Energy Scenarios (2021).
Source: AFRY, CCC

This study modelled the dispatch of new and existing interconnectors between markets. The interconnectors were assumed to be employed to their optimal capacity, akin to a market coupling arrangement, and were based on the arbitrage of market prices.

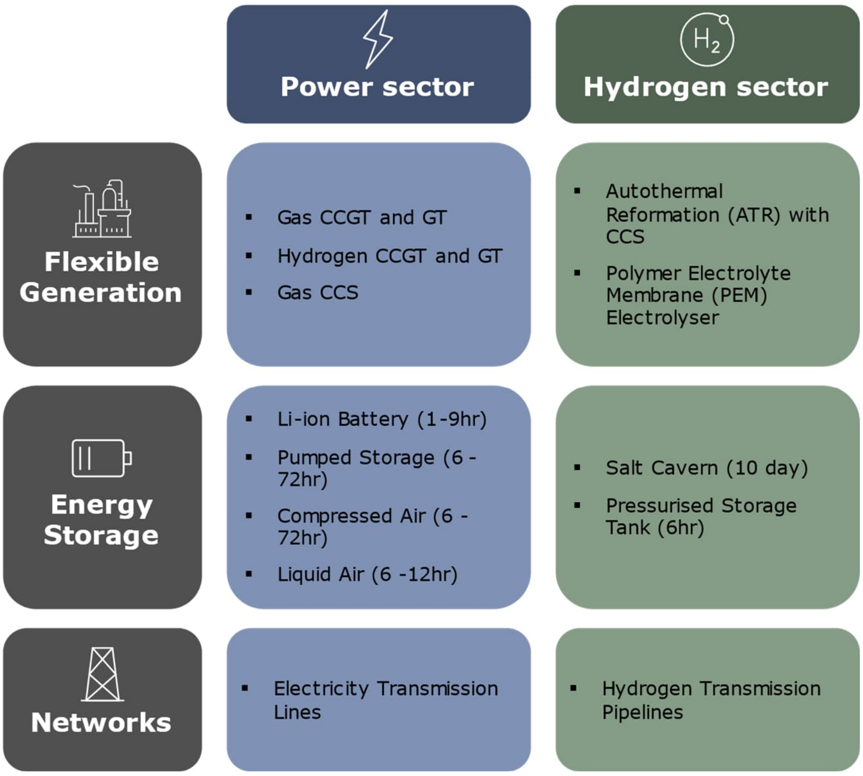
In scenarios and sensitivities featuring comparable patterns of residual demand, fixed interconnector flows from the Central scenario were utilised. However, for sensitivities displaying significant deviation, interconnector flows were subject to re-optimisation[27].

[26] NG ESO, Future Energy Scenarios, July 2021
[27] This included the Low RES/Nuclear, Low Wind Year, and Long Wind Drought sensitivities.

3.1.2 The capacity and dispatch of flexible technologies is subject to the optimisation process

By incorporating the above-mentioned fixed capacity assumptions, together with the base demand outlooks, the analysis establishes a framework for optimising the capacity and dispatch of flexible technologies in the system. The diverse set of flexibility requirements of a low-carbon and weather-dependent electricity system is mirrored by a similarly diverse set of technologies which are considered as part of the BID3 optimisation. These are grouped into three broad categories[28]: flexible generation, energy storage, and network solutions (see Exhibit 3.8).

Exhibit 3.8 – Optimised flexible capacity technology options

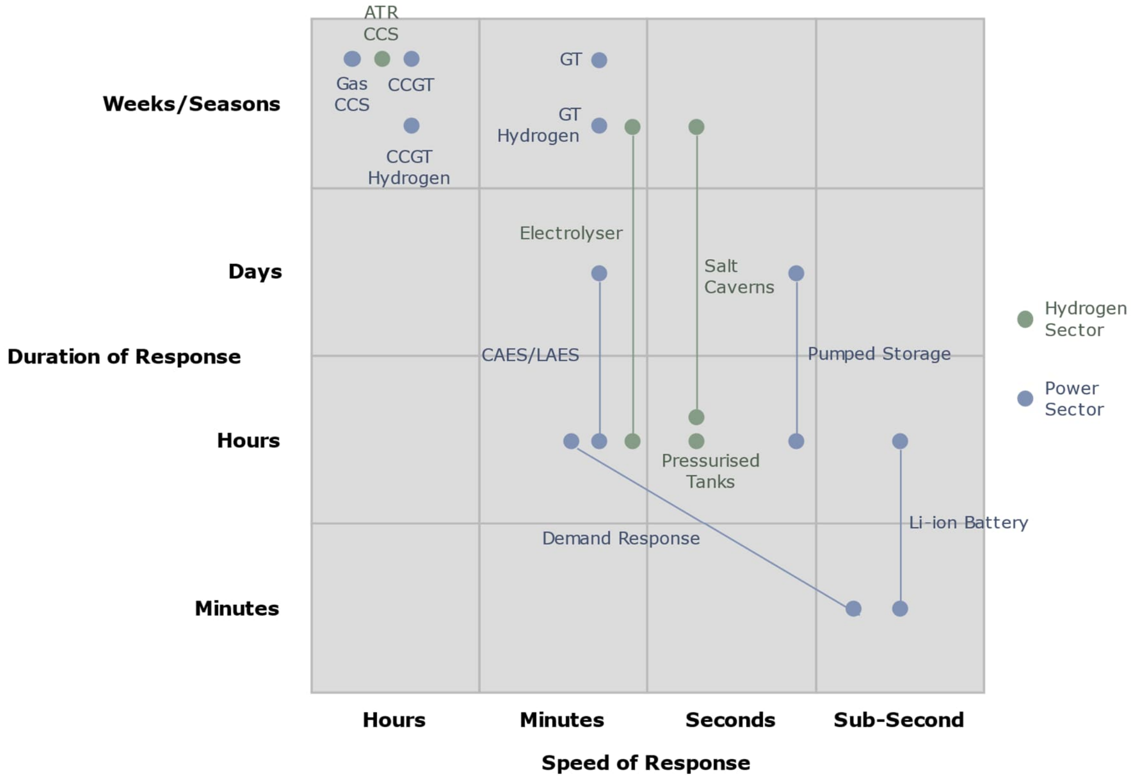


Hydrogen CCGT considers both new build and retrofit of existing Gas CCGT.
Electricity Transmissions Line reinforcement out to 2030 is fixed, based on the 2021 NOA[29]. Post-2030 the model optimised the investment in power transmission lines across the 10 boundaries mapped in the modelling methodology.

The identified solutions are capable of addressing all 3 of the main flexibility requirements identified in section 2.1. These requirements include balancing supply and demand over multiple timeframes, ensuring system stability, and managing location-based constraints. Each technology can perform different roles within the system depending on their bespoke flexibility characteristics. Examples of technology-specific flexibility parameters, such as duration and speed of response, are shown in Exhibit 3.9.

[28] The capacity of DSR is a fixed input in this study.
[29] NG ESO, Network Options Assessment, January 2021

Exhibit 3.9 – Flexibility matrix for sample set of technologies (illustrative)



Trends can be inferred from this flexibility matrix, such as that flexible generation technologies such as Gas CCS and Hydrogen CCGT, are ideal for addressing longer periods of residual demand due to their innate ability to run continuously. On the other hand, grid storage and DSR are better placed to handling extreme ramps and within-day variability.

3.2 Sensitivities

In addition to the 3 core scenarios, this study included the design and assessment of a range of sensitivities to complement the core scenarios and explore key uncertainties. The Central scenario (guided by the Balanced Pathway) acted as a 'reference' scenario – a baseline against which sensitivities are derived and compared (see Exhibit 3.10).

The sensitivities can be grouped into three themes:

1. Technology mix: The fixed capacities in the core scenarios are predicated on highly uncertain assumptions, particularly with regards to the ambitious delivery of RES and Nuclear (as outlined in the BESS). It is important to understand how sensitive the development of flexible capacity is to these assumptions. To explore this, 3 'technology mix' sensitivities were created to reflect alterative future energy mix: a more conservative deployment of RES and nuclear; increasingly responsive and synergistic demand; and, reallocation of limited biomass feedstock across the energy system.

2. Technology risk: The Central scenario relies heavily on the delivery of emerging technologies (e.g. Gas CCS and hydrogen plant) and the supporting infrastructure (e.g. H_2/ CO_2 pipelines and storage). This creates a risk since the speed with which these technologies can be commercialised and deployed is uncertain. To understand the impact of this risk we have undertaken several 'technology risk' sensitivities by limiting or delaying deployment of such technologies.

3. System stress events: With the energy system being increasingly weather driven, it is important to understand how robust the system is to extreme weather events. To capture this, we have undertaken two sensitivities that reflect particular extremes in future weather patterns – a 'Low Wind Year' and a more extreme sensitivity that combines this with a 'Long Wind Drought'. For both these sensitivities we have examined the optimal investment pattern and dispatch relative to the Central scenario in order to examine the characteristics of a more resilient energy system. In addition to weather-driven shortfall events, system stress originating from poor market design has been investigated. This focuses on the inefficient procurement of ancillary services due to the decentralisation of balancing responsibility.

Exhibit 3.10 – Sensitivities by theme

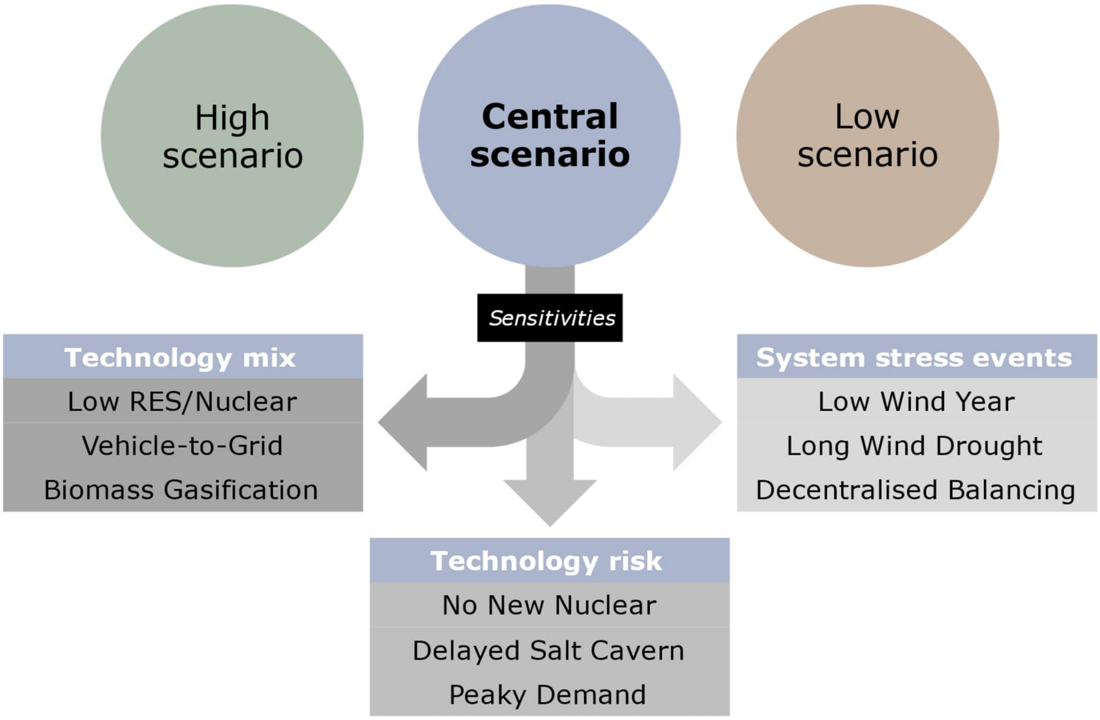


Exhibit 3.11 provides a high-level summary of each sensitivity. A thorough synopsis, alongside a more detailed description of the adjusted inputs and constraints, can be found in the Results chapter.

Exhibit 3.11 – Sensitivity descriptions

Sensitivity	Description
Low RES/Nuclear	This sensitivity explored the impact of a more conservative deployment of RES and Nuclear capacity. The reduced RES/Nuclear capacity outlook is based on the CCC's view in 2020.
Vehicle-to-grid	This sensitivity examines a future in which EV demand plays a more active role in the power system, enabling energy to be pushed back to the power grid from the battery of an electric vehicle (not just responsively charge).
Biomass Gasification	In this sensitivity, biomass allocated to CCS-enabled power generation is shifted to CCS-enabled biomass gasification for hydrogen production.
No New Nuclear	This sensitivity examines a future GB energy system with limited reliance on nuclear power. It assumes no new build nuclear after Hinkley Point C.
Delayed Salt Caverns	This sensitivity examines how the timely development of salt caverns impacts the balance of flexible capacity. While in the core scenarios salt caverns can be used as a hydrogen storage solution from 2030, this sensitivity delays salt cavern availability until 2040.
Peaky Demand	Electrified heat demand has been increased, exhibits a peakier profile and demand is considered unresponsive to price. This reflects weak building energy efficiency improvements and limited implementation of smart heating controls.
Low Wind year	Weather patterns from year 2010 are used in the optimisation, which exhibits the lowest wind load factor since 1990. Optimising capacity against an outlier year in this manner is reflective of setting capacity market auction parameters against a more conservative reliability standard. Future climate impacts on wind strength and wind regimes remain uncertain, hence historical data have been used.
Long Wind Drought	This sensitivity investigates a worst-case combination of weather patterns and tests if there is sufficient capacity deployed in the core scenarios, by combining the 'Low Wind Year' sensitivity with an artificially imposed sustained period of low wind. Future climate impacts on wind strength and wind regimes remain uncertain, thus historical data have been used.
Decentralised Balancing	This sensitivity examined the decentralisation of balancing responsibility; promoting a more 'active' role for market participants (i.e. generators and/or suppliers) with the intention to minimise the importance of central decisions.

In addition to the sensitivities described above, 3 additional sensitivities have been modelled for the project: Grid Storage, Ban Unabated Gas, and Low Interconnector. The design and results of these sensitivities have been outlined in a supporting document due to project timing constraints. It should be noted that the Grid Storage sensitivity is included in the tracking indicators range.

4 Results

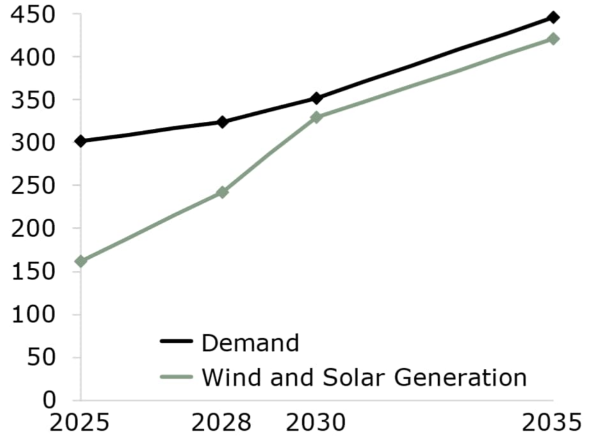
In this chapter, the modelled results for the scenarios and sensitivities are summarised. A detailed examination of the Central scenario provides a reference against which a synopsis of the high/low scenarios and sensitivities are compared. The assessment focuses on the capacity of flexible technologies required in the power and hydrogen sector as we transition to a decarbonised power system by 2035.

4.1 Central scenario

4.1.1 Power Sector

4.1.1.1 The shape of residual demand will be becoming increasingly variable and extreme

Exhibit 4.1 – Demand and wind/solar generation (TWh)

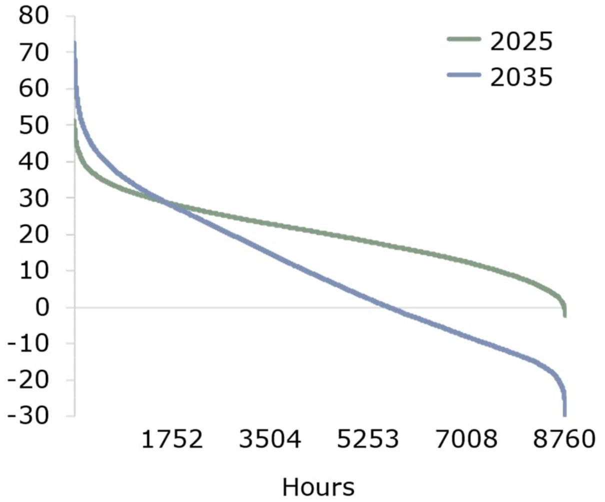


Notes: Central scenario and 2012 weather patterns

Electricity demand is expected to increase from around 300TWh in 2025, to 450TWh in 2035. Meanwhile, wind and solar generation will grow faster, increasing from 160TWh to over 420TWh in the same period, as shown in Exhibit 4.1.

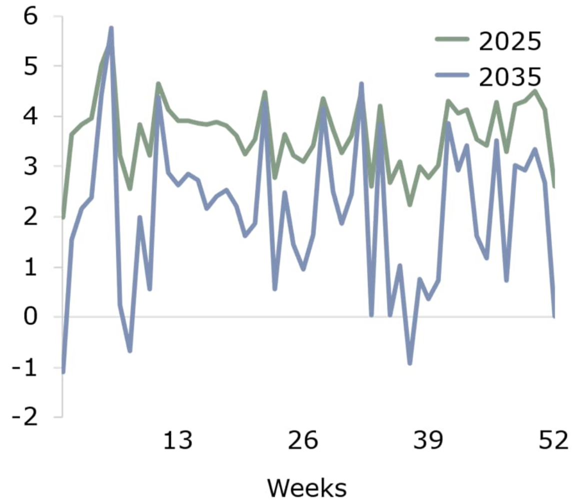
Residual demand, defined as final consumption minus renewable generation, represents the load that must be met by non-renewable sources, such as power plants, interconnector flows, energy storage, or DSR. The volume and shape of residual demand are crucial determinants of the capacity and combination of flexible solutions required to balance an electricity system.

Exhibit 4.2 – Duration curves for hourly residual demand (GWh)



Notes: Central scenario and 2012 weather patterns

Exhibit 4.3 – Weekly net total residual demand (TWh)



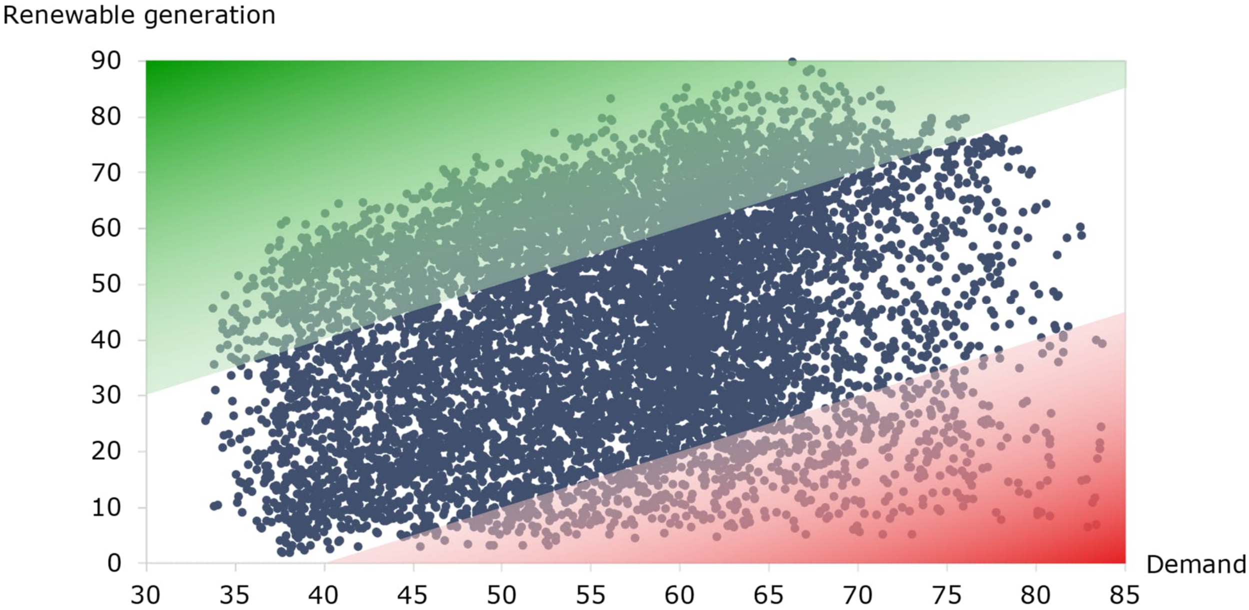
Notes: Central scenario and 2012 weather patterns

Growing demand for electricity, combined with the expansion of renewable energy, significantly alters the nature and scale of residual demand:

- Exhibit 4.2 illustrates the development of the residual demand duration curve and how it becomes increasingly extreme. In 2035, the hours of high residual demand (generation deficit) are more severe and occur more frequently compared to 2025; the hour with the highest residual demand in 2035 is 73GW, a significant increase of 21GW from the peak residual demand hour in 2025. Moreover, there will be a considerable rise in the number of instances of negative residual demand (generation surplus) that need to be balanced; in 2025, negative periods of residual demand occur only about 1% of the time, but this increases to 36% of the time in 2035.
- Exhibit 4.3 shows that residual demand will become more unpredictable with longer periods of high and low residual demand, and more frequent fluctuations from week-to-week. There will be multi-week periods where residual demand is as high as in 2025 and also multi-week periods where it is close to zero. Furthermore, the highest residual demand week is in 2035.

Challenges of balancing the electricity system are poised to intensify with both more extreme residual demand positions to manage and greater volatility over time

Exhibit 4.4 – Relationship between hourly renewable generation and electricity demand in 2035 (GWh)



Green area comprises hours with negative residual demand.
Red area comprises hours with >40GW of residual demand.
Notes: Scatter plot using 2012 weather patterns.

Exhibit 4.4 presents the relationship between renewable generation and demand in each hour of 2035. Hourly renewable generation and demand are weakly correlated[30] and this creates two situations, highlighted by the coloured areas:

- The dots within the red area correspond to hours of high demand relative to renewable generation (over 40GW of residual demand). This requires a high level of flexible resource to meet the shortfall.
- The dots within the green area correspond to hours of negative residual demand. This requires interconnector exports, demand increases, electrolyser activation, and/or charging of energy storage technologies to avoid curtailment of generation.

In summary, the challenges of balancing the electricity system are poised to intensify. To effectively address these issues, a range of flexible solutions will be required, each tailored to meet specific demands. During system stress events, there must be sufficient dispatchable capacity to meet these demands. Rapidly responding capacity will be necessary to address the most extreme ramping requirements. And overall, there must be enough flexibility to balance supply and demand over both short and long timeframes, from adjustments needed to align intraday deviations, to the longer-term solutions required to balance the prolonged ups and downs of weather-driven renewable energy sources.

[30] Pearson Product-Moment Correlation Coefficient is 0.34 (hourly analysis using average correlation coefficient across 5 weather years).

4.1.1.2 Residual demand will be met by a diverse set of technologies

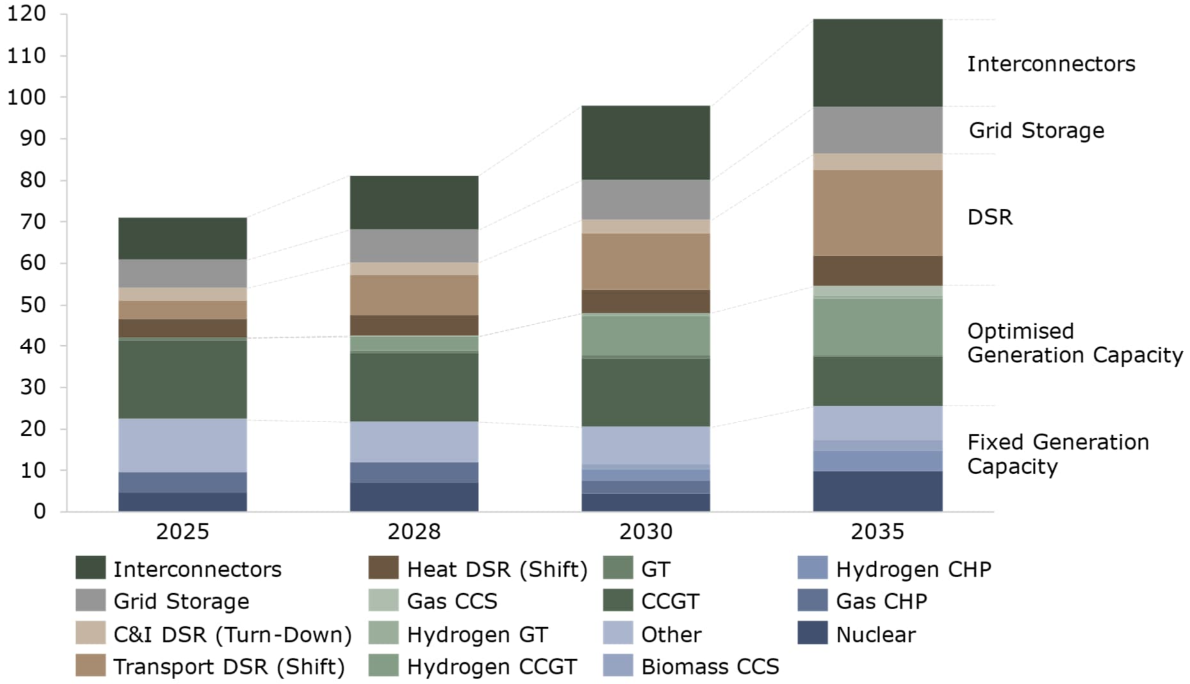
Exhibit 4.5 and Exhibit 4.6 present the outlook for the capacity and annual generation mix (excluding intermittent renewables) in the Central scenario. The fixed generation capacity, interconnector capacity and DSR potential are set out in the input assumptions in Chapter 3, whereas the optimised generation capacity and grid storage capacity are modelled outputs.

These charts highlight the following key trends:

Grid Storage and DSR provide a substantial and growing fraction of capacity

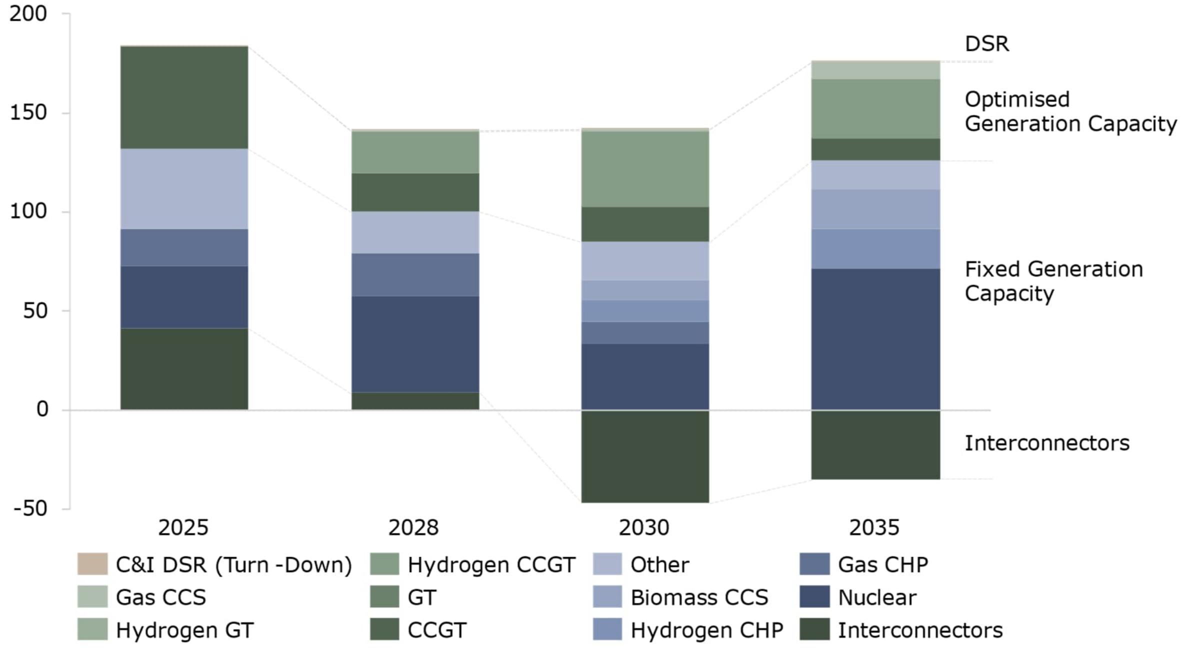
- The share of non-renewable capacity provided by generation technologies (both fixed and optimised) declines over the modelled period; from 59% in 2025, to 46% in 2035. This is due to the rapid expansion of capacity from Interconnectors, Grid Storage, and DSR.
- Grid Storage and DSR provide a substantial and growing fraction of capacity. This provides short-duration flexibility though hourly/daily load-shifting.
- Interconnector flows reverse from net importing pre-2030, to net exporting in the latter years presented. This is driven by the rapid expansion of renewables in the 2030s which dampens GB power prices relative to neighbouring markets undergoing decarbonisation at slower rates.
- The capacity contributions of fixed and optimised generation technologies are approximately equal, however fixed generation technologies provide twice as much generation. This is because the majority of fixed technologies are baseload (nuclear, CHP, Biomass CCS, etc.) while the optimised technologies are dispatchable and are operating at lower load factors.
- The varying generation contribution of nuclear reflects the closures and new build nuclear capacity assumed over the modelled period. Output increases in 2028 with the commissioning of Hinkley Point C, but decreases in 2030 as Heysham and Torness decommission, before increasing again in 2035 as two further plant come online.
- Due to the projected decrease in unabated gas generation by 2035, the combined power and hydrogen sector emissions are expected to decline to 7.5MtCO_2. This represents a 96% drop relative to 1990 power sector emissions (204MtCO_2), or an 85% decrease relative to 2021 power sector emissions (48MtCO_2).

Exhibit 4.5 – Installed capacity mix excluding intermittent renewables (GW)



Other technologies include unabated biomass, EfW, engines, and Hydro.

Exhibit 4.6 – Annual generation mix excluding intermittent renewables (TWh)



Other technologies include unabated biomass, EfW, engines, and Hydro.
Notes: Interconnectors contribution refers to net annual flows: Positive indicates net imports and vice versa.

The trends identified are underpinned by uncertain input assumptions. The sensitivity analysis, presented later in this chapter, tests the robustness of these assumptions regarding the need for flexible capacity. For example, the delivery of Nuclear and the contribution of DSR are examined in the 'No New Nuclear' and 'Vehicle-to-Grid' sensitivities.

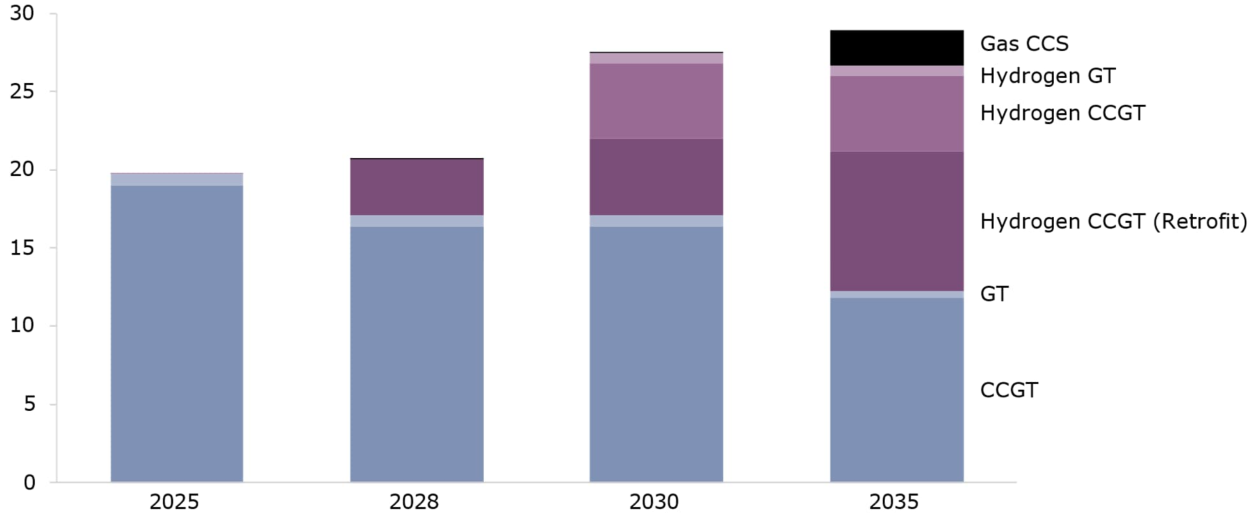
4.1.1.3 The mix of dispatchable generation capacity will undergo a transformative shift and become indispensable in delivering long-duration flexibility

Low-carbon generation technologies that can be dispatched to balance the fluctuations of renewable energy are critical for decarbonising the power system while ensuring long-term flexibility. As the electricity system becomes increasingly reliant on renewables, the need for flexible capacity that can respond to prolonged periods of low energy production becomes more important. Renewable energy sources, like wind and solar, can face long stretches of low power generation that can last multiple weeks. Flexible solutions such as DSR, energy storage, and network solutions may not be able to address these low output periods. During these times, it will be crucial to have low-carbon generation technologies that can operate continuously to maintain reliable system operation.

Exhibit 4.7 and Exhibit 4.8 present the optimised capacity and annual generation of flexible generation technologies; this comprises Gas CCGT and GT, Hydrogen CCGT and GT, and Gas CCS[31].

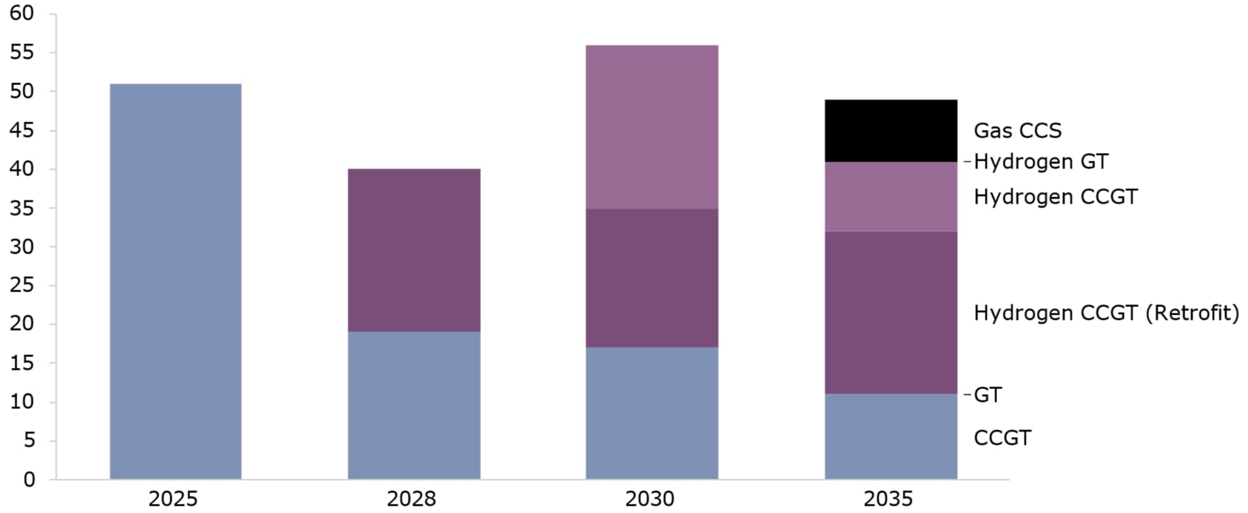
[31] Excludes fixed capacity technologies – see Section 3.1.1 for details.

Exhibit 4.7 – Installed capacity of flexible generation (GW)



Notes: This excludes CCGT capacity that is mothballed in 2025 ahead of anticipated conversion to Hydrogen CCGT (Retrofit).

Exhibit 4.8 – Annual generation of flexible generation technologies (TWh)



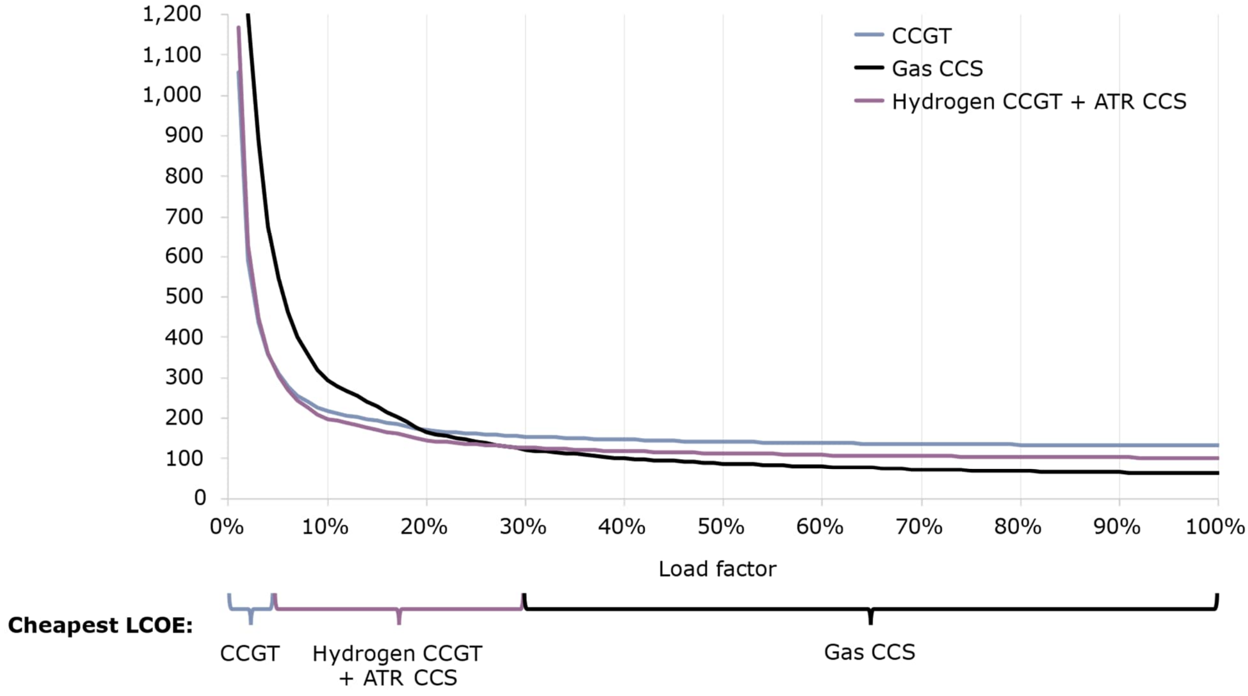
Decarbonisation[32] drives the magnitude and balance of flexible capacity and generation to change substantially over the presented period. In 2025, all the dispatchable capacity and generation is composed of Gas CCGT and GT, totalling 20GW of capacity and generating 51TWh. Over the next decade, low-carbon flexible technologies are rapidly deployed and unabated gas technologies decline. By 2035, the system comprises 12GW of unabated

[32] Driven by the prohibitive running costs associated with the assumed value of avoided emissions; the carbon price exceeds £300/tCO_2 in 2035.

gas[33] with an annual generation of 11TWh, and 17GW of low-carbon flexible capacity generating close to 40TWh.

The shift in the flexible power generation mix is primarily driven by economic factors. Exhibit 4.9 presents the levelised cost of electricity (LCOE) for a selection of flexible generation technologies in 2035 across a range of annual load factors.

Exhibit 4.9 – Levelised cost of electricity (£/MWh) of flexible generation technologies in 2035



Notes: Technology cost assumptions are provided in a supporting workbook.

At a high level the chart illustrates the following trends:

- CCGT is the most cost-effective solution for operations with very low utilisation rates (<5% load factor);
- Hydrogen CCGT supplied by Auto-Thermal Reforming with Carbon Capture and Storage (ATR CCS) is the most economical technology for medium utilisation rates (5-30% load factor); and
- Gas CCS is the most cost-effective solution for operations with high utilisation rates (>30%).

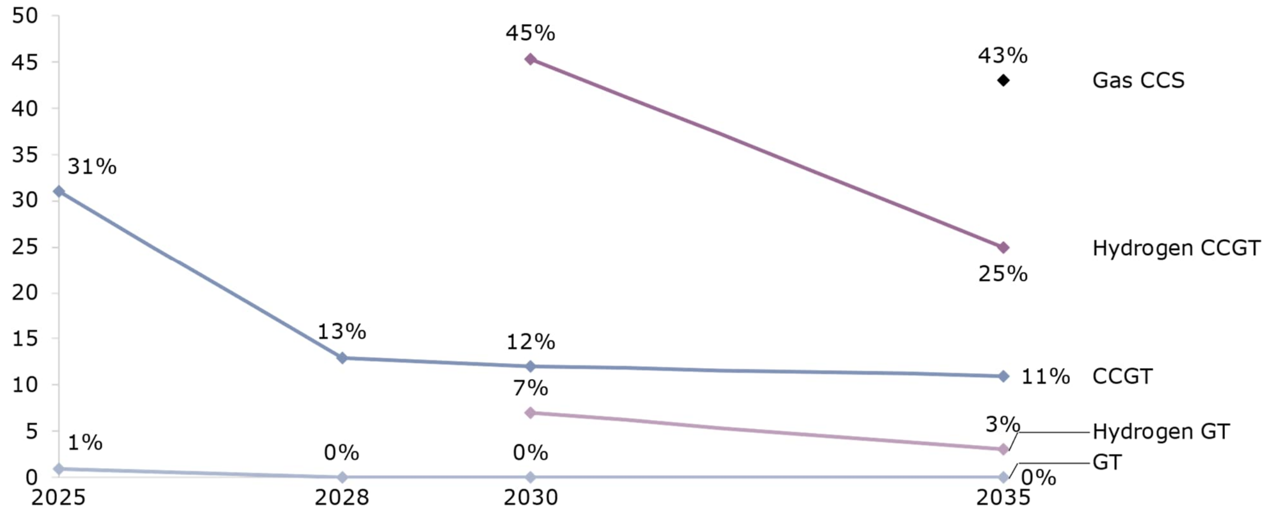
These cost hierarchy trends are overly simplistic, but generally accurate. Complex factors to consider include the existing CCGTs that have already

33 In addition to CCGT and GT capacity, which we commonly refer to as unabated gas throughout this report, there is also around 3.5GW of gas engines (grouped into the ‘Other’ technology type), which run at very low load factor (2%) and the capacity of which is fixed.

absorbed sunk capital costs and are only faced with operating and maintenance expenses, making them more cost-effective at higher utilisation rates and deterring decommissioning. Additionally, the LCOE of hydrogen-fired plants can be significantly lower if they are retrofitted instead of new build and if they are supplied by electrolysers operating at near-zero wholesale power prices (even after accounting for storage costs). The complexities obscure the utilisation boundaries for technology cost-effectiveness, however the identified trends persist.

In the Central scenario, 2035 sees hydrogen-fired plants preferred over Gas CCS, due to the balance of costs aligning better with the expected medium load factors required to adequately balance future patterns of residual demand (see Exhibit 4.10). The large deployment of renewables out to 2050 results in abundant low-cost green hydrogen, amplifying the cost advantage of hydrogen-fired plant over its lifetime. Moreover, there are benefits from a whole system perspective through synergies with the expansion of the non-power hydrogen sector.

Exhibit 4.10 – Load factor of flexible generation (%)



Notes: Hydrogen CCGT load factor is weighted average of both new-build and retrofit plant types.

The scale and balance of low-carbon flexible capacity

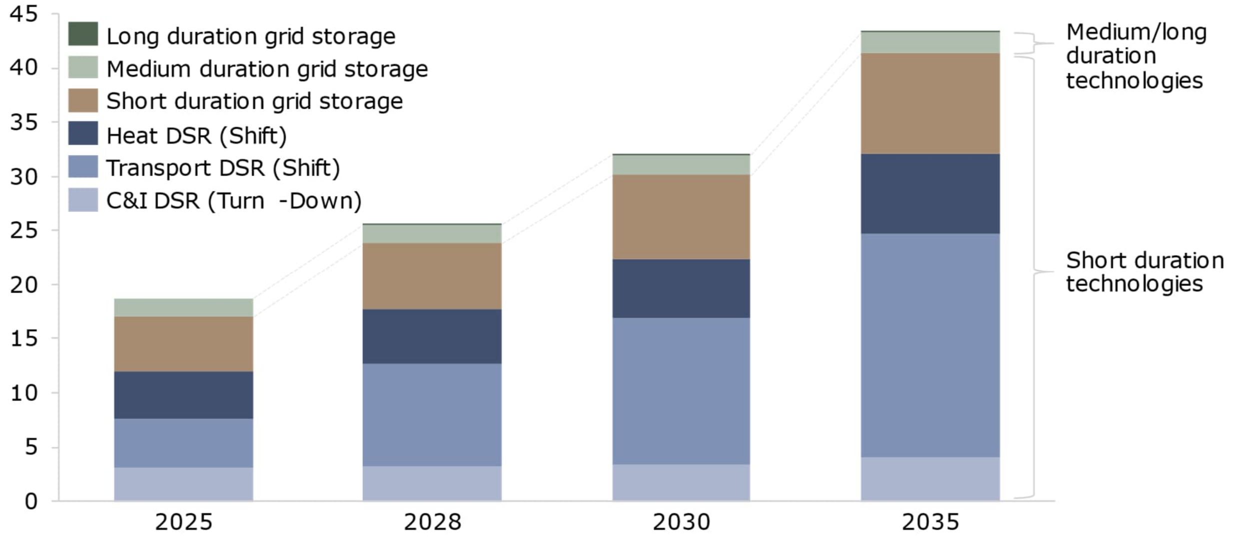
The exact scale and optimal mix of hydrogen-fired plants and Gas CCS is highly uncertain. Peripheral developments in the wider energy system will influence deployment, including the shape of residual demand (particularly the peak hour and largest continuously accrued volume of residual demand), delivery risk of enabling infrastructure, competition from alternative solutions (e.g. DSR and energy storage), and regulatory restrictions on gas operation. In addition to this, low-carbon generation technologies that can be dispatched as needed are still in their early stages of development and will require government support initiatives, which may experience delays or face uneven priorities and funding. These uncertainties are explored in the sensitivity analyses.

In the Central scenario, a sizable tranche of unabated gas capacity remains on the power system in 2035. Despite running at low load factor and making up only 2% of total generation, these plants can provide valuable flexibility, including intra-day balancing and support during extended periods of generation deficit. The future of unabated gas plants remains uncertain, and this will have a major effect on the necessary implementation of alternative low-carbon flexible technologies.

4.1.1.4 The use of grid storage and DSR is expected to rapidly grow, providing efficient and effective means of balancing short-term residual demand

The operational parameters of grid storage and DSR are well-suited to enhance short-duration system stability. Grid storage and DSR are able to fulfil similar flexibility services (albeit certain components of DSR have additional operational time constraints), rapidly responding to extreme fluctuations in supply and demand, shifting load to periods of surplus generation, and general balancing of intra-day volatility. For this reason, Exhibit 4.11 presents the combined outlook for grid storage and DSR output capacity.

Exhibit 4.11 – Output capacity of grid storage and DSR by technology group and duration grouping (GW)



Short duration technologies include DSR and ≤4hr grid storage (e.g. short-duration Batteries and short-duration Pumped Storage)
Medium duration technologies include grid storage ranging from over 4hr to 12hr (e.g. 6hr Batteries and medium-duration Pumped Storage)
Long duration technologies include >12hr grid storage (e.g. CAES)

The provision of short-duration flexibility from ≤4hr grid storage technologies and DSR demonstrate rapid growth, more than doubling from 17GW in 2025, to 41GW in 2035. It is expected that the cumulative capacity of DSR and grid storage will rise sharply in response to the increasingly extreme and volatile patterns of residual demand. The exact combination of short-term flexible solutions is unclear, but the fixed DSR capacity used in the Central scenario (input provided by the CCC[34]) anticipate that a substantial proportion of the new demand for electricity from transportation and heating is flexible and can readily be accessed by the system to address short-term flexibility needs.

Short-duration grid storage technologies are projected to grow with a gradual preference for lower C-ratings[35] out to 2035, but their growth may be restricted by the high assumed availability of DSR. Batteries are expected to experience growth in the 1-2 hours duration capacity levels until 2030, and 4-6 hours thereafter. This pattern of growth is driven by the increasing need for extreme residual demand balancing, which leads to higher arbitrage spreads while maintaining a similar frequency of charge-discharge cycles.

The deployment of grid storage capacity is limited by the high assumed availability of DSR. If the projected levels of DSR do not materialise, it is probable that a greater amount of grid storage will be needed to compensate for the deficit.

Large-scale, long-duration energy storage (LLES)

LLES is well suited to managing the trends in residual demand that will become more prevalent over time. According to the Central scenario, the role of medium- and long-duration grid storage solutions is expected to be limited, with only existing pumped storage and small levels of CAES on the system by 2035. Instead, alternative sources of flexibility such as hydrogen storage and low-carbon dispatchable capacity are considered to be more cost-effective given the base technology cost/availability assumptions and the patterns of residual demand.

However, the role of long-duration grid storage solutions is dependent on multiple uncertain factors. The Central scenario optimisation only considered grid storage in up to 3-day duration units, which may not be the most cost-effective configuration (this is explored in the sensitivity analysis). Moreover, if the Government intervenes to de-risk long-duration grid storage technologies, it could drive more rapid deployment. This could be a prudent move as diversifying technology risks will reduce the reliance on technologies with high delivery risk, particularly hydrogen storage, and provide future optionality.

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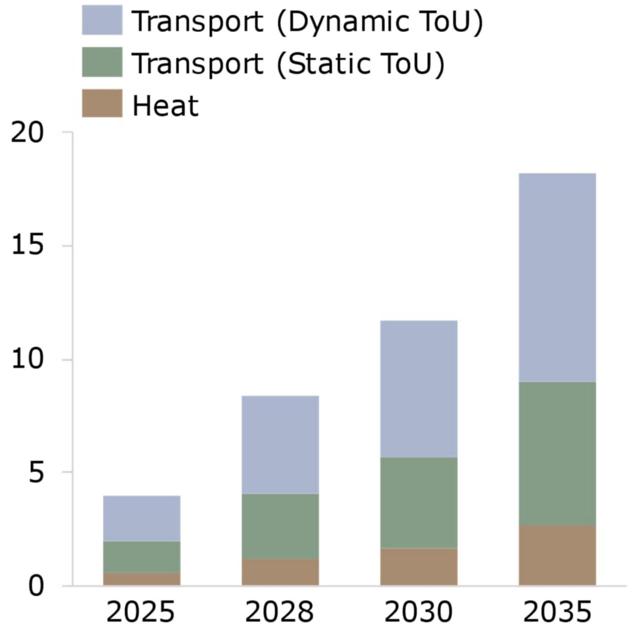
[34] For the purpose of this study, the CCC provided assumptions regarding the ability of consumers to shift transport (i.e. public, residential and work charging) and heat (i.e. heat pumps and heat storage) demand. This was combined with AFRY assumptions for turn-down DSR (from C&I demand).
[35] The C-rating of a battery is a measure of its discharge rate, expressed as a multiple of its storage capacity.

Exhibit 4.12 – Shifted demand (TWh)



The analysis anticipates that a significant portion of the new demand for electricity from transportation and heating will be flexible and readily accessible to the system to address short-term flexibility needs. Exhibit 4.12 presents the volume of demand that is shifted relative to demand that remains inflexible.

The increase in total shifted demand out to 2035, from 4TWh to 18TWh, is equivalent to 8.3GW of 4-hour batteries operating at 1.5 cycles per day or 12.5GW of 2-hour batteries operating at 2 cycles per day. The level of demand shifting in 2035, 50GWh per day or 4% of total demand, is significant and demonstrates the impact that demand response programs can have on the energy storage requirements of the grid. However, the emergence of this smart and responsive demand is heavily dependent on the adoption rates of electric vehicles and heat pumps, as well as consumer engagement in these areas.

In addition to transport and heat shifting DSR, the analysis also modelled C&I turn-down DSR. However, the use of a high activation price of £500/MWh resulted in minimal activation, with less than 100 hours per year expected in 2035. As a result, turn-down DSR was found to only deliver capacity provision during system stress events.

4.1.1.5 The GB transmission network is expected to undergo significant expansion to accommodate growing renewable generation

To evaluate the need for locational flexibility and incorporate the cost of electricity transportation, the model divided GB into 11 zones based on flow constraints within the power transmission network across 10 boundaries (refer to Exhibit 4.13). The optimisation process factors in the reinforcement of the electrical transmission network[36], alternative energy vector transport options, such as the transport and storage of hydrogen via pipelines, the charging of power storage technologies behind constraints, and a certain level of renewable curtailment.

[36] Reinforcement out to 2030 is fixed, based on the 2021 NOA. Post-2030 the model optimised the investment in power transmission lines across the 10 boundaries.

Exhibit 4.13 – GB boundary map

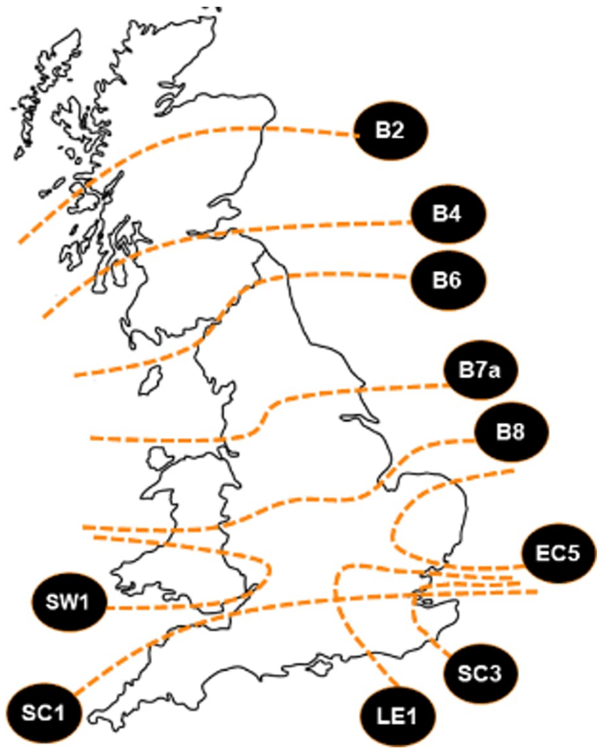


Exhibit 4.14 – GB transmission network capability heat map

Capability (GW)

2.9 – 21.0

	2025	2028	2030	2035
B2	3.8	4.5	6.0	6.9
B4	4.3	4.7	6.5	11.5
B6	7.7	10.7	12.7	14.5
B7a	10.5	11.2	13.2	18.2
B8	13.0	14.5	16.5	21.0
EC5	3.5	12.5	16.0	20.7
LE1	9.7	10.5	12.0	14.1
SC1	6.1	8.5	10.0	15.0
SC3	6.7	7.4	7.4	7.4
SW1	2.9	2.9	2.9	4.7

All the boundaries examined will require some level of reinforcement, with an average doubling of their capability out to 2035

To meet the Government's ambitions for renewable energy capacity and cater to the increased demand for electricity, it is imperative to strengthen the electrical transmission network. As evidenced in Exhibit 4.14, all the boundaries examined will require some level of reinforcement, with an average doubling of their capability out to 2035 (relative to 2025 baseline). The reinforcement of the boundaries will mainly depend on the distribution of demand in relation to renewables and interconnector converter substations:

- B8 and B7a hold considerable transmission capability, being centrally located and connecting the North and South;
- EC5, B4 and B6 require significant reinforcement to facilitate transport of wind generation; and
- SC1 requires significant reinforcement to facilitate interconnector flows on the South coast.

Expanding the electrical transmission network is essential to meet the Government's targets and ensure power system stability. With the uncertain route to Net Zero power and the long timelines involved in constructing transmission networks, it is essential to conduct the design process promptly and ensure that strategic decisions are taken in a coordinated manner involving different stakeholders (e.g. Government, Transmission & Distribution Operators, ESO, Ofgem).

Outlook for expanding the transmission network

Despite the presence of secondary factors, such as the advancement of longer-duration storage and expedited development of alternative transmission vectors, the proliferation of renewable energy sources and the escalation of electricity consumption remain the paramount factors in determining the expansion rate of the transmission network. The scenarios and sensitivities in this analysis show that the network reinforcement outputs remain consistent, with a deviation of less than 10% up to 2040. This implies that a substantial assumption change from the Central scenario would be required to significantly alter the course of development.

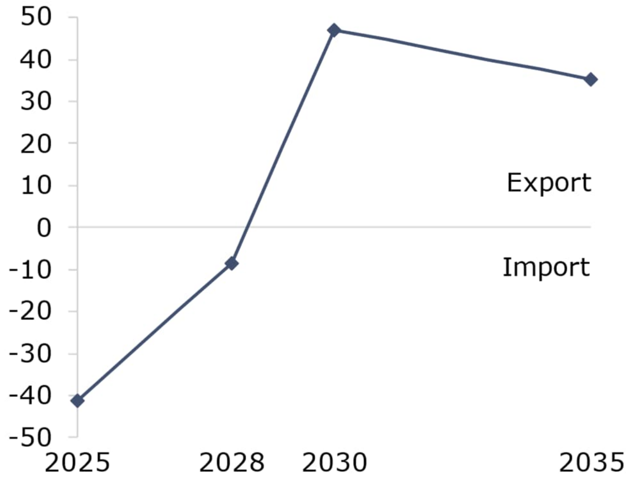
4.1.1.6 Interconnectors help with balancing the system, however cannot be relied upon

Interconnectors play a crucial role in the transfer of electricity between energy markets, especially during instances of divergent system needs. This allows for a more efficient distribution of electricity, reducing the need for curtailment and overproduction.

While they can help balance the system by responding to its needs, interconnectors cannot be solely relied upon to ensure energy security during periods of high residual demand. The general balancing actions of interconnectors can be demonstrated by the net flows positively correlating with residual demand over the modelled period[37] (i.e. importing during periods of high residual demand and vice versa). However, interconnectors can worsen imbalance and cannot be relied upon to ensure GB's energy security during extended periods of high residual demand. This can be evidenced by assessing the forecast interconnector flows during the most extreme and prolonged periods of low renewable generation. During these system stress events, the interconnector flows generally provide less than 20% of their GB import capability and in some instances, provided negligible contribution[38]. This is due to large weather events affecting multiple connected markets, which drive similar market needs. As a result of this, the interconnector flows likely impact the utilisation rate of flexible technologies, but not necessarily the cumulative capacity, which is dimensioned against extreme residual demand patterns that are not reliably met by interconnectors.

[37] Pearson Product-Moment Correlation Coefficient is 0.77 in 2025 and 0.64 in 2035 (hourly analysis using average correlation coefficient across 5 weather years).
[38] In 2035, the periods of largest continuously accrued residual demand amounted to 7-10TWh of generation deficit over a period of 8-15 days. Interconnectors typically net imported <1TWh during these periods, equating to <20% potential import capability.

Exhibit 4.15 – Net annual Interconnector flows (TWh)



GB is poised to see an increase in its interconnectivity with neighbouring energy markets. The outlook for interconnector capacity was predetermined in this analysis and factored in several uncertain factors, including country specific congestion rent.

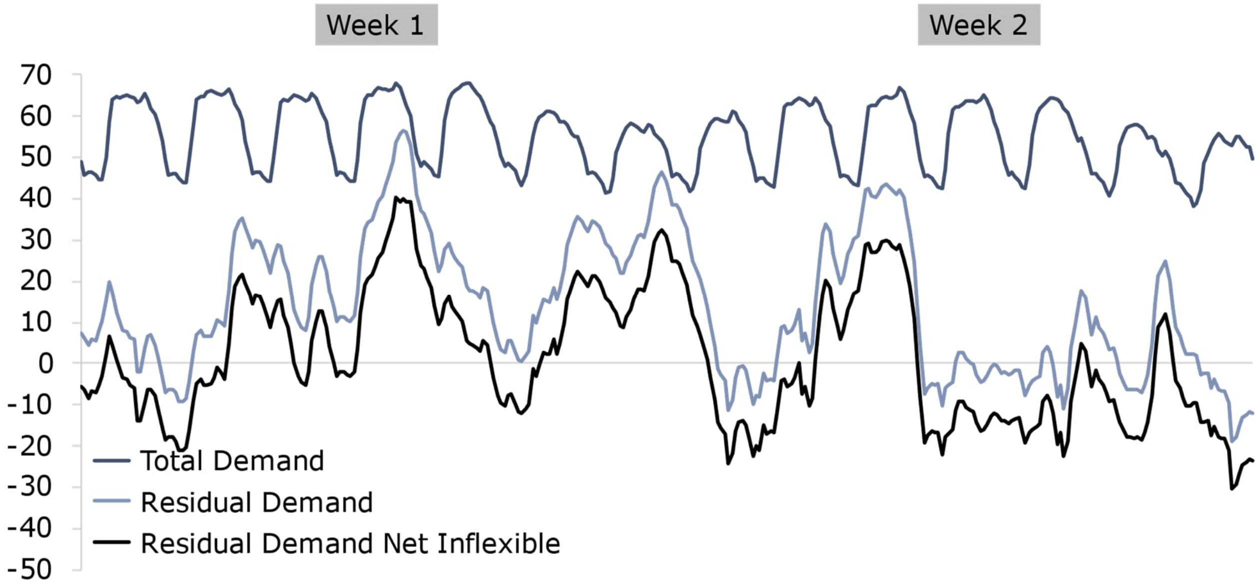
In this analysis, GB net flows reverse from net import prior to 2030, to net export by 2035 (see Exhibit 4.15). This shift is brought about by the rapid expansion rate of renewables in GB under the BESS lowering power prices relative to other markets that are decarbonising at a slower pace. Significant interconnection capacity paired with uneven rates of decarbonisation between connected markets can lead to unexpected, but nonetheless important, outcomes: for example, exceeding current Government ambitions for renewable capacity may result in a substantial portion of the additional renewable energy produced being exported. However, there may be alternative options to address periods of negative residual demand, such as further green hydrogen production, if new interconnection does not materialise or policy designed to incentivise domestic usage is enacted

4.1.1.7 Snapshot 2-week period in 2035

To better comprehend the intricate operations of electricity systems and the balancing actions required to maintain stability, it is beneficial to analyse how hourly demand patterns are met. For this purpose, we have selected a two-week period in May 2035 that showcases instances of positive and negative residual demand, and therefore, upward and downward balancing actions. Please note that this system behaviour is a consistent phenomenon that can be observed throughout the year.

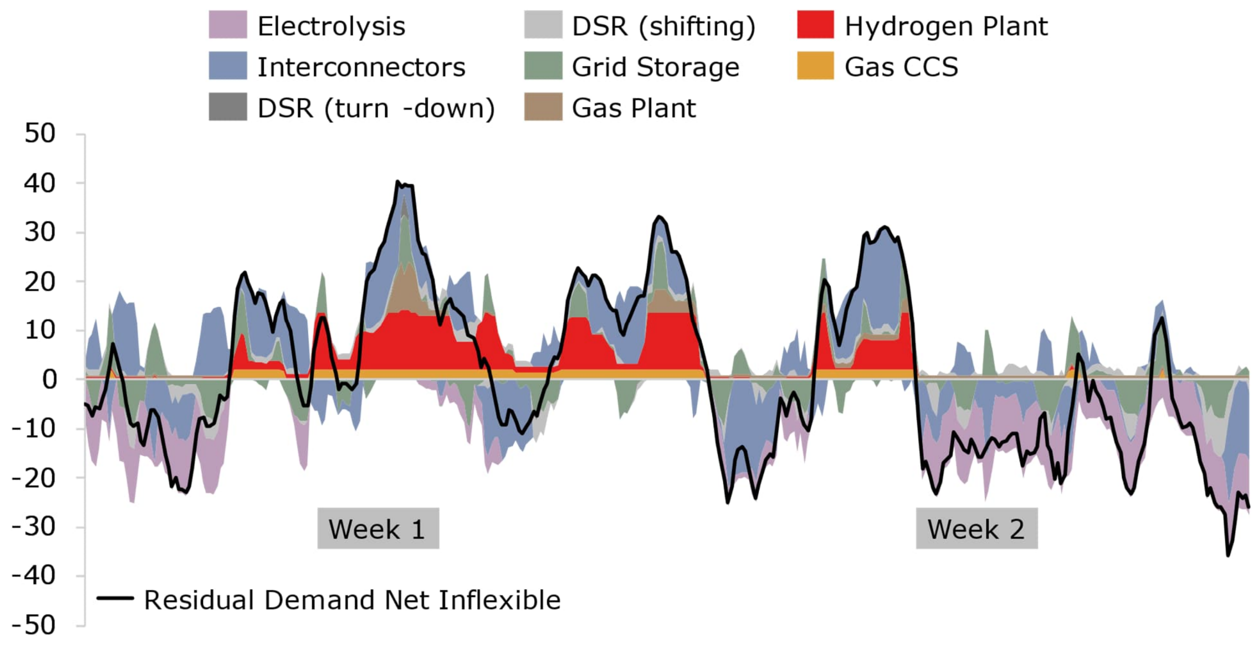
In Exhibit 4.16, three distinct guises of demand are presented for the chosen two-week period. While the Total Demand profile remains relatively consistent throughout the period, with fluctuations of around 20GW between day and night, Residual Demand is much more varied and less predictable due to the intermittency of renewable technologies. Going one step further, the Residual Demand Net Inflexible is shown, which also excludes inflexible technologies such as Nuclear, CHP, and Biomass CCS. This final depiction of demand highlights the balancing act that dispatchable capacity must balance in order to meet demand patterns.

Exhibit 4.16 – Depictions of hourly electricity demand for 2-week period in 2035 (GW)



Total Demand: Final consumption of electricity, excluding electrolysis.
Residual Demand: Final consumption, excluding electrolysis, net renewables (Offshore Wind, Onshore Wind, Solar PV)
Residual Demand Net Inflexible: Residual demand, net inflexible plant (Nuclear, Biomass CCS, CHP, Other)
Notes: This modelling exercise represents a fortnight period in May 2035, using 2012 weather patterns.

Exhibit 4.17 – Hourly snapshot of flexible technologies balancing the system (GW)



Interconnectors contribution refers to hourly net flows: Positive indicates import and vice versa.

Exhibit 4.17 illustrates how flexible capacity is utilised on an hourly basis to meet the Residual Demand Net Inflexible profile. This provides a graphical depiction of the functions and behaviours of the diverse set of flexible technologies, during periods of varying system needs.

During periods of generation shortfall:

- Hydrogen plant and Gas CCS provide long term flexibility, operating almost continuously during extended periods of positive residual demand and with hydrogen-plant providing greater flexibility for downward dispatch (i.e. part loading). Technologies with low start-up costs are preferred for abrupt or intermittent periods of generation demand.
- Grid storage, DSR (shifting) and gas plant balance intraday variability, smoothing out fluctuations and providing capacity during the peakiest hours.
- DSR (turn-down) is activated during the most extreme period of generation deficit (3 hours during the week 1 peak).

Conversely, during periods of generation excess:

- Activation of Electrolysers and Interconnector exports are utilised to address the majority of system imbalance.
- Grid Storage and DSR (shifting) contribute to shifting in additional load, particularly during extreme troughs, but comparatively lower volumes.

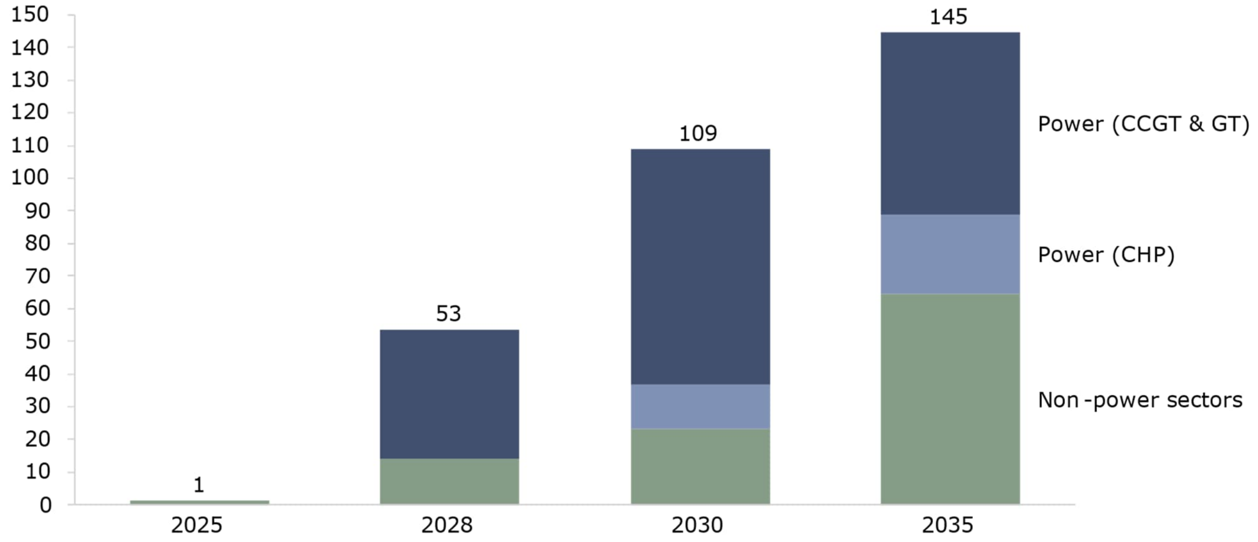
In addition to the above points, it is generally observed that Interconnector flows help in maintaining a balance between the supply and demand. However, there are certain periods when Interconnector flows exacerbate the imbalance position. This is partly caused by transmission constraints from North to South in the system (i.e. advantageous to electrolyse Scottish generation and import power in the South) or more extreme market conditions in neighbouring countries driving counterintuitive domestic behaviour (e.g. charging GB-located grid storage during periods of generation shortfall).

4.1.2 Hydrogen sector

4.1.2.1 Hydrogen demand anticipated to grow rapidly towards 2035

The demand for hydrogen can be categorized into three parts: Hydrogen CCGT & GT, Hydrogen CHP, and non-power sectors (refer to Exhibit 4.18). The capacity and demand profile for Hydrogen CHP and non-power sectors are predetermined inputs[39], whereas the capacity and demand profile for CCGT and GT are optimised outputs of the modelling process.

Exhibit 4.18 – Hydrogen demand by source (TWh)



Power (CCGT & GT) hydrogen demand is an output of the optimisation.
Power (CHP) consists of existing large-scale CHP assumed to undergo gas-to-hydrogen retrofit by 2035.
Non-power sectors hydrogen demand was provided by the CCC. This includes Removals, Surface Transport, Aviation, Shipping, Residential Building, Non-Residential Building, Agriculture, Manufacturing & Construction, Fuel Supply, and Waste.

The analysis makes assumptions and projections regarding the growth of hydrogen demand over the presented period, from negligible volumes in 2025 to 145TWh in 2035. The power sector is projected to be the primary driver of hydrogen demand in 2028 and 2030, although by 2035, demand in the non-power sectors is expected to increase significantly while hydrogen demand in the power sector is predicted to decline. Consequently, the overall demand for hydrogen becomes relatively even between the power and non-power sectors by 2035.

The non-power demand for hydrogen is assumed based on the scenarios presented in the CCC's Sixth Carbon Budget, but this remains highly uncertain. Given that the hydrogen economy is still in its early stages, the actual demand for hydrogen will depend on the success of policies and

[39] The demand profiles for Hydrogen CHP and non-power sectors are assumed to be baseload, except for residential and non-residential buildings where the profiles incorporate variations in heat demand. As the demand from buildings is assumed to account for only 2% of the fixed demand, the total hydrogen demand profile exhibits minimal seasonality.

regulations supporting the adoption of hydrogen-based solutions. The extent to which these solutions will be integrated into the energy mix and replace fossil fuels is subject to several unknown factors, such as the timely development of necessary infrastructure, economic conditions, and consumer preferences.

Hydrogen demand originating from the power sector is also subject to significant uncertainty. The existing large-scale CHP plants are assumed to retrofit given the early commercial interest. However, the technical and economic factors that will drive this decision are highly uncertain. The demand from hydrogen CCGTs and GTs are outputs of the optimisation process, but they do not account for any significant enabling infrastructure constraints such as networks and storage. In reality, the delivery of such infrastructure is likely to be subject to significant delivery risk. Therefore, it is important to consider these uncertainties and delivery risks when assessing the potential demand for hydrogen.

4.1.2.2 The expansion of low-carbon hydrogen production is a response to the growing demand for hydrogen in the power sector and throughout the wider economy

Hydrogen can be produced through various technologies in the modelling and the indicators are impartial to the method used. Green hydrogen is produced through the electrolysis of water using renewable electricity, while blue hydrogen is produced through the reforming of natural gas or other hydrocarbons, with the resulting CO_2 captured and stored.

Exhibit 4.19 – Low-carbon hydrogen production capacity (GW)

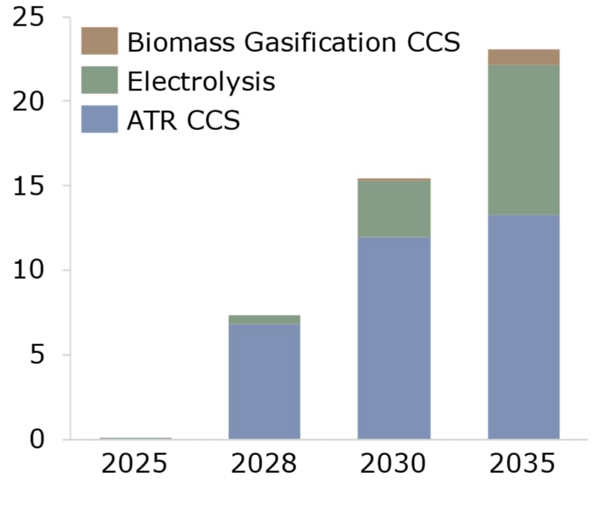
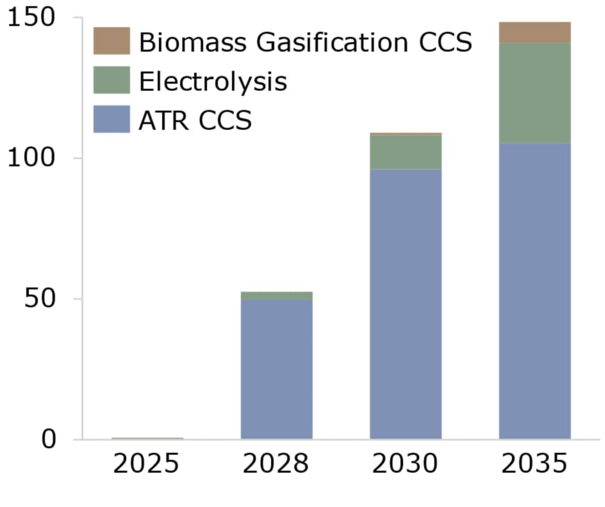


Exhibit 4.20 – Low carbon hydrogen production (TWh)



The expansion of low-carbon hydrogen production is a response to the growing demand for hydrogen in the power sector and throughout the wider economy. Exhibit 4.19 and Exhibit 4.20 display the breakdown of low-carbon hydrogen capacity and production by technology type. The analysis shows that both capacity and production increase from a baseline of zero to 23GW and 148TWh by 2035, respectively. It is worth noting that the supply is slightly higher than demand, which is due to the efficiency losses associated with the compression and decompression process required for hydrogen storage in salt caverns.

Green dream or blue horizon

According to the Central scenario and other sensitivities, blue hydrogen is expected to remain the dominant source of hydrogen production until 2035. This is despite the fact that the levelised cost of hydrogen (LCOH) for ATR CCS is higher at £50/MWh (real 2020), compared to the cost of electrolysis operating at zero electricity cost (including additional storage costs), which is £34/MWh (real 2020). This is due to the limited availability of excess renewable generation for electrolysis once all other balancing methods, such as exporting via interconnectors or load shifting with DSR/grid storage, are considered. Additionally, CCS technologies are better equipped to meet stable demand profiles projected for non-power sectors. If alternative methods of balancing negative residual demand become less accessible or competitive, the proportion of green hydrogen could increase.

Based on this logic, the composition of hydrogen production is heavily influenced by the amount of negative residual demand that can be cost effectively electrolysed, with blue hydrogen fulfilling the remaining demand. This trend is visible in the modelling results of later years, where green hydrogen becomes the dominant fraction of hydrogen production in 2050. This is attributed to a faster increase in renewable and nuclear generation as compared to electricity demand.

4.1.2.3 The success of hydrogen as a vector for decarbonising the power sector and wider economy is dependent on the timely development of infrastructure

To evaluate the need for locational flexibility and incorporate the cost of hydrogen transportation, the model divided GB into 11 zones based on flow constraints within the hydrogen pipeline network across 10 boundaries (refer to Exhibit 4.21).

The distribution of hydrogen demand across different locations is a nuanced picture that takes into account various input assumptions and optimised outputs of different demand components. The demand for "Manufacturing & Construction" was allocated across industrial clusters[40], while the remaining non-power sector demand was distributed based on population[41]. The demand in Grangemouth (SPT zone) and Humberside (North zone) was further increased by large-scale CHP plants assumed to have retrofit. The hydrogen demand for Hydrogen CCGT/GT was determined through optimisation.

In contrast, the hydrogen supply distribution is clearer. The deployment location of hydrogen supply was optimised, with 75% of the electrolyser

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[40] The industrial clusters consist of Grangemouth, Teeside, Humberside, Merseyside, South Wales, and Southampton. Humberside and Merseyside located in the North zone.
[41] In reality, this distribution of demand may be unlikely, especially if there is a shift towards repurposing gas networks and prioritising regions near industrial clusters for cost-effectiveness.

capacity built in Scotland and the upper North due to the regional oversupply of generation driven by high wind capacity in these locations. This approach proved to be a cost-effective means of managing transmission constraints. Blue hydrogen production was restricted to five zones (SHETL North, Upper North, North, East, and Midlands) guided by CCS feasibility studies. Additionally, hydrogen salt cavern storage was limited to Upper North, North, South Wales, and South. Further information can be found in the methodology Annex A.

Exhibit 4.21 – GB hydrogen zones

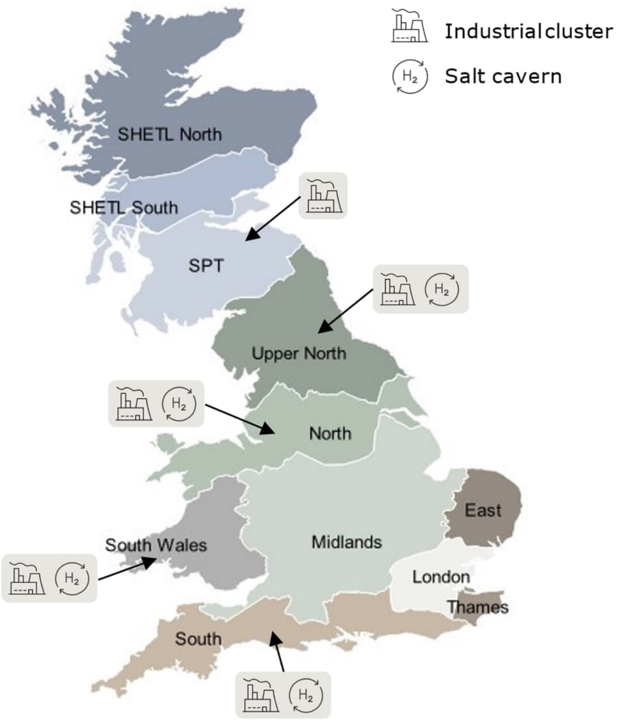


Exhibit 4.22 – GB hydrogen pipeline capacity (GW)

Capacity (GW) 0.0 – 7.3

	2028	2030	2035
SHETL_N - SHETL_S	0.0	0.4	1.3
SHETL_S - SPT	0.0	1.7	2.6
UpperNorth - SPT	0.0	1.3	2.8
North - UpperNorth	0.0	1.0	3.0
Midlands - North	0.0	6.0	7.3
East - Midlands	0.0	0.6	0.7
London - Midlands	0.0	3.1	3.7
London - South	0.0	2.5	3.0
London - Thames	0.0	0.2	0.4
Midlands - SWales	0.0	0.2	0.5

Exhibit 4.22 presents the capacity of hydrogen transmission pipeline capacity from 2025 to 2035. This shows that a hydrogen network ‘backbone’ is required to connect production sites with salt cavern storage and demand centres. The most significant growth in hydrogen transmission capacity can be found:

- Connecting the North and South of England, particularly the Midlands-North boundary with 7.3GW of hydrogen pipeline capacity – this infrastructure connects salt caverns in Northern England, with both demand in the South and green hydrogen production in the East;
- Connecting London to the Midlands and South, driven by flows into London to satisfy non-power hydrogen demand (partially population weighted demand distribution); and
- Connecting Scotland with the North of England, facilitating flows of green hydrogen produced in Scotland to salt caverns and demand in Northern England.

Exhibit 4.23 – Hydrogen transmission pipeline length (km)

Kilometer	2028	2030	2035
Total H2 pipeline length	0	2,800	3,800

Notes: Reference hydrogen pipeline with standard metrics.
Source: AFRY analysis

The boundary capacities have been translated into a transmission pipeline length to gain a better understanding of the delivery challenges. To build the necessary hydrogen capacity across the 10 boundaries, taking into consideration the distance between the conceptual centres of each energy zone, a total pipeline length of 3,800km by 2035 would be required in the Central scenario. This assumes standard metrics for pipeline size, temperature, and pressure[42]. This pipeline network would be a substantial undertaking that would require coordinated planning, construction, and maintenance. Nonetheless, it could play a critical role in facilitating the transition to a low-carbon economy, given the importance of hydrogen-based solutions.

The future hydrogen market relies heavily on storage, as it plays a critical role in enabling the efficient and flexible use of hydrogen supply. While dispatchable blue hydrogen production is well-suited to meet the consistent hydrogen demand from the non-power sector, the variable demand from the power sector requires a more flexible solution[43]. An effective approach to cost-effectively meeting the variable hydrogen demand is to store low-cost green hydrogen produced during periods of surplus renewable energy.

Projections of hydrogen storage output and duration capacity are presented in Exhibit 4.24 and Exhibit 4.25. In the early years before 2030, hydrogen storage deployment is expected to be negligible, with pressurized storage being the only viable technology during this period. However, once salt caverns become feasible in 2030, rapid growth is expected, with hydrogen storage capacity projected to reach 5TWh by 2035.

[42] Reference hydrogen pipeline assumed to be 900mm diameter, 20°C operating temperature, 80bar inlet pressure, and 30bar terminal pressure.
[43] While this statement is valid, it oversimplifies the situation since hydrogen usage outside of the power sector, such as in transportation, may be more suitable for electrolysis due to two key reasons: first, the demand for hydrogen is distributed, and second, electrolysis produces hydrogen with fewer impurities, which may be of higher quality.

Exhibit 4.24 – Hydrogen storage output capacity (GW)

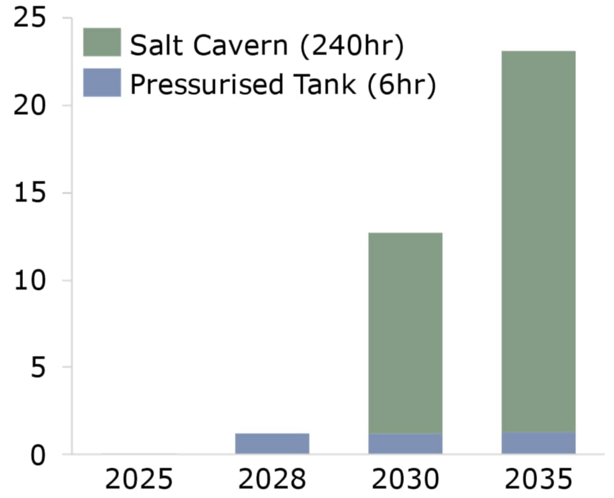
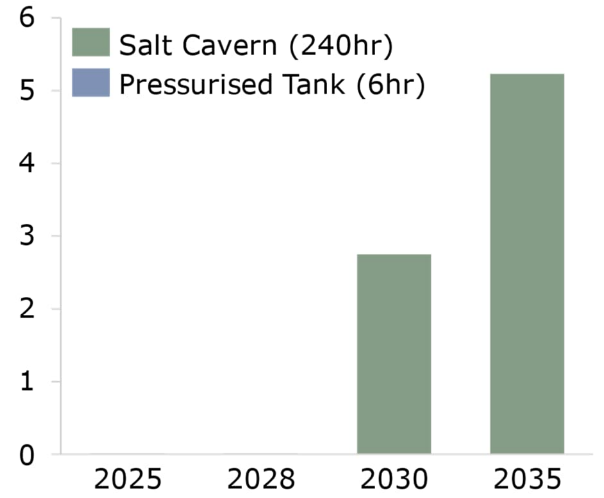


Exhibit 4.25 – Hydrogen storage capacity (TWh)



In 2035, the hydrogen storage capacity of 5TWh is 125 times greater than the total grid storage capacity of 40GWh. This is due to the cost-effective nature of long-duration salt cavern hydrogen storage solutions, which are better suited to address the patterns of residual demand than multiple shorter-duration grid storage technologies.

The 10-day salt cavern storage unit configuration is well-suited to meet the dimensioning metrics of hydrogen storage, particularly when it comes to addressing the variable hydrogen demand originating from the power sector[44]. Firstly, the output capacity (i.e. maximum discharge rate) of hydrogen storage, in combination with dispatchable hydrogen production plants, can marginally meet peak hydrogen demand in a single hour when the entire fleet of Hydrogen CCGT and GT are running alongside the baseload non-power sector and hydrogen CHP[45]. Additionally, the duration capacity of hydrogen storage (i.e. volume of hydrogen that can be stored) from full allows the entire fleet of Hydrogen CCGT and GT to run at full load for approximately 15 days, which closely aligns with the maximum continuous periods of generation deficit. These dimensioning metrics are marginally satisfied, suggesting that the 10-day salt cavern is a suitably balanced configuration in 2035.

It should be emphasised that achieving 5TWh of hydrogen storage by 2035 poses a considerable infrastructure challenge, which will necessitate

[44] The variability in hydrogen demand is primarily influenced by the power sector's demand, which, in turn, is determined by the intermittency of renewable energy generation. While there is some seasonality in power demand, this is largely offset by wind generation in the patterns of residual demand, as it positively correlates with electricity demand.

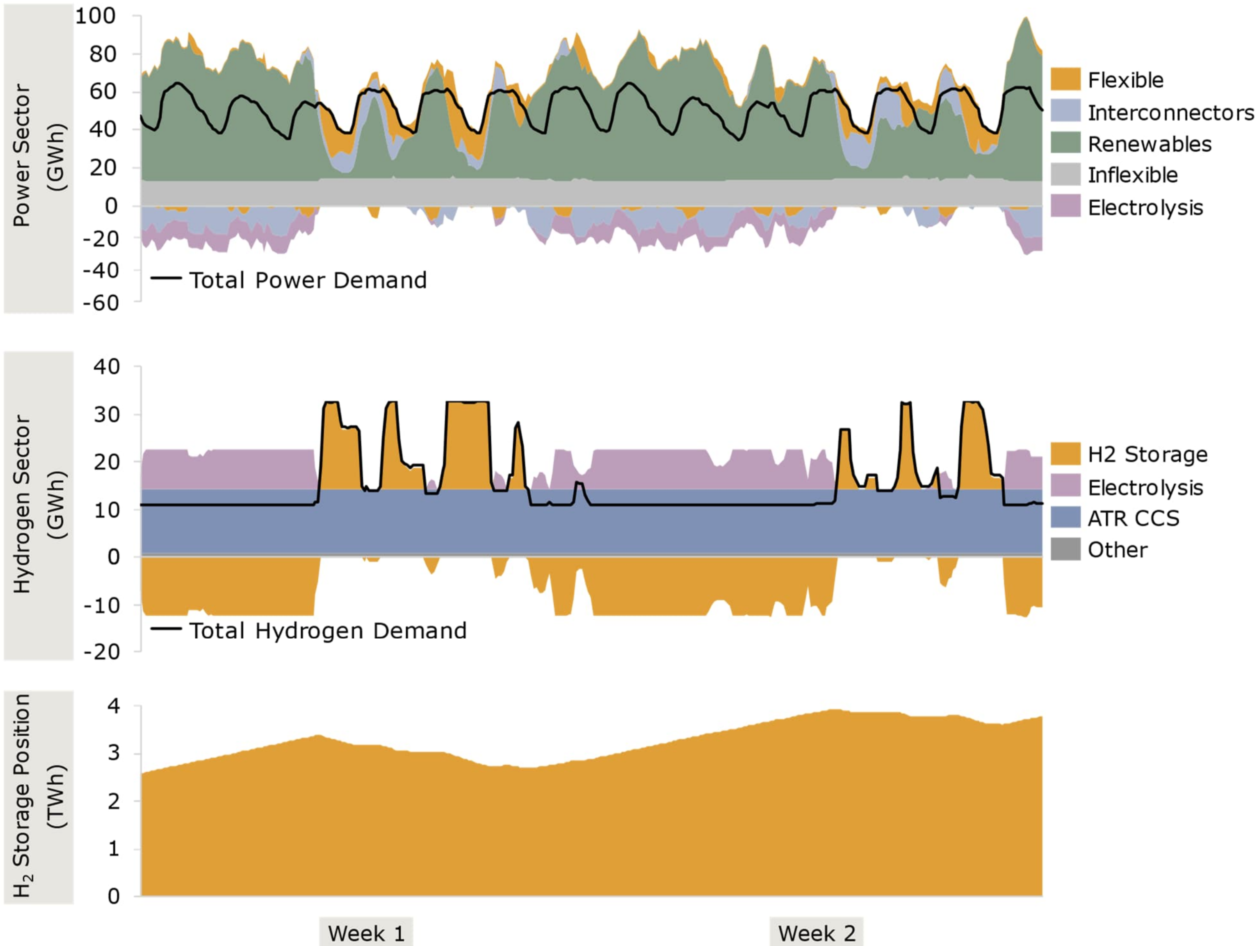
[45] Based on calculations for 2035, there is approximately 37GW of maximum supply and demand in an individual hour.

adequate funding and legislative backing, as well as coordinated efforts across the entire hydrogen supply chain. The sensitivity analysis examines potential scenarios where hydrogen storage is less prominent, reflecting the significant technical and economic hurdles related to delivery that must be addressed for hydrogen storage to become a practical energy storage solution.

4.1.2.4 Snapshot 2-week period in 2035

To gain a comprehensive understanding of the intricate workings of the hydrogen sector and its interactions with the electricity system, it is necessary to analyse the operations on an hourly basis. To facilitate this analysis, we have selected a two-week period in June 2035 that showcases instances of both positive and negative residual demand. This particular period provides valuable insights into the bidirectional flows of hydrogen, as well as the charging and discharging of hydrogen storage.

Exhibit 4.26 – Hourly snapshot of interactions and concurrent action in the power and hydrogen sector (units below)



Notes: This modelling exercise represents a fortnight period in June 2035, using 2012 weather patterns.

Exhibit 4.26 provides an overview of the interactions between the power and hydrogen sectors and hydrogen storage over a two-week period in 2035. The charts highlight several key trends, including:

- the continuous operation of ATR CCS meeting a base level of hydrogen demand from non-power sectors and power sector CHPs;
- periods of surplus generation being partially balanced by the activation of electrolysis, with excess hydrogen produced at this time moved into storage; and
- conversely, periods of deficient generation leading to the dispatch of Hydrogen CCGT and GT, resulting in the consumption of stored hydrogen.

4.1.3 Total system costs

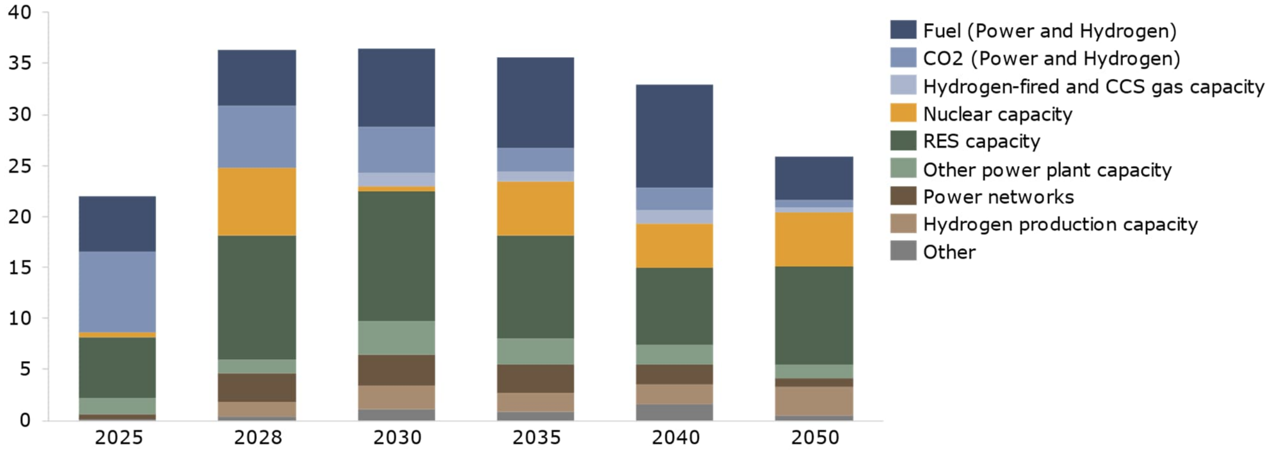
Exhibit 4.27 presents the annual undiscounted system costs. These are in-year costs (i.e. investment is allocated to the year in which it occurs rather than spread across the lifetime of the asset), and as such are not directly comparable across years. However, the chart highlights several key trends, including:

- The total annual system costs are expected to rise up to 2028 due to the increasing deployment rate of renewables and commissioning of Hinkley Point C by that year. These higher annual costs are projected to continue until 2035 before declining until 2050.
- Fuel costs are projected to peak in 2040 due to sustained gas demand and a 22% real-term increase in gas prices between 2025 and 2040.
- Despite the carbon price escalating out to 2050, the total carbon cost is considerably higher in the earlier periods of analysis due to higher emissions from unabated gas plants.
- The cost of nuclear power is dependent on the assumed deployment years.
- Investment in hydrogen production technologies increases in 2028 and beyond, mainly driven by ATR CCS in the short term, while later in the modelled period, the costs are mostly due to investment in electrolysers.
- Though they may represent only a small proportion of total system costs, power networks require significant investment to accommodate demand growth and the expansion of renewable capacity.
- The cost of hydrogen storage capacity, hydrogen pipes capacity, grid storage capacity, and C&I DSR is grouped together as ‘Other’. While these costs may only represent a small portion of the total system costs, their significance for the safe and secure operation of the future Net Zero system should not be underestimated.

These costs do not represent the cost of decarbonising the electricity system, which should be determined by comparing them to a high-carbon counterfactual scenario (e.g. where demand is met through unabated gas).

The scenarios are cost-effective compared to the Government's Net Zero consistent carbon values.

Exhibit 4.27 – Annual undiscounted system costs (£bn, real 2020)



'Other' costs include grid storage capacity, hydrogen networks and storage capacity, and C&I DSR costs.
Notes: Capital expenditures are calculated by dividing the total new capacity over a multi-year period by the number of years in that range (e.g. the 2025 capital expenditure for capacity deployed between 2023-2026 is divided by 4). All investments made prior to 2025 are excluded from the system costs calculation. For simplicity, all RES capacity is expected to operate beyond 2050 and interconnector import/export costs/revenues are not considered. Additionally, it is assumed that only 50% of the capital and operational expenditures for new interconnectors are borne by GB, while the remaining costs are covered by GB's neighbouring countries.

4.2 High and Low scenarios

The outlook for electricity and hydrogen demand is subject to a high degree of uncertainty. Therefore, it is crucial to comprehend how diverse demand projections can affect the necessity for flexibility. The three core scenarios were defined by the CCC to reflect a plausible range of demand outlooks for both power and hydrogen. These were guided by demand projections from the CCC's Balanced Pathway and two of their exploratory scenarios, Widespread Innovation and Headwinds (for more information, see section 3.1).

Exhibit 4.28 – Electricity demand difference relative to the Central scenario (TWh)

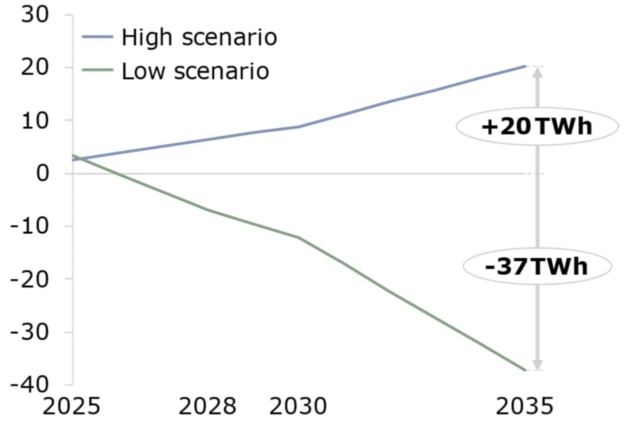


Exhibit 4.29 – Hydrogen demand (non-power) difference relative to the Central scenario (TWh)

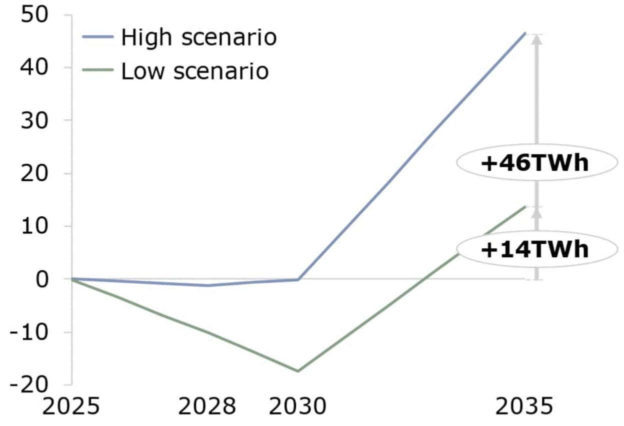
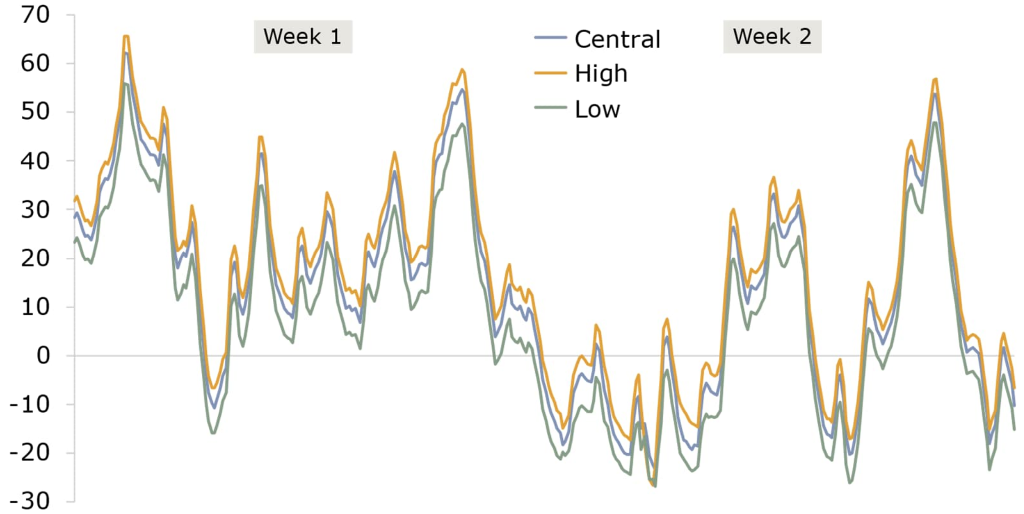


Exhibit 4.28 and Exhibit 4.29 illustrate the variances in electricity and hydrogen demand between the High and Low scenarios compared to the Central scenario. In the power sector, demand varies by +5% and -8% in the High and Low scenarios, respectively, by 2035.

Implementing these modelling modifications causes a shift in the pattern of residual demand, with the fundamental shape remaining relatively similar due to the comparable patterns of RES generation and load profiles utilised[46] (see Exhibit 4.30).

Exhibit 4.30 – Hourly residual demand in the core scenarios over a 2-week period

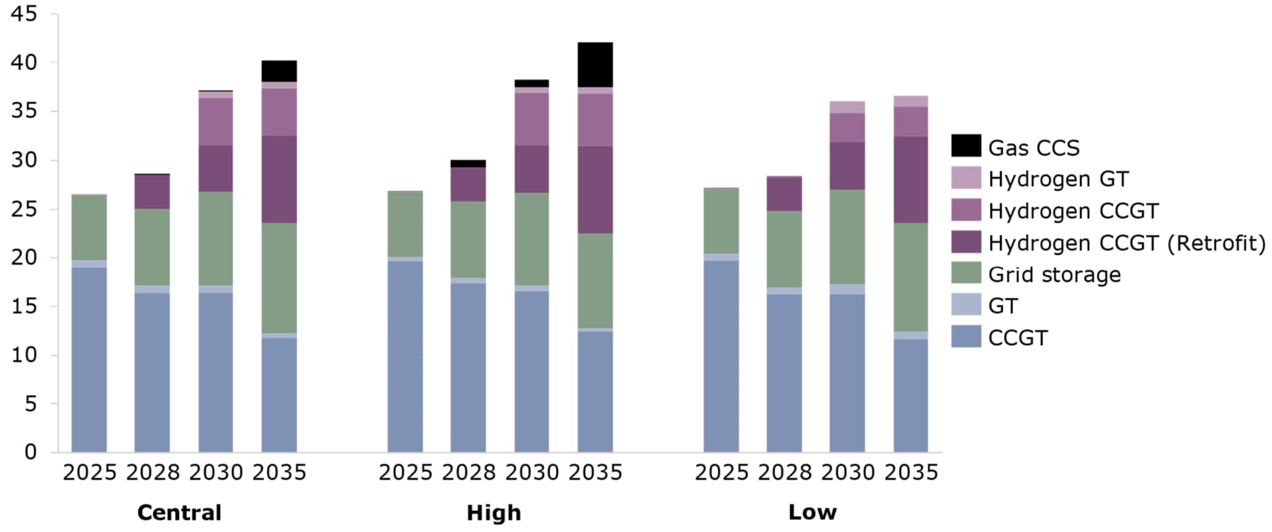


Notes: This system behaviour is a consistent phenomenon that can be observed throughout the year.

[46] Differences in demand assigned to each sub-division of demand leads only to minor spatial and load profile variations across the scenarios.

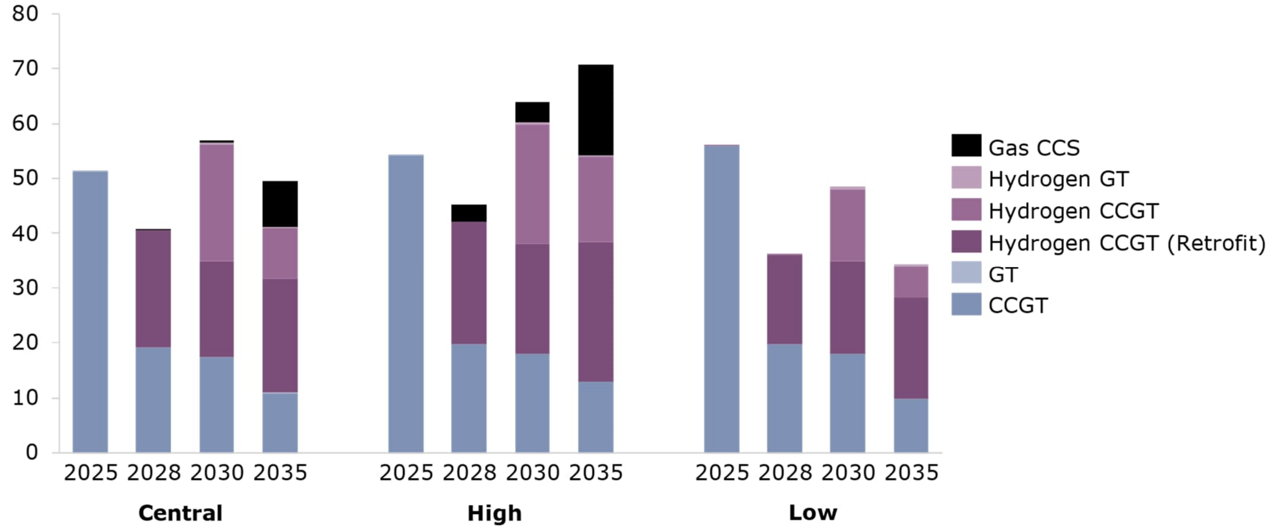
The variations in electricity demand result in differences in the system's flexibility requirements, which, in turn, affects the scale and balance of flexible capacity needed. These differences are reflected in the installed capacity and yearly generation of flexible technologies for the three core scenarios illustrated in Exhibit 4.31 and Exhibit 4.32.

Exhibit 4.31 – Installed (operational) capacity of flexible generation and grid storage for the three core scenarios (GW)



Notes: This excludes Gas CCGT capacity that is mothballed ahead of anticipated conversion to hydrogen operation.

Exhibit 4.32 – Annual generation of flexible technologies for the three core scenarios (TWh)



In the High scenario, the rise in power demand leads to an additional capacity of 2GW relative to the Central scenario, primarily consisting of Gas CCS and Hydrogen CCGT. This pattern persists in generation, with Hydrogen CCGT and Gas CCS generating 11TWh and 8TWh more than the Central scenario, respectively, by 2035.

In contrast, the Low scenario demonstrates the opposite trend, with a total capacity of 4GW less than the Central scenario, mainly composed of Gas CCS and Hydrogen CCGT. Moreover, the lowered power demand is partially compensated by a reduction in generation from Hydrogen CCGT and Gas CCS, which is 6TWh and 8TWh lower, respectively.

The changes in demand volume have a greater impact on technologies that provide medium- and long-term flexibility, such as Hydrogen CCGT and Gas CCS, as opposed to short-term flexibility technologies like unabated gas and Grid Storage. This is because the changes in demand modelling mainly affect the residual demand curve's position rather than its shape or volatility. This indicates that the short-term flexibility requirements in an electricity system depends largely on the shape and volatility of the residual demand curve, rather than just the overall volume of residual demand.

Exhibit 4.33 and Exhibit 4.34 present the capacity and annual production of low-carbon hydrogen across different technology types for the three core scenarios. Both metrics demonstrate significant growth in all scenarios, driven by the varying components of hydrogen demand:

- The High scenario shows an increase in hydrogen demand of 68TWh in 2035 compared to the Central scenario, with 46TWh originating from non-power sector demand and 21TWh from power demand.
- In the Low scenario, hydrogen demand in 2035 is only 3TWh higher than the Central scenario, as the 14TWh increase in non-power sector demand is offset by a decrease of -11TWh in power demand.

Exhibit 4.33 – Installed capacity of hydrogen production technologies for the three core scenarios (GW)

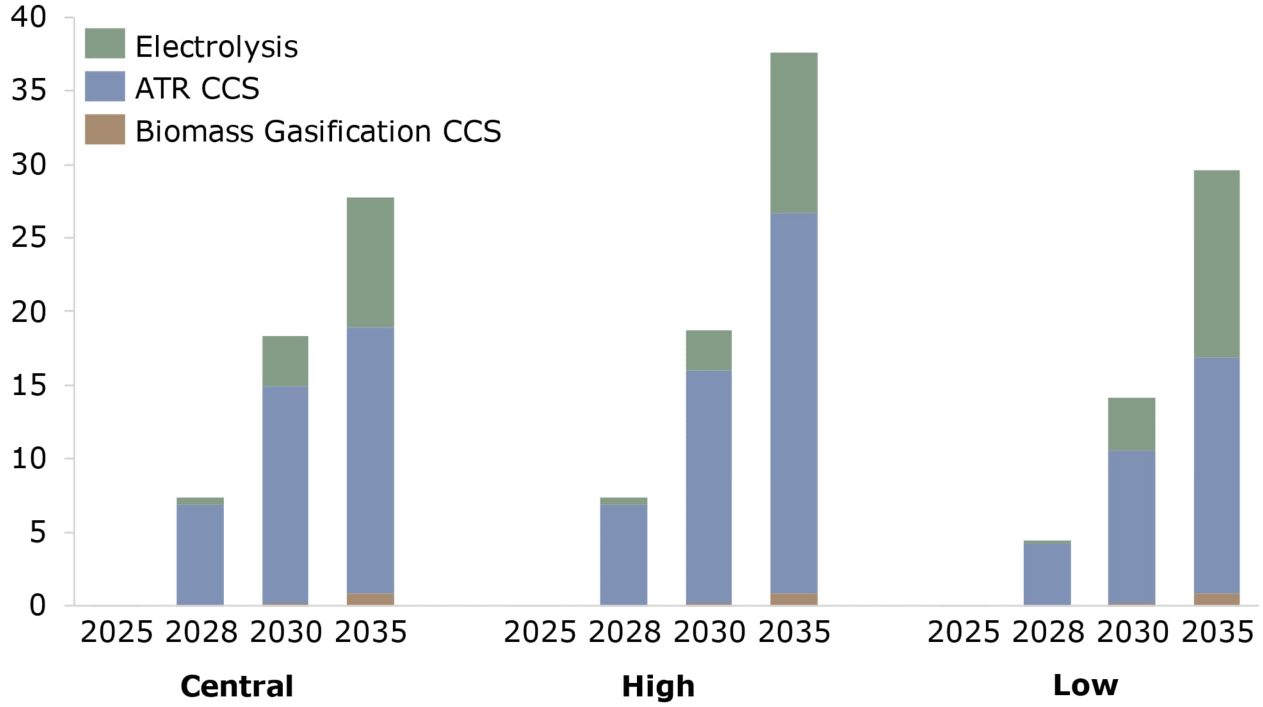
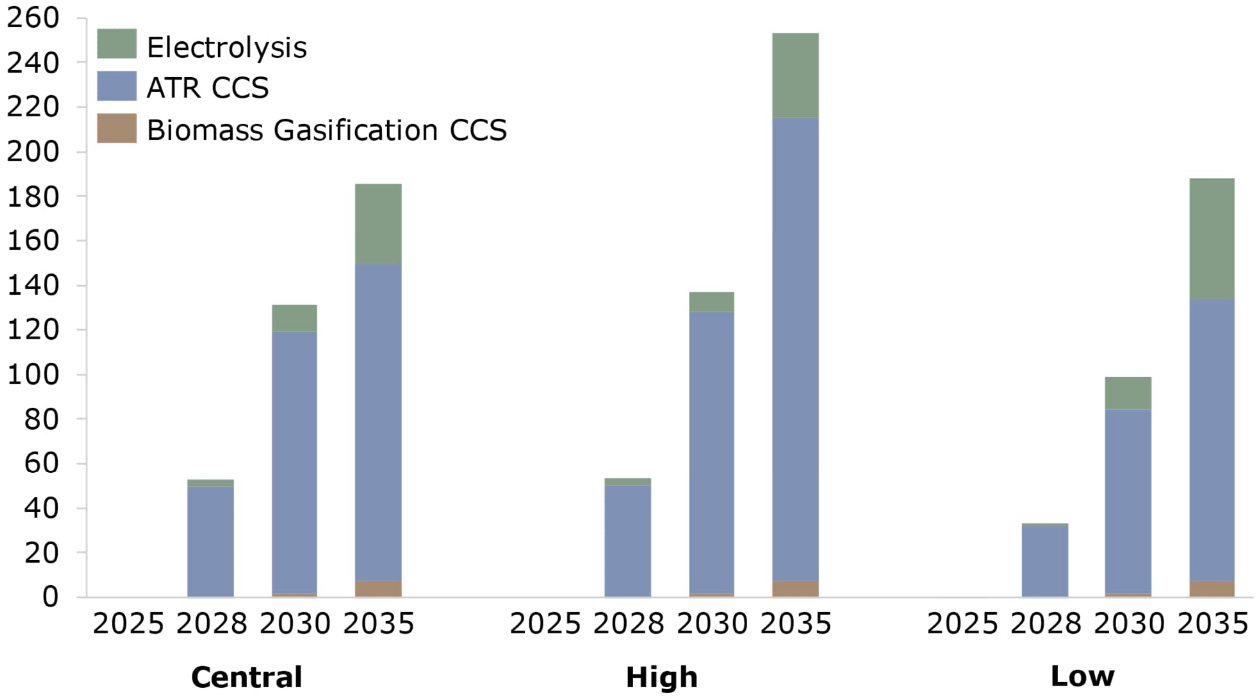


Exhibit 4.34 – Annual hydrogen production for the three core scenarios (TWh)



Blue hydrogen is expected to remain the dominant source of hydrogen production in all the core scenarios out to 2035, however the precise composition varies based on several factors.

In the Low scenario, the reduced electricity demand shifts the residual demand curve downward in comparison to the Central scenario. This amplifies the periods of negative residual demand, creating more opportunities for electrolysis of excess renewables. As a result, there is an increase in electrolyser capacity, displacing the more expensive blue hydrogen. Specifically, by 2035, there is an additional 4GW of electrolysis capacity and 19TWh of green hydrogen production compared to the Central scenario; green hydrogen production accounts for 29% of the total hydrogen production.

Conversely, the High scenario features reduced instances of negative residual demand, which limits opportunities for green hydrogen production and increases reliance on blue hydrogen production. Additionally, the higher non-power sector hydrogen demand further exacerbates this reliance on blue hydrogen. As a result, by 2035, there is an additional 8GW of ATR CCS capacity and 65TWh of blue hydrogen production compared to the Central scenario. Despite the reduced volume of surplus renewable generation, green hydrogen production still increases by 2TWh. This is because the increasing demand for hydrogen favours electrolysis over grid storage solutions to address surplus generation periods, and higher volumes of renewable curtailment are considered cost-effective to capture.

4.3 Sensitivities

In addition to the 3 core scenarios, this study included the design and assessment of a range of sensitivities to complement the core scenarios and explore key uncertainties. Exhibit 4.35 presents an overview and comparison of key metrics in 2035.

Exhibit 4.35 – A snapshot of scenario and sensitivity results for 2035

Scenarios/Sensitivities	Flexible Generation					Energy Storage		Networks			DSR	Emissions	
	Power			Hydrogen		Power	Hydrogen	Power	Hydrogen	Power	Power	Power	Hydrogen
	Unabated gas generation / capacity	Gas CCS generation / capacity	H_2-fired generation / capacity	Blue hydrogen production	Green hydrogen production	Storage duration	Storage duration	Boundary capability	Pipeline capability	IC net exports	Shifted energy	Carbon emissions	Carbon emissions
	TWh / GW	*TWh / GW*	*TWh / GW*	*TWh*	*TWh*	*GWh*	*GWh*	*GW*	*GW*	*TWh*	*TWh*	*$MtCO_2$*	*$MtCO_2$*
Central Scenario	11 / 12	8 / 2	30 / 14	105	36	41	5228	134	25	35	18	4.8	2.7
High Scenario	13 / 13	17 / 5	41 / 15	171	38	36	5238	137	25	35	21	6.0	4.0
Low Scenario	10 / 12	0 / 0	24 / 13	89	54	38	5194	132	27	35	17	4.2	2.2
Sensitivity: Low RES/Nuclear	7 / 10	18 / 4	23 / 11	104	23	35	3940	130	20	-12	18	3.7	2.6
Sensitivity: Vehicle-to-Grid	15 / 12	2 / 1	34 / 12	115	33	30	4138	132	20	35	19	5.9	2.8
Sensitivity: Biomass Gasification	10 / 12	16 / 4	33 / 16	82	29	40	5099	132	25	35	18	4.7	2.2
Sensitivity: No New Nuclear	10 / 12	26 / 6	32 / 15	120	24	48	4802	131	26	35	18	5.0	2.9
Sensitivity: Delayed Salt Caverns	15 / 16	20 / 7	18 / 9	93	23	120	62	133	16	35	19	6.9	2.4
Sensitivity: Peaky Demand	9 / 16	14 / 3	27 / 15	103	32	64	5234	132	23	35	16	4.5	2.6
Sensitivity: Low Wind Year	12 / 11	19 / 5	43 / 15	144	22	30	4003	131	20	5	19	5.6	3.5
Sensitivity: Long Wind Drought	18 / 25	36 / 9	18 / 13	102	15	47	3525	128	17	5	18	7.7	2.5
Sensitivity: Decentralised Balancing	9 / 19	9 / 2	29 / 17	105	35	44	5204	134	25	35	19	4.1	2.6

Notes: Hydrogen-fired refers to Hydrogen CCGT/GT and excludes Hydrogen CHP. IC net exports are in the direction from GB to the neighbours.

The Central scenario (guided by the CCC’s Balanced Pathway) acted as a ‘reference’ scenario – a baseline against which sensitivities are derived and compared. The sensitivities are grouped into three themes: technology mix, technology risk, and system stress. For each sensitivity, a brief synopsis highlighting the notable differences in results is provided.

The sensitivity synopses focus on the essential outcomes with respect to flexible capacity and are not intended to be an exhaustive analysis. More detailed information is contained in the accompanying results workbook.

4.3.1 Technology mix sensitivities

The fixed capacities in the core scenarios are predicated on highly uncertain assumptions, particularly with regards to the ambitious delivery of RES and Nuclear (as outlined in the BESS). It is important to understand how sensitive the development of flexible capacity is to these assumptions.

To explore this, 3 ‘technology mix’ sensitivities were created to reflect alterative future energy mixes: a more conservative deployment of RES and nuclear; increasingly responsive and synergistic demand; and, reallocation of limited biomass feedstock across the energy system.

4.3.1.1 Sensitivity: Low RES/Nuclear

The BESS has set out ambitious renewable and nuclear targets, but there is a risk of delivery failure if the required Government funding does not materialise or if future nuclear development experiences delays. To assess the impact of this uncertainty, this sensitivity explored the effects of a more conservative deployment of RES and Nuclear capacity, guided by the CCC’s 2020 pre-BESS outlook. While input assumption adjustments were made for the entire modelled period until 2050, not all technologies were altered for the presented period until 2035. However, it should be noted that capacity adjustments in 2040 and 2050 continue to impact the optimised capacity mix deployed in earlier years, as investment decisions consider the asset's entire lifetime.

In comparison to the Central scenario, the headline input assumptions differ in 2035 as follows:

- there is 11GW less Offshore Wind capacity;
- there is 23GW less Solar PV capacity;
- Onshore Wind and Nuclear capacity remain unchanged, with reduced Nuclear capacity applied in 2040 and 2050; and
- as a result of these changes, there is a reduction of 63TWh in RES generation in 2035 relative to the Central scenario (see Exhibit 4.36).

The decrease in RES and nuclear generation also leads to a reduction in surplus generation available for electrolysis, resulting in a roughly one-third decrease in green hydrogen production in 2035, equivalent to 13TWh of hydrogen, relative to the Central scenario. This limits the potential for the power system to depend on cheaper green hydrogen for flexibility and creates a shift towards alternative solutions, particularly Gas CCS.

Exhibit 4.36 – RES and nuclear generation (TWh)

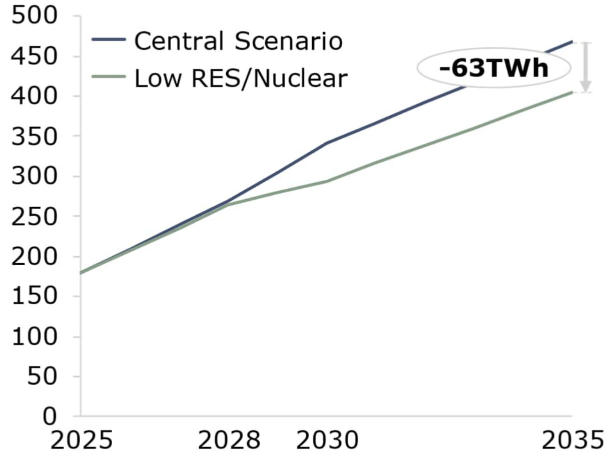
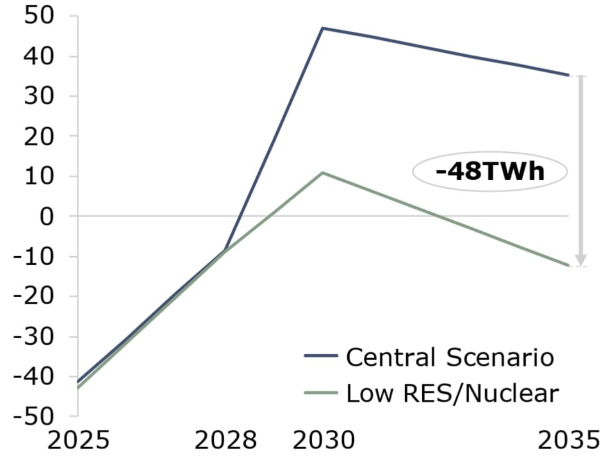


Exhibit 4.37 – Total net interconnector power exports from GB (TWh)



This sensitivity analysis underscores how interconnectors can equalise decarbonisation efforts across markets with varying levels of progress. Additionally, it shows the interdependencies across competing solutions, meaning the presence or absence of one solution can affect the need or utilisation of another solution. In this instance, a lower deployment of electrolysers, due to reduced levels of negative residual demand, increases the need for CCS-enabled technologies.

4.3.1.2 Sensitivity: Vehicle-to-Grid

The core scenarios include a provision for flexible charging of a percentage of EV demand. This sensitivity explores a future where EV demand plays a more active role in the power system by allowing energy to be supplied to the grid from the battery of an EV through Vehicle-to-grid (V2G) technology. Exhibit 4.38 illustrates the volume of EV demand with V2G capability in this sensitivity, which is estimated at 13TWh (21% of total EV demand) in 2035 based on the "Consumer Engagement in V2G" metric from National Grid's FES 2021 "Leading the Way" scenario[47].

The modelling (in general) treats the EV fleet as an aggregated storage unit. Demand is placed on this storage according to end-user driving patterns. In order to ensure that the EVs can drive, the aggregated EV storage must be charged up, subject to further limits. Firstly, EVs cannot charge when driving, and secondly the fleet must exceed a minimum level of charge at certain times of day, to represent drivers’ minimum range expectations. The charging capacity and storage volume are determined based on the number of cars on the road and typical EV charging and battery properties.

[47] National Grid ESO, Future Energy Scenarios, July 2021

In this sensitivity, V2G capability was also applied. V2G usage is contingent upon the storage's state of energy; the storage can offer V2G as long as it still has sufficient charge to meet the driving needs of the vehicles. The total V2G capacity was equivalent to a 22GW storage that can fully discharge in 8 hours. However, in practise the model is rarely able to achieve such capacities, due to the operational limits given above.

The introduction of V2G demand flexibility reduces the requirement for flexible generation and grid storage capacity (Exhibit 4.39). By 2035, this smarter and more interactive EV demand is projected to reduce the need for grid storage by 2GW and dispatchable generation capacity by 5GW. This underscores the significance of implementing demand response programs that can leverage existing battery capacity to serve secondary functions within the power system, while ensuring that the battery's primary function as an EV is not compromised.

The V2G capability can also provide increased competition to electrolysis for balancing negative residual demand positions. This results in a shift in the balance of hydrogen production technologies from electrolysis to ATR CCS. By 2035, the V2G sensitivity shows 3TWh less electrolysis and 8TWh more ATR CCS, relative to the Central scenario.

Exhibit 4.38 – EV annual demand split in the V2G sensitivity (TWh)

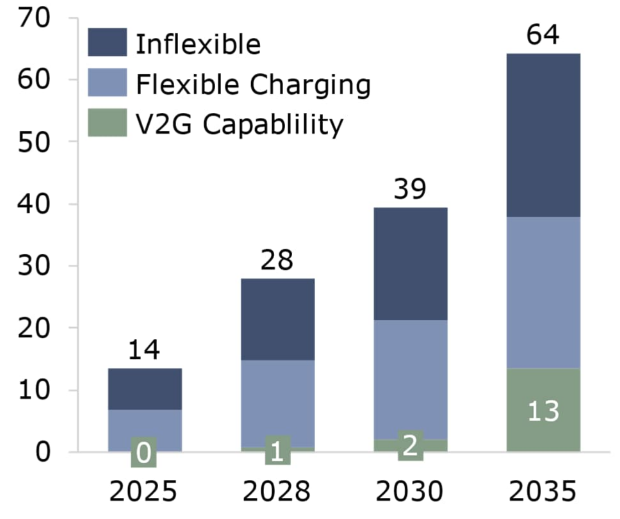
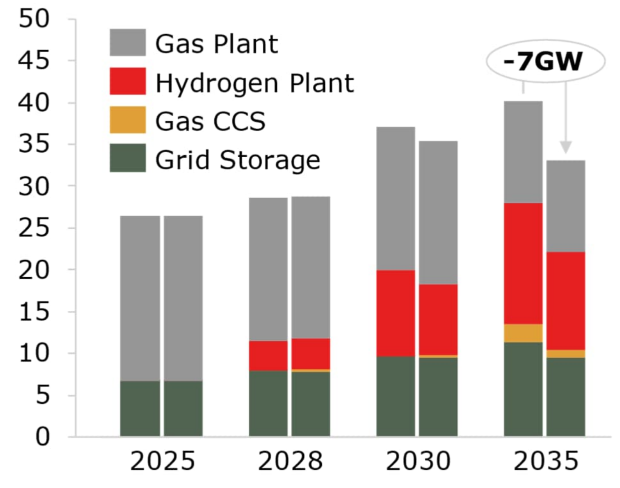


Exhibit 4.39 – Flexible generation and grid storage capacity in the Central scenario (left bar) and V2G sensitivity (right bar) (GW)



This sensitivity highlights the interdependence between demand and supply-side flexibility, emphasizing the importance of unlocking the full potential of DSR to achieve a more efficient means of balancing the system. Moreover, the emergence of technologies capable of addressing negative residual demand positions, such as V2G and electrolysis, is expected to impact the role and production composition of hydrogen in the energy system. As the energy sector moves towards a more sustainable and decarbonised future, it will be crucial to fully leverage the potential of smart demand response management to cost-effectively meet the system's flexibility requirements.

4.3.1.3 Sensitivity: Biomass Gasification

In a decarbonised future, the allocation of finite biomass resources in the energy sector becomes a critical issue as it raises questions about the optimal use of biomass to provide flexibility and address hard-to-abate emissions where alternative solutions may be particularly expensive.

In the Central scenario, the availability of biomass feedstock for the power and hydrogen sectors was assumed to be fixed and modelled as the baseload operation of a Biomass Gasification CCS system in the hydrogen sector and Biomass CCS plant in the power sector. For this sensitivity, biomass was reallocated from the power sector to the hydrogen sector, resulting in a shift in the technology mix in both sectors.

To be specific, in 2035:

- the 2.5GW of baseload Biomass CCS capacity removed from the power sector was replaced with 1.5GW of Gas CCS and 1GW of hydrogen plant; and
- the 4GW of baseload Biomass Gasification CCS capacity added to the hydrogen sector replaced 2.5GW of ATR CCS and 1GW of Electrolyser capacity.

This sensitivity analysis highlights the interdependence between the power and hydrogen sectors and the critical need for co-optimisation of finite resources between them to achieve the most cost-effective provision of flexibility from a holistic energy system perspective. Furthermore, the analysis demonstrates that developing substitute solutions is feasible provided there is a clear understanding of the future use of biomass.

4.3.2 Technology risk sensitivities

The Central scenario relies heavily on the delivery of emerging technologies (e.g. Gas CCS and hydrogen plant) and the supporting infrastructure (e.g. H_2/CO_2 pipelines and storage). This creates a risk since the speed with which these technologies can be commercialised and deployed is uncertain.

To understand the impact of this risk we have undertaken several ‘technology risk’ sensitivities by limiting or delaying deployment of such technologies.

4.3.2.1 Sensitivity: No New Nuclear

The BESS outlines the Government's ambitious plans to progress up to 24 GW of nuclear capacity by 2050.

This sensitivity examines a future GB energy system with limited reliance on nuclear power. It has been designed with the exclusion of new build nuclear energy after Hinkley Point C, resulting in the total nuclear capacity remaining flat at 4.5GW from 2030 onward[48]. The reduced baseload nuclear energy (see Exhibit 4.40) shifts the Residual Demand Net Inflexible[49] curve up relative to the Central scenario. While reduced baseload nuclear energy results in a shortfall in generation that must be addressed by the use of flexible capacity technologies, it also mitigates the extent of negative residual demand positions that occur during periods of excessive generation.

As indicated in Exhibit 4.41, Gas CCS and Hydrogen CCGT predominantly substitute nuclear generation, resulting in a significant increase of 20TWh in production in 2035. These technologies can operate continuously for extended periods, simulating the baseload operation of nuclear energy, especially during extended periods of generation deficit.

The reduction in inflexible nuclear generation decreases the need to balance negative residual demand positions during times of excessive generation, leading to a decline of 11TWh in green hydrogen production in 2035, attributed to the lowered potential for electrolysis. However, the demand for hydrogen in the power sector, primarily to substitute nuclear capacity and generation, remains constant, resulting in a corresponding increase in blue hydrogen production. Additionally, there is a reduction of 5TWh in renewables curtailment.

Exhibit 4.40 – Nuclear power generation (TWh)

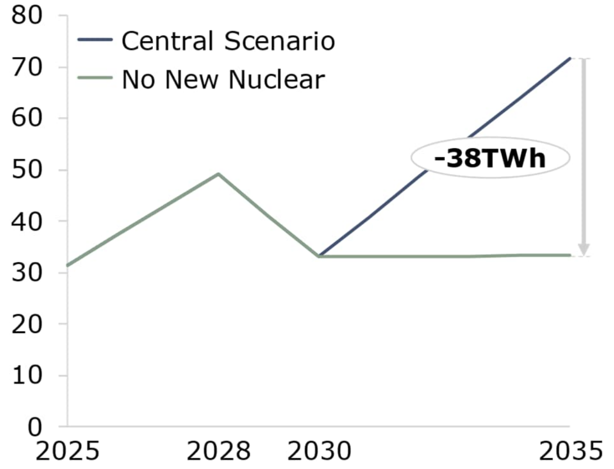
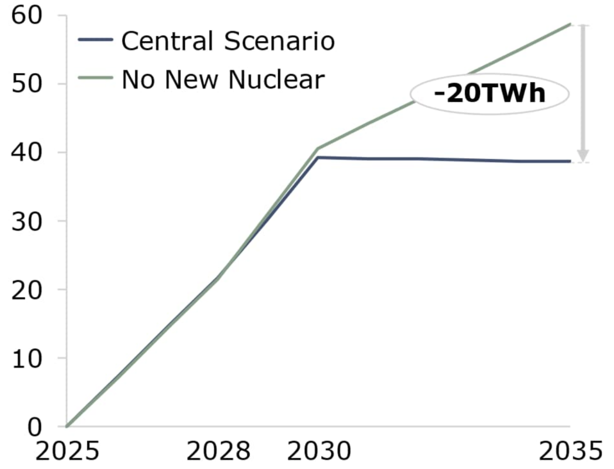


Exhibit 4.41 – Gas CCS & hydrogen fired generation (TWh)



This sensitivity analysis reveals that low-carbon dispatchable plant, such as Gas CCS, could substitute for nuclear. Additionally, it highlights how reduced deployment of inflexible operation plants in the power sector decreases the requirement for electrolysis to balance the system's needs.

[48] The 4.5GW nuclear capacity consists of the existing Sizewell B and new build Hinkley Point C, which is assumed to be online in 2028. For the Central scenario, two new reactors at both Sizewell C and Bradwell are assumed to be commissioned in 2035.
[49] Residual Demand Net Inflexible: Final consumption, excluding electrolysis, net renewables (Offshore Wind, Onshore Wind, Solar PV) and inflexible plant (Nuclear, Biomass CCS, CHP, Other).

4.3.2.2 Sensitivity: Delayed Salt Caverns

This sensitivity examined how the timely development of salt caverns impacts the balance of flexible capacity. While in the Central scenario salt caverns can be used as a hydrogen storage solution from 2030, this sensitivity delays salt caverns until 2040. This is founded on the premise that early salt cavern development phases, such as planning and permitting, are bureaucratic and lengthy and commercialisation requires coordination across the value chain.

This restricts the pre-2040 hydrogen storage solutions to 6-hour pressurised tanks, which are considerably more costly at storing hydrogen over longer durations; the Capex assumptions used in the study imply that, as a function of kWh capacity, storage is more than 20-fold cheaper in 240-hour salt caverns relative to 6-hour pressurised tanks.

Hydrogen demand can be split into three components – non-power sectors, base power sector (Hydrogen CHP) and variable power sector (Hydrogen CCGT and GT). The non-power sectors and base power sector hydrogen demand is a fixed input and must be met in this sensitivity regardless of the restricted storage options. As such, there is still a significant level of hydrogen production (Exhibit 4.42) and network to satisfy this demand.

The inaccessibility to store hydrogen for longer durations erodes the value of electrolysing excess renewable generation. This has a ripple effect on other parts of the energy system:

- Increased levels of electricity curtailment as surplus generation is unable to be economically utilised or stored. In 2035, there is a 68% (17TWh) increase in the level of curtailment (see Exhibit 4.43).
- Diminished role for flexible hydrogen plant in the power sector. In 2035, Hydrogen CCGT and GT generate 18TWh, relative to 30TWh in the Central scenario – this equates to a 40% reduction. This is largely compensated by increased generation from Gas CCS.
- The size of the hydrogen network is strongly influenced by the utilisation of salt caverns. In 2035, the hydrogen pipeline infrastructure is 36% smaller than the Central scenario. In particular, the capacity of boundaries connecting Scotland to England, and Eastern England with the Midlands are reduced, as flows of green hydrogen are no longer channelled to salt caverns in the North of England.
- Other forms of energy storage are more readily able to compete, with the duration capacity of pressurised hydrogen tanks and 72-hour grid storage (CAES) increasing by 54GWh and 82GWh respectively in 2035 relative to the Central scenario.
- Restricting the deployment of hydrogen salt caverns, will see a £1.7bn increase in total system costs in 2035.

Exhibit 4.42 – Hydrogen production in the Central scenario (left bar) and delayed salt cavern sensitivity (right bar) (TWh)

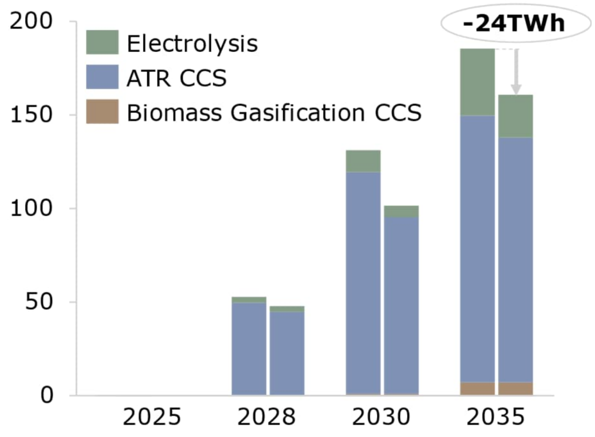
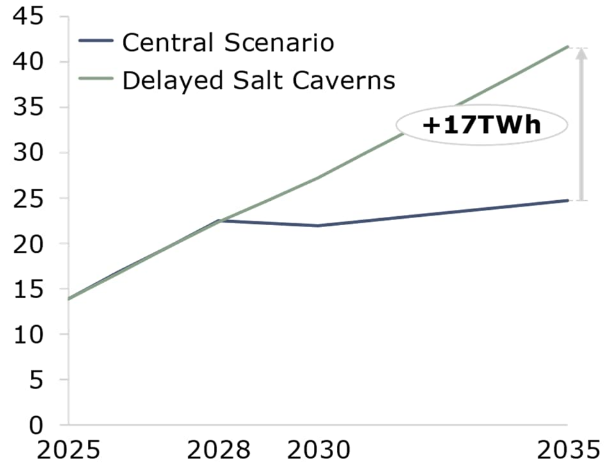


Exhibit 4.43 – Renewable curtailment (TWh)



This sensitivity shows that hydrogen salt caverns can increase the value of green hydrogen and facilitate its use in power sectors with volatile demand requirements. This delayed infrastructure assumption also underscores the interdependence of competing technologies, as CCS-enabled solutions may replace electrolysis and hydrogen-fired power plants. Additionally, diversifying investments in grid storage technologies can help mitigate delivery failure risks associated with enabling hydrogen infrastructure.

4.3.2.3 Sensitivity: Peaky Demand

This sensitivity was designed to investigate uncertainty surrounding future demand profiles and consumer engagement in demand response programs. The design of this sensitivity is built on the premise that there are higher levels of disengagement from residential energy consumers with electrified heating, manifesting as weak building energy efficiency improvements and reduced implementation of smart heating controls.

This has been incorporated into the modelling by making three changes to the Central scenario:

1. The use of new, peakier profiles for "additional electrified heat demand" that assume no embedded consumer behavioural response (e.g. from ToU tariffs).

2. An increase in annual heat demand, based on numbers provided by the CCC that assume insufficient fabric energy efficiency improvement in residential buildings with heat pumps (see Exhibit 4.44).

3. Disabling DSR capacity that allows for shifting of demand from heat pumps/hot water storage.

These changes are estimated to result in a combined increase of between 7-8GW in total peak demand by 2035.

The increased total peak demand resulting from the changes made in the sensitivity demand inputs necessitates an increase in flexible capacity. This capacity is fulfilled by a combination of flexible generation technologies and grid storage, as shown in Exhibit 4.45. The peakier demand profile and inability to shift heat demand also increase the need for short-term flexibility. This demand is met by Gas GT and 4-hour batteries, which are effective in balancing the increased intraday variability.

Exhibit 4.44 – Additional annual demand from residential heat in the Peaky Demand sensitivity (TWh)

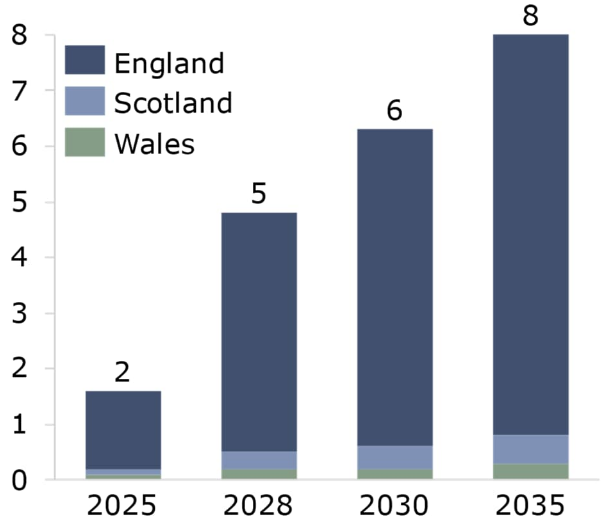
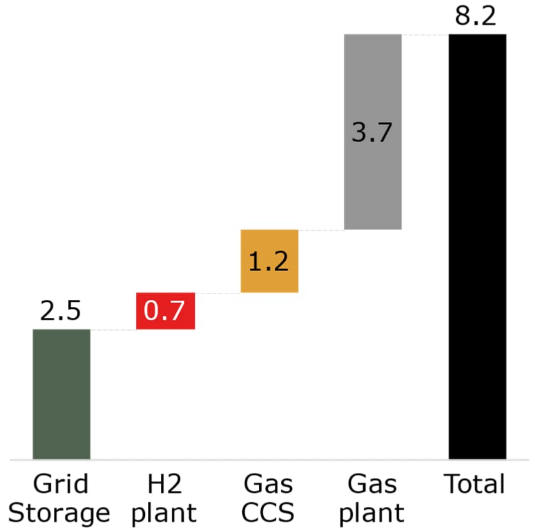


Exhibit 4.45 – Additional flexible capacity in Peaky Demand sensitivity relative to Central scenario in 2035 (GW)



This sensitivity analysis emphasises the importance of developing demand response capabilities to avoid unnecessary investments in supply-side assets. Moreover, it highlights how the shape of peakiness in residual demand influences the need for short-term flexibility solutions, as well as the competition and interdependence between DSR and grid storage.

4.3.3 System stress sensitivities

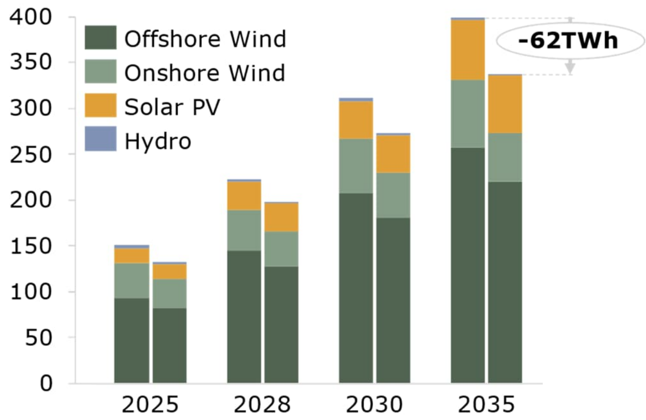
With the energy system being increasingly weather driven, it is important to understand how robust the system is to extreme weather events. To capture this, we have undertaken two sensitivities that reflect particular extremes in future weather patterns – a 'Low Wind Year' and a more extreme sensitivity that combines this with a 'Long Wind Drought'. For both these sensitivities we have examined the optimal investment pattern and dispatch relative to the Central scenario in order to examine the characteristics of a more resilient energy system.

In addition to weather-driven shortfall events, system stress originating from poor market design has been investigated. This focuses on the inefficient procurement of ancillary services due to the decentralisation of balancing responsibility.

4.3.3.1 Sensitivity: Low Wind Year

This sensitivity was developed to better understand the resilience of the energy system to extreme weather events, particularly in light of the potential impact of climate change on the severity of such future events.

Exhibit 4.46 – RES generation in the Central scenario (left bar) and Low Wind Year sensitivity (right bar) (TWh)



Two modelling exercises were conducted using 2010 weather patterns, which were determined to be representative of a 1-in-50 low-wind year. Exhibit 4.46 illustrates the total renewable energy generation using 2010 weather patterns compared to the Central scenario, emphasising the substantial difference between the two.

The security of supply for capacity in the Central scenario[50] was initially tested by using weather patterns from 2010 to assess whether the capacity would be adequate to ensure security of supply during an extreme low wind year. The findings are presented in Exhibit 4.47, which indicates that the capacity in the Central scenario does not meet the reliability benchmark of a 3-hour Loss of Load Expectation (LOLE) per year. The insufficient capacity would lead to load shedding of 30GWh over 15-hours.

Exhibit 4.47 – Power and hydrogen lost load in the Low Wind Year sensitivity relative to the Central scenario

Label	Unit	2025	2028	2030	2035
Power sector					
Number of hours with lost load	Hours	77	95	10	15
Volume of lost load	GWh	117	209	16	30
Hydrogen sector					
Number of hours with lost load	Hours	85	87	10	0
Volume of lost load	GWh	0	14	0	0

Notes: The Central scenario exhibited negligible load loss. The reason why positive hours with hydrogen lost load did not result in any volume of lost load is because the total volume of lost load was small, amounting to <0.5 GWh.

The second modelling exercise consisted of re-optimising capacity for the 2010 weather patterns to simulate how the system could be made more secure. This approach of optimising capacity against an outlier year reflects

[50] Determined using 5 historic weather years (2012, 2014, 2015, 2017, and 2018) chosen to capture a range of weather patterns – described in section 2.3.

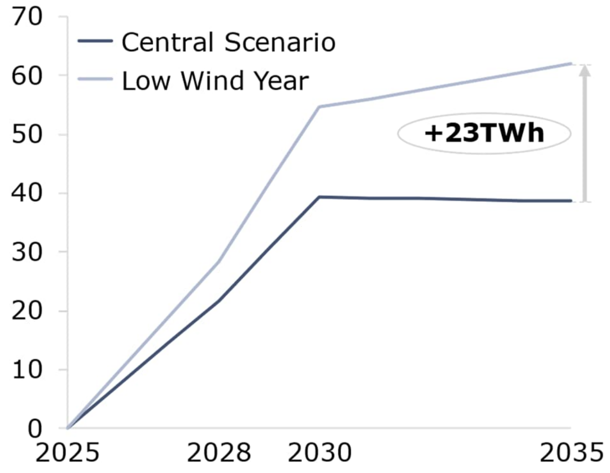
setting capacity market auction parameters against a more conservative reliability standard to enhance resilience to extreme weather events.

The decrease in renewable generation has significant implications in terms of the capacity and dispatch for the power sector, including:

- An increased reliance on interconnectors, with 31TWh of additional imports in 2035.
- A shift in capacity investment towards longer duration flexibility solutions with higher load factors. Specifically, in 2035, 3GW of additional Gas CCS replaces 1.5GW of both gas-fired plant and Battery, resulting in an additional 9TWh of Gas CCS generation (as shown in Exhibit 4.48).
- Hydrogen CCGTs run at a higher load factor, increasing to 35% in 2035 (compared to 25% in the Central scenario), leading to an additional 13TWh of hydrogen-fired generation in 2035 (also shown in Exhibit 4.48).
- In total, there is a net capacity increase of 4GW, mainly from dispatchable low-carbon generation technologies.

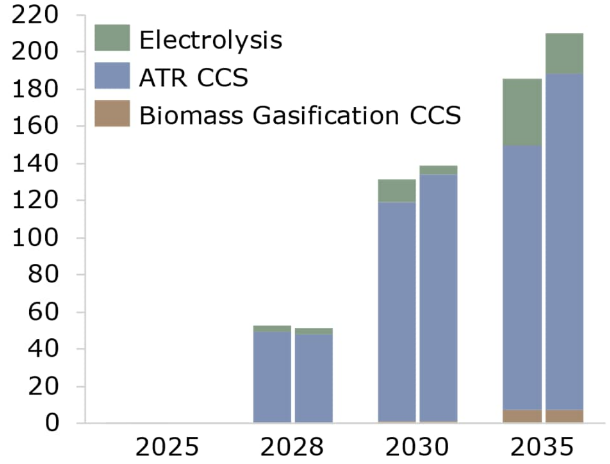
Furthermore, reduced renewable generation has a notable impact on the composition of hydrogen production. Electrolysis is constrained by reduced periods of surplus renewable generation, and therefore, ATR CCS makes up an increasingly dominant fraction of hydrogen production (as demonstrated in Exhibit 4.49). Despite more total hydrogen production driven by increased demand from hydrogen-fired electricity generation, hydrogen storage and transmission networks are approximately 20% smaller in 2035. This is due to the dimensioning of hydrogen infrastructure being disproportionally weighted by the production volume and flows of green hydrogen.

Exhibit 4.48 – Generation from low carbon dispatchable plant (TWh)



Notes: Low carbon flexible generation technologies consist of Hydrogen CCGT, Hydrogen CCGT (Retrofit), Hydrogen GT, and Gas CCS.

Exhibit 4.49 – Hydrogen production in the Central scenario (left bar) and Low Wind Year sensitivity (right bar) (TWh)



This sensitivity analysis demonstrates that planning the power system for extreme low wind years requires a slight increase in capacity but, more significantly, a higher load factor for dispatchable generation technologies such as Gas CCS and Hydrogen CCGT. Interconnectors can also play a significant role in supporting domestic generation by diluting the impact of extreme weather conditions across connected markets.

In the hydrogen sector, this sensitivity highlights the interdependence of hydrogen production technologies, where less green hydrogen production has a knock-on impact on the need for blue hydrogen. Lastly, this sensitivity analysis underscores how the production and flows of green hydrogen have a disproportionate impact on the need for hydrogen infrastructure, including networks and storage.

4.3.3.2 Sensitivity: Long Wind Drought

The dimensioning of a weather driven energy system is heavily influenced by the longest period of residual demand. In order to test this, we combined the 'Low Wind Year' sensitivity with a sustained period of wind drought. This sensitivity investigates a worst-case combination of weather patterns, testing whether the capacity deployed in the Central scenario is adequate and how the system would need to be redesigned to withstand severe wind droughts.

To design this sensitivity, the 30-day period with the highest volume of residual demand[51] from 2009 to 2019 was identified, which turned out to be in Winter 2010. Next, wind load factors over the same 10-year period were analysed and identified the lowest wind load factor during a 30-day period, which occurred in Summer 2018 at 16% (combining both onshore and

[51] Adjusting for capacity and demand.

offshore load factors). The two factors were combined by scaling down the wind load factor during the 30-day period with the highest residual demand to match the record low 30-day wind load factor identified during the 10-year period from 2009 to 2019. In simple terms, this made the 30-day period with the largest generation deficit even worse by further reducing the wind load factor.

Similar to the Low Wind sensitivity, the capacity from the Central scenario was assessed to determine its capability to ensure a secure supply during a low wind year, which is now further exacerbated by an amplified wind drought. The results are presented in Exhibit 4.50, which demonstrates that the capacity in the Central scenario fails to meet the reliability benchmark of a 3-hour Loss of Load Expectation (LOLE) per year. Moreover, due to the added impact of the wind drought, the capacity shortfall is much more pronounced, resulting in hundreds of hours and significant volumes of lost load in the power and hydrogen sector.

Exhibit 4.50 – Power and hydrogen lost load in the Long Wind Drought sensitivity relative to the Central scenario

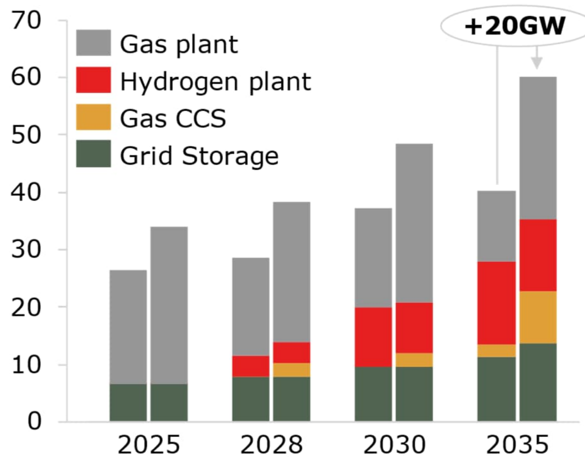
Label	Unit	2025	2028	2030	2035
Power sector					
Number of hours with lost load	Hours	199	222	188	197
Volume of lost load	GWh	853	1262	877	943
Hydrogen sector					
Number of hours with lost load	Hours	271	343	688	598
Volume of lost load	GWh	0	91	1578	7696

Notes: The Central scenario exhibited negligible load loss. The reason why positive hours with hydrogen lost load did not result in any volume of lost load is because the total volume of lost load was small, amounting to <0.5 GWh.

To maintain security of supply in a sustained wind drought requires significant additional investment in flexible capacity relative to the Central scenario (and Low Wind Year sensitivity) (see Exhibit 4.51). The composition of flexible capacity is significantly influenced by the extreme wind drought event, with a preference for gas plant and Gas CCS over hydrogen plant. When dimensioning against a single extreme 30-day residual demand period, it is more cost-effective to deploy technologies that can run continuously for the entire wind drought period, such as gas plants, rather than hydrogen plants, which have limited continuous running hours without overbuilding storage and investing in additional blue hydrogen production capacity. This increased use of gas-fired generation leads to increased emissions relative to the Central scenario, with an additional 4MtCO_2 of emissions expected in 2035.

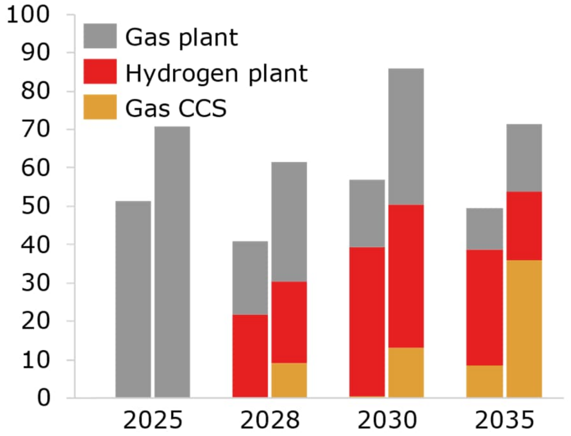
Exhibit 4.52 shows a similar trend in generation, with the adjusted 2010 weather patterns resulting in an increase in generation from dispatchable technologies as renewable generation levels decrease. Gas plant and Gas CCS play a more prominent role in the generation mix, while hydrogen-fired generation is reduced due to lower capacity and reduced levels of electrolysis.

Exhibit 4.51 – Flexible (operational) capacity in the Central scenario (left bar) and Long Wind Drought sensitivity (right bar) (GW)



Notes: This excludes Gas CCGT capacity that is mothballed ahead of anticipated conversion to hydrogen operation.

Exhibit 4.52 – Flexible generation in the Central scenario (left bar) and Long Wind Drought (right bar) (TWh)



In summary, this sensitivity emphasises that extreme weather events, especially sustained periods of positive residual demand, are critical factors for determining the necessary system flexibility. It also supports the notion that energy storage technologies are less effective than flexible generation technologies in guarding against these events. Therefore, existing unabated gas may have a role to play in ensuring security of supply in the short- to medium-term until sufficient low-carbon dispatchable capacity is available. Finally, the analysis highlights that the reliability of hydrogen-fired electricity generation during long periods of residual demand depends not only on the GW capacity of hydrogen-fired power plants but also on the supply chain and enabling infrastructure.

4.3.3.3 Sensitivity: Decentralised Balancing

The BESS, published in April 2022, promised a comprehensive Review of Electricity Market Arrangements (REMA). REMA will consider a range of options for reform to electricity markets, including the provision of ancillary services. In this sensitivity we examine the decentralisation of balancing responsibility; promoting a more ‘active’ role for market participants (i.e. generators and/or suppliers) with the intention to minimise the importance of central decisions.

For the purpose of this analysis, trip risk and wind forecast error was distributed to six separate entities. Each of these represent a portfolio of equally sized thermal and renewable assets that must procure peaking capacity dimensioned against the loss of their largest infeed and upward/downward flexibility for wind forecast error. We are assuming that each entity must procure their full balancing needs and that no sharing or secondary trading of these services is possible. This results in inefficiency and over procurement of ancillary services relative to the centralised buyer (NG ESO) model currently in place.

Exhibit 4.53 presents the hourly requirement of reserve products in this sensitivity and the Central scenario.

Exhibit 4.53 – Reserve products' hourly requirements (GW)

Product	Direction	2025	2028	2030	2035
Central scenario					
Frequency response	Up/downward	1.6	1.8	1.8	1.8
Regulating reserve	Up/downward	2.5	3.0	3.5	3.8
STOR	Upward	1.6	1.9	1.9	1.9
Decentralised Balancing sensitivity					
Frequency response	Up/downward	1.6	1.8	1.8	1.8
Regulating reserve	Up/downward	5.0	6.0	7.0	7.5
STOR	Upward	4.0	4.8	4.8	4.8

Frequency response: Expected to remain centrally dispatched, thus unchanged.
Regulating reserve (wind forecast error): Generally speaking, the larger the installed wind power capacity, the smaller the spread of the distribution of forecast error; this is related to the geographic diversity of having more turbines experiencing different weather conditions at the same time. We examined wind forecast error of smaller sized clusters relative to at a national level; unsurprisingly the wind forecast error is generally localised and thus error distributions exhibit higher variance in smaller regions. We estimate that if GB were divided into 6 distinct, non-overlapping regions, the cumulative error distribution would be approximately double that relative to a national level. Therefore, we anticipate that the six entities would procure double the upward/downward flexibility required to balance wind forecast error relative to the centralised ESO mechanism in the Central scenario.
STOR (trip risk): We made some high-level assumptions (e.g. thermal capacity, average unit size, outage rate, outage length) in order to create a binomial distribution of outage probability in each hour. Note that we assumed that Entity 1 holds the trip risk for Hinkley. We then calculated the 1/365 outage risk, assuming each entity would buy against this requirement. This results in an approximately three-fold increase in the procurement of cumulative peak capacity held for trip risk relative to the centralised ESO mechanism in the Central scenario.

The decentralisation of balancing responsibility for trip risk and wind forecast error results in increased procurement of regulating reserve and STOR. This increased perceived demand is met by some additional capacity, totalling almost 10GW by 2035 (see Exhibit 4.54). The precise nature of the capacity required will depend on the nature of the forecast error or trip risk. It is likely that this capacity would need to include a mixture of grid scale storage and peakers.

Exhibit 4.54 – Additional peaker and grid storage capacity required relative to Central scenario (GW)

GW	2025	2028	2030	2035
Additional peaker and grid storage capacity	6.6	6.6	6.8	9.6

To function properly, markets must allow for supply and demand to be matched in an efficient manner. Decentralisation of balancing responsibility without providing a means of sharing reserve provision will result in significant over procurement and unnecessary flexible capacity investment.

5 Indicators to monitor progress

This chapter presents a new set of tracking indicators for low-carbon flexible capacity within the power and hydrogen sectors. These indicators have been developed based on the insights gained from our energy modelling and are intended to assist in monitoring the progress of flexibility within the GB energy sector. Additionally, this chapter outlines the key policy milestones that must be achieved in order to realise these indicators.

5.1 Introduction

In the 2021 Report to Parliament titled 'Progress in reducing emissions' the CCC developed tracking indicators to assess the underlying progress in each sector towards meeting the Sixth Carbon Budget and Net Zero 2050 target. These indicators serve as future milestones for metrics that act as implicit proxies for decarbonisation progress, such as EV market share and heat pump installations.

Although indicators for flexible capacity, such as dispatchable low-carbon generation capacity and low-carbon hydrogen production, were created, they do not completely capture the complexities and uncertainties related to monitoring flexible capacity in the GB energy system. This is especially true given the dependence on emerging technologies and the necessity for coordinated development of energy system infrastructure.

This chapter introduces an updated set of tracking indicators for low-carbon flexible capacity in the power and hydrogen sectors, which includes a broader range of potential solutions, distinguishes between technology deployment and development, and uses ranges for each indicator to reflect the interactions and substitutability across technology solutions. After extensive consultation, the CCC carefully selected specific scenarios and sensitivities from the pool of 3 core scenarios and 12 sensitivities to inform the indicator ranges.

The scenarios and sensitivities chosen for this purpose are as follows:

- The 3 core scenarios (Central, High, and Low);
- Low RES/Nuclear sensitivity;

- Biomass Gasification sensitivity;
- Low Wind Year sensitivity; and
- Grid Storage sensitivity.

To effectively account for the complex and interconnected nature of energy systems, the selection process concentrated on key assumptions with high levels of uncertainty, while also taking into account a diverse set of outcomes that recognises the uncertainty in how the system will ultimately deliver the Net Zero transition.

5.2 Developing deeper indicators of progress

The updated tracking indicators for flexible capacity consist of 17 indicators that are divided into two categories: 9 technology indicators and 8 development indicators:

- Technology indicators monitor the installed capacity and operational parameters of various technology groups. These have been intentionally designed to be technology-agnostic, grouping together technologies that perform similar roles in providing flexibility to the energy system, due to the current uncertainty regarding which technology will be best suited to meet future flexibility needs.
- Development indicators focus on the development and construction milestones of flexible technology groups and enabling infrastructures with protracted lead times. By tracking the pipeline of these technologies and infrastructures, it is possible to identify potential roadblocks and delays, and take action to mitigate them in order to meet the tight timeline for achieving targets.

By tracking the pipeline of these technologies and infrastructures it is possible to identify potential roadblocks and delays

In simple terms, technology indicators help in flagging that the system is working as should be expected, while development indicators tell us whether we can expect to have enough flexible capacity in future years to facilitate the transition to Net Zero.

5.2.1 Technology indicators

Exhibit 5.1 defines the updated and expanded set of technology indicators for low-carbon flexible capacity in the power and hydrogen sectors.

The analysis highlights the need for a diverse range of technology solutions with varying flexibility characteristics to achieve Net Zero in the power sector. Specifically, low-carbon dispatchable generation is required to address longer periods of residual demand imbalance, while grid storage and DSR are needed to balance growing within-day variability. As a result, the CCC's existing set of indicators has been expanded to include grid storage and DSR, which encompasses indicators for both the output and duration capacity of grid storage solutions, as well as the proportion of demand that actively responds to price signals.

Exhibit 5.1 – Definition of technology indicators

Indicator	Unit	Definition
Power sector		
Dispatchable low-carbon percentage of generation	%	Dispatchable low-carbon generation (Gas CCS and hydrogen-fired plant) as a fraction of total domestic generation
Dispatchable low-carbon generation capacity	GW	Dispatchable low-carbon capacity (Gas CCS and hydrogen-fired plant)
Output capacity of grid storage	GW	The sum of maximum discharge capacities of grid storage technologies (Batteries, CAES, LAES, and Pumped Storage)
Grid storage capacity	GWh	The total amount of energy that can be stored in grid storage technologies (Batteries, CAES, LAES, and Pumped Storage)
Active demand response as percentage of total demand	%	The fraction of total domestic demand that is shifted or avoided
Hydrogen sector		
Low-carbon hydrogen production	TWh/yr	Low-carbon hydrogen production (Electrolysis, ATR CCS, and Biomass Gasification CCS)
Low-carbon hydrogen production derated capacity	GW	Low-carbon hydrogen production derated capacity (Electrolysis 50% LF, ATR CCS 90% LF, and Biomass Gasification CCS 95% LF)
Hydrogen storage capacity	TWh	Total amount of hydrogen that can be stored in storage technologies (Salt Caverns and Tanks)
Economy-wide		
Volume of CO_2 cumulatively captured	$MtCO_2$	The economy-wide volume of CO_2 cumulatively captured from CCS technologies

Dispatchable low-carbon generation capacity: The CCC's existing indicator for 'dispatchable low-carbon capacity' has been modified in this analysis to exclude Biomass CCS. This is because Biomass CCS is not assumed to offer flexible dispatch in this study due to the economics (negative short-run marginal cost due to assumed carbon price) and to integrate feedstock availability forecasts into the modelling.
Volume of CO_2 cumulatively captured: This includes CO_2 emissions from the CCS technologies in this analysis (Biomass CCS, Gas CCS, ATR CCS, Biomass Gasification CCS) and assumed CO_2 emissions from M&C, Refining, Waste, and Other Fuel Supply, provided by the CCC. Cumulative volumes are used for the indicator in order to assess the capacity of CO_2 storage that must be developed, however annual volume of captured emissions can be found in the accompanying results Excel workbook.

The current 'dispatchable low-carbon generation' and 'low-carbon hydrogen production' indicators used by the CCC are valid, but they do not fully contextualise or express the unique flexibility parameters of these technology groups. To address this, the indicators have been expanded to include capacity provision as well as the percentage of supply. In the case of hydrogen production technologies, the capacity has been adjusted to account for expected variations in load factors.

The development of enabling infrastructure for emerging energy vectors and combustion by-products, such as hydrogen and CO_2, is crucial for the effective deployment of low carbon dispatchable technologies. Put simply, lower-carbon power plants and hydrogen production units are largely ineffective without a proper network and storage system in place. In recognition of this need, new indicators have been added to track the progress of hydrogen storage capacity and the volume of CO_2 that is cumulatively captured.

5.2.2 Development indicators

The scenario-based energy modelling results emphasise the importance of flexible technologies and their required capacity in the power and hydrogen sectors. However, as a significant portion of this required capacity is yet to be constructed, and as it involves emerging technologies with protracted build times, it is important to anticipate potential issues arising from delays in infrastructure deployment and possible insufficient projects in the pipeline.

It is important to anticipate potential issues arising from delays in infrastructure deployment and possible insufficient projects in the pipeline

To monitor this, a set of development indicators has been devised to ensure sufficient flexible capacity is 'in development' or 'under construction' at any point in time. Both metrics are back-calculated from the operational capacity in the development indicators.

Development indicators were selected for emerging technology groups and infrastructure types that have long lead times:

- Dispatchable low-carbon generation capacity;
- Low-carbon hydrogen production derated capacity;
- Hydrogen storage capacity; and
- CCS storage capacity.

It is important to note that not all projects that are in development reach the operational stage. To account for this, a success rate has been applied to capacity that is 'in development,' taking into account the possibility that projects may not progress to construction, or may have an approved capacity that is lower than originally proposed. Due to the lack of robust evidence on planning challenges that new projects face, an assumed success rate of 80% has been applied to all capacity that is 'in development' (for example, if 100MW of capacity is 'in development,' then 80MW is expected to reach construction). All capacity that is 'under construction' is anticipated to be commissioned.

5.3 Final indicators

In Exhibit 5.2, the technology indicators are presented for snapshot years up to 2035, in line with the Net Zero target for the power sector and to concentrate on the delivery in the short term. The ranges are derived from the scenarios and sensitivities chosen by the CCC, which consider a broad range of outcomes that recognise the uncertainty surrounding the Net Zero transition's ultimate delivery.

Exhibit 5.2 – Technology indicators

Indicator	Unit	2025	2028	2030	2035
Power sector					
Dispatchable low-carbon percentage of generation	%	0%	5%-9%	7%-13%	4%-12%
Dispatchable low-carbon generation capacity	GW	0	3-6	9-13	12-20
Output capacity of grid storage	GW	7	8-9	10-11	10-19
Grid storage capacity	GWh	24	26-100	30-159	30-366
Active demand response as percentage of total demand	%	1%	2%-3%	3%-4%	4%-5%
Hydrogen sector					
Low-carbon hydrogen production	TWh/yr	0	33-55	76-121	115-216
Low-carbon hydrogen production derated capacity	GW	0	4-7	9-14	14-25
Hydrogen storage capacity	TWh	0	0	2-3	3-5
Economy-wide					
Volume of CO_2 cumulatively captured	$MtCO_2$	1	20-34	60-96	242-361

Notes: Definitions can be found in for each indicator in Exhibit 5.1.

Exhibit 5.3 presents the development indicators, displaying the development and construction stages of crucial technology groups and infrastructure types, back-calculated from the operational capacity in the development indicators. For instance, the capacity of operational dispatchable low-carbon generation technologies in 2030 should range from 9GW to 13GW, with an additional 2GW to 4GW under construction and 3GW to 7GW in development.

Exhibit 5.3 – Development indicators

Indicator	Unit	Phase	2025	2028	2030	2035
Dispatchable low-carbon capacity	GW	Operational	0	3-6	9-13	12-20
		Under Construction	3-6	7-8	2-4	2-8
		In Development	8-11	2-5	3-7	2-7
Low-carbon hydrogen production derated capacity	GW	Operational	0	4-7	9-14	14-25
		Under Construction	4-7	6-9	3-7	3-8
		In Development	8-12	4-8	3-6	5-15
Hydrogen storage capacity	TWh	Operational	0	0	2-3	3-5
		Under Construction	1-2	2-4	1-2	1-2
		In Development	2-4	1-2	2-3	2-3
CCS storage capacity	$MtCO_2$	Operational	1	20-34	60-96	242-361
		Under Construction	39-64	113-168	146-212	168-271
		In Development	207-304	207-312	256-405	274-467

Notes: Development and construction times are not typically applied to technology buckets, however these grouping exhibit similar lead time assumptions.
Sources: AFRY analysis, Leigh/Fisher (Electricity Generation Costs and Hurdle Rates, August 2016)

Key findings that arise from the results and indicators:

- The indicators show a range of possible outcomes, which underlines that there are competing technology solutions in any pathway. Future uncertainty is driven by factors such as the cost competitiveness of different technologies, the availability of supply chains and infrastructure, and the evolution of residual demand. The latter, in particular, is subject to significant uncertainty and depends on factors such as the level of electricity demand, the deployment of renewable energy sources, and the progression of the nuclear fleet.
- There are interdependencies across competing solutions. The flexible capacity options are interdependent, meaning the presence or absence of one solution can affect the need or utilisation of another solution. For instance, a high deployment of Hydrogen CCGT may reduce the need for Gas CCS as both provide similar flexibility services. Similar relationships can be observed between electrolysers and CCS-enabled technologies for hydrogen production, as well as between grid storage and DSR for the provision of short-duration flexibility.
- The hydrogen and power sectors are closely connected and one sector's failures can impact the other. For instance, if the development of hydrogen infrastructure lags, the power sector may have to rely more on CCS and grid storage to make up for the deficit. The relationship between these sectors should also be considered when developing policy to avoid skewed or inefficient co-development.
- The lower bound of the indicators requires significant investment and effective Government support policies for implementation. To maintain progress towards Government targets, the indicators suggest the energy system must have at least 9GW of dispatchable low-carbon generation capacity, 10GW of grid storage, 76TWh/yr of low-carbon hydrogen production, 2TWh of hydrogen storage, and 60MtCO_2 of cumulatively captured and stored emissions by the end of this decade.
- The urgency to act is amplified by the protracted development and construction times for these emerging technologies and their supporting infrastructure. Concurrent progress across the hydrogen supply chain (i.e. supply, transport and storage) and the establishment of CCS infrastructure is crucial to meet Government targets. Due to lead times extending up to 10 years, immediate action is crucial. By 2025, the indicators suggest the energy system must have underway the construction of at least 3-6GW of low-carbon dispatchable generation capacity, 4-7GW of low-carbon hydrogen production, 1-2TWh of hydrogen storage, and 39-64Mt of CO_2 storage space.

5.4 Policy gap

The transformation of the energy system, especially in the deployment of CCUS-enabled technologies and the development of the hydrogen market, will depend on Government support for early and coordinated expansion. It will be crucial to develop supporting infrastructure and reform market designs to accommodate new technologies in a timely manner.

5.4.1 It is unclear to what extent Government's targets for low-carbon hydrogen production capacity are consistent with the indicators

The Government has made clear its intentions to rapidly develop a low-carbon hydrogen economy. This includes the aims of up to 2GW of low-carbon hydrogen production operational or under construction by 2025 and up to 10GW operational by 2030, doubling the original 5GW target set out in the Ten Point Plan[52] and UK Hydrogen Strategy[53].

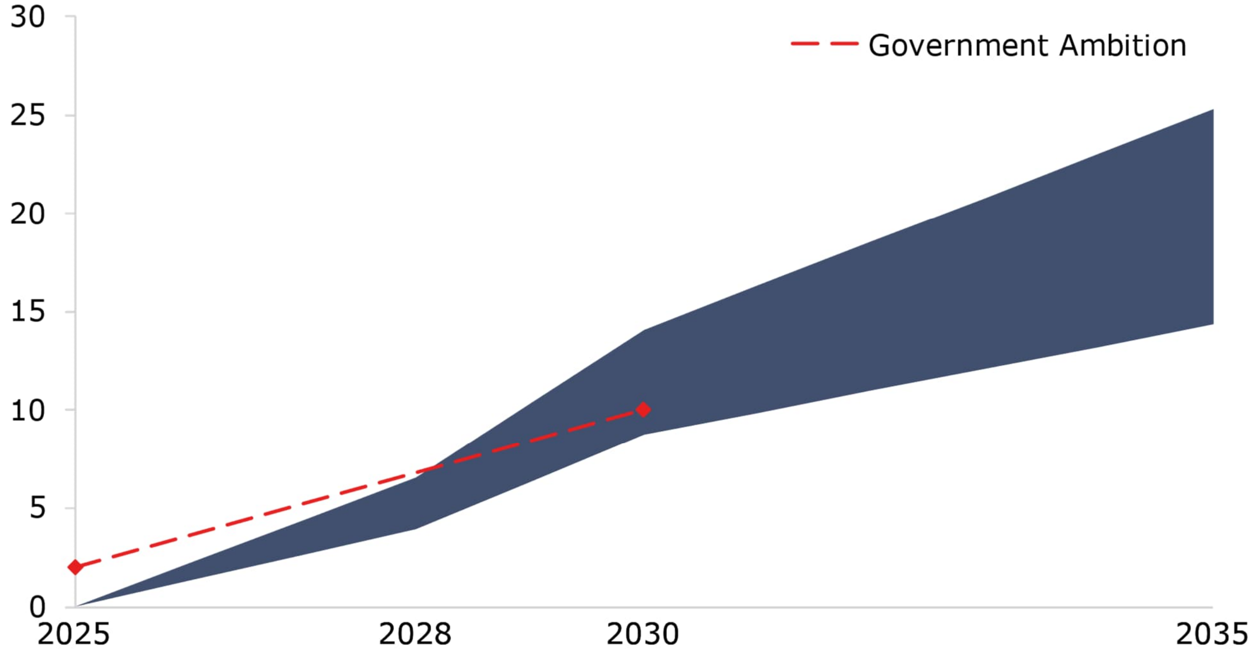
These ambitions are underpinned by key policies set out in the Hydrogen Investor Roadmap[54], including:

- Net Zero Hydrogen Fund (NZHF): This £240m fund is designed to support at-scale deployment of low carbon hydrogen production during the 2020s.
- Hydrogen Business Model (HBM): Business model design, alongside indicative Heads of Terms for hydrogen business model contracts. Funding for projects operational before March 2025 will be provided by up to £100m of announced Government funding through the Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS) scheme.

Exhibit 5.4 illustrates that the Government ambitions are broadly in alignment with the de-rated capacity indicator for low-carbon hydrogen production. The format of the Government's target for low-carbon hydrogen production capacity is unclear, as it is ambiguous whether they are using a nameplate or derated capacity figure. The choice of format depends on the context and purpose of the capacity figure, particularly whether the Government intends to consider the theoretical maximum discharge or the practical output of the facilities.

[52] BEIS, The ten point plan for a green industrial revolution, November 2020
[53] BEIS, UK Hydrogen Strategy, August 2021
[54] Department for International Trade, Hydrogen Investor Roadmap – Leading the Way to Net Zero, April 2022

Exhibit 5.4 – Technology Indicator for low-carbon hydrogen production derated capacity (GW)



Notes: Low-carbon hydrogen production derated capacity (Electrolysis 50% LF, ATR CCS 90% LF, and Biomass Gasification CCS 95% LF)
Source: AFRY analysis, BEIS

According to the analysis conducted in this project, the operational capacity of low-carbon hydrogen production by 2025 is expected to be negligible. Therefore, if the Government's 2025 aim of up to 2GW in the operational or under construction phase is achieved, it has the potential to over-deliver. However, the development indicator of 4-8GW of low-carbon hydrogen production capacity under construction by 2025 will require an acceleration of projects progressing to construction.

The Government's ambition for 10GW of low-carbon hydrogen production capacity by 2030 is within the bounds of the indicator for derated capacity. However, if the target refers to a nameplate capacity, this will be marginally insufficient and should be bolstered[55].

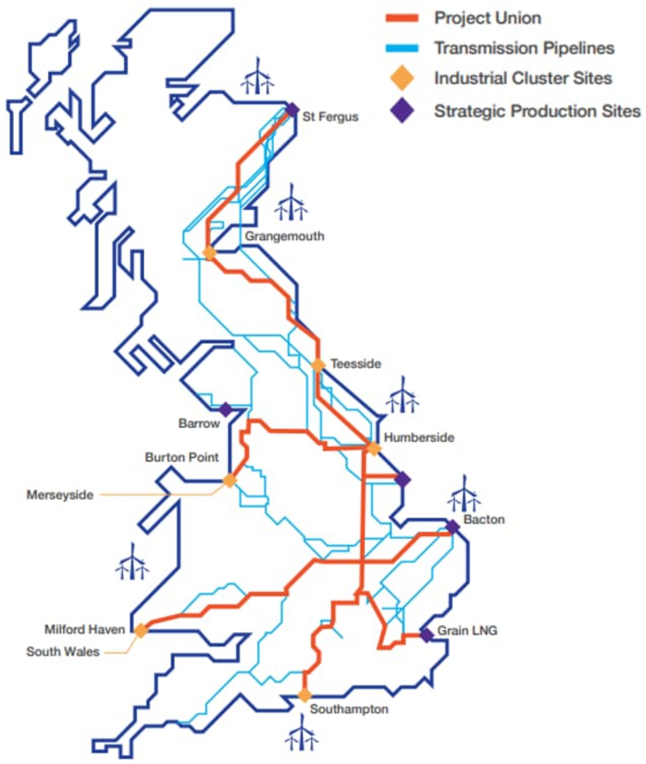
The Hydrogen Investor Roadmap includes a tracker of hydrogen projects across the UK, which identifies an estimated pipeline of up to 20GW of hydrogen production capacity, consisting of over 40 electrolytic and 10 CCUS-enabled projects. This exceeds the in-development indicator in 2025, indicating high levels of commercial interest and suggesting that the limiting factor for project development will be the supporting mechanisms to mobilise sufficient private investment.

[55] Based on the assumptions made in this report, a nameplate capacity of 11-17GW of low-carbon hydrogen production capacity should be deployed by 2030, which exceeds the government's target of 10GW.

5.4.2 Plans to develop a centralised hydrogen network may need to be fast-tracked to enable the use of hydrogen salt caverns

Establishing the necessary infrastructure for the hydrogen value chain is essential for linking hydrogen production and end-users, both geographically and temporally. While the pipeline of hydrogen salt cavern storage projects is significant, such as the Hynet Keuper Gas Storage Project, SSE Aldbrough Hydrogen Storage, and UKOG Portland Port Hydrogen Project, the early emphasis on developing hydrogen clusters, where production sites are located near end-users, and the later ambitions to deliver a centralised hydrogen network, may delay the development of large salt cavern storage sites.

Exhibit 5.5 – Project Union's map hydrogen transmission (illustrative)



Source: National Grid UK GT

As illustrated in Exhibit 5.5, Project Union's hydrogen transmission map from NG's Gas Transmission (UK GT) business aims to provide the "hydrogen backbone" by deploying hydrogen transmission pipelines from regions with a high relative penetration of renewables, such as Scotland and Eastern England, to hydrogen salt caverns, and to end-users, which are industrial clusters dispersed across the GB. However, with completion targeted in the mid-2030s, the centralised hydrogen network required to support long-term salt cavern storage of hydrogen is unlikely to develop at the speed required to meet the 2030 indicator presented in this report.

This project estimates that 2-4TWh of hydrogen storage should be operational by 2030. Salt cavern lead times are estimated to exceed 5 years, therefore all of this capacity must be in development or construction by 2025. However, with the Government's emphasis on hydrogen transport and storage focusing on clusters (localised pipeline networks) and inter-cluster transmission pipelines, the Government's ambition to 'design new business models for transport and storage infrastructure by 2025'[56] may need to be fast-tracked to achieve the levels of hydrogen infrastructure outlined in this report.

[56] BEIS, Hydrogen transport and storage infrastructure – a consultation on business model designs, regulatory arrangements, strategic planning and the role of blending, November 2022

Salt cavern hydrogen storage is only feasible with significant and concurrent investment across the supply chain, which presents an urgent delivery risk, considering the early policy focus on H_2 and CCUS clusters. Deferred or minimal development in salt cavern hydrogen storage will require alternative flexibility providers to compensate. As examined in the Delayed Salt Cavern sensitivity, this will likely require increased levels of Gas CCS and other forms of energy storage, such as hydrogen tanks, CAES, LAES, and pumped storage.

5.4.3 The Government should conduct detailed research into the integration options of the existing gas fleet

To ensure cost-effective decarbonisation, the Government should conduct in-depth research into retrofitting existing gas-fired plants with hydrogen or integrating CCS capability. The feasibility study should include technical and economic factors such as plant age, condition, and local infrastructure. Thorough investigation of these integration options can assist the Government in identifying the optimal pathway to achieve their emission reduction targets while leveraging existing gas assets to lower costs.

The modelling conducted in this study assumes that existing unabated gas CCGTs can be retrofitted to 100% Hydrogen CCGT, at a cost of £113/kW (real 2020) with an extended lifetime of 10 years. In the Central scenario these moderate assumptions of the retrofit capability resulted in 3.5GW of Hydrogen CCGT retrofit in 2028, rising to 9GW in 2035.

While there is commercial interest in fuel-flexible and full hydrogen retrofit of existing gas plants, particularly those with CHP capabilities located near proposed hydrogen clusters[57,58,59], further research is needed to understand the costs and barriers associated with retrofitting a significant portion of the existing CCGT fleet by 2035.

5.4.4 The captured emissions targets set by the Government could be in line with the indicators

CCS technologies can play a significant role in achieving a decarbonised power and hydrogen sector. This study emphasizes the importance of such dispatchable technologies, particularly in addressing extended periods of high demand.

The CCUS roadmap[60] sets out the joint commitments of the UK Government and Industry to deploy CCUS across the economy, with a goal of capturing 20-30MtCO_2 per year by 2030. This objective is supported by a range of existing and proposed policy initiatives, including[61]:

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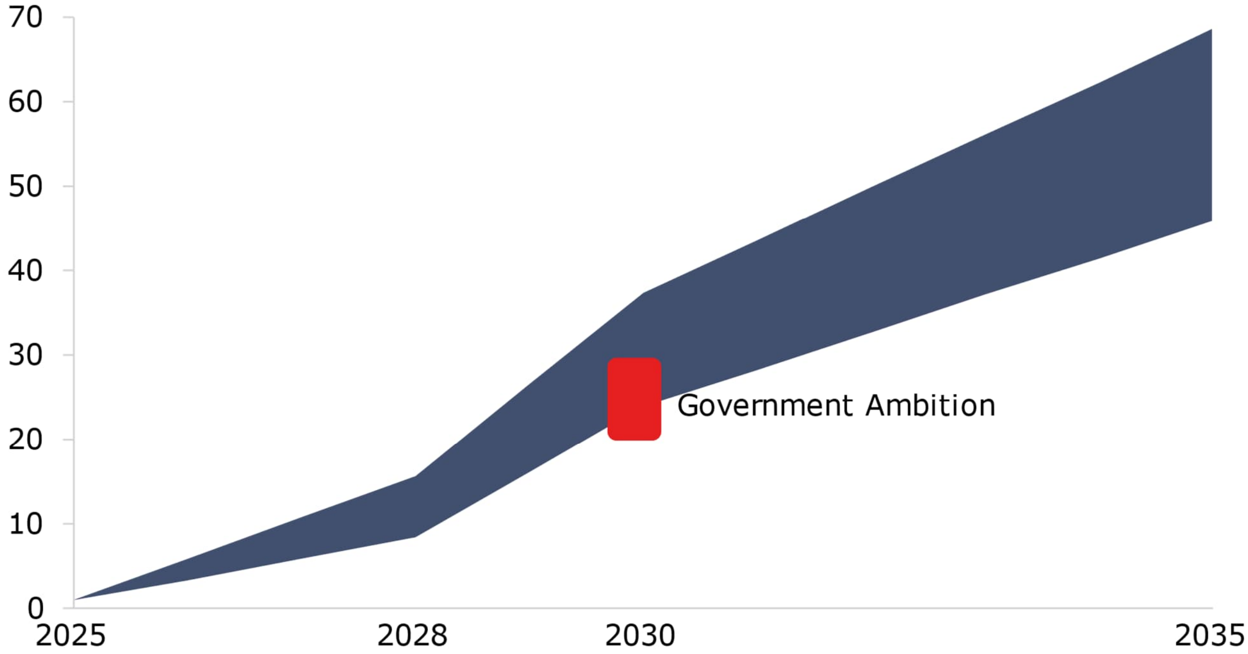
[57] Uniper, Grain, February 2022: https://www.uniper.energy/news/grain-power-station-an-innovative-site
[58] Equinor, H2H Saltend, August 2022: https://www.equinor.com/news/20220812-h2h-saltend-selected
[59] SSE, Keadby Hydrogen Power Station, 2022: https://www.keadbyhydrogen.com/
[60] BEIS, Carbon capture, usage and storage (CCUS): investor roadmap, April 2022.
[61] Some initiatives for CCUS-enabled technologies overlap with those for hydrogen policy.

- The launch of the Cluster Sequencing process with industry to achieve four low carbon industrial clusters by 2030 and at least one net zero industrial cluster by 2040.
- CCUS Infrastructure Fund (CIF): This £1bn fund will support the capital costs of strategic CCUS infrastructure.
- Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS): This scheme will provide £140m to fund new hydrogen and industrial carbon capture business models.

In order to assess the necessary level of CO_2 storage capacity in each development stage, the indicator used for captured CO_2 emissions is cumulative. This metric has been converted into an annual volume of CO_2 captured in Exhibit 5.6, which enables comparison against the Government target.

Exhibit 5.6 – Volume of CO_2 annually captured ($MtCO_2$)



Source: AFRY analysis, BEIS

The analysis from this project indicates that 24-37$MtCO_2$ per year[62] can be captured by 2030. Therefore, the Government target of 20-30$MtCO_2$ per year falls within the range of the indicator, albeit on the lower end. It should be considered sufficient if the upper end of the target range is achieved.

[62] The indicator in question encompasses the entire economy, incorporating captured CO_2 emissions from M&C, Refining, Waste, and Other Fuel Supply, which have been provided as a fixed assumption by the CCC.

5.4.5 Diversifying the deployment of energy storage solutions will mitigate against delivery risk of emerging technologies

Large scale, long duration energy storage (LLES) is well suited to managing the trends in residual demand that will become more prevalent over time. This study indicates that the patterns of residual demand are more cost-effectively addressed through hydrogen storage solutions, rather than grid storage technologies.

Despite the potential cost savings, there are concerns that the deployment of salt cavern hydrogen storage may face significant delivery risks, such as lengthy development times and the need to coordinate the entire hydrogen supply chain. To mitigate these risks associated with emerging technologies, it may be wise to spread the delivery risk across a variety of long-duration energy storage technologies.

In response to the call for evidence on LLES[63], the Government acknowledges the crucial role of energy storage[64], while also recognising the importance of diversifying technology risks to overcome deployment barriers and provide future optionality. These findings will inform the development of policies aimed at enabling adequate investment in LLES by 2024.

5.4.6 Policy gap summary

Achieving the Net Zero objectives in the power sector and beyond requires a significant increase in investment. To support this, a range of policy measures have been proposed or implemented, with additional initiatives being considered as part of the REMA process. Although the Government's policy targets could be consistent with the indicators outlined in this study, there are some areas where significant challenges arise in terms of coordinating infrastructure, such as networks and storage infrastructure that enable emerging hydrogen and CO_2 capture technologies. Due to the urgency of meeting these targets, it will be crucial to closely monitor the implementation and effectiveness of these policies.

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[63] BEIS, Call for Evidence on large-scale and long-duration electricity storage, July 2021
[64] BEIS, Facilitating the deployment of large-scale and long-duration electricity storage – Government Response, August 2022

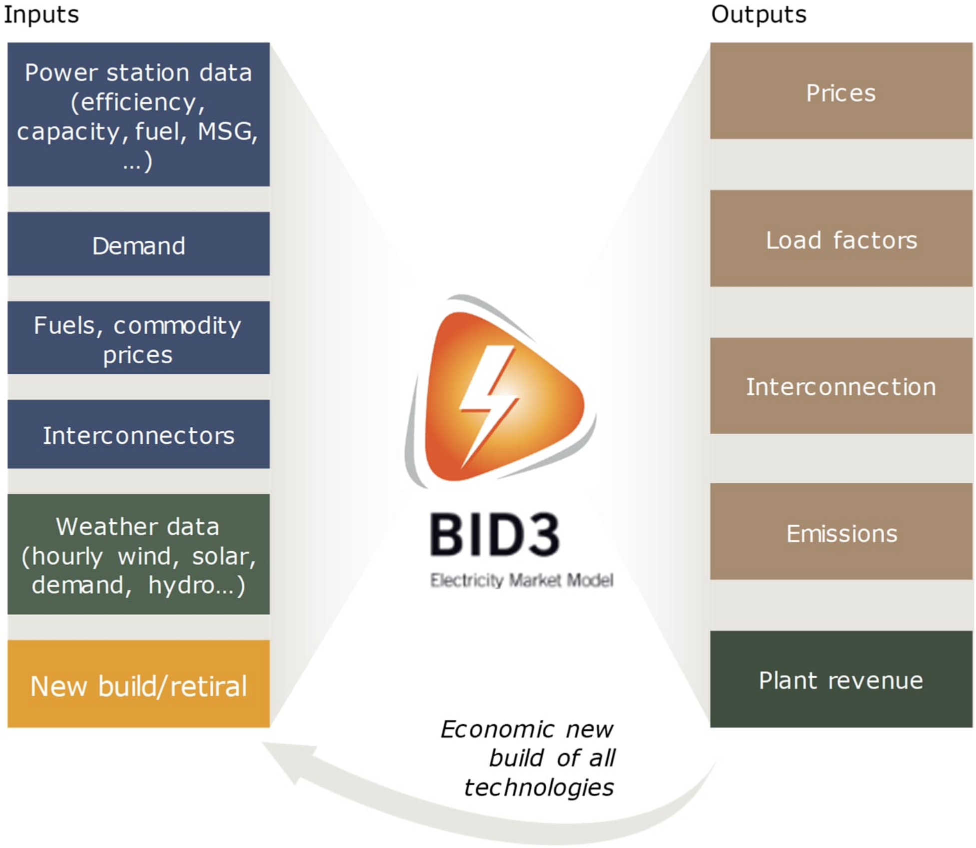
Annex A Detailed modelling methodology

A.1 BID3 Overview

For the purposes of this research, market modelling was performed using AFRY's proprietary software, BID3.

BID3 is an economic dispatch model based around optimisation. It simulates the dispatch of all power plants and interconnectors on the system, on an hourly (or sub-hourly) basis. Based on this, it creates power market metrics – electricity prices, reserve and balancing market prices and system costs. The costs associated with sector coupling (e.g. hydrogen), inertia, and transmission constraints are also output. Key inputs and outputs are summarised in Exhibit A.1.

Exhibit A.1 – BID3 inputs and outputs



Each future year is simulated under 5 historical weather patterns (2012, 2014, 2015, 2017, and 2018), to reflect a range of possible outcomes for uncertain, weather-driven features of power systems. Weather directly impacts electricity market operation through the following factors:

- Electricity demand: High demand is often associated with colder periods.
- Renewable generation: Output from solar and wind will vary significantly through time as a result of variation in weather patterns.
- Hydro availability: Drier years typically see lower hydro generation than years with high rainfall. This can be an important price driver in markets with a high penetration of hydro in the generation mix.

In order to create the scenarios and sensitivities, extensive use of the BID3 "Auto Build" module was made. This module exists to endogenously determine the optimal, least cost, future plant capacity of a given scenario. It does so fully reflecting the input weather patterns. In addition to power plant and grid storage, the module also includes endogenous investment in interconnectors, transmission grid reinforcement, and the production, storage and transmission capacity of hydrogen.

The dispatch of both existing and new interconnection was modelled between markets. Interconnectors are assumed to be optimally utilised (i.e. equivalent to a market coupling arrangement). For scenario and sensitivities with similar residual demand patterns, hourly interconnector flows were fixed[65]. The weather patterns for the 5 historic years have been analysed at a European scale, and the interconnector flows have considered the temporal and spatial correlations of renewable energy sources generation across the continent.

The renewable generation profiles were developed using a location-specific analysis that considered the historical profiles for existing plants in each energy zone, taking into account their local wind variability and speed. We then applied a learning curve and used wind speed data with an atlas resolution of 15km. The load factor of existing, planned, future, and repowered turbines was determined by considering factors such as turbine development and adjusted deployment behaviours (for example, offshore wind likely to have higher turbines and be located further from the coast).

In all scenarios/sensitivities, unless the focus of sensitivity examination (and explicitly stated), the following constraints had to be met:

- Security of supply was required to ensure lower than 3 hours of loss of load expectation.
- All investment options had to respect resource potentials and build rate limits. These are particularly relevant for emerging technologies, where both national and locational limits are applied.
- Ancillary service requirements, namely STOR, regulating reserve, and frequency response (see Exhibit A.2).

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[65] New Interconnector flows were run for the Low RES/Nuclear, Low Wind Year, and Long Wind Drought sensitivities.

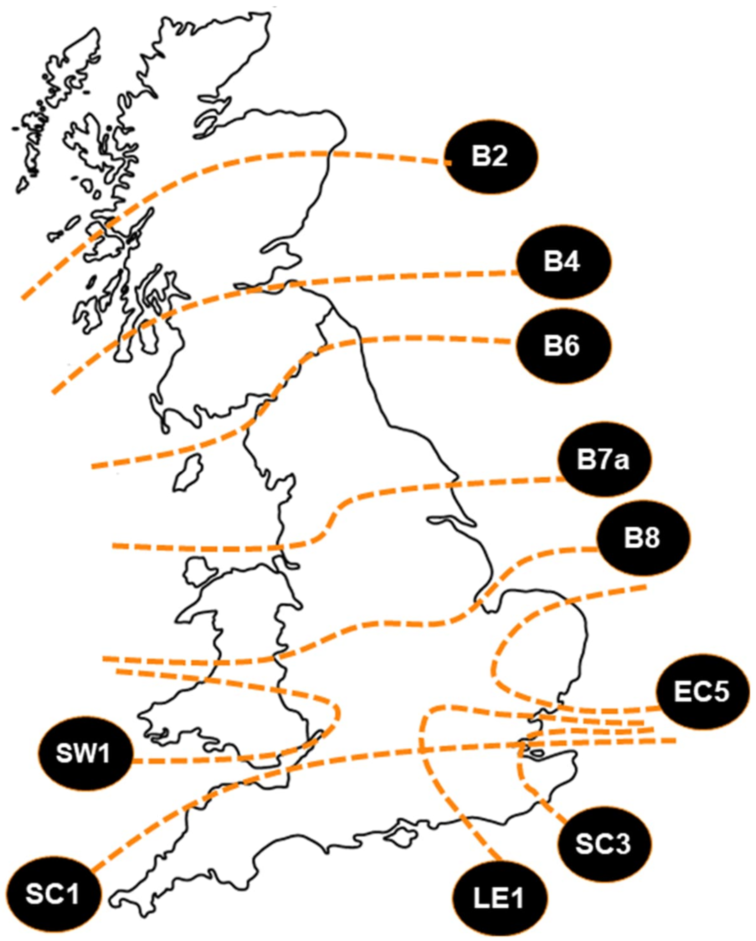
Exhibit A.2 – Ancillary service products' hourly requirements (GW)

Product	Direction	2025	2028	2030	2035	2040	2050
STOR	Upward	1.6	1.9	1.9	1.9	1.9	1.9
Regulating reserve	Up/downward	2.5	3.0	3.5	3.8	4.0	4.5
Frequency response	Up/downward	1.6	1.8	1.8	1.8	1.8	1.8

Notes: These system stability requirements take into consideration changes to the largest infeed loss, wind forecast error, and liability factors.
These requirements are modelled as a representation of expected future ancillary markets, as per expected NG ESO market reform. With regards to frequency response, this requirement maps onto the combined expected procurement volumes in the Dynamic Frequency Response markets (DC/DM/DR). Regulating Reserve is dimensioned to include both a future Quick Reserve market and the headroom and footroom reserve quantities procured by BM actions. STOR (Short Term Operating Reserve) is assumed equivalent to a future Slow Reserve market.

The modelling also included GB on a locational basis, with 11 separate power zones included, determined by the key constraints that exist in the power transmission network at present and in the future which are shown in Exhibit A.3.

Exhibit A.3 – Modelled GB boundaries, representing the transmission limits considered



The physical locations of the zones and transmission boundaries considered were identical for power and hydrogen. Furthermore, the viability of deploying CCS and utilising salt caverns for hydrogen storage were zonally assigned in order to better understand the locational feasibility of different technologies:

- Salt Cavern utilisation was restricted to 4 zones (i.e. Upper North, North, South Wales, and South) based on salt structure suitability assessments in GB[66]. Furthermore, the earliest deployment date was set at 2030 to account for the protracted lead time.
- CCS technologies (i.e. Biomass CCS, Gas CCS, ATR CCS, Biomass Gasification CCS) were subject to restricted deployment in 5 zones (i.e. SHETL North, Upper North, North, East, and Midlands). The maximum cumulative build assumptions for the optimised CCS technologies are presented in Exhibit A.4.

Exhibit A.4 – Maximum cumulative capacity of optimised CCS technologies

Sector	Unit	2025	2028	2030	2035
Gas CCS	GW	0	5.0	8.7	10.4
ATR CCS	GW	0	10.0	19.8	25.3

Notes: Guided by the Global Leadership scenario in the CCUS Delivery Plan 2035[67].

In addition to this, grid storage technologies were subject to constraints including:

- CAES utilisation was restricted to 4 zones (i.e. Upper North, North, South Wales, and South) based on geological assessments in GB and limited to 10GW in each zone.
- Pumped storage new build was restricted to Scotland and limited to 15GW capacity.

The renewable capacity allocation to energy zones was carried out by our GB team. For offshore wind, the existing capacity was based on current deployment locations, and planned capacity was determined based on an internal database containing announced projects that were prioritised according to a merit order. The first 61GW of offshore wind were built out, taking into account ScotWind leasing round and floating offshore targets. For the future, the repowering of existing sites was considered, and capacity was allocated based on current capacity location and potential development. For onshore wind, the existing capacity was used, and for the future, repowered sites were considered, and the remaining capacity was pro-rated in line with existing capacity. For solar PV, the historic split was pro-rated up. These capacity allocation methods were compared against the distribution in the FES scenarios for a sense check, and we were satisfied with the comparison.

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[66] https://www.researchgate.net/figure/Map-of-European-salt-deposits-and-salt-structures-as-a-result-of-suitability-assessment_fig4_336607889
[67] CCSA, CCUS Delivery Plan 2035, March 2022

A.2 Hydrogen dispatch and cost assumptions in BID3

In BID3, a specific level of non-power sector hydrogen demand and baseload power sector hydrogen (Hydrogen CHP) is required to be met through ATR CCS (producing blue hydrogen), electrolysis (producing green hydrogen), and Biomass Gasification CCS, with the necessary connecting hydrogen pipeline and the use of hydrogen storage where necessary. Variable power sector hydrogen-fired plants (CCGT and GT) increase the hydrogen demand. Both sectors are optimised simultaneously in order to ensure full consistency.

The demand profiles for Hydrogen CHP and non-power sectors are all assumed a flat profile except for residential and non-residential buildings, which integrate heat variation. The demand profile for variable power sector hydrogen-fired plants is an output of the optimisation.

Both blue and green hydrogen technologies are dispatched on a least cost basis. In practice, this will broadly mean that electrolysers will operate whenever the cost of power is lower than the variable cost of blue hydrogen production. There can be a variety of business models (and project configurations) for electrolysis; in this study the assumption is that hydrogen is produced via electrolysis with power taken from the grid. Co-location business models have not been explored in detail. In other words, electrolysis requires excess renewable generation, either due to national or locational excess renewables. Electrolysis located behind transmission constraints is an important option for easing location congestion, due to the ability it has to operate for extended periods of high wind output.

While in the long-term electrolysis was assumed to have lower capex and opex than ATR CCS in the scenarios modelled, this is offset by electrolysis tending to run at a lower load factor. This results in electrolysis being the higher cost hydrogen production option.

Hydrogen storage solutions (via pressurised tanks and/or salt caverns) are utilised to bridge mismatches between intermittent renewable generation and hydrogen demand profiles. The intermittent nature of solar and wind will likely bring issues of large mismatches between renewable generation and hydrogen demand patterns. Hydrogen fuelled power generation is most likely to operate in periods when electrolysis is not operating. Both hydrogen (non-power) and power sector demand for hydrogen will require hydrogen storage.

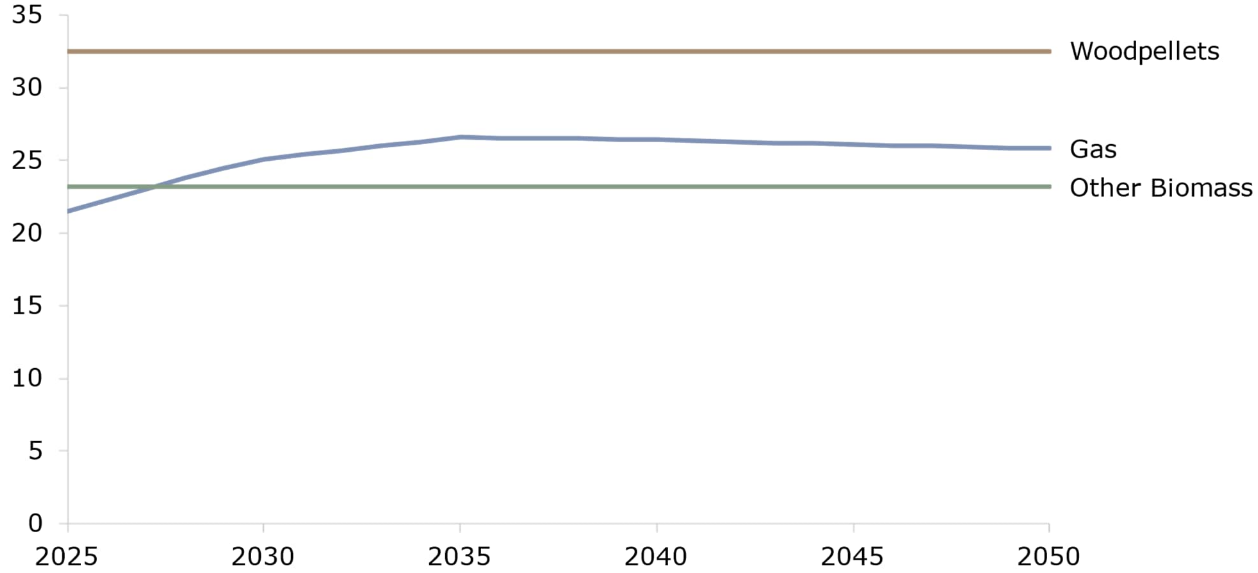
A.3 Pipeline transmission for hydrogen

Hydrogen zones were introduced in BID3 along the lines of the power zones. Hydrogen demand (outside the power sector) was disaggregated between these zones, with particular reference to the locations of the industrial clusters that give rise to the majority of the hydrogen demand. Non-industrial, non-power sector hydrogen demand was split according to the share of population in each zone.

The model optimised the investment in hydrogen pipeline transmission capacity, alongside the optimisation of other sources of capacity and network infrastructure. This consideration is important in the context of electrolysis, since it has the potential to play an important role in managing congestion in the power transmission network. Ability to locate electrolysis close to RES, where potential to be curtailed due to power transmission congestion, is beneficial. However, this may potentially require transmission of hydrogen to the end users. Salt caverns are also geographically limited in their availability, and the ability of green hydrogen production to access salt cavern storage is another important consideration.

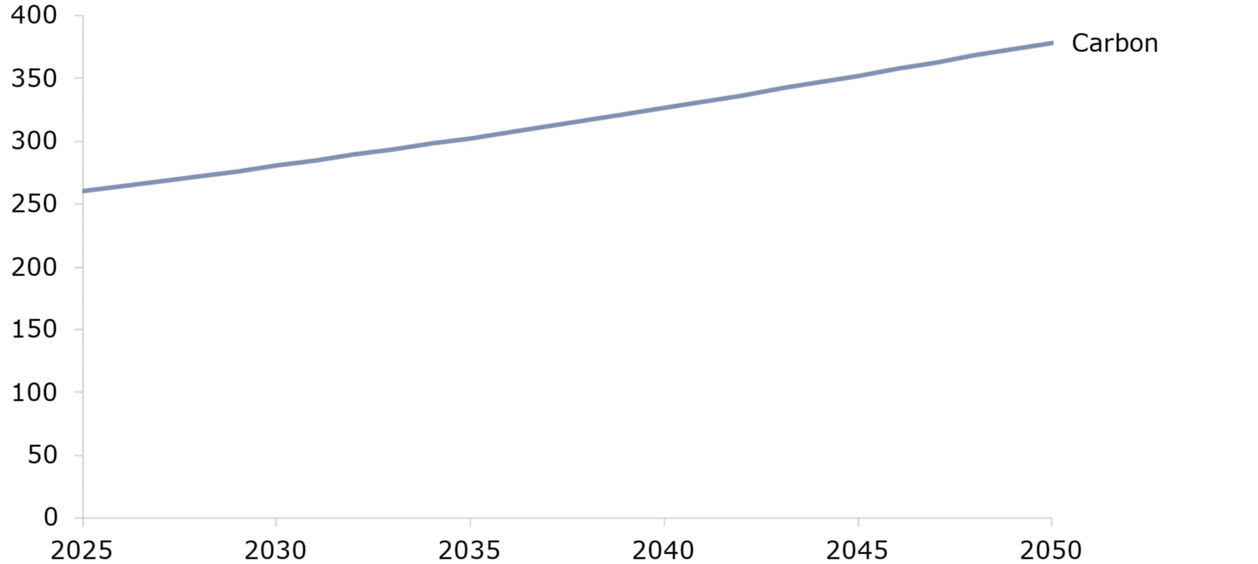
A.4 Commodity prices

Exhibit A.5 – Fuel prices (£/MWh)



Source: AFRY, CCC

Exhibit A.6 – Total carbon price (£/tCO_2)

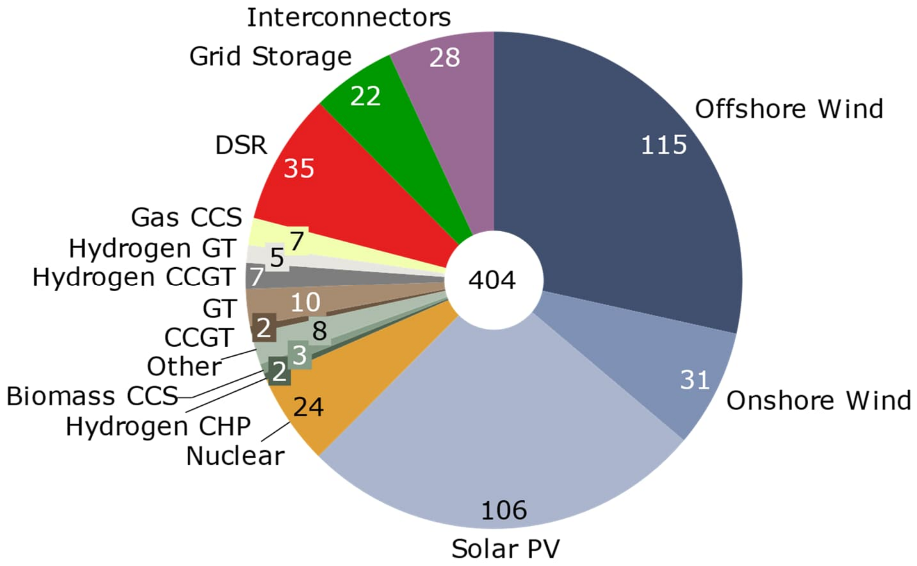


Source: CCC

Annex B Central scenario results for 2050

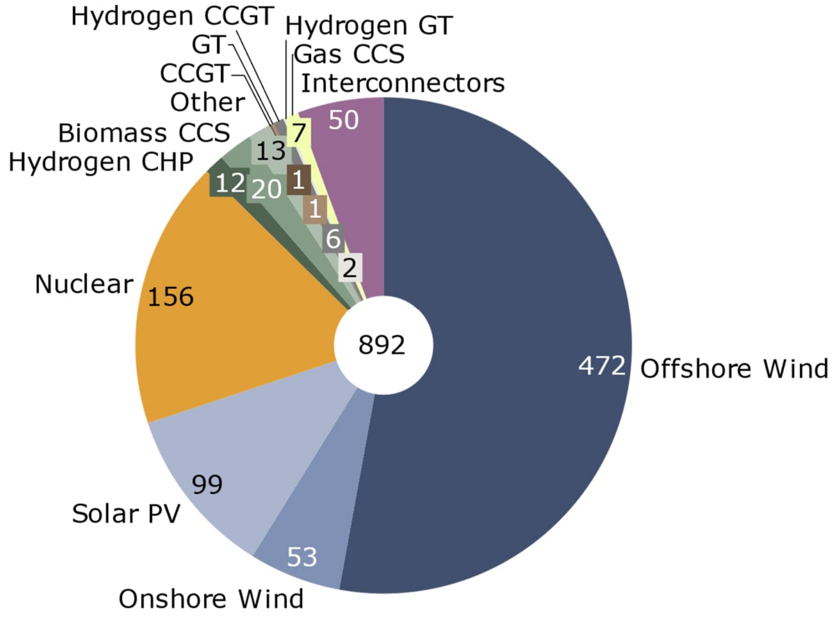
B.1 Power sector

Exhibit B.1 – Installed capacity mix (GW)



Notes: 'Other' includes Hydro, Energy from Waste and Distributed Engines.

Exhibit B.2 – Annual generation mix (TWh)



Notes: 'Other' includes Hydro, Energy from Waste and Distributed Engines.

B.2 Hydrogen sector

Exhibit B.3 – Hydrogen production installed capacity (GW)

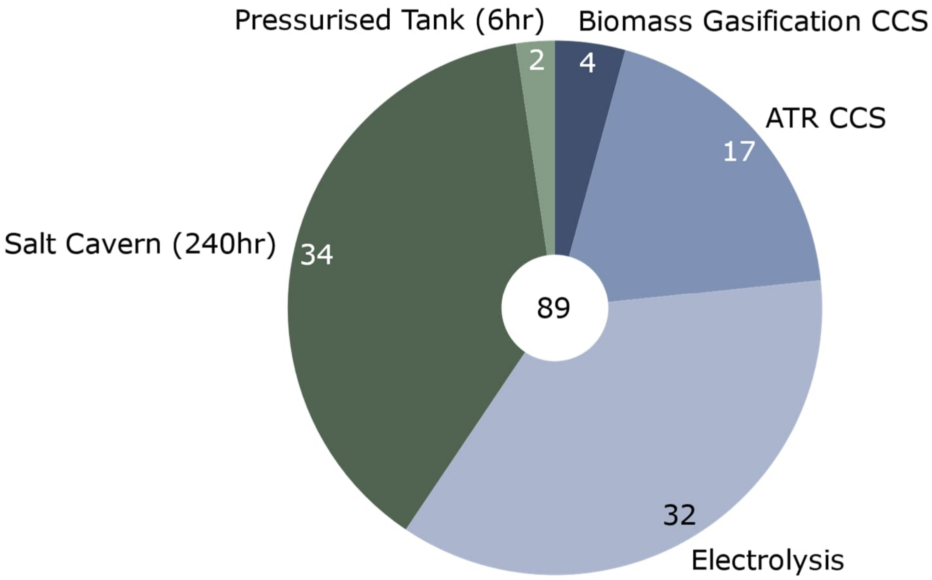
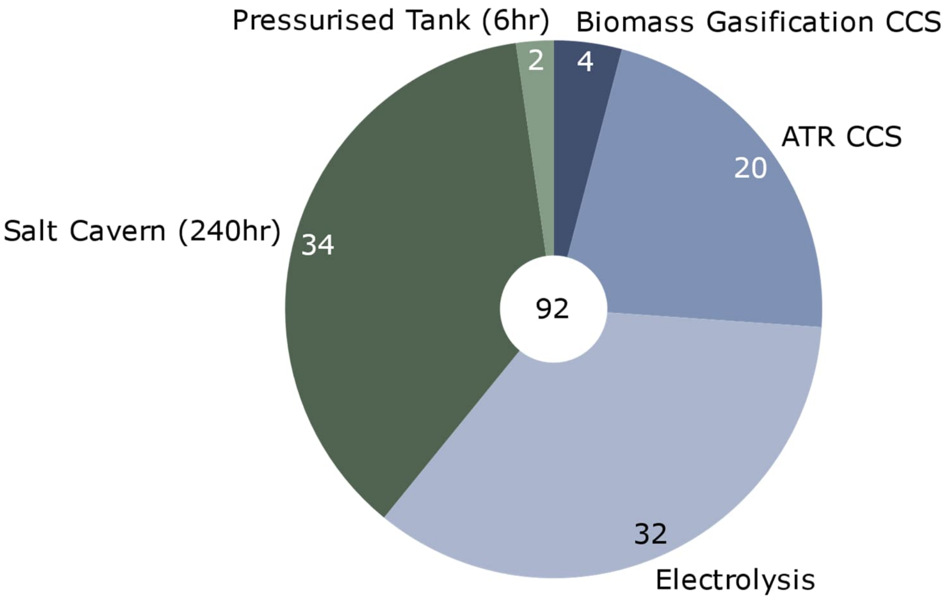
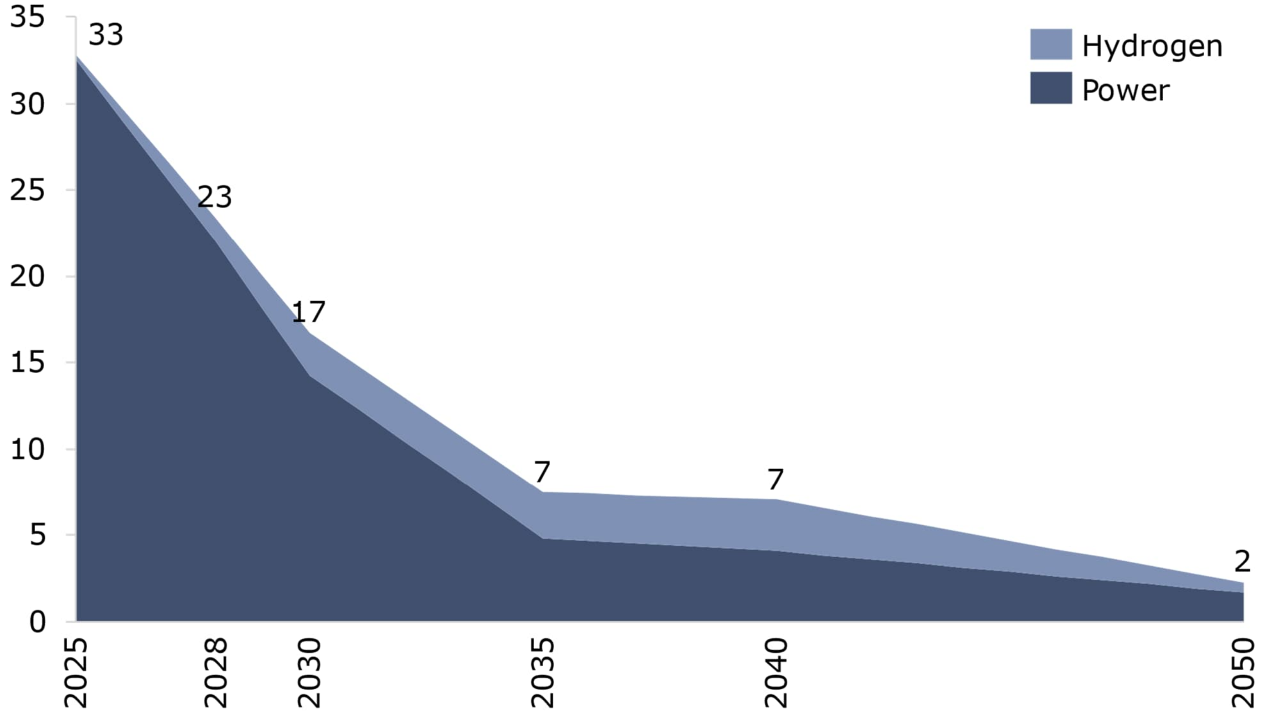


Exhibit B.4 – Hydrogen production mix (TWh)



B.3 Carbon emissions

Exhibit B.5 – Carbon emissions from the power and hydrogen sectors ($MtCO_2$)



Annex C Glossary

Exhibit C.1 – Glossary of terms

Term	Definition
Auto-Thermal Reforming (ATR)	Type of chemical synthesis which can produce pure hydrogen gas from methane using a catalyst.
Auto-Thermal Reforming with Carbon Capture and Storage (ATR CCS)	Type of chemical synthesis which can produce pure hydrogen gas from methane using a catalyst – emissions are captured, transported and stored underground.
British Energy Security Strategy (BESS)	Policy paper from UK Government, published in April 2022.
Carbon Capture and Storage (CCS)	Capturing carbon dioxide emissions produced during combustion process by transporting and storing it underground.
Combined Cycle Gas Turbine (CCGT)	Combustion turbine power plant with heat recovery steam generator for added efficiency.
Climate Change Committee (CCC)	Independent, statutory body established under the Climate Change Act 2008.
Demand-Side Response (DSR)	The modification of consumer demand for energy through various methods.
Department for Business, Energy and Industrial Strategy (BEIS)	The Department for Business, Energy and Industrial Strategy was a department of His Majesty's Government.
Electric Vehicle (EV)	Vehicle that can be powered by an electric motor that draws electricity from a battery and is capable of being charged from an external source.
Energy From Waste (EFW)	The process of generating energy from the primary treatment of waste, or the processing of waste into a fuel source.
Flexible capacity	Diverse set of technological solutions that can be grouped into four broad categories – flexible generation, energy storage, demand response and network solutions.
Flexible generation (fixed)	Technologies include Nuclear, Gas CHP, Hydrogen CHP, Biomass, Biomass CCS, and Others.
Flexible generation (optimised)	Technologies include Gas CCGT, Gas GT, Hydrogen CCGT, Hydrogen GT, and Gas CCS.
Gas with Carbon Capture and Storage (Gas CCS)	Gas CCGT with Carbon Capture and Storage capability.
Gas Turbine (GT)	Combustion turbine power plant.
Great Britain (GB)	Island comprising the nations of England, Scotland and Wales.
Hydrogen plant or hydrogen-fired plant	Hydrogen CCGT/GT (excludes Hydrogen CHP).

Large-scale, Long-duration Energy Storage (LLES)	Energy storage technologies with significant duration capacity – in this analysis, long duration refers specifically to energy storage technologies with durations exceeding 12 hours, while short-duration storage has a maximum duration of 4 hours, and medium-duration storage ranges from over 4 to 12 hours.
Lead time	The length of time from project inception to first operational year.
Levelised Cost Of Electricity (LCOE)	A measure of the average net present cost of electricity generation for a generator over its lifetime.
Levelised Cost Of Hydrogen (LCOH)	A measure of the average net present cost of hydrogen production for a technology over its lifetime.
Load Factor (LF)	The average load divided by the peak load in a specified period.
Loss Of Load Expectation (LOLE)	The expected number of defined periods in a year in which load loss or generation deficiency occurs.
Low-carbon flexible generation	Hydrogen CCGT/GT and Gas CCS.
Maximum Export Limit (MEL)	Maximum level at which the BM Unit may be exporting (in MW) to the GB Transmission System.
National Grid Electricity System Operator (NG ESO)	Performs several important functions in GB; from second-by-second balancing of electricity supply and demand, to developing markets and advising on network investments.
National Infrastructure Commission (NIC)	The executive agency responsible for providing expert advice to the UK Government on infrastructure challenges facing the UK.
Polymer Electrolyte Membrane (PEM) electrolyser	Type of electrolysis plant using a solid polymer electrolyte membrane; electrolysers use electricity (primarily excess) to produce hydrogen from water.
Renewable Energy Source (RES)	Referencing renewable energy technologies (e.g., Offshore Wind, Onshore Wind, and Solar PV).
Residual Demand	Residual demand is defined as final consumption, excluding electrolysis, minus renewable generation (e.g., Offshore Wind, Onshore Wind, and Solar PV).
Residual Demand Net Inflexible	Residual demand, net of inflexible plant generation (e.g., Nuclear, Biomass CCS, CHP, and Other).
System Flexibility	The ability to shift in time or location the consumption or generation of energy.
Transmission System Operator (TSO)	Entity entrusted with transporting energy in the form of natural gas or electrical power.
Unabated gas generation or gas-fired plant	Gas CCGT/GT (excludes CHP).
Value of emissions avoided	Assigning a value to mitigating emissions, modelled as a carbon price in this analysis.
Vehicle to Grid (V2G)	Describes a system in which plug-in electric vehicles sell demand response services to the grid, by either delivering electricity or reducing their charging rate.

Quality control

Roles	Name	Date
Authors	John McShane Alessandro Crosara	27 Feb 2023
Approver	Gareth Davies	08 Mar 2023

Document control

Report Identifier: 2022 Net Zero Power and Hydrogen: Capacity Requirements for Flexibility

Version	Date	Comments
V100	20/09/2022	Initial version released to CCC
V200	23/11/2022	First revision following feedback from CCC
V300	27/02/2023	Second revision following feedback from CCC
V400	06/03/2023	Revision following CCC feedback
V500	08/03/2023	Final report

ÅF and Pöyry have come together as AFRY. We don’t care much about making history.

We care about making future.