



Delivering a reliable decarbonised power system

March 2023

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Baroness Brown has disclosed on her Register of Interests a number of organisations with interests in renewable energy. As Chair of the Adaptation Committee, Baroness Brown's contribution has focused on the resilience and adaptation aspects of this report.

The Committee



**The Rt. Hon John Gummer, Lord Deben,
Chair**

Lord Deben was the UK's longest-serving Secretary of State for the Environment (1993 to 1997). He has held several other high-level ministerial posts, including Secretary of State for Agriculture, Fisheries and Food (1989 to 1993). Lord Deben also runs Sancroft, a corporate responsibility consultancy working with blue-chip companies around the world on environmental, social and ethical issues.



Professor Keith Bell

Keith Bell is a co-Director of the UK Energy Research Centre (UKERC), a Chartered Engineer and a Fellow of the Royal Society of Edinburgh. He has been at the University of Strathclyde since 2005, was appointed to the Scottish Power Chair in Smart Grids in 2013 and has been involved in energy system research in collaboration with many academic and industrial partners.



Professor Michael Davies

Michael Davies is Professor of Building Physics and Environment at the UCL Institute for Environmental Design and Engineering (IEDE). At UCL his research interests relate to the complex relationship between the built environment and human wellbeing. He is also Director of the Complex Built Environment Systems Group at UCL and a member of the Scientific Advisory Committee of 'Healthy Polis'.



Professor Piers Forster

Piers Forster is Director of the Priestley International Centre for Climate and Professor of Physical Climate Change at the University of Leeds. He has played a significant role authoring Intergovernmental Panel on Climate Change (IPCC) reports, and is a coordinating lead author role for the IPCC's sixth assessment report.



Paul Johnson CBE

Paul Johnson is Director of the Institute for Fiscal Studies and a visiting professor at University College London (UCL). He is widely published on the economics of public policy, and he co-wrote the 'Mirrlees review' of tax system design. He was previously Chief Economist at the Department for Education (2000 to 2004).



Professor Corinne Le Quéré FRS

Corinne Le Quéré is a Royal Society Research Professor at the University of East Anglia (UEA), specialising in the interactions between climate change and the carbon cycle. She was lead author of several assessment reports for the UN's Intergovernmental Panel on Climate Change (IPCC) and she currently Chairs the French Haut Conseil pour le Climat.



Baroness Brown of Cambridge DBE FRS
Chair, Adaptation Committee

Baroness Brown of Cambridge DBE FREng FRS (Julia King) is an engineer, with a career spanning senior engineering and leadership roles in industry and academia. She currently serves as Chair of the CCC's Adaptation Committee; non-executive director of Ceres Power, Ørsted and Frontier IP; Chair of the Carbon Trust; and Chair of the House of Lords Science and Technology Select Committee.



Dr Ben Caldecott

Ben Caldecott is the founding Director of the Oxford Sustainable Finance Group and the inaugural Lombard Odier Associate Professor of Sustainable Finance at the University of Oxford. Ben is also the founding Director and Principal Investigator of the UK Centre for Greening Finance & Investment (CGFI), established by UK Research and Innovation in 2021 as the national centre to accelerate the adoption and use of climate and environmental data and analytics by financial institutions internationally.



Professor Richard Dawson

Richard Dawson is Professor of Earth Systems Engineering and Director of Research in the School of Engineering at Newcastle University. Over the last two decades his research has focused on the analysis and management of climatic risks to civil engineering systems, including the development of systems modelling of risks to cities, catchments and infrastructure networks.



Professor Nathalie Seddon

Nathalie Seddon is Professor of Biodiversity and Founding Director of the Nature-based Solutions Initiative in the Department of Biology at the University of Oxford. Nathalie trained as an ecologist at Cambridge University and has over 25 years of research experience in a range of ecosystems across the globe. As a University Research Fellow of the Royal Society, she developed broad research interests in the origins and maintenance of biodiversity and its relationship with global change.



Professor Swenja Surminski

Swenja Surminski is Chair of the Munich Climate Insurance Initiative, Managing Director Climate and Sustainability at Marsh McLennan and Professor in Practice at the Grantham Research Institute at the London School of Economics (LSE). Her work focuses on capacity building and knowledge transfer between science, policy and industry, building on her work in industry and as advisor to governments, private sector and civil society, including as Visiting Academic at the Bank of England.



Executive summary

Delivering a reliable and resilient decarbonised power system

Introduction and key messages

A decarbonised power system is the central requirement for achieving Net Zero. Access to reliable, resilient and plentiful decarbonised electricity – at an affordable price to consumers – is key to a thriving modern economy, less dependent on imported oil and gas. That goal is now within sight; the UK Government has committed to decarbonise electricity supply by 2035, in line with the Climate Change Committee's advice. However, the Government has not yet provided a coherent strategy to achieve its goal nor provided essential details on how it will encourage the necessary investment and infrastructure to be deployed over the next 12 years.

The cascading impacts of electricity failure are already significant. These will continue to grow as the economy becomes increasingly electrified and as extreme weather events become more common and severe. Critical services such as telecoms, banking and infrastructure already depend on a reliable and resilient electricity system. This dependency will grow to other areas with the continued digitalisation of the economy and the spread of electrified technologies to transport, home heating and industry. In our increasingly electrified society, the low-carbon transformation must have resilience embedded throughout. More frequent and intense weather events such as heatwaves, droughts and floods must be anticipated alongside other likely changes to weather. These include possible changes to wind conditions, increasingly critical to the function of the whole energy system.

This report illustrates what a reliable, resilient, decarbonised electricity supply system could look like in 2035, and the steps required to achieve it. It provides new insights and new advice on how such a system can be achieved by 2035, using real weather data and hourly analysis of Great Britain's power system (Northern Ireland is part of the all-Ireland system). It also looks at the implications for hydrogen.

A decarbonised power system by 2035 is achievable, but it requires that barriers to swift deployment of critical infrastructure are removed, and policy gaps remedied. This will open the path to major new investment in renewable generation and infrastructure. It can also support essential flexible low-carbon technologies – these must remain a critical priority for Government alongside the delivery of renewables and nuclear.

The 2035 electricity system envisaged in this report would maintain energy security, while coping with the expected increase in electricity demands and potentially long periods of low wind. The consequent dramatic reduction in gas consumption would also cut our exposure to volatile international fossil fuel markets, with greater reliance on homegrown low-cost renewables. These conclusions have new significance following the recent period of heightened energy insecurity.

- **A reliable, resilient, decarbonised electricity system can be delivered by 2035.** This is needed to deliver emissions reductions in line with the path to Net Zero, while ensuring a reliable and resilient electricity supply and substantially reducing the UK's dependence on imported fossil fuels. However, achievement of this goal rests on a series of urgent changes:

- Careful system-level and asset-level planning and design is needed from the outset to ensure that a decarbonised system, with a higher degree of weather-dependence, can be made reliable and resilient. The Government must take on the role of designing the overall system or delegate clearly to another body with the powers and capacity to do so.

- A number of processes – including planning, consenting and connections – must be urgently reformed to deploy infrastructure at sufficient speed to deliver the required range of system components by 2035. Infrastructure build rates, both for generation and network capacity, will need to exceed what has been achieved historically in a number of areas and represent large increases relative to today. Given the level of investment needed, we must not miss the opportunity to build in system-and asset-level resilience from the start. Reformed processes must ensure infrastructure is built to be resilient to the changes in UK weather (including flood risks and heat extremes) that will occur over its lifetime.
 - Delivering the portfolio of low-carbon flexibility and back-up capacity needed will require new regulations, incentives and business models. These must be put in place with urgency to enable the necessary investment decisions to be taken on a timely basis and at the appropriate scale. Regulatory frameworks and market design must be fit for purpose and capable of galvanising the £300-430 billion of investment¹ required and the supporting supply chains.
 - There is an important role for Government in setting strategic direction for power and non-power uses of hydrogen. Hydrogen infrastructure will be required regardless of decisions in 2026 on its potential use for heat in buildings – the Government should identify a set of low-regret investments that can proceed now. Decisions on hydrogen transmission and the development of business models for hydrogen transportation and storage should be fast-tracked, given long lead-times associated with hydrogen storage. Delays in the delivery of hydrogen infrastructure could limit the role for hydrogen in the 2035 energy system, including its role to provide low-carbon back-up capacity. If hydrogen use in the electricity system is towards the high end of its potential range, the Government's targets for hydrogen production capacity in 2030 look insufficient.
- **The Government must give equal focus to low-carbon flexible solutions** as to the full delivery of its existing renewables and nuclear commitments. This is vital to ensuring the future variable renewable-dominated electricity system is reliable and resilient to potential future weather extremes.
- In a typical year, a balanced supply mix could comprise around 70% of annual generation from variable renewables (primarily offshore wind), complemented by around 20% from relatively inflexible generation such as nuclear and bioenergy with carbon capture and storage (BECCS). The remaining generation will need to come from low-carbon back-up generation (e.g. hydrogen-fired turbines and fossil gas plants with carbon capture and storage – CCS) alongside other forms of flexibility.
 - However, variations in both wind output and electricity demand, necessitate system design which is resilient not only to average weather, but to plausible future extreme weather and demand scenarios. Changes in the frequency and intensity of large-scale wind droughts due to climate change cannot be ruled out based on current evidence and need to be considered in system design and stress testing.

- Our modelling suggests that a portfolio of low-carbon flexibility solutions, including responsive demand (e.g. smart electric vehicle charging), interconnection, storage and low-carbon back-up plants can provide much of the flexibility needed, even under modelled low-wind sensitivities. Within this, both gas CCS and hydrogen-fired back-up plants are likely to be needed.
 - The Committee regards a small amount of remaining unabated fossil gas capacity in 2035 as compatible with a decarbonised power system, with its occasional use acting to balance the system and ensure security of supply. The impact is expected to be small in terms of annual emissions and generation shares (meeting up to around 2% of annual electricity production in 2035). A system without the use of unabated gas may be possible in 2035, but is likely to increase costs and delivery risks. Ensuring that sufficient gas capacity is on the system to accommodate a plausible range of future weather extremes (and future-proofed to be CCS / hydrogen-ready as far as possible) needs to be considered now as part of a strategy for system design.
- **Decarbonising and expanding the electricity system will rapidly reduce the UK's dependence on imported oil and gas**, reducing in turn our exposure to volatile international prices.
 - Decarbonisation of the energy system, through deployment of zero carbon generation such as wind and solar and reduced end-uses of fossil fuels through electrification of buildings, transport and industry, will lead to a rapid reduction in the UK's demand for fossil fuels.
 - However, pushing out all fossil fuel use in electricity and hydrogen supply by 2035 currently looks implausible, given constraints on the feasible build-out of zero carbon capacity. Even when achieving a decarbonised system by the mid-2030s, the GB electricity system will still require significant volumes of fossil gas for use with CCS, whether in post-combustion power plants or 'blue' hydrogen production to fuel hydrogen turbines. Demand for fossil gas with CCS can be expected to reduce to 2050 as non-fossil (e.g. green) hydrogen displaces blue and energy end-uses decarbonise further.
- **Transforming the electricity system provides opportunities for growth.**

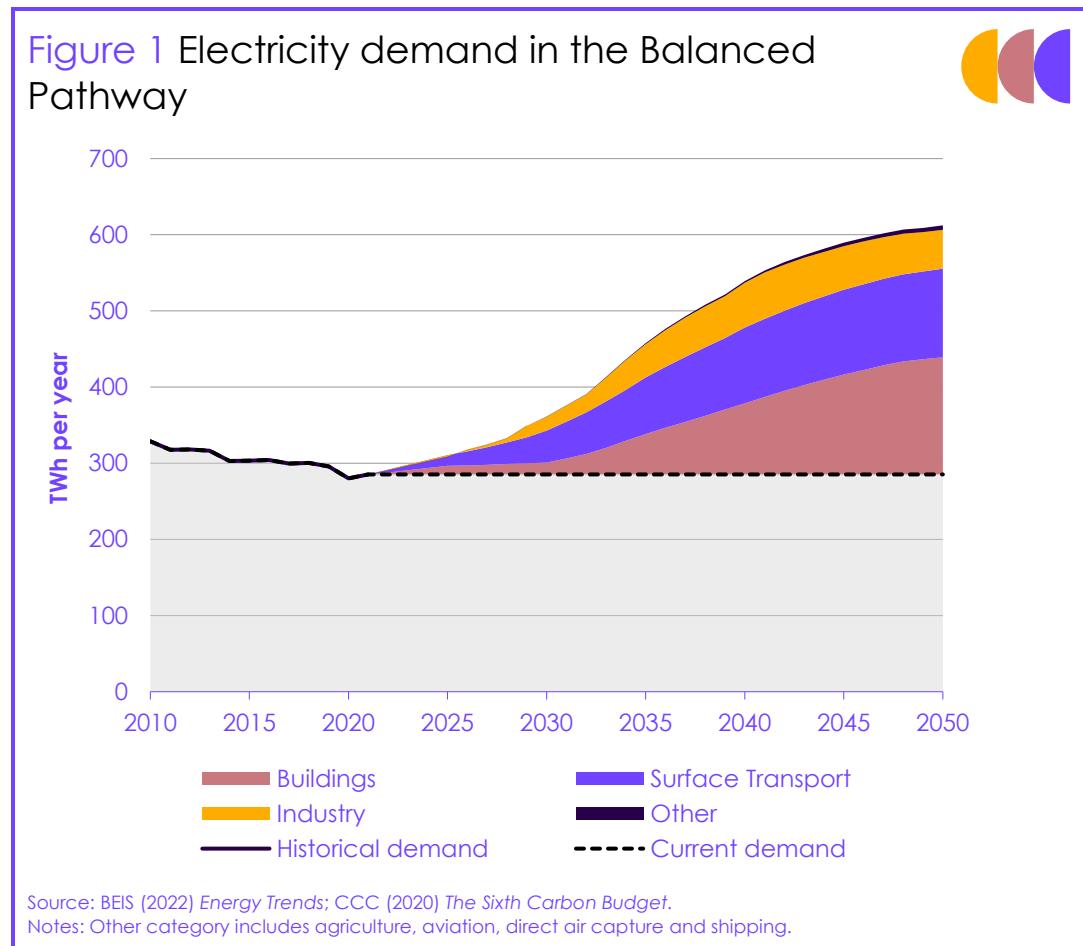
Currently, over 31,000 people across the UK are employed in offshore wind alone – this is set to rise to 97,000 by 2030, driven by £155 billion in private investment, with further investment and employment in solar and onshore wind. There are opportunities for the UK to become a global leader in emerging technologies such as floating offshore wind, which is estimated to have the potential to deliver £43.6 billion in UK gross value add (GVA) by 2050.² There are also opportunities for innovation, investment and employment across electricity storage, hydrogen infrastructure, smart charging of electric vehicles, flexible heating systems, electricity networks and interconnection.

The rest of this executive summary provides more detail in a number of these areas:

- (a) Future electricity demand
- (b) Reliable, resilient and decarbonised system design
- (c) Hydrogen supply and infrastructure
- (d) Reducing dependence on fossil fuel imports
- (e) Delivery challenges
- (f) Recommendations
- (g) This report

(a) Future electricity demand

A substantially electrified economy will bring major energy efficiencies as we move away from wasteful fossil-fuelled technologies. Nevertheless, electricity demand is expected to increase with the electrification of key sectors such as transport, buildings and industry. In the CCC's Balanced Pathway for the Sixth Carbon Budget, there is a 50% increase in electricity demand by 2035 and a doubling in electricity demand by 2050 (with some CCC pathways projecting as much as a trebling by 2050) (Figure 1). Alongside this, continued digitalisation is expected to further embed the critical role of electricity to the functioning of the UK economy.



(b) Reliable, resilient and decarbonised system design

Alongside the growth in demand for electricity as we electrify energy end-uses, supply will change too: low-cost variable renewables, especially offshore wind, should form the backbone of the future system, supplemented by a range of complementary solutions.

A balanced supply mix could comprise around 70% of annual generation from variable renewables, complemented by around 20% from inflexible generation such as nuclear and BECCS and the remaining generation from low-carbon back-up generation and other forms of flexibility (Figures 2 and 3). There should be no role for large-scale unabated biomass generation beyond expiry of existing subsidy support in 2027.

The Energy Security Strategy (ESS) sets out strong ambitions for the contributions of renewables and nuclear, but the Government has not yet published detail on how this generation will be complemented by low-carbon forms of flexibility to ensure a reliable and resilient decarbonised system. The modelling for this report indicates the range and scale of investments required to achieve this.

While these ambitions entail greater weather-dependence and increased exposure to outages due to weather extremes, our analysis shows that a decarbonised system, with a higher degree of weather-dependent generation, can be made both reliable and resilient. Achieving this will require careful system planning and design, rapid infrastructure build and policy change.

It is critical that the system is designed from the outset to be resilient to extreme weather, including low wind years and wind droughts. It is also essential to have solutions that can cope with extended periods of low renewable generation while continuing to meet demand. This must be informed by historical precedent alongside further research on the expected impacts of climate change:

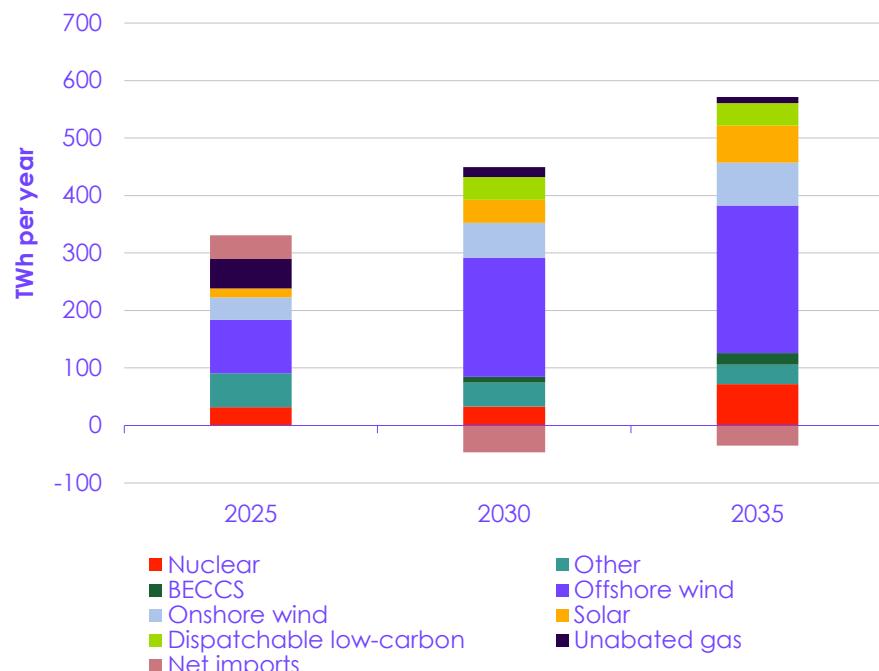
- Having offshore wind as the backbone of the future system is beneficial, as its average output across the year is seasonally correlated with the pattern of demand – generating more in winter than in summer – particularly as we electrify heating. However, there will be periods of low wind output, so while there may be less need for solutions to deal with seasonal swings in demand (e.g. long-term storage) it creates a need to ensure that demand can still be met during the occasional extended (e.g. up to multi-week) periods of low wind generation.
- For periods when output from variable renewables and nuclear is insufficient to meet demand, our modelling suggests that a portfolio of low-carbon flexibility solutions can meet the remainder of demand (i.e. ‘residual demand’) to provide a reliable, fully decarbonised supply for the large majority of the time (Figure 4).
 - Smart shifting of demand can help to smooth peaks in demand and absorb excess supply (e.g. through controlled timing of electric vehicle charging, or use of heat pumps and smart appliances). The potential for this will grow over the coming decades as the electrification of transport and heating increases. Consumers can also be encouraged to reduce their demand in response to price signals.
 - Storage solutions will be important to take in electricity at times of surplus and keep it for when it is needed. While batteries (including those within electric vehicles) provide useful storage services on an

hours-to-days basis, other solutions will be required to provide storage at the multi-week scale to help manage extended lulls in wind output.

- In particular, the use of surplus generation via electrolysis to produce hydrogen, in combination with its long-term storage and use in turbines as back-up capacity, looks to have an important role. This provides power on demand in a low-carbon way, both to meet peaks in demand and to compensate for periods of lower wind output.
- For low-carbon back-up plants with relatively high load factors (e.g. operating for around half the hours of the year), hydrogen will compete with use of gas plants with CCS. In this report, in order to be technology-neutral while the relative long-run costs remain uncertain, we combine hydrogen turbines and gas CCS plants into a category called 'low-carbon dispatchable' generation.
- Interconnection of the power grid to neighbouring markets enables imports when this is cheaper and provides a market for surplus generation, enabling more efficient use of electricity across the European system. However, there is potential for the GB system and neighbouring countries to be simultaneously impacted by weather extremes at times, potentially limiting potential for cross-border trade.

We consider the occasional use of a small amount of unabated gas capacity (for up to around 2% of annual electricity production in 2035) to be consistent with ensuring security of supply in a cost-effective manner without excessive adverse impact on emissions. It is for Government to decide how much headroom capacity to build into the system to account for a range of plausible future extreme weather patterns, to ensure security of supply.

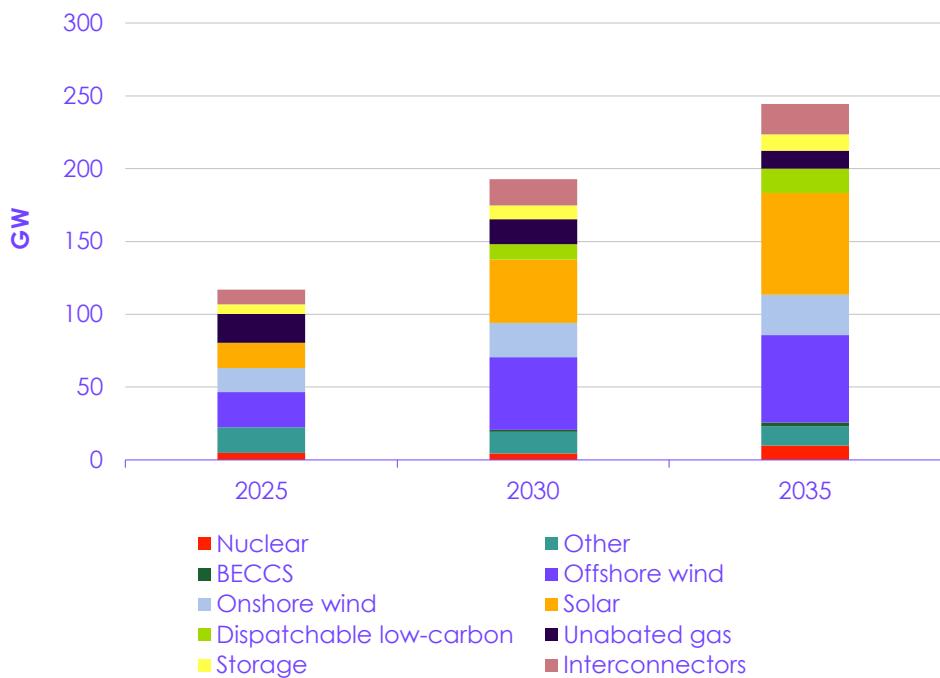
Figure 2 Electricity generation mix to 2035 in the Central scenario



Source: AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

Notes: Figures are before losses through the transmission and distribution system. 'Other' includes Combined Heat and Power (CHP) and unabated biomass. Dispatchable low-carbon includes gas CCS and hydrogen. Analysis is representative of a 'normal' weather year.

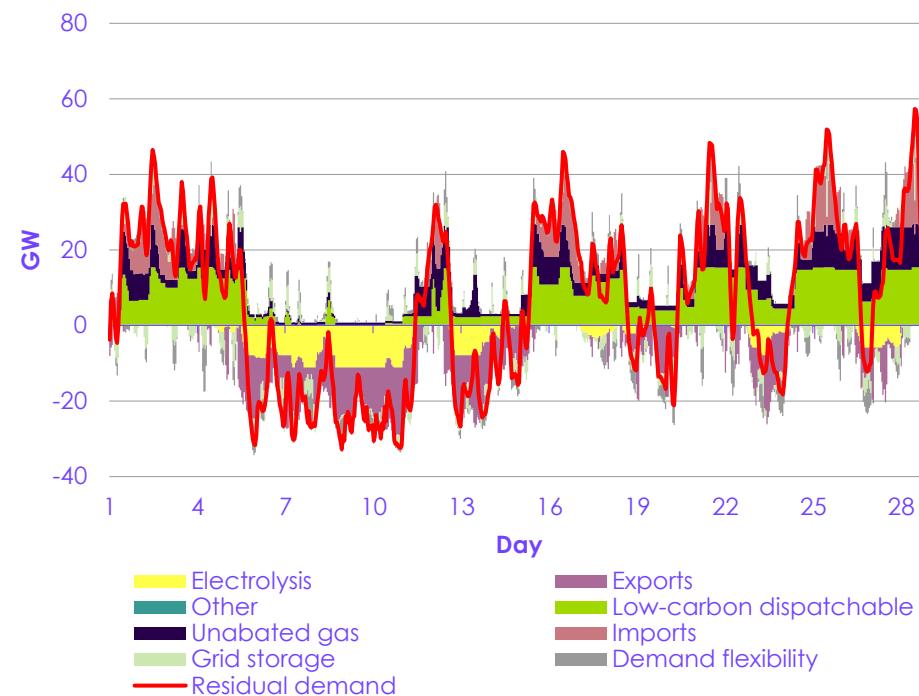
Figure 3 Electricity capacity mix to 2035 in the Central scenario



Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility.

Notes: 'Other' includes Combined Heat and Power (CHP) and unabated biomass. Dispatchable low-carbon includes gas CCS and hydrogen. Analysis is representative of a 'normal' weather year.

Figure 4 Meeting the highest four-week period of residual demand in 2035 (Central scenario)



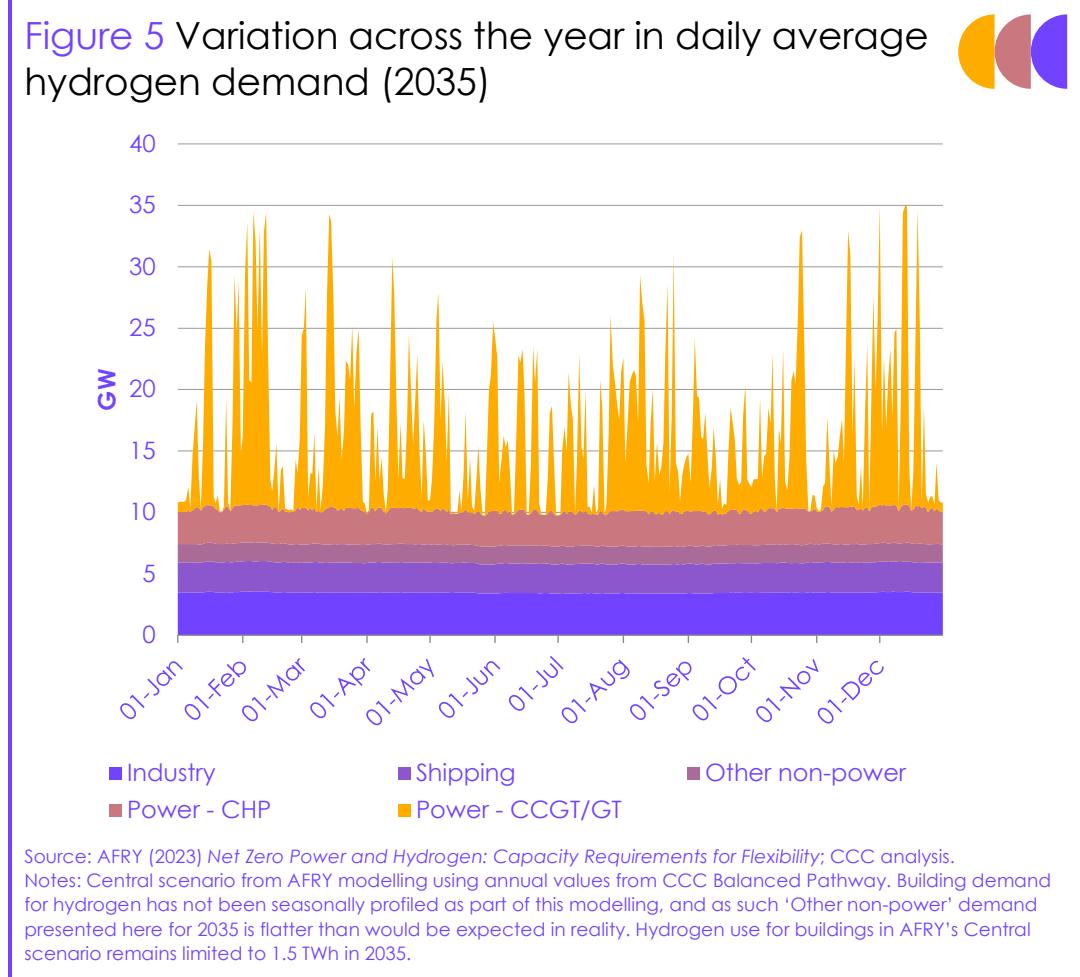
Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility.

Notes: Residual demand is demand required to be met after taking account of generation from renewables, nuclear, BECCS, and other inflexible generation. Dispatchable low-carbon generation includes gas CCS and hydrogen. Chart based on 2012 weather patterns, representing a 'normal' weather year.

(c) Hydrogen supply and infrastructure

In the modelling for this report, the production, storage and use of low-carbon hydrogen plays an essential role in achieving the 2035 goal of a reliable, resilient decarbonised power system.

While the precise balance between use of hydrogen-fired turbines and fossil gas plants with CCS in the power sector remains uncertain, some use of some hydrogen to provide on-demand power to meet peaks and back-up renewables appears necessary. This is likely to lead to a very variable demand for hydrogen in the power sector, necessitating the use of hydrogen storage to ensure that the necessary hydrogen is available (Figure 5).



Some level of hydrogen use is also necessary in the wider economy, to decarbonise applications that cannot be easily electrified such as industry and shipping (e.g. as ammonia).

There remains uncertainty around the scale of future hydrogen use in power and end-use sectors, but the volumes of hydrogen produced and used in the power system alone by 2035 have potential to be substantial.

- Government targets for hydrogen production capacity by 2030 need to be clarified, but currently they look to be at the lower end of what may be required for hydrogen to play a central role in providing low-carbon dispatchable power by 2035.

- We have not attempted to define the appropriate balance of hydrogen and gas CCS for low-carbon back-up capacity, but a mix of the two is likely to be sensible. Build rates for hydrogen production seem infeasible if a hydrogen-only approach is taken, while a portfolio approach would help to manage risks relating to delivery of technologies that have not yet been commercially deployed. Strategic decisions around infrastructure build which determine the deliverable balance of hydrogen and gas CCS are required urgently.
- It appears implausible that all UK hydrogen demand could be met from domestic non-fossil production by 2035, given likely limits on the rate at which renewable generation capacity can feasibly be built. Zero-carbon electricity must be prioritised for displacing unabated fossil generation and meeting increasing demands from electric vehicles and heat pumps. Hydrogen production can require significant water use – if hydrogen production is located in regions projected to be at risk of water stress in future (typically the south and east of England) water availability may also be a constraint on how much hydrogen can be produced, particularly at times of drought.
- Hydrogen availability therefore remains a key risk for future UK Net Zero scenarios with high levels of hydrogen use outside of the power system (e.g. scenarios with extensive use of hydrogen for heat in buildings). It is likely that any additional energy for this extra hydrogen use would need to be imported, whether through increased imports of fossil gas for blue hydrogen production with CCS or through imported renewable energy. For these scenarios to be viable, it would need to be clear that hydrogen with sufficiently low lifecycle emissions can be sourced at the necessary scale, while not risking security of supply or excessive exposure to volatile fossil fuel markets.

There is an important role for Government in setting strategic direction for power and non-power uses of hydrogen. Hydrogen infrastructure will be required regardless of decisions in 2026 on its use for buildings heat – the Government should identify a set of low-regret investments that can proceed now and fast-track business models to deliver it.

(d) Reducing dependence on fossil fuel imports

The UK is already a net importer of fossil gas, and production is projected to continue to fall over coming decades. A key aim of the ESS is to reduce the UK's dependence on imported oil and gas, thereby reducing exposure to volatile international prices. The Government has set a target for the UK to be a net energy exporter by 2040.

The decarbonisation of the electricity system, together with its expansion to meet new demands through electrification of transport, buildings and industry, will cut the UK's fossil fuel consumption rapidly, at a similar rate to the decline in production.

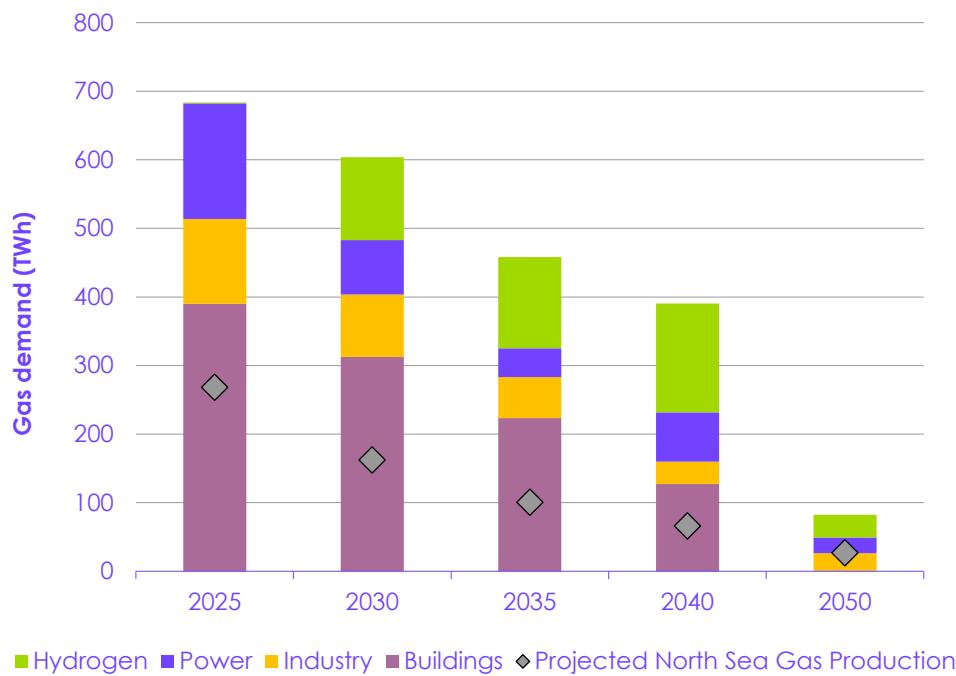
The UK will therefore continue to be a net importer of fossil gas over coming decades. Supplies of gas from UK production are expected to be insufficient to meet even falling demands for gas in existing uses as we decarbonise: buildings, industry – including as a chemical feedstock – and unabated use in electricity generation, until the late 2040s (Figure 6).

Further fossil gas demands on top of these uses (in new facilities with CCS for energy production, whether of electricity or hydrogen) will increase the amount of gas imports by a corresponding amount. Uses of fossil gas with CCS can therefore effectively be considered to be using imported gas.

Reducing our reliance on gas imports and becoming an overall net exporter of energy depends on building out a large amount of zero-carbon generation capacity, as well as pursuit of energy efficiency and efficient electrification across the buildings, industry and transport sectors. Using hydrogen in place of efficient electrification (e.g. instead of heat pumps for buildings) would be a much less efficient use of domestic energy resources, leading to greater need for imported energy to supplement them.

The modelling for this report does not include the potential for hydrogen to be produced from non-grid-connected green hydrogen production in the UK or for extra green hydrogen to be supplied via imported energy. To the extent that this is possible, the UK's reliance on imports of fossil gas can be reduced.

Figure 6 Annual GB gas usage in the Central scenario and our Balanced Pathway (TWh)



Source: AFRY Central Scenario, CCC (2020) Sixth Carbon Budget Balanced Pathway; NSTA (2022) August 2022 oil and gas production projections.

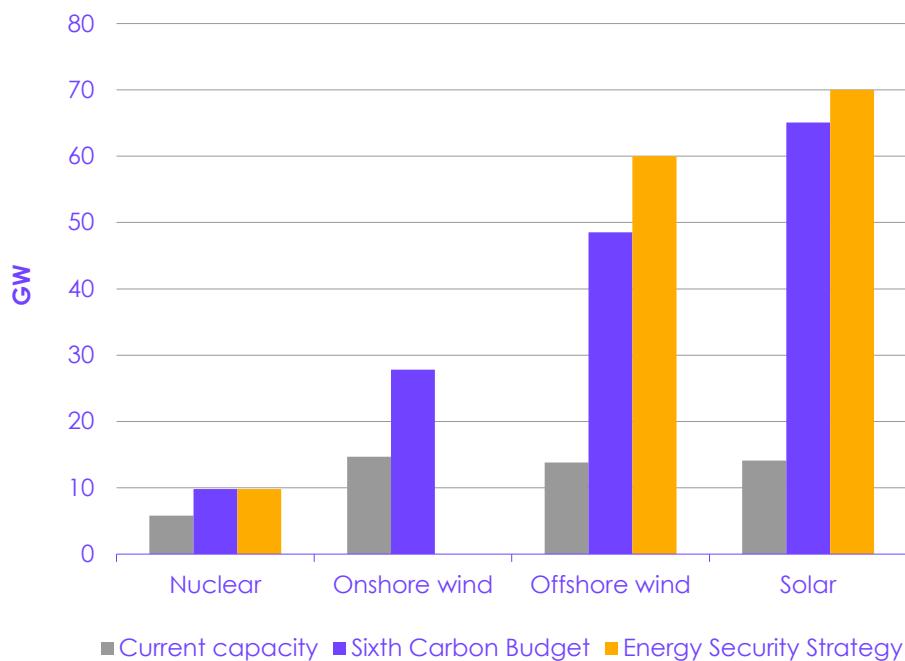
Notes: Gas demands in buildings and industry taken from the CCC's Balanced Pathway; those for power and hydrogen are taken from AFRY's Central scenario modelled for this report.

(e) Delivery challenges

Delivering a decarbonised electricity system by 2035 is a critical national delivery milestone for Net Zero. Delivery and deployment of infrastructure must be achieved at a much greater pace than the present regulatory, planning and consenting regimes can achieve.

Infrastructure build rates in a number of areas represent large increases on current capacity (Figure 7) and need to exceed what has been achieved historically. The Government plans to increase offshore wind capacity by four times over current levels by 2030, and solar by five times by 2035. While the build rate this implies for solar remains close to historical peak, for offshore wind it implies annual build rates around 40% higher than emerging data on the 2022 peak. On nuclear, Government has ambitions to increase investment dramatically relative to historical levels.

Figure 7 Zero-carbon capacity in the scenarios (2035)



Source: BEIS (2022) *Energy Trends Table 6.2*, BEIS (2022) *Digest of UK Energy Statistics Table 5.11*, BEIS (2022) *British Energy Security Strategy*, CCC (2020) *The Sixth Carbon Budget*, CCC analysis.

Notes: ESS nuclear capacity ambition is for up to 24 GW by 2050 with one project to final investment decision this Parliament and two in the next; deployment therefore assumed to be relatively backloaded and follow CCC Balanced Pathway in the medium-term. No ESS bar shown for onshore wind as no firm capacity commitment. Offshore wind ambition in ESS is up to 50 GW by 2030.

The network and storage infrastructure needed to support a decarbonised system will also be very significant, with build required for the transport and storage of electricity, hydrogen and CO₂.

- For instance, the scale of transmission reinforcement needs continues to be assessed by National Grid. It has stated that, in order to support the Government target of up to 50 GW of offshore wind by 2030, in the next seven years it will have to install more than five times the amount of transmission infrastructure in England and Wales than has been built in the last 30 years.³ The requirements in Scotland will add to this further.*
- The analysis undertaken for this report found that in order to facilitate the delivery of the decarbonised system, all the electricity transmission network boundaries examined would be expected to require some level of reinforcement, with an average doubling of their capability required between 2025 and 2035.

The transition will also require a number of technologies that have not yet been deployed commercially in the UK to be brought to significant commercial scale, including CCS, low-carbon hydrogen production and storage, and hydrogen-fuelled generation.

This will not be achieved without a strategic programme of reform, making regulatory frameworks and market design fit for purpose and capable of galvanising the £300-430 billion of investment required, while also removing significant barriers such as in the planning and connections processes.

It is imperative that resilience to the effects of climate change is built into this asset investment programme from the start. Much of the UK's Net Zero electricity system is yet to be built and requires significant additional investment to replace many existing generation assets as well as significantly expand the system. During this renewal of the electricity system capital stock it is vital that the system and assets are built to be sufficiently resilient to future climate conditions. This will require appropriate governance arrangements for resilience, systematic risk assessment (underpinned by further research and reporting) and appropriate resilience standards across the system. If climate resilience is neglected in this investment, there is significant risk of locking in increased climate vulnerability or additional costs later on.

(f) Recommendations

In assessing the path from here to a reliable, resilient, decarbonised system by 2035, it is clear that actions in a wide range of areas are required. While some are in train and on track, others need to be accelerated. There are also gaps in the current set of actions, and roles and responsibilities in delivering the system need clarification. Below we set out summaries of our recommendations, with full recommendations set out in the course of the report (Table 1).

* The transmission network is the higher-voltage network for long-distance transfer of power, distinct from the distribution network which is the lower-voltage local network.

Table 1

Recommendations

Location	Priority recommendations	Owner (Timing)
Ch 2, Section 3	Publish a comprehensive long-term strategy for the delivery of a decarbonised, resilient, power system by 2035.	DESNZ (2023)
Ch 4, section 2 (d)	Set out, in NAP3, the Government's vision for what a well-adapted and climate-resilient energy system will look like.	Defra (2023)
Ch 2, section 3 (a)	Clarify urgently and formalise the institutional responsibilities of the FSO, Ofgem and Ministers, for strategic planning and delivery of the decarbonised, resilient system.	DESNZ (2023)
Ch 4, section 2 (d)	Conduct a review of governance arrangements for resilience to climate hazards in the energy system, to ensure they are fit for the new expanded and more diverse low-carbon system given increasing societal reliance on electricity.	DESNZ, Ofgem (2024)
Ch 2, section 3 (a)	Develop a long-term cross-sectoral infrastructure strategy to adapt and build respectively the distribution of liquid and gaseous fuels, electricity, CO ₂ and heat networks over the next decade.	DESNZ, FSO (by 2025 at the latest)
Ch 2, section 3 (a)	Identify a set of low-regret electricity and hydrogen investments that can proceed now.	DESNZ, FSO (by 2024 at the latest)
Ch 2, section 3 (a)	Create a Minister-led infrastructure delivery group, advised by the new Electricity Networks Commissioner, to ensure enabling initiatives for energy infrastructure build are taken forward at pace, and necessary policy changes are implemented across the UK, to deliver a decarbonised and resilient power system by 2035.	Electricity Networks Commissioner, UK, Scottish & Welsh Governments (2023)
Ch 2, section 3 (b)	Through the Review of Electricity Market Arrangements, develop a strategy as soon as possible on market design for the medium- to long-term for a fully decarbonised, resilient electricity system in the 2030s and onwards.	DESNZ (2023)
Ch 3, section 2 (e)	Finalise funding mechanisms and allocate funding to support the development of 10 GW of low-carbon hydrogen production by 2030.	DESNZ (2023)
Ch 3, section 3 (c)	Fast-track the development of new business models for hydrogen transportation and storage infrastructure, with a view to keeping options open for larger scale hydrogen use by 2030.	DESNZ (2023)
Chapter 1		
Ch 1, section 2	Identify and address potential key supply chain bottlenecks for delivering up to 50 GW of offshore wind by 2030.	DESNZ (2023)
Ch 1, section 2	Ensure that large-scale unabated biomass power plants are converted to BECCS as early as feasible, and are not given extended contracts to operate unabated at high load factors beyond 2027.	DESNZ (2023)

Location	Priority recommendations	Owner (Timing)
Chapter 2		
Ch 2, section 2	Ensure new gas plant are genuinely CCS- and / or hydrogen-ready as soon as possible and by 2025 at the latest.	DESNZ (2025 at the latest)
Ch 2, section 2	Ensure that future system design explicitly plans for the range of climate hazards that will face the energy system over its lifetime.	DESNZ, Ofgem, FSO (ongoing)
Ch 2, Section 3	Publish the second transitional Centralised Strategic Network Plan, identifying the strategic investments required for a decarbonised and resilient electricity system in 2035 and delivery of Net Zero.	ESO/FSO (2023)
Chapter 3		
Ch 3, section 2 (e)	Finalise and deliver the CCUS Transport and Storage Regulatory Investment business model, consistent with the Government's ambition to establish at least two CCS transport and storage clusters in the mid-2020s.	DESNZ (Q1 2023)
Ch 3, section 2 (e)	De-risk the future Carbon Capture and Storage project pipeline by launching the next cluster selection process as soon as possible.	DESNZ (Q1 2023)
Ch 3, section 2 (e)	Publish a plan for CO ₂ transport from dispersed sites.	DESNZ (2023)
Ch 3, section 3 (c)	Publish a site-specific plan for distribution and storage of hydrogen and other low-carbon infrastructure outside of clusters.	DESNZ (Q1 2023)
Chapter 4		
Ch 4, section 1 (c)	Commission further research to improve understanding of how climate change is altering key weather hazards that will impact the energy system.	DESNZ, UKRI, Defra (ongoing)
Ch 4, section 1 (c)	Coordinate a systematic assessment of risks posed from cascading impacts across multiple sectors due to failures of the decarbonised energy system as part of the next round of the Adaptation Reporting Power.	Defra (2025)
Ch 4, section 1 (c)	Require all energy system organisations to report under the Adaptation Reporting Power.	Defra (2023)
Ch 4, section 2 (a)	Develop a pathway to setting appropriate minimum resilience standards (both at asset and system level) to relevant climate hazards identified in the UK Climate Change Risk Assessment (CCRA), covering all relevant parties.	DESNZ, Cabinet Office (by 2028 at latest)
Ch 4, section 2 (d)	Designate Ofgem and parties responsible now and in the future (including the new Future System Operator) for the maintenance of energy sector codes and standards, with a clear mandate to ensure climate and weather resilience.	DESNZ, Ofgem (2024)
Ch 4, section 2 (d)	Extend requirements for reporting on outages to include the cause, duration and magnitude of all outages.	Ofgem, DESNZ (2024)

(g) This report

In the Sixth Carbon Budget, the Committee recommended that electricity supply should be fully decarbonised by 2035, subject to ensuring security of supply. The Government subsequently adopted this commitment as part of their Net Zero Strategy.

The Government's Energy Security Strategy (ESS) set out strong ambitions for the contributions of renewables and nuclear. Taking the Government's Energy Security Strategy (ESS) as the starting point, this report considers:

- What mix of further solutions will be needed to run a secure, reliable and resilient decarbonised electricity system by 2035, taking account of the potential for future electrification of sectors such as transport and home heating.
- Several of the wider enabling factors required, including network and system planning and changes to the design of electricity markets.
- The implications of a decarbonised electricity system for hydrogen use, how it is produced and the infrastructure required to support it.
- How to manage climate-related risks to the energy system, given the increasing dependence of the future economy on clean electricity.
- Delivery risks and the actions needed to address them.

The report is organised in four chapters:

1. Setting the context for the future power system
2. Delivering a reliable decarbonised power system
3. Implications for hydrogen production, use and infrastructure
4. The need for climate resilience

Endnotes

¹ BEIS (2021) *Net Zero Strategy: Build Back Greener*,

<https://www.gov.uk/government/publications/net-zero-strategy>

² Offshore Renewable Energy Catapult (2021) *Industrial leadership – unlocking the UK's floating wind potential*, <https://ore.catapult.org.uk/?orecatapultreports=industrial-leadershipunlocking-uks-floating-wind-potential>

³ National Grid (2022) *2022/23 Half Year Results Statement*,

<https://www.nationalgrid.com/document/148586/download>.



Chapter 1

Setting the context for the future power system

1. Historical trends in demand and emissions	29
2. Future changes to demand and supply	31

Introduction

The decarbonisation of the electricity system has been one of the biggest successes in UK decarbonisation to date, with rapid progress made in reducing emissions from electricity supply. Emissions have fallen by 69% since 2010, largely reflecting a move away from coal and the success of developing offshore wind as a cheap and scalable form of zero-carbon generation. Over this period, considerable advances have also been made in understanding how a decarbonised electricity system can be delivered and operated – and this is now within grasp.

In this chapter we set out progress to date, before looking ahead to the expected changes in demand and zero-carbon supply as we transition to a resilient Net Zero economy by 2050.

We set out our analysis in this chapter in two sections:

1. Historical trends in demand and emissions
2. Future changes to demand and supply

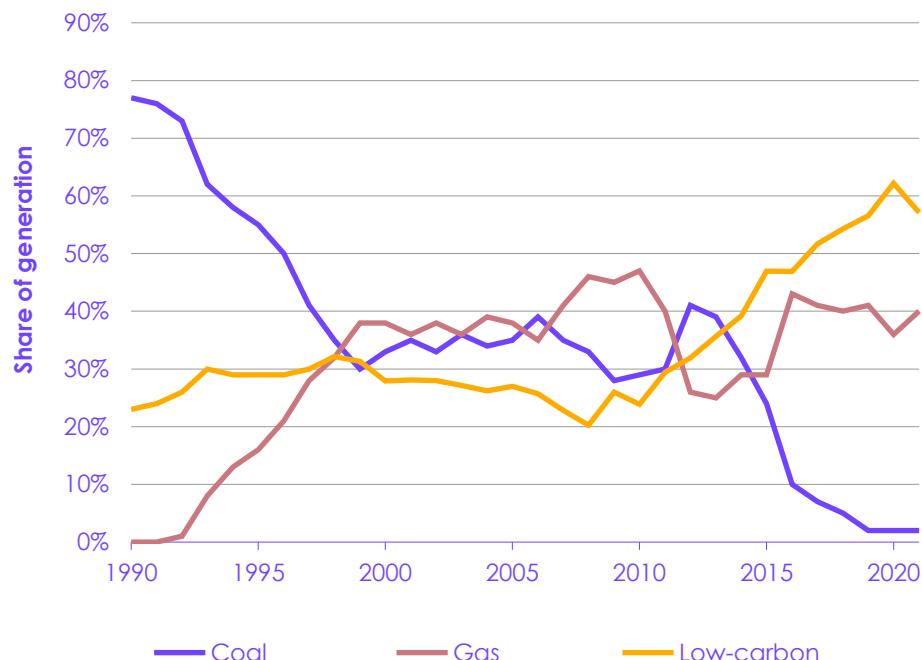
1. Historical trends in demand and emissions

UK emissions from electricity have fallen by 69% since 2010, reflecting improved energy efficiency and a move away from coal.

UK electricity demand and emissions have both fallen since 2010, by 13% and 69% respectively, largely reflecting improved energy efficiency and a move away from coal:

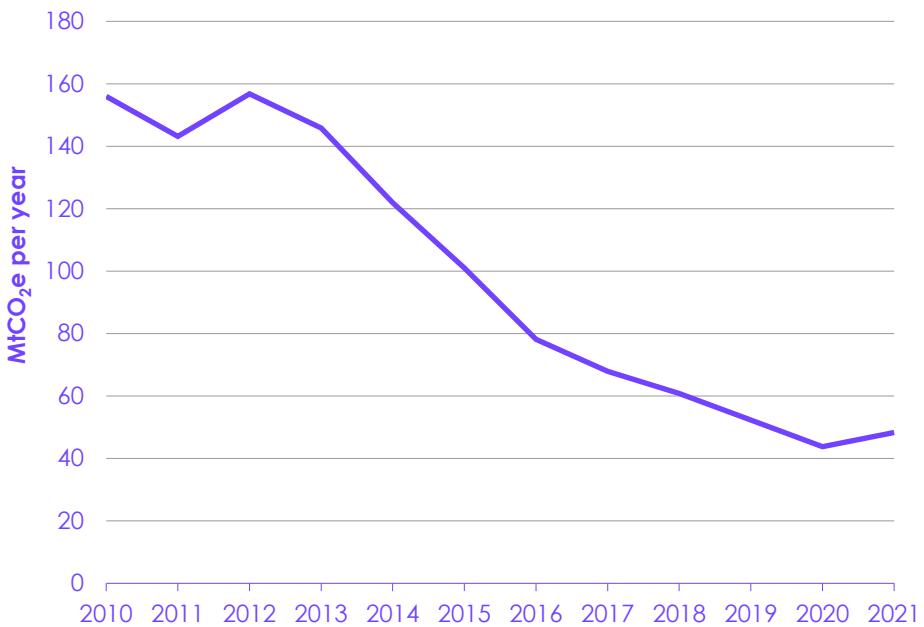
- Coal was replaced by gas in the 1990s and by renewables in the 2010s, such that it now only represents 2% of electricity generation (Figure 1.1). The Government has committed to phasing out its use by the end of 2024. Low-carbon generation has grown significantly over the last decade and is now over half of annual electricity generation. As a result, the emissions intensity of electricity generation has fallen to 200 gCO₂/kWh in 2021, a reduction of 60% since 2010.
- In addition, UK electricity demand has been falling by around 1% per year over the past decade, and is now 13% lower than in 2010. A key reason for this is the continued improvement and uptake of energy-efficient appliances and lighting.
- The combination of decreasing emissions intensity and falling demand has resulted in a reduction in emissions of 69% from 2010 to 2021 (Figure 1.2).

Figure 1.1 Historical electricity generation mix



Source: BEIS (2022) Energy Trends; CCC analysis.

Figure 1.2 Historical emissions from electricity supply



Source: BEIS (2022) Provisional UK greenhouse gas emissions national statistics 2021; BEIS (2022) Final UK greenhouse gas emissions national statistics: 1990 to 2020; CCC analysis.

2. Future changes to demand and supply

(a) Future demand for electricity

In the future, overall energy demand is expected to fall, but electricity demand is projected to rise as we electrify the economy - rising 50% by 2035 and doubling by 2050.

In the future we expect overall energy demand to fall, but electricity demand to increase significantly as key sectors switch from fossil fuels to electricity. Our Sixth Carbon Budget analysis included a range of scenarios reflecting different patterns of electrification of the economy out to 2050, consistent with Net Zero.

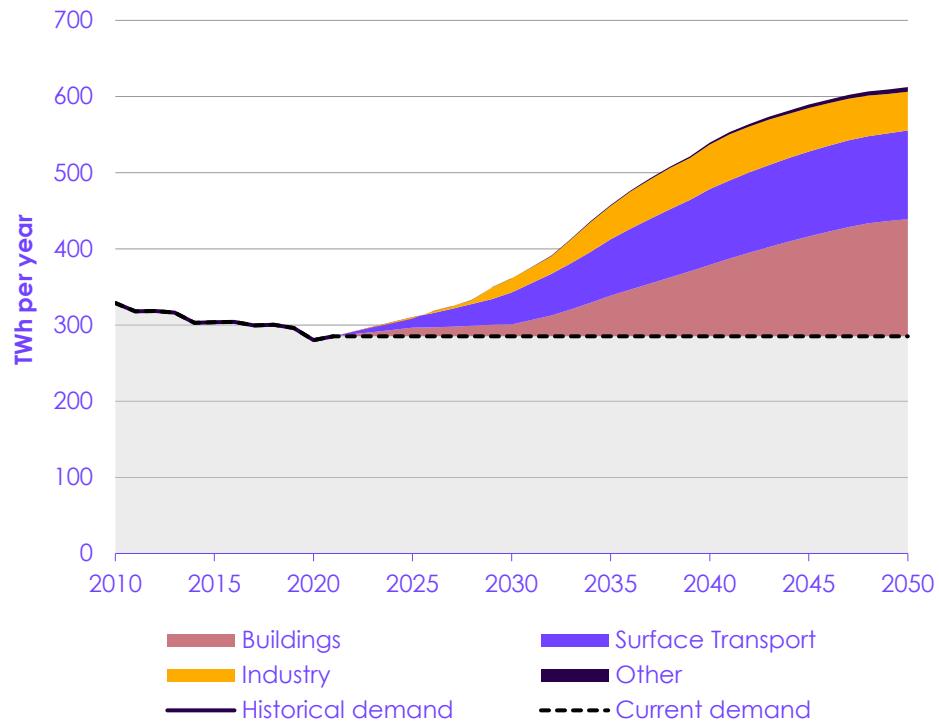
- The Balanced Pathway scenario, upon which the budget was based, has annual electricity demand around 50% higher than pre-Covid levels in 2035 and around 100% higher by 2050 (Figure 1.3), incorporating the electrification of surface transport, heating, and industry.
- The forms of electrification included in the Sixth Carbon Budget Balanced Pathway scenario are typically very efficient compared to their fossil fuel equivalents. Total energy demand in the Balanced Pathway falls by around a third by 2050, and by up to half in other scenarios, reflecting this efficiency improvement as well as some reductions in demand.

This, alongside continued digitalisation, will drive greater economic and strategic dependence on a secure, reliable and resilient electricity supply.

Electrification of the economy to this extent, alongside continued digitalisation, will drive greater economic and strategic dependence on a secure, reliable and resilient electricity supply.

There is the potential for further use of decarbonised electricity beyond that included in the Balanced Pathway, such as electrolytic hydrogen production at scale, powering direct air capture of CO₂ and production of synthetic aviation fuels. These could become feasible with significant further falls in the costs of zero-carbon electricity (e.g. a further halving compared to today's costs of wind and solar). Our Widespread Innovation scenario, which assumes such cost reductions and deployment of less-efficient electricity-based decarbonisation, has electricity consumption reaching three times current levels by 2050.

Figure 1.3 Electricity demand in the Balanced Pathway



Source: BEIS (2022) *Energy Trends*; CCC (2020) *The Sixth Carbon Budget*.

Notes: Other category includes agriculture, aviation, direct air capture and shipping

Alongside the changes in demand that we can expect to see from electrification as we decarbonise, demand will also be affected by the changing climate. The UK climate is set to change over the period to 2050, regardless of UK progress towards Net Zero. Hotter, drier summers and warmer, wetter winters will be more likely and temperature extremes will become more intense and frequent in the decades to 2050. Significant cold events in winter will remain possible.¹

Demand will also be affected by the changing climate, with an increased demand for cooling in summer and a likely reduction in heat demand in winter.

Some of the changes in climate and weather patterns will drive changes in energy demand, including an increased demand for cooling in summer and a likely reduction in demand for heating in winter. These changes are not expected to be significant in the context of overall demand, and have been accounted for in our Sixth Carbon Budget analysis which has in turn informed the modelling underpinning this report:

- In our Sixth Carbon Budget analysis, we assume increases in average winter temperatures to 2030 result in a 6.6% reduction in demand for space heating (before consideration of changes in energy efficiency and heating technologies).^{*} We hold this reduction constant from 2030 to 2050.[†] Later in the century, and particularly under higher levels of global warming, reductions could be significantly greater.[‡]

* Based on the average from an ensemble of UK regional climate projections, using Met Office analysis of Heating Degree Day data derived from the 2018 UK Climate Projections, calculated for a 15.5°C threshold and based on the RCP8.5 pathway – note that the outputs are similar for any emissions scenarios before 2050 (Riahi et al 2007).

† Our residential heat analysis is based on an assessment of end state technology mixes in 2050, which are then deployed over the trajectory to 2050. While further warming after 2030 is expected, we hold the heat demand reduction constant to ensure that the technologies deployed in our modelling are able to meet the heat demands expected from 2030 onwards.

‡ For example, Heating Degree Days (the number of days with average air temperatures below 15.5°C) – which is a proxy for heating demand – are projected to fall by 10% below the average of 2000-2017 at a global warming level of 2°C above pre-industrial levels, 20% at 3°C and 30% at 4°C when averaged across the UK as whole.

- Despite these changes, future electricity demand is still likely to be highest in winter, as is the case today (Figure 1.4).
 - Electricity consumption for heating in the Balanced Pathway adds around 45 TWh to annual electricity demand in 2035, an addition equivalent to 16% of total current UK electricity consumption.
 - Electricity demand for air conditioning remains likely to be smaller than the demand for heating. While our Balanced Pathway assumes 5 TWh of new demand for cooling in residential buildings by 2050, it includes around 145 TWh demand for heat pumps to heat buildings.*³

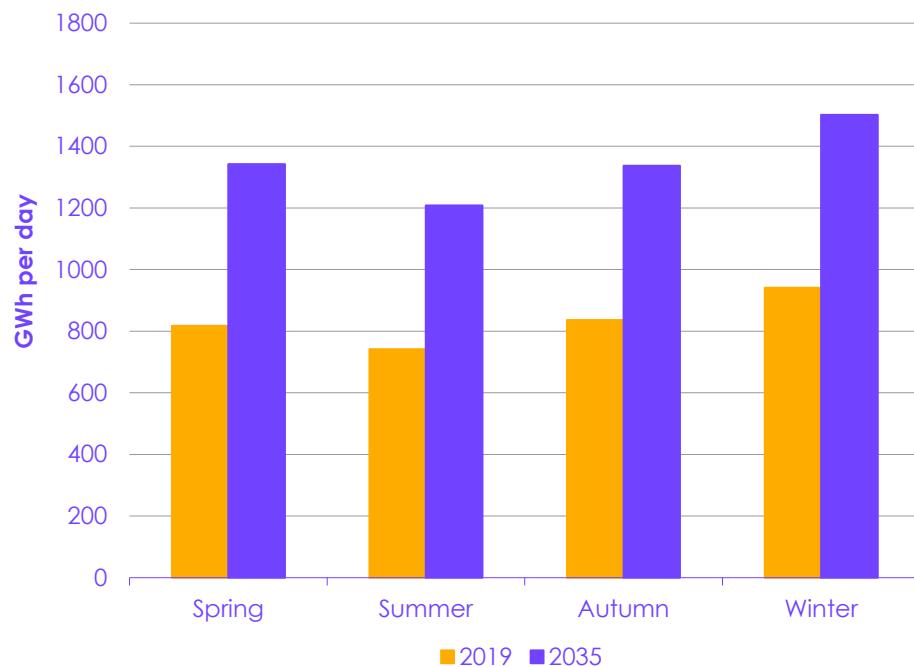
Heatwaves will have potentially serious impacts on health and productivity (around 3,000 excess deaths were linked to raised temperatures in 2022 – almost exclusively in people aged over 65), and also driving economic costs associated with heat-related mortality and illness.^{†,4,5}

It will therefore be important that increased mechanical cooling in residential and non-residential buildings features in Government plans for adapting the UK to higher temperatures, along with passive cooling, behaviour change and emergency response plans. It is expected that it will largely fall to homeowners and occupants to pay for this (passive and mechanical) cooling, although public funding may be required for those in areas of high climate risk and low incomes.⁶

* Cooling demand assumption aligned with Energy Systems Catapult's projections, based on an increase in energy demand for cooling calibrated to levels for households in EU countries which currently experience similar levels of Cooling Degree Days to those predicted for the UK in 2050. Some estimates remain higher – a recent study by BEIS estimated between 6-12 TWh pa of additional power demand for cooling in summer, in low and high emissions scenarios, see BEIS (2021) *Cooling in the UK: Research Study*. Given their scale, heat demand has been seasonally profiled but additional demand for air conditioning has not.

[†] Despite a limited UK-specific evidence base, one study suggests that a 2°C warming trajectory could cost around 0.4% of economic output for London in a warm year due to a reduction in productivity.

Figure 1.4 Seasonal electricity demand in 2019 and 2035



Source: BEIS (2022) Energy Trends; CCC (2020) *The Sixth Carbon Budget*; AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

Notes: Winter includes January, February and December. Spring: March, April and May. Summer: June, July and August. Autumn: September, October and November. Given their scale, heat demand has been seasonally profiled but additional demand for air conditioning has not.

(b) A low-carbon technology mix

(i) The need for bulk low-carbon generation

In the future, demand will be met primarily by renewables, with a role for nuclear alongside this. Significant expansion is planned, at rates faster than have been achieved before.

In the future we expect electricity demand to be met primarily through bulk zero-carbon generation at scale,* with variable renewables forming the backbone of the system as the cheapest form of low-carbon electricity generation. Significant expansion of these technologies is planned (Figure 1.5):

- **Variable renewables** (i.e. wind and solar) are now the cheapest form of electricity generation, given cost reductions over the past decade. The Government has significant expansion plans.
 - The most recent auction results for low-carbon contracts delivered prices for offshore wind, onshore wind and solar ranging from £37 to £46/MWh.[†] We have assumed the same (relatively conservative) potential for future cost reduction as in our Sixth Carbon Budget Balanced Pathway scenario, to around £35/MWh in 2050 across variable renewable technologies.

* Generation, quoted in TWh, measures the output from a given level of capacity, quoted in GW. This varies by technology depending on load factor (i.e. what proportion of total hours in the year it generates for). For example, solar has a load factor of around 10% reflecting that it is sunniest around midday and does not generate overnight, whereas nuclear has a load factor of around 90% reflecting that it is relatively inflexible.

[†] In 2012 prices. As with levelised costs, these do not reflect the wider costs of integrating variable renewables into the electricity system (e.g. for system infrastructure and flexible back-up). These costs might add £10-20 per MWh (see section on BECCS below). The modelling for this report was undertaken on a system-wide basis meaning that these costs are fully incorporated in the analysis (see Box 2.1).

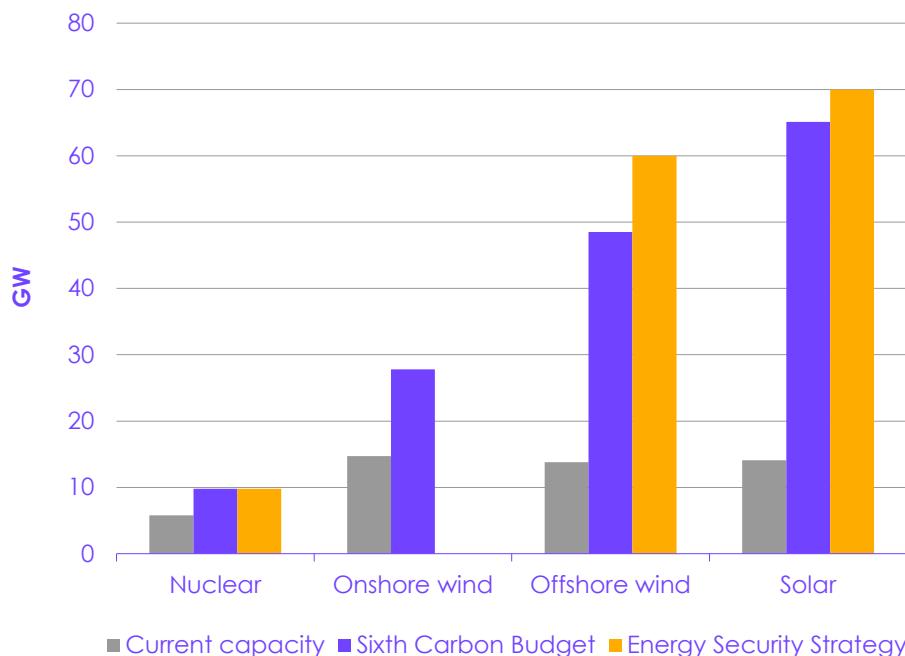
- The Government plans to increase offshore wind capacity by four times over current levels by 2030, and solar by five times by 2035. On average this requires 4.5 GW per year of offshore wind to be installed and 4.3 GW per year of solar.
- These build rates remain above historical annual peak build rates, with 4.1 GW of solar having been achieved historically and emerging data suggesting 2022 was a record year for offshore wind deployment at 3.2 GW.⁷ Around 100 GW of offshore wind is in the pipeline, including 14 GW under construction or with support secured for a route to market. Concerted action will be required to deliver this, including on removing supply chain bottlenecks and improving network connections (e.g. through progressing the work of the Offshore Transmission Network Review).
- Other renewables (e.g. tidal) may be able to play a role but are currently relatively expensive.

Recommendation	Owner (timing)
Identify and address potential key supply chain bottlenecks for delivering up to 50 GW of offshore wind by 2030 , including for investment in ports, adequate vessel capacity, manufacturing capability and floating wind. Take opportunities to link supply chain action to key decision points in offshore leasing and Contract for Difference auctions.	DESNZ (2023)

- **Nuclear** can provide valuable zero-carbon generation at scale. While it is relatively expensive on a levelised cost basis* and has a relatively inflexible supply profile, it could have a role in hydrogen production (which in turn can support system flexibility) and the provision of other system services. The Government is aiming to bring forward new projects, and funding innovative new types of nuclear.
 - The new nuclear plant Hinkley Point C, which is currently under construction, has a low-carbon contract for around £90/MWh (in 2012 prices). As in the Balanced Pathway, in the longer-term we assume costs for new plants could fall by around one-third to £60/MWh, broadly in line with the nuclear sector deal ambition.
 - The Government aims to take one project to a final investment decision this Parliament, and two projects in the next Parliament. They are setting up a new body, Great British Nuclear, to help deliver this, and providing funding for new nuclear technologies including small modular reactors (SMRs) and advanced modular reactors (AMRs). The Balanced Pathway assumes two of these projects are online by 2035. To the extent this is not feasible, additional generation would be required from a combination of other low-carbon sources.

* And noting offshore wind would still be competitive in comparison to nuclear even after system integration costs are taken into account.

Figure 1.5 Zero-carbon capacity in the scenarios (2035)



Source: BEIS (2022) Energy Trends Table 6.2; BEIS (2022) Digest of UK Energy Statistics Table 5.11; BEIS (2022) British Energy Security Strategy; CCC (2020) The Sixth Carbon Budget; CCC analysis.

Notes: ESS nuclear capacity ambition is for up to 24 GW by 2050 with one project to final investment decision this Parliament and two in the next; deployment therefore assumed to be relatively backloaded and follow CCC Balanced Pathway in the medium-term. No ESS bar shown for onshore wind as no firm capacity commitment. Offshore wind ambition in ESS is up to 50 GW by 2030.

(ii) The role for biomass with carbon capture and storage (BECCS)

Sustainable bioenergy with carbon capture and storage is expected to play a role, running inflexibly on a similar basis to nuclear.

BECCS from sustainable feedstocks provides both decarbonised electricity generation and a form of engineered greenhouse gas removals. BECCS is expected to run inflexibly, similarly to nuclear, due to its relatively high capital-intensity and the value of the removals it provides alongside the electricity.

Subsidies for large-scale unabated biomass generation were put in place early in the last decade, at a time when costs of low-carbon generation from a range of sources were relatively high, and when there was an opportunity for coal units to be converted to burn sustainably-sourced biomass. This was appropriate as an interim measure, but sustained use of large-scale biomass generation is not compatible with the path to Net Zero.

Unabated biomass generation is counted as zero-emission at the point of use, but even sustainable biomass supplies have significant lifecycle greenhouse gas emissions. Furthermore, large-scale biomass plants are large point-sources of CO₂ emissions, which provides an opportunity for conversion to BECCS plants. Such a conversion provides a very good use of finite sustainable biomass supplies in climate terms (Box 1.1).

Due to constraints on sustainable supply and high costs, unabated biomass should not be part of the least-cost decarbonised electricity system which should be largely in place by 2030.

In addition to constraints on the supply of sustainable biomass, the relatively high costs of unabated biomass generation compared to other low-carbon forms of generation mean that unabated biomass is not part of a least-cost decarbonised electricity system that should be very largely in place by 2030. The existing low-carbon contract for unabated biomass generation has a price of £100/MWh (in 2012 prices). As a form of bulk decarbonised generation, unabated biomass is considerably more expensive than wind and solar, even after allowing for the additional costs of managing their variability, which might add £10-20 per MWh of renewable generation.⁸

Unabated biomass capacity could, in principle, be used at low load factors to support the operation of variable renewables. However, existing biomass plants currently have a subsidy regime that encourages them to run for as many hours as possible rather than operating flexibly in a back-up role.

The CCC's Balanced Net Zero Pathway, which underpinned our recommendations on the 2030 Nationally Determined Contribution to the UN process and the Sixth Carbon Budget, sees existing unabated biomass capacity switching over to using CCS (i.e. becoming BECCS) in the second half of the 2020s. Over the period to 2050, biomass supplies switch largely to UK-grown feedstocks. In the Government's Net Zero Strategy, at least 5 MtCO₂ is being removed from the atmosphere and stored annually by 2030 and around 80 MtCO₂ annually by 2050.

At the time of writing, we have not yet seen the Government's Biomass Strategy, which was due by the end of 2022. We expect this to confirm the important role for BECCS, with sustainable feedstocks, in reaching UK Net Zero, and an increasing share of UK feedstocks over time.

The Energy Prices Act gave the Government powers to award Contracts for Difference (CfDs) to existing generators. These powers should not be used in a way that extends subsidies for large-scale unabated biomass electricity generation at very high load factors beyond the scheduled expiry of existing Renewables Obligation and CfD support in 2027.

Recommendation	Owner (timing)
Ensure that large-scale unabated biomass power plants are converted to BECCS as early as feasible, and are not given extended contracts to operate unabated at high load factors beyond 2027.	DESNZ (2023)

Large-scale unabated biomass power plants should be converted to BECCS as early as feasible, and should not be operating at high load factors beyond 2027.

Box 1.1

The role for BECCS in the transition to Net Zero

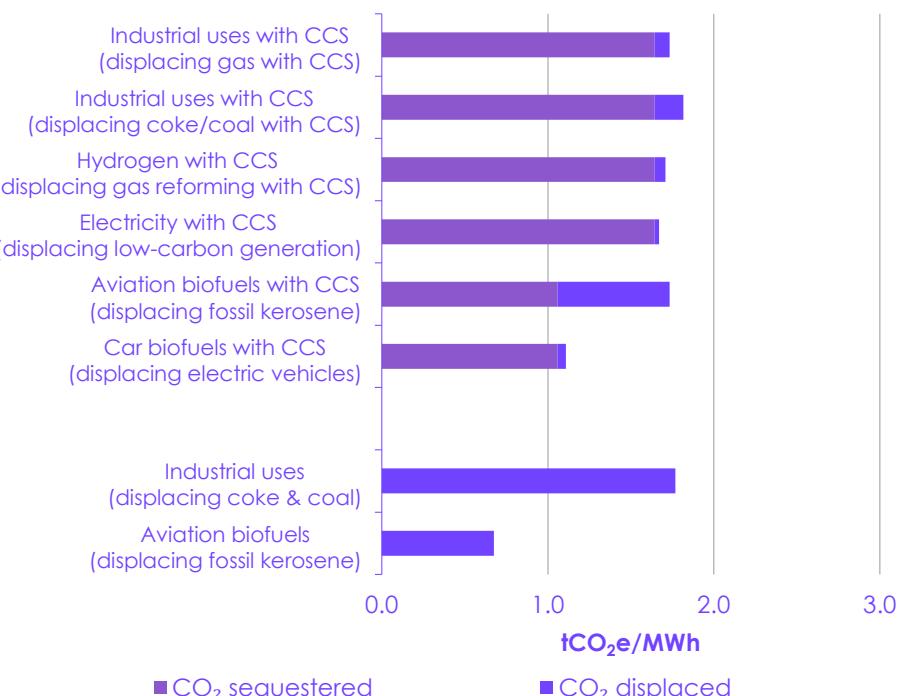
The CCC considered the best uses of biomass in our 2018 Biomass report, as did BEIS in its 2021 Biomass Policy Statement. Both reviews concluded that the use of finite sustainable biomass for unabated electricity generation (i.e. without CCS) is not appropriate on a long-term basis, and that it is important to develop domestic biomass supply chains.

- Sustainable sources of biomass are finite, so the use of biomass must be limited and focused on those applications that maximise its contribution to Net Zero. In the 2010s, this was achieved by using biomass to displace coal generation, through converting coal units to biomass. However, by the second half of this decade, once coal has been phased out and CCS infrastructure is available, the best use of sustainable biomass resources will shift to using bioenergy with CCS (BECCS), for a range of applications (e.g. power generation, hydrogen production, aviation fuel production) (Figure B1.1).

- The UK should also shift from relying primarily on imported biomass for power generation to developing domestic supplies as much as possible. It is challenging to ensure that biomass imported to the UK meets the necessary sustainability standards, given the lesser regulatory oversight that is possible around land use and forest management in other countries. Internationally tradable sustainable solid biomass resources are also finite, so a substantial UK dependence on imports would risk taking more than a fair share of this valuable global decarbonisation resource. In turn, as countries pursue Net Zero, competition for finite sustainable biomass could drive up international biomass prices, meaning that biomass imports become increasingly expensive over the period to 2050.

Although combustion of biomass is accounted for as carbon-neutral under standard greenhouse gas accounting rules, biomass does have significant other emissions when looking across the full supply chain. Estimates of the lifecycle emissions of unabated biomass generation in the UK, submitted by generators to Ofgem, are typically around 125 gCO₂e/kWh (on a scope that excludes any emissions relating to changes in forest carbon stocks). This is considerably higher than the lifecycle emissions of wind, solar and nuclear generation, which are no higher than 35 g/kWh for wind, nuclear and most forms of solar PV generation. Fitting CCS to biomass plants would mean that these plants provide net removals of CO₂ from the atmosphere. While the costs of generation will be higher than for unabated biomass, the emissions benefits of capturing and storing the CO₂ make baseload BECCS plants a justifiable part of a decarbonised electricity system provided the biomass is sourced in a sustainable way.

Figure B1.1 Estimated GHG abatement per oven dried tonne of biomass across different applications



Source: CCC (2018) *Biomass in a low-carbon economy*.

Notes: This chart shows estimates of GHG abatement provided by an oven-dried tonne of biomass used in various sectors, considering the most appropriate counterfactual (i.e. what we would expect it to be displacing, long-term). We have shown abatement broken down by sequestered carbon (the amount of CO₂ stored and/or not released into the atmosphere due to CCS technology) and displaced carbon (the amount of CO₂ that would have been emitted to the atmosphere in the counterfactual case had biomass not been used). The underlying calculations do not include biomass lifecycle emissions.

Source: Ofgem (2022) *Biomass Sustainability Dataset 2021-21* (<https://www.ofgem.gov.uk/publications/biomass-sustainability-dataset-2020-21>); UNECE (2021) *Life Cycle Assessment of Electricity Generation Options* (<https://unece.org/sites/default/files/2021-10/LCA-2.pdf>); CCC (2018) *Biomass in a low-carbon economy*.

In order to deliver a reliable and resilient system, this inflexible low-carbon generation will need to be complemented by low-carbon flexibility, which will play an increasingly important system role.

(iii) The role for low-carbon flexibility

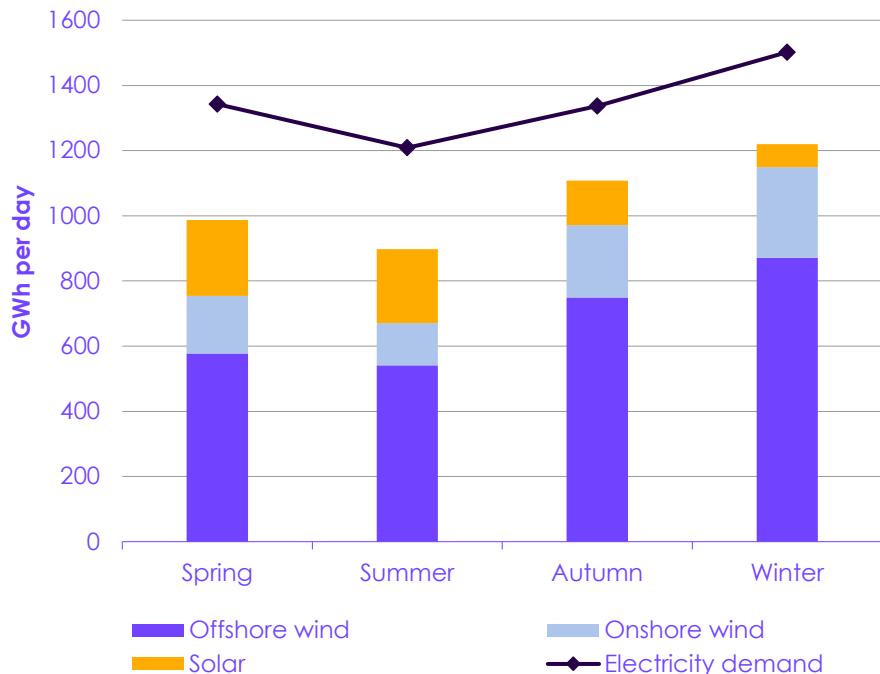
Given the relative inflexibility of variable renewables and nuclear generation, these will need to be complemented by various forms of flexibility, in order to manage the electricity system over the necessary timescales (see Chapter 2).

The role of bulk non-fossil fuel generation will grow over time. Over the rest of this decade, its main role will be displacing unabated gas-fired generation and reducing emissions from the power sector. Over time, and especially beyond 2035, the primary role for additional capacity will be meeting new demands for electricity as the economy further electrifies, reducing emissions in the transport, buildings and industry sectors.

A shift towards variable renewables in providing the majority of electricity has implications for the energy system:

- The variable nature of renewable generation means that flexibility will become increasingly important across a range of timescales:
 - **Short-term variability.** On the scale of minutes to hours, fast response flexibility will be important to manage predictable fluctuations in weather patterns. These fluctuations may be correlated with demand to a certain extent (e.g. solar generation and cooling demand in the middle of the day).
 - **Medium-term variability.** On daily to weekly timescales, planning for flexibility will be needed to manage longer-lasting weather fluctuations (e.g. wind droughts) and for the possibility that these might be more intense and frequent in future.
 - **Longer-term variability.** Monthly to yearly variability (e.g. in wind speeds) is possible given weather patterns, affecting the amount of production required from other sources. Seasonal variability is potentially less of an issue in future given the correlation of offshore wind generation with seasonal demand patterns (i.e. both are highest in winter, see Figure 1.6), although some planning will still likely be required given the dependence of the economy on variable generation.
- Power from variable renewables will start to exceed demand. Our modelling suggests that the Government's ambitions for variable renewables will mean that the power available from renewables exceeds demand in around one-third of hours in 2035.
 - The demand required from other sources in these periods will be negative, and there will no longer be a positive minimum level of demand that would allow other generation to run continuously as baseload.
 - To complement the variability of a very large capacity of renewables, other sources of power must be capable of running flexibly, with the ability to ramp output up and down and be easily shut down and restarted, if surpluses during high wind periods are to be managed.

Figure 1.6 Seasonal demand and renewable generation in 2035



Source: CCC (2020) *The Sixth Carbon Budget*; AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

Notes: Figure shows renewable generation in 2035 based on the modelling undertaken for this report. It reflects the capacity ambitions set out in the Government's ESS (e.g. up to 50 GW of offshore wind in 2030). Electricity demand is based on the Sixth Carbon Budget Balanced Pathway scenario. Not all renewable generation is used to meet electricity demand (e.g. some is used to produce electrolytic hydrogen). Winter includes: January, February and December. Spring: March, April and May. Summer: June, July and August. Autumn: September, October and November. Given their scale, heat demand has been seasonally profiled but additional demand for air conditioning has not. Analysis is representative of a 'normal' weather year.

(c) Managing climate risks

A changing climate will bring increased and new supply-side risks for the energy system.

A changing climate will bring increased and new supply-side risks for the energy system, which will need to be effectively managed:

- Potentially large-scale and correlated loss of wind generation during wind droughts.
- Temporary loss of capacity due to damage from storms, winds, and floods.
- Generation efficiency reductions and the reduction of electricity network thermal ratings (i.e. the capacity to carry power) during heatwaves.*
- Loss of thermal generation capacity due to lack of water supply for cooling and other production processes during periods of drought.

Planning for some of these risks poses new challenges, as the evidence projecting changes in some important weather hazards, including storms, wind strength and wind regimes, remains uncertain (Box 1.2).

* Sagging electricity wires during heatwaves can also be dangerous to those around them under certain conditions.

As the UK moves towards a significant reliance on wind for electricity generation (particularly from the North Sea), it becomes more important to understand wind speeds and wind droughts in order to operate power systems reliably.

The possibility of more frequent and severe wind droughts due to global climate change cannot be ruled out. Future system design must therefore plan for these, and other climate risks.

Wind droughts (extended periods of low-wind conditions) already occur in the UK. For example, January 2021 saw the lowest wind speeds for at least 20 years and as a result offshore wind generation was 16% lower than the same period a year before. Evidence from the latest set of UK climate projections on the impacts of climate change on future wind speeds around the UK suggests no clear signal for significant change in generation potential in winter, when the most electricity is needed and generated. These projections do show the potential for declines in wind power generation in other months, although there is a need for new evidence to assess these risks appropriately.⁹

The possibility of more frequent and severe wind droughts due to global climate change cannot be ruled out and needs to be considered within robust planning for a resilient future electricity system. We have therefore undertaken dedicated analysis on how the system should be designed to cope with low wind periods and droughts. These are discussed further in Chapter 2.

Implications of reduced water availability depend greatly on the success of adaptation measures by 2050 to reduce water demand (across all abstractors of water), improve the efficiency of the water system and find new sources of supply. They will also depend on the electricity system pathway to Net Zero. Without significant additional adaptation efforts there will be an increased occurrence of drought, constraining water abstraction for energy production, particularly in England and parts of Wales.

Modelling of projections in water use in electricity and hydrogen production to 2050 concludes that there is considerable uncertainty in future energy sector potential water needs at regional geographic scale.* This depends on the range of pathways that are compatible with Net Zero by 2050 and the location of large-scale hydrogen production facilities within the country.[†] Hydrogen production accounts for a significant proportion of future water use.

Overall, water consumption for energy production is projected to reduce until 2025, after which it is projected to increase to 2050 as hydrogen production ramps up.¹⁰ In general, the modelling finds the range of use post-2035 often exceeds that in the 2018 baseline year. Given projected constraints on future water availability due to climate change, this is an area of significant concern. It is essential that water availability considerations are reflected in energy policy delivery for Net Zero, and that hydrogen production is integrated within cross-sector regional planning for water usage.

It is also possible that, rather than use in turbines for electricity generation, hydrogen could instead be used to generate electricity using fuel cells, enabling the water from the process to be captured rather than emitted into the atmosphere as vapour.

These uncertainties make it even more important that climate resilience is fully incorporated into Net Zero delivery. Chapter 2 looks in more detail at the risks of wind droughts and low-wind years and how they can best be managed.

* Modelling based on 2020 Future Energy Scenarios and CCC Net Zero pathway scenarios.

† The east and south-east of England are expected to be where risks of water shortages are most significant.

Chapter 4 looks in more detail at the future risks of weather-related failures in the context of climate change, and what is required to make the system resilient to these risks.

Box 1.2

Uncertain climate impacts & implications for supply

Storms. Storms are an important climatic impact driver for the UK. Recent storms have demonstrated the potential impacts on the electricity system and knock-on impacts which can cascade across society (see Chapter 4). Recent studies assessed for the UK's Third Climate Change Risk Assessment (CCRA3) concluded that there is no clear observational evidence for increased UK storminess.¹¹ Trends in storm activity depend on the time period analysed. The apparent increase in storminess between 1960 and 1990 is part of a longer-term record that reveals significant multi-decadal variability. More research is needed to address this important question for the UK and to better understand the potential for changes in future UK storminess.

High wind speeds. Wind turbines are designed to stop operation when wind speeds exceed a certain level, typically around 25 ms^{-1} (around 56 mph), to avoid mechanical damage from excess stress. A weather front passing across the country with wind speeds consistently above that level can therefore lead to total wind generation dropping, potentially to near zero, in just a few hours. In an electricity system with a large share of generation from co-located offshore wind, the drop in available generation from such events could be significantly greater than the variations the system operator is accustomed to managing today and would require a large amount of replacement generation to be ramped up sufficiently quickly. Similarly to storminess, there is currently no observational evidence for changes in the occurrence of strong wind gusts in the UK and limited understanding of possible future changes. CCRA3 identified this as an area for further investigation in order to understand the possible implications on energy system resilience.

Wind droughts. Wind droughts are extended periods of low-wind-speed conditions. Through summer and early autumn 2021, Europe experienced a long period of dry conditions and low wind speeds. April to September 2021 was the least windy period for most of the UK and parts of Ireland in the last 60 years.¹² SSE stated that its renewable assets produced 32% less energy than expected. In 2018, the power available from wind generation was reduced for a sustained period during the summer heatwave. National Grid reported that wind power production was down from 12.9% to 10.4% of total electricity production in summer 2018, when compared to 2017, despite 10% more installed wind generation capacity. CCRA3 assessed the observed seasonal changes in near surface wind speeds (1981-2000) and UK climate projections for wind under 2°C , 3°C and 4°C warming thresholds (UKCP09 regional model, UKCP18 regional model and CMIP5 global model). The analysis concluded that in winter there is a large spread and no clear signal across the three sources of evidence, that would imply robust changes in wind energy supply. In other seasons there is a consistent, but small, signal of weaker winds, except in summer where the declines are larger, especially in the UKCP18 results. Further research into the impacts of climate change on future maximum wind speeds and the seasonal change of wind speeds would enable a better understanding of the extent of any adaptation shortfall associated with wind related impacts.

Lightning. Lightning strikes can and do have large-scale impacts on the electricity system. A lightning strike on a transmission line triggered the large-scale outage in South-East England in 2019 when a number of generators responded to the voltage fluctuation incorrectly, with large cascading impacts. Lightning strikes are also an important cause of wildfire, which could have impacts on the electricity system. However, there is currently conflicting evidence suggesting significant changes in the frequency of lightning strikes over coming decades. Long-term uncertainty also exists for other hazards, such as sea-level and coastal storm surges.

Source: Slingo, J. (2021) *Latest scientific evidence for observed and projected climate change*. In: The third UK Climate Change Risk Assessment Technical Report [Betts, R.A., Haward, A.B. and Pearson, K.V. (eds.)] Prepared for the Climate Change Committee, London; World Climate Service 2021.

Endnotes

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Chapter 2

Delivering a reliable decarbonised power system

1. What flexibility is needed?	47
2. Types of flexibility and options for the flexibility capacity mix	50
3. Facilitating delivery and addressing risks	63
4. Indicators for measuring progress	73

Introduction

A low-cost renewables-based system will need a range of flexible low-carbon solutions to ensure reliable and resilient electricity supply.

In this chapter we set out the options for low-carbon flexibility and how these can complement a renewables-based system to deliver reliable and secure supply. Using these scenarios we present a range of indicators for monitoring progress towards the 2035 objective, as part of our annual reporting to Parliament.

We do this in four sections:

1. What flexibility is needed
2. Types of flexibility and options for the flexibility capacity mix
3. Facilitating delivery and addressing risks
4. Indicators for monitoring progress

1. What flexibility is needed?

Low-carbon flexibility will be needed on a range of timescales, to ensure the system is balanced both in the shorter-term (e.g. seconds, minutes, hours) and the longer-term (e.g. days and weeks).

We commissioned the consultancy AFRY to undertake modelling to inform an assessment of the flexibility requirements for a decarbonised system by 2035.

We commissioned the consultancy AFRY to undertake modelling to inform an assessment of the flexibility requirements for a decarbonised system by 2035 (Box 2.1) and beyond to 2050.

Box 2.1

Modelling to assess the flexibility requirements for a decarbonised, reliable and resilient electricity system

Our approach to assessing the flexibility requirements for a decarbonised system is based on modelling undertaken by AFRY, incorporating the following key high-level features:

- Hourly representation of demand and generation, optimising the power and hydrogen production and storage systems simultaneously. Technologies are dispatched to give a minimum cost of electricity.
- 11 geographic zones across Great Britain and simultaneous modelling of pan-European interconnected markets, accounting for the geographic coverage of weather systems, with weather patterns at 15 km² resolution.
- Five historical annual weather patterns used to simulate each future year, and a wider selection available for sensitivity testing, to reflect a range of possible outcomes for uncertain, weather-driven features of power systems.
- Investment (e.g. by type and location for new generation capacity, transmission grid reinforcement, and the production, storage and transmission capacity of hydrogen) determined endogenously to give the economically optimal, least-cost, system reflecting the range of weather patterns.
- In all scenarios the following constraints must be met:
 - Security of supply required to ensure lower than three hours of loss of load expectation, in line with Government requirements.
 - All investment options required to respect resource potentials and build rate limits.
 - Ancillary service requirements met, including short-term operating reserve, regulating reserve, and frequency response and inertia.

The modelling used the capacities for renewables and nuclear from the ESS, with the flexibility options required to balance the system then optimised around these. Key input assumptions included the following:

- Fixed capacity assumptions were drawn from the ESS, with 50 GW of offshore wind in 2030 (assumed to rise to 115 GW in 2050), 70 GW of solar PV in 2035 (assumed to rise to 105 GW in 2050), and 24 GW of nuclear in 2050. Additionally, 28 GW of onshore wind were assumed in 2035, rising to 31 GW in 2050, with 2.5 GW of BECCS and 21 GW of interconnection capacity based on National Grid's Network Options Assessment.
- Technology costs were based on the Sixth Carbon Budget Balanced Pathway assumptions, supplemented by AFRY for those options not covered in the Sixth Budget (see Chapter 1 and Tables 2.1 and 3.1).
- Carbon values were taken from the Government's Green Book for a Net Zero consistent pathway, reaching £300/tCO₂ in 2035 and £380/tCO₂ in 2050 (in 2020 prices).

- Fossil fuel prices were based on the Sixth Carbon Budget assumptions, including gas prices of around 2.5 p/kWh over the period to 2050 (in 2020 prices). We investigated the impact of significantly higher and sustained gas prices, but given all scenarios very significantly reduce gas use, other factors (e.g. technology build rates) were found to be more significant in driving outcomes. As a result, and given uncertainty surrounding the future gas price profile, Sixth Carbon Budget assumptions were used. To the extent that gas prices are higher than were assumed based on projections in 2020, decarbonisation costs will be lower.
- Electricity and non-power hydrogen demands were based on the Sixth Carbon Budget scenarios. Hydrogen demand in power was determined by the model's simultaneous optimisation of the power and hydrogen systems.

In conjunction with AFRY, we developed a range of scenarios and sensitivities that combined these assumptions in different ways.

- The Core (Central, High and Low) scenarios use the capacities from the ESS and vary electricity and hydrogen demands.
 - The Central scenario uses electricity and hydrogen demands from the Balanced Pathway.
 - The High scenario uses demands from the Widespread Innovation scenario.
 - The Low scenario uses demands from the Headwinds scenario.
- In order to account for uncertainty in the indicator ranges, and to stress-test the results, a range of sensitivities were undertaken.
 - The indicators, and ranges quoted throughout this report (unless otherwise stated) reflect the Core scenarios and a subset of the sensitivities, selected with a view to reflecting the range of outcomes which might be achieved pending uncertainty.
 - The indicator range included sensitivities on the impact of different assumptions on policy (e.g. different uses for biomass), technology (e.g. potential for hydrogen conversion of existing gas plant and additional progress in grid storage technologies), market developments (e.g. progress in renewable and nuclear build, the balance between hydrogen and gas CCS in low-carbon dispatchable power) and weather/security of supply considerations (e.g. low wind).

Further detail is set out in the accompanying technical report by AFRY, available on our website at www.theccc.org.uk.

Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility.

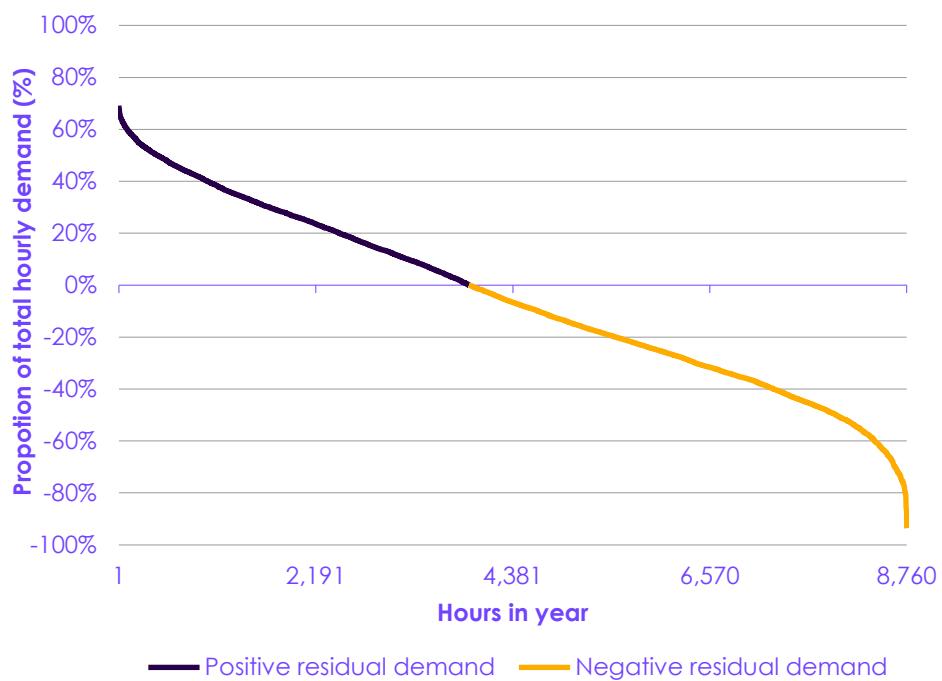
A significant amount of low-carbon flexibility is expected to be needed in a typical year, both to meet residual demand, and absorb surplus supply.

The modelling undertaken for this report suggests a significant amount of low-carbon flexibility will be needed in a typical 2035 weather year,* with flexibility expected to be utilised in around half of days and hours to meet residual demand,[†] and in around half of days and hours to absorb surplus electricity supply (Figure 2.1).

* All hourly modelling results are shown applying 2012 weather patterns to 2035. 2012 was judged by AFRY to be representative of a typical weather year, but does not take account of any future changes in climate.

[†] Residual demand is defined as the difference between demand at a particular point in time and the power available at that time from wind, solar, BECCS and – by virtue of its relative inflexibility – nuclear. It therefore represents, when it is a positive value, the demand to be met from flexible, schedulable sources or, when it is negative, the power available for use by flexible demand, export or storage.

Figure 2.1 Residual electricity demand in 2035



Source: CCC analysis based on AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

Notes: Figure shows hourly residual demand for the Central scenario in 2035, ordered from highest to lowest and adjusted to reflect the proportion of total electricity demand in that hour. Positive residual demand means there is not sufficient renewable, nuclear, BECCS and other inflexible generation to meet demand. Negative residual demand means generation from these sources exceeds demand.

2. Types of flexibility and options for the flexibility capacity mix

(a) Options for providing low-carbon flexibility

There are a wide range of options for providing low-carbon flexibility, including demand flexibility, generation, storage and interconnection.

There are a wide range of potential options for providing low-carbon flexibility, across the different timescales that are required:

- **Demand.** Managing demand can help reduce the need for use of generation or storage (particularly at peak demand periods) as well as minimising the amount of network capacity needed, without affecting consumers' quality of service provision. In doing so demand management can both reduce costs and improve security of supply.
 - **Smart demand shifting** can help to smooth peaks in demand and absorb excess supply (e.g. through controlled timing of electric vehicle charging, and smart management of heat pumps and appliances). The potential for this will grow in future as the deployment of these technologies increases, driven by the growth of smart-enabled technology and the electrification of transport and heating in buildings.
 - **Demand response.** Consumers, both residential and commercial, can participate voluntarily in markets to reduce their demand in response to price signals or automatic controls. Around 0.5 GW of commercial demand response has been contracted through the capacity market.
 - **Electrolytic hydrogen production.** By providing a source of demand, producing hydrogen via electrolysis can help to absorb electricity surpluses when available supply exceeds demand. However, it may not be a fully flexible option given business models and the need to maintain production efficiencies.
- **Generation.** Dispatchable options for providing low-carbon flexibility through back-up generation include gas with carbon capture and storage (CCS) and hydrogen-fired turbines.
 - **Gas CCS.** These gas plants have additional technology fitted to capture the CO₂ emitted, and therefore need access to CO₂ storage and transport infrastructure. The capture process incurs an efficiency and cost penalty, meaning it is likely to be more cost-effective to run these plants relatively consistently rather than ramping up to meet peaks in demand.
 - **Hydrogen-fired turbines.** These are similar to conventional gas turbines currently used in electricity generation, but substituting hydrogen gas for natural gas. This can be a low-carbon solution provided that the hydrogen is produced in a low-carbon way. Existing gas plants can also potentially be converted to use hydrogen.¹ Hydrogen-fired turbines are likely to have similar characteristics to existing gas turbines, and therefore could play a similar role in the electricity system by providing both mid-merit and peak generation.

- **Storage.** These options can capture energy, typically when it is cheap, to provide electricity in periods when demand is higher, and electricity is more valuable. They can operate on short to long timescales, to provide flexibility when it is most valuable.
 - **Shorter-term.** Lithium-ion batteries can provide flexibility by discharging power on timescales from minutes to hours. Currently around 2 GW of grid connected battery storage is operational in the UK.
 - **Medium-to-longer-term.** A number of storage options could operate on timescales covering hours to days and weeks or longer.
 - Pumped storage and compressed air energy storage (CAES) are mature technologies, with 2.5 GW of pumped storage currently installed in the UK and CAES installed overseas.²
 - Gas CCS and hydrogen, enabled by appropriate levels of gas and/or hydrogen storage (or imports) could play a longer-term role over weekly timescales or more.
 - A range of other storage technologies exist at different – and generally earlier - stages of commercialisation. These include liquid air storage, flow batteries, flywheel and gravity storage, and thermal storage technologies.
- **Interconnection** of the electricity grid to neighbouring markets enables imports of electricity when it is cheaper to do so, and provides a market for surplus generation. Currently there is 8.4 GW of interconnection capacity. Generation in neighbouring markets will also be impacted by climate and weather extremes, potentially impacting their ability to export to the UK at particular times.*

Table 2.1 sets out the characteristics of the flexibility options included in our modelling, which focuses on those options closer to market deployment.

Table 2.1
Options for flexibility in a decarbonised power system

Option	Potential to be zero-carbon?	Techno-economic modelling assumptions					Status
		Duration	Efficiency (%)	Cost in 2035 (£2012)		Financial lifetime (years)	
Unabated gas	No	Weeks-seasons	57	170 - 180	£/MWh	25	<ul style="list-style-type: none"> Mature technology, deployed at grid scale
Gas CCS	Low-carbon	Weeks-seasons	50	75 - 90		25	<ul style="list-style-type: none"> Demonstrated but not yet commercialised Several projects underway through UK Track 1 cluster

* For example, Electricity provider EDF was forced to reduce output at its nuclear power stations on the Rhône and Garonne due to river temperatures increasing during a heatwave in summer 2022. This was to comply with regulation following the 2003 heatwave in France, which ensures that the water used to cool plants does not affect wildlife when it is pumped back out. This came at a time when many of EDF's reactors were shut down for maintenance, resulting in its lowest output levels for 30 years. Nuclear output in France fell by 15% in the first six months of the year, while drought and unusually low river levels meant hydroelectricity production declined by 23%.

Hydrogen							
New Build	Yes	Weeks-seasons	55	90 - 125	£/MWh	25	<ul style="list-style-type: none"> Based on mature unabated gas technology but hydrogen versions not yet deployed at scale UK projects planned, including near industrial clusters
Retrofit	Yes	Weeks-seasons	55	65 - 100		25	
Storage							
Batteries	Yes	Minutes-hours	85	260 - 980	£/kW	15	<ul style="list-style-type: none"> Mature technology deployed at grid scale in the UK
Pumped	Yes	Hours-days	85	1290 - 1830		30	<ul style="list-style-type: none"> Mature technology deployed at grid scale in the UK
Compressed air	Yes	Hours-days	60	860 - 1420		25	<ul style="list-style-type: none"> Technology deployed overseas but not yet in the UK
Liquid air	Yes	Hours-days	60	900 - 1050		25	<ul style="list-style-type: none"> Demonstrated but not yet commercialised
Demand							
Electrolysis	Yes	Hours-seasons	78	22	£/MWh	30	<ul style="list-style-type: none"> Alkaline electrolyzers are a mature technology Proton Exchange Membrane electrolyzers have been demonstrated but not deployed commercially
Smart response	Yes	Hours	N/A				<ul style="list-style-type: none"> Smart meters and half-hourly metering planned for mid-2020s to enable smart flexibility Electric vehicles and heat pumps commercialised
Other							
Interconnection	Yes	Up to seasonal	N/A				
Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility; CCC analysis. Notes: Levelised costs include value of carbon in 2035 applied to any unabated emissions, gas price range from the Sixth Carbon Budget, and load factors consistent with the Central scenario from this report. Unabated gas and hydrogen shown for CCGT plant. Efficiency column represents plant efficiencies, and in the case of hydrogen does not reflect the efficiencies associated with the hydrogen production process (see Table 3.1). Levelised costs shown for generation technologies and capital costs for storage technologies. Storage technologies and costs not directly comparable, given different storage durations and hence system roles.							

(b) What a reliable and secure renewables-based system looks like

A renewables-based system, complemented by a suitable portfolio of low-carbon flexibility, can provide a secure and reliable supply of energy.

We consider that use of a small amount of unabated gas to ensure security of supply (up to around 2% of annual electricity production) would be cost-effective and consistent with the delivery of a decarbonised system by 2035.

A decarbonised electricity system is cost-effective and will bring wider benefits, including for energy security and economic growth.

In a typical year by 2035, variable renewables are expected to produce around 70% of generation, with other inflexible sources such as nuclear and BECCS contributing around 20%.

A renewables-based energy system in Great Britain offers low emissions by making the most of abundant natural resources. If complemented by a suitable portfolio of low-carbon flexibility options, a renewables-based system can provide a secure and reliable supply of energy. In this section, we set out the results of our analysis, demonstrating this to be true both for a normal weather year, and when testing more extreme weather scenarios, particularly around wind droughts.

We consider that use of a small amount of unabated gas (up to around 2% of annual electricity production) to ensure security of supply would be cost-effective and consistent with the delivery of a decarbonised system by 2035. A system without the use of unabated gas may be possible in 2035, but is likely to increase costs and delivery risks.

A decarbonised system such as we describe in this section is cost-effective and will bring wider benefits, including for energy security and economic growth:

- **Cost-effective.** A decarbonised system in 2035 with a small amount of unabated gas (up to around 2% of generation) is cost-effective, reflecting the low cost of renewables compared to unabated gas, with these meeting the majority of demand. Although their variability does impose costs on the wider system, these are manageable with the combination of low-carbon flexibility options, given that these only make up a relatively small proportion of generation (e.g. less than 10% over the year as a whole) and capacity.
- **Energy security.** The 2035 electricity system envisaged in this report would maintain energy security, while coping with the expected increase in electricity demands and periods of low wind. The consequent dramatic reduction in gas consumption would also cut our exposure to volatile international fossil fuel markets, with greater reliance on homegrown low-cost renewables (see Chapter 3, section 4). These conclusions have new significance following the recent period of heightened energy insecurity.
- **Economic growth.** Currently, over 31,000 people across the UK are employed in offshore wind alone – this is set to rise to 97,000 by 2030, driven by £155 billion in private investment, with further investment and employment in solar and onshore wind.³ There are opportunities for the UK to become a global leader in emerging technologies such as floating offshore wind, which is estimated to have the potential to deliver £43.6 billion in UK gross value added (GVA) by 2050.⁴ There are also opportunities for innovation, investment and employment across electricity storage, hydrogen infrastructure, smart charging of electric vehicles, flexible heating systems, electricity networks and interconnection.

(i) Running a reliable and secure renewables-based system in 2035

Demand can be met by a diverse range of solutions. The modelling illustrates that in a normal weather year, variable renewables (i.e. solar and wind) and other relatively inflexible sources (e.g. nuclear and BECCS) produce around 70% and 20% of total generation respectively, across the year as a whole.

Flexible solutions are needed for the remainder. Different solutions play different roles and no one solution will provide all the flexibility required. A portfolio approach is needed.

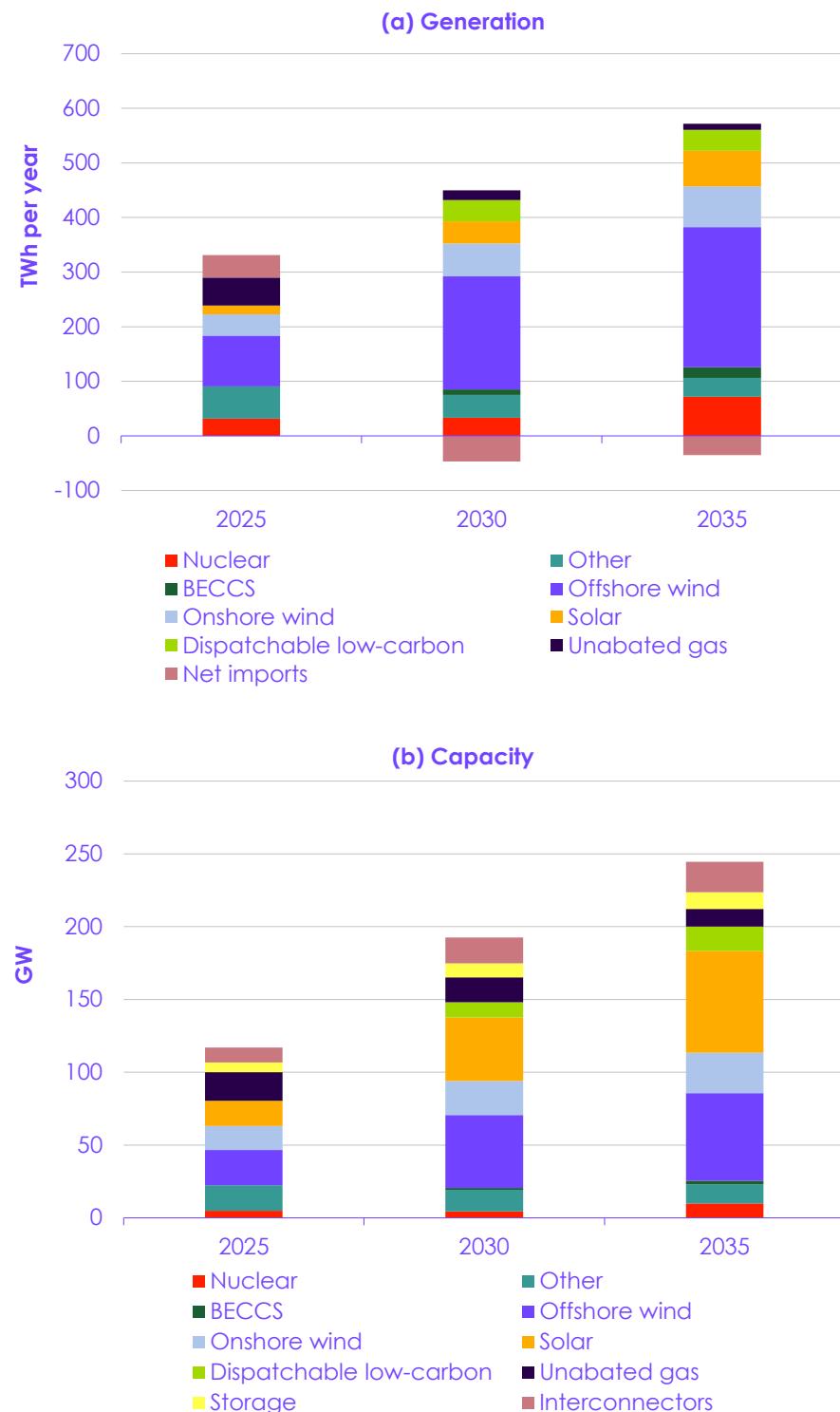
While these forms of generation can provide most of the electricity required across the year, there are times at which they need to be supplemented by low-carbon flexible solutions. Different solutions play different system roles, and no one solution provides all the flexibility that is required. A portfolio approach, relying on a range of established and emerging technologies, is therefore likely to be important.

- **On an annual basis in 2035 (Figure 2.2),** around 40 TWh of low-carbon dispatchable generation is used in the Central scenario, supported by 17 GW of dispatchable low-carbon capacity. Similar amounts are exported and used for producing electrolytic hydrogen respectively, which helps manage times of surplus.
 - Low-carbon back-up technologies provide around 40 TWh of generation in the Central scenario, within a range of 25-60 TWh across the range of scenarios used for our indicators.
 - This is made up of 30 TWh of hydrogen generation (with a range of 15-45 TWh) and 10 TWh of gas CCS (with a range of 0-20 TWh).
 - Given uncertainty over the appropriate mix of hydrogen and gas CCS generation, and the fact that these can play similar system roles, we group these technologies together as low-carbon dispatchable generation in our charts below, and for the purposes of our indicators.
 - At other times, when there is surplus generation, a similar amount of energy is used in the Central scenario and ranges for production of electrolytic hydrogen.
 - Across most scenarios GB is a net exporter of electricity, with up to 35 TWh exported in the Central scenario. A small contribution of unabated gas (up to around 2% of annual electricity production) is used to help meet peak demands, with storage and smart demand management making a similar contribution.
 - The Central scenario has 17 GW of dispatchable low-carbon capacity, with a range of 12-20 GW across the indicator scenarios.
 - Dispatchable low-carbon capacity is made up of 14 GW of hydrogen plants (with a range of 8-16 GW) and 2 GW of gas CCS plants (with a range of 0-5 GW).
 - The average build rate for new dispatchable low-carbon capacity from the late-2020s until 2035 is 1.1 GW per year in the Central scenario, with a range of 0.6-1.5 GW per year across the indicator scenarios and a peak annual build rate of 3.3 GW per year. This is within the historical peak annual build rate for unabated gas Combined Cycle Gas Turbines (CCGT) of 3.7 GW.
 - The Central scenario has 11 GW of grid storage output capacity (with a range of 10-19 GW), and 41 GWh of grid storage capacity (with a range of 30-366 GWh).*

* The output capacity of grid storage (GW) represents the maximum rate of discharge which can be achieved, while grid storage capacity represents the total amount of energy stored (GWh).

- The large range for grid storage capacity is reflective of the different technologies available, with the upper bound illustrating a scenario with use of longer-duration CAES technologies (which take advantage of the same geological structures as salt caverns, enabling large increases in the total amount of energy that can be stored).
- The average build rate for grid storage capacity is 0.5 GW per year from the late-2020s until 2035, with a range of 0.2-1.4 GW per year and a peak annual build rate of 1.5 GW. In recent Capacity Market auctions 2.3 GW of new-build battery capacity won contracts for 2023/24 and 5 GW for 2026/27. This will more than double GB battery capacity by next winter. In addition, there is around 50 GW of capacity in the pipeline.
- **On a seasonal basis in 2035 (Figure 2.3),** the generation mix reflects the pattern of demand and supply, with higher demand in winter well correlated with higher generation potential from offshore wind but also requiring increased contributions of dispatchable generation. The higher levels of generation in autumn and winter also allow for increased exports.

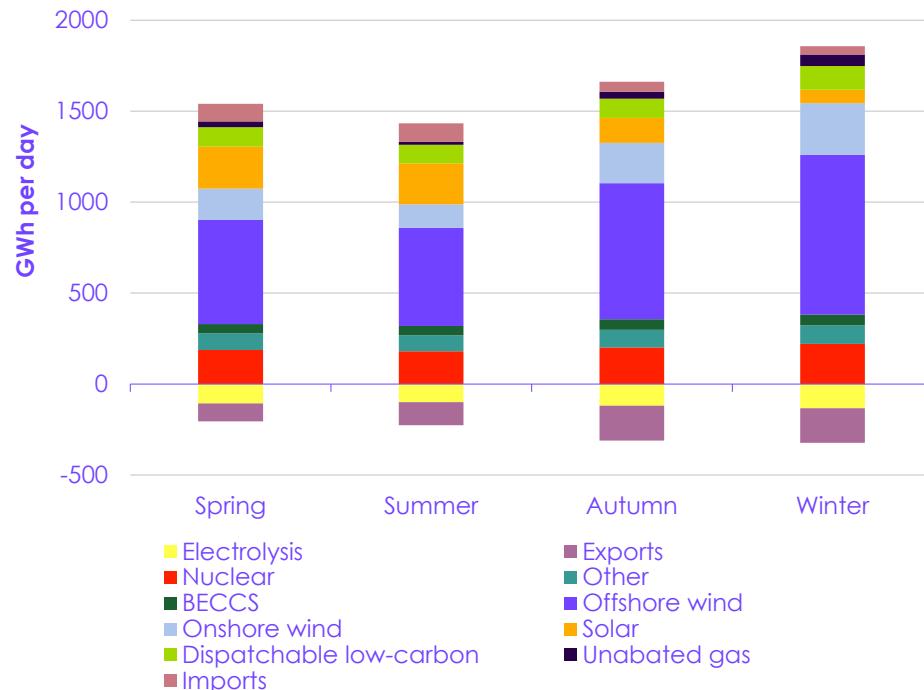
Figure 2.2 Electricity generation and capacity mix to 2035 in the Central scenario



Source: AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

Notes: Figures are before losses through the transmission and distribution system. 'Other' includes Combined Heat and Power (CHP) and unabated biomass. Dispatchable low-carbon includes gas CCS and hydrogen. Analysis is representative of a 'normal' weather year.

Figure 2.3 Seasonal generation mix in 2035 in the Central scenario



Source: AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

Notes: Figures are before losses through the transmission and distribution system. 'Other' includes Combined Heat and Power (CHP) and unabated biomass. Dispatchable low-carbon includes gas CCS and hydrogen. Chart based on 2012 weather patterns, representing a 'normal' weather year. Winter includes: January, February and December. Spring: March, April and May. Summer: June, July and August. Autumn: September, October and November.

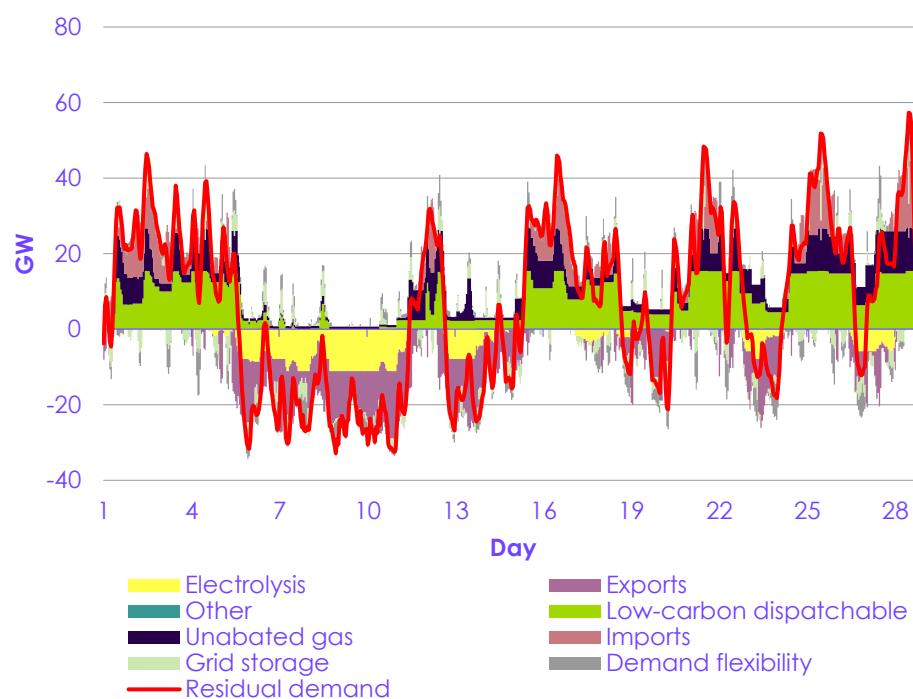
There is no need to trade-off decarbonisation, reliability and resilience. Meeting residual demand is manageable on a wide range of timescales, cost-effective and with a small amount of unabated gas at the margin in 2035 (up to around 2% of annual electricity production). A system without the use of unabated gas may be possible in 2035, but is likely to increase costs and delivery risks.

There is no need to trade-off decarbonisation, reliability and resilience. Meeting residual demand is manageable on a wide range of timescales, and cost-effective with a small amount of unabated gas at the margin in 2035 (up to around 2% of annual electricity production). A system without the use of unabated gas may be possible in 2035, but is likely to increase costs and delivery risks.

- Figure 2.4 shows hourly generation in the modelled four-week period in 2035 with the highest total of residual demand that needs to be met. Over this four-week period, demand is met through a combination of different low-carbon flexibility options and some unabated gas.
- Figure 2.5 shows hourly generation in the modelled four-week period in 2035 with the lowest total of residual demand. Over this four-week period, surplus electricity generation, shown as negative residual demand, is primarily absorbed by electrolysis for hydrogen production, grid connected storage, and exports to interconnected markets.
- Our modelling shows how low-carbon dispatchable power such as hydrogen or gas CCS, combined with storage of those gases, and occasional use of unabated gas capacity (up to around 2% of electricity production annually), can be utilised to ensure security of supply consistent with a decarbonised system. A system without the use of unabated gas may be possible in 2035, but is likely to increase costs and delivery risks. However, in the longer-term there should not be a role for unabated gas and there is more scope to sufficiently develop alternatives and address potential delivery risks.

- Under the Central scenario, around 2% of generation (10 TWh) comes from unabated gas, which is cost-effective even with the high value of carbon assumed in 2035 (i.e. around £300/tCO₂). This is achieved with around 12 GW of unabated gas plants operating at low load factors of around 10%.
- We have also explored a scenario with no unabated gas generation at all in 2035. Compared to the Central scenario, this requires an additional 11 GW of low-carbon dispatchable capacity and an additional 6 GW of storage capacity (e.g. batteries) to be installed. It would also require additional accompanying infrastructure (e.g. CO₂ transport and storage, hydrogen production). This may be possible but is likely to increase costs and delivery risks.

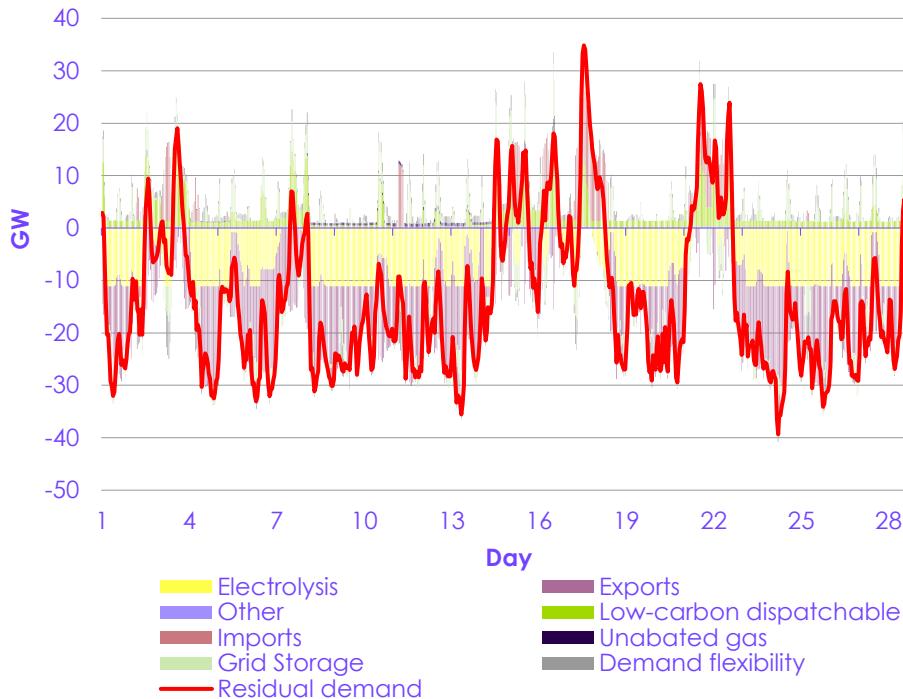
Figure 2.4 Meeting the highest four-week period of residual demand in 2035 (Central scenario)



Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility.

Notes: Residual demand is demand required to be met after taking account of generation from renewables, nuclear, BECCS, and other inflexible generation. Dispatchable low-carbon generation includes gas CCS and hydrogen. Chart based on 2012 weather patterns, representing a 'normal' weather year.

Figure 2.5 Meeting the lowest four-week period of residual demand in 2035 (Central scenario)



Source: AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

Notes: Residual demand is demand required to be met after taking account of generation from renewables, nuclear, BECCS, and other inflexible generation. Dispatchable low-carbon generation includes gas CCS and hydrogen. Chart based on 2012 weather patterns, representing a 'normal' weather year.

A decarbonised, reliable and resilient system in 2035 remains feasible even when tested by more extreme weather scenarios, particularly around wind droughts.

A decarbonised, reliable and resilient system in 2035 remains feasible even when tested by more extreme weather scenarios, particularly around wind droughts:

- Wind droughts already occur in the UK. Current evidence on the impacts of climate change on future wind suggests no significant change in energy supply in winter, when the most electricity is needed and generated. There is potential for declines in wind energy supply in other months, though there is a need for new evidence to assess these risks appropriately.
 - Winter is when most electricity is needed. It is also the season when most is generated from wind farms, and this is expected to remain the case as the climate changes. The latest available evidence on the impacts of climate change on future wind speeds concludes there is not yet strong evidence to robustly project changes in the frequency and severity of future wind variability around the UK in winter.
 - In autumn and spring there is a consistent, but small, expectation of weaker winds in future.
 - In summer, the expected declines in wind generation due to climate change are larger, although more evidence is needed.⁵

- We cannot rule out wind droughts, so we need to plan for them. As part of the modelling undertaken for this report, we have tested additional sensitivities examining the impact of reduced wind generation. One looks at the impact of a low wind year, and one looks at an extended period of low wind.
 - We have tested the impact of a low wind year, using weather patterns from 2010, which is judged to have been a 1-in-50 low wind year.
 - We have also tested a scenario of an extended 30-day period of wind drought. This scenario builds on the low wind year and looked over the period 2009-2019 to combine the 30-day period of highest residual demand with the 30-day period of lowest wind load factors. This is designed to test a more extreme scenario* and does not have a historical precedent, but effective resilience planning requires considering potential impacts outside the historical record.
- The analysis shows when optimising the system around a low wind year, similar levels of unabated gas capacity and use are seen as in the Central scenario, representing around 2% of generation served by 11 GW of capacity. When optimising the system around an extreme extended wind drought, higher levels of unabated gas generation (3% of total generation) and capacity (25 GW) are required in the model to maintain security of supply. Both scenarios also build some additional dispatchable low-carbon capacity beyond the Central scenario (3 and 5 GW respectively).

When optimising the system around a low wind year, unabated gas use remains around 2% of generation supported by 3 GW of additional dispatchable low-carbon capacity. Levels were shown to be only slightly higher in the case of a very extreme wind drought.

There remains a decision for Government around security of supply and how much allowance to build into the system to account for uncertainties around future weather. Further work is needed to determine this.

The broad alignment between the required unabated gas capacity suggested by our modelling to 2035, and the capacity already expected to be on the system, reinforces the importance of ensuring new capacity is future-proofed as soon as possible.

There remains a decision for Government around security of supply and how much allowance to build into the system to account for uncertainties around future weather. That our low-wind sensitivities build more overall capacity than the Central scenario suggests some potential for less secure supply were only the capacities in the Central scenario available. Recent work by National Grid confirms security of supply for a decarbonised system can be met even in extreme cases with a portfolio of low-carbon options,⁶ but further work is needed to determine what reasonable allowance should be made for weather extremes.

Nevertheless, the broad alignment between the required unabated gas capacity suggested by our modelling to 2035, and the capacity already expected to be on the system (Figure 2.6),[†] reinforces the importance of ensuring new capacity is future-proofed as soon as possible.

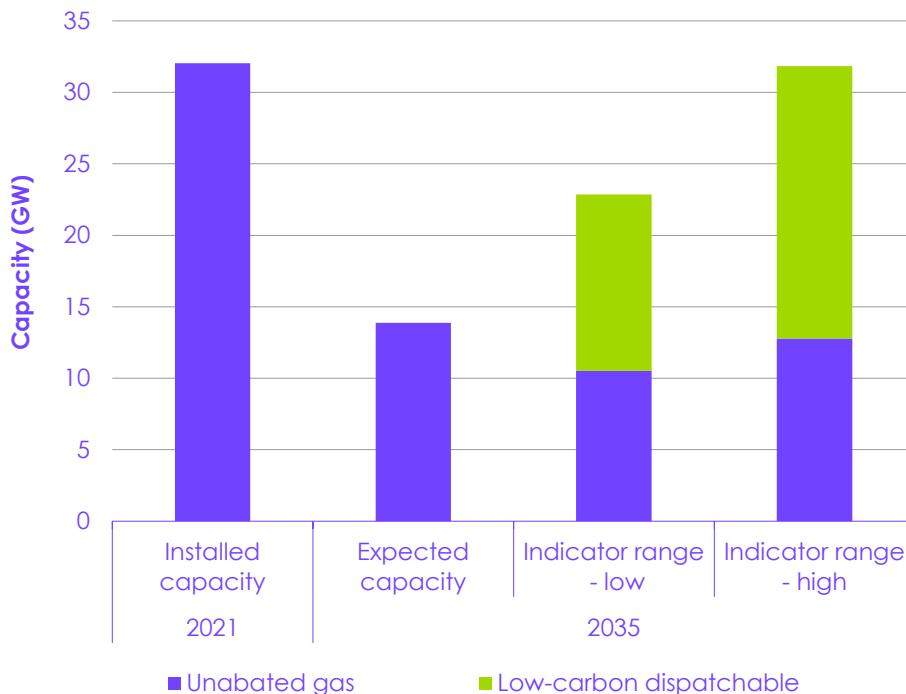
As part of our Sixth Carbon Budget advice, we recommended that new gas plants be made properly CCS- and/or hydrogen-ready as soon as possible and by 2025 at the latest.

Government intends to publish a consultation on updated Decarbonisation Readiness proposals shortly which would require new-build and substantially refurbished combustion power plants to be built in such a way that they can easily decarbonise by converting to either hydrogen generation or carbon capture within the plant's lifetime.

* For example, in comparison, a recent study for National Grid testing weather extremes in a decarbonised system found no 'critically tight periods' beyond six days duration in 2035.

[†] Comprising existing capacity still expected to be on the system by 2035, plus planned capacity with approval.

Figure 2.6 Unabated gas capacity to 2035



Source: BEIS (2022) Digest of UK Energy Statistics; National Grid (2023) Transmission Entry Capacity (TEC) Register; CCC analysis; AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility.

Notes: Expected unabated gas capacity has been determined by considering the lifetime of all existing and future plants with approval. We have assumed that plants in operation after 2030 and located near to an industrial cluster will have opportunities to be converted to hydrogen. Analysis only considers major power producers (companies whose prime purpose is the generation of electricity). The low and high indicator ranges have been taken from the AFRY Grid Storage sensitivity and High scenario, respectively. Low-carbon dispatchable capacity includes new-build gas CCS and hydrogen, plus conversion of some existing gas CCGT to hydrogen CCGT.

Recommendation	Owner (timing)
Ensure new gas plants are genuinely CCS- and/or hydrogen-ready as soon as possible and by 2025 at the latest.	DESNZ (2025 at the latest)

(ii) Planning appropriately to account for weather-related uncertainty

In order to ensure a decarbonised electricity system can be made secure and robust to weather risks, system planning will need to consider geographic diversity in supply, building the evidence base on risks, and stress-testing. System design must plan for the range of climate hazards that will face the energy system over its lifetime.

The modelling for this report has illustrated how a decarbonised system in 2035 can be made secure and robust to weather risks through a portfolio of low-carbon flexibility options, including dispatchable plants, smart demand management, storage and interconnection, alongside a small amount of unabated gas.

The following approaches will need to form part of system planning, in order to deliver these outcomes:

- **Increasing geographical diversity:** The more diverse the source of supply, the lower the proportional impact of any single failure. Increasing geographical diversity, particularly in meeting Government commitments to increase offshore capacity, can help to manage the impact of regional wind droughts.

A recent study by Regen found that balancing offshore wind capacity between east and west coasts offers multiple benefits, including more consistency and reduced variability of total available GB generation, with no reduction in total energy generation (yield) per year.⁷

- **Building the evidence base:** Further research on the impacts of climate change on future wind speeds and the seasonal change of wind speeds would enable a better understanding of what further adaptation action might be needed to prepare for wind-related impacts. National Grid ESO has recognised the importance of new datasets to understand risks due to weather patterns and ensure adequacy in a fully decarbonised system with high levels of weather-dependent generation.⁸
- **Stress testing:**
 - In order to maximise resilience, understanding of future weather-related extremes needs to be factored into decisions on future energy system design. System operators can stress-test future supply using credible examples of observed low-wind conditions and up-to-date evidence on future climate impacts on wind.
 - A recent project between the Met Office, the National Infrastructure Commission and the CCC has developed a dataset of adverse weather scenarios, presenting a range of possible extreme events and the effects of future climate change.⁹ These present a set of extreme events that can be used to stress test the resilience of a future highly renewable system to extreme weather and climate conditions.

Recommendation	Owner (timing)
<p>Ensure that future system design explicitly plans for the range of climate hazards that will face the energy system over its lifetime. This includes those hazards expected with high confidence (such as higher temperatures, reduced water availability and flooding) in addition to low-likelihood high-impact scenarios (such as more frequent and severe wind droughts and storminess). Planning should include consideration of concurrent hazards and hazards with the potential to impact multiple interconnected countries simultaneously.</p>	DESNZ, Ofgem, FSO (ongoing)

The objective for Government is now to ensure that all aspects of the power transition are delivered at the speed and scale necessary to ensure a secure and decarbonised system by 2035. That includes the bulk zero-carbon capacity (i.e. renewables and nuclear) the Government has committed to, as well as a portfolio of low-carbon flexibility solutions and the required enabling conditions such as sufficient network capacity.

3. Facilitating delivery and addressing risks

The scale of build required, when taken across the range of system components, is unprecedented. A decarbonised power system by 2035 is achievable, but it requires that barriers to swift deployment of critical infrastructure are removed, and policy gaps remedied.

The scale of build required, when taken across the range of system components, is unprecedented. A decarbonised power system by 2035 is achievable, but it will require removal of barriers to the swift deployment of critical infrastructure, and policy gaps to be remedied.

While many of the scenarios modelled for this report take the levels of renewable and nuclear deployment set out in the ESS as their starting point, achieving this alongside the flexibility required is a very significant undertaking. It will require a concerted push in a wide range of areas, alongside rapid action to address barriers, if the required pace is to be achieved.

- As set out in Chapter 1, the Government plans to increase offshore wind capacity by four times over current levels by 2030, and solar by five times by 2035. While this implies a build rate for solar close to the historical peak, for offshore wind it implies annual build rates around 40% higher than emerging data on the 2022 peak.
- On nuclear, Government has ambitions to dramatically increase investment relative to historical levels. Where it is not feasible to deliver on these ambitions, additional generation would be required from a combination of other low-carbon sources.
- Our scenarios envisage a strong role for demand-side response, both through transport demand shifting and heat demand shifting, which will require sufficient consumer engagement and uptake, facilitated by smart technology and appropriate price signals.
- As stated in Chapter 2, the required build rates for new dispatchable low-carbon capacity (gas CCS or hydrogen) are projected to remain within the bounds of historical peak annual build rates for unabated gas CCGT, but are reliant on immature technologies.

CCS is a necessity for delivering a decarbonised power system by 2035 (whether in post-combustion power plants or blue hydrogen production), for engineered greenhouse gas removals and for the delivery of Net Zero more broadly. However, it has yet to be delivered at scale in the UK. In our 2022 Progress Report to Parliament we noted Government ambitions to deliver CCS have been subject to repeated cancellations and delays. Low-carbon hydrogen production and storage, and hydrogen-fuelled generation have also yet to be delivered at significant commercial scale.

Alongside this, the challenge of delivering the network and storage infrastructure required to support a decarbonised system will be very significant, with build required for the transport and storage of electricity, hydrogen and CO₂.

Due to the scale and complexity of the task, and the inherent interdependencies, this can only be achieved through a co-ordinated and strategic approach to delivery, with appropriate oversight. The Government must urgently publish a strategy for the delivery of a decarbonised, resilient power system by 2035.

Due to the scale and complexity of the task, and the inherent interdependencies, delivery of a decarbonised resilient power system by 2035 can only be achieved through a co-ordinated and strategic approach to delivery, with appropriate oversight.

The Government has not yet provided a coherent strategy to achieve its goal nor provided essential details on how it will encourage the necessary investment and infrastructure to be deployed over the next 12 years. This is urgently needed.

- In 2020, as part of our Sixth Carbon Budget advice, and in our subsequent Progress Reports to Parliament, we have recommended Government develop a long-term strategy for the phase out of unabated gas and the delivery of a decarbonised electricity system by 2035.
- The need for this has been echoed by the National Audit Office (NAO) who have identified the risks associated with a lack of a delivery plan. The NAO has also noted the need for management of performance and risks to be better joined up and aggregated across DESNZ's energy portfolio (noting there are seven teams across three top-level groups responsible for decarbonising the power sector).¹⁰

Recommendation	Owner (timing)
Publish a comprehensive long-term strategy for the delivery of a decarbonised, resilient, power system by 2035. This should comprise a portfolio approach to developing the full range of low-carbon flexibility options, including demand flexibility, storage, hydrogen, gas CCS and interconnection capacity. It should set out how the low-carbon flexibility required to replace unabated gas will be delivered (12-20 GW of low-carbon dispatchable capacity by 2035), as well as clarifying any minimal residual role unabated gas is expected to play by 2035 (up to around 2% of annual electricity production) and the strategy for unabated gas phase out. It must set out plans and contingencies for addressing key risks on a co-ordinated basis (e.g. network development and connections, planning and consenting, CCS, hydrogen and nuclear).	DESNZ (2023)

The planning and delivery of the very significant network infrastructure needed, alongside the necessary reforms to market design to mobilise investment and to drive efficient operation of the system, remain among the most significant challenges faced for delivery.

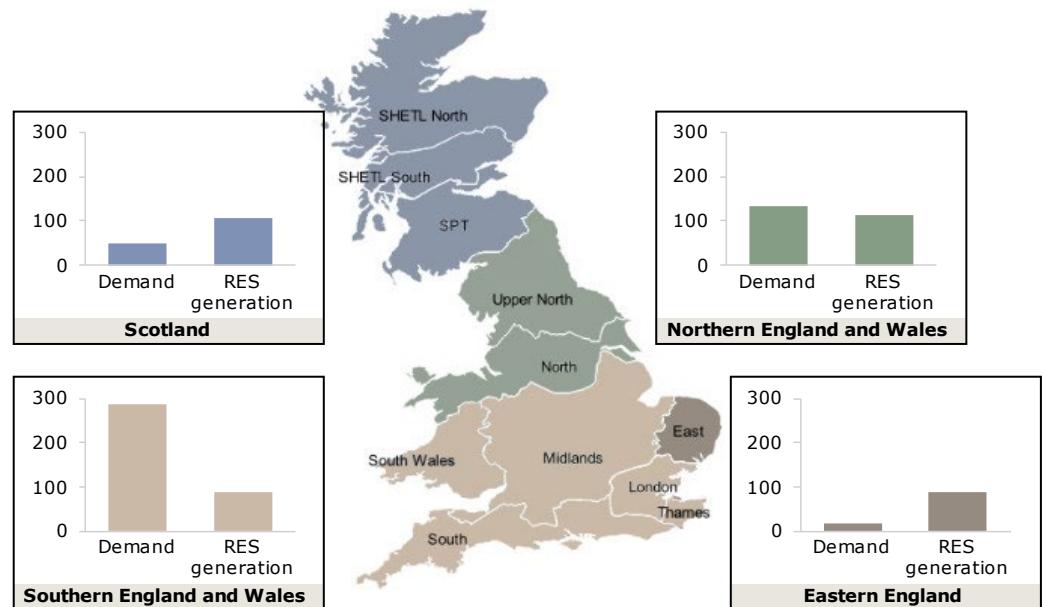
(a) Network and system planning

(i) Electricity network needs

As we move to an increasingly renewables-based system, growing quantities of generation are expected to be located further from centres of demand (Figure 2.7).

Where there is insufficient network capacity to transport this generation, there is a risk of wasted supply (or less-efficient use of that supply where it must be diverted into energy storage with associated efficiency losses), and increased costs and/or emissions where additional generation is required closer to the demand source.

Figure 2.7 GB regional annual demand and RES generation (TWh) in 2035



Source: Central scenario, AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.
 Notes: 2012 weather patterns were used in this analysis. Total power demands for England, Scotland and Wales based on CCC analysis, and divided among the respective zones using the current demand split, with additional demand from electrolyzers an output of modelling. Regarding supply, existing capacity allocated in line with current deployment, with additional renewable deployment informed by planned capacity, repowering of existing sites and potential further development of current locations. Renewable generation profiles for plants in each energy zone, local wind variability and speed. Nuclear deployment agreed in discussion with CCC. Location of remaining capacity subject to optimisation, taking into account constraint management, TNUoS cost and other relevant factors.

Very large investments in network capacity are expected to be needed to support the transition.

The analysis undertaken for this report, and work by others such as National Grid Electricity System Operator (ESO) in its Pathway to 2030, illustrate the need for very large investment in transmission network capacity as we transition to a resilient decarbonised system. Significant distribution network investment is expected to be needed alongside this.

- The modelling undertaken for this report considered the transmission-level network needs associated with the scenarios.
 - Planning and identification of transmission investment needs involves splitting the UK transmission system into ‘zones’, with the boundaries between these zones reflective of where the main bottlenecks lie. These change over time as the network is reinforced and network users’ needs change.
 - A number of boundaries have been identified by the ESO as being particularly critical to the facilitation of a decarbonised electricity system by 2035. The network’s capability to transfer power across these boundaries, relative to future need, has been assessed in the analysis we commissioned from AFRY.*

* Boundaries assessed in modelling undertaken by AFRY based on 2021 Network Options Assessment. While capacity can be defined as the physical MW capacity of the asset, boundary capability is defined as the maximum MW flow that can be transferred across a boundary while maintaining compliance with the National Electricity Transmission System Security and Quality of Supply Standards. Limiting factors on transmission capacity include thermal circuit ratings, voltage constraints and dynamic stability.

- The analysis used assumed costs of reinforcement. An optimisation was then undertaken, considering generation dispatch, network utilisation, alternative energy transport solutions (such as electrolysis / transport / storage of hydrogen via pipelines, charging power storage technologies, and a degree of renewable curtailment) and network reinforcement.
- The modelling undertaken for this report found that in order to facilitate the delivery of the decarbonised system, all the electricity transmission network boundaries examined would be expected to require some level of reinforcement, with an average doubling of their capability required between 2025 and 2035 (Table 2.2).*
 - The disproportionately large growth in network capacity, relative to the growth in demand (a 50% increase by 2035) is driven largely by the geographical disparities between supply and demand.
 - Increased temperatures, not factored into the network modelling, would require even greater strengthening of network capacity.
- The scale of transmission reinforcement needs continues to be assessed by National Grid amongst others, who have stated that, in order to support the Government target of 50 GW of offshore wind by 2030, in the next seven years it will have to install more than five times the amount of transmission infrastructure in England and Wales than has been built in the last 30 years.¹¹ The requirements in Scotland will add to this further.
- While the modelling undertaken for this report focuses on transmission needs, distribution networks will need reinforcement alongside this. Growth in demand, driven in particular by the electrification of transport and heat, will lead to a need for significant distribution network investment. The scale remains uncertain in the context of data limitations around low voltage network utilisation, and decisions yet to be taken on the decarbonisation of home heating, but Government figures (calculated prior to publication of the Energy Security Strategy) put the potential investment required by 2050 at between £60-180 billion.¹² Engagement with Distributed Network Operators (DNOs) undertaken for our Sixth Carbon Budget advice highlighted the importance of strategic planning and co-ordination if the required build is to be achieved.¹³

* While the modelling assesses an approximately optimal level of capacity required in each year (tracking growth in demand and supply), in reality the number of upgrades should be minimised, future-proofing in anticipation of future needs.

Table 2.2

GB transmission network reinforcement by zone in Central scenario (GW)

Boundary	2022	2025	2028	2030	2035
B2	3.3	3.8	4.5	6.0	6.9
B4	3.4	4.3	4.7	6.5	11.5
B6	6.3	7.7	10.7	12.7	14.5
B7a	9.7	10.5	11.2	13.2	18.2
B8	11.1	13.0	14.5	16.5	21.0
EC5	3.4	3.5	12.5	16.0	20.7
LE1	9.7	9.7	10.5	12.0	14.1
SC1	3.2	6.1	8.5	10.0	15.0
SC3	7.3	6.7	7.4	7.4	7.4
SW1	3.0	2.9	2.9	2.9	4.7
Total	60.3	68.2	87.4	103.2	134.0

Source: Central scenario, AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*.

The scale of investment required at both transmission and distribution level has the potential to be minimised where the locations of demand and generation can be optimised, and where full use is made of flexible solutions, facilitated by well-designed market mechanisms. However, the scope for optimising will necessarily be constrained by wider considerations.

- Decisions on the location of generation developments will impact the level of transmission investment required. However, these decisions are a function of a wide range of factors including planning, generation potential and geographical diversity in the case of wind (key for helping to manage the impact of regional wind droughts).
- Flexibility of demand and distributed resources such as local-scale generation and storage can, depending on the precise location, lead to a reduced need for distribution network reinforcement.
- Both generation and network capacity need to be practically deliverable in the timescales required to meet the 2035 target and accommodate further growth in electricity demand, not just theoretically optimal. This is likely to place constraints on location of generation and the nature of network reinforcement.

(ii) The role for strategic investment and planning

Strategic investment will be key to timely and cost-effective delivery. The network should be designed and built anticipating major new sources of generation and demand to 2050.

Strategic investment will be key to timely and cost-effective delivery. The network should be designed and built anticipating major new sources of generation and demand to 2050.

- We have previously advised that the cost of upgrading distribution networks is relatively insensitive to the size of the capacity increase as most of the cost is in the civil works rather than the equipment (e.g. larger cables).
- At transmission level too, there is scope to maximise efficiency and minimise costs and disruption where networks can be future-proofed on the basis of anticipated future needs, avoiding the need for repeated upgrades.
- Wherever possible, when grid capacity is increased this should be to a level sufficient to avoid having to upgrade the capacity again prior to 2050.

Strategic planning and investment must also ensure that infrastructure is resilient to the changing climate.

Strategic planning and investment must have a view to both delivering the infrastructure required to meet our climate change targets and ensuring that infrastructure is resilient to the changing climate.

- While IT, protection and control equipment used on the network may typically only have a 10-year life, most network assets should last 40-60 years. This means that the investments in the transmission network expansion and upgrades to the distribution network required in the next few years will likely be in use through to 2050 and beyond.
- Climate hazards will pose an increasing risk to network infrastructure over the coming decades, with heatwaves giving rise to reductions in electricity network thermal ratings (the capacity to carry power), and hazards such as flooding and high winds capable of causing losses in network capacity. These risks are discussed further in Chapter 4.
- Given the scale of network build required, mitigation and adaptation needs must be considered holistically in strategic planning and investment.

There is a need for the institutional responsibilities of the FSO, Ofgem and Ministers to be formalised in these areas and more broadly, clearly delineating respective roles in the strategic planning and delivery of a decarbonised, resilient system.

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- It is important Ofgem and the FSO have formalised responsibilities in respect of the statutory Net Zero target, and ensuring climate and weather resilience, to ensure these outcomes can be prioritised accordingly.
- We set out above that due to the scale and complexity of the task, and the inherent interdependencies, a decarbonised power system can only be achieved through a co-ordinated and strategic approach to delivery. This includes ensuring clear respective roles in delivery for the Government, Ofgem and the FSO.
- Careful system-level and asset-level planning and design will be needed from the outset. The Government must take on the role of designing the overall system or delegate clearly to another body with the powers and capacity to do so.

- Future System Operator (FSO) roles have yet to be finalised, but areas identified for potential future roles and functions include hydrogen, CCUS, and heat decarbonisation amongst others.¹⁴ This report demonstrates the clear value in having an integrated view across electricity, gas and hydrogen sectors given interdependencies. We set out later in this section the value of a cross-sectoral perspective, which accommodates CO₂ and heat networks in addition.

Recommendation	Owner (timing)
<p>Clarify urgently and formalise the institutional responsibilities of the FSO, Ofgem and Ministers, for strategic planning and delivery of a decarbonised, resilient energy system. As part of this, Ofgem's objectives and duties must be updated to drive explicitly the delivery of the statutory Net Zero target, and to ensure climate and weather resilience. In addition to its Net Zero objective, the FSO must have responsibility for ensuring weather and climate resilience through its strategic planning role. The critical role of strategic investment in delivering these outcomes must be recognised, with appropriate mandates and powers for Ofgem and the FSO. The formalisation of responsibilities should be implemented through the Energy Bill and revisions to the Strategy and Policy Statement. As part of the phased approach to the implementation of the FSO, expanding the remit with respect to hydrogen should be considered as a priority.</p>	DESNZ (2023)

A range of work is ongoing to identify strategic investment needs. Ofgem, DESNZ, the ESO and the network owners have been working on processes to identify the key transmission network developments needed and inform a 'Centralised Strategic Network Plan' (CSNP), building on the 'Holistic Network Plan' (HND) and the 'Network Options Assessment' (NOA) process. There are currently challenges in identifying transmission network development needs with the level of precision needed to define projects and advance them in a timely manner. These must be overcome, with the CSNP giving sufficient foresight and confidence in needs, such that development projects can be rapidly advanced.

Recommendation	Owner (timing)
<p>Publish the second transitional Centralised Strategic Network Plan, identifying the strategic investments required for a decarbonised and resilient electricity system in 2035 and delivery of Net Zero. Provide a robust treatment of uncertainty and sufficient, clear information for network development projects to be advanced in a timely manner. Ensure such projects are designed to be resilient to a changing climate.</p>	ESO/FSO (2023)

In addition to ongoing electricity network strategic planning, we strongly support the call made in the Mission Zero review for a long-term cross-sectoral infrastructure strategy, which should be delivered by 2025 at the latest.

In addition to ongoing electricity network strategic planning, we strongly support the call made in the Mission Zero review for a long-term cross-sectoral infrastructure strategy. This should be delivered by 2025 at the latest, following the second National Infrastructure Assessment (planned for 2023), and drawing on the advice of the FSO (planned to be established by 2024).

- We consider it important that the scope should be extended to cover heat networks, given the interactions with decisions on electricity and hydrogen infrastructure which will be needed for heat decarbonisation.
- In addition to being critical to timely delivery, a coordinated plan across liquid and gaseous fuels, electricity, CO₂ and heat networks has potential to drive significant efficiency savings. For instance, where streets only need be dug once for the purposes of multiple co-ordinated infrastructure upgrades.

A key early aim should be to inform and narrow the space for future decisions on hydrogen use, by identifying which areas are unlikely to be suitable for hydrogen (enabling electrification to be progressed), alongside the identification of potential candidate areas for hydrogen. This should be used to inform a set of low-regret investments that can proceed immediately.

- This assessment should be on a whole-system basis (considering liquid and gaseous fuels, electricity, CO₂ and heat networks) and looking across economy-wide decarbonisation needs (including buildings, industry and transport).
- Building on our previous recommendations, a key early aim of this strategy process – published by 2024 at the latest (either prior to, or as part of publication of the strategy as a whole) – must be to inform and narrow the space for future decisions on hydrogen use and identify low-regrets hydrogen and electricity infrastructure development.
 - This should include identification of areas that are unlikely to be suitable for hydrogen, such that electrification and other alternatives can be progressed, alongside the identification of potential candidate areas for hydrogen.
 - It should include consideration of hydrogen infrastructure developments, such as on storage and transmission, that are low-regret regardless of subsequent decisions on use of hydrogen for buildings heat.
 - This should be used to inform a set of low-regret hydrogen and electricity infrastructure investments that can proceed immediately.

Recommendation	Owner (timing)
<p>Develop a long-term cross-sectoral infrastructure strategy to adapt and build respectively the distribution of liquid and gaseous fuels, electricity, CO₂ and heat networks over the next decade. This should be led by DESNZ, drawing on the advice of the FSO and building on the findings of the forthcoming National Infrastructure Assessment. It must have a view to facilitating Net Zero while ensuring climate and weather resilience. A key aim should be to inform and narrow the decision space for future decisions on hydrogen use.</p>	DESNZ, FSO (by 2025 at the latest)
<p>Identify a set of low-regret electricity and hydrogen investments that can proceed now. Either prior to, or as part of publication of the cross-sectoral infrastructure strategy, identify on a whole system and economy-wide basis which areas are unlikely to be suitable for hydrogen (such that electrification and alternatives can be progressed), alongside potential candidate areas for hydrogen. This should be used to inform a set of low-regret investments that can proceed immediately.</p>	DESNZ, FSO (by 2024 at the latest)

(iii) Expediting build

A number of processes – including planning, consenting and connections – must be urgently reformed to deploy infrastructure at sufficient speed. A wide number of enabling initiatives are already in train, but their criticality necessitates effective oversight. We consider a Minister-led delivery group would best support timely progress.

A number of processes – including planning, consenting and connections – must be urgently reformed to deploy infrastructure at sufficient speed to deliver the required range of system components by 2035. Infrastructure build rates, both for generation and network capacity, will need to exceed what has been achieved historically in a number of areas and represent large increases relative to today. Given the level of investment needed, we must not miss the opportunity to build in system- and asset-level resilience from the start. Reformed processes must ensure infrastructure is built to be resilient to the changes in UK weather (including flood risks and heat extremes) that will occur over its lifetime.

The Electricity Networks Commissioner, appointed by BEIS, has been tasked with finding ways of speeding up the delivery of new transmission network capacity and is considering the whole process from identification of need, to acquisition of planning consents and procurement, construction and commissioning.

Given that there are separate consenting and planning regimes for electricity infrastructure in Scotland, and in England and Wales, a key part of this role will be co-ordinating effectively between UK and devolved administrations.

A wide number of enabling initiatives are already in train. However, their criticality necessitates effective oversight and commitment to implementation if timelines are to be met. We consider a Minister-led delivery group, with the Electricity Networks Commissioner in an advisory role, would best support timely progress.

Recommendation	Owner (timing)
<p>Create a Minister-led infrastructure delivery group, advised by the new Electricity Networks Commissioner, to ensure enabling initiatives for energy infrastructure build are taken forward at pace, and necessary policy changes are implemented across the UK, to deliver a decarbonised and resilient power system by 2035. This should bring together key senior parties in DESNZ, Ofgem, Defra, DLUHC, the Scottish and Welsh Governments, the FSO and asset owners, to deliver necessary policy changes and monitor progress across the initiatives so that swift action can be taken where required to expedite progress. Priorities include overhauling planning and consenting (with strategically important projects prioritised); adequately resourcing regulatory, planning and environmental consenting bodies; reforming the connections process; driving strategic investment; and ensuring the necessary strategic planning and skills/supply chain development is taking place.</p>	Electricity Networks Commissioner, UK, Scottish, and Welsh Governments (2023)

(b) Market reform

Decarbonising the power sector by 2035 – and realising the benefits of cleaner, cheaper power - will bring challenges which current market arrangements and policy are not designed for.

Decarbonising the power sector by 2035 – and realising the benefits of cleaner, cheaper power - will bring challenges which current market arrangements and policy are not designed for, including:

- Changing cost structures, towards assets with high capital costs and low marginal costs.
- The need to encourage and reward system flexibility, through both supply and demand sides.
- The need to phase out unabated gas, subject to security of supply (with any remaining unabated gas plants operating at very low load factors, raising questions around appropriate frameworks for cost recovery).

The case for decarbonisation, and for market reform to enable consumers to realise the benefits of it, has been strengthened further over the past year in the context of Russia's war in Ukraine and the current affordability challenge.

The Government published its first consultation on the Review of Electricity Market Arrangements (REMA) in 2022, setting out the case for change and an initial assessment of the options.

In its advisory role to Government, the CCC convened a high-level Expert Group on market reform, to feed into the REMA consultation.¹⁵ The Group identified the following priority areas for REMA against the key challenges identified:

- **Incentivising low-carbon investment:** Contracts for Difference should be retained but evolved to reduce dispatch distortions.
- **Security of supply:** Changes to the Capacity Market will be needed to address the energy duration challenge, not just peak capacity adequacy, and to phase-out non-low-carbon solutions.

- **Operating a low-carbon electricity system:** The energy mismatch (extended shortfalls in some periods, excess supply in others) needs to be addressed, with more accurate market signals for curtailment.
- **Locational signals:** There is a case for stronger locational signals in the wholesale market to improve dispatch efficiency, and potentially to strengthen investment signals. The appropriate level of locational granularity needs to weigh up the benefits, against the degree of market disruption and whether other mechanisms can achieve similar outcomes, particularly in investment timeframes.
- **Whole-system coordination:** Changes in the wholesale market must take into account potential changes in governance arrangements for the distribution system and emergence of markets at the distribution level.
- **Customers and affordability:** Market design needs to unlock flexibility from small-scale assets through effective customer engagement. Any market reform should aim to improve affordability through efficient signals, maximising competition and promoting transparency.

Key conclusions of the Expert Group were that:

- Current policies are not sufficient alone to meet the challenges identified for fully decarbonising electricity generation and delivering Net Zero.
- The biggest challenge for the 2020s will be mobilising the huge investment needed in low-carbon generation, storage and networks; with the biggest challenge for the 2030s being the efficient operation of the decarbonised electricity system (with a much more dynamic demand-side).
- In order to avoid an investment hiatus, an evolutionary approach is needed in the near term (2020s), with any more fundamental reforms, such as full locational marginal pricing and centralised dispatch, considered for the 2030s.

It is important that the new regulations, incentives and business models required are put in place with urgency to enable the necessary investment decisions to be taken on a timely basis and at the appropriate scale.

It is notable that since the group was convened, the investment climate is reported to have become even more challenging as a result of inflationary pressures driven by Russia's war in Ukraine, and competition for finance driven by the US Inflation Reduction Act and EU Green Deal Industrial Plan. Alongside the successful, timely and cost-effective delivery of a reliable and resilient decarbonised system, market reform should look to maximise economic opportunities; ensure fair access to and affordability of energy; support regional development; and provide appropriate protection for natural capital and ecosystem services. It is important that the new regulations, incentives and business models required are put in place with urgency to enable the necessary investment decisions to be taken on a timely basis and at the appropriate scale. Regulatory frameworks and market design must be fit for purpose and capable of galvanising the £300-430 billion of investment required and the supporting supply chains.¹⁶

Recommendation	Owner (timing)
Through the Review of Electricity Market Arrangements, develop a strategy as soon as possible on market design for the medium- to long-term for a fully decarbonised, resilient electricity system in the 2030s and onwards. It is essential that in introducing changes to market arrangements, this is done in a way that does not deter the investment required to deliver a decarbonised system by 2035.	DESNZ (2023)

4. Indicators for measuring progress

We have developed a provisional set of indicators against which we plan to monitor progress towards 2035, with ranges to reflect uncertainty. We will be keeping the set of indicators under review, including considering any other areas where future indicators may be needed.

We have set out below a provisional set of indicators against which we plan to monitor progress towards 2035 (Table 2.3).

The range in these indicators reflects a subset of the scenarios and sensitivities modelled for the purposes of this report, selected with a view to reflecting the range of outcomes which might be achieved pending uncertainty. This includes uncertainty around:

- Future demand;
- Policy choices (e.g. different uses for biomass, the use of hydrogen across the economy);
- Technology (e.g. potential for hydrogen conversion of existing gas plants);
- Market developments (e.g. progress in renewable and nuclear build, the balance between hydrogen and gas CCS in low-carbon dispatchable power; and
- Weather/security of supply considerations (e.g. low wind).

Where ranges are quoted throughout this report, they reflect these scenarios and sensitivities unless otherwise stated. We will be keeping the set of indicators under review, including considering how best to monitor progress in the context of the indicator ranges, and considering any other areas where future indicators may be needed (e.g. in relation to network build).

Indicators relating to hydrogen production and storage, and CCS are set out at the end of Chapter 3. Indicators for climate resilience will be discussed in the energy chapter of our upcoming Adaptation Progress Report to Parliament in March 2023.

The most up-to-date list of indicators will remain visible in our published monitoring framework.¹⁷

Table 2.3

Indicators for low-carbon flexibility to 2035

Indicator	Unit	2025	2028	2030	2035
Unabated gas share of generation	%	18 - 23	4 - 7	4 - 5	1 - 2
Dispatchable low-carbon capacity					
In operation	GW	0	3 - 6	9 - 13	12 - 20
Under construction	GW	3 - 6	7 - 8	2 - 4	2 - 8
In development	GW	8 - 11	2 - 5	3 - 7	2 - 7
Grid storage					
Output capacity	GW	7	8 - 9	10 - 11	10 - 19
Capacity	GWh	24	26 - 100	30 - 159	30 - 366
Other					
Active demand response as share of total demand	%	1	2 - 3	3 - 4	4 - 5

Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility.

Endnotes

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Chapter 3

Implications for hydrogen production, use and infrastructure

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Introduction

Hydrogen has a crucial role to play in decarbonisation of the energy system. It will be needed for hard-to-decarbonise sectors such as industry and shipping and is expected to have a role in power generation (as discussed in previous chapters) although the scale of this remains uncertain.

In this chapter, we build on the analytical findings of previous chapters, examining what hydrogen demands in a future system could look like across power and non-power uses, and the range of ways those demands can be met.

We will then consider what this implies for the infrastructure required to transport and store hydrogen.

We present a range of indicators for monitoring hydrogen production and storage progress towards the 2035 objective, which will be used as part of our annual reporting to Parliament.

This chapter is set out in five sections:

1. Hydrogen demands in a future energy system
2. Implications for hydrogen supply
3. Hydrogen infrastructure
4. Implications for fossil fuel consumption
5. Indicators for monitoring progress

1. Hydrogen demands in the future energy system

In this report, we consider the role of hydrogen not only in the electricity sector, but also the demand for hydrogen from across the economy, and how those demands can be met.

Hydrogen is likely to have a number of roles in the future energy system; decarbonising applications that cannot be easily electrified and helping to manage the power system.

Hydrogen is likely to have a number of roles in the future energy system:

- Decarbonising applications that cannot be easily electrified.
- Decarbonising at least some current industrial gas combined heat and power (CHP) plants, providing low levels of power generation.
- Providing flexibility in the power sector to store excess power and generate on-demand to back up variable renewables.

The latter two roles are represented as outputs of the modelling AFRY has undertaken for this report. Non-power demands for hydrogen were provided by the CCC as an input to the modelling (based on Sixth Carbon Budget scenarios), enabling simultaneous optimisation of the power and hydrogen production and storage systems. Before stepping through the findings of this work, we set out below the hydrogen production and storage assumptions used by AFRY in their modelling (Table 3.1).

Table 3.1

Options for hydrogen in a decarbonised power system

Option	Potential to be zero-carbon?	Techno-economic modelling assumptions				Status
		Duration	Efficiency (%)	Cost in 2035 (£/MWh, £2012)	Financial lifetime (years)	
Production						
Autothermal reforming of natural gas (ATR) CCS	Low-carbon	N/A	77	48	30	<ul style="list-style-type: none"> Has been demonstrated but not deployed commercially
Electrolysis	Yes	N/A	78	22	30	<ul style="list-style-type: none"> Alkaline electrolyzers are a mature technology Proton Exchange Membrane electrolyzers have been demonstrated but not deployed commercially
Biomass gasification CCS	Negative-carbon	N/A	55	61	30	<ul style="list-style-type: none"> Has been demonstrated without CCS
Storage						
Salt cavern	Yes	240 hours	95	4.1 – 5.9	40	<ul style="list-style-type: none"> Mature technology, not deployed at scale
Medium-pressure tank	Yes	6 hours	95	2.6	40	<ul style="list-style-type: none"> Mature technology
<p>AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility; CCC analysis.</p> <p>Notes: All efficiencies are on a HHV basis. Exact costs depend on the technology load factor and have been informed here based on the average load factors across the full range of AFRY scenarios. Storage durations refer to the length of time that the store can be emptied for at the maximum emptying rate. While it is recognised that different salt caverns can have different durations, all the salt caverns used in the modelling have been assumed to have a 10-day duration.</p>						

(a) Hydrogen demand outside the power sector

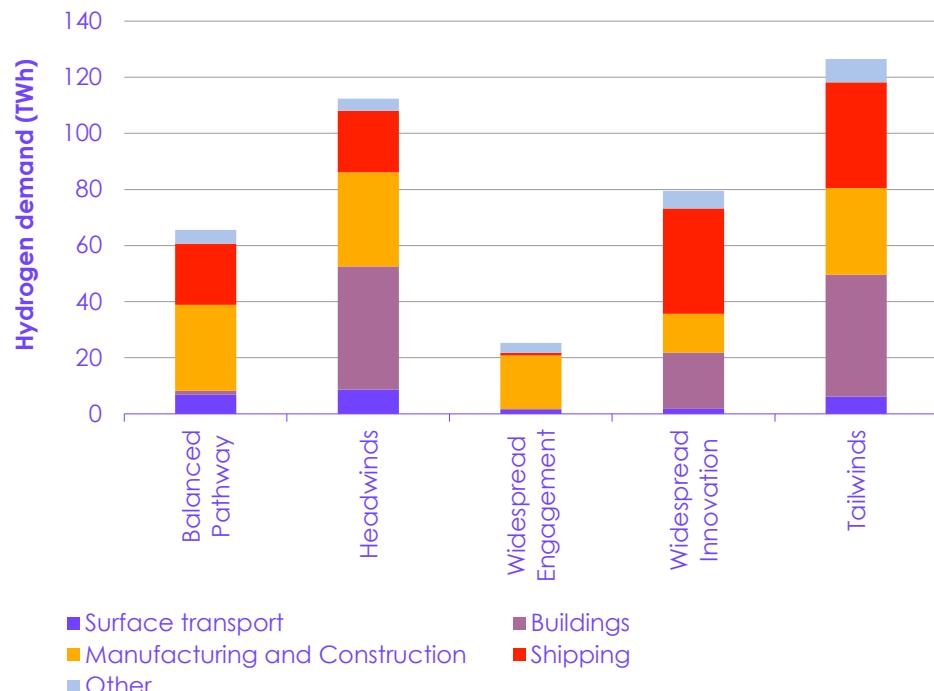
Non-power hydrogen demand varies significantly across our Sixth Carbon Budget scenarios, ranging from 25–127 TWh in 2035 and 123–375 TWh in 2050.

Non-power hydrogen demand varies significantly across the scenarios from our Sixth Carbon Budget advice. These range from 25 TWh in 2035 for the Widespread Engagement scenario to 127 TWh for the Tailwinds scenario (Figure 3.1). The range by 2050 is 123–375 TWh. Our Sixth Carbon Budget Balanced Pathway scenario remains a relatively moderate scenario for hydrogen use, reflecting our advice on the need for widespread electrification. Hydrogen has a smaller but crucial role in decarbonising those areas where it is likely to be infeasible or prohibitively expensive to pursue electrification.

- In 2035, non-power hydrogen demand in the Balanced Pathway is 65 TWh with manufacturing and construction (30 TWh) and shipping (22 TWh, potentially as ammonia) being the largest of these sectors. Together they account for 80% of non-power hydrogen demand.

- Our Sixth Carbon Budget Balanced Pathway assumes a limited role for hydrogen in buildings (11% of homes using hydrogen for heat, primarily as part of a hybrid heating system including a heat pump), heavy electrification of surface transport (apart from a small role for hydrogen in some HGVs) and a balance of electrification and hydrogen for manufacturing.
- In our Balanced Pathway, we projected that the UK's non-power hydrogen demands will grow steadily throughout the 2030s and 2040s, from 66 TWh in 2035 to 117 TWh in 2040 and 204 TWh in 2050.

Figure 3.1 Non-power hydrogen demands in the Sixth Carbon Budget scenarios for 2035



Source: CCC (2020) *Sixth Carbon Budget*.

The analysis in this report uses ranges which reflect scenarios and sensitivities based on demands for electricity and hydrogen in the Balanced Pathway, Headwinds and Widespread Innovation.

The Balanced Pathway assumes relatively little use of hydrogen for heating buildings. Instead, buildings primarily rely on electrification of heating – at both building-scale and via heat networks – using mainly heat pumps with a supplementary role for smart resistive (i.e. lower-efficiency) heating. This adheres to the principle set out in our 2018 Hydrogen Review that electrification of energy end-uses should be pursued where feasible, given the challenges of supplying low-carbon hydrogen at scale, with hydrogen prioritised to displace fossil fuels where electrification is not feasible.¹

In our Balanced Pathway, there was only a small role for hydrogen in heating buildings. However, much larger roles for hydrogen have been conceived of.

In the Balanced Pathway, there is only 1.6 TWh of hydrogen demand in the buildings sector in 2035 and 22.4 TWh in 2050, with the demand coming primarily from its role in hybrid heat pump systems (comprising a heat pump and a hydrogen boiler operating as a back-up).

However, much larger roles for hydrogen in heating buildings have been conceived of, which would lead to much higher consumption of hydrogen from buildings. In our Headwinds scenario, there is a greater deployment of hydrogen boilers with 71% of homes using hydrogen for heat in 2050 (compared to 11% in the Balanced Pathway). The resulting demands for hydrogen would be 44 TWh in 2035 and 182 TWh in 2050.

Higher levels of demand for hydrogen from buildings would likely increase dependence on imported energy considerably.

These much higher levels of demand for hydrogen from buildings would likely increase dependence on imported energy considerably (see section 2 below). In order for this to be a reasonable option, it would need to be clear that hydrogen with sufficiently low lifecycle emissions can be sourced at the necessary scale, while not risking security of supply or excessive exposure to volatile fossil fuel markets.

In our previous analysis, we have assumed that the hydrogen supply gap is filled by default with domestic production from fossil gas with carbon capture and storage (CCS) (i.e. blue hydrogen). Blue hydrogen supply, particularly at the Headwinds scale (or above), comes with numerous challenges. These include: lifecycle emissions savings well below 100%, dependence on imported gas, and the requirement for large-scale infrastructure for CCS (see section 2 below).

Recent evidence has emerged that indicates fugitive hydrogen emissions have a stronger warming effect than previously thought, raising potential concerns over the climate impacts of putting hydrogen into gas distribution grids.

Evidence published in 2022 indicating a considerably stronger warming effect of fugitive hydrogen emissions, raises further concerns that putting hydrogen into gas distribution grids may have negative impacts on the climate (Box 3.1), depending on the hydrogen leakage rates that could be expected.

Developments since our Sixth Carbon Budget advice, on the evidence regarding hydrogen's impact as an indirect greenhouse gas and the spike in international and UK fossil gas prices, provide further support for the limited role for hydrogen in buildings decarbonisation; especially in the case that UK blue hydrogen production is the main option to fill the supply gap. The Government is planning to make decisions on the respective roles for electrification and hydrogen in heating in 2026.²

Box 3.1

Recent evidence on the indirect warming effect of fugitive hydrogen

There is increasing evidence relating to hydrogen's role as an indirect greenhouse gas. While hydrogen is not a strong absorber of infrared radiation and does not directly contribute to the greenhouse effect itself, it interacts with other chemicals in the atmosphere that lead to an increase in the atmospheric lifetime of other greenhouse gas emissions. Hydrogen reacts with, and consequently depletes, hydroxyl radicals in the earth's atmosphere, which play an important role in reducing the lifetime of methane. Increased levels of hydrogen in the atmosphere then reduce the ability of the hydroxyl radicals to control methane, indirectly increasing the warming effect of methane in the atmosphere. While this effect has previously been considered at the troposphere – the lowest layer of the earth's atmosphere – new evidence has explored the effect at the stratosphere – the second lower layer of the earth's atmosphere – and estimates that the GWP of hydrogen may be higher than initially thought. Greater attention may therefore need to be given to hydrogen leakage and its role offsetting some of the benefits of a hydrogen-based economy. However, it is currently not possible to quantify hydrogen leakage and its scale is therefore uncertain. The recent evidence has not yet been considered in our analysis and will be explored in further detail in our future work.

Source: BEIS (2022) *Atmospheric implications of increased hydrogen use*; Frazer-Nash Consultancy (2022) *Fugitive hydrogen emissions in a future hydrogen economy*.

(b) Hydrogen demand in the power sector

Hydrogen also has a potentially key role in electricity generation, particularly in reaching the 2035 decarbonisation target. The modelling commissioned for this report estimates that hydrogen demand from the power sector could peak in the 2030s and decline over the course of the 2040s, as the balance between renewables and low-carbon back-up shifts.

Hydrogen is well suited to decarbonise at least some current CHP plants, providing small levels of power as a by-product of any heat production outside the power sector. Demand for hydrogen CHP is likely to be focused in the industrial sector but could also exist in the buildings sector, with its use in the latter depending on decisions on the role of hydrogen for heating.

Hydrogen can play an important role in the power sector by providing flexibility options to manage both deficits and surpluses in supply.

However, the potentially greater role for hydrogen in the power sector is likely to be in providing flexibility options to manage both deficits and surpluses in supply from other sources:

- When demand is greater than supply and hydrogen turbines are needed to act as low-carbon dispatchable power; and
- When supply is greater than demand and electrolysis can provide a productive use for surplus electricity (e.g. to avoid curtailment of renewable generation).

The scale of hydrogen demand in the power sector depends on the balance between hydrogen CCGTs and gas CCS plants in providing low-carbon dispatchable capacity.

The scale of hydrogen demand in the power sector will depend on the balance between hydrogen CCGT and gas CCS plants in providing low-carbon dispatchable capacity (see Chapter 2). The modelling commissioned for this report typically favours the use of hydrogen over gas CCS across its range of scenarios (with hydrogen-fired generation making up between 46-100% of low-carbon dispatchable supply across scenarios in 2035). However, due to uncertainty over their future costs and efficiencies, the precise future balance between hydrogen and gas CCS remains unclear:

- At least until the 2040s, additional hydrogen demand at the margin might need to be met through blue hydrogen production (see section 2 below). As such, the choice might well be between providing low-carbon dispatchable capacity through hydrogen-fired capacity fuelled by blue hydrogen versus gas CCS plants.
- Gas CCS plants have higher capital costs than hydrogen-fired plants, but are expected to have lower operating costs (given a slight advantage in efficiency in going from fossil gas to electricity compared to use of blue hydrogen in hydrogen-fired plants). At higher load factors, the lower operating costs of gas CCS might be sufficient to justify the higher upfront investment, while hydrogen looks preferable at low load factors.
- For the higher load factor role, while initially the two options might have similar overall costs and residual emissions, there is a difference in lock-in. Whereas a gas CCS plant continues to require methane to operate, the hydrogen plant can initially operate on blue hydrogen before switching later to hydrogen from a non-fossil zero-carbon source of production. So while there may be little difference between the two options in 2035, by 2050 there is scope to switch away from blue hydrogen in the transition to Net Zero. This would reduce the UK's dependence on fossil fuel imports and increase emissions savings.

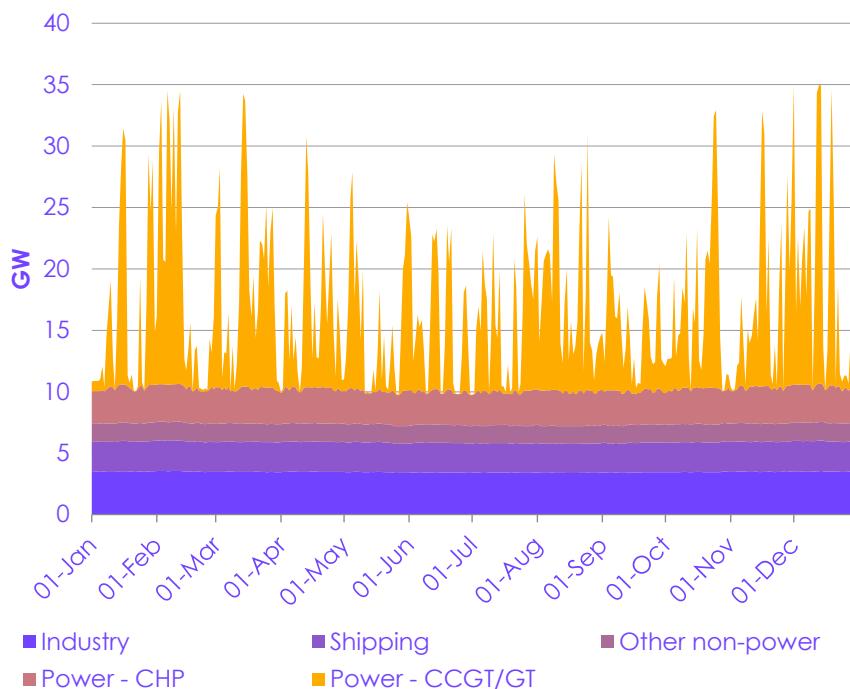
While hydrogen storage and use in electricity could in principle be strongly seasonal, in the modelling undertaken by AFRY for this report, the higher demand in winter is largely met by the greater output of offshore wind. In the modelling, rather than playing a strongly seasonal role, hydrogen storage and use for electricity generation is largely determined by the need to back-up variable renewable output on a multi-day / multi-week timescale (see Chapter 2).

Power sector demand for hydrogen fluctuates considerably on an hourly and daily basis.

Power sector demand for hydrogen therefore fluctuates considerably both on an hourly and a daily basis, but with little seasonal variation in 2035 (Figure 3.2). Seasonality of demand could be expected to grow as buildings decarbonise, but much of the corresponding increase in electricity supply is expected to come from offshore wind (which positively correlates with seasonal demand), so the role for hydrogen to provide seasonal storage may not be large even by 2050. The intermittency of the demand for hydrogen in the power sector increases the requirements for storage.

- The Central scenario finds that power demand for hydrogen – combining both the relevant portion of inflexible CHP demand and flexible demand from hydrogen CCGTs and Gas Turbines (GTs) – could be around 85 TWh in 2035. The flexible demand fluctuates up to around 580 GWh/day, equivalent to average daily demands of 24 GW.
- Baseload production alone would not be able to meet the variation in the demand for hydrogen in the power sector, and consequently storage would be required to support the use of hydrogen in this sector. Hydrogen storage is discussed in more detail later in this chapter.

Figure 3.2 Variation across the year in daily average hydrogen demand (2035)



Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility; CCC analysis.

Notes: Central scenario from AFRY modelling using annual values from CCC Balanced Pathway. Building demand for hydrogen has not been seasonally profiled as part of this modelling, and as such 'Other non-power' demand presented here for 2035 is flatter than would be expected in reality. Hydrogen use for buildings in AFRY's Central scenario remains limited to 1.5 TWh in 2035.

This scale of hydrogen use in the power sector in 2035 is not expected to come from hydrogen-dedicated new-build plants alone. There would likely also be retrofits of existing fossil gas plants and hydrogen-ready plants in the mix. This would be driven both by regulation and commercial incentives to avoid stranded asset risk.

- It appears technically feasible that modest retrofits to existing power plants could be made to convert some gas plant to hydrogen.³ However, the suitability of power plants will need to be assessed on a case-by-case basis. Not all plants may have the required space for the widening of the pipework required for higher volumes of gas (per unit of energy) and the selective catalytic reduction technology that may be required to manage emissions of nitrous oxides.
- New gas plants could be designed that consider the future conversion to hydrogen such that they are built ‘hydrogen-ready’. These plants would initially burn natural gas before switching to burn hydrogen at a future date with the upfront design considerations helping to limit the future cost of conversion.
- The location of hydrogen-based power generation will be somewhat driven by proximity to the availability of fuel, as well as access to hydrogen storage sites and transmission networks. Consequently, decisions on the development of a hydrogen network need to be made strategically (see section 3 below).
- In the Central scenario of the modelling undertaken for this report, about a third of hydrogen CCGT capacity in 2035 would be made up of new-build plants and the rest would be retrofits.
 - New-build CCGT capacity is expected to increase over the 2020s but then remain flat afterwards. This is driven by the assumed 25-year lifetime of a new-build hydrogen-fired power plant, combined with an expected decline in demand for hydrogen-to-power generation in the 2040s, as generation from renewable energy sources increases.
 - The modelling does however see the capacity of hydrogen-fired turbines suitable for a ‘peaking’ role (e.g. hydrogen open-cycle gas turbines) continue to increase throughout the 2030s and 2040s, given the continued system role of low-carbon peaking plants.
 - CCGT retrofit capacity is expected to overtake new-build CCGT capacity in the 2030s. Retrofitting a gas plant to hydrogen is expected to extend an asset’s lifetime by 10 years and have lower capex costs than a new-build CCGT (set out by AFRY as £110/kW instead of £740/kW based on published values),⁴ while also preventing at least some of the current gas fleet from being stranded.

The need for hydrogen supply and demand to grow in tandem creates coordination challenges. Hydrogen-ready turbines and hydrogen blending could help to relax this need for tight coordination.

The need for hydrogen supply and demand to grow in tandem creates coordination challenges to ensure that there is both a sufficient market for the low-carbon hydrogen production and sufficient low-carbon production to meet new hydrogen demands. There is a value in developing solutions that relax this need for tight coordination between hydrogen supply and demand.

- The build of hydrogen-ready turbines enables plant to be built based on fossil gas prior to the availability of low-carbon hydrogen supplies, and only switch once hydrogen is available.

- Similarly, blending of hydrogen with fossil gas could provide a flexible demand for hydrogen, whether in power plants or in the gas grid in small proportions – current estimates are that up to 7% hydrogen by energy (equating to 20% by volume) could be blended into the gas grid without changes being required to gas appliances.⁵ While this flexibility is useful, it is as a short-term measure to manage the hydrogen supply-demand balance rather than as a long-term solution compatible with Net Zero, which will require 100% decarbonised solutions.

Hydrogen-ready turbines and blending could therefore be used as a method of enabling hydrogen supply chains if utilised in the 2020s, by providing a use case for hydrogen ahead of its wider scale roll-out in power and non-power sectors. However, given its value only as a short-term interim solution, hydrogen blending has not been modelled in the analysis presented in this report.

2. Implications for hydrogen supply

Low-carbon hydrogen can be produced in a range of ways. The main routes for UK production include electrolysis, methane reformation with CCS and biomass gasification with CCS.

Low-carbon hydrogen can be produced in a range of ways. In this report, we focus on three routes for UK production, outlined in Box 3.2, plus some options for its importation.

Box 3.2

Hydrogen can be produced in a range of ways

There are several routes to produce hydrogen. The most relevant methods for UK low-carbon production are:

- **Electrolysis** – producing ‘green hydrogen’ (where using renewables), or ‘pink hydrogen’ (where using nuclear) – involves running an electric current through water to split the molecules into hydrogen and oxygen. When this is done using zero-carbon electricity, there are no CO₂ emissions associated with the operation of the electrolyser or the energy input to it.
- **Methane reformation with CCS** – producing what is known as ‘blue hydrogen’ – using oxygen to split the carbon and hydrogen in the fossil gas, forming carbon dioxide and hydrogen. We have previously estimated that blue hydrogen can provide a reduction in greenhouse gas emissions of 60-85% compared to unabated use of fossil gas.
- **Biomass gasification with CCS** - uses biomass as the feedstock and, with use of sustainable biomass and carbon capture, is one form of bioenergy with CCS (BECCS) and is considered carbon-negative. This type of hydrogen production is not expected to comprise a major proportion of future hydrogen supply due to constraints on sustainable biomass feedstock availability and alternative uses in other forms of BECCS.

Source: CCC (2018) *Hydrogen in a low-carbon economy*.

(a) Hydrogen production capacity requirements

The Energy Security Strategy sets a target of 2 GW and 10 GW of low-hydrogen capacity by 2025 and 2030, respectively. However, these targets give a relatively poor indication of the amount of hydrogen that could actually be produced.

The ESS set a target of 2 GW of low-carbon hydrogen production capacity in the UK by 2025 and up to 10 GW by 2030, of which at least 5 GW is to be electrolytic. However, these targets for combined GW give a relatively poor indication of the amount of hydrogen that could actually be produced:

- Blue hydrogen plants (or biomass gasification plants with CCS) could operate essentially flat out across the year, leading to the production of up to around 8 TWh annually of hydrogen per GW of capacity – this might require hydrogen storage to provide the flexibility to meet demands as they arise. Alternatively, such plants could be operated more flexibly, with a lower load factor, but with less need for hydrogen storage.
- Grid-connected electrolysis, to soak up excess decarbonised electricity generation, will have low load factors linked to the frequency and size of those surpluses. Based on a 25% load factor, this might lead to around 2.2 TWh annually per GW of electrolysis capacity.
- Electrolysis based on dedicated renewables would have a higher load factor, linked to the output of the renewable capacity. For example, a dedicated electrolyser facility linked to an offshore wind farm could have a load factor of around 50%, producing 4.5 TWh annually per GW.

The hydrogen production targets should be set out in a way that provides a better indication of hydrogen production capacity (e.g. de-rated GW or TWh/year).

The modelling for this report suggests that the Energy Security Strategy targets are on the lower end of what could be needed to meet the 2035 decarbonisation target.

The current Government targets, while providing some indication of ambition for the sector, could therefore provide production capacity equating to somewhere between 22 and 62 TWh annually. In order to avoid this lack of clarity, in this report we use the term 'de-rated capacity' to represent the level of hydrogen production capacity if it were provided by a producer operating constantly at full capacity. It would be valuable if the Government provided a better indication of hydrogen production capacity needs by 2030 (e.g. in de-rated GW or TWh/year).

The results of the modelling for this report suggest that the ESS targets are on the lower end of what could be needed to decarbonise the power sector by 2035.

- Across the scenarios and sensitivities which make up our provisional indicator range (see section 5 below), between 9-14 GW of low-carbon hydrogen de-rated production capacity is deployed in GB by 2030, rising to 13-25 GW by 2035.* In both years the majority of the hydrogen production capacity is blue (CCS-enabled), at least in part due to constraints on availability of 'surplus' electricity generation, with 11-31% being electrolytic in 2030 and 22-51% in 2035.
- The lower bounds have potential to be further reduced where heating in buildings is fully electrified (as in our Sixth Carbon Budget Widespread Engagement scenario) or where there is a reduced role for hydrogen in the power system relative to that envisaged in the modelling for this report.[†]
- Lower demands for hydrogen would yield lower demands for blue hydrogen production (with the volume of electrolysis largely unaffected). However, a different balance would still see similar overall consumption of fossil gas and use of CCS, with the use for gas CCS in power generation approximately compensating for the reduction for hydrogen production.

(b) The domestic hydrogen demand-supply gap

A key aim of the ESS is to reduce the UK's dependence on imported oil and gas, to reduce the UK's exposure to volatile international prices. In this section we look at what role domestic hydrogen production could play in meeting hydrogen demand, and the different options for importing any remaining energy required to meet demands.[‡]

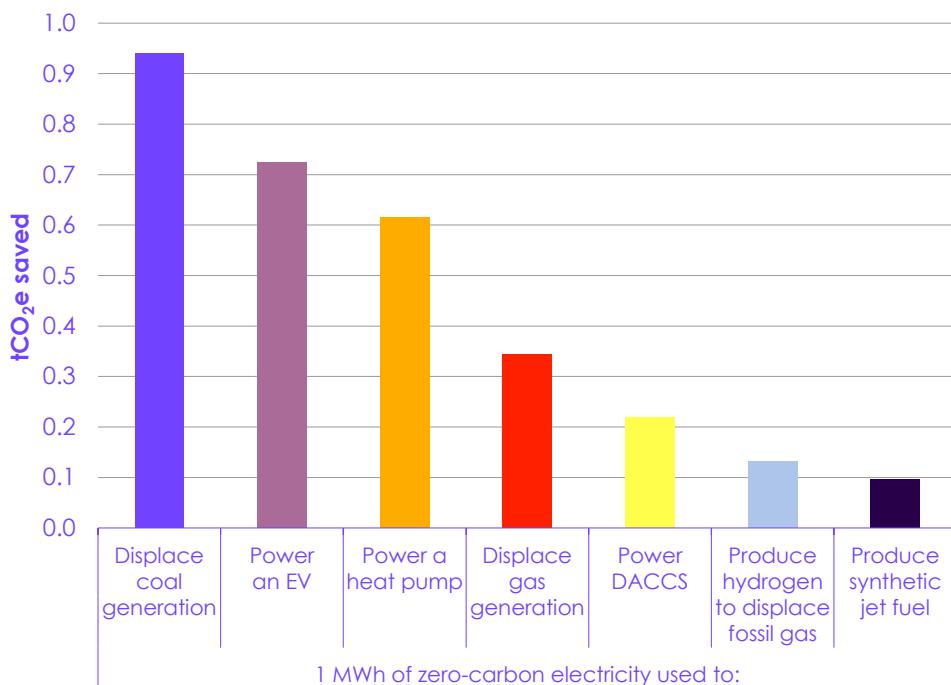
Domestically produced electrolytic hydrogen is one route to meeting hydrogen demands while minimising import dependency risks. However, low-carbon electricity has its highest value when displacing fossil generation and meeting 'core' electricity demands – those that already exist in buildings and industry, and those from highly efficient forms of electrification such as electric vehicles and heat pumps (Figure 3.3).

* Underpinned by 11-17 GW and 19-33 GW of hydrogen production capacity respectively. The ranges reflect the uncertainty in the scale of future demand for hydrogen.

[†] The modelling undertaken by AFRY for this report typically favours the use of hydrogen over gas CCS to provide low-carbon dispatchable capacity (with hydrogen-fired generation making up between 46-100% of low-carbon dispatchable supply across scenarios in 2035).

[‡] We exclude blue hydrogen from the analysis in this section on the basis that it remains exposed to volatile international prices, and the UK is already a net importer of fossil gas and is projected to remain an importer as we transition to Net Zero, such that blue hydrogen should be considered as effectively meeting hydrogen demands through imported energy. This is discussed further in section 2d.

Figure 3.3 Emissions saved with 1 MWh of zero-carbon electricity in different applications



Source: CCC analysis.

Zero-carbon electricity has its highest value when displacing fossil generation and meeting 'core' electricity demands. Once these demands have been met, surpluses can then be used to produce electrolytic hydrogen.

Once these core demands have been met surpluses can be used in various ways, including exporting electricity; for electrolytic hydrogen production; and use in flexible applications such as hybrid heating systems.

- The modelling undertaken for this report assumes a role for both electrolytic hydrogen production and exports, in managing surplus electricity.
 - Based on modelling of pan-European interconnected markets (and accounting for the geographic coverage of weather systems), interconnectors are found to play a valuable role in balancing the system, importing during periods of supply deficit and exporting during periods of supply surplus.
 - The activation of electrolysis is also an important means of managing periods of surplus electricity. This produces relatively cheap electrolytic hydrogen which, when combined with storage, can be used to generate electricity later on. However, there are sizable inefficiencies in this process, firstly in the process of electrolysis (assumed to be around 75% efficient), and then in the use of the resulting hydrogen (with hydrogen CCGTs assumed to be around 55% efficient).

There are alternative ways to use surplus electricity in the economy beyond those modelled for this report. For example, the deployment of hybrid heat pumps in homes in the near term (i.e. alongside existing gas boilers), could provide a direct and highly efficient use of surplus electricity while providing flexibility to switch to the boiler at times of insufficient electricity supply. Heat pumps can have efficiencies of 300% or more, displacing gas boiler use (at best 87% efficient).⁶ The potential emissions savings and reductions in fossil

gas consumption are around four times greater than if this surplus electricity were used for electrolysis. Near-term hybrid heat pump deployment also has potential to drive wider benefits, including around public acceptability of heat pumps more generally.⁷

The possible gap between overall hydrogen demand and domestic non-fossil hydrogen supply in 2035 could be in the region of 7-174 TWh, with the range driven by the use of hydrogen outside the power sector and the low-carbon dispatchable generation mix.

We have used the range of scenarios developed for this report, alongside our Sixth Carbon Budget scenarios, to illustrate the possible gap between overall hydrogen demand and the modelled domestic non-fossil hydrogen supply – from electrolysis using surplus electricity and with a small contribution from biomass gasification with CCS – in 2035 and 2050 (Figure 3.4).

Depending on the scale of interconnector exports and the use of hydrogen outside the power sector, we estimate the overall gap between hydrogen production from these modelled non-fossil sources and demand in 2035 could be in the region of 7-174 TWh.

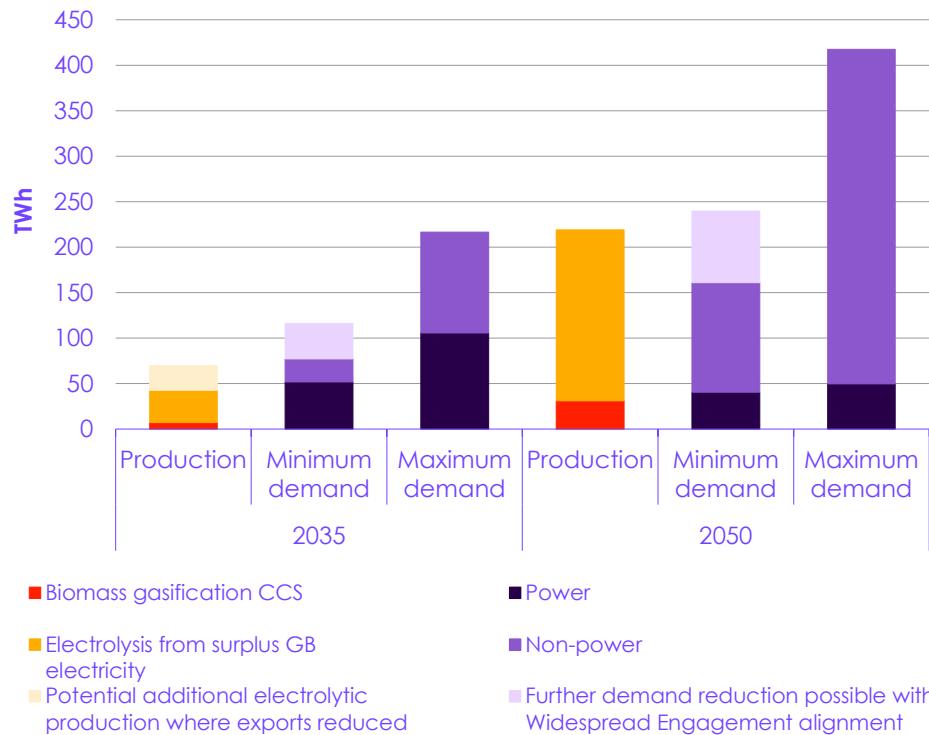
- As set out in section 1 of this chapter, there is significant variation in non-power hydrogen demand across our Sixth Carbon Budget scenarios. In the modelling commissioned for this report, the minimum and maximum non-power demands were taken from our Balanced Pathway and Widespread Innovation scenarios, but demand could be lower where there is alignment with our Widespread Engagement scenario where there is no use of hydrogen in the buildings sector and lower demand for energy overall.
- Power demands for hydrogen were determined in the modelling based on the overall power demands used in our Balanced Pathway and Widespread Innovation scenario, giving a range in the power demand for hydrogen between 52-106 TWh. The demand here also depends on the low-carbon dispatchable power mix, with hydrogen use in electricity generation potentially lower in a mix with a greater share of gas CCS.
- Regarding supply, there could be a role for biomass gasification, but this is unlikely to be significant due to the limits on the availability of sustainable biomass and the relatively slow development to-date of biomass gasification technology. Biomass gasification deployment in combination with CCS would be worthwhile, but the biomass feedstock could instead be used for BECCS in power (see section 2 of Chapter 1).
- Expected production of electrolytic hydrogen from surplus electricity in the Central scenario is 36 TWh in 2035. This is limited to some degree by electricity exports in the modelling (with GB acting as a net exporter in 2035). In the event GB was able to maintain a neutral balance of import and export flows (e.g. pending EU decarbonisation progress), this could free up a further 27 TWh of electricity for domestic hydrogen production.

While there is greater demand for hydrogen outside the power sector in 2050, the size of the gap has potential to be lower – and even eliminated if non-power demands align with the Widespread Engagement scenario – due to reductions in demand for hydrogen in the power sector in the 2040s. However, expansions in hydrogen demand beyond what's in the Balanced Pathway (e.g. extensive use of hydrogen for buildings heat) could see the gap increase, potentially considerably.

It appears unlikely that all hydrogen demand in 2035 can be met from domestic non-fossil fuel production, particularly in light of the already ambitious levels of renewable and nuclear build assumed in the modelling, on the basis of Government commitments.

By 2050 there is increased scope for domestic production to meet domestic demand, but this will be heavily dependent on the Government's strategic decisions on the use of hydrogen for heat in buildings, expected in 2026.

Figure 3.4 The gap between annual GB domestic hydrogen production and demand



Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility; CCC analysis.

Notes: AFRY modelling uses demand values from CCC Sixth Carbon Budget. Hydrogen production values have been taken from the AFRY Central scenario, in which GB is assumed to be a net exporter of electricity in 2035. The light orange area represents potential additional electrolytic production in the event exports are lower than AFRY's Central scenario assumes. Blue hydrogen production and dedicated electrolytic hydrogen projects are covered later in the chapter, as means of closing the gap presented in this chart. The minimum and maximum demands (represented by the dark purple, purple, and light purple bars) have been taken from the range of AFRY scenarios, reflecting the range and uncertainty in the scale of future hydrogen demand. The minimum and maximum demands correspond to the AFRY Grid Storage and High scenarios, respectively. The High scenario uses our Sixth Carbon Budget Widespread Innovation pathway for non-power hydrogen demands. The Grid Storage scenario uses our Sixth Carbon Budget Balanced Pathway for non-power hydrogen demands. It remains that non-power demands for hydrogen could be even lower than this. The light purple area represents the demand that could be netted off, where aligning non-power hydrogen demands to the CCC's Sixth Carbon Budget Widespread Engagement scenario, in which greater societal shifts in behaviour are assumed and buildings are fully electrified (Figure 3.1).

(c) Dedicated zero-carbon electricity to fill the hydrogen supply gap

One option to fill the gap is to dedicate zero-carbon electricity to the production of electrolytic hydrogen.

The amount of electrolytic hydrogen production in the AFRY model is estimated on the basis of the assumption that electrolytic hydrogen will be produced using surplus electricity (i.e. where the power available at a point in time exceeds demand).

However, electrolysis can also be applied to zero-carbon electricity dedicated to the purpose of producing hydrogen in the UK. This approach is not dependent on importing energy from other countries and can consequently support greater energy security.

Electrolysers operating from a dedicated zero-carbon electricity supply can achieve much higher load factors than those operating from surplus electricity, and more continued modes of operation can support higher operating efficiencies. Higher load factors mean that the contribution of electrolyser capital costs to overall hydrogen production costs is lower, as the cost is spread over more units of output. However, much higher electricity costs would be incurred, with estimates suggesting that hydrogen produced from dedicated zero-carbon electricity would be more expensive than hydrogen from curtailed electricity.

- Assuming the capacity of the electricity source matches the capacity of the electrolyser (no overplanting), electrolysis can run at the same load factor as the source.
- Hydrogen produced from dedicated zero-carbon electricity would likely pay the levelised cost of its electricity source as the electricity price.
- While electrolyzers could be connected to a variety of zero-carbon electricity sources, offshore wind would be the most likely due to its high load factor and low levelised cost of energy. Green hydrogen produced from a dedicated source of offshore wind has been estimated to cost around £80/MWh in 2035 falling to around £70/MWh in 2050. In contrast, hydrogen produced from curtailed electricity is estimated to cost £46-53/MWh in 2035 and £42-50/MWh in 2050.⁸

Dedicated electrolytic production in the UK is likely to be preferable to importing electrolytic hydrogen. This is due to the uncertainties surrounding the development of an internationally traded market for hydrogen (discussed below), as well as the lower costs and energy security benefits of domestic production compared to imports.

Zero-carbon electricity must be prioritised to displace fossil generation and meet core electricity needs (including EVs and heat pumps). Hydrogen from dedicated zero-carbon electricity should therefore only be based on generation sources where it is not possible to connect to the grid.

The highly ambitious build rates for planned zero-carbon electricity mean that the potential for dedicated projects to contribute to filling the 2035 gap is limited.

However, as discussed earlier in this chapter, zero-carbon electricity must first be used to displace fossil generation, then used to meet core electricity demands (such as EVs and heat pumps) before being used to solely produce hydrogen. This means that existing zero-carbon electricity capacities and commitments must not be allocated to dedicated hydrogen production.

Hydrogen from dedicated zero-carbon electricity should therefore only be based on extra zero-carbon electricity capacity or from zero-carbon electricity sources where it is not possible to connect to the grid (e.g. 'stranded' renewable capacity that cannot feasibly connect to the electricity system).

The highly ambitious build rates planned for zero-carbon electricity in the path to 2035 imply that the potential for dedicated electrolysis projects to contribute to hydrogen supply on this timeframe is likely to be limited, with a more material role in the longer term.

(d) Importing energy to fill the hydrogen supply gap

The modelling commissioned for this report was set up to require all hydrogen demands to be met through GB-based hydrogen production. The model predominantly chooses to fill the gap between demand and what can be supplied from non-fossil sources of domestic production with production from fossil gas with CCS ('blue hydrogen').

However, the UK is already a net importer of fossil gas, and domestic production of fossil gas is projected to continue to fall over coming decades (Figure 3.5).

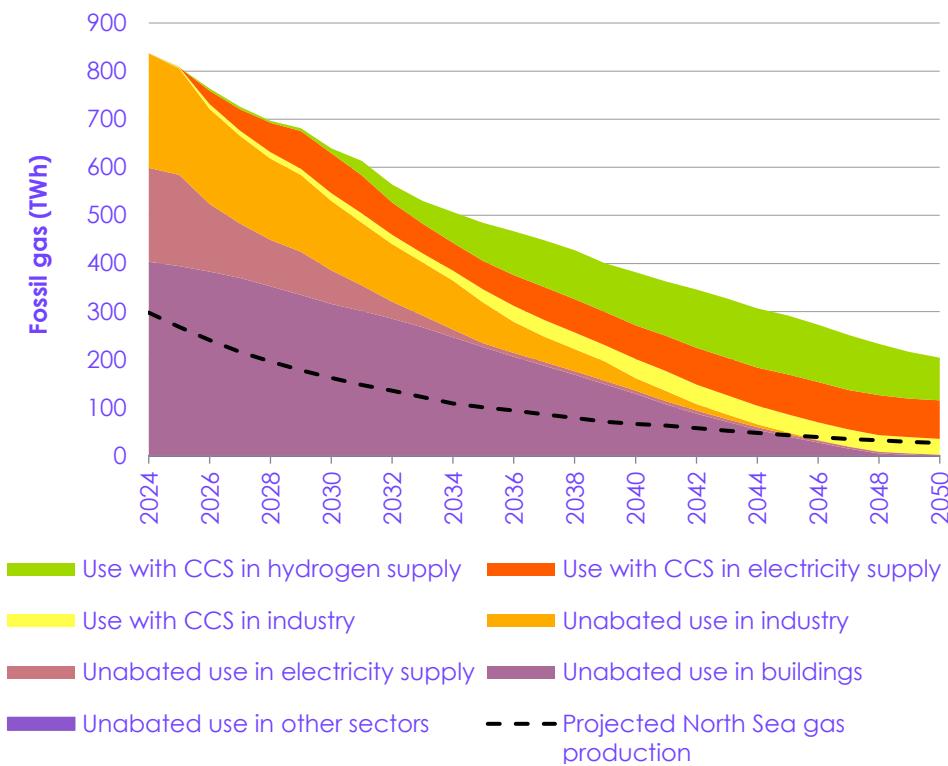
Although the UK's consumption of gas will also have to fall to be on track for Net Zero, our previous analysis indicates that these two declines will occur at similar rates.

The UK is expected to continue to be a net importer of fossil gas over the coming decades with UK gas production unable to meet even the falling demands for gas as we decarbonise. Further gas demands for use with CCS (to produce electricity or hydrogen) will increase gas imports by a corresponding amount.

The UK is therefore likely to continue to be a net importer of fossil gas over coming decades, with supplies of gas from UK production being insufficient to meet even falling demands for gas in existing uses as we decarbonise: buildings, industry – including as a chemical feedstock – and unabated use in electricity generation, until the late 2040s (Figure 3.5).

Further gas demands on top of these uses, by building new facilities in the next two decades using fossil gas with CCS for energy production (whether for electricity or hydrogen), will increase the amount of gas imports by a corresponding amount, and can effectively therefore be considered as using imported gas.

Figure 3.5 Projected fossil gas consumption in the Balanced Pathway compared to UK production



Source: CCC analysis; NSTA (2022) August 2022 oil and gas production projections; CCC (2021) Letter: Advice to the UK Government on compatibility of onshore petroleum with UK carbon budgets.

Notes: The wedges represent different uses of fossil gas in the CCC's Balanced Pathway from the CCC's advice in 2020 on the Sixth Carbon Budget. The use of CCS with gas for electricity generation and hydrogen production is different to that presented in this report, based on AFRY modelling, both in volumes and balance between electricity and hydrogen. Projected consumption includes non-energy use at 2019 levels (4.5 TWh/year).

Imported energy could be used to fill the gap between domestic hydrogen production and demand. However, hydrogen based on imported energy would have to demonstrate that it is low-carbon across its lifecycle.

In reality, there are various ways in which imported energy could be used to fill the domestic hydrogen demand/supply gap. Hydrogen based on imported energy, regardless of route, would have to demonstrate that it is low-carbon across its lifecycle:

- The UK has developed a Low-carbon Hydrogen Standard that defines low-carbon hydrogen up to the point of production* as having an emissions intensity of no more than 60.8 gCO₂e/kWh.⁹
- The Government has also announced plans to use the standard to develop a globally recognised certification scheme for low-carbon hydrogen, with the intention of being introduced by 2025.¹⁰ It can be expected that any hydrogen imports would have to adhere to this standard.

In this section, we consider the challenges and benefits of blue hydrogen, imported green hydrogen and using imported electricity to make electrolytic hydrogen in GB.

(i) Blue hydrogen

Fossil gas can be used to produce blue hydrogen. However, supplying blue hydrogen at scale requires a developed UK CCS infrastructure, a reliance on imported gas and challenges with lifecycle emissions to be overcome.

Blue hydrogen supply at scale comes with several challenges for compatibility with the cost-effective delivery of Net Zero. These include ensuring it has sufficiently low lifecycle emissions, deploying CCS in the UK at the scale required and its reliance on imported gas:

- When produced in a way that aims to minimise residual emissions, we estimate that blue hydrogen could provide lifecycle emissions savings of 60-85% compared to unabated gas. Where usage is limited to sectors of the economy it is not feasible to electrify or reduce demand further, this level of reduction is a valuable contribution to Net Zero (considering the alternative is continued use of unabated fossil fuels). Nevertheless, ideally the emissions savings would be towards the top end of this range, or even higher.
 - Producing hydrogen via autothermal reformation of methane with CCS is expected to have an efficiency of about 80%, with carbon capture of between 90-95%. When including upstream emissions from fossil gas supply, for which we assume a range of 15-70 gCO₂e/kWh based on our work on gas supply, this represents a reduction of around 60-85% relative to use of unabated gas.[†]
 - Such calculations, and adherence with any future low-carbon certification scheme, depend strongly on the upstream emissions from fossil gas production and transportation. Indeed, it currently appears plausible that the bulk of imported gas will be in the form of Liquefied Natural Gas (LNG). This can have high supply-chain emissions if significant quantities of the methane leak.
 - Unless strong rules are developed and implemented on upstream emissions of fossil fuel imports, this option provides little control over the likely significant contribution of the fossil gas production process to the lifecycle emissions of blue hydrogen.

* The point of production is specified as including all emissions from raw materials acquisition, upstream suppliers and the operation of the hydrogen production plant

[†] Calculations on the lifecycle emissions of blue hydrogen do not include any contribution from fugitive hydrogen emissions acting as an indirect greenhouse gas, which would depend on leakages rates – these are currently uncertain and likely to depend on the application for which hydrogen is used (see Box 3.1 in the previous section).

- While our assessment is that carbon capture and storage (CCS) is essential to meeting Net Zero, it has not yet been deployed at scale in the UK. With the large-scale infrastructure development it implies, the scale to which a CCS industry can be developed by the time the UK reaches Net Zero remains unknown. Given this uncertainty, and the need to prioritise CCS for industry and greenhouse gas removals ahead of energy generation from fossil fuels, it is prudent to limit use of CCS on fossil gas where possible.
- As set out above, the consumption of fossil gas for blue hydrogen production in the UK will increase imports by a corresponding amount. As illustrated over the past year, international fossil gas prices can be highly volatile, and security of supply is not guaranteed.

Using only blue hydrogen to fill the hydrogen supply gap in 2035 (as outlined in Figure 3.4 above) would imply fossil gas imports for this purpose of 9-217 TWh/year.* The central value of this range is comparable to the 138 TWh/year of fossil gas consumption (and therefore imports) from use with CCS in hydrogen production and power generation estimated in the Balanced Pathway.

In terms of the required infrastructure, multiple domestic production plants would likely be required, with early plants located near CO₂ storage facilities/infrastructure.

- The optimal production profile for blue hydrogen is baseload, as it cannot easily be ramped up or down quickly. However, having multiple production plants allows for staged increases or decreases in output. In combination with hydrogen storage, this can potentially create enough operational flexibility to meet variations in required supply.
- While all forms of hydrogen depend on the development of infrastructure for its transportation and storage, blue hydrogen also depends on a CO₂ transport and storage network. Therefore, in the early days of its development blue hydrogen is likely to be located near a CCS sink to minimise the requirements for CO₂ transportation and storage.
- While it is also conceivable that the UK could import blue hydrogen made overseas, in practice it appears more likely - given the existing LNG and gas pipeline infrastructure - that the energy would be imported as fossil gas rather than as hydrogen.

The gap between hydrogen demands and domestic non-fossil hydrogen supply has the potential to be smaller by 2050 than in 2035, given the potential for the UK to increase domestic zero-carbon hydrogen production to be ramped up in the period post-2035. In this event, some blue hydrogen capacity put in place in the early 2030s would be expected to fall into a back-up role during the 2040s. However, this back-up role – in combination with the existing LNG import infrastructure – would provide additional energy security (e.g. for a low-wind year) in a decarbonised way.

* Assuming 80% efficiency.

(ii) Imported green hydrogen

Green hydrogen could be imported from renewable energy resources outside the UK, especially from countries with abundant potential for low-cost generation.

If the UK is going to import energy to fill the hydrogen supply gap, it is important to consider how renewable energy resources outside the UK might be utilised, especially from countries with abundant potential for low-cost generation (e.g. from solar in sunny regions).

Hydrogen is relatively difficult and costly to transport so while a small amount of transportation currently occurs, the vast majority of current hydrogen use is captive and occurs directly on the same site as its production. However, there is potential for its international trade, especially if costs reduce:

- Producing green hydrogen is expected to have large potential for cost reductions.
 - Green hydrogen costs are driven by the cost of zero-carbon electricity and the capital costs and efficiencies of electrolyzers, alongside associated network costs.¹¹ The cost of renewable energy has continued to fall over the past decade, while electrolyser costs can be expected to reduce from around £705/kW to below £100/kW by 2050 as economies of scale and learning curve effects are realised.¹²
 - In the UK, producing green hydrogen from curtailed electricity currently costs between £65-133/MWh depending on the electrolyser technology used.¹³ This could reduce to around £50/MWh by 2050. However, in locations with access to plentiful, low-cost renewable energy resource, this could fall below £30/MWh in 2050.¹⁴
- In years to come it is likely that a greater number of countries will be competitively exporting green hydrogen than there are which currently export fossil gas or blue hydrogen.¹⁵ This offers the UK an opportunity to diversify its energy imports across multiple countries and geographical areas.
 - Fossil fuel reserves are concentrated in a few locations with 64% of global gas reserves located in five countries. Security of supply from these countries is not guaranteed and price spikes have occurred when supplies have been disrupted.¹⁶
 - Globally there is much wider access to renewable energy than fossil energy. Countries including Chile, Norway, Australia and those in North Africa are expected to become key exporters of green hydrogen (Box 3.3).

Several countries have announced their intentions to export green hydrogen. This offers the UK an opportunity to diversify its energy imports.

Hydrogen can be compressed and imported via pipelines or converted to a transportable form and shipped. Pipelines are expected to be more cost-effective than shipping for distances less than 2,000 km.

Large volumes of hydrogen can be imported via pipelines or shipping, with the most cost-effective method depending on the distance from the exporter. Shipping enables green hydrogen to be imported from countries where the construction of pipelines is not possible and as such green hydrogen via hydrogen vectors would be the expected mode of transport from countries such as Chile and Australia.

Box 3.3

Several countries have announced plans to be net exporters of green hydrogen

Several countries with high potential for renewable energy have published hydrogen strategies that outline their intentions to become exporters of green hydrogen.

- **Morocco** published its green hydrogen roadmap in 2021, identifying green hydrogen as a key growth sector for its economy. By 2030, Morocco envisages a local hydrogen market of 4 TWh and plans for an export market of 10 TWh, requiring the construction of 6 GW of new renewable energy capacity.
- **Chile** announced their National Green Hydrogen Strategy in 2020. The strategy aims to have developed the most cost-efficient green hydrogen by 2030 and to be among the top three exporters of green hydrogen by 2040. To achieve these goals, Chile intends to have deployed 5 GW of electrolyser capacity by 2025 and 25 GW by 2030.
- **Australia** outlined its intentions to encourage the development of domestic hydrogen production capabilities for domestic and export purposes in its 2019 National Hydrogen Strategy. The strategy sets a vision for commercial green hydrogen exports by 2030 and Australia aims to be among the top three exporters of hydrogen to Asian markets by 2030.

Source: Royaume Du Maroc Kingdom of Morocco (2021) Feuille de Route Hydrogène Vert; Gobierno de Chile (2020) National Green Hydrogen Strategy; COAG Energy Council (2019) Australia's National Hydrogen Strategy; IRENA (2022) Geopolitics of the Energy Transformation: The Hydrogen Factor.

Hydrogen can be shipped by converting it into a more easily transportable form (e.g. as liquid hydrogen or hydrogen vectors such as ammonia or liquid organic hydrogen carriers). Converting to these forms and then reconverting back to hydrogen incurs additional costs due to efficiency losses in the conversions and the energy required to be input. Shipping therefore tends to be outcompeted by pipeline transport over shorter distances. Due to the cost of the conversions, it may be advantageous to focus the use of shipping imports on sectors where the hydrogen vectors can be used directly (e.g. use of ammonia as a low-carbon fuel for the shipping sector).

The cost of importing hydrogen via ships varies based on the hydrogen vector used:

- Ammonia is the cheapest hydrogen vector for shipping, with costs of around £2-6/MWh per 1,000-10,000 km travelled. However, the costs of converting and reconverting to and from hydrogen can currently add up to between £60-90/MWh.¹⁷
- Liquifying hydrogen and shipping is expected to be more expensive, with costs around £30-45/MWh per 1,000-10,000 km travelled, and a further £60/MWh for the conversion processes. Technology to ship liquid hydrogen is also at an earlier stage of development relative to shipping ammonia and is unlikely to be an economically feasible transport option in the near future.¹⁸
- The conversion and reconversion costs can be expected to reduce with technological innovations. However it remains likely that the costs of converting hydrogen into a transportable form and back again will be far greater than the costs of shipping, adding significantly to the cost of imports.

Despite ammonia already being transported globally, all these energy vectors need to resolve safety issues around flammability, toxicity and safe storage in order to be viable options for transporting and storing hydrogen at scale.

For short distances, importing compressed hydrogen over pipelines is expected to be more economical than converting the hydrogen into a transportable form and shipping.

- Pipeline transportation of hydrogen is considered to be cheaper than shipping for distances of up to 2,000 km with this increasing to over 3,000 km if large volumes (greater than 14 TWh/year) can be transported.¹⁹ Transporting hydrogen via pipelines would be the expected mode for green hydrogen imports from Europe and North Africa. BEIS has commissioned research on using pipelines to import compressed hydrogen from Norway and Spain.²⁰
- The UK currently has gas pipelines with Norway, the Netherlands, Belgium and Ireland. There is the possibility that these could be repurposed for hydrogen. Retrofitting existing high-capacity gas pipelines for hydrogen transportation could cost 40-65% of new pipeline construction.²¹ However, it is unclear whether embrittlement issues could mean conversions are not possible.
- It is currently not possible to quantify hydrogen leakage and there are uncertainties around the extent of leakage that could occur during its transportation.²²

While unlikely to be cost-competitive in the near-term, green hydrogen imports are expected to be cost-competitive with domestic green hydrogen production by 2050.

While long-term projections are uncertain, green hydrogen imports are estimated to be cost-competitive with domestic green hydrogen production from curtailed wind by 2050. (Figure 3.6).

- It is unlikely that importing green hydrogen will be cost-competitive with domestic green hydrogen production from curtailed electricity in the near term. However, published projections suggest that imports will exhibit significant cost reductions over the next few decades that are likely to increase its competitiveness.
- AFRY modelled the cost of domestic blue hydrogen production to be £50/MWh in 2035 and around £45/MWh in 2050. Based on these cost projections, green hydrogen imports could be expected to also be competitive with blue hydrogen by 2050.

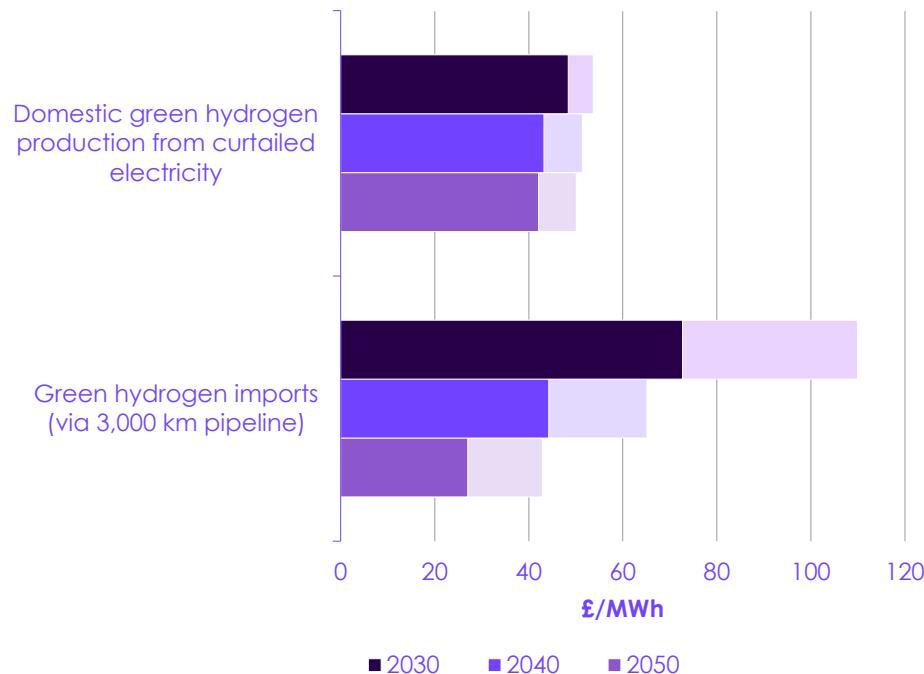
The UK's ability to import green hydrogen by 2035 will depend on how much green hydrogen is globally available for export and the competing demands of other countries.

The UK's ability to import green hydrogen by 2035 will depend in large part on how much green hydrogen is globally available for export, and the competing demands of other countries.

- The level of global interest in low-carbon hydrogen suggests that a global hydrogen market is likely emerge over the next few decades. However, there are a wide range of estimates for the potential scale of global green hydrogen production, and the quantity which could be available for export.^{23,24}
- 2035 is not far away. Given that an international hydrogen market has not been established yet, the viability of imported green hydrogen for any role in the UK by 2035 remains highly uncertain.

- The European Union has also set a target to import 390 TWh of green hydrogen by 2030, further increasing the challenge of meeting the 2035 shortfall with green hydrogen imports.²⁵

Figure 3.6 Projected costs for domestic green hydrogen compared to imported green hydrogen (£2020)



Source: BEIS (2021) Hydrogen production costs; IEA (2022) Global Hydrogen Review; European Hydrogen Backbone (2021) Analysing future demand, supply, and transport of hydrogen; Energy Transitions Commission (2021) Making the Hydrogen Economy Possible; PwC (2022) The green hydrogen economy; Hydrogen Council (2022) Global Hydrogen Flows; CCC analysis.

Notes: Domestic green hydrogen production costs based on the curtailed electricity cost estimates in BEIS (2021) Hydrogen production costs. This assumes an electrolyser load factor of 25%. The costs for alkaline and PEM technology have been used to inform the range. Green hydrogen import costs have been determined by combining published literature estimates for green hydrogen costs in favourable locations with literature estimates for the cost of transportation via pipeline. High volume pipeline estimates have been used with a pipeline distance of 3,000 km (the point at which high volume pipelines are estimated to be cheaper than shipping). The range reflects the variation in literature values and differences in pipeline capacities. Depending on the end destination for hydrogen, some additional storage costs are likely to be required.

(iii) Imported electricity for domestic hydrogen production

Electricity could be imported via interconnectors from countries with abundant, low-cost renewable electricity to produce green hydrogen domestically.

A third option to fill the gap between domestic production and demand is to import electricity directly from countries with abundant, low-cost renewable electricity via interconnectors and produce green hydrogen domestically.

Interconnectors already play an important role in supporting the UK's security of electricity supply. The number of interconnectors between the UK and neighbouring countries is expected to increase in future with a number of interconnection projects under development.

- The Government has committed to deliver at least 18 GW of interconnection capacity by 2030 and appears on track to achieve this target.²⁶

- The UK currently has 7.4 GW of existing interconnector capacity with France, the Netherlands, Norway, the Republic of Ireland and Belgium. In 2021, the UK was a net importer of electricity and imported 24.6 TWh via these interconnectors with 53% of the imported electricity from France and 24% from Belgium.²⁷
- A further 8.5 GW of capacity has received regulatory approval. This includes connections with Denmark and Germany. Other interconnectors are also planned.²⁸

Transporting electricity via High Voltage Direct Current (HVDC) cables for the production of electrolytic hydrogen domestically, has advantages over transporting hydrogen via pipelines or shipping:

- Interconnector costs exhibit greater unit-cost reduction over longer distances than hydrogen pipelines, which require compressor stations to be installed at regular intervals. Consequently, interconnectors can be used cost-effectively between the UK and a larger number of countries.
- It may be possible to realise hydrogen pipeline cost savings by converting existing gas pipelines for hydrogen transportation. However, the overall opportunities for cost reduction are expected to be more limited because pipelines are considered to be a more mature technology than HVDC interconnectors with more limited opportunities for cost reduction overall.
- Literature estimates indicate that interconnectors could be used to import electricity for hydrogen production at a cost of £29-40/MWh by 2050,* making interconnectors highly cost-competitive with hydrogen imports.²⁹
- Hydrogen leakage rates could mean far greater transport efficiencies for HVDC interconnectors over gas pipelines. Leakage reduction potential is also of particular importance given recent higher estimates of the indirect warming effects of fugitive hydrogen (see Box 3.1).

Although the UK could import additional electricity via interconnectors with mainland Europe, until the European system is decarbonised, this risks increasing overall emissions. Dedicated cables with green sources could provide earlier decarbonised supply.

The carbon-intensity of hydrogen produced from imported electricity depends on emissions at the other end of the cable. Although the UK could import additional electricity via the existing and planned interconnectors with mainland Europe to produce green hydrogen, until the European system is decarbonised this risks increasing overall emissions. Dedicated cables for imported electricity from green sources (e.g. from solar in Southern Europe or North Africa), could be one route to deliver earlier decarbonised supply.

(e) Delivery risks

It is unlikely that contributions to hydrogen supply from dedicated zero-carbon electricity sources, green imports or electricity imports would remove the need for blue hydrogen in 2035.

It is unlikely that any contributions from green hydrogen imports, or electricity imports for domestic green hydrogen, would remove the need for blue hydrogen on a 2035 timescale. The build rates required for the Government's existing ambitions for zero-carbon electricity (included in the modelling undertaken for this report) mean that further zero-carbon capacity for dedicated hydrogen production is not expected to be available at significant scale by 2035.

Blue hydrogen will therefore have an important part to play in filling the gap between domestic production and demand.

* A distance of 3,000 km is applied.

However, a portfolio of blue hydrogen and energy imports for hydrogen – imported as green hydrogen and/or electricity – would provide greater diversity of supply and lower lifecycle emissions.

Further progress in funding mechanisms is required if the Energy Security Strategy's commitment of 10 GW of low-carbon hydrogen production by 2030 is to be met.

In order to meet the commitment made in the ESS of up to 10 GW of low-carbon hydrogen production capacity by 2030, Government will need to make further progress in finalising funding mechanisms. We note that the scale of deployment of hydrogen in the power sector in the AFRY modelling (which tends to prefer hydrogen over gas CCS) would require hydrogen production capacity that goes beyond existing commitments. While it might be necessary to go further, there is also a question of what is feasible by 2030. A balanced approach to provision of low-carbon back-up capacity is likely to be needed to limit hydrogen requirements to manageable levels.

The Government has work in train on the Net Zero Hydrogen Fund and the Hydrogen Production Business model, with Government responses to consultations having been published in 2022, in addition to terms and conditions for the Hydrogen Production Business Model contract. The overall framework has yet to be finalised with allocation rounds due this year.

Recommendation	Owner (timing)
Finalise funding mechanisms and allocate funding to support the development of 10 GW of low-carbon hydrogen production by 2030 , ensuring these are designed to limit residual and upstream emissions, but also reflect hydrogen costs in a way that does not bias towards hydrogen where electrification is competitive.	DESNZ (2023)

CCS is a critical enabler for delivery and Government plans to deliver it have faced repeated cancellations and delays. It is crucial that Government plans are progressed urgently.

CCS also remains a critical enabler for delivery, applied both to biomass and to fossil gas, across hydrogen production and electricity generation. In our 2022 Progress report to Parliament we noted that Government ambitions to deliver it have faced repeated cancellations and delays. The ten-point plan established a commitment to deploy CCUS in a minimum of two industrial clusters by the mid-2020s, and four by 2030 at the latest. While Track 1 projects have been announced, and a project shortlist has been developed for phase 2 of the cluster sequencing; Track 2 has not yet been launched and no further update has been published on the CCUS Transport and Storage Regulatory Investment model (previously planned for 2022).³⁰ These must be progressed urgently.

Recommendation	Owner (timing)
Finalise and deliver the CCUS Transport and Storage Regulatory Investment business model, consistent with the Government's ambition to establish at least two CCS transport and storage clusters in the mid-2020s. This will require promptly beginning the process of awarding permits and construction of the necessary infrastructure, to ensure that it is ready in time for deployment.	DESNZ (Q1 2023)
De-risk the future Carbon Capture and Storage project pipeline by launching the next cluster selection process as soon as possible , consistent with the Government's ambition to enable final investment decisions on Track 2 projects from 2024.	DESNZ (Q1 2023)
Publish a plan for CO₂ transport from dispersed sites.	DESNZ (2023)

3. Hydrogen infrastructure

Hydrogen transportation and storage infrastructure is necessary to connect supply and demand.

The infrastructure for the transportation and storage of hydrogen is necessary to connect supply and demand in space and time, both for known needs, and as a catalyst for growth of the hydrogen economy.

(a) Hydrogen storage

(i) Hydrogen's role in long-term energy storage

The UK's energy demands are higher in the winter than the summer and will continue to be so in the future (see Chapter 1). It is therefore necessary to have infrastructure and energy supply that can flex to meet this pattern of demand, through some combination of increased energy generation in the winter and long-term storage.

The future energy system will likely require less seasonal flexibility from a gaseous energy vector (e.g. hydrogen, replacing the role of fossil gas) in the future than it is the case today:

- As winters get milder and summers hotter, less energy will be required for heating in winter and more required for cooling in summer. This will lead to some reduction in the current seasonal differences.
- Further reduction in the winter peak is achievable with energy efficiency (including use of more efficient technology such as heat pumps), and demand-side response.
- Generation from offshore wind is greater in the winter. This correlation with demand is helpful to the energy system as a whole and reduces the need for seasonal energy storage.

Section 1 of this chapter illustrates the weak seasonality expected in hydrogen demand in 2035 under the Central scenario (Figure 3.2). The seasonality of demand could be expected to grow as buildings decarbonise, but much of the corresponding increase in electricity supply is expected to come from offshore wind (which positively correlates with seasonal demand), so the role for hydrogen to provide seasonal storage may not be large even by 2050.

Long-term storage will be needed to act as back-up for extended periods of low wind generation. Hydrogen storage can play an important role here.

Despite reductions in seasonality, there will still be demand for long-term storage. This is energy storage that can be maintained for a long period of time until it is needed. Hydrogen storage has potential to play an important role here.

- Rather than being used primarily to meet seasonal swings in energy demand, this long-term storage acts as back-up for extended periods of low wind generation.
- In addition to providing a balance between demand and supply for energy over the year, hydrogen storage also has a valuable role in addressing profile mismatches in hydrogen supply and non-power demands, as well as outages.

The modelling commissioned for this report envisages a strong role for hydrogen storage, with hydrogen use in the power sector likely to be a strong determinant on the scale required.

The modelling commissioned for this report envisages a strong role for hydrogen storage in meeting the needs of the energy system.

- Across the range of scenarios used for our indicators, 2.1-2.8 TWh of hydrogen storage is deployed by 2030, with 3.3-5.2 TWh by 2035, and 7.1-11.6 TWh by 2050.
- Our 2030 range remains in the middle to higher end of projections recently published as part of research undertaken for Government.³¹ The lower bounds of our ranges have potential to be further reduced where there is an even greater reduction in the role of hydrogen in the power system than envisaged in the modelling for this report (with hydrogen-fired generation making up between 46-100% of low-carbon dispatchable supply across scenarios in 2035). However, a more limited use in the power system would require a stronger role for gas CCS and the associated infrastructure.
- The use of hydrogen in the power sector is likely to be a strong determinant of the scale of hydrogen storage required, with stable sources of hydrogen demand (e.g. in industry) likely to need much less storage than intermittent hydrogen demand.

(ii) Different forms of hydrogen storage

While there are a range of hydrogen storage options, salt caverns are the main solution being explored in the UK.

Salt caverns are the main underground storage solution being explored in the UK. Studies by the British Geological Survey suggest the UK has the potential for thousands of TWh of salt cavern storage.³² Although other options for storing hydrogen exist – including depleted gas fields, aquifers, and lined hard rock caverns (Box 3.4) – these are not being considered by the Government, and so are not discussed in detail in this report.

To some extent, the Government has a choice about precisely how much hydrogen storage capacity is developed in the UK to support time-varying production and use. For example, instead of blue hydrogen capacity operating consistently at full capacity, with storage providing a buffer for variation in demands, an alternative would be greater variation in the level of blue hydrogen production to better match the demand profile. This may entail a greater requirement for fossil gas storage. This is not discussed further here but remains an option for the proportion of supply met by blue hydrogen.

Box 3.4

Alternatives to salt caverns for underground hydrogen storage

Aside from in salt caverns, hydrogen can be stored underground via several different methods, with each having their own advantages and challenges.

- **Depleted gas fields** account for 76% of current natural gas storage capacity worldwide and tend to have a larger capacity and be more geographically widespread than salt caverns. They can only operate on a few cycles a year, so are better for seasonal storage than providing short-term flexibility. They could also be used for carbon capture and storage.
- **Aquifers** represent 11% of existing gas storage and operate similarly to depleted gas fields except they contain water instead of natural gas. This means that they must be overlaid with an impermeable cap rock to keep the gas underground. They may not be tight on all sides, so extensive surveys are needed. Like depleted gas fields, aquifers require more cushioned gas than salt caverns and allow less flexibility.

- **Lined hard rock caverns** tend to store natural gas liquids rather than gases. They could be used to store compressed or liquified hydrogen, but require the largest amount of investment, and have the smallest capacity of all options. However, these caverns only require 10-20% cushioned gas – the lowest of all hydrogen storage options – and can have multiple cycles, providing more flexibility to the system.

There are currently no projects in the UK that are looking into storing hydrogen in depleted gas fields, aquifers, or lined hard rock caverns.

Source: IEA (2022) *Global Hydrogen Review 2022*.

Salt caverns are already used in the UK to store hydrogen and other gases. The caverns have the lowest levelised cost of all hydrogen storage options and can be operated flexibly to support power sector flexibility.

Salt caverns are created by drilling into existing salt beds deposits and injecting water to dissolve the salt, leaving a cavern from which hydrogen can be piped in and out. Existing salt caverns in the UK already store hydrogen and other gases (e.g. in Teesside since 1972) and three projects are looking into hydrogen storage further: Humber Hydrogen Storage, HyNet / HyKeuper, and HySecure. It may be possible for salt caverns holding other gases to be repurposed for hydrogen.

Salt caverns can be operated flexibly with multiple cycles a year, making them more suitable to support power sector flexibility and electrolysis than other forms of underground storage. They have the lowest levelised costs of all hydrogen storage options and require less cushion gas than some other options (meaning more capacity can be used). However, salt caverns typically have a smaller storage capacity than some other options, and the geographical availability may be limited.^{33,34}

The modelling commissioned for this report assumes that salt caverns are the only type of underground hydrogen storage in GB,* with four locations modelled: Cheshire Basin, East Irish Sea, East Yorkshire and Wessex. The following techno-economic and deployment assumptions are used in the modelling:

- Capex is assumed to be between £100-150/kW, with opex assumed to be £3.8-6.8/kW/year. Costs vary between the sites but are not expected to reduce over time.
- Capacity is only assumed to become available in 2030. Each site has a lifetime of 40 years and a build time of four years.
- Efficiency is assumed to be 95%. This means that for every 100 MWh of hydrogen that goes into storage, 95 MWh of hydrogen can be extracted again, with the losses factoring in the energy required for the hydrogen compression.

There are two other potential types of hydrogen storage that could also play important roles in managing hydrogen supply:³⁵

- Above-ground storage in medium-pressure storage tanks for a storage duration of up to six hours. Storage tanks would be able to have several cycles a day and could fill up directly from, and empty into, the transmission network for morning and evening peaks.

* They are accompanied by medium-pressure storage tanks, but these account for a tiny fraction of storage capacity – 8 GWh compared to 5,220 GWh of salt cavern storage in 2035 in the AFRY Central scenario.

- Linepack storage, as in the gas networks today, where hydrogen is effectively stored in transmission pipelines by dropping the outlet pressure. There would likely be reduced opportunity for hydrogen linpack compared to natural gas today, given the lower energy density of hydrogen.

(b) Hydrogen networks

A hydrogen network is required for hydrogen use to expand outside of planned clusters.

A hydrogen network is required for hydrogen use to expand outside of the planned clusters. The factors which will determine the appropriate levels of network build will include: the range of hydrogen end-uses (including any role in home heating); the geographical location of end-uses, a function both of policy decisions and economics; the nature and location of hydrogen supply and associated infrastructure; and security of supply and competition considerations. Insufficient build has potential to drive inefficiencies (e.g. in the location of assets, or in the volume of production and storage infrastructure required) and, in turn, system costs.

There are a number of ways to transport hydrogen domestically:

Pipelines are the only transport mode suited to transporting significant volumes of hydrogen. It may be possible to repurpose some gas pipelines to hydrogen.

- Hydrogen could in theory be transported by pipeline, rail, road, and sea. However, pipelines are the only mode suited to transporting significant volumes of hydrogen. The Government's Hydrogen Strategy indicates that road transport will only be used in the early to mid-2020s, and this will be replaced by pipelines as distances and scale increase.³⁶
- In some cases, gas pipelines can be repurposed to hydrogen. This can reduce costs and prevent stranded assets.
 - Repurposing is more likely to be possible where there are underused parallel pipelines which would allow one line to be temporarily closed and repurposed, allowing the other to satisfy existing natural gas demand needs. This scenario is likely to rely on there being a minimum hydrogen uptake by relatively large consumers that are co-located with the repurposed timelines.
 - Repurposing a pipeline may involve regularly monitoring pipeline integrity, adding a hydrogen barrier coating, or reducing pressure (and its swings) so safety thresholds can be met. Repurposing can save 50-80% of the costs of building new pipelines.³⁷
 - However, if repurposing is technically infeasible or the natural gas demand is too strong, then new pipelines would need to be built.
- Projections for pipeline needs vary, with uncertainties around the role of hydrogen in power, and in buildings demand for hydrogen.
 - National Grid is exploring options to develop a UK hydrogen backbone (Project Union). This aims to join industrial clusters together to connect major sites of hydrogen production with its end-uses (industry, transport, power, and possibly heat) via up to 2,000 km of network.³⁸

- Research undertaken for Government suggests between 100 km and 1,000 km of pipeline could be needed by 2030 (with the range driven by uncertainty in the role of hydrogen in power), with 700-26,000 km needed by 2035 (with the range largely driven by uncertainty around demand for hydrogen for buildings).³⁹

The modelling undertaken for this report projects that GB would require 20-27 GW of transmission pipeline capacity by 2035. In the Central scenario, this capacity is equivalent to around 3,800 km of pipeline.

The modelling undertaken for this report examined the scale of hydrogen pipeline transmission capacity that could be required to meet the levels of demand included in the modelled scenarios. It did so by considering GB as 11 hydrogen zones with industrial clusters dispersed across GB and broadly aligned with those identified in Project Union.

The modelling projects that GB would need 20-27 GW of pipeline capacity by 2035 (Table 3.2).

- The modelling deploys hydrogen pipeline capacity at a rate of 1.2-2.4 GW a year between 2030 and 2035, with deployment constrained before 2030.
- The pipeline build projected in the Central scenario is equivalent to around 2,800 km of pipeline by 2030 and around 3,800 km of pipeline by 2035.
- The growth of pipeline capacity is limited in some areas (such as between the Midlands and South Wales) but is significant in others (such as between the Midlands and the North).
 - Capacity was assigned based on the location of production and salt caverns. The largest deployment of new pipelines occurs between the Midlands and the North of England and Scotland. This links a supply of hydrogen from the North to salt cavern storage in the Midlands.
 - Hydrogen flows are partially population weighted (replicating non-power demands) and pipeline capacity is deployed between London and the Midlands and South.

Late network delivery has the potential to inhibit the development of the storage and production infrastructure needed.

The scale of hydrogen network required is highly dependent on the decisions yet to be taken in high demand sectors (e.g. the 2026 hydrogen for heat decision). However, late hydrogen network delivery has potential to act as a blocker to storage and production infrastructure needed to support the 2035 power system decarbonisation target. This must be a key consideration in strategic decisions around infrastructure build.

Table 3.2

GB hydrogen transmission pipeline capacity in the Central scenario

	Boundary	2028	2030	2035
	SHETL North – SHETL South	0.0	0.6	0.7
	SHETL South – SPT	0.0	3.1	3.7
	Upper North - SPT	0.0	2.5	3.0
	North – Upper North	0.0	0.2	0.4
	Midlands – North	0.0	6.0	7.3
	East – Midlands	0.0	0.0	0.0
	London – Midlands	0.0	0.2	0.5
	London – South	0.0	1.0	3.0
	Midlands – South	0.0	0.4	1.3
	London – Thames	0.0	1.7	2.6
	Midlands – South Wales	0.0	1.3	2.8
	Total	0.0	16.9	25.1

Source: AFRY (2023) Net Zero Power and Hydrogen: Capacity Requirements for Flexibility.

(c) Delivery risks

Long lead-times for hydrogen infrastructure build suggest that Government's development timelines may not be ambitious enough to deliver the levels of infrastructure outlined in this report.

The Government has committed to develop new business models for the transport and storage of hydrogen by 2025.⁴⁰ However, the long lead-times associated with infrastructure build suggest that Government's timeframes for development may not be sufficiently ambitious to achieve the levels of infrastructure outlined in this report.

- The modelling undertaken for this report implies a need for between 2.3-2.8 TWh of hydrogen storage by 2030. The lead-times required for new salt cavern storage are around 7-8 years (both planning and construction). Alongside this, 20-27 GW of pipeline capacity is estimated to be necessary by 2035.
- There is potential for the lower bounds of hydrogen use to be reduced further relative to those set out in this report (where heating is fully electrified or low-carbon dispatchable power is planned to be heavily gas CCS dominant), in turn implying lower requirements for storage and transport infrastructure. However, this will require additional build of alternative infrastructure in its place, (e.g. increased levels of gas CCS and other forms of storage).

- There is also a risk of stranded assets where there is a mismatch between the proportion of gas plants being future proofed for hydrogen relative to gas CCS, and strategic decisions around infrastructure build which determine the deliverable balance of hydrogen and gas CCS in the future power system.

The Government needs to fast track its development of business models for hydrogen transport and storage to keep options open on the scale of hydrogen use by 2035. Strategic decisions will also be needed.

It is not sensible to delay all decisions on hydrogen infrastructure until after decisions on the use of hydrogen for heating. Development of hydrogen infrastructure must be initiated sooner, pursuing investments considered low-regret given the need for hydrogen in the electricity system, and in industry.

These factors imply that the Government needs to fast track its development of new business models for hydrogen transport and storage. This will keep options open on the scale of hydrogen usage by 2030 and 2035. The Government should also set out strategic decisions as part of a comprehensive long-term strategy for the delivery of a decarbonised power system by 2035 (as recommended earlier in this report) alongside a plan on the distribution and storage of hydrogen outside of clusters.

While the decisions in 2026 on the respective roles of hydrogen and electrification for buildings heating will affect the precise shape of future electricity and hydrogen infrastructure, it is not sensible to delay all decisions on hydrogen infrastructure for three years. Development of hydrogen infrastructure must be initiated sooner, pursuing a set of ambitious investments that are considered low-regret given the need for hydrogen infrastructure to manage the electricity system and in industry.

Recommendation	Owner (timing)
Fast track the development of new business models for hydrogen transportation and storage infrastructure, with a view to keeping options open for larger scale hydrogen use by 2030. Legislate in the Energy Bill to create enabling powers for the hydrogen storage business model and finalise the business model by the end of 2023. Fast track the hydrogen transportation business model alongside this, clarifying the respective responsibilities of Government, Ofgem and the FSO in funding and delivery.	DESNZ (2023)
Publish a site-specific plan for distribution and storage of hydrogen and other low-carbon infrastructure outside of clusters.	DESNZ (Q1, 2023)

4. Implications for fossil fuel consumption

A key aim of the Energy Security Strategy is to reduce the UK's dependence on imported fossil fuels.

A key aim of the ESS is to reduce the UK's dependence on imported oil and gas, thereby reducing exposure to volatile international prices. The Government has set a target for the UK to be a net energy exporter by 2040.⁴¹

The UK is currently a net importer of oil and gas, with net imports of fossil gas (485 TWh) and crude oil (420 TWh) both significant in 2021, prior to Russia's invasion of Ukraine and the turmoil this caused in international fossil fuel markets.⁴²

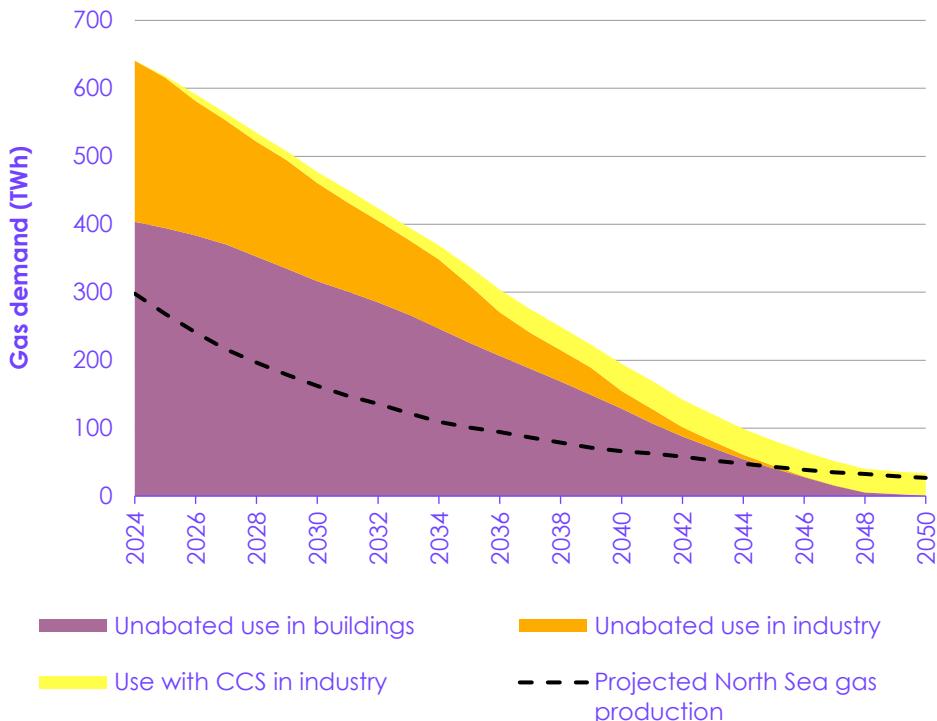
- The UK currently produces around 440 TWh of domestic gas and imports around 500 TWh of natural gas, with 88% of these coming from just four countries (62% Norway, 15% Qatar, 6% USA and 5% Russia).*
- The UK can also act as a 'land bridge', importing gas (e.g. as LNG) and then re-exporting it. This effect was small in comparison to the volumes of imported gas up to 2021, with net exports of around 75 TWh, mainly to Ireland.
- This 'land bridge' phenomenon has been seen more strongly in the last 12 months, as the UK's LNG import infrastructure has effectively enabled it to import fossil gas as LNG on behalf of mainland European countries, exporting it via existing interconnector pipelines (as well as exporting gas-fired generation via electricity interconnectors). We will review these dynamics in our annual Progress Report later in 2023, once more complete energy data for 2022 are available.

Gas demands in end-use sectors are projected to decrease steadily on the path to Net Zero.

Gas demands in end-use sectors (i.e. outside electricity generation and hydrogen production) are expected to reduce steadily over the period to 2050 (Figure 3.7).

* These figures are for the years 2018-2020. There was a 17.2% drop in production in 2021 due to an extensive maintenance schedule, which required a spike in imports.

Figure 3.7 Overall UK gas demand in non-power sectors in our Balanced Pathway (TWh)



Source: CCC (2020) Sixth Carbon Budget Balanced Pathway; NSTA (2022) August 2022 oil and gas production projections.

Notes: Demand for gas from other non-power sectors not shown on figure. These account for around 0.2% of gas demands each year.

There will still be a significant requirement for gas with CCS for energy generation in 2035. However, increases in renewable energy and electrolyser capacity will enable a significant reduction in gas demand for energy generation by 2050.

Regarding gas demands for energy generation (across power and hydrogen), there will still be a significant requirement for gas in 2035 for use with carbon capture and storage (CCS), across some combination of post-combustion gas power plants and blue hydrogen production.

However, fossil gas consumption can be expected to reduce from 2040 to 2050 as increases in renewable energy capacity decrease the demand for low-carbon dispatchable generation, and increases in electrolyser capacity ramp up the production of domestic electrolytic hydrogen (Figure 3.8):

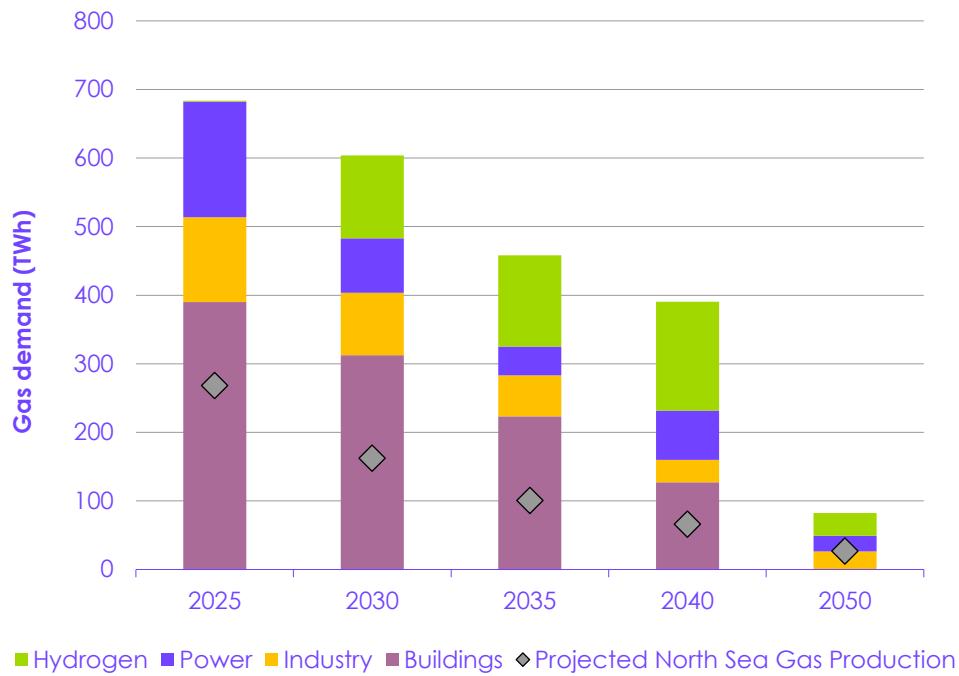
- The power demands for gas will be impacted to some degree by the balance between gas CCS and hydrogen in delivering low-carbon dispatchable power. However, a move towards a greater gas CCS mix will make only a small difference to overall gas demand (power from blue hydrogen requires around 14% extra gas per MWh generated than power from gas CCS).
- Instead, the demand for gas is driven by size of the hydrogen supply gap, between consumption and what can be met through non-fossil supply, with blue hydrogen production expected to play an important role in filling this gap by 2035 but then falling into a back-up role as zero-carbon forms of hydrogen grow to dominate.
- Across the range of scenarios developed for this report there is 135-379 TWh of GB gas demand for power and hydrogen in 2035 and 30-281 TWh in 2050.

When combined with the non-power demands for gas in our Sixth Carbon Budget scenarios, this equates to total gas demands of 439-845 TWh in 2035 and 66-611 TWh in 2050.

Reducing the UK's reliance on gas imports depends on building large amounts of zero-carbon generation capacity, as well as energy efficiency and efficient electrification across end-use sectors.

Reducing our reliance on gas imports and becoming an overall net exporter of energy depends on building out a large amount of zero-carbon generation capacity, as well as pursuit of energy efficiency and efficient electrification across the buildings, industry and transport sectors. Using hydrogen in place of efficient electrification (e.g. instead of heat pumps for buildings) would be a much less efficient use of domestic energy resources, leading to greater need for imported energy to supplement them.

Figure 3.8 Annual GB gas usage in the Central scenario and our Balanced Pathway (TWh)



Source: AFRY Central Scenario, CCC (2020) Sixth Carbon Budget Balanced Pathway; NSTA (2022) August 2022 oil and gas production projections.

Notes: Gas demands in buildings and industry taken from the CCC's Balanced Pathway; those for power and hydrogen are taken from AFRY's Central scenario modelled for this report.

While reducing the demand on fossil fuel imports, the shift towards a decarbonised energy system will increase the demand for critical minerals with several low-carbon energy sources dependent on certain minerals.

While the deployment of renewable energy and electrolyser capacity will reduce demands on fossil fuel imports, the shift towards a decarbonised energy system will increase the demand for critical minerals. Several low-carbon energy sources and storage options are reliant on certain critical minerals whose supply is dominated by only a few countries.

- Wind turbines use magnets that require rare earth elements including neodymium, dysprosium and praseodymium while solar panels use gallium. The current market-leading form of battery storage requires the use of lithium, cobalt and granite. Ongoing research aims to find alternative materials that give similar performance.⁴³
- The production of these critical minerals is centred in only a few countries. For example, China is the main producer of rare earth metals, accounting for an estimated 70% of global production in 2022.⁴⁴

The Government published a Critical Minerals Strategy in 2022 that aims to improve the resilience of critical supply chains and combat the risk of increasing dependence on critical mineral imports. The strategy focuses on maximising the UK's domestic capabilities, diversifying its supply across further countries and enhancing the ability and transparency of international markets.⁴⁵

5. Indicators for monitoring progress

We have developed a provisional set of indicators against which we plan to monitor progress on hydrogen production and storage towards 2035, with ranges to reflect uncertainty.

We will be keeping the set of indicators under review, including considering any other areas where future indicators may be needed.

In addition to the indicators on electricity system flexibility set out in Chapter 2, we have also set out a provisional set of indicators against which we plan to monitor progress on hydrogen production and storage towards 2035 (Table 3.3).

As explained in Chapter 2, the range in these indicators reflects a subset of the scenarios and sensitivities modelled for the purposes of this report, selected with a view to reflecting the range of outcomes which might be achieved pending uncertainty.

We will be keeping these indicators under review, including considering how best to monitor progress in the context of the indicator ranges, and considering any other areas where future indicators may be needed (e.g. in relation to infrastructure development).

We also note that the lower bounds of our hydrogen indicator ranges have potential to be further reduced where heating is fully electrified (as in our Sixth Carbon Budget Widespread Engagement scenario) or where there is a lesser role for hydrogen in managing the power system than envisaged in the modelling for this report (with hydrogen-fired generation making up between 46-100% of low-carbon dispatchable supply across scenarios in 2035). We intend to keep these under consideration pending future work. The most up-to-date list of indicators will remain visible in our published monitoring framework.⁴⁶

Table 3.3

Indicators for hydrogen production and storage to 2035

Indicator	Unit	2025	2028	2030	2035
Low-carbon hydrogen production	TWh/year	0	33 - 55	76 - 121	115 - 216
Low-carbon hydrogen production de-rated capacity					
In operation	GW	0	4 - 6	9 - 14	13 - 25
Under construction	GW	4 - 7	6 - 9	3 - 7	3 - 8
In development	GW	8 - 12	4 - 8	3 - 6	5 - 15
Hydrogen storage capacity					
In operation	TWh	0	0	2 - 3	3 - 5
Under construction	TWh	1 - 2	2 - 4	1 - 2	1 - 2
In development	TWh	2 - 4	1 - 2	2 - 3	2 - 3
Carbon capture and storage					
CO₂ captured	Mt/year	1	8 - 16	24 - 37	46 - 69

Source: AFRY (2023) *Net Zero Power and Hydrogen: Capacity Requirements for Flexibility*; CCC analysis.

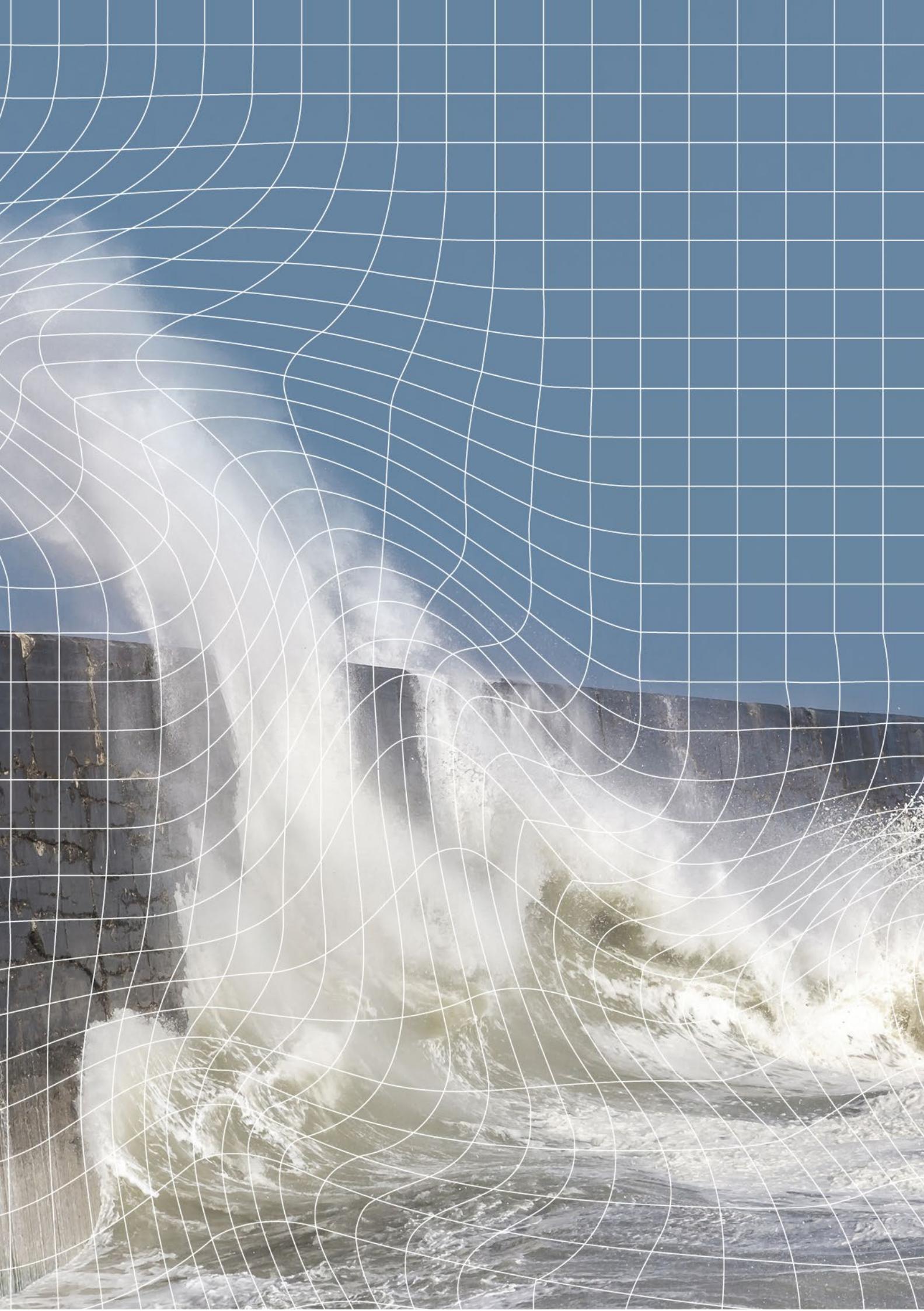
Notes: The in-operation values for low-carbon hydrogen production de-rated capacity have been calculated from the installed production capacity and the respective load factors for the different technologies determined by the modelling (in 2035, the load factors are 95-96% for biomass gasification CCS, 79-92% for ATR CCS and 39-48% for electrolysis).

Endnotes

- ¹ CCC (2018) *Hydrogen in a low-carbon economy*, <https://www.theccc.org.uk/publication/hydrogen-in-a-low-carbon-economy>.
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Chapter 4

The need for climate resilience

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2. Delivering a climate-resilient decarbonised energy system	125

Introduction

The changing climate is expected to lead both to changes in the ‘business as usual’ weather patterns that impact supply and demand profiles, and changes in extreme events which have potential to drive weather-related system faults. Previous chapters have dealt with the first of these, and here we focus on the second.

Climate risks to the power system were among some of the most urgent risks facing the UK in the latest UK Climate Change Risk Assessment (CCRA3).

Climate risks to the power system were among some of the most urgent risks facing the UK in the latest UK Climate Change Risk Assessment (CCRA3).¹ The CCC identified risks to people and the economy from climate-related failure of the power system as one of eight priority areas for further action by Government, given the potentially far-reaching consequences of a power failure across society, and the growing importance of electricity in the transition to a Net Zero economy.

Given the growing interdependencies between key societal functions and the energy system, together with the move towards a system more dominated by variable renewables, it is essential for policymakers to consider changing climate hazards as part of system planning. A resilient energy system will deliver a reliable supply of decarbonised energy, despite climate change.

This chapter covers the resilience of today’s energy system, the potential impacts of extreme weather events on the future decarbonised system, and what is needed to ensure resilience to those hazards.

This chapter is set out in two sections:

1. Climate and weather risks to a decarbonised energy system
2. Delivering a climate-resilient decarbonised energy system

1. Climate and weather risks to a decarbonised energy system

(a) Current weather-related disruption

It is currently not possible to adequately assess the extent to which the energy system is resilient to today's weather climate.

Recent storms have highlighted that the energy system is insufficiently resilient to today's weather and climate. Disruptions to the energy system can have substantial impacts on society and the economy. The financial impact of weather-related outages has also not been comprehensively assessed.

Despite the critical economic role of a functioning electricity system, reporting and monitoring standards for weather-related electricity outages are currently limited. Data on outages to electricity supply are currently not reported at a national scale, and weather-related faults on the distribution network, transmission network or generation facilities are not recorded consistently:

- Distribution network failures: Distribution Network Operators report 'customer interruptions' and 'customer minutes lost' to Ofgem each year. However, data on the weather-related cause, as well as the impact on other key systems, are not available.
- Transmission network failures: Available data suggest that half of all transmission network faults are weather-related, with transmission overhead line fault rates about a thousand times higher in storms than in 'normal' weather.^{2,3}
- Generator failures: Data on outages to generating capacity are also poorly reported. Reports produced under the Government's Adaptation Reporting Power do provide some insights on some events, although this is not consistently collated or reported at a national level.

As energy storage becomes an increasingly important part of the electricity system over coming years, good reporting practices on weather-related disruption should be implemented.

Specific instances of weather-related power failures over recent years highlight the potential for significant impacts.

Specific instances of weather-related power failures over recent years highlight the potential for significant impacts (Box 4.1).

Box 4.1

Recent weather-related disruption to the electricity system

- In 2019, a lightning strike initiated a cascade of events that, via a number of incorrect automatic responses by generators, led to interruption of power supply to one million people in the South-East of England and caused significant knock-on effects on the rail sector, leaving passengers stranded on trains for many hours.
- Storm Arwen, in 2021, caused extensive damage to the local grids across Northern England and Scotland, initially leaving over one million customers without power. The North-East of Scotland experienced the equivalent of almost two years' worth of overhead line faults in a 12-hour period. Much of the damage was caused by wind gusts of about 100 mph, with over 1,000 points of damage recorded in the North-East of Scotland. Thousands of customers remained without power for days.
- Storm Barra, also in 2021, brought gusts of around 80 mph along with blizzards and heavy rain, causing a loss of power to around 30,000 homes in Northern Ireland. Wales and parts of England were also affected.

- In 2022, extreme temperatures during the July heatwave caused power cuts due to conductors sagging and transformers overheating, with temperatures exceeding 40°C in some places. During the heatwave grid operators were forecasting a 70% chance that demand would outstrip supply, an outcome that would have caused blackouts across the network.

Source: Ofgem (2022) *Final report on the review into the networks' response to Storm Arwen*; MacIver, C., Bell, K., & Nedd, M. (2021) *An analysis of the August 9th 2019 GB transmission system frequency incident*. Electric Power Systems Research, 199; various media reports.

(b) Changing risks of weather-related failures

Over the decades to 2050 and beyond, global climate change will drive changes to UK weather and climate, altering the types of weather hazards the energy system will face.

Over the decades to 2050 and beyond, global climate change will drive changes to UK weather and climate. This will alter the types of weather hazards the energy system will face (Table 4.1). Climate change elsewhere will also create risks to the UK through direct routes (e.g. disrupting the supply of electricity flowing through interconnectors) and indirect ones (e.g. disrupting international key component supply chains). The expected changes in UK and global climate through to 2050 will occur largely independently of how rapidly global greenhouse gas emissions are reduced, although further change beyond 2050 is strongly dependent on whether global efforts to reduce emissions are effective. Changes will emerge continuously, but weather and climate fluctuations will still strongly influence what hazards are experienced in any one year. The design of the decarbonised system we build by 2035 must consider the range of possible future climate conditions that it will be required to operate under over its lifetime.

By 2050, some weather hazards that can impact on the functioning of the electricity system will become more common and intense and will have potentially larger effects on the system than today. Some hazards will become less likely but will still occur occasionally in the future. Changes in some potentially important weather hazards remain uncertain (Chapter 1).

Table 4.1

Potential impacts on the energy system due to climate trends & extreme weather events in the UK

Climate hazard	Expected change by 2050	Potential impacts on the energy system	
		Generation and storage	Transmission and distribution networks
Heatwaves	~50% chance of 2018 summer each year*	Efficiency loss at thermal generation plants; efficiency loss of solar PV generation; higher electricity demand for cooling; maximum operating temperatures for components exceeded.	Efficiency loss on transmission lines; restrictions of thermal ratings of assets; risk of faults increased if power flows not reduced; potentially dangerous sagging of power lines.
Flooding (river, surface and coastal)	~5% wetter winters on average** ~10% increased intensity of heavy rainfall 10 – 30 cm increase in average sea levels***	Loss of generation capacity or storage due to inundation.	Loss of transmission & distribution capacity due to flood damage.

Drought	~10% drier summers on average****	Loss of generation capacity due to lack of water supply for cooling and production of hydrogen.	
Wind strength and wind regimes	Highly uncertain	Potential large-scale and coordinated loss of wind generation during wind droughts; or high wind speed shutdown of turbines.	Loss of network capacity due to damage in high winds.
Storminess and occurrence of storm events	Highly uncertain	Loss of generation capacity due to damage during storm events; potential large-scale and coordinated loss of wind generation during high wind speed shutdown of turbines.	Loss of network capacity due to damage in storm events.
Snow and ice	Decreasing but still possible	Potential during periods of very low temperatures for failure of gas supply or electricity generation equipment.	Loss of network capacity due to icing of power lines.

Source: UKCP18 Projections; summarised in CCC (2021) *Independent Assessment of UK Climate Risk*.

Notes: * around 10-25% today; ** compared to 1981-2000 ***above 1981-2000 levels; **** than over 1981 – 2000.

(c) Cascading failures

The cascading impacts of electricity failure are already significant. These will continue to grow in an increasingly electrified economy facing more common and severe extreme weather events.

Extreme weather events can create cascading risks that spread across the economy, with impacts an order of magnitude higher than impacts that occur within a single sector. The cascading impacts of electricity failure are already significant. These will continue to grow as the economy becomes increasingly electrified and as extreme weather events become more common and severe. As well as an increasing reliance on electricity among other critical national infrastructure (CNI) sectors, energy and other infrastructure operators increasingly use mobile or internet-based means to communicate with their staff, thus they are increasingly exposed to telecoms outages. Energy, water and IT infrastructure are often co-located, meaning that weather-related power cuts can affect multiple sectors simultaneously. Transport routes can become unpassable, delaying the restoration of power after an outage.

CCRA3 concluded that more action is needed to understand the scale of interdependency risk between the energy system and other key infrastructure. The available evidence suggests that Governments and industry may be significantly underestimating the vulnerability of interconnected systems.⁴ Evidence obtained during a recent parliamentary inquiry into critical national infrastructure and climate adaptation found numerous recent examples of cascade events and near misses, including:

- During Storm Arwen in 2021, BT's ongoing transition to digital phone lines (which are reliant on electricity) meant that some customers were left without access to communication, even for calls to the emergency services.
- A power station had to reduce operations for two to three weeks when the canal water level fell below the required level for abstraction in 2021.

- An energy company reported that engineers had trouble visiting sites to deal with technical faults during the ‘Beast from the East’ storm in 2018 due to major travel disruption.⁵

Gaps in understanding of these risks remain and need to be addressed.

Gaps in understanding of these risks remain and need to be addressed to understand the full scale of climate risks facing the future electricity system. These include:

- Improved understanding of how climate change will alter key weather hazards (such as wind and lightning extremes).
- The full range of potential storm impacts, including future risks of damage from storm-felled trees falling on power lines.
- A more systematic assessment of risks posed from cascading impacts across multiple sectors due to failures of the electricity system.

The next UK Climate Change Risk Assessment (CCRA4) presents an opportunity to improve the evidence base in these areas.

Recommendation	Owner (timing)
<p>Commission further research to improve understanding of how climate change is altering key weather hazards that will impact the energy system, including developing plausible high-impact low-likelihood scenarios to stress test the system against.</p>	DESNZ, UKRI, Defra (ongoing)
<p>Coordinate a systematic assessment of risks posed from cascading impacts across multiple sectors due to failures of the decarbonised energy system as part of the next round of the Adaptation Reporting Power. This coordination role should include: producing a template or guidance for assessing interdependency risks, including transition risks; further building the evidence base on interdependency risks; supporting sector forums to enable collaboration; working with regulators to support cross-sector working; and leading a stress-testing exercise on core infrastructure systems to identify key weaknesses and points of failure under plausible extreme events from future climate conditions.</p>	Defra (2025)
<p>Require all energy system organisations to report under the Adaptation Reporting Power, to link their adaptation actions to climate risks, with clear ownership and timescales, and to provide more information on the effectiveness of adaptation actions in reducing risk within their ARP reports.</p>	Defra (2023)

2. Delivering a climate-resilient decarbonised energy system

A decarbonised energy system will not be reliable if it is not climate-resilient. If future climate risks are not considered and reflected in energy system planning and operation, there is a significant risk that new infrastructure and system design may not be well adapted to the climate and weather hazards expected over its lifetime, creating additional costs to retrofit later and/or locking in increased climate vulnerability. In addition to climate risks, other critical risks to the functioning of the system, for example space weather incidents, also need to be considered in planning for the energy system to be resilient overall.

A decarbonised energy system will not be reliable if it is not climate-resilient. We must not lock-in increased climate vulnerability or additional cost.

Energy UK reports that the majority of existing generation assets will reach the end of their life by 2039.⁶ In addition to replacement of existing assets, significant additional generation capacity will be required by 2050 to deliver Net Zero (driven by growing use of variable renewables and meeting demand arising from the electrification of road transportation and household heating).

As the UK upgrades its energy system for 2035 and beyond, we should be doing a range of things to manage these risks:

- Reduce the vulnerability of network and generation assets to climate hazards.
- Increase system-level security of supply.
- Identify and manage interdependencies.

The rest of this chapter sets out actions needed to build a climate-resilient, decarbonised energy system.

(a) Reduced vulnerability of assets

To reduce vulnerability of generation and network assets, climate impacts such as flood risk, extreme heat and reduced water availability must be considered in site selection and design, maintenance and life extension.

To reduce the vulnerability of generation and network assets, climate impacts such as flood risk, extreme heat and reduced water availability must be considered in site selection and design. These should also factor into the maintenance and life-extension of existing assets. This is crucial to maximise system outputs under future climate conditions and minimise risks of damage and disruption. For example, enhancing flood defences or burying assets, which reduces exposure to some hazards, or designing assets to higher maximum operating temperatures.

The National Policy Statement for new energy infrastructure, and provisions under the Planning Act, require applications for new energy infrastructure to account for the potential impacts of climate change. These include using the latest UK Climate Projections available at the time and with adaptation measures that are based on the latest UK Climate Change Risk Assessment (CCRA). The extent to which these tests are being applied is not known.

For projects in the Government's Major Projects Portfolio (GMPP), the Infrastructure and Projects Authority (IPA) has recently published tests for climate resilience to be applied in assurance reviews of all GMPP projects. However, a monitoring regime is not yet in place. Such a regime would improve transparency around climate resilience considerations in major energy infrastructure projects and produce data that could be published on Government registers of major projects.

Standards and guidance for network operators cover resilience against some climate hazards – primarily flooding. Technical guidance (ETR138)⁷ requires significant substations (i.e. those with more than 10,000 connections) to be resilient for a 1-in-1,000-year flood event. Other standards for vegetation management around overhead lines, act to reduce damage caused by trees felled in severe weather. International standards for heat that apply to component parts of the electricity network and transformers, state that equipment should function at ambient air temperatures of between -25°C and 40°C.

There is a need for minimum resilience standards, covering all relevant parties and all relevant climate hazards.

The UK is already experiencing regular heat-related outages and heatwaves are projected to become more common and extreme in the decades to 2050 and beyond.⁸ As such the current maximum operating threshold requirements for generation and network assets are unlikely to be sufficient in some parts of the UK. The UK Government has committed to new standards for resilience by 2030 under the new UK Resilience Framework.⁹ This presents an opportunity to ensure that the future energy system is resilient to the full range of climate conditions under which it will operate.

Recommendation	Owner (timing)
<p>Develop a pathway to setting appropriate minimum resilience standards (both at asset and system level) to relevant climate hazards identified in the UK Climate Change Risk Assessment (CCRA), covering all relevant parties. These need to be established with a mechanism to regularly review and revise as understanding of these risks improves.</p>	DESNZ, Cabinet Office (by 2028 at latest)

Energy generators, electricity transmission and distribution grid companies, and gas transportation companies are invited to report their climate risk assessments and adaptation plans to Defra every five years, under the Adaptation Reporting Power (ARP).^{*} However, participation is voluntary and as a result there are gaps in reporting across the sector. The CCC assessed all third round ARP reports and found good coverage of adaptation plans for electricity transmission and distribution, but a lack of detailed adaptation plans from generators, and Ofgem declined to report.¹⁰ Reporting under the ARP should be mandatory and the requirements for reporting by generators and regulators should be reviewed to ensure sufficient coverage across the sector.

(b) System-level security of supply

A reliable and resilient decarbonised energy system will have sufficient generation capacity, flexibility, and redundancy to respond to variations in the weather on which it is reliant, and to climate and weather-related changes in demand.

- **Capacity.** Sufficient capacity is needed to be able to account for seasonal and weather-related changes in demand. These are associated with greater electricity demands in the winter and summertime peaks associated with increased cooling demands, and may occur at times when generation from weather-dependent renewable sources are low. There also needs to be sufficient capacity to allow for maintenance and outages of key electricity system assets.

* Covers GB electricity transmission and distribution companies, GB energy generators generating over 10 TWh and transportation companies serving over 50 000 customers.

- **Flexibility.** There must be sufficient flexibility options that allow demand for and supply of electricity to be balanced on the grid for various timescales. Chapter 2 discusses the generation mixes and levels of firm unabated gas capacity that can ensure sufficient flexibility, even under more extreme but plausible low wind scenarios.
- **Redundancy.** Adequate redundancy is required in network design to reduce the likelihood of loss of supply to locations, and in downstream services e.g. local generation, increased storage, and diversity of generation.

(c) Interdependencies identified and managed

Interdependency risks are not being consistently incorporated into climate change risk assessments and adaptation action plans of energy network and system operators.

ARP reports submitted in 2021 show that network and system operators are starting to actively consider their interdependencies with other infrastructure systems. However, interdependency risks are not being consistently incorporated into climate change risk assessments and adaptation action plans. We made recommendations to Defra in 2022, aimed at improving understanding of interdependency risks at operator level and the steps being taken to manage them.

(d) Facilitating delivery

(i) Governance

Current governance arrangements for resilience in the energy system are complex.

Current governance arrangements for resilience in the energy system are complex. A wide range of Government bodies, public sector agencies and private organisations play a role in design of the energy system and maintaining resilience in its operation (Box 4.2). Effective co-ordination on resilience between these bodies will be vital.

Box 4.2

Governance of climate resilience in the energy sector

Governance of resilience in the energy sector is complex, responsibilities are often overlapping and not always clear.

- **Central Government.**
 - DESNZ: energy policy and meeting statutory decarbonisation targets.
 - Defra: national adaptation planning.
 - Cabinet Office: co-ordination and emergency response.
 - Treasury: sets the direction of the UK's economic policy and influences every policy across Government.
- **Regulators.** Ofgem regulates the electricity and gas market; its powers and duties do not currently explicitly reference Net Zero or climate resilience.
- **System operators.**
 - National Grid ESO operates the electricity transmission system, and takes steps to ensure that it operates in a stable manner. It is also responsible for the development of transmission network reinforcement strategy and for maintenance of a number of key industry standards and codes that have a major influence on resilience of electricity supply.
 - The new Future System Operator (FSO) will oversee the UK energy system and will play a key role in ensuring resilience (expected to be established in 2024).

- National Grid Gas operates the gas transmission system and may manage any future large-scale hydrogen network infrastructure.
- **Infrastructure owners.**
 - Electricity generation companies are responsible for the resilience of individual generation facilities.
 - Transmission network owners are responsible for the design, construction and maintenance of the high voltage network.
 - Distribution Network Operators (DNOs) provide the infrastructure which takes the electricity from the transmission network and from smaller scale 'distributed generation' and delivers it to homes and businesses. DNOs also have a responsibility for identifying vulnerable consumers and developing priority service registers, and face incentives from Ofgem related to vulnerable consumers.
- **Trade Bodies.** The Energy Networks Association (ENA), representing energy network owners and operators, leads the maintenance of a large suite of 'engineering recommendations' and guidance documents on behalf of the sector. Energy UK also has an influential role, with members representing around 80% of the UK's power generation and over 95% of the energy supply.
- **Planning authorities** are responsible for ensuring that applications for planning consents submitted by developers of electricity system assets are well-adapted to the changing climate.

The Government has not yet defined its vision for what a well-adapted, climate-resilient energy system will look like. This should be a priority in the next National Adaptation Programme in 2023 (NAP3).

Recommendation	Owner (timing)
Set out, in NAP3, the Government's vision for what a well-adapted and climate-resilient energy system will look like. This vision should be supported by clear outcomes, actions and ownership.	Defra (2023)
Conduct a review of governance arrangements for resilience to climate hazards in the energy system, to ensure they are fit for the new expanded and more diverse low-carbon system given increasing societal reliance on electricity.	DESNZ, Ofgem (2024)
Designate Ofgem and parties responsible now and in the future (including the new Future System Operator) for the maintenance of energy sector codes and standards, with a clear mandate to ensure climate and weather resilience.	DESNZ, Ofgem (2024)

(ii) Research and data

We have already set out a need for the evidence base on climate risks to be improved, and for research to be undertaken to deliver this.

To understand future risks, there must be improved data collection on the challenges faced today. This will also support the development of indicators which can be used to measure progress.

Work is underway in the sector, via Ofgem, DESNZ and others, to identify adaptation indicators for the energy system. Current reporting requirements on DNOs do not require outages to be categorised by weather cause.

Consistent reporting and collation of this data, covering the full extent of the UK, would provide a meaningful indicator of how climate-related impacts on the energy system are changing. This should be combined with improvements in reporting on climate risks and adaptation plans by network and system operators, as recommended to Defra in our evaluation of ARP3 in 2022.

Recommendation	Owner (timing)
Extend requirements for reporting on outages to include the cause, duration and magnitude of all outages (with weather-related outages specifically identified), and collate this as a national indicator.	Ofgem, DESNZ (2024)

(iii) Investment

Investment in the UK's energy sector is currently largely delivered by the private sector - over 80% of energy projects and almost 100% of utilities projects in the Treasury's Infrastructure and Construction Pipeline are privately funded.¹¹ It is this private investment that must deliver electricity system resilience to weather hazards. Government's role is to work with industry, regulators, sector bodies, and other stakeholders to ensure that the investment in the electricity system is resilient and secure against the impacts of climate change, and to provide policy and regulatory oversight to ensure predictable and attractive long-term investment opportunities, together with ensuring the system is well-managed to mitigate risk from weather related impacts.

Our recent Adaptation Investment report¹² explores barriers to investing in climate resilience and identifies funding streams that could enable adaptation projects to secure investment. The UK Infrastructure Bank (UKIB) was launched in 2021, tasked with accelerating investment into ambitious infrastructure projects, cutting emissions and levelling-up the UK. Investment is likely to be heavily weighted towards energy projects, presenting an opportunity to ensure that the Net Zero electricity system is resilient to the future climate conditions which will pose increasing risks to energy supply. However, to date the UKIB has focussed on emissions reduction in financing projects and is yet to demonstrate a strategy to addressing Net Zero and adaptation together.

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Climate Change Committee
1 Victoria St
Westminster
SW1H 0ET

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