The implications of a gas-free GB energy system by 2050 (D)

Energy sector modelling to support the second National Infrastructure Assessment

Prepared for the National Infrastructure Commission
October 2023

Contents

Executive Summary

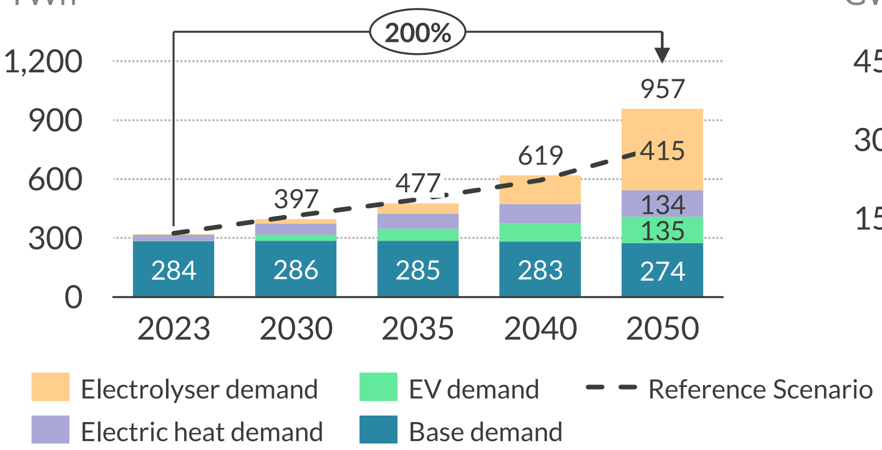
- The UK energy market relied on natural gas for meeting over a third of energy demand in 2021[1], with total gas consumption reaching 857 TWh, 668 TWh of which is used in power and heating
- The UK is targeting Net Zero by 2050. Despite having beaten its carbon budgets to date, the UK will have to significantly increase its ambition to meet upcoming budgets without compromising its energy security
- Meeting emissions targets will require the UK to heavily reduce its natural gas dependency in the medium term and abate what remains by 2050; in 2021 natural gas accounted for 40% of power generation, 67% of heating and 40% of industry [1]
- Previous analyses produced by Aurora Energy Research ("Aurora") for The National Infrastructure Commission ("NIC") investigated the decarbonisation of the power and heating sectors separately (Projects A and B) and the interplay between the decarbonisation of both sectors simultaneously (Project C)
  - Project A: explored how flexibility can support the deployment of renewables in order to achieve Net Zero in GB
  - Project B: explored how different types of low carbon heating can be used to decarbonise the building stock in GB
  - Project C: explored how different paths to heat decarbonisation will impact the power sector in GB
- For Project D, this report, the aim is to step beyond heating and power sector decarbonisation and analyse the impact of removing natural gas entirely, abated or otherwise, from GB's entire energy sector by 2050 (heating, power, hydrogen production, industry and transport)
  - This report focuses analysis on a power system that is capable of meeting the demand and supply needs of a gas-free energy system by 2050, focusing on demand, capacity build out, power system costs and costs to consumers
  - Additionally, it will comment on the wider effects a gas-free energy system has on the hydrogen system, focusing on transport and storage and costs
- Aurora has modelled a gas-free by 2050 power market scenario on behalf of NIC, using Scenario 1 from Project C[2] as a starting point for analysis and as a comparative benchmark for quantifying results. This is termed the **reference scenario** in this report
- Different pathways to 2050 were tested to ensure that the most efficient use of capacity deployment has been followed

1) Total energy demand data taken from Digest of UK Energy Statistics (DUKES), which includes Northern Ireland .2) Scenario 1 Project C is a power scenario that has a gas-free heating system, but gas-dependant power and hydrogen production.
Source: Aurora Energy Research

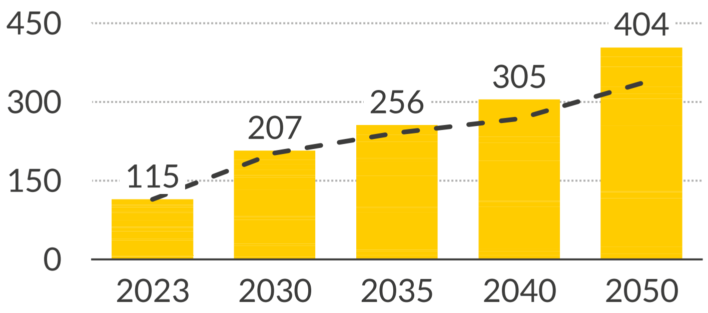
Executive Summary

- **Power demand** in gas-free energy system is 25% higher than in the reference scenario by 2050, reaching 957 TWh, driven predominantly by the increased electrolyser capacity needed to displace blue and grey hydrogen production
- At the same time, **baseload capacity** is 24 GW lower than the reference scenario by 2050 in a gas-free energy system due to CCS decommissioning. Thus, the power system requires an additional 54 GW of **renewable capacity** (75% offshore wind) and 38 GW of **flexible capacity** (68% batteries) by 2050 to ensure energy security is maintained
- Including **CCS** as a flexible generating technology in the pathway to 2050 to help the transition of the power system can help save the power system £33 billion (37%) in average annual power system costs[1]
- Average annual **power system costs**[1] will rise by just 2% compared to the reference scenario , reaching £57 billion by 2050, with consumer costs averaging £103/MWh[1,2]. The higher subsidy costs in the 2030's – required to bring on additional capacity – are offset by the lower wholesale costs in the 2040s, which are caused by increased RES generation weighing on baseload power prices
- However, the **hydrogen system** of a gas-free energy system will require more storage and transport infrastructure than the reference scenario to support its additional 33 GW of electrolyser capacity by 2050. The additional green capacity, alongside the larger piping and distribution infrastructure, will increase the costs to the consumer

Total Annual Power Demand
TWh



Total Installed Capacity
GW



1) Average from 2025 – 2050 and excluding additional costs of operating the hydrogen system. 2) Including Climate Levy, Supplier Charges & VAT.

Source: Aurora Energy Research

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Gas is a key part of the UK's energy system, accounting for 70%, 40% and 30% on average of the total energy usage in the heating, industry and power sectors

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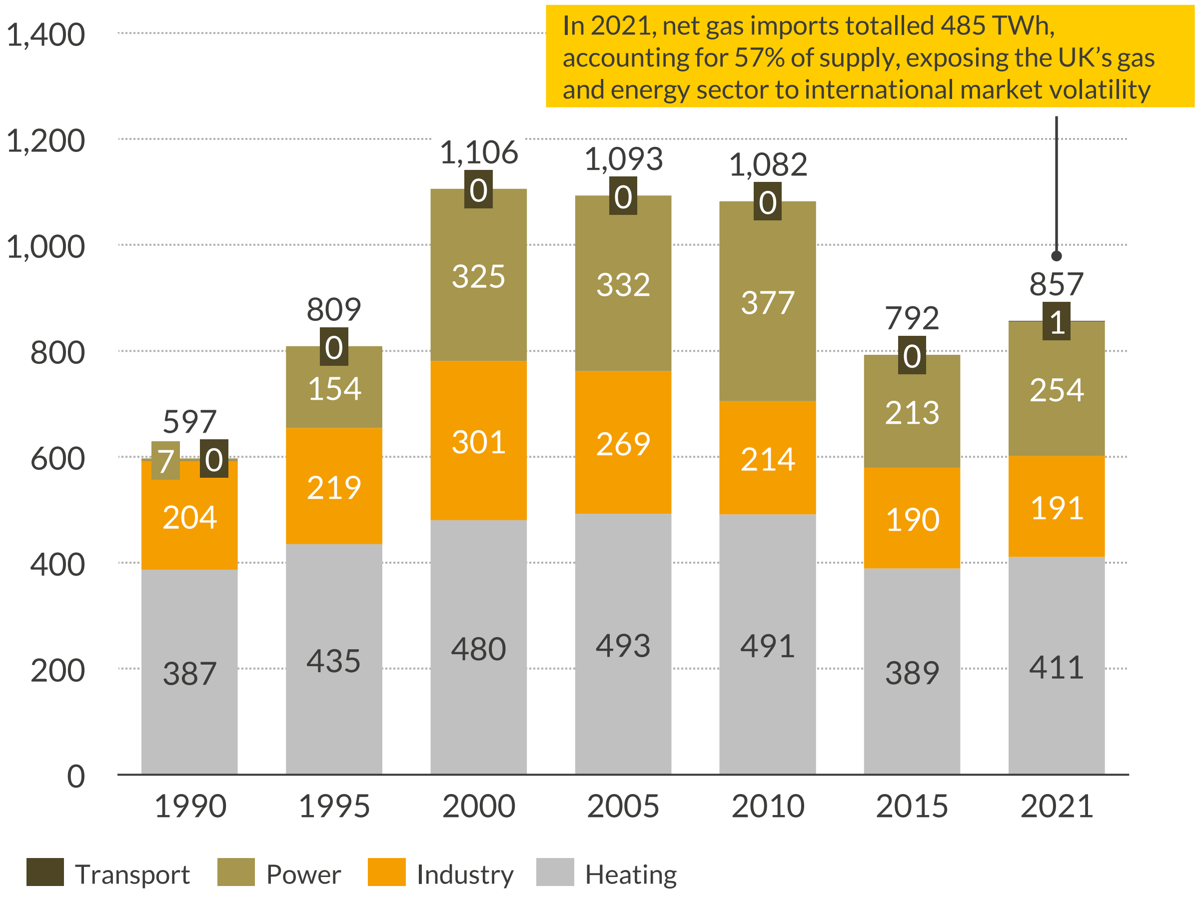
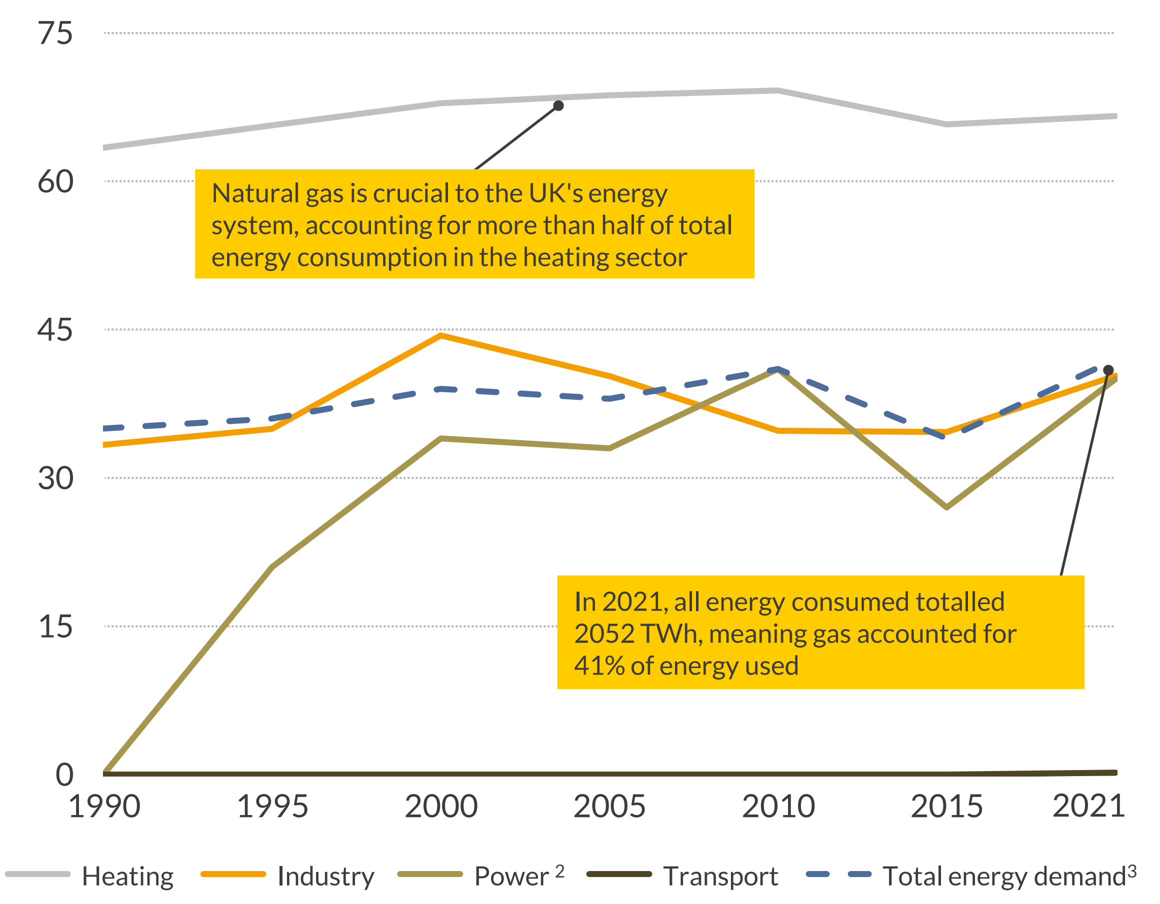
Natural gas consumption in the UK[1]
TWh



Market share of natural gas within each sector[1]
%



1) Data taken from Digest of UK Energy Statistics (DUKES), which includes Northern Ireland. 2) Commodity market volatility in the 2010s (the recovery of global demand from the Great Recession increased prices, after which the shale and oil sands revolution brought prices down again. This volatility took place from 2010-2016). High gas prices reduced gas burn across sectors, but most prominently in the power sector, where low coal prices in 2015 caused strong gas-to coal switching 2) The natural gas market share of sector labelled "Total energy demand" represents the proportion of total primary energy in the UK than comes from natural gas.

Sources: Aurora Energy Research, Digest of UK Energy Statistics (DUKES)

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In order to meet upcoming carbon budgets, the UK will need to significantly reduce gas consumption, and abated what remains by 2050

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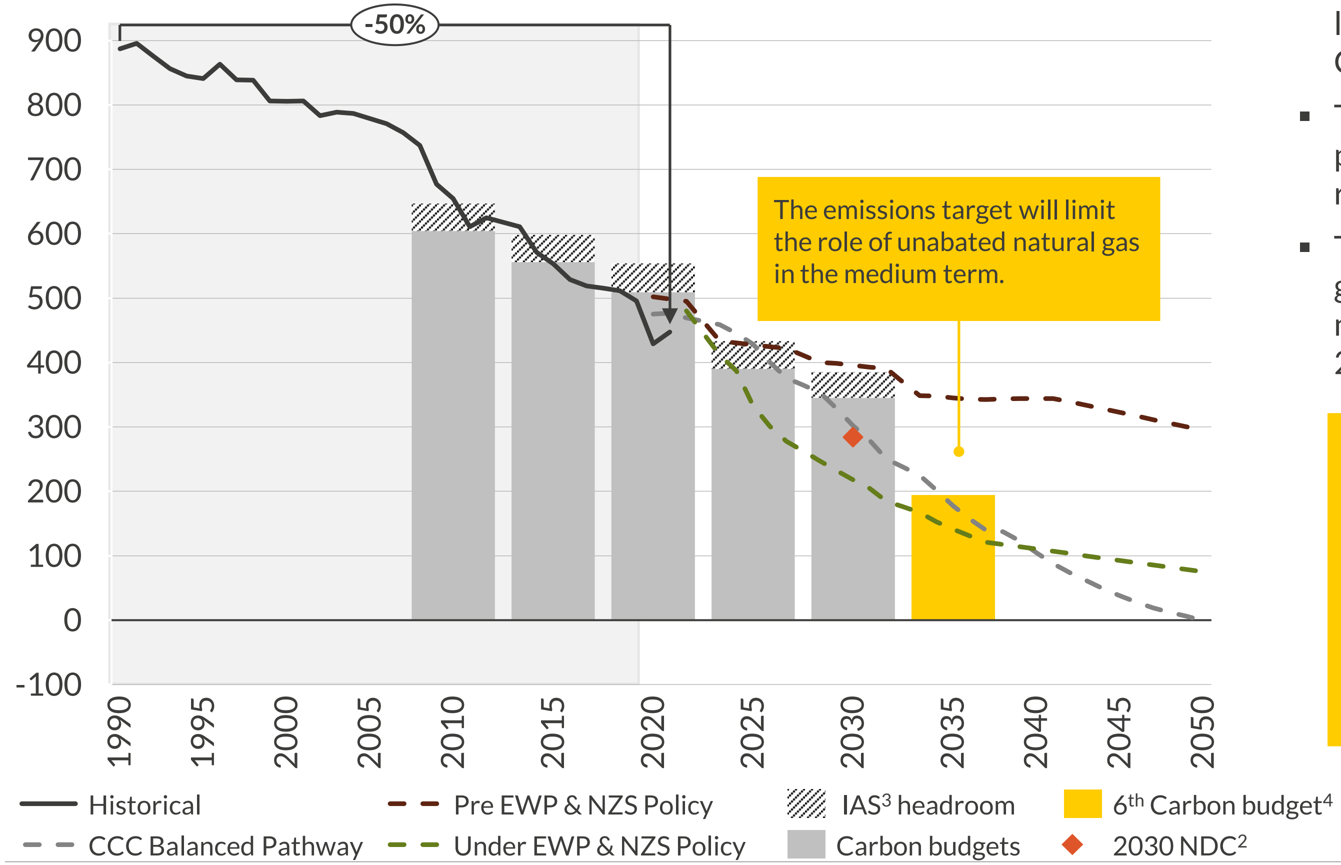
The CCC's 6th carbon budget recommendation seeks to align emissions targets with the Net Zero ambition and was enriched into law in April 2021. This with further limit the role for unabated natural gas in the system in the medium term and eliminates it in the long-term entirely.

Total UK Greenhouse Gas Emissions and carbon budgets

$MtCO_2e$



- The UK has seen a 50% decline in emissions since 1990 and has beaten all of its carbon budgets to date
- This has mainly been driven by decarbonisation in the power sector, initially linked to the switch from coal to gas, and later due to the introduction of the Carbon Price Support, and growth in renewables through subsidies
- The 6th carbon budget, published in December 2020, which covers the time period between 2033 – 2037, seeks to align the UK's trajectory with its recently legislated 2050 net-zero target in June 2019
- The CCC recommend a **78% reduction from 1990 levels** across greenhouse gas emissions by 2035 (including international aviation and shipping). This new target brings forward the previous 80% emission reduction target for 2050 forward by 15 years

As decarbonisation policy evolves, the role of **unabated natural gas** is becoming limited in the medium term. By 2050, the Net Zero target means unabated natural gas has no role in the energy system

Abated natural gas (using CCS in power production or for the production of blue hydrogen) can help the UK meet carbon budgets by providing a low-carbon thermal energy source without the emissions intensity

1) Nationally Determined Contributions. 2) NDCs excludes international aviation and shipping as per UN convention. 3) International aviation and shipping. 4) CCC's 6th Carbon budget includes IAS emissions.

Sources: Aurora Energy Research, BEIS, CCC

Gas abatement can help the UK reach net zero by reducing combustion emissions by up to 95%, and policy to support CCS development is evolving

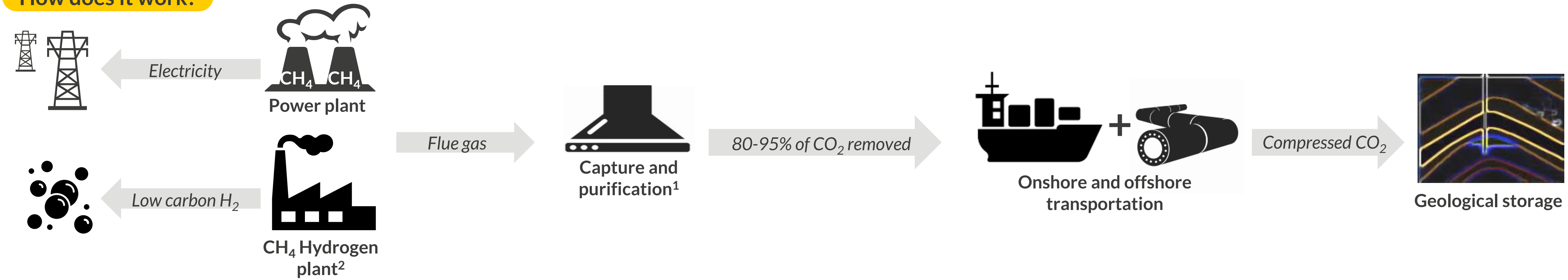
What is gas CCS and where is policy now?

- Carbon capture and storage can reduce the emissions from CCGTs and biomass (power) or blue hydrogen production[2] by up to 95%, helping reach Net Zero
- The Government has outlined the key design aspects of a support mechanism for power CCS through a Dispatchable power agreement (DPA). This will provide availability and variable payments to ensure that abated generation dispatches before unabated. A number of provisions are still to be defined by the Government prior to finalisation of the DPA
- The Government has proposed a regulated asset base (RAB) model to incentivise the development of the transport and storage infrastructure
- The Government has announced the Low Carbon Hydrogen Business Model (HPBM), which aims to support selected producers of low carbon hydrogen, via a CfD-like mechanism, by paying them a premium per MWh of hydrogen production. UK government is finalising the design of HPBM currently

What are the risks to CCS?

- The technology faces several challenges:
  - CCS has multiple downstream steps with additional costs and infrastructure requirements; plant construction takes several years and the energy intensive nature of the capture and purification creates an efficiency and capacity penalty on unabated plants
  - CCS has residual emissions (5-10%), meaning reliance on CCS will result in some emissions still taking place
  - CCS does not mitigate the UK's natural gas dependency, exposing the energy sector to commodity market volatility, and it relies on gas network that will need to compete with a future hydrogen network
- Cost barriers means that CCS is currently not economically viable. Without clear policy support through the introduction of subsidy mechanisms, CCS will struggle to compete with unabated technologies

How does it work?



1) The captured flue gas is first cooled using water then fed into an absorber where the CO_2 is bound with amines then fed into a separation unit where it is heated, and the pure CO_2 is stripped out. 2)Hydrogen production using natural gas via steam methane reforming or autothermal reforming.

Sources: Aurora Energy Research, BEIS, Zero Emissions Platform, Global CCS Institute

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For the power sector, Aurora's model finds the optimum economic technology mix based on the input parameters given

Aurora's modelling is based on a profit maximisation approach, with the model solving to find the most optimum economic technology mix whilst still meeting security of supply standards

INPUTS

- Commodity prices
- Demand
- Policy
- Technology
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Carbon emissions

- For each scenario, Aurora's model will consider the input assumptions provided and take decisions on additional capacity build out that is required in order to meet demand.
- Build decisions are NPV/IRR driven. The resulting technology mix will be the most economic option available, given the input assumptions made. However, network costs are not accounted for here.
- The model solves to ensure security of supply standards are met.
- Carbon emissions are an output of the model and the model does not optimise for emissions.

Source: Aurora Energy Research

Key input assumptions were made in collaboration with NIC

- **Commodity prices**
  - E.g. Gas, carbon & H2 prices
- **Demand**
  - Total and peak power demand, broken down in demand vectors (H2, transport, heating etc). Demand inputs account for the "smartness" of demand and its ability to shift to periods of lower power prices
- **Policy**
  - Capacity targets for renewables and low carbon technologies that are needed to meet emissions targets, but would not build out without subsidies or policy support
- **Technology**
  - E.g. CAPEX, performance, learning rates
- **Weather patterns**
  - Weather driven load factor patterns for renewables

Aurora's methodology for modelling the power system needed for a gas-free GB energy sector solves for energy security in 2050

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NIC tasked Aurora with modelling a power system that is capable of meeting the demand and supply requirements of an energy system that has zero natural gas by 2050. This required the removal of natural gas used in power generation, hydrogen production, heating, transport and industry.

1 Remove gas from the energy system

- Start with Scenario 1 from Project C[1] (a power scenario that has a gas-free heating system, but gas-dependant power and hydrogen production) – **this is the reference scenario**
- Remove all remaining natural gas from the energy system by 2050
- Limit abated natural gas in the power and hydrogen production to pipeline projects[2]

2 Revise up power demand

- Calculate the increase in power demand required to displace energy from natural gas in industry, hydrogen production and transport by 2050
- Additional power generation will be required for green hydrogen production and for electrification of systems previously reliant on gas

3 Calculate the technical potentials

- Calculate the UK's technical potential capacity limits of all low-carbon gas-free power generation[3]

4 Balance the power system in 2050

- Increase capacities for gas-free low-carbon generation in 2050 until there is enough capacity to meet demand and achieve system security
- Be sure not to exceed the UK's technical limits for 2050 for each technology
- Be sure not to exceed the deployment rates of each technology by limiting build rates throughout the forecast

5 Select a feasible pathway to 2050

- Test different pathways to a 2050 gas-free energy system by varying propositions of dispatchable and flexible power generation
- Compare and contrast the pathways by calculating total power system costs of both scenarios
- Select the most feasible trajectory to a gas-free GB energy system by 2050

1) Scenario 1 from Project C will be referred to as the "reference scenario" in this report.2) Gas CCS capacity is adjusted to be in line with current government projections. Note that CCS capacity is limited because of the investment required for CCS infrastructure, the 20+ year lifetime of plants and thus the implied early retirement of any CCS used for electricity and Hydrogen production by 2050. 3) Based on the Future Energy Scenarios (FES) from National Grid ESO and the UK Energy Strategy

Source: Aurora Energy Research

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Gas prices stabilise from recent highs by the late 2020s, and steadily rise to £25.2/MWhth by 2050, with carbon prices increasing to £174/tCO_2 by 2050

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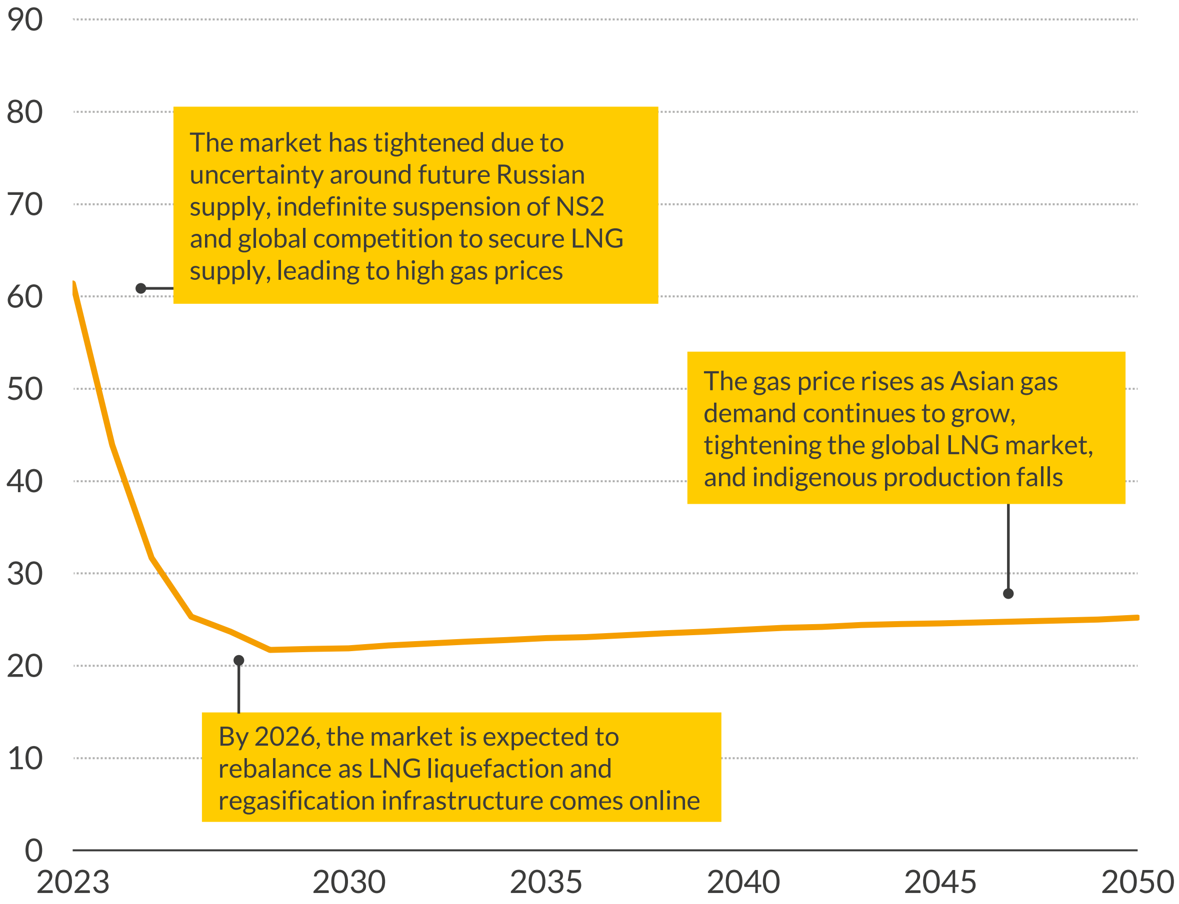
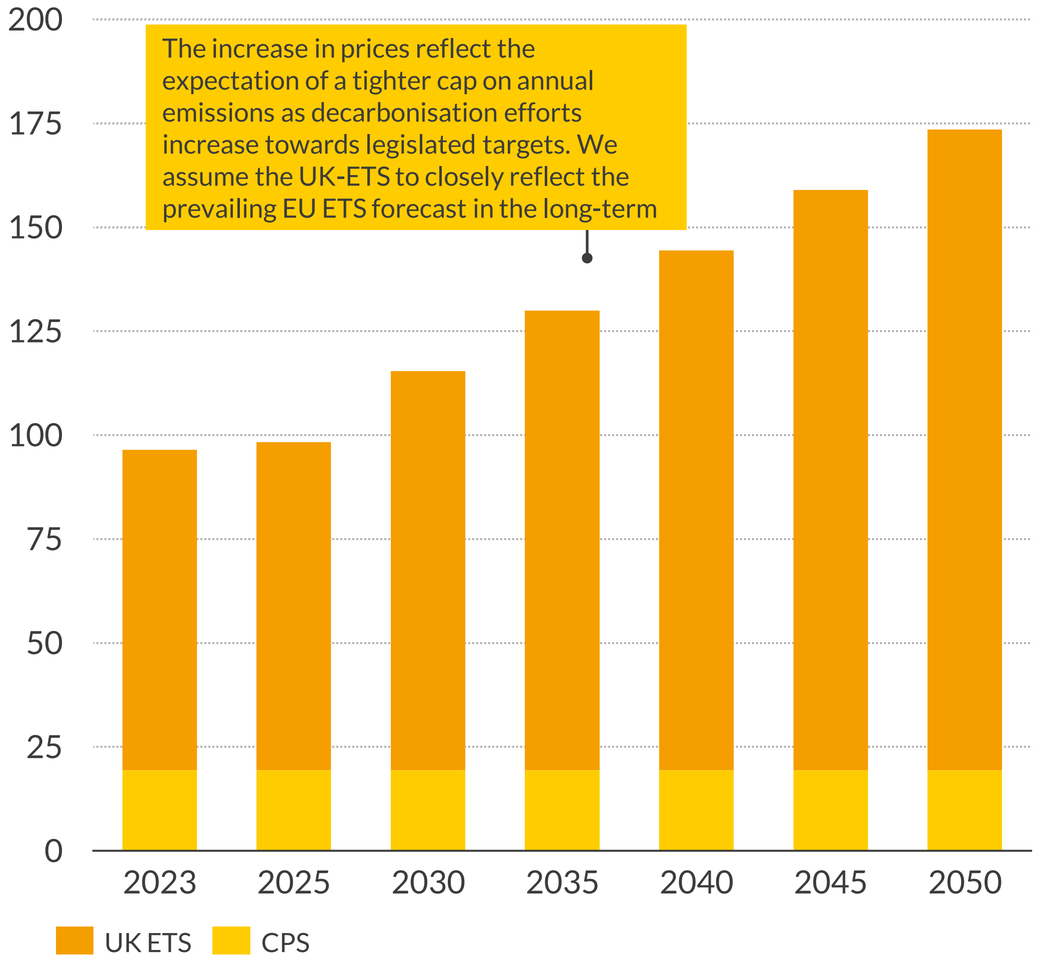
Gas price
£/MWhth (real 2022)



Total GB carbon price (UK ETS + CPS)[1]
£/tCO_2 (real 2022)



1) This is economics based and not based on the social cost of carbon

Sources: Aurora Energy Research, EIKON, FES 2022

Input assumptions were adjusted to ensure no gas in the heating, industry, hydrogen production, transport or power system by 2050

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1 Remove gas from the energy system

Input assumptions		Modelled Scenario
Commodities	Gas price	Reference Scenario
	Carbon price	Reference Scenario
	H2 price	H2 price is an endogenous model outcome (fully integrated hydrogen system)
Demand	Heat demand (heating units and unit consumption)	Reference Scenario
	Industry demand (including H2 demand for industry)	Reference Scenario
	Transport demand (including H2 demand for transport)	Reference Scenario
Hydrogen production	Grey H2 production technologies	Phasing out gradually from 2023 until 2034. Grey H2 production is banned from 2035
	Blue H2 production technologies	No new build capacities after 2035. Assume a lifetime of CCS plants of 20 years. Blue H2 production is banned from 2050
	Inflexible electrolysers	Inflexible electrolysers are not included in the system across the whole forecast horizon[1]
	Flexible electrolysers	Additional electrolyser capacity required to keep the total installed capacity of hydrogen production constant while grey and blue H2 production phases out comes from flexible electrolysers only
	Hydrogen imports	Hydrogen imports are not considered in this scenario
	Hydrogen storage	The increased electrolyser demand across the forecast will be supported by an increase in hydrogen storage capacity based on technical limits in the UK[2]
Unabated thermal generation	Gas CCGTs, Gas/oil peakers and other thermal	Unabated gas power generation banned from 2035
Abated thermal generation	Gas CCS	No new build capacities after 2030. Assume a lifetime of Gas CCS plants of 20 years. Abated gas power generation banned from 2050

1) This is because reducing the number of inflexible electrolysers lowers peaking demand, decreasing flexible capacity requirements and , as a result, electrolyser demand. 2) Hydrogen storage is modelled ensuring that it doesn't exceed the Oct 2022 gas storage levels in the UK by 2035 (which is equivalent to 4.5 GW of hydrogen storage) and it does not go above technical UK limits by 2060 (the theoretical limit in the UK is approximately 70 GW)

Sources: Aurora Energy Research, NIC, NGESO

Removing all gas from the energy system increases demand by 25% by 2050 vs. the reference scenario due to high electrolyser demand

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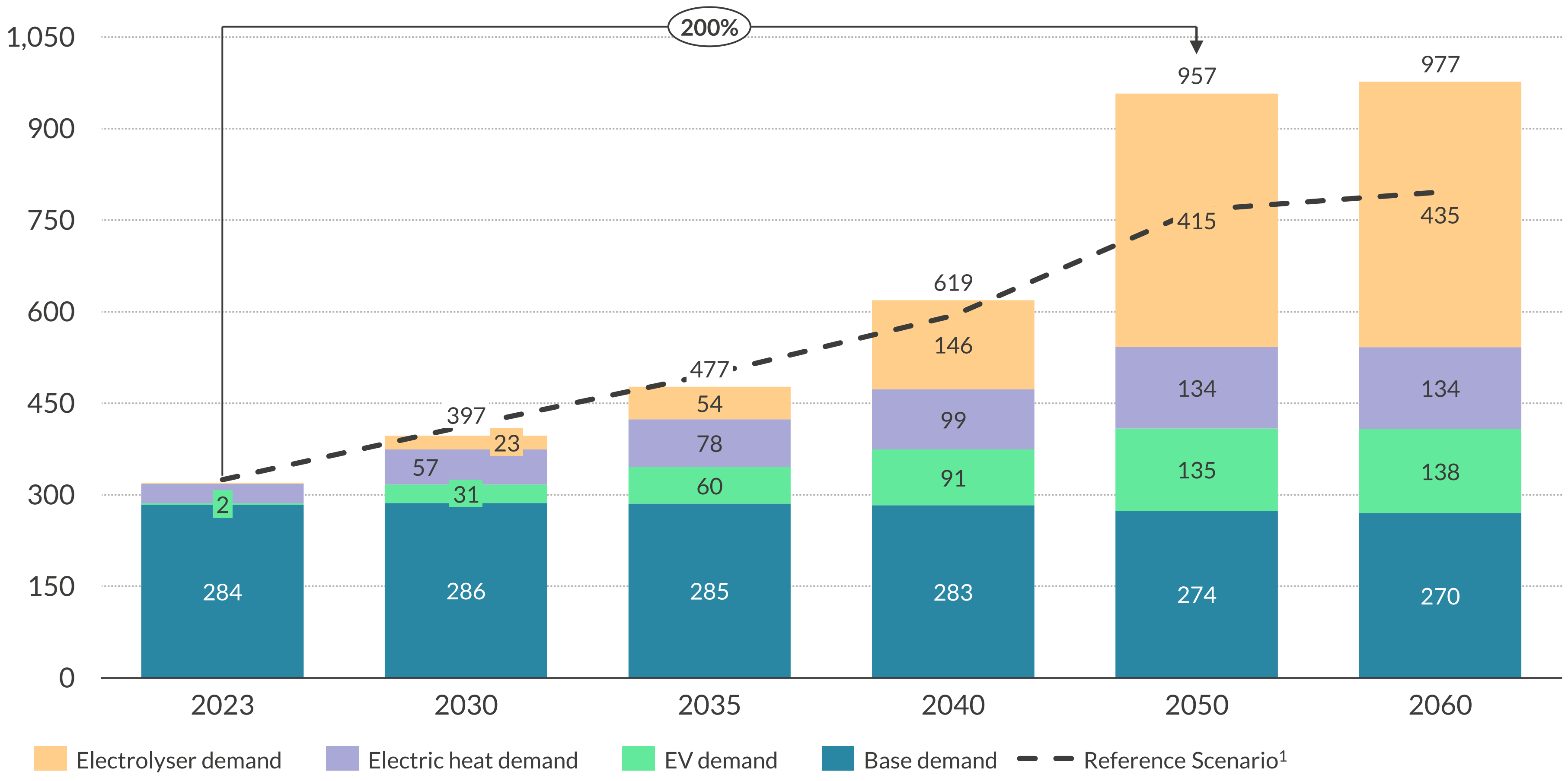
2 Revise up power demand

Total Annual Power Demand
TWh



- Total installed capacity is 181 GW higher in the 2050 gas-free energy system than in the reference scenario by 2060
- This is due to the removal of natural gas from hydrogen production by 2050. Electrolyser capacity increases to offset the fall in blue and grey hydrogen production, both of which require natural gas. The increased electrolyser demand raises total power demand
- Additionally, the 2050 gas-free energy system assumes no hydrogen imports across the whole forecast horizon, unlike the reference scenario, which allowed hydrogen imports. Additional green domestic production is required to replace hydrogen imports, boosting total power demand

1) This is Scenario 1 from Project C. It assumes no natural gas in the heating sector by 2050 and no unbated thermal generation in the power sector by 2035. The new modelled scenario in this report assumes no natural gas in the heating sector by 2050 and no abated and unbated gas generation in the power sector by 2050.
Source: Aurora Energy Research

Hydrogen imports and blue and grey H2 production are banned in a no-natural gas scenario by 2050, resulting in an extreme electrolyser deployment

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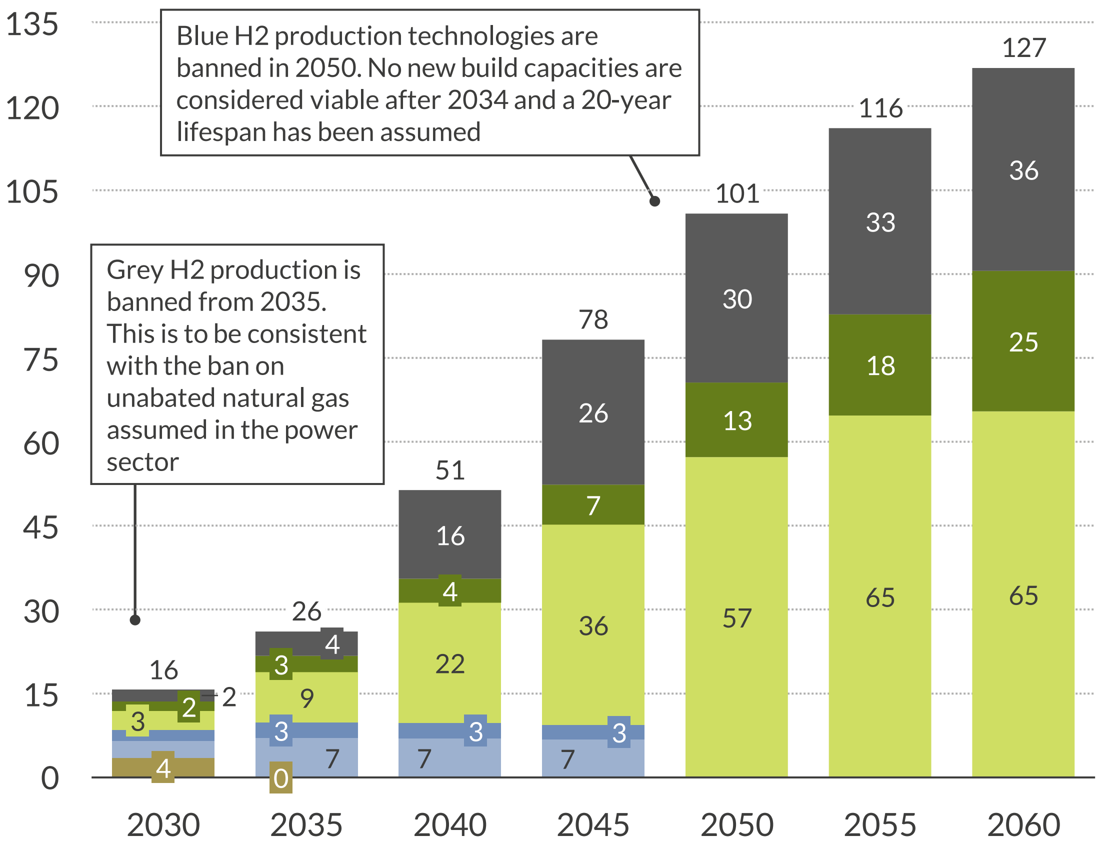
2 Revise up power demand

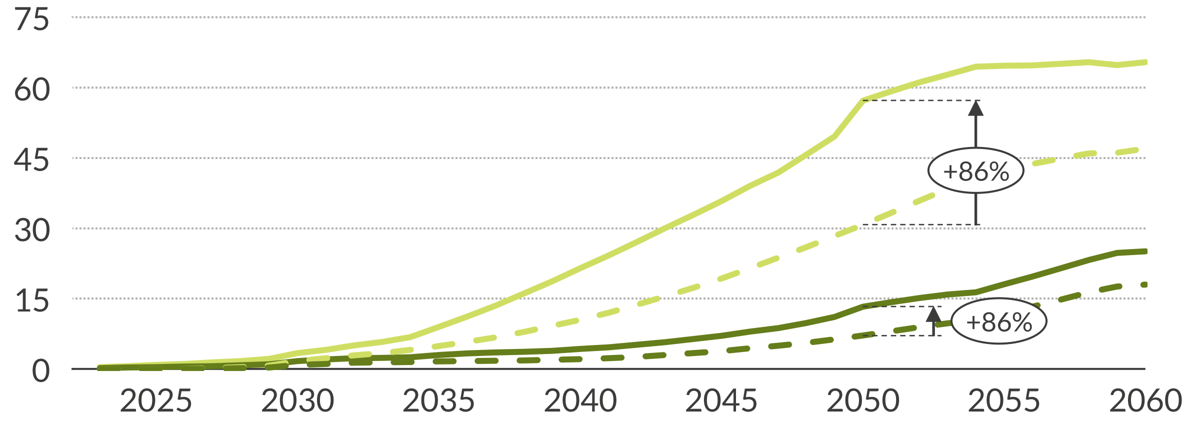
Capacity of hydrogen production technologies

GW



Trajectory for flexible electrolysers

GW



- Only flexible electrolysers are allowed across the whole forecast horizon to decrease strain on the power system and ensure no loss of load. This is because reducing the number of inflexible electrolysers lowers peaking demand, decreasing flexible capacity requirements. As a result, this also reduces H2 peaker generation, lowering electrolyser demand and overall power demand
- No hydrogen imports are assumed in this scenario. This further increases the demand for electrolysers, which raises the total power demand in the model
- The increased electrolyser demand across the forecast will be supported by an increase in hydrogen storage capacity based on technical projections in the UK[6]

Salt Cavern | Flexible PEM Electrolyser[1] | Flexible Alk Electrolyser[2] | SMR CCS[3] | ATR CCS[4] | SMR[5] | Reference Scenario

1) Polymer electrolyte membrane electrolyser. 2) Alkaline water electrolyser. 3) Steam-methane reformer with carbon capture and storage. 4) Autothermal reformer with carbon capture and storage. 5) Steam-methane reformer. SMR produces grey hydrogen since it uses natural gas and does not capture greenhouse gases made in the process. 6) Hydrogen storage is modelled ensuring that it doesn't exceed the Oct 2022 gas storage levels in the UK by 2035 (which is equivalent to 4.5 GW of hydrogen storage) and it does not go above technical UK limits by 2060 (the theoretical limit in the UK is approximately 70 GW)

Sources: Aurora Energy Research, Storage Working Group

The technical potential of low-carbon gas-free generation in 2050 exceeds assumptions in the reference scenario (1/2)

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3 Calculate the technical potentials

Installed capacity[1] assumption in 2050	Reference Scenario[2]	Modelled Scenario	Maximum Potential by 2050	Feasibility comments on maximum potential
Interconnector capacity	17.9 GW	17.9 GW	27. 4 GW *(FES Maximum Potential)*	Modelling of interconnectors is out of scope since this analysis only focuses on removing natural gas in the UK by 2050 without adjusting other interconnected regions[3]
Biomass/other RES capacity	3.3 GW	0 GW	1.3 GW *(FES Maximum Potential)*	Unabated biomass power generation banned from 2050
BECCS	4.5 GW	11.8 GW	11.8 GW *(FES Maximum Potential)*	All of the UK's BECCS potential will need to be utilised to displace natural gas
Nuclear capacity	7.9 GW	10.9 GW	24 GW *(UK Energy Strategy)*	Nuclear investment is assumed to follow a one-by-one build approach, with only one plant, not exceeding 3 GW, to be built and commissioned at a time. This is due to high investment costs, and significant historic delays to existing projects. Build and commissioning time is assumed to be 10 years
Solar capacity	96.5 GW	92 GW	92 GW *(FES Maximum Potential)*	All of the UK's solar capacity potential will need to be utilised to displace natural gas

Green: Opportunity to increase capacity to reach Maximum Potential by 2050 (Interconnector 17.9 GW, Nuclear 10.9 GW)
Red: Reaching Maximum Potential by 2050 (BECCS 11.8 GW, Solar 92 GW)

1) Includes policy driven subsidised/ supported capacities and economic build that takes place within the model. 2) Scenario 1 – Project C. 3) Adjusting interconnector capacities will lead to falsely high imports.

Sources: Aurora Energy Research, NIC, NGESO, BEIS

The technical potential of low-carbon gas-free generation in 2050 exceeds assumptions in the reference scenario (2/2)

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3 Calculate the technical potentials

Installed capacity[1] assumption in 2050	Reference Scenario[2]	Modelled Scenario	Maximum Potential by 2050	Feasibility comments on maximum potential
Offshore wind capacity	85 GW	125 GW	135 GW *(FES Maximum Potential)*	Includes fixed and floating offshore wind
Onshore wind capacity	37 GW	51 GW	47 GW *(FES Maximum Potential)*	Onshore wind capacity builds above the estimated maximum potential from FES to ensure high demand assumptions are met whilst gas is removed
Pumped storage capacity	4.5 GW	10 GW	10 GW *(Technical Potential)*	Part or all of the UK's pumped hydro potential will need to be utilised to displace natural gas
Battery capacity	12.7 GW	38 GW	42 GW[3] *(FES Maximum Potential)*	-
Demand Side Response	9.5 GW	19 GW	*Between 35% and 15% of the total peak demand in 2050 (FES Maximum Potential)*[4]	-
Gas CCS capacity	27 GW	0 GW	14 GW *(FES Maximum Potential)*	Abated gas power generation banned from 2050

Opportunity to increase capacity to reach Maximum Potential by 2050 · Reaching Maximum Potential by 2050

1) Includes policy driven subsidised/ supported capacities and economic build that takes place within the model. 2) Scenario 1 – Project C. 3) By 2050, the maximum battery storage potential is approximately 42 GWh. Assuming that all batteries have 1h duration, the maximum battery capacity potential will be approximately 42 GW in 2050.4) Within National Grid's forecasted DSR range

Sources: Aurora Energy Research, NIC, NGESO, BEIS

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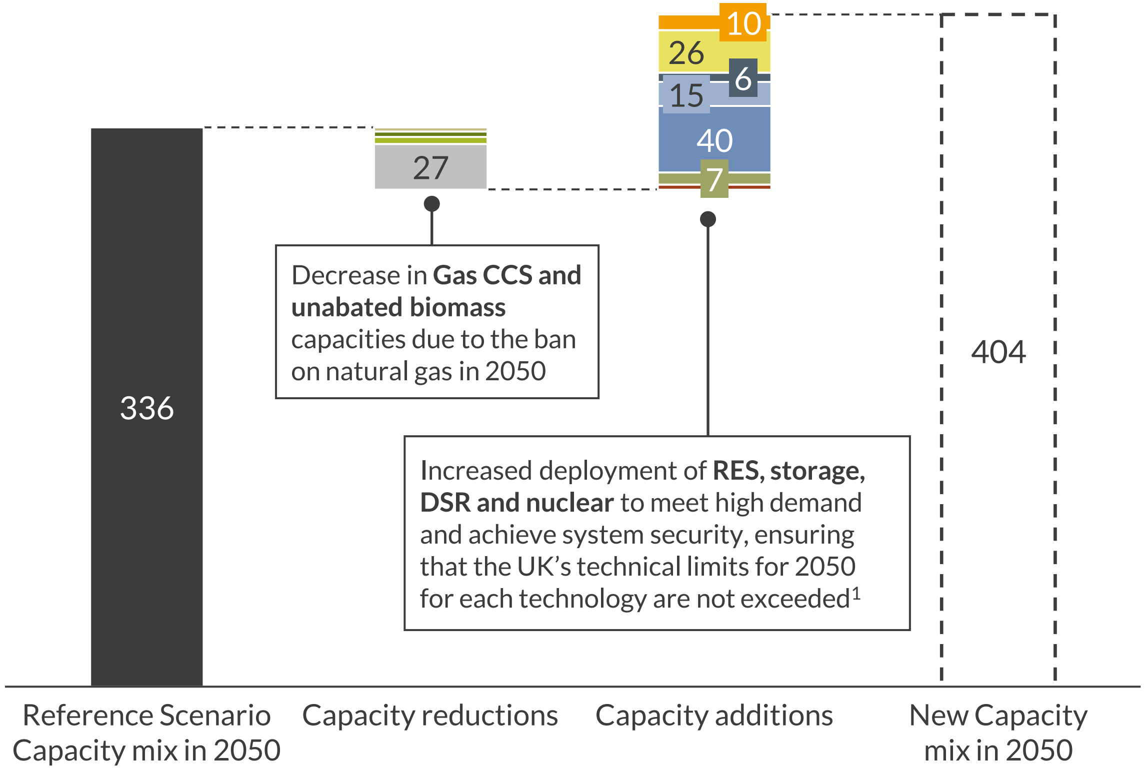
The 2050 power system can be balanced adding additional low-carbon gas-free capacity to ensure supply meets demand

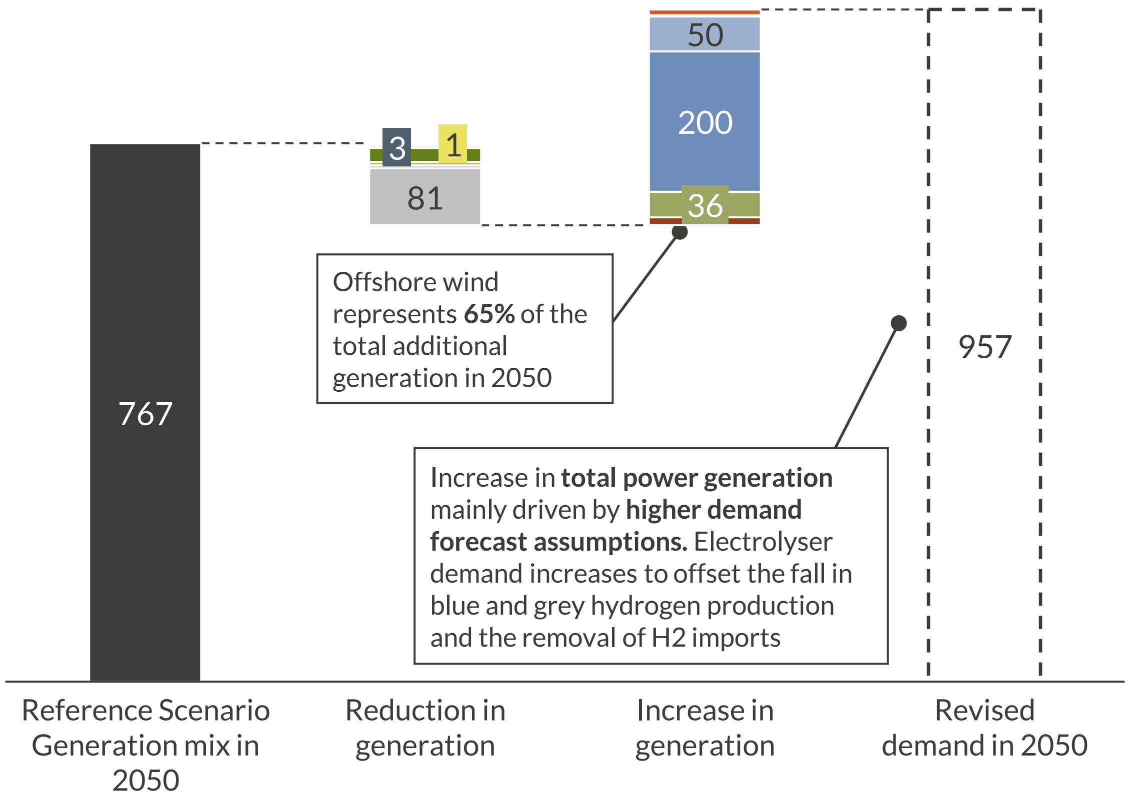
4 **Balance the power system in 2050**

Deep dive in Section IV

Total installed capacity in 2050
GW



Total power generation and demand in 2050
TWh



Nuclear | Coal | Gas CCGT | Gas CCS | Hydrogen CCGT | Other thermal[3] | Solar PV | Other RES[4] | BECCS | Hydro | Offshore wind | Onshore wind | Pumped storage | Gas / oil peaker[5] | Hydrogen peaker | Battery storage | DSR[2] | Interconnectors

1) Onshore wind is the only technology that exceeds the UK technical potential in 2050 (by 8 %) . 2) Demand Side Response.3) Other thermal includes embedded CHP. 4) Other RES includes biomass and EfW. 5) Gas / Oil peakers includes gas recips, OCGTs and oil peakers

Source: Aurora Energy Research

Using CCS in the pathway to alleviate the strain on the power system reduces power system costs by 37%[1]

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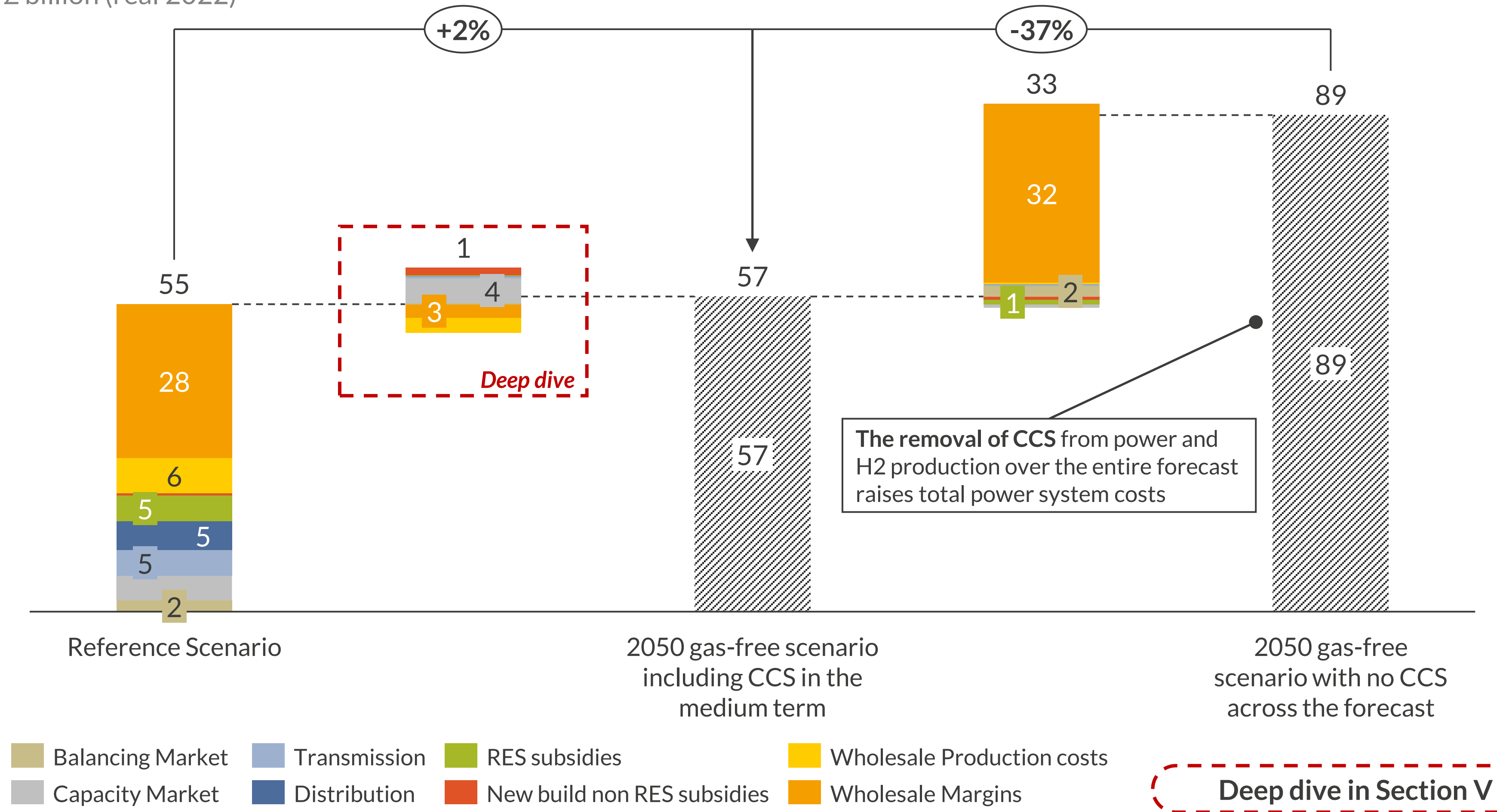
5 Select a feasible pathway to 2050

Average annual power system costs (2025 – 2050)[2] (excluding additional costs of operating the hydrogen system)

£ billion (real 2022)



Deep dive in Section V

- If CCS is not used in the pathway to 2050 in the power and hydrogen sectors, the system is more constrained, leading to a spike in wholesale prices and increasing overall system costs and the burden on the consumer
- Gas CCS in the power system alleviates system tightness due to increased available firm capacity after banning unabated thermal generation in 2035
- CCS in hydrogen production (blue hydrogen production, which combined steam methane reforming and CCS) reduces power demand by displacing electrolyser capacity, thereby alleviating system tightness further and lowering costs

1) Average between 2025 and 2050. 2) Note the 2023-2024 period is excluded from these calculations as current high gas prices distort results.

Source: Aurora Energy Research

However, a 2050 gas-free GB energy system will need more hydrogen production capacity, which will likely amplify the delta in total system costs

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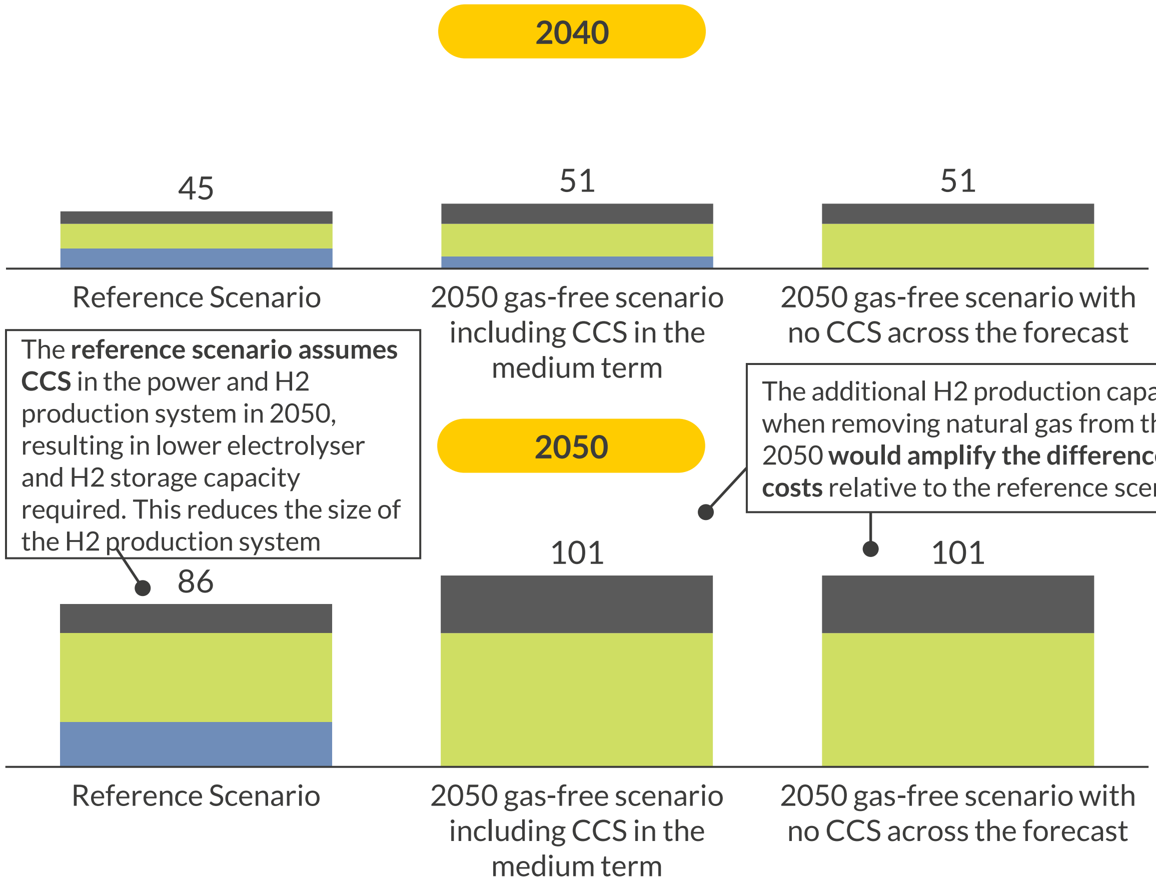
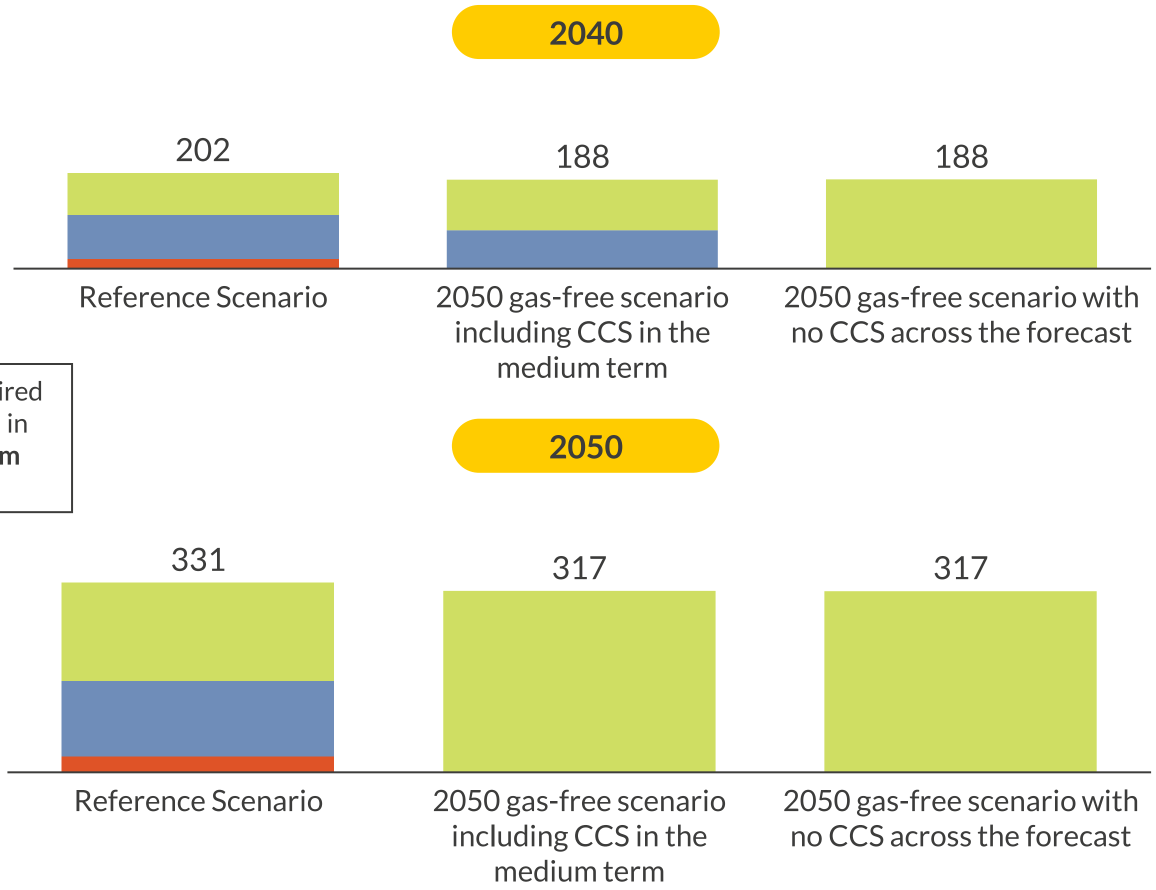
5 Select a feasible pathway to 2050

Total hydrogen production capacity
GW



Total hydrogen production[5]
TWh



H2 storage[1] | Green H2[2] | Blue H2[3] | Grey H2[4] | H2 imports

1) Salt Cavern. 2) Produced by flexible and inflexible electrolysers. 3) Produced by steam-methane reformer with carbon capture and storage and autothermal reformer with carbon capture and storage. 4) Produced by steam-methane reformer. 5) Note that iimports are banned in the 2050 gas-free scenarios. Hydrogen production is higher in the Reference scenario due to increased hydrogen peaker capacity build and generation in the power system, increasing total hydrogen demand (see slide 29 for more).

Source: Aurora Energy Research

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High power demand and reduced baseload capacity incentivise merchant renewables capacity deployment

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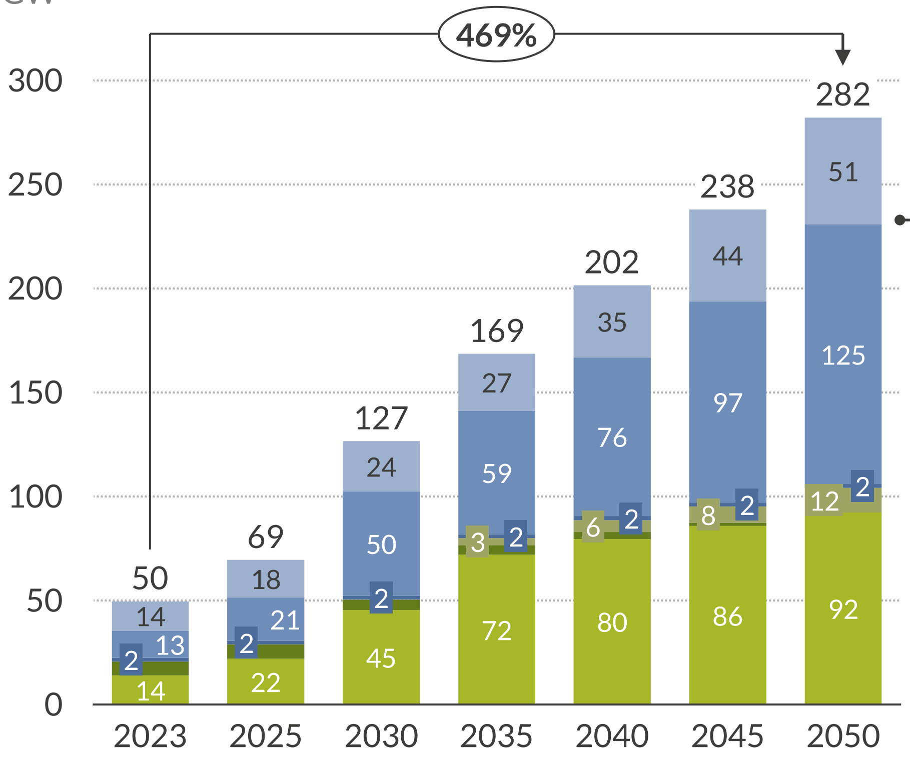
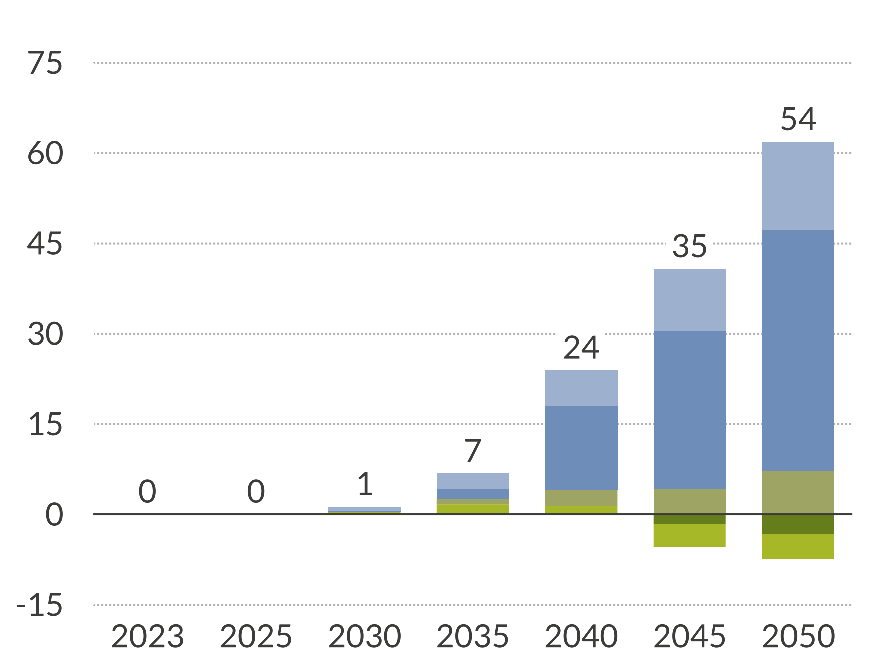
Total installed renewable capacity
GW



Renewable capacity delta compared to the reference scenario
GW



	Solar	Offshore wind	Onshore wind
UK technical potential[1] in 2030, GW	42	51	31
UK technical potential[1] in 2050, GW	92	135	47

	Solar	Offshore wind	Onshore wind
Delta over technical potential in 2035, GW	+3	-1	-7
Delta over technical potential in 2050, GW	0	-10	+4

Onshore wind | Offshore wind | Hydro | BECCS | Other RES[2] | Solar

1) Based on the Future Energy Scenarios (FES) from National Grid ESO. 2) Other RES includes biomass and EfW.

Sources: Aurora Energy Research, NGESO

- Total installed renewable capacity is 54 GW higher in the 2050 gas-free energy system than in the reference scenario by 2050
- This is primarily due to:
  - Higher demand forecast assumptions, which are caused by increased electrolyser demand as grey and blue hydrogen production requires natural gas and H2 imports are not allowed in this scenario, leading to a larger power system
  - Lower Gas CCS capacity (reduced baseload capacity) assumptions over the forecast as a result of the ban on abated gas in 2050, leading to additional renewable capacity to ensure no loss of load in this scenario
- Onshore wind buildout is 4 GW (8%) higher than the FES maximum potential in 2050, while offshore wind installed capacity is 10 GW (7%) lower than the UK technical limit in 2050. Solar capacity reaches the exact UK technical limit in 2050

Total renewable generation follows the same pattern as renewable capacity deployment

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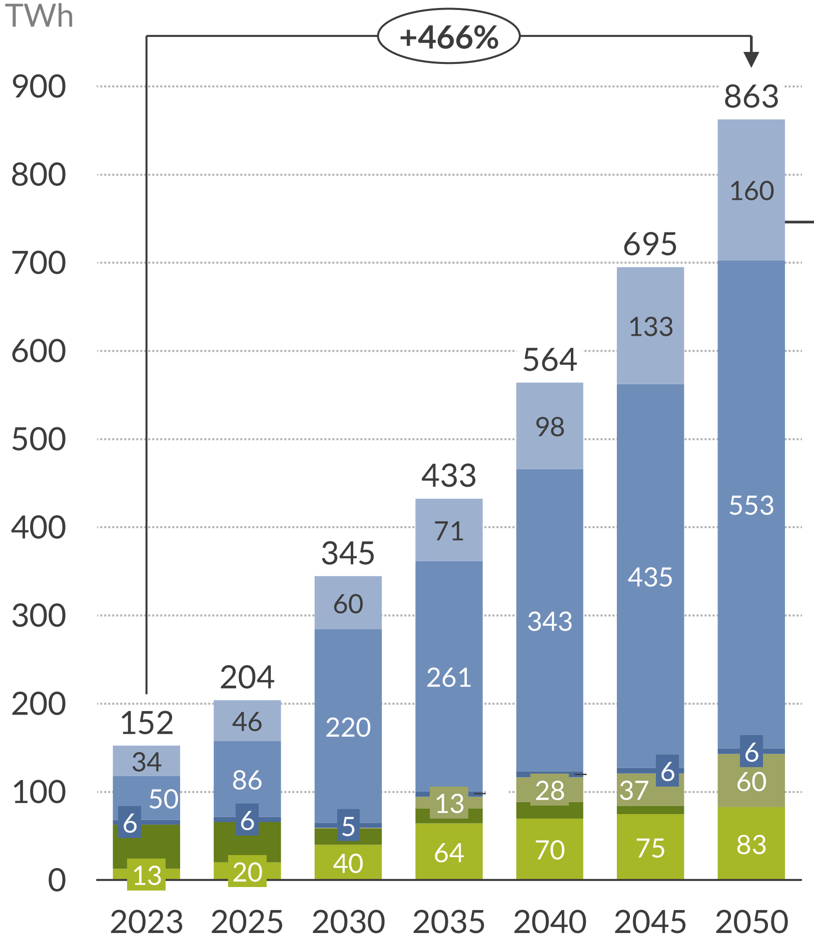
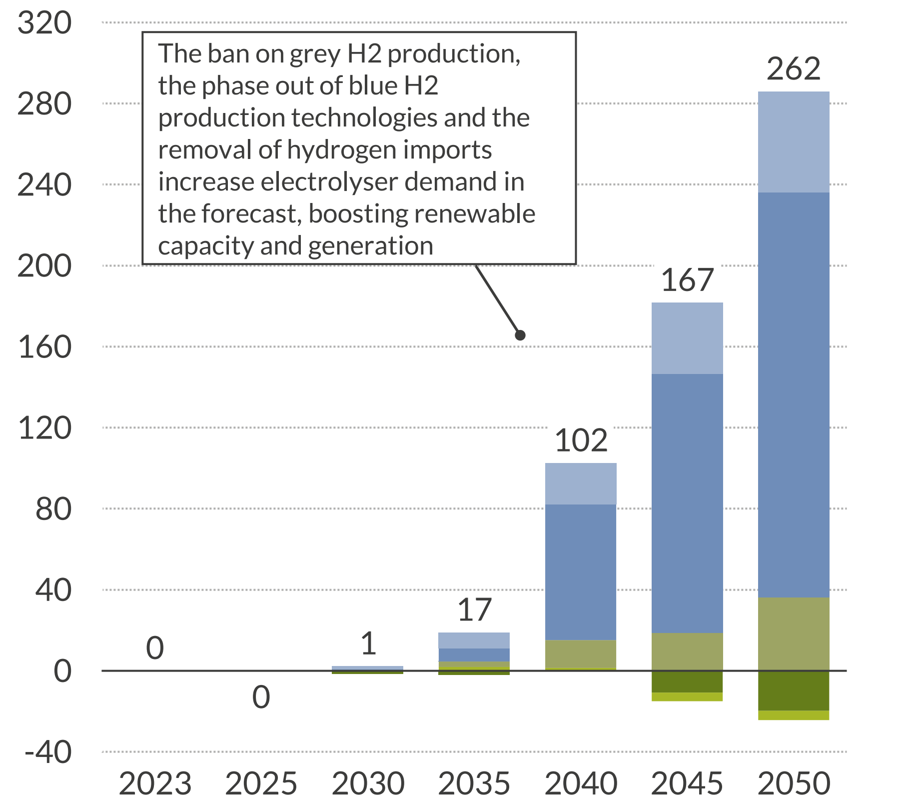
Total renewable generation
TWh



Renewable generation compared to the reference scenario
TWh



Onshore wind | Offshore wind | Hydro | BECCS | Other RES[1] | Solar

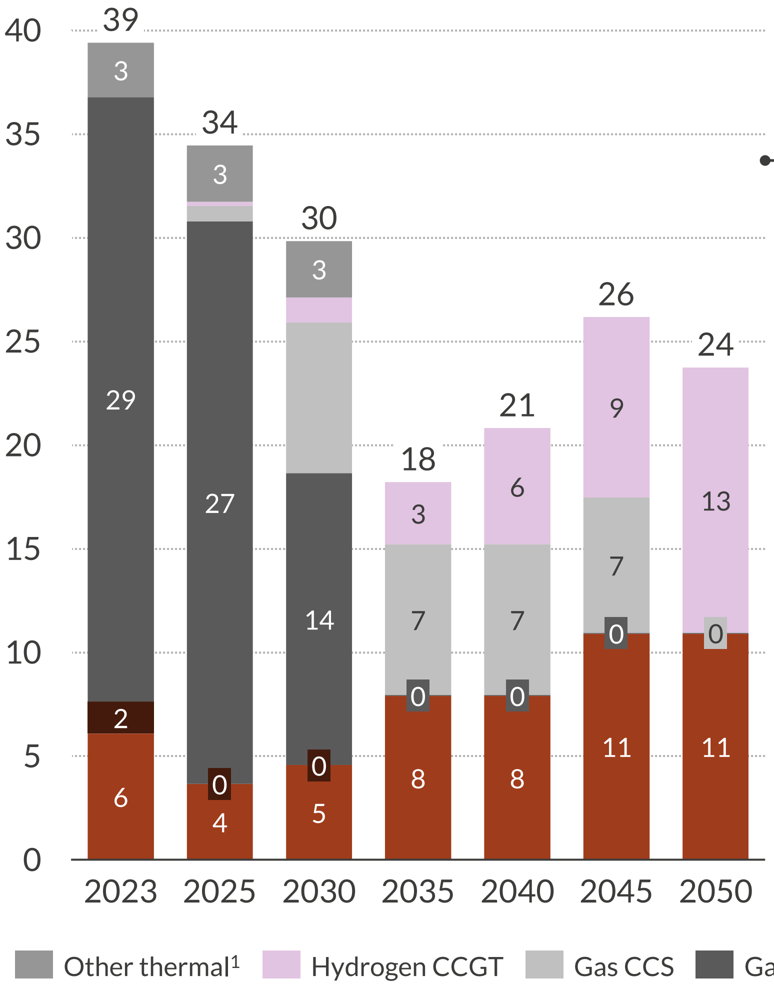
- Total renewable generation follows the same patterns as renewable capacity deployment. Therefore, the increased total power demand in the low-carbon gas-free scenario in 2050 increases renewable generation volume requirements by 44% in 2050 compared to the reference scenario
- Total renewable generation accounts for 90% of the total power generation by 2050. In a power system with no natural gas by 2050 and no hydrogen imports, the hydrogen market will be entirely reliant on domestic green hydrogen production, increasing overall power demand and resulting in accelerated build of RES capacity and high renewable generation

1) Other RES includes biomass and EfW.

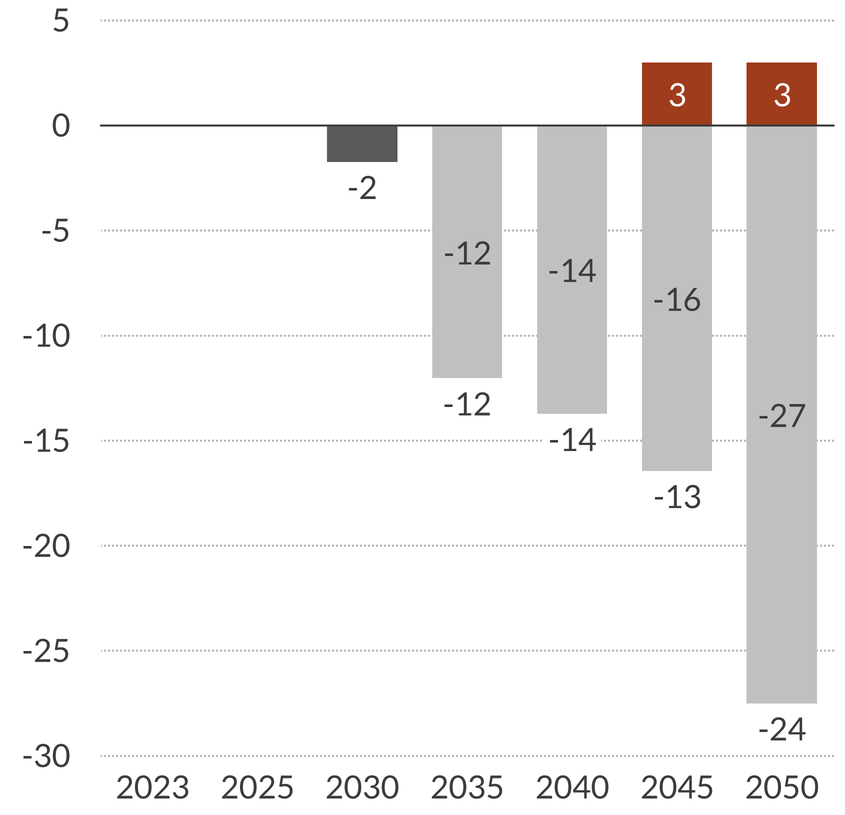
Source: Aurora Energy Research

Removing Gas CCS will reduce baseload capacity by 24 GW in 2050, straining the system

Total installed baseload capacity
GW



Baseload capacity delta compared to the reference scenario
GW



- The modelled scenario has unabated gas power generation banned from 2035. Therefore, existing unabated gas CCGTs must retire by 2035
- No new build capacities of Gas CCS are assumed in the power system after 2030 as it is not economically feasible for those plants to commission if they must retire by 2050 due to the ban on natural gas in 2050
- Nuclear capacity is only 38% higher than in the reference scenario by 2050 due to the assumed technical limitation of investing in up to 3 GW of nuclear new build every 10 years
- As a result, net baseload capacity is 24 GW lower than in the reference scenario, leading to an accelerated build of renewables to meet demand

1) Other thermal includes embedded CHP.

Source: Aurora Energy Research

With no natural gas in the power system by 2050, 90% of the total baseload generation will be produced by nuclear power plants

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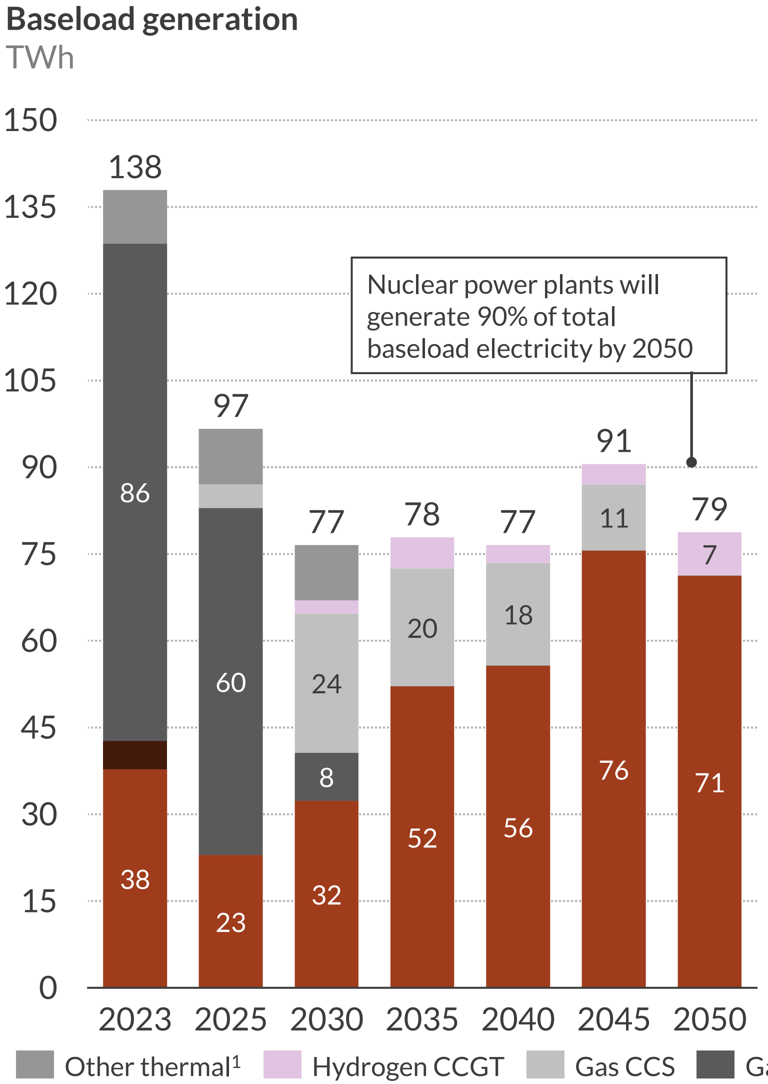

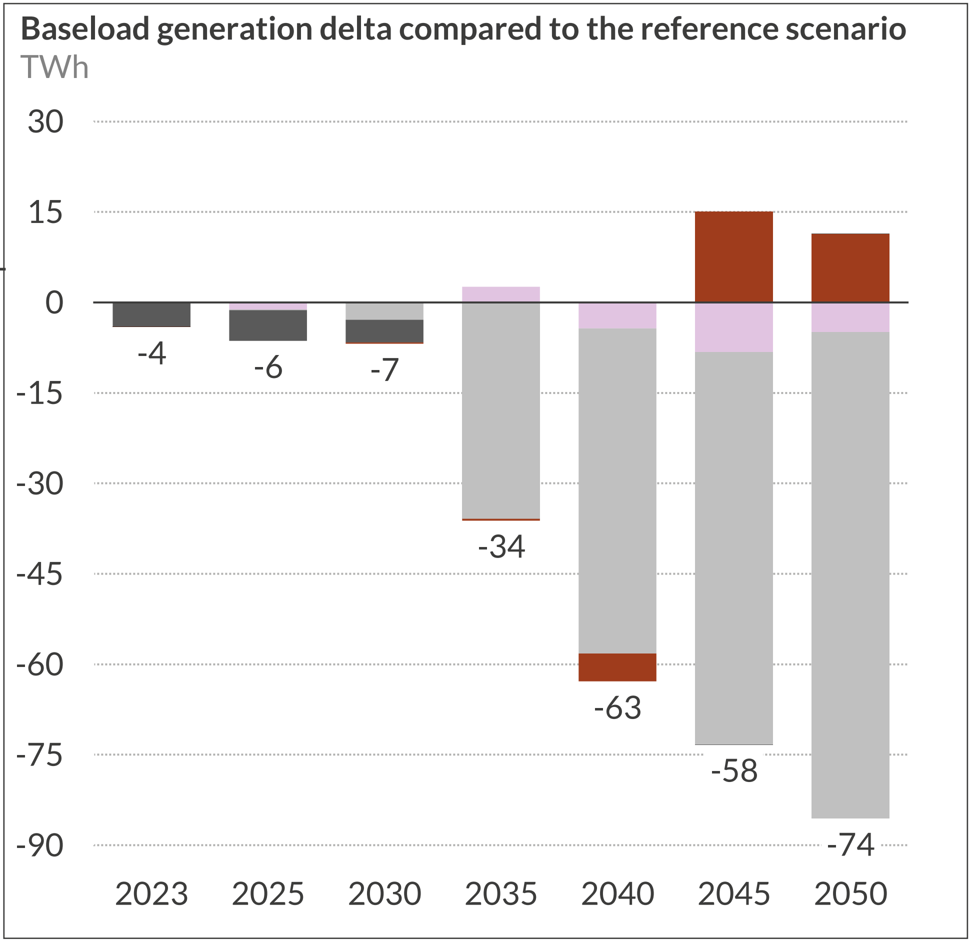

- Total baseload generation in the new modelled scenario is 49% lower than in the reference scenario by 2050. This is primarily driven by the decrease in Gas CCS generation as no-natural gas in allowed in the power system by 2050
- More flexible electrolysers (lower peak demand) and higher hydrogen market price, combined with increased renewable generation in the system, pushes H2 CCGTs out of merit more often, resulting in 5 TWh less by 2050, compared to the reference scenario

1) Other thermal includes embedded CHP.

Source: Aurora Energy Research

The deployment of an additional 54 GW of RES capacity by 2050 boosts the value case for additional flex capacity vs. the reference scenario

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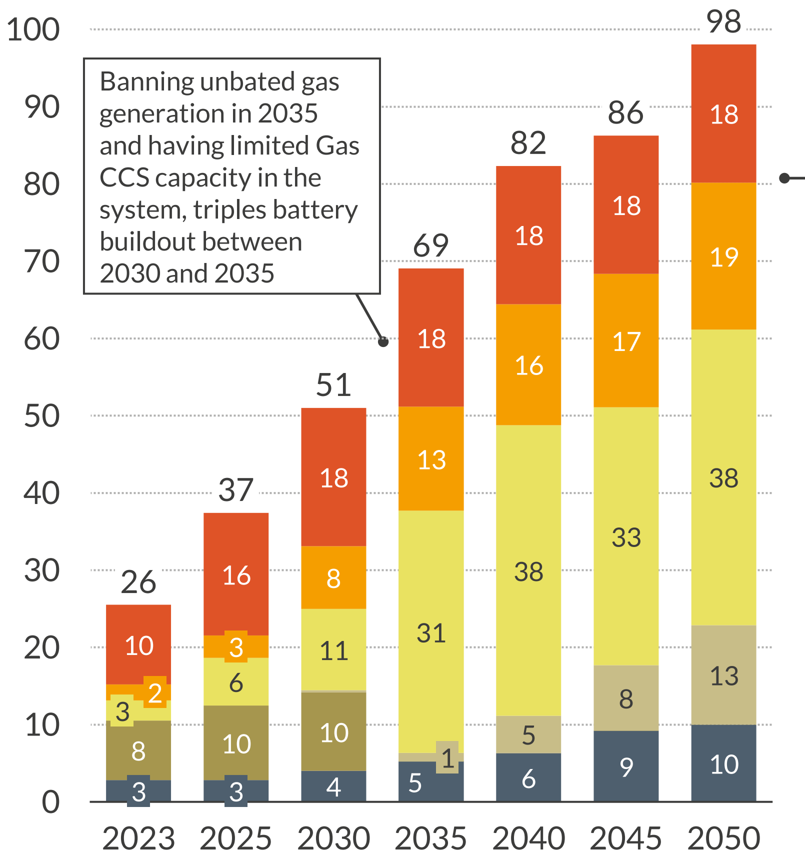
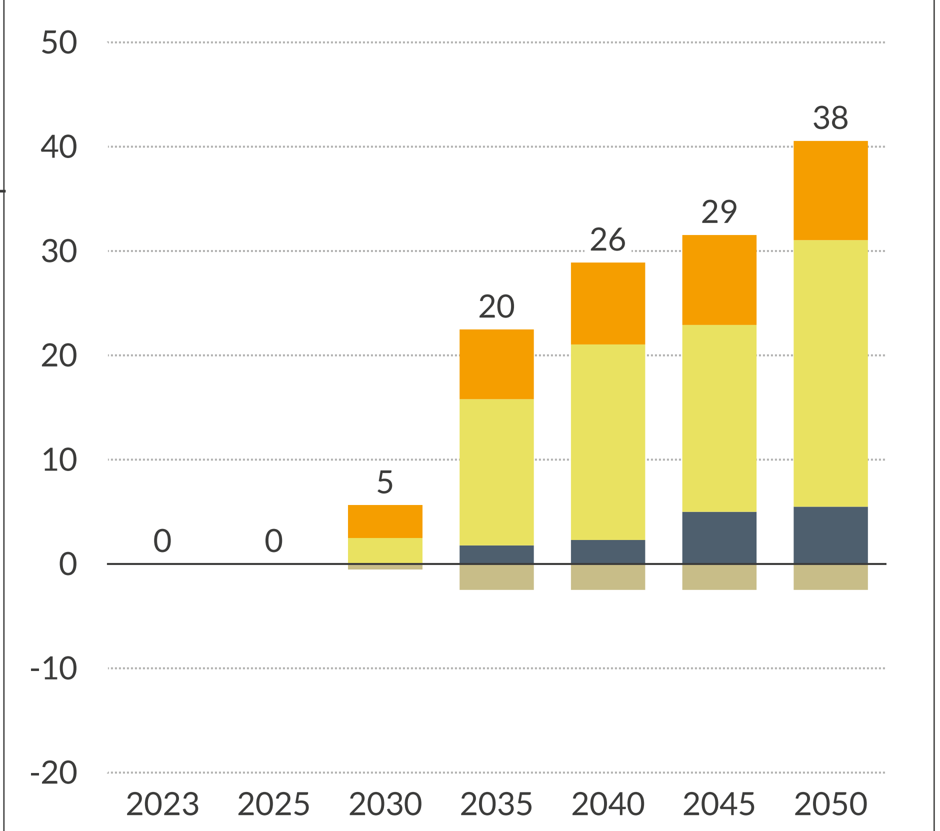
Total installed flexible capacity
GW



Flexible capacity delta compared to the reference scenario
GW



- Flexible capacity is 38 GW higher than in the reference scenario by 2050. Higher battery build is underpinned by growing price spreads. Increased renewable buildout weighs on bottom prices, while top prices are inflated by higher hydrogen prices caused by green-only hydrogen supply
- The 2050 gas-free energy system also assumes double the demand side response capacity as in the reference scenario to ensure that supply always meets demand over the forecast
- A higher hydrogen market price than in the reference scenario, caused by limiting hydrogen production to green H2 only, impacts the economics of H2 peakers resulting in lower H2 peaking build out

Interconnectors | DSR[1] | Battery storage | Hydrogen peakers | Gas / Oil peakers[2] | Pumped storage

1) Demand Side Response. 2) Gas / Oil peakers includes gas recips, OCGTs and oil peakers.

Source: Aurora Energy Research

Increased nuclear and RES capacity leads to high interconnector exports from GB in the medium term due to low baseload prices

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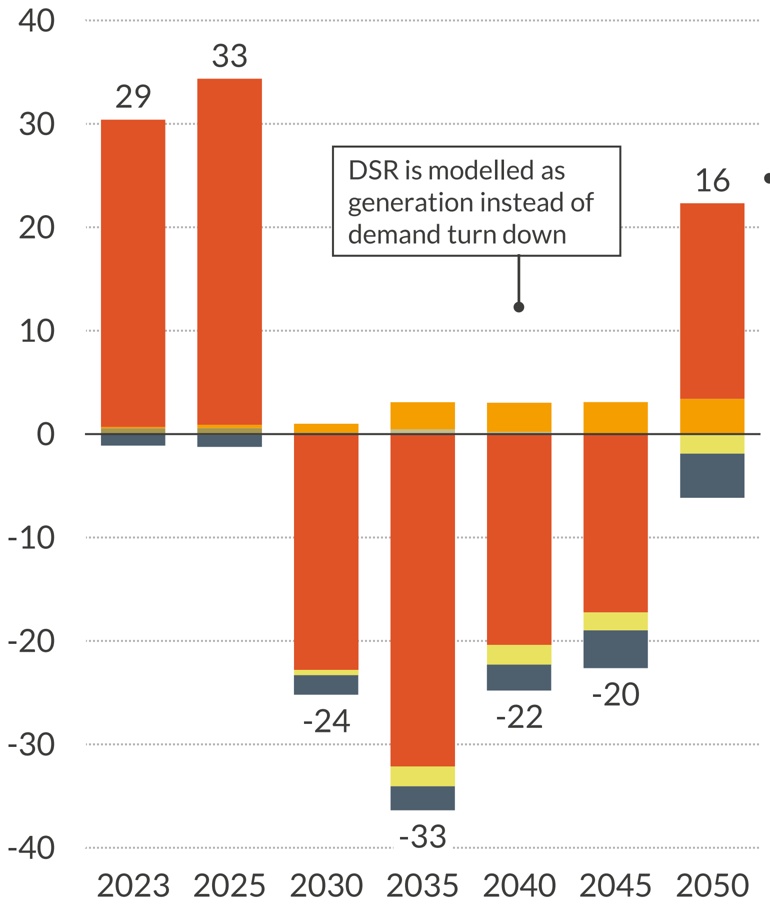
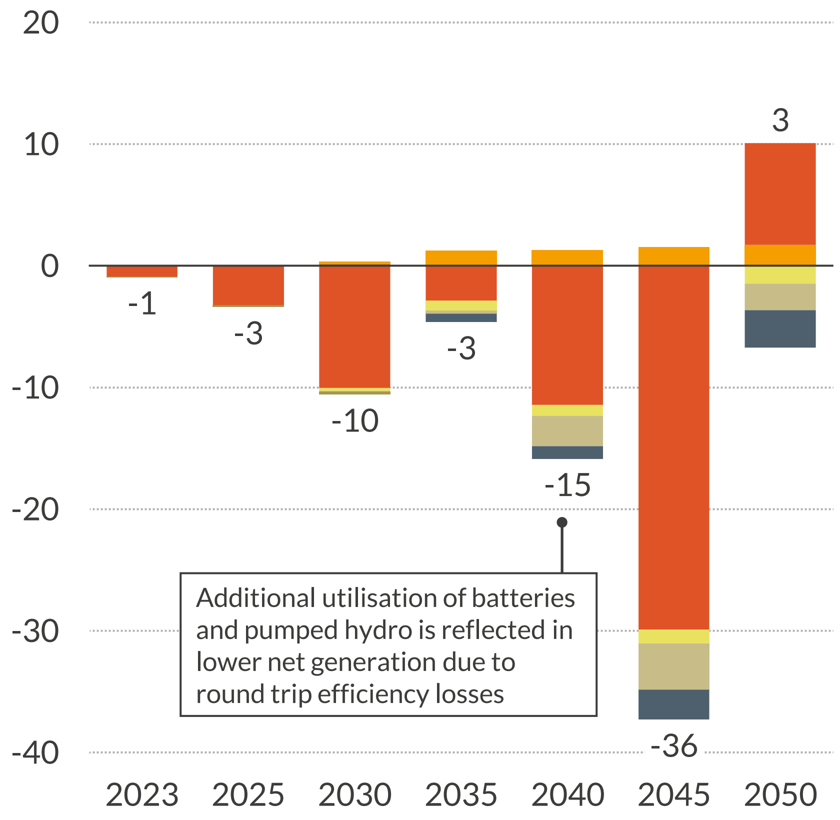
Total flexible generation
TWh



Flexible generation delta compared to the reference scenario
TWh



Interconnectors | DSR[1] | Battery storage | Hydrogen peakers | Gas / Oil peakers[2] | Pumped storage

- High renewable deployment and increased nuclear capacity, due to high power demand assumptions and limited baseload capacity, decreases baseload prices due to their low running costs, leading to interconnector exports from GB until 2050
- Natural gas is banned in the system by 2050, leading to the decommissioning of abated thermal generation in the power system and the retirement of blue hydrogen technologies, causing system tightness. As a result, after 2050, baseload and hydrogen prices increase in the system, triggering interconnector imports
- Additionally, higher hydrogen prices, due to increased power demand, compared to the reference scenario decreases H2 peaker generation across the forecast

1) Demand Side Response. 2) Gas / Oil peakers includes gas recips, OCGTs and oil peakers .

Source: Aurora Energy Research

Contents

Removing natural gas by 2050 will reduce power sector emissions by 1.5 $MtCO_2$ vs. the reference scenario due to a 27 GW reduction in Gas CCS capacity

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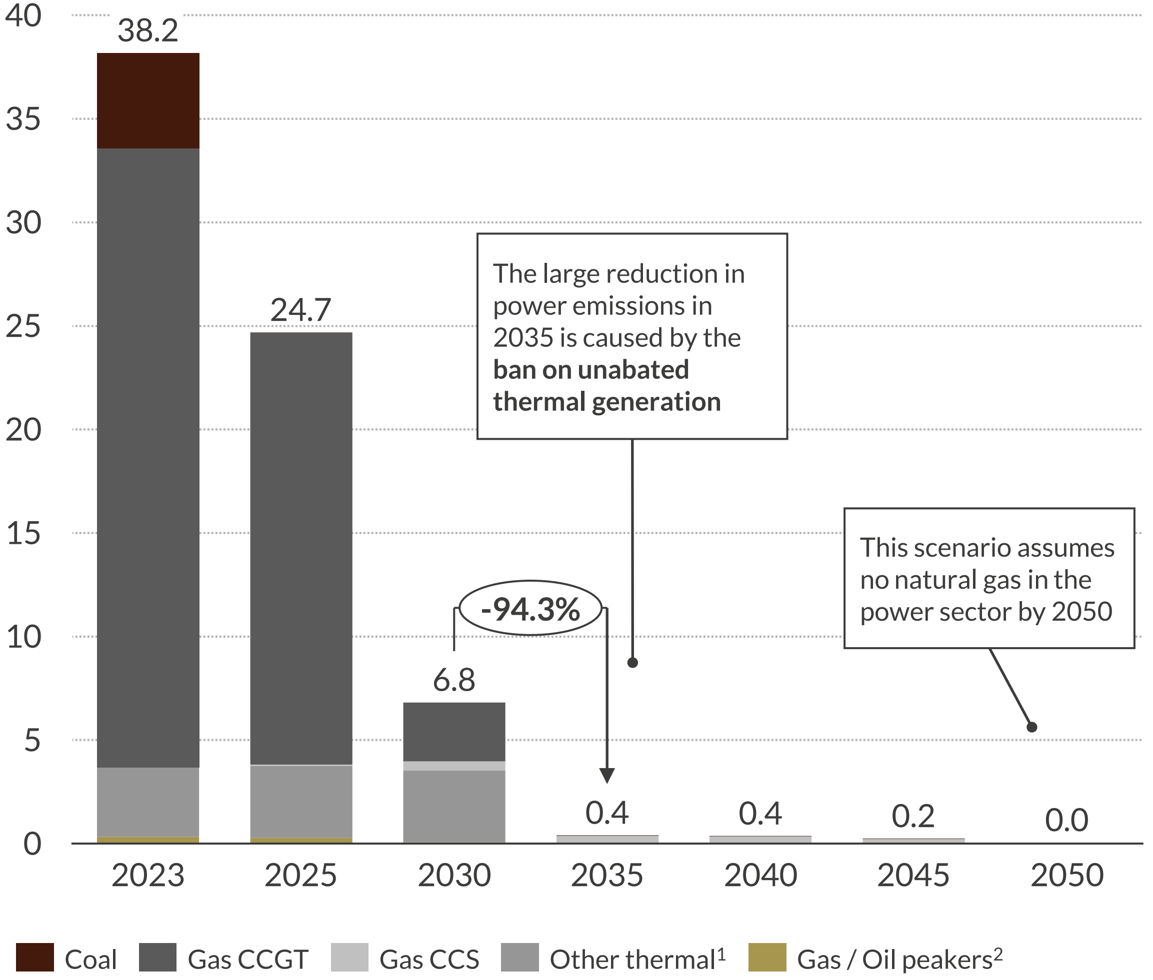
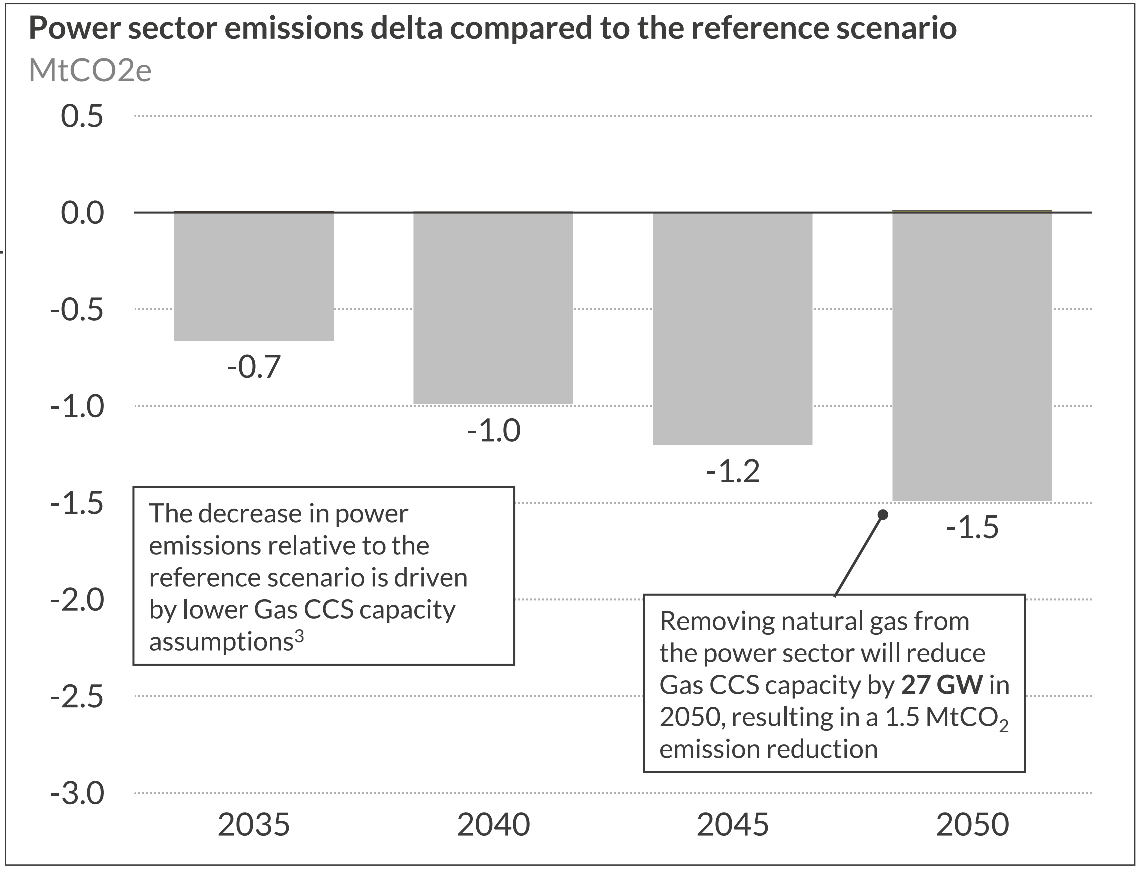
Power sector carbon emissions

$MtCO_2e$





1) Other thermal includes embedded CHP. 2) Gas / Oil peakers includes gas recips, OCGTs and oil peakers. 3) Gas CCS capacity is adjusted to be in line with current government projections. Note that CCS capacity is limited because of the investment required for CCS infrastructure, the 20+ year lifetime of plants and thus the implied early retirement of any CCS used for electricity and Hydrogen production by 2050.

Source: Aurora Energy Research

Contents

Total power system costs[1] are calculated for each scenario, based on its capacity and generation mix and resulting prices (1/3)

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	Cost components	Methodology
Wholesale costs	**Wholesale production costs**	▪ Wholesale production costs cover the costs of producing units of power within the wholesale market. Costs reflected here include fuel[1] and carbon costs as well as other variable O&M costs (the short run marginal cost - SRMC), but do not reflect CAPEX or fixed O&M costs. ▪ Different technologies have different production costs, reflecting different costs of fuel. **Total wholesale production costs can be calculated as: short run marginal cost x generation**
	Wholesale margins[2]	▪ Wholesale margins reflect the revenues achieved by a plant, minus its production costs. ▪ In any given period, the wholesale price is set by the SRMC of the highest cost plant that has to dispatch in order for demand to be met, meaning that plants that have lower SRMC can earn an “inframarginal rent” (see slide 42). ▪ Plants typically recover a proportion of their CAPEX and fixed O&M costs through wholesale margins achieved (CAPEX costs are also recovered through balancing and ancillary revenues, subsidies and the capacity market). ▪ Wholesale margins do not account for additional payments made via CfDs, ROCs or REFIT contracts, which are accounted for separately, and within this component we assume all plants receive the wholesale price. CfD payments allow renewable assets to achieve a fixed “strike price” for power produced. In periods where the wholesale price is lower than the strike price, a top-up is provided, however in periods where the wholesale price is higher than the strike price, the asset owner must pay back the difference. Both top-up payments and paybacks are accounted for under the low-carbon subsidies component, which results in calculated wholesale margins being an overestimate of actual wholesale margins. **Wholesale margins can be calculated as: wholesale market spend (wholesale market price x generation) – wholesale production costs (SRMC x generation)**

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants.
2) CAPEX is recovered through revenues in the wholesale market, balancing mechanism, capacity market, subsidies and ancillary services

Source: Aurora Energy Research

Total power system costs[1] are calculated for each scenario, based on its capacity and generation mix and resulting prices (2/3)

AURORA

	Cost components	Methodology
Balancing Mechanism	Balancing Costs[2]	▪ Balancing costs represent the total cost of balancing the system and can be calculating by considering the total volume of balancing actions required, and the price at which balancing actions were procured. ▪ Higher balancing volumes are typically required in periods with high renewable generation. **Balancing costs can be calculated as: net imbalance volumes x imbalance price**
Capacity Market	Capacity Market[2]	▪ Capacity market costs reflect the costs incurred to bring sufficient capacity on the system to ensure loss of load standards are met. ▪ Capacity prices reflect the “missing money” problem faced by some technologies, which are required for security of supply but which do not achieve sufficient revenues from other markets to remain available to the system. ▪ All technologies which achieve a capacity market contract in a given year receive the same capacity market price, but have different de-rating factors, which reflect each technology’s contribution to security of supply. **Capacity Market costs can be calculated as: CM clearing price x capacity x derating factor**
Subsidies	Low Carbon Subsidies[2]	▪ Low carbon subsidies cover the cost of subsidies for CfDs, ROCS and REFIT plants. ▪ Negative payback payments from CfD plants to suppliers when wholesale prices are above strike prices are included within this category.
	Non-RES subsidies[2]	▪ Non-renewable subsidies cover support or subsidies needed to bring non-renewable plants, particularly nuclear and low carbon flexible capacity, onto the system if they would not otherwise build out on an economic basis. **Non-RES subsidies can be calculated as: Full lifetime technology costs – sum of market revenue (wholesale, balancing, capacity market[3] & ancillary services)**

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants.
2) CAPEX is recovered through revenues in the wholesale market, balancing mechanism, capacity market, subsidies and ancillary services 3) Renewable subsidy schemes typically do not allow capacity market revenues to be stacked, however some support schemes for low carbon flexibility (such as the proposed cap and floor scheme for pumped hydro/long duration storage) do allow capacity payments to be paid

Sources: Aurora Energy Research

Total power system costs[1] are calculated for each scenario, based on its capacity and generation mix and resulting prices (3/3)

Cost components		Methodology
Network	Transmission	▪ Transmission costs reflect the costs of operating the transmission network in each scenario and are calculated based on the Ofgem RIIO[2] network price control methodology. ▪ Transmission system expenditure is driven by the volume of new build transmission connected capacity and the volume of new boundary transfer capacity. Boundary transfer capacity is an important measure of the imbalance in generation and demand in different regions across GB. Scenarios with a higher imbalance between regions will have higher boundary transfer costs. ▪ Transmission system expenditure is not charged to generators or demand (or ultimately the consumer) in the year the expenditure occurs; but is also determined by an allowable return on the rate asset value (the depreciated value of the transmission system), amongst other factors, with rules clearly laid out by Ofgem. ▪ For each scenario, we calculate the transmission system expenditure and then follow the Ofgem formula to determine total network costs in any given year.
	Distribution	▪ Distribution costs reflect the costs of operating the distribution networks in each scenario and are calculated based on the Ofgem RIIO[1] network price control methodology. ▪ Distribution system expenditure is driven by the volume of new build distribution connected capacity and by the level of peak demand in each scenario, with higher demand peaks requiring additional distribution expenditure to manage. ▪ Distribution system expenditure is not charged to generators or demand (or ultimately the consumer) in the year the expenditure occurs; but is also determined by an allowable return on the rate asset value (the depreciated value of the distribution system), amongst other factors, with rules clearly laid out by Ofgem. ▪ For each scenario, we calculate the distribution system expenditure and then follow the Ofgem formula to determine total network costs in any given year.

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants.
2) Revenue = Incentives + Innovation + Outputs; this methodology determines the allowable transmission costs chargeable by the network operator
Sources: Aurora Energy Research

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Higher renewable capacity deployment increases the need for firm capacity on the system, raising capacity market costs

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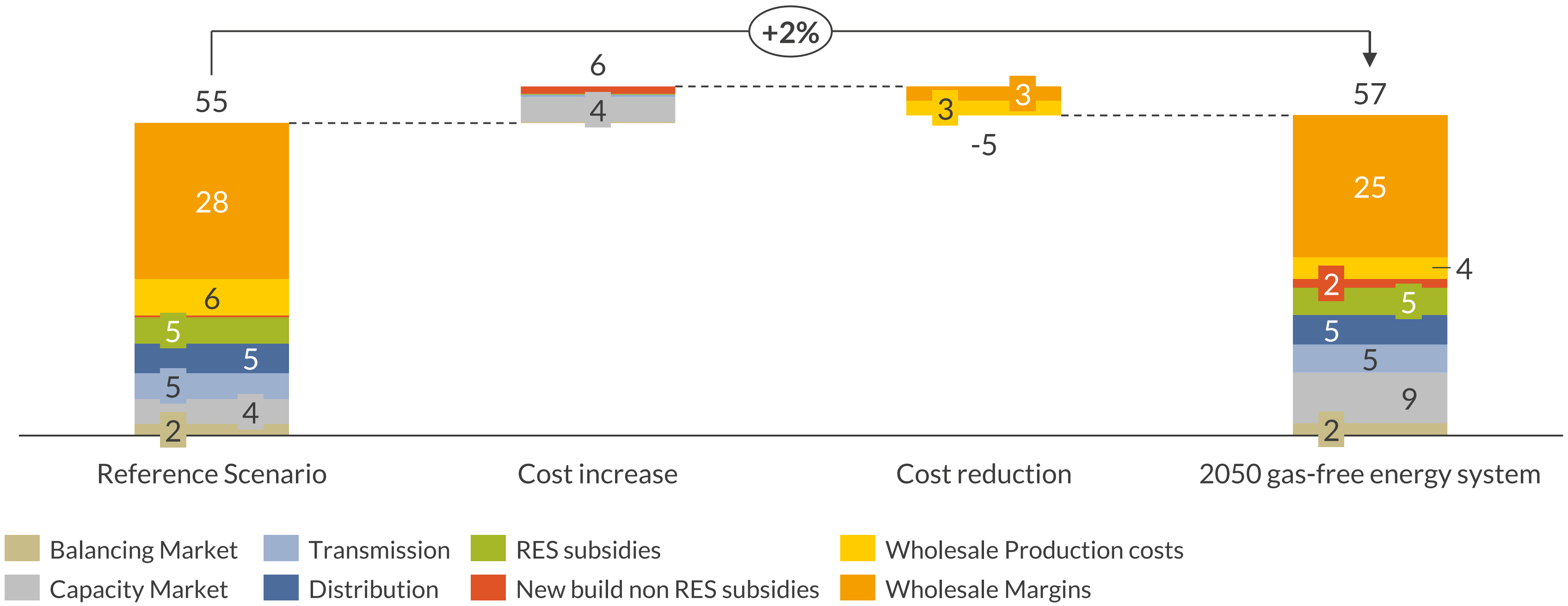
Average annual power system costs (2025 – 2050)[1,2] (excluding additional costs of operating the hydrogen system)
£ billion (real 2022)



Average consumer costs (2025-2050)[1,2] (Excluding Climate Levy, Supplier Charges & VAT)
£/MWh (real 2022)

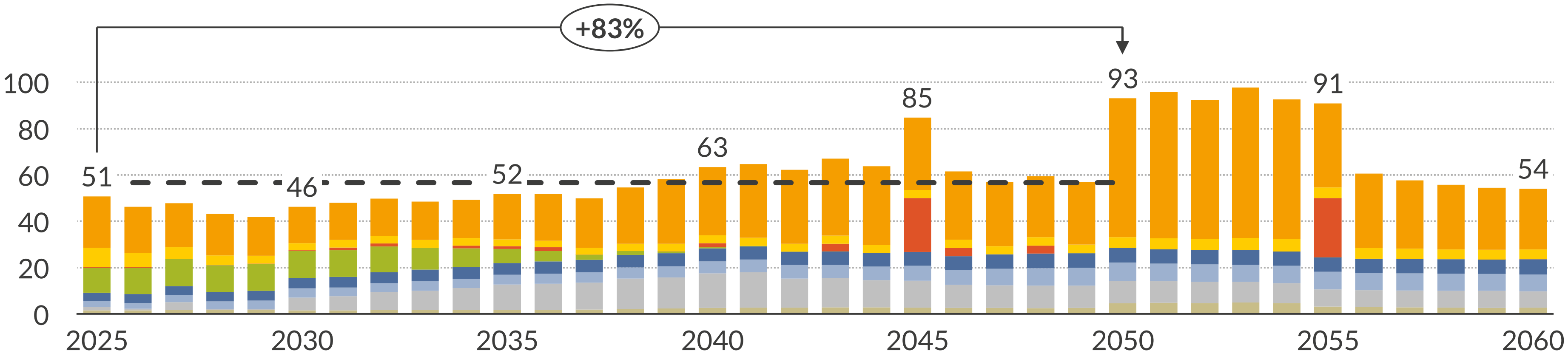
- Removing natural gas from the energy system by 2050 results in a power system that is 2% more expensive than the reference scenario, excluding costs of operating the hydrogen system
- This is primarily due to the high renewable deployment in the power system, which increases capacity market spend in this scenario as additional firm capacity is needed to ensure security of supply
- Additionally, the retirement of abated thermal generation by 2050, raises the non-renewable subsidy costs required to bring nuclear and low carbon flexible capacity onto the system to ensure that supply always meets demand as natural gas is phased out from the energy system
- Wholesale margins and wholesale production costs fall compared to the reference scenario as the increased proportion of renewables and nuclear capacities in the overall power system reduces wholesale prices in the medium term

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants. 2) Note the 2023-2024 period is excluded from these calculations as current high gas prices distort results.
Source: Aurora Energy Research

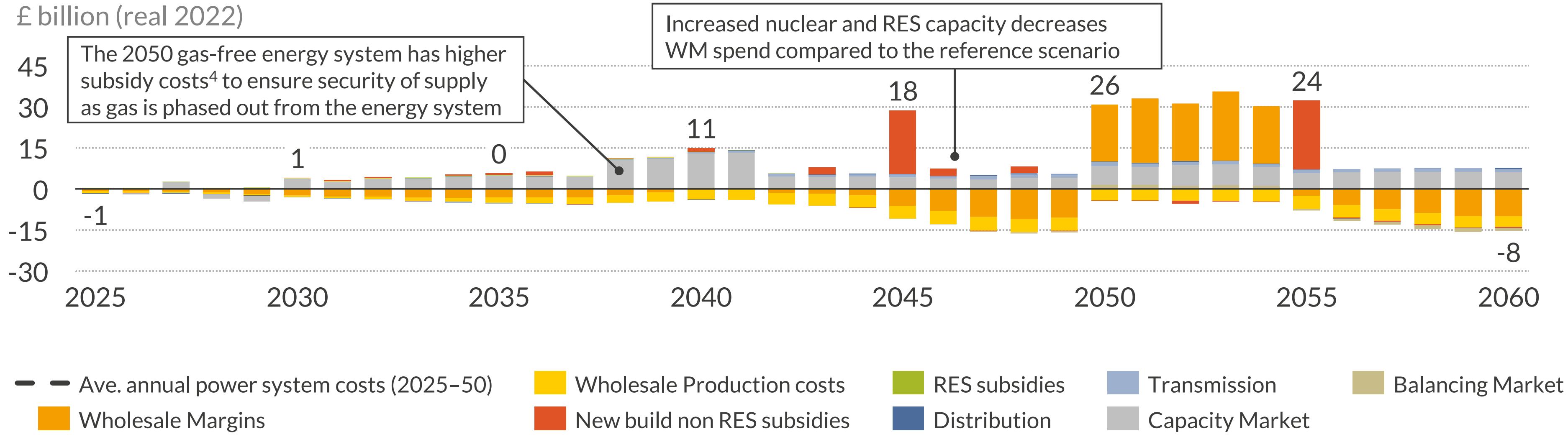
Wholesale costs represent the majority of the total power system costs in the long-term as removing gas by 2050 spikes power prices

Annual total power system costs (2025 – 2050)[1,2]
£ billion (real 2022)

Excluding additional costs of operating the hydrogen system



Difference relative to the reference scenario
£ billion (real 2022)



- **Total power system costs rise 83%** from 2025 to 2050 in the 2050 gas-free scenario, excluding additional costs from the hydrogen system
- **Wholesale market costs[3]** are the largest cost component of total system costs and are driven by changes in commodity prices, demand and supply mix
- **RES subsidy costs** are high until 2035 as renewable plants with existing CfDs, ROCs and REFITs have high strike prices compared to renewable capture prices
- **New build non-RES subsidy costs** raise in 2045 and 2055 following the addition of new build 3 GW nuclear plants onto the system
- **In 2050-55**, wholesale and H2 prices rise, causing a spike in power system costs. This is due to the 2050 decommissioning of abated gas from the power and H2 production systems, which causes system tightness. Growing renewables, nuclear and electrolyser capacity alleviates tightness by 2056.

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. Note that the hydrogen price is still used but only to determine the SRMC of hydrogen burning power plants. 2) Note the 2023-2024 period is excluded from these calculations as current high gas prices distort results. 3) Wholesale costs include both wholesale margins and wholesale production costs. 4) Capacity Market spend and new build non-RES subsidy costs.

Source: Aurora Energy Research

Wholesale market costs are on average[1] 15% lower pre-2050 than in the reference scenario due to increased RES and nuclear capacity

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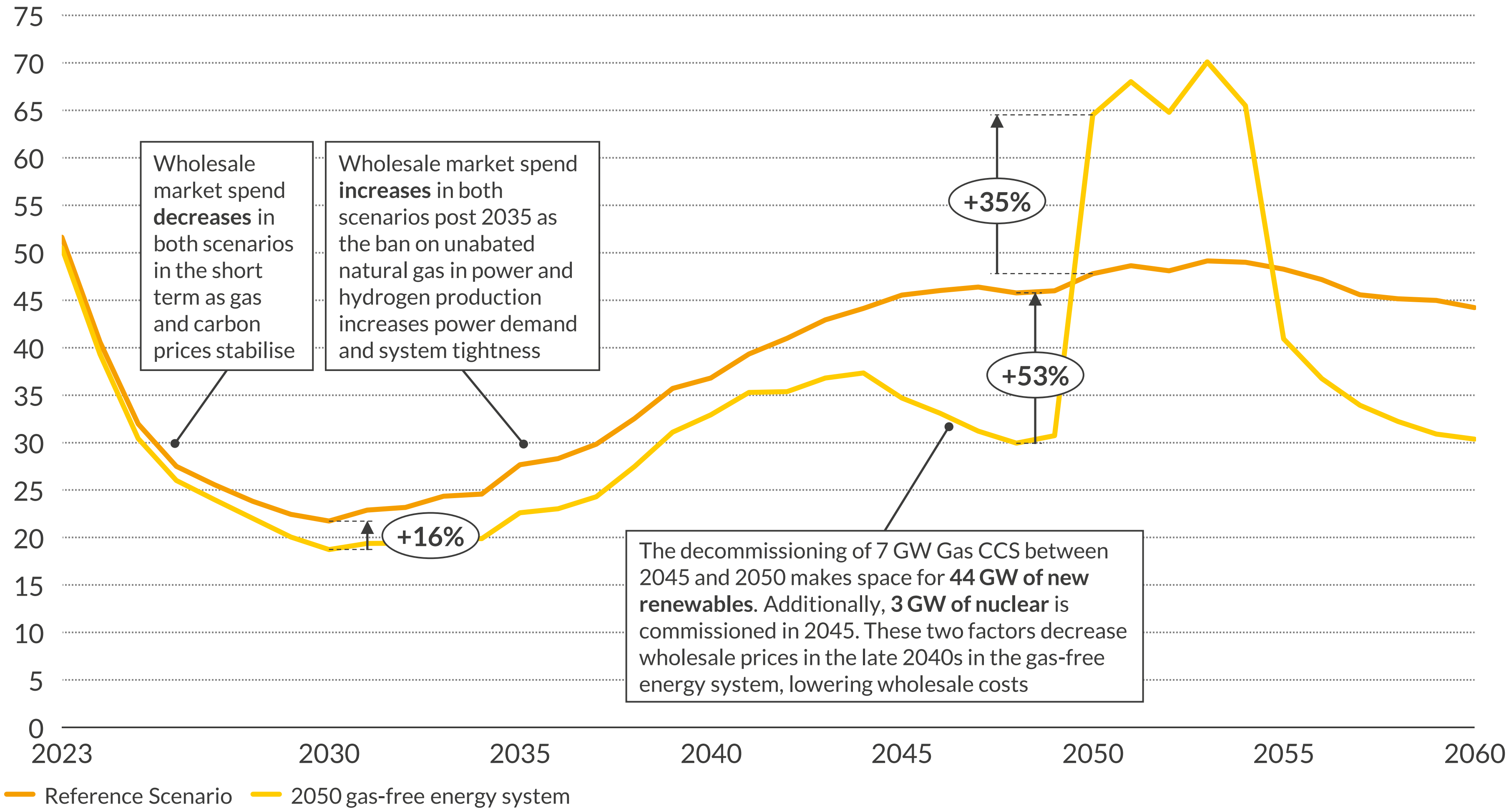
Annual wholesale costs[2]
£ billion (real 2022)



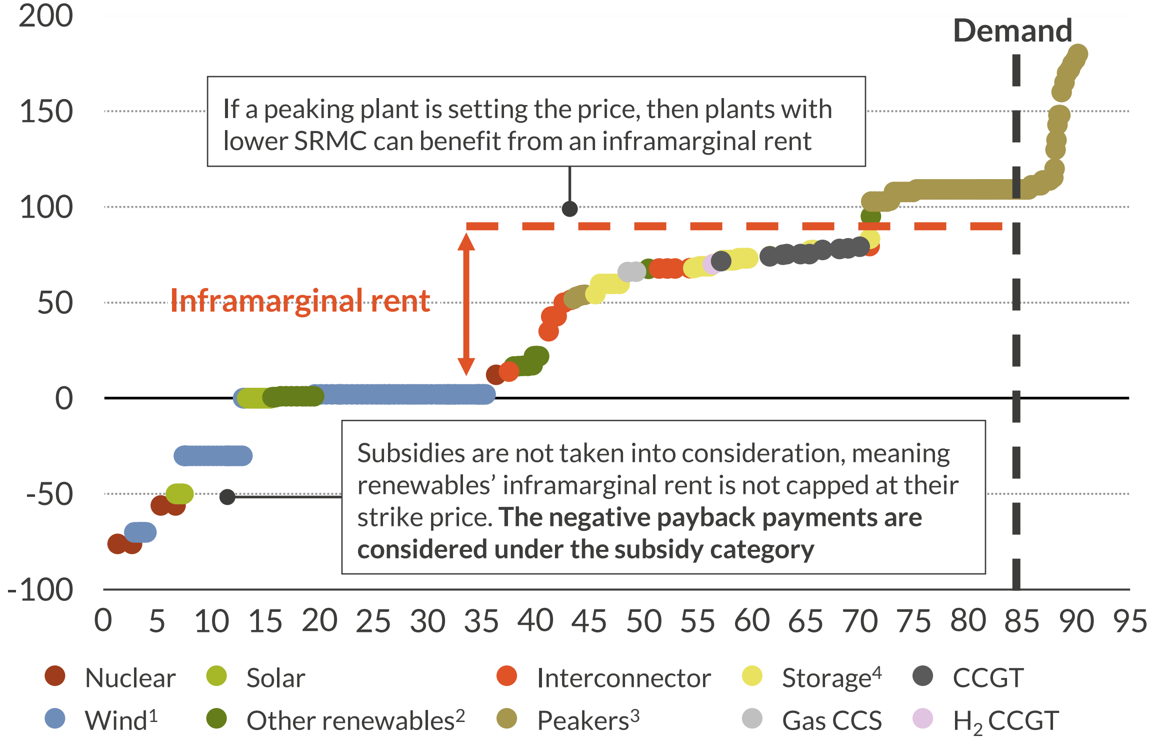
- **Pre-2050**, increased renewable deployment and nuclear capacity result in lower wholesale market spend[2] compared to in the reference scenario as these technologies have low short run marginal costs; they dispatch sooner in the merit order compared to other more expensive thermal generating technologies
- **In 2050**, the ban on natural gas in the entire energy system (power and hydrogen production) causes a supply shock that lasts to 2055. Electrolysers, now the only supply of hydrogen, have higher load factors and drive-up power demand. Higher demand and the removal of gas CCS force peaking technologies (H2 peakers) into merit more often – pushing hydrogen and the power prices up and spiking wholesale costs.
- **Post 2055**, additional nuclear deployment, continued RES build out and rising electrolyser capacity alleviate tightness of the system, stabilising baseload and hydrogen prices and lowering wholesale costs

1) Average between 2025 and 2050. 2) Wholesale costs include both wholesale margins and wholesale production costs.

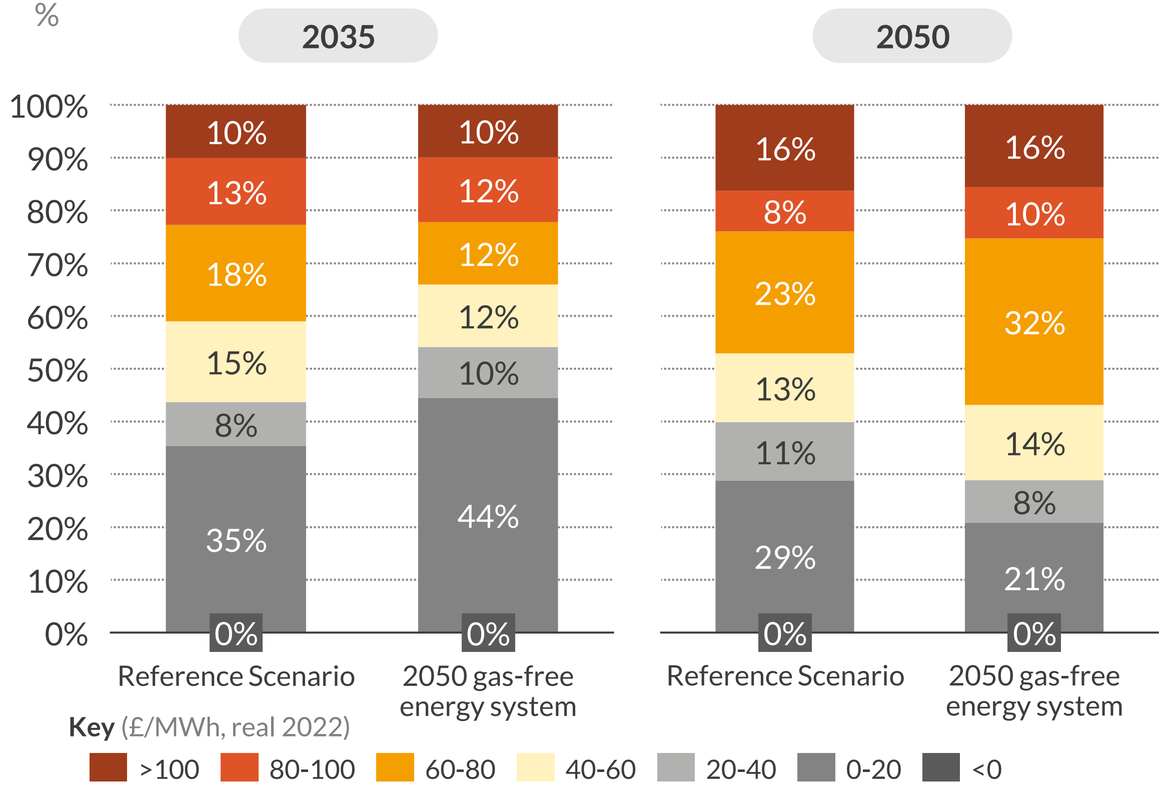
Source: Aurora Energy Research

Wholesale margins refer to the difference between the SRMC of an asset and the marginal bid price; higher frequency of top prices increases margins

Short run marginal costs
£/MWh



Frequency distribution of the electricity price
%



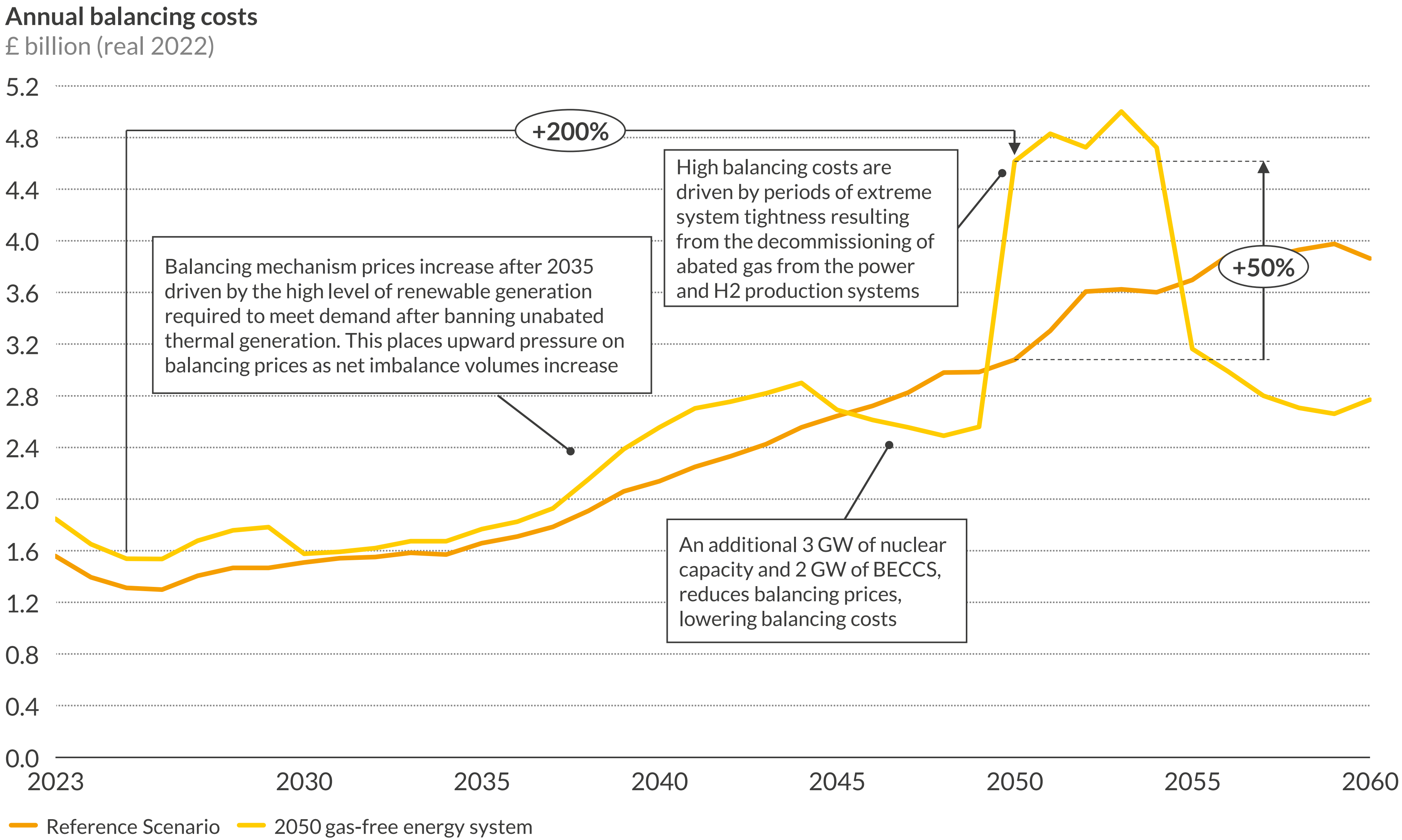
- Peaking assets have the highest SRMC, setting the price at £100-200/MWh
- When calculating wholesale margins, subsidised RES achieves the wholesale price. The delta between the wholesale price and the strike price (for subsidy top ups and paybacks) is then accounted for in the subsidy section

- Increased RES and nuclear capacity leads to higher frequency of low prices by pushing higher SRMC assets out of merit, lowering wholesale margins in the 2050 gas-free energy system until 2049
- Removing natural gas in 2050, increases the frequency of top prices, as H2 peakers will set the price more often, resulting in higher wholesale margins

1) Includes both offshore and onshore wind. 2) Other renewables includes biomass, EfW, hydro and CHP. 3) Peakers includes OCGT, recips, H2 peakers, gas peakers and DSR. 4) Storage includes batteries and pumped storage.

Source: Aurora Energy Research

Removing all gas from the energy system increases Balancing Mechanism costs by 9% on average[1] versus to the reference scenario



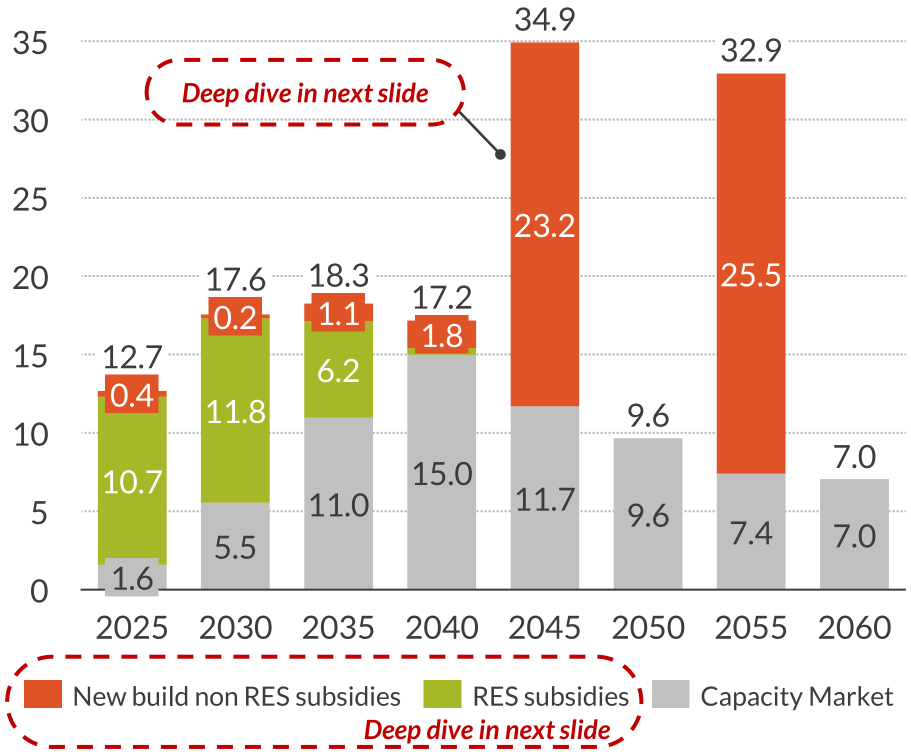
1) Average between 2025 and 2050

Source: Aurora Energy Research

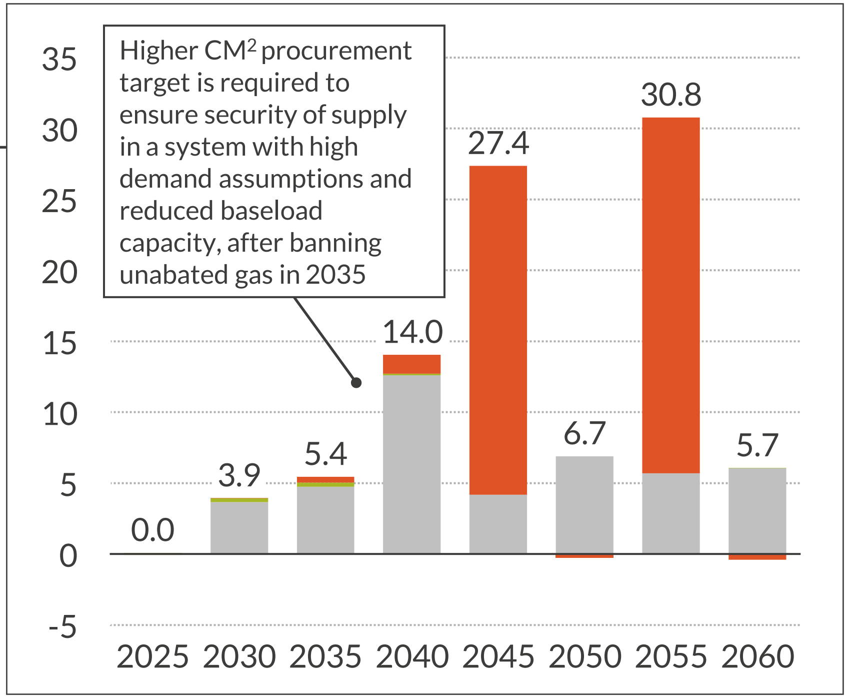
- The 2050 gas-free energy system has 9% higher on average[1] balancing costs than the reference scenario. This is due to an increased intermittent renewable generation as a result of high demand assumptions and reduced baseload capacity, which causes an accelerated build of RES capacity. This increases volatility in the system and, as a result, net imbalance volumes
- Banning natural gas in the energy system in 2050 leads to the decommissioning of abated thermal generation in the power and hydrogen production systems, causing system tightness. Baseload and hydrogen prices increase, impacting the SMRC of H2 peakers and rising balancing costs. Increase nuclear build out in 2055 reduces system balancing needs, stabilising balancing costs

High renewable deployment and reduced baseload capacity increases the need for firm capacity in the system, increasing CM spend[2]

Annual subsidy costs[1]
£ billion (real 2022)



Difference relative to the reference scenario
£ billion (real 2022)



Average subsidy costs[1], as seen on consumer bills (2025 – 2050)
£/MWh (real 2022)

30

2050 gas-free energy system

20

Reference Scenario

1) Including new build non RES subsidies, RES subsidies and Capacity Market. 2) Capacity Market

Source: Aurora Energy Research

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Capacity Market
Capacity market spend reflects the costs of firm capacity for energy security. Capacity market costs are higher in the 2050 gas-free scenario to support the deployment of additional firm capacity required in a system with high RES deployment and reduced baseload capacity

New build non-RES subsidies
The 2050 gas-free energy system requires a high level of non-renewable subsidy spend as reduced thermal generation increases the need for nuclear and BECSS capacity in the system. Additionally, high renewable deployment lowers wholesale price, meaning non-RES assets will need additional support to deploy

Renewable Subsidies
Low carbon subsidies cover the cost of subsidies for CfDs, ROCs and REFIT plants. This category also includes negative payback payments from CfD plants to suppliers when wholesale prices are above strike prices

Subsidies: increased nuclear capacity rises the non-renewable subsidy spend required due to its high levels of upfront CAPEX expenditure

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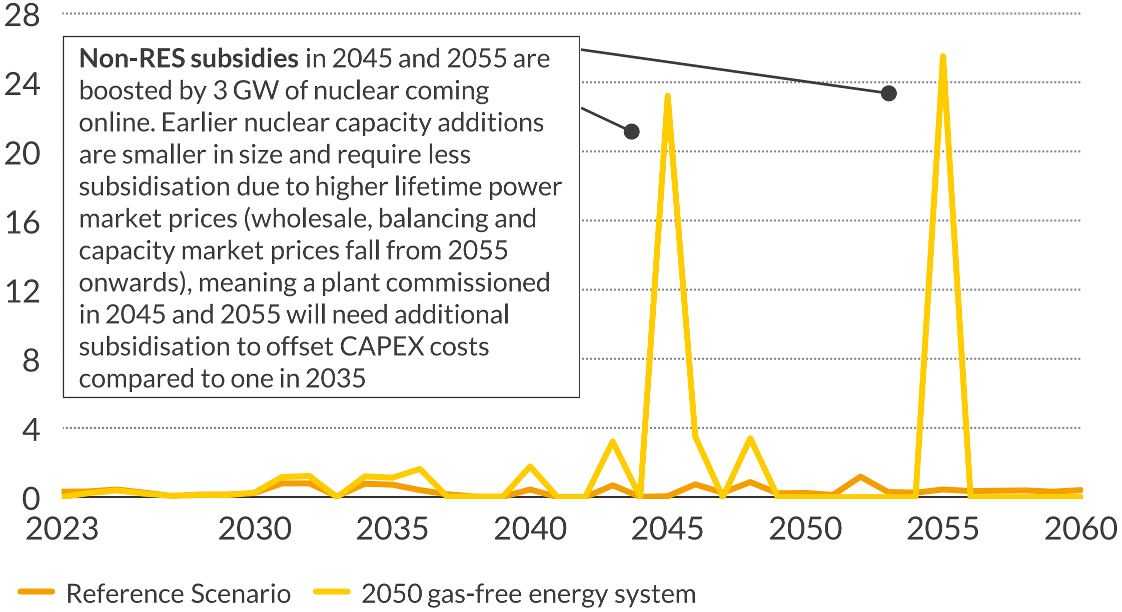
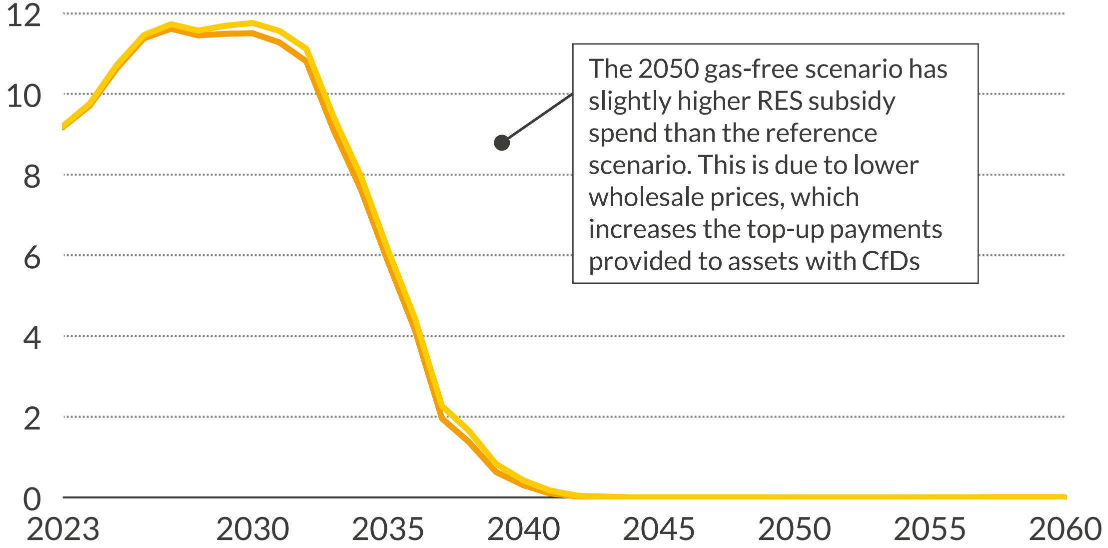
Deep dive

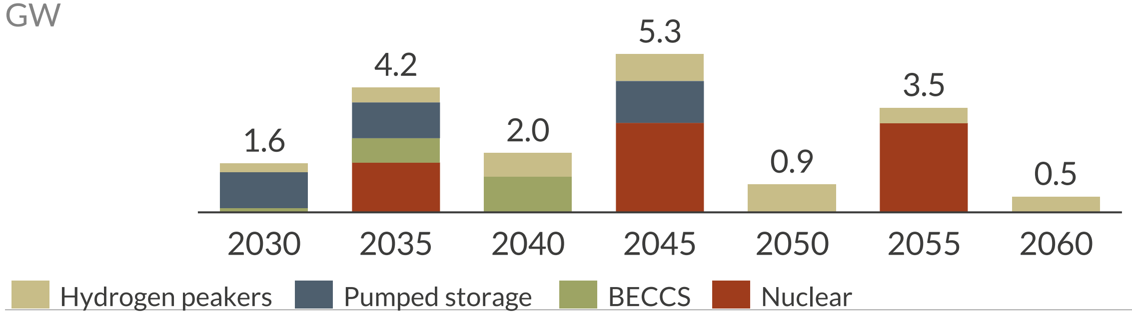
Annual non-RES subsidy costs
£ billion (real 2022)



Annual RES subsidy costs
£ billion (real 2022)



Year-on-year adoption, 2050-gas free energy system
GW



- Subsidy costs are high until 2035 as renewable plants with existing CfDs, ROCs and REFITs have relatively high strike prices compared to renewable capture prices
- From 2035, subsidy spend falls significantly. Renewables and low carbon capacity are still eligible for support, however as technology learning rates decrease costs and subsidy auctions become more competitive, strike prices reduce, reducing subsidy expenditure

Source: Aurora Energy Research

The increased capacity requirements of the 2050 gas-free scenario increases total network costs due to higher infrastructure needs

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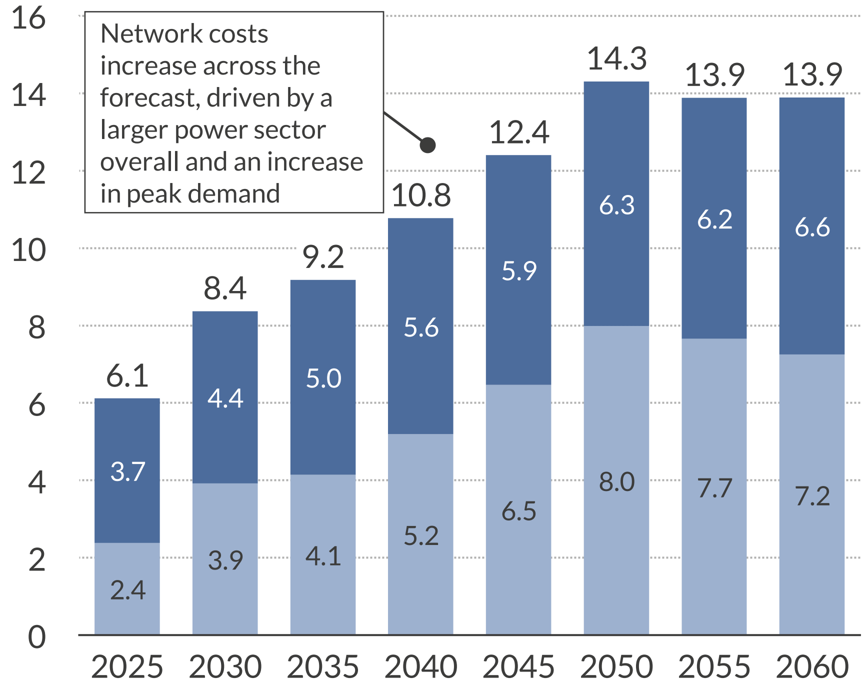
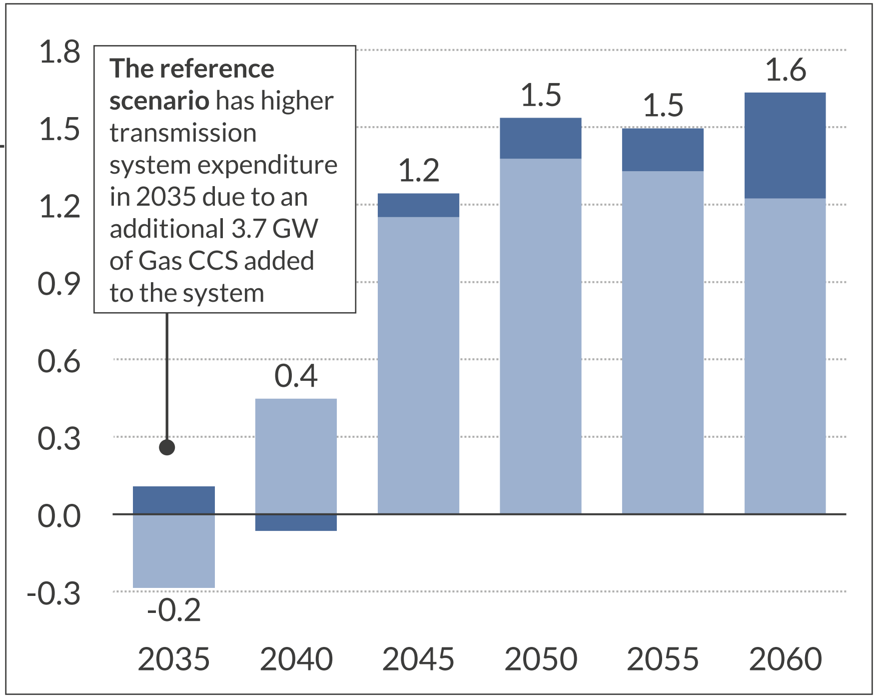
Annual network costs
£ billion (real 2022)



Difference relative to the reference scenario
£ billion (real 2022)



Average network costs, as seen on consumer bills (2025 – 2050)
£/MWh (real 2022)

18	18
2050 gas-free energy system	*Reference Scenario*

Distribution Transmission

1) Average between 2025 and 2050

Source: Aurora Energy Research

Infrastructure costs are driven by new-build capacity, the proximity of supply to demand and the connection type (transmission vs distribution) for capacity mixes

Total transmission and distribution costs are 4% greater on average[1] than in the reference scenario due to higher power demand from increased green hydrogen production, leading to a larger sized power sector overall. As a result, higher infrastructure investment is required

Transmission system expenditure in the 2050 gas-free energy system is higher than in the reference scenario after 2035 due to the additional nuclear, BECCS and offshore wind capacity required to ensure security of supply

In the long-term, the 2050 gas-free energy system has higher **distribution costs** compared to the reference scenario . This is mainly driven by high battery build, which is underpinned by growing spreads in a system with increased renewable generation and high hydrogen prices

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Annual consumer bills fall over time as reduced wholesale costs mitigate higher CM and subsidy spend in the 2050 gas-free scenario

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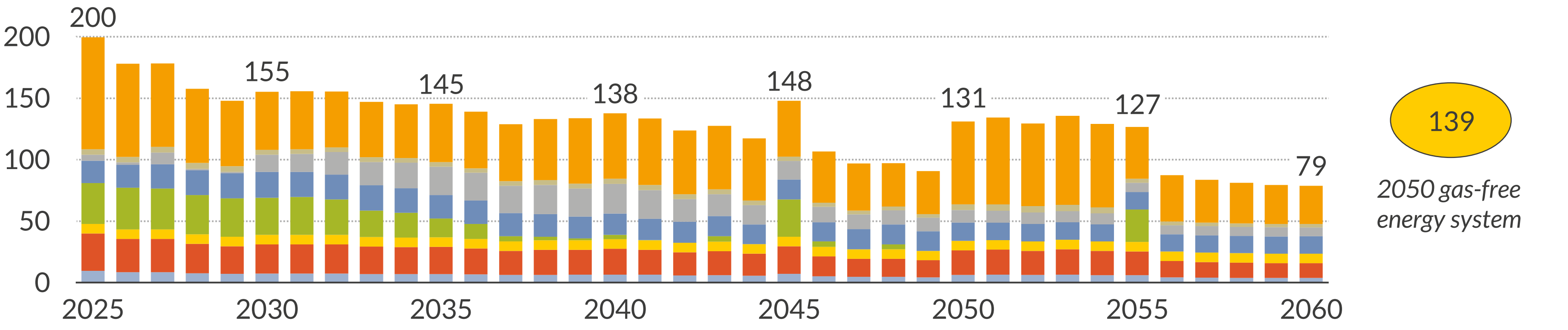
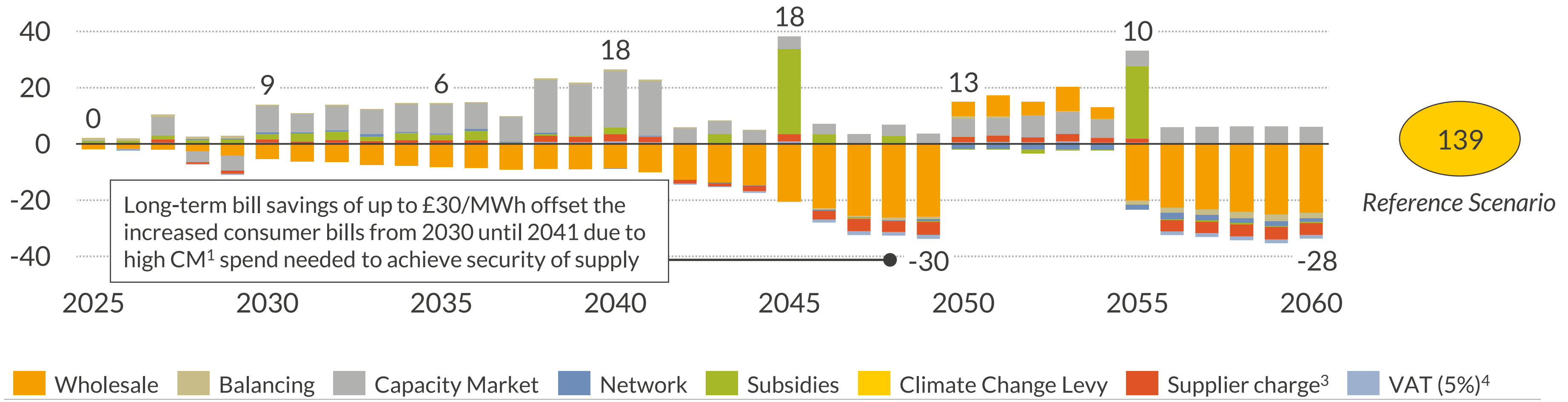
Annual consumer bills[1] (Including Climate Levy, Supplier Charges & VAT)
£/MWh (real 2022)

Average consumer bills (2025 – 2050)[1,2]
£/MWh (real 2022)



Difference relative to the reference scenario
£/MWh (real 2022)



- **In the medium term**, consumer bills are up to 18 £/MWh higher than in the reference scenario. This is mostly due to the higher CM spend required to bring enough firm capacity into a system to match the increased renewable deployment and mitigate the 2035 ban on unabated thermal generation.
- **Pre-2050**, additional renewable and nuclear capacity coming online pre-2050 decreases baseload prices, reducing consumer bills vs. to the reference scenario. As a result, the 2025-2050 average[5] consumer bills for both scenarios is 139 £/MWh, as higher medium term spend is offset by wholesale cost savings.
- **Post 2050**, consumer bills rise in 2050 as a result of the removal of natural gas from the energy system, causing a supply shock. However, after 2055, the system will be less constrained as demand stabilises and RES and nuclear capacity continue to increase, reducing consumer bills

1) This excludes H2 production costs (blue and grey hydrogen production, hydrogen imports and storage and electrolysers) and heating system costs. 2) Including Climate Levy, Supplier Charges & VAT. 3) Supplier charges are comparable as the assumption is that when suppliers set their prices, they would aim to cover their operating costs while still making a profit. 4) VAT is a government tax on services and goods. VAT is similar across all scenarios as homeowners are required to pay 5% on consumer electricity bills. 5) Average between 2025 and 2050.

Source: Aurora Energy Research

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A 2050 gas-free energy sector will require strong hydrogen demand growth to displace gas from the industry, heat and power sectors

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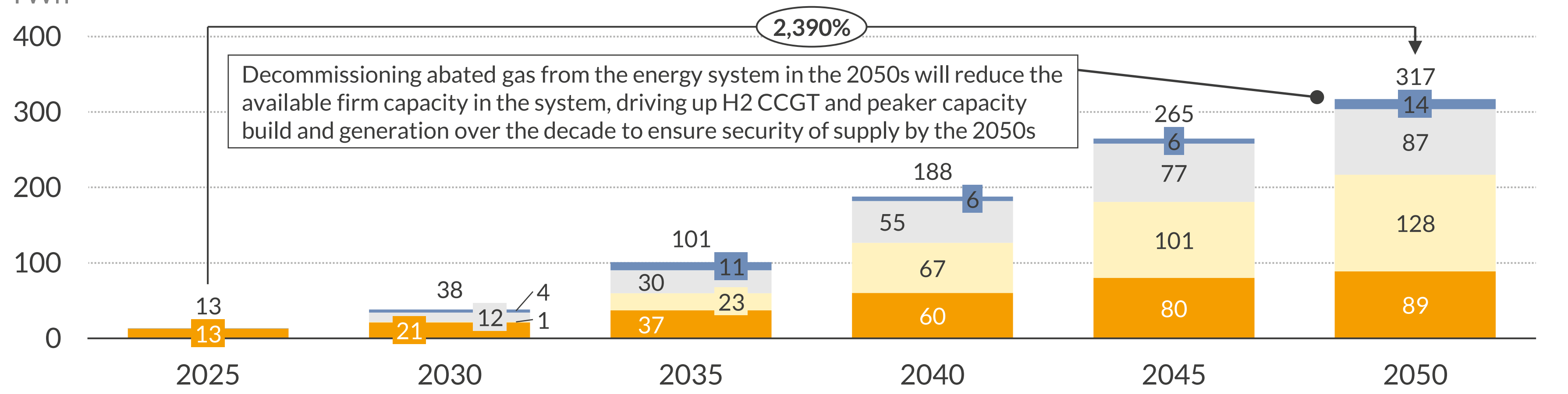
Total hydrogen demand

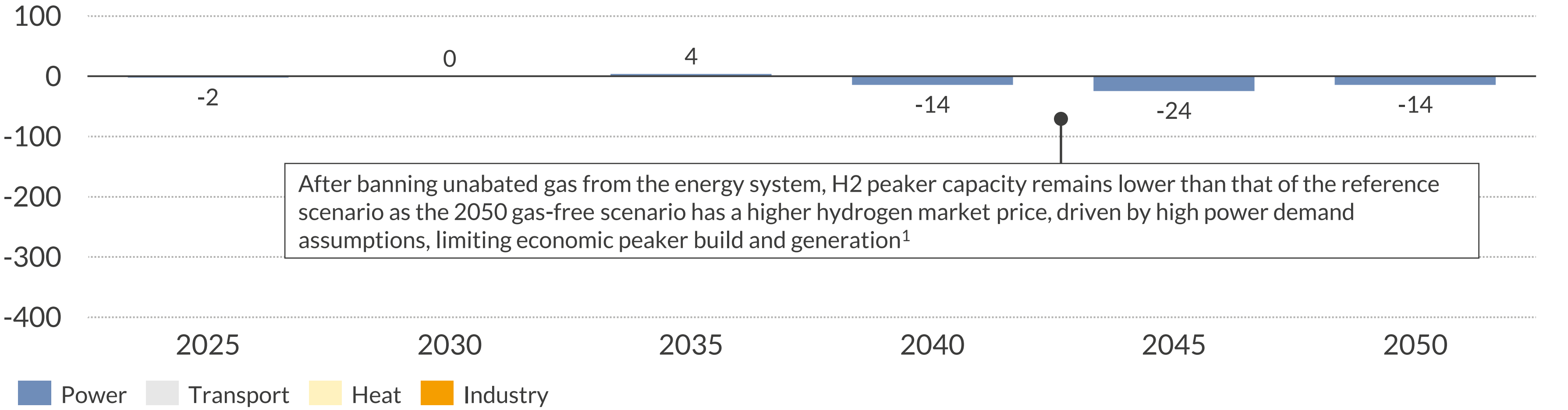
TWh



Difference relative to the reference scenario

TWh

Only H2 demanded from the power sector varies across scenarios as the reference scenario also assumes decarbonisation of the heating, transport and industry sectors by 2050



- Total hydrogen demand increases by 2390% between 2025 and 2050 in the 2050 gas-free energy system, with 40% of demand in 2050 needed to decarbonise heating in GB
- In the heating sector, hydrogen is used as a primary energy option in boilers. The 2050 gas-free energy system assumes that 128 TWh of H2 will be required in 2050 to decarbonise the heating sector
- Industry sector demand grows by >300%[2] (89 TWh) to 2050 as H2 is used to decarbonise processes that rely on fossil fuels to reach high temperatures and as feedstock
- In the 2050 gas-free energy system, H2 demand from the power sector represents 5% on average[3] of the total hydrogen demand and will increase across the forecast to support the generation of H2 burning plants as natural gas is phased out from the energy system

1) See slide 29 for more information. 2) From 2025 to 2050. 3) Average from 2025 to 2050

Source: Aurora Energy Research

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Removing gas from H2 production leads to a larger system vs. the reference scenario due to increased H2 storage needed by green H2

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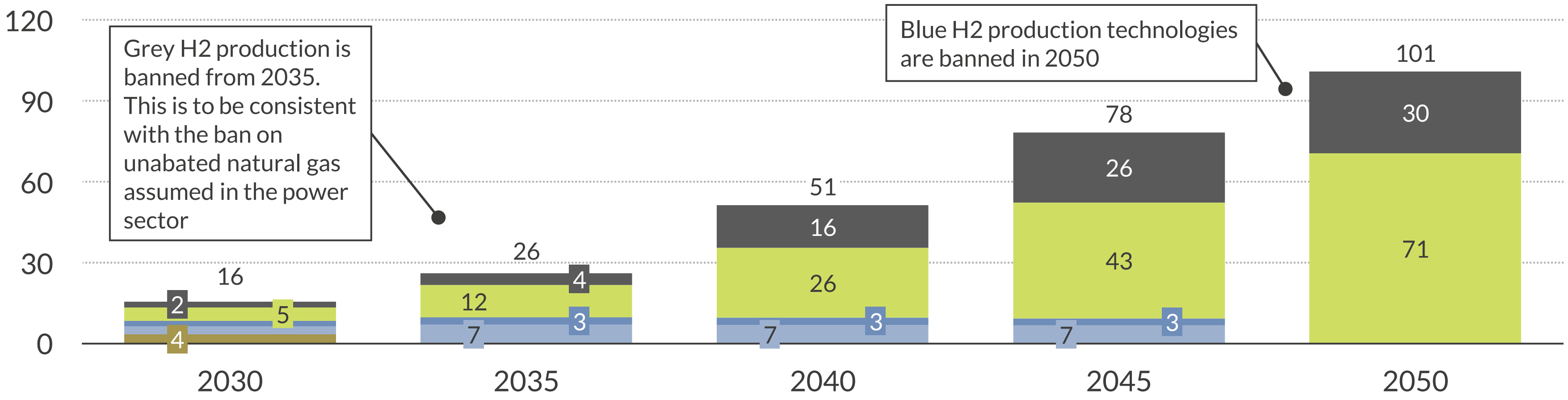
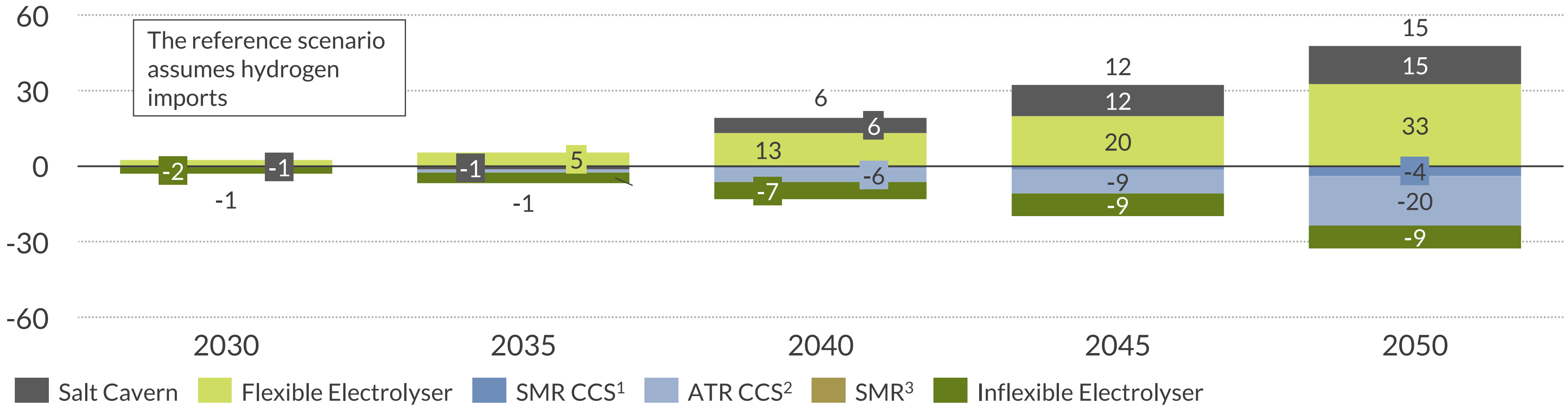
Capacity of hydrogen production technologies

GW



Difference relative to the reference scenario

GW



- Total hydrogen production capacity is 15 GW higher in the 2050 gas-free energy system than in the reference scenario by 2050
- This is due to the removal of natural gas from the hydrogen production system by 2050. Electrolyser capacity increases 24 GW to offset the fall in blue hydrogen production, which requires natural gas, relative to the reference scenario
- The increased electrolyser demand will be supported by an increased hydrogen storage capacity[4]. Salt cavern H2 storage is critical in a system with high levels of green hydrogen production because of the seasonality of this technology
- Additionally, the 2050 gas-free energy system has 9 GW less of inflexible electrolysers by 2050 than the reference scenario, replaced by flexible electrolysers, to alleviate the strain on the power system as natural gas is phased out

1) Steam-methane reformer with carbon capture and storage. 2) Autothermal reformer with carbon capture and storage. 3) Steam-methane reformer. SMR produces grey hydrogen since it uses natural gas and does not capture greenhouse gases made in the process. 4) Hydrogen storage is modelled ensuring that it doesn't exceed the Oct 2022 gas storage levels in the UK by 2035 (which is equivalent to 4.5 GW of hydrogen storage) and it does not go above technical UK limits by 2060 (the theoretical limit in the UK is approximately 70 GW)

Source: Aurora Energy Research

Hydrogen storage utilisation is seasonal, driven by the annual variation in heating demand

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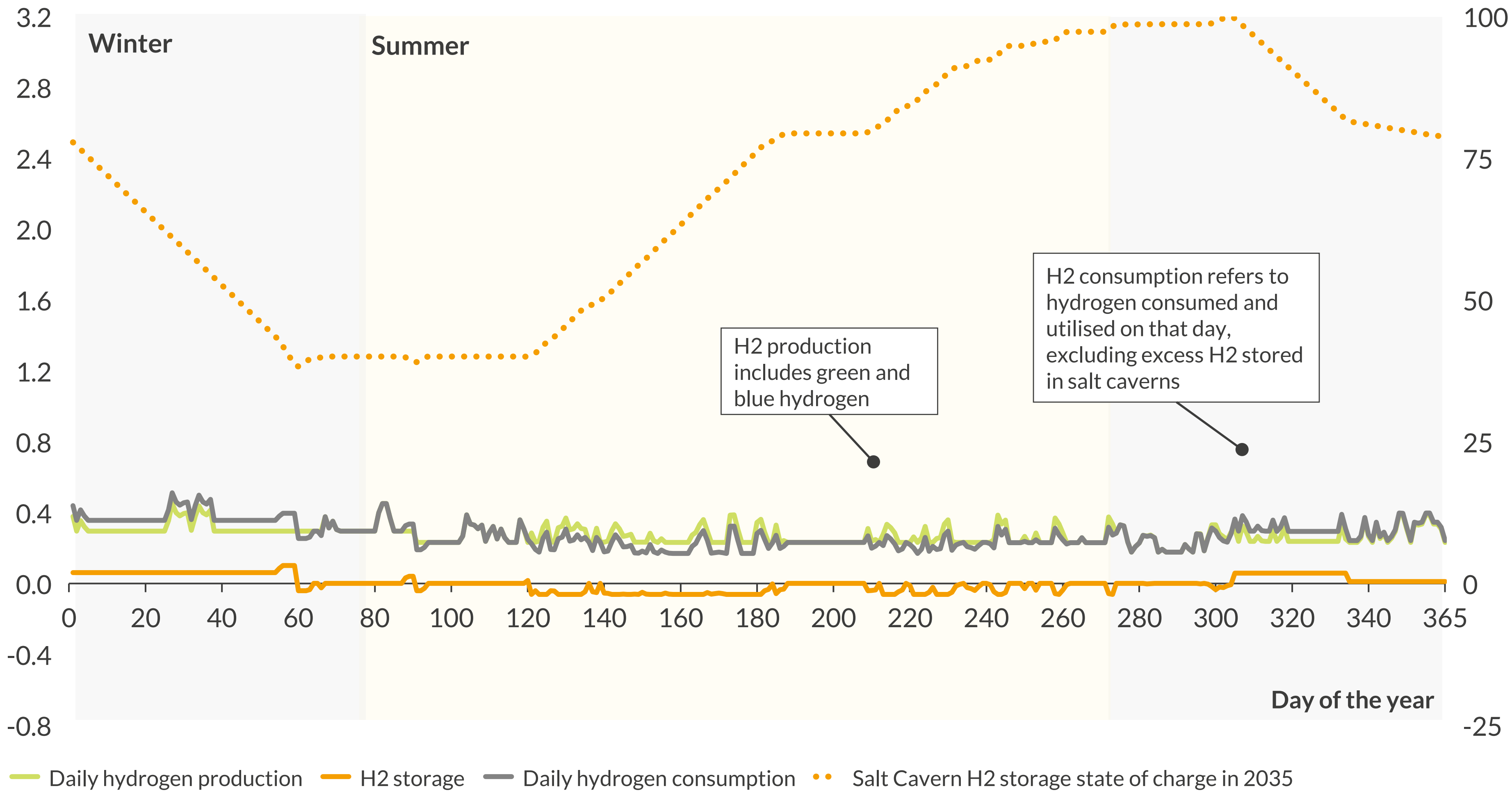
Daily hydrogen production and consumption[1] in 2035
TWh/day

GB salt cavern H2 storage state of charge in 2035
%



1) Hydrogen consumption refers to H2 consumed and used on that day and excludes excess hydrogen stored in salt caverns.

Source: Aurora Energy Research

2050 gas-free energy system in 2035

- H2 storage state of charge increases to the maximum levels during Summer period due the seasonality of hydrogen heating demand and of green hydrogen production. During summer months, heating demand is low, lowering both hydrogen and power demand, weighing on prices. Additionally, RES generation is high, incentivising flexible electrolysers to operate at higher load factors. With hydrogen supply exceeding demand, excess hydrogen is stored
- During winter months, heating demand is high, boosting hydrogen and power demand, and inflating prices. Flexible electrolysers will operate at lower load factors, and due to higher power prices, hydrogen prices will increase. This will incentivise storage withdrawals to ensure supply means demand

Increased hydrogen demand in 2050 will require more summer storage to balance green hydrogen production

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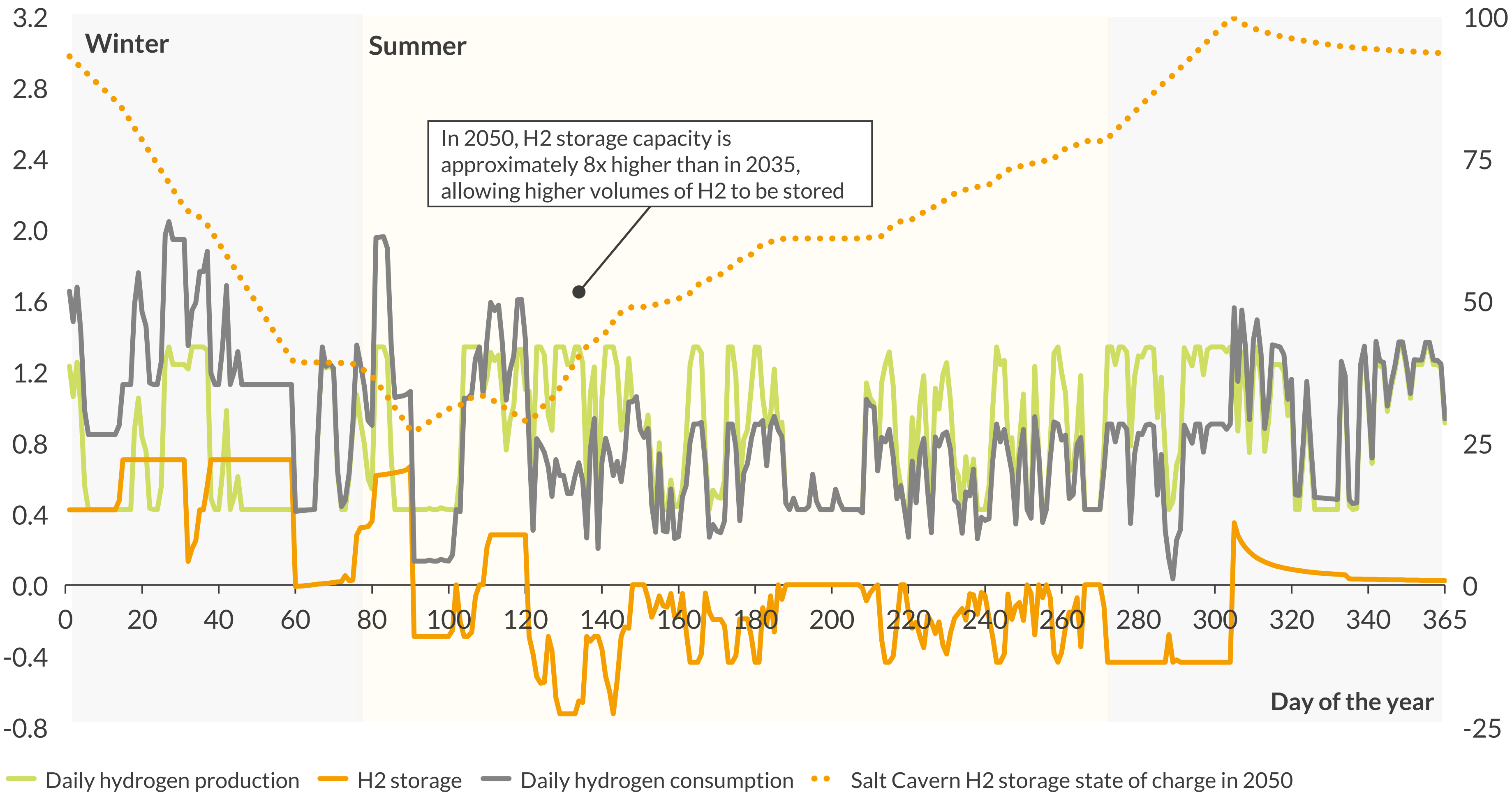
Daily hydrogen production and consumption[1] in 2050
TWh/day

GB salt cavern H2 storage state of charge in 2050
%



1) Hydrogen consumption refers to H2 consumed and used on that day and excludes excess hydrogen stored in salt caverns.

Source: Aurora Energy Research

2050 gas-free energy system in 2050

- Daily hydrogen consumption in 2050 is 0.87 TWh/day on average, 214 % higher than the daily average H2 consumption in 2035
- The decommissioning of all abated gas in 2050 leads to an increased electrolyser capacity. This increase in electrolysers' production will be supported by a growth in hydrogen storage capacity (>300% from 2035 to 2050), allowing greater volumes of H2 to be stored
- As in 2035, H2 storage consistently discharges in winter when demand is high and charges in summer months when demand and prices are low

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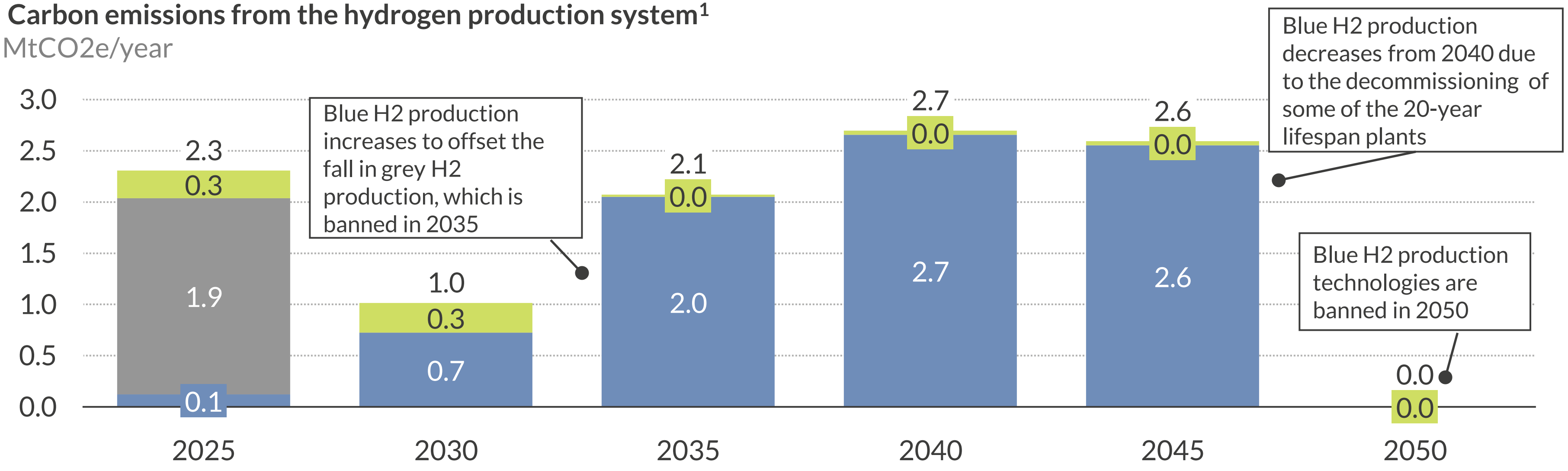
Removing natural gas from the energy system reduces carbon emissions from H2 production to less than 1 $MtCO_2$ by 2050

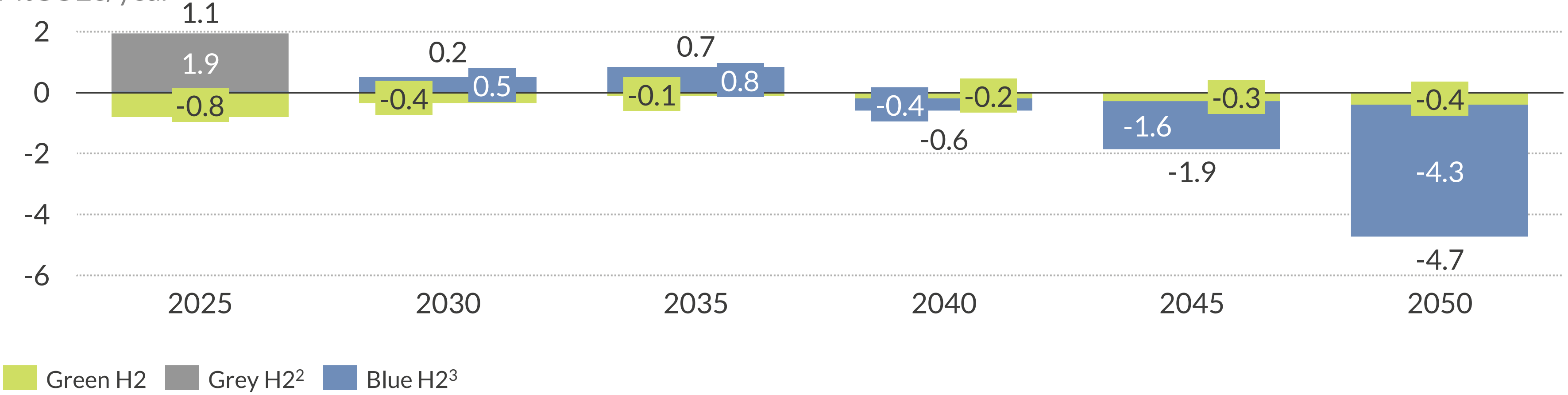
Carbon emissions from the hydrogen production system[1]

MtCO2e/year



Difference relative to the reference scenario

MtCO2e/year



- Carbon emissions from hydrogen production are higher in the 2050 gas-free energy system than in the reference scenario at the beginning of the forecast. This is due to a reduction of inflexible electrolyser capacity (fixed 90% load factor). As a result, the reference scenario produces more hydrogen through inflexible electrolysers and less hydrogen using a cheaper but more carbon intensive methods (grey/blue H2), reducing emissions
- After 2035, carbon emissions from the hydrogen production are lower than in the reference scenario. This is primarily due to the reduced blue hydrogen capacity in the 2050 gas-free energy system. In this scenario, no new build of blue H2 capacities are considered viable after 2034 as natural gas is removed entirely from the energy system by 2050

1) Assuming a 90% carbon capture rate for blue hydrogen production. Emissions from production of electrolytic hydrogen calculated based on carbon intensity of the power sector. Calculations do not include emissions from H2 transportation, compression or further conversion into H2 derivatives. 2) Produced by steam-methane reformer. 3) Produced by steam-methane reformer with carbon capture and storage and autothermal reformer with carbon capture and storage.

Source: Aurora Energy Research

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A gas-free GB energy system by 2050 will incur additional costs associated with a large hydrogen network required to support the transition

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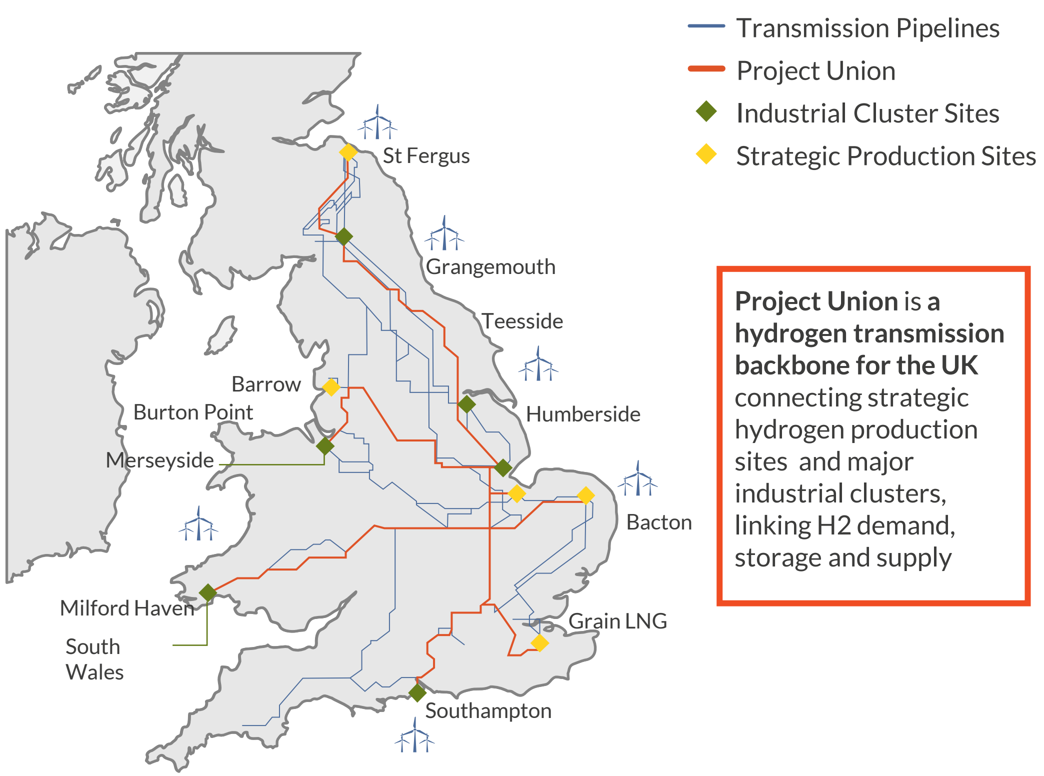
1 Illustrative Hydrogen Backbone for the UK[1]



Project Union is a **hydrogen transmission backbone for the UK** connecting strategic hydrogen production sites and major industrial clusters, linking H2 demand, storage and supply

- Hydrogen will play a crucial role in decarbonising the energy system by 2050. However, a hydrogen transport network will be required in the future UK H2 market to support this transition. Exiting infrastructure such as natural gas pipeline networks can be repurposed to transport gaseous hydrogen

2 Cost implications of a hydrogen network

- The removal of natural gas used in power generation, hydrogen production, heating, transport and industry will result in a larger hydrogen production system. This will raise the cost of the system due to the expenses associated with a hydrogen network, such as:

Hydrogen pipeline infrastructure	Capital cost of building new hydrogen pipelines and repurposing exiting gas pipelines in the UK
Operating costs for hydrogen distribution	These depend on compression system design and costs (compressor technology choice, required operating pressure, etc)
Hydrogen storage facilities	Salt caverns can be repurposed or develop for hydrogen storage
Green hydrogen production costs	A gas-free GB energy system by 2050, assuming no hydrogen imports, will result in a hydrogen market that is entirely reliant on domestic green hydrogen production. The levelized cost of green hydrogen is greater than blue or grey LCOH[2]

1) Map subject to updates resulting from new government announcements, considering natural gas supplies and LNG flows.2) According to the IEA, the global average LCOH of green hydrogen in 2019 was between 160% and 260% higher than that of blue hydrogen and 350%-380% higher than that of grey hydrogen.

Sources: Aurora Energy Research, EHB, Project Union, IEA

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Power system cost components are levied via different mechanisms however are ultimately recovered through consumer bills

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Total power system cost components

Electricity
Total spending on all power produced to meet demand

Balancing
Spending needed to balance the system

Capacity Market
Spending needed to bring forward new capacity

Network
Total spending on transmission and distribution network

Subsidies
Spending required to bring in capacity to meet decarbonisation targets

Hydrogen
Costs of hydrogen production and generation

Consumer Bills

System Costs + Supplier Charges + VAT

Households

Consumer Bill

Supplier Charges

When suppliers set their prices they will try to cover their operating costs as well as make a profit. These costs cover things like customer service and billing, typically around 20%

VAT

VAT is a government tax on services and goods. Homeowners are required to pay 5% on consumer electricity bills

Total system costs represent power system costs only, and do not account for the deployment of EVs, decarbonised heating systems or other demand side technologies. Costs also do not account for the total costs of operating the gas or potential future hydrogen network.

Source: Aurora Energy Research

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