Flexibility in Great Britain

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Imperial College London Consultants

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Project delivery team

The Carbon Trust's mission is to accelerate the move to a sustainable, low carbon economy. It is a world leading expert on carbon reduction and clean technology. As a not-for-dividend group, it advises governments and leading companies around the world, reinvesting profits into its low carbon mission.

Imperial College London Consultants

Imperial College London is a world top ten university with an international reputation for excellence in teaching and research. The research team at Imperial's Department of Electrical and Electronic Engineering is at the forefront of innovation in the development of new classes of tools for analysing technical, economic, security and market performance of future low carbon energy systems. The team from Imperial were commissioned via Imperial Consultants to provide analysis on an independent basis.

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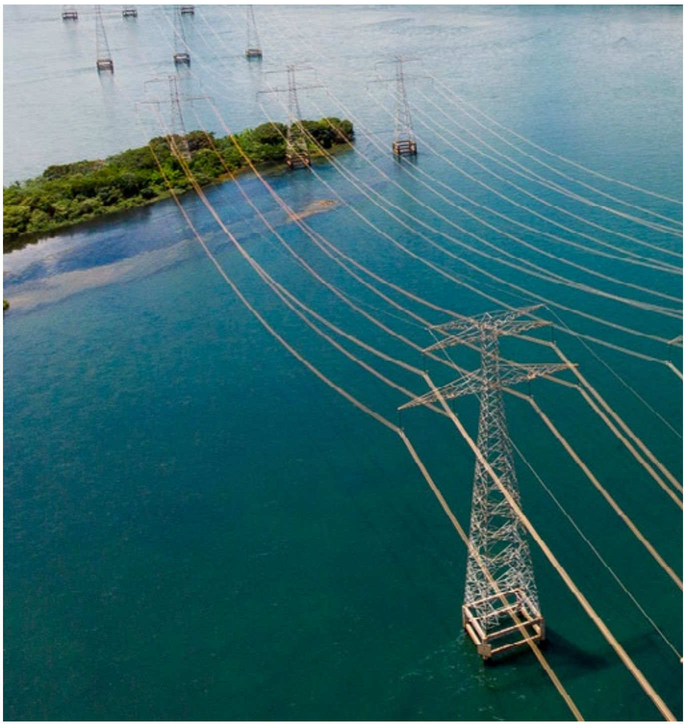

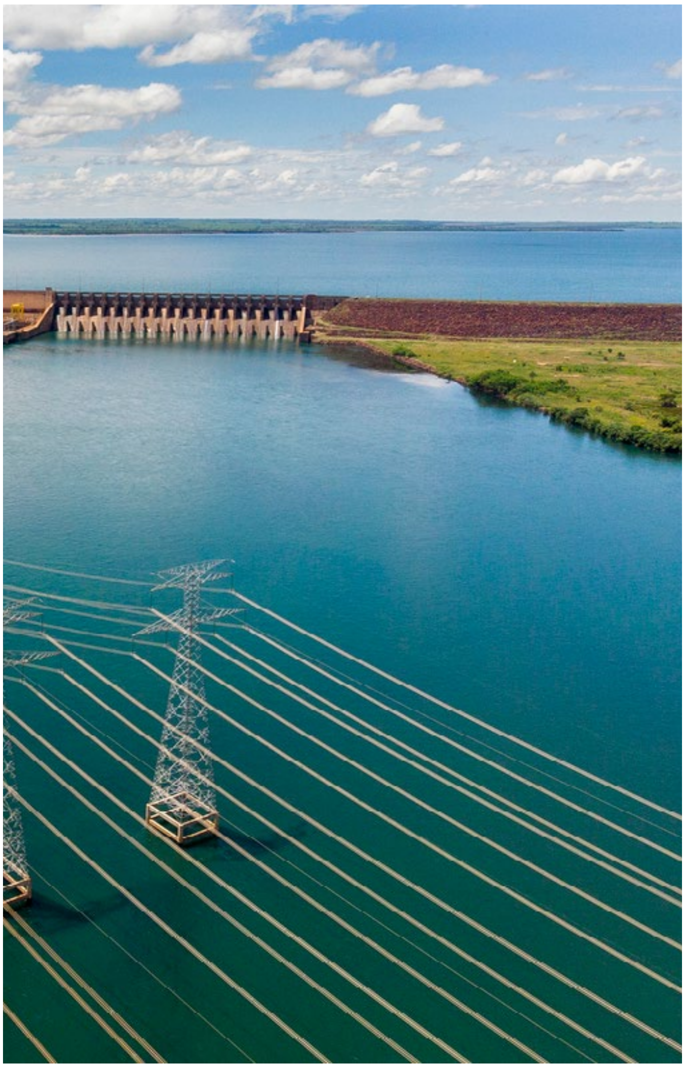

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List of abbreviations

Abbreviation	Meaning
ADE	Association for Decentralised Energy
ASHP	Air Source Heat Pump
ATR	Autothermal Reforming
BEAMA	British Electrotechnical and Allied Manufacturers Association
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy and Industrial Strategy
BES	Battery Energy Storage
BEV	Battery Electric Vehicle
BM	Balancing Mechanism
BSI	British Standards Institute
CAPEX	Capital Expenditure
CCC	Climate Change Committee
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CfD	Contracts for Difference
CHP	Combined Heat and Power
CM	Capacity Market
CO_2	Carbon Dioxide
COP	Coefficient of Performance
DACCS	Direct Air Carbon Capture and Storage
DCC	Data Communications Company
DH	District Heating
DHN	District Heating Network
DNO	Distribution Network Operator
DNUoS	Distribution Network Use of System Charges

DSO	Distribution System Operator
DSR	Demand Side Response
ESAP	Energy Smart Appliances Programme
ESC	Energy Systems Catapult
ESO	Electricity System Operator
EU	European Union
EV	Electric Vehicle
EWP	Energy White Paper
FES	Future Energy Scenario
GB	Great Britain
H2	Hydrogen
HF	High Flexibility
HGV	Heavy Goods Vehicle
HHP	Hybrid Heat Pump
HHV	Higher Heating Value
HP	Heat Pump
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
I&C	Industrial and Commercial
ICE	Internal Combustion Engine
ICT	Information and Communications Technology
IWES	Integrated Whole Energy System
LEM	Local Energy Market
LF	Low Flexibility
LGV	Light Goods Vehicle
LOLE	Loss of Load Expectation
LV	Low Voltage
NG	Natural Gas

NSIP	Nationally Significant Infrastructure Project
O&M	Operation and Maintenance
O2	Oxygen
OCGT	Open Cycle Gas Turbine
OPEX	Operational Expenditure
OZEV	Office of Zero Emissions Vehicles
P2H	Power-to-Heat
PAS	Publicly Available Specifications
PEM	Proton Exchange Membrane
PV	Photovoltaic
R&D	Research and Development
RAG	Red-Amber-Green
SA	Smart Appliances
SME	Small to Medium Enterprises
SMIP	Smart Meter Implementation Programme
SMR	Small Modular Reactor
SOEC	Solid Oxide Electrolysis Cell
STOR	Short Term Operating Reserve
TCR	Targeted Charging Review
TES	Thermal Energy Storage
TRL	Technology Readiness Level
UK	United Kingdom
ULEV	Ultra Light Electric Vehicle
V1G	Smart Charging (Vehicle from Grid)
V2G	Vehicle-to-Grid
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WESIM	Whole Energy System Investment Model

Foreword

Julia King, Baroness Brown of Cambridge

The race to achieve net zero is on. Around the world, the enormity of this challenge is coming clearly into focus. The move to accelerate action to meet this target is highlighted in the UK's latest commitment to reduce emissions by 78% from 1990 levels by 2035, incorporating international aviation and shipping emissions for the first time.

Concurrent decarbonisation at pace and scale, beyond the energy sector, of heat, transport and industry is critical, requiring large amounts of sustained investment. As we move away from direct use of fossil fuel, these sectors will become increasingly coupled to the electricity system via direct electrification and hydrogen use.

This economy-wide effort will no doubt put stresses on the energy system, at a scale not seen previously in its history. While this increased coupling brings new and complex challenges, it also presents us with an opportunity to super-charge the net zero transition.

The energy system must become both smart and flexible to handle these increasing linkages effectively, both in terms of cost and security of supply. Security of supply is particularly important in the context of being resilient to extreme weather events. A portfolio approach, such as using CCS and hydrogen together with electrification underpinned by energy system flexibility, will help create a more resilient future energy system.

This Flexibility in Great Britain report led by the Carbon Trust unpacks these complex dynamics between achieving net zero, decarbonising heating and whole energy system flexibility at all scales. This analysis is underpinned by Imperial College London's cutting-edge modelling of the power, heat, transport and industry sectors in the UK, providing an integrated whole systems approach.

The work examines the different uncertainties the net zero transition throws up and in doing so, offers a comprehensive evidence base on the role and value of energy system flexibility under different energy system futures. The report demonstrates that energy flexibility can reduce the cost of meeting net zero and mitigate the impact of wider changes in the energy system, ensuring we reach net zero efficiently, effectively and at lowest cost.

Delivering net zero in 2050 cost-effectively requires immediate action, and this report goes beyond modelling and identifies the key barriers that could delay or even prevent the development of a smart, flexible net zero system.

As the UK prepares to host COP26 in Glasgow this year, this report presents an evidence base for the role and value of flexibility, and identifies the challenges which government and industry need to address to deliver concerted and immediate action on climate change.

Executive summary

Background to this report

Between 2016 and 2017, the Carbon Trust and independent researchers from Imperial College London delivered two milestone reports covering the role and value of electricity storage and analysis of wider flexibility within the electricity system in Great Britain (GB). Both reports used a systems approach to analyse the GB energy transition and made recommendations on flexibility technology integration that could deliver net savings across the system. While these reports and their findings continue to be used by industry and government alike, the context and ambition continues to change significantly. The net zero target has brought focus and urgency to decarbonising the energy sector beyond power to heat and transport. This created a strong rationale to develop a robust evidence base that is up to date, covers the entire energy system and considers recent advancements in technologies.

The Carbon Trust has once again collaborated with Professor Goran Strbac from Imperial College London, this time using the advanced integrated whole energy system (IWES) model to analyse the role and value of flexibility in various energy scenarios through to 2050. The scope of the analysis has been extended to cover heat, transport and hydrogen to allow due consideration to multi vector flexibility and its wider impact, ensuring comprehensive results. In addition to the previous reports, a new chapter has been added that focuses on delivering flexibility in the medium term to get us on the trajectory to a smart, adaptable and cost-effective system in 2050. This analysis takes its strategic insights from the IWES model and examines the building blocks such as policy, regulation, business models and skills required to achieve this transition. This is key as we need to consider the entire landscape in order to make the right decisions now so that we make this transition as inclusive and seamless as possible. This will give us the best chance of meeting net zero.

Given the wide-ranging scope of the analysis and insights for supporting multiple aspects of energy system development through to 2050, the report's writers convened 12 organisations across the sector from generation, energy infrastructure, retail and flexibility developers through to local government. This breadth of expertise was used throughout the project to guide its direction, challenge the results and provide insights into developments across the energy system to make the analysis as relevant as possible.

This report is therefore a response to the call from both the energy industry and government for an objective, evidence-based assessment on the role and value of flexibility in a net zero 2050 system.

Key findings

The role and value of flexibility in a 2050 net zero system

Investing in flexibility is a no-regrets decision as it delivers material net savings of up to £16.7bn/yr across all net zero scenarios analysed in 2050

Across all the heating scenarios analysed, flexibility always delivers a net saving ranging between £9.6-16.7bn/yr and supports a cost-effective decarbonisation of the energy system. This value is delivered by a portfolio of flexibility technologies including: battery storage, thermal storage (in homes and integrated with heat networks), interconnectors and a range of demand side response technologies across domestic, non-domestic and EV demands. The savings predominantly come from avoidance of gas generation (CapEx and OpEx), reduced reliance on carbon negative technologies and reduced network reinforcement. Beyond technologies such as these, flexible operation of systems like hybrid heat pumps and coordination of the hydrogen system (production, storage, conversion and use) help to maximise synergies with the wider system. High levels of flexibility deployment are required from different sources to help deliver the scale of savings in a net zero system. Up to c.48GW of flexibility from EVs, 12GW from domestic smart appliances, 11GW from non-domestic DSR, 83GW of battery storage and 900GWh of thermal storage are deployed across the different scenarios. These are significant additions to the energy system and, to put it into context, there was c.51GW of flexible electrical capacity installed in 2019 out of which 75% were gas plants.

For more details on analysis of the value of flexibility across different heating scenarios, please refer to 3.2 Electric heating pathway, 3.3 Hybrid heating pathway and the 3.4 Hydrogen heating future sections.

Flexibility supports a net zero energy system to cope with dark, cold and windless days in winter

It is important to consider the impact of weather patterns that cause very cold temperatures and very low wind speeds in a system that has a high penetration of renewables. This study has considered such an event across all scenarios where there is a 72 hour-period of extreme cold weather driving up heat demand coinciding with very low wind and solar PV output (<5% of maximum). An important implication of this weather event is the requirement for flexible, low-cost fossil fuel plants (such as CCGT, OCGT or Gas Reciprocating Engines) which are mainly used to support the system during this high stress period. These gas plants are providing firm dispatchable power over consecutive days, to maintain system security. However, without negative emission technologies, or if unabated fossil fuel plants are not deployed, alternate forms of reliable power supply would be required.

The addition of flexibility helps to reduce the peak demand for electricity and heat during this high stress period which helps to significantly reduce fossil fuel generation capacity required and its associated costs. For example, the deployment of additional flexibility in a fully electric scenario displaces over 90GW of unabated gas generation (largely OCGTs) which predominantly supports the system during peak stress times. However, even under this scenario 126GW of gas generation (largely CCGTs or high performing Gas Reciprocating Engines) is still required as firm dispatchable generation. This highlights the importance of modelling extreme future weather events to determine factors such as system security and adequacy.

For more details on how the model is set up, including assumptions on future weather patterns, please refer to 2.2 Integrated whole energy systems modelling - overview of modelling approach.

Embedding flexibility in zero carbon heat and transport solutions will help to reduce their system impact and costs making their decarbonisation economically more feasible

Having smart charging and V2G allows large scale EV charging to be delivered aligned to renewable generation, whilst reducing the impact on the network through peak demand reduction. Similarly, having large scale deployment of thermal storage (up to 900GWh) allows the heat demand to be made flexible. This provides several whole system benefits: including balancing of supply and demand, better use of renewable output and peak electricity demand reduction leading to lowering the cost of network reinforcement. Additionally, the coordinated interaction between energy for heating and EV charging further helps to reduce overall system cost highlighting the importance of coordination between different flexibility sources.

For more details on analysis of the value of flexibility including those integrated within heat and transport solutions, please refer to 3.2 Electric heating pathway, 3.3 Hybrid heating pathway and the 3.4 Hydrogen heating pathway sections.

Developing a portfolio of flexibility, including on the demand side, across the energy system is an effective strategy to manage uncertainties and reduce costs

Delivering flexibility from multiple sources across the energy system allows any impact of price or technology availability to be minimised. We find a variety of flexibility sources being deployed across all heating scenarios to minimise system cost rather than a few dominant ones given their individual value. For example, if sources of demand side response (DSR) flexibility across domestic, non-domestic and EVs are not developed and available, this creates significant pressure on other sources leading to an overall increase in 2050 system cost up to £4.5bn/yr in the electric heating scenario. This highlights the importance of having a portfolio of flexibility sources to manage risks such as high costs or low availability. Even in the electric heating scenario that relies heavily on battery storage, there is only a marginal increase in costs (c.£0.2bn/yr) due to lower than anticipated cost reduction of batteries. This risk is mitigated by drawing on additional thermal storage capacity. There is also a similar effect when thermal storage's availability is minimised and additional battery storage is able to compensate, thereby increasing the cost only marginally (c.£0.9bn/yr).

For more details on the sensitivities conducted on the value of different flexibility sources, please refer to section on 3.6 Impact of flexibility technology availability.

Flexibility is deployed more locally in 2050 and delivers significant value nationally

A large proportion of the flexibility across scenarios will be distributed sources deployed locally, closer to demand. This is a significant departure from the current flexibility portfolio which is dominated by large scale plants. Analysing the distribution of benefits of deploying flexibility across different regions in this study suggests a significant value is returned back to these regions via savings in the local distribution network infrastructure. While these values are material in 2050 (£0.48bn/yr for London as an example), the local flexibility unlocks close to twice this amount in the wider system (£0.94bn/yr). This highlights the materiality of system wide value of flexibility installed locally. Additionally, using flexibility to focus on only local value, such as distribution network cost reduction, increases cost marginally (£0.6bn/yr). This outlines the importance of focussing on whole system value even as the sources of flexibility and energy system development become more localised.

For more details on dynamics between local and national value of flexibility, please refer to the case study on 3.10 Local versus system benefits of flexibility.

Energy system considerations for achieving net zero by 2050

Reaching net zero by 2050 whilst meeting security of supply requires unprecedented build-out across the energy system

Regardless of the scenario or sensitivity, the 2050 net zero energy system, is significantly larger relative to the current GB system particularly when additional flexibility is not deployed. Across the core heating scenarios analysed, the total electricity required to be delivered in 2050 rises to a maximum of c.830TWh, which represents a three times increase relative to 2019. The network build-out required is also significant, driven by an increase in total peak demand on the distribution network up to 228GW in an electric heating scenario. Flexibility present in the distribution network needs sufficient capacity to be able to charge up and discharge in response to system needs. Thus, investment in networks is also important to unlock flexibility that can deliver wider system benefits.

Depending on the scenario and carbon target imposed on the energy system, there is also a significant need for deployment of carbon negative technologies such as BECCS and DACCS up to several tens of GW by 2050. The key area of convergence between the three core heating scenarios (fully electric, hydrogen and hybrid heating) is maximising deployment of flexibility and renewables particularly offshore wind (120GW) and PV (30-55GW), thus making these no-regret actions for achieving net zero targets.

For more details on analysis of the wider system implications across different heating scenarios, please refer to 3.2 Electric heating pathway, 3.3 Hybrid heating pathway and the 3.4 Hydrogen heating pathway sections.

Pushing the energy system to go beyond zero carbon has material cost and infrastructure implications

The cost of meeting a net-negative carbon target of -50MtCO_2/yr by 2050 could add up to c.£5bn/yr to the energy system. The increase in cost in our analysis is primarily driven by additional electricity generation capacity and negative carbon technology deployment in the hydrogen heating scenario where this was analysed. Beyond just a scale-up of the energy system to meet the negative emissions, this target has an implication on the wider system including the cost optimal strategy for heat decarbonisation. For example, a more stringent carbon target in a hydrogen dominant scenario drives a shift in the cost optimal production methods by reducing the proportion of hydrogen generated via natural gas reformation.

For more details on the system and flexibility implications of a net negative and zero carbon target, please refer to 3.9 Zero carbon versus net negative carbon targets for the 2050 energy system section.

Carbon negative technologies have an important role in helping to meet the net zero target in 2050

There is a consistent deployment of negative emission technologies including BECCS and DACCS across all scenarios analysed. A key finding from this study is that the negative emissions technologies are important even when the carbon target for the energy system in 2050 is zero rather than net negative (i.e 50MtCO_2/yr). This is driven by the need to negate emissions from use of natural gas for electricity generation, hydrogen production and/or for home heating via boilers. While the deployment of BECCS is linked to the level of hydrogen demand in the system across heating and other uses, DACCS is predominantly linked to the use of natural gas in the system. In scenarios of significant natural gas use such as the hybrid heating scenario, unavailability of DACCS drives heating to be predominantly electric, needing significant additional build out of renewables and CCS capacity. In a low flexibility scenario this drives a £22bn/yr increase in system cost, while in a high flexibility scenario this is only £3bn/yr owing to peak demand management and capacity optimisation. This further highlights the value of having a flexible system which is able to mitigate against risks of technology development uncertainty with only marginal cost increases.

For more details on value of carbon negative technologies and interaction it's with flexibility, please refer to the sensitivity on 3.8 Impact of negative emissions technology availability.

Any single heating solution dominant future has a significant cost and infrastructure impact on the energy system in 2050

GB's choice of heating decarbonisation has a significant impact on several aspects of the energy system including scaling up existing technologies and networks to needing new technologies including those that can negate carbon emissions. For example, a fully electric heating scenario without additional flexibility requires significant additional electricity generation capacity (c.422GW required - current capacity is c.108GW), with just over 50% being in reserve with very low utilisation (<5%). Similarly, a hydrogen heating scenario needs a significant scale-up of relatively new technologies such as electrolysers (35GW), hydrogen storage (c.8TWh), bio energy gasification plants (14GW) including CCS infrastructure. Hybrid heating has the ability to coordinate the use of natural gas and heat pumps that allows it be built and operated at lower cost relative to the other heating scenarios, highlighting the importance of cross-vector optimisation. However, even such a scenario requires significant increase in electricity generation capacity (294GW) and the largest deployment of DACCS across the three core heating scenarios.

Strategic areas that are therefore particularly sensitive to the choice of heat decarbonisation are: levels of carbon negative technologies required, natural gas infrastructure, hydrogen infrastructure (including storage) and electricity distribution infrastructure.

For more details on how the different heating scenarios are set up, please refer to 2.3 Background to core pathways and sensitivity scenarios.

The use of hydrogen across the energy system brings carbon and cost benefits and requires a portfolio of production methods and availability of CCS infrastructure

Development of hydrogen use and associated infrastructure (electrolysers, hydrogen turbines and storage) for 2050 has significant system benefits if coordinated effectively. The ability of the system to optimise production to high energy supply times, store hydrogen and then use it for heating, power production and other applications across transport and industry, drives this value. This optimisation enables significant cost reduction in network and generation investment relative to an Electric Heating scenario in which this level of system-wide coordination is not possible. Integrating additional flexibility into a hydrogen dominant system has a significant effect on cost reduction and has the largest impact across all the scenarios in terms of reducing the total electricity generation capacity requirement.

The total cost of the hydrogen system is sensitive to technology (production and conversion) costs, fuel costs and availability of carbon negative technologies. Thus, retaining a diverse portfolio of hydrogen production routes (gasification, reforming and electrolysis) along with the integration of flexibility can help to avoid shocks if one or several of these dependencies become expensive and/or unavailable. However, even across this diverse portfolio, the ability to deliver hydrogen needs across the system cost-effectively is dependent on the availability of CCS infrastructure, without which significant additional costs will be incurred.

For more details on the implications of a hydrogen dominant scenario, please refer to the Hydrogen heating future section. For details on the implications of different hydrogen production routes and other key sensitivities, please refer to 3.7 Impact of hydrogen production route section.

Considerations for delivering a smart, flexible energy system

Flexibility should be integrated into enabling infrastructure including low carbon heat and transport solutions from the start

A key consideration across the different flexibility technologies assessed is the importance of enabling infrastructure for its cost-effective and large-scale deployment by 2050. For technologies such as DSR (domestic and non-domestic), this is about ensuring the smart meter roll out does not face additional delays and having a clear route to secure cost-effective data access across millions of potential sites/devices. For technologies that are tied to broader strategies around heat and transport decarbonisation, it is important to build flexibility into technologies and service offerings right from the start rather than retrofit in the future which could make it prohibitive. Examples of such integration includes thermal storage in district heating schemes with heat pumps in domestic and non-domestic buildings and building in smart charging for all EV charging points. Delivering flexibility and associated cost-effective decarbonisation requires coordinated planning and operation across all energy sectors including electricity, gas, hydrogen and transport.

Consumer engagement on flexibility beyond just commercial value is a critical aspect to scaling up flexibility technology deployment

Unlike previous decarbonisation challenges such as large-scale generation, the roll out of flexibility needs to consider users across all stages of deployment. While early adopters of flexibility technology might find the commercial value from participating sufficient and/or be driven by other factors such as interest in new technology, translating this to 'late majority' and 'laggards' will be difficult but important. Taking a rational approach to consumer engagement that is focused solely on commercial value is unlikely to put the sector on a pathway to achieving the GW scale required to deliver material system benefits. Understanding consumer needs, crafting appropriate narratives for different segments and building them into the user experience requires significantly greater focus in technology development and demonstration programmes going forward. This is especially critical for the success of DSR, EV and TES flexibility in which the flexibility integration is tied to the broader challenge of consumer acceptance of new solutions for mobility and heating.

An evolving regulatory environment, combined with potentially low financial gains in the long term, creates challenges for business model development

Business models for flexibility have to straddle the constantly evolving regulatory environment that affects how to access, and what the value of flexibility is, with the consumer need for consistent and secure revenue streams. Novel business models and propositions that go beyond focusing on financial value of flexibility into embedding into core transport and heating service provision is important to avoid high drop off rates going forward and mitigating 'willingness to pay' issues. Improving routes for cost-effective data access, leveraging the significant investments into infrastructure such as the DCC will help alleviate some of the cost burden in the business models and avoid redundant investments. Fundamentally, market signals need to reflect whole system benefits across generation, networks, carbon savings and system security to incentivise the effective deployment and operation of different flexibility technologies including those on the demand side. This will also require effective coordination between actors to support deployment of flexibility for not only their benefit but also for the wider system. Greater focus to ensure effective market signals incentivise consideration of flexibility into long life time infrastructure even though the system value in the short-term might not be present or material is also important.

A smart and flexible system can only be enabled by digitalisation of the energy system

As shown this in study, the value of flexibility is unlocked through real time coordination between assets to operate in-sync to deliver whole system benefit. For example, we see the coordination between smart EV charging V2G and thermal storage in heat networks working together to minimise demand during periods of system stress. These assets sit at different levels in the energy system and also across vectors and between different ownership boundaries. Thus, a critical consideration to enable this future is the need for digitalisation across the energy system to allow information sharing, monitoring and coordination between assets and organisations at this scale. Building-in interoperability and cyber security into these plans will be important, to minimise the risk at stake for the system, retain consumer confidence and trust and to allow novel business models to flourish.

Continued efforts for new technology development and innovation focused on cross vector integration is important to have them ready in time

This study has found significant flexibility deployment needs by 2030 - for example the system could require 1GW of domestic DSR, 1GW of hydrogen electrolysers, up to 3GW of EV flexibility and significant roll out of thermal storage. Innovation is important to bring technologies such as TES and electrolysers to the market at the appropriate cost point and technical capability ahead of 2030. Given the linkages between these technologies and the wider system, especially electrolysers, it is important to design and integrate them from a whole-system perspective rather than in isolation.

For technologies such as DSR, battery and thermal storage and EV flexibility, development efforts should focus on cost-effective system integration and engaging consumer experience going forward. Additionally, a greater focus on innovation that demonstrates cross-vector flexibility is important to understand the issues and scale of complexity (technical, regulatory and social) in delivering this in practice.

Structure of the report

This report is structured across five main chapters excluding the appendices. The details covered in each chapter is outlined below.

Chapter 1

Provides an overview of the current GB energy system and an introduction to different forms of flexibility.

Chapter 2

Describes the integrated whole energy systems (IWES) model and the scenarios modelled.

Chapter 3

Sets out the results of the IWES modelling and the value of flexibility under various energy system futures in 2050.

Chapter 4

Considers what flexibility needs to be deployed by 2030 and examines the barriers facing these different types of flexibility.

Chapter 5

Sets out recommendations for further research areas

Appendices (separate download)

Describes the IWES model and model inputs and provides more detail on the evidence collected about barriers to flexibility deployment.

Overview of methodology

Modelling overview

This work is underpinned by Imperial College London's integrated whole energy systems (IWES) model. IWES is a least cost optimisation model that can simultaneously minimise long-term investment and short-term operating costs across the whole energy system while meeting required carbon targets and system security constraints. IWES is an enhancement of the Whole Energy System Investment Model (WESIM), which has been used extensively, including in the Carbon Trust and Imperial College London's 2016 reports 'An analysis of electricity system flexibility for Great Britain' and 'Energy storage report: can storage help reduce the cost of a future UK electricity system?'. The key enhancement in the IWES model is the addition of other heating technologies, including the ability to optimise natural gas, hydrogen, district heating (DH) networks, thermal and hydrogen storage. This advancement has allowed this work to take a comprehensive whole systems approach to analysing the role and value of flexibility across the energy system.

Summary of scenarios and sensitivities undertaken

The report's focus is on understanding the role and value of flexibility in a net zero 2050 energy system. It takes a scenario-based approach to lay out three different 2050 futures driven primarily by the heat decarbonisation strategy - electric heating, hydrogen heating and hybrid heat pump heating. These were chosen as heat decarbonisation was found to have the greatest uncertainty but also the most impact on the shape and form of the energy system.

The electric heating scenario is dominated by air source heat pumps (ASHP) across domestic and non-domestic buildings. The hydrogen heating scenario deploys mainly hydrogen boilers while the hybrid heating scenario uses ASHPs coupled with a gas boiler. Across all three scenarios there is assumed to be DH networks consisting of ASHP or water-source heat pumps supplying around 20% of all domestic heat demand. Properties not connected to the gas grid are assumed to have individual ASHP and resistive heating in all scenarios.

In reality, heat decarbonisation is likely to consist of a mixture of technologies. However, in this report we have looked at scenarios dominated by one heating technology to highlight the role and value of flexibility alongside these heating approaches. This allows a greater understanding of the type of flexibility technologies required, including how they interact with the heating system to deliver the demand and with the wider system to reduce costs. Each scenario is analysed with (high flexibility) and without (low flexibility) additional flexibility technology deployment to help determine the impact of flexibility across key metrics such as system cost, system demand, electricity generation capacity and emissions profile.

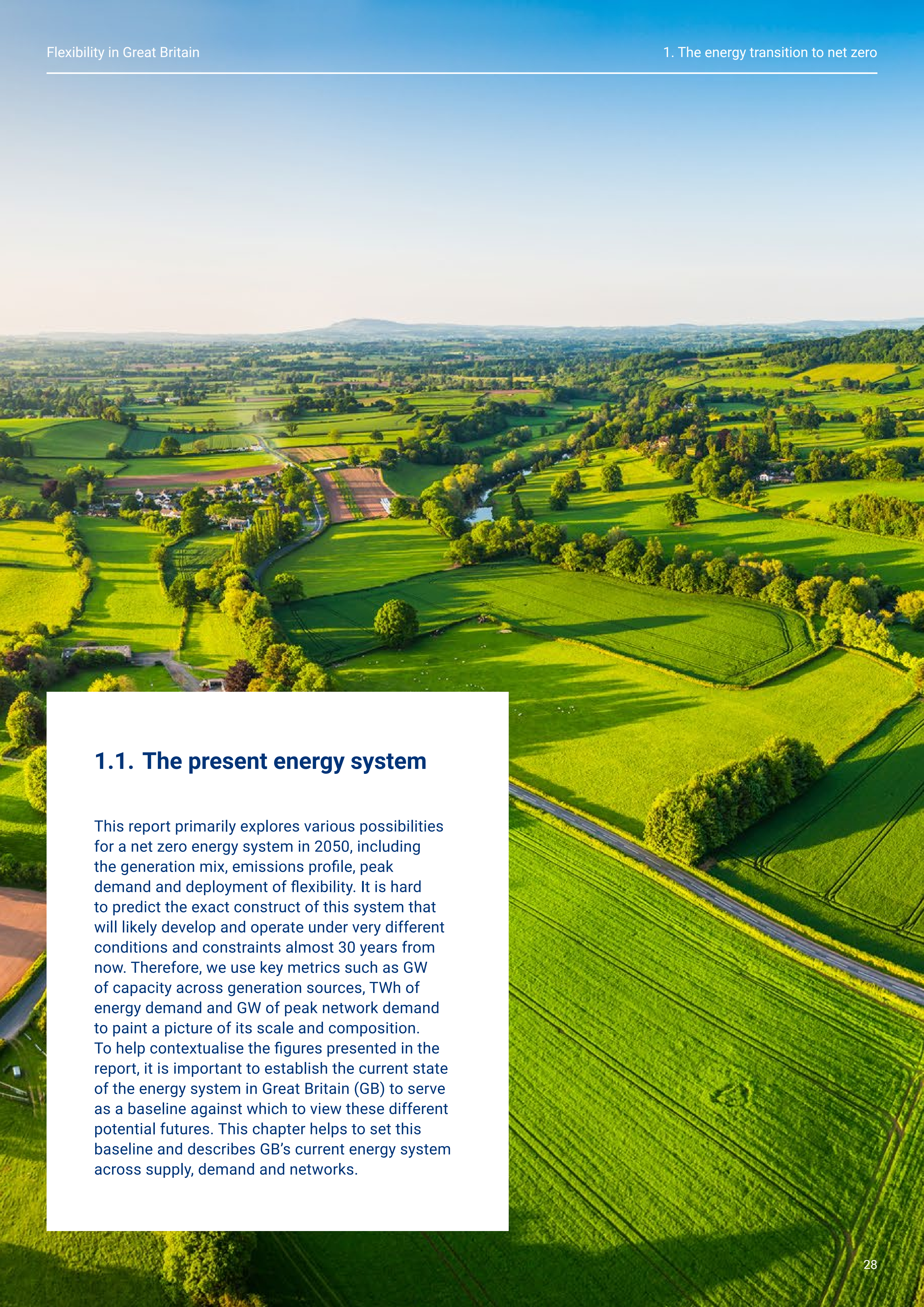
In addition, the report undertakes a range of sensitivity analyses across the three scenarios to develop diverse results not only on the role and value of flexibility, but also on the impact on the wider system of key uncertainties in a 2050 energy system. These include: the cost and availability of key flexibility technologies; diversified and dominant hydrogen production pathways; unavailability of carbon negative technologies; reducing the carbon target of the energy system from net negative to just zero to reflect potential solutions development in currently hard to decarbonise sectors; and optimisation of system costs for local or national energy system benefits.

Overview of delivering flexibility analysis

This section focuses on identifying key actions required between now and 2050 to achieve the scale of deployment of each source of flexibility indicated by the model in the 'high flexibility' scenarios. The technologies include domestic demand side response (DSR) from smart appliances, non-domestic DSR, electric vehicle flexibility (smart charging and vehicle-to-grid), thermal energy storage (TES) integrated with DH schemes and within buildings, electricity storage and hydrogen electrolysers.

This analysis has been carried out by first developing an indicative 2030 deployment trajectory for each source of flexibility using a simplified diffusion curve. These indicative interim deployment goals have then been used to assess any barriers using the Deployment Readiness Assessment framework. This framework takes a holistic view of market enablers, business models and other key factors required to successfully deploy flexibility on a large scale.

1. The energy transition to net zero



1.1. The present energy system

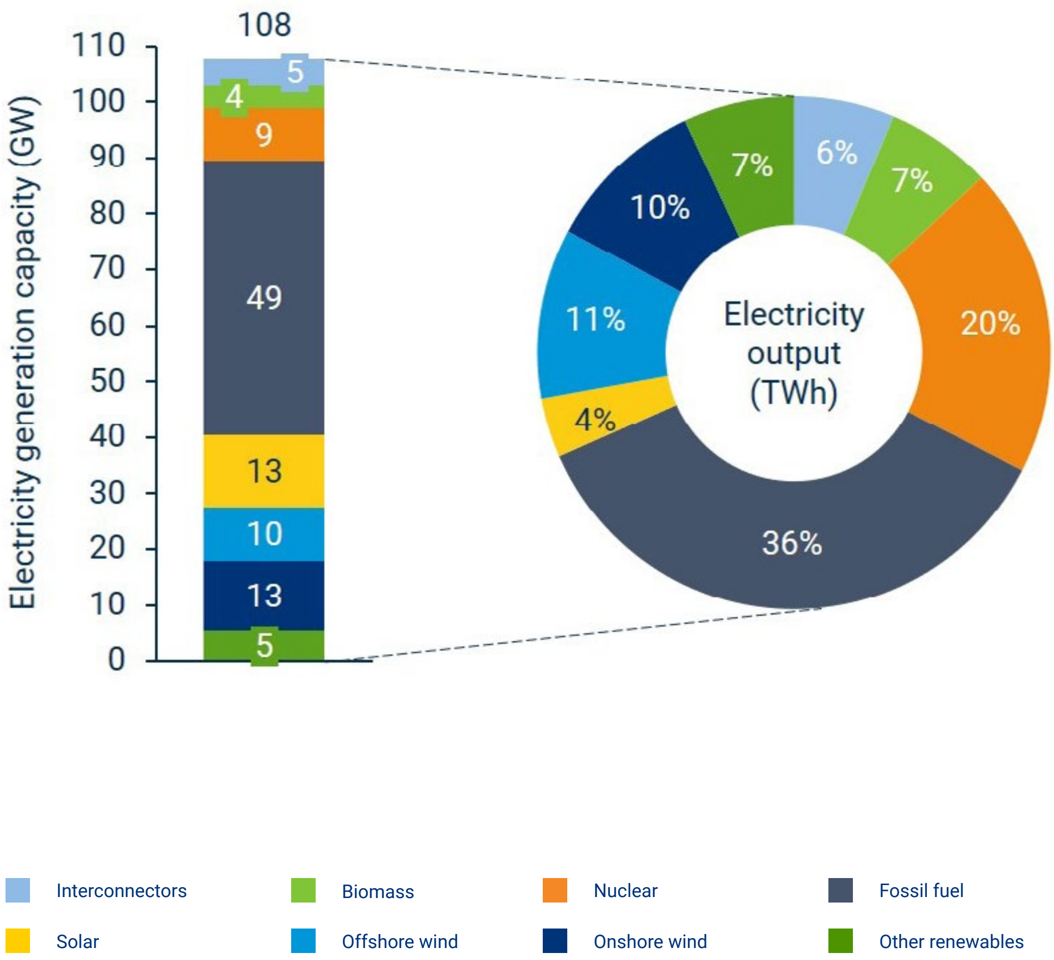
This report primarily explores various possibilities for a net zero energy system in 2050, including the generation mix, emissions profile, peak demand and deployment of flexibility. It is hard to predict the exact construct of this system that will likely develop and operate under very different conditions and constraints almost 30 years from now. Therefore, we use key metrics such as GW of capacity across generation sources, TWh of energy demand and GW of peak network demand to paint a picture of its scale and composition. To help contextualise the figures presented in the report, it is important to establish the current state of the energy system in Great Britain (GB) to serve as a baseline against which to view these different potential futures. This chapter helps to set this baseline and describes GB's current energy system across supply, demand and networks.

1.1.1 Electricity supply

In 2019, GB's installed capacity of electricity generation was split broadly between low carbon sources (renewables and nuclear) and fossil fuels. The largest sources of renewable capacity were solar PV and onshore wind at 13GW each, with offshore wind lower at 10GW. The electricity output from this installed capacity base in 2019 was slightly more skewed towards renewables and nuclear, generating just under 65% of the total output with the remaining coming from fossil fuels.

To give a sense of the pipeline for rapidly growing renewables, as of September 2020, there were 3.69GW of offshore wind farms under construction and a further 11GW with planning permission. These projects are likely to be delivered by 2030.

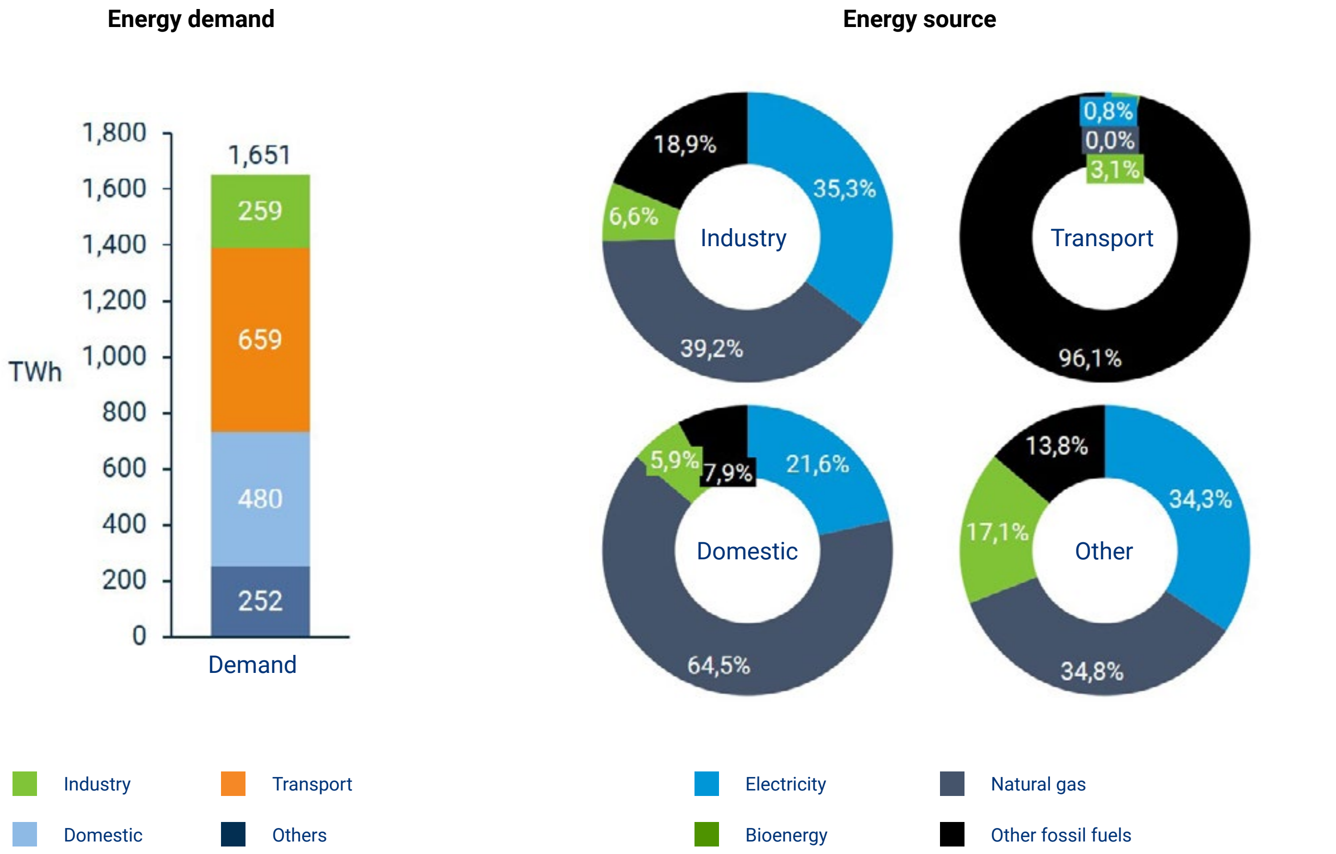
Figure 1. GB electricity generation capacity and output in 2019[1]



1 National Grid ESO, Future Energy Scenarios, 2020. *https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents*

1.1.2 Energy demand

Figure 2. UK energy consumption split by end use and overview source of energy used across the different end uses in 2019[2]



Total GB energy demand across industry, transport and domestic use was around 1,651TWh in 2019. Transport (rail, road, water and air) accounts for almost 40% of the total demand, followed by domestic at around 30%, industry accounting for around 15% and the remainder from 'other' end uses. As this report primarily refers to road transport in the later sections, it is useful to note that c.75% of the transport end use in 2019 is attributable to road travel.

It is also important to understand the breakdown of the sources of energy supplying the different end use categories as we examine optimising these categories using different vectors to minimise cost and bring emissions down to zero (or negative) in 2050. Industry (c.15% of total demand) was primarily supplied by natural gas (c.39%) and electricity (c.35%) with the remainder coming from bioenergy and other fossil fuels.

Transport's energy use (40% of total energy demand) was supplied overwhelmingly (c.96%) by fossil fuels such as petroleum, and the remainder from bioenergy (mainly for road transport). Domestic energy consumption (30% of total) was primarily supplied by natural gas (c.65%), followed by electricity (around 22%) and small portions of bioenergy and other fossil fuels. It's worth noting that direct gas use was approximately three times the size of electricity use.

Some of the key metrics to note in the present energy system are peak electricity and gas demand as these changes significantly in the different futures presented later in the report. The peak electricity demand is around 60GW, while for gas it was c.400 million cubic metres as of 2018/19.[3]

2 BEIS, Digest of Energy Statistics (DUKES) Chapter 1.1.5 Energy consumption by final user, 2020. https://www.gov.uk/government/statistics/energy-chapter-1-digest-of-united-kingdom-energy-statistics-dukes.

3 Ofgem, State of the energy market, 2019. https://www.ofgem.gov.uk/system/files/docs/2019/11/20191030_state_of_energy_market_revised.pdf.

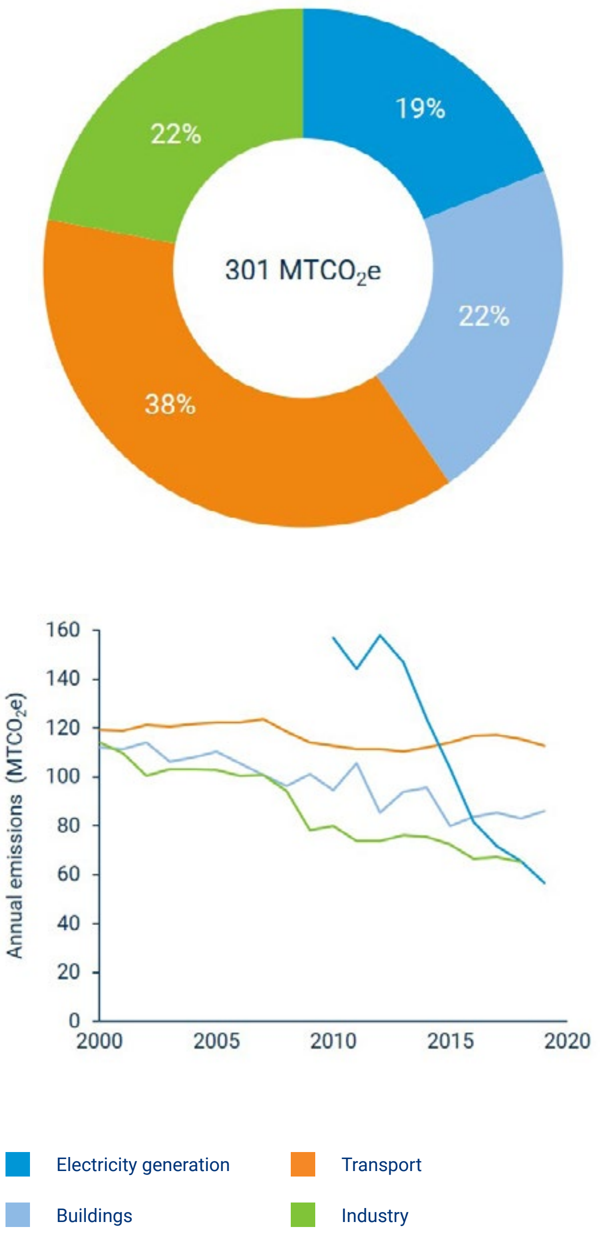
1.2. Net zero transition

1.2.1 Move to net zero

The energy system described in the previous section is undergoing tremendous change. This is driven primarily by climate change legislation, which requires emissions to go down across the economy to net zero by 2050. As modelling results detailed in this report all seek to bring down the emissions in the energy system in the most cost-effective way, it is useful to understand the profile of current emissions.

Economy-wide emissions in 2019 were 520MTCO_2e. More than 50% of these emissions (301MTCO_2e) are from sectors that are currently part of, or coupled with, the energy system. The transport sector constitutes close to 40% of these emissions with industry, electricity and buildings emitting roughly 20% each.

Figure 3. Emissions of the UK in 2019 by sector and trends across those sectors from 2010-20[4]



The UK has legislated a net zero target for 2050 that requires greenhouse gas emissions to reach net zero across most sources, with any remaining emissions offset by removing CO_2 from the atmosphere. Reducing emissions to net zero in the next three decades requires a transformation of energy supply, demand patterns and technology, building stock, the transport system and wider societal behaviour.

As seen in the time series of emissions chart in Figure 3, there have been big gains in terms of emissions reductions in the electricity sector, mainly from adding renewables capacity and retiring coal. The other sectors have either reduced more slowly, as is the case for industry and buildings, or have been static with potentially a small increase, as has happened with transport. These sectors currently have a very low base of low carbon technologies; e.g. less than 5% of energy used for heating homes and meeting industrial demand is met by low carbon sources [5]. Given the net zero legislation, the UK must decarbonise these sectors quickly to achieve an overall net zero position in 2050. This includes using carbon negative technologies to support sectors that may be hard to decarbonise within the timescales.

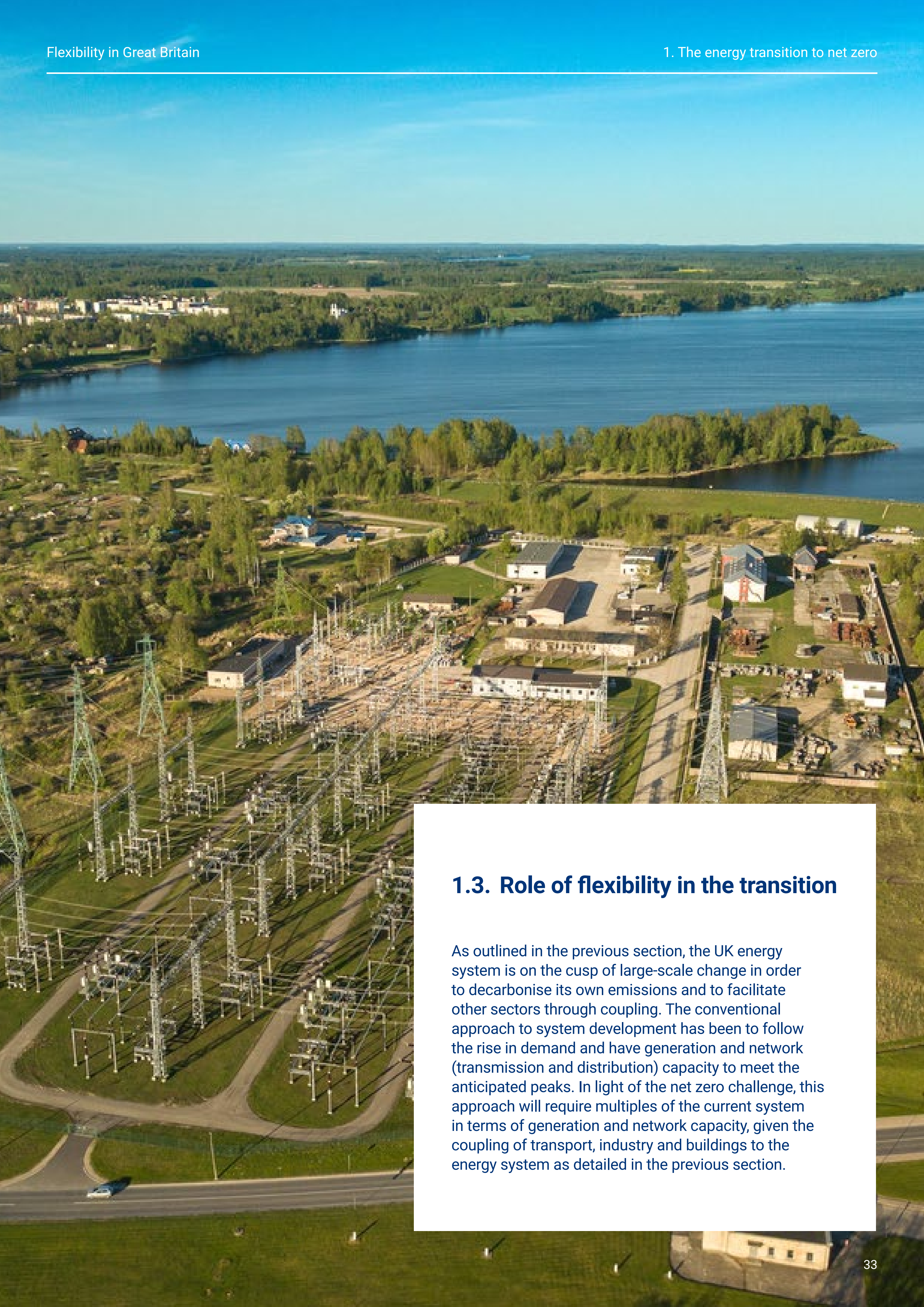
The energy system is at the centre of these net zero transition efforts. The opportunities for decarbonisation are reliant on two broad strategies: direct electrification and hydrogen production and use. The direct electrification route involves moving current processes for mobility, industrial production (including process heating) and wider space heating from natural gas and other fossil fuels to electricity via technologies such as electric vehicles and heat pumps. The hydrogen strategy involves creation of an alternate vector (i.e. hydrogen) via natural gas (steam methane reforming), electricity (electrolysis) or gasification of biomass (BECCS), which can then be used to substitute for fossil fuels across the end use cases outlined above. Similar to the electrification strategy, the hydrogen strategy requires a change in end use technologies, such as fuel cell vehicles and hydrogen boilers. Hydrogen can also be used as a direct combustion substitute for fossil fuels in industries requiring high temperature processes.

This 'coupling' leverages the decarbonisation of the energy system to bring down emissions in these sectors. While this offers a great opportunity to encourage the rapid cost reductions seen across renewables such as solar photovoltaics (PV) and offshore wind, it places an immense burden on the energy system to be able to meet these demands.

The enormity of the challenge is captured by two key figures in the 2019 energy system: total energy demand, which was c.1,651TWh and total electricity supplied, which was c.313TWh. The key challenge for the energy system then is to effectively scale up across generation and networks to meet five times the demand to get to net zero. Although electrification offers a more efficient process for energy conversion and use, the scale of the challenge is still unprecedented. In addition to the infrastructure challenge, there is also the need for commercialisation, scale up and integration of new technologies across the energy system to facilitate the move to electrification and hydrogen.

4 Climate Change Committee, Sixth Carbon Budget - charts and data in the report, 2020. https://www.theccc.org.uk/publication/sixth-carbon-budget/

5 Climate Change Committee, Sixth Carbon Budget - UK's path to Net Zero, 2020. https://www.theccc.org.uk/publication/sixth-carbon-budget/



1.3. Role of flexibility in the transition

As outlined in the previous section, the UK energy system is on the cusp of large-scale change in order to decarbonise its own emissions and to facilitate other sectors through coupling. The conventional approach to system development has been to follow the rise in demand and have generation and network (transmission and distribution) capacity to meet the anticipated peaks. In light of the net zero challenge, this approach will require multiples of the current system in terms of generation and network capacity, given the coupling of transport, industry and buildings to the energy system as detailed in the previous section.

The development of novel technologies such as storage (electricity and thermal), along with the rise of digitalisation, creates an opportunity to take a new approach to system development to meet the net zero challenge. This approach relies on optimising energy flows using these novel technologies to create a smart, flexible and more cost-effective system. The different forms of flexibility and how they deliver benefits to the system are detailed in the section below. These form the basis for this report and the supporting modelling undertaken to analyse the net savings such technologies can generate in different net zero energy futures.

The Carbon Trust and the team from Imperial College London undertook an assessment of the value of flexibility in 2016. The report estimated that deploying flexibility technologies could save the UK £17-40 billion from 2015 to 2050[6]. While a significant value, however, this focused solely on the electricity system with an emissions reduction target of 80% by 2050, relative to a 1990 baseline.

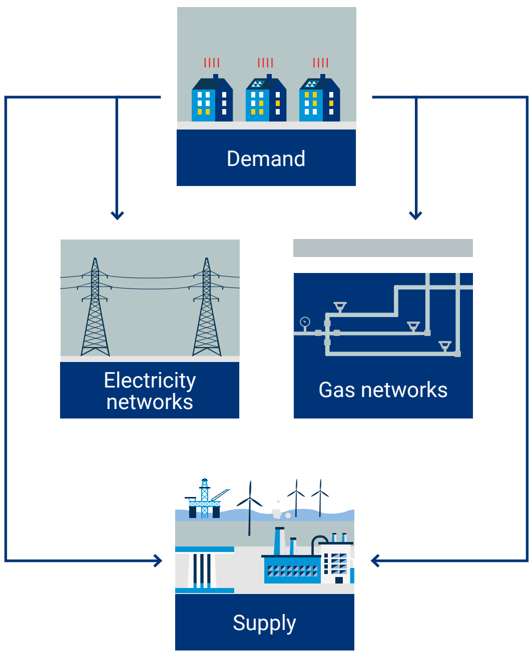
Figure 4. Outline of the key differences between a smart and the conventional to energy system planning and operation

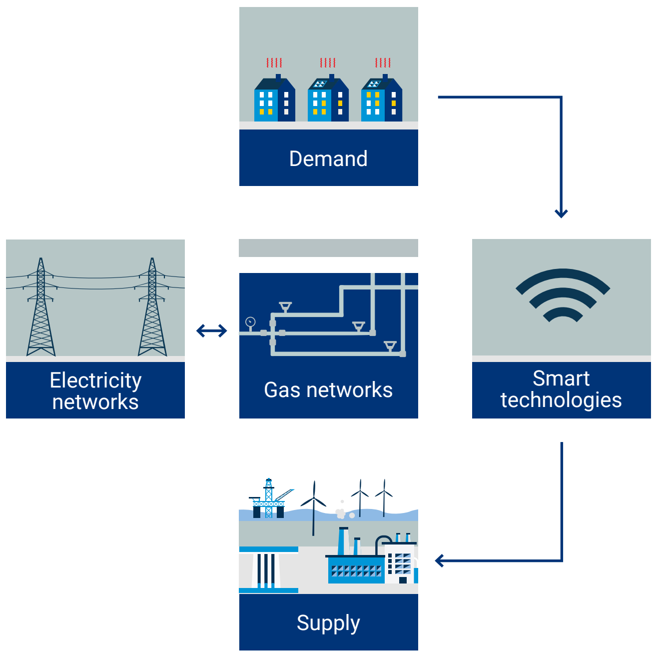
Conventional approach:

- **Demand seen as fixed input and drives system development**
- **Limited network coordination**
- **Energy used when generated**

Smart integrated approach:

- **Demand decoupled from supply**
- **Networks coordinate operation and planning**
- **Energy stored and flows optimised to reduce overall system cost**





6 The Carbon Trust, An analysis of electricity system flexibility for Great Britain, 2016 https://www.carbontrust.com/news-and-events/news/capturing-the-benefit-of-a-smart-flexible-energy-system

Overview of forms of flexibility and their value to the system

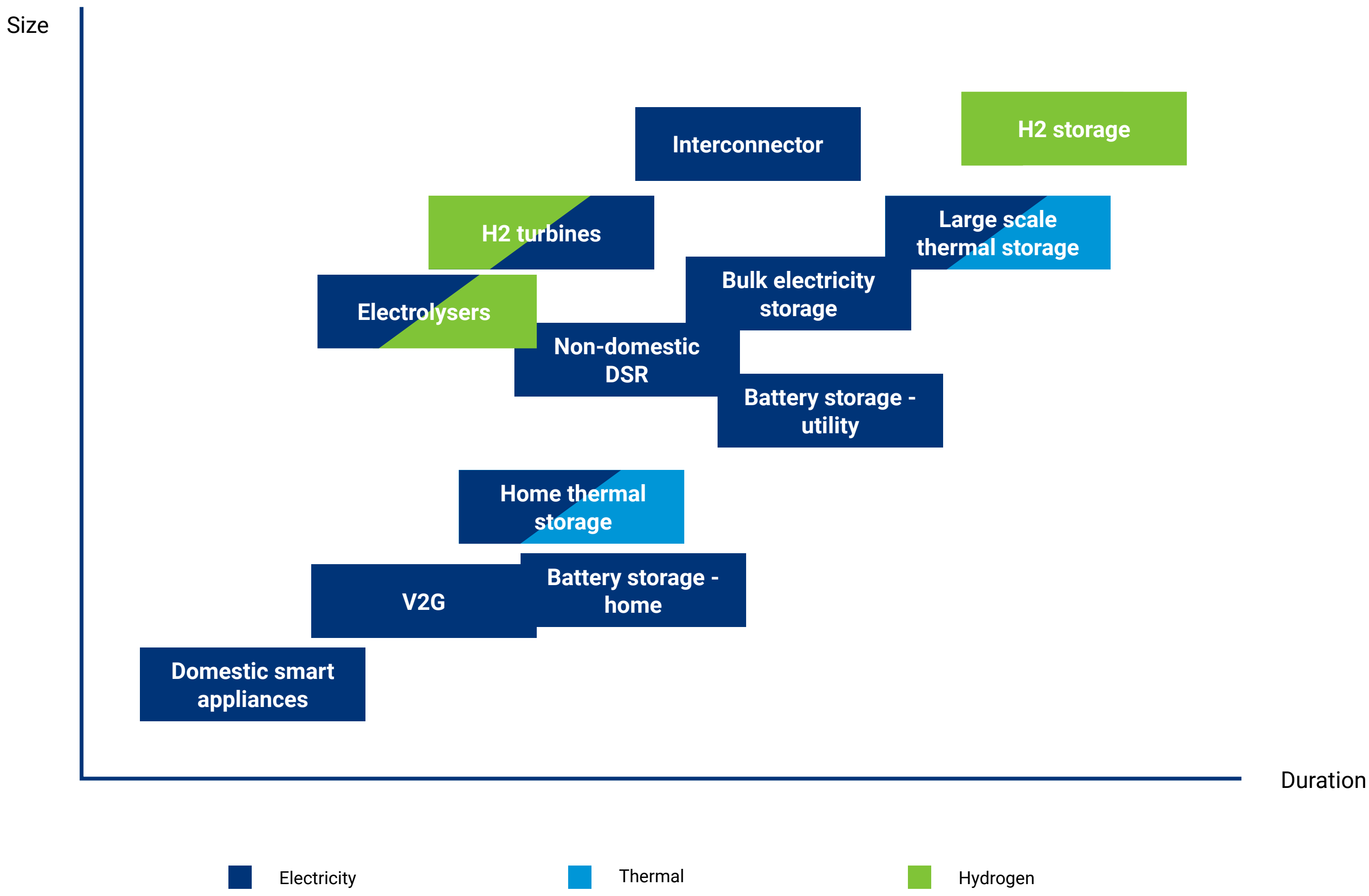
Flexibility is defined as:

'modifying generation and/or consumption patterns in reaction to an external signal (such as a change in price) to provide a service within the energy system'

Ofgem

Given the broad nature of the technology, there are several forms of flexibility across the energy system. This section will focus on sources of flexibility that are analysed in detail in this report to provide a context of what these technologies are and how they operate in practice. Several publicly available reports examine the technical detail of the different flexibility technologies. For that reason, this report only provides a high-level overview. For details on the high-level modelling assumptions across these technologies, please refer to the Section 2.3. More details on the technical and cost assumptions across these technologies can be downloaded separately to this report.

Figure 5. Types of flexibility categorised by size (GW), duration for which they typically provide flexibility through using energy, generating energy or moving demand, and vectors involved (left = vector in, right = vector out)



Energy storage

Energy storage comprises the charge, storage and discharge of energy in a controlled manner based on external signals. It is related to different energy vectors, such as electricity, heat and synthetic fuels, including gas. Energy storage technologies are typically categorised at a high level by the energy vectors involved in charging it and the vector that is discharged. There is an energy (thermal or electrical) efficiency loss during every cycle of charge and discharge and the exact amount of loss varies across different storage technologies.

This report considers four types of storage technologies that can be used across the energy system, as outlined below.

Thermal energy storage (TES)	TES is a type of storage technology that stores thermal energy by heating or cooling a storage medium so the stored energy can be used later for heating and cooling applications or power generation. This report focuses only on TES that can store and discharge heat. While TES can broadly be categorised into four groups - sensible, latent, thermochemical and mechanical-thermal coupled systems - this report only includes tank thermal storage using water as a medium, which is a form of sensible TES.
Lithium ion batteries	Lithium is emerging as one of the fastest growing battery technologies for grid applications. It consists of a battery cell containing two reactive materials that undergo an electron transfer chemical reaction. Its current market position is aided by the presence of large-scale manufacturing of these systems, driven primarily by the EV market that continues to contribute to cost reduction.
Pumped hydro	This the most technologically mature of all the storage technologies and also the most widely deployed by global installed capacity. Energy is stored in the form of water in an upper reservoir pumped up from another reservoir at a lower level. This water is released when required, driving a turbine in a similar fashion to a hydropower plant.
Hydrogen electrolysis and storage	Electrolysis is the process of splitting water molecules into hydrogen and oxygen using electricity. This process needs water and electricity to be supplied to the electrolyser to produce hydrogen. There are three key technology options available to produce hydrogen from water (electrolysis) out of which two are modelled in this study and outlined below. Proton exchange membrane (PEM): this uses a membrane to separate the protons (H+) from water and oxygen. A key advantage of the PEM system is its ability to respond to rapid changes in the power input, which is usually in the milliseconds range. There is also a global interest in this technology which is driving increased manufacturing, use and associated cost reductions. Alkaline electrolysis: this is the most mature hydrogen production method used globally. The process of electrolysis is enabled by passing an electric current between the electrodes and an aqueous solution circulating within the cell. A membrane is then used to separate hydrogen from the other electrolysis products.

Domestic and non-domestic demand side response (DSR)

Demand side response (DSR) is the changing of the amount of energy consumed from the grid by customers in response to an external signal. Domestic DSR technologies such as auxiliary load controllers or smart appliances can be used to control regular home appliances including washing machines, dishwashers and refrigerators. Non-domestic DSR involves a similar process for shifting larger demands in sectors such as food and beverages, logistics and manufacturing. Non-domestic DSR is more technically and commercially mature than domestic DSR with several GWs already being operated in the UK currently.

EV flexibility - smart charging and vehicle-to-grid (V2G)

Smart charging involves coordinating charging of EV chargers to reduce peak loads on networks, deferring conventional reinforcement costs. This provides the ability to make EV charging demand dynamic in order to provide a range of system flexibility services. This also helps with better utilisation of renewable energy by aligning charging times (demand flexibility) with periods of high generation from renewables.

V2G enables bidirectional power flows between EVs and the grid, leveraging the storage capacity of vehicle batteries. As vehicles are parked for a large majority of their operational life, this provides an opportunity to tap into their storage capacities for flexibility needs similar to a stationary battery unit. This process requires specialised charging points.

Interconnectors

Interconnectors are transmission networks that enable the bidirectional flow of electricity between two countries. The direction of electricity flow is typically from the country of lower prices to one with higher relative prices. The underlying technology can either be high voltage alternating current (HVAC) or high voltage direct current (HVDC). The latter tends to be used for interconnectors covering long distances.

Gas turbines

There are two primary types of plants available and modelled in this work: combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs).

OCGTs: these plants typically consist of a single gas turbine which is connected via a shaft to an electricity generator. These tend to have lower efficiencies than CCGTs and are used as a peaking plant - i.e. used to meet demand during peak system demand times.

CCGT: these plants are very similar to an OCGT with the key difference being the recovery and use of the heat generated to drive a steam turbine, which produces electricity and so has a higher efficiency. These are typically used for baseload power but can be operated flexibly according to system needs.

Whilst the analysis has modelled gas turbines technology, any energy demand met by gas turbines can be interpreted as a proxy for the minimum level of gas reciprocating engines that is cost-effective to deploy in a 2050 system. The exact mix of these technologies is highly dependent on market dynamics and is not something the modelling analysed.

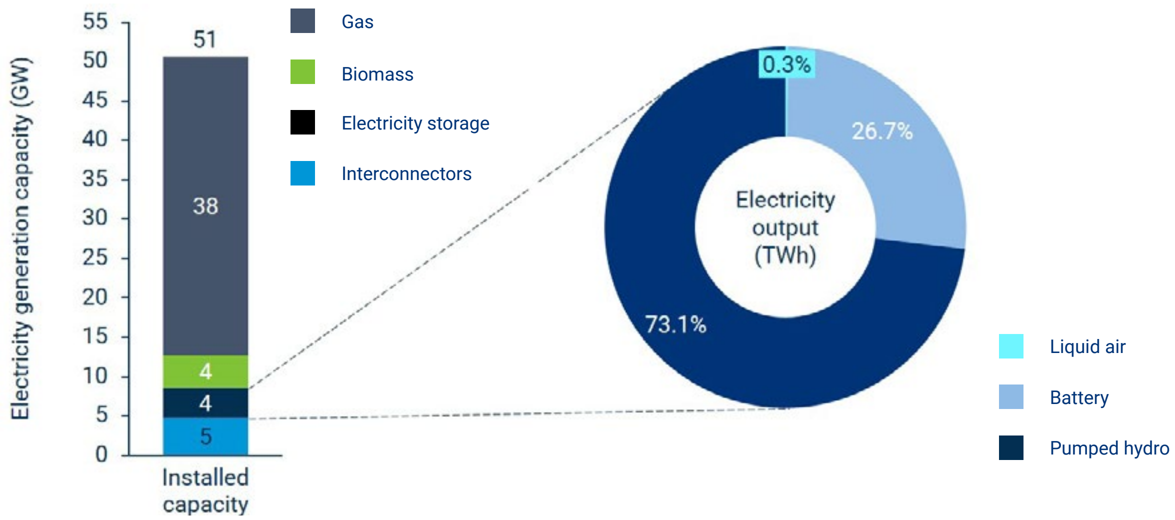
Hydrogen turbines

Hydrogen turbines offer a variation on the existing gas turbine technology to allow it to burn hydrogen blends or pure hydrogen. While some existing gas turbine designs can use material blends of hydrogen due to design modifications made for syngas use, changes to the combustion technology is carried out for specialised hydrogen turbines. The modelling for this report assumes these turbines can run on 100% hydrogen.

Baseline of flexibility in the system

This report focuses on the potential states of the GB energy system in 2050 and specifically the optimal levels of different flexibility sources described in the previous section. It is therefore important to baseline the status of flexibility deployment in the current system to be able contextualise the 2050 figures discussed later in the report.

Figure 6. Installed flexibility capacity in the GB electricity system in 2019. Source: NG, FES 2020



Supply side flexibility

The current portfolio of GB energy system flexibility is predominantly thermal generation (75%). This is due to the CCGT and OCGT capacities installed, which provide a variety of flexibility services to the system. The supply side also includes a small capacity of biomass plants (c.4GW), which can and do operate flexibly. There is an equivalent amount of storage (c.4GW) which is 75% pumped hydro with the rest coming from batteries.

Demand side flexibility

It is hard to assess exactly how much and what type of demand side flexibility capacity is readily available to provide service as it is not currently catalogued. While markets such as the Capacity Market do specify DSR as a fuel type in auction results, batteries often bid as DSR units, making the distinction difficult to make[7]. Power Responsive's 2019 report[8] provides a snapshot of the DSR capacities by looking across several markets. It notes that there was potentially up to 650MW of demand side flexibility providing services to the short term operating reserve (STOR) market in December 2019. However, these figures likely include diesel engines and combined heat and power plants, so load flexibility is likely to be a much smaller number.

7 Liam Stoker, Energy Storage News - Shut out of UK's Capacity Market, battery storage registers as DSR instead - and wins, 2020 - https://www.energy-storage.news/news/shut-out-of-uks-capacity-market-battery-storage-register-as-dsr-instead-and

8 National Grid ESO, power responsive - Demand Side Flexibility Annual Report, 2019 - http://powerresponsive.com/power-responsive-annual-report-2019/

2. Overview of modelling approach - exploring the role of flexibility in a 2050 energy system

2.1. Overview of overall approach

In this report, whole system modelling has been used to explore the question: what is the value of flexibility in delivering a net zero energy system in 2050?

Delivering the whole system modelling outputs followed four main steps:

1

Inputs

- Generation cost (capex and opex)
- Flex tech cost (capex and opex)
- Network cost (capex and opex)
- Deployment caps
- Carbon target
- System security target

Gathering input data and setting constraints on the model. The input data collected was on technology and network cost, and performance characteristics. Model constraints were set in terms of end user demand and the carbon target the energy system must meet. Further detail on the structure of data required by the whole system model is provided in Section 2.2 and in the accompanying report.

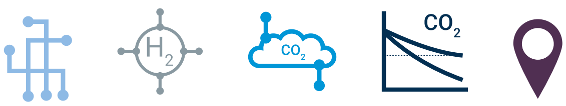
2

Modelling

Setting up three key heat decarbonisation pathways ('core pathways'). These pathways - the electric heating, hybrid heating (heat pumps and natural gas boilers) and hydrogen heating pathways - were selected as extreme scenarios to explore the link between different heating solutions and the value of flexibility. In reality, the pathway to net zero in GB is likely to incorporate elements of all three solutions. The three pathways are described in Section 2.3.

3

Scenarios



Exploring sensitivities. In order to understand more about the interactions between different forms of flexibility and the extent to which flexibility can mitigate the impact of removing key generation technologies from the energy system, sensitivities were explored for each of the three heat decarbonisation pathways to 2050. These sensitivities are set out in Section 2.3.4.

4

Outputs

Annual system cost (£bn/yr)	Hydrogen production by technology (GWh/yr)
Electricity demand by sector (TWh/yr)	Hydrogen production capacity (GW)
Heat demand met by heating technology (TWh/yr)	Carbon captured ($MtCO_2/yr$)
Electricity generation capacity by technology (GW)	Emissions by energy system sector ($MtCO_2/yr$)
Electricity generation by technology (GWh/yr)	Flexibility deployed by technology type (GW or GWh/yr)

Results and conclusions from the analysis of the core scenarios and sensitivities are presented in Chapter 3.

2.2. Integrated whole energy systems modelling - overview of modelling approach

The modelling results presented in this report have been produced using the integrated whole energy systems (IWES) model developed at Imperial College London. The IWES model is a least cost optimisation model which minimises the total cost of long-term infrastructure investment and short-term operating costs across the energy system, encompassing power, natural gas & hydrogen, heat, and carbon capture and storage (CCS) technologies while meeting carbon targets and system security constraints.

The model solves a deterministic optimisation problem. Each solution is system and scenario-specific, but the impact of different assumptions or parameters can be studied through sensitivity analysis. It is formulated as a large-scale linear optimisation problem and simplifies the non-linear properties of the energy system.

In this project, the IWES model has been used to explore the question: what is the value of flexibility in delivering a net zero energy system in 2050?

This chapter presents more detail on the model functionality and the energy system scenarios developed in this project to explore the main research question. Supplementary information on the data inputs used are provided in a separate report.

2.2.1 Energy system representation

The IWES model is an enhancement of the whole electricity system investment model (WESIM), which has been used extensively at Imperial College London to examine different electricity decarbonisation pathways, including in its 2016 joint report with the Carbon Trust, 'Can storage help reduce the cost of a future UK electricity system?'[9]

The main change to the model since 2016 is the addition of heating technologies, modules to optimise natural gas, hydrogen and district heating networks, as well as thermal and hydrogen storage. This enables the model to examine the role of flexibility across the heat and power sectors, including the interplay of flexibility between the electricity and gas systems.

9 The Carbon Trust and team from Imperial. Can storage help reduce the cost of a future UK electricity system?, 2020. https://www.carbontrust.com/resources/energy-storage-report-can-storage-help-reduce-the-cost-of-a-future-uk-electricity-system

On the **supply side**, the IWES model represents the following aspects of the energy system:

Electricity: Generation from thermal, nuclear and renewable sources, transmission and distribution networks, plus storage in the form of batteries and pumped hydro.

Natural gas and hydrogen: Production of hydrogen from biomass, natural gas or electricity, repurposing of gas transmission and distribution networks to transmit hydrogen, and storage of hydrogen in salt caverns (large scale) or in pressurised containers (small/medium scale). Natural gas storage is not represented.

Carbon capture and storage (CCS): The model includes CCS technologies coupled with power and hydrogen production, as well as direct air carbon capture and storage (DACCS). The cost of carbon dioxide (CO_2) networks and long-term storage are also included. Industrial CCS (e.g. steel or cement manufacturing capturing CO_2 from fossil fuels used directly) is not modelled.

On the **demand side**, the IWES model considers different types of end use demand, and demand-side flexibility:

Heat demand: Domestic and industrial heat demand are an input to the model. In this project we have analysed three different approaches to meeting domestic heat demand: one scenario dominated by electric heating (heat pumps and resistive heaters); one with largely hydrogen boilers; and one with hybrid heat pumps (heat pumps coupled with a back-up natural gas boiler). These heating pathways are described in more detail later in the report. Thermal storage, in the form of hot water tanks, is available in the model as a form of flexibility.

The model optimises the aggregated scheduling of millions of heating appliances and does not concern itself with specific individual building requirements, for example, between new and old buildings. However, aggregated heat demand profiles consider different types of building.

Electricity demand: Half-hourly electricity demand for domestic and industrial (non-heat, non-transport) end user applications is an input into the model. Industrial and commercial DSR and domestic smart appliances are two forms of flexibility modelled in this project.

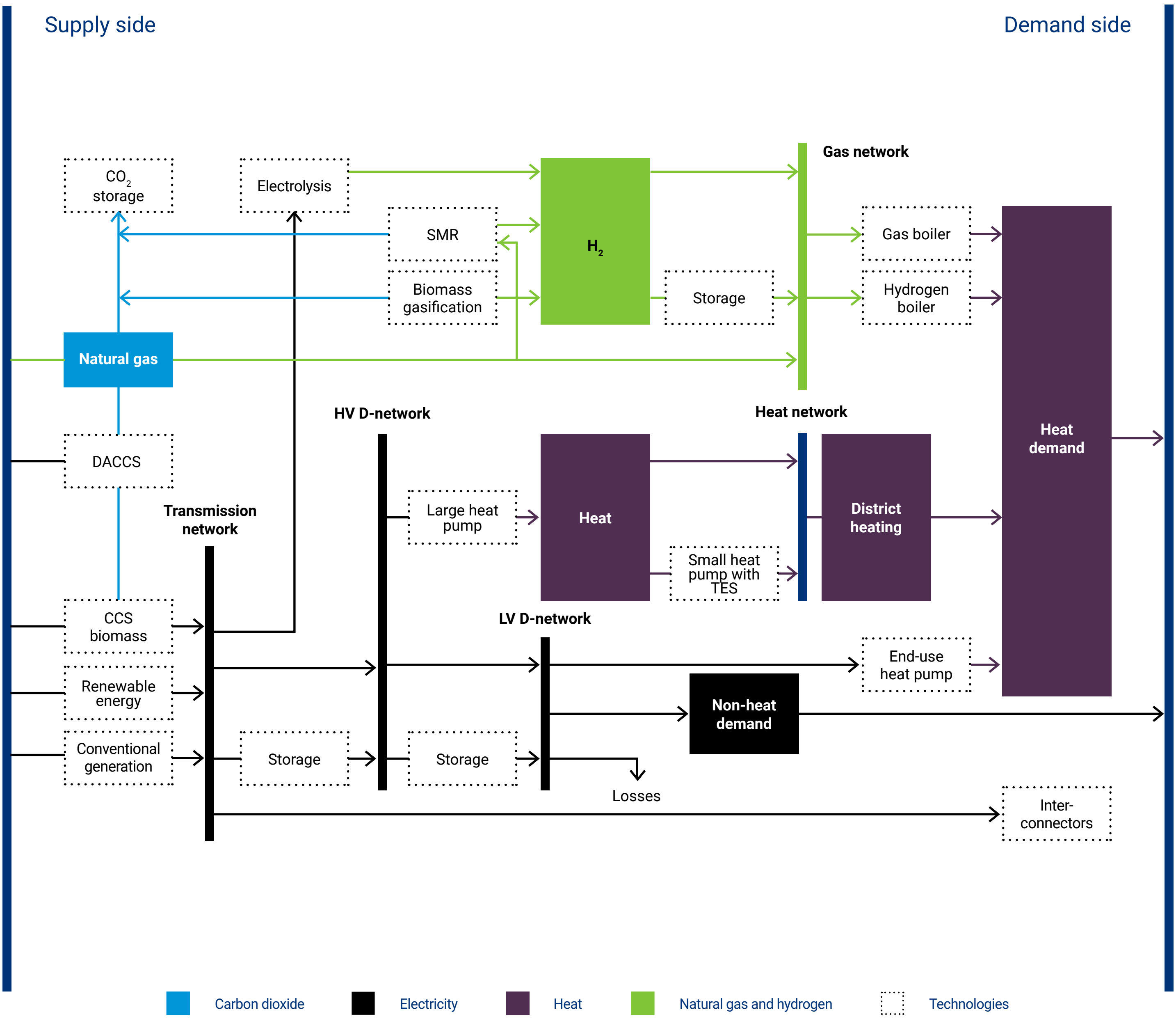
Any additional electricity demand resulting from technologies deployed by the model, such as DACCS, electrolysers, charging of electricity storage, or parasitic loads of methane reforming processes for hydrogen production are added to the original demand and considered in the system optimisation.

Electric vehicles (EVs): The number of EVs and their typical charging patterns are an input to the model. Smart charging and V2G capabilities can be deployed by the model to manage this demand and provide system services.

Additional hydrogen demand: The amount of hydrogen required to meet domestic heat demand is calculated by the model. However, in a 2050 economy, hydrogen may be used in other sectors, including industrial processes and as fuel for heavy goods vehicles (HGVs) and some trains. An additional 123TWh demand for hydrogen is included as an input. This is derived from Climate Change Committee analysis and explained further in the accompanying report on data inputs. The profile of this demand over a year is modelled flat.

For clarity, the proportions of transport and industrial demand met by electricity and hydrogen are not optimised in the model - the demand for each vector is an input to the model.

Figure 7.Interaction between gas, heat and electricity systems in IWES



2.2.2 Model boundaries

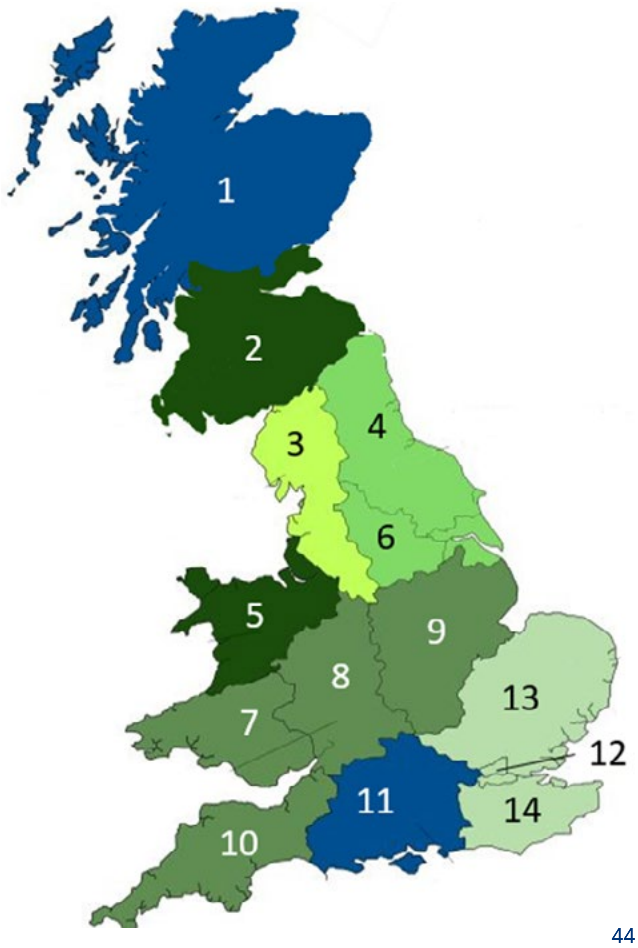
This section sets out the spatial and temporal boundaries of the model, as well as the carbon emission and system operation constraints.

2.2.2.1 Spatial

This project has focused on the GB energy system and the modelling results presented in this report cover the energy system in Great Britain only. System cost differences demonstrate the value of flexibility to the GB energy system alone.

Figure 8. Regions of GB used in the IWES model and the corresponding electricity Distribution Network Operator (DNO)

#	Region	DNO
1	North Scotland	Scottish and Southern Energy
2	South Scotland	Scottish Power Energy Networks
3	North-west England	Electricity North West
4	North-east England	Northern Powergrid
5	North Wales, Merseyside and Cheshire	Scottish Power Energy Networks
6	Yorkshire	Northern Powergrid
7	South Wales	Western Power Distribution (WPD)
8	West Midlands	
9	East Midlands	
10	South-west England	
11	Southern England	Scottish and Southern Energy
12	London	UK Power Networks (UKPN)
13	East England	
14	South-east England	



However, to generate results for Great Britain, IWES models the electricity system in Great Britain, Ireland and continental Europe as part of the least cost-optimisation to reflect the correlation of both electricity demand and supply with interconnected markets. The energy system in Europe is also optimised in the same fashion as the GB system. The model optimises the whole system, including Europe, and so optimises investment, operation, and the energy exchanges and capacity sharing for system security between GB, Ireland and continental Europe. The exchanges are constrained by GB interconnection capacity. Investment in new interconnection is limited to 11.7GW in low flexibility scenarios and 20GW in high flexibility scenarios.

In calculating the least cost solution, IWES optimises across the European energy system, not just GB. This can result in GB being a net importer or exporter of electricity via interconnectors.

2.2.2.2 Temporal boundaries and operational constraints

IWES is set up to reflect the technical needs of balancing the supply and demand of energy across different time horizons (seconds to years).

In this analysis, all scenarios have been modelled for the year 2050 only - the transition to 2050 is not analysed. Therefore, for modelling purposes, all generation, storage & flexibility, network and heating assets are optimised without historical constraints, with the following exceptions:

- Existing (2019) gas and electricity networks
- 2.7GW of pumped hydro schemes: Dinorwig (1.6GW) and Ffestiniog (0.4GW) in North Wales, and Cruachan Dam (0.4GW) and Foyers (0.3GW) in Scotland
- 4.4GW of large scale nuclear: Sizewell B (1.2GW) in the East of England and Hinkley Point C (3.2GW) in the south-west[10]

Within 2050, supply and demand are aligned on an hourly basis, using a full year of hourly annual demand profile as input data, rather than sampling representative days. The alignment of supply and demand also takes into account spatial differences when considering the flow rate of natural gas or hydrogen through the gas networks. More detail on the demand data used is provided in an accompanying report.

At a more granular level, IWES requires the system to maintain grid frequency by providing sufficient system inertia and frequency response on a second-by-second basis. In delivering these services, the model takes into account the technical parameters of the energy generation and flexibility technologies, such as the speed at which they can ramp their output up or down. Further details on the technical characteristics of generation and flexibility technologies considered within the model, are provided in an accompanying report.

10 NIA, Nuclear Sector Deal: Nuclear New Build Cost Reduction Report, 2020. https://www.niauk.org/wp-content/uploads/2020/09/New-Build-Cost-Reduction-Sector-Deal-Working-Group.pdf
Sizewell B is expected to continue operating 'well beyond' 2035. Hinkley C is expected to be operational in 2025.

System adequacy (ensuring there is sufficient generation to meet demand) is also taken into account in IWES. The model result must meet a given level (three hours) of loss of load expectation (LOLE) across the year. Within the 2050 demand profile used, there is a 72-hour period of extremely cold weather (a 1-in-20 year cold winter, resulting in high heating demand), coupled with low availability of wind and solar energy (less than 5% of maximum output), to ensure system adequacy to cope with these days. Throughout the year, short-term operating reserve (STOR) requirements are also accounted for. Sufficient reserve (both spinning and standing) is required to deal with uncertainty in generation output.

Reactive power requirements are not modelled.

On the gas networks, natural gas storage is not modelled. It is assumed that natural gas is available in the quantities required at the time needed. It is also assumed that the present natural gas transmission system will be able to deal with the future requirement for natural gas transport. For modelling purposes, separate natural gas and hydrogen transmission networks are modelled, although it is recognised that these gases may be blended in reality. At a distribution network level, it is assumed that the existing network can be repurposed to transport hydrogen in the hydrogen heating scenario.

Any costs associated with meeting the criteria for system operation are taken into account in the total energy system cost.

2.2.2.3 Carbon target

Unless otherwise stated, all scenarios had to meet a carbon target of -50Mt CO_2/yr across the energy system during 2050. The net negative carbon target takes into account the fact that, to deliver a net negative economy overall, some sectors will need to deliver negative emissions to offset hard-to-decarbonise, sectors such as aviation and sections of heavy industry. This was derived from the Climate Change Committee's net zero analysis[11] which identifies the energy sector as a part of the economy which could deliver these negative emissions through the use of biomass with CCS, or DACCS.

The carbon target is applied across the whole energy system. There are no specific targets for the electricity or heat sector.

11 Climate Change Committee (CCC), Net Zero - The UK's Contribution to stopping global warming, 2019. https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

2.2.3 Objective function and costs

The IWES model is a least cost optimisation model that minimises the total cost of long-term infrastructure investment and short-term operating costs across the energy system, while meeting carbon targets and system security constraints.

All costs and revenues for assets are based on cost assumptions in 2050, expressed in £ (GBP) based on the value of money in 2019.

As mentioned in Section 2.2.2.1 above, in calculating the least cost solution, IWES optimises across the European energy system, not just GB. However, the modelling results presented in this report cover the energy system in GB only, and the difference in system cost between two scenarios represents the value to the GB energy system alone.

In calculating the least cost solution, IWES takes into account the following costs:

- ✓ **Investment/Capital costs (CapEx)** of new generation, storage, heating solutions, interconnection, transmission and distribution reinforcements or upgrades. These costs are annualised, using an asset-specific lifetime and weighted average cost of capital (WACC).

  For large-scale hydrogen storage and for CO_2 storage, CapEx is calculated on a £/GWh stored (for hydrogen) or a £/tCO_2 stored.

- ✓ **Operational costs (OpEx)** for generation, storage, heating solutions, DSR provision, interconnection and gas and electricity network assets. This includes both fixed and variable costs.

  For all fuelled generation, start-up costs (£/start up) and no-load costs (£/hr) are included, as are fuel costs for natural gas and biomass. This is in addition to standard fixed and variable costs. There is no cost of hydrogen in the model as this is generated within the scenario, not imported.

- ✓ **Revenue or cost from interconnector flows.** IWES estimates the 'revenues' of energy export to Europe by multiplying the net energy export with the average cost of electricity production based on the generation mix deployed in GB. Depending on the direction of the net flow, this can be an additional system cost for GB or a source of revenue. It is worth noting that the 'revenue' is used to recover the cost of investment and operation for the energy exported to Europe. The market value of it is likely to be higher.

The following costs are not considered in the IWES model:

- X **The cost of purchasing EVs or domestic smart appliances.** It is assumed that these assets, which can provide flexibility to the energy system, are primarily purchased to provide other services, so the purchase price shouldn't be included in the energy system cost.

- X **The cost of EV charging infrastructure.** Similarly, EV infrastructure enables smart charging and V2G flexibility, but its primary function is not provision of system services. In addition, the use of EVs is consistent across all scenarios, so including the cost would make no difference to a comparison between two scenarios.

- X **The cost of home insulation or other efficiency measures.** Demand for heat is an input into the model and is consistent across all scenarios. This project has not explored the interplay between flexibility and efficiency or demand, but it is noted as an area for further research in Chapter 5.

- X **The CapEx cost of existing assets still operational in 2050.** As noted in Section 2.2.2.2 above, some large-scale nuclear and pumped hydro plants currently operational or under construction will still be in use in 2050. Similarly, the gas and electricity networks will build on current capacity. The capital costs of these assets are not included in the model.

- X **Policy costs.** The IWES model is policy neutral and includes no existing or presumed incentives for low carbon generation, nor does it include a carbon tax.

The modelling outputs provide details on the energy system cost, structure and utilisation. Outputs from the model used in this report include:

Annual system cost (£bn/yr)	**Carbon captured ($MtCO_2$/yr)**
Electricity demand by sector (TWh/yr)	**Electricity generation by technology (GWh/yr)**
Electricity generation capacity by technology (GW)	**Emissions by energy system sector ($MtCO_2$/yr)**
Flexibility deployed by technology type (GW or GWh/yr)	**Heat demand met by heating technology (TWh/yr)**
Hydrogen production by technology (GWh/yr)	**Hydrogen production capacity by technology (GW)**

How to read the charts

Throughout this report, charts of the same type, e.g. 'annual system cost', are formatted consistently for ease of interpretation.

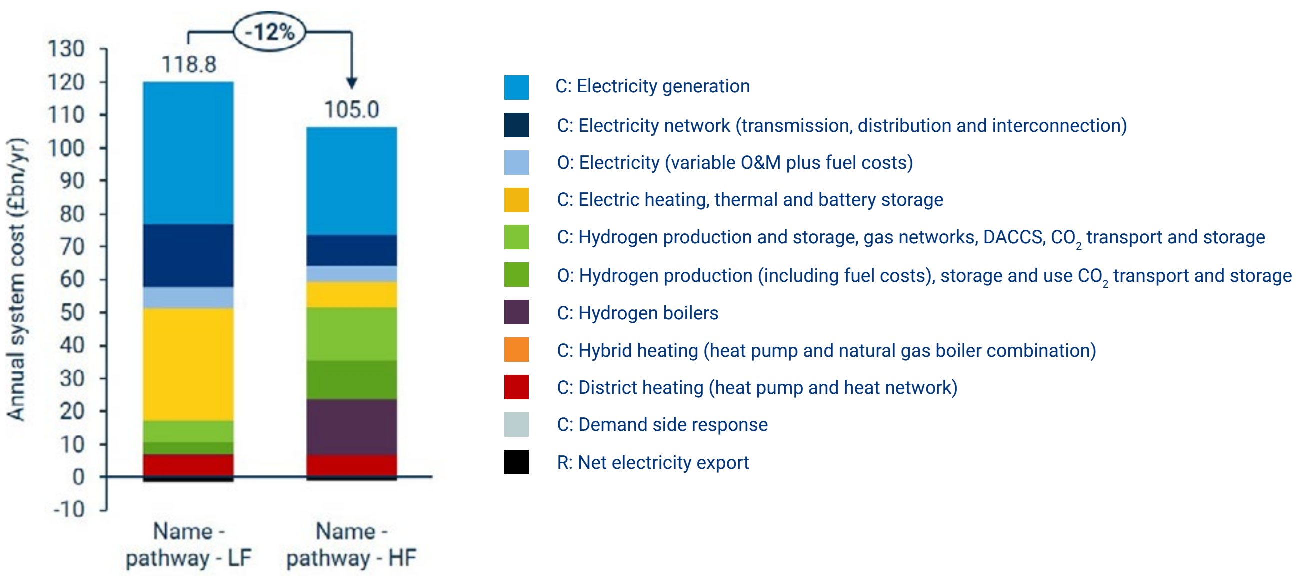
The figure label provides details of the sensitivity name and heating pathway, e.g, **'Annual heat demand met by heating technology (TWh/yr) - Electric heating pathway - low flexibility (LF) and high flexibility (HF)'**.

The x-axis labels indicate which model run the data refers to, and whether it is from a low or high flexibility run.

Data labels indicate the total of each stacked column. The percentage difference between the total of two columns is indicated in the arrow at the top of the chart.

For system cost charts, the total cost of building and operating an energy system in 2050 is annualised using an asset-specific lifetime and weighted average cost of capital (WACC).

Figure 9. Chart heading - data type - heating pathway - low flexibility (LF) or high flexibility (HF)



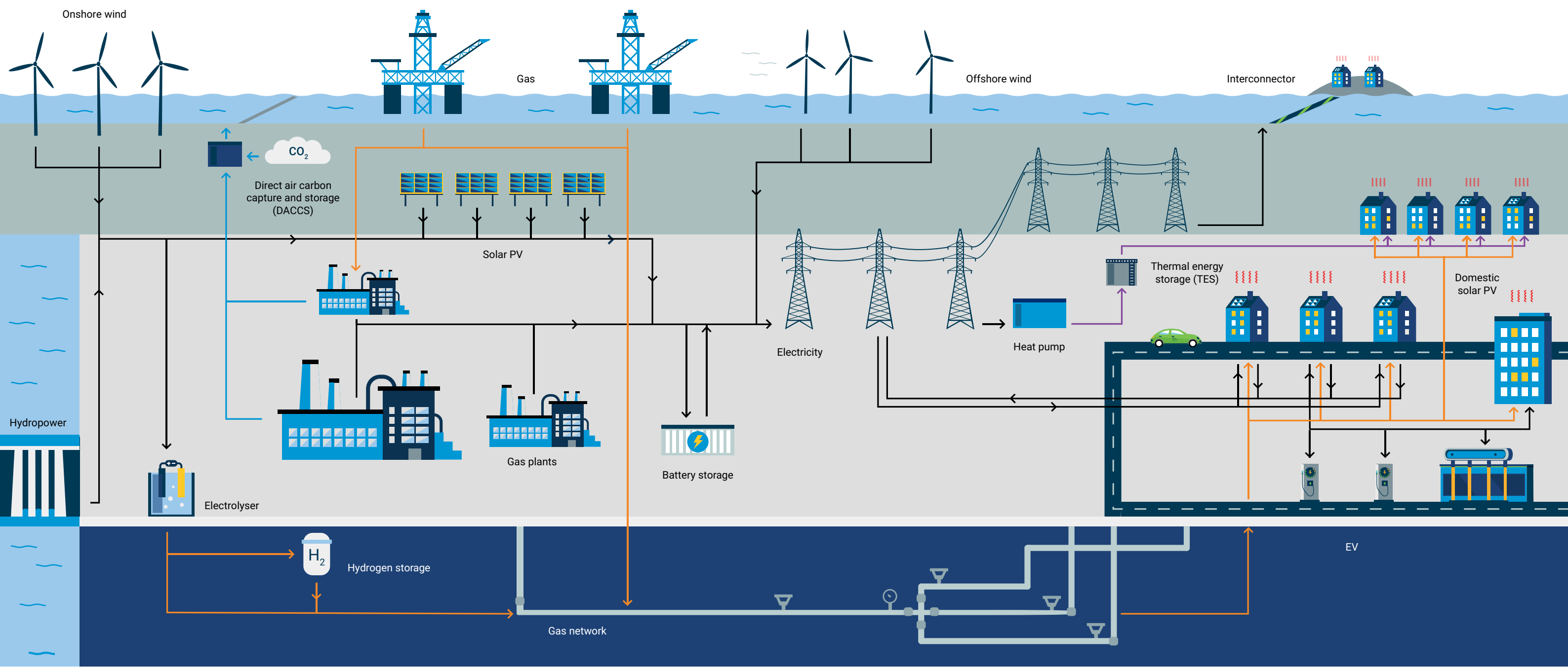
2.3. Background to core pathways and sensitivity scenarios

The primary research question for this project is: what is the value of flexibility in delivering a net zero energy system in 2050?

This question was explored by looking at the role and value of flexibility under three different heating decarbonisation pathways: electric heating, hydrogen heating and hybrid heat pump heating. These are referred to in this report as core pathways. Each core pathway was modelled as a low flexibility and high flexibility system (Figure 10). Further details of how each flexibility technology is represented in the model in both the high and low flexibility scenarios is provided below.

Figure 10. Low flexibility heating scenario visualisation

Low flexibility heating scenario



High flexibility heating scenario

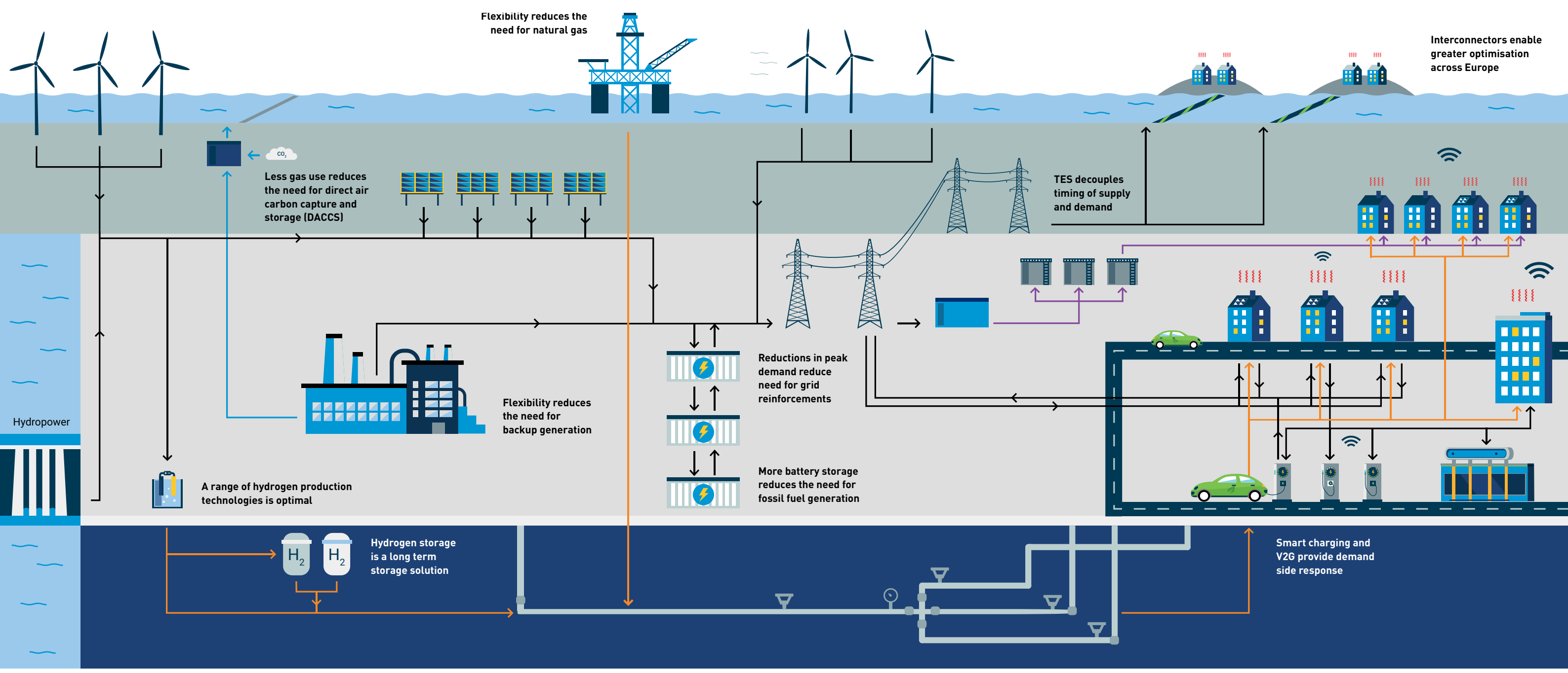
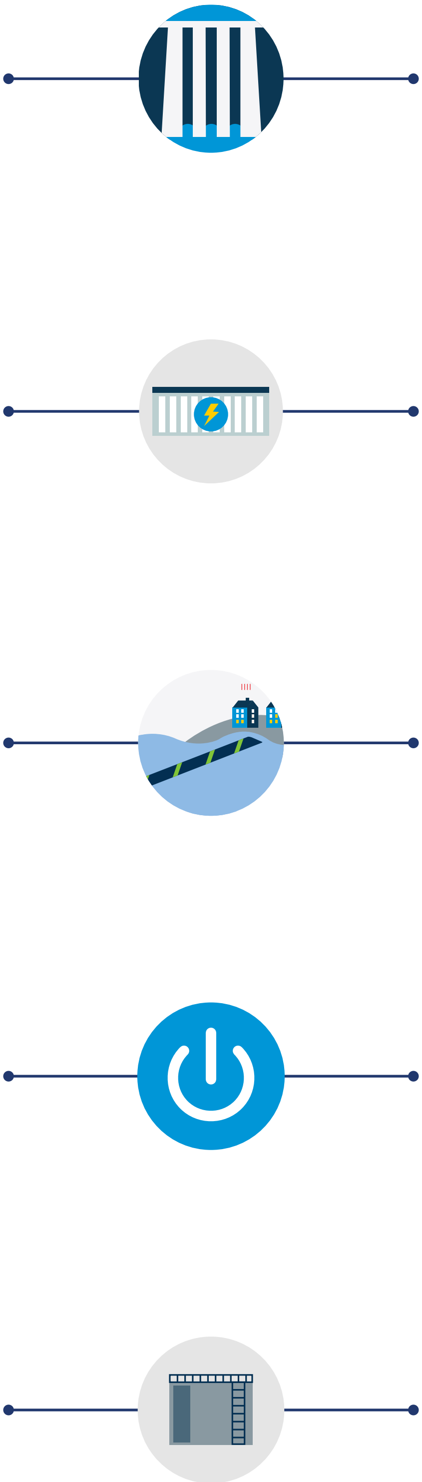


Figure 11. Flexibility deployment limits in the low and high flexibility scenarios



Low flex	High flex
2.7GW pumped hydro capacity	**2.7GW** pumped hydro capacity
1.1GW battery electric storage (4hr duration) - similar to current GW capacity	**Unlimited** battery electric storage (minimum 4hr duration)
11.7GW interconnection to Ireland and continental Europe	Up to **20GW** interconnection to Ireland and continental Europe
No DSR from either domestic smart appliances, industrial and commercial, or EV smart charging or V2G services	**DSR** from domestic smart appliances, industrial and commercial or EV smart charging or V2G services
Limited Thermal Energy Storage (TES) - 2kWh flexible hot water tank alongside domestic heat pumps. District Heating storage can provide around 6 hours maximum heat demand	**Additional** TES at both a domestic and DH scale

Sources of system flexibility

For domestic **smart appliances**, such as washing machines, tumble dryers, fridges and freezers, up to 41% of daily demand can be shifted within the day. The GW capacity represents the maximum change in demand for these appliances at any point in the year. There are negligible losses associated with this demand shift.

For **EVs**, the GW figure combines the maximum change in demand at any one point in the year as a result of both smart charging (moving demand to another time of day) and V2G services (discharging energy into the grid). At its peak, 85% of vehicles can move their charging time, of which 25% cannot only 'not charge', but can also discharge any remaining power back into the grid. There are negligible losses associated with this demand shift.

TES is assumed to be hot water tanks, either installed in domestic properties or part of DH schemes. The energy capacity of the TES is measured in GWh, and the conversion to GW assumes a minimum six-hour discharge time for DH scale TES, and a minimum one hour discharge time for domestic scale TES. Thermal energy can be stored for several days, but heat losses over time are factored into the model optimisation. Unlike DSR and EVs, the GW capacity does not reflect the peak discharge of TES at any point during the year. The deployment of TES is a function of both the power rating and total energy capacity. In the Electric heating pathway, deployment of TES is capped at 111GW in the low flexibility scenario, and 211GW in the high flexibility scenario. In the hybrid heating and hydrogen heating pathways, deployment of TES is capped at 49GW in the low flexibility scenario and 149GW in the high flexibility scenario.

The capacity of the **interconnectors** represents the maximum potential power flows (either import or export). The utilisation of the interconnectors is determined by the model optimisation. Up to 11.7GW of interconnection capacity can be installed in the low flexibility scenario and up to 20GW of interconnection capacity can be installed in the high flexibility scenario. See Section 2.2.2.1 for further detail on the representation of the GB and EU networks in the model.

For **industrial and commercial (I&C) DSR**, the GW figure represents the maximum change in demand at any point in the year. Up to 20% of I&C demand can be shifted within the day. The efficiency of this demand shift is 95%. This means if 100kWh of demand is moved to a different time of day, 105.3kWh will need to be supplied to meet demand (100/95 = 105.3).

For **battery storage**, all batteries deployed have a minimum four-hour discharge period, which means the energy storage capacity of batteries is four times the GW figures shown in the charts later in this section. As with TES, the deployment of battery storage is a function of both the total energy storage capacity (GWh) and the maximum discharge rate (GW). A round trip efficiency of 80% is assumed.

Existing **pumped hydro** capacity (2.7GW) is included in the model, representing existing capacity. The minimum duration of the discharge period is dependent on the size of the reservoir of each unit.

Although **electrolysers** are primarily a means of generating hydrogen from water using electricity, the way in which they are operated is a form of flexibility, allowing hydrogen to be produced at times of least cost to the wider energy system, and enabling integration between the gas and electricity networks. There is no limit on electrolyser deployment in either the low or high flexibility scenario.

Hydrogen storage can be deployed at two scales – large underground caverns (onshore) or small/medium pressurised overground containers. Specific sites for large hydrogen storage are identified in the modelling inputs (although are not a limiting factor in the scenarios considered in this report) and unlimited small/medium storage can be deployed.

Finally, the operation of electricity generation assets, gas boilers or hydrogen production facilities using natural gas, hydrogen or biomass as a fuel can be operated flexibly (within their technical limits) to ensure continuous alignment of supply and demand. This **'inherent' energy system flexibility** is used in both the low and high flexibility scenarios.

2.3.1 Core heating pathways

Electric heating

Under an electric heating future, 20% of all domestic heat demand is met through district heating in urban areas. These schemes are powered by ground-source, or water-source heat pumps with thermal storage (hot water tank) that can provide around 6 hours maximum heat demand in the low flexibility scenario. The remaining domestic households and non-domestic spaces, such as offices, meet their space and hot water heating needs through individual ASHP and resistive heating. Under a low flexibility scenario, all domestic scale ASHP are installed with 2kWh (2kW) of TES, in the form of a hot water tank. Under a high flexibility scenario, the capacity of TES installed can be increased. In addition, extra battery storage and interconnection can be deployed, and demand response and V2G services can be used.

Hybrid heating

Under a hybrid heating future, 20% of all domestic heat demand is met through district heating in urban areas. These schemes are powered by ground-source, or water-source heat pumps and are installed with a hot water tank that can provide around 6 hours maximum heat demand in the low flexibility scenario. All remaining space heating and hot water demand which is connected to the existing gas network has its needs met by an ASHP, coupled with a small natural gas boiler to provide heat during periods of high demand. Properties not connected to the gas grid have their space and hot water heating needs met through individual ASHP and resistive heating only. Under a low flexibility scenario, all domestic scale ASHP are installed with 2kWh (2kW) of TES in the form of a hot water tank, regardless of whether they are also connected to the gas grid.

In the high flexibility scenario, all domestic properties and district heating schemes can install additional TES. In addition, extra battery storage and interconnection can be deployed, and demand response and V2G services can be used.

Hydrogen heating

Under a hydrogen heating future, 20% of all domestic heat demand is met through district heating in urban areas. These schemes are powered by ground-source or water-source heat pumps and are installed with thermal storage that can provide around 6 hours maximum heat demand in the low flexibility scenario. All remaining space heating and hot water demand which is connected to the existing gas network has its needs met by hydrogen boilers. Properties not connected to the gas grid have their space and hot water heating needs met through individual ASHPs and resistive heating. Under a low flexibility scenario, all domestic scale ASHP are installed with 2kWh (2kW) of TES in the form of a hot water tank.

In the high flexibility scenario, all domestic properties and district heating schemes can install additional TES. In addition, extra battery storage and interconnection can be deployed, and demand response and V2G services can be used.

2.3.2 Sensitivity scenarios

As with any systems modelling project, there are a multitude of combinations of input data points and constraints that can be placed on the model. The three core scenarios described above are intended to test three different ways of meeting heat demand and the value of flexibility in doing so.

Sensitivity studies were carried out on each of the core scenarios to explore five main aspects of the energy system below.

The results from these sensitivities are explored in more detail in the following chapter.

Impact of flexibility technology availability

Changing assumptions on flexibility technology availability and costs to understand the extent to which other forms of flexibility can compensate for the removal of one type of technology.

Impact of carbon targets

Changing the energy system carbon target to identify the additional system cost incurred if the energy system delivers net negative emissions.

Impact of hydrogen production route

Changing assumptions on production and use of hydrogen. In particular, this explored the impact of moving from a portfolio of hydrogen production technologies to systems dominated by either electrolysis or production from natural gas and biomass.

Local versus system benefits

Exploring the value of flexibility at both a local and national level, and the impact on national energy system cost if systems are optimised at a local level.

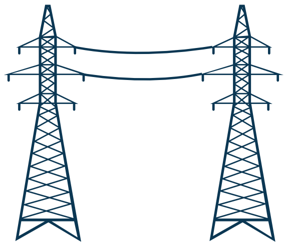
Impact of negative emissions technology availability

Assessing the impact of removing DACCS technology from the energy system mix to understand the value of being able to decouple CO_2 extraction from the point of emissions.

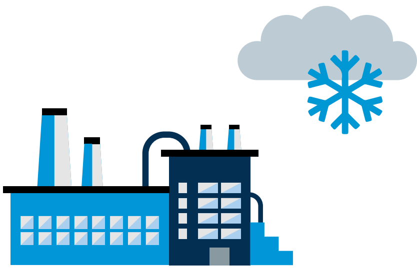
3. Role and value of flexibility in a 2050 energy system

Benefits of a flexible energy system - core pathway focus

Flexibility can deliver energy system savings of up to £16.7bn/yr

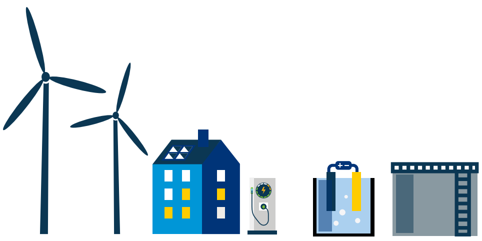


Flexibility reduces grid reinforcement requirements on the distribution network by lowering peak demand

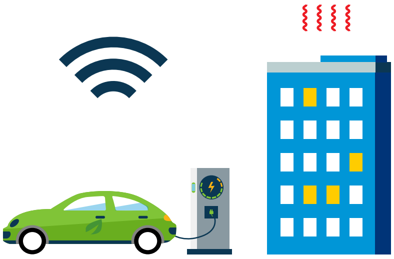


Flexibility reduces the need for dedicated back up generation for severe weather events

Flexibility is deployed throughout the system at local and national levels



A portfolio of flexibility adjusting supply and demand is most cost-effective



Flexibility embedded within transport and heating solutions helps to reduce the cost of decarbonisation of these sectors

3.1. Core pathways - overview of structure

This chapter sets out the results of the IWES modelling of the core pathways and sensitivity scenarios. Chapter 4 then explores the variation in deployment of flexibility across the core scenarios and considers whether GB is on track to deploy sufficient flexibility and what barriers may stand in its way.

As described in Section 2.3, there are three core pathways - electric heating, hybrid heating and hydrogen heating. The purpose of the core pathways is to understand the value of flexibility to the GB energy system under different dominant heating methods. As set out in the previous chapter, the three pathways are intended to test the extremes of how heat could be provided in 2050; the reality is much more likely to be a mix of all three. Nevertheless, exploring each option in turn provides useful insight into how flexibility is provided and used in each energy system.

The following sections explore each pathway in turn and then return to discuss all three pathways before examining sensitivity scenarios.

Each core pathway section is structured to address the following questions:

- **What key insights can we draw from this pathway?**
- **What is the heating pathway?**
- **What system savings can flexibility deliver?**
- **How does flexibility change energy demand and how demand is met?**
- **How does flexibility change the electricity generation capacity mix?**
- **What flexibility is deployed in a high flexibility scenario and how does it deliver system savings?**
- **What impact does flexibility have on the need for CCS infrastructure?**

The sensitivity scenarios that follow set out how each varies from the relevant core pathway then address how the difference between the scenarios alters the system cost, make-up and impact of flexibility.

Key messages for each core scenario and sensitivity are given at the start of each section. Overarching conclusions are presented at the end of the chapter.

3.2. Electric heating pathway

Key insights

Is it feasible to rely on a predominantly electric heating strategy to meet net zero?

Electrifying all heat demand in buildings has a large impact on total electricity demand - in a low flexibility electric heating pathway, electricity demand in 2050 is 798TWh, more than two and a half times the total final consumption of electricity in Great Britain in 2019.

Meeting this demand requires significant build out of low carbon generation - predominately offshore wind in our modelling. However, whilst low carbon generation can meet much of the demand for heat throughout the year, it is important to consider the system implications of 'high demand, low renewable electricity supply' periods. In this analysis we have considered a 72 hour-period of extreme cold weather driving up electricity demand (c.230GW) coincident with very low wind and PV output (<5% of maximum). This results in a heavy reliance on fossil fuel plants to ensure adequacy and, under a low flexibility scenario, requiring over 200GW of gas turbines capacity to support the system during this period. This is more than the total generating capacity of the current GB electricity system and calls into question the feasibility of an electric heating scenario without significant investment in flexibility.

How does flexibility help a scenario dominated by heat pumps?

Flexibility reduces the total electricity demand by 4%, peak demand on distribution networks by 61GW (c.25%) and total combined generation and battery storage capacity by 11GW (2.5%). Technologies such as thermal storage in homes and in heat networks help to decouple electricity demand and supply. This in turn helps to reduce demand from heat pumps particularly during periods of system stress which reduce the need for additional generation capacity and network infrastructure. In our analysis, investing in additional flexibility such as battery & thermal storage, demand side response and interconnection significantly reduces the requirement for fossil fuel plants (by over 80GW) particularly during periods of system stress.

Delivering the above helps to reduce the cost of an electric heating pathway by £16.7bn/yr which is a 13% reduction from the scenario without additional flexibility.

3.2.1 Electric heating pathway - scenario description

Under an electric heating future, 20% of all domestic heat demand is met through district heating in urban areas. These schemes are powered by ground-source, or water-source heat pumps with thermal storage (hot water tank) that can provide around 6 hours maximum heat demand in the low flexibility scenario. The remaining domestic households and non-domestic spaces, such as offices, meet their space and hot water heating needs through individual ASHP and resistive heating.

Under a low flexibility scenario, all domestic scale ASHP are installed with 2kWh (2kW) of TES, in the form of a hot water tank. Under a high flexibility scenario, the capacity of TES installed can be increased. In addition, extra battery storage and interconnection can be deployed, and demand side response and V2G services can be used.

3.2.2 Key findings

3.2.2.1 System cost - increasing energy system flexibility reduces the cost of meeting demand by £16.7bn/yr

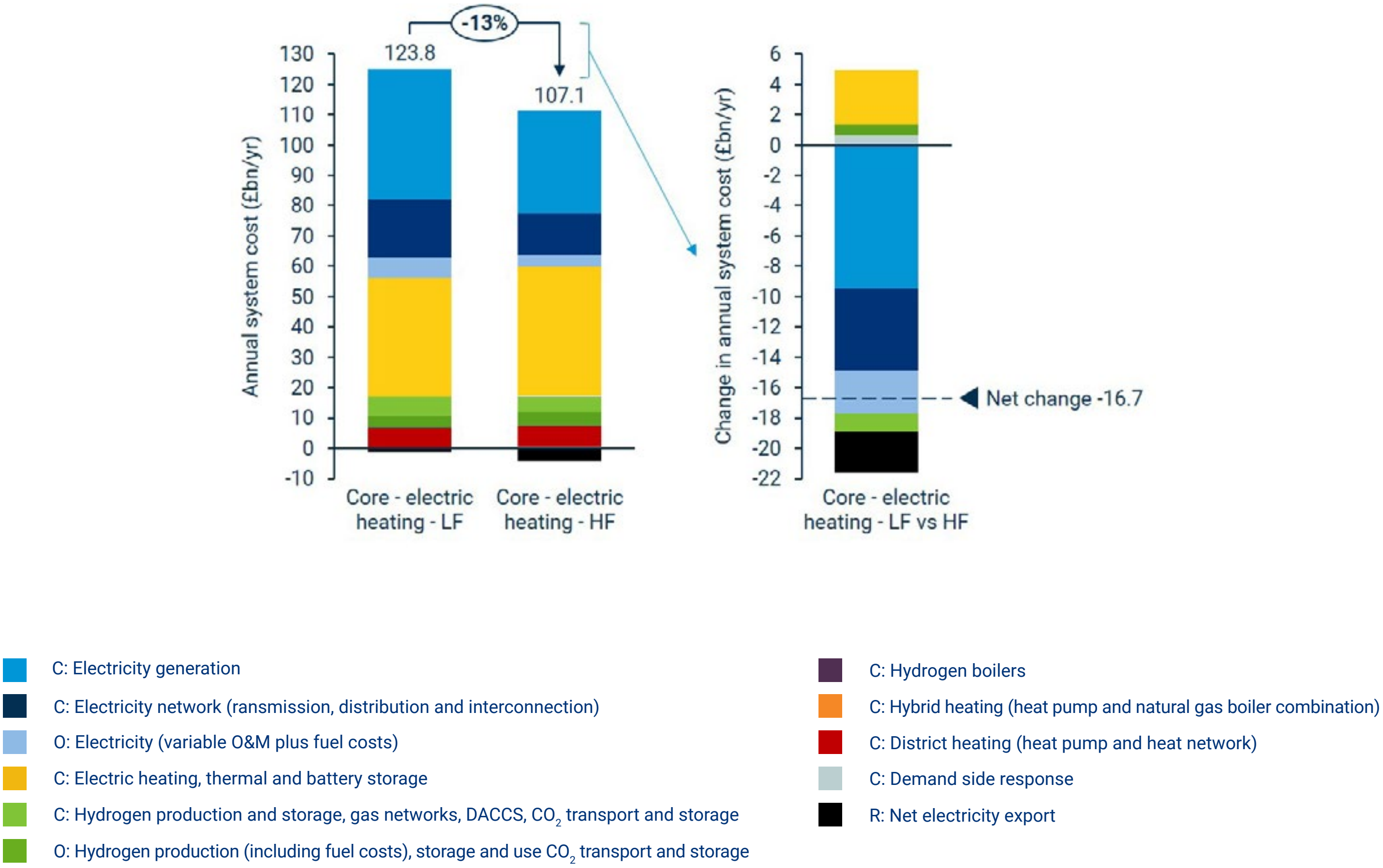
Our modelling suggests that delivering an electric heating pathway with low levels of flexibility will cost £123.8bn/yr from 2019 to 2050. Enabling additional system flexibility to be deployed reduces the annual system cost associated with the electric heating scenario by 13% (£16.7bn) (Figure 12).

The investment in additional storage and flexibility reduces the investment required in the electricity networks by reducing peak flows on the distribution network from 229GW in the low flexibility scenario to 168GW in the high flexibility scenario. This is due to a combination of flexibility technologies enabling load to be shifted to periods of lower demand (EV charging & V2G, smart appliances and I&C demand) and thermal storage decoupling the time-of-use of electricity from the time at which heat or power is provided.

The investment in additional storage and flexibility also reduces the investment required in electricity generation as different forms of flexibility help to meet demand during periods of system stress. This is described further in Section 3.2.2.3.

The following sections explore how these cost savings are delivered in more detail.

Figure 12. Left: Annual system cost (£bn/yr). Right: Reduction in annual system cost from low to high flexibility - electric heating pathway - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue



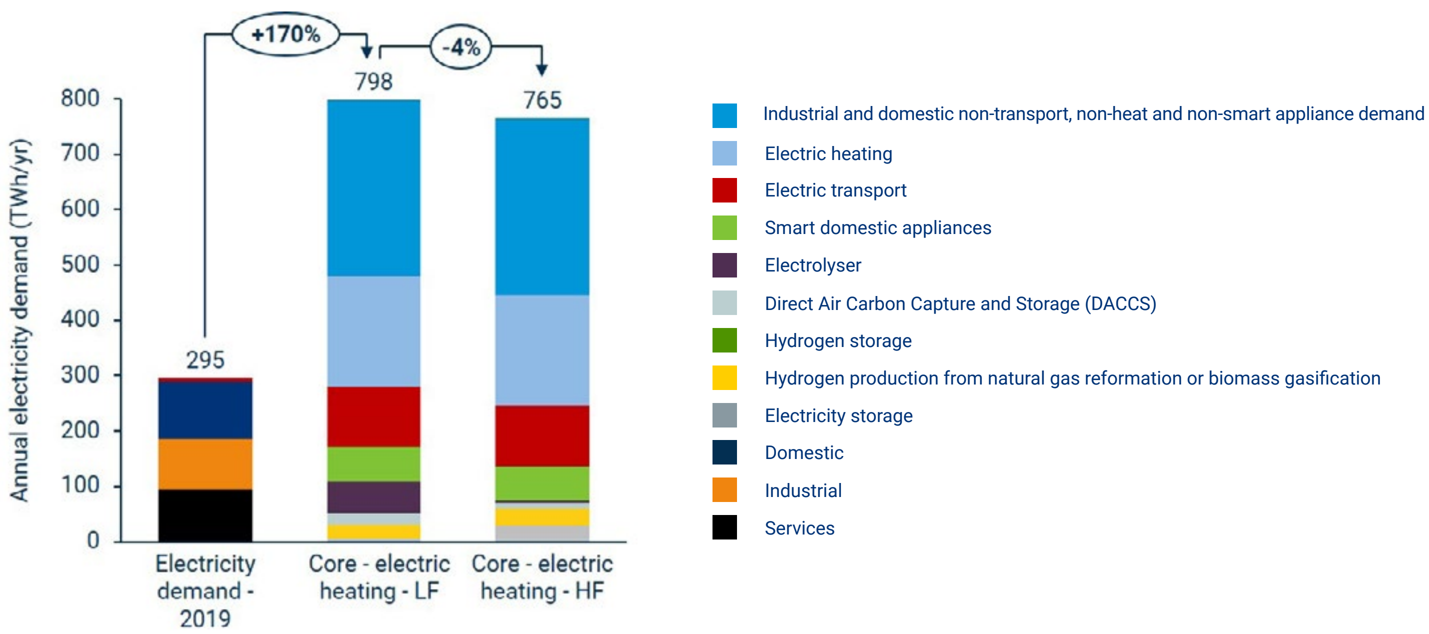
3.2.2.2 Energy demand - electrifying heat and transport more than doubles current electricity demand

In the electric heating pathway, all end user demand is either direct electricity demand for heat, transport and appliances or demand for hydrogen for high temperature industrial processes and HGVs (totalling 123TWh/yr of hydrogen).

The impact of electrification on total electricity demand is highlighted in Figure 13. Total electricity demand under the low flexibility scenario in 2050 is 798TWh - more than two-and-a-half times the total final consumption of electricity in GB in 2019. As well as electrification of end user activities, such as electric transport and heating, new demands for electricity use in hydrogen production (electrolysis) and powering DACCS increase total electricity demand.

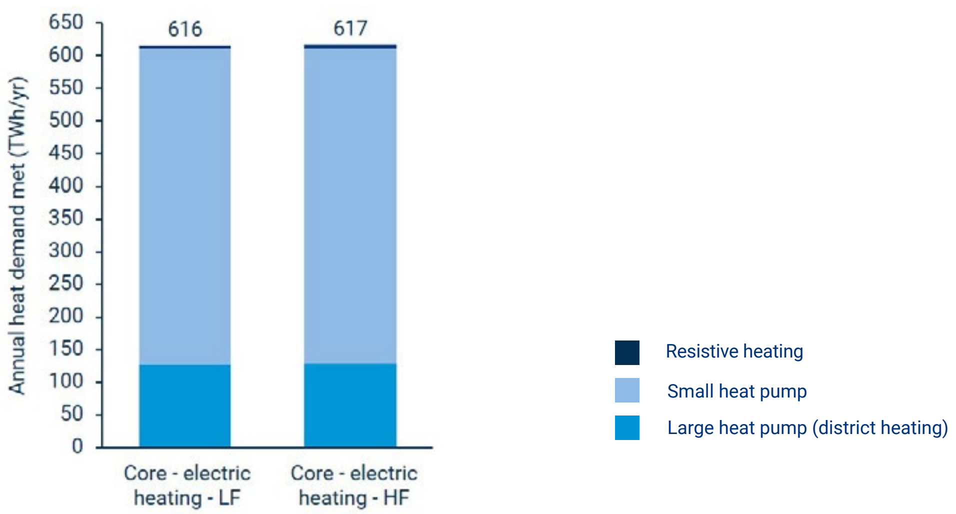
Allowing more flexibility to be deployed reduces total electricity demand by 4% to 765TWh/yr. This is partly the result of a move away from generating hydrogen via electrolysis towards hydrogen production via biomass gasification. The shift in hydrogen production methods is in part due to other forms of flexibility being able to help match supply and demand, reducing the value of a flexible demand such as an electrolyser. In addition, there is a reduction in demand for DACCS as fewer unabated emissions from back-up gas power plants need to be offset. The reason for this reduction in gas use is discussed further in Section 3.2.2.5.

Figure 13. Annual electricity demand (TWh/yr) - electric heating pathway - 2019 demand[12], 2050 low flexibility (LF) and high flexibility (HF) (right)



Heat demand is largely met through heat pumps with little reliance on resistive heating. Resistive heating is mainly used during extremely cold weather when the coefficient of performance (COP) for ASHPs drops.[13]

Figure 14. Annual heat demand met by heating technology (TWh/yr) - electric heating pathway - low flexibility (LF) and high flexibility (HF)



12 BEIS, Energy Consumption in the UK, 2020. https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

13 All small heat pumps shown in the figure are ASHPs. Large heat pumps are ground or water sourced heat pumps

3.2.2.3 Meeting electricity demand - ensuring system adequacy drives significant capacity investment, but a more flexible system reduces investment need

In order to meet electricity demand while maintaining system stability and adequacy throughout the year, significant additional electricity generation capacity is required, as shown in Figure 15. 423GW (low flexibility scenario) is more than four times the current generation capacity of the GB electricity system of 103GW, excluding interconnection.

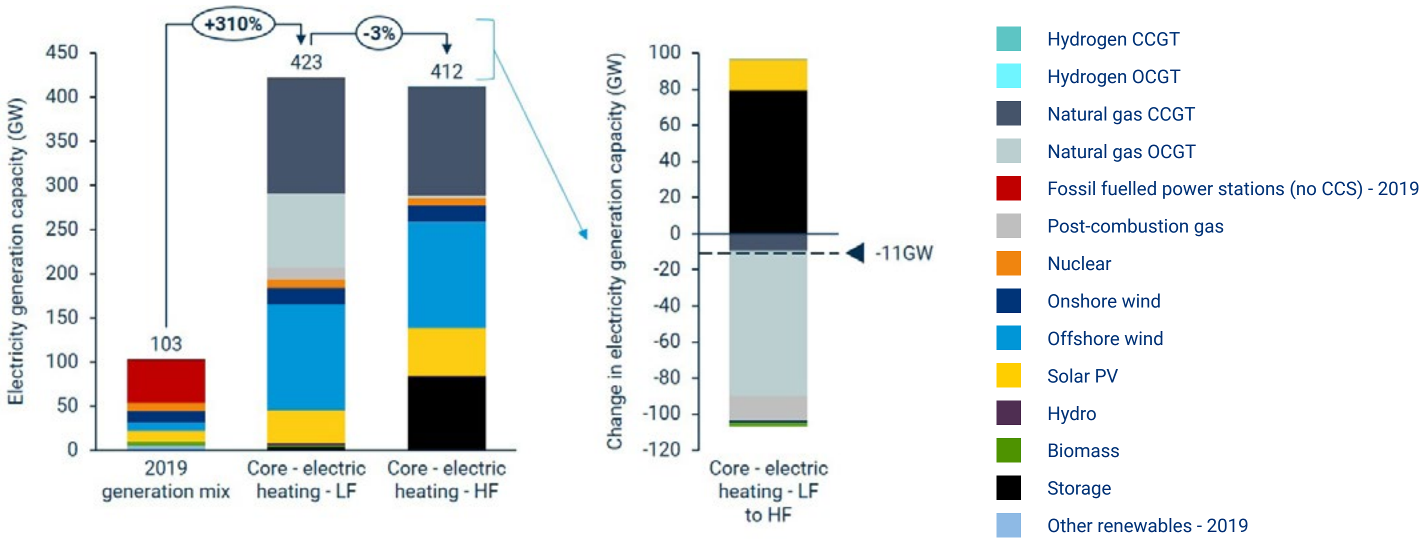
While part of this transition to a net zero economy includes significant rollout of renewables, including up to 120GW of offshore wind, the modelled low flexibility 2050 energy system also includes significantly more unabated fossil fuel generation than in the current electricity system. This includes 132GW of unabated natural gas combined cycle gas turbines (CCGTs) and 84GW of natural gas power open cycle gas turbines (OCGTs). Whilst the analysis has modelled gas turbines technology, any energy demand met by gas turbines can be interpreted as a proxy for the minimum level of gas reciprocating engines that is cost-effective to deploy in a 2050 system. The exact mix of these technologies is highly dependent on market dynamics and is not something the modelling analysed.

However, as shown in Figure 16, these gas-fired units only have an annual load factor of 3.1% and 0.1% respectively, and are almost exclusively used during winter periods when demand is high but the output of renewables is low (referred to in this report as the high demand - low wind week) or when there is scarcity triggered by plant outages.

The vast majority of generation throughout the year comes from offshore wind, which is assumed to further reduce in cost by 2050 and have a significantly higher load factor than other renewables. For these reasons, it is strongly favoured in the least cost optimisation model. Large scale nuclear is the second largest source of generation, assuming an 85% load factor across the year.[14]

Under a high flexibility scenario, flexibility reduces the need for both unabated fossil fuel generation and gas CCS plants. There is a combined 90GW reduction in natural gas CCGTs and OCGTs and a 13.6GW reduction in post combustion gas CCS in the high flexibility scenario, compared with the low flexibility run. This is because demand side flexibility and storage help to shift or meet demand during periods of system stress. However, even with additional flexibility, there remains considerable CCGT (123GW) and OCGT (3GW) capacity operating with extremely low annual load factors of 2.4% and 0.2% respectively. This capacity is still a significant increase compared to today's energy system, much of which is driven by the need to ensure system adequacy for a much higher peak demand.

Figure 15. Left: Electricity generation capacity and electrical energy storage (GW). Right: Change in electricity generation capacity and electrical energy storage (GW) - electric heating pathway - 2019 capacity, 2050 low flexibility (LF) and high flexibility (HF)

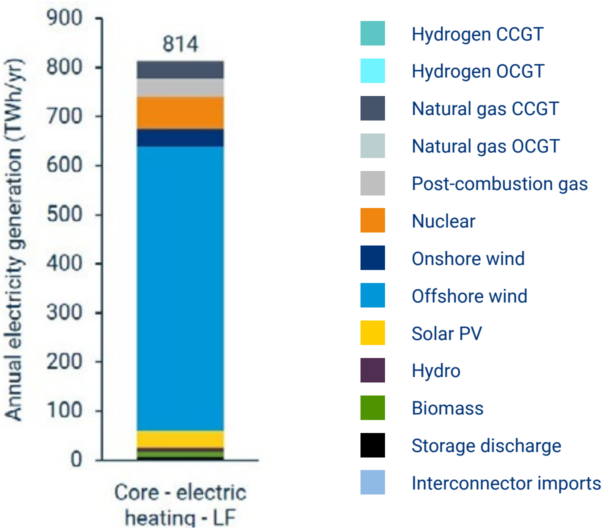


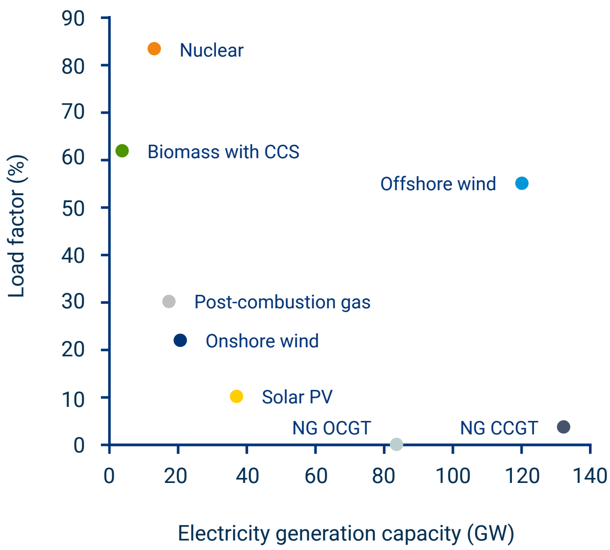
14 120GW is the maximum capacity of offshore wind which can be deployed. In the core scenarios, large scale nuclear deployment is limited to 9GW

Overall, these results show the significant wider system infrastructure requirements of supporting a heavily electrified future. This project has focused on the extent to which additional flexibility can reduce overall energy system costs. However, the reduction in fossil fuel generation in a high flexibility scenario also shows the link between a flexible energy system and being able to cost-effectively reduce reliance on fossil fuels.

However, under both the low and high flexibility scenarios, building the amount of electricity generation capacity required by 2050 and maintaining unabated natural gas assets with very low utilisation incurs significant system costs. It is also inconsistent with recommendations by the Climate Change Committee (CCC), which recommends phasing out unabated gas plants by 2035[15]. Unabated gas usage is also reliant on net negative emissions technologies, such as biomass with CCS and DACCS, to meet overall carbon targets. The fact that these results are driven by extreme weather events highlights the importance of including periods of system stress in any analysis of 2050 energy system requirements. One of these periods of system stress is examined in more detail in the next section.

Figure 16. Left: Annual electricity generation (TWh/yr). Right: Electricity generation capacity (GW) versus annual load factor (%) by technology - electric heating pathway - low flexibility (LF)





15 Committee on Climate Change. Sixth Carbon Budget, 2020. https://www.theccc.org.uk/publication/sixth-carbon-budget/

3.2.2.4 System flexibility - system savings are delivered through a portfolio of flexibility technologies

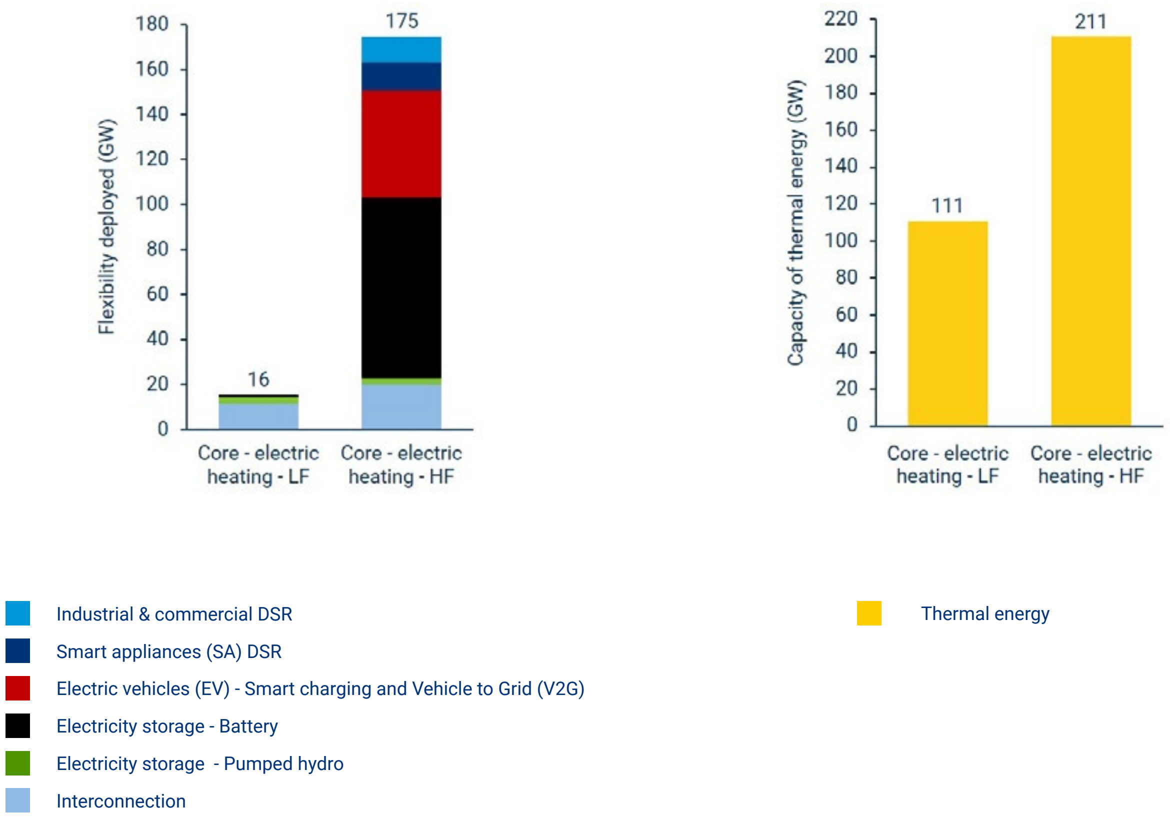
Figure 17 (right) shows that under a high flexibility scenario, the model almost doubles the maximum power thermal energy storage can deliver from 111GW to 211GW. This is equivalent to 895GWh energy storage capacity across a mix of one-hour duration domestic hot water tanks and (mostly) six-hour duration district heating scale hot water tanks.

80GW of four-hour duration batteries, totalling 320GWh energy storage capacity, are also deployed. Load shifting via smart appliances, industrial and commercial DSR and the smart charging and V2G capabilities of EV charging infrastructure provide additional flexibility. The capacity of DSR and EV flexibility deployed represents the maximum shift in GW demand delivered through these technologies across the year modelled.

Interconnection capacity increases to 20GW in the high flexibility scenario (the maximum allowed under modelling constraints) from 11.7GW in the low flexibility scenario, increasing energy flows between GB, Ireland and continental Europe. This project didn't examine the impact of higher interconnection limits, but higher levels of deployment may impact the wider portfolio of flexibility deployed.

As well as the flexibility technologies depicted in Figure 17, there is also inherent flexibility in the operation of the energy system, through varying the output of electricity generators, using electrolysers to generate hydrogen and varying the use of DACCS technology, to minimise its impact on wider system costs. These measures are possible in both the low and high flexibility scenarios.

Figure 17. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage (GWth) - electric heating pathway - low flexibility (LF) and high flexibility (HF)



3.2.2.5 Meeting winter demand during periods of low renewables output drives investment in fossil fuel generation

During winter, the IWES model includes a three-day high demand - low wind period where wind generation less than 5% of maximum output and demand is high due to extreme cold weather. Peak demand for electricity is driven by the extreme cold event. Peak winter demand outside of the extreme weather event is c.150GW, compared to 230GW (a more than 50% increase) during the extreme cold event under the low flexibility scenario. This is driven by the need for heat being met by heat pumps (which will operate less efficiently during this period due to cold temperatures) and topped up by resistive heating on demand.

Ensuring electricity system adequacy during this period drives significant investment in fossil fuelled generation with low utilisation. Use of unabated gas dominates the generation mix during this three-day period in both the low and high flexibility scenarios. However, flexibility is able to reduce the peak demand during this period and make use of electricity storage and interconnection, thereby reducing the need for investment in back-up gas generation and reducing peak demand on the networks.

Figure 18. Hourly electricity demand (GW) during severe winter week - electric heating pathway - low and high flexibility
Electricity demand includes interconnector exports.

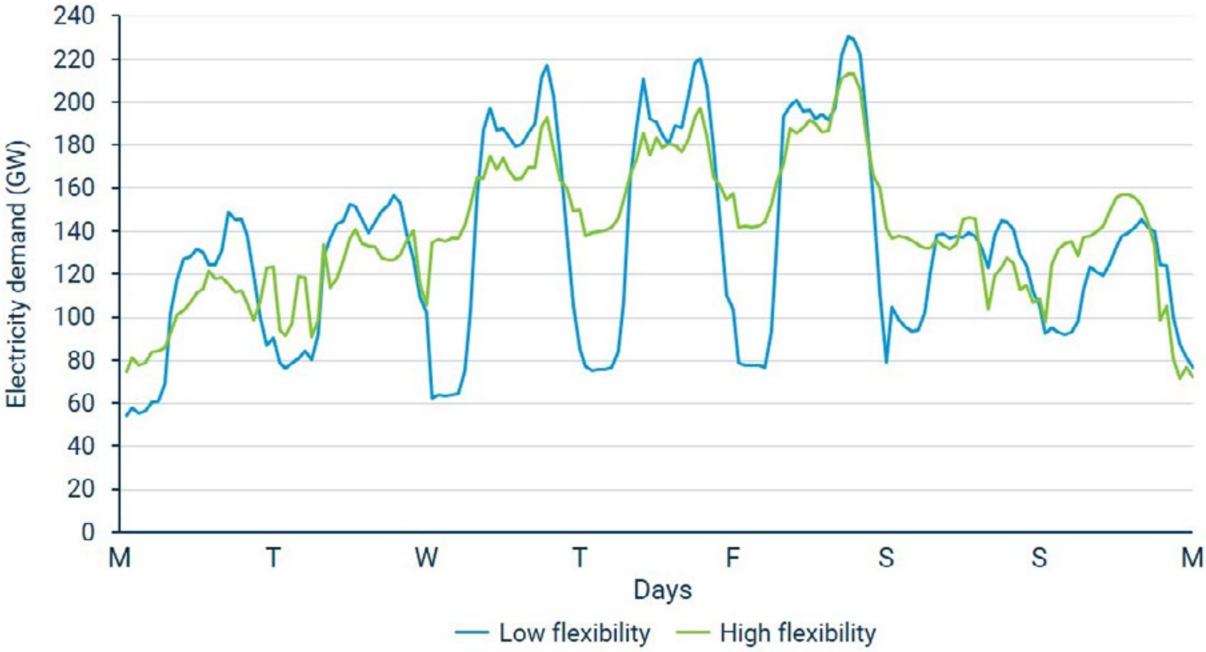


Figure 19. Hourly electricity demand (GW) for appliances, electric vehicles and industrial & commercial demand during severe winter week - electric heating pathway - low flexibility (LF) and high flexibility (HF)

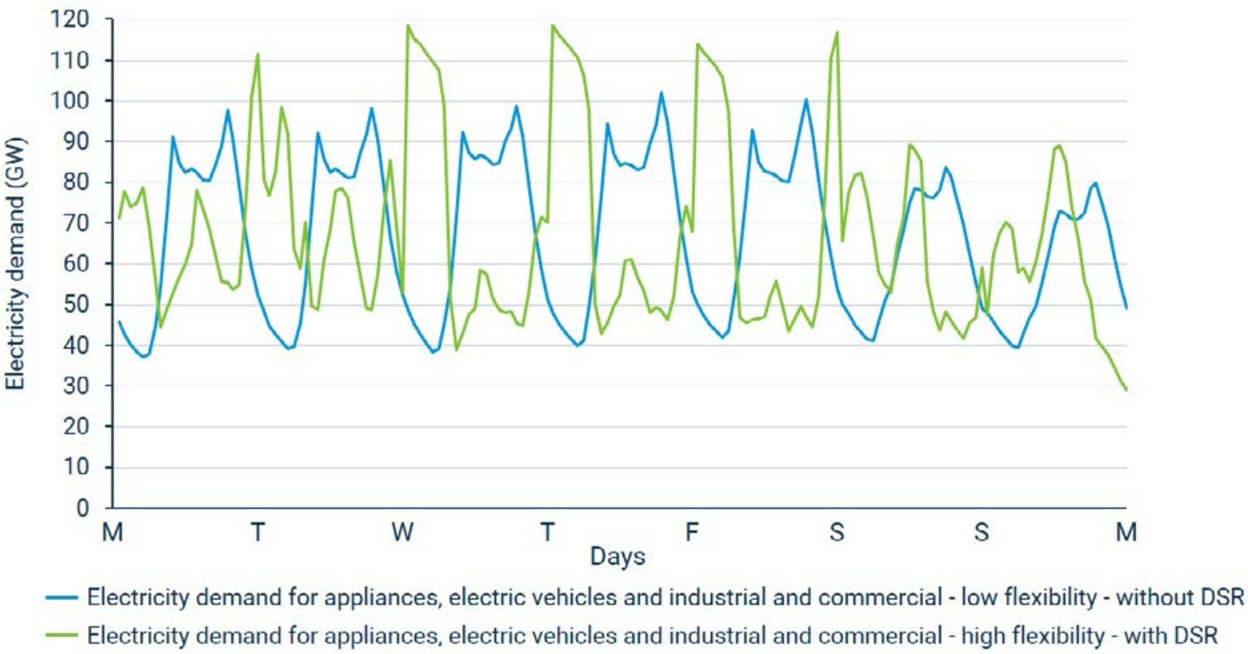
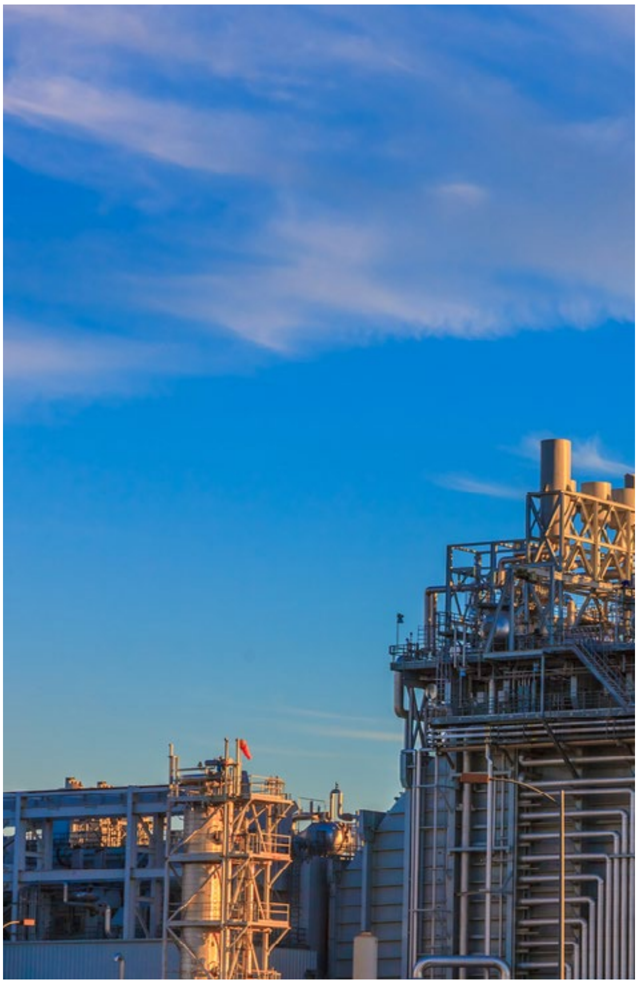


Figure 18 shows the overall difference in total electricity demand over a three-week winter period, including the three-day high demand - low wind period (Wednesday to Friday). The high flexibility scenario achieves a reduction in peak demand compared to the low flexibility scenario (from 230GW to 213GW) and also reduces fluctuations in demand over the three-day high demand - low wind period through intra-day DSR (domestic smart appliances, industrial and commercial processes, EV smart charging and V2G).

Figure 19 provides further detail on how some of the demand shift is realised. It focuses on the combined demand profile of domestic smart appliances, industrial and commercial processes, EV smart charging and V2G (i.e. those demands which can be shifted within a day). This shows that, on most days, DSR moves some demand away from current periods of high demand (daytime/evening) to times of otherwise low demand (overnight). In addition to DSR, additional thermal storage in the high flexibility scenario decouples to an extent the timing of electricity demand for heat pumps from the time at which heat is delivered.



To meet remaining demand during the high demand - low renewables period, unabated natural gas power dominates the generation mix in both the low flexibility and high flexibility scenarios. However, the combination of different forms of flexibility reduces the maximum output of unabated gas from 177GW to 126GW during the three-day high renewables - low wind period (Figure 20 and Figure 21). In particular, in the high flexibility scenario, interconnector imports provide 20GW of baseload 'generation', whilst discharging electricity storage (mostly batteries, plus 2.7GW of pumped hydro) supplies electricity during peak demand periods.

Figure 20. Hourly electricity generation (GW) during severe winter week, by technology - electric heating pathway - low flexibility

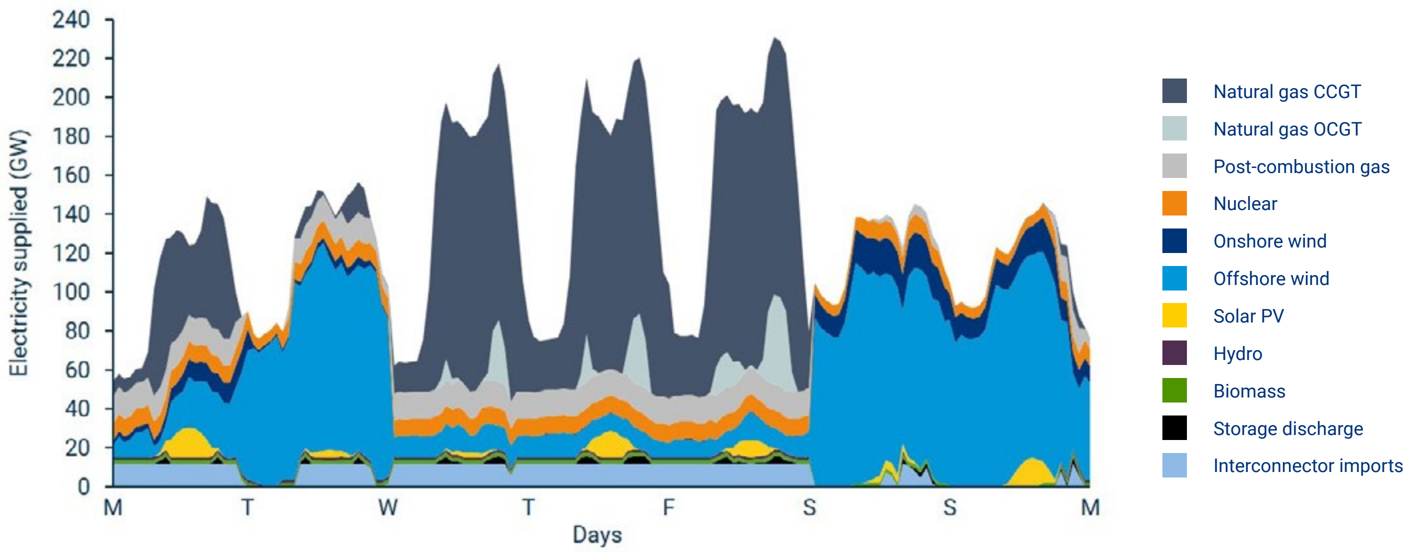
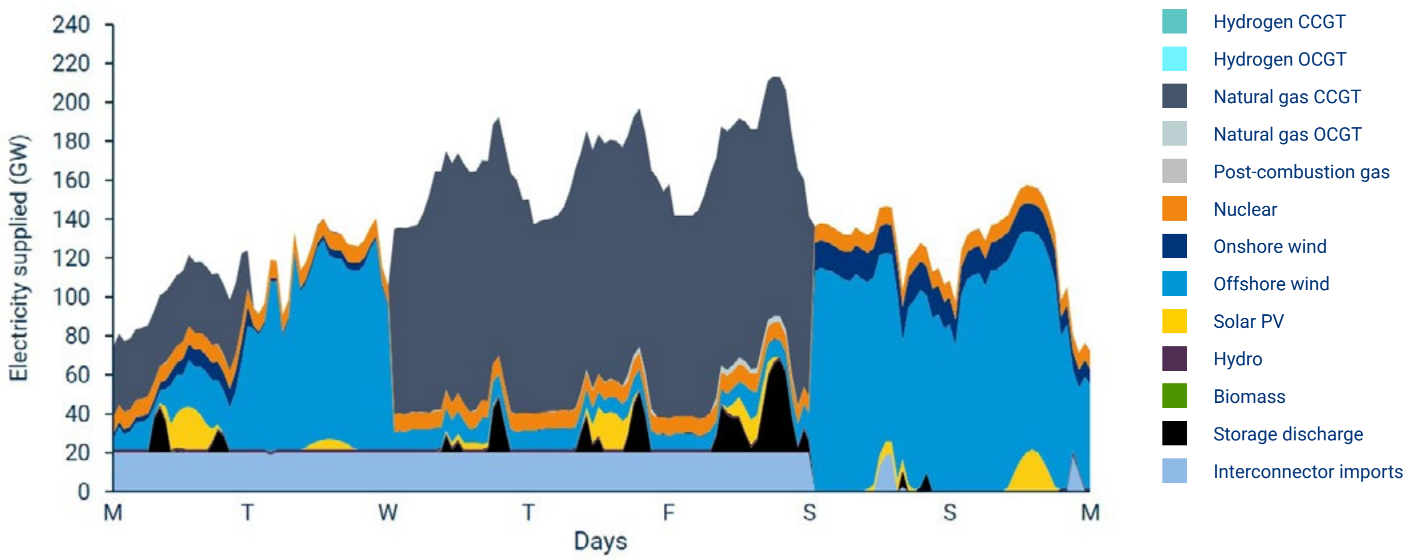


Figure 21. Hourly electricity generation (GW) during severe winter week, by technology - electric heating pathway - high flexibility



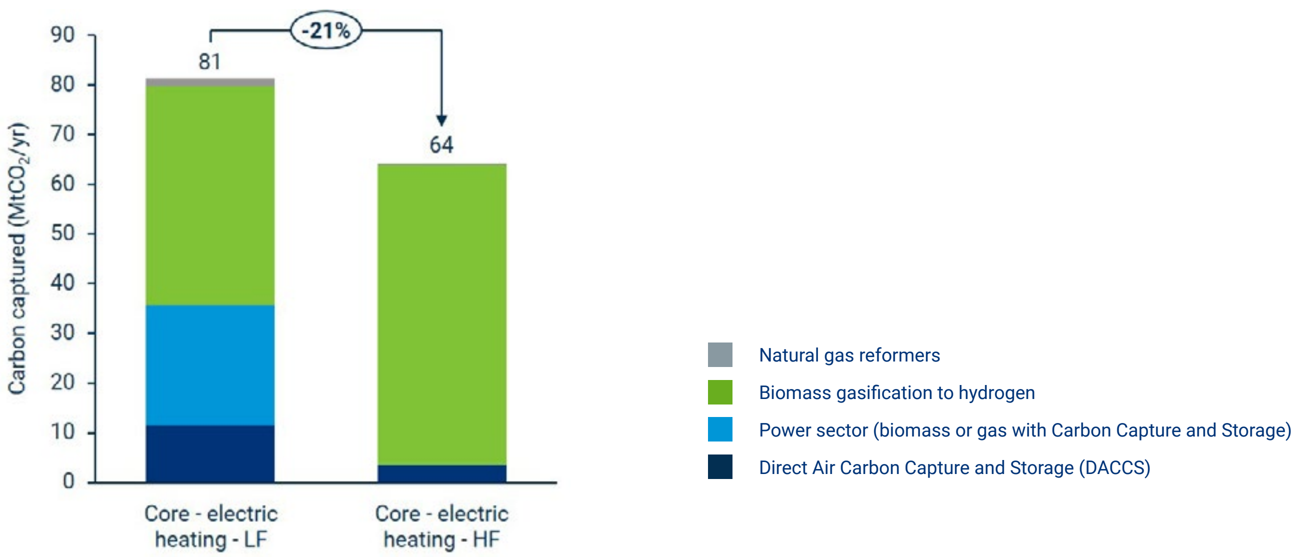
3.2.2.6 Carbon capture and storage - flexibility reduces the burden on negative emissions technologies

Both the low and high flexibility scenarios meet the net -50MtCO_2/yr target through a combination of capturing emissions at the point of production and offsetting any emissions to the atmosphere through net negative emissions technologies. Under both the low and high flexibility scenarios of the electric heating pathway:

- **Positive emissions** (emissions to the atmosphere) result from the use of natural gas in unabated OCGTs and CCGTs, as well as residual emissions from production of electricity and hydrogen from natural gas with CCS.
- The majority of CO_2 emissions from electricity and hydrogen production from natural gas with CCS are captured directly. They are apparent in the total amount of CO_2 captured (Figure 22), but **do not increase or decrease the total energy sector emissions**.
- **Net negative emissions technologies** include biomass to power with CCS (BECCS), gasification of biomass to hydrogen with CCS and DACCS.

Figure 22 shows the total amount of carbon captured in the low and high flexibility scenarios. In the higher flexibility scenario, there is a 75% drop in the amount of natural gas used in the production of electricity and hydrogen, from 127TWh/yr to 32TWh/yr. This reduces the amount of CO_2 that needs to be captured directly from natural gas reformers or power plants, or offset via negative emissions technologies, from 81MtCO_2 to 64MtCO_2 (Figure 22). In particular, the reliance on DACCS to meet the carbon target falls by two thirds to 4MtCO_2 in the high flexibility scenario. In the high flexibility scenario, more biomass is used to produce hydrogen as opposed to power, which is why the carbon captured from biomass gasification to hydrogen with CCS is greater under a high flexibility scenario and CO_2 captured by the power sector falls.

Figure 22. Carbon captured by source (MtCO_2/yr) - electric heating pathway - low flexibility (LF) and high flexibility (HF)



3.3. Hybrid heating pathway

Key insights

Can we rely on hybrid heating solutions to meet net zero?

The hybrid heating scenario relies predominantly on a combination of heat pumps with back-up natural gas boilers. To deliver a cost-effective hybrid heating system which meets carbon targets, the operation of the two systems must be optimised, and the emissions from natural gas offset. This pathway looked at a low flexibility scenario where the use of the heat pump and natural gas boiler wasn't perfectly optimised, and low and high flexibility scenarios where it was optimised. With additional optimisation, the system cost is reduced by £4.5bn/yr highlighting the importance of cross-vector optimisation.

When comparing the low and high flexibility scenarios, additional flexibility reduces the amount of natural gas used for heating, but both the low and high flexibility scenarios are dependent on negative emissions technologies to offset these emissions to meet the carbon target. Our analysis shows that without flexibility, a higher than expected cost of DACCS would lead to a 22% (£22bn/yr) increase in system cost annually in 2050. However, in a more flexible system, the cost impact of expensive DACCS is only 1.7% (£1bn/yr) outlining the importance of a smart and flexible system.

Thus, the feasibility of a Hybrid heating scenario is highly reliant on optimal coordination between gas and electricity use for heating, availability of carbon negative technologies and deployment of flexibility to enhance coordination and provide system support.

How does flexibility help a scenario dominated by hybrid heat pumps?

One of the key benefits of deploying flexibility in the hybrid heating scenario is the enhanced ability to optimise between the electric and the natural gas heating. Use of TES helps to increase heat delivered by heat pumps from c.70% to c.90% by decoupling electric supply and heat demand. Flexibility also provides a cheaper alternative to OCGTs to support the system during high stress periods. Doing this also helps to reduce the usage of DACCS required to absorb emissions from using natural gas. It is important to also note the inherent benefits of a hybrid system wherein natural gas can be used during peak periods to reduce stress on the electricity system. This ability combined with demand shifting provides a key benefit in reducing peak electricity demand during periods of stress.

In addition, demand side response (DSR) helps to smooth demand, reducing peak demand by c.6GW while interconnectors help to meet any shortfall in supply. Battery storage is not deployed widely in this scenario owing to the availability of other forms of flexibility. Thus, flexibility reduces total electricity demand by c.7% and electricity generation capacity by 17% (51GW), leading to an overall system cost reduction of £15.4bn/yr in 2050.

3.3.1 Hybrid heating pathway - scenario description

Under a hybrid heating future, 20% of all domestic heat demand is met through district heating in urban areas. These schemes are powered by ground-source, or water-source heat pumps and are installed with a hot water tank that can provide around 6 hours maximum heat demand in the low flexibility scenario. All remaining space heating and hot water demand which is connected to the existing gas network has its needs met by an ASHP, coupled with a small natural gas boiler to provide heat during periods of high demand. Properties not connected to the gas grid have their space and hot water heating needs met through individual ASHP and resistive heating only. Under a low flexibility scenario, all domestic scale ASHP are installed with 2kWh (2kW) of TES in the form of a hot water tank, regardless of whether they are also connected to the gas grid.

In the sub-optimal low flexibility scenario, there is a minimum requirement for gas use in heating to reflect sub-optimal operation of the hybrid heating systems. In Section 3.3.2.6 we look at the cost and system infrastructure impact of optimising the operation of the heat pump and boiler in an otherwise low flexibility scenario.

In the high flexibility scenario, operation of the heat pumps and natural gas boilers are perfectly optimised and all domestic properties and district heating schemes can install additional TES. In addition, extra battery storage and interconnection can be deployed, and demand response and V2G services can be used.

3.3.2 Key findings

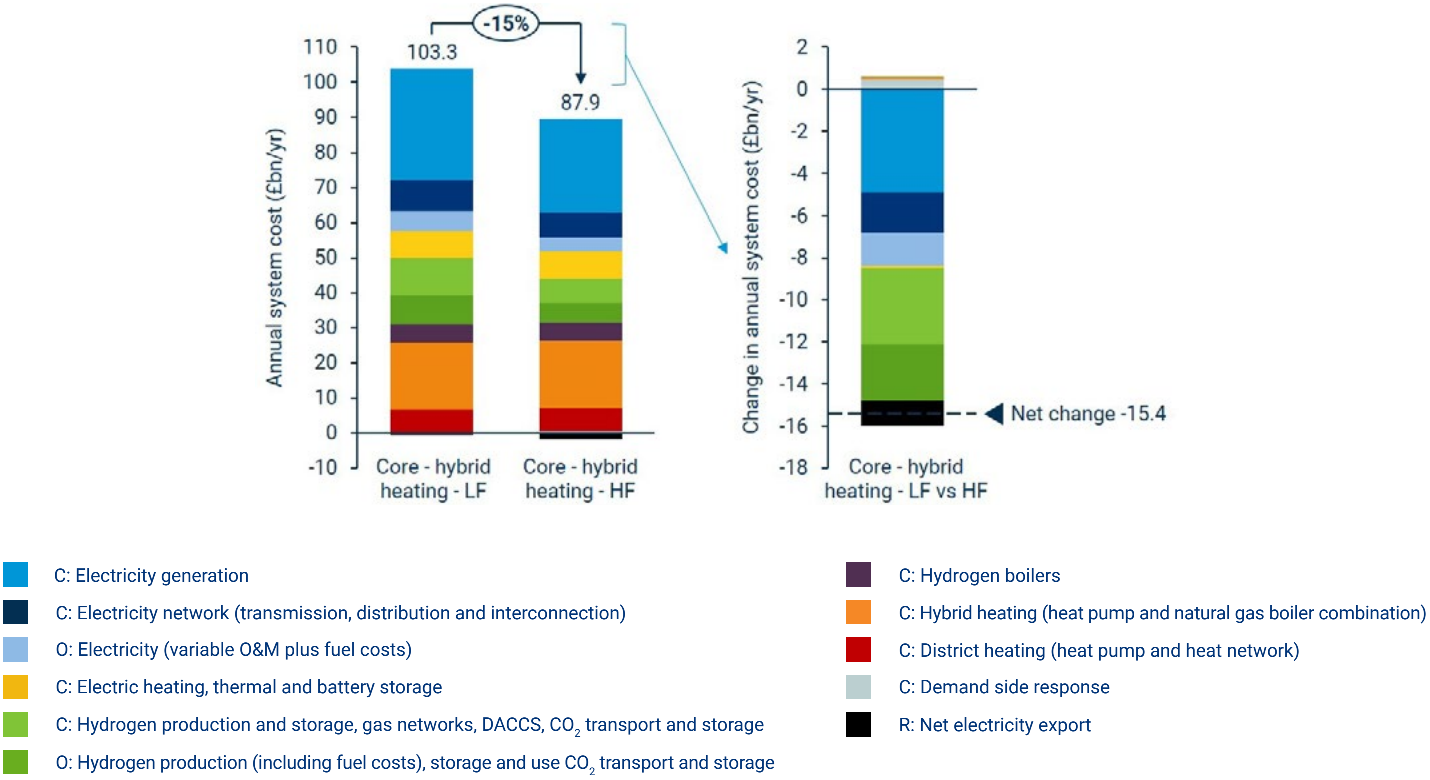
3.3.2.1 System cost - flexibility can help reduce system cost by £15.4bn annually in 2050 in a full hybrid heating scenario

Delivering a hybrid heating pathway with limited additional flexibility will cost £103.3bn/yr to 2050. Enabling additional system flexibility to be deployed reduces the annual system cost associated with the hybrid heating scenario by 15% (£15.4bn/yr). One area of high system cost savings is the reduction in CapEx and OpEx costs for hydrogen production and carbon capture and storage. This unlocks savings of £6.4bn/yr (gross) in 2050 as less DACCS capacity is required (of which some is hydrogen-powered).

The investment in additional storage and flexibility also reduces the investment required in electricity generation and network capacity by £8.4 bn/yr. The addition of flexibility has a significant impact on the make-up and capacity of generation in the hybrid heating scenario (see Section 3.3.2.3). There is a net reduction of c.50GW of generation capacity enabled by the addition of flexibility. This results in an overall reduction of cost while meeting both demand and the net zero carbon target. This reiterates the importance of co-developing the energy system along with deployment of flexibility to avoid overbuild of capacity and associated additional CapEx and OpEx.

As well as the additional flexibility technologies deployed in the high flexibility scenario, there is also inherent flexibility in the operation of the energy system as outlined in the previous electric heating scenarios. The operation of the hybrid heating systems is optimised between electricity and gas use in the high flexibility scenarios. This is also true of the low flexibility scenario, although there is a minimum gas use constraint to reflect that gas and electric heating systems may not be perfectly coordinated to minimise system cost. The inherent flexibility in this scenario is a key consideration when comparing the cost of the three core heating pathways.

Figure 23. Left: Annual system cost (£bn/yr). Right: Reduction in annual system cost from low to high flexibility - hybrid heating pathway - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue

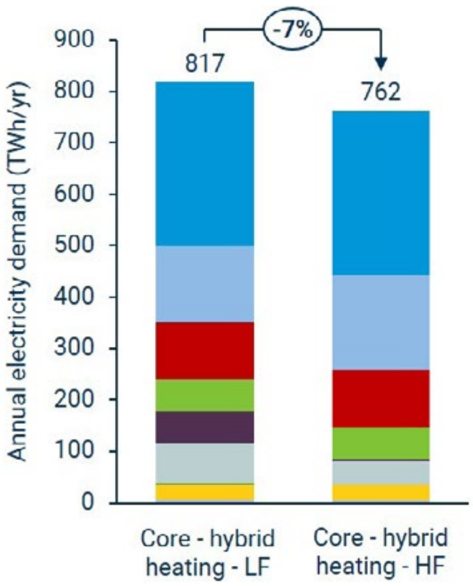


3.3.2.2 Energy demand - flexibility reduces total electricity demand while reducing demand for gas heating

Figure 24 shows that flexibility can reduce overall electricity demand by 7%, bringing it in line with demand for electricity in the electric heating high flexibility scenario (762TWh/yr compared to 765TWh/yr for the electric pathway). This is almost entirely the result of a reduction in demand for electrolysers. As other forms of flexibility are deployed, production of hydrogen switches towards natural gas reformation and biomass gasification. There is also a switch away from natural gas heating towards electric heating. This increase in electricity demand is offset by a reduction in electricity required to power DACCS plants to capture unabated gas emissions.

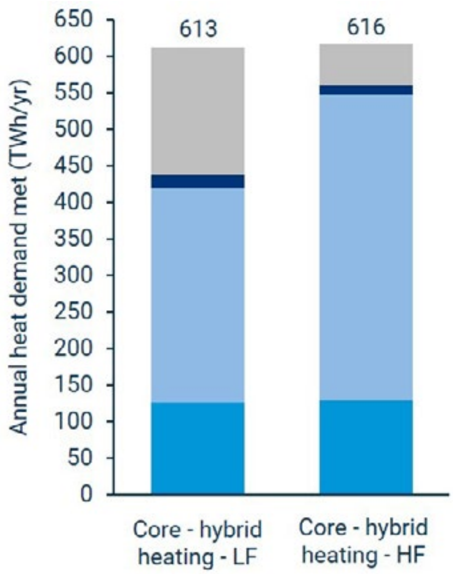
As seen in Figure 25 below, heat delivered through heat pumps or resistive heating increases from c.71% to c.91% of heat demand. This shift is enabled by the addition of flexibility (particularly TES) allowing greater use of the heat pump part of hybrid systems. This increases the electricity used in electric heating, but the reduction in natural gas required for heating reduces the power required by DACCS to absorb the associated emissions by an equivalent amount. Between the low and high flexibility scenarios, there is a 44% reduction in the amount of electricity used by DACCS.

Figure 24. Annual electricity demand (TWh/yr) - hybrid heating pathway - low flexibility (LF) and high flexibility (HF)



Industrial and domestic non-transport, non-heat and non-smart appliance demand
Electric heating
Electric transport
Smart domestic appliances
Electrolyser
Direct Air Carbon Capture and Storage (DACCS)
Hydrogen storage
Hydrogen production from natural gas reformation or biomass gasification
Electricity storage

Figure 25. Annual heat demand met by heating technology (TWh/yr) - hybrid heating pathway - low flexibility (LF) and high flexibility (HF)



Natural gas boiler
Resistive heating
Small heat pump
Large heat pump (district heating)

3.3.2.3 Meeting electricity demand - hybrid heating enables electricity demand reduction during times of system stress, reducing the need for investment in electricity generation capacity

Figure 26. Left: Electricity generation capacity and electrical energy storage (GW). Right: Change in electricity generation and storage capacity - hybrid heating pathway - low flexibility (LF) and high flexibility (HF)

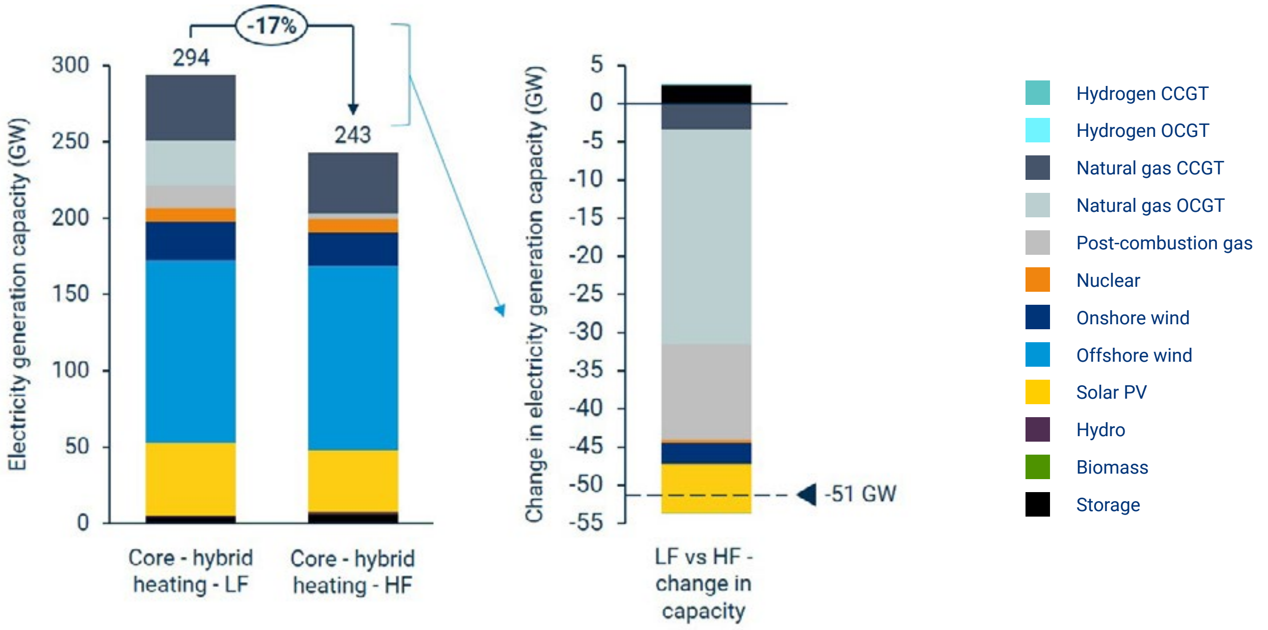
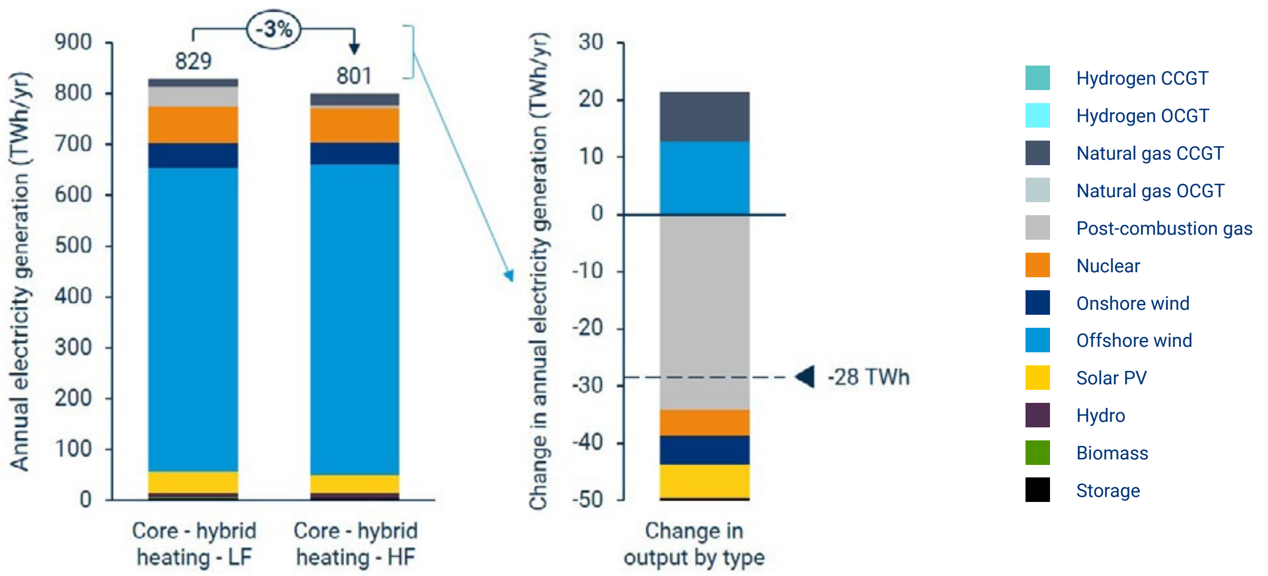


Figure 27. Left: Annual electricity generation (TWh/yr) Right: Change in annual electricity generation - hybrid heating pathway - low flexibility (LF) and high flexibility (HF)



There is a 17% reduction in the generation capacity installed in the high flexibility scenario, compared to the low flexibility scenario (Figure 26) but only a 3% reduction in electricity generated (Figure 27). This signifies the displacement primarily of fossil fuel capacity that was acting as reserve, or back-up plants to support the system during low supply and high demand periods. Deployment of additional flexibility almost completely displaces the OCGT fleet and post combustion gas CCS fleet.

Beyond the capacity reduction of fossil fuel plants, flexibility also reduces the installed capacity of renewables, but to a lesser extent: 6.4GW of PV and 2.6GW of onshore wind. While it is true that flexibility can enable greater deployment of renewables by reducing the system integration cost, in this case, flexibility reduces the renewables capacity required to meet demand.

3.3.2.4 The optimum source of flexibility in a hybrid heating scenario is a portfolio of different technologies

Figure 28. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage (GWth) - hybrid heating pathway - low flexibility (LF) and high flexibility (HF)

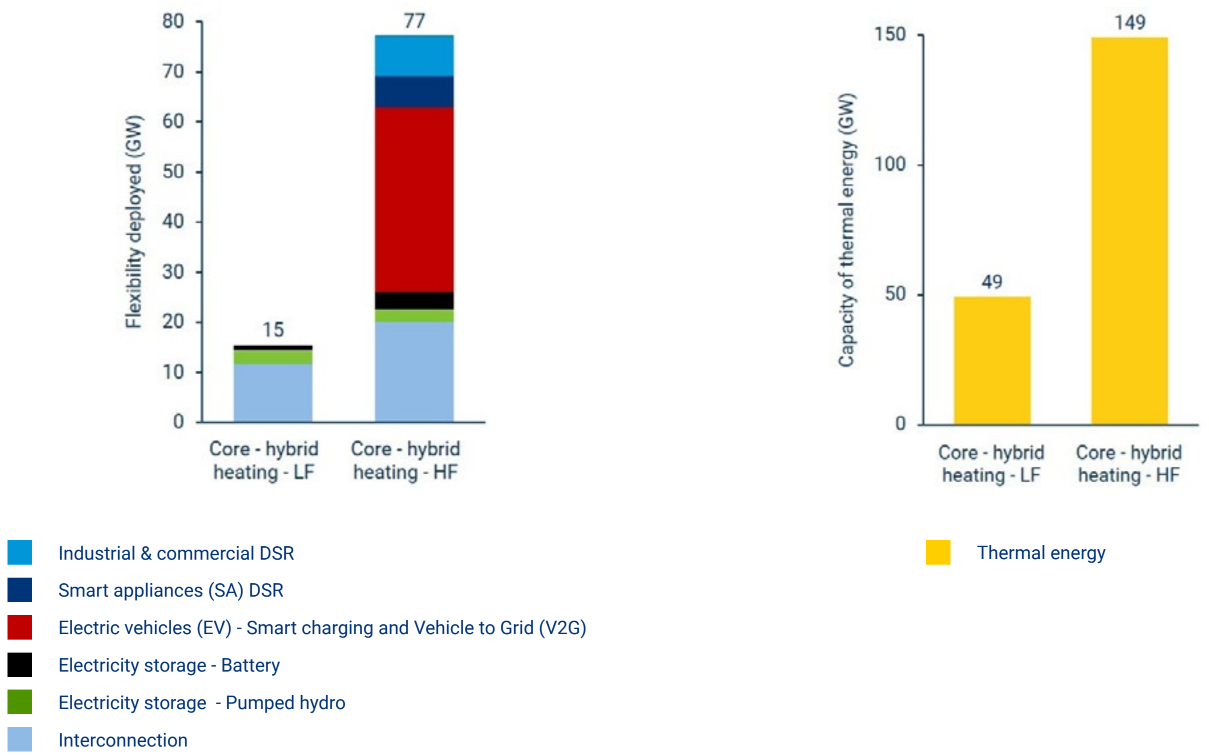


Figure 29. Hourly electricity demand (GW) during severe winter week - hybrid heating pathway - low and high flexibility. Electricity demand includes interconnector exports

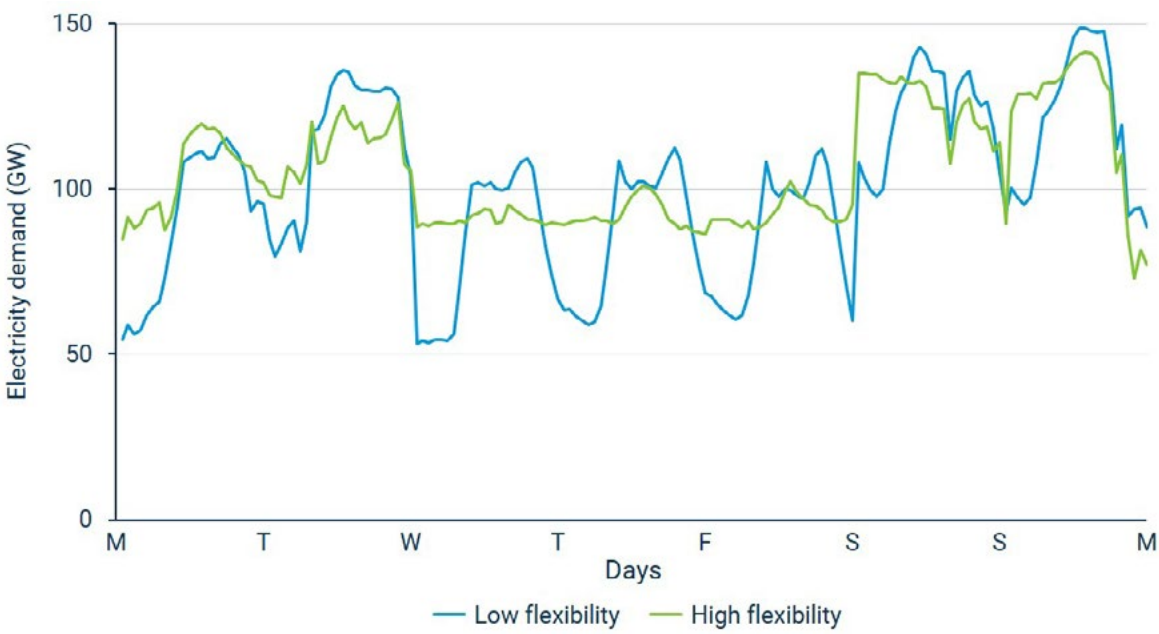


Figure 28 shows that under a high flexibility scenario, DSR and interconnection dominate the flexibility mix in the electricity system[16]. While this provides an indication of the installed capacity of flexibility, the scale of deployment of each technology is not directly proportional to its system value. TES is deployed to its maximum limits in both the low and high flexibility scenario. In the high flexibility scenario, the 149GWth maximum thermal energy output is based on the deployment of 800GWh capacity installed, largely in the form of large hot water tanks in district heating networks which could provide up to 6 hours of thermal energy at maximum output.

Different forms of flexibility have a different impact on how demand is met over the course of a day. Focusing on a winter week, with a three-day period of high demand and low wind outputs (Wednesday to Friday), Figure 29 shows that under both the low and high flexibility scenarios, electricity demand is suppressed below its normal levels during this three-day period as the hybrid heating solutions switch to provide more heat via natural gas. Nevertheless, DSR in the high flexibility scenario smooths this demand profile over the three days and reduces peak demand over this period by 10GW - from 112GW to 102GW.

With a smoother demand profile in the high flexibility scenario, the additional interconnection capacity deployed provides a steady 20GW of supply over the three day extreme winter weather event. This reduces the requirement for post combustion gas CCS which provided a similar service in the low flexibility scenario. In addition, the smoother demand profile almost entirely removes the need for natural gas OCGTs as peaking plants (Figure 30 and Figure 31).

16 The capacity of DSR and EV flexibility deployed represents the maximum shift in GW demand delivered through these technologies across the year modelled.

Figure 30. Hourly electricity generation (GW) during severe winter week, by technology - hybrid heating pathway - low flexibility

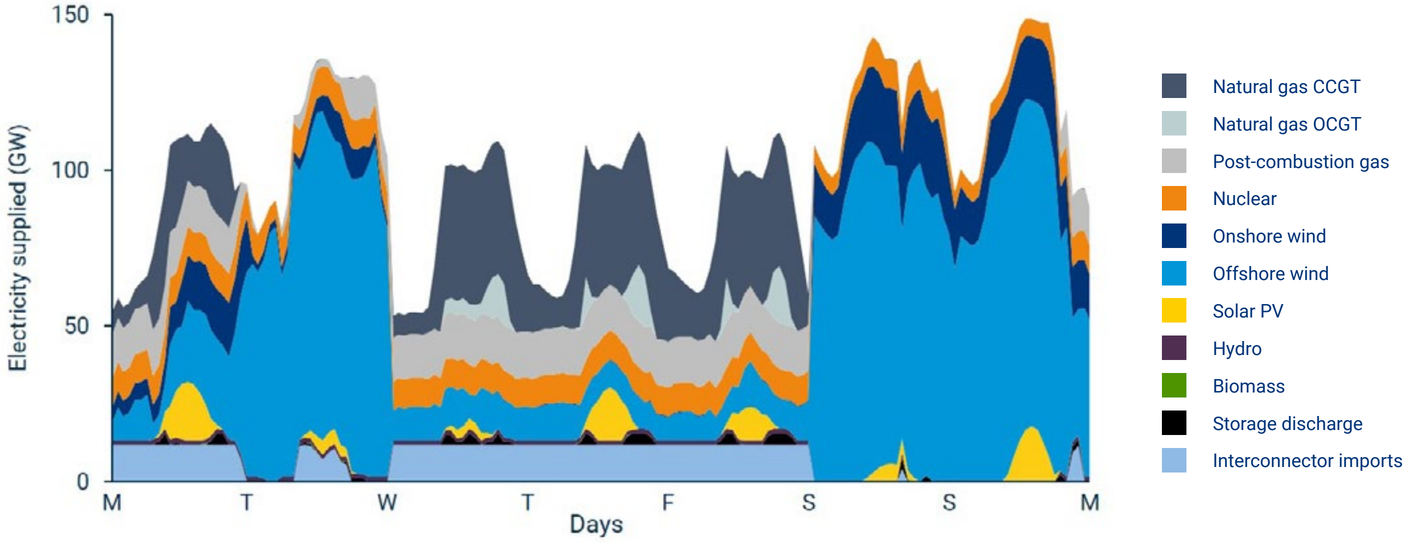
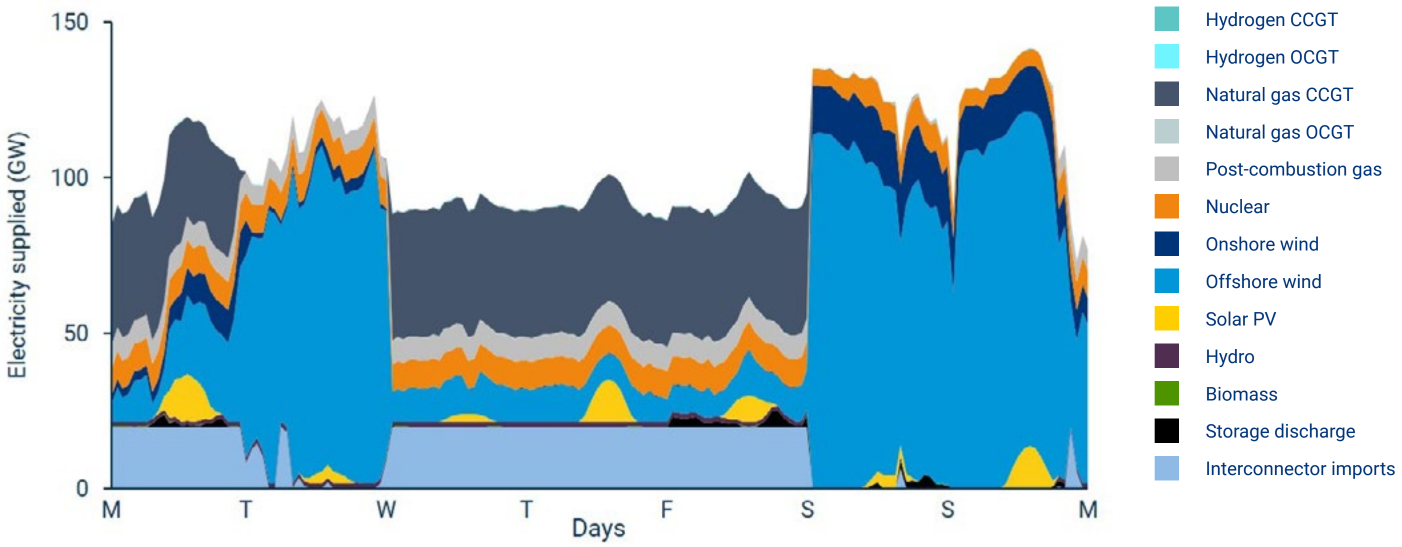


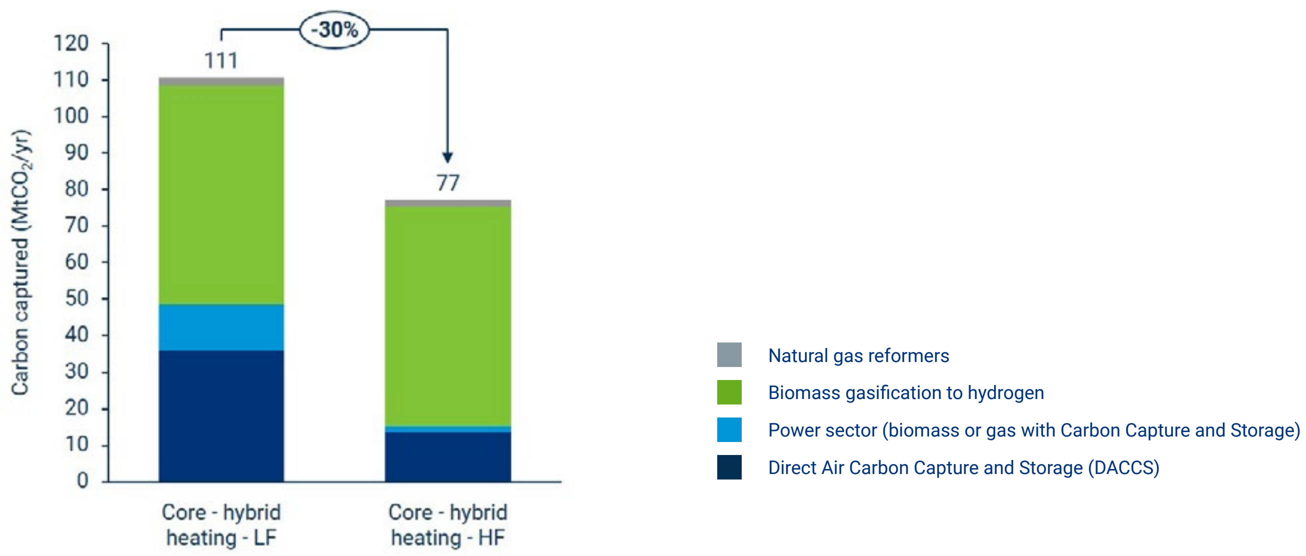
Figure 31. Hourly electricity generation (GW) during severe winter week, by technology - hybrid heating pathway - high flexibility



3.3.2.5 Flexibility reduces the need for DACCS by reducing use of unabated natural gas in heating

Both the low and high flexibility scenarios meet the net $-50MtCO_2/yr$ target through a combination of capturing emissions at the point of production and the use of net negative emissions technologies. As noted earlier, additional flexibility reduces the use of gas for heating and power generation, which in turn reduces the need for DACCS and emissions captured directly from power generation, resulting in an overall 30% drop in emissions captured (Figure 32).

Figure 32. Carbon captured by source ($MtCO_2/yr$) - hybrid heating pathway - low flexibility (LF) and high flexibility (HF)



3.3.2.6 Realising the benefit of a hybrid heating scenarios requires heat pump and boiler operations to be optimised in line with system need

In the low flexibility scenario discussed above, there is no upper limit set on either the use of the heat pump or the gas boiler of the hybrid heating system, other than an overall carbon and cost minimisation objective. However, a minimum amount of natural gas must be used in boilers over the course of a year to reflect the fact that their operation may not be optimised within the wider system. Over and above this constraint, the model optimises the use of gas and heat pump heating. This results in a 70/30 split in terms of heating delivered by heat pumps or resistive heating versus gas boilers, using 176TWh of heat delivered via natural gas whose emissions are then offset by negative emission technologies such as DACCS.

To examine if there is even more efficiency in this scenario, a sensitivity analysis was carried out to further optimise the use of heat pumps in the hybrid systems by removing the minimum natural gas usage constraint in the low flexibility scenario. The right-hand column in Figure 33 shows the heat pump and resistive heating component rising to 91% of all heat delivered. This more optimal low flexibility scenario is £4.5bn/yr cheaper than the low flexibility scenario with the minimum gas constraints described in the previous section (Figure 34). This highlights the value of cross-vector optimisation where end user demand can be met by either electricity or gas.

Figure 33. Annual heat demand met, by heating technology (TWh/yr) - hybrid heating pathway. Left: Low flexibility, non-optimised. Right: Low flexibility, optimised

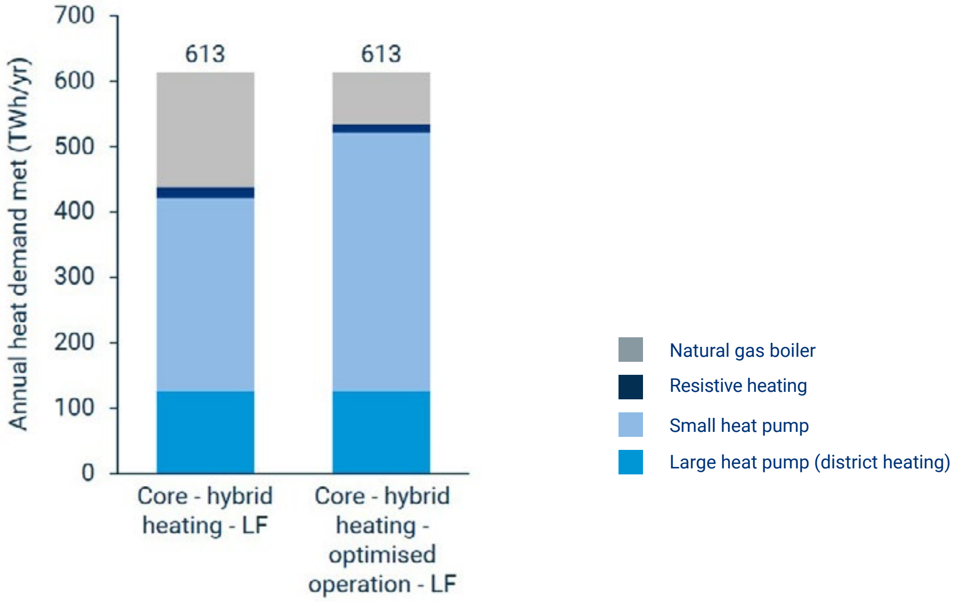
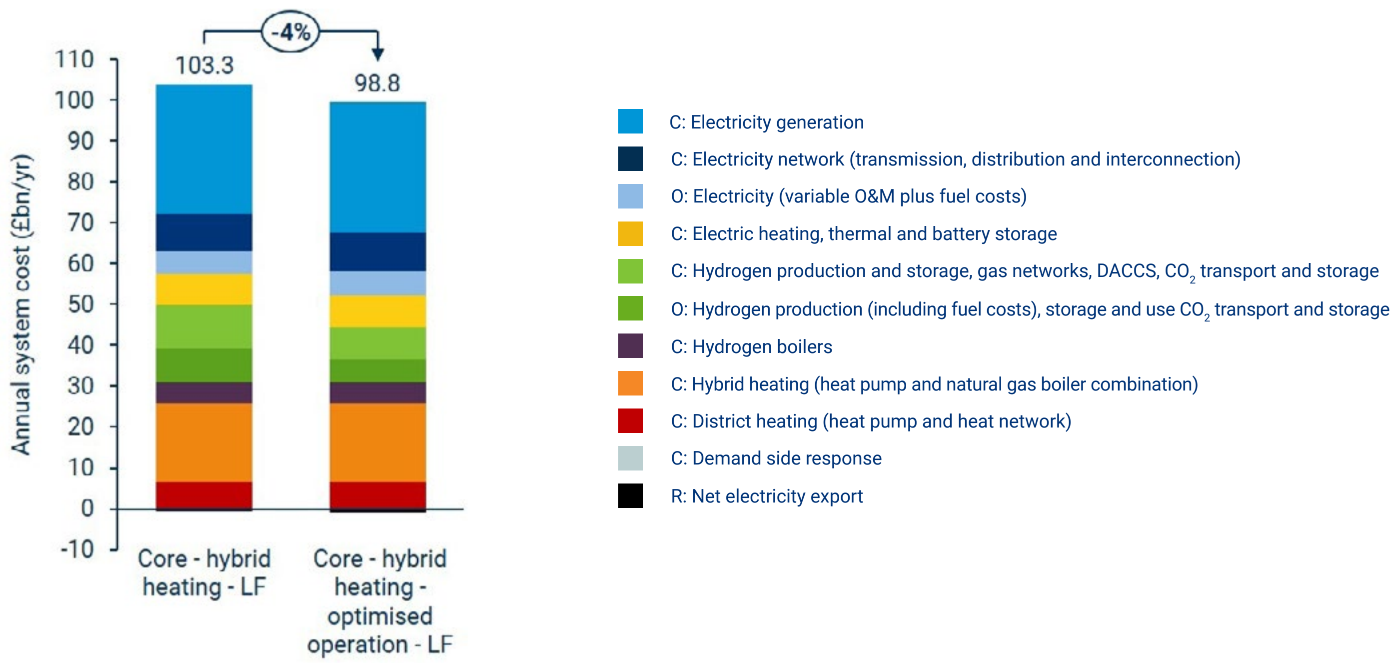


Figure 34. Annual system cost (£bn/yr) - hybrid heating pathway. Left: Low flexibility, non-optimised. Right: Low flexibility, optimised. C = Capital cost, O = Operational cost, R = Revenue



3.4. Hydrogen heating pathway

H_2

Key insights

How feasible is a hydrogen dominant system in 2050?

The key consideration for a scenario with significant hydrogen use is how it is produced and its enabling infrastructure requirements across generation, carbon capture and storage. In addition to large capacities of renewables as seen in the other heating scenarios, this also requires deployment of electrolysers (35GW), natural gas reformation plants with CCS (76GW) and biomass gasification to hydrogen with CCS (14GW) in the low flexibility case. This drives the largest use of natural gas across the heating scenarios with 408TWh required annually in 2050. The other key infrastructure requirements are hydrogen storage (7.9TWh) and 13kGW-km of dedicated transmission networks. The majority of this infrastructure needs to be developed from a very low base currently.

How does flexibility help in a hydrogen heating scenario?

The addition of flexibility in a hydrogen heating scenario provides benefits across the system. For example, it helps to reduce the peak demand on the distribution networks by c.34GW (25%), reduce electricity generation capacity by 64GW (21%) and total demand by 88TWh (11%).

Flexibility also helps to optimise the production of hydrogen between electrolysis and methane reformation, and reduce the capacity of DACCS required. As electrolysers also provide flexibility by coordinating their production to supply, the addition of other forms of flexibility reduces this need and instead drives greater hydrogen production from natural gas and biomass. Additionally, the combination of DSR and interconnectors drive the system to export surplus production rather than using electrolysis to convert and store hydrogen which also helps to optimise electrolyser capacity. This ultimately helps to reduce total electricity demand and investment in network infrastructure. Flexibility also helps to support the system during periods of high stress and provides a more cost-effective alternative to fossil fuel capacity (gas plants) that act as reserves.

Some demand is still met by large heat pumps in heat networks. TES is still deployed as a valuable means of decoupling heat demand from electricity supply.

Delivering the support outlined above helps flexibility to reduce the system cost of a hydrogen heating pathway by £9.6bn/yr (9%) in 2050.

3.4.1 Hydrogen heating pathway - scenario description

Under a hydrogen heating pathway, 20% of all domestic heat demand is met through district heating in urban areas. These schemes are powered by ground-source or water-source heat pumps and are installed with thermal storage that can provide around 6 hours maximum heat demand in the low flexibility scenario. All of the remaining space heating and hot water demand connected to the existing gas network has its needs met by hydrogen boilers. Properties not connected to the gas grid have their space and hot water heating needs met through individual ASHPs and resistive heating. Under a low flexibility scenario, all domestic scale ASHP are installed with 2kWh (2kW) of TES in the form of a hot water tank.

In the high flexibility scenario, all domestic properties and district heating schemes can install additional TES. In addition, extra battery storage and interconnection can be deployed, and demand response and V2G services can be used.

3.4.2 Key findings

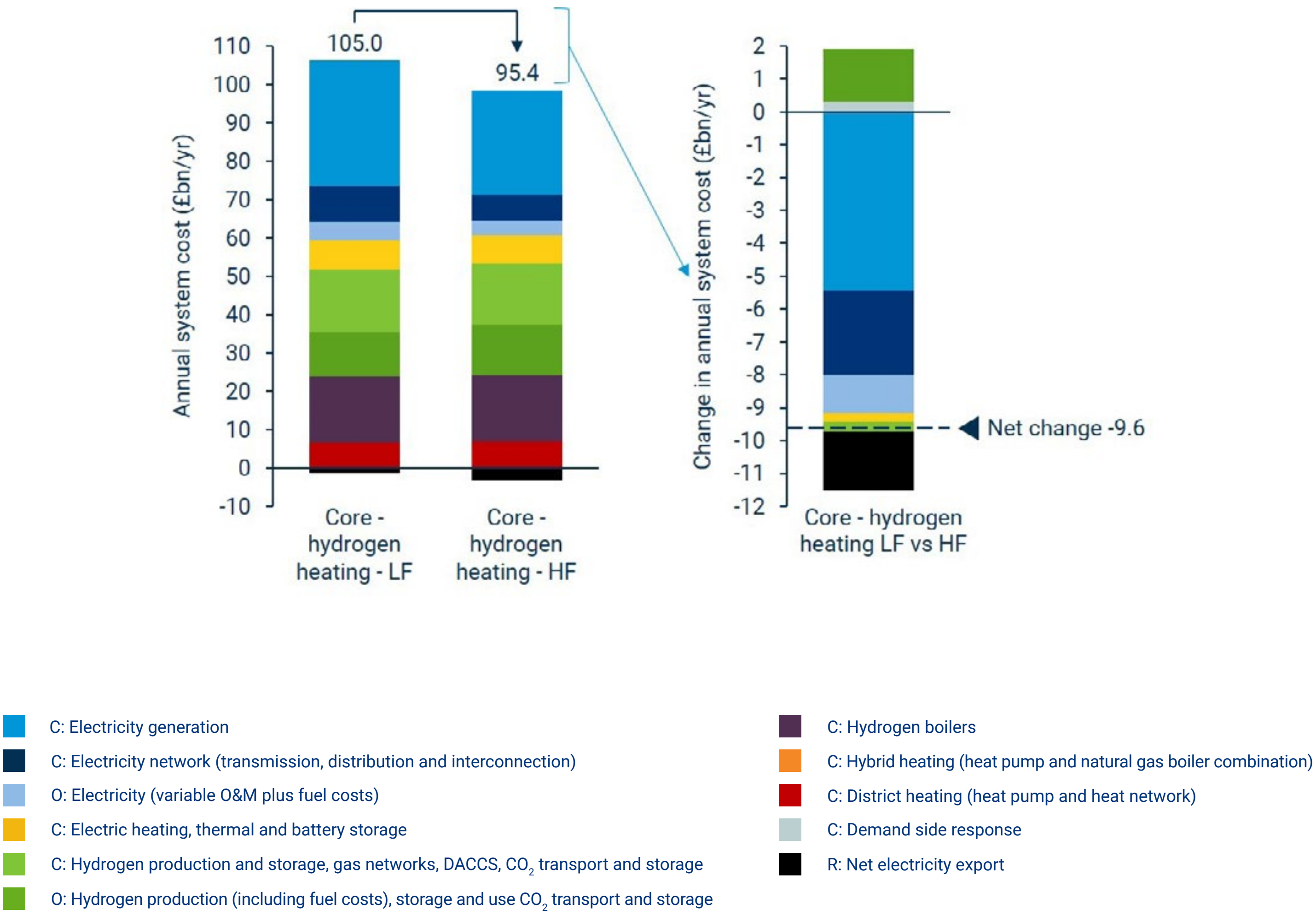
3.4.2.1 System cost - increasing energy system flexibility reduces the cost of meeting demand by £9.6bn/yr

Delivering a hydrogen heating pathway with limited flexibility will cost £105bn/yr to 2050. Enabling additional system flexibility to be deployed reduces the annual system cost associated with the hydrogen heating scenario by 9% (£9.6bn/yr) (Figure 35).

The deployment of additional storage and flexibility, predominantly DSR and TES, reduces the investment required in the electricity networks by £2.5bn/yr. This is achieved by reducing peak distribution network demand from 132GW in the low flexibility scenario to 99GW in the high flexibility scenario. It also reduces the investment required in electricity generation capacity and operation by £6.6bn/yr.

Finally, flexibility adjusts the hydrogen production ratio between electrolysis and methane reformation as other forms of flexibility reduce the need for flexible demand, such as electrolysers. Figure 35 shows that the deployment of additional flexibility reduces the cost of electricity generation as demand for electrolysis reduces, but increases operational costs of hydrogen production; this includes the cost of natural gas and transport and storage of CO_2 resulting from blue hydrogen production.

Figure 35. Left: Annual system cost (£bn/yr). Right: Reduction in annual system cost from low to high flexibility - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue



3.4.2.2 Energy demand - demand for electricity is double current demand, but flexibility can reduce this by 11%

As with the electric and hybrid heat pump heating scenarios, demand for electricity in the hydrogen heating pathway is more than double current demand of 295TWh/yr. This is in part due to electrification of light vehicle transport demand and heating off gas-grid properties and those connected to district heating schemes, as in the other scenarios. However, it is also due to the demand to produce hydrogen via electrolysis, methane reformation and biomass gasification. In the electric heating and hydrogen heating low flexibility scenarios, demand for electricity is very similar (798TWh/yr in the electric heating scenario versus 793TWh/yr in the hydrogen heating scenario).

Additional flexibility significantly reduces electricity demand for electrolysis as shown in Figure 36. This is a result of hydrogen production switching to methane reformation with CCS. This is likely due to other forms of flexibility providing electricity system flexibility and eroding some of the value of flexible electrolyser operation seen in the low flexibility scenario. Along with a reduction in demand for DACCS, the higher flexibility scenario sees an 11% reduction in electricity demand compared to the low flexibility scenario.

Figure 36. Left: Annual electricity demand (TWh/yr). Right: Change in annual electricity demand (TWh/yr) - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF)

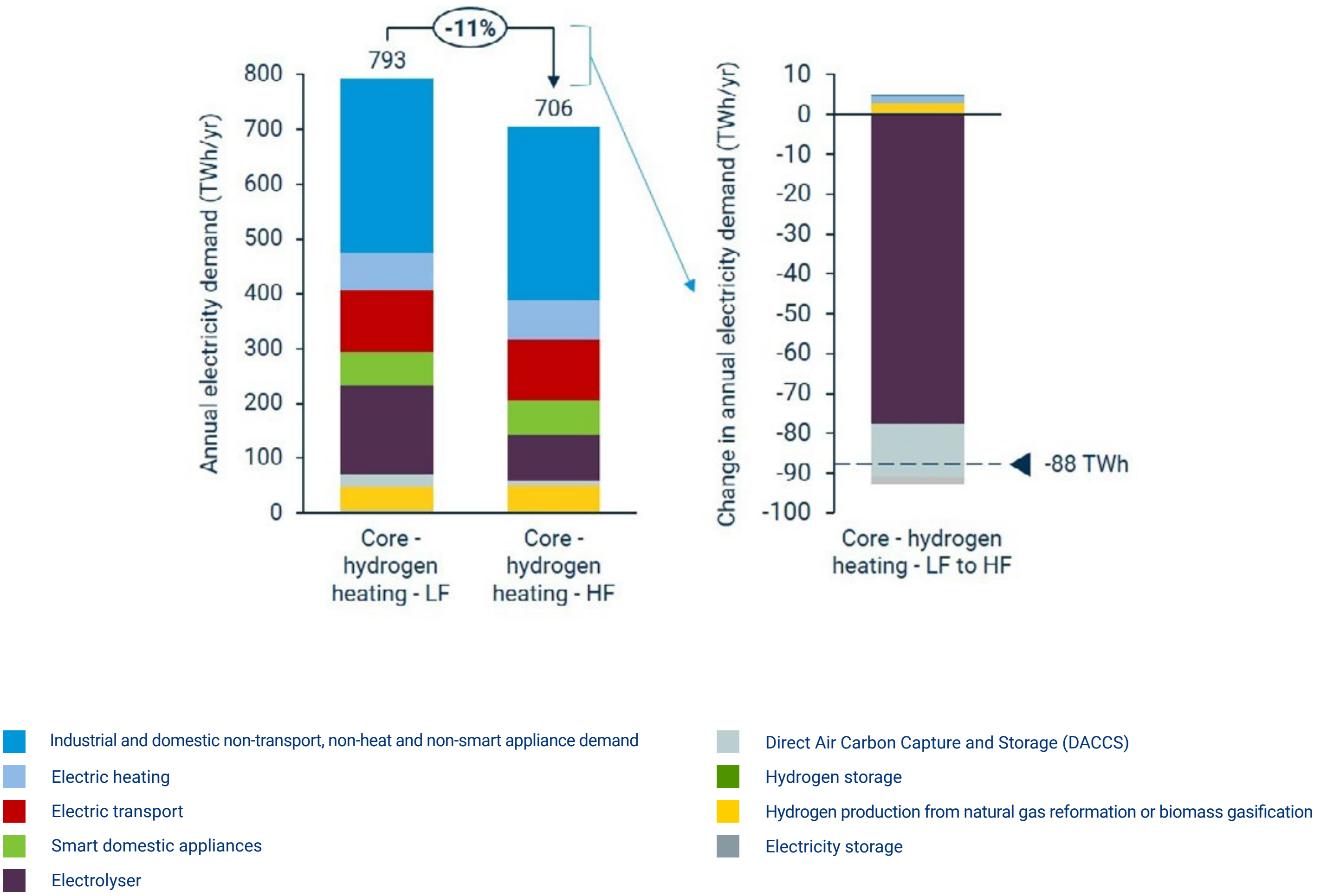
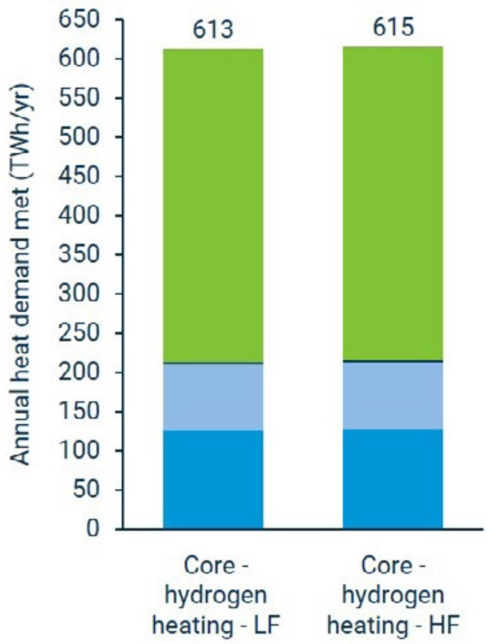


Figure 37 shows the proportion of heat demand met by each technology. There is minimal difference in how heat demand is met between the low and high flexibility scenarios, with around two thirds met by hydrogen boilers and a third by heat pumps or resistive heating.

Figure 37. Annual heat demand met by heating technology (TWh/yr) - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF)



Hydrogen boiler
Resistive heating
Small heat pump
Large heat pump (district heating)

3.4.2.3 Meeting electricity demand - flexibility reduces the electricity generation capacity requirement by 21%

As in the other heating scenarios, the majority of demand is met by offshore wind, with onshore wind, solar PV and large-scale nuclear power plants providing the majority of the remainder (Figure 38).

Figure 38. Annual electricity generation (TWh/yr) - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF)

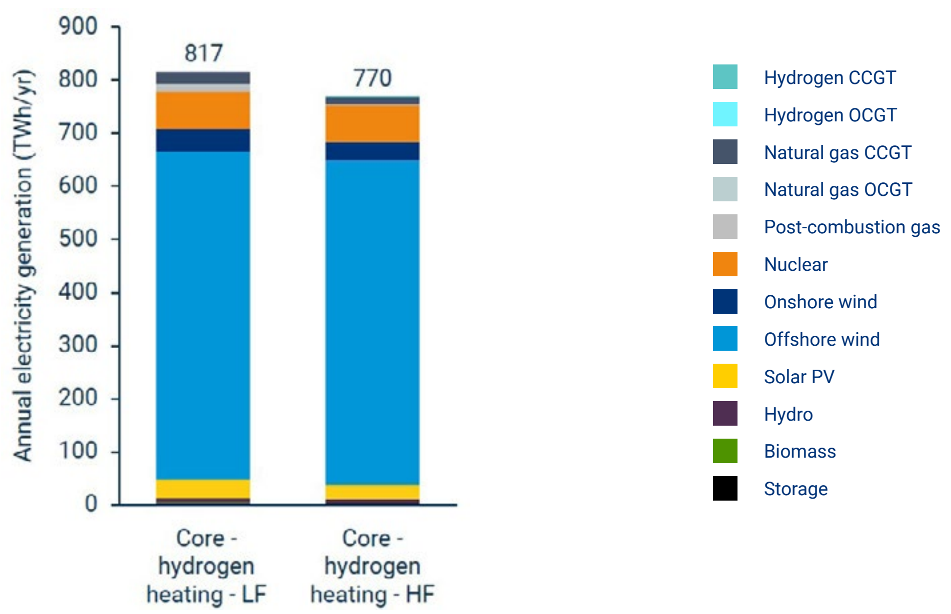
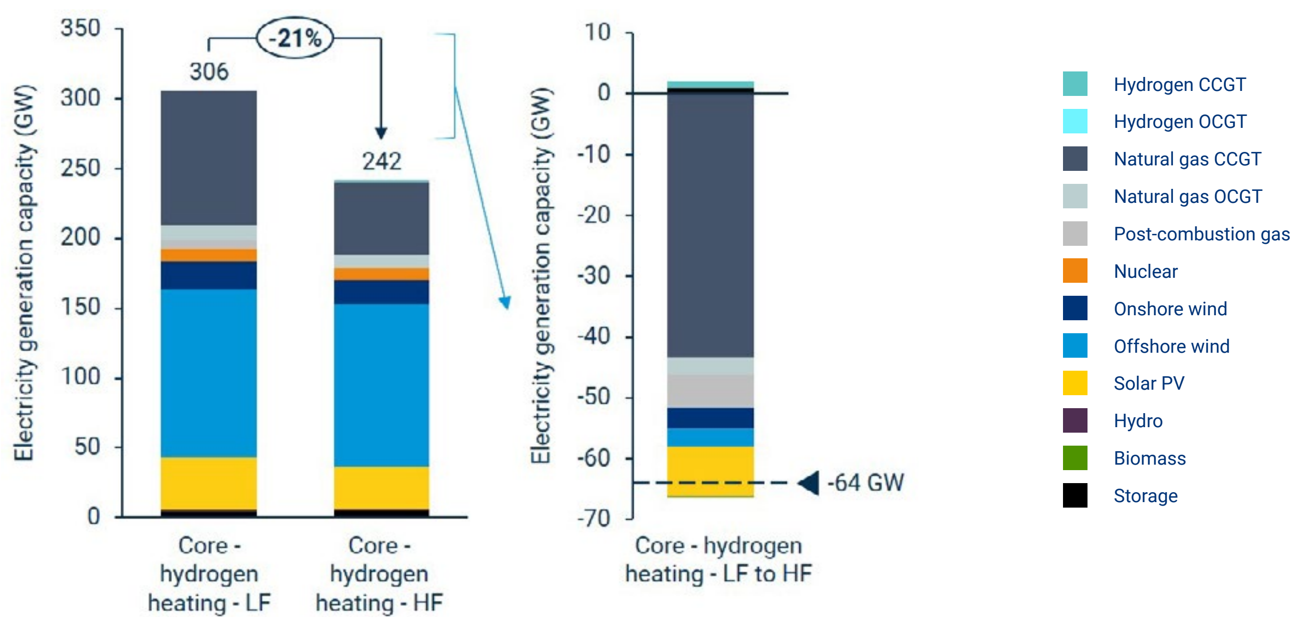


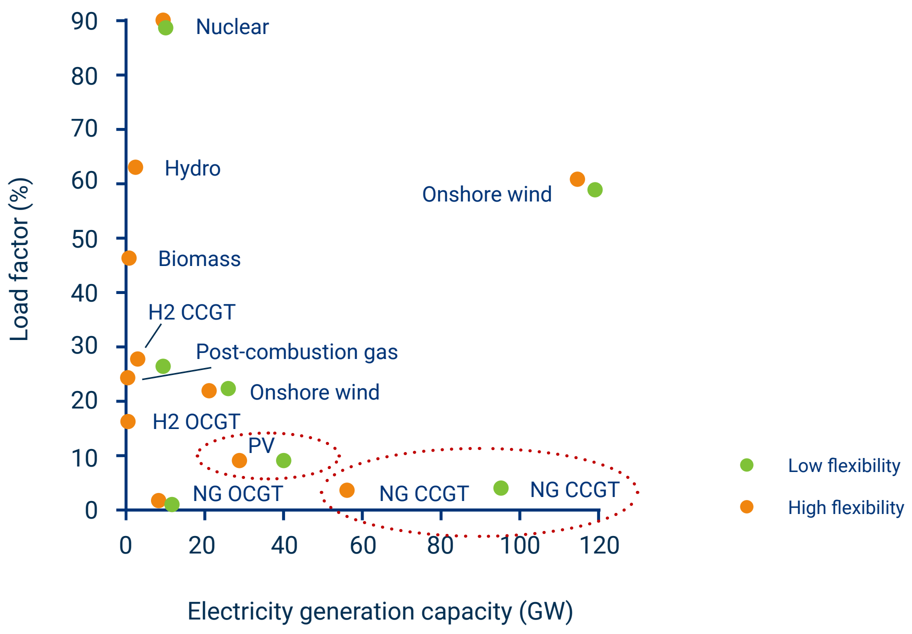
Figure 39. Left: Electricity generation capacity (GW) Right: Change in electricity generation capacity (GW) - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF)



While unabated gas generation only provides 3% of electricity in the low flexibility scenario, it accounts for 35% (108GW) of electricity generation capacity (Figure 39) and consequently has annual load factors of only 2.9% (CCGT) and 0.1% (OCGT) (Figure 40).

Additional flexibility reduces the requirement for unabated fossil fuel generation by 46GW (Figure 39). This generation continues to have a low annual load factor (2.7% for CCGT and 0.8% for OCGT), indicating that it is still used to meet demand during periods of system stress, but that the system uses flexibility to manage or meet demand during these periods (Figure 40). As with the hybrid heating scenario, adding flexibility results in a more modest decrease in renewable generation.

Figure 40. Electricity generation capacity (GW) versus annual load factor (%), by technology - hydrogen heating pathway - low and high flexibility. Where a green dot it not visible, this is due to it either not being deployed in the low flexibility scenario - H2 OCGT and H2 CCGT - or having the same capacity and load factor in each scenario

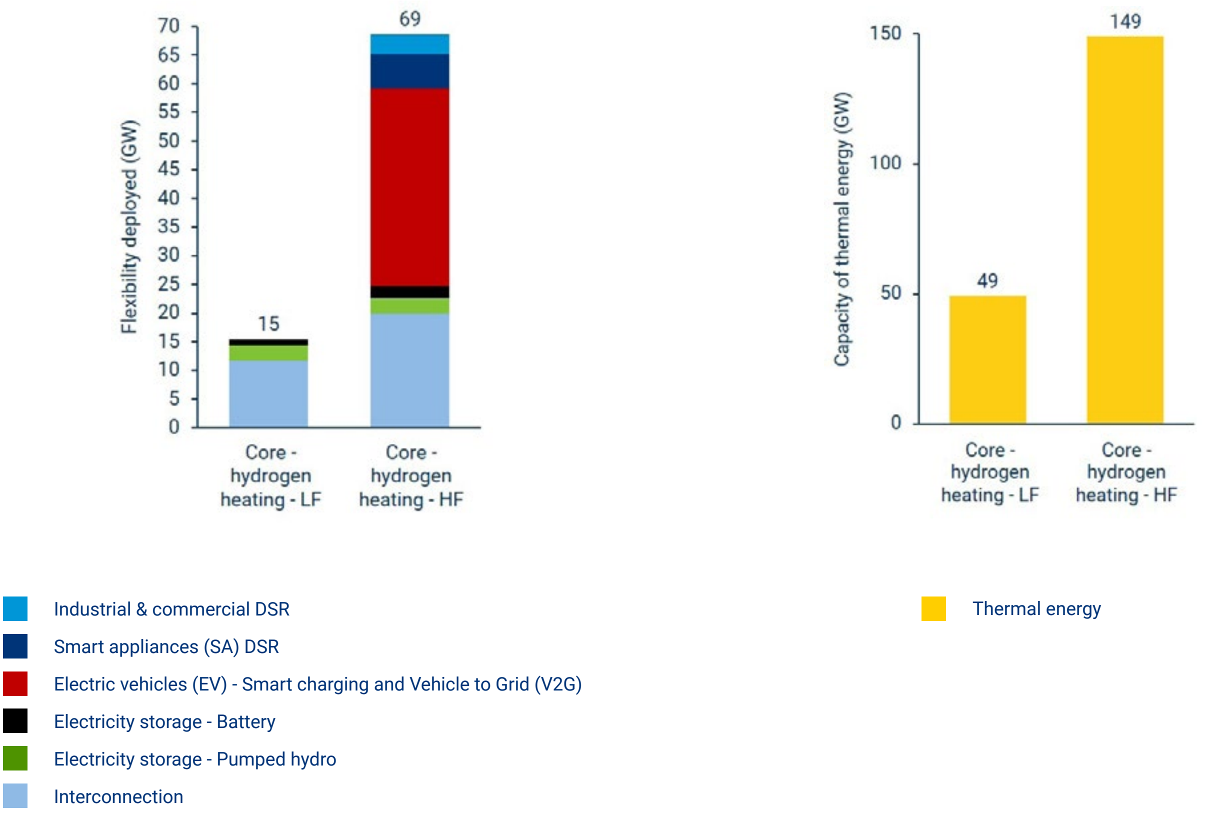


3.4.2.4 System flexibility - DSR, interconnection and thermal storage provide the majority of flexibility capacity

Figure 41 (right) shows that under a high flexibility scenario, the model triples capacity of TES to 149GW, which is equivalent to 859GWh of storage, the vast majority of which is district heating scale hot water tanks which can provide 6 hours of thermal energy at maximum output.

In the electricity system, interconnection and DSR from EV smart charging and V2G dominate. The capacity of DSR and EV flexibility deployed represents the maximum shift in GW demand delivered through these technologies across the year modelled, not the total amount of energy demand shifted over the course of a year.

Figure 41. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage (GWth) - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF)



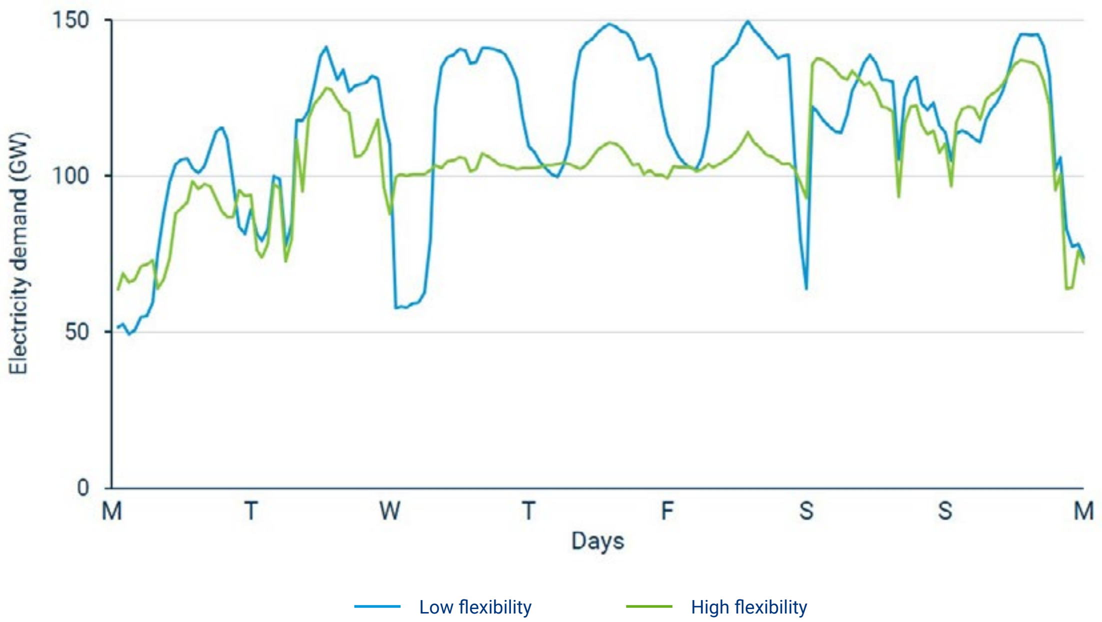
3.4.2.5 During an extreme cold weather event, the portfolio of hydrogen production and storage capacity influences the impact on the electricity system

As seen in the previous two core pathways, meeting electricity demand during an extreme (1-in-20 year) cold weather event coupled with low renewables output (high demand - low wind), drives significant investment in back up generation capacity. This was particularly true for the electric heating pathway, whilst the hybrid heating pathway was able to use natural gas heating to reduce electricity demand during the high demand - low wind period and consequently lower the need for back-up generation.

In this hydrogen heating scenario, the difference in demand during the high demand - low wind (period Wednesday to Friday) is quite pronounced (Figure 42). In the low flexibility scenario hydrogen production continues during the high demand - low wind period as well as drawing down on hydrogen stored, predominately in large salt caverns in order to meet demand. In the high flexibility scenario, the use of stored hydrogen is also crucial in meeting demand, but a larger proportion of hydrogen is produced from biomass and natural gas which use less electricity. It is interesting that the cost optimal solution is to continue to produce hydrogen during the extreme weather event, rather than investing in additional hydrogen storage to cover demand during this period. Exploring the cost optimal amount of hydrogen storage at different investment & operational costs is outside the scope of this project, but could be explored in more depth in further work.

As well as the change in hydrogen production, in the high flexibility scenario, intra-day load shifting via smart appliances, industrial and commercial DSR, and the smart charging and V2G capabilities of EV charging infrastructure provide additional flexibility and further reduce peak demand by flattening demand over the high demand - low wind period (Figure 42).

Figure 42. Hourly electricity demand (GW) during severe winter week - hydrogen heating pathway - low and high flexibility. Electricity demand includes interconnector exports



To meet demand during the high demand - low wind period, the electricity system relies heavily on natural gas OCGTs and CCGTs. In the high flexibility scenario, additional interconnector capacity (which assumes 20GW can be imported consistently over the three-day period) reduces the capacity of natural gas CCGTs and OCGTs required to meet demand.

Figure 43. Hourly electricity generation (GW) during severe winter week, by technology - hydrogen heating pathway - low flexibility

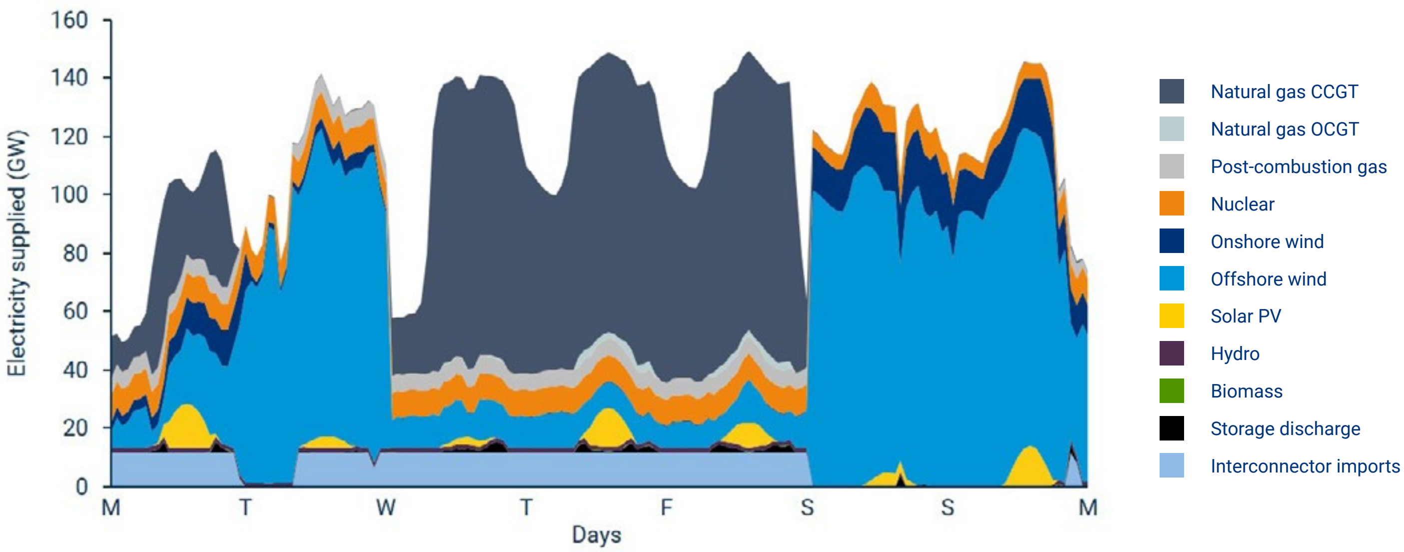
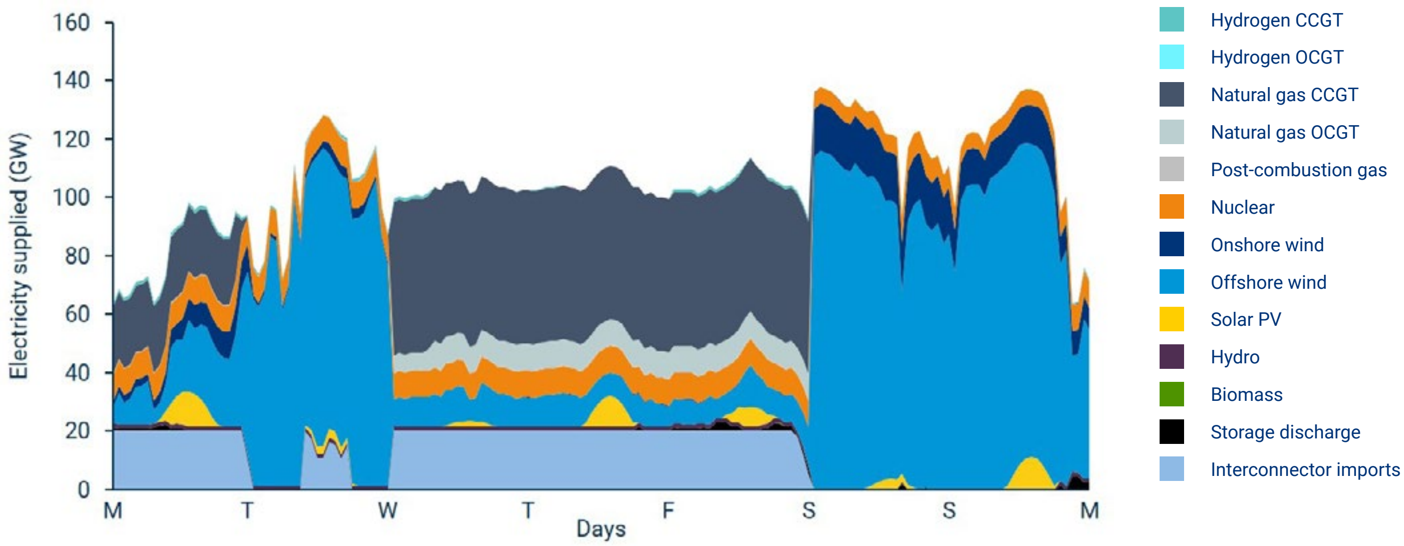


Figure 44. Hourly electricity generation (GW) during severe winter week, by technology - hydrogen heating pathway - high flexibility



3.4.2.6 The value of using electrolysers as a form of flexibility depends on the wider flexibility portfolio

There is an interplay between demand side flexibility, interconnection export, and the means of hydrogen production. The use of DSR enables a greater proportion of electricity to be used to meet electricity demand directly and increased interconnection means surplus generation can be exported to other markets, rather than needing to meet demand in the UK. In our modelling these are considered more cost optimal solutions than using electrolysers to create demand for power during periods when demand would otherwise be low. As a result, hydrogen production from electrolysis is lower in the high flexibility scenario compared to the low flexibility scenario.

This is highlighted most acutely over a summer week when electricity demand is typically at its lowest. Figure 45 shows electricity generation over a summer week in the low flexibility scenario, predominantly from renewables. Figure 46 then shows that the use of electrolysers varies over the week to correspond with periods of higher renewables output.

Figure 47 shows electricity generation over a summer week in the high flexibility scenario, again predominantly from renewables. Figure 48 shows the corresponding electricity demand. In this high flexibility scenario, DSR has shifted demand to better correspond to periods of high renewable generation, while the model makes use of additional interconnection capacity (which increases from 11.7GW to 20GW in the high flexibility scenario) to export generation, rather than convert to hydrogen. This reduces the frequency with which electrolysers are used and, in turn, the capacity required.

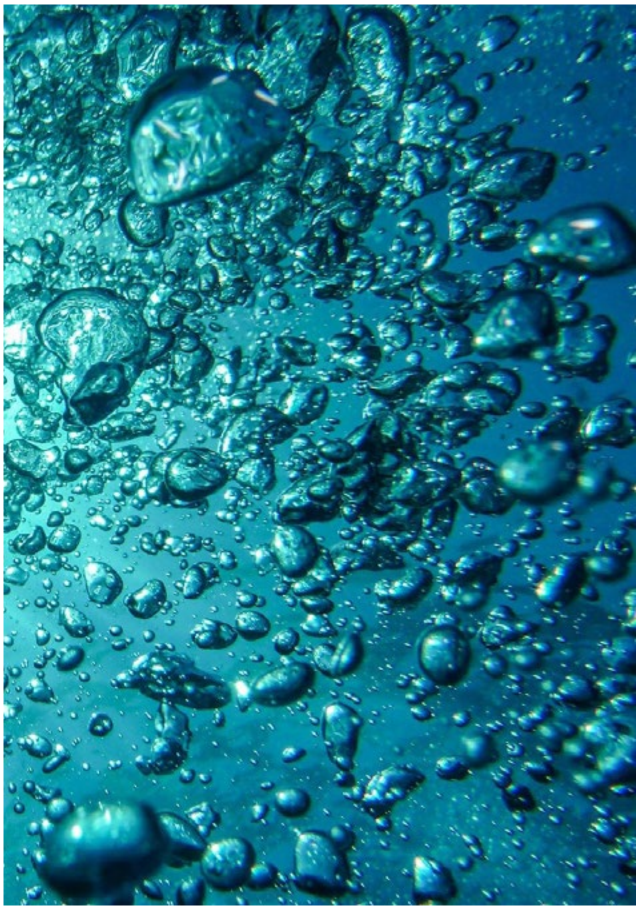


Figure 45. Hourly electricity generation (GW) during a summer week, by technology - hydrogen heating pathway - low flexibility

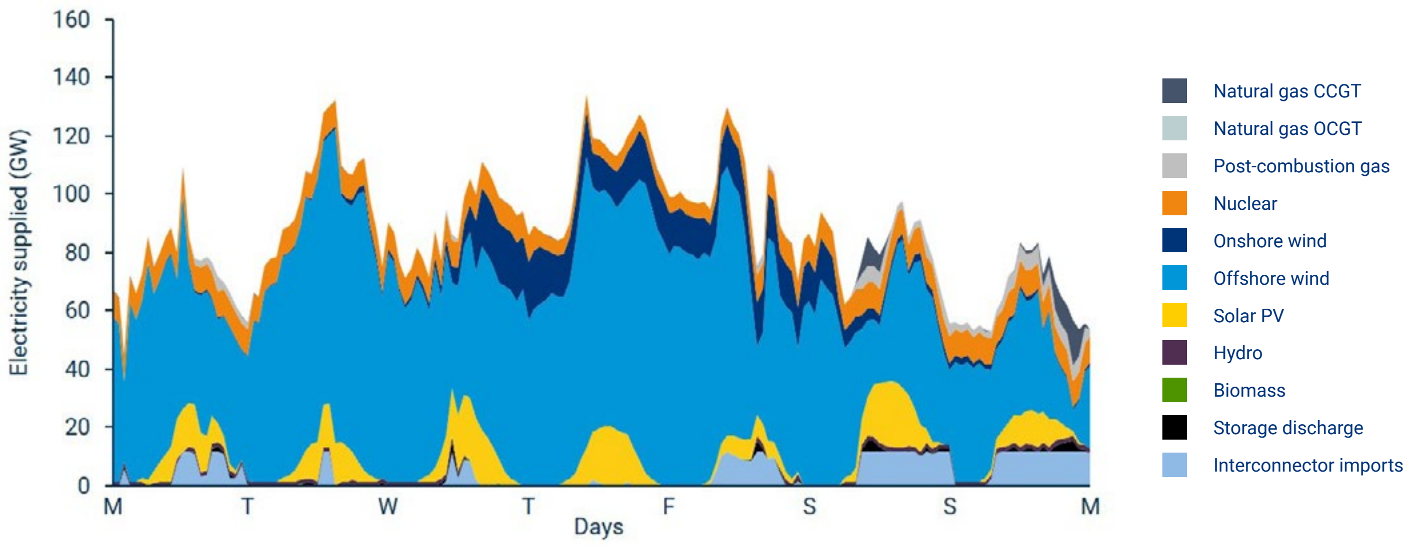


Figure 46. Hourly electricity demand (GW) during a summer week, by technology - hydrogen heating pathway - low flexibility

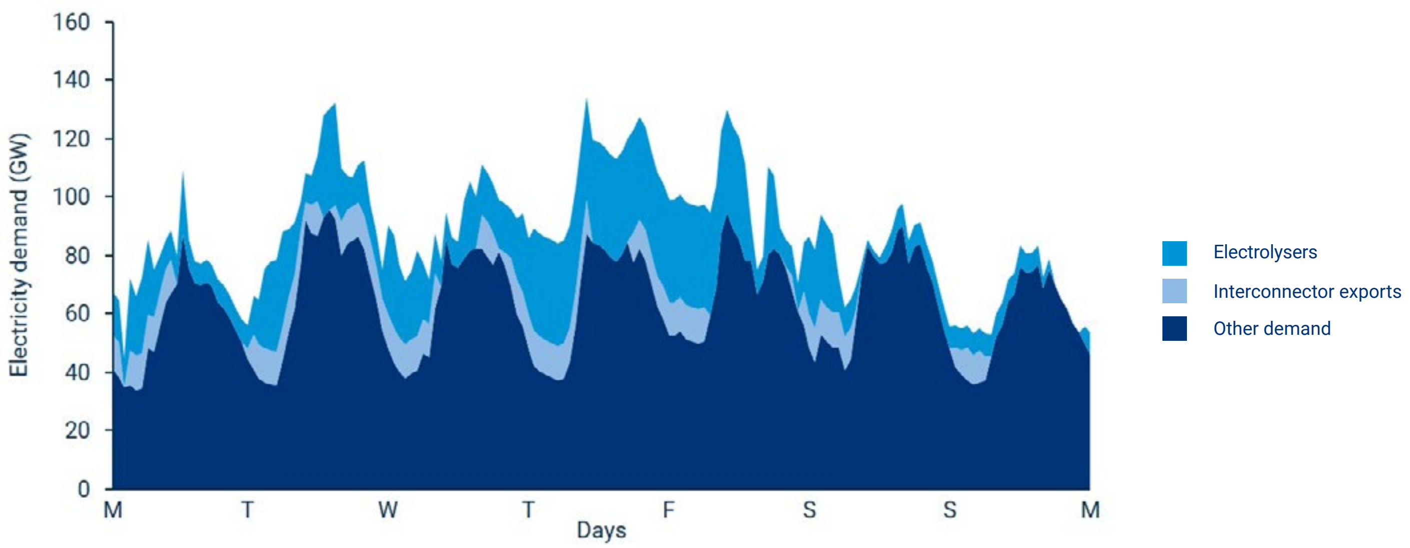


Figure 47. Hourly electricity demand (GW) during a summer week, by technology - hydrogen heating pathway - high flexibility

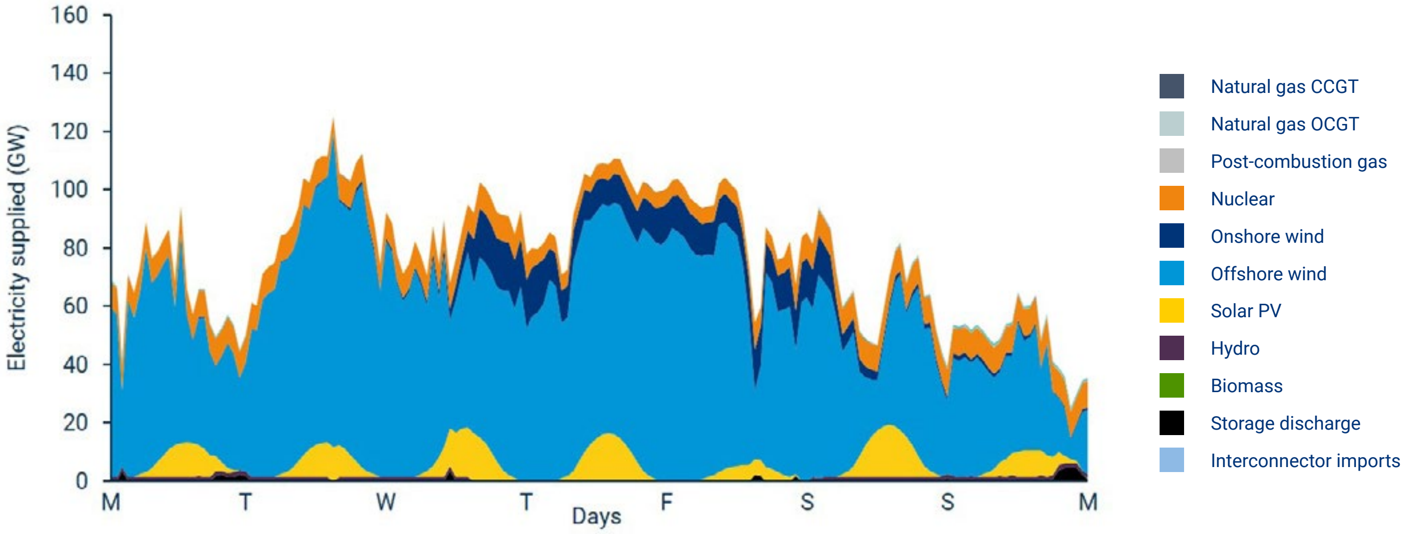


Figure 48. Hourly electricity demand (GW) during a summer week, by technology - hydrogen heating pathway - high flexibility

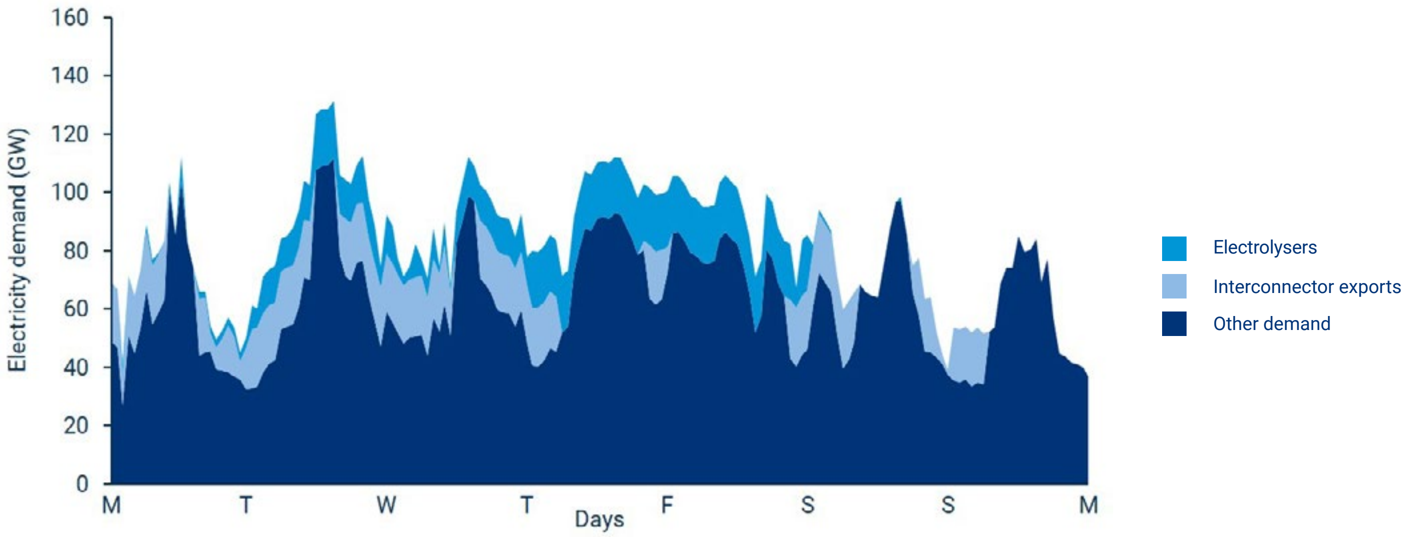
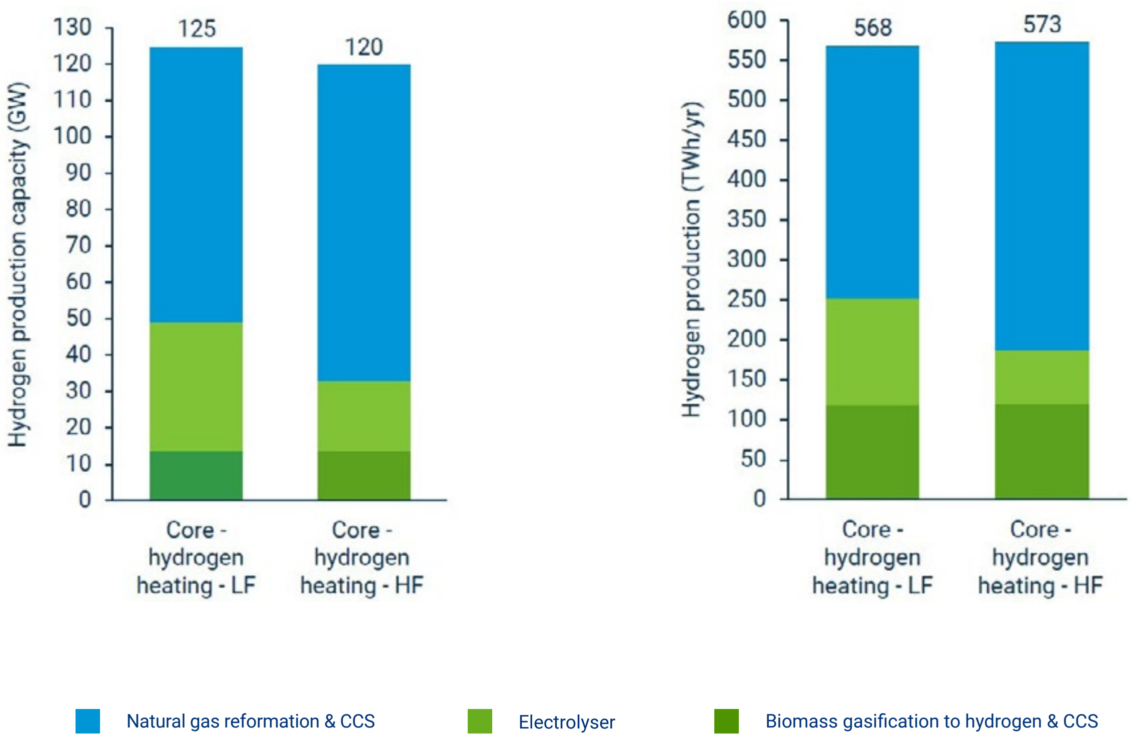


Figure 49. Left: Hydrogen production capacity (GW). Right: Hydrogen production by technology (TWh, right) - low flexibility (LF) and high flexibility (HF)



Overall, in both the low and high flexibility scenarios, a portfolio of hydrogen production technologies is cost optimal at a system level. However, with additional flexibility in the wider energy system, there is a shift away from electrolysis towards methane reformation with CCS as shown in Figure 49. Biomass gasification to hydrogen with CCS is constant across both scenarios, limited by biomass feedstock availability, but still highly valuable for its ability to deliver negative emissions.

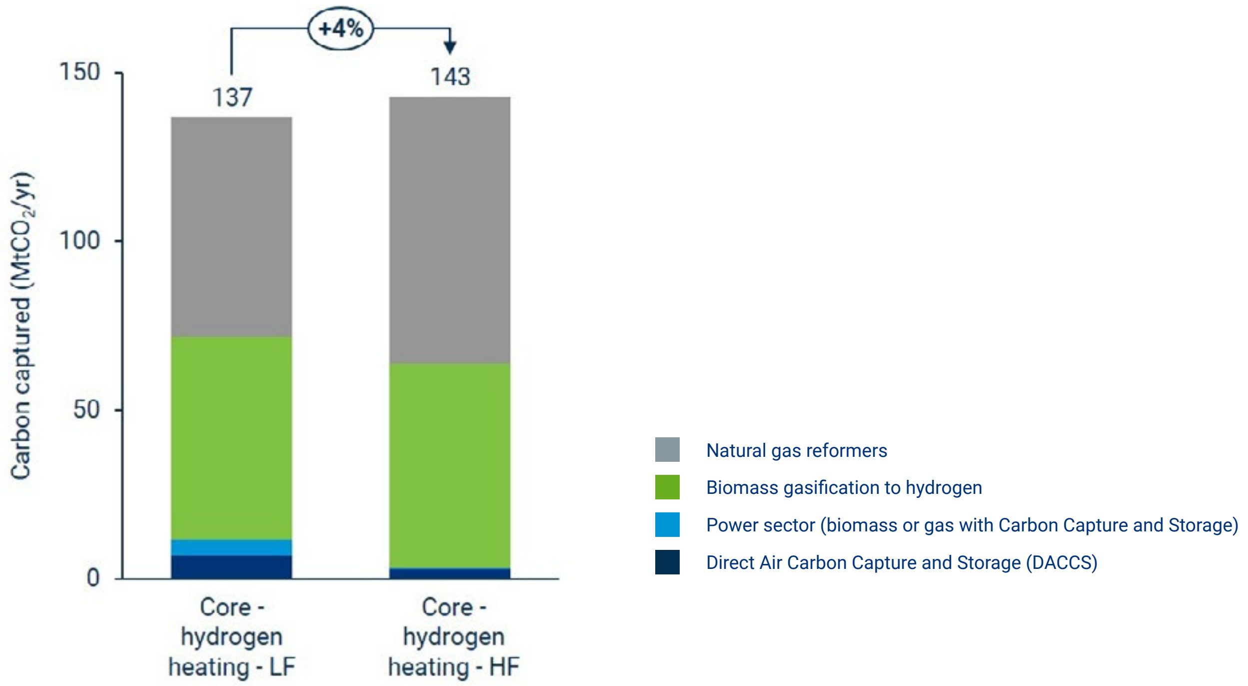
3.4.2.7 Carbon capture and storage - flexibility increases the amount of carbon captured while reducing reliance on direct air capture technology

Both the low and high flexibility scenarios meet the net -50MtCO_2/yr target. Emissions from fossil fuel use are captured at source or offset via DACCS and biomass with CCS. These two routes also deliver net negative emissions.

The hydrogen heating scenario has the highest use of natural gas across the core scenarios due to higher hydrogen demand. In the higher flexibility scenario, natural gas use is 7.7% higher than in the low flexibility scenario (440TWh/yr compared to 408TWh/yr). This is around half current energy system demand for natural gas.[17]

As a result of higher natural gas use, the total amount of CO_2 that needs to be captured is higher in the high flexibility scenario compared to the low flexibility scenario. This increase is due to more carbon captured directly from natural gas reformation, increasing from 65MtCO_2 to 79MtCO_2. However, under a high flexibility scenario, the reliance on DACCS to meet the carbon target more than halves from 7MtCO_2/yr to 3MtCO_2/yr due to a reduction in the use of unabated natural gas in the power sector (Figure 50).

Figure 50. Carbon captured by source (MtCO_2) - hydrogen heating pathway - low and high flexibility



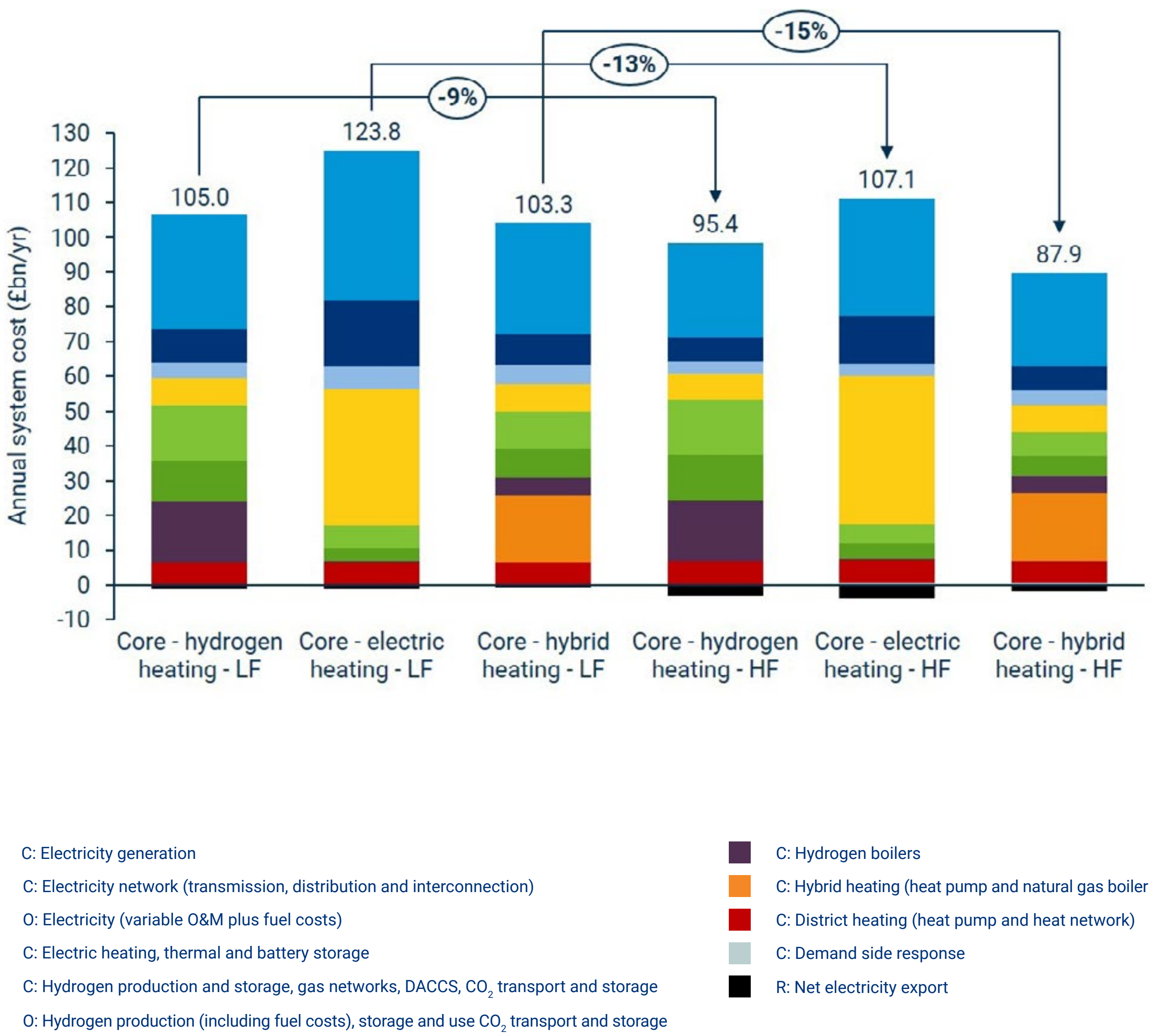
17 In 2019, natural gas used in the energy system was 868TWh. Source: BEIS, Digest of UK Energy Statistics (DUKES), Table 1.1: Aggregate Energy Balance, 2020. https://www.gov.uk/government/statistics/energy-chapter-1-digest-of-united-kingdom-energy-statistics-dukes

3.5. Core pathways - key messages

Deploying additional flexibility is a no-regrets decision delivering material net system savings of between £9.6 and £16.7bn/yr across all core pathways

Across all three pathways, the savings predominantly come from avoided gas generation (CapEx and OpEx) to meet demand during times of system stress and reduced network reinforcement due to a reduction in peak demand on the distribution network. In the hybrid scenario, there is also a material reduction in DACCS costs as a more flexible system reduces the use of natural gas in domestic properties.

Figure 51. Annual system cost (£bn/yr) - All core pathways - low flexibility (LF) and high flexibility (HF)

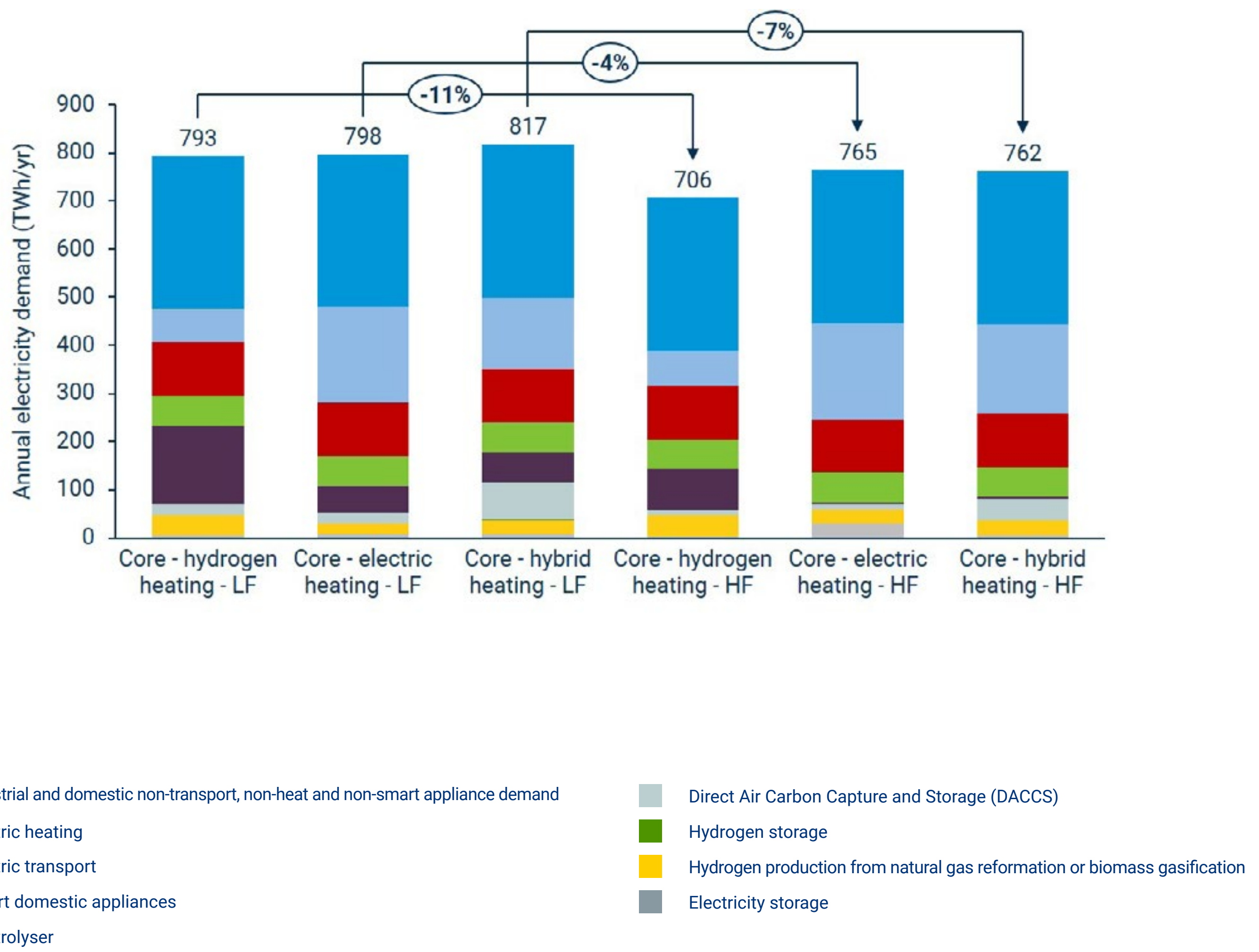


Total electricity demand is similar across different heating pathways - and can be reduced by additional flexibility

Across all low flexibility scenarios, total electricity demand is similar, but split differently across end use categories. The electric heating scenario unsurprisingly uses more electricity for heating, while the hybrid scenario uses more power for DACCS to capture emissions from unabated natural gas used in boilers. The hydrogen heating pathway uses more electricity for hydrogen production via electrolysis.

Flexibility reduces demand across all three heating pathways, most noticeably in the hydrogen heating scenario. Across all three scenarios, the demand reduction is in large part due to a reduction in demand for electrolysers, as deploying other forms of flexibility results in a shift away from electrolysis towards natural gas reformation. In the high flexibility hybrid heating scenario, a reduction in electricity demand for DACCS offsets an increase in electric heating demand.

Figure 52. Annual electricity demand (TWh/yr) - All core pathways - low flexibility (LF) and high flexibility (HF)



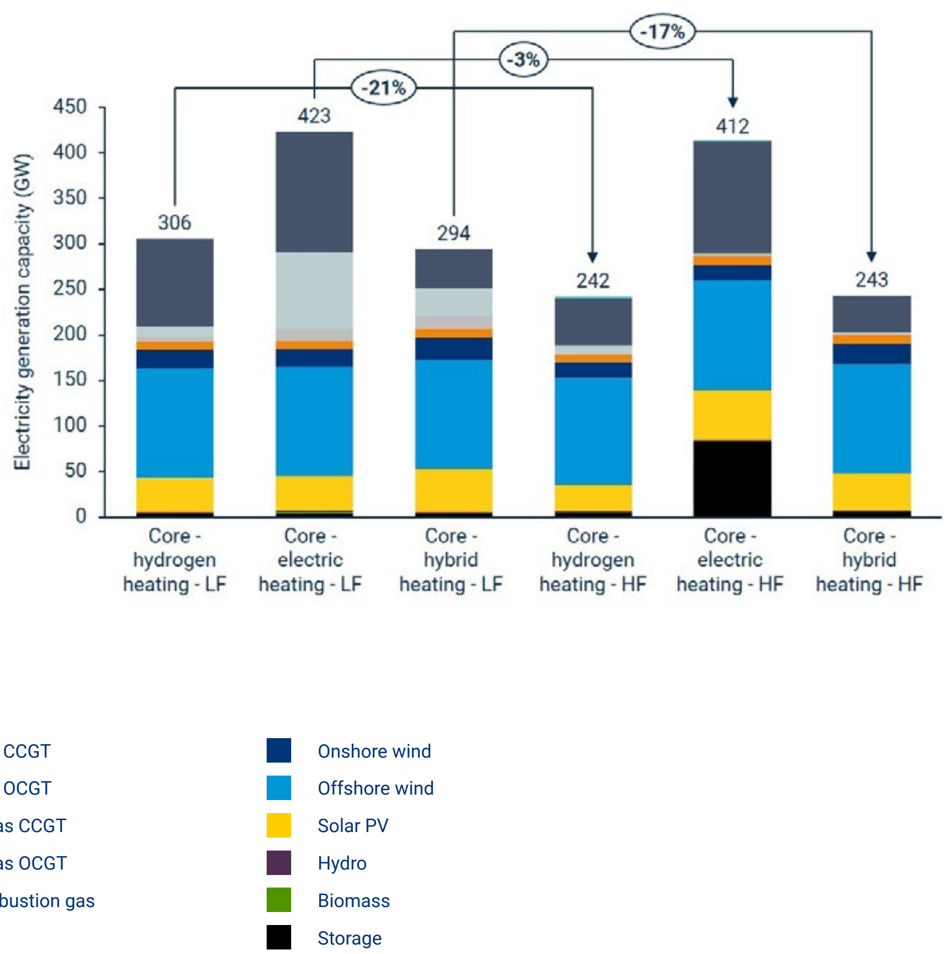
Flexibility, including vector integration, supports a net zero energy system to cope with dark, cold and windless days

It is important to consider the impact of weather patterns that cause very cold temperatures and very low wind speeds in a system that has a high penetration of renewables. This report has considered such an event across all scenarios where there is a 72 hour-period of extreme cold weather driving up heat demand coincident with very low wind and solar PV output (less than 5% of maximum).

An important implication of this weather event is the requirement for low-cost fossil fuel plants, particularly in the low flexibility scenarios, which are mainly used to support the system during this high stress period.

While there is less than 10% difference in electricity demand across the three low flexibility scenarios and three high flexibility scenarios (Figure 52), the profile of end user demand and the extent to which it can be moved or met by other vectors (natural gas boilers) when renewable output is low results in very different requirements for electricity generation capacity. The deployment of renewables and nuclear is broadly similar across all scenarios (both high and low flexibility), but significantly more back-up generation (in this case unabated gas generation) is needed to meet demand in a fully electric heating pathway compared to the hybrid heating pathway, despite most heat in both pathways being met by heat pumps or resistive heating.

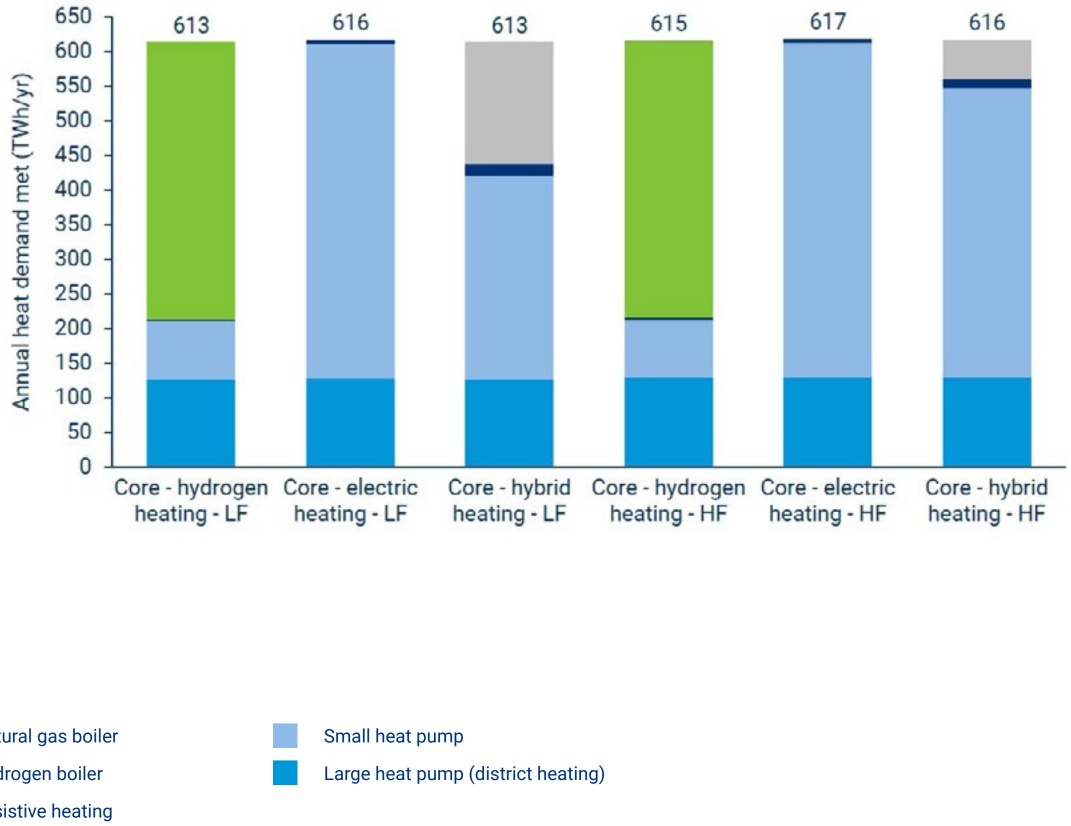
Figure 53. Electricity generation capacity and electricity storage (GW) - All core pathways - low flexibility (LF) and high flexibility (HF)



Under the high flexibility hybrid heating scenario, 430TWh/yr of heat is delivered via domestic heat pumps or resistive heating. This is 88% of total heat provided by the same technologies in the high flexibility electric heating scenario (488TWh). The hybrid heating scenario provides the difference (58TWh) using natural gas (Figure 54). However, meeting this relatively small additional amount of heating via natural gas reduces the requirement for fossil fuelled generation by 78GW (from 126GW in the high flexibility electric scenario to 43GW in the hybrid scenario). This indicates that cross-vector integration - flexibility in how end user demand is met - has a high system value and impact on generation requirements, alongside DSR and energy storage.

In this case, the flexibility is between electric and natural gas heating, which relies on negative emissions technologies to remain within the carbon constraint. Further research could examine whether electric/hydrogen hybrid heating systems could deliver the same value (while reducing unabated natural gas use) or the impact of efficiency measures on total end user demand.

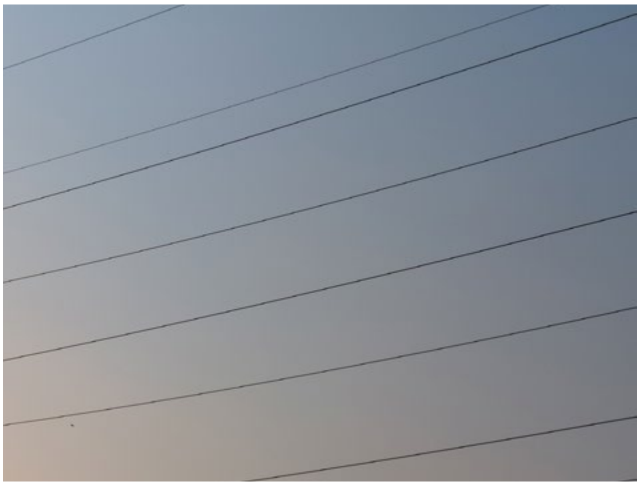
Figure 54. Annual heat demand met by heating technology (TWh/yr) – all core pathways - low flexibility (LF) and high flexibility (HF)



Peak demand drives electricity network investment - flexibility can reduce peak demand, but the main driver for investment is the choice of heating solution

Peak demand in 2050 is significantly higher than in 2019. It is expected to grow about 2.5 times in the hydrogen and hybrid heating scenarios (to 150GW), and up to almost four times the 2019 amount in the electric heating scenario (to 230 GW). This reinforces the point made above: the method by which heat demand is met results in very different requirements for electricity generation capacity.

The differences in peak demand in the high and low flexibility scenarios are relatively small in the hydrogen and hybrid heating pathways, with only a reduction of 3GW in both cases (about 2% of peak demand). This is more significant in the electric heating scenario, with a potential 17GW reduction in peak demand (representing 7% of peak demand in the low flexibility scenario). However, as shown in the core scenario descriptions, DSR can deliver a much greater change in capacity at a given point in time, such as when renewable output drops.

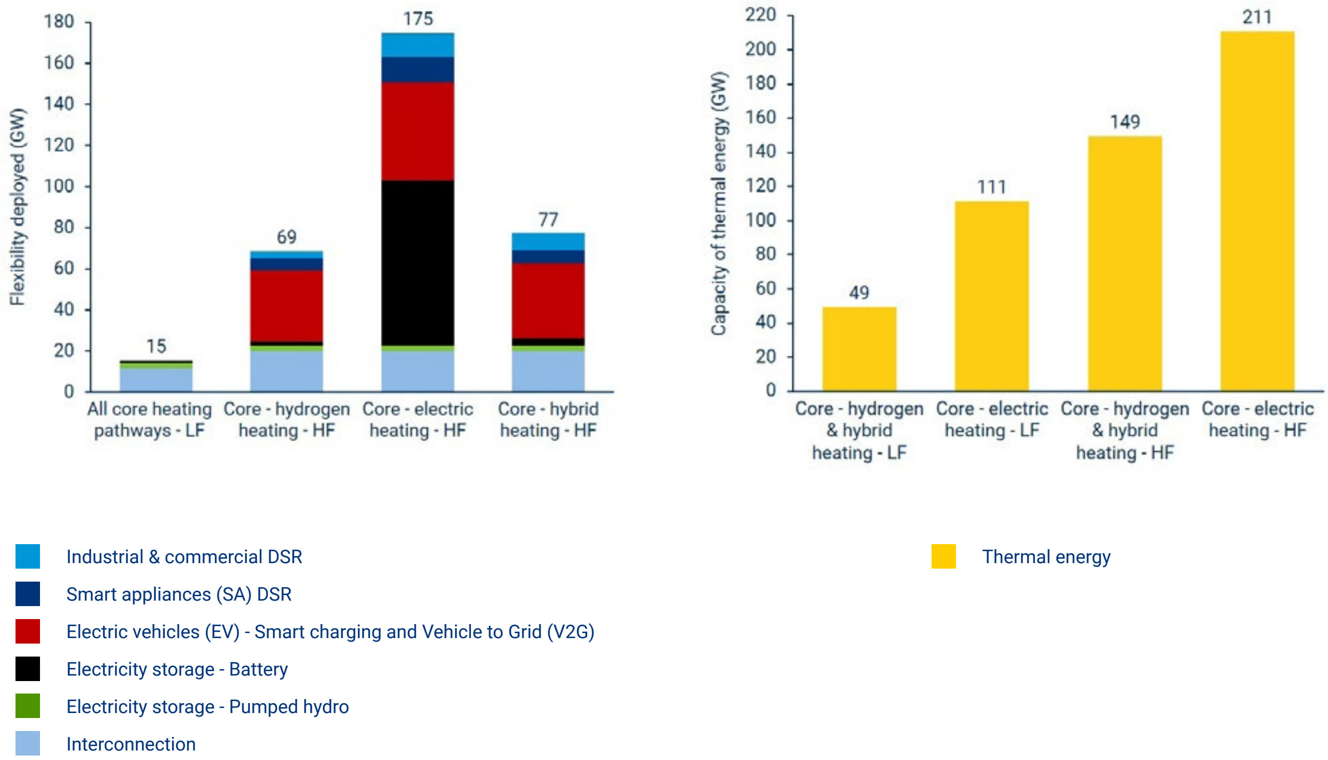


Developing a portfolio of flexibility across the energy system reduces the cost of decarbonisation

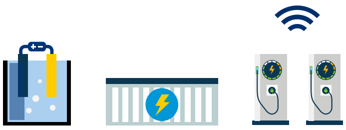
In all three scenarios, DSR enables a closer alignment between supply and demand. Interconnection also provides additional supply, as well as the opportunity to export during periods of high renewable generation. Thermal storage is widely deployed across all three pathways, decoupling supply of electricity from demand for heat which reduces pressure on the electricity system and can reduce the capacity of heat pumps required to meet demand within a building.

Deployment of battery storage varies significantly between scenarios, ranging from 2GW in the hydrogen scenario to 83GW in the fully electric heating scenario. In the latter, it is used to meet short-term peaks in demand. In the hydrogen and hybrid heating scenarios, demand during periods of system stress is lower (and smoother), reducing the need for shorter term flexibility. However, as mentioned in Chapter 2, these scenarios test the extremes of how GB might meet net zero, and the results are sensitive to changes in assumptions. These sensitivities are set out in the following sections.

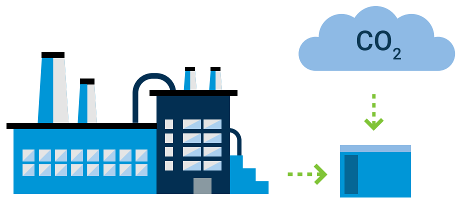
Figure 55. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage (GWth) - all core heating pathways - low flexibility (LF) and high flexibility (HF)



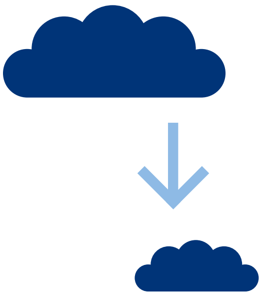
Benefits of a flexible energy system - key messages from wider analysis



A portfolio approach to flexibility enables the energy system to mitigate impacts of wider system changes



Negative emissions technologies are an important part of a cost-effective energy system but flexibility can minimise the wider system impact if these are not deployed



Flexibility helps deliver net negative emissions cost effectively

Demand Side Response (DSR) is a key part of the flexibility portfolio – without it the system cost increases significantly

Electrolysers provide flexibility, but developing a portfolio of hydrogen production technologies from electricity and gas is most cost-effective

3.6. Impact of flexibility technology availability

This project performed three sensitivity analyses to understand more about the value of different flexibility technologies within the portfolio of technologies deployed. These sensitivities explored:

- **How valuable is unlocking DSR capabilities in an otherwise high flexibility scenario?** DSR capabilities considered include smart appliances, I&C demand side response, and EV smart charging and V2G. This was performed on the electric heating pathway. This study sought to understand the extent to which other technologies could mitigate this loss of capability and the impact on the wider electricity system.
- **How important is battery storage CapEx at a system level?** Costs were increased from £55/kWh to £90/kWh (in 2050) for a 50MW four-hour duration battery on the high flexibility electric heating pathway. This study sought to understand the extent to which deployment of battery storage, and other flexibility technologies, are sensitive to battery CapEx costs.
- **How valuable is TES (hot water tank) deployment in an otherwise high flexibility scenario?** We reduced the TES deployment in the high flexibility scenarios to the levels used in the low flexibility runs. This study was performed on both the electric and hydrogen heating pathways in order to understand the extent to which other technologies could mitigate this loss of capacity and the impact on the wider energy system.

A summary of differences between the sensitivities is provided in the table below.

Table 1. A summary of differences between the sensitivities

Item	Removing DSR	Increasing cost of BES	Reducing availability of TES
Heating pathway	Electric	Electric	Electric and Hydrogen
Energy system carbon target	-50 $MtCO_2$/yr	-50 $MtCO_2$/yr	-50 $MtCO_2$/yr
Scenarios compared	1. Core Low Flex 2. Core High Flex 3. High Flex with DSR removed	1. Core Low Flex (£55/kWh BES) 2. Core High Flex (£55/kWh BES) 3. High Flex (£90/kWh BES)	1. Core Low Flex 2. Core High Flex 3. High Flex with reduced TES deployment cap *In Electric HF scenario, TES limited to 110W (compared to 211GW in Core HF Scenario).* *In Hydrogen HF, TES limited to 49GW (compared to 149GW in Core HF Scenario).*

3.6.1 How valuable is unlocking DSR capabilities in an otherwise high flexibility scenario?

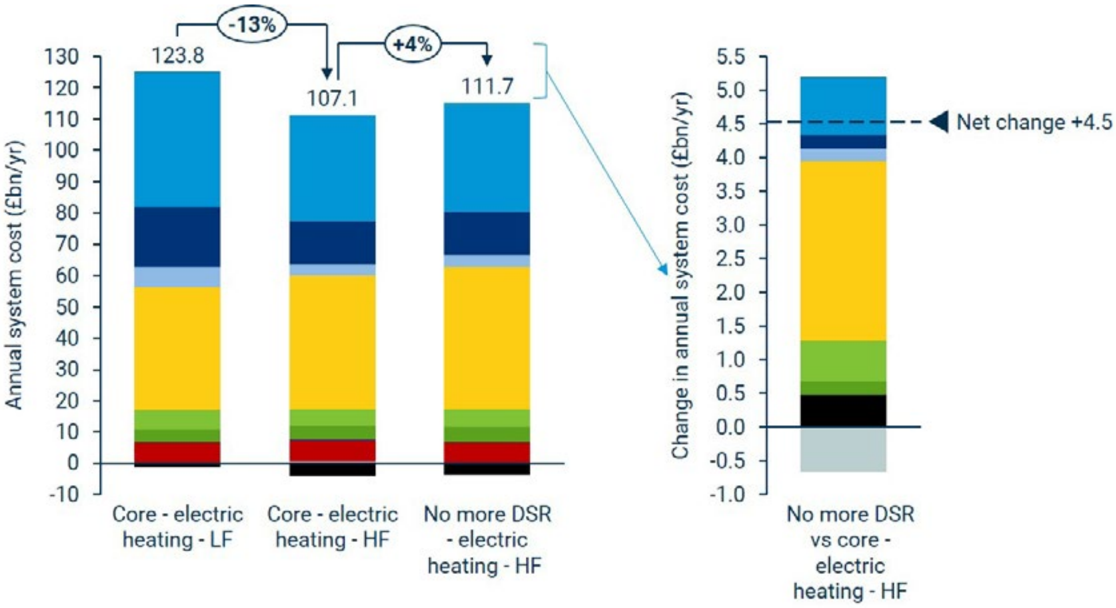
Key insight

DSR reduces the requirement for battery storage and reduces system cost by £4.5bn/yr in an electric heating pathway.

Section 3.2 Electric heating pathway indicates that deploying additional flexibility in a system where the vast majority of demand is electrified could deliver a significant reduction in system cost (£16.7bn/yr, a 13% reduction relative to low flexibility scenario) as a result of reducing the investment needed in electricity generation capacity - particularly under-utilised gas-fired generation - and reducing the network investment requirement by reducing peak load demand.

If DSR (smart appliances, I&C DSR, and EV smart charging and V2G) cannot be used in an otherwise high flexibility scenario, our modelling suggests that the remaining portfolio of technologies cannot replace all of the value DSR delivers. Figure 56 shows that a high flexibility scenario without DSR is still £12.2bn/yr cheaper than a low flexibility scenario but is £4.5bn/yr more expensive than the high flexibility scenario with DSR.

Figure 56. Left: Annual system cost (£bn/yr). Right: Increase in annual system cost from core electricheating pathway (HF) to electricheating pathway with no DSR (HF). LF = low flexibility, HF = high flexibility. C = Capital cost, O = Operational cost, R = Revenue



- C: Electricity generation
- C: Electricity network (transmission, distribution and interconnection)
- O: Electricity (variable O&M plus fuel costs)
- C: Electric heating, thermal and battery storage
- C: Hydrogen production and storage, gas networks, DACCS, CO_2 transport and storage
- O: Hydrogen production (including fuel costs), storage and use CO_2 transport and storage
- C: Hydrogen boilers
- C: Hybrid heating (heat pump and natural gas boiler combination)
- C: District heating (heat pump and heat network)
- C: Demand side response
- R: Net electricity export

Figure 56 shows a breakdown of the difference in cost between the high flexibility scenario with and without DSR. If there is no investment in DSR, (a saving of £0.7bn/yr), the energy system must invest much more in battery storage (£2.7bn/yr) and incurs additional costs for electricity generation and networks (a combined £1.3bn/yr increase) and hydrogen production (£0.8bn/yr).

This is illustrated in Figure 57 and Figure 58, which show that a highly flexible system without DSR can deliver several of the benefits of a system with DSR. These include reducing the capacity of fossil fuel fired generation by more than 40% and increasing the capacity of solar PV which can be accommodated on the network; however, it needs to invest in significant additional battery storage capacity in order to do so (100GW in the no DSR scenario, compared to 80GW in the core high flexibility pathway). Battery storage has a higher CapEx cost than DSR, and has a lower round trip efficiency (85%, compared to 95% efficiency for I&C DSR, negligible losses for smart appliances and EV smart charging, and modest losses for V2G). This means that more electricity needs to be generated to meet the same level of end user demand (Figure 58).

Figure 57. Electricity generation capacity and electricity storage capacity (GW) - electric heating pathway with no DSR in HF scenario sensitivity - low flexibility (LF) and high flexibility (HF)

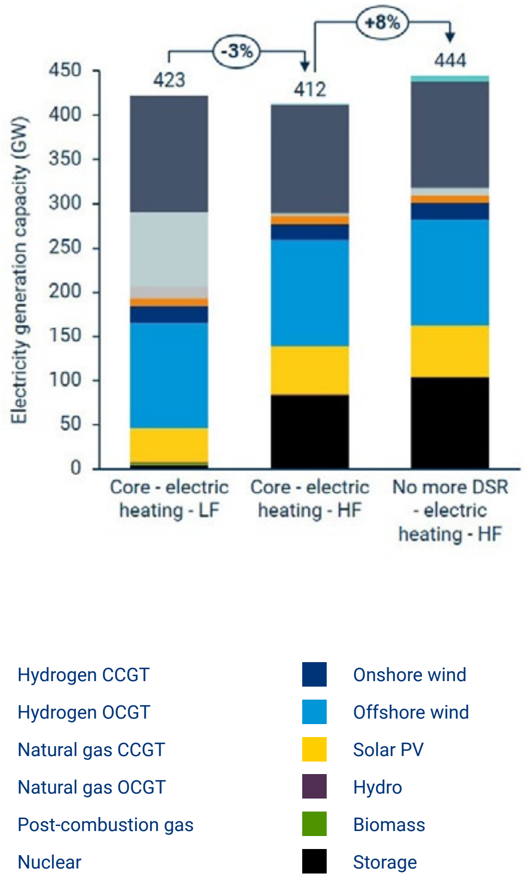
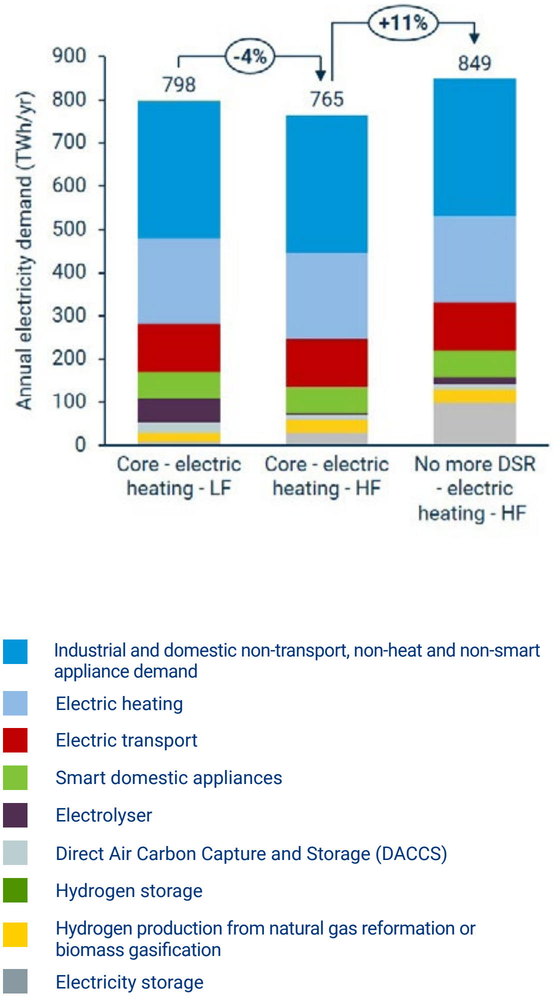


Figure 58. Annual electricity demand (TWh/yr) - electric heating pathway with no DSR in HF scenario sensitivity - low flexibility (LF) and high flexibility (HF)



3.6.2 How important is battery storage CapEx at a system level?

Key insight

Wider system changes can mitigate the impact of higher battery storage costs.

There is naturally significant uncertainty surrounding the cost of energy technologies in 2050. Within the scope of this project, there has not been time to test the robustness of all scenarios to changes in the cost of generation and flexibility technologies. This scenario takes just one example to explore the system impact of increasing the capital cost of battery storage from £55/kWh to £90/kWh under the electric heating scenario. This scenario was selected as it had the highest deployment of battery storage across all scenarios.

Figure 59 shows that increasing the cost of battery storage has a small impact on the total system cost, resulting in a 0.1% increase (£0.2bn/yr). Figure 61 shows that deployment of battery storage reduces from 80GW to 61GW - offset by more investment in heat pump capacity and thermal storage (Figure 60). This is the result of a change in location for TES; maximum thermal output of TES does not change, but total energy capacity slightly reduces as a larger proportion of TES is deployed in domestic properties, as opposed to district heating schemes.

Figure 59. Annual system cost (£bn/yr) - electric heating pathway with higher cost of BES in HF scenario sensitivity - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue

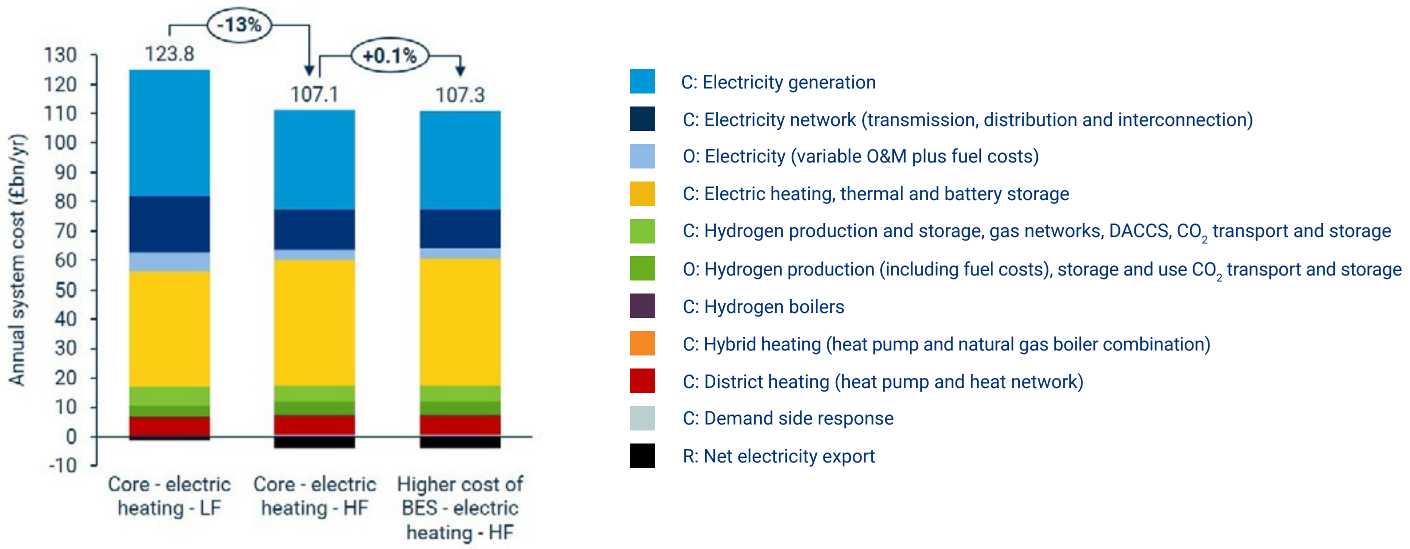


Figure 60. Detailed change in annual system cost (£bn/yr) between core pathway and higher cost of BES - electric heating pathway - high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue

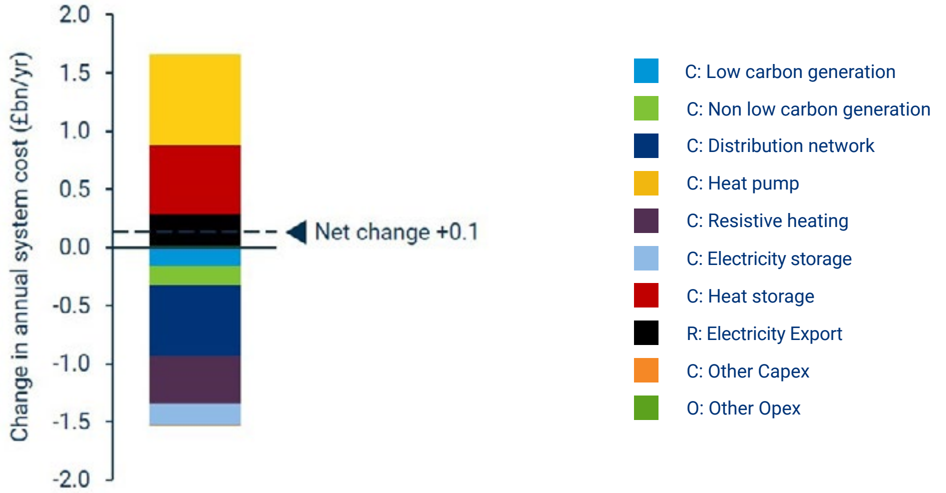
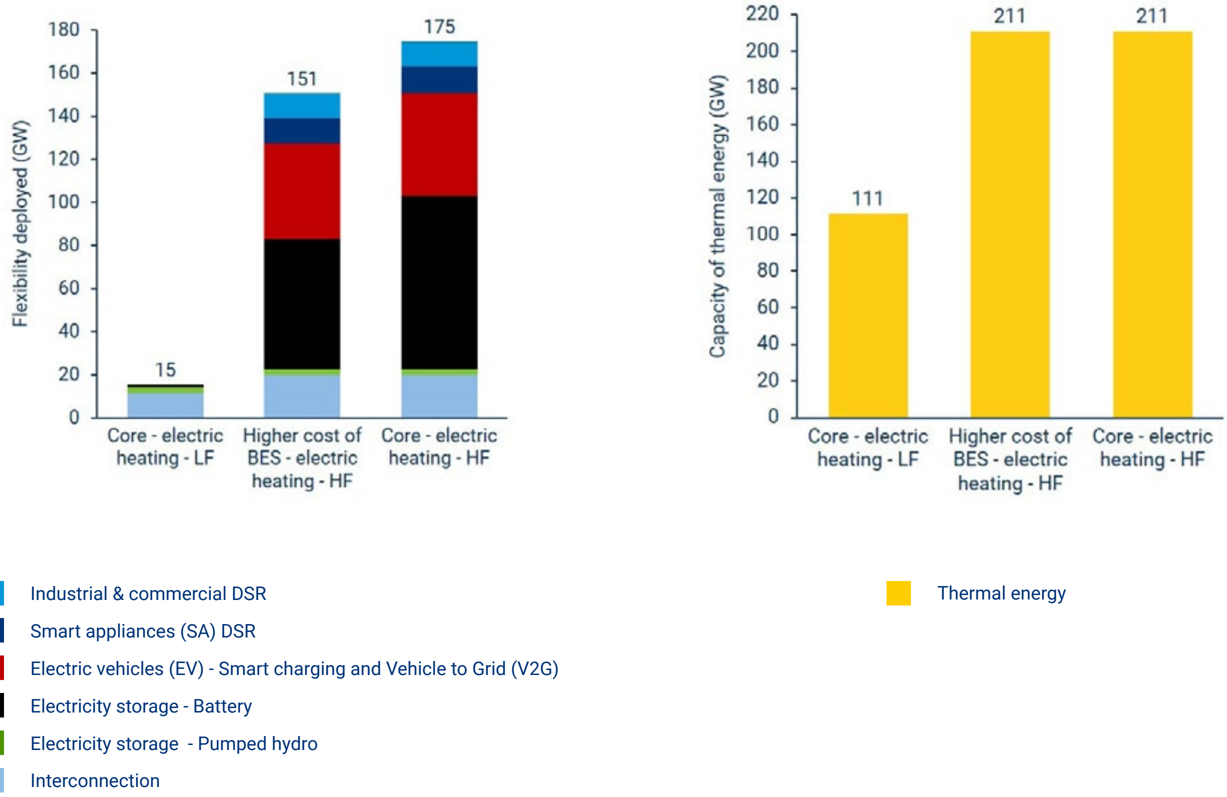


Figure 61. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage capacity (GWth) - difference between core pathway and higher cost of BES - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF)



3.6.3 How valuable is TES (hot water tank) deployment in an otherwise high flexibility scenario?

Key insight

A portfolio of flexibility technologies reduces the impact of limited TES.

Across all core scenarios, TES (hot water tanks), is deployed to the full extent permissible by the model in both the low and high flexibility scenarios. This sensitivity tested the impact of limiting TES to the maximum permissible in a low flexibility scenario, in an otherwise high flexibility scenario. This sensitivity was applied to both the hydrogen and electricity heating scenario.

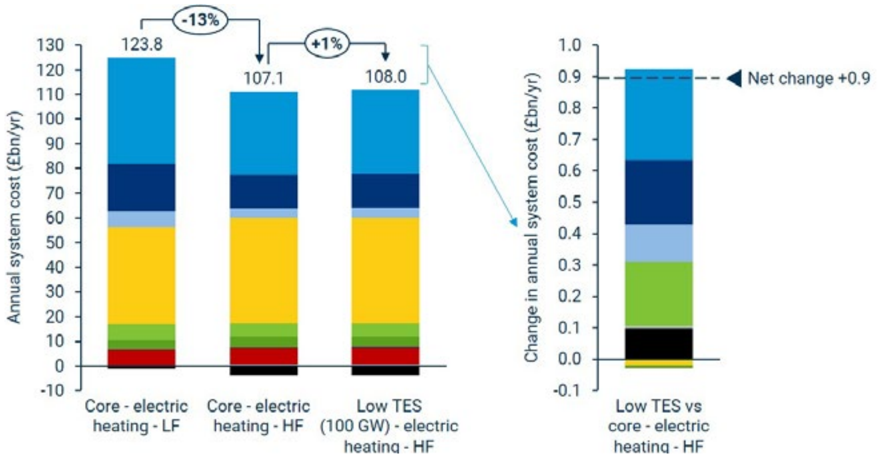
In both scenarios, TES can be deployed alongside district heating heat pumps or domestic air source heat pumps.[18]

In both the electric heating (Figure 62) and hydrogen heating (Figure 64) scenarios, limiting TES increases annual system cost by around 1%.

Electric heating scenario

In the electric heating scenario, the additional system cost is due to additional investment in 5GW of battery storage (which increases from 80 to 85GW), as well as a 5GW increase in electricity generation capacity, just over half of which is fossil fuelled generation and 0.7GW is hydrogen fuelled. The higher demand for hydrogen for use in the power sector also increases the cost of production from both electrolysers and reformers (Figure 62). Utilisation of fossil fuel generation is low across both high flexibility scenarios[19], which indicates that the electricity system requires slightly more capacity to meet demand during extreme periods without additional TES.

Figure 62. Left: Annual system cost (£bn/yr). Right: Increase in annual system cost between core electric heating pathway (HF) and electricheating pathway with low TES deployment (HF). LF = low flexibility, HF = high flexibility. C = Capital cost, O = Operational cost, R = Revenue

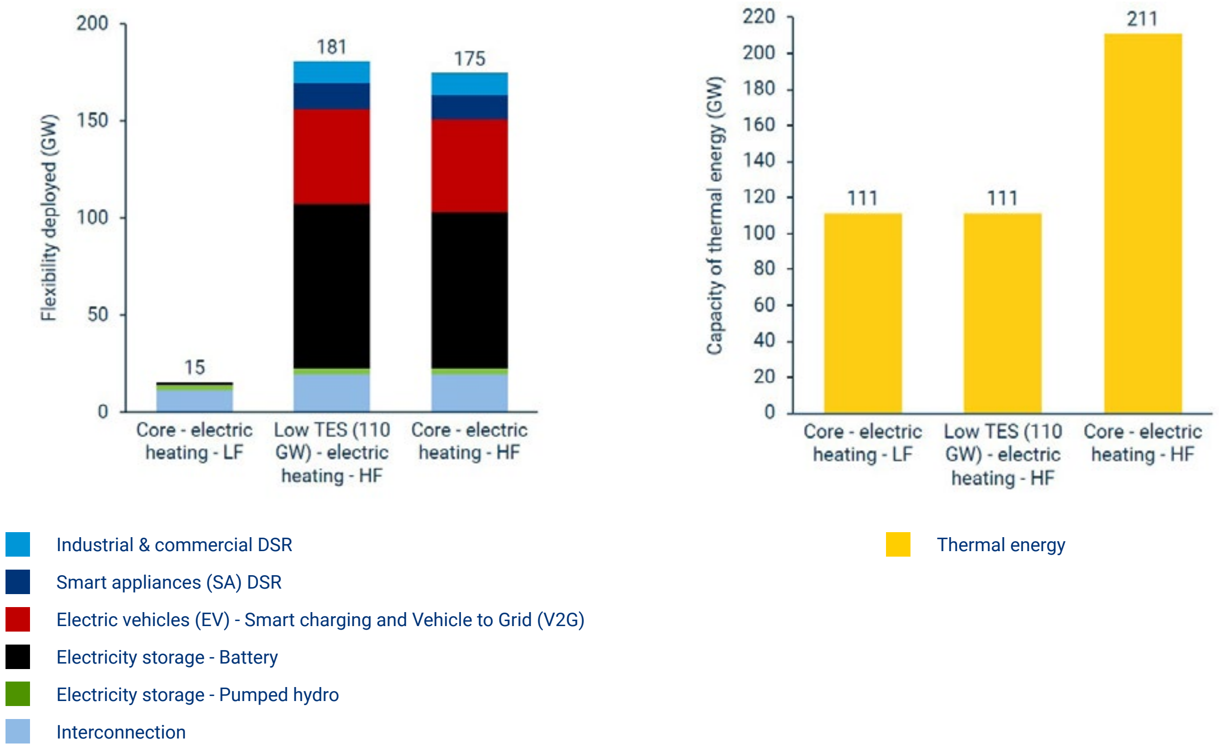


- C: Electricity generation
- C: Electricity network (transmission, distribution and interconnection)
- O: Electricity (variable O&M plus fuel costs)
- C: Electric heating, thermal and battery storage
- C: Hydrogen production and storage, gas networks, DACCS, CO_2 transport and storage
- O: Hydrogen production (including fuel costs), storage and use CO_2 transport and storage
- C: Hydrogen boilers
- C: Hybrid heating (heat pump and natural gas boiler combination)
- C: District heating (heat pump and heat network)
- C: Demand side response
- R: Net electricity export

18 In the hydrogen heating scenario, heat pumps are installed in off-gas grid domestic properties only.

19 2.4% for natural gas CCGT, and 0.2%-0.4% for natural gas OCGT in the high flexibility scenario, with and without additional TES.

Figure 63. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage (GWth) - difference between core pathway and low TES deployment - electric heating pathway - low flexibility (LF) and high flexibility (HF)



H_2 Hydrogen heating scenario

In the hydrogen heating scenario, the additional system cost is due to an extra 1GW investment in battery storage (which increases from 5 to 6GW), as well as a 3GW increase in electricity generation capacity, most of which is unabated natural gas (Figure 64). Similar to the electric heating scenario, this indicates that additional TES can reduce peak demand during extreme weather events (high demand, low renewables).

Figure 64. Left: Annual system cost (£bn/yr). Right: Increase in annual system cost between core hydrogen heating pathway (HF) and hydrogen heating pathway with low TES deployment (HF). LF = low flexibility, HF = high flexibility. C = Capital cost, O = Operational cost, R = Revenue

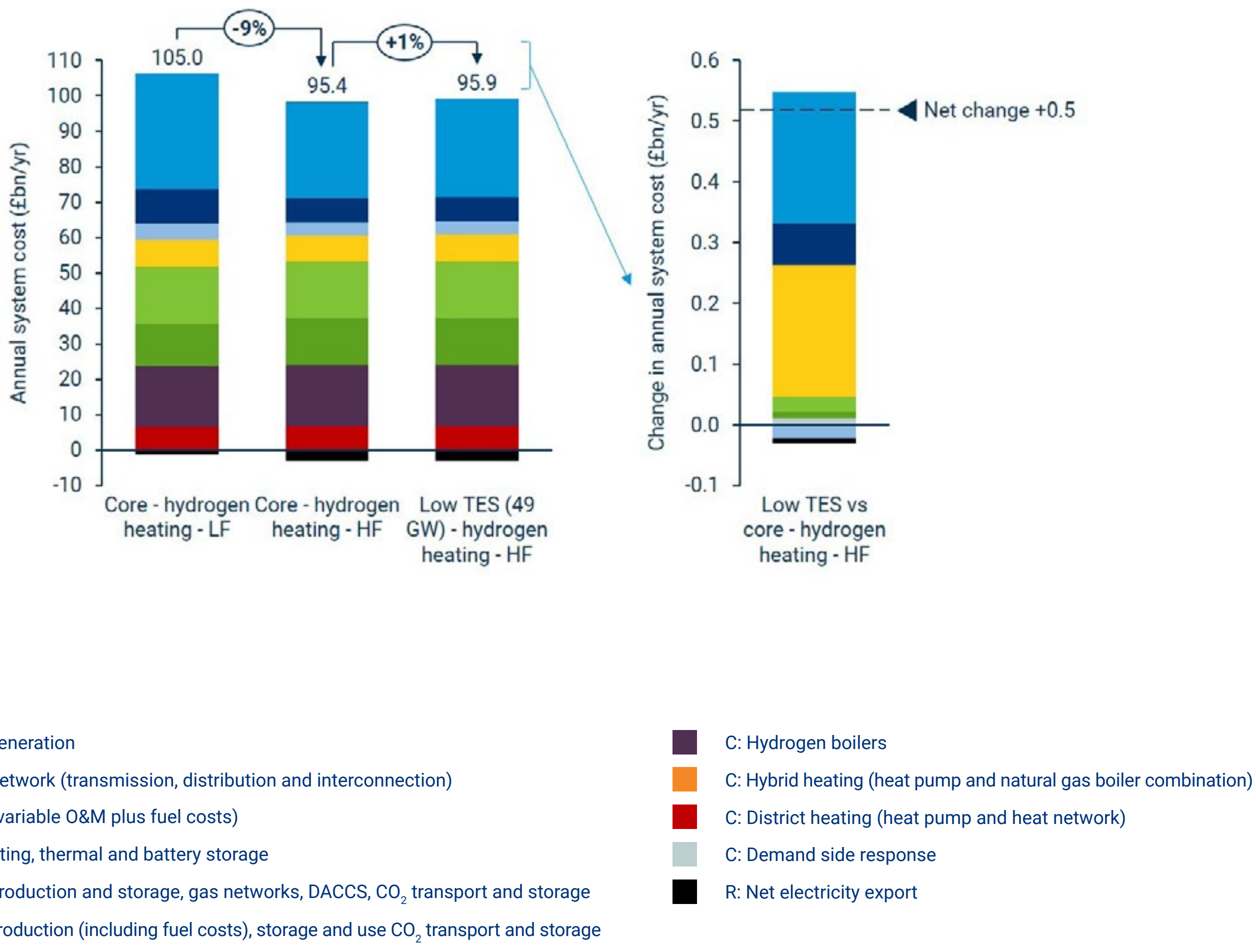
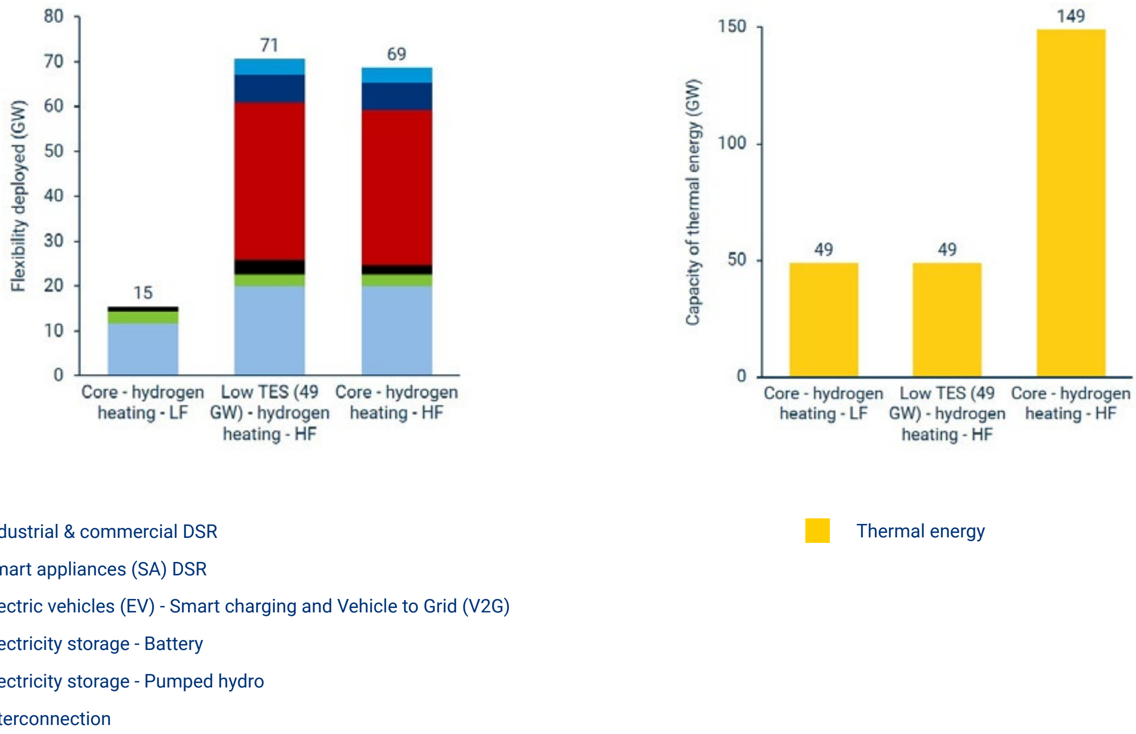


Figure 65. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage (GWth) - difference between core pathway and low TES deployment - hydrogen heating pathway - low flexibility (LF) and high flexibility (HF). Summary - impact of flexibility tech availability



3.6.4 Summary - impact of flexibility technology availability

The three sensitivities explored in this section each look at the impact of changing the availability or cost of different flexibility technologies.

Reducing the availability of TES or increasing the cost of battery storage had a small impact on total system cost (c.0.1-1% increase). In both sensitivities the energy system responded by investing in slightly more of other forms of flexibility, but in neither case fully replacing the GW capacity of the thermal or battery storage removed. In the TES sensitivity, both the hydrogen and electric heating scenario also had to invest in additional generation capacity, primarily to ensure system adequacy during periods of low demand.

While the impact of a significant reduction in both thermal and battery storage capacity had a disproportionately small impact on total system cost, we cannot conclude from this that all flexibility capacity of a given technology type has the same per unit value. The large difference in system cost between the core low and high flexibility scenarios shows there is value in a flexible system. Additional analysis into the value of each incremental unit of flexibility would provide useful insights into the levels of flexibility deployment required to obtain the majority of the system cost benefit.

3.7. Impact of hydrogen production route

In the core pathways, hydrogen can be produced via three different means:

- **Electrolysis**
- **Autothermal reforming (ATR) of natural gas with CCS**
- **Gasification and upgrade of biomass with CCS**

In a series of sensitivity scenarios, the project explored the impact on system cost of removing different means of hydrogen production, and the extent to which a portfolio of flexibility technologies could mitigate the impact of the absence of a particular means of hydrogen generation.

This section explores three main questions related to hydrogen production:

1. **What is the impact of meeting hydrogen demand through electrolysis only?**
2. **What is the impact of producing hydrogen from gas and biomass only, and what is the value of sector coupling?**
3. **What is the impact of changing gas prices or PEM electrolyser costs on the optimal mix of hydrogen production techniques?**

3.7.1 What is the impact of meeting hydrogen demand through electrolysis only?

Key insight

Using only electrolysis to produce hydrogen significantly increases system cost and requires electricity generation capacity in excess of what it is likely to be possible to deploy by 2050.

In the first set of sensitivities (Table 2), the study explored the impact of removing autothermal reforming and gasification of biomass from the hydrogen production mix. This would effectively require all hydrogen needs to be met via electrolysis. In both sensitivities the carbon target was relaxed (from -50MtCO_2/yr to 0MtCO_2/yr) as it was assumed the requirement to use electrolysis only was driven by little to no deployment of CCS infrastructure.

To achieve an electrolysis-only scenario, two scenarios were considered: one with higher renewables deployment and one with higher nuclear deployment. In both cases, the deployment of these technologies far exceeded the deployment caps set in the core scenario, highlighting the difficulties of delivering a substantial hydrogen sector via electrolysis only.

Table 2. Overview of sensitivity scenarios on the impact of meeting hydrogen demand through electrolysis only

Item	Core scenarios	Electrolysis only - high renewables	Electrolysis only - high nuclear
Heating pathway(s)	Hydrogen and electric	Hydrogen	Electric and hydrogen
Low or high flexibility	Low and high	Low and high	Low and high
Energy system carbon target	-50MtCO_2/yr	0 MtCO_2/yr	0 MtCO_2/yr
Large-scale nuclear cap	9.8GW	9.8GW	Unlimited
CCS availability	Yes - all technologies	Only for power generation and DACCS	No
Renewable deployment limits	-	Renewable deployment cap removed	Same as core scenario

H_2 Hydrogen heating pathway

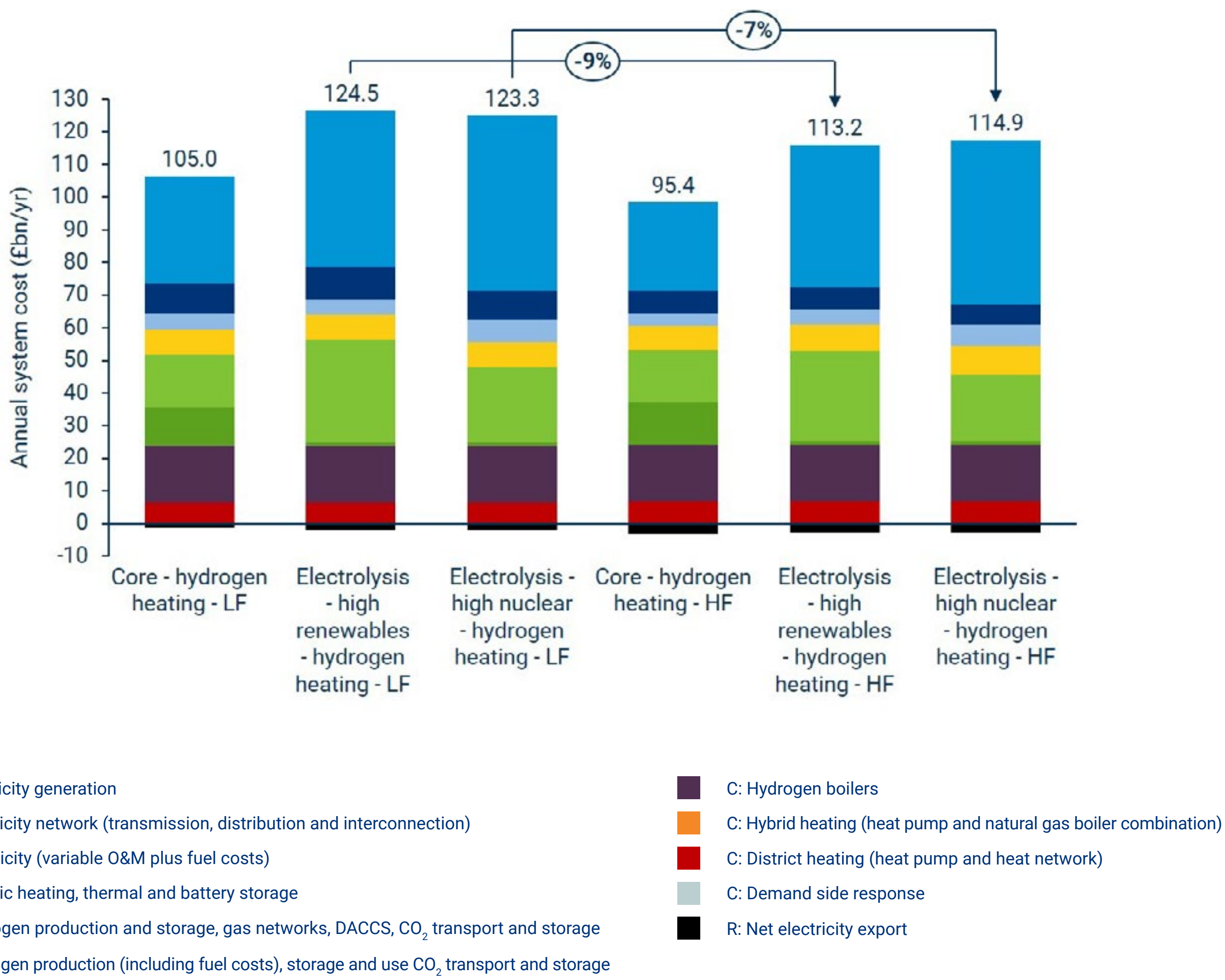
Under a hydrogen heating pathway, an electrolysis-only approach is more expensive, but flexibility can mitigate some of the cost increase

Within the hydrogen heating pathway, an electrolysis-only scenario sees system costs increase by up to £19.5bn/yr under both the low and high flexibility scenarios compared to the core pathway. Investing in flexibility is still valuable, reducing costs by 7-9%, compared to their low flexibility equivalents (Figure 66).

In both the low and high flexibility scenarios, the move from the core scenario to an electrolysis-only scenario increases the capital investment required in electricity generation, hydrogen storage and in electrolysers. These increases are only partially offset by the lower operational costs of hydrogen production due to no natural gas or biomass being used for hydrogen production and no associated CCS infrastructure required.

Comparing the low flexibility scenarios to their high flexibility counterparts, the value of flexibility across all three hydrogen production scenarios is dominated by a reduction in capital spend on electricity generation and a reduction in the need for network investment.

Figure 66. Annual system cost (£bn/yr) - hydrogen heating pathway - core scenario, electrolysis only with high renewables, and electrolysis only with high nuclear - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue



The impact of different hydrogen production routes on the electricity generation mix is shown in Figure 67 and Figure 68. While the move from the core scenario to an electrolysis-only route increases the investment required in generation, the generation mix is very different, depending on whether hydrogen production is delivered via additional renewables or nuclear generation.

In the high renewables scenarios, deployment of offshore wind and solar PV increase significantly in order to meet electricity demand from electrolysers (Figure 67). There is an 84% increase in offshore wind capacity to 222GW - well above the 120GW deployment limit set in the core scenarios and more than is plausible to deploy in British waters by 2050. In terms of back-up generation, almost all unabated gas generation is eliminated, replaced by hydrogen CCGTs, OCGTs and post-combustion gas CCS. Total generation capacity increases by 39% from 306 to 424GW.

Increasing the flexibility of the energy system reduces this total by 14% (59GW) to 365GW, of which 50GW is a reduction in fuelled generation (natural gas and hydrogen), suggesting that flexibility reduces the need for back-up generation during colder periods with low wind output, as seen in the core pathways. The portfolio of flexibility is similar to the core hydrogen heating scenario, but with an additional 5GW of electricity storage deployed. However, it should be noted that most other forms of flexibility were already used to their fullest extent in the core hydrogen heating scenario.

In the high nuclear scenario, deployment of large nuclear plants far exceeds our core scenario maximum deployment limit of 9.8GW, with 73GW deployed under a low flexibility scenario, and 67GW under a high flexibility scenario (Figure 68). As with offshore wind above, this capacity far exceeds expectations of what could be deployed in Great Britain by 2050. This underlines the need to consider decisions on heating decarbonisation within the context of wider energy system developments. Meeting a significant portion of heat demand through hydrogen heating is very unlikely to be possible or cost-effective via electrolysis alone; other means of hydrogen production using CCS are required.

Unusually, the addition of greater system flexibility leads to a 14% increase in total generation capacity in the high nuclear scenario, driven by a 71GW increase in solar PV and 20GW increase in electricity battery storage. This is only partially offset by a 46GW reduction in hydrogen fuelled OCGT and CCGT (leaving only 1GW installed) and 6GW reduction in large-scale nuclear (Figure 68). This suggests that the combination of nuclear, storage and DSR provides sufficient system adequacy to cope with periods of network stress. The portfolio of flexibility delivered is similar to the core pathway.

Figure 67. Electricity generation capacity and electricity storage capacity (GW) - hydrogen heating pathway - core scenario and electrolysis only with high renewables scenario - low flexibility (LF) and high flexibility (HF)

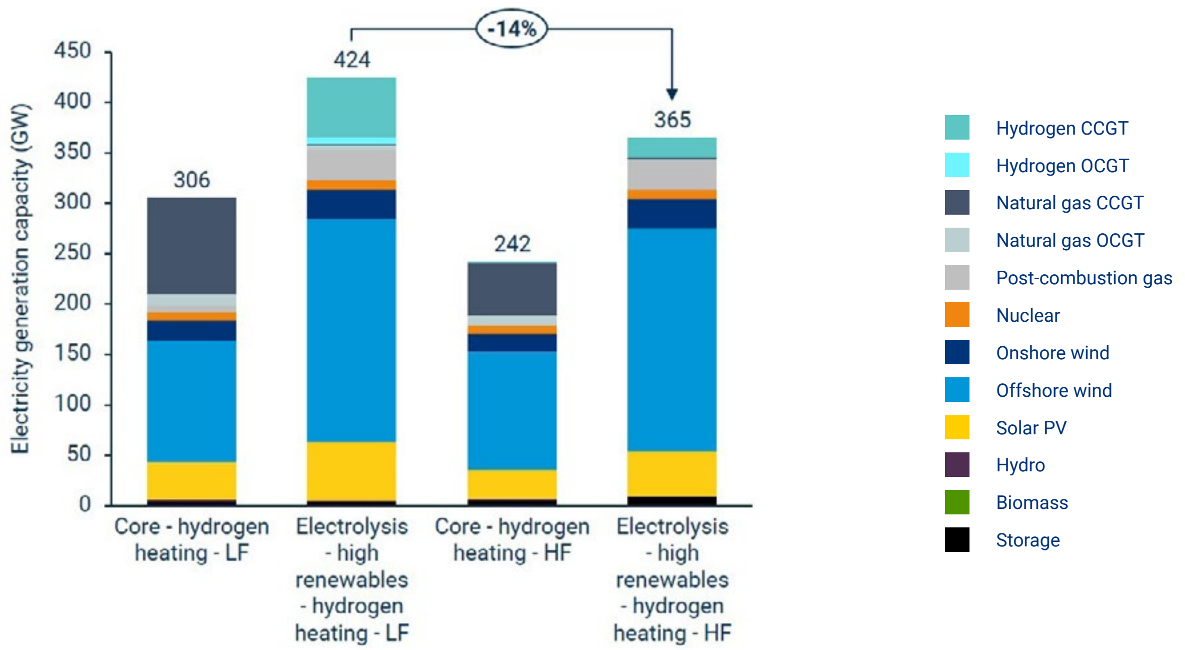
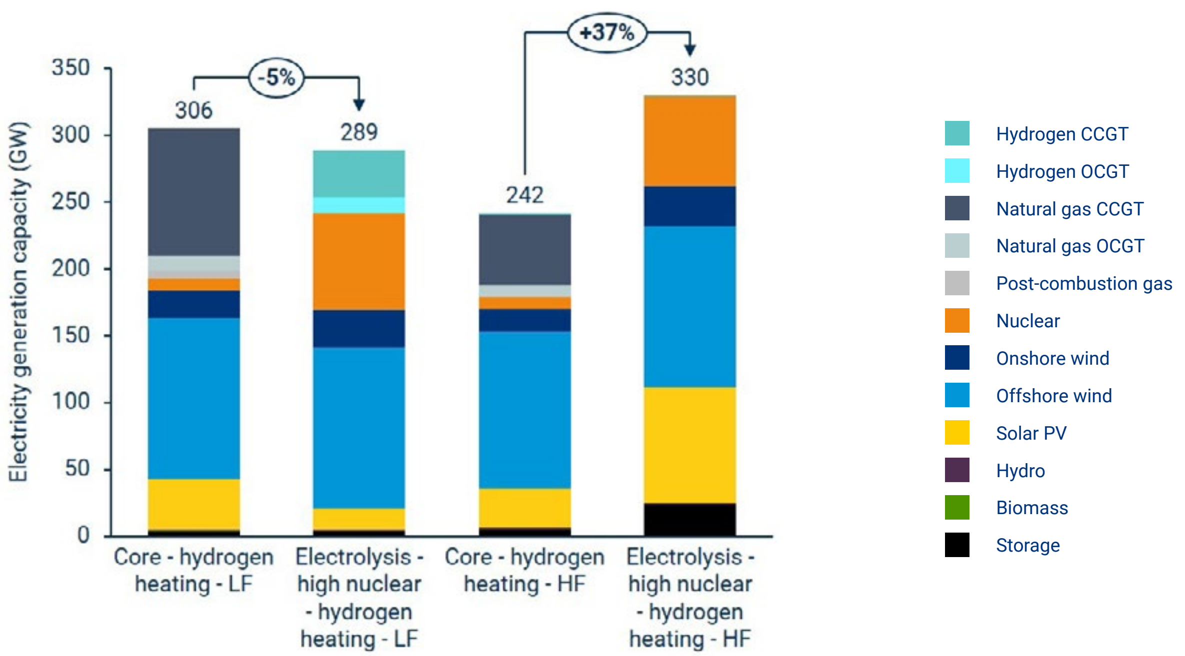


Figure 68. Electricity generation capacity and electricity storage capacity (GW) - hydrogen heating pathway - core scenario and electrolysis only with high nuclear scenario - low flexibility (LF) and high flexibility (HF)

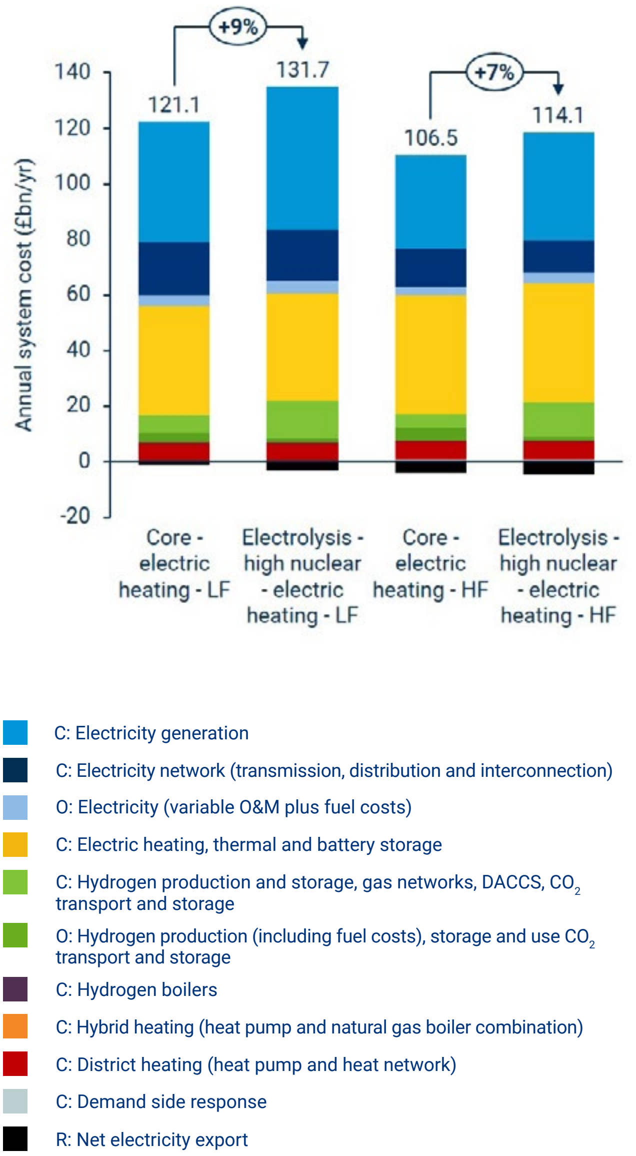


Under an electric heating pathway, an electrolysis-only approach is more expensive, but flexibility reduces system impact

Under the electric heating pathway, an electrolysis-only scenario using additional nuclear deployment sees system costs increase by 7-9% (£7.6-10.6bn/yr), compared to the high or low flexibility core pathway. This total system cost increase is lower than seen in the hydrogen heating scenario due to the lower demand for hydrogen[20]. As in the hydrogen heating scenario with high nuclear, the cost increase from the core scenario to the green hydrogen scenario is the result of additional investment in low carbon generation and hydrogen storage, partially offset by a reduction in fuelled generation capacity (Figure 69).

Additional flexibility reduces the cost of delivering green hydrogen relative to the low flexibility alternative by 14% (£17.6bn/yr) (Figure 69). The portfolio of flexibility deployed in both high flexibility scenarios is similar - the main difference being that less electrical energy storage is needed when additional nuclear is deployed, with 69GW deployed in the high nuclear, high flexibility scenarios, compared to 83GW in the core scenario.

Figure 69. Annual system cost (£bn/yr) - electric heating pathway - core scenario and electrolysis only with high nuclear scenario - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue

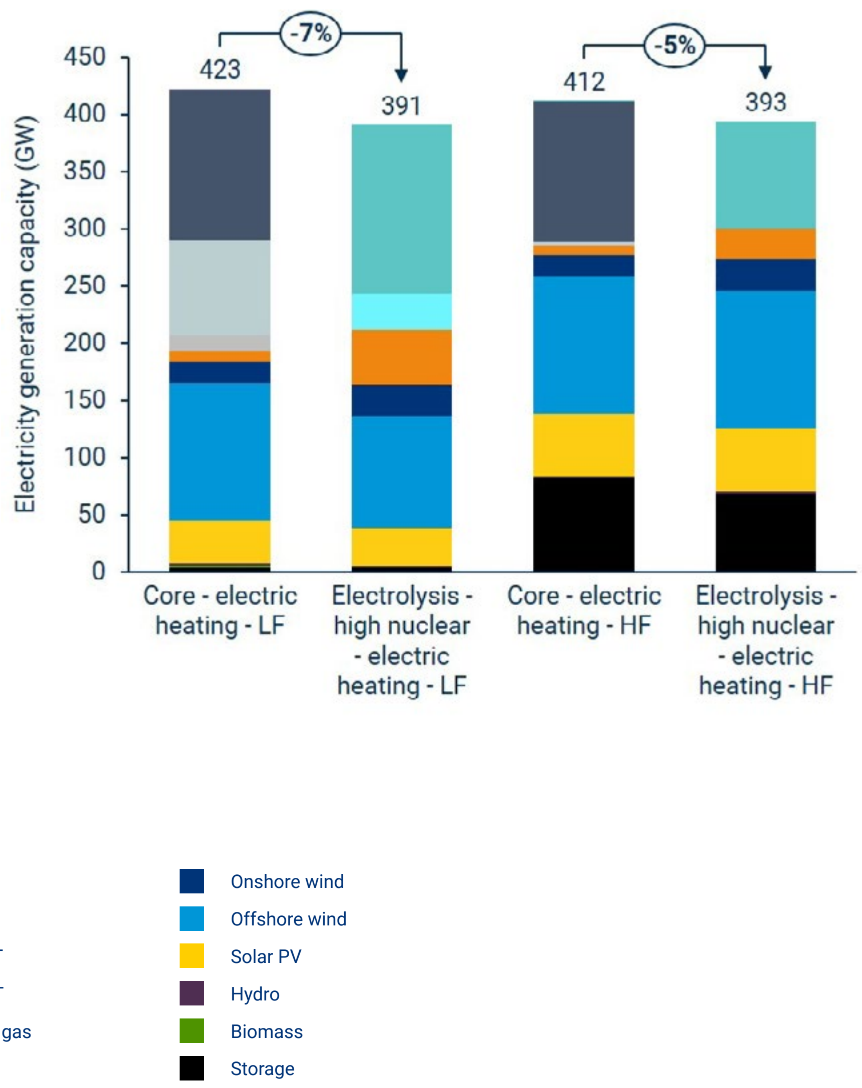


20 Both the electric and hydrogen heating pathways must meet 123TWh of hydrogen demand for transport and industrial use. The hydrogen scenario must also produce 445TWh of additional hydrogen to meet heating demand. Demand for hydrogen in the power sector varies across scenarios but is always small (c.5TWh), compared to heat and transport/industry.

Relaxing the nuclear deployment cap and removing CCS technologies in the electrolysis-only scenario results in a switch from unabated natural gas capacity to hydrogen fuelled OCGTs and CCGTs, and an increase in nuclear deployment, from 9GW in the core scenario to 48GW (low flexibility) and 26GW (high flexibility). For both hydrogen fuelled generation and nuclear power plants, additional system flexibility reduces the capacity required to ensure system adequacy (Figure 70).

This increase in nuclear generation results in an overall reduction in generation capacity required to meet demand in the electrolysis-only scenario as nuclear plants run at a very high annual load factor. Additional flexibility reduces the amount of nuclear capacity required to deliver electrolysis-only hydrogen and enables a greater proportion of demand to be met via renewable generation.

Figure 70. Electricity generation capacity and electricity storage capacity (GW) - electric heating pathway - core scenario and electrolysis only with high nuclear scenario - low flexibility (LF) and high flexibility (HF)



3.7.2 What is the impact of producing hydrogen from gas and biomass only, and what is the value of sector coupling?

Key insight

In the absence of a wider flexibility portfolio, sector coupling of hydrogen production and electricity networks can deliver significant system savings.

Where a wider portfolio of flexibility is deployed, this flexibility minimises the impact of deploying electrolysers on the electricity generation mix.

Flexibility between different parts of the energy system is expected to become increasingly intertwined as some hydrogen is produced via electrolysis, and thermal storage decouples demand for thermal comfort from electricity demand for heat pumps.

Following on from the previous section, which looked at delivering hydrogen through electrolysis alone, this set of sensitivities examines the impact of removing electrolysis as a means of hydrogen production, along with the removal of hydrogen turbines (OCGT and CCGT). This, to an extent, decouples the gas and electricity networks to assess the value of sector coupling.

Table 3. Overview of sensitivity scenarios on the impact of producing hydrogen from natural gas and biomass only

Item	Low flexibility - decoupled	Low flexibility - core	Low flexibility - coupled	High flexibility - decoupled	High flexibility - coupled (core scenario)
Heating pathway(s)	Hydrogen and electric				
Low or high Flexibility	Low	Low	Low	High	High
Energy system carbon target	-50MtCO$_2$/yr				
H2 OCGT and CCGT deployed	No	No	Yes	No	Yes
Electrolysers deployed	No	Yes	Yes	No	Yes

In the absence of a wider flexibility portfolio, sector coupling can deliver significant system savings

H_2 Hydrogen heating scenario

In a low flexibility hydrogen heating scenario, removing electrolysers increases costs by £5.1bn/yr (+5%). Figure 71 also shows that enabling hydrogen OCGT and CCGT to be deployed in an otherwise core low flexibility scenario reduces the cost of the low flexibility scenario by £1bn/yr (-1%). This indicates the value of flexibility provided by electrolysis and hydrogen turbine use in the absence of a wider portfolio of flexibility technologies under the hydrogen heating scenario.

The use of electrolysers and hydrogen OCGT and CCGTs in the integrated sensitivity scenario reduces the system cost by reducing the amount of natural gas used in both power and hydrogen production and the capacity of DACCS required to offset emissions from these activities.

In the high flexibility scenario, there is very little reduction (£0.5bn/yr, 0.6%) in the system cost when comparing a siloed and integrated system (Figure 72). Both high flexibility scenarios deploy similar flexibility portfolios. This indicates that an otherwise flexible system can more easily mitigate the impact of removing electrolysis production on system cost.

Investing in flexibility also reduces the difference between the electricity generation mix in siloed and integrated scenarios. Figure 73 looks across all five scenarios examined above. To compare the first three columns (low flexibility) with the remaining two columns (high flexibility), not only has a more flexible system reduced total generation capacity requirements, but the two high flexibility scenarios have very similar generation mixes - the only notable difference being a 13GW difference in offshore wind deployment.

Figure 71. Annual system cost (£bn/yr) - hydrogen heating pathway - siloed Network (no hydrogen turbines or electrolysers), core scenario (electrolysers only) and Integrated Networks (hydrogen turbines and electrolysers) - low flexibility (LF). C = Capital cost, O = Operational cost, R = Revenue

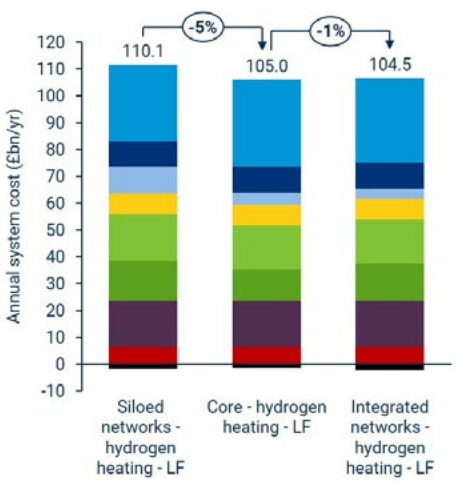
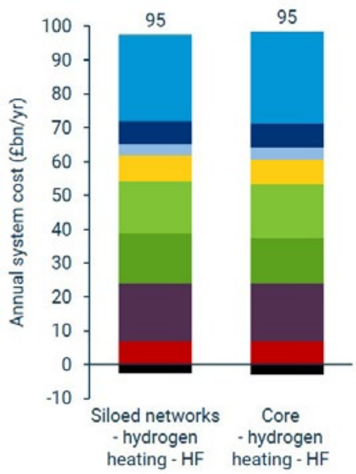
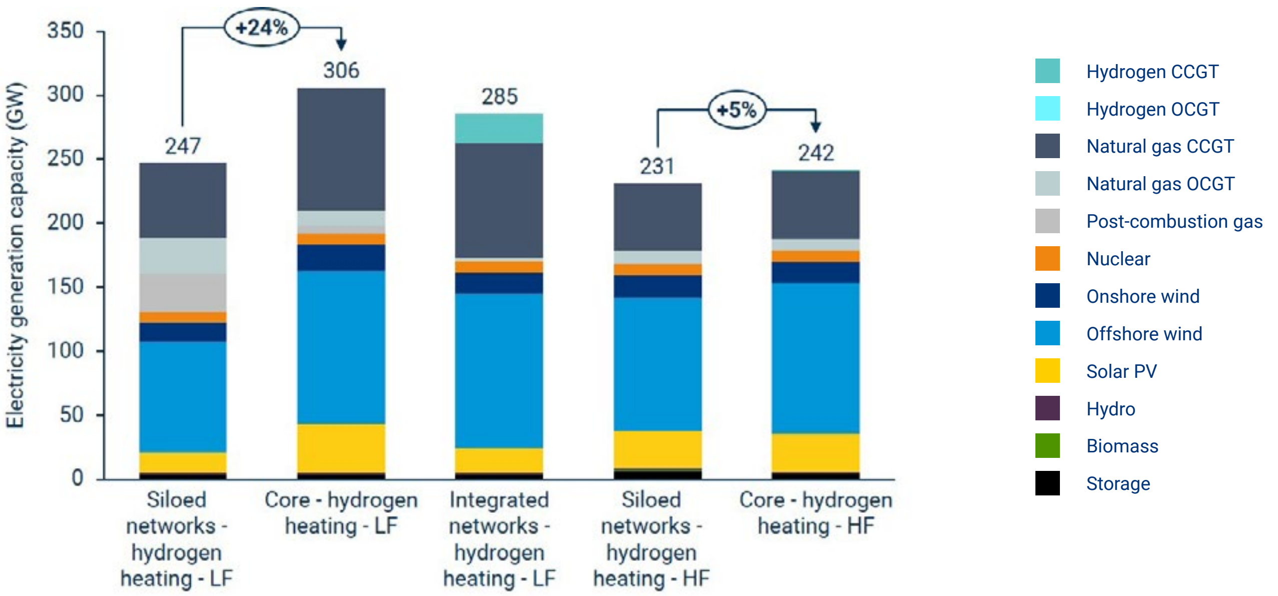


Figure 72. Annual system cost (£bn/yr) - hydrogen heating pathway - siloed Network (no hydrogen turbines or electrolysers), core scenario (hydrogen turbines and electrolysers) - high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue



- C: Electricity generation
- C: Electricity network (transmission, distribution and interconnection)
- O: Electricity (variable O&M plus fuel costs)
- C: Electric heating, thermal and battery storage
- C: Hydrogen production and storage, gas networks, DACCS, CO_2 transport and storage
- O: Hydrogen production (including fuel costs), storage and use CO_2 transport and storage
- C: Hydrogen boilers
- C: Hybrid heating (heat pump and natural gas boiler combination)
- C: District heating (heat pump and heat network)
- C: Demand side response
- R: Net electricity export

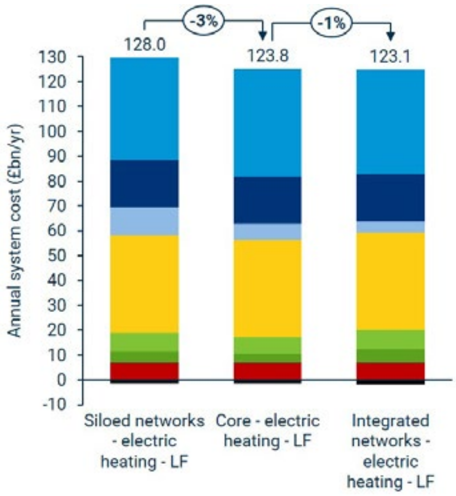
Figure 73. Electricity generation capacity and electricity storage capacity (GW) - hydrogen heating pathway - siloed Network (no hydrogen turbines or electrolysers), core scenario (electrolysers only in LF, electrolysers and hydrogen turbines in HF), Integrated Networks (electrolysers and hydrogen turbines) - low flexibility (LF) and high flexibility (HF)



Electric heating scenario

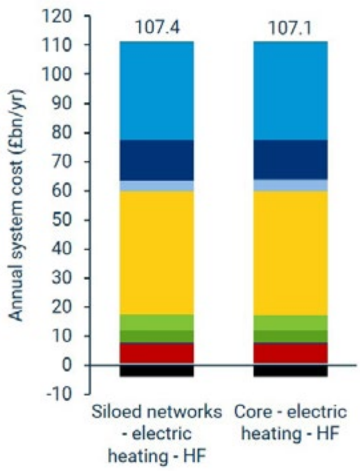
Similar results are seen in the electric heating pathway. Under a low flexibility scenario, moving from a siloed scenario to one with electrolysis (core scenario) reduces the system cost by £4.2bn/yr (3.3%), with a further £0.8bn/yr reduction (0.6%) when hydrogen CCGT and OCGT are deployed (Figure 74). In contrast, there is only £0.3bn/yr (0.3%) difference between the two high flexibility scenarios (Figure 75).

Figure 74. Annual system cost (£bn/yr) - electric heating pathway - siloed Network (no hydrogen turbines or electrolysers), core scenario (electrolysers only) and Integrated Networks (hydrogen turbines and electrolysers) - low flexibility (LF). C = Capital cost, O = Operational cost, R = Revenue



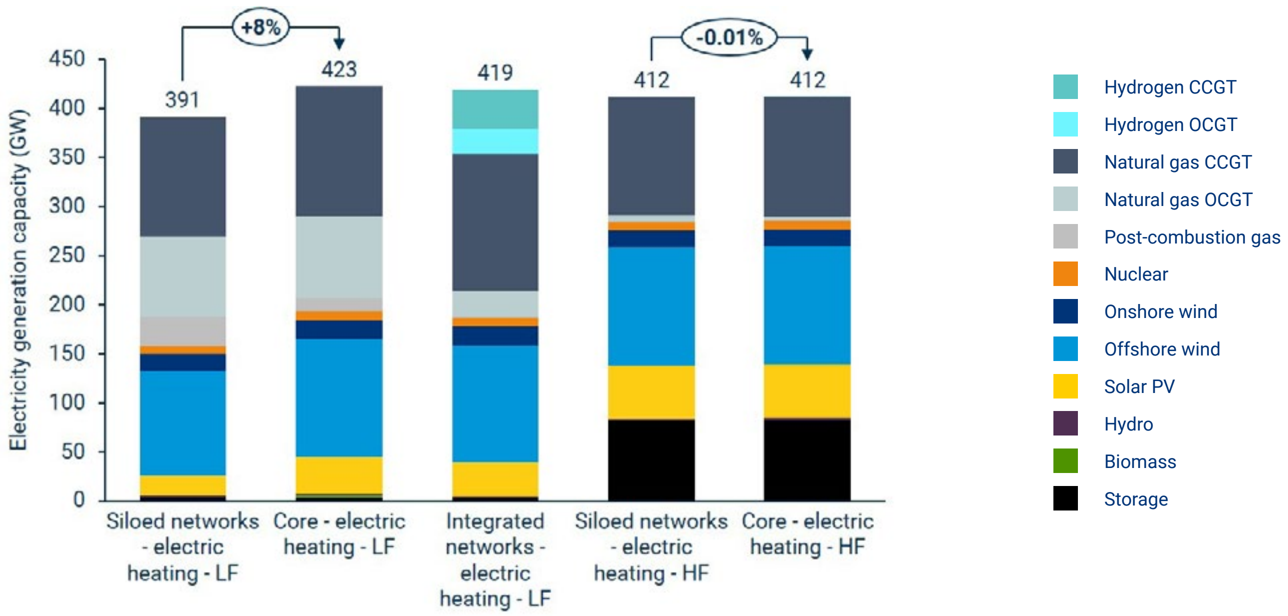
- C: Electricity generation
- C: Electricity network (transmission, distribution and interconnection)
- O: Electricity (variable O&M plus fuel costs)
- C: Electric heating, thermal and battery storage
- C: Hydrogen production and storage, gas networks, DACCS, CO_2 transport and storage
- O: Hydrogen production (including fuel costs), storage and use CO_2 transport and storage
- C: Hydrogen boilers
- C: Hybrid heating (heat pump and natural gas boiler combination)
- C: District heating (heat pump and heat network)
- C: Demand side response
- R: Net electricity export

Figure 75. Annual system cost (£bn/yr) - electric heating pathway - siloed Network (no hydrogen turbines or electrolysers), core scenario (hydrogen turbines and electrolysers) - high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue



Similarly, the generation mix for the high flexibility scenarios does not materially change in response to the removal of electrolysis (two right-hand columns, Figure 76). This is in contrast to the material change in generation mix across the three low flexibility scenarios (left-hand columns).

Figure 76. Electricity generation capacity and electricity storage capacity (GW) - electric heating pathway - siloed Network (no hydrogen turbines or electrolysers), core scenario (electrolysers only in LF, electrolysers and hydrogen turbines in HF), Integrated Networks (electrolysers and hydrogen turbines) - low flexibility (LF) and high flexibility (HF)



3.7.3 What is the impact of changing gas prices or PEM electrolyser costs on the optimal mix of hydrogen production techniques?

Key insight

Under a low flexibility scenario, gas price changes can have a material impact on optimal infrastructure investment. A portfolio approach to hydrogen production could help to mitigate significant changes in CapEx or OpEx across different production routes.

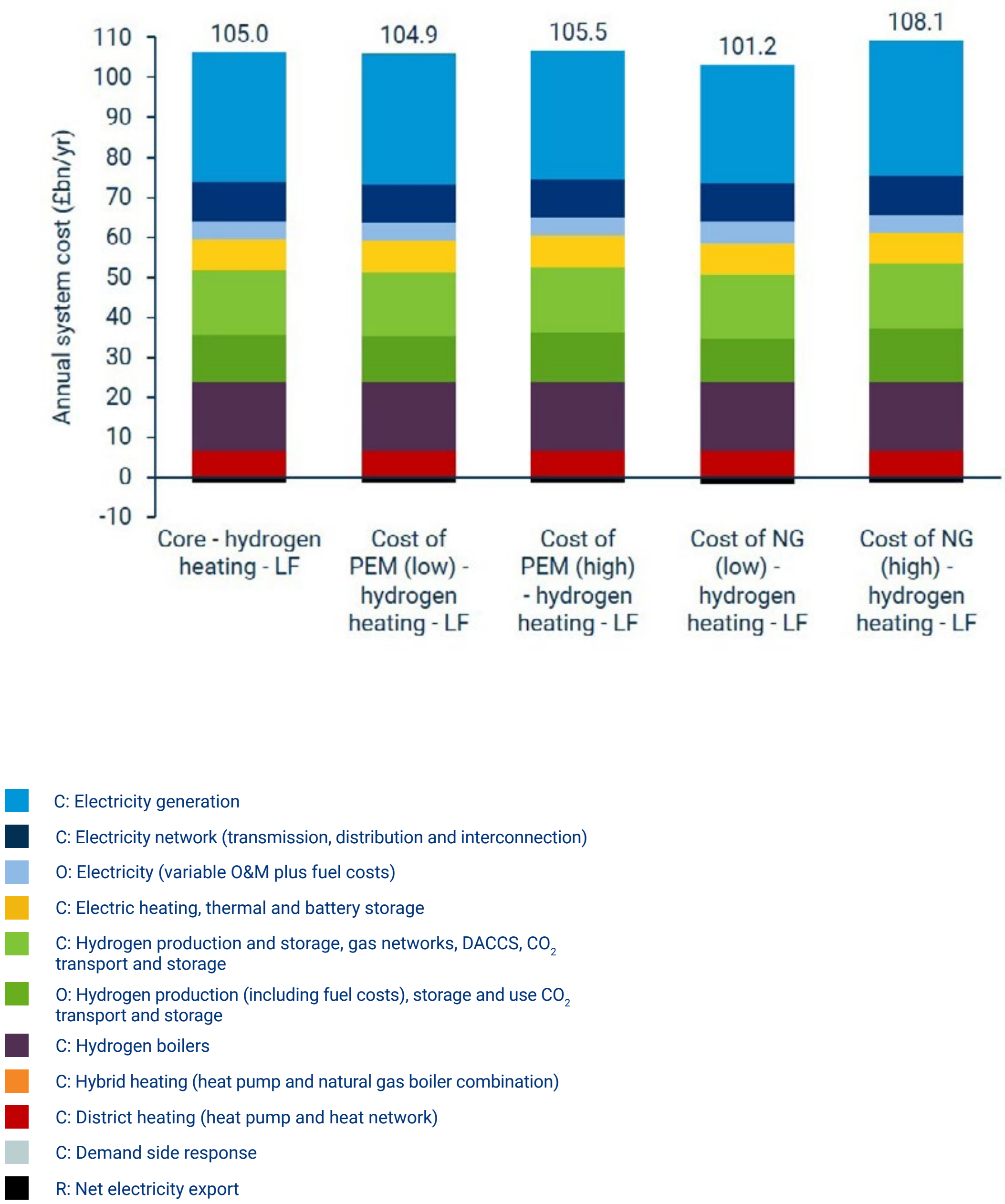
We tested the impact of polymer electrolyte membrane (PEM) electrolyser capital costs and natural gas costs on total system cost and the deployment of hydrogen production technologies under the low flexibility, hydrogen heating pathway. Table 4 shows the assumptions made in each scenario.

Table 4. Prices used in the sensitivity scenarios on the impact of electrolyser costs and natural gas prices on hydrogen production

Value	Unit (2050 prices)	Low	Medium (core)	High
Gas price	p/kWh	1.47	2.18	3.00
PEM CapEx	£/kW	265	340	620

Figure 77 shows that the impact on system cost of changing PEM electrolyser CapEx costs to the extent shown in Table 4 is minimal (up to 0.5% or £0.6bn/yr change). However, under a low flexibility scenario, changes in gas prices (-33% to +37% from the central price of 2.18p/kWh) resulted in more material changes, from -£3.8bn/yr (-3.6%) to +£3.1bn/yr (+2.9%).

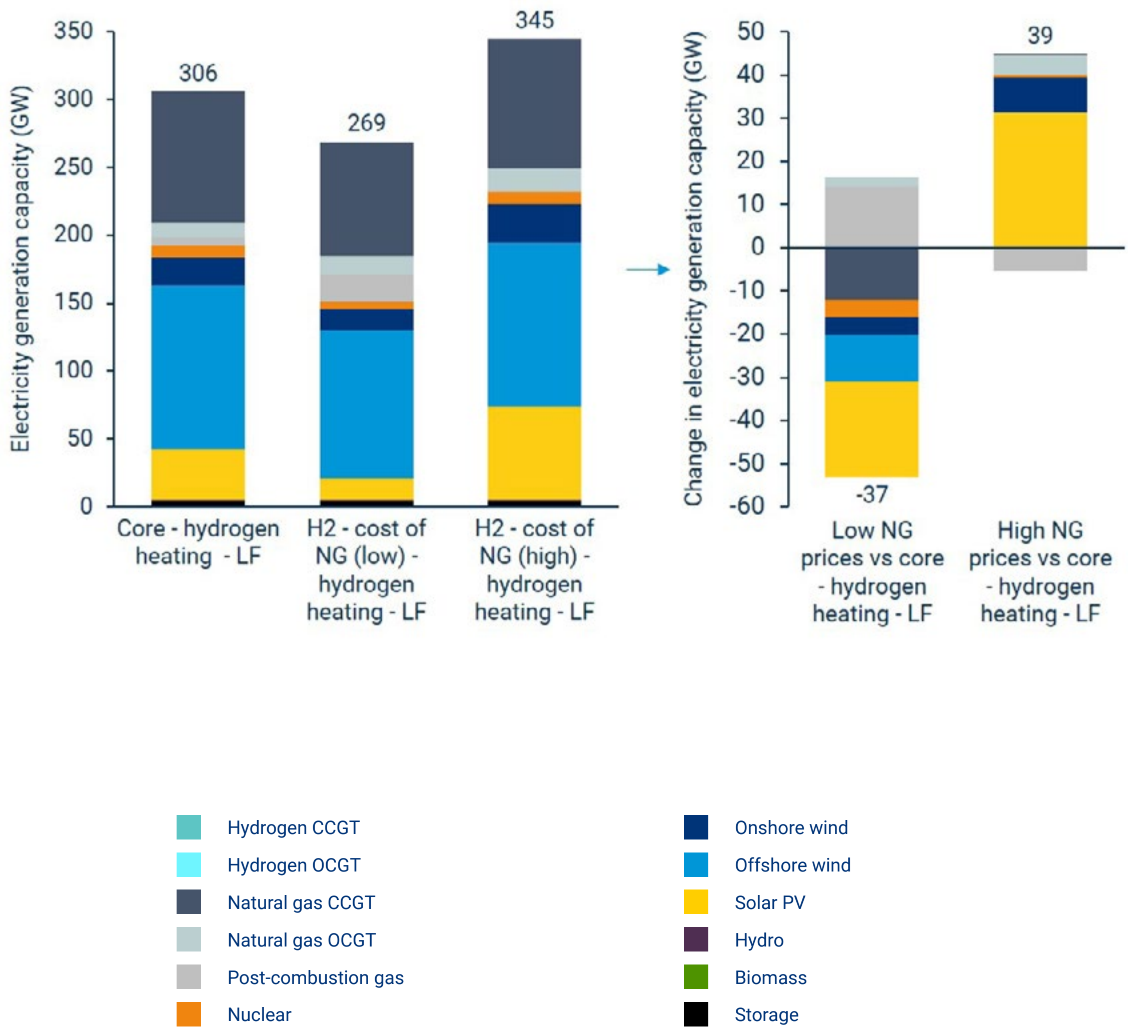
Figure 77. Annual system cost (£bn/yr) - hydrogen heating pathway -core scenario, high and Low cost of PEM electrolysers and high and Low Natural Gas (NG) prices - low flexibility (LF). C = Capital cost, O = Operational cost, R = Revenue



Changing the gas price also has a material impact on how electricity and hydrogen demand are met. Under a low gas price, the proportion of electricity generated from gas increases from 5% to 12% (Figure 78). This results in a shift away from unabated gas generation (which typically has very low factors - below 3% across all scenarios considered in this section - and is only used to meet demand in extreme conditions) towards post-combustion gas CCS, which has an annual load factor of 26% in the core scenario but 39% with low gas prices.

Linked to the change in gas combustion capacity, a change in gas price significantly changes the optimal deployment of nuclear, on and offshore wind, and solar PV, with reductions across all four technologies under a low gas price scenario, and significant increases in solar PV and onshore wind when gas prices are high (large-scale nuclear deployment is capped at 9GW, as is offshore wind at 120GW).

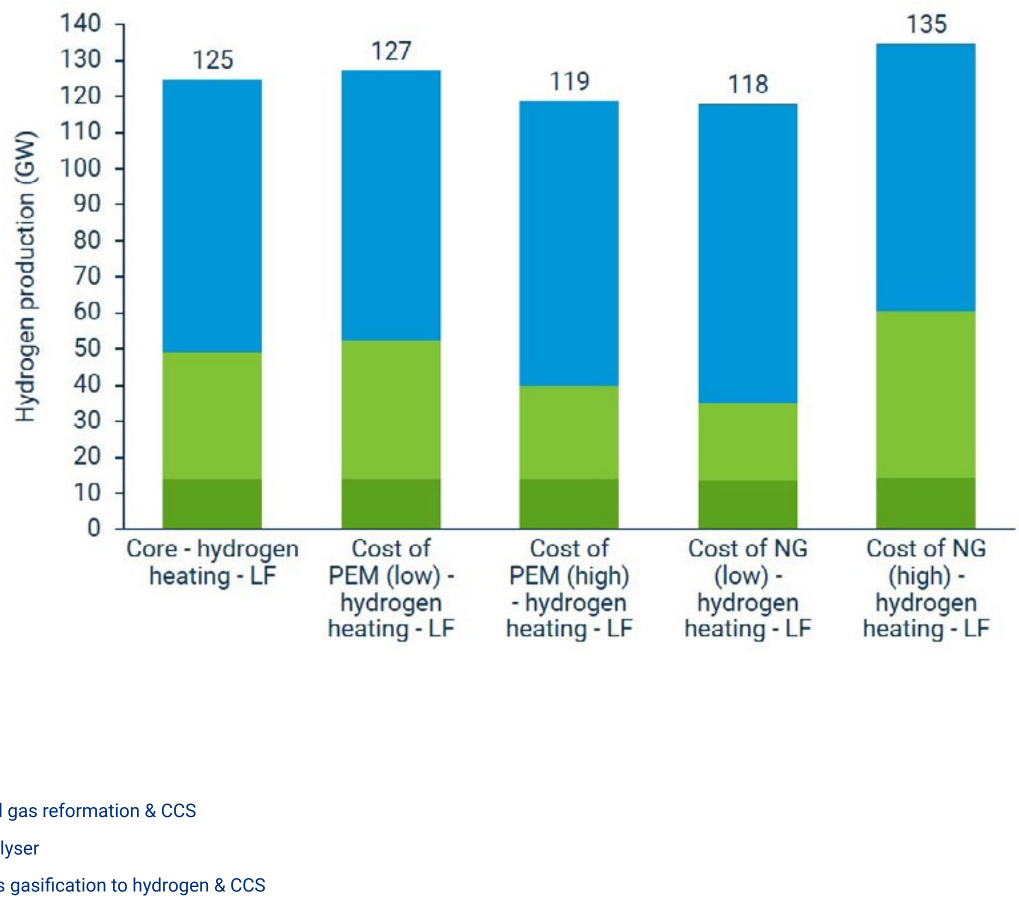
Figure 78. Left: Electricity generation capacity and electricity storage capacity (GW). Right: Change in electricity generation and storage capacity (GW) - hydrogen heating pathway - core scenario and high and Low Natural Gas (NG) prices - low flexibility (LF)



Similar changes are seen for hydrogen production capacity. Looking across both sensitivities (capital cost of electrolysers and natural gas costs), a combination of hydrogen production methods is most cost-effective at a system level, but the ratio of electrolyser capacity to natural gas reformation with CCS capacity varies depending on the relative cost, either of the technologies or gas (FIgure 79).

This project has only explored gas price sensitivity through this one scenario, but it indicates a potential risk of system cost increases if investment decisions are made based on assumptions of a lower gas price than that which materialises. Equally, as shown earlier in this chapter, a drive for hydrogen from electrolysis only could result in much higher electricity system costs in order to meet demand. Further analysis on the impact of gas (and other fuel) prices under different heating pathways, as well as testing whether greater flexibility can reduce the impact of gas price changes on the energy system mix under various heating pathways, would be needed to draw firmer conclusions. However, this sensitivity suggests that maintaining a portfolio of hydrogen production technologies could mitigate future risks.

Figure 79. Hydrogen production capacity (GW) - hydrogen heating pathway - core scenario, high and Low cost of PEM electrolysers and high and Low Natural Gas (NG) prices - low flexibility (LF)



3.7.4 Summary - impact of hydrogen production technology availability

Overall, the sensitivities in this section have demonstrated that developing a range of hydrogen production techniques delivers lower system cost and can mitigate against future changes in technology or gas prices. In particular, meeting demand through electrolysis alone significantly increases system cost.

These sensitivities have assumed that the heating pathway is unaltered by deployment of different types of hydrogen production. In reality, the demand for hydrogen will be influenced by availability and cost of supply. This highlights how intertwined the development of hydrogen demand is with other aspects of the energy system, including CCS infrastructure rollout, gas network conversion and electricity generation capacity.

Relying heavily on electrolysis in a hydrogen heating scenario requires more renewables or nuclear than most forecasts estimate can be delivered by 2050. This further emphasises the need to consider hydrogen production and demand as part of a whole system: without CCS, significant deployment of hydrogen heating is unlikely to be feasible. In addition, a lack of CCS would mean the energy sector couldn't deliver net negative emissions, requiring additional savings elsewhere in the economy.

The value of flexibility across different hydrogen production routes rests in limiting the impact of changing hydrogen production methods on the total generation capacity required and the make-up of the electricity generation system.

3.8. Impact of negative emissions technology availability

Key insight

Investing in flexibility in the hybrid heating scenario almost eliminates any system cost increase associated with a reduction in DACCS capacity, and minimises the need to invest in additional low carbon electricity generation.

Previous sections have noted that without either DACCS or combining biomass with CCS to generate power or hydrogen, the energy system can't deliver net negative emissions. All core pathways deploy both technologies to meet the carbon target[21].

In particular, the low flexibility hybrid heat pump heating scenario is reliant on natural gas for heating to a material extent, which leads to emissions of around 34 $MtCO_2$ annually in 2050 (UK annual emissions in 2019 were 351$MtCO_2$[22]). DACCS is a key part of the system in the hybrid heating scenario that allows the continued use of natural gas for heating (via boilers) and so has wider implications on system generation mix. Given the relatively early current stage of the technology, there is a risk of slower than anticipated development, which means it may not be available at the cost and scale envisaged in 2050. For this reason, a sensitivity analysis of the hybrid heating pathway with more expensive DACCS (Table 5) was carried out to understand the cost and wider system implications, as well as the extent to which a more flexible system could mitigate the impact of effectively losing this technology from the energy system mix.

21 Nature-based solutions such as tree planting are out of the scope of this model.

22 BEIS, 2019 UK Greenhouse Gas emissions, provisional figures, 2020 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/875485/2019_UK_greenhouse_gas_emissions_provisional_figures_statistical_release.pdf

Negative emissions technologies

Globally, there are 65 commercial scale CCS plants in operation[23] with carbon capture technology directly capturing emissions from power generation or industrial processes. In the UK, Drax power station has trialled carbon capture on its biomass units[24] and the UK Government has announced investment to establish two Carbon Capture, Utilisation and Storage (CCUS) 'hubs' by the mid-2020s with a further two established by 2030[25].

DACCS is a less well-developed technology than capturing carbon from point sources. There are only a handful of small-scale pilot plants in operation globally, and DACCS has yet to demonstrate its scalability[26].

Table 5. High cost DACCS sensitivity parameters

Item	Hybrid heat pump - smart operation	Hybrid heat pump - smart operation, high cost of DACCS
Heating pathway(s)	Hybrid heat pump	
Low or high flexibility	Low and high	
Energy system carbon target	$-50MtCO_2/yr$	
Cost of DACCS	Low (£1m/unit)	High (£100m/unit)
Hybrid heat pump operation	The use of gas can be fully optimised - there is no minimum requirement to use gas	

23 Global CCS Institute, Global Status of CCS Report, 2021. https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Global-Status-of-CCS-Report-English.pdf

24 Global CCS Institute, Global Status of CCS Report, 2021. https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Global-Status-of-CCS-Report-English.pdf

25 HM Government, The Ten Point Plan for a green industrial revolution, 2020. https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution

26 UKERC, UKERC Technology and Policy Assessment. Bioenergy with carbon capture and storage, and direct air carbon capture and storage: Examining the evidence on deployment potential and costs in the UK, 2019. https://d2e1qxpsswcpgz.cloudfront.net/uploads/2020/05/UKERC-TPA-Negative-Emissions-V3-Final.pdf

3.8.1 Flexibility mitigates the cost implications of not deploying DACCS

When comparing the impact of flexibility on a smart hybrid heat pump scenario with low and high cost DACCS, the value of flexibility is stark.

With low system flexibility, increasing the cost of DACCS effectively eliminates the use of DACCS, and results in a 22% (£22bn) increase in system cost (Figure 80), with £20bn of that increase the result of additional investment required in electricity generation and network reinforcement. This additional investment in generation is clear when looking at the electricity generation capacity mix under the low flexibility scenarios (Figure 81).

Effectively removing DACCS from the energy system means that less natural gas can be used for heating (Figure 82). This in turn means that a greater proportion of heat demand must be met by electric heating. In addition to meeting additional demand for electric heating, unabated gas use for power generation must reduce, so a greater proportion of power generation is met by power plants directly coupled with CCS plants (both gas and biomass) and renewables. The most significant increase is in solar PV capacity, which increases from 47GW to 135GW. However, as seen in all previous scenarios, the majority of the fossil fuelled capacity is used infrequently: in the high cost DACCS, low flexibility scenario, post-combustion gas and CCS has an annual load factor of 11%, compared to 30% in the low cost DACCS scenario.

Figure 80. Annual system cost (£bn/yr) - hybrid heating pathway - low cost DACCS (core pathway) and high cost DACCS - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue

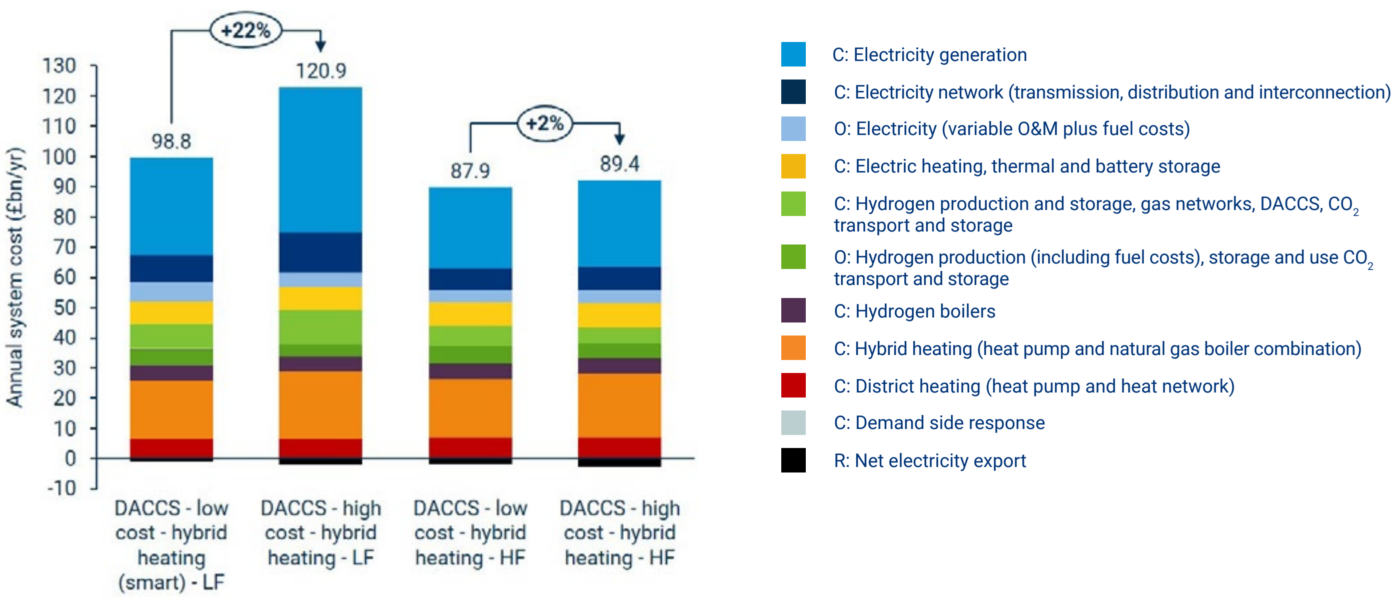


Figure 81. Electricity generation capacity and electricity storage capacity (GW) - hybrid heating pathway - low cost DACCS (core pathway) and high cost DACCS - low flexibility (LF) and high flexibility (HF)

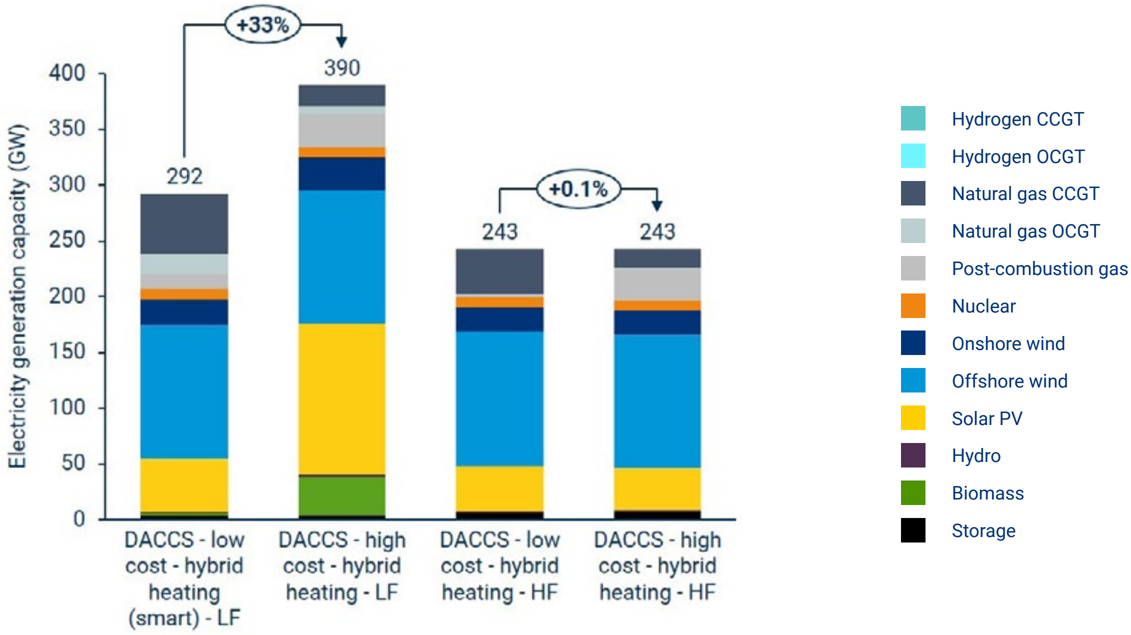
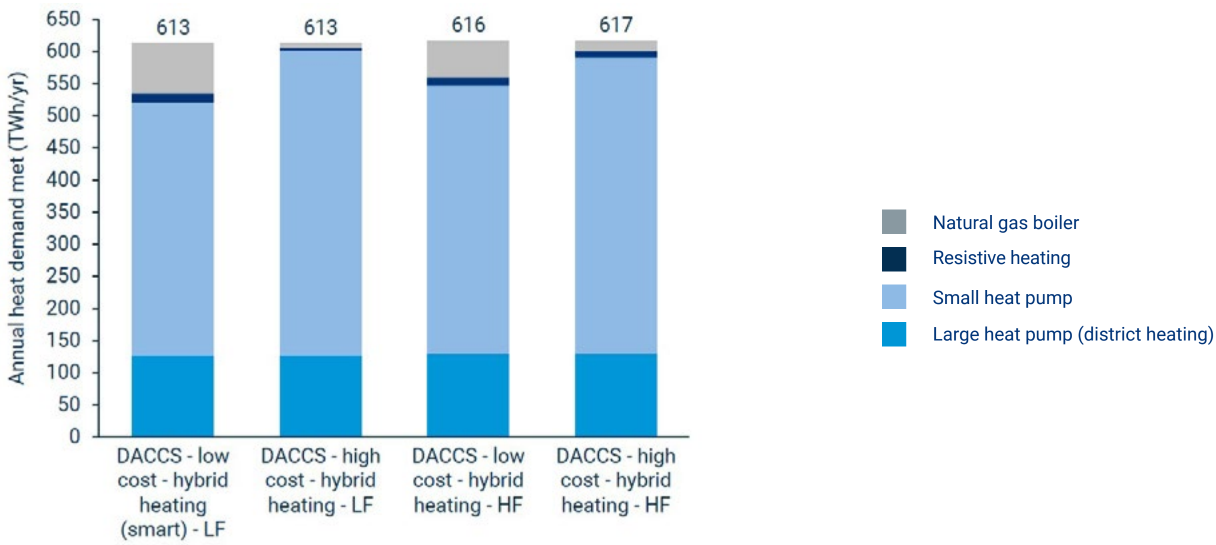


Figure 82. Annual heat demand met by heating technology (TWh/yr) - hybrid heating pathway - low cost DACCS (core pathway) and high cost DACCS - low flexibility (LF) and high flexibility (HF)



Additional system flexibility almost eliminates the cost impact of more expensive DACCS technology

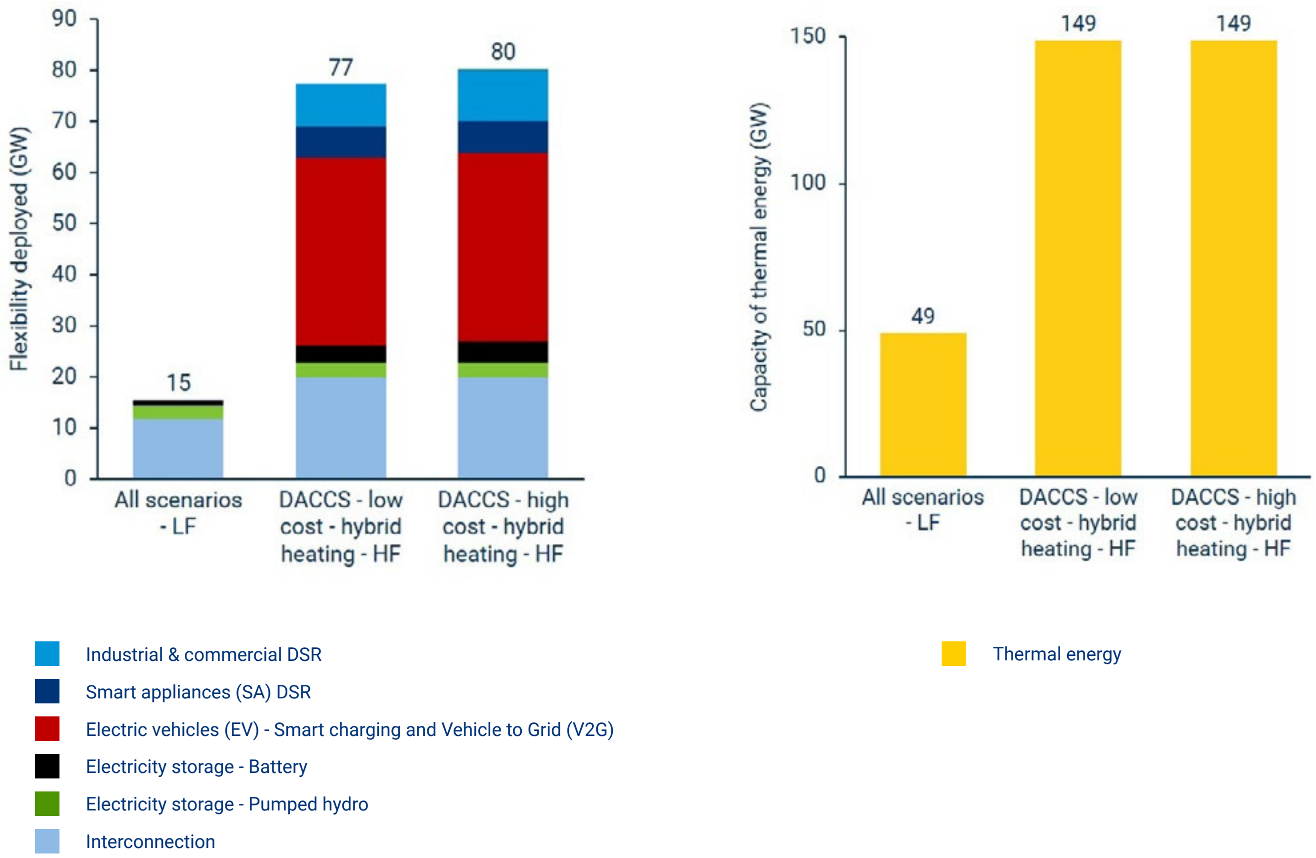
Figure 80 shows that, with additional system flexibility, the total system cost reduces to £87.8bn/yr with low cost DACCS and only increases to £89.3 bn/yr when DACCS is expensive[27]. This 1.7% (£1.5bn/yr) increase is much smaller than the 22.4% (£22.1bn/yr) increase seen under the low flexibility scenarios. This highlights the value of system flexibility, not only in reducing system cost overall, but in mitigating the system cost impact of not deploying a key technology such as DACCS.

The additional flexibility deployed - the mix of which is largely similar across the two high flexibility scenarios (Figure 83) - also results in a lower electricity generation capacity requirement and a more stable electricity generation mix across the high flexibility scenarios (Figure 81), with the most significant change being a shift from unabated gas to post-combustion gas CCS under a high DACCS cost scenario.

The high cost DACCS, high flexibility scenario sees slightly more battery storage deployed and a small increase in the maximum demand change delivered by industrial and commercial DSR compared to the high flexibility core pathway. Given that unabated natural gas is largely used during cold winter periods with low renewable output (see section 3.3.2.4), this additional flexibility is likely to be deployed during this period (as well as at other times of the year) to reduce unabated natural gas use.

It should be noted that these scenarios are still delivering net negative emissions (-50MtCO_2/yr) through biomass with CCS technologies. If the carbon target for the energy system were relaxed, the energy system cost would likely reduce, although the carbon savings would need to be made in other sectors of the economy.

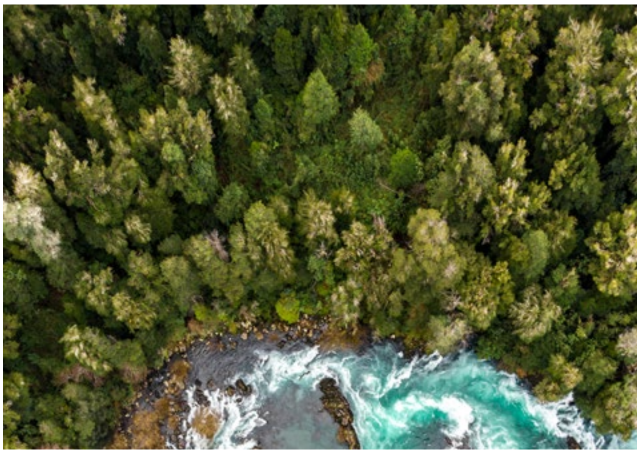
Figure 83. Left: Flexibility in the electricity system (GWe). Right: Thermal energy storage (GWth) - difference between core pathway (low DACCS cost) and high DACCS cost - hybrid heating pathway - low flexibility (LF) and high flexibility (HF)



27 The high cost of DACCS means it is not deployed in either the low or high flexibility scenario.

3.8.2 Summary - impact of negative emissions technology availability

The presence of DACCS creates dependencies on how heat is delivered within the wider energy system under a hybrid heating scenario. When DACCS is expensive, a higher proportion of heat demand is met by heat pumps or resistive heaters, and less through gas boilers. Without both flexibility and DACCS, meeting this additional electricity demand whilst still meeting a -50MtCO_2 carbon target requires significant additional investment in low carbon electricity generation capacity. Flexibility helps to deliver electric heating more cost-effectively, significantly reducing the cost and electricity system impact of not deploying DACCS.



3.9. Zero carbon versus net negative carbon targets for the 2050 energy system

Key insight

Meeting a net negative carbon target adds cost to the energy system. However, regardless of the carbon target, CCS is still an important technology in a cost-effective energy system.

Across all core pathways, the energy system is required to deliver net negative emissions of -50MtCO_2 in 2050. This assumption was derived from analysis by the CCC, which indicates that the energy sector will need to deliver net negative emissions in order to offset emissions in hard to decarbonise sectors if the UK is to reach its overall net zero target[28].

This sensitivity compared delivering -50MtCO_2 target to a zero carbon (0MtCO_2) target to examine the impact on system structure and cost under the hydrogen pathway.

28 Climate Change Committee, Net Zero: The UK's contribution to stopping global warming, 2019. https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

Figure 84 shows that delivering -50MtCO_2/yr in 2050 increases the energy system cost by 4-5% (£4.0-5.2bn/yr), largely driven by more investment in renewable electricity generation. Dividing this additional cost by the carbon saved gives a carbon abatement cost of £84 - 104/tCO_2. The extent to which this represents the most cost-effective means of delivering net negative emissions in 2050 (or reaching net zero across the economy) is outside the scope of this project. However, if the energy system is to deliver net negative emissions to offset emissions in other parts of the economy, it will be important to consider how these additional costs are met, and by whom. It is important to avoid burdening energy consumers, particularly those in fuel poverty, with the cost of offsetting emissions in other areas of the economy.

Figure 84. Annual system cost (£bn/yr) - hydrogen heating pathway - core carbon target (-50 MtCO_2/yr) and zero carbon target (0 MtCO_2/yr) - low flexibility (LF) and high flexibility (HF). C = Capital cost, O = Operational cost, R = Revenue

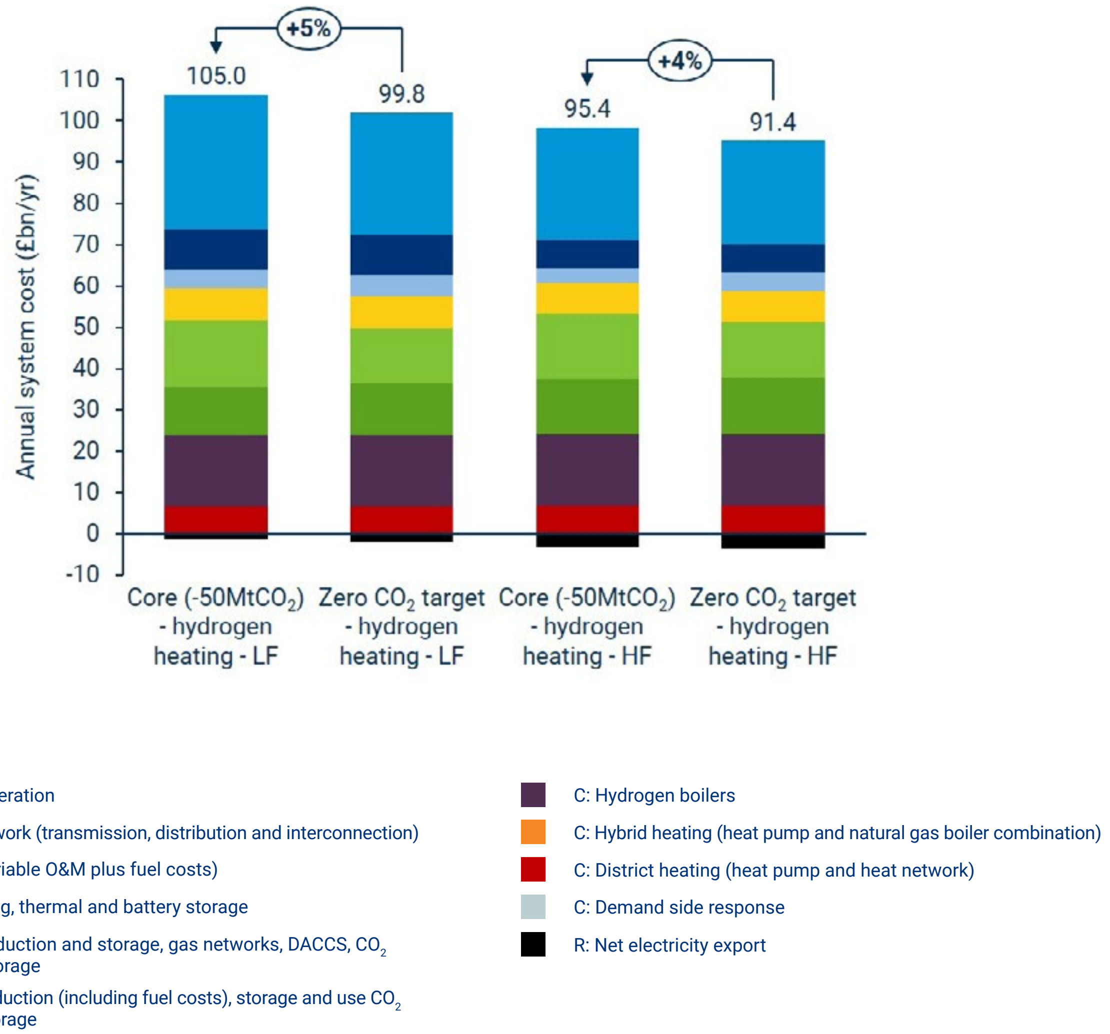
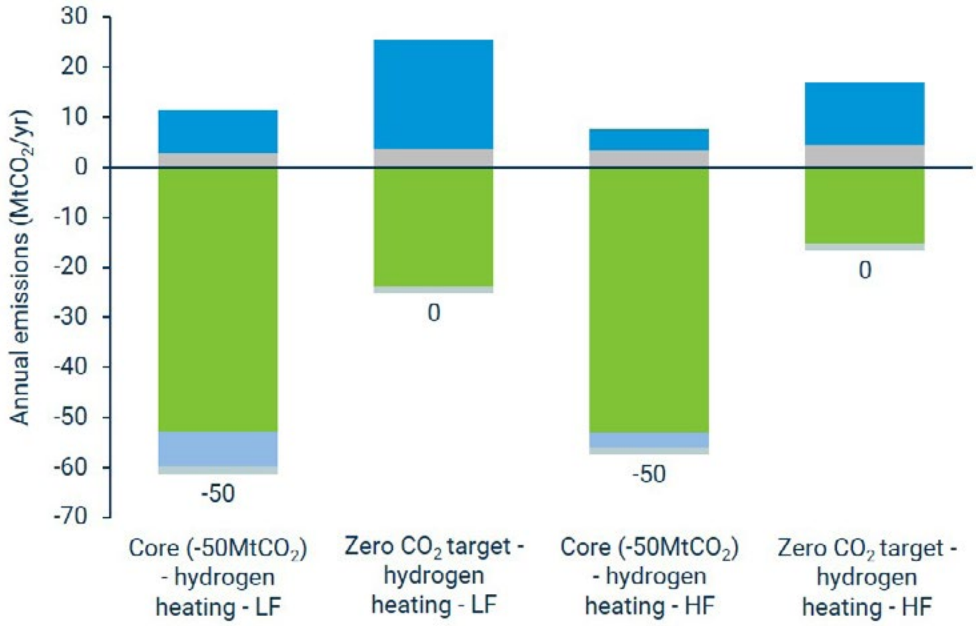


Figure 85. Carbon dioxide (CO_2) emissions by source ($MtCO_2$/yr) - hydrogen heating pathway - core carbon target (-50 $MtCO_2$/yr) and zero carbon target (0 $MtCO_2$/yr) - low flexibility (LF) and high flexibility (HF)



When removing the requirement for the energy system to deliver net negative emissions, negative emissions technologies are still an important part of the energy system, albeit it in reduced quantities, to offset positive emissions from the electricity sector and residual emissions from hydrogen production using natural gas with CCS[29]. Moving from a net negative carbon target to a zero carbon target sees an increase in positive emissions from the electricity sector as a result of greater use of unabated gas (Figure 85). However, Figure 86 shows that non-fossil fuel generation still provides 92-94% of electricity generated in the zero carbon target scenarios, compared to 95-98% with a net negative target. Under both carbon targets, deploying more flexibility increases the proportion of low carbon generation used and reduces direct emissions from the electricity sector.

29 The model considers that the cost of offsetting these emissions through biomass gasification to hydrogen with CCS is more cost-effective than limiting emissions at source. However, it is important to note that the same amount of biomass feedstock is available across all scenarios. In reality, if the energy sector doesn't deliver net negative emissions, other sectors of the economy, such as heavy duty transport, aviation and shipping, will be under more pressure to minimise their emissions and a greater proportion of available biomass feedstock may be used to create biofuels. This may limit the extent to which the energy sector can offset its own emissions through negative emissions technologies.

Figure 86. Annual electricity generation (TWh/yr) - hydrogen heating pathway - core carbon target (-50 $MtCO_2$/yr) and zero carbon target (0 $MtCO_2$/yr) - low flexibility (LF) and high flexibility (HF)

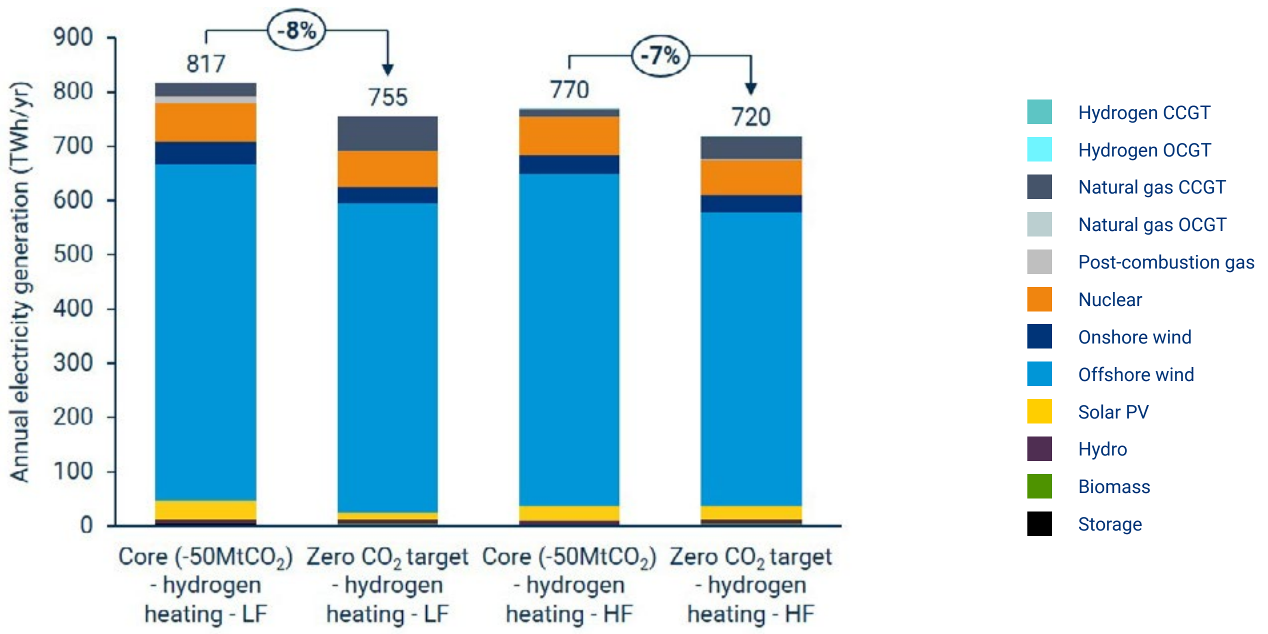


Figure 86 and Figure 87 also show that, under a hydrogen heating pathway, relaxing the carbon target to 0$MtCO_2$/yr reduces total demand for electricity by 7-8%, with a corresponding reduction in generation capacity of 7-12% (17-36GW). The reduction in demand is almost entirely due to a reduction in electricity use for hydrogen production. Under a 0$MtCO_2$ target, a higher proportion of hydrogen is produced via reformation of natural gas plus CCS (Figure 88). This uses less electricity per unit of hydrogen produced than both electrolysis and gasification and upgrade of biomass to hydrogen.

Finally, it is worth noting that under the high flexibility scenarios, the total generation capacity required is lower (under both carbon targets) than under the low flexibility scenarios. There is also a smaller absolute difference in the generation capacity required between the two targets (17GW difference, as opposed to 36GW difference under the low flexibility scenarios). This could indicate that greater flexibility enables the electricity generation sector to adapt more easily to meet different carbon targets, although this hypothesis would need to be examined across different decarbonisation pathways and carbon targets.

Figure 87. Electricity generation capacity and electricity storage capacity (GW) - hydrogen heating pathway - core carbon target (-50 $MtCO_2$/yr) and zero carbon target (0 $MtCO_2$/yr) - low flexibility (LF) and high flexibility (HF)

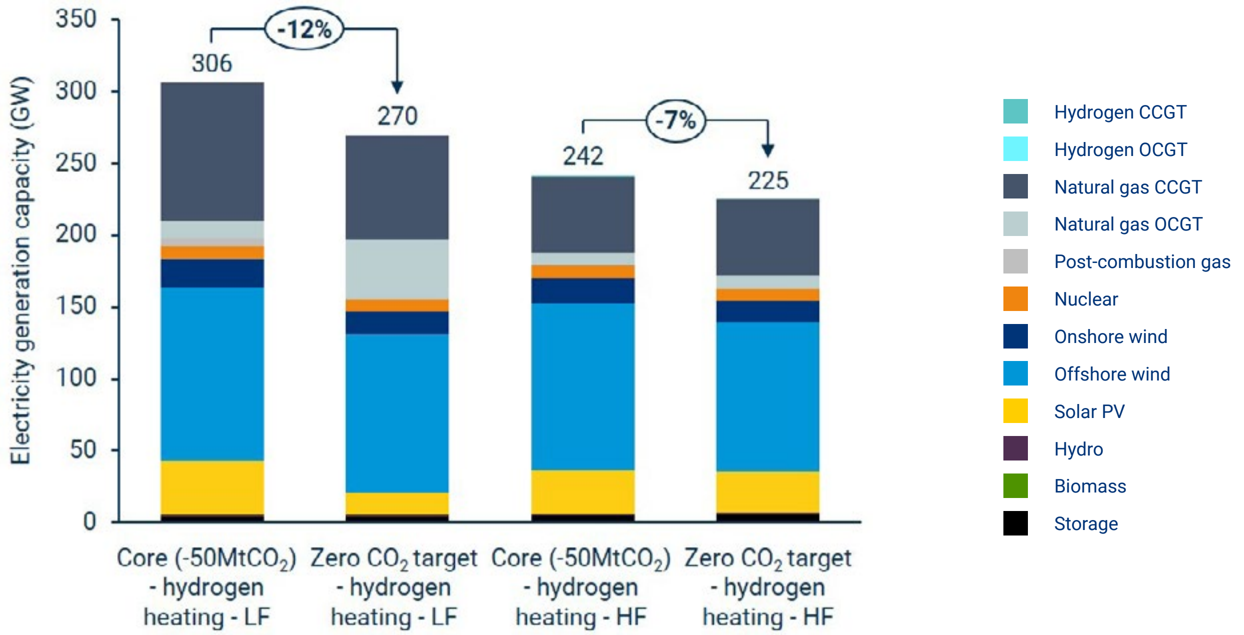
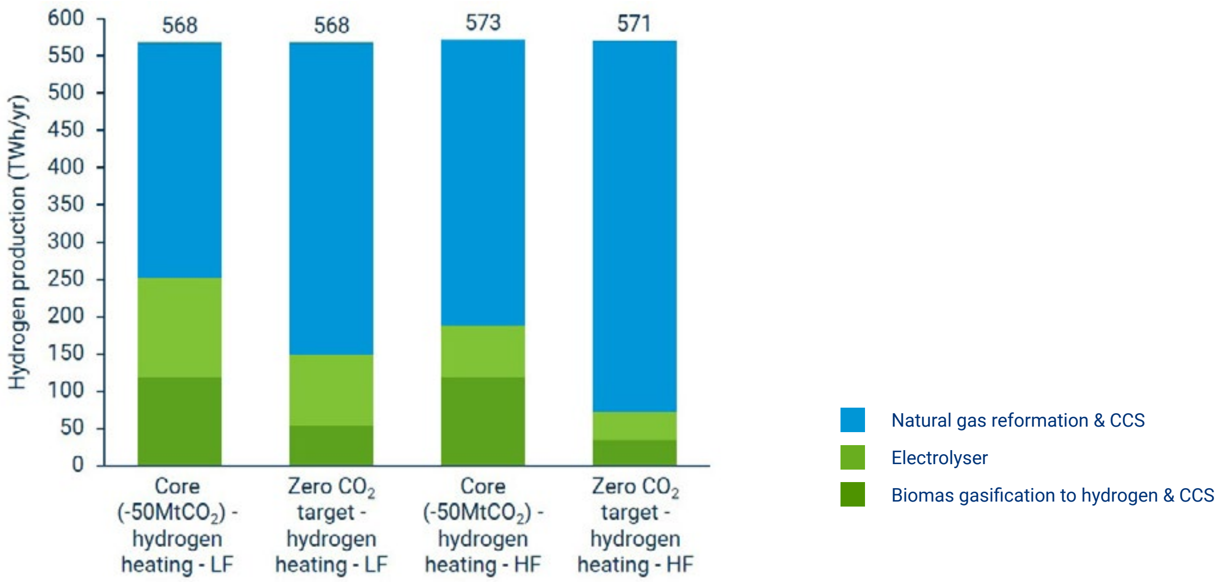


Figure 88. Annual hydrogen production (TWh/yr) - hydrogen heating pathway - core carbon target (-50 $MtCO_2$/yr) and zero carbon target (0 $MtCO_2$/yr) - low flexibility (LF) and high flexibility (HF)

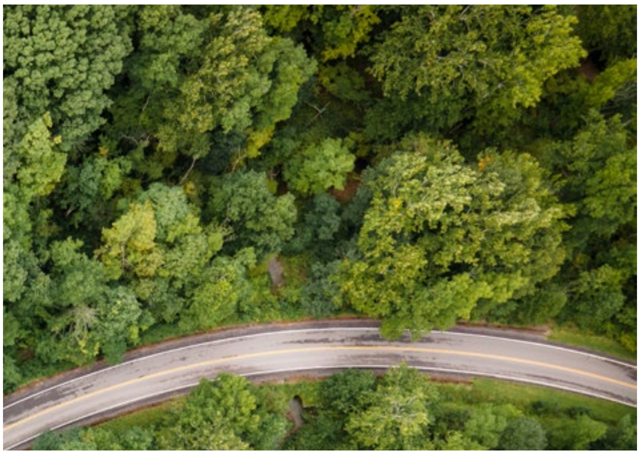


3.9.1 Summary - impact of changing carbon target

This sensitivity analysis shows that meeting a net negative carbon target adds cost to the energy system. However, regardless of the carbon target, CCS is still an important technology in a cost-effective energy system.

Under the hydrogen heating pathway, the additional cost is largely a result of changes in hydrogen production techniques. The impact of carbon targets under other heating pathways therefore needs to be explored in more detail.

Flexibility reduces the system cost regardless of carbon target and reduces the difference in the generation mix required to meet different carbon targets. This could indicate that greater flexibility enables the electricity generation sector to adapt more easily to meet different carbon targets, although this hypothesis would need to be examined across different decarbonisation pathways and carbon targets.



3.10. Local versus system benefits

Key insight

The system boundary for energy system optimisation is important. Investing in local flexibility reduces system cost at a national level. However, making use of distributed flexibility requires appropriate investment in distribution networks to ensure flexibility can be accessed by the wider system.

Developing an energy system primarily focused on minimising investment in networks is a false economy. Distribution network reinforcement requirements should take into consideration whole system impacts. Investing in distribution network capacity can reduce total generation capacity required as local networks can make use of generation and flexibility assets in other regions.

Overall, it is important to recognise the national system value of local investment in flexibility and networks and ensure that local flexibility assets can be operated in alignment with system need.

All scenarios described so far are optimised to minimise the annualised cost of the entire GB energy system. At a local or regional level, there may be pressure to ensure that energy costs are minimised for the local population, and the value of additional investment which could lead to savings at a national level is not recognised. Similarly, the wider system benefits of investment in local distribution networks need to be recognised in the business case for investment.

This report looks more closely at the Greater London region to understand the value of local investment in two ways:

- The value local investment brings to the national energy system within a whole system optimisation.
- Exploring what would happen if each region focused on minimising local distribution network costs, without considering an overall system optimisation approach. This is labelled as 'local network optimisation'.

Key differences between the results of the two sensitivities are set out in Table 6 and discussed in more detail below.

Table 6. Difference between whole system optimisation and local network optimisation

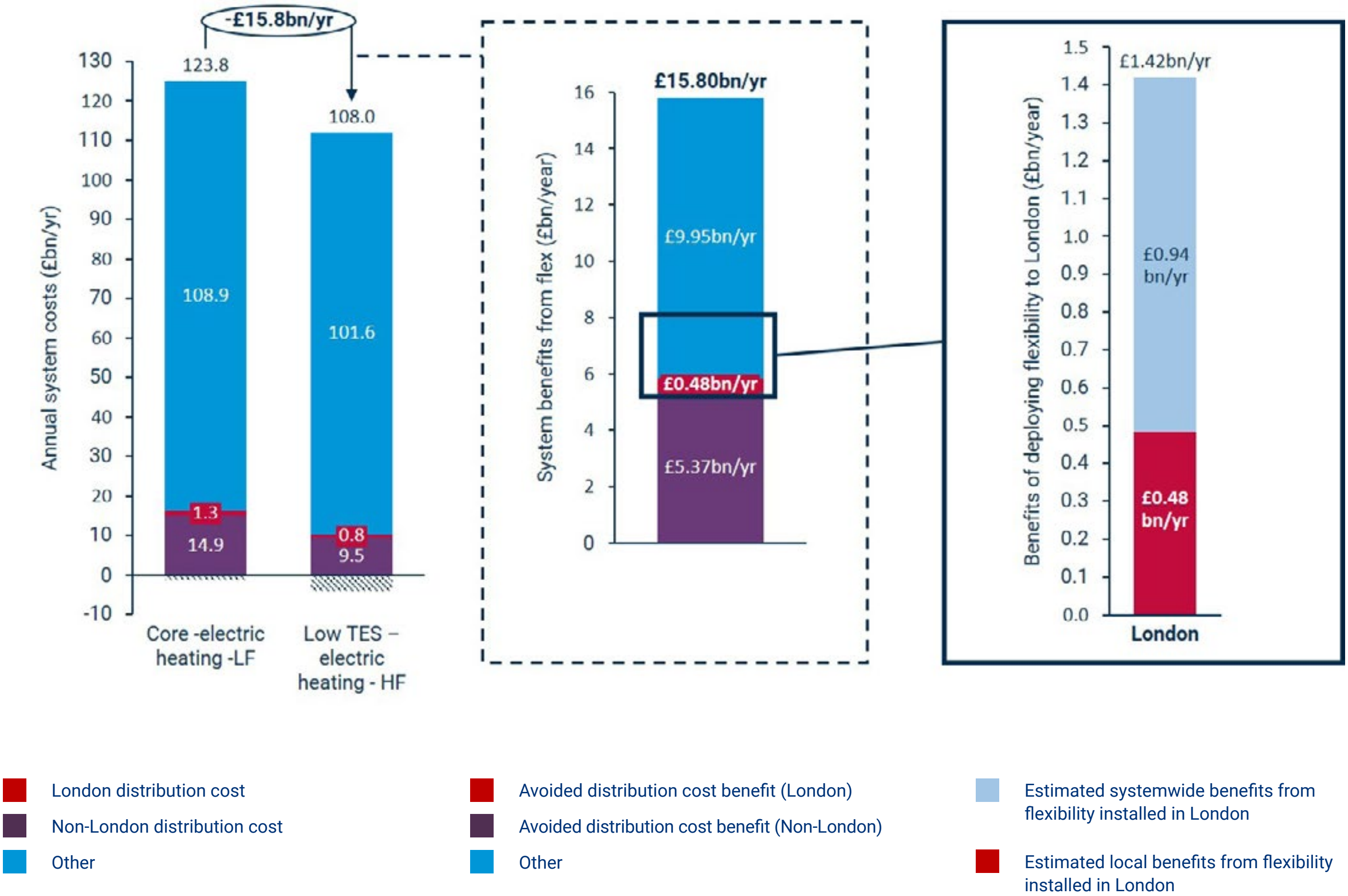
Whole system optimisation (electric heating, high flexibility)	Local network optimisation (electric heating, high flexibility)
Investment in transmission and distribution networks is optimised to minimise whole system costs at a national level.	The model is optimised to meet the same demand and carbon constraints as a whole system optimisation, but whilst minimising distribution network reinforcement costs.
	Higher capacity of battery storage compared to the whole system optimisation to support local networks.
Generation portfolio characterised by fewer, larger generators connected at the transmission network.	Generation portfolio characterised by more, smaller, generators connected at the distribution network.

Whole system optimisation

In the whole system optimisation scenario, we compared the core electric heating low flexibility scenario with a high flexibility electricity scenario (but with thermal storage limited to c.100GW – the same as in the low flexibility scenario). It is possible for the IWES model to extract the distribution network investment cost for each region, and apportion all other investment costs by region (based on population). Comparing the low and high flexibility scenarios, we can estimate that investing in additional flexibility within London delivers £0.48bn/yr savings to London directly in reduced distribution network costs.

In addition, the investment in local flexibility in London delivers an additional £0.94bn/yr of wider system savings (Figure 89). Therefore, it is important to consider wider system benefits that could be delivered from local investment, and to ensure that local areas are appropriately incentivised to develop an energy system that works with the wider system effectively.

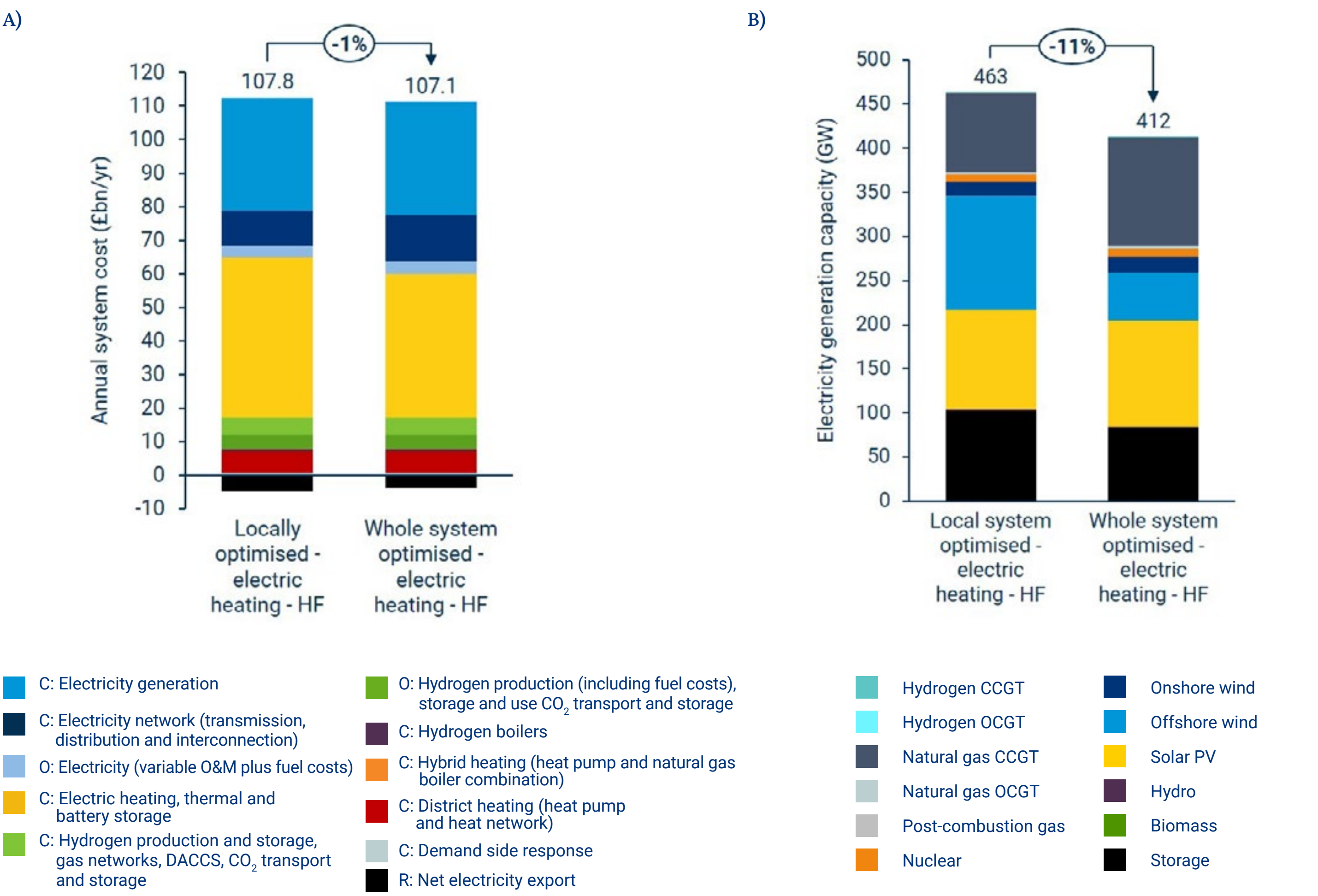
Figure 89. Apportioning energy system savings to the Greater London region - electric heating pathway



Local system optimisation

In the local system optimisation scenario, the core electric heating pathway with high flexibility was rerun, but with the requirement to minimise investment in distribution networks, rather than minimise costs across the whole system. In this example, taking a local distribution cost minimisation strategy rather than a national system cost minimisation approach, is slightly more expensive at a GB level (£0.6bn/yr) (Figure 90A).

Figure 90. A) Annual system cost (£bn/yr), and B) Electricity generation capacity and storage capacity (GW) - local versus national optimisation - electric heating pathway - high flexibility (HF)



However, there are several key differences in certain cost categories that make up the whole system cost. The locally optimised system (minimising distribution network costs) requires significantly more spending on heat pumps, distributed generation (particularly solar PV) and thermal and battery energy storage. It spends less on distribution networks (by definition), conventional generation and resistive heating technologies (Figure 90A).

This has an impact on the electricity system developed (Figure 90B), with 20GW additional battery storage and a significant increase in distributed renewable generation (solar PV capacity more than doubles from 55GW to 129GW) required to meet the same total demand. This highlights the need to ensure optimal investment in local distribution network capacity to reduce the whole system cost by enabling more effective access to generation and flexibility across the wider energy system.

3.10.1 Summary - local versus system benefits

Locally installed flexibility delivers national value but it needs to be coupled with sufficient investment in networks to ensure that flexibility can be made use of at a national as well as local level.

The system boundary for energy system optimisation is important. Investing in local flexibility reduces system cost at a national level. However, making use of distributed flexibility requires appropriate investment in distribution networks to ensure flexibility can be accessed by the wider system.

Developing an energy system primarily focused on minimising investment in networks is a false economy. Distribution network reinforcement requirements should take into consideration whole system impacts. Investing in distribution network capacity can reduce total generation capacity required as local networks can make use of generation and flexibility assets in other regions.

Overall, it is important to recognise the national system value of local investment in flexibility and networks and ensure that local flexibility assets can be operated in alignment with system need.

3.11. Summary of findings

Reaching net zero by 2050 while meeting security of supply requires unprecedented scaling up across the energy system

Regardless of the scenario or sensitivity, the 2050 net zero energy system is significantly larger relative to the current GB system, particularly when additional flexibility is not deployed. Across the core heating scenarios analysed, the total electricity required in 2050 rises to a maximum of 830TWh, which represents an almost threefold increase relative to 2019. The network build out required is also significant, driven by a potential increase in total peak demand on the distribution network of up to 228GW in an electric heating scenario. Flexibility present in the distribution network needs sufficient capacity to be able to charge up and discharge in response to system needs. Therefore, investment in networks is also important to unlock flexibility that can deliver wider system benefits.

Across the scenarios, there is also a significant need for deployment of carbon negative technologies such as BECCS and DACCS up to several 10s of GW by 2050. This is true even when the net negative carbon target is replaced with a 0MtCO_2/yr target as negative emissions technologies allow unabated natural gas to be used during short periods of system stress, such has cold winter days with low renewable output.

The key area of convergence between the three core heating pathways (electric, hydrogen and hybrid heating) is maximising deployment of renewables, particularly offshore wind (120GW) and PV (30-55GW), thus making them no-regret actions for achieving net zero targets.

Decarbonisation of heat has a significant bearing on the corresponding cost optimal energy system in 2050

GB's choice of heating decarbonisation pathway has a significant impact on several aspects of the energy system, including scaling up existing technologies and networks and the need for new technologies such as those that can negate carbon emissions. For example, a fully electric heating scenario without additional flexibility requires significant additional electricity generation capacity (422GW required, compared to the current capacity of 108GW), with just over 50% in reserve with very low utilisation (<5%). Similarly, a hydrogen heating scenario needs a significant scale-up of relatively new technologies such as electrolysers (35GW), hydrogen storage (c.8TWh), bioenergy gasification to hydrogen plants (14GW) including CCS infrastructure.

Strategic areas that are therefore particularly sensitive to the choice of heat decarbonisation include: levels of carbon negative technologies required; natural gas infrastructure; hydrogen infrastructure (including storage); and electricity distribution infrastructure.

Investing in flexibility is a no-regrets decision as it delivers material net savings across all scenarios and sensitivities analysed in 2050

The addition of flexibility to the energy system can save up to £16.7bn/yr and meet net zero targets in 2050. Across all the scenarios and sensitivities, there is always a material net saving that can be achieved by integrating flexibility. It is also important to consider that flexibility includes optimal operation of systems, such as hybrid heat pumps and coordinating the hydrogen system (production, storage, conversion and use) to maximise synergies with the wider system effectively. The savings predominantly come from avoidance of gas generation (CapEx and OpEx), reduced reliance on carbon negative technologies and lower network reinforcement.

Flexibility beyond the power sector, including that integrated with zero carbon heat and transport solutions, is critical to unlock value

Embedding flexibility into zero carbon heat and transport solutions will help to reduce their system impact and associated costs, making their decarbonisation economically more feasible. For example, the deployment of smart charging and V2G allows large-scale EV charging to be delivered, aligned to renewable generation while reducing impact on networks through peak demand reduction. Additionally, the coordinated interaction between energy for heating, EV charging and smart appliances helps to reduce overall system cost. This is critically enabled by the deployment of flexibility that allows shifting of demand without any impact on delivering the end heat or mobility service. The value of such flexibility in heat and transport is even more acute during periods of system stress (low renewable ouptut and high demand), outlining its contribution to operating a secure and robust system.

The use of hydrogen across the energy system brings carbon and cost benefits, but requires careful planning

Development of hydrogen use and associated infrastructure (electrolysers, hydrogen turbines and storage) for 2050 has significant system benefits if coordinated effectively. Integrating flexibility into a hydrogen dominant system has a significant effect on cost reduction and has the largest impact across all the scenarios, in terms of reducing the total electricity generation capacity requirement. The total cost of the hydrogen system is sensitive to technology (production and conversion) costs, fuel costs and availability of carbon negative technologies. Therefore, retaining a diverse portfolio of hydrogen production routes (gasification, reforming and electrolysis), even with the integration of flexibility, can help to avoid shocks if one or several of these dependencies becomes expensive and/or unavailable. However, even across this diverse portfolio, the ability to deliver hydrogen needs throughout the system cost-effectively is dependent on the availability of CCS infrastructure, without which significant additional costs will be incurred to meet demand.

4. Delivering a smart, flexible energy system

4.1. Introduction

How to read this chapter

The outputs of the IWES model indicate the scale of the 'optimal' deployment of different sources of flexibility required in 2050 across the three core heating scenarios. These are discussed in detail in Chapter 3 and summarised below for reference. These scenarios represent the extreme cases of how heat may be decarbonised in Great Britain. It is likely that a combination of technologies will be required to decarbonise heat.

This section of the report focuses on key actions required between now and 2050 in order to achieve the scale of deployment of each source of flexibility indicated by the model in the 'high flexibility' scenarios.

The diffusion of each source of flexibility was modelled to estimate what level of deployment might be required in 2030 in order to achieve the levels expected in 2050. Using the 2030 deployment estimate as a 'short-term' target, the report then assesses the key criteria required to enable the desired diffusion of each source of flexibility. The sources of flexibility assessed were:

- **Domestic DSR from smart appliances**
- **Non-domestic DSR**
- **Flexibility provided by EVs (both through smart charging and V2G)**
- **TES linked to district heating schemes and buildings**
- **Electricity storage**
- **Hydrogen electrolysers**

For more details on these flexibility technologies, please refer to section 2.3.

Overview of high flexibility scenario

Electric heating

- 20% of non-domestic and domestic heat met by district heating powered by heat pumps.
- Remaining heat load met by ASHPs and resistive heating.

Hybrid heating

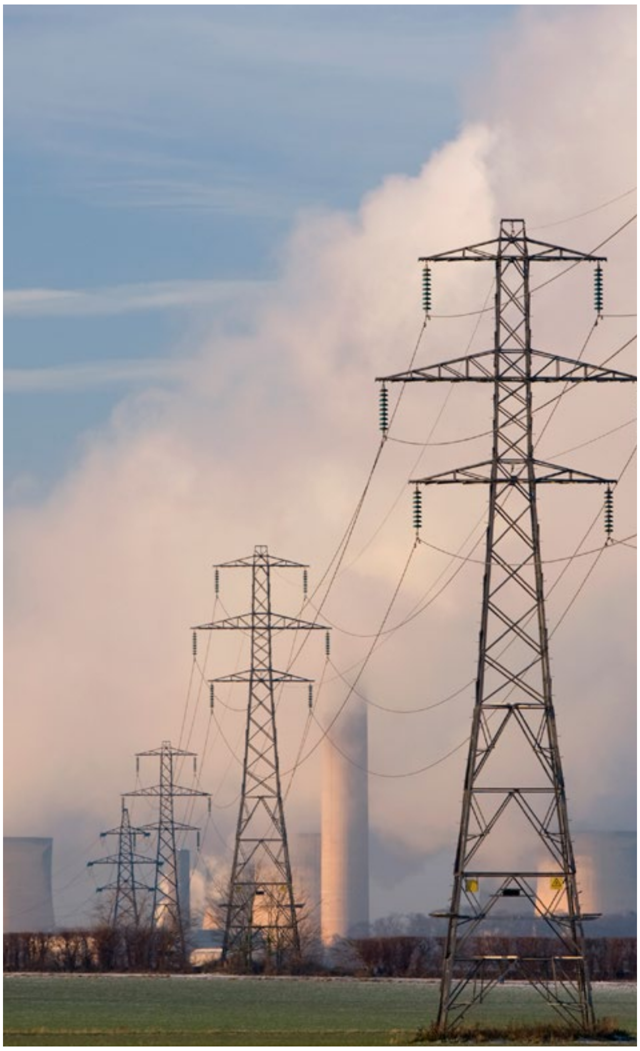
- 20% of non-domestic and domestic heat met by district heating powered by heat pumps.
- Remaining space heating and hot water demand connected to mains gas network is met by hydrogen.
- Properties not connected to mains gas grid have heat load met by ASHPs and resistive heating.

Hydrogen heating

- 20% of non-domestic and domestic heat met by district heating powered by heat pumps.
- Remaining space heating and hot water demand connected to mains gas network is met by ASHPs coupled with a small natural gas boiler.
- Properties not connected to mains gas grid have heat load met by ASHPs and resistive heating.

Indicative 2030 deployment trajectories

Indicative deployment trajectories of each source of flexibility were estimated from 2020 to 2050. The growth trajectories were based on technology diffusion curves, from which the required deployment of the flexibility technology in 2030 can be estimated. The diffusion curves were developed by assuming a deployment saturation in 2050, at which point GB has achieved a net zero energy system. These trajectories were not developed using a system optimisation for 2030, so do not reflect the system needs in 2030 (or any other year between 2020 and 2050), but serve purely to help visualise an indicative deployment target using the 2050 results and an understanding of current and recent levels of deployment of each source of flexibility.



Deployment readiness assessments

An assessment of the barriers to achieving this 'interim' 2030 deployment goal was conducted for each source of flexibility. The 'deployment readiness assessments' consider a holistic view of the market enablers, business models and other factors required to deliver the required level of deployment of each source of flexibility in 2030.

A framework was developed for this study to support the identification of the key barriers to the deployment of sources of flexibility. This framework helps provide a snapshot of the deployment maturity of each source of flexibility at this moment in time, considering the indicative deployment need of the source of flexibility estimated for 2030. An overview of the framework is shown in Table 8.

The framework assesses indicators across three themes: **market enablers, the business model** and **capacity to deliver**. Each theme has four indicators underpinning it. Evidence was collected across each indicator, through secondary research and primary research conducted with the consortium partners, to understand the extent to which there are barriers to the deployment of the source of flexibility. A simple traffic light assessment was taken against each of these, to help highlight areas that required particular attention in order to unlock the required levels of deployment.

This method has its limitations. The deployment readiness analysis is inherently subjective, based on an assessment of a sample of publicly available evidence and insights from consortium partners. There also could be other indicators that are helpful to assess the deployment status of a technology. However, the main objective of the analysis is to highlight the fact that there are a broad range of factors needed to support required deployment of the technology in 2050 and unlock the benefits highlighted earlier in this report.

Table 7. Description of red-amber-green (RAG) rating for deployment readiness assessment

Rating	Description of rating
Green	**No significant barrier was identified to the deployment of a source of flexibility required to meet the indicated level in 2030.**
Amber	**Key barriers/needs have been identified, but there are processes in motion today that suggest the barrier could be overcome in time to enable the indicated level of deployment of flexibility in 2030.**
Red	**Key barriers have been identified that could hold back achieving the level of deployment of the source of flexibility. There is little or no evidence to suggest this barrier will be overcome to the extent to which the level of deployment indicated for 2030 can be achieved.**

Table 8. Deployment readiness assessment framework

Theme	Indicator	Description of indicator
Enablers	**Enabling infrastructure**	The extent to which infrastructure, which itself is a prerequisite for the technology to be able to be deployed effectively, exists.
	Regulatory environment	The extent to which there exists a well-functioning regulatory environment that sends clear signals to the market regarding the regulations around a technology and doesn't contradict other regulations.
	Stakeholder acceptance	An assessment of the extent to which relevant stakeholders accept the deployment and use of the technology, and do not perceive there to be considerable risks to its adoption.
	Level of political support	An assessment of the level of support for a particular source of flexibility from government, indicated by clear signalling such as funding or policy targets.
Business model	**Availability of funding**	The availability of finance to invest in sources of flexibility at a low cost, for both consumers and businesses, commercial or for research and development (R&D).
	Willingness to pay	The extent to which the investor/business/consumer is willing to pay for the adoption of certain technologies to unlock flexibility, both in terms of time and resources.
	Financial performance	The strength of the financial proposition to investors/consumers, based on revenue generation through providing flexibility against the cost of developing the source of flexibility or accessing a source of flexibility that already exists.
	Market opportunities	The extent to which markets exist that internalise the value the model shows flexibility can deliver.
Capability to deliver	**Resource availability**	The extent to which there are adequate resources/raw materials available to deliver the required deployment of the technology.
	Technological maturity	The extent to which the technology/source of flexibility has been technologically proven and is readily available at the required scale.
	Supply chain and skills	The extent to which the necessary supply chain is in place to deliver the technology at the required scale and pace.
	Maturity of company landscape	An assessment of the maturity and competitiveness of the private sector landscape looking to deliver the source of flexibility.

4.2. DSR from domestic smart appliances

Quantifying flexibility

Model inputs

The IWES model assumes that a maximum of 41% of wet (e.g. dishwashers, washing machines) and cold (e.g. fridges, freezers) domestic appliance load can be shifted during each day. Winter evening peak of domestic appliance demand is c.14GW in 2050, with off-peak night levels at c.4GW. The cost of DSR capacity was estimated to be £28/kW, and is associated with the CapEx of control and telecoms infrastructure, assuming zero OpEx.

Flexibility in operation

Figure 91 shows the demand curve for domestic smart appliances before and after DSR is implemented, and the difference between the two. This data is from the electric heat scenario during the week in which there is an extreme weather event where very cold temperatures (and therefore a high heat demand) coincide with very low wind supply. It demonstrates that demand is shifted from daytime to night (in the hours just after midnight) on Tuesday, Wednesday and Thursday. Just under 6GW of the evening peak (which would otherwise be 14GW) is turned down, and 12.4GW is turned up overnight. The maximum demand turn-up is 12.4GW, seen in the early mornings of Wednesday and Thursday.

Figure 91. Domestic smart appliance demand, before and after DSR implemented, during the week of an extreme weather event in winter (electric heating scenario)

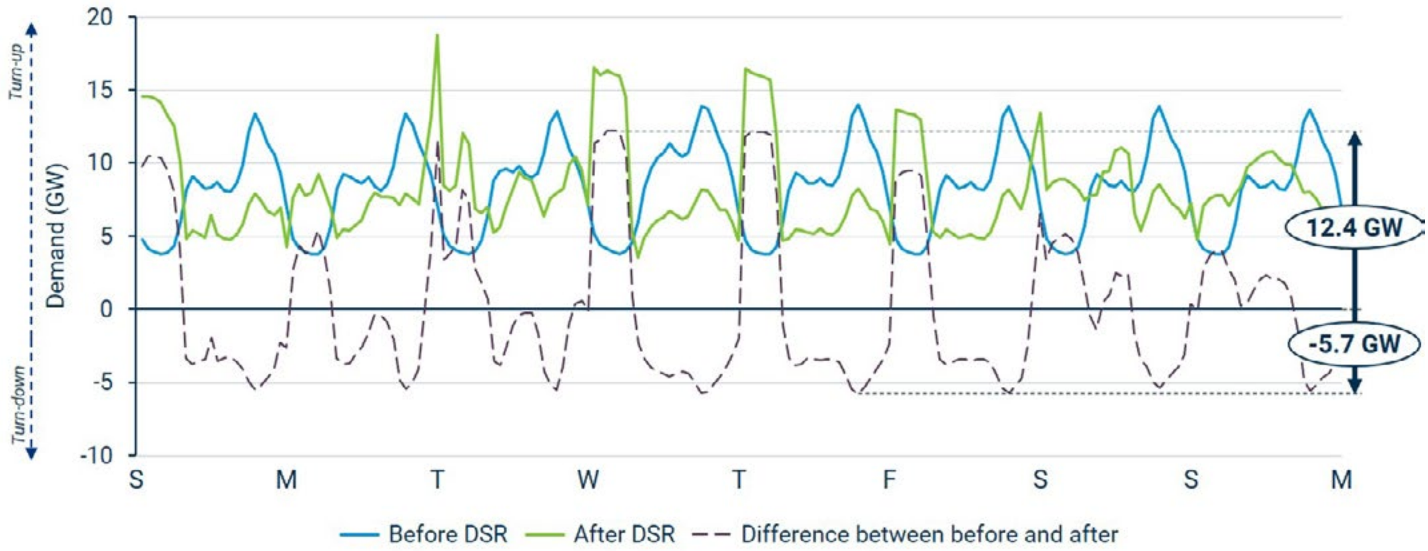


Figure 92. Demand shifting by domestic smart appliances across a typical three-week period in each season (electric heating scenario)

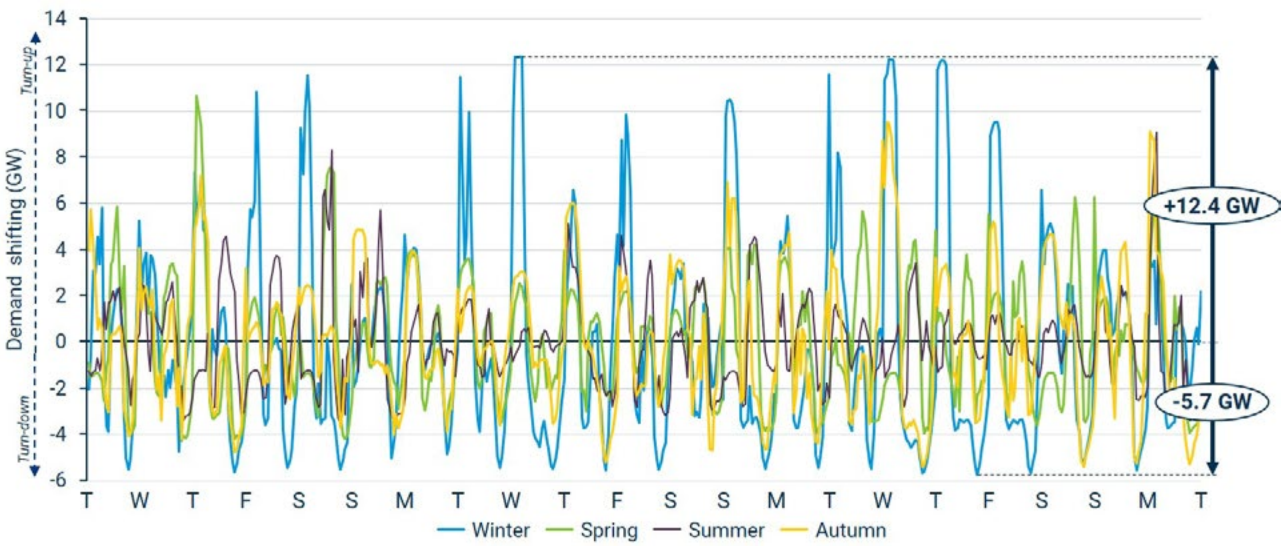


Figure 92 shows the performance of DSR in domestic smart appliances across the rest of the year for the electrification of heat scenario. It demonstrates that during the winter, peak demand reduction remains relatively constant at between 5-6GW, with the turn-up reaching more than 10GW on a handful of occasions. For reference, the maximum theoretical turn-down potential from wet and cold appliances in 2030 was estimated to be about 6.5GW.[30]

During autumn, summer and spring, both the turn-down and turn-up amounts are lower than in winter. Shifting demand can be driven by a number of factors such as reducing peak load or smoothing renewables. However, the patterns of shifted demand are generally regular and consistent across each day and season.

30 Flexible demand in the GB domestic electricity sector in 2030, Drysdale B et al, 2014 https://orca.cf.ac.uk/68342/1/OA-20142015-71.pdf

Delivering flexibility

Unlocking flexibility

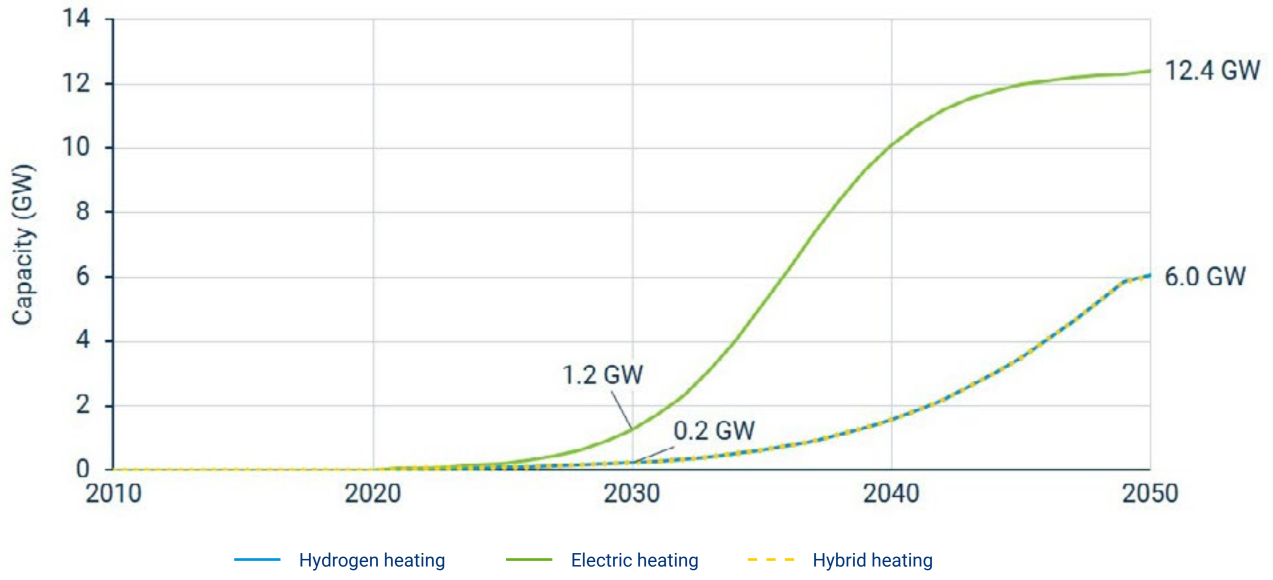
The flexibility of demand could result from domestic users with smart appliances that respond to financial (time-of-use tariffs) or non-financial signals (e.g. carbon intensity) - through automation and/or behaviour change. Tariffs could include critical peak pricing mechanisms that incentivise significant behaviour change during critical supply periods. However, the regular turn-down of c.6GW compared to a baseline of c.14GW (as shown during the critical supply period in Figure 92, but also repeated daily in winter in Figure 93) indicates a regular reduction in the peak of between 40% and 50%. This level of flexibility from domestic smart appliances necessitates high consumer engagement (with or without automation of appliances) on a regular basis that is considered habitual.

Indicative 2030 deployment level target

Figure 93 shows the indicative deployment trajectory of DSR from smart appliances across the three core heating scenarios. The values for 2050 were defined as the largest difference in demand during the year due to DSR, as illustrated in the electric heating scenario (Figure 91 and Figure 92). While the maximum difference in the electric heating scenario was 12.4GW, the equivalent figure for the hybrid heat pump and hydrogen heating scenarios was 6.0GW.

The estimated range of values from domestic DSR in 2030 is between 0.2 and 1.2GW, growing from a base of negligible capacity in 2021.

Figure 93. Indicative diffusion curve for DSR from smart appliances across the three core scenarios



Since the model assumes that the daily domestic appliance demand could be shifted by a maximum of 41% in 2050, a 2030 estimate of 0.2-1.2GW represents a much smaller proportion of domestic appliance demand being flexible, perhaps in the region of 5% of the aggregate domestic appliance demand. This may represent a 2030 system in which the domestic smart meter rollout has been completed, and a small proportion of the population are using smart appliances linked to time-of-use tariffs.

This would necessitate a significant rise in DSR potential between 2030 and 2050. The price signals of electricity are expected to evolve as the penetration of renewables increases, lifting the potential value that can be obtained through the provision of flexibility services.

Deployment readiness assessment

Table 9. Deployment readiness assessment summary for domestic DSR

Theme	Indicator	Barrier assessment
Enablers	Enabling infrastructure	
	Regulatory environment	
	Stakeholder acceptance	
	Level of political support	
Business model	Availability of funding	
	Willingness to pay	
	Financial performance	
	Market opportunities	
Capability to deliver	Resource availability	
	Technical performance/TRL	
	Supply chain and skills	
	Maturity of company landscape	

Domestic DSR - where are we on track?

The smart meter rollout is the key piece of **enabling infrastructure** that supports smart tariffs and settlement. Today it has reached around 40% completion, with a stated target completion date of 2024. Unless there are further stakeholder acceptance issues, it is expected that the required smart meter infrastructure will be in place by 2030, along with market-wide half-hourly settlement that will help support the development of smart time-of-use tariffs.

Beyond smart meters, the infrastructure required is the large-scale deployment of smart appliances via mandates or effective labelling schemes underpinned by robust standards for cybersecurity and interoperability. To establish easy, cost-effective and secure access to smart appliances, it is also critical to make rapid strides in leveraging the smart meter rollout and the DCC and its infrastructure. This will help avoid multiple and potentially disparate systems across market actors that could pose a barrier to scaling up of residential DSR. There are several UK government programmes and consultations underway across these areas. It is critical that they conclude and move into practice in the next few years.

While the **political support** exists in government to develop a smart energy system with domestic DSR and smart appliances, political leadership could be required to help overcome public resistance to the rollout of smart meters.

The **financial proposition** for smart appliances today is too weak to attract much attention from consumers, suppliers or appliance manufacturers. It is expected that this will improve over time as price signals evolve and the financial benefit of combining smart appliances with time-of-use tariffs increases.

Smart meter enabled time-of-use tariffs are emerging, but the **market** is still immature. Critical peak pricing tariffs and dynamic time-of-use tariffs, which may be required to unlock the type of DSR required in extreme events in a system with high levels of renewables, may emerge as the system evolves - and there is already a dynamic time-of-use tariff on the market. Domestic flexibility from smart appliances could also support overcoming local constraints. However, the current (emerging) market for local flexibility services is geared towards non-domestic providers and there may be barriers to accessing these markets. Furthermore, distribution network operators may be uncertain of the extent to which domestic DSR from smart appliances would fulfil any obligations made for providing flexibility.

Overall, there were no major barriers identified across the ‘capability to deliver’ indicators. Flexibility from domestic smart appliances is expected to require many of the same **skills, technologies** and **supply chains** being developed in other related areas such as accessing flexibility from EVs. There were no identified **resource availability** challenges, and the manufacturing, aggregator and supplier **company landscape** are perceived to be mature and competitive even now.

Domestic DSR - key barriers

There are certain barriers across the market enablers which risk holding back the potential for domestic DSR from smart appliances, up to 2030 and beyond. There exist **stakeholder acceptance** issues with smart meters, which may well be amplified in the case of smart appliances. Concerns around autonomy, cybersecurity and privacy, as well as exposure to higher prices from time-of-use tariffs, could act as key barriers to the uptake of smart appliances that can provide DSR.

Consumers' **willingness to pay,** irrespective of any stakeholder acceptance issues, may also be problematic. The lifetime cost of non-smart appliances with non-smart tariffs may be more expensive, compared to smart alternatives linked to time-of-use tariffs in the future. The monetary value that can be derived from shifting the time of appliance use will relate to the pricing signals of the tariff itself. The analysis carried out as part of this work suggests a maximum of c.£17bn annual savings from all forms of flexibility across the energy system including DSR from smart appliances. While this is a large value at the systems and societal level, it might not be financially attractive enough at an individual or household level to drive significant change in behaviour.

Given that only 21% of households switched supplier in 2019[31] despite the potential for significant financial consumer benefits, this suggests a lack of engagement or awareness. This highlights that more attention will need to be invested in engaging with the public in order to achieve high levels of deployment of DSR capacity from smart appliances. This public engagement strategy may need to be based on non-financial incentives and/or an increased emphasis on automation over behaviour change.

A collation of all evidence used to support the assessment can be found in Appendix 2.

31 Energy UK, 2021 https://www.energy-uk.org.uk/publication.html?task=file.download&id=7804

4.3. DSR from the non-domestic sector

Quantifying flexibility

Model inputs

The non-domestic electricity demand covers demand from both large industrial and commercial users, as well as small businesses, and amounts to an annual demand of 243TWh. The IWES model assumes 20% of non-domestic demand can be shifted during each day. It is also assumed that the demand is shifted with 95% efficiency, and the flexibility comes at a cost of £244/kW.

Flexibility in operation

Figure 94 shows the demand curves of non-domestic demand before and after DSR is implemented, and the difference between the two, i.e. the demand shifted. This data is from the electric heating scenario for the week of the extreme weather event in which there are very cold temperatures (and therefore a high heat demand) and very low wind supply. The results show that as a result of DSR, demand drops by up to 11GW across the morning and evening peaks on Wednesday, Thursday and Friday, from around 50GW to 40GW, and demand increases by 11GW overnight.

Figure 94. Non-domestic demand, before and after DSR implemented, during the week of an extreme weather event in winter (electric heating scenario)

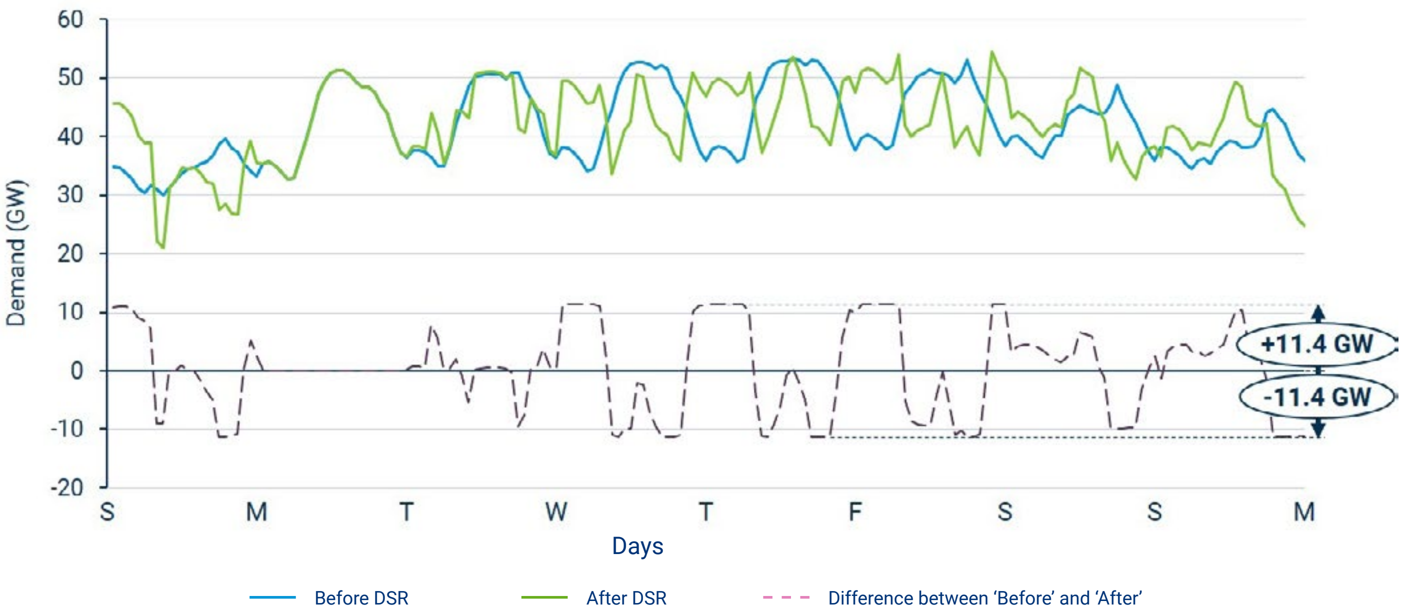


Figure 95. Non-domestic demand flexibility across a typical week in each season (electric heating scenario)

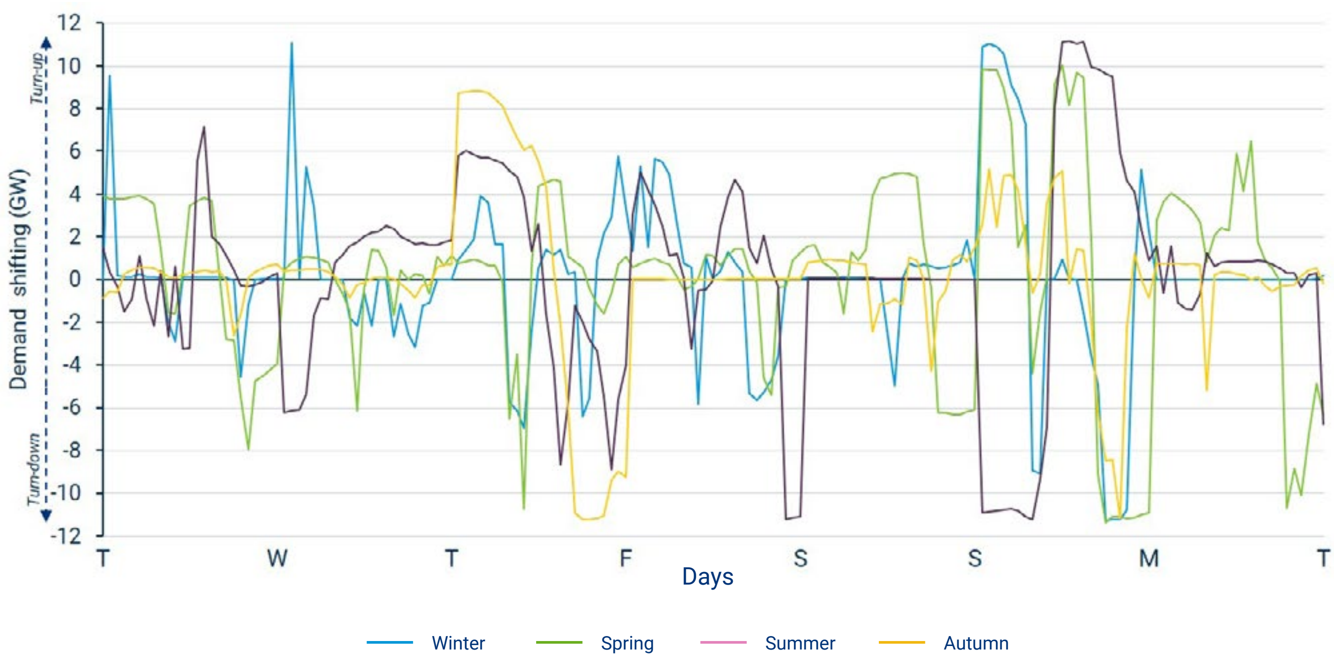


Figure 95 shows the flexibility of non-domestic demand across four different week-long periods throughout the year for the electric heating scenario. It demonstrates that turning demand up or down by the maximum 11.4GW isn't uncommon, and takes place at all times of the year, rather than just on a few isolated incidents, such as during the extreme weather event in winter.

It also shows that its operation doesn't follow as regular a pattern as the domestic DSR, as seen in Figure 92. This is likely driven by the fact that the cost of non-domestic DSR (£244/kW) is assumed to be much higher than for domestic DSR (£28/kW).

Delivering flexibility

Unlocking flexibility

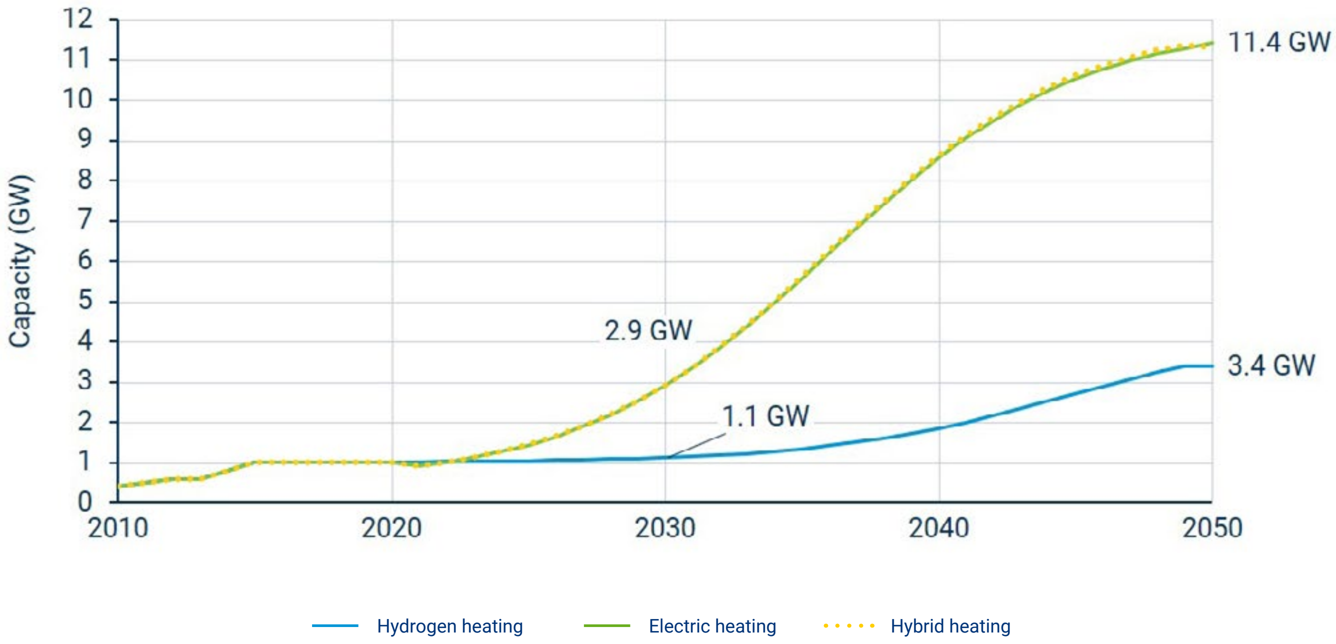
Flexibility in the non-domestic sector can include non-domestic consumers on different types of time-of-use tariffs, with the ability to shift demand accordingly (e.g. through smart appliances), as well as demand turn-down/turn-up actions responding to signals within specific electricity system operators (ESO), distribution system operators (DSO) and/or other markets for DSR. The provision of flexibility will be different according to the type of non-domestic energy consumer, including large industrial users who run energy intensive operations, commercial offices with building management systems linked to space heating and cooling and small businesses who could use smart appliances linked to time-of-use tariffs.

Indicative 2030 deployment level target

Figure 96 shows the indicative deployment trajectory of non-domestic DSR required to reach the levels estimated by the modelling across the three heating scenarios. The values for I&C DSR from 2010 to 2020 were sourced from National Grid's Future Energy Scenarios (FES) 2020, which estimated 1GW of industrial and commercial DSR capacity online today. The estimated deployment curves for 2030 in the electrified heating and hybrid heat pump heating scenarios suggest a potential required capacity of about 3GW by 2030, with practically no growth needed in the hydrogen heating scenario between now and 2030.

For reference, Ofgem estimates that 3GW of DSR potential from large industrial and commercial users existed in GB in 2016. National Grid's FES 2020 scenarios estimate a range for I&C non-heat pump-related DSR in 2050 of between 2.0-7.2GW.

Figure 96. Indicative deployment trajectory of non-domestic DSR across the three core scenarios



Deployment readiness assessment non-domestic DSR

Non-domestic DSR can be broadly split into DSR from large energy users (e.g. steel and manufacturing industries), commercial users (e.g. airports, water utilities, data centres, office buildings and universities), public sector sites (e.g. hospitals) and SMEs (e.g. retail sites, hospitality, etc.). This analysis looks at barriers to unlocking DSR across both large and small energy users. However, there are different opportunities and challenges associated with each.

Table 10. Deployment readiness assessment summary for non-domestic DSR

Theme	Indicator	Barrier assessment
Enablers	Enabling infrastructure	
	Regulatory environment	
	Stakeholder acceptance	
	Level of political support	
Business model	Availability of funding	
	Willingness to pay	
	Financial performance	
	Market opportunities	
Capability to deliver	Resource availability	
	Technical performance/TRL	
	Supply chain and skills	
	Maturity of company landscape	

Non-domestic DSR - Where are we on track?

Some of the **enabling infrastructure** already exists, such as the presence of building management systems in large commercial buildings. Other potential key enablers are ongoing, such as the rollout of smart meters at non-domestic sites. The regulatory environment has been, and continues to be, in a state of development. Although the outlook is positive, the dynamic nature of the **regulatory environment**, such as Targeted Charging Review (TCR) and the Capacity Market, impacts certainty of revenue streams and hampers today's business case for unlocking flexibility.

The **maturity of technologies** required to unlock non-domestic flexibility is relatively far along in terms of control hardware and software. However, smart appliances haven't yet reached market maturity and much more work is required to enable some heavy industrial sectors to adapt their processes and develop the confidence to provide flexibility. The costs today of instrumentation and controls are similar across a small commercial site and a large site, despite the difference in size of the flexible load. This makes the business case difficult, particularly for the smaller end of the non-domestic market. Therefore, further effort is required to develop and commercialise low cost plug-and-play-type solutions to monitor and control loads in smaller sites.

Many of the **relevant skills and supply chain** expertise exists already. It was the view of some consortium partners that there are perhaps fewer opportunities for a skilled workforce to exploit, rather than a lack of skilled workforce to meet the opportunities that exist today. As these opportunities develop, the supply chain and skills were likely to develop in tandem without significant issues.

The **maturity of the company landscape, availability of resources, funding, and political support** are not seen to be the cause of any strong barriers to the deployment of, or ability to access, DSR within the non-domestic sector.

Non-domestic DSR - Key barriers

The key barriers identified were the concerns that businesses and non-domestic sites had surrounding the **perceived risks** of taking part in DSR to their primary business, which outweigh the **relatively small financial gains** they receive from doing so. The **markets** exist for providing flexibility, such as through ESO and DSO services, as well as emerging smart time-of-use tariffs. However, the value to be gained from engaging with them does not yet overcome perceptions of risks to primary business operations, cybersecurity concerns in regards to sharing data with outside parties and hardware that could potentially be hacked, and the upfront cost and time required to unlock flexibility. This has the potential to change over time as the penetration of renewables increases, and price signals boost the value that can be obtained through engaging in flexibility. However, **stakeholder acceptance** issues will likely remain, particularly when going beyond the sectors that currently provide flexibility, such as cold storage warehouses and water utilities.

A collation of all evidence used to support the assessment can be found in Appendix 2.

4.4. Electric vehicles (EVs)

Quantifying flexibility

Model inputs

The IWES model assumes that the entire passenger fleet (i.e. both domestic and non-domestic) will have been electrified by 2050. This includes cars and light goods vehicles (LGVs) but excludes HGVs and trains.

It assumes that 72% of charge points can facilitate smart charging, and a further 27% of charge points are V2G capable, meaning they can facilitate injection of energy back into the grid. It assumes that 80% of daily EV demand (annual demand: 111TWh) can be shifted throughout each day, when compared to a baseline demand profile of unmanaged charging. It is also assumed that a further 25% of the load that is avoided during any time period can be injected back into the grid through V2G.

Flexibility in operation

Figure 97 shows the demand curves of EVs before and after smart charging and V2G is implemented, as well as the difference between the two, i.e. the demand shifted. This data is from the electric heat scenario for the week of the extreme weather event in which there are very cold temperatures (and therefore a high heat demand) and very low wind supply. The results show that demand drops almost entirely during the day when compared to the unconstrained EV demand profile, with the vast majority of charging taking place overnight. The model's output value for EV flexibility capacity (48GW) therefore represents the largest demand difference recorded across the year, compared to the non-optimised charging baseline demand curve.

Figure 97. Time series data outlining the EV demand changes during a week in winter, including the extreme event (electric heat scenario)

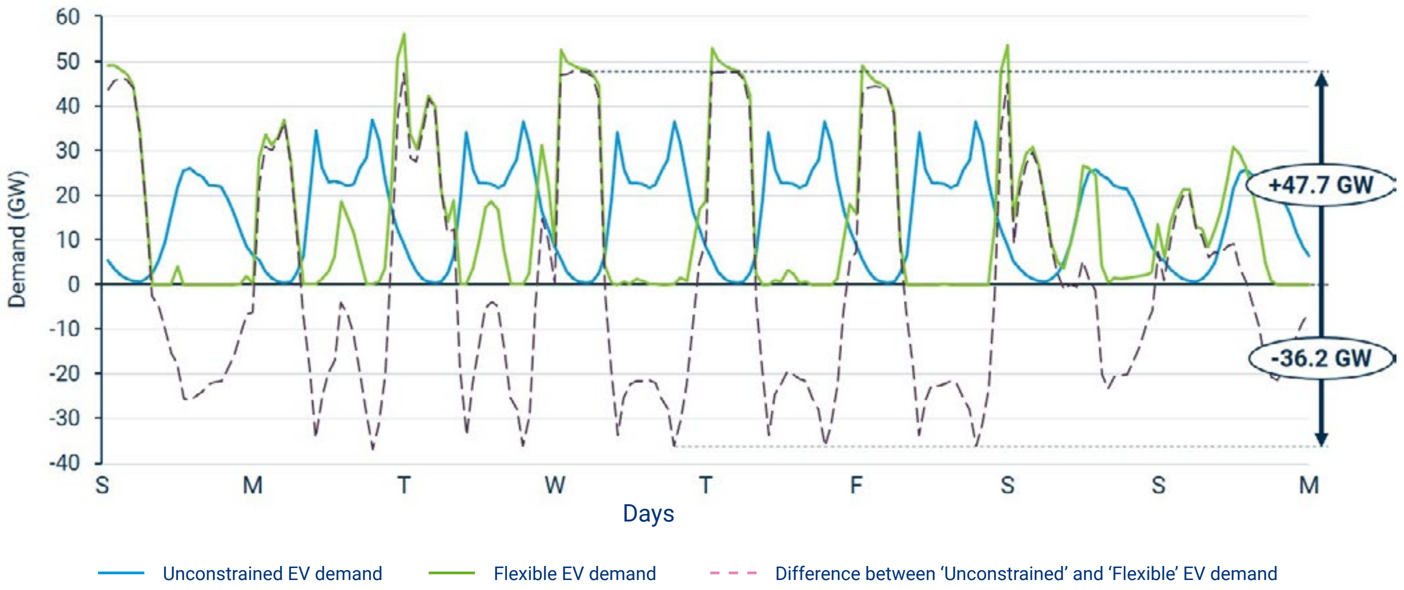
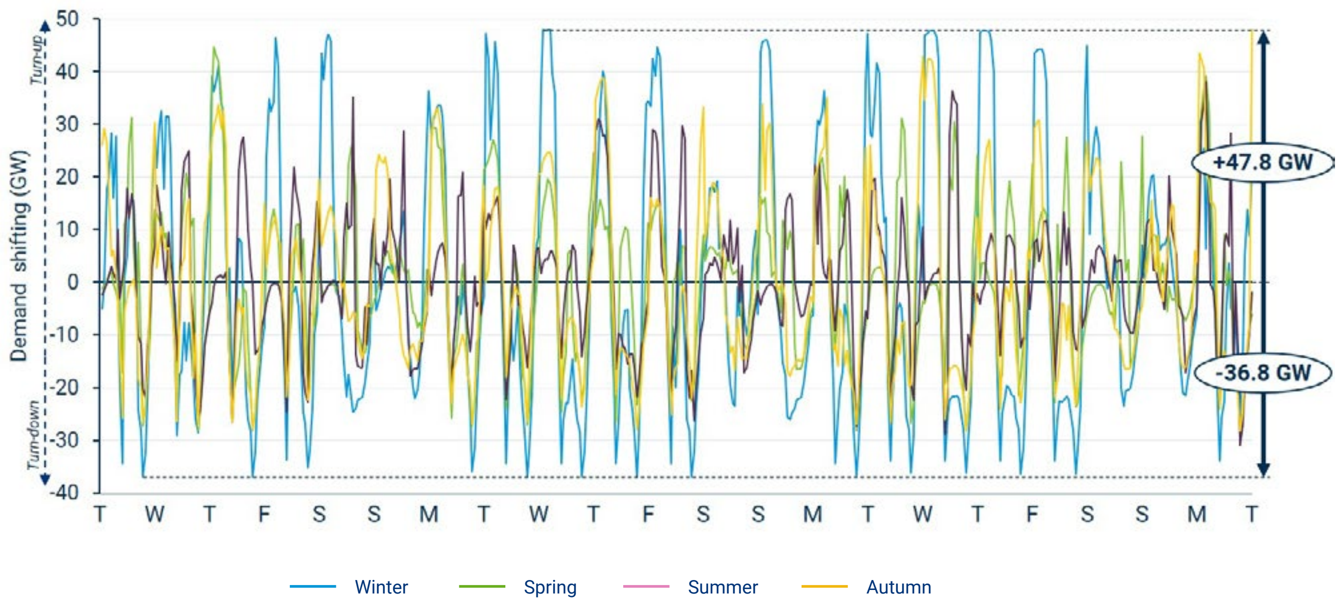


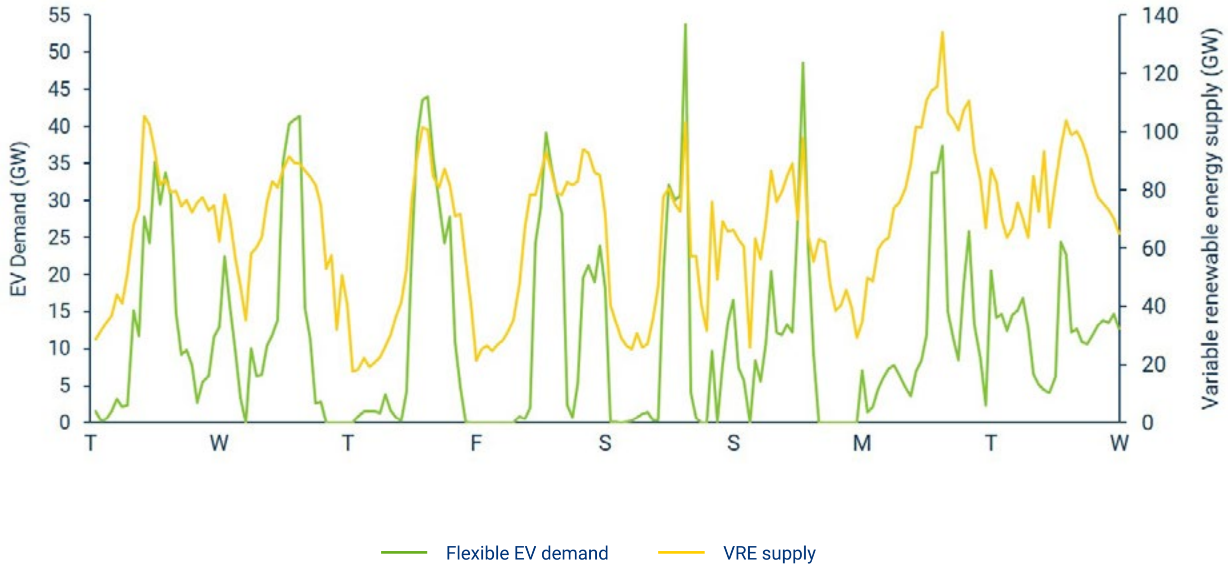
Figure 98. Seasonal variation of demand shifting of EV demand in the electric heating, high flexibility scenario



This change in demand is not unique to the extreme weather event. Figure 98 shows the shift in EV demand across three typical weeks in each season for the high flexibility electric heating scenario. Demand is regularly shifted from taking place during the day to overnight. This is especially the case during winter, where electrified heat demand drives more shifting of EV demand, hence the increase in frequency of 30+ GW of demand shifting compared to other seasons.

Although EV demand is generally shifted to take place overnight, this isn't always the case. Figure 99 shows a week during the summer in which the typical morning and afternoon peaks are reduced, but demand increases during the middle of the day to align with variable renewable energy supply.

Figure 99. Flexible EV demand and variable renewable energy supply during a week in summer in the electric heat scenario



Delivering flexibility

Unlocking flexibility

Flexibility from EVs is expected to come in two key forms: smart charging and V2G. Smart charging, whereby the charging of vehicles is optimised according to smart tariffs and consumer needs, is the cornerstone of enabling a flexible load.

V2G is available across 25% of the passenger fleet and may be more typically enacted by commercial fleets. V2G enables EVs to discharge energy from their batteries into the grid, which can help to reduce peak demand even more so than smart charging, and can also provide grid services such as fast frequency response. V2G requires compatible vehicles and chargers, but also needs the right market and regulatory environment so that V2G providers are incentivised to provide a V2G service.

Broadly speaking, the three underlying aspects which would need to be met by 2050 to unlock the amount of flexibility optimised by the model are:

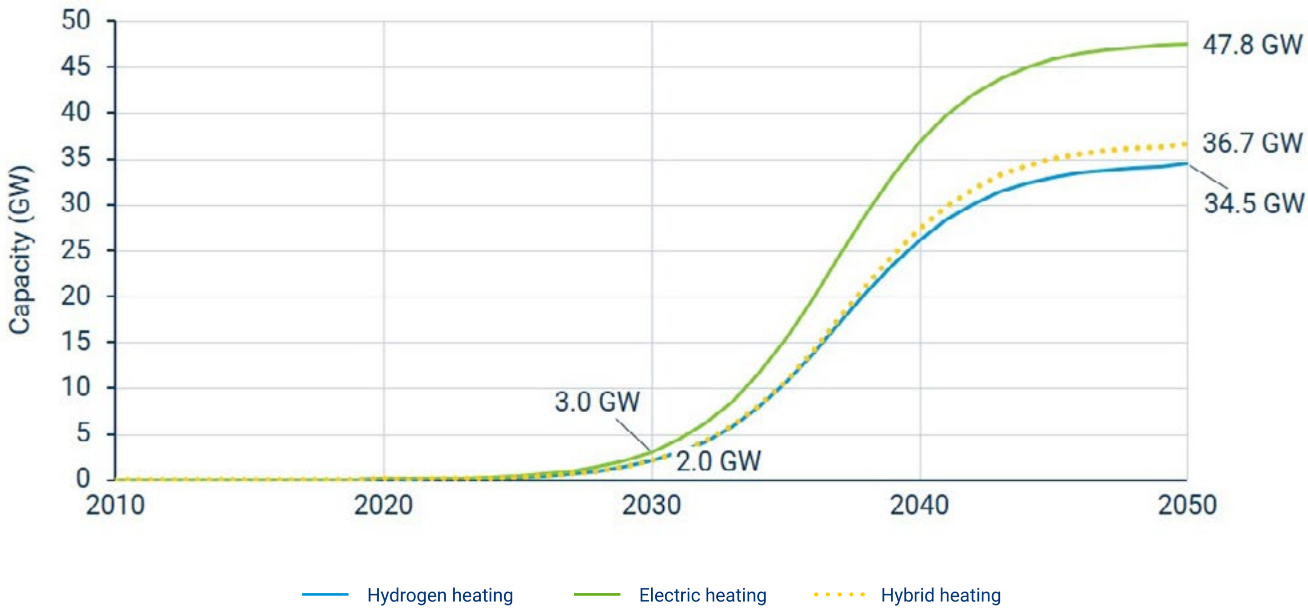
- The total electrification of cars and LGVs.
- 99% of charge infrastructure being smart, with 27% of chargers V2G compatible.
- High uptake of smart charging (i.e. tariffs), leading to 80% of the EV load to be 'shiftable', compared to an unconstrained baseline.

Indicative 2030 deployment level target

Figure 100 shows the deployment levels of flexibility from EVs across the three core heating scenarios, and the indicative deployment trajectories from 2020 to 2050. The level of flexibility in 2050 ranges from 34.5-47.8GW, despite all three heating scenarios having the same underlying assumptions about the capacity for EVs to provide flexibility. The difference in results is due to the needs of the system to access flexibility from EVs.

The estimated target level of flexibility for EVs in 2030 ranges between 2-3GW, although this is system contextual. In reality, it will be determined by the number of EVs on the system, the level of uptake of smart charging (V1G) and V2G, and the system's need for EV flexibility in 2030. It was assumed that most of the growth in EVs would take place after 2030, in line with the ban on sales of new internal combustion engine (ICE) vehicles from 2030.

Figure 100. Indicative deployment trajectory of flexibility from EVs across the three core scenarios



Given the ambitious prerequisites to unlock the levels of flexibility assumed in the model as outlined in the previous section, reasonable 2030 interim targets could be:

- Ensuring that GB is on course to have all passenger vehicles electrified by 2050.
- Ensuring all chargers are smart (i.e. V1G capable) and supporting the growth of V2G charging and business models.
- High uptake of smart charging (V1G) and consumer engagement, with commercial use of V2G.

National Grid's latest FES scenarios estimate EV deployment in the UK could range from 3.6-11.7m vehicles in 2030. However, FES also estimates the total electricity demand from EVs in 2050 to range from 81-87TWh, compared to 111TWh in the IWES model. Alternatively, the Climate Change Committee (CCC)'s Sixth Carbon Budget estimates a battery electric vehicle (BEV) fleet of 48-49m vehicles in 2050 (equating to 104-140TWh annual demand), with 11m-15m EVs in 2030 (equating to 41-49TWh annual demand). There is a broad range in estimated level of deployment for EVs in 2030 across the FES and CCC's scenarios (4m-15m), as well as for 2050.

The smart charging capability assumptions used in IWES modelling are based on FES's Consumer Transformation assumptions for 2050. The Consumer Transformation scenario for 2030 estimates 11.1m EVs on the road by 2030 (about a third of the total expected in 2050). If a third of the UK's passenger fleet are EVs by 2030, it is likely that the potential capacity of EV flexibility would be considerably higher than 3GW in 2030, potentially nearer to 16GW (a third of the 48GW achievable with total fleet electrification).

Deployment readiness assessment

The following analysis considers the extent to which GB is on the right track to achieve the indicative 2030 deployment targets for flexibility from EVs.

Table 11. Deployment readiness assessment summary for EV flexibility

Theme	Indicator	Barrier assessment
Enablers	Enabling infrastructure	
	Regulatory environment	
	Stakeholder acceptance	
	Level of political support	
Business model	Availability of funding	
	Willingness to pay	
	Financial performance	
	Market opportunities	
Capability to deliver	Resource availability	
	Technical performance/TRL	
	Supply chain and skills	
	Maturity of company landscape	

Electric vehicles - Where are we on track?

The **political support** is there to accelerate the transition to electrified transport, as demonstrated by the ban on new petrol and diesel cars and vans in 2030 and by a wide range of grants and financial support being provided to early adopters and local authorities to develop public charging infrastructure.

Stakeholder acceptance issues are expected to be more problematic for EVs (range anxiety) and V2G, than for V1G, at least in the short to medium term. However, the results in Figure 97 and Figure 99 suggest periods where total EV charging is near zero. This would likely require charging to prioritise the needs of the grid over personal preferences, and as such will likely come up against stakeholder acceptance issues. It is critical to ensure a smooth consumer experience for EV flexibility (from access operation and billing) without any compromise in the mobility needs of the consumer, which is the primary purpose of the vehicle.

Generally speaking, the **regulatory environment** is moving in the right direction, with a particular focus being placed on how to ensure that the energy system can make use of the flexibility offered by EVs.

There are no key barriers to the business model indicators for EV flexibility. The **market opportunities** are emerging already for EV specific smart tariffs, as well as the initial examples of commercial DSO contracts for aggregated EV flexibility. While V1G today can help lower the cost of ownership for EV owners, actual uptake of EV specific tariffs by new EV owners is less than 50%,[32] indicating potential **willingness to pay** issues or simply a lack of awareness of the benefits. The **financial performance** for V2G isn't yet there, but is expected to improve in the next decade as the cost of chargers come down and the value proposition and associated business models for V2G provision mature. Furthermore, **financial incentives** have been made available to early adopters of EVs, as well as for relevant innovation trials, to help push the market forwards.

There are some potential concerns surrounding the capability to deliver the scale of flexibility indicated by the model. Assuming lithium-ion batteries continue to be the battery of choice for EVs, there could be **resource availability** constraint concerns related to the deployment of EVs. The **supply chain and skills** were perceived to be relatively strong in the UK, given the expertise across industry and academia. DNOs may struggle to deliver the amount of network reinforcement and connections that might be required once the deployment of EVs and charge points accelerates. However, increasing flexibility of charging can help to reduce the amount of reinforcement required. The **maturity of the company landscape** was seen to be positive, with many industry players competing to innovate and understand their role in the future value chain. Nevertheless, there is a concern that there could be a stifling of innovation as different players remain closed on issues such as energy data.

Smart charging is a mature technology today. BEIS and the Office for Zero Emissions Vehicles (OZEV), in partnership with Innovate UK, have funded V2G trials, however the technology is still relatively immature and untested and will require further demonstrations and real world trials.

32 DeltaEE, Residential Charging webinar, 2020. https://youtu.be/Yo68mpwQ8Cg?t=1045

Electric vehicles - Key barriers

There is no flexibility from EVs without the appropriate charging infrastructure. In order to unlock flexibility, there are key pieces of **enabling infrastructure** that are required: EVs (including those that are V2G compatible), smart chargers and V2G compatible smart chargers. Deployment levels of both electric vehicles and charging infrastructure are limited today, but there are signs to suggest that they will be accelerated in the next decade. However, the scale of the challenge is significant and cannot be overlooked.

There is also a lack of clarity around the future of **scalable cost-effective data access** (e.g. DCC-type model) and **secure control of distributed flexibility assets** (including EVs) and **clear roles/responsibilities of different parties**.

A collation of all evidence used to support the assessment can be found in Appendix 2.

4.5. Thermal energy storage (TES)

Quantifying flexibility

Model inputs

Domestic space heating in 2050 was assumed to be 10.2MWhth per household per year, and domestic water heating was assumed to be 1.9MWhth per household per year. This equates to 282.6TWhth per year for domestic space heating, and 66TWhth per year for domestic water heating. Total annual demand for non-domestic space heating was 125.2TWhth and non-domestic water heating was 28TWhth.

The 2050 model assumes 20% of heat is met by district heat networks in urban areas in all three heating scenarios. These schemes are powered by industrial scale ground-source or water-source heat pumps. In the low flex scenarios, the district heating schemes are installed with a fixed amount of TES that enables the provision of six hours worth of thermal energy at a time of peak thermal demand. This equates to 53GWth / 318GWhth of TES. In the high flex scenarios, the model allows the further installation of TES to optimise the system.

The remaining domestic households and non-domestic spaces meet their space and hot water heating needs through different heating technologies, depending on the heating scenario (details outlined in Section 4.1). All building scale ASHPs are installed with a minimum of 2kWh (2kW) of TES, in the form of a hot water tank.

The model optimises how much TES should be deployed both at the building-level and linked to district heat networks. The model assumes a TES cost of £11/kWhth for district heat networks, £103/kWhth for residential buildings, and £75/kWhth for non-domestic buildings.

The TES is modelled to lose 1%[33] of its stored heat every hour, meaning a fully charged storage system will lose all its heat after about four days. This incentivises using energy directly rather than storing it.

33 After 10 days, more than 90% of heat stored would have been lost.

Flexibility in operation

TES enables the demand from the industrial heat pumps that supply the district heating networks to be decoupled from the supply of energy. Figure 102 shows the industrial heat pump demand (which supplies all the heat for district heating schemes) during a week in winter. It's important to note that the low flex scenario still has a considerable level of TES deployed, enabling the flexibility of industrial heat pumps through the decoupling of supply and demand. The additional deployment of TES seen in the high flex scenarios enables a slightly lower level of capacity required of the industrial heat pumps, reducing in deployment capacity from about 11GW to 10GW.

Figure 101. Heat supply during a typical week in winter in the electric heating, high flexibility scenario

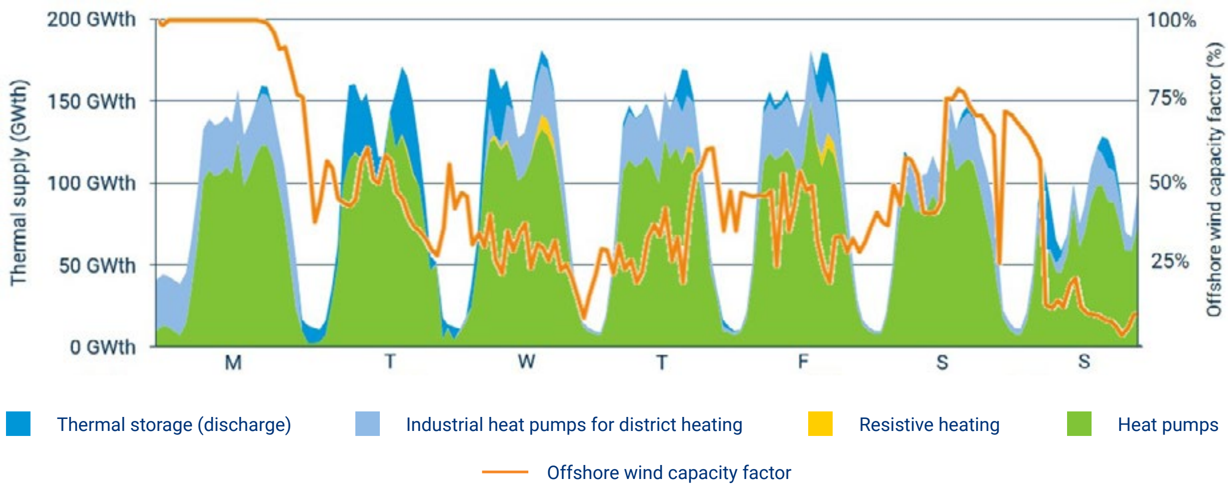
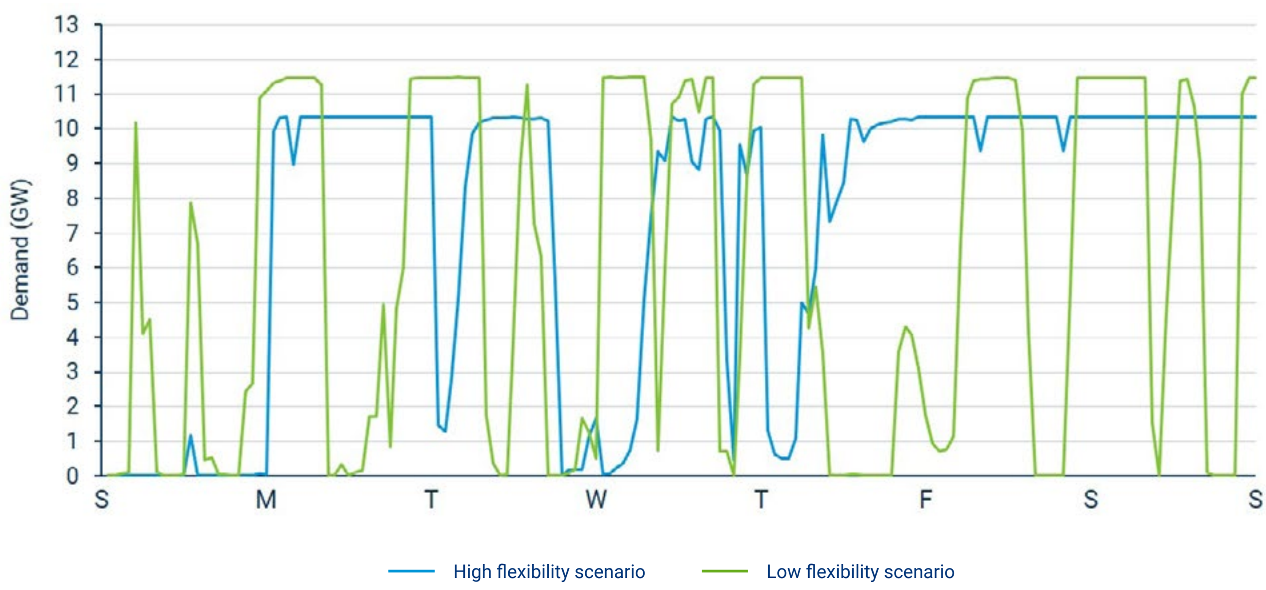


Figure 102. Industrial heat pump demand in the electricheating scenario, for a week in winter



2050 deployment results

Figure 103. 2020 and 2050 estimates of TES deployment across high flex heating scenarios

Figure 103 shows the deployment of TES in 2050 across the three heating scenarios with high flexibility. Significant amounts of TES for district heating schemes are deployed across all scenarios. This level of TES deployment enables the storage of about one to two days' worth of thermal demand for district heat schemes. This helps to support the system through critical supply periods and enables significant flexibility for 20% of GB's heat demand, as the industrial heat pumps supplying district heat networks can be used at optimal times for the system.

Two key reference points are the level of TES installed today (estimated to be roughly 150GWh) and an estimated forecast by the Energy System Catapult's clockwork model for 2050[34], which estimated about 655GWh of TES deployed (split across c.290GWh for buildings, and c.365GWh for district heating).

The high levels of district heating TES across all three models are driven by their very low price point (£11/kWhth). On the other hand, TES for buildings (ranging between £75-£103/kWhth) was only developed at a limited scale.

There is more TES in buildings today than would be required in 2050, based largely on the fact there are c.125GWhth of legacy electric storage heaters present in homes today that have been assumed will be decommissioned in the next three decades. There are also an estimated c.10m water tanks in the UK today[35], which would equate to 20GWhth of thermal storage assuming 2kWhth storage per hot water tank.

For the electric heating scenario, where the remaining 80% of heat that isn't provided by district heat schemes is provided by ASHPs, there is 74GWhth of building-scale TES deployed. The vast majority of the TES deployed at building-level (55GWhth) was driven by the input assumption that each ASHP in buildings is installed with a 2kWhth TES unit.

34 Thermal Energy Storage for Heat Networks, Energy Systems Catapult, 2020. https://es.catapult.org.uk/reports/storage-and-flexibility-thermal-energy-storage-for-heat-networks/

35 BEIS, Evidence Gathering: Thermal Energy Storage (TES) Technologies, 2016

Delivering flexibility

Unlocking flexibility

In order to achieve optimal levels of TES in district heat networks for 2050, it is worth considering the district heating network supplied by heat pumps with TES as the flexible asset, rather than just the TES asset in isolation. Newly built heat networks have a designed lifetime of 60 years, meaning that all need to either be powered by heat pumps and integrated with TES or be built so that retrofits are possible and cost-effective to add increasing levels of TES in future.

The Association of Decentralised Energy estimated that 7% of the UK's 5,500+ district heating schemes use a thermal store. Most district heating schemes today are supplied by gas-powered CHP plants, with only 1% of heat networks having their heat supplied by heat pumps[36].

Indicative 2030 deployment level

The 2050 modelling outputs show that the deployment of TES is dominated by TES connected to DHNs supplied by industrial heat pumps. If heat networks supplied by industrial heat pumps are built, there may be only a few barriers to the deployment and operation of TES.

The deployment of building-level TES was not prioritised by the model, likely as a result of the relative cost of domestic TES as a source of flexibility compared to other sources. What building-level TES was installed in the electric heat scenario was predominantly due to the hot water tank assumed to be installed alongside a heat pump, which has its own challenges and is not the focus of this report. As such, the following analysis focuses on TES for heat pump powered DHNs, and some of the key barriers identified are also barriers to the deployment of heat pump-supplied district heat networks.

Based on the 2050 results, an indicative interim deployment level for 2030 could be:

- **5% of heat being met by heat networks supplied by industrial heat pumps, with no new combined heat and power (CHP) networks being built.**
- **All new heat networks to plan sizing and operation of TES suitable for a net zero energy system.**
- **Low cost, high energy density TES technologies are commercially available.**

36 Heat Networks in the UK, Association for Decentralised Energy, 2018. https://www.theade.co.uk/assets/docs/resources/Heat%20Networks%20in%20the%20UK_v5%20web%20single%20pages.pdf

Deployment readiness assessment

Table 12. Deployment readiness assessment summary for TES

Theme	Indicator	Barrier assessment
Enablers	Enabling infrastructure	
	Regulatory environment	
	Stakeholder acceptance	
	Level of political support	
Business model	Availability of funding	
	Willingness to pay	
	Financial performance	
	Market opportunities	
Capability to deliver	Resource availability	
	Technical performance/TRL	
	Supply chain and skills	
	Maturity of company landscape	

Thermal energy storage (TES) - where are we on track?

There are **market opportunities** for flexibility, through purchasing power using time-of-use tariffs, entering DSO markets (albeit very location-specific), and engaging in the Balancing Mechanism (BM). The capacity market has been opened up to DSR for 15 year contracts, and this could be a mechanism to support the business case for district heat networks with heat pumps and TES.

There isn't perceived to be a **resource availability** challenge other than physical space in dense areas, and the **supply chain and skills and company maturity** were not noted as being problematic given the players involved in DHNs, aggregation and heat pumps. However, compared to other forms of energy storage, there are fewer large industry players exploring the opportunities for next generation TES technologies.

There is a need to accelerate the commercialisation of highly energy dense TES **technologies** to mitigate the space premium barrier to deployment and enable (cost-effective) bulk storage. Currently, the majority of district heating scale TES uses hot water tanks. However there are earlier stage technologies, such as those that use phase change materials and thermochemical storage media, that can enable the high energy densities. These technologies have been demonstrated internationally, but not yet in the UK.

Thermal energy storage (TES) - key barriers

There are several barriers to the deployment of heat pump powered DHNs, which is the key piece of **enabling infrastructure**. This is partly due to the lack of **political support** and certainty around the heat decarbonisation strategy (although the government's Heat and Buildings Strategy should be on its way). A firm strategy will signal the future role that heat networks will play and how they will be supplied (CHP and/or heat pumps).

The **regulatory environment** isn't regarded as a particularly strong barrier. However, the lack of cross-vector regulation was noted as impeding the role that TES and heat pumps can play through providing cross-vector flexibility. There is negligible regulation specific to TES. The Association for Decentralised Energy (ADE)'s voluntary code of conduct is not mandatory, but does set out guidance on sizing TES - although this is for today's needs, rather than future needs where longer-term storage may be required.

For those DHNs that are supplied by heat pumps and are installed with a small TES, the **financial performance** of providing flexibility is mixed. The main value of the TES is to enable the heat pump to minimise part-load operation, and to decouple the supply and demand of heat and power. This peak shaving can help reduce the required size of the heat pump and heat network, as well as reduce the cost of energy through the use of dynamic time-of-use tariffs. On the other hand, the value gained from providing services to the grid today was noted as being relatively small. These weak price signals to engage with flexibility are problematic given the long lifetimes of the DHNs and their associated TES. There is a lack of long-term price signals to incentivise heat network developers to at least futureproof their design so that storage systems can be upgraded to provide more flexibility in future.

There are **funding** mechanisms to support the development of DHNs. However, no funding is ringfenced specifically for TES. The government has recently launched the Longer Duration Energy Storage Demonstration innovation competition, which includes TES within its scope, but broadly speaking there is a general lack of R&D funding for TES technologies, compared to electricity storage technologies. The government has also recently launched a consultation for a Green Heat Network Fund, which could be an opportunity for increased support for DHNs with TES and heat pumps.

Stakeholder acceptance was also highlighted as a minor barrier in project partner feedback. There is a lack of awareness of the potential benefits and importance of the role that DHNs with TES could play to provide flexibility to an energy system with a high penetration of renewables. Furthermore, stakeholders involved in developing DHNs (developers, or those commissioning them, such as local authorities) might be put off by the complexities of DSR and the perceived risk to their operations. This lack of awareness and certainty around the potential future benefits, as well as the financial performance, inhibits the **willingness to pay** for TES and other technological enablers of flexibility. District heating schemes are likely to be developed in areas with a high density of consumers, typically urban areas where the cost of land is high.

4.6. Electricity storage

Quantifying flexibility

Model inputs

In all scenarios, the electricity storage deployed is a mixture of pumped hydro storage and four-hour duration battery storage. The existing pumped hydro storage in Scotland is 740MW with 20h storage (14.8GWh), while the pumped hydro in North Wales is 2GW with 5h storage (10GWh), which in total equates to 2.74GW/24.8GWh pumped hydro storage. The pumped hydro storage was deployed in all scenarios (low and high flexibility). The model allowed other storage assets to be built with the following inputs (note that the prices represent 2050 prices in 2019):

Domestic batteries: 5kW batteries, of four-hour duration at a cost of £413/kWh; round trip efficiency of 85% and two cycles allowed per day.

C&I scale batteries: 5MW batteries, of four-hour duration at a cost of £147/kWh; round trip efficiency of 85% and two cycles allowed per day.

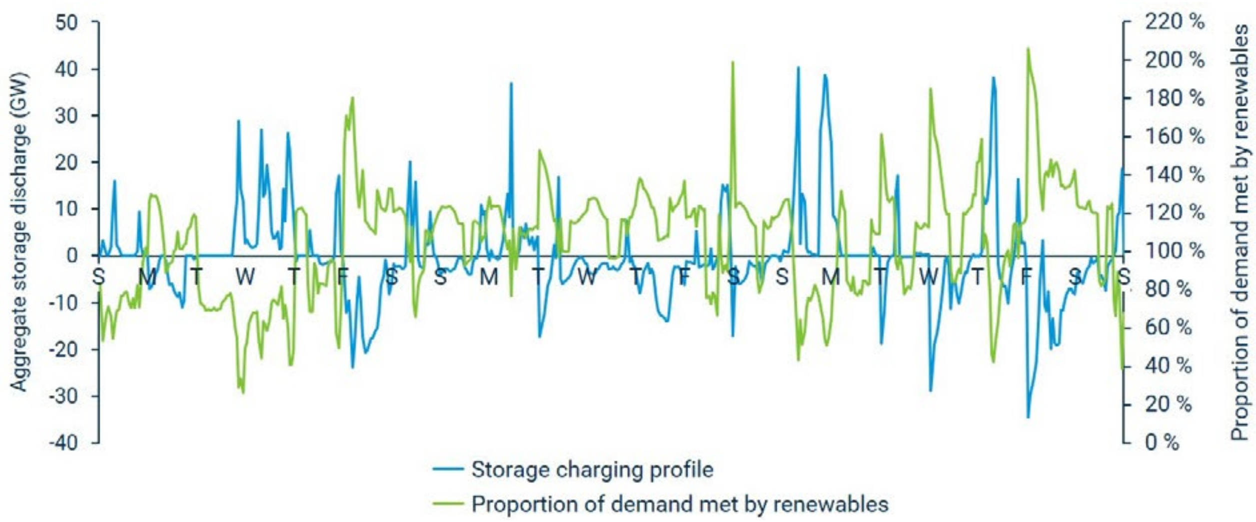
Grid scale batteries: 50MW batteries of four-hour duration at a cost of £55/kWh; round trip efficiency of 85% and two cycles allowed per day.

Flexibility in operation

Figure 104 shows the aggregate charging and discharging profile of electricity storage during a three-week period in spring in the electric heating scenario. Across the year, the peak aggregate storage discharge is 58GW although in the diagram below a maximum of about 40GW is observed.

Figure 104 shows how this aggregate profile behaves on a daily basis, juxtaposed against the ratio of demand (excluding demand from interconnectors and storage charging) to renewable generation[37]. At an aggregate level, it shows that storage helps to provide daily balancing, charging when renewable supply exceeds demand and discharging when demand exceeds renewable supply. Further discussion of electricity storage's contribution to system flexibility in the electric heating scenario can be found in Section 3.2.

Figure 104. Aggregate charge (negative y-axis) and discharge profile (positive y-axis) of energy storage during a three-week period in spring in the high flexibility electric heating scenario



37 When this value is more than 100%, it implies that renewable generation is either being stored in batteries and/or exported through interconnectors.

Delivering flexibility

Unlocking flexibility

The levels of deployment of each technology for each of the high flexibility scenarios across the core heating scenarios are shown in Table 13. There was a wide range of electricity storage being deployed across the three heating scenarios. In the scenarios without electric heating, the model adds only limited extra storage compared to today's levels. However, for the electric heating scenario, the model states the optimal amount of storage is 83GW/347GWh. This is about a twenty-fold increase in terms of GW capacity, and a tenfold increase in terms of GWh capacity, compared to estimated deployment levels today. It is important to note that the scenarios represent different extremes of system development in 2050, so the associated flexibility deployment figures should be viewed as an indication of scale rather than precise estimates.

The growth of storage was delivered exclusively by grid-scale batteries (50MW, four-hour duration, at £55/kWh), likely due to the low CapEx of £55/kWh, which was significantly cheaper than alternative battery types and scales. The batteries were assumed to be lithium-ion. However, other technologies could theoretically also play this role if they fit the right price point, round trip efficiency and response time.

In the electric heating scenario, the maximum aggregate storage discharge at any single point in the year was 58GW, and the equivalent maximum aggregate charge was 38.8GW. However, the sum total of the regional storage discharge maxima, which didn't occur simultaneously, was 74.6GW. The sum total capacity of storage across each region was 83GW. This difference can be explained by the limitation model had to deploy storage assets with four hour duration, meaning that at the aggregate level the model chose to deploy storage based on the total energy (GWh) capacity it could provide the system, rather than the total power (GW) capacity.

Table 13. Energy storage deployment across the core heating scenarios

Item	Hydrogen heating scenario	Electric heating scenario	Hybrid heat pump heating scenario
Pumped hydro (20 hrs)	0.7GW/15.0GWh	0.8GW/15.7GWh	0.8GW/15.1GWh
Pumped hydro (5 hrs)	2.0GW/10.1GWh	2.1GW/10.6GWh	2.0GW/10.1GWh
Batteries (4 hrs)	2.0GW/7.8GWh	80.0GW/320.2GWh	5.9GW/23.6GWh
Total	**4.7GW/32.9GWh**	**83.0GW/346.5GWh**	**8.7GW/48.8GWh**

Indicative 2030 deployment level target

Figure 105. Diffusion curve and trajectory for electricity storage (power capacity GW) to 2050 across the three core scenarios

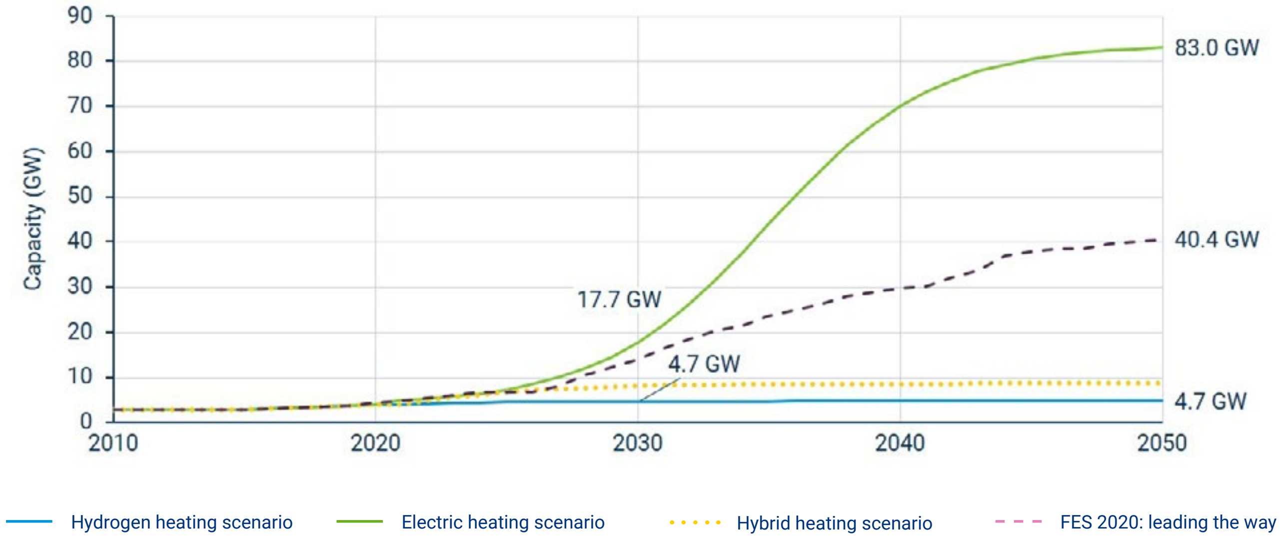


Figure 106. Diffusion curve and trajectory for electricity storage (energy capacity GWh) to 2050 across the three core scenarios

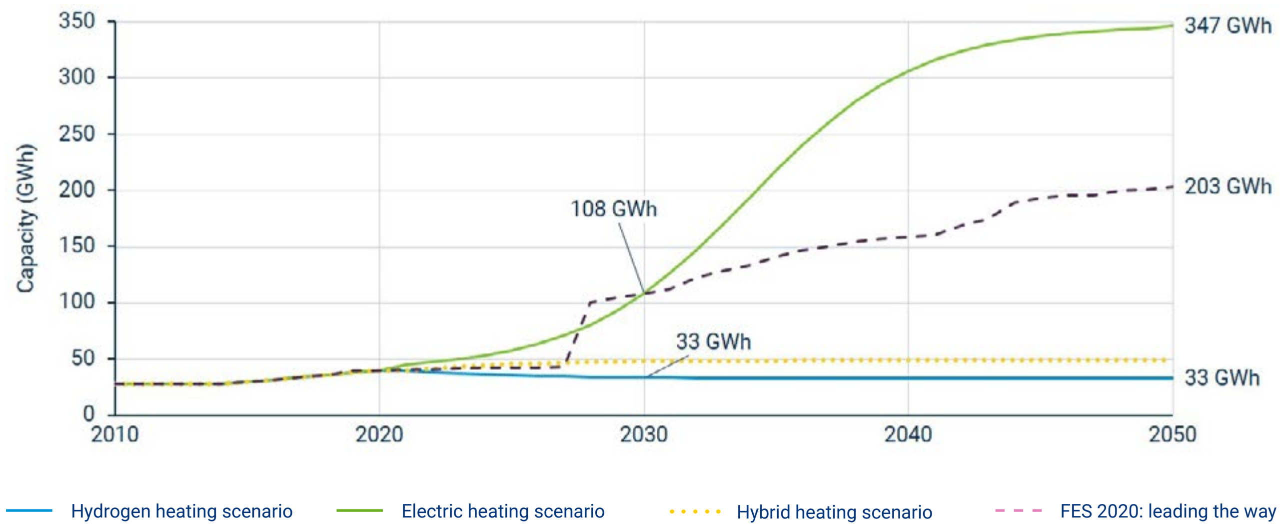


Figure 105 and Figure 106 suggest an indicative deployment of 18GW /108GWh in 2030 in the electrified heat scenario. This would necessitate, on average, the deployment of about 1GW /7GWh of storage each year over the next decade.

National Grid ESO's most ambitious FES scenario in terms of storage deployment, Leading the Way, was plotted alongside the indicative S-curves. The level of deployment up to 2030 is relatively similar. However, after this point the deployment doesn't increase as rapidly, and the final deployment need in 2050 is roughly half the deployment needed in the electric heating high flexibility scenario.

Deployment readiness assessment

Table 14. Deployment readiness assessment summary for electricity storage

Theme	Indicator	Barrier assessment
Enablers	Enabling infrastructure	
	Regulatory environment	
	Stakeholder acceptance	
	Level of political support	
Business model	Availability of funding	
	Willingness to pay	
	Financial performance	
	Market opportunities	
Capability to deliver	Resource availability	
	Technical performance/TRL	
	Supply chain and skills	
	Maturity of company landscape	

Energy storage - where are we on track?

The **financial performance** of storage assets has generally been good, and the cost of batteries continues to drop. Despite this, building investible business cases for storage assets can still be challenging and there are sometimes willingness to pay concerns partly due to uncertainty around long-term revenue streams.

The dynamic **regulatory environment,** such as the TCR, caused uncertainty around the business case for some storage projects and has deterred risk-averse investors. However, the outlook is generally positive in regards to levelling the playing field and closing loopholes. The **political will** is there too: the Energy White Paper (EWP) stated it will define electricity storage in law when Parliamentary time allows, and Parliament will also legislate to remove storage from the Nationally Significant Infrastructure Project (NSIPs) regime, which essentially limited battery projects to <50MW.

In general, the **market** is well set up for storage, with new services introduced by National Grid ESO, improvements to ancillary service markets with day ahead auctions, easier access to the BM and emerging opportunities in local DSO markets, as well as the Capacity Market enabling storage to capture the value it provides to different stakeholders. This is evidenced by the large amount of storage assets in the pipeline (16GW at time of writing), underpinned by a competitive **company landscape** of storage developers, aggregators and innovators.

Energy storage - key barriers

Broadly speaking, there are no significant barriers to the deployment of storage over the next decade. Potential key barriers that may emerge will be related to the scale and pace of deployment. Most energy storage today is in the form of lithium-ion batteries, which have **supply chain** risks and potential **resource availability** constraints for component minerals.

The high levels of storage in 2050 estimated by the IWES model is dependent on the very low cost of four-hour (or longer) storage of £55/kWh, which represents more than a five-fold decrease in costs, compared to the cost of four-hour lithium-ion storage in 2019[38]. There has been a rapid reduction in lithium-ion battery costs over recent years. However, there is an expectation that alternative lower cost bulk storage **technologies** need to be developed and commercialised in the years to come, given the potential resource constraints of materials that go into lithium-ion batteries and competition from the automobile sector. Potential solutions include TES, redox flow batteries and liquid air energy storage among others; this is an area that has recently received demonstration **funding** from the government.

38 Assuming a cost of $380/kWh, from NREL (2020). *https://www.nrel.gov/docs/fy20osti/75385.pdf*

4.7. Hydrogen electrolysers and storage

Quantifying flexibility

Model inputs

Electrolysers provide the means of generating hydrogen from water and electricity. They also act as a form of flexibility: allowing hydrogen to be produced at times of least cost to the wider energy system, reducing the amount of renewable energy that needs to be curtailed, acting as a form of energy storage and enabling integration between gas and electricity networks.

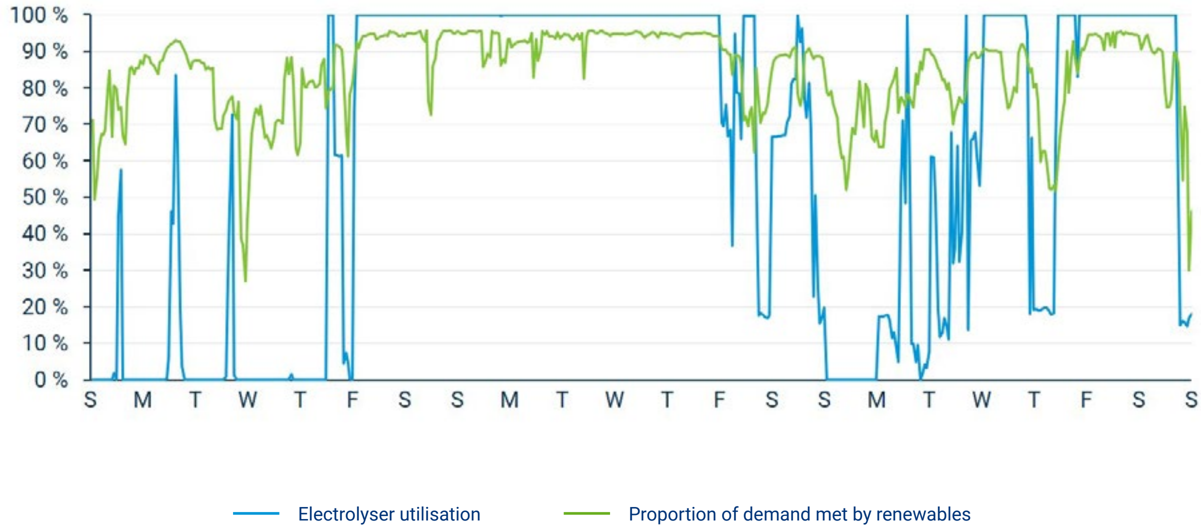
The model was able to choose to build either PEM or alkaline electrolysers. PEM electrolysers in 2050 were assumed to have a CapEx of £340/kW, a fixed OpEx of £29/kW/yr, an efficiency of 48% (in terms of kWe/kg). Alkaline electrolysers were assumed to have a CapEx of £455/kW, a fixed OpEx of £29/kW/yr and an efficiency of 48% (in terms of kWe/kg).

Hydrogen storage can be deployed at two scales - large underground caverns (onshore) or small/medium pressurised overground containers. Specific sites for large hydrogen storage are identified in the modelling inputs (although are not a limiting factor in the scenarios considered in this report) and unlimited small/medium storage can be deployed. There were no limits or differing input assumptions for hydrogen storage between the high and low flexibility scenarios.

Flexibility in operation

Figure 107 shows the utilisation of electrolysers alongside the proportion of electricity demand that is met by renewable generation during a three-week period in spring. The data shows that electrolysers typically operate when there is a very high proportion (typically at least 90%) of demand being met by renewables. Electrolysers therefore serve as a form of flexibility that takes advantage of excess renewable generation to generate hydrogen which can be used later to provide heat or serve other needs, such as in industry, power production and/or for HGVs.

Figure 107. Utilisation of electrolysers versus proportion of demand met by renewable generation during a three-week period in spring in the high flexibility hydrogen heating scenario



Delivering flexibility

Electrolysers have a dual purpose - to produce hydrogen for use across the system and deliver system flexibility in the process. This means that other forms of hydrogen production and sources of flexibility compete with electrolysers for deployment, with the model optimising for overall cost minimisation. Unlike other forms of flexibility, such as DSR and storage, the model did not constrain the deployment and usage of electrolysers, nor the level of hydrogen storage, in the low flexibility scenarios.

Table 15 shows the capacities of electrolysers deployed and their annual capacity (or utilisation) factors. The data shows that in the high flexibility scenarios, the deployment of electrolysers actually decreases, compared to the low flexibility scenarios. This could be because electrolysers are already operating flexibly for system benefit in the low flexibility scenario where there are fewer forms of flexibility for the model to choose from, whereas some of this flexibility gets displaced by other forms in the high flexibility scenarios.

Table 15. Capacity and capacity factors of electrolysers, amount of green hydrogen produced, and levels of hydrogen storage deployed across the three core heating scenarios, both for high and low flexibility scenarios

Heating scenario		Low flexibility	High flexibility
Hydrogen heating	**Capacity**	35.2GW	19.3GW
	Capacity factor	53%	50%
	Hydrogen produced	133TWh HHV [39] (23% of total H2 supply)	69TWh HHV (12% of total H2 supply)
	Hydrogen storage	7.9TWh HHV	10.2TWh HHV
Electric heating	**Capacity**	9.3GW	0.8GW
	Capacity factor	47%	47%
	Hydrogen produced	46TWh HHV (30% of total H2 supply)	3TWh HHV (2% of total H2 supply)
	Hydrogen storage	0.3TWh HHV	0.0TWh HHV
Hybrid heat pump heating	**Capacity**	9.8GW	0.9GW
	Capacity factor	71%	48%
	Hydrogen produced	50TWh HHV (26% of total H2 supply)	3TWh HHV (2% of total H2 supply)
	Hydrogen storage	0.2TWh HHV	0.0TWh HHV

In all cases, the model favoured the deployment of PEM over alkaline electrolysers due to the lower cost of PEM electrolysers in 2050 assumed in the model inputs.

Hydrogen storage was deployed in both the low and high flexibility hydrogen heating scenarios. There was slightly more hydrogen storage in the high flexibility scenario (10.2TWh HHV) than in the low flexibility scenario (7.9TWh). Storage is useful to decouple all forms of hydrogen production from the demand profile, not just electrolysers. Hydrogen storage should therefore enable hydrogen demand to be met by a lower amount of hydrogen production capacity.

Levels of hydrogen storage deployment for the electric heating and hybrid heat pump heating scenarios was close to zero, since the demand for hydrogen for non-heating purposes was assumed to be flat across the year for non-heating purposes.

39 HHV = Higher Heating Value

Indicative 2030 deployment level target

Figure 108. Indicative deployment trajectory of hydrogen electrolyser capacity across the three core scenarios (high flexibility)

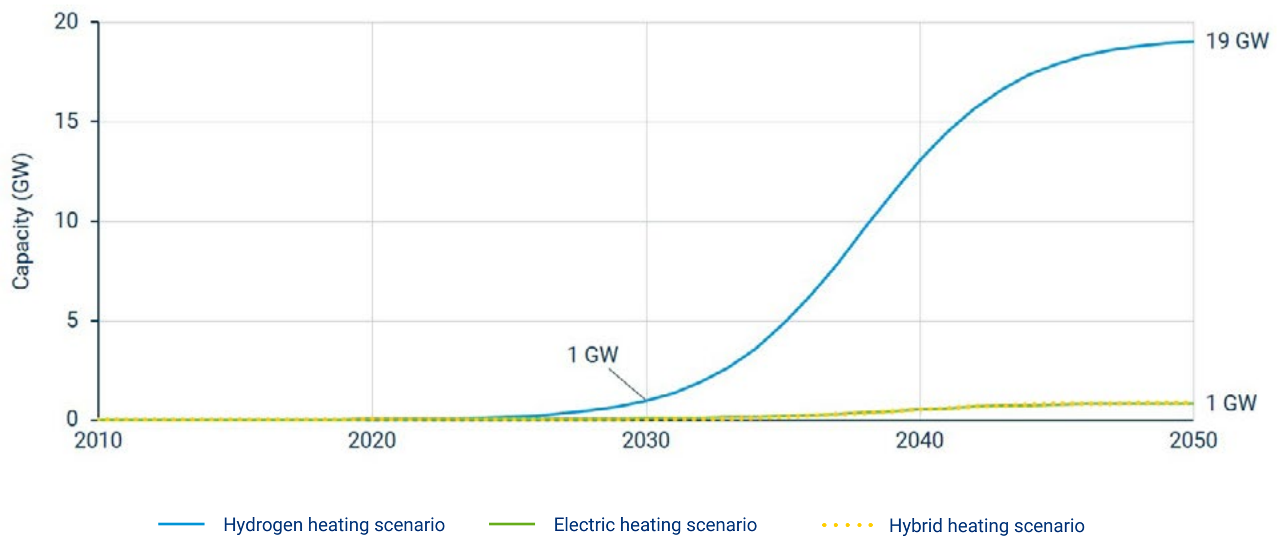


Figure 108 shows the indicative deployment trajectory of hydrogen electrolyser capacity in the high flexibility scenarios. Based on a need for 19GW of electrolyser capacity by 2050 in the high flexibility hydrogen heating scenario (producing 69TWh of hydrogen annually), an indicative estimate for deployment need for 2030 could be around 1GW. It is important to note that the level of hydrogen demand and overall strategy will drive the electrolyser capacity and the figures in the electrified heating and hybrid heating scenario should be seen as an extreme indication only, rather than a target.

The UK government 'hopes to see' 1GW of 'clean hydrogen' production in 2025, and 5GW capacity in 2030 with 42TWh hydrogen produced. However, this refers to both blue and green hydrogen, and it isn't clear to what extent the balance between the two will be. It is worth noting that about 12GW of electrolyser capacity would be required to produce the government's 2030 target of 42TWh hydrogen, assuming the same 50% capacity factor is seen in the hydrogen scenario for 2050.

Deployment readiness assessment

Table 16. Deployment readiness assessment summary for hydrogen electrolysers

Theme	Indicator	Barrier assessment
Enablers	Enabling infrastructure	🟥
	Regulatory environment	🟨
	Stakeholder acceptance	🟨
	Level of political support	🟨
Business model	Availability of funding	🟨
	Willingness to pay	🟨
	Financial performance	🟥
	Market opportunities	🟥
Capability to deliver	Resource availability	🟨
	Technical performance/TRL	🟨
	Supply chain and skills	🟩
	Maturity of company landscape	🟨

Hydrogen electrolysers and storage - where are we on track?

The **regulatory environment** for hydrogen is undergoing changes to allow increased amounts of blending into the gas networks, which is currently limited to 0.1%. However, there is a lack of clarity in the regulatory regime on co-located electrolysers with renewables and stand-alone plants, in terms of network and connection charges, as well as on treatment of hydrogen storage. This is critical to unlock the benefits of flexible operation of electrolysers and effectively deal with over-supply and low-demand events.

In terms of **stakeholder acceptance**, the CCC has evidenced the fact that there is a preference for hydrogen boilers (as opposed to heat pumps) based on the ease of the switch in heating technology from the consumer perspective, although concerns around safety remain. Furthermore, the lack of maturity of the hydrogen market makes it hard to determine levels of stakeholder acceptance and how it compares for green hydrogen versus other forms of hydrogen.

There have been strong signals of **political support** for the growth of clean hydrogen, with a target of 5GW for 2030. However, what is less clear is the extent to which green hydrogen will make up this target. The UK government's Energy White Paper announced that a hydrogen strategy would be published later in 2021, which should provide the roadmap for scaling up green hydrogen. Other indicators, such as the setting up of a £240m fund for hydrogen innovation, suggest the political will is there for developing a hydrogen economy more broadly.

In terms of **availability of funding**, while the government has earmarked £240m for its Net Zero Hydrogen Fund, it is worth comparing the scale of ambition with other countries (e.g.The UK government's Energy White Paper)[40]. There is also a current lack of other financing mechanisms, such as a Contracts for Difference scheme, to incentivise the supply of green hydrogen.

Today it is hard to assess how **willingness to pay** will be a barrier to green hydrogen when compared to blue or grey hydrogen, given that the demand for all hydrogen is nascent. Green hydrogen is currently more expensive and this is expected to continue in the short-to-medium term, but consumers may prefer green hydrogen for its environmental credentials as a zero carbon source of hydrogen compared to blue hydrogen, which still has some emissions associated with it.

Potential **resource** constraints may exist for PEM electrolysers with iridium, and on larger scales there will be increasing demand for electricity and suitable water supply.

In terms of the **technological maturity**, while electrolysers are commercially operational today, further innovation is needed to scale up manufacturing capability, improve technical characteristics and reduce costs to improve the financial performance of green hydrogen compared to blue and grey hydrogen.

The UK benefits from the **skills and expertise** found in a mature oil and gas sector within the gas networks. There are more than 100 companies and 35 research groups active in fuel cell and hydrogen production technologies in GB, and the availability of skilled personnel is expected to grow as market size increases.

40 House of Commons Library, UK Hydrogen Economy, 2020. *https://commonslibrary.parliament.uk/research-briefings/cdp-2020-0172/*

Hydrogen electrolysers and storage - key barriers

The suitability of the current gas **infrastructure** to support the transition to hydrogen is a key barrier, although it is being addressed. Distribution networks have proven to be more amenable to carrying hydrogen. Industry testing is expected to take place in 2023 to allow 20% blending, with a trial of a 'hydrogen town' planned for 2030. However, concerns remain on the suitability of the transmission network to transport hydrogen, and further innovation is required to unlock storage capabilities within salt caverns. Furthermore, scaling up electrolysers also requires a material amount of additional renewable energy infrastructure.

The other key barriers are related to the business model. The challenge is to develop both the supply and demand of hydrogen simultaneously. The UK government is drafting hydrogen potential business models for 2022, as well as investing in developing the demand for hydrogen (green or otherwise). However, this will be particularly challenging for green hydrogen, which is expected to be more expensive than blue in the short-to-medium term.

The **financial performance** of green hydrogen is another key barrier. The financial performance of electrolysers is also related to the capacity factor, assuming revenues proportional to hydrogen produced, and the cost of electricity, as well as both CapEx and OpEx costs. CapEx costs are high today, but expected to fall as economies of scale of electrolyser manufacturing increase. The model's optimal levels of electrolyser capacity across all heating scenarios for the high flex scenario had a corresponding capacity/utilisation factor of about 50%, indicating that the market needs to reward the electrolysers for the system value they provide in addition to direct sales of hydrogen.

4.8. Summary of deployment challenges and the key needs

The assessment below represents a snapshot view of the current barriers to the deployment of each source of flexibility, based on reaching the optimal deployment dictated by the model in 2050.

		Domestic DSR	Non-domestic DSR	EVs	TES	Electricity storage	H2 Electrolysers
	Potential 2050 need	6-12GW	3-11GW	35-48GW	800-900GWh	5-83GW	1-19GW
	Indicative 2030 target	1GW	1-3GW	2-3GW		5-18GW	1GW
Enablers	Enabling infrastructure	Amber	Amber	Amber	Red	Green	Red
	Regulatory environment	Green	Amber	Green	Red	Green	Amber
	Stakeholder acceptance	Red	Red	Amber	Red	Green	Amber
	Level of political support	Green	Green	Amber	Red	Green	Amber
Business model	Availability of funding	Amber	Green	Green	Red	Green	Amber
	Willingness to pay	Red	Red	Amber	Red	Green	Amber
	Financial performance	Amber	Amber	Green	Red	Amber	Red
	Market opportunities	Amber	Amber	Amber	Amber	Green	Red
Capability to deliver	Resource availability	Green	Green	Amber	Amber	Amber	Amber
	Technical performance/TRL	Amber	Amber	Amber	Amber	Amber	Amber
	Supply chain and skills	Green	Amber	Amber	Amber	Amber	Green
	Maturity of company landscape	Amber	Green	Amber	Amber	Green	Amber

Flexibility should be integrated into enabling infrastructure including low carbon heat and transport solutions from the start

A key consideration across the different flexibility technologies assessed is the importance of enabling infrastructure for its cost-effective and large-scale deployment by 2050. For technologies such as DSR (domestic and non-domestic), this is about ensuring the smart meter roll out does not face additional delays and having a clear route to secure cost-effective data access across millions of potential sites/devices. For technologies that are tied to broader strategies around heat and transport decarbonisation, it is important to build flexibility into technologies and service offerings right from the start rather than retrofit in the future which could make it prohibitive. E.g. of such integration includes thermal storage in district heating schemes with heat pumps in domestic and non-domestic buildings and building in smart charging for all EV charging points. Delivering flexibility and associated cost-effective decarbonisation requires coordinated planning and operation across all energy sectors including electricity, gas, hydrogen and transport.

Consumer engagement on flexibility beyond just commercial value is a critical aspect to scaling up flexibility technology deployment

Unlike previous decarbonisation challenges such as large-scale generation, the roll out of flexibility needs to consider users across all stages of deployment. While early adopters of flexibility technology might find the commercial value from participating sufficient and/or be driven by other factors such as interest in new technology, translating this to 'late majority' and 'laggards' will be difficult but important. Taking a rational approach to consumer engagement that is focused solely on commercial value is unlikely to put the sector on a pathway to achieving the GW scale required to deliver material system benefits. Understanding consumer needs, crafting appropriate narratives for different segments and building them into the user experience requires significantly greater focus in technology development and demonstration programmes going forward. This is especially critical for the success of DSR, EV and TES flexibility in which the flexibility integration is tied to the broader challenge of consumer acceptance of new solutions for mobility and heating.

An evolving regulatory environment, combined with potentially low financial gains in the long term, creates challenges for business model development

Business models for flexibility have to straddle the constantly evolving regulatory environment that affects how to access, and what the value of flexibility is, with the consumer need for consistent and secure revenue streams. Novel business models and propositions that go beyond focusing on financial value of flexibility embedding into core transport and heating service provision is important to avoid high drop off rates going forward and mitigating 'willingness to pay' issues. Improving routes for cost-effective data access, leveraging the significant investments into infrastructure such as the DCC will help alleviate some of the cost burden in the business models and avoid redundant investments. Fundamentally, market signals need to reflect whole system benefits across generation, networks, carbon savings and system security to incentivise the effective deployment and operation of different flexibility technologies including those on the demand side. This will also require effective coordination between actors to support deployment of flexibility for not only their benefit but also for the wider system. Greater focus to ensure effective market signals incentivise consideration of flexibility into long life time infrastructure even though the system value in the short-term might not be present or material is also important.

A smart and flexible system can only be enabled by digitalisation of the energy system

As shown this in study, the value of flexibility is unlocked through real time coordination between assets to operate in-sync to deliver whole system benefit. For example, we see the coordination between smart EV charging, V2G and thermal storage in heat networks working together to minimise demand during periods of system stress. These assets sit at different levels in the energy system and also across vectors and between different ownership boundaries. Thus, a critical consideration to enable this future is the need for digitalisation across the energy system to allow information sharing, monitoring and coordination between assets and organisations at this scale. Building-in interoperability and cyber security into these plans will be important, to minimise the risk at stake for the system, retain consumer confidence and trust and to allow novel business models to flourish.

Continued efforts for new technology development and innovation focused on cross vector integration is important to have them ready in time

This study has found significant flexibility deployment needs by 2030 – for example the system could require 1GW of domestic DSR, 1GW of hydrogen electrolysers, up to 3GW of EV flexibility and significant roll out of thermal storage. Innovation is important to bring technologies such as TES and electrolysers to the market at the appropriate cost point and technical capability ahead of 2030. Given the linkages between these technologies and the wider system, especially electrolysers, it is important to design and integrate them from a whole-system perspective rather than in isolation.

For technologies such as DSR, battery and thermal storage and EV flexibility, development efforts should focus on cost-effective system integration and engaging consumer experience going forward. Additionally, a greater focus on innovation that demonstrates cross-vector flexibility is important to understand the issues and scale of complexity (technical, regulatory and social) in delivering this in practice.

5. Areas for future work

While this work has delivered a comprehensive analysis to meet this objective, some research questions remain that could not be addressed given the time available. In addition, the analysis itself has opened up areas for further investigation. These are summarised below and we hope this is a useful guide for organisations looking to contribute further evidence in the area of smart and flexible energy systems.

Theme	Overview
Cross-vector	Determining value of smart cross-vector coordination in the case of hydrogen and hybrid systems. Systems modelling of low carbon heating pathways using multiple solutions and associated analysis of system impact and flexibility
Energy efficiency	Impact of different levels of energy efficiency across different heating scenarios on total system cost, generation capacity and type and capacity of flexibility required
Extreme weather	Modelling other extreme weather events, and understanding of likelihood of occurrence, and what level of system adequacy and resilience needed/desired in GB
Interconnectors	Impact of additional interconnection and implications for Europe wide flexibility needs
Marginal value	Understanding the incremental value of each flexibility unit through marginal value modelling rather than average value
Nuclear	Modelling system impact of new nuclear configurations such as coupled with district heating networks and hydrogen production (electrolysers)
Technology	Modelling value of different thermal storage technologies beyond hot water tanks. Across the flexibility portfolio, using system value to support appropriate RD&D strategies
Unabated gas	Explore in more detail impact of no unabated gas usage on system cost in 2050
Uncertainty	Develop modelling solutions to determine a least regret approach to the role and value of flexibility in integrated energy systems

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