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ENERGY RESEARCH

The role of system flexibility in achieving net zero (A)

Energy sector modelling to support the second National Infrastructure Assessment

Prepared for the National Infrastructure Commission
October 2023

Agenda

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Executive Summary

- Decarbonisation of the power sector has lead to an increased need for system flexibility in order to meet residual demand[1], driven by:
  - A decline in traditional thermal baseload generation,
  - Higher levels of intermittent renewable generation,
  - Higher demand/peak demand, driven by increased electrification of other sectors.
- Flexibility is required over different timescales, from fast response ramping to interseasonal demand shifting.
- Power system flexibility can come from a range of technologies, including demand side flexibility and supply side flexibility; each form of flexible technology has its own associated costs, operating parameters and resulting emissions.
- Therefore, different pathways of deployment for flexible technologies will result in different total system costs and costs to consumers, and different emissions reduction pathways.
- This report has been produced by Aurora Energy Research ("Aurora") for The National Infrastructure Commission ("NIC"). It aims to explore how different forms of system flexibility can support the deployment of renewable energy, in order to achieve Net Zero in GB.
- The Government's Energy Security Strategy outlines plans to accelerate the deployment of renewable energy to meet Net Zero targets: 50 GW offshore wind is targeted to be deployed by 2030 and 70 GW solar PV is targeted by 2035.
- Aurora has modelled eight scenarios on behalf of NIC, testing different policy questions and potential pathways to Net Zero to understand how these can be met whilst ensuring security of supply targets are reached, and the impact on costs to the consumer and on carbon emissions.
- Three of these scenarios have been tested against extreme weather events, to understand what additional capacity may be required if an extreme wind drought occurs, and how the system will behave.

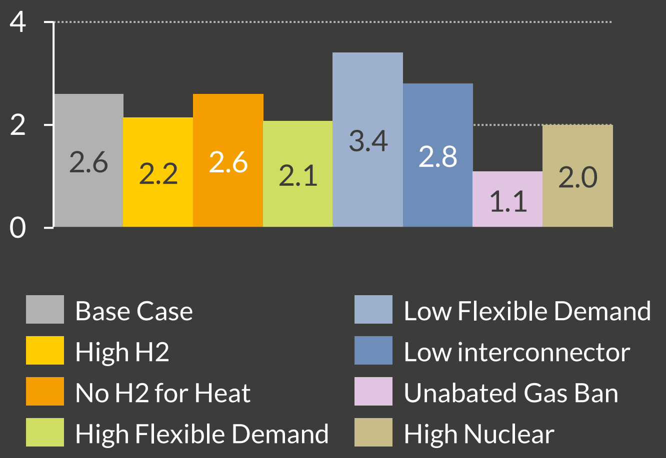
1) Demand not met by nuclear, renewables or other low carbon generation such as BECCS

Source: Aurora Energy Research

Executive Summary

Aurora has modelled 8 scenarios on behalf of NIC, testing different policy questions and potential pathways to Net Zero

Power sector carbon emissions, 2050
$MtCO_2e$



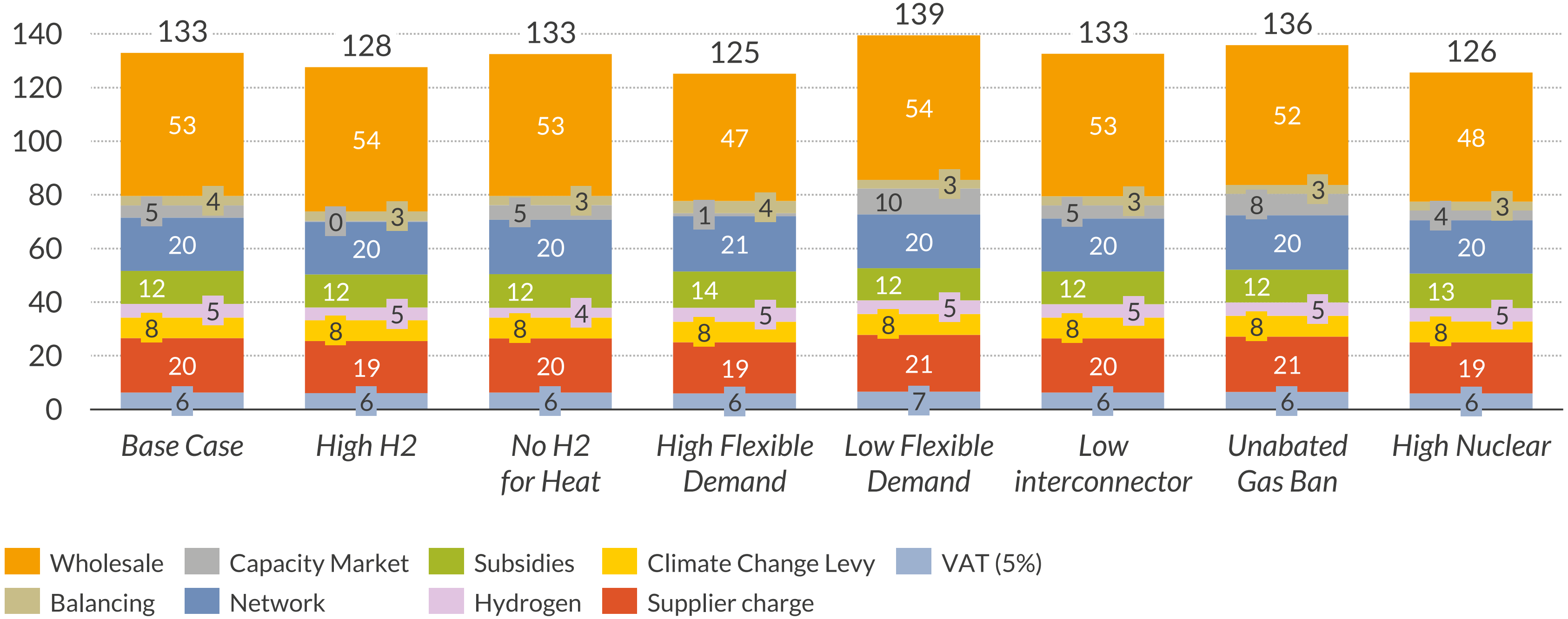
- The ***Base Case*** scenario demonstrates that a power system with high renewable deployment, meeting Energy Security Strategy targets for Offshore Wind and Solar, that is supported by a high proportion of flexible capacity can meet security of supply standards and emission targets in 2035 and 2050, with emissions falling to 2.6 $MtCO_2$ by 2050.
- The ***High Hydrogen*** scenario shows that producing additional power from hydrogen can reduce carbon emissions, which fall to 2.2 $MtCO_2$ by 2050, as hydrogen assets displace unabated forms of flexibility, such as recips and OCGTs, as well as batteries. However, increased load factors for H2 assets, which here are assumed to receive a dispatch based subsidy, lowers power prices in GB and therefore results in increased interconnector exports.
- If all decarbonisation of heating takes place via electrification, and there is ***No Hydrogen for Heat***, total demand will be lower, but peak demand will be higher, resulting in a smaller power system with increased reliance on low carbon and unabated peaking technologies. Increased emissions from unabated peaking plants are offset by the smaller size of the power system, and emissions fall to 2.6 $MtCO_2$ by 2050, allowing emissions targets to be met.
- Peak demand is reduced in a system with ***High Flexible Demand***, as demand can shift to lower price periods. This reduces the volume of peaking capacity required and reduces total carbon emissions, which fall to 2.1 $MtCO_2$ by 2050, as more demand can be met in periods of high renewable generation.
- Peak demand is increased in a system with ***Low Flexible Demand***, as demand is unable to shift to higher price periods. This increases the volume of peaking capacity required and therefore increases total carbon emissions. This scenario is the only scenario modelled where emissions targets are not met: emissions fall to 3.4 $MtCO_2$ by 2050.
- ***Lower Interconnector*** availability leads to increased renewable curtailment and higher reliance on abated thermal generation, which leads to emissions of 2.8 $MtCO_2$ by 2050.
- An ***Unabated Gas Ban*** in 2035 leads to emissions falling to 0.9 MtCO2 in 2035 and 1.1 MtCO2 in 2050 (the increase from 2035 to 2050 is driven by increasing electrification leading to a larger power sector overall, but would be reflected in lower emissions from the transport, heating and industrial sectors). This scenario sees bigger and faster emissions reductions compared to other scenarios modelled as part of this study.
- A ***High Nuclear*** scenario that sees the deployment of 24 GW nuclear baseload capacity by 2050 reduces the need for the deployment of renewable and abated thermal assets. Reduced generation from Gas CCS leads to emissions falling to 2.0 MtCO2 by 2050.

Source: Aurora Energy Research

Executive Summary

- In all scenarios, average consumer bills from 2025-2050 range from £125/MWh to £139/MWh. The largest component of consumer bills comes from wholesale market expenditure, followed by network costs, as well as supplier charges.
- Average consumer bills from 2025-2050 are lowest in a scenario with ***High Flexible Demand*** where higher balancing costs are more than offset by lower wholesale market expenditure.
- Average consumer bills from 2025-2050 are highest in a scenario with ***Low Flexible Demand*** which sees higher peak demand and therefore higher capacity market costs, as additional capacity needs to be procured to ensure security of supply. Wholesale costs are also high in this scenario.

Average consumer bills (2025 – 2050)
£/MWh



Component	Base Case	High H2	No H2 for Heat	High Flexible Demand	Low Flexible Demand	Low interconnector	Unabated Gas Ban	High Nuclear
Wholesale	53	54	53	47	54	53	52	48
Balancing	4	3	3	4	3	3	3	3
Capacity Market	5	0	5	1	10	5	8	4
Network	20	20	20	21	20	20	20	20
Subsidies	12	12	12	14	12	12	12	13
Hydrogen	5	5	4	5	5	5	5	5
Climate Change Levy	8	8	8	8	8	8	8	8
Supplier charge	20	19	20	19	21	20	21	19
VAT (5%)	6	6	6	6	7	6	6	6
Total	133	128	133	125	139	133	136	126

Source: Aurora Energy Research

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Reduced baseload thermal generation and increasing levels of renewable deployment leads to a greater need for system flexibility

Impacts of decarbonisation

Unabated baseload thermal generation phase-out

Increased renewable deployment

Electrification of other sectors (transport, heat, hydrogen production)

Effect on power markets

Wholesale Markets

- Changing generation mix driven by increasing intermittent renewables results in price volatility

Capacity Markets

- Retiring baseload thermal plants coupled with higher renewable penetration reduces firm capacity on the system. Coupled with higher peak demand, the procurement of more dispatchable capacity is needed

Balancing mechanism

- Higher imbalance volumes are driven by increased renewable penetration

Ancillary Services

- Volume of synchronous generators on the system reduces as thermal plants retire, whilst renewable roll out results in increased need for system services

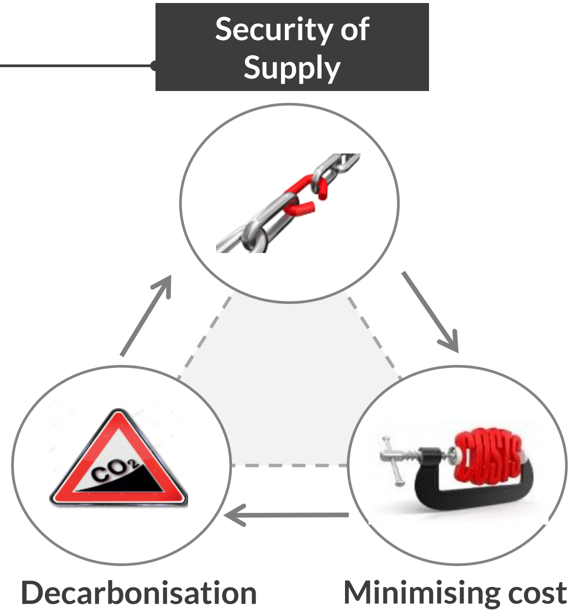
Power system flexibility needs

Need for **dispatchable capacity** that is not dependent on weather conditions in order to generate

Need for **flexible capacity** that can ramp up and down quickly over different time horizons to meet residual demand

Need for **capacity that can support broader system operability**

Energy trilemma



Energy policy aims to meet three overarching objectives, often referred to as the 'energy trilemma'. Of the three, ensuring energy security is expected to be most challenging in a Net Zero world for several European countries

Key takeaway:

- Flexible assets are becoming an increasingly valuable component of energy systems, as all three key aspects of power system flexibility needs are growing

Source: Aurora Energy Research

Flexible technologies can be evaluated against 4 key criteria, with flexibility able to be provided by both generation and demand

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For the purposes of this report, dispatchable assets are defined as those that are able to generate electricity more or less on-demand, without being linked to the weather, and whose economics incentivises them to dispatch on-demand. ***For these reasons, and due to their run constraints, we do not consider nuclear or CHP plants as dispatchable in this report.***

	1 Duration / continuous supply	2 Ramping speed	3 Minimising cost to consumer	4 Contribution to decarbonisation
Definition of metric	Length of time for which the asset can generate a continuous supply of electricity, independent of weather conditions	A measure of the asset's ability to ramp up and down in response to market signals and system needs	Measure of the cost <u>today</u> of a technology in terms of its LCOE and it's contribution to reducing balancing costs	This metric considers the technology's <u>current</u> (i.e. unabated) contribution to decarbonisation
Basis of rating	Scores consider the duration of the asset, and its availability to generate on-demand as well as potential for seasonal generation/storage	Scores consider the warm start time of the asset (i.e. response time when on load) to reflect the asset's ability to respond to system needs	Scores consider the LCOE[1] of the technology, and avoided cost of loss of load and blackouts	Score considers the technology's carbon intensity (as measured for imported electricity for interconnectors and batteries)
Example of rating	***Min. (1)*** *= Asset is unavailable for on-demand generation and has a low duration (<1h)* ***Max. (5)*** *= Asset has high availability and high (>24h) duration*	*1 = Asset has a long warm start time (>60min), precluding participation in half hourly system balancing* *5 = Asset has rapid warm start time (<60sec) and can participate in ancillary services*	*1 = Expensive technology with high LCOE (>£200/MWh)* *5 = Mature technology with low LCOE (<£75/MWh, does not require subsidies to dispatch)*	*1 = Technology has high carbon intensity (>350 gCO_2e/kWh)* *5 = Technology has low carbon intensity (<5 gCO_2e/kWh)*

- **Flexible technologies will be a vital component of a net zero power system, providing fast ramping and firm capacity when intermittent renewables are insufficient to meet supply requirements**
- **Different forms of flexibility are likely to be required, with each providing different contributions to security of supply, whilst also having different effects on consumer costs and decarbonisation targets**

1) Levelised cost of energy, estimated using price differentials for battery and interconnector technology classes.

Sources: Aurora Energy Research, National Grid

A combination of various flexible technologies is likely to required to ensure security of supply in a decarbonised power system

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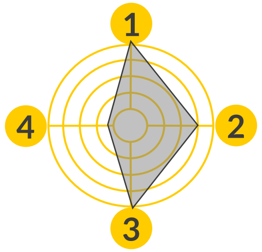
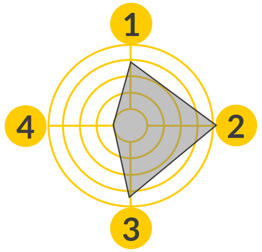
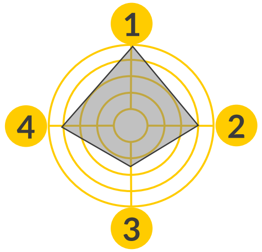
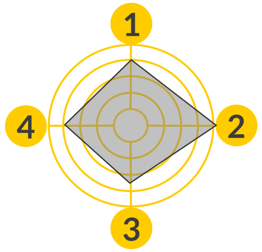
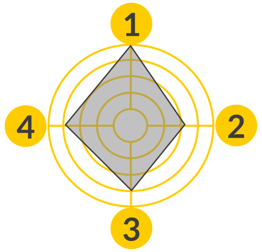
Generation

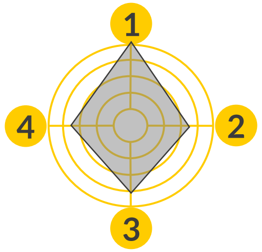
Unabated CCGTs


Gas peakers/OCGTs


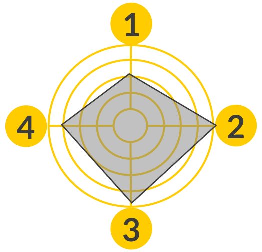
H2 CCGTs


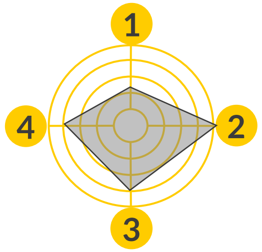
H2 Peakers


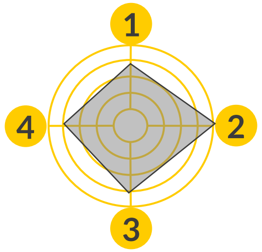
Gas CCS


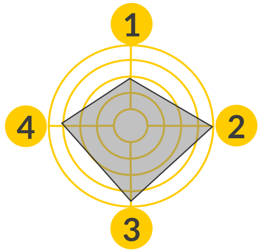
Biomass/BECCS


Demand

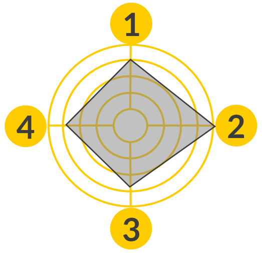
Smart EVs


Smart Heat Pumps


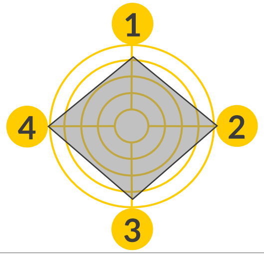
Flexible Electrolysers


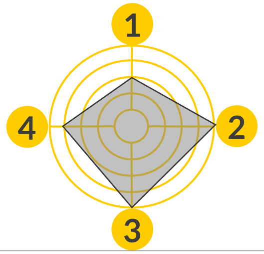
DSR


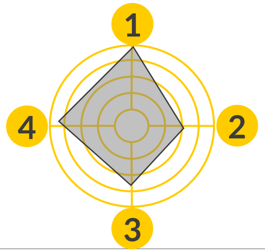
Interconnectors

Interconnectors[2]


Demand/ Generation

Pumped hydro


Battery storage[1,2]


Hydrogen Storage


Scores are on a 1-5 scale increasing with the diameter of the circles (i.e. largest circle = 5 = best). Scaling non-linear.

Key	1	2	3	4
Metric	Duration / continuous supply	Ramping speed	Minimising cost to consumer	Contribution to decarbonisation

1) Only mature assets referenced i.e. battery storage with durations ranging between half hour and 2 hours. 2) Carbon intensity of batteries and interconnectors based on assumptions that they only charge/discharge/transfer power in periods of low prices where low cost low carbon assets (e.g. renewables, nuclear) are generating. 3) Biological material obtained from living or recently living plant matter.

Sources: Aurora Energy Research, EMR, BEIS, National Grid

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For each scenario, 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.

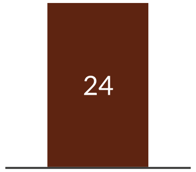
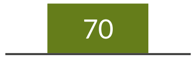
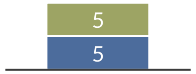
Source: Aurora Energy Research

Key input assumptions were made in collaboration with NIC

- **Commodity prices**
  - E.g. Gas, carbon & H_2 prices
- **Demand**
  - Total and peak power demand, broken down in demand vectors (H_2, 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

The Energy Security Strategy lays out plans to accelerate renewable and nuclear roll out, with most of these targets incorporated into our Base Case

The Government published on the 7th April 2022 its Energy Security Strategy as a response to the rising global energy prices. The plan is central to weaning Britain off fossil fuels which are subject to volatile international markets. To boost energy security the plan sets out how Britain will accelerate the deployment of nuclear, renewables and hydrogen while also supporting the production of domestic oil and gas. The main announcements from the Strategy include:

	Announced in Energy Security Strategy	Government Target
Nuclear	▪ A target of **24 GW** of nuclear energy by 2050, fulfilling 25% of energy demand, with Small Modular Reactors forming a key part of the nuclear pipeline ▪ Set up a new Government body, 'Great British Nuclear' that will bring forward new projects, and launch the £120m Future Nuclear Enabling Fund later in April ▪ The Government will work closely with developers to progress projects faster this decade, including the Wylfa site in Anglesey, and get 2 projects to FID[1] in the next Parliament	**Installed nuclear target in 2050,** GW  *Note: The nuclear target is not included in Base Case*
Offshore wind	▪ Ambition to reach up to **50 GW** of offshore wind by 2030 (up from the previous 40 GW target) of which 5 GW will come from floating offshore wind ▪ To meet this target the Government will reform current planning rules to cut the approval times from 4 years to 1 year	**Installed offshore wind target in 2030,** GW 
Onshore wind	▪ Consult on developing partnerships with supportive communities who wish to host new onshore wind infrastructure in return for lower energy bills	**N/A**
Solar PV	▪ Consult on rules for solar projects with an ambition to increase installed solar capacity by up to 5x the current levels by 2035 reaching **70 GW**	**Installed solar PV target in 2035,** GW 
Hydrogen	▪ Target up to **10 GW** of low carbon hydrogen capacity by 2030 (double the current target) of which half should come from electrolysers	**Installed H_2 production target in 2030[2],** GW 

1) Final Investment Decision; 2) Green colour represents electrolysers and blue colour represents hydrogen produced with steam methane reforming (SMR) with carbon capture and storage.

Sources: Aurora Energy Research, HM Government

Key assumptions in the Base Case are taken from the Energy Security Strategy, National Grid's FES 2022, 6th Carbon Budget and Aurora's Net Zero scenario

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Input	Assumption	Source
Gas prices	<£25/MWh by 2050	FES 2022 Baseline
Carbon prices	£160/tCO2 by 2050	FES 2022 High scenario
Hydrogen price	Hydrogen price is subsidised to allow hydrogen plants to dispatch ahead of gas plants in the merit order of dispatch	Aurora Net Zero
EV demand	100% of new sales from 2030	CCC CB6 (volumes) Aurora (split dumb/smart)
Heat demand	High electrification of heating and phase out of natural gas/move to hydrogen from 2030s.	CCC CB6
Hydrogen demand	90 TWh by 2035 280 TWh by 2050	Aurora Net Zero
Interconnectors	18GW of interconnectors	Energy White Paper
RES capacity	50GW offshore wind by 2030 70GW solar by 2035 85GW offshore wind by 2050	British Energy Security Strategy (BESS) targets (2030) CCC CB6 (2050)
CCS capacity	17GW by 2050	Aurora Net Zero
Nuclear capacity	Nuclear plants build 1 by 1 , if economic to do so	NIC's NIA 2018 recommendation
Hydrogen electrolyser production capacity	5GW by 2030 40GW by 2050	BESS targets (2030) Aurora Net Zero (2050)

Sources: Aurora Energy Research, NIC, CCC, National Grid, BEIS

Aurora modelled 8 scenarios to test policy questions and paths to Net Zero laid out by NIC; for 3 cases we also examine the impact of extreme weather events

For each scenario, we model the impact that changes to our assumptions has on capacity and generation mixes, carbon emissions and system & consumer costs

Scenarios	Key input assumptions
Base Case (tested against extreme weather year)	**Demand:** Mix of smart/dumb EV fleet and heat pumps **Heat:** Mix of electrification of heating and hydrogen for heating **Capacity:** Energy Security Strategy targets for onshore/offshore wind, solar & hydrogen production; Energy White Paper targets for Interconnectors **Commodity prices:** Gas prices reach £23/MW, Carbon prices reach £160/t, H2 prices reach £52/MWh by 2050
High Hydrogen	**H2 storage capacity:** 30GW salt cavern storage by 2050
No H2 for heat	**Heat:** Decarbonisation of heat takes place via electrification, with no deployment of hydrogen in heating
High Flexible Demand	**Demand**: 92% smart EV fleet and 92% smart heat pumps by 2050
Low Flexible Demand	**Demand**: majority dumb EV fleet and heat pumps by 2050
Lower Interconnector	**Interconnector availability:** reduced to 37.5%
Unabated Gas Ban (tested against extreme weather year)	**CCS Capacity:** 27 GW by 2050
High Nuclear (tested against extreme weather year)	**Nuclear capacity:** 24GW by 2050

Source: NIC

Specific assumptions have been adjusted in each modelled scenario, to test their impact on the power sector

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Input assumptions in 2050 (note capacities represent input capacity timelines only, and therefore do not reflect additional economic build that takes place within the model). A detailed breakdown of assumptions taken is shown from slides 17-26.

Input assumption in 2050		Base Case	High H2	No H2 for Heat	High Flex Demand	Low Flex Demand	Low Inter connector	Unabated Gas Ban	High Nuclear
Commodities	Gas price	£23/MWh	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*
	Carbon price	£160/tCO2	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*
	H2 price	£52/MWh	£37/MWh	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*
Demand	Total demand	707 TWh	*Base Case*	622TWh	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*
	Peak demand	99 GW	*Base Case*	105GW	82GW	104GW	*Base Case*	*Base Case*	*Base Case*
	H2 demand	278 TWh	*Base Case*	163TWh	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*
Capacity timelines (assumed policy driven subsidised/ supported capacities)	Interconnector capacity	18 GW (75% availability)	*Base Case*	*Base Case*	*Base Case*	*Base Case*	37.5% availability	*Base Case*	*Base Case*
	Solar capacity	81GW	*Base Case*	79GW	*Base Case*	*Base Case*	*Base Case*	*Base Case*	79 GW
	Offshore wind capacity	85GW	*Base Case*	71 GW	*Base Case*	*Base Case*	*Base Case*	*Base Case*	72 GW
	Onshore wind capacity	36GW	*Base Case*	32 GW	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*
	CCS capacity	17GW	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	27 GW	15 GW
	H2 CCGT capacity	13 GW	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	8 GW
	Nuclear capacity	8 GW	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	*Base Case*	24GW

Sources: Aurora Energy Research, NIC, NGESO, CCC, BEIS

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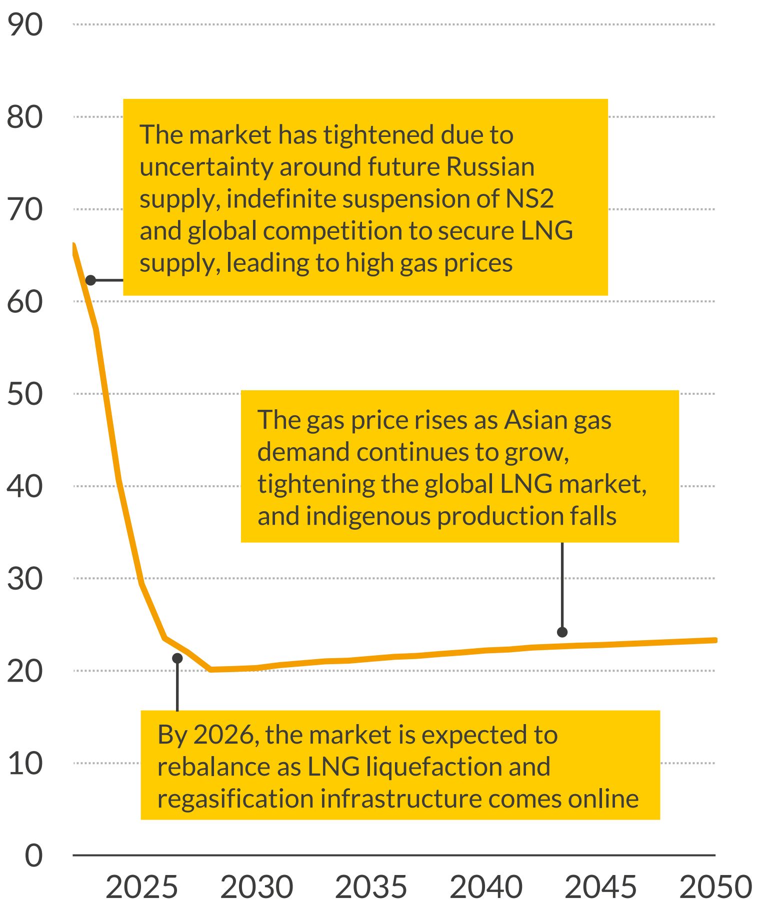
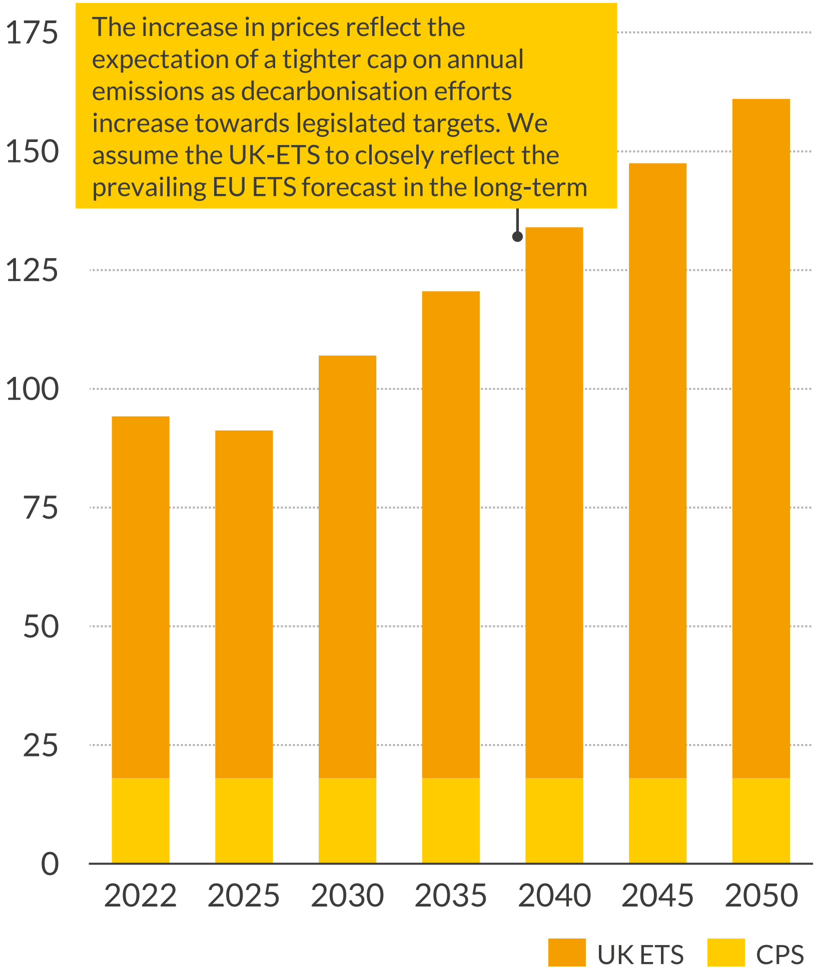
Gas prices stabilise from recent highs by the late 2020s, and steadily rise to £23.3/MWhth by 2050, with carbon prices increasing to £161/tCO_2 by 2050

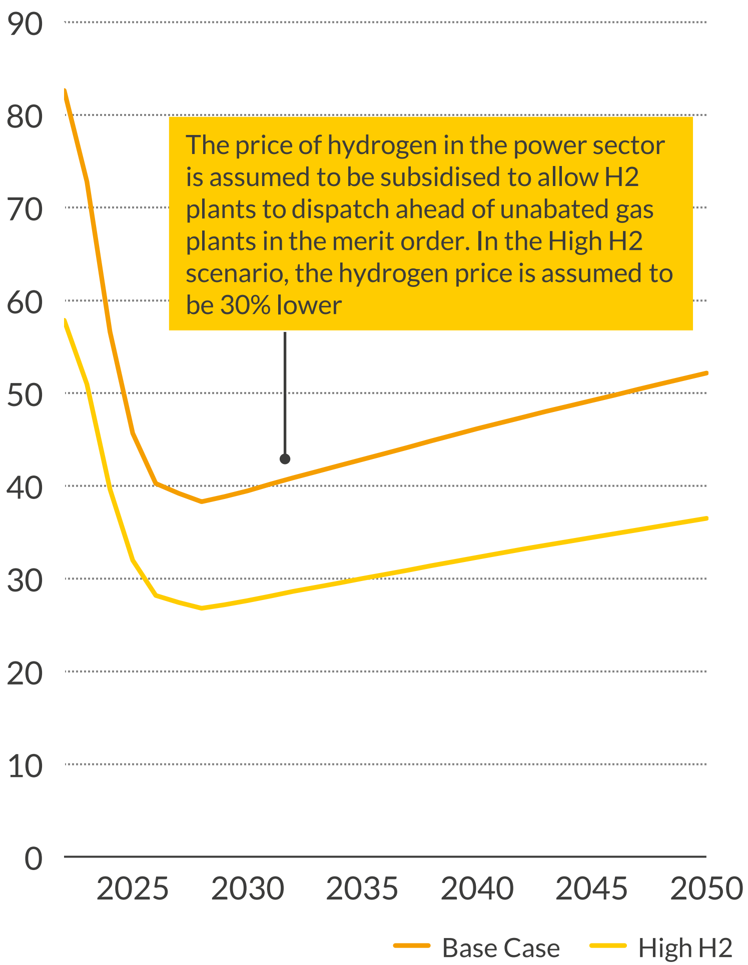
Gas price
£/MWhth (real 2021)



Total GB carbon price (UK ETS + CPS)[1]
£/tCO_2 (real 2021)



Hydrogen price
£/MWh (real 2021)



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

Sources: Aurora Energy Research, EIKON, FES 2022

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Total electricity demand increases to 707 TWh by 2050 in the Base Case, but is reduced in the No Hydrogen for Heat scenario

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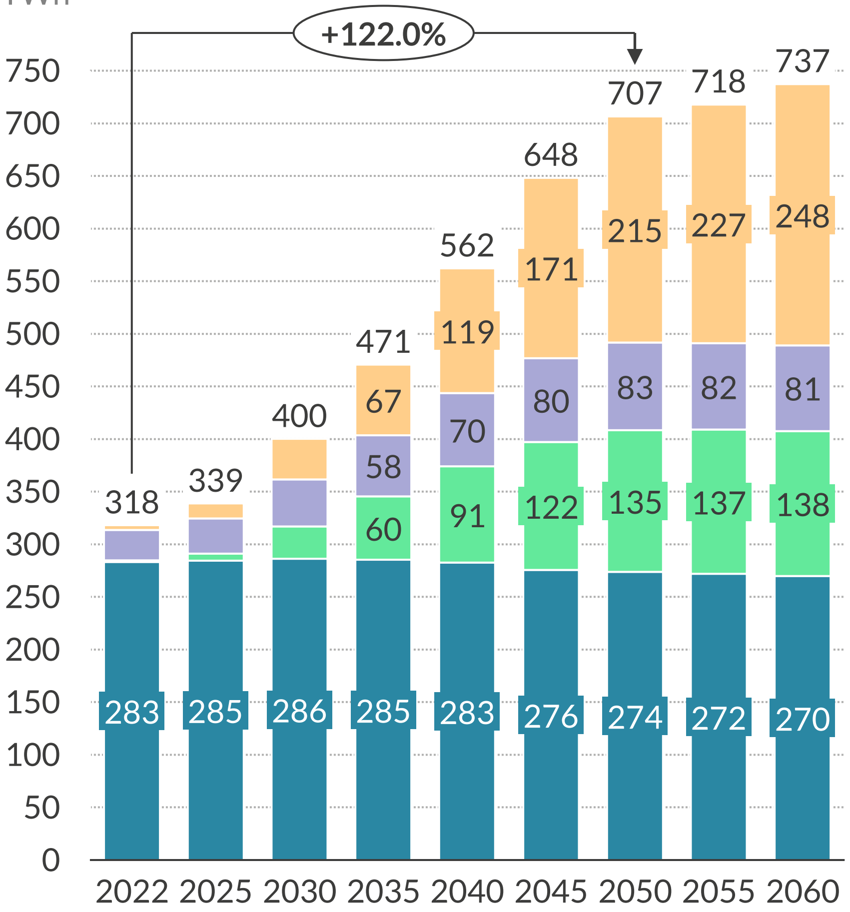
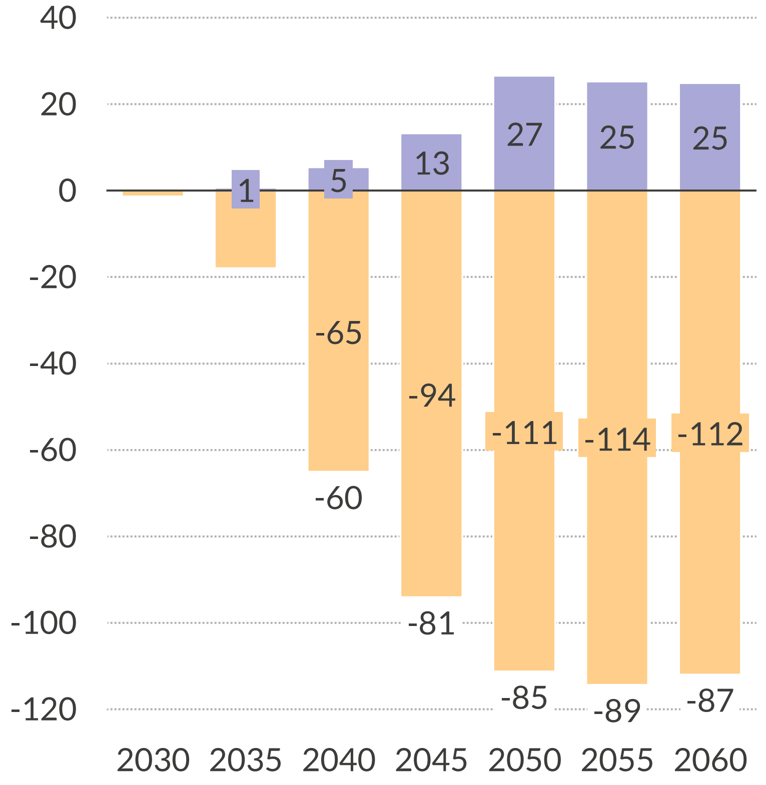
Annual Power Demand by Type[1]
TWh



Difference in No Hydrogen for Heat demand relative to Base Case, TWh



Base demand · EV demand · Electric heat demand · Electrolyser demand[2]

1) Note final power demand will depend on scenario, as round trip efficiency losses from factors such as H2 production are taken into account. 2) Decided endogenously by the model. Varies depending on the hydrogen demand in the scenario.
Source: Aurora Energy Research

Base Case
In the Base Case, and all other modelled scenarios (except No Hydrogen for Heat), demand increases by 388 TWh (122%) between 2022 and 2050, driven by the electrification of transport and heating, and the growth of the H2 economy.

No Hydrogen for Heat
In this scenario, the decarbonisation of heating is assumed to take place via electrified forms of heating, with no deployment of H2 boilers.

Electrified heating is significantly more efficient compared to using H2 boilers, because of the higher direct efficiencies of electric heating systems (100-500% vs c.80% for a H2 boiler), and also because of the round-trip efficiency losses associated with H2 production. Therefore, total electricity demand is lower in this scenario, reducing by 85 TWh in 2050 compared to the Base Case.

Peak demand increases 65% to reach 99GW in 2050 in the Base Case, before falling to 91GW by 2060

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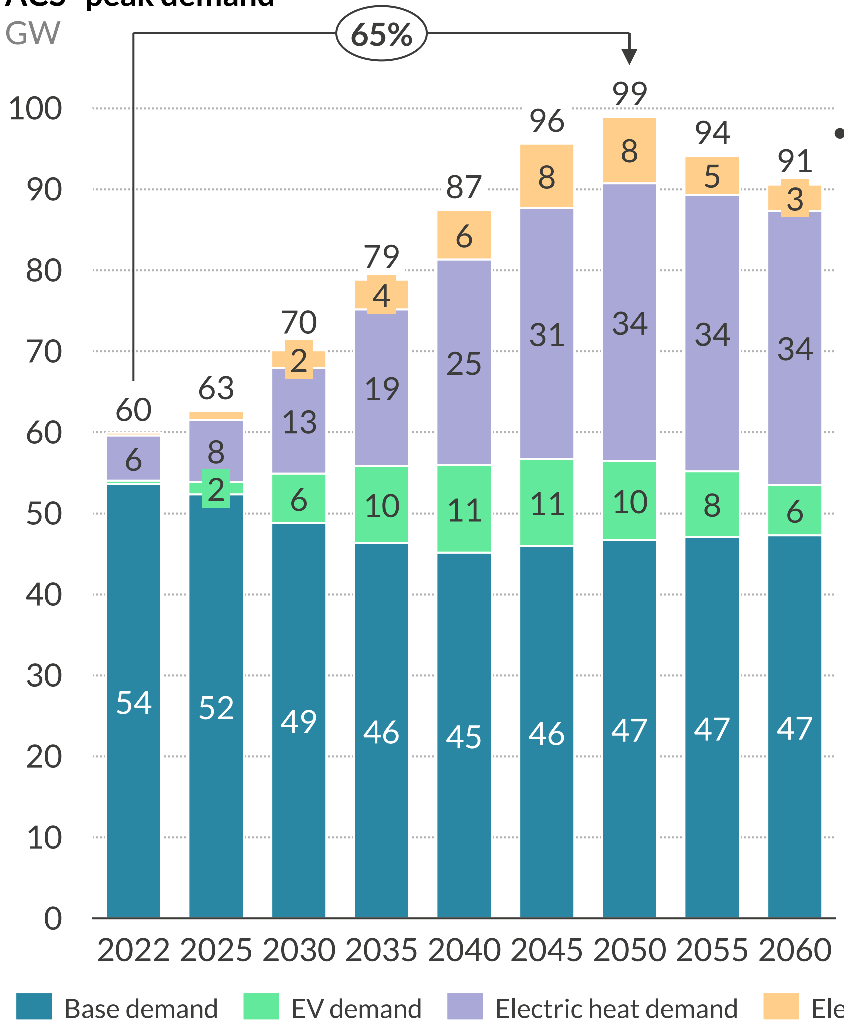
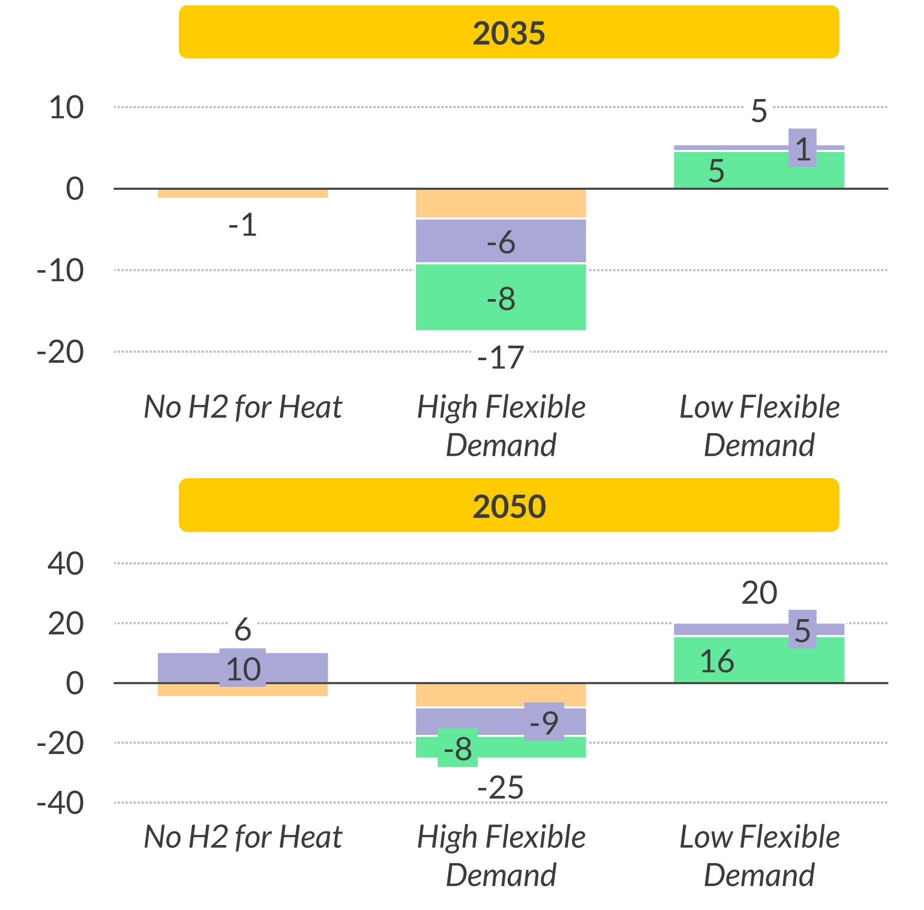
ACS[1] peak demand
GW



Difference in peak demand relative to Base Case
GW



1) Average Cold Spell

Source: Aurora Energy Research

Base Case
Base Case peak demand increases by 39GW by 2050 but drops thereafter, as demand becomes more flexible, electrification levels off and efficiency improvements continue.

No Hydrogen for Heat
Decarbonisation of heating takes place via electrification in this scenario, with no H2 boilers built. Electrified heating systems have limited ability to shift demand from peak periods compared to using H2, as H2 heating systems allow power demand to be shifted to periods of high renewable generation, with H2 produced by electrolysis then stored to meet later demand. **While total demand is lower if electrified heating meets all heat demand, by 2050 peak demand increases in this scenario.**

High/Low Flexible Demand
Low flexible demand results in higher peak demand, whilst higher flexible demand results in reduced peak demand, as the ability of demand to shift from high price peak periods is reduced or increased respectively.

The Base Case assumes an additional 49 million electric vehicles will be in operation by 2050

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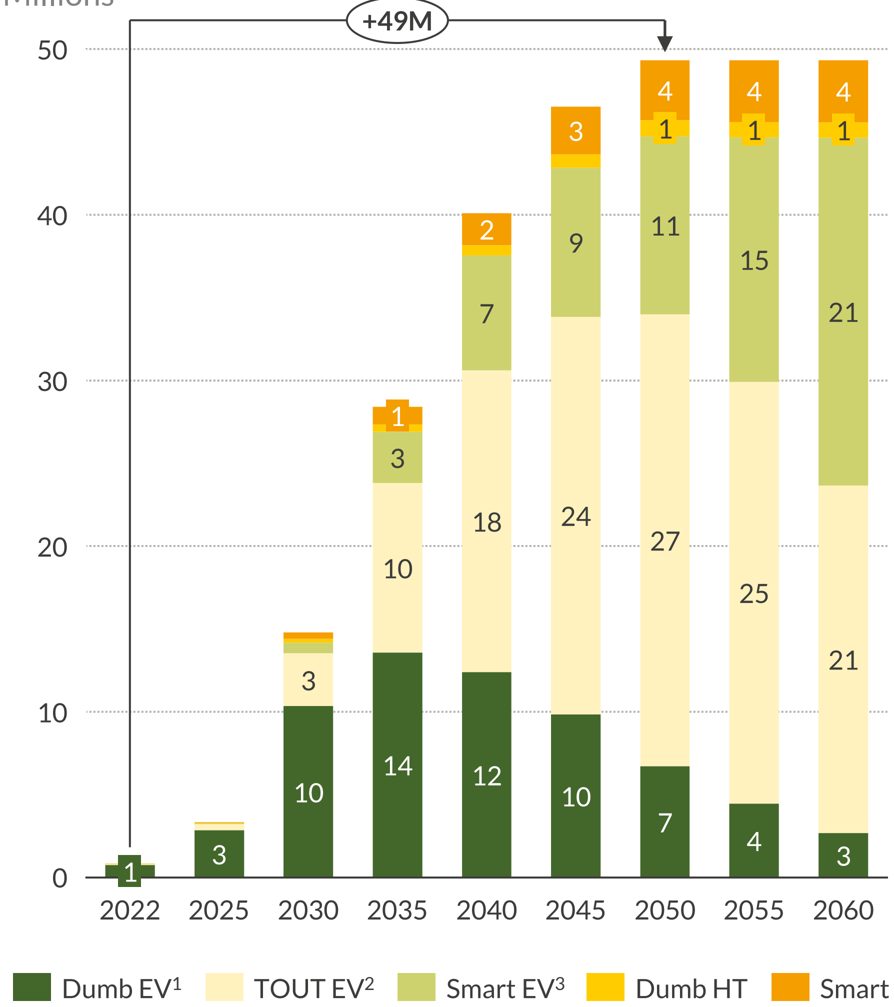
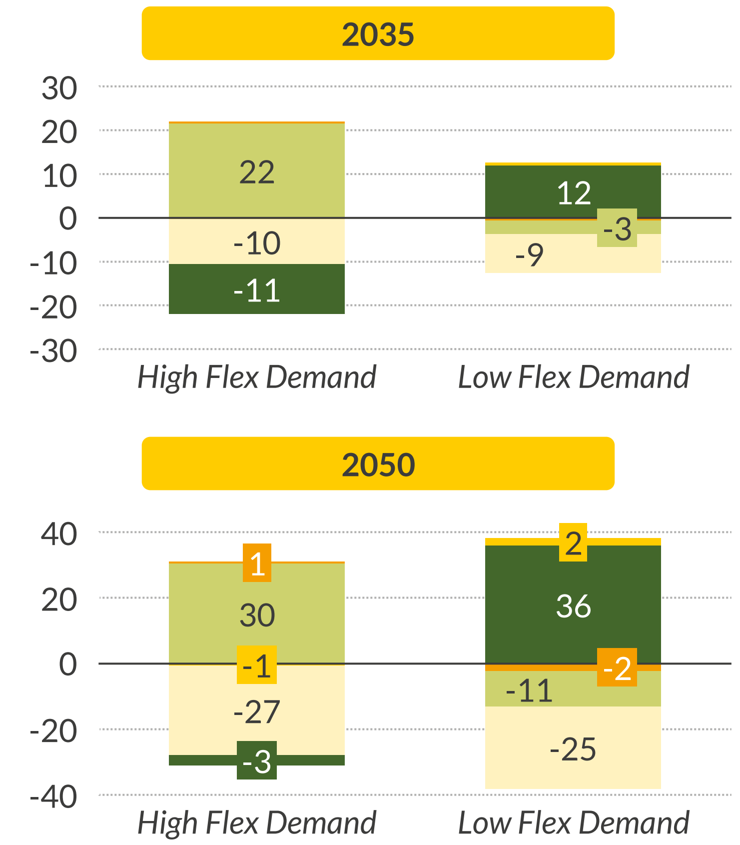
Electric vehicles (EVs) and Heavy Transport (HT)
Millions



Difference in transport units relative to Base Case
Millions



1) Charging profile of Dumb vehicles is not price responsive and vehicles will not shift charging times away from peak periods; 2) Time of use tariff - vehicles will favour charging during cheap TOUT periods but charging periods are not fully responsive to power prices 3) Fully price responsive – vehicles will favour charging in the cheapest power price periods

Sources: Aurora Energy Research, National Grid

Base Case
The total EV fleet is expected to reach 14.1 million in 2030 and 44.7 million by 2050 then stay relatively flat to 2060. The proportion of smart vehicles will continue to increase across the forecast; smart EVs will total 47% of the EV fleet by 2060.

The growth of battery electric HTs is driven by the conversion of Light Goods Vehicles; the total electrified HT fleet is expected to reach 0.6 million in 2030 and 4.6 million by 2050, then stay relatively flat to 2060. However, the proportion of smart vehicles increases to 80% of the fleet by 2060.

High Flexible Demand
The total number of electrified vehicles remains the same as in the Base Case, however 92% of vehicles are smart charging in this scenario.

Low Flexible Demand
The total number of electrified vehicles remains the same as in the Base Case, however the majority of vehicles are Dumb in this scenario.

Electrified heating and H2 boilers are deployed to decarbonise the heating sector

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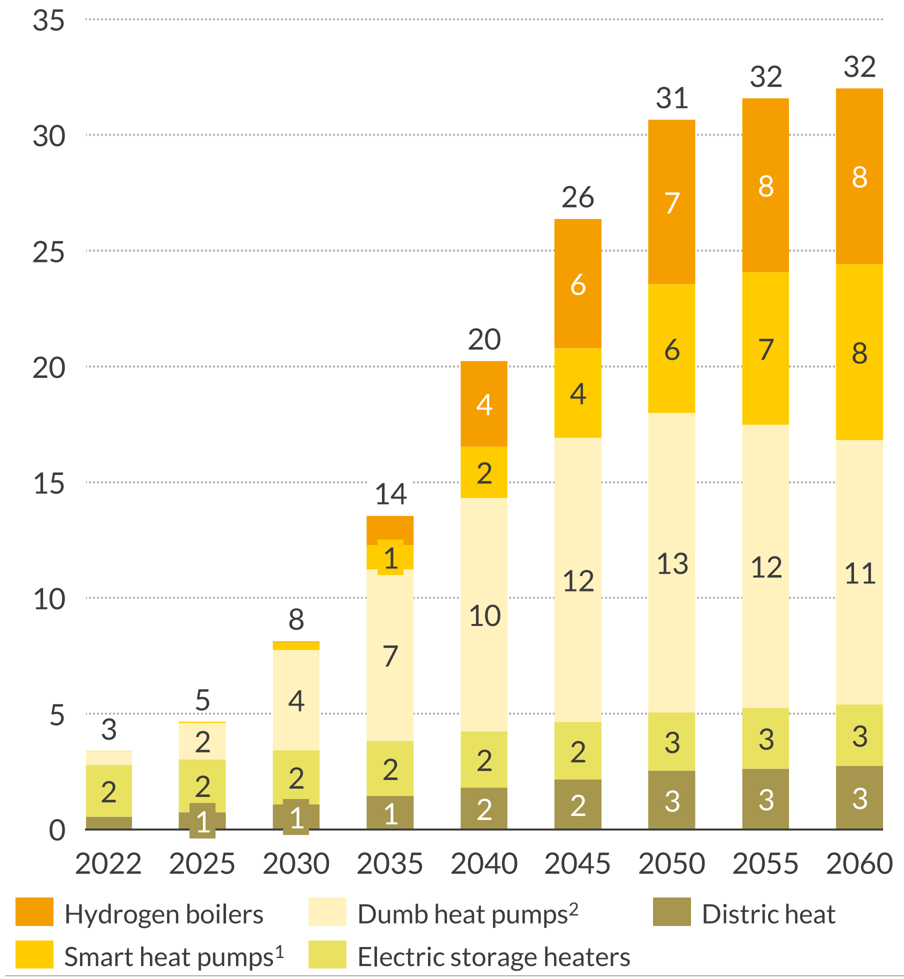
Heating – Total number of heating and electric units in GB
Millions



Difference in heating units relative to Base Case
Millions

Base Case
By 2050, c.31 million decarbonised heating units are assumed to have been deployed in GB, including 7.1 million H2 boilers.

No H2 for Heat
No H2 boilers are deployed in this scenario, with the assumption that 2.25 million more smart heat pumps and 5.26 million more dumb heat pumps are utilised by 2050 compared to the Base Case.

High Flexible Demand
The total deployment of heat pumps is the same as in the Base Case, however 92% of heat pumps are flexible in this scenario.

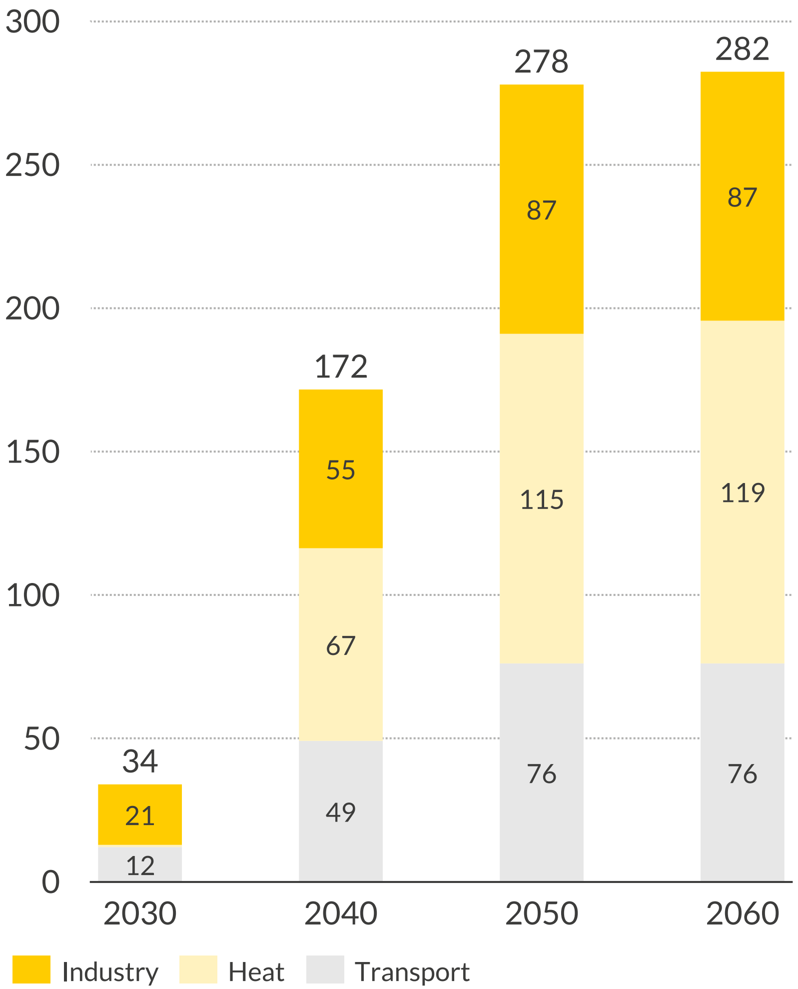
Low Flexible Demand
The total deployment of heat pumps is the same as in the Base Case, however in this scenario almost all electrified heating is from Dumb systems.

1) Smart heating systems can shift demand for heating away from peak periods. Deployment of smart heating assumes buildings are efficient enough to slow the rate of heat loss to allow this to take place. 2) Dumb heating systems are assumed to have no demand shifting to cheaper periods.

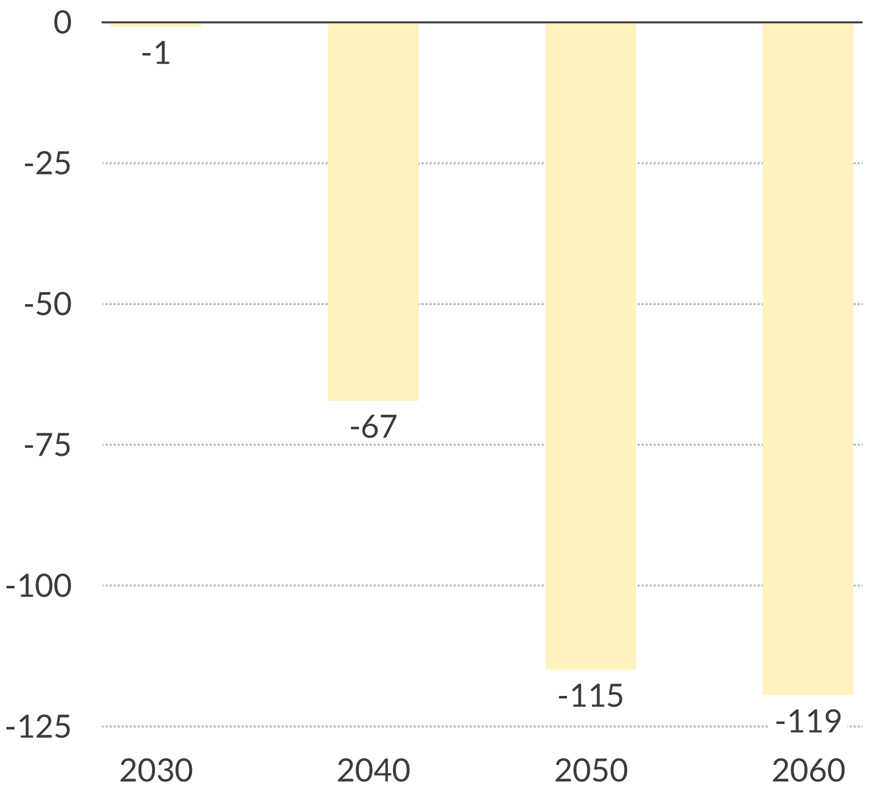
Sources: Aurora Energy Research, National Grid

Hydrogen will help decarbonise hard to abate sectors like industry and heavy transport, and could play a role in decarbonising heating

Total hydrogen demand
TWh



Difference in No Hydrogen for Heat demand relative to Base Case
TWh



1) Alkaline water electrolyser; 2) Autothermal reformer with carbon capture and storage; 3) Polymer electrolyte membrane electrolyser; 4) Steam-methane reformer with carbon capture and storage.

Source: Aurora Energy Research

Base Case
Hydrogen plays a role in decarbonising the Industry, Heat and Transport sectors.

In 2030 there is 34TWh of demand, largely from industry (21TWh). Industry sector demand grows by >300% (87TWh) to 2050 as hydrogen is used to decarbonise high grade heat in industrial processes as well as continuing to serve as feed stock.

In the Base Case, H2 also meets heating demand in certain areas in the country with advantageous conditions, but use is not widespread.

There is moderate presence of H2 in transport, with some usage of H2 in heavy goods vehicles, and in the maritime and rail transport sectors.

No Hydrogen for Heat
Total hydrogen demand is reduced in this scenario compared to the Base Case, as the decarbonisation of the heating sector entirely takes place through electrification.

Total electrolyser capacity reaches 5GW by 2030 and 40GW by 2050 in the Base Case

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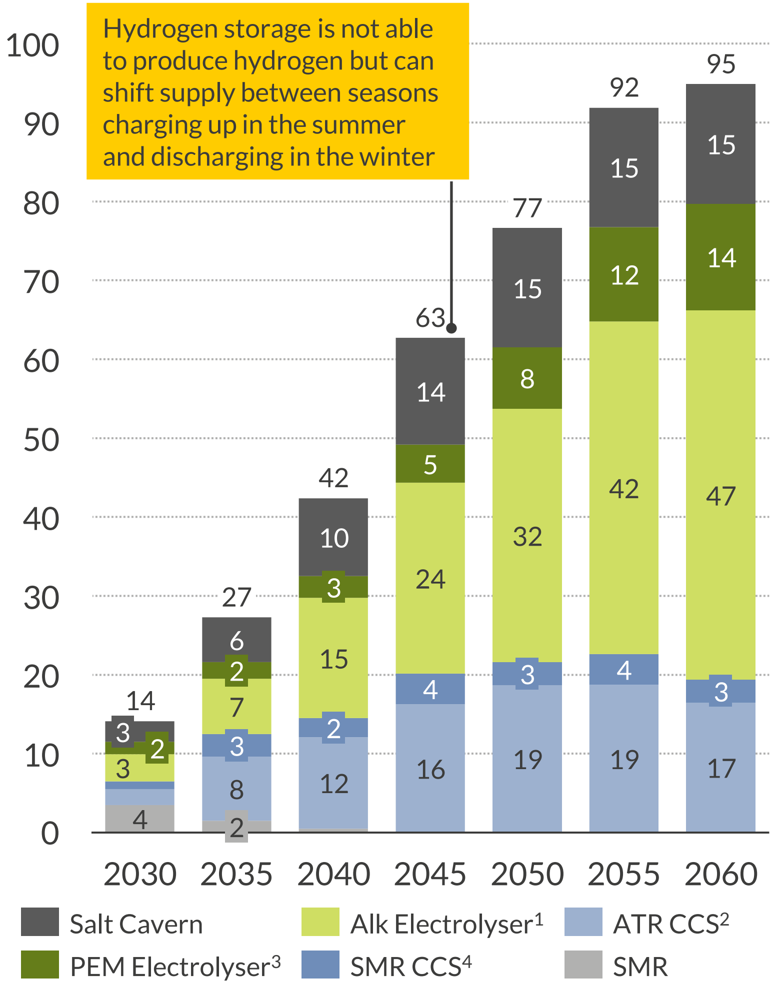

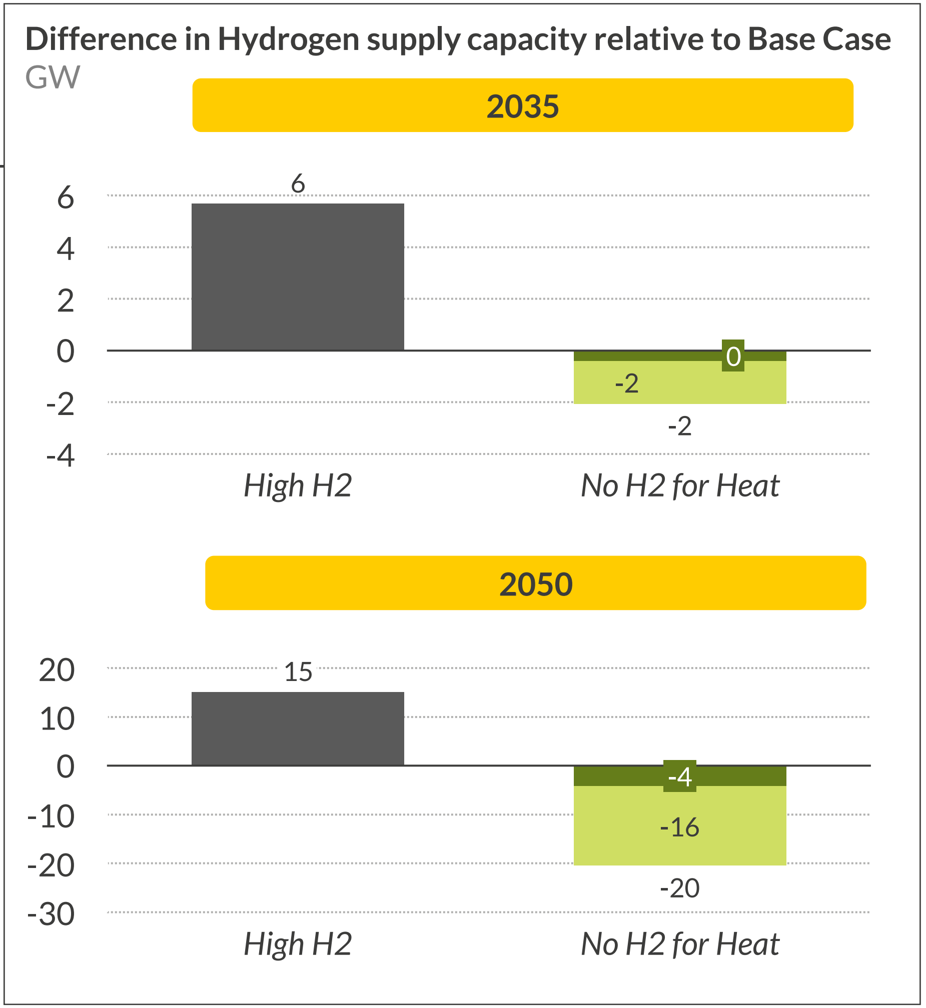

Base Case
5GW of electrolyser capacity is deployed by 2030, and 40GW is deployed by 2050 in the Base Case, with remaining hydrogen production taking place through SMR or ATR with CCS. Hydrogen storage facilities are also able to increase hydrogen availability during peak periods.

High Hydrogen
The High Hydrogen scenario looks to model a scenario where hydrogen is able to play a greater interseasonal role in shifting demand. Therefore, hydrogen storage capacity has been increased by 15 GW by 2050, to allow more interseasonal shifting of demand.

No Hydrogen for Heat
This scenario has reduced H2 demand as heating fully electrifies. Therefore, 20GW fewer electrolysers are deployed by 2050.

1) Alkaline water electrolyser; 2) Autothermal reformer with carbon capture and storage; 3) Polymer electrolyte membrane electrolyser; 4) Steam-methane reformer with carbon capture and storage.

Source: Aurora Energy Research, BEIS

Agenda

In the Base Case scenario, we assume the Energy Security Strategy targets are met for offshore wind and solar

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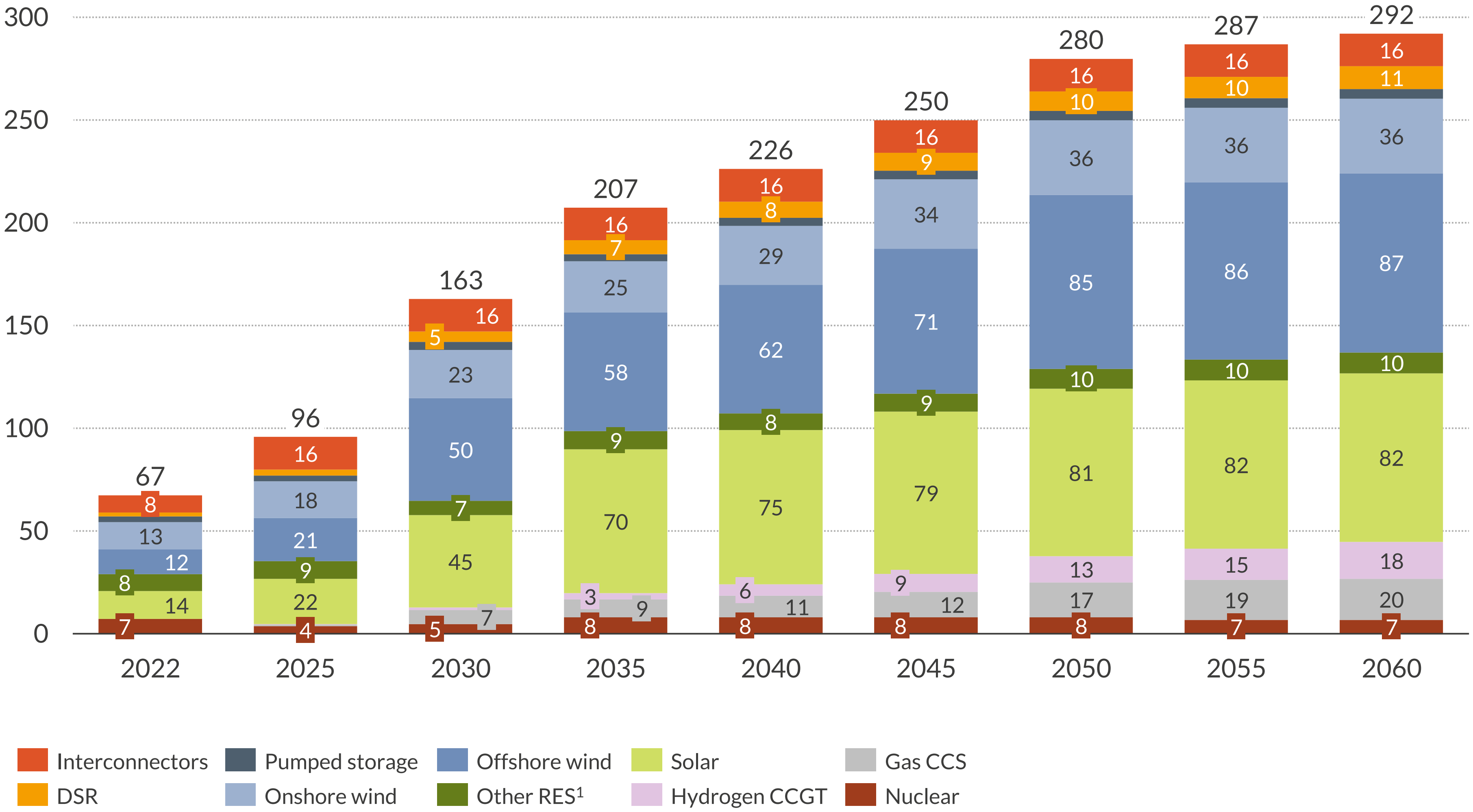
Exogenous capacity timeline
GW



1) Other RES includes hydro, BECCS, biomass & EfW

Source: Aurora Energy Research

- Exogenous capacity refers to capacity build decisions that are assumed will take place in the Base Case scenario and inputted directly to the model.
- New-build capacity timelines are created for
  - — Offshore & onshore wind
  - — Solar
  - — Gas CCS
  - — H2 CCGTs
  - — Nuclear
  - — BECCS
  - — Interconnectors
  - — Pumped hydro/hydro
  - — Demand side response (DSR)
- Existing assets are also given an expected retirement timeline.
- Additional capacity will build on an economic basis, in order to ensure system supply standards are met.

Agenda

Base Case: The Base Case scenario shows that a highly renewable and highly flexible power system can meet system security needs and emissions targets

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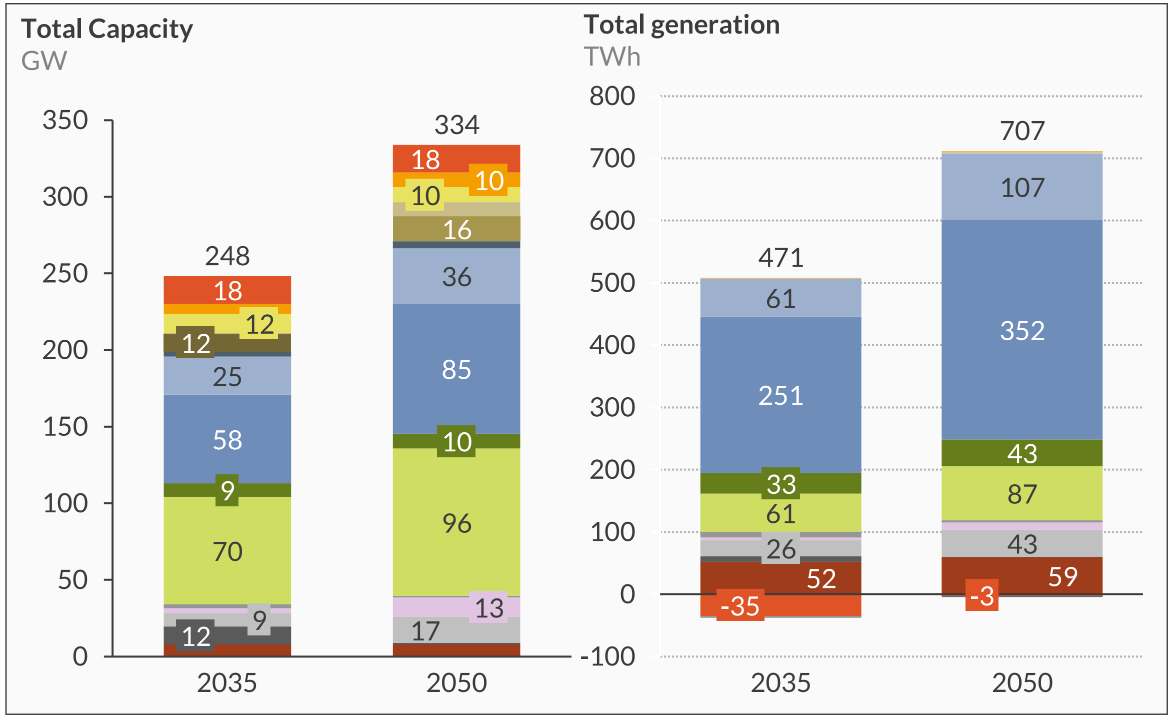
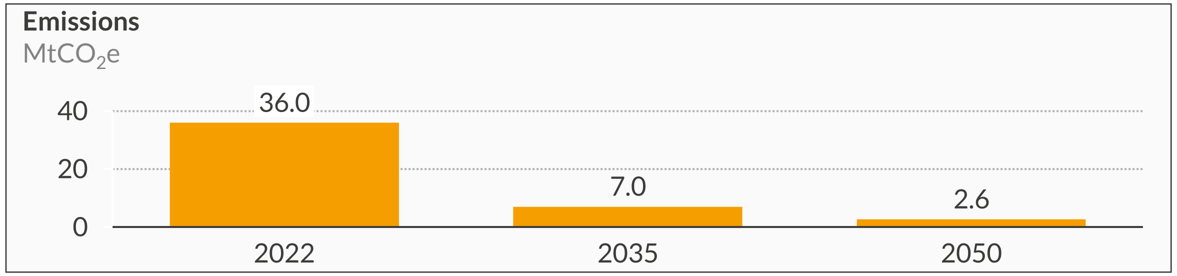
Scenario overview

- The Base Case scenario shows that a power system with high renewable (RES) deployment that is supported by a high proportion of flexible capacity can meet security of supply standards and emission targets in 2035 and 2050.
- Energy Security Strategy targets of 70 GW solar by 2035 and 85 GW offshore wind by 2050 are met, a further 36 GW onshore wind is also assumed to build. This allows 77% of generation (546 TWh) to be met by wind and solar in 2050.
- Additional RES generation, from BECCS, EfW, biomass and Hydro contributes another 6% (43 TWh) of total generation in 2050.
- RES deployment is supported by high flexible capacities, which allows security of supply standards to be met. Low carbon flexibility (inc. abated gas, storage and interconnectors) deliver 7.5% (53 TWh) of generation in 2050, after round trip efficiency losses and net interconnector flows are accounted for.
- Flexibility is also provided by flexible demand technologies. These include smart EVs, smart electrified heating and flexible electrolysers, which allow demand to be shifted from peak periods, reducing requirements for peaking capacity. c.10 GW DSR (from industrial or commercial settings) can be deployed in the Base Case, which provides added capacity in peak periods.
- Nuclear build takes place on a 1 by 1 basis, if economic to do so, however no new nuclear build out takes place in this scenario after Sizewell C. As a result, just 59 TWh baseload generation occurs from nuclear in 2050 (8% of total).
- This results in 5 TWh generation coming from unabated thermal plants in 2050, (<1% of total) allowing emissions targets to be met (note emissions do not include impact of negative emissions from BECCS, or emissions from EfW).





Interconnectors | Battery storage | Unabated peakers[1] | Onshore wind | Other RES[2] | Other thermal[3] | Gas CCS | Nuclear
DSR | Hydrogen peakers | Pumped storage | Offshore wind | Solar | Hydrogen CCGT | Gas CCGT

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

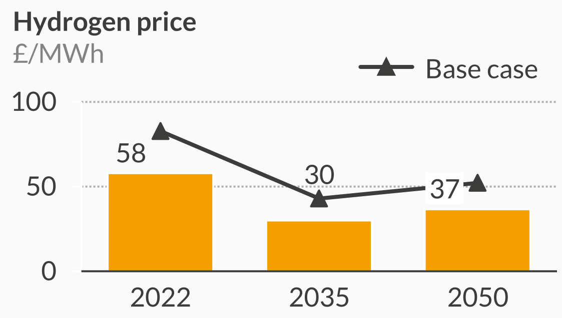
Source: Aurora Energy Research

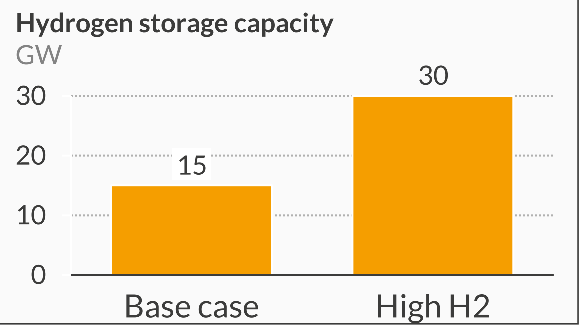
High Hydrogen: Producing additional power from hydrogen can lower emissions, but may result in increased interconnector exports

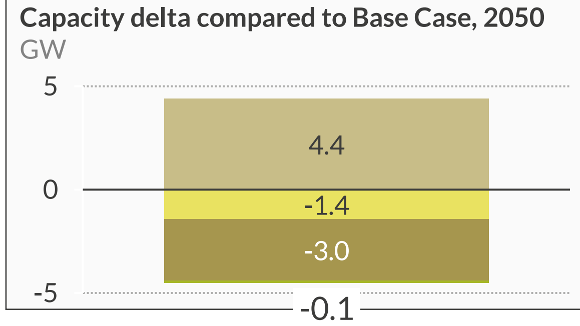
AURORA

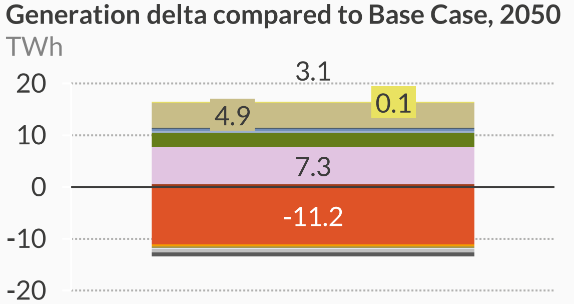
Scenario overview

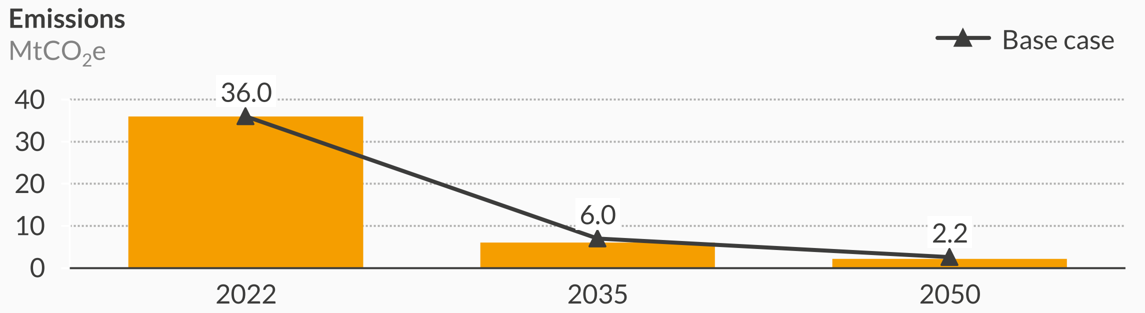
- Producing additional power from H2 can reduce carbon emissions, as H2 assets displace unabated forms of flexibility, such as recips and OCGTs, as well as batteries. However, increased load factors for H2 assets, which here are assumed to receive a dispatch based subsidy, lowers power prices in GB and therefore results in increased interconnector exports.
- Total H2 demand and overall power demand is higher than the Base Case, as additional H2 must be produced for use in the power sector. However, some of this additional demand is met by blue H2 production, which lowers efficiency losses from producing electrolytic H2 for use in power generation.
- The H2 price is 30% lower and H2 storage capacity is doubled relative to the Base Case.
- The lower H2 price and increased generation from H2-fired assets results in an additional 4.4 GW H2 peaking capacity building out, displacing unabated recips and OCGTS, as well as battery capacity.
- The lower H2 price also results in additional dispatch of H2-fired assets, and by 2050, 7.3 TWh additional generation is seen from H2 CCGTs and 4.9 TWh additional generation is seen by H2 peakers.
- The lower H2 price results in lower wholesale prices in GB, which then results in an additional 11.2 TWh exports to interconnected regions.
- Total emissions as lower in this scenario compared to the Base Case, as a result of reduced generation from unabated thermal and an increase in generation from hydrogen-fired technologies. Total emissions reach 2.2 $MtCO_2e$ by 2050 (0.4 $MtCO_2e$ lower than the Base Case).











Interconnectors | Battery storage | Unabated peakers[1] | Onshore wind | Other RES[2] | Other thermal[3] | Gas CCS | Nuclear
DSR | Hydrogen peakers | Pumped storage | Offshore wind | Solar | Hydrogen CCGT | Gas CCGT

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

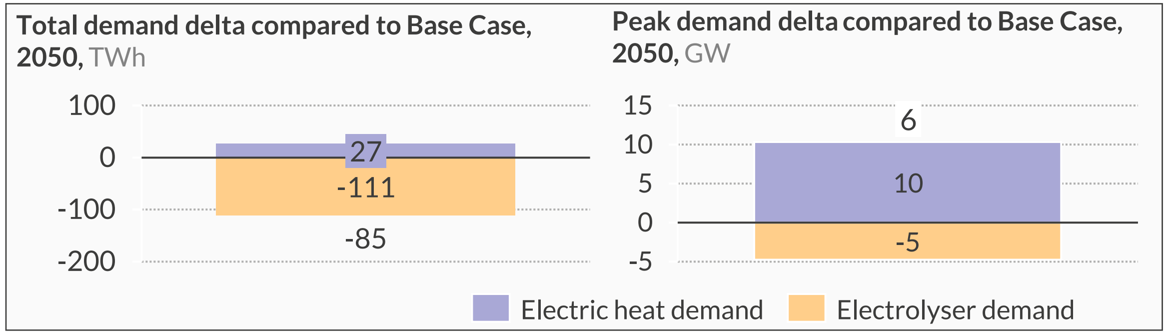
Source: Aurora Energy Research

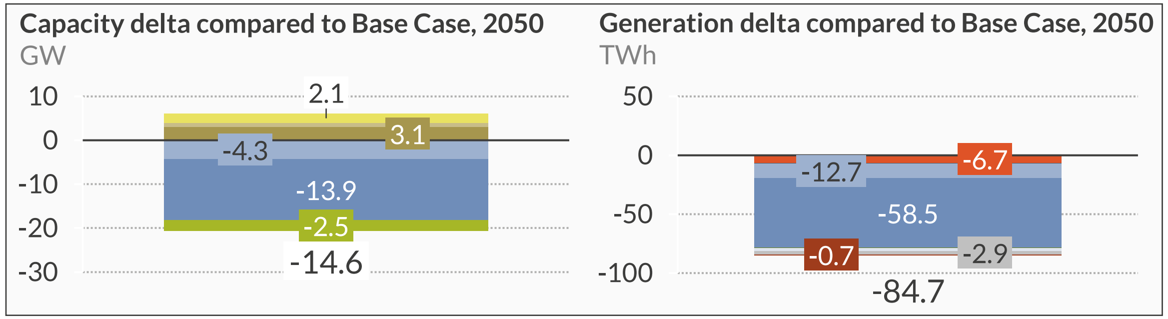
No H2 for Heat: An increased dependence on electrified heating increases peak demand and therefore reliance on peaking assets

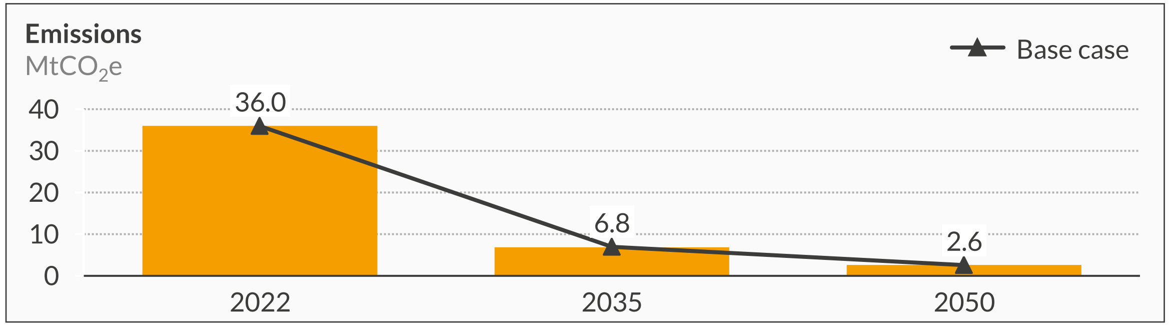
AURORA

Scenario Overview

- If all decarbonisation of heating takes place via electrification, total demand will be lower, but peak demand will be higher, resulting in a smaller power system with increased reliance on both low carbon and unabated peaking technologies. Increased emissions from unabated peaking plants are offset by the smaller size of the power system.
- In this scenario, no H2 boilers are deployed and electrified heating is used for all heat decarbonisation. Compared to the Base Case, the total demand for electricity is lower, as the electricity used to produce hydrogen for heating in the Base Case is greater than that required for electrified heating.
- Lower electricity demand results in a smaller power system overall, with 20.7 GW less solar, offshore wind and onshore wind capacity required by 2050.
- Lower demand sees 2.9 TWh less generation from Gas CCS and 6.7 TWh higher interconnector exports compared to the Base Case by 2050, driven by lower wholesale market prices in GB relative to interconnected regions.
- Peak electricity demand is higher in the No H2 for Heat scenario by 2050 as electrified heating systems place a higher load on the electricity system during cold snaps, that would not be seen in a scenario where hydrogen is used.
- Higher peak demand increases the need for peaking capacity, and by 2050 an additional 6.1 GW of batteries, recips and H2 peakers build in this scenario.
- Total power sector emissions in this scenario are comparable to the Base Case, as the higher reliance on unabated peaking assets is offset by the smaller size of the power sector. Emissions intensities are higher in this scenario.







Interconnectors · Battery storage · Unabated peakers[1] · Onshore wind · Other RES[2] · Other thermal[3] · Gas CCS · Nuclear
DSR · Hydrogen peakers · Pumped storage · Offshore wind · Solar · Hydrogen CCGT · Gas CCGT

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

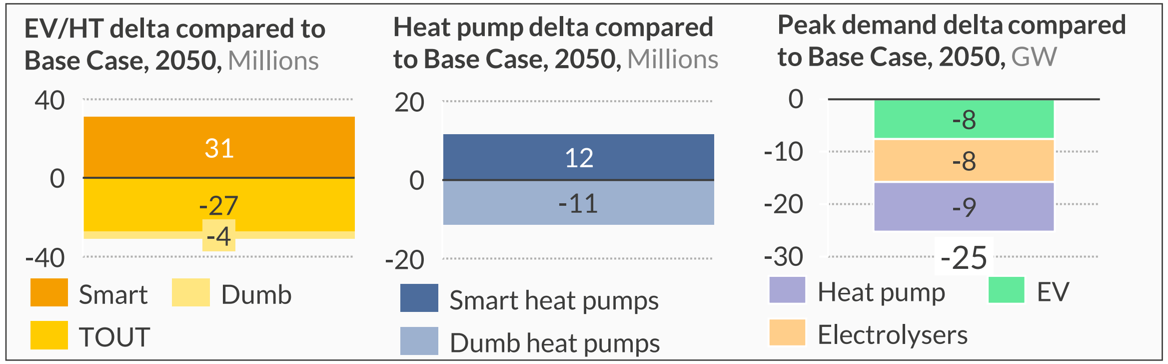
Source: Aurora Energy Research

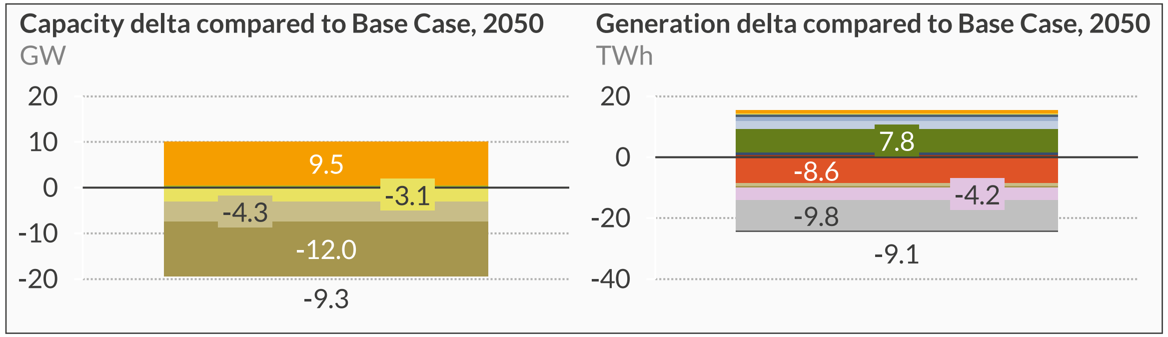
High Flexible Demand: Increasing flexible demand reduces the need for peaking capacity and leads to lower carbon emissions

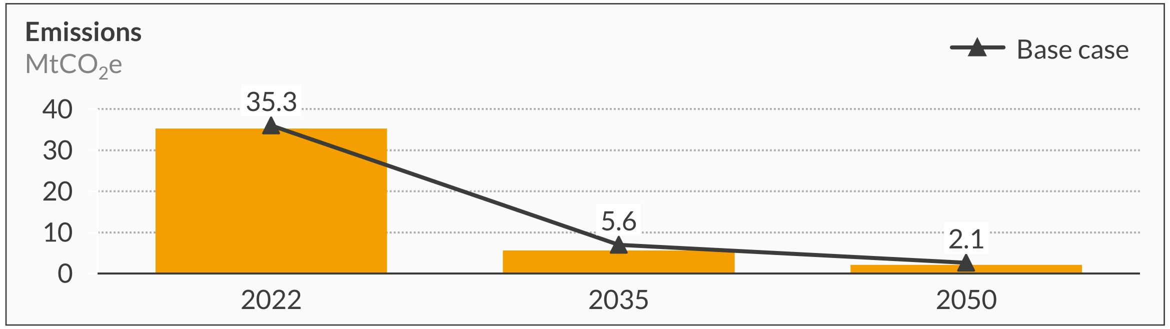
AURORA

Scenario Overview

- Peak demand is reduced in a system with higher levels of flexible demand, as demand can shift to lower price periods. This reduces the volume of peaking capacity required and reduces total carbon emissions.
- Peak demand is c.25% (25 GW) lower in this scenario by 2050 compared to the Base Case, driven by an increase in smart heating technologies, smart EVs and flexibly operating electrolysers. There is also an additional 9.5 GW DSR on the system (19 GW in total, from industrial and commercial settings), which can act to provide additional capacity to the system in peak periods.
- Lower peak demand results in less need for peaking and battery storage capacities. Demand flexibility also results in less need for baseload generation, particularly from Gas CCS and H2 CCGTs, which reduce by 9.8 TWh and 4.2 TWh by 2050 respectively.
- Demand side flexibility shifts demand to periods of high renewable generation, leading to less curtailment.
- Wholesale prices are lower in this scenario, driven by reduced peak demand, leading to an additional 8.6 TWh interconnector exports.
- The reduction in battery and thermal peaking capacities reduces the capacities available for turn-up actions in the balancing mechanism, and whilst security of supply standards are maintained in both the wholesale and balancing mechanism, this scenario approaches *balancing* loss of load in some periods.
- Reduced baseload and peaking generation results in reduced emissions compared to the Base Case, reaching 2.1 $MtCO_2e$ by 2050 (0.5 $MtCO_2e$ lower than Base Case).







Interconnectors | Battery storage | Unabated peakers[1] | Onshore wind | Other RES[2] | Other thermal[3] | Gas CCS | Nuclear
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1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

Source: Aurora Energy Research

Low Flexible Demand: Reduced demand side flexibility increases requirements for peaking capacities and leads to higher emissions

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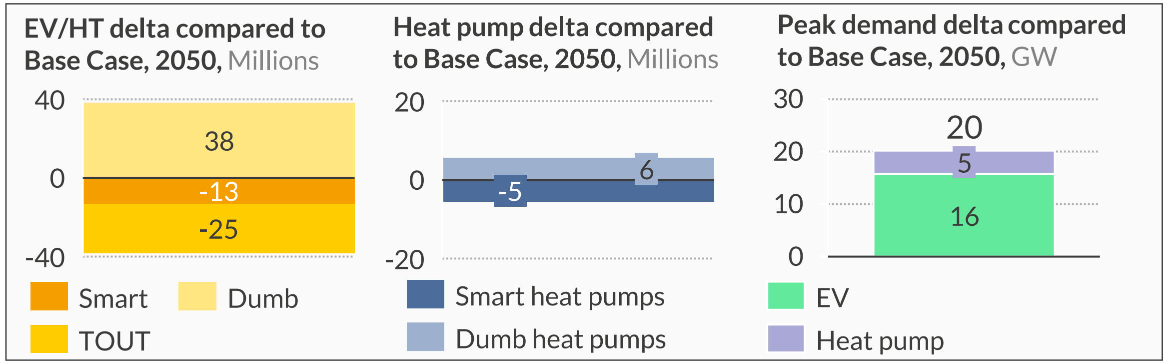
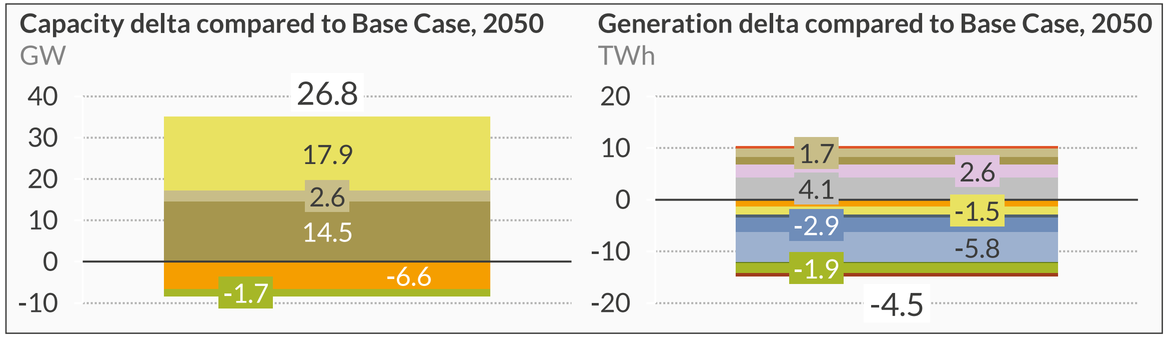
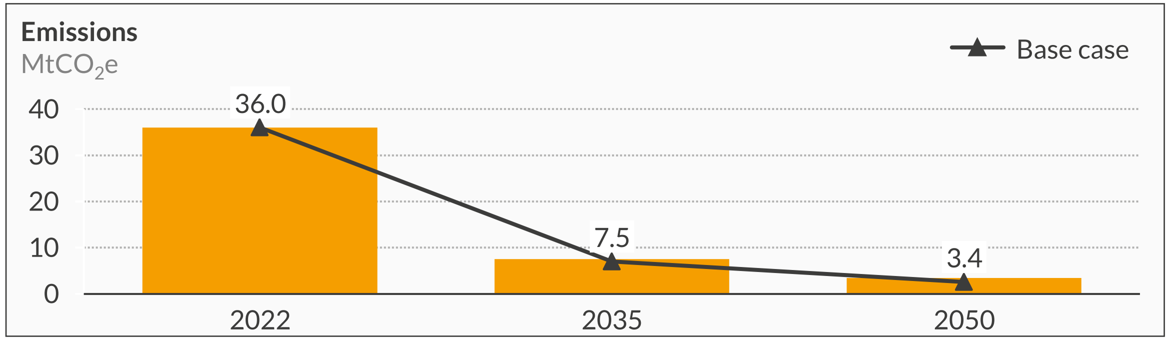
Scenario Overview

- Peak demand is increased in a system with low levels of flexible demand, as demand is unable to shift to higher price periods. This increases the volume of peaking capacity required and increases total carbon emissions.
- Peak demand is c.20% (20 GW) higher in this scenario by 2050 compared to the Base Case, driven by a decrease in the deployment smart heating technologies, smart EVs and flexibly operating electrolysers. There is also a 6.6 GW decrease in DSR on the system compared to the Base Case (2.9 GW in total, from industrial and commercial settings), reducing DSRs ability to act to provide additional capacity to the system in peak periods.
- Higher peak demand results in increased need for peaking and battery storage capacities, with an additional 14.5 GW unabated peakers and 2.6 GW H2 peakers, and 17.9 GW batteries deployed by 2050.
- Additional thermal generation from Gas CCS (4.1 TWh), H2 CCGTS (2.6 TWh) and H2 peakers (1.7 TWh) is also required to meet demand.
- Reduced demand side flexibility means demand cannot shift to low price periods, which typically correspond with high renewable generation periods. This leads to higher levels of curtailment in periods where renewable generation exceeds demand, with 8.7 TWh less wind generation seen in this scenario by 2050 compared to the Base Case. c.1.7 GW less merchant solar also builds in this scenario by 2050, resulting in reduced solar generation.
- Increased baseload and peaking generation results in higher emissions compared to the Base Case, exceeding 3 $MtCO_2e$ by 2050 (0.8 $MtCO_2e$ higher than the Base Case).







Interconnectors | Battery storage | Unabated peakers[1] | Onshore wind | Other RES[2] | Other thermal[3] | Gas CCS | Nuclear
DSR | Hydrogen peakers | Pumped storage | Offshore wind | Solar | Hydrogen CCGT | Gas CCGT

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

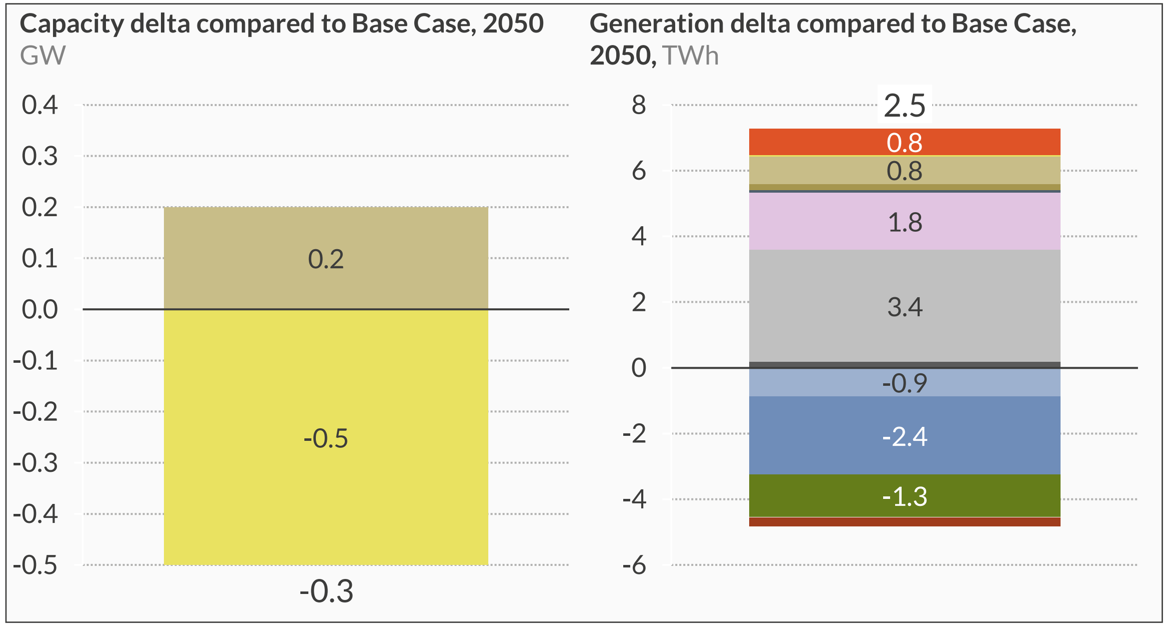
Source: Aurora Energy Research

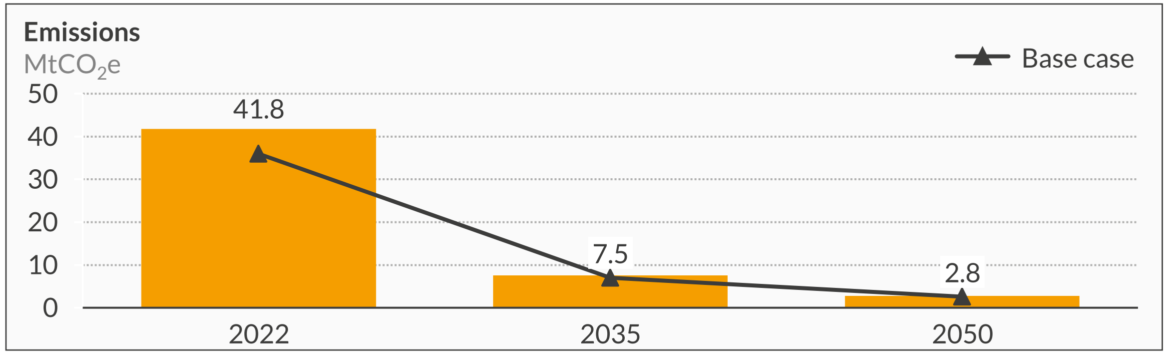
Low Interconnector: Reduced import and export capabilities means more renewable curtailment and higher reliance on Gas CCS

AURORA

Scenario Overview

- Reducing interconnector availability leads to increased renewable curtailment and higher reliance on abated thermal generation, which leads to increased emissions compared to the Base Case.
- Interconnector availability for imports and exports is reduced by 50% compared to the Base Case (from 75% availability in the Base Case to 37.5% availability here).
- This leads to higher levels of renewable curtailment, driven by a reduced ability to export in periods when renewable generation exceeds total demand. By 2050, c.4.6 TWh less renewable generation is seen in this scenario.
- Additional thermal generation from Gas CCS (3.4 TWh), H2 CCGTs (1.8 TWh) and H2 peakers (0.8 TWh) is also required to meet demand in high price/high demand periods, as less power can be imported.
- Interconnector imports and exports are equally impacted by reduced availability, resulting in a net import increase of 0.8 TWh compared to the Base Case.
- Increased residual emissions from higher Gas CCS utilisation causes total emissions to reach 2.8 $MtCO_2e$ by 2050 (0.2 $MtCO_2e$ higher than the Base Case).





Interconnectors | Battery storage | Unabated peakers[1] | Onshore wind | Other RES[2] | Other thermal[3] | Gas CCS | Nuclear
DSR | Hydrogen peakers | Pumped storage | Offshore wind | Solar | Hydrogen CCGT | Gas CCGT

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

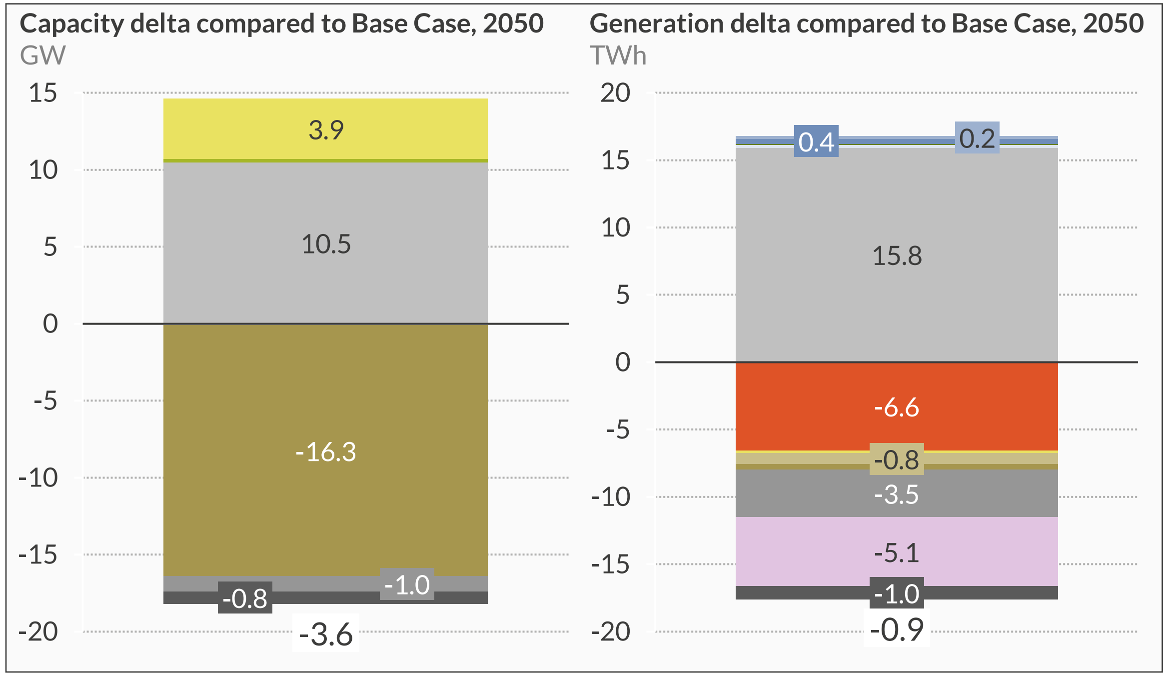
Source: Aurora Energy Research

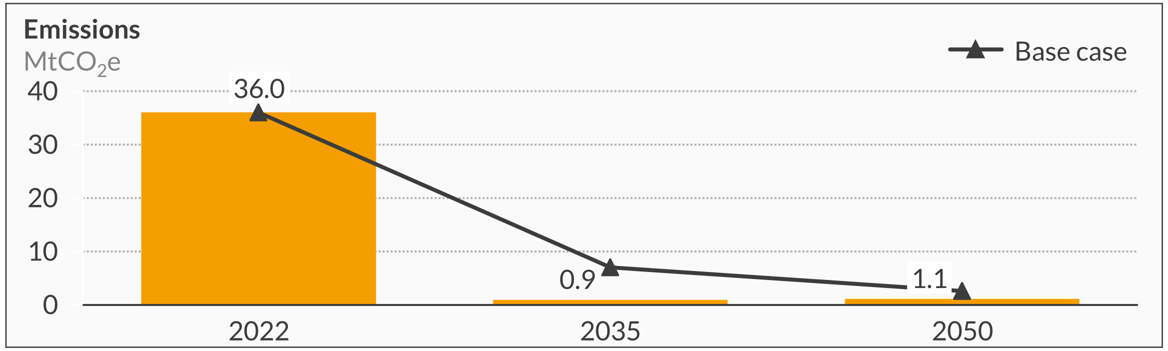
Unabated Gas Ban: Banning generation from unabated gas in 2035 results in a significant fall in total emissions, to 1.1 $MtCO_2$ in 2050

AURORA

Scenario Overview

- Banning unabated gas in 2035 leads to emissions falling to 0.9 $MtCO_2$ in 2035 and 1.1 $MtCO_2$ in 2050 (the increase from 2035 to 2050 is driven by increasing electrification leading to a larger power sector overall, but would be reflected in lower emissions from the transport, heating and industrial sectors).
- However, a ban on unabated gas in 2035 means increased deployment of Gas CCS is required to meet demand in the 2030s, as the pace of renewable deployment is insufficient to allow demand to be met by a combination of renewables and other forms of flexibility by 2035. As renewable deployment continues through the 2040s, Gas CCS load factors decrease, and an increase in exports to interconnected regions is seen.
- An unabated gas ban in 2035 is likely to require some existing CCGTs to convert to Gas CCS, as the build rate of new plants is likely to be insufficient to ensure security of supply standards are met. However new-build assets are also likely to be required alongside conversions. New or refurbished assets in the 2030s results in increased thermal capacities on the system until c.2060.
- The ban on unabated thermal also leads to no gas recip or OCGT capacity on the system by 2035, battery capacity increases by 3.9 GW.
- As unabated gas peaking, CCGT and CHP plants can no longer deploy, total emissions to fall to 1.1 $MtCO_2e$ by 2050 (1.5 $MtCO_2e$ lower than the Base Case). However, emissions do not reach 0 $MtCO_2e$ owing to residual emissions from CCS.





Interconnectors | Battery storage | Unabated peakers[1] | Onshore wind | Other RES[2] | Other thermal[3] | Gas CCS | Nuclear
DSR | Hydrogen peakers | Pumped storage | Offshore wind | Solar | Hydrogen CCGT | Gas CCGT

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

Source: Aurora Energy Research

High Nuclear: The deployment of 24 GW nuclear by 2050 reduces the need for renewable and abated thermal deployment

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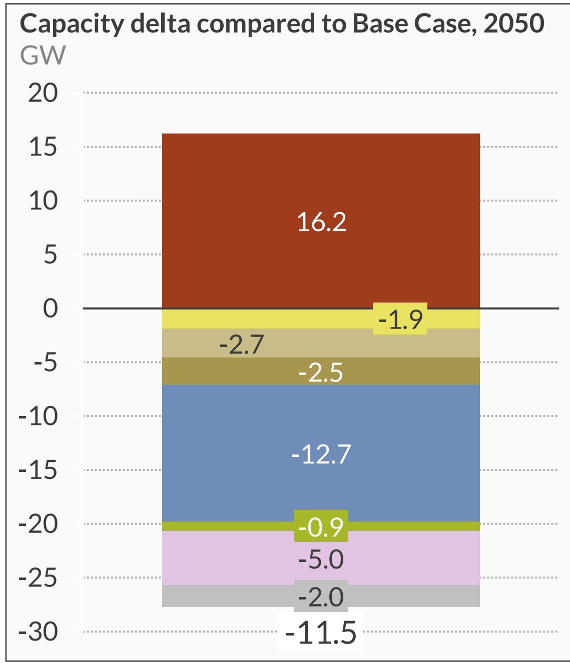
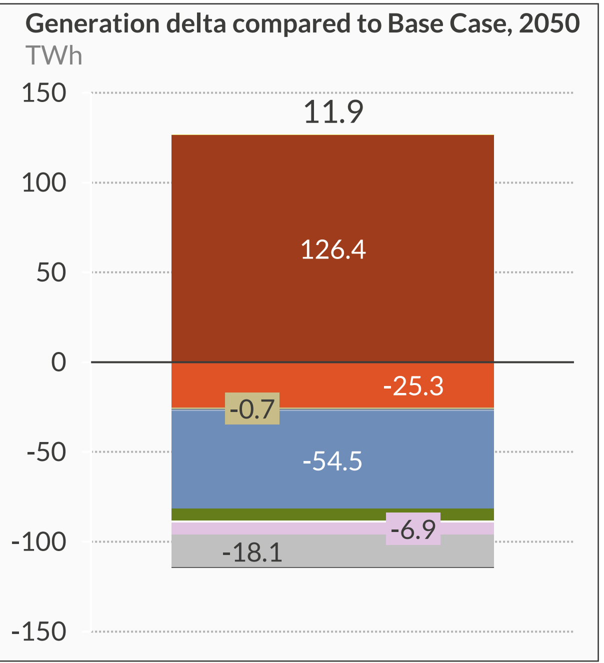
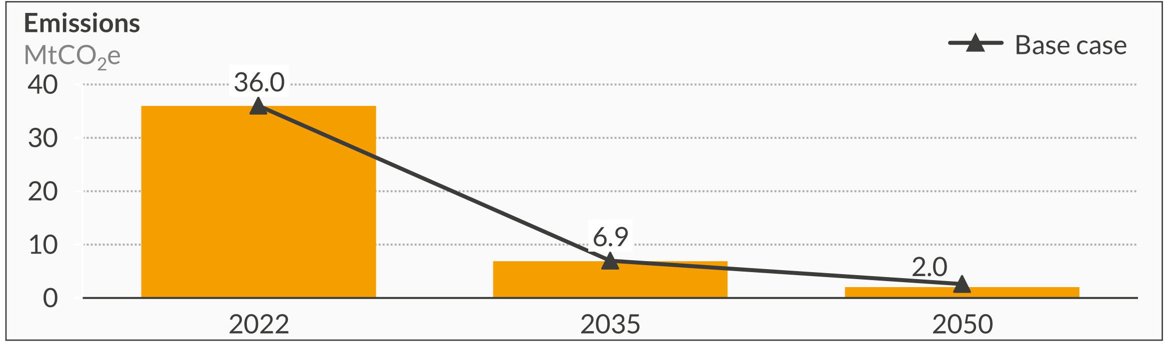
Scenario Overview

- The deployment of 24 GW nuclear baseload capacity by 2050 reduces the need for the deployment of other low carbon technologies. Reduced generation from Gas CCS leads to emissions falling to 2 $MtCO_2$ by 2050.
- Nuclear capacity operates as baseload and so higher levels of nuclear deployment reduces the amount of renewable and flexible capacity required for security of supply standards to be met. In this scenario, a reduction of 12.7 GW offshore wind, 5 GW H2 CGGT and 2 GW Gas CCS capacity is assumed.
- High nuclear deployment also reduces the peaking capacity required, as higher nuclear generation reduces the residual demand in all periods, resulting in a reduction of 7.1 GW of batteries and peakers building out by 2050.
- Nuclear generation reduces the wholesale market price due to its lower running costs compared to other firm baseload technologies, which leads to higher interconnector exports. Exports are also required because nuclear does not ramp down flexibly in periods of high renewable generation. This leads to greater excess generation compared to demand in some periods, which can be exported.
- Higher nuclear generation leads to a significant reduction in Gas CCS generation, causing total emissions reach 2 $MtCO_2e$ by 2050 (0.6 $MtCO_2e$ lower than the Base Case).







1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

Source: Aurora Energy Research

Agenda

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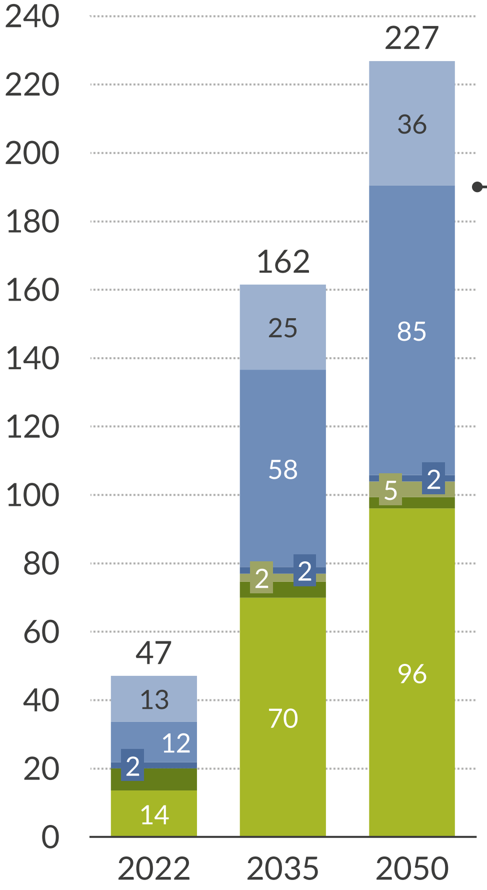
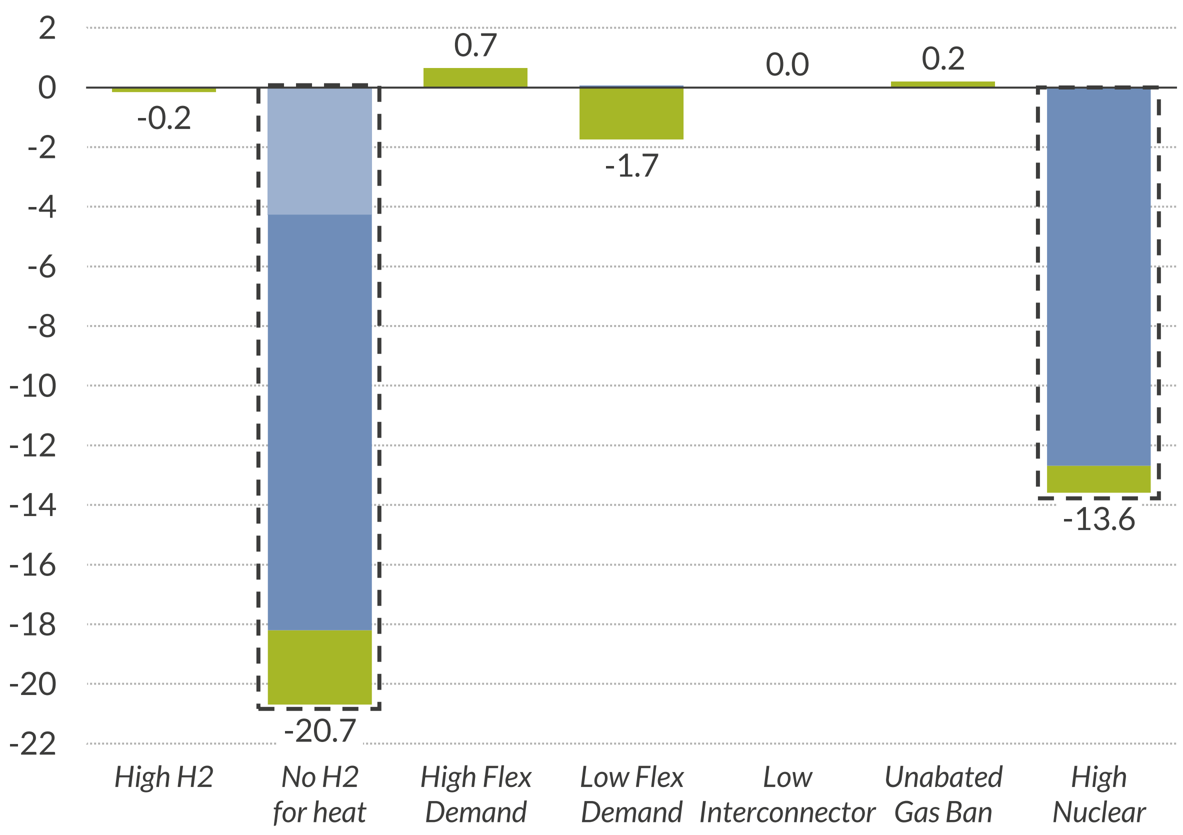
No Hydrogen for Heat and High Nuclear have lower renewable deployment, driven by reduced requirements for generation volumes

Base Case total installed renewable capacity, GW



Renewable capacity deltas compared to the Base Case, 2050
GW



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

1) Other RES includes biomass and EfW.

Source: Aurora Energy Research

No H2 for Heat
Lower total demand in this scenario results in a smaller power system, and less renewable capacity is required.

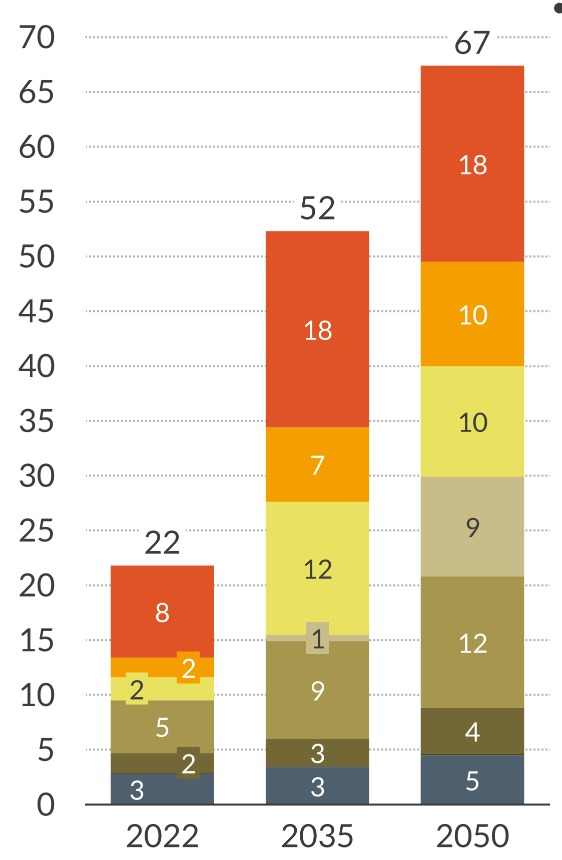
High Flexible Demand
Increasing flexible demand puts upwards pressure on solar capture prices, as demand shifts to periods of high renewable generation, increasing the merchant build of solar.

Low Flexible Demand
Low flexible demand results in lower capture prices for solar, decreasing merchant build out, as demand is unable to shift to periods of high renewable generation.

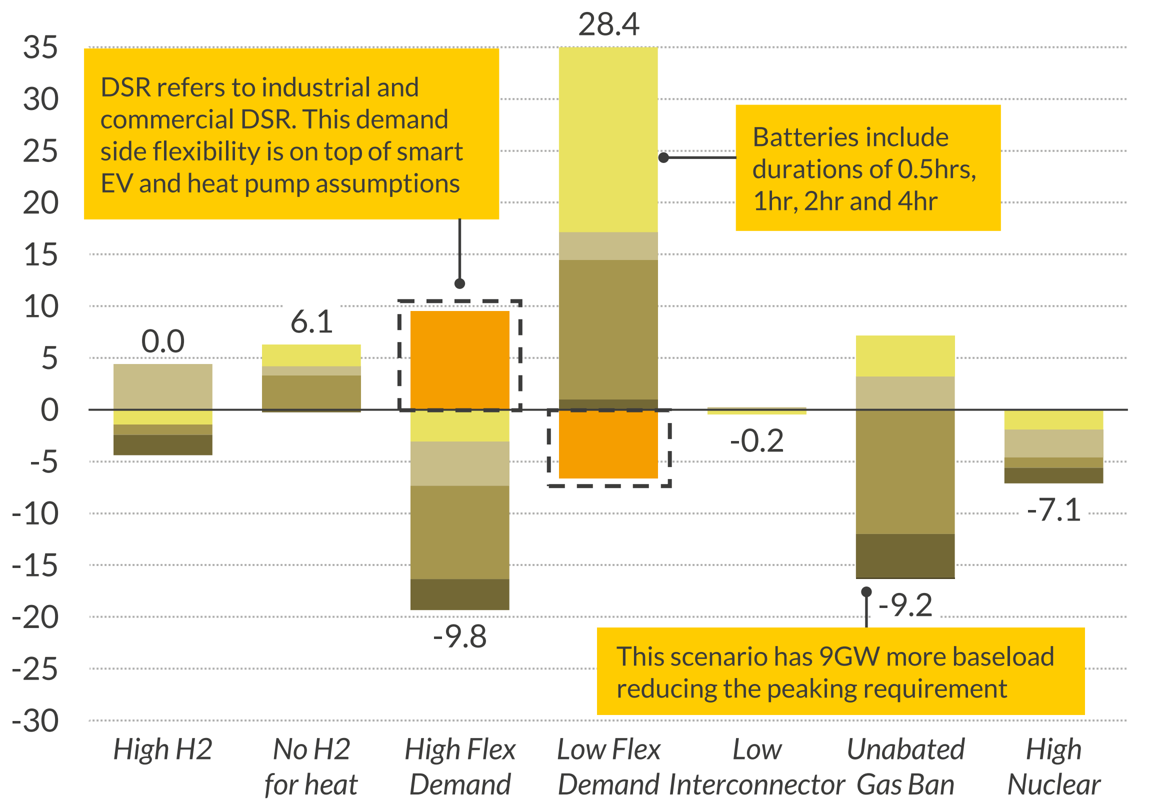
High Nuclear
Higher nuclear deployment leads to a lower requirements for renewables.

No Hydrogen for Heat and Low Flexible Demand necessitates increased flexible capacity, leading to higher battery build out

Base Case total installed flexible capacity
GW



Flexible capacity deltas compared to the Base Case, 2050
GW



Exogenous assumption

Interconnectors | DSR[1] | Battery storage | Hydrogen peakers | Gas Recip. | OCGT | Oil/ other peaking | Pumped storage

1) Demand Side Response

Source: Aurora Energy Research

High H2
A lower hydrogen price improves the economics of H2 peakers resulting in higher H2 peaking capacity, but fewer unabated peakers and batteries.

High Flexible Demand
There is less requirement for supply side flexibility as a higher proportion of demand is able shift its load, lowering peak demand.

Low Flexible Demand
With less demand side flexibility, this scenario has the highest peak demand. Higher battery and gas/H2 peaker build-out is therefore required.

Unabated Gas Ban
A ban on all unabated thermal assets means that hydrogen peakers and batteries are required to provide system flexibility, whilst gas recips and OCGTs are no longer part of the capacity mix.

An additional 16GW nuclear capacity by 2050 in the High Nuclear scenario reduces the need for abated gas capacity

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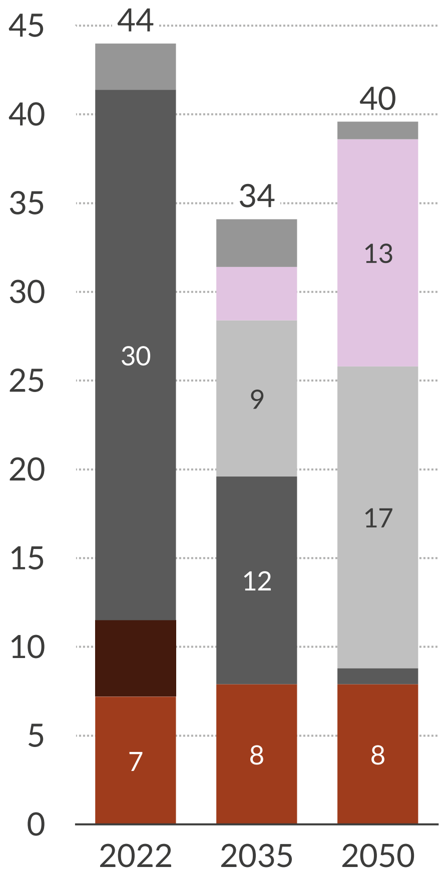
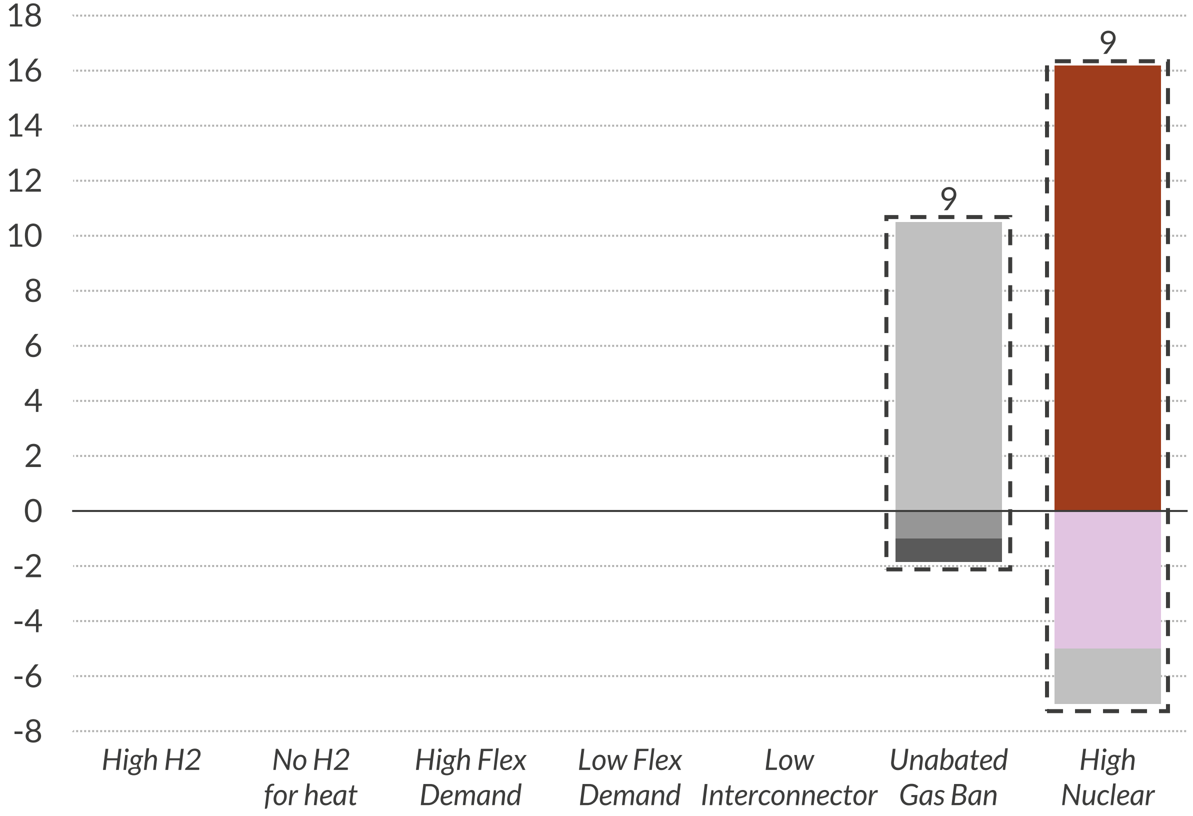
Base Case total installed baseload capacity
GW



Baseload capacity deltas compared to the Base Case, 2050
GW



Other thermal[1] | Hydrogen CCGT | Gas CCS | Gas CCGT | Coal | Nuclear | Exogenous assumption

1) Other thermal includes embedded CHP.

Source: Aurora Energy Research

Unabated Gas Ban
In this scenario, existing unabated gas CCGTs must retire or convert to Gas CCS by 2035; with new build Gas CCS capacity required if the existing fleet chooses to retire. This additional capacity is required to ensure there is no loss of load in 2035, however by 2050 there is an additional 10GW on the system compared to the Base Case.

High Nuclear
In this scenario the government target of 24GW of nuclear by 2050 is achieved, reducing the requirement for other forms of low carbon firm power.

Agenda

Hydrogen and gas peaking assets are at the top end of the merit order, whilst renewables are at the lower end

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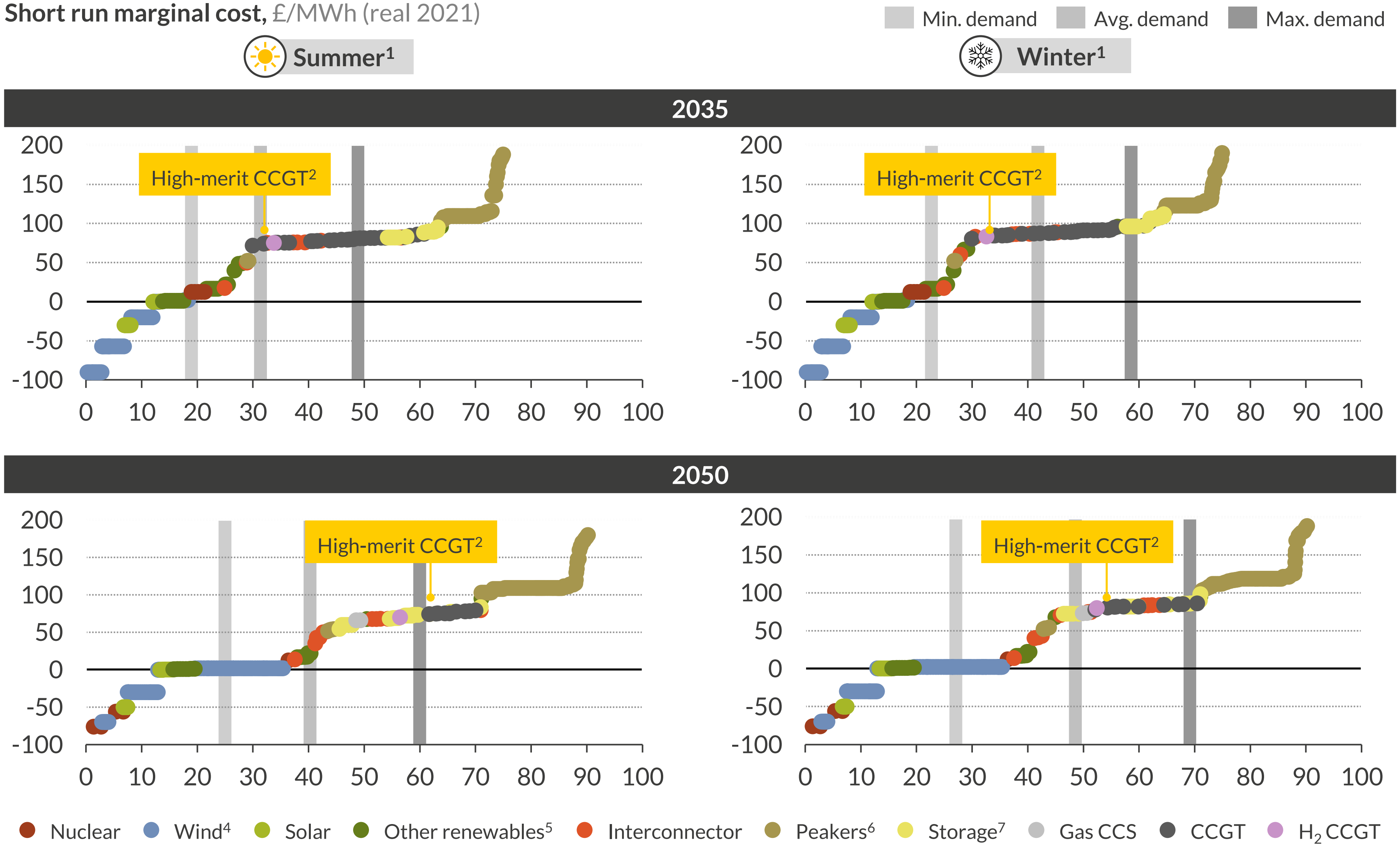
Short run marginal cost, £/MWh (real 2021)

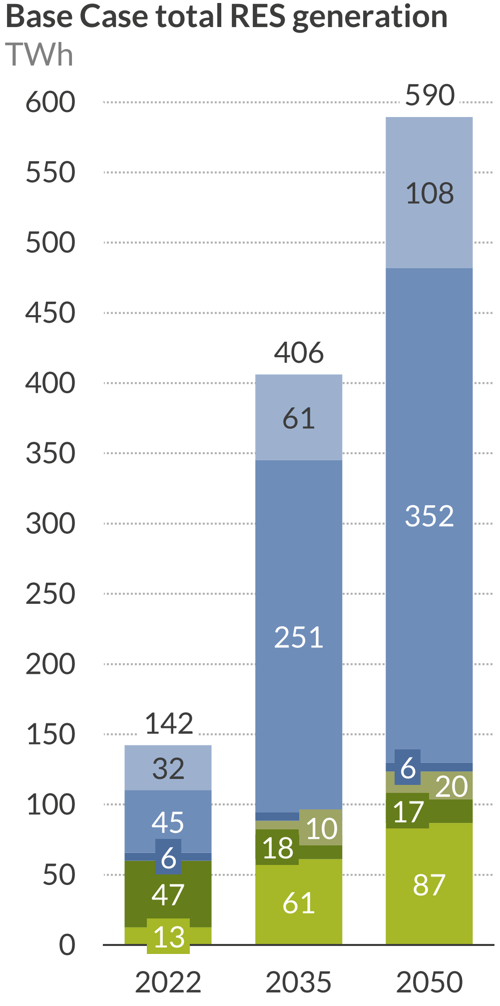


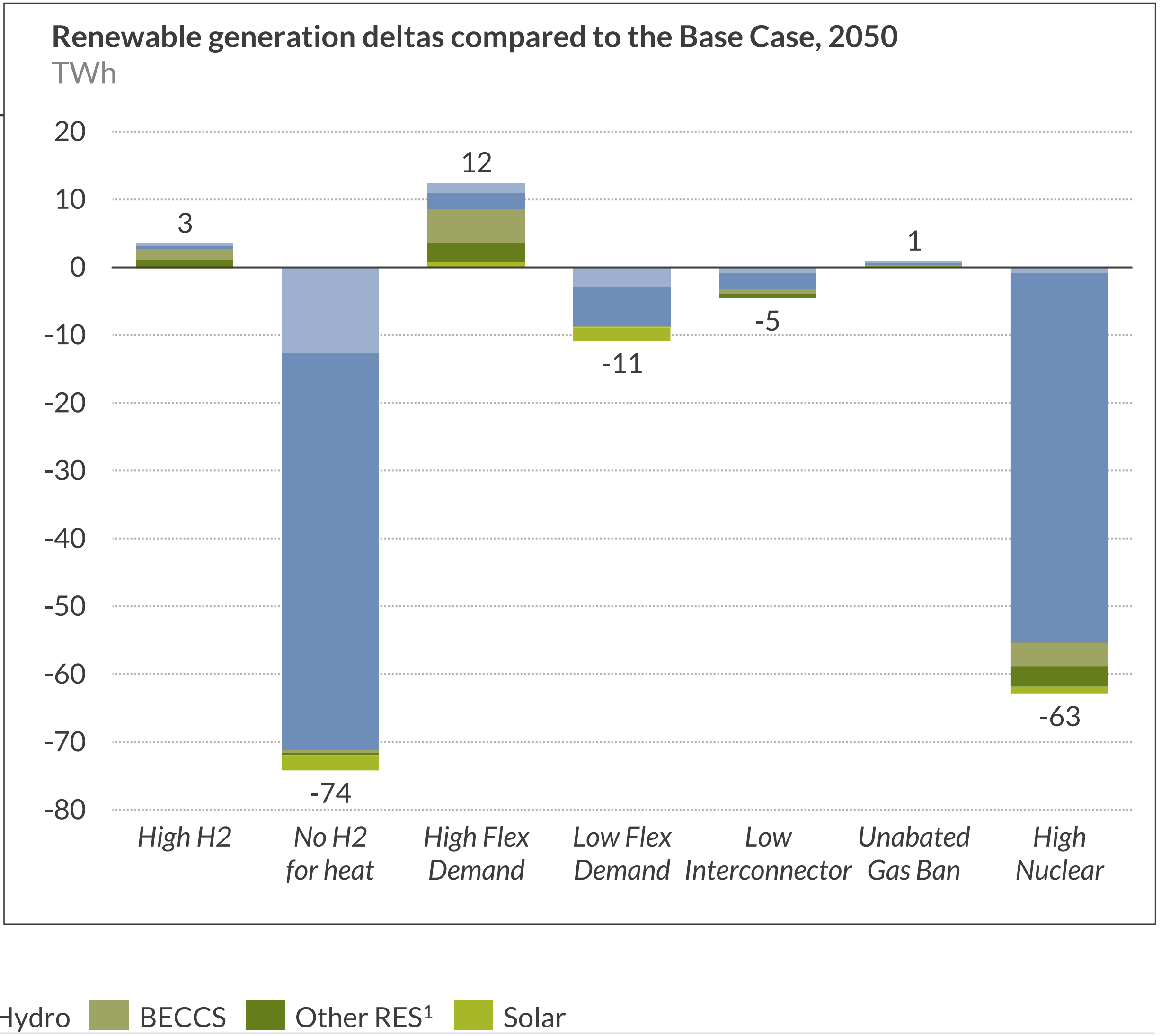
1) Summer is defined as April – Sept and winter as Oct to March. 2) Assuming 54% HHV efficiency. 3) Wind and solar contributions are accounted for by their load factors, not their de-rating factor. 4) Includes both offshore and onshore wind. 5) includes biomass, EfW, hydro and CHP. 6) Includes OCGT, recips, H2 peakers, gas peakers and DSR. 7) Includes batteries and pumped storage.

Source: Aurora Energy Research

- The merit order of generation is shown for the Base Case and is determined by the short run marginal cost of each technology in the capacity mix.
- Power supply in GB is typically dispatched in preference of:
  - Low-marginal cost assets such as nuclear/renewables
  - Thermal baseload assets such as CCGTs
  - Peaking assets as such recips
- The highest cost plant that dispatches in any given period sets the wholesale power price.
- More renewable deployment will result in low-cost assets meeting more than minimum demand by 2035, whilst the retirement of CCGTs results in high-cost peakers setting the price more often.
- In the High H2 scenario, the H2 price is reduced, which would bring H2 plants further down the merit order, increasing the dispatch of H2 assets.

Lower renewable capacities in No H2 for Heat & High Nuclear reduces generation; scenarios with higher flexible demand see less curtailment





1) Other RES includes biomass and EfW.

Source: Aurora Energy Research

No H2 for Heat
This scenario has the smallest total power system as it has lowest demand. The resulting lower renewable deployment reduces renewable generation.

High Flexible Demand
Smart EVs, heat pumps and flexible electrolysers can shift their load to high renewable periods in this scenario reducing curtailment, leading to higher generation.

Low Flexible Demand
EVs and heat pumps are unable to shift their demand to high renewable periods, increasing the amount of curtailment.

Low Interconnector
Reduced interconnector availability increases curtailment, as excess generation cannot be exported.

High Nuclear
Increased nuclear capacity reduces the need for renewable deployment, therefore less generation takes place.

Increased nuclear capacity leads to greater exports from GB, while lower flexible demand increases generation from gas and H2 peakers

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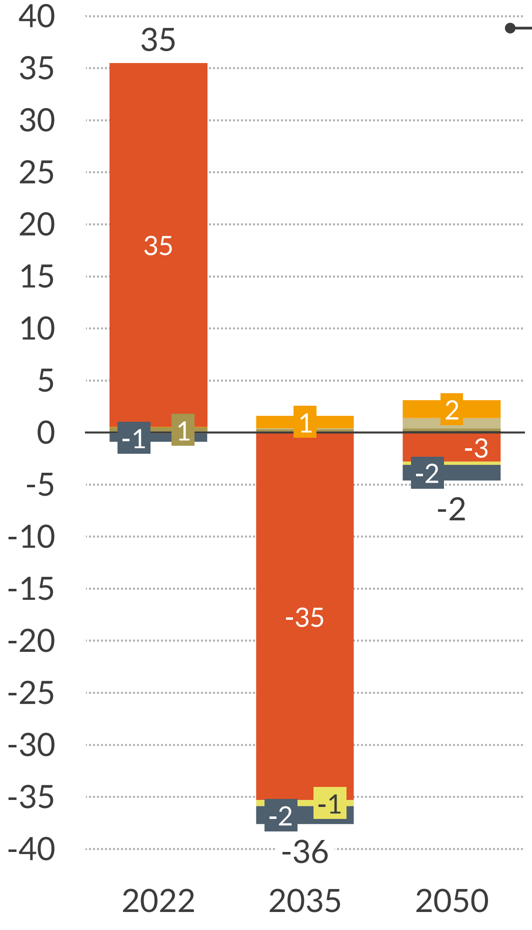
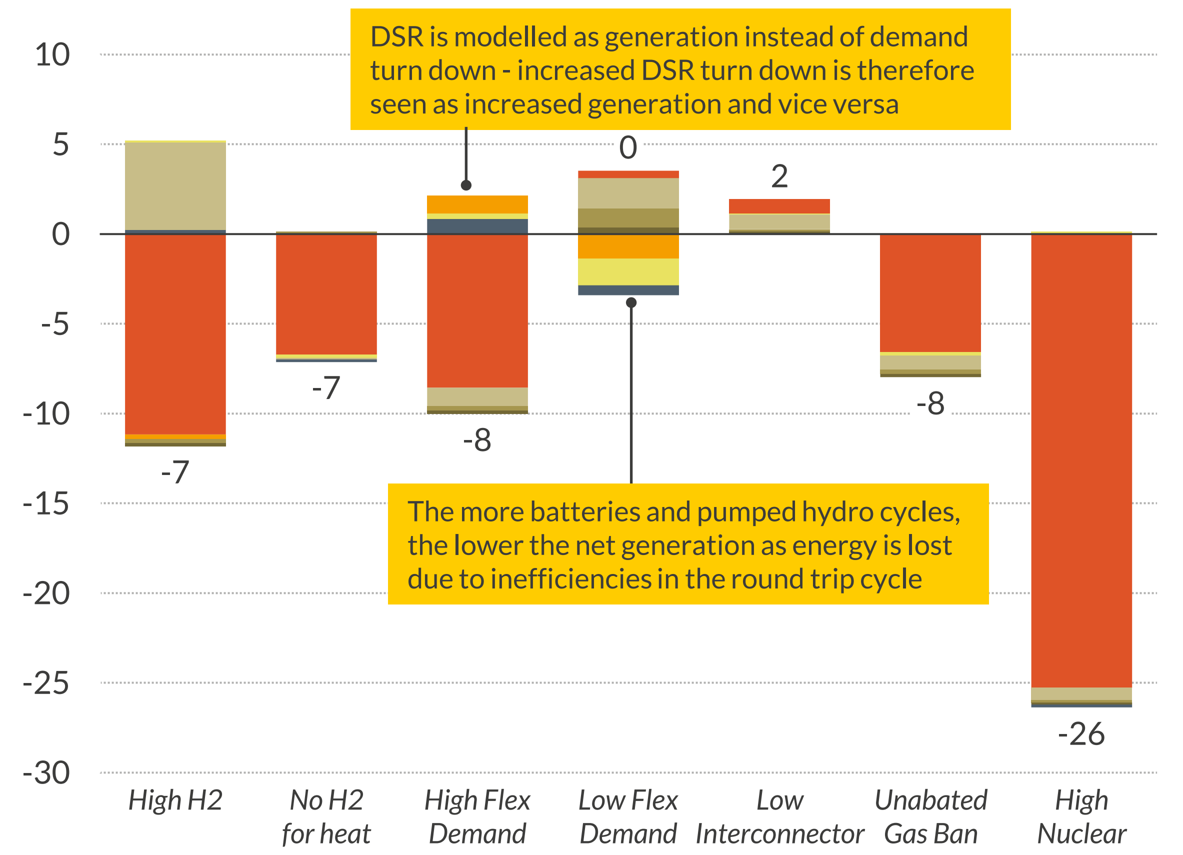
Base Case total flexible generation
TWh



Flexible generation deltas compared to the Base Case, 2050
TWh



Interconnectors | DSR | Battery storage | Hydrogen peakers | Gas Recip. | OCGT | Oil/ other peaking | Pumped storage

Source: Aurora Energy Research

High H2
Low H2 prices lead to 5 TWh additional H2 peaker generation by 2050. Lower wholesale prices increase exports.

High Flexible Demand
Lower peak demand reduces the need for supply side flexibility. Lower wholesale prices increase exports.

Low Flexible Demand
Higher peak demand requires additional gas/H2 peaking generation, and additional cycling of battery and pumped hydro storage (additional utilisation of storage is reflected in lower net generation due to round trip efficiency losses).

Unabated Gas Ban
Higher CCS generation pushes peakers out of merit and increases exports.

High Nuclear
Nuclear deployment can reduce wholesale prices due to its low running costs, leading to to higher exports. Exports also increase as nuclear does not ramp down flexibly, leading to greater excess generation in some periods, which can be exported.

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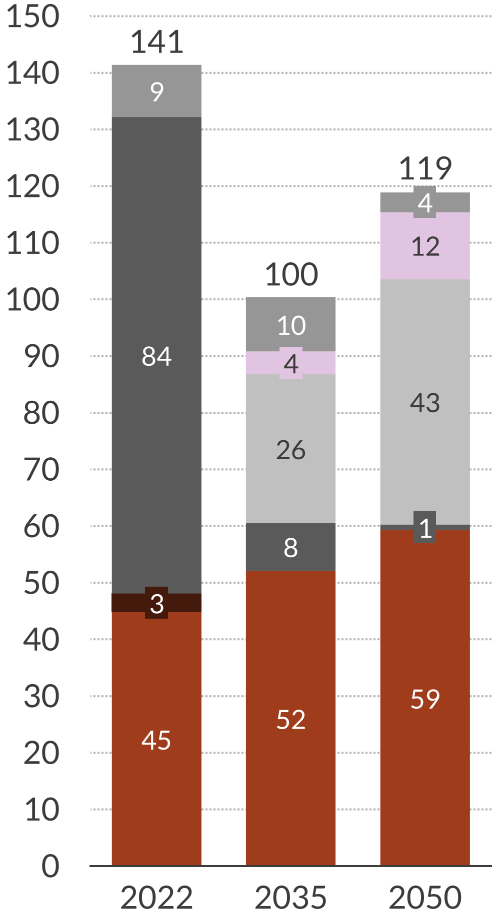
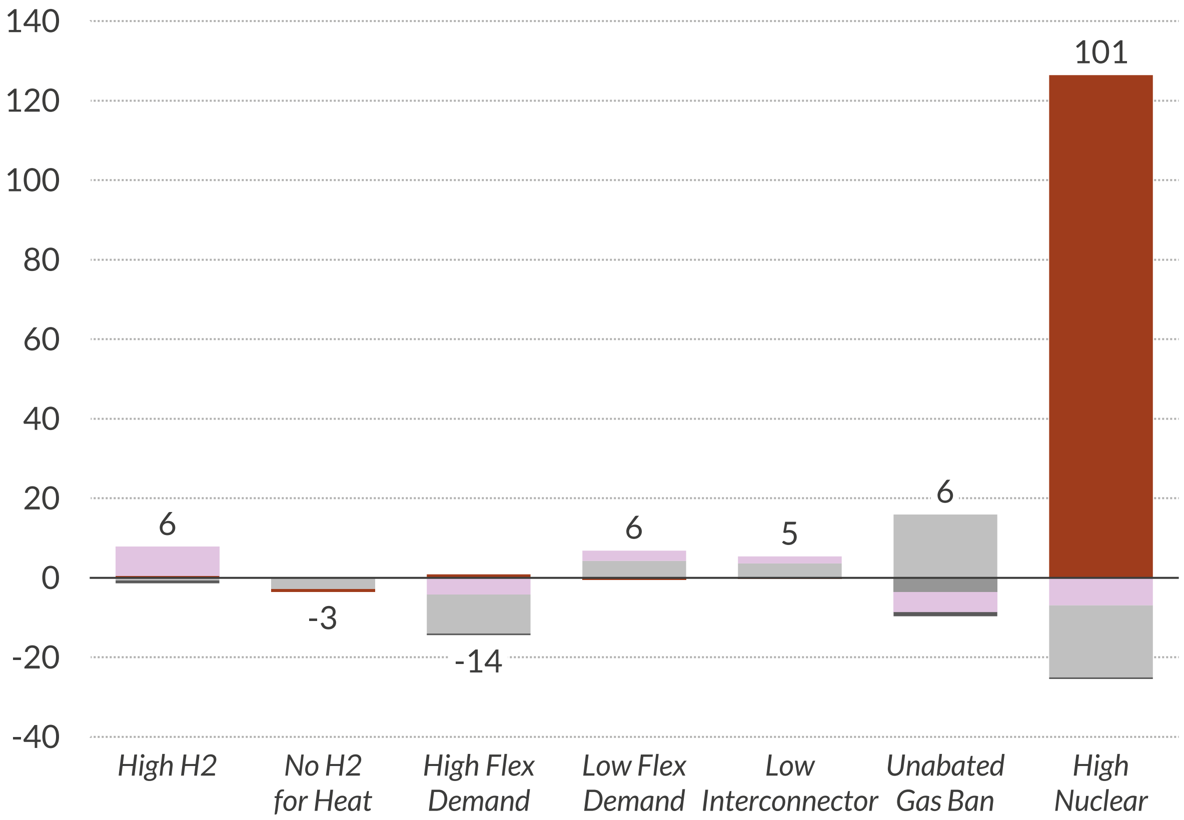
Increasing the deployment of flexible demand and nuclear decreases the need for other baseload generation

Base Case baseload generation
TWh



Baseload generation deltas compared to the Base Case, 2050
TWh



Other thermal[1] | Hydrogen CCGT | Gas CCS | Gas CCGT | Coal | Nuclear

1) Other thermal includes embedded CHP.

Source: Aurora Energy Research

High H2
Subsiding the H2 price pushes H2 CCGTs down the merit order resulting in an additional 7 TWh generation by 2050, compared to the Base Case.

High Flexible Demand
Smart EVs and heat pumps reduce the need for baseload generation as they shift demand to high renewable periods.

Low Interconnector & Low Flexible Demand
Less supply-side flexibility means H2 CCGTs and Gas CCS generates more.

Unabated Gas Ban
Deploying additional Gas CCS by 2035 leads to 16 TWh more Gas CCS relative to the Base Case, displacing 5 TWh from H2 CCGTs. However, Gas CCS is typically operating at low load factors by 2050.

High Nuclear
Increasing nuclear capacity by 16 GW results in 126 TWh additional nuclear baseload generation in 2050, reducing Gas CCS and H2 CCGT generation by 25 TWh.

Agenda

I. Executive summary

II. Growing need for flexibility in a net zero world

III. Overview of modelled scenarios

IV. System composition

1. Summary
2. Capacities comparison
3. Generation comparison
4. **Emissions comparison**

V. Impacts on flexibility

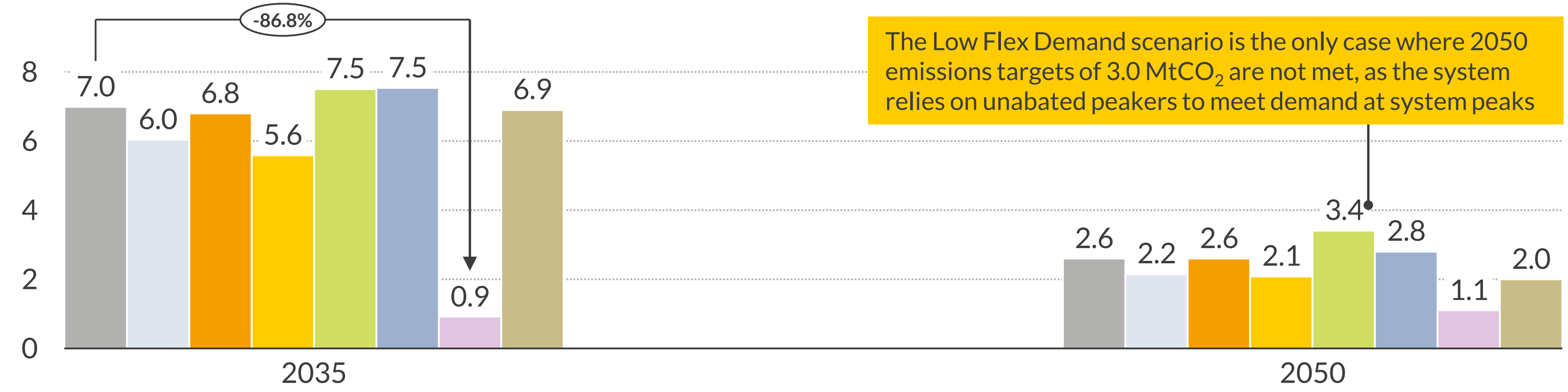
VI. Effects on system costs

VII. Extreme weather years

The largest emissions reductions can be achieved with a ban on unabated gas in 2035

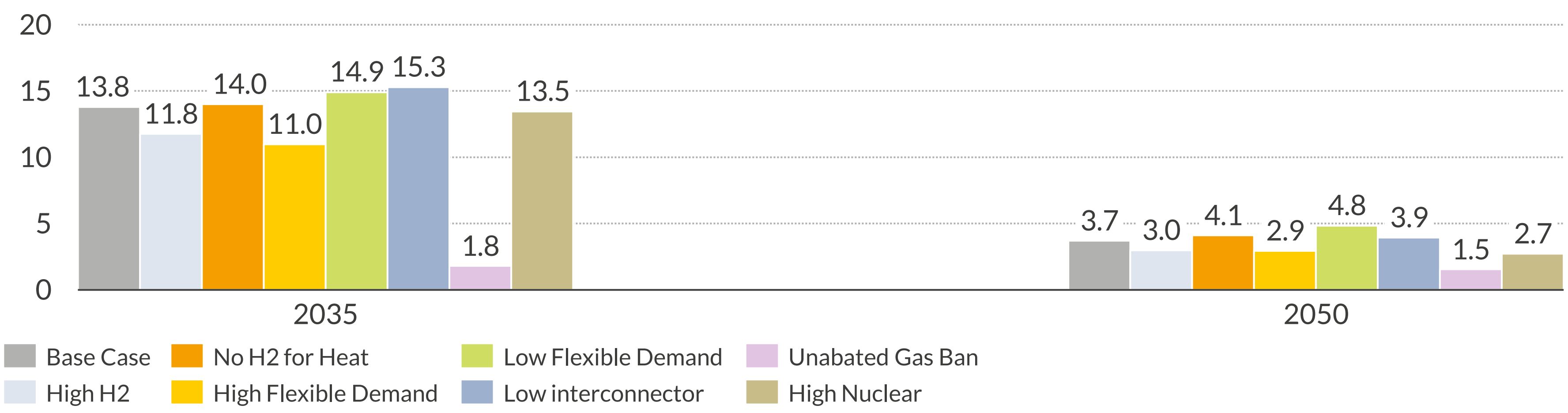
Power sector carbon emissions

$MtCO_2e$



Power sector carbon intensity

CO_2e/kWh



High H2
Hydrogen peakers and CCGTs replace unabated CCGTs and peakers, reducing emissions by 0.4$MTCO_2$ in 2050 compared to the Base Case.

No H2 for Heat
The No H2 for Heat scenario has comparable overall emissions to the Base Case in 2050, however as the overall size of the power sector is smaller in this scenario, the carbon intensity is higher.

Low/High Flexible Demand
Reduced flexible demand results in a 31% increase in emissions in 2050, as EVs and heat pumps are unable to shift their load to high-RES periods. The inverse is true for high flexible demand where emissions fall by 20%.

Unabated Gas Ban
Banning unabated gas in 2035 results in the largest decrease in emissions relative to the Base Case; emissions fall by 87%.

Source: Aurora Energy Research

Lower levels of demand side flexibility increases emissions from gas recips, which are the cheapest available form of peaking capacity

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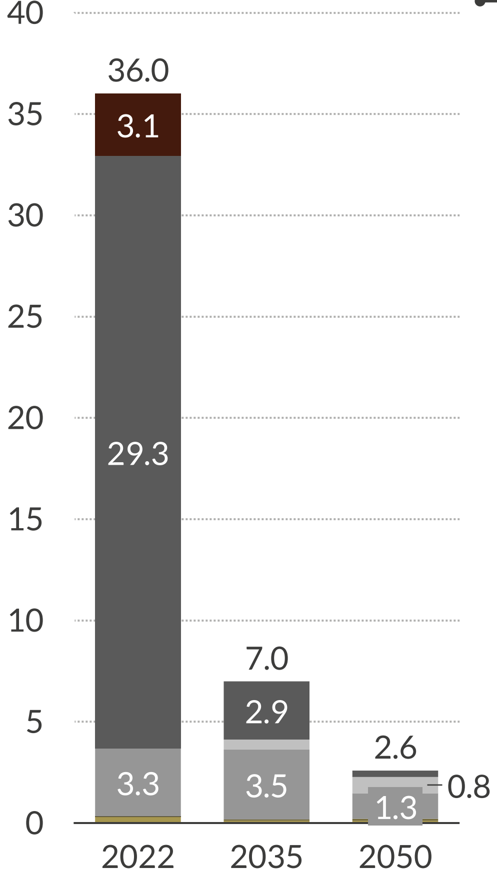
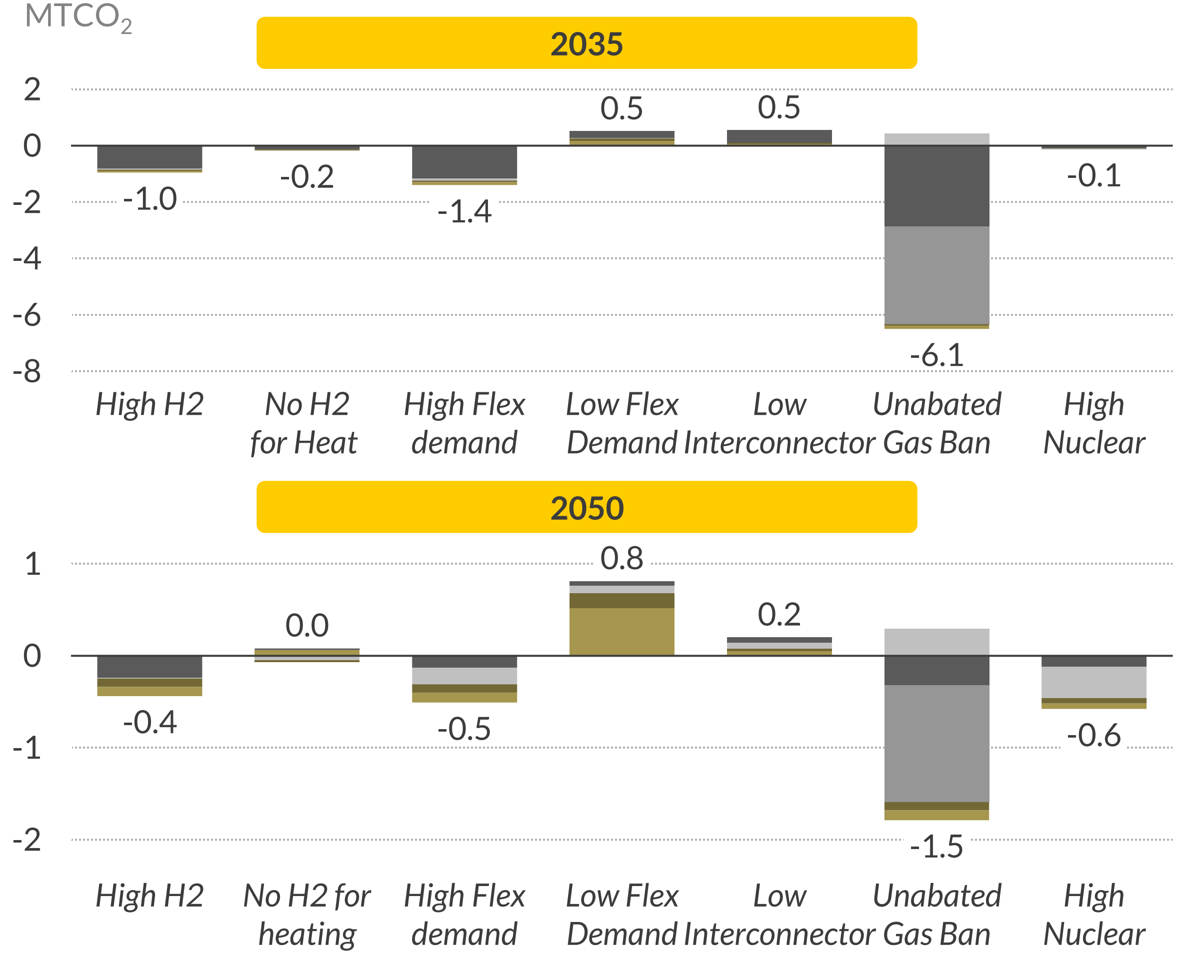
Base Case CO_2 emissions by technology
$MTCO_2$



Emissions deltas to the Base Case
$MTCO_2$



Coal | Gas CCGT | Gas CCS | Other thermal[1] | Oil/ other peaking | OCGT | Gas Recip.

1) Other thermal includes embedded CHP

Source: Aurora Energy Research

High H2
H2 CCGTs and peakers displace gas CCGTs and recips in the merit order, reducing emissions.

High/Low Flexible Demand
Increased demand-side flexibility reduces reliance on CCGTs, decreasing emissions whilst low flexible demand has the opposite impact.

Low interconnectors
Lower interconnector availability means GB has limited ability to import in periods of RES shortfall, leading to higher emissions.

Unabated Gas Ban
Emissions from unabated CCGTs, CHP and recips are entirely displaced, additional residual emissions from Gas CCS take place.

High Nuclear
Increased low carbon nuclear generation displaces unabated thermal, reducing emissions.

Agenda

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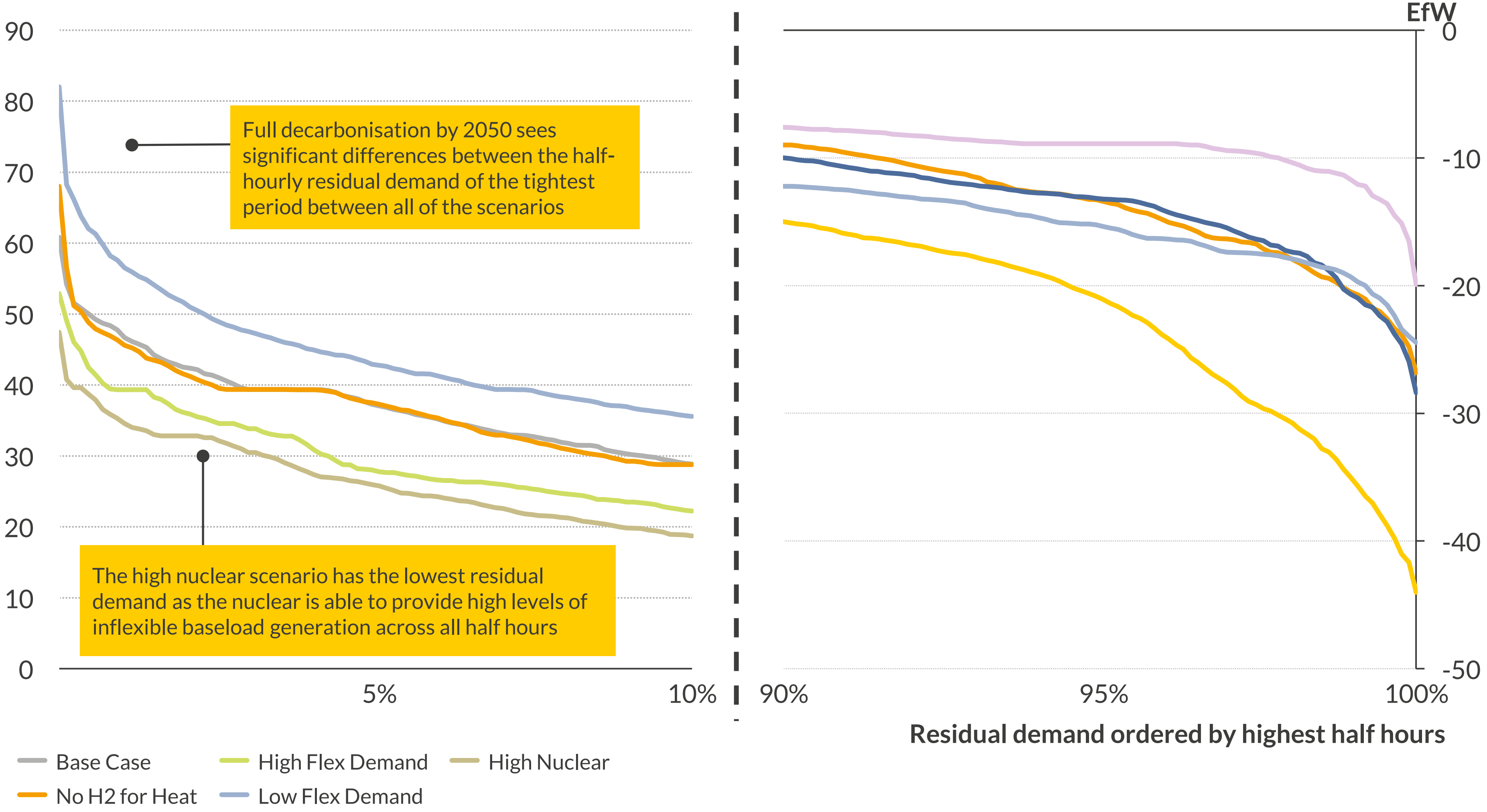
Increased flexibility shifts demand to periods of high renewable generation and reduces residual demand in peak periods

Residual demand in 2050
GW

Residual demand is the total demand (including demand side flexibility[1]) minus the sum of all nuclear and renewable generation, including biomass, BECCS and EfW



No Hydrogen for Heat
Higher deployment of heat pumps, which are unable to shift demand interseasonally like hydrogen, increases peak residual demand by 8 GW compared to the Base Case by 2050.

High Flexible Demand
Smart EVs and heat pumps shift demand to periods of high renewable generation, reducing the spread of shortfall and excess generation in 2050.

Low Flexible Demand
Results in 21 GW higher residual demand in the peak period, compared to the Base Case.

High Nuclear
With 125 TWh of extra inflexible baseload generation, the residual demand curve is shifted downwards relative to the Base Case.

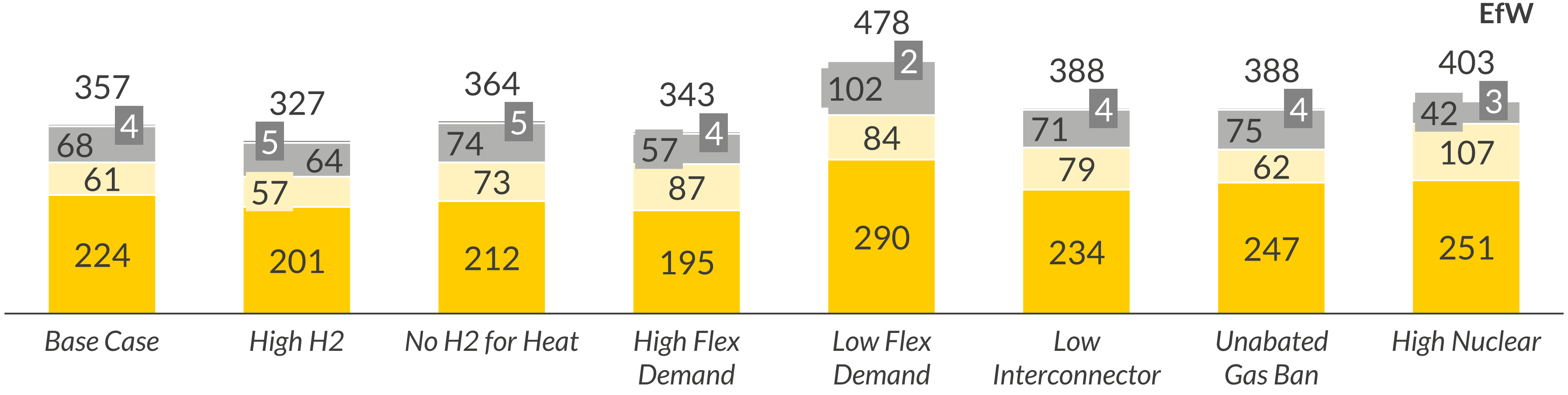
1) Demand side flexibility includes shifts in peak demand as a result of electric vehicles, heat pumps and electrolysers choosing to operate in cheaper periods

Source: Aurora Energy Research

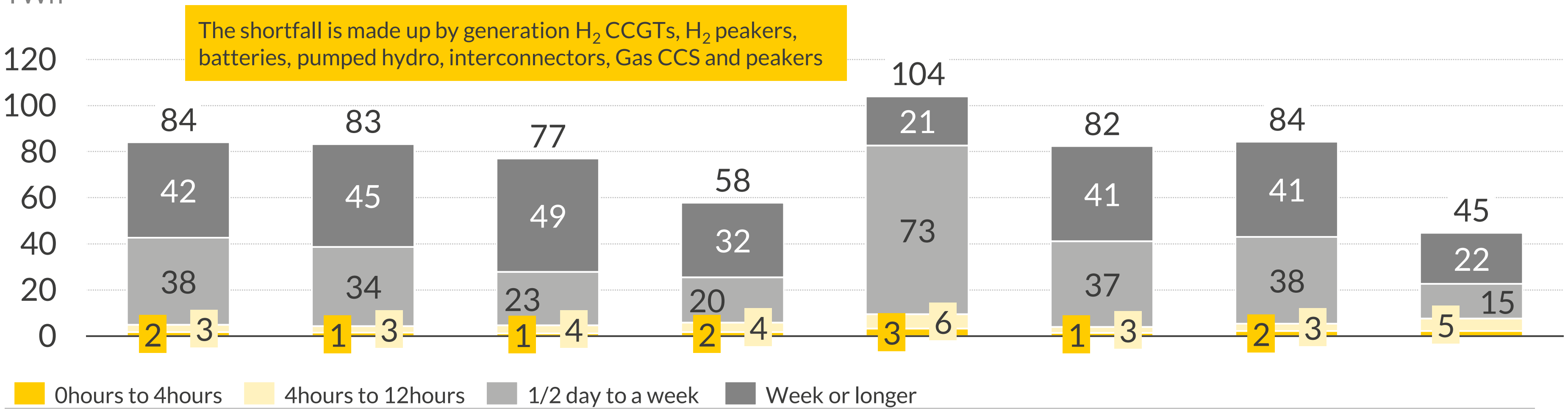
Lower flexibility sees increased instances and larger volumes of shortfalls in renewable and nuclear generation

Count of RES[1] and nuclear shortfall by duration in 2050
#

Residual demand is the total demand (including demand side flexibility[1]) minus the sum of all nuclear and renewable generation, including biomass, BECCS and EfW



Volume of continuous renewable and nuclear shortfall by duration in 2050
TWh



1) Demand side flexibility includes shifts in peak demand as a result of electric vehicles, heat pumps and electrolysers

Source: Aurora Energy Research

AURORA

Low Flexible Demand
EVs and heat pumps are inflexible, leading to the highest number of shortfall events and the highest volume (20TWh more than the Base Case). The number of 'week or longer' events is smaller as the daily demand profile is relatively fixed. This means that demand cannot shift from evening peaks to night-time troughs, making it more likely that long periods of shortfall will be broken overnight when demand is lower.

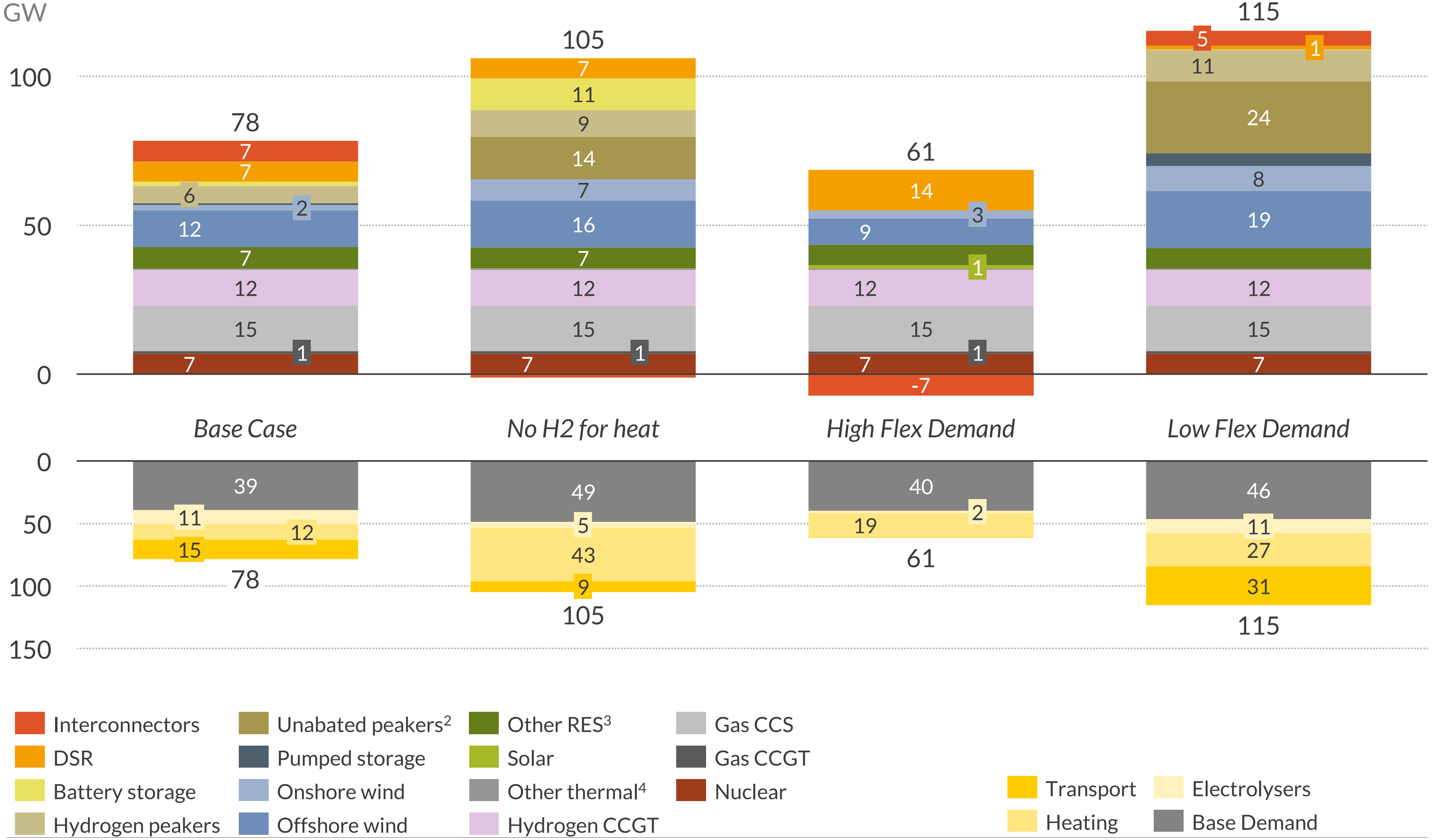
High Flexible Demand
Smart EVs and Heat pumps are able to effectively shift demand to high renewable periods, reducing the number and volume of shortfall events.

High Nuclear
This scenario has the most baseload generation, leading to the lowest number of long-duration shortfall events and the lowest overall volume of continuous shortfall.

Flexible technologies required to meet winter demand peaks varies based on the Net zero Pathway

Half hourly generation and demand – period of highest residual demand[1]

GW



1) Period varies between all scenarios dependant on when the period of highest residual demand occurs 2) Unabated peakers includes gas recips, OCGTs & oil peakers 3) Other RES includes hydro, BEECS, biomass & EfW. 4) Other thermal includes embedded CHP

Source: Aurora Energy Research

No H2 for Heat
The increase in electrified heating results in a large winter demand peak. 14 GW unabated peakers, 9 GW H2 peakers and 11 GW of batteries are needed to generate alongside baseload assets to meet demand.

High Flexible Demand
Here, flexible demand shifts its load to a lower price period, meaning peaking capacity is not required. GB exports as prices are higher in interconnected regions (as interconnected countries typically have similar climates, peak periods are often correlated).

Low Flexible Demand
Demand is unable to shift away from this period forcing 35GW of peaking capacity (abated and unabated) to generate.

Many non-power sector H2 end use cases require a continuous supply of H2 and so some electrolysers continue to operate in system peaks. Alternatively, GB would require the deployment of a H2 network, which is not assumed in these scenarios.

Higher levels of demand side flexibility can shift demand to allow more renewable generation in Summer

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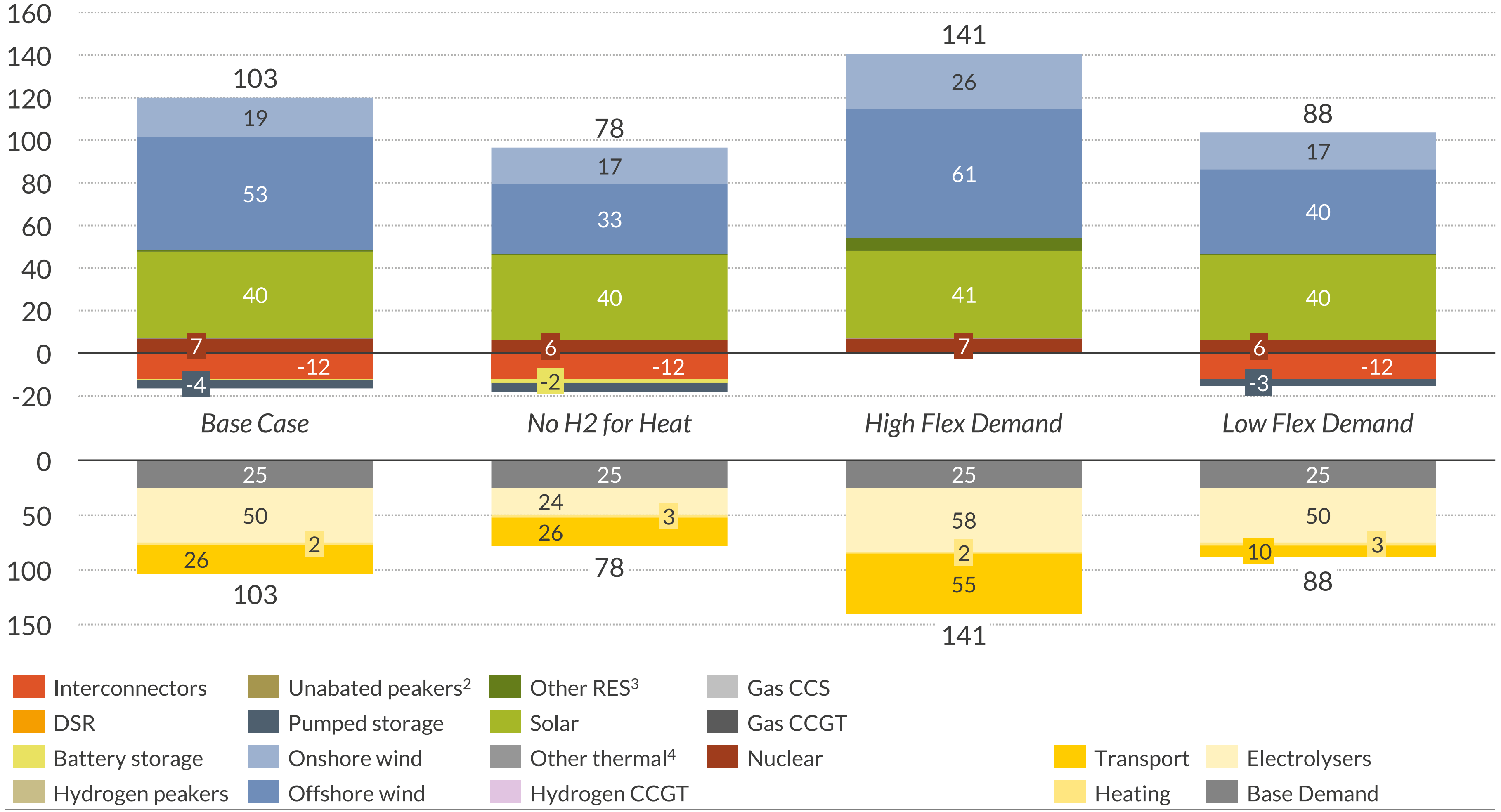
Half hourly generation and demand – high RES generation hour in summer 2050[1]
GW



1) 14:30 03/08/2050 2) Unabated peakers includes gas recips, OCGTs & oil peakers 3) Other RES includes hydro, BECCS, biomass and EfW; 4) Other thermal includes embedded CHP.

Source: Aurora Energy Research

No H2 for Heat
Reduced demand for H2 results in lower electrolyser deployment, and lower total power demand in this scenario, which reduces the renewable capacity deployed. Therefore, total renewable generation is lower compared to the Base Case and less electrolytic hydrogen production is seen.

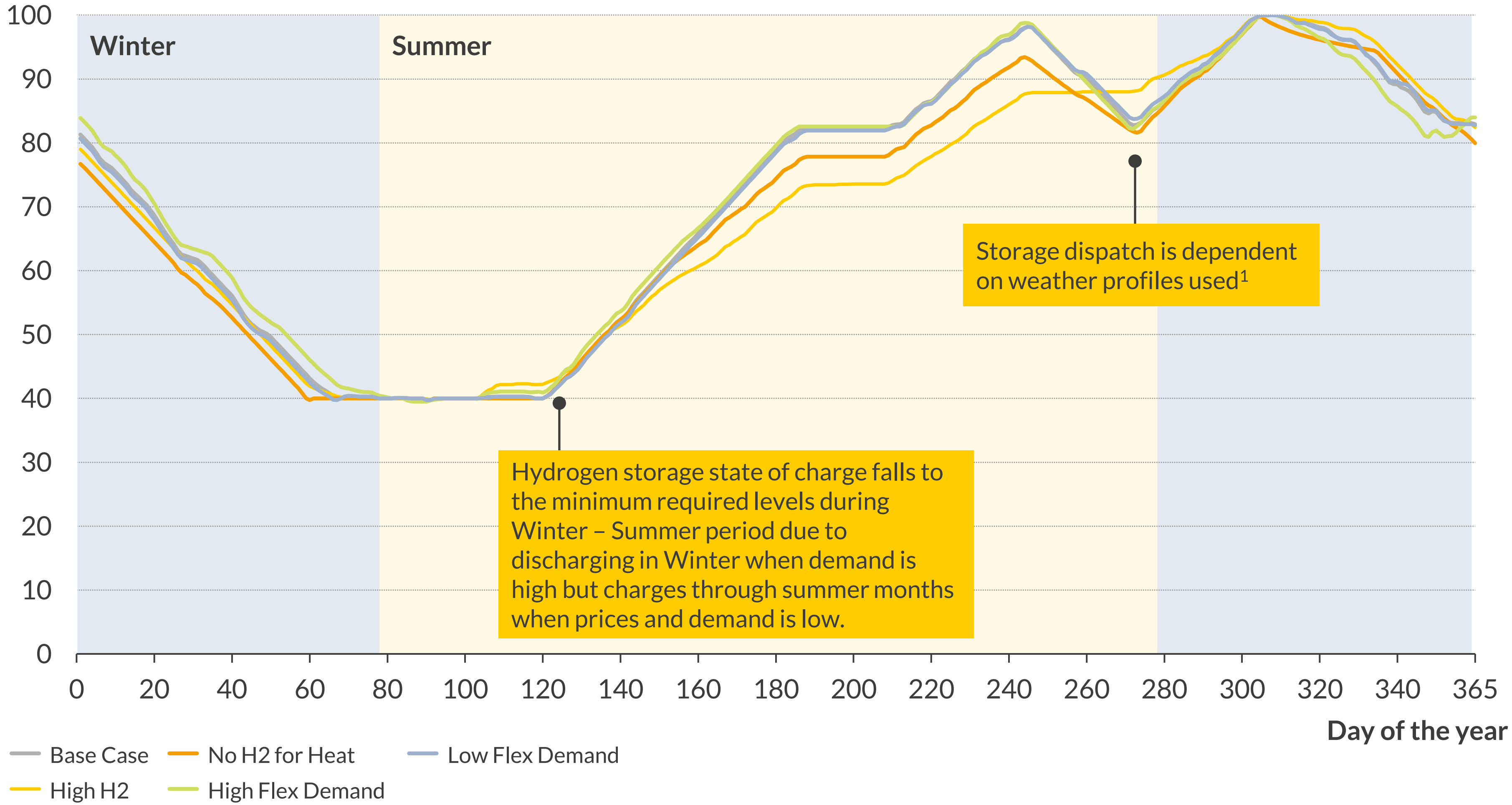
High Flexible Demand
High levels of flexible demand means EVs and electrolysers can shift their demand to this high renewable generation period, leading to no renewable curtailment and no reliance on interconnector exports

Low Flexible Demand
Low flexible demand means EVs and other sources of demand flexibility are unable to shift their demand to a high renewable generation period, causing renewables to curtail, pumped hydro and interconnectors also choose to charge/export here.

H2 storage consistently discharges in winter when demand is high and charges in summer months when demand and prices are low

GB salt cavern H2 storage state of charge in 2050

%



- Seasonality in hydrogen storage levels is driven by storing hydrogen to meet high winter demand for heating, followed by stockpiling through summer months when hydrogen demand is lower.
- Storage utilisation is similar across all scenarios.
- The High Hydrogen scenario has double the total storage volume, allowing higher volumes of H2 to be stored, however utilisation rates are lower in this scenario.
- No H2 for Heat also sees lower utilisation as less hydrogen is produced and stored interseasonally for use heating, however storage is still needed to reduce costs for hydrogen use in industry, power and transport.

1) Aurora uses 2013 weather patterns which represents an average weather year in GB. However, weather patterns vary throughout the year, resulting in some utilisation of hydrogen storage in Autumn

Source: Aurora Energy Research

Increasing demand side flexibility decreases wholesale price volatility as demand can be shifted from high to low price periods

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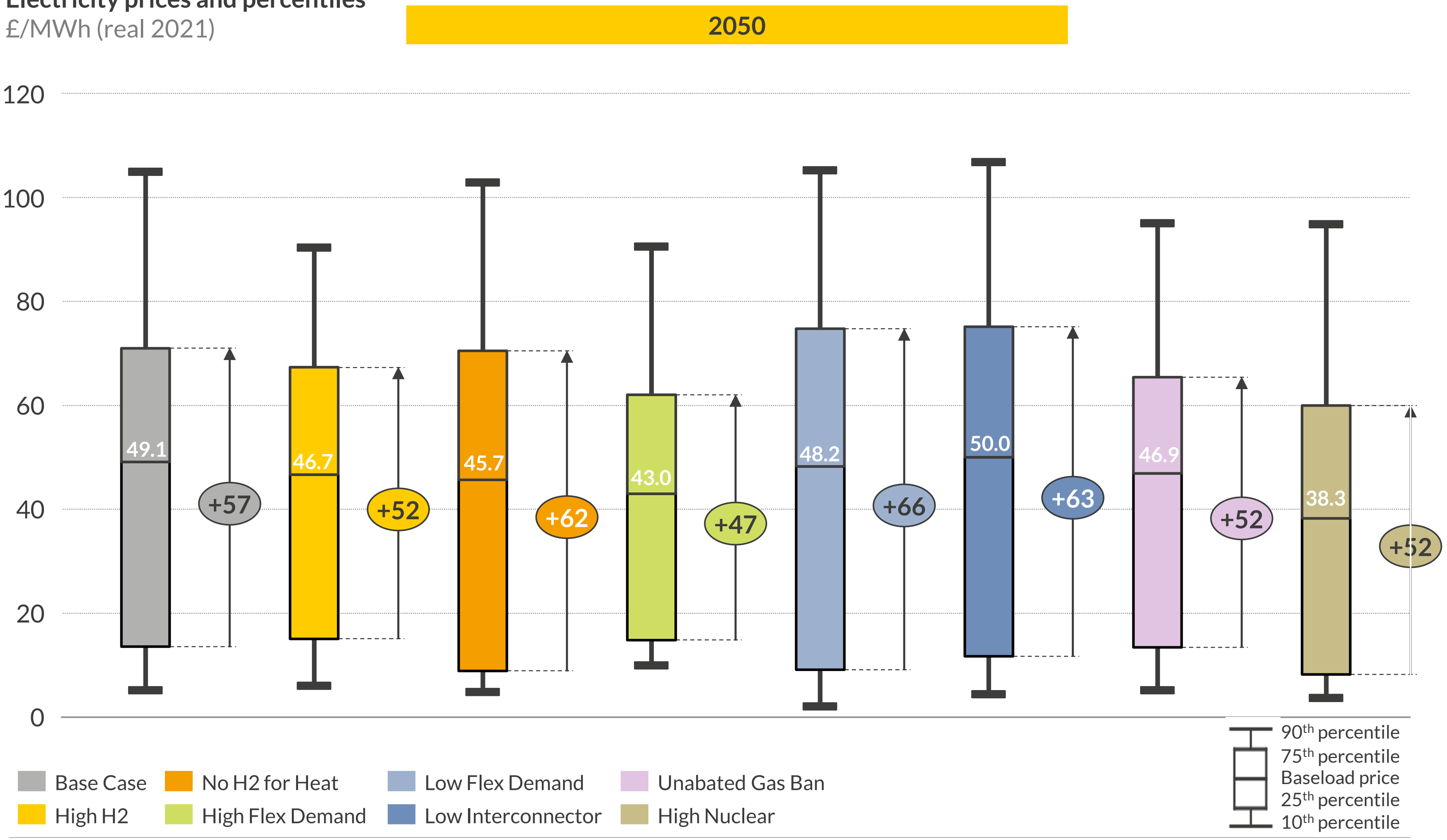
Electricity prices and percentiles
£/MWh (real 2021)



Source: Aurora Energy Research

High H2
Lower hydrogen prices pushes down top prices whilst higher hydrogen demand boosts bottom prices compared to the Base Case, as electrolysers operate in low price periods.

High Flexible Demand
Less price volatility is seen compared to the Base Case, as flexible demand (EVs and heat pumps) shifts to lower price periods, reducing peak prices and increasing bottom prices.

Low Flexible Demand/Low Interconnector
Spreads are largest in the low flexible demand and low interconnector scenarios, driven by reduced demand side flexibility which can respond to low and high prices.

High Nuclear
More nuclear generation pushes down top and bottom prices as nuclear is a cheap form of baseload generation.

Agenda

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

AURORA

Total 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

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

	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 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[1]	▪ 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 73). ▪ 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) CAPEX is recovered through revenues in the wholesale market, balancing mechanism, capacity market, subsidies and ancillary services

Source: Aurora Energy Research

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

	Cost components	Methodology
Balancing Mechanism	Balancing Costs[1]	▪ 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[1]	▪ 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[1]	▪ 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[1]	▪ 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[2] & ancillary services)**

1) CAPEX is recovered through revenues in the wholesale market, balancing mechanism, capacity market, subsidies and ancillary services 2) 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 system costs are calculated for each scenario, based on its capacity and generation mix and resulting prices (3/3)

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Cost components		Methodology
Hydrogen	Hydrogen	▪ Hydrogen costs reflect the cost of producing hydrogen and **does not** reflect the total cost of the hydrogen system, any hydrogen specific subsidies, or the costs to consumers of having hydrogen supplied for heating: **Hydrogen costs can be calculated as: hydrogen demand x hydrogen price**
Network	Transmission	▪ Transmission costs reflect the costs of operating the transmission network in each scenario and are calculated based on the Ofgem RIIO[1] 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) Revenue = Incentives + Innovation + Outputs; this methodology determines the allowable transmission costs chargeable by the network operator

Sources: Aurora Energy Research

Base Case: Wholesale market costs are the largest cost component of system costs, followed by network and subsidy spend

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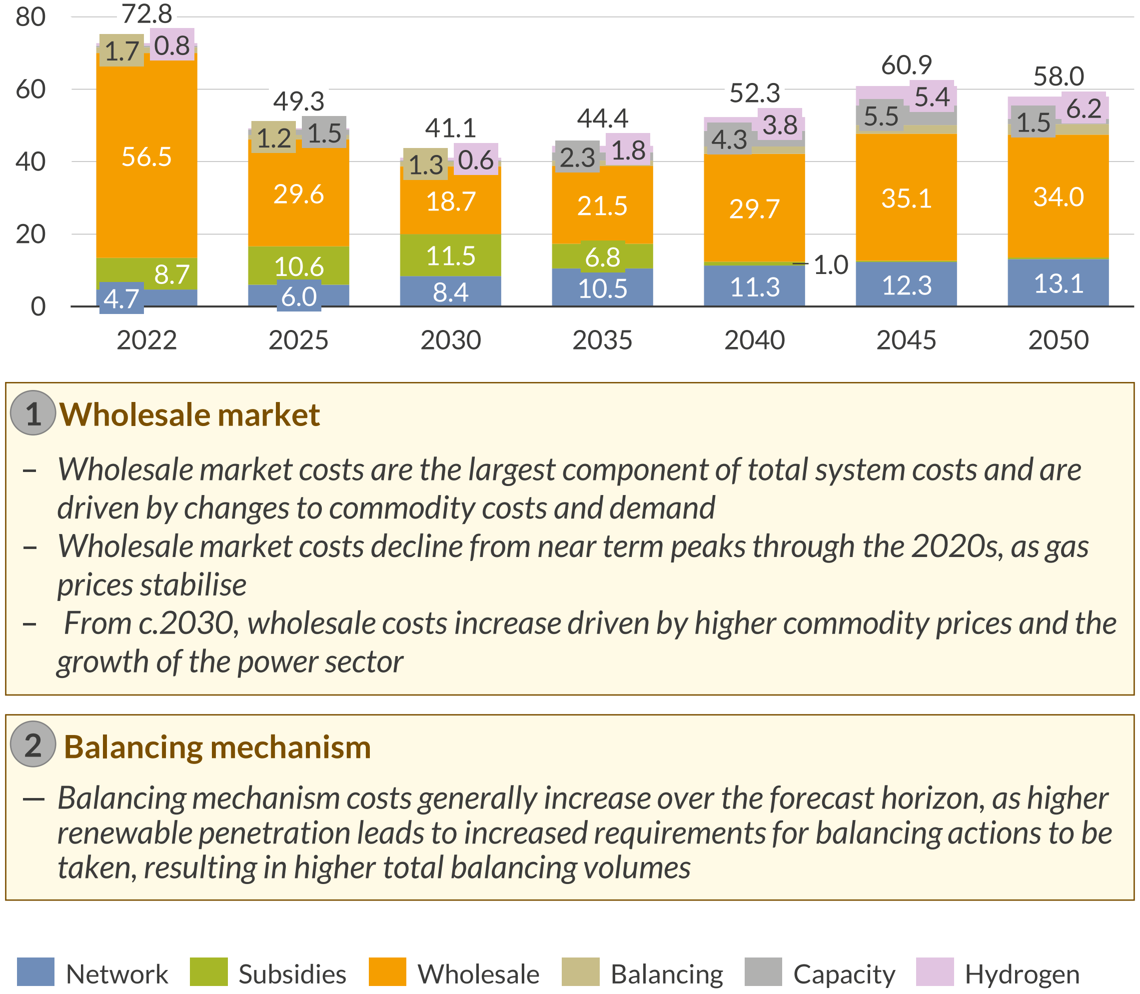
Annual total system costs
£ billion



1 Wholesale market

- *Wholesale market costs are the largest component of total system costs and are driven by changes to commodity costs and demand*
- *Wholesale market costs decline from near term peaks through the 2020s, as gas prices stabilise*
- *From c.2030, wholesale costs increase driven by higher commodity prices and the growth of the power sector*

2 Balancing mechanism

- *Balancing mechanism costs generally increase over the forecast horizon, as higher renewable penetration leads to increased requirements for balancing actions to be taken, resulting in higher total balancing volumes*

3 Capacity market

- *Capacity market spend reflects the costs of ensuring there is sufficient firm capacity on the system to ensure security of supply standards are met*
- *Capacity market spend typically increases across the forecast as baseload thermal plants retire and renewable deployment increases, increasing the need for additional firm capacity procurement*

4 Subsidies

- *Subsidy costs support the deployment of renewables, nuclear and low carbon forms of flexibility*
- *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, and plants with ROCs are not required to make back payments if the wholesale price is above this*
- *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*

5 Hydrogen market

- *Hydrogen market costs increase across the forecast horizon as the size of the hydrogen system increases*

6 Network costs

- *Network costs increase across the forecast horizon, driven by an increase in total transmission and distribution connected capacity, and an increase in peak demand*

Source: Aurora Energy Research

High hydrogen: Higher demand leads to higher wholesale costs compared to the Base Case, offset by reduced spending in other areas of the system

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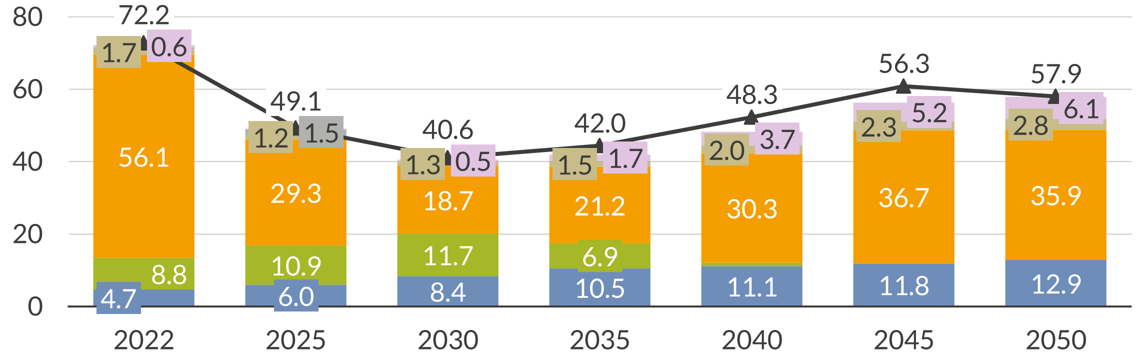
Annual total system costs
£ billion



1 **Wholesale market**
- *Wholesale production costs are higher than the Base Case as total power demand is higher, driven by increased electrolysis. Wholesale margins are also higher, driven by the increase in total demand, however top prices are lower, as H2-fired assets which receive fuel subsidies set the price more often*

2 **Balancing mechanism**
- *Balancing mechanism prices fall compared to the Base Case as higher deployment of H2 peakers, which receive fuel price subsidies, increases the availability of flexible capacity to deliver upward balancing*

3 **Capacity market**
- *Lower build out of batteries and gas peaking assets decreases capacity market spend compared to the Base Case*

4 **Subsidies**
- *Renewable subsidies are similar to the Base Case due to similar deployment of subsidised renwable capacity*
- *New build non-RES subsidies are slightly lower as there is less need low carbon flexible capcity deployment*

5 **Hydrogen market**
- *Hydrogen market costs are lower than the Base Case, as hydrogen prices receive additional subsidies in this scenario*

6 **Network costs**
- *Distribution costs are slightly lower driven by reduced deployment of distribution connected batteries and peakers*
- *Transmission costs remain consistent with the Base Case*

Advantages
- **Utilising additional hydrogen in the power sector results in lower balancing mechanism, capacity market, and network expenditure**

Disadvantages
- **Utilising additional hydrogen in the power sector increases wholesale market costs as the additional power demand required for hydrogen fuel production increases power sector demand**

Source: Aurora Energy Research

No H2 for Heat: Lower total demand reduces wholesale costs while capacity market costs are higher as more flexible capacity is needed

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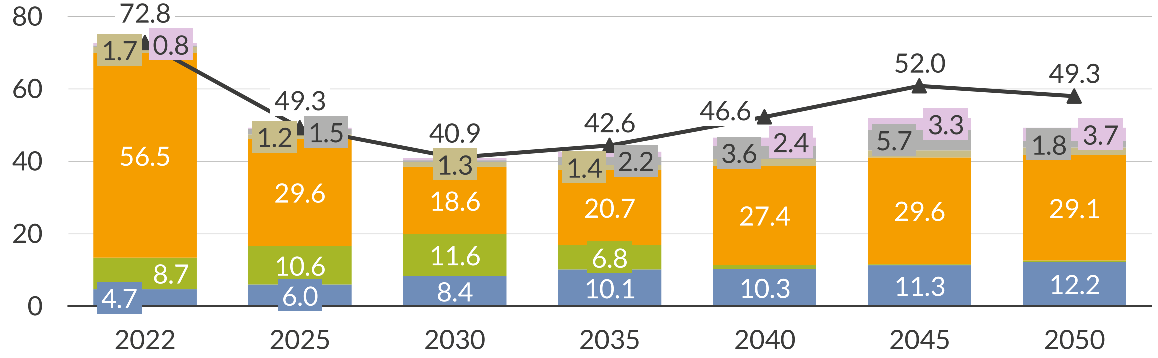
Annual total system costs

£ billion



1 Wholesale market

- *Lower total demand leads to lower wholesale market spend compared to the Base Case, as more expensive peaking assets are pushed out of merit more often, reducing top prices*
- *Wholesale margins are lower than the Base Case, as lower total annual demand results in lower cost plants setting the marginal price more often*

2 Balancing mechanism

- *Balancing mechanism spend is lower than the Base Case, as higher deployment of flexible capacities reduces balancing prices compared to the Base Case*

3 Capacity market

- *Higher peak demand in the 2040s in this scenario means more peaking capacity is procured via the capacity market, leading to higher costs than the Base Case*

4 Subsidies

- *Total subsidy spend for both renewable and non-renewable forms of low carbon capacity are broadly aligned with the Base Case*

5 Hydrogen market

- *H2 market spend is reduced compared to the Base Case as less H2 is produced for use in heating*

6 Network costs

- *Distribution costs are broadly aligned with the Base Case, as reduced distribution capacity deployment is offset by higher peak demand*
- *Transmission costs are lower compared to the Base Case, as there is less transmission capacity built in this scenario*

Advantages

- **Lower total demand leads to lower wholesale market costs, and reduced total capacity leads to lower network costs**

Disadvantages

- **Higher capacity market costs in the 2040s are required to support additional flexible capacity needed to meet higher peak demand**

Source: Aurora Energy Research

High Flexible Demand: Wholesale costs are reduced by demand shifting and capacity market spend is lower as less firm capacity needs to be procured

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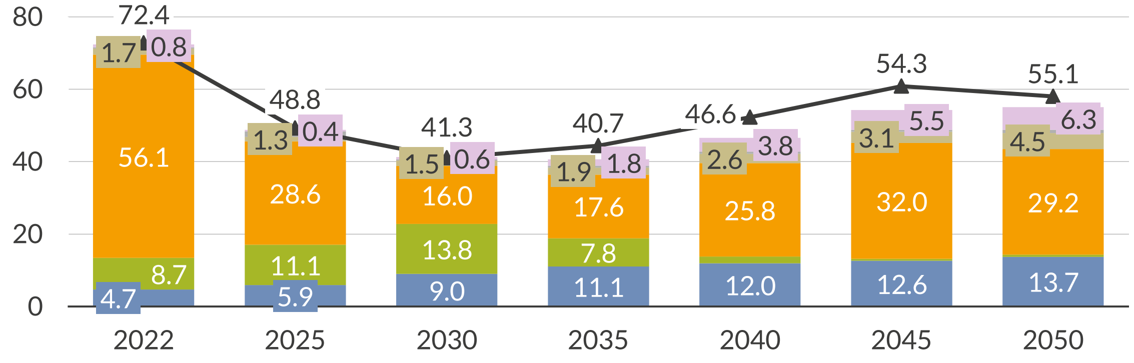
Annual total system costs[1]

£ billion



1 Wholesale market

- *Wholesale production costs are lower compared to the Base Case as lower peak demand means high-cost peaking assets are pushed out of merit more often*
- *Wholesale margins are lower due to lower peak demand and less expensive assets setting the marginal prices*

2 Balancing mechanism

- *Balancing mechanism prices are extremely high in some periods as the system almost reaches loss of balancing load, which means ultra-high cost turn up actions are required in some periods, increasing balancing costs*

3 Capacity market

- *Lower peak demand means less capacity needs to be procured via the capacity market to ensure security of supply standards are met, decreasing spend*

4 Subsidies

- *New build non-RES subsidies are higher as additional support is needed for peaking and hydrogen assets which generate less in the wholesale market due to overall lower demand*

5 Hydrogen market

- *No change compared to the Base Case as H2 prices and demand are unchanged*

6 Network costs

- *Distribution costs are similar to the Base Case*
- *Higher transmission costs are driven by higher boundary transfer capacity requirements*

Advantages

- **More demand shifting leads to lower demand peaks and lower wholesale market spend**
- **Less flexible capacity deployment is required, decreasing capacity market costs**

Disadvantages

- **Higher balancing mechanism costs are driven by ultra-high balancing actions being taken as the system approaches loss of balancing load**
- **Higher levels of subsidies are required for low carbon flexible capacity**

1) The cost of smarter heat pumps and EVs are not captured in this analysis.

Source: Aurora Energy Research

Low Flexible Demand: Total system costs are significantly higher due to the additional investment required for increased flexible capacity deployment

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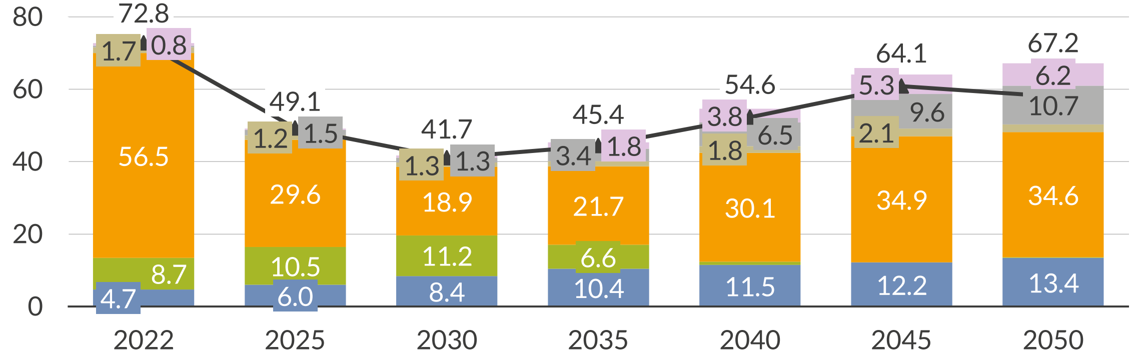
Annual total system costs

£ billion



1 Wholesale market
- *Wholesale production costs are higher compared to the Base Case as more expensive peaking assets generate more often to meet higher peak demand*

2 Balancing mechanism
- *Balancing mechanism prices are lower as there is significant deployment of flexible capacity in this scenario, primarily batteries, which can provide upwards and downwards balancing actions, reducing costs*

3 Capacity market
- *Capacity market costs are higher in this scenario compared to the Base Case, as high peak demand requires higher build out of dispatchable capacity, especially batteries and peakers, which takes place with support from the capacity market*

4 Subsidies
- *New build non-RES subsidies are lower as a result of higher revenues obtained in the capacity and wholesale market*

5 Hydrogen market
- *No change compared to the Base Case as H2 prices and demand are unchanged*

6 Network costs
- *Distribution costs are higher compared to the Base Case, as peak demand is higher, and more distribution connected batteries are deployed*

Advantages
- Balancing costs and subsidy costs are lower

Disadvantages
- Decreases in demand shifting and higher peak demand leads to higher wholesale market costs
- Higher peak demand also increases distribution network costs
- Increased capacity market spend is required to support the deployment of additional firm capacity required to ensure security of supply

Source: Aurora Energy Research

Low Interconnector: Lower balancing mechanism costs are offset by higher capacity market spend

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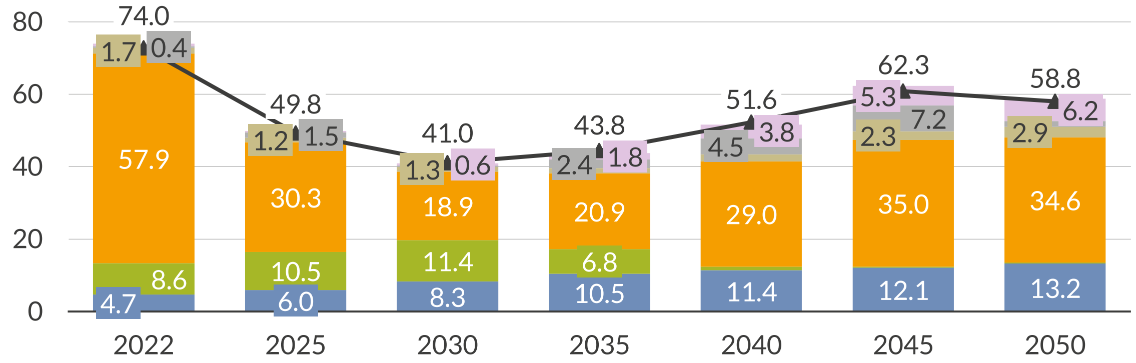
Annual total system costs

£ billion



1 Wholesale market

- *Wholesale production costs are higher as interconnector imports are reduced, meaning additional high-cost peaking assets are deployed to meet peak demand*
- *However, wholesale margins are lower, resulting in total wholesale market spend that is comparable to the Base Case, as reduced renewable deployment combined with additional thermal generation reduces the inframarginal rents that can be achieved*

2 Balancing mechanism

- *Balancing mechanism costs are slightly lower as renewable generation volumes are lower*

3 Capacity market

- *Capacity market costs are higher in this scenario compared to the Base Case, as reduced wholesale margins increases the "missing money" problem for thermal assets, increasing the capacity market price required to keep capacity available*

4 Subsidies

- *Total subsidy spend is comparable to the Base Case*

5 Hydrogen market

- *No change compared to the Base Case as H2 prices and demand are unchanged*

6 Network costs

- *Network charges are comparable to the Base Case, as total transmission and distribution connected capacity build out is similar in both scenarios*

Advantages

- **Balancing market costs are slightly reduced**

Disadvantages

- **Higher capacity market spend is required to offset lower wholesale margins**

Source: Aurora Energy Research

Unabated Gas Ban: Additional build out of Gas CCS leads to lower wholesale market costs but requires higher capacity market spend

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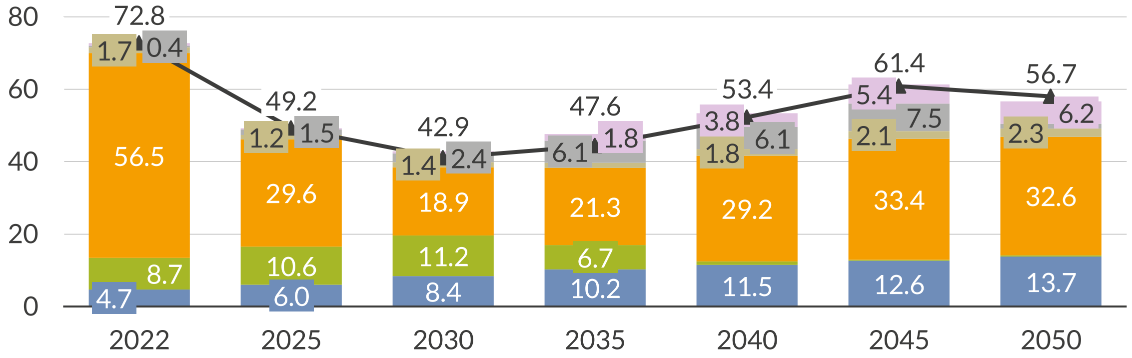
Annual total system costs

£ billion



1 Wholesale market

- *Wholesale production costs are higher as CCGT and gas peaking generation is replaced by Gas CCS and hydrogen assets*
- *Wholesale margins are lower, resulting in decreased wholesale market spend, as increased firm capacity reduces wholesale market prices*

2 Balancing mechanism

- *Balancing mechanism prices are slightly lower as more batteries deploy*

3 Capacity market

- *Significantly higher build out of Gas CCS increases capacity market spend as plants do not achieve sufficient revenues in the wholesale market to cover costs*

4 Subsidies

- *Renewable subsidies are similar due to similar levels renewable generation requiring subsidy payments*
- *Non-renewables subsidies are also comparable to the Base Case*

5 Hydrogen market

- *No change compared to the Base Case as H2 prices and demand are unchanged*

6 Network costs

- *Distribution costs are comparable to the Base Case*
- *Transmission costs are higher due to the overbuild of CCS capacity replacing CCGTs to ensure security of supply, which are transmission connected*

Advantages

- **Deployment of more batteries to balance the system leads to lower investment needed in Balancing mechanism**

Disadvantages

- **Additional Gas CCS plants require capacity market payments to remain on the system, increasing capacity costs**

Source: Aurora Energy Research

High Nuclear: 16GW additional nuclear capacity decreases wholesale and balancing mechanism spend but requires higher subsidies to build

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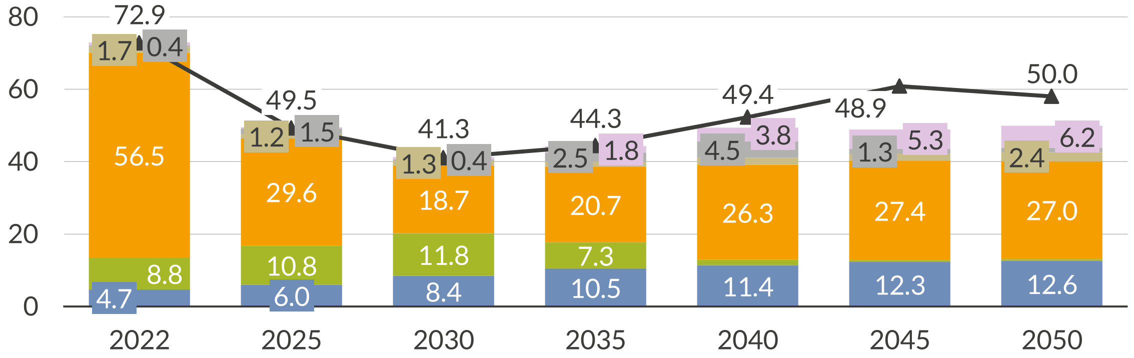
Annual total system costs

£ billion



1 Wholesale market
- *Wholesale production costs are slightly lower as there is less reliance on more expensive gas peaking generation*
- *Wholesale margins are lower as additional firm nuclear generation places downward pressure on wholesale market prices*

2 Balancing mechanism
- *Lower net imbalance volumes driven by less variable renewable generation*
- *Balancing mechanism prices are slightly lower due to smaller imbalance volumes*

3 Capacity market
- *Slightly lower due to less deployment of batteries and peaking assets*

4 Subsidies
- *New build non-RES subsidies are higher as the high CAPEX costs for nuclear typically means costs cannot be reccovered through the wholesale market and additional support is required for deployment. However, high costs for new build nuclear are partially offset by a reduced need for support for other forms of low carbon capacity*

5 Hydrogen market
- *No change compared to the Base Case as H2 prices and demand are unchanged*

6 Network costs
- *Total network costs are broadly aligned with the Base Case*

Advantages
- **Lower wholesale market prices due to nuclear pushing gas peaking and CCGT generation out of merit**
- **Less variable renewable generation means imbalance volumes are reduced**

Disadvantages
- **Higher subsidies required to support nuclear deployment**

Source: Aurora Energy Research

Agenda

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The High Nuclear scenario requires the highest levels of upfront CAPEX expenditure

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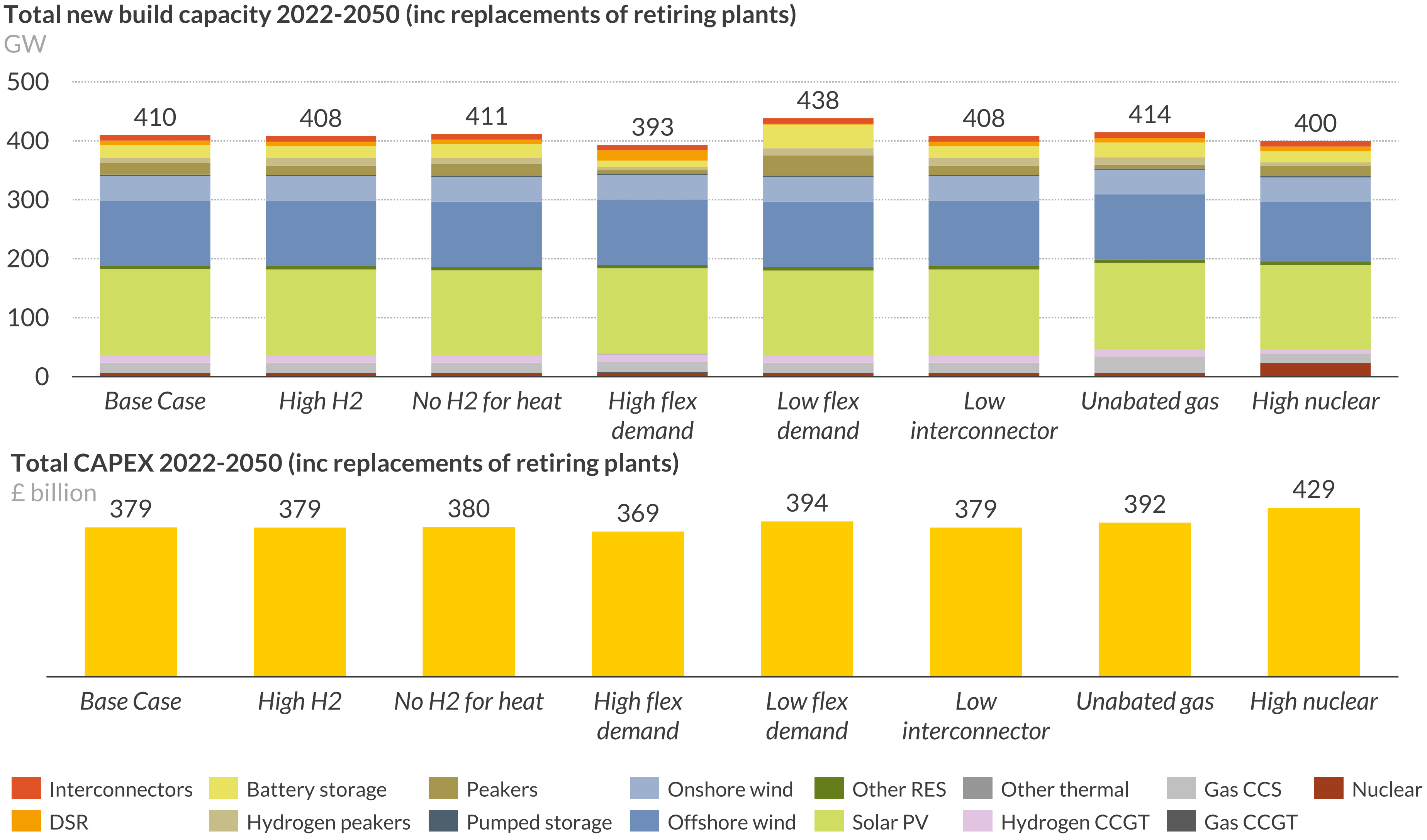

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

Source: Aurora Energy Research

CAPEX costs are recovered via the wholesale market, the balancing mechanism, ancillary services and subsidy mechanisms (including the capacity market).

- **High Flexible Demand** has the least new build flexible capacity as peak demand is lower and therefore less investment in new builds, reducing CAPEX costs compared to the Base Case.
- **Low Flexible Demand** requires additional battery and peaking capacity to be deployed to meet higher peak demand, leading to higher total CAPEX costs than the Base Case.
- **Unabated Gas Ban** needs £13 billion more CAPEX expenditure compared to the Base Case, to support the deployment of additional Gas CCS capacity.
- **High Nuclear** sees an extra 16GW nuclear by 2050, requiring £50 billion extra CAPEX spend compared to the Base Case.

Average annual system costs range from £46.2 billion/a to £52.9 billion/a between scenarios

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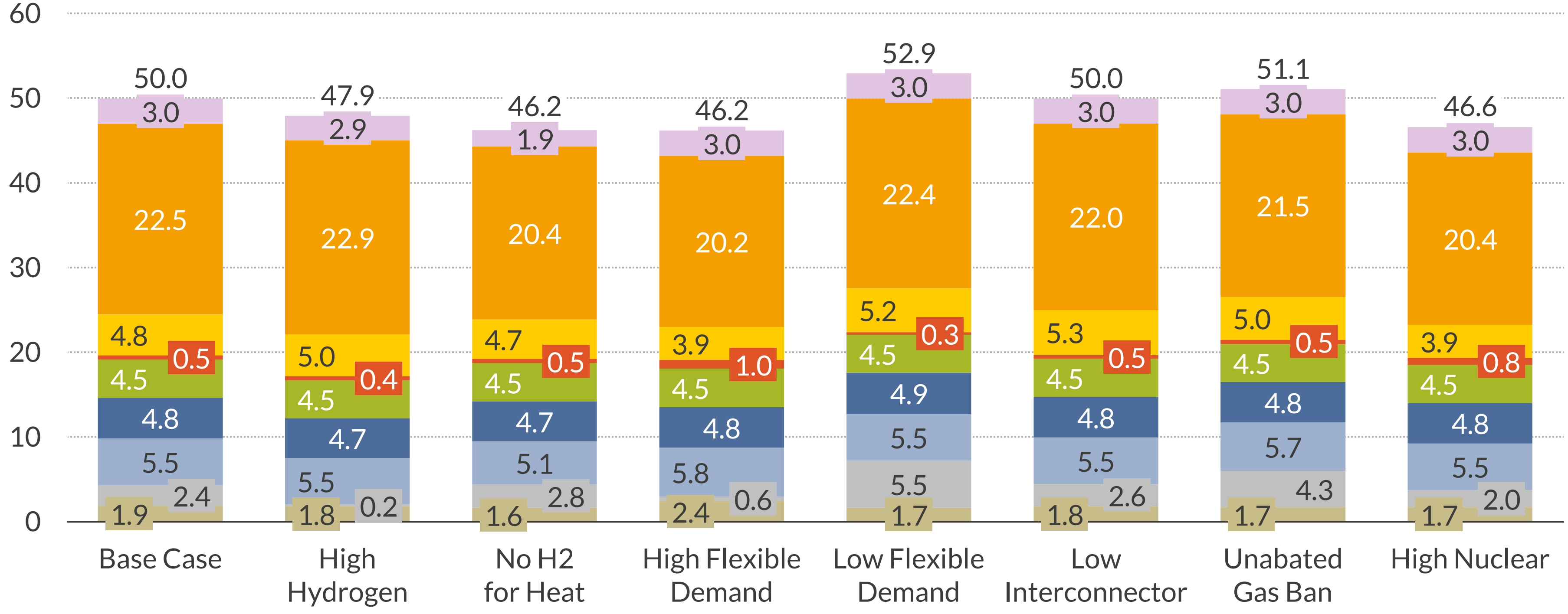
Average annual system costs (2025 – 2050)
£ billion

Note the 2022-2024 period is excluded from these calculations as current high gas prices distort results



Average consumer costs 2025-2050 (Excluding Climate Levy, Supplier Charges & VAT)
£/MWh

Base Case	High Hydrogen	No H2 for Heat	High Flexible Demand	Low Flexible Demand	Low Interconnector	Unabated Gas Ban	High Nuclear
99	94	98	92	104	98	101	93

Hydrogen Market; Wholesale Production costs; RES subsidies; Transmission; Balancing Market
Wholesale Margins; New build non RES subsidies; Distribution; Capacity Market

1) Excluding Climate Levy, Supplier charges & VAT

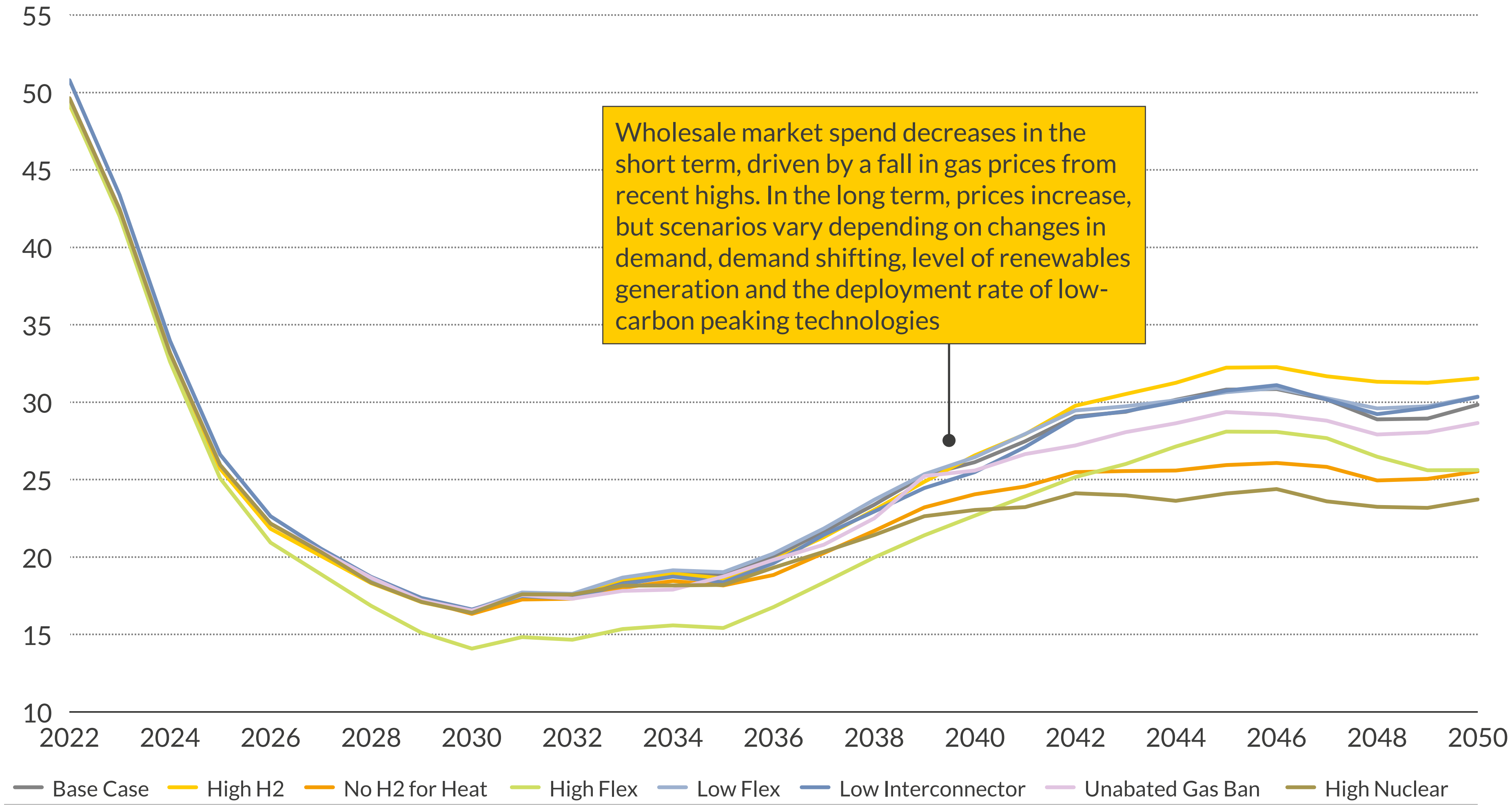
Source: Aurora Energy Research

Overview of cost items

- **Wholesale market spending** is the key driver of total system spend across scenarios and is directly linked to the supply mix.
- **Hydrogen market spending** reflect the cost to produce hydrogen and **does not** reflect the total cost of the hydrogen system.
- **RES and Non-RES subsidies** reflect the additional costs of rolling out low carbon capacity that would not deploy on a merchant basis.
- **Infrastructure costs** are driven by levels of new-build capacity, the proximity of supply to demand and the connection type (transmission vs distribution) for capacity mixes.

Wholesale market costs: Less RES curtailment and less peaking generation in High Flexible Demand leads to lower wholesale costs

Annual wholesale costs
£bn



Source: Aurora Energy Research

- Lower demand in **No Hydrogen for Heat** decreases wholesale margins as the price is set by high SRMC assets less often.
- **High Flexible Demand** significantly decreases wholesale spend as lower peak demand results in less reliance on gas peakers.
- **Low Flexible Demand** has higher wholesale production costs as higher peak demand means high cost peakers set the price more often.
- Wholesale market production costs and margins are high in the **Low Interconnector** scenario as reduced imports results in higher cost thermal plants setting the wholesale price more often.
- Wholesale spend for **High Nuclear** is lower, particularly in the 2040s, as firm nuclear generation pushes higher SRMC assets out of merit.

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

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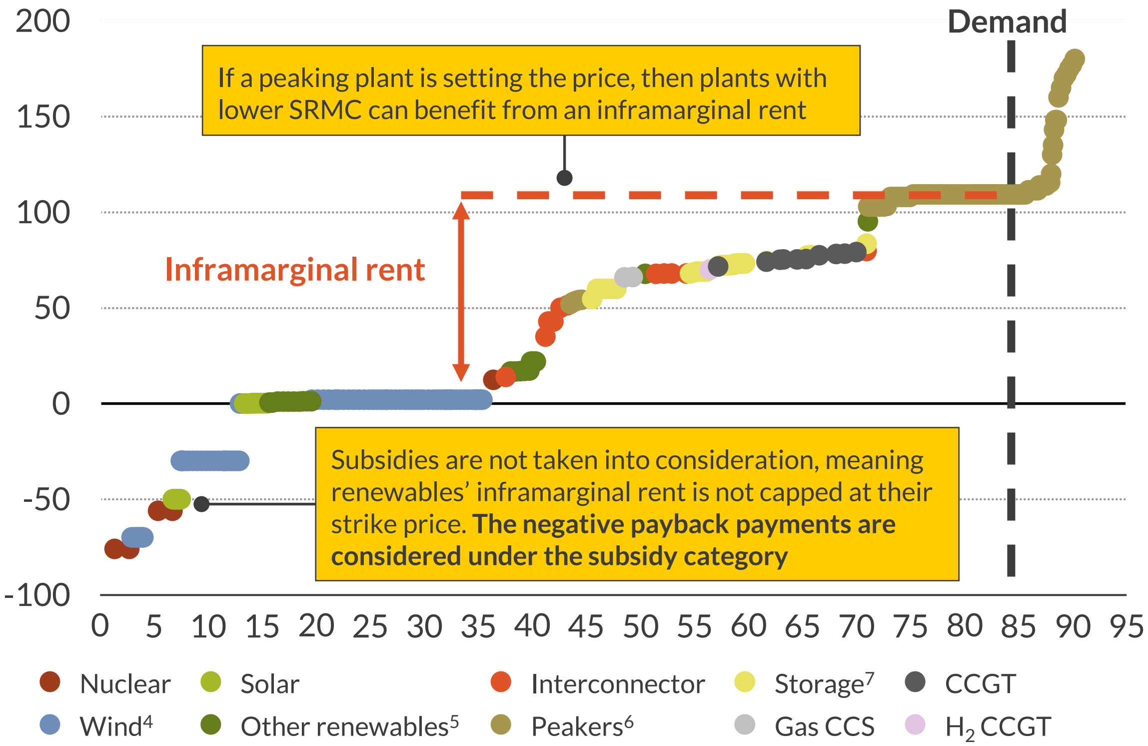
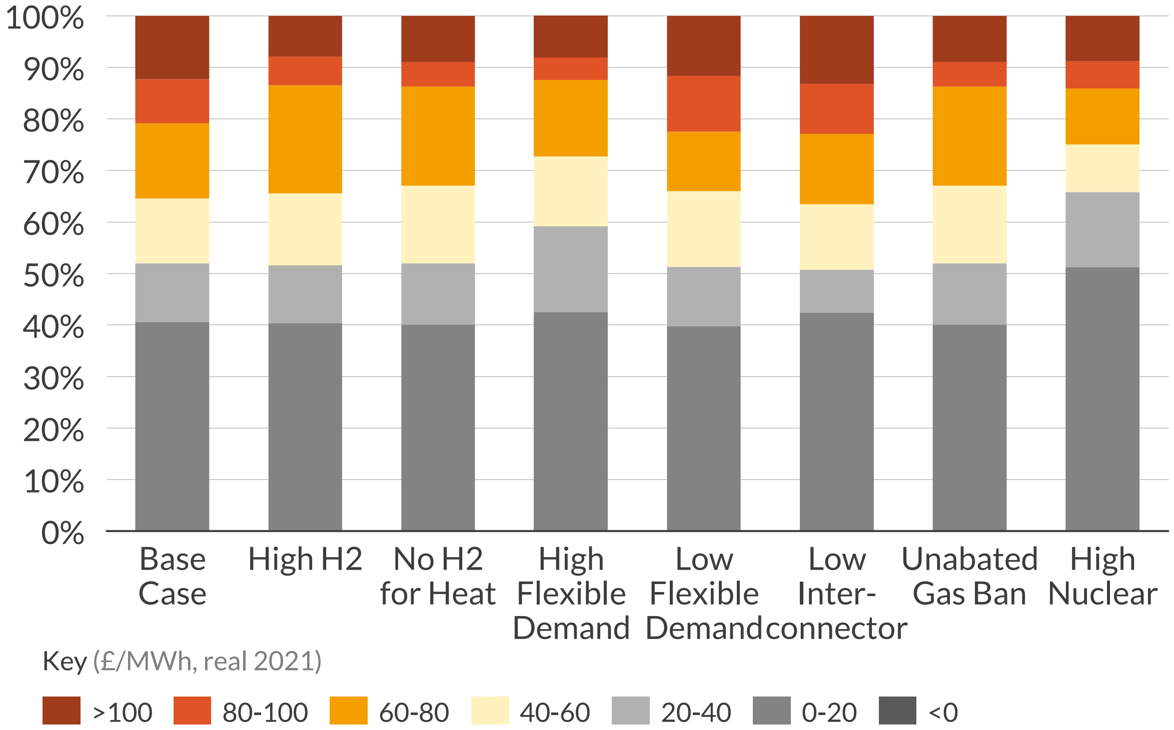
Short run marginal costs
£/MWh



Frequency distribution of the electricity price in 2050
%



- 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

- Higher frequency of top prices, where peakers set the price more often, leads to higher wholesale margins for other technologies
- More RES and nuclear generation leads to higher frequency of low prices and significantly lower wholesale margins

1) Summer is defined as April – September and winter as October to March. 2) Assuming 54% HHV efficiency. 3) Wind and solar contributions are accounted for by their load factors, not their de-rating factor. 4) Includes both offshore and onshore wind. 5) includes biomass, EfW, hydro and CHP. 6) Includes OCGT, recips, H2 peakers, gas peakers and DSR. 7) Includes batteries and pumped storage.

Source: Aurora Energy Research

Balancing Mechanism Costs: More renewable generation and lower flexible capacity deployment leads to higher balancing costs

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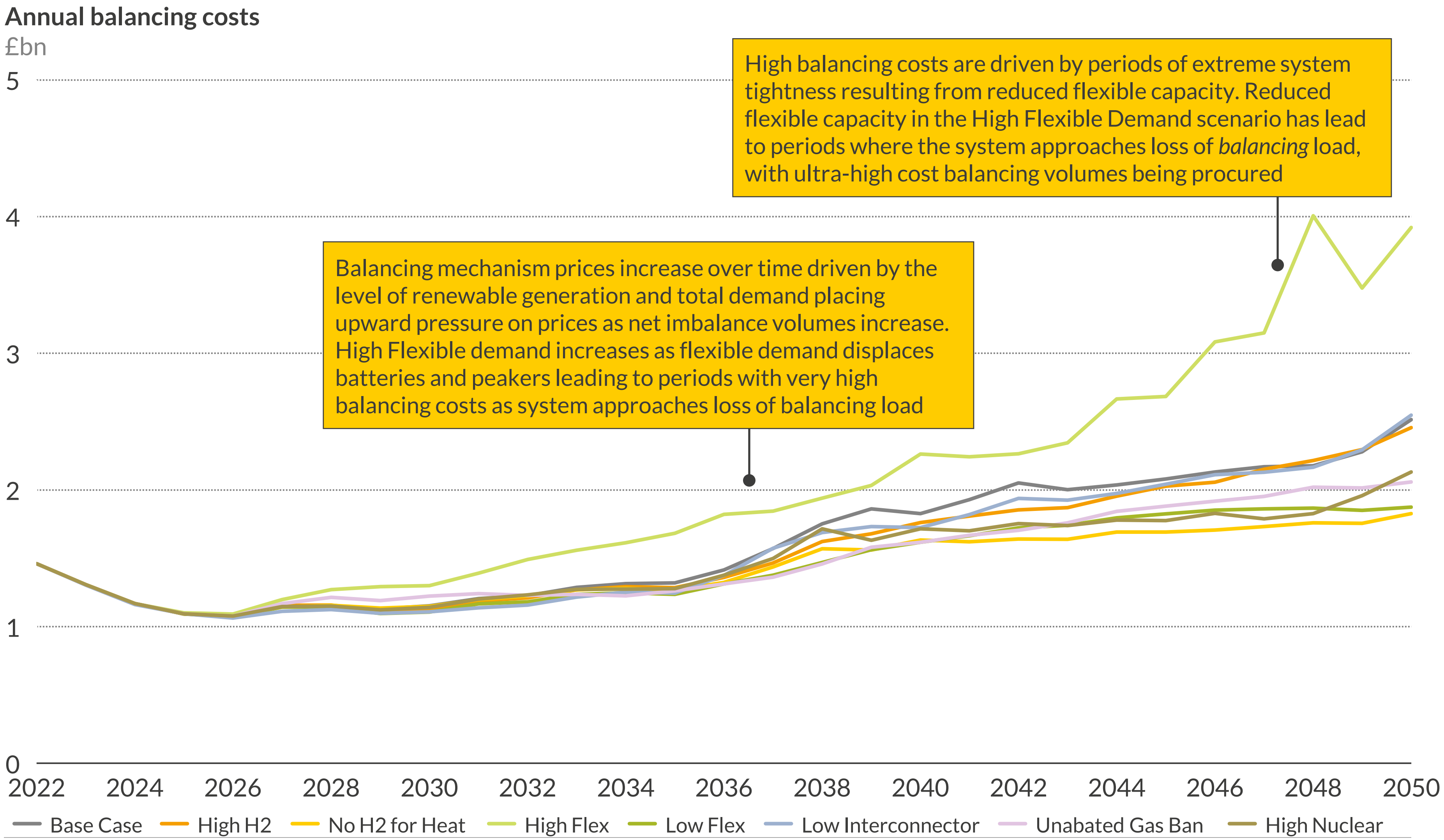

Source: Aurora Energy Research

- **High Flexible Demand** has a high Balancing mechanism spend as less flexible capacity deploys, as it is displaced by flexible demand. Flexible demand technologies are less able to provide balancing actions and the system approaches loss of balancing load in the 2040s, with ultra high cost balancing actions being procured, pushing up costs.
- **Low Flexible Demand** and **No Hydrogen for Heating** have lower Balancing mechanism costs as balancing prices are reduced by increased deployment of batteries and peakers in these scenarios.

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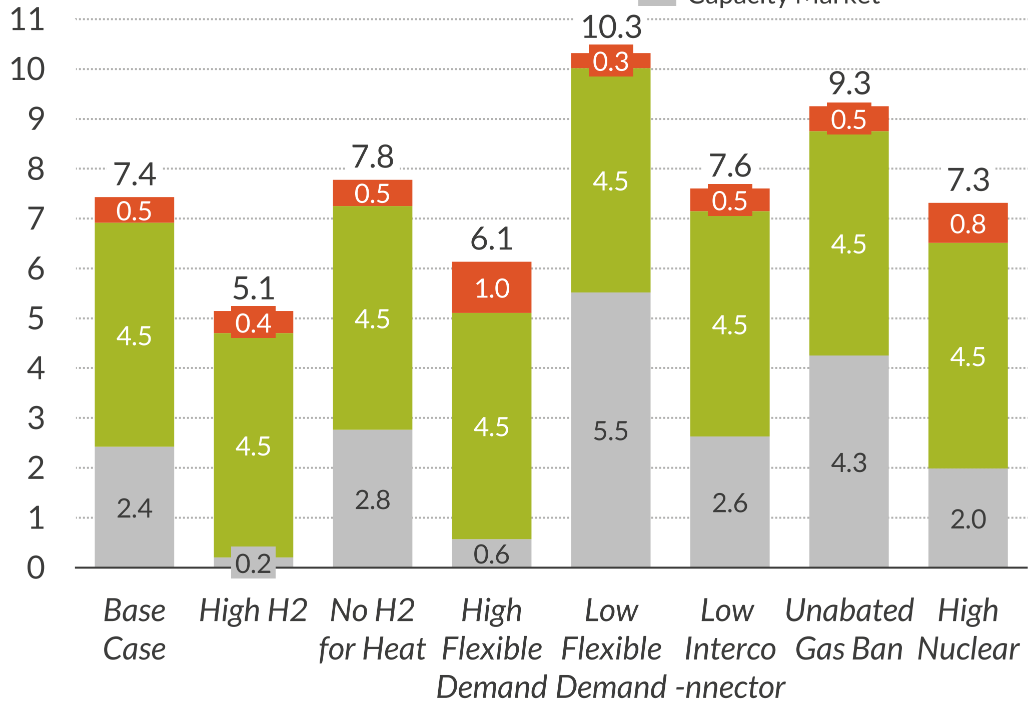
Subsidies: Reduced flexible demand increases capacity market expenditure, whilst renewable subsidies are similar in all scenarios

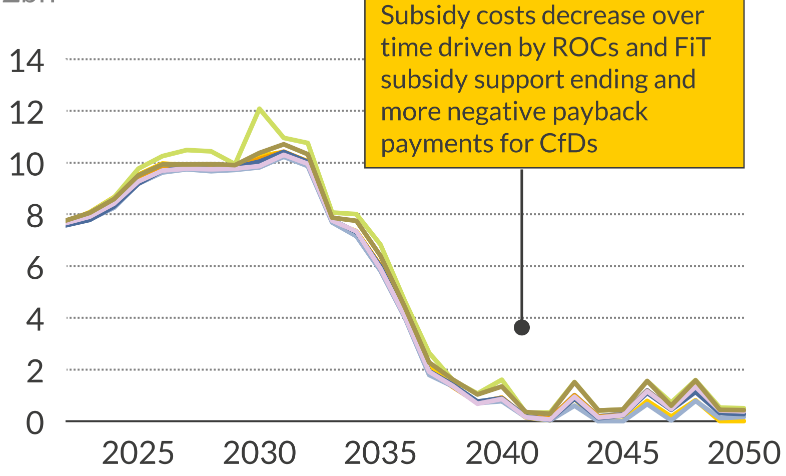
Average subsidy costs (2025 – 2050)
£bn



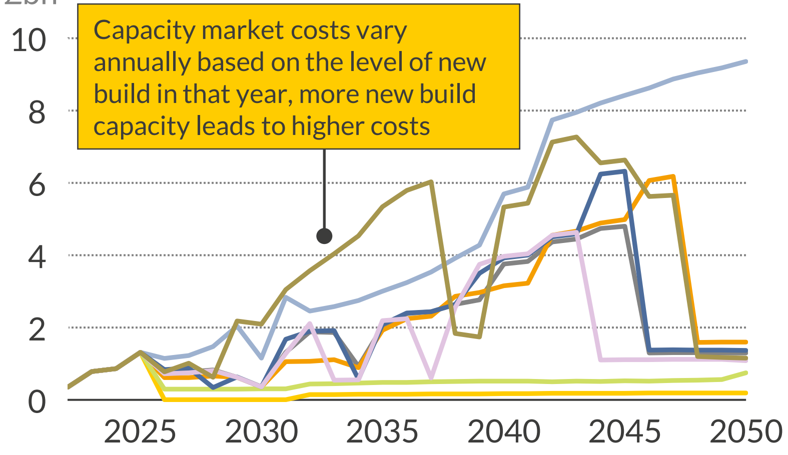
Average subsidy costs, as seen on consumer bills (2025 – 2050)
£/MWh

Base Case	High H2	No H2 for Heat	High Flexible Demand	Low Flexible Demand	Low Interconnector	Unabated Gas Ban	High Nuclear
17	13	18	15	22	17	20	17

Annual subsidy costs
£bn



Annual capacity market costs
£bn



Base Case — No H2 for Heat — Low Flex — Unabated Gas Ban
High H2 — High Flex — Low Interconnector — High Nuclear

Source: Aurora Energy Research

Non-Renewable Subsidies
This is dependent on the amount of non-renewable new build capacity required, and is typically needed to support forms of low-carbon flexibility like CCS or Pumped storage.

- **High Flexible Demand** requires a high level of non-renewable subsidy spend as flexible demand displaces flexible and thermal assets in wholesale market, meaning these assets need additional support to deploy.
- **Low flexible demand** requires the lowest non-renewable subsidies as higher wholesale and capacity market prices reduce the additional need for support for these technologies.

Capacity Market
Driven by endogenous new build capacity deployment. Scenarios with reduced flexible demand require significantly higher flexible capacity deployment.

Network costs: As all scenarios see similar levels of capacity build out, there is little variation between network costs across scenarios

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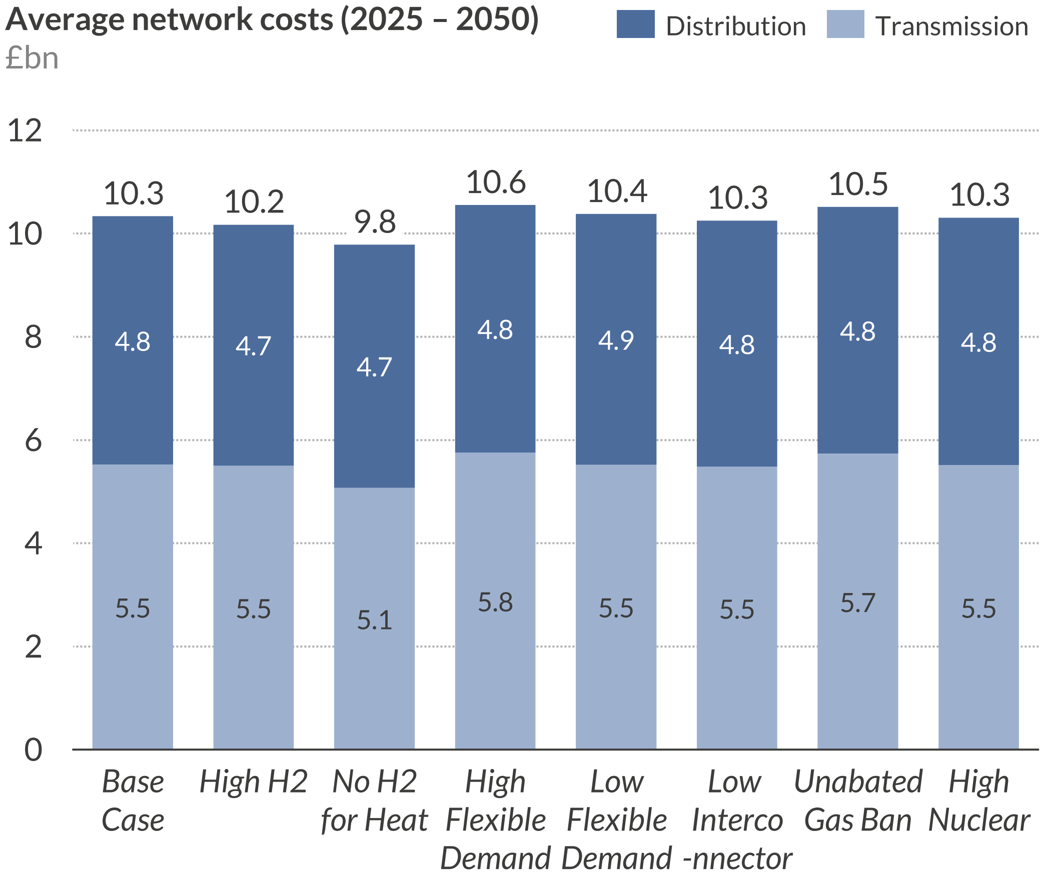
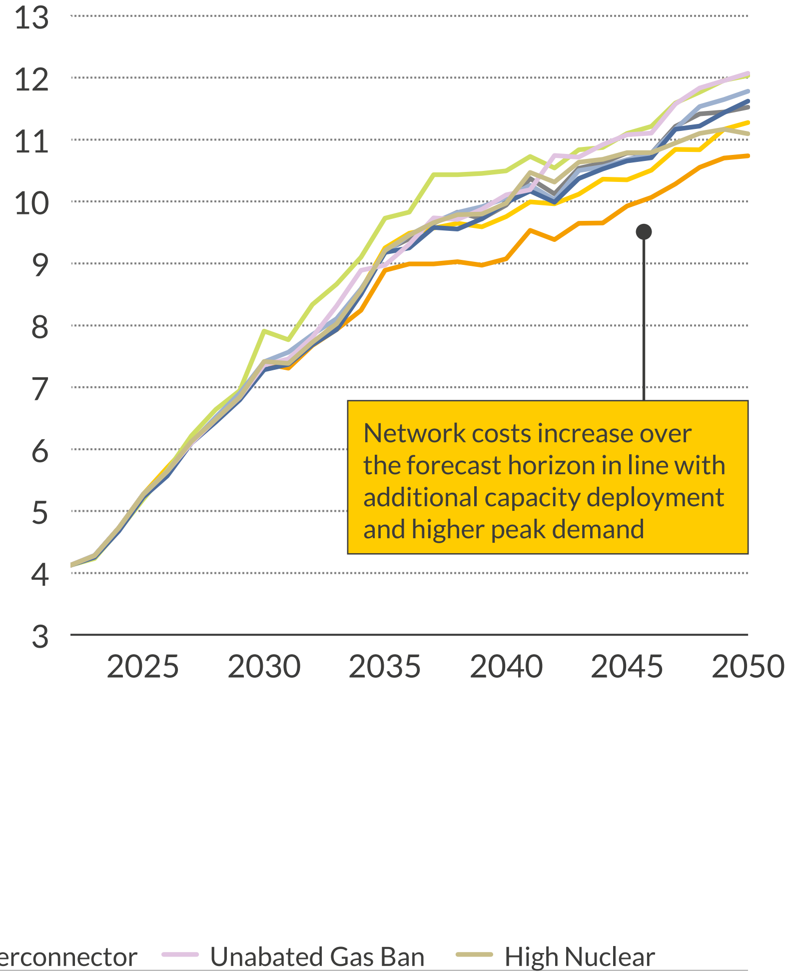
Average network costs (2025 – 2050)
£bn



Annual network costs
£bn



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

Base Case	High H2	No H2 for Heat	High Flexible Demand	Low Flexible Demand	Low Interconnector	Unabated Gas Ban	High Nuclear
20	20	20	21	20	20	20	20

Investment in networks is needed to support a larger power system, with more dispersed capacities and higher peak demand .

As all scenarios see similar levels of capacity build out, there is little variation between network costs across scenarios.

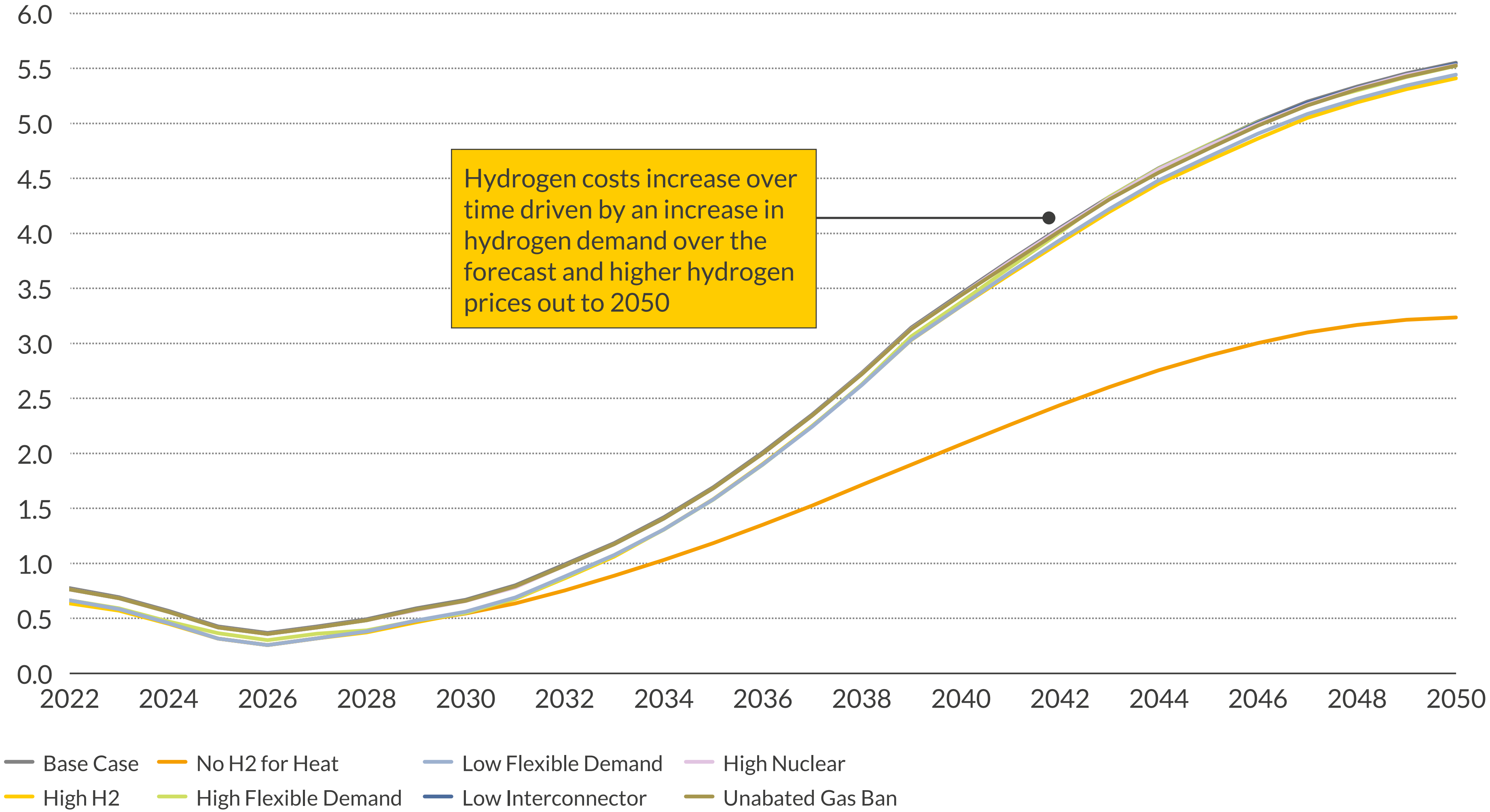
No H2 for Heat
Lowest total transmission and distribution costs are seen in the No Hydrogen for Heating scenario due to significantly lower demand resulting in a smaller sized power sector overall.

Source: Aurora Energy Research

Hydrogen costs: Demand and hydrogen prices are consistent across most scenarios leading to similar hydrogen costs

Annual hydrogen costs

£bn



1) Hydrogen costs reflect the cost of producing hydrogen and **does not** reflect the total cost of the hydrogen system, any hydrogen specific subsidies, or the costs to consumers of having hydrogen supplied for heating

Source: Aurora Energy Research

Base Case

The hydrogen price and demand are input assumptions into the model. The same assumptions are used across all scenarios except High Hydrogen and No Hydrogen for Heat, meaning total hydrogen costs are the same across most scenarios. Note hydrogen costs here do not account for the costs of a hydrogen system or potential future subsidies.

High Hydrogen

Hydrogen demand is slightly higher as more power demand is met from hydrogen-fired assets. However, prices are lower, which mitigates the increase in demand and results in lower hydrogen market spend.

No H2 for Heat

No hydrogen boilers are assumed in this scenario, decreasing the total demand for hydrogen. The hydrogen price remains consistent with Base Case resulting in lower hydrogen market spend.

Agenda

Average consumer costs range from £125/MWh to £140/MWh between scenarios

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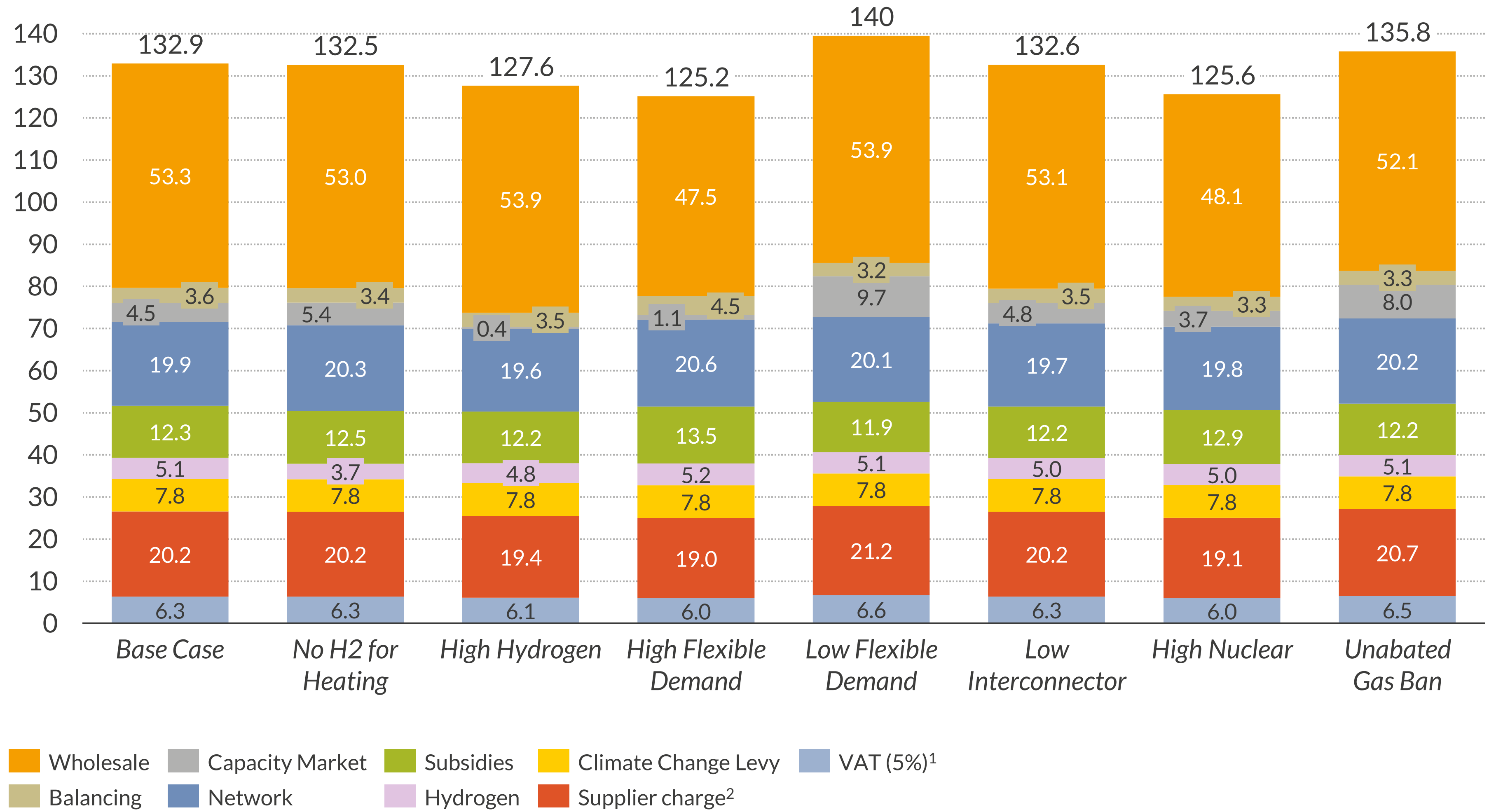
Average consumer bills (2025 – 2050)

£/MWh



1) VAT is a government tax on services and goods. VAT is relatively similar across all scenarios as homeowners are required to pay 5% on consumer electricity bills.2) Supplier charges are similar as assumption is 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.

Source: Aurora Energy Research

- The lowest average consumer bills are seen in the High Flexible Demand and High Nuclear scenario; reduced bills are driven by lower wholesale market costs.
- The highest bills are seen in the Low Flexible Demand and Unabated Gas Ban scenarios, driven by higher capacity market spend.
- Consumer bills reflect power system costs only and do not account for the cost of deploying demand (e.g. EVs, electrified heating systems, electrolysers). However, whilst the flexibility of demand changes between some scenarios, the overall rates of deployment of demand side technologies are similar.

Agenda

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A highly renewable system could be vulnerable to extreme weather events and additional flexible capacity may be needed to ensure security of supply

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Extreme weather data produced by the Met Office has been used to the impact of a prolonged wind drought on the system. For three of our scenarios (Base Case, Unabated Gas Ban and High Nuclear) we modelled the impact of these events, assuming the system builds sufficient capacity to ensure loss of load standards are met

The Met Office produced datasets for use by energy modellers

- The Met Office has published data for use in energy analysis, setting out potential extreme events that would impact weather dependent generation across Europe and considered their probability under different climate change scenarios
- The methodology used describes weather events of differing durations on a numerical index, considering wind speeds, temperature and other key data points, mapped on a gridded dataset over NW Europe
- The Met Office then applied statistical analysis to quantify the probability of these events occurring
- This methodology is used to analyse both historical and forward climate simulation data sets to identify instances of significant events

We select a weather event that would impact GBs generation mix

- A weather event was selected from the Met Office data to capture the case that would have the most significant impact on GB's system:
  - i. Wind drought event
  - ii. 1 in 100 year event
  - iii. 2 degrees heating scenario
  - iv. Long duration
- The longest duration of wind droughts was selected to test the vulnerability of our scenarios to extreme weather

Wind generation data is translated to an annual load factor series

- Using historical data, we compared wind speeds to aggregated GB wind load factors
- We then developed a curve-of-best-fit between load factors and wind speeds
- This allowed us to derive load factors from specific wind speeds from Met Office extreme weather event data
- As the Met Office provided daily wind speeds, this produced daily load factor datasets
- Aurora then produced half hourly datasets by calibrating daily load factors from Met Office data to historical half hourly load factor patterns
- **The load factor profiles implicitly assume a wind drought every year**

We re-run certain scenarios to test the impact of a wind drought on the system

- The model was then re-run to allow new capacity build decisions to be made, to ensure that loss of load standards were met in any year
- **In reality, an extreme weather event would not be expected to happen in every year, and so in many years the system would have built excess capacity. However, as capacity cannot be planned around single events the results represent the overall level of capacity that would be needed in any given year if an extreme event is being planned for**
- Three core scenarios were tested:
  1. Base Case
  2. High Nuclear
  3. Unabated Gas Ban

Sources: Aurora Energy Research, Met Office

Extreme Weather Year: To ensure security of supply in the event of a long duration wind drought, more peakers are required

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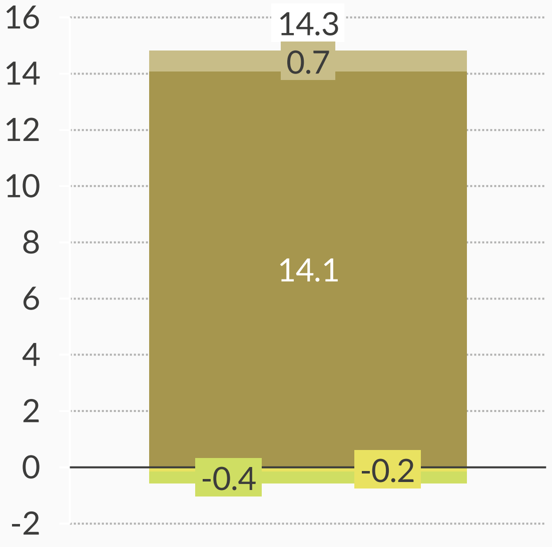
Scenario Overview

- If an extreme weather event is planned for, by 2050 an additional 14.8 GW gas peaker, H2 peaker and OCGT capacity will be required, compared to the Base Case where no extreme event is planned for, in order to ensure security of supply standards are met.
- However, this capacity would not be needed in every year, and so would generally operate at low load factors.
- *If* an extreme weather event takes place in 2050, an additional 47.4 TWH Gas CCS and 16.8 twH H2 CCGT generation, combined with 36.5 TWh additional interconnector imports, and additional biomass/BECCS generation, would be required to meet the shortfall, compared to the Base Case scenario where no extreme event occurs.
- This scenario has lower wind generation across the whole year but there is a 25 day period in February which has extremely low wind generation.
- **A long duration wind drought would lead to higher carbon emissions in that year due as wind generation is replaced by Gas CCS and gas peaking generation. However, this increase in emissions would not be expected in every year as the additional thermal generation is only needed during the wind drought.**
- If an extreme weather event occurred in 2050, it is unlikely that decarbonisation targets would be met in that year.

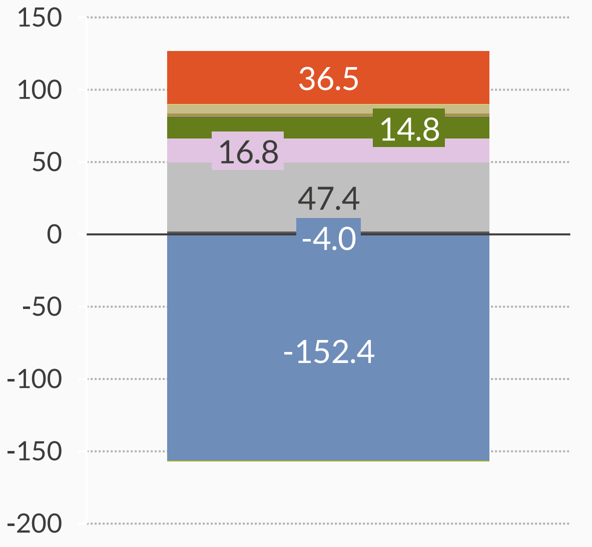
2050 capacity delta, compared to Base Case (No EWY)

GW



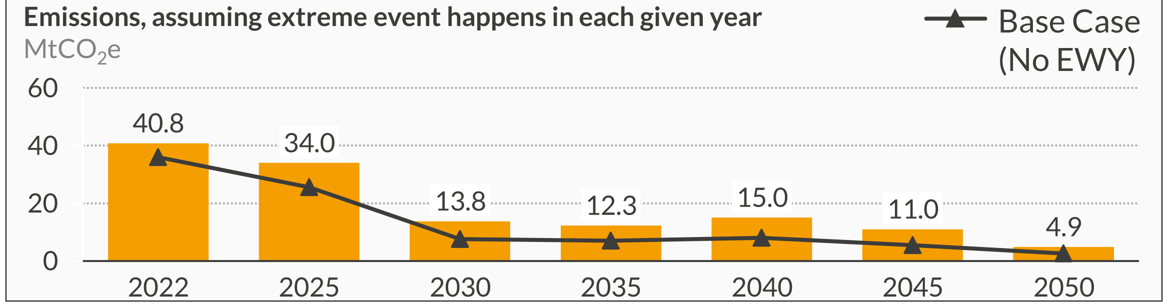
2050 generation delta compared to Base Case (No EWY), during weather event

TWh



Emissions, assuming extreme event happens in each given year

$MtCO_2e$



Interconnectors | Battery storage | Unabated peakers[1] | Onshore wind | Other RES[2] | Other thermal[3] | Gas CCS | Nuclear

DSR | Hydrogen peakers | Pumped storage | Offshore wind | Solar | Hydrogen CCGT | Gas CCGT

1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

Sources: Aurora Energy Research, BEIS, CCC

Extreme Weather Year: Higher investment is required in order to deploy more flexible peaking capacity to meet demand in the event of low wind periods

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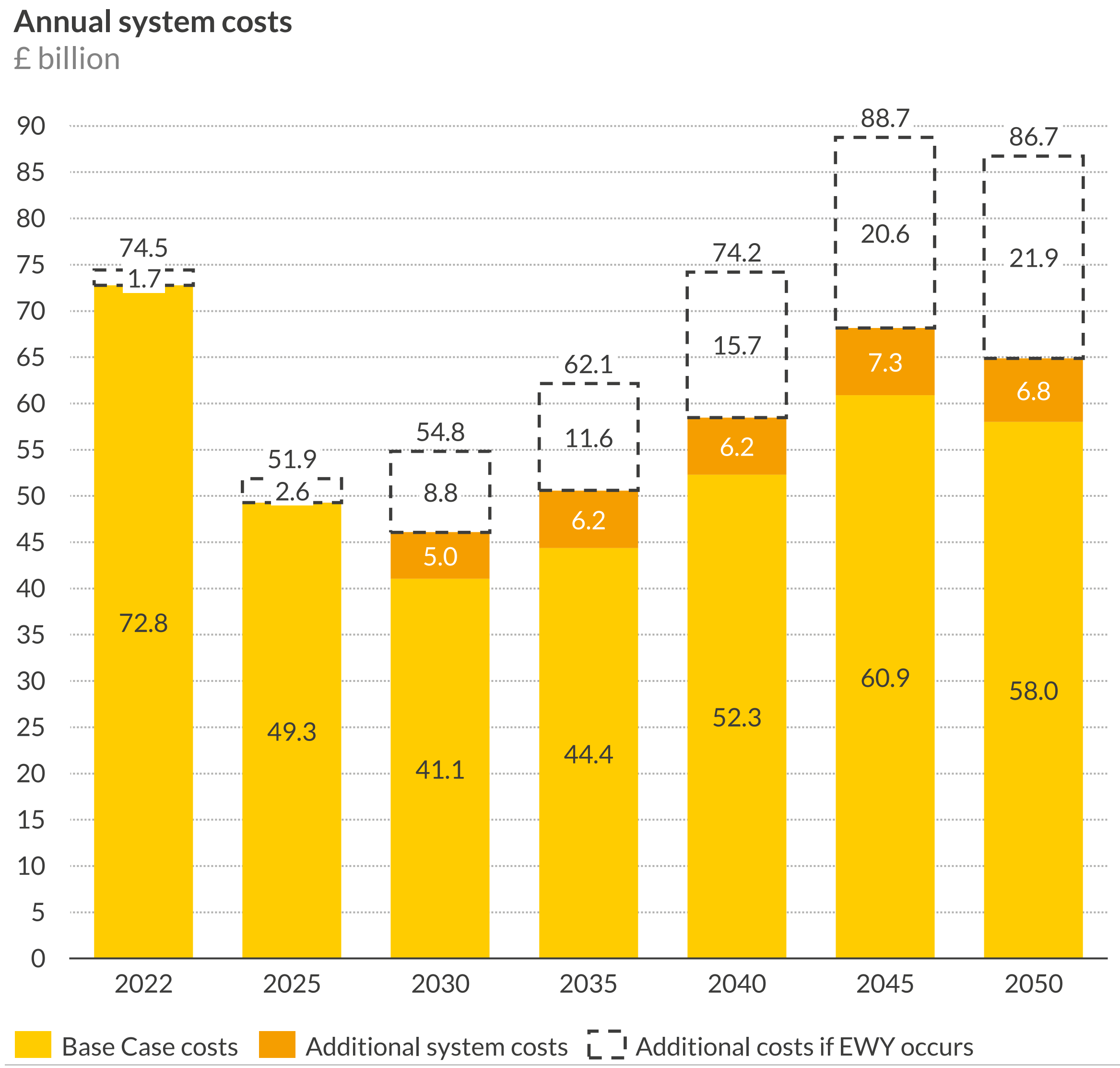


Base Case costs

- Base Case costs reflect the total system costs for the Base Case scenario, where no planning for an extreme weather event takes place, and so no additional capacity is deployed to ensure security of supply is maintained.

Additional system costs

- Additional system costs reflect the costs associated with ensuring sufficient capacity is deployed to met security of supply standards in the event a wind drought occurs, including additional network and capacity market costs, but does not include the costs of this capacity generating to meet demand if the extreme event actually takes place.
- Additional system spending would be required every year, in order to maintain the system in preparation for an extreme event.
- Investment is primarily required to support the deployment of gas peakers.
- Costs increase over time as wind generation and demand increase, meaning in the event of a low wind period more peaking generation would be needed.

Additional costs if EWY occurs

- **These costs reflect the additional system costs that would be incurred in any given year IF there is a wind drought in that year. These costs would not be expected to be incurred every year.**
- The additional cost is driven by higher wholesale costs, driven by increased thermal generation during the extreme event.
- Costs rise to 2050 as more flexible generation is needed to meet demand.

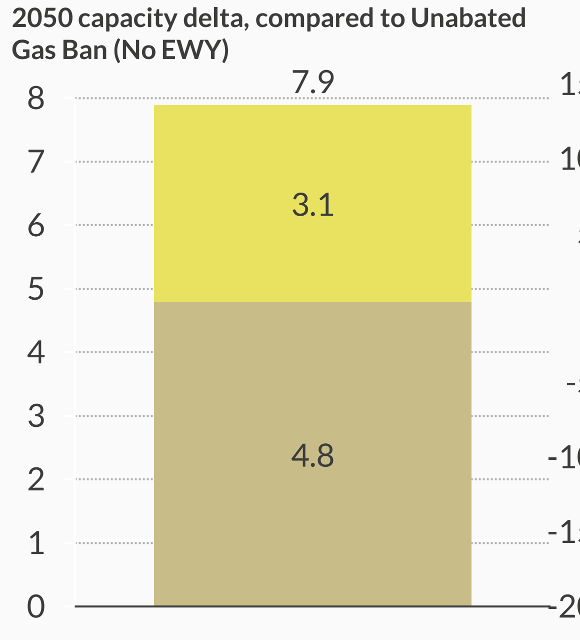
Source: Aurora Energy Researcch

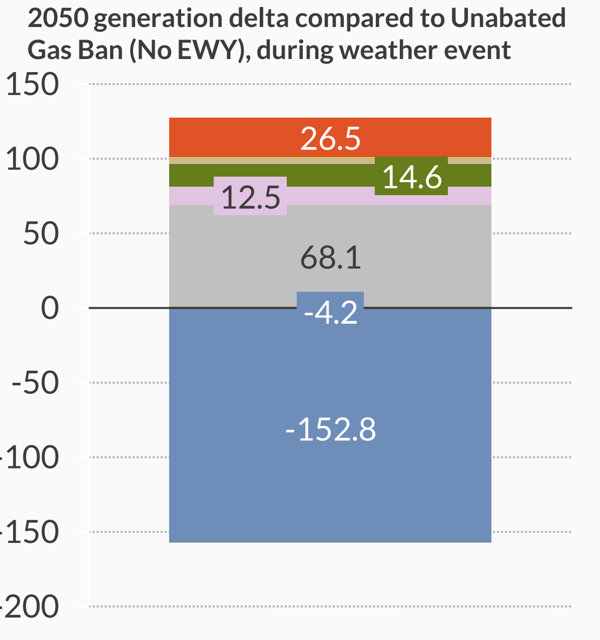
Unabated Gas Ban / Extreme Weather: A ban on unabated gas would be effective at preventing higher emissions during a wind drought

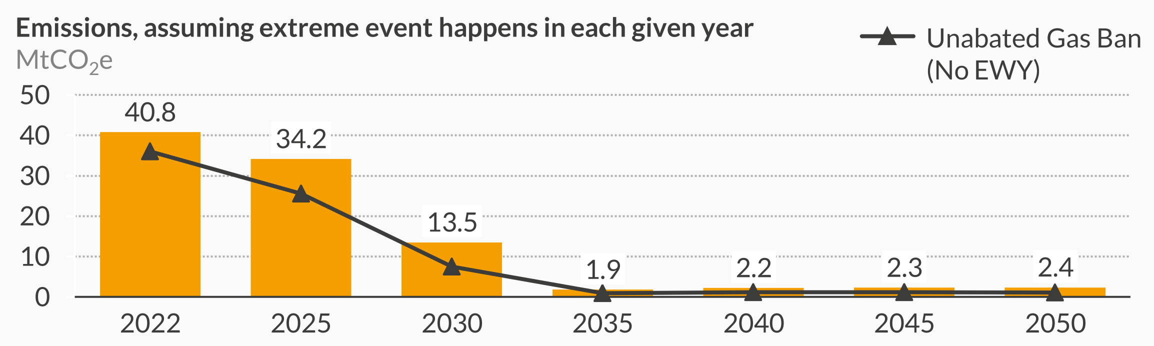
AURORA

Scenario Overview

- If unabated gas is banned by 2035, Gas CCS plants would be required to ensure security of supply. Gas CCS provides low carbon firm capacity which is available to dispatch during a wind drought, meaning less additional capacity is required if planning for this extreme event. If an extreme weather event takes place, demand can be met without a significant emissions increase.
- Gas CCS must be deployed (either through new builds or conversion of existing plants, or a combination) in the early 2030s to ensure there is sufficient capacity available by 2035. These plants will then be online until c.2060. As renewable deployment continues to grow, load factors for Gas CCS decrease, meaning there is capacity available in the event of a wind drought.
- However, if the extreme event is planned for, an additional 3.1 GW batteries and 4.8 GW H2 peakers would build by 2050 on top of the Gas CCS, to guarantee security of supply.
- *If* the extreme weather event occurs in 2050, 157 TWh wind generation (onshore & offshore) would be replaced by 68.1 TWh Gas CCS, 12.5 TWh H2 CCGT and 26.5 TWh imports.
- Post-2035, even in years an extreme weather event took place, emissions would remain below 2.5 $MtCO_2/a$.







1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

Source: Aurora Energy Research

Unabated Gas Ban / Extreme Weather: An unabated gas ban would mean lower additional system costs are needed to prepare the system for extreme weather

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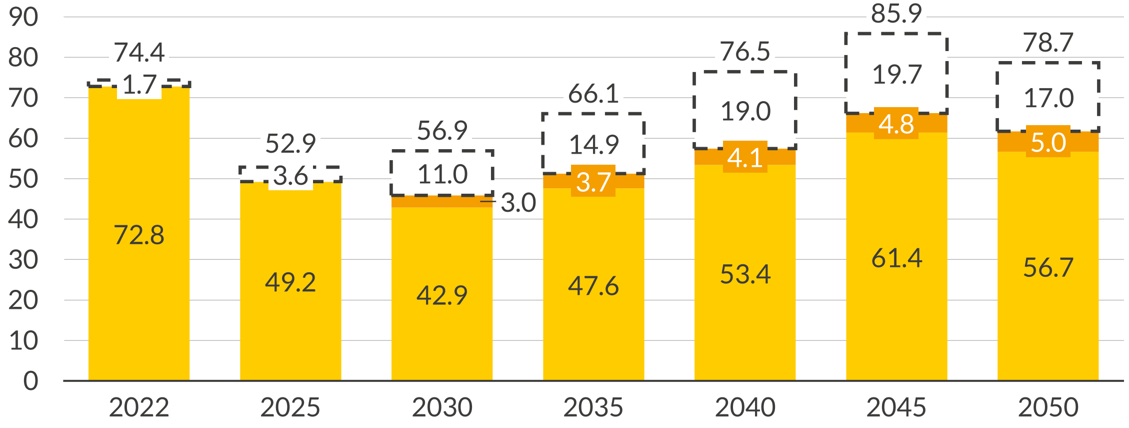
Annual system costs

£ billion



Advantages

- **In the event of extreme low wind, additional system costs are lower in the long term, relative to the Base Case EWY.**
- **As this scenario already sees additional CCS capacity and H2 peakers by 2035, less investment in new build capacity beyond 2040 is required to meet demand in an extreme weather event.**

Disadvantages

- **Additional costs required if an extreme weather year occurs are high, particularly during the 2030's as additional fuel costs are required (in the Base Case EWY, more imports take place).**

Unabated Gas Ban costs | Additional system costs | Addiitonal costs if EWY occurs

Unabated Gas Ban costs

- Unabated Gas Ban costs reflects the Unabated Gas Ban scenario annual system costs, not including additional capacity procurement to plan for an extreme weather event.
- Costs increase to 2050 and are higher than the Base Case, as support is needed for CCS deployment.

Additional system costs

- Additional system costs reflect the costs of ensuring security of supply standards are met in if a wind drought occurs.
- If planning for an extreme weather event, additional investment is needed to support the deployment of H2 peaking and battery assets in this scenario.
- Costs are lower, relative to the Base Case EWY, as in the Unabated Gas Ban EWY case additional Gas CCS plants can ramp up for extended periods of time and so less additional capacity procurement is required.

Additional costs if EWY occurs

- **These costs reflect the additional system costs incurred IF there is a wind drought. These costs would not be expected to be incurred every year.**
- The additional costs result from additional fuel costs of operating abated thermal plants at higher load factors for a protracted periods. Costs increase over the forecast horizon, as demand is higher, which would have to be meet in the event of the drought.

Source: Aurora Energy Research

High Nuclear / Extreme Weather: High nuclear deployment requires less additional flexible capacity as nuclear can meet demand in low wind periods

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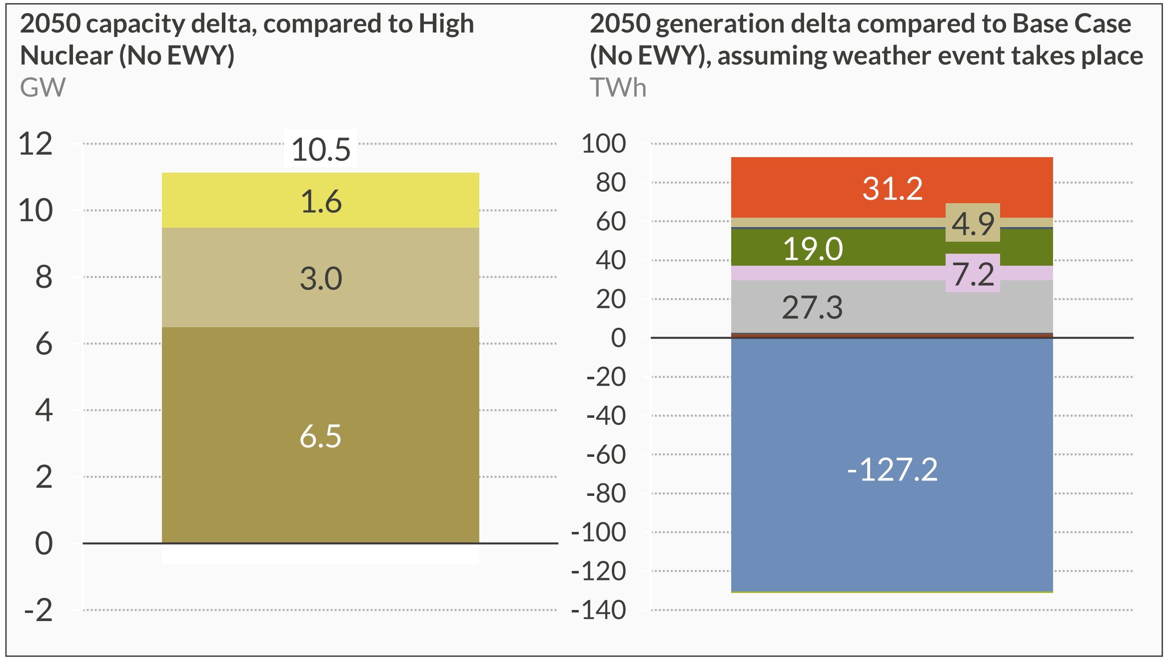
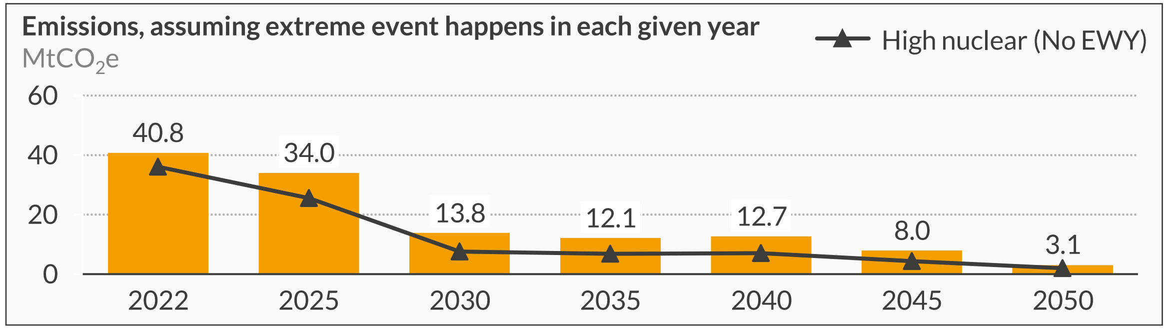
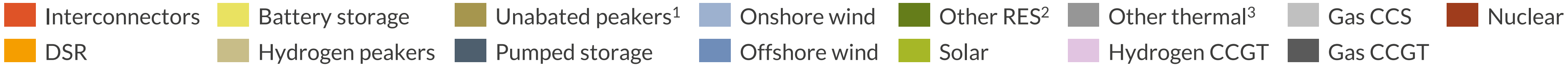
Scenario Overview

- High nuclear deployment means less low carbon flexible capacity needs to be procured in preparation for potential extreme weather events compared to the Base Case EWY scenario, however emissions targets are not met in years extreme weather events takes place.
- High nuclear deployment reduces the amount of additional flexible capacity that needs to be built if an extreme weather event is planned for, with 10.5 GW additional battery and peaking capacity required by 2050. This represents a reduction in additional peaking capacity compared to the 14.3 GW required in the Base Case EWY, but is higher than the additional 7.9GW required in the Unabated Gas Ban EWY.
- If the extreme event takes place in 2050, 127 TWh offshore wind generation will be replaced by a combination of Gas CCS, other RES (biomass, BECCs, hydro, EfW), H2 CCGTs and H2 peakers, and an increase in net imports. As nuclear is already operating as baseload, nuclear generation does not ramp up during the weather event.
- In this scenario, if an extreme weather event does take place in any given year, emissions targets will not be meet, due to the reliance on additional unabated thermal peakers to maintain security of supply.





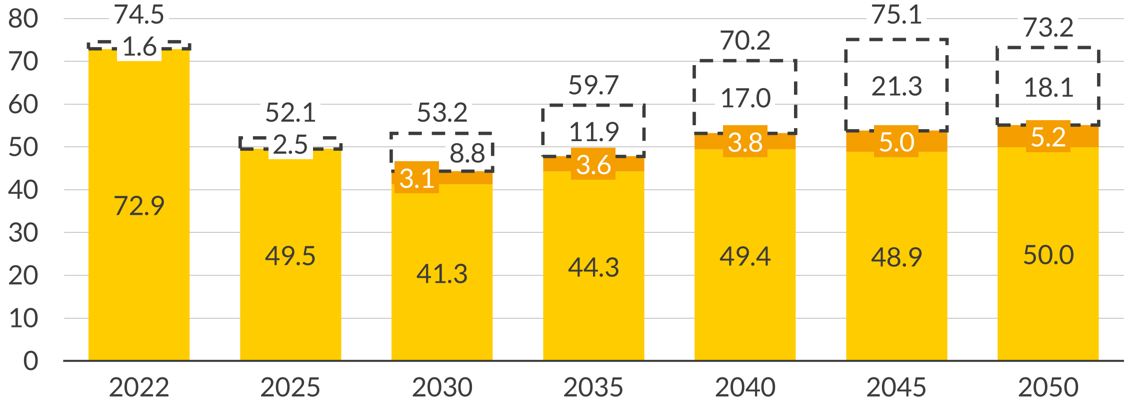


1) Unabated peakers includes gas recips, OCGTs & oil peakers 2) Other Res includes hydro, BECCS, biomass & EfW 3) Other thermal includes CHP

Source: Aurora Energy Research

High Nuclear / Extreme Weather: Some additional investment is required in a High Nuclear scenario to support additional hydrogen peaking assets

Annual system costs
£ billion



Advantages

- **In the event of extreme low wind, additional system costs are lower relative to the Base Case EWY scenario as increased firm nuclear generation reduces the residual demand that must be met in these periods, meaning less additional peaking capacity is required**

Disadvantages

- **Additional hydrogen peakers are required in addition to nuclear capacity**

High Nuclear costs | Additional system costs | Additional costs if EWY occurs

High Nuclear costs

- High Nuclear costs reflects the High Nuclear scenario annual system costs, not including additional capacity procurement to plan for an extreme weather event.

Additional system costs

- Additional system costs reflect the costs of ensuring security of supply standards are met in if a wind drought occurs.
- Investment is required to support deployment of peaking and battery assets in this scenario but costs are lower relative to the Base Case as less additional capacity is required.
- Costs increase over time as wind generation and demand increase, meaning in the event of a low wind period more peaking generation would be needed.

Additional costs if EWY occurs

- **These costs reflect the additional system costs incurred IF there is a wind drought. These costs would not be expected to be incurred every year.**
- The additional costs result from additional fuel costs of operating abated thermal plants at higher load factors for a protracted periods. Costs increase over the forecast horizon, as demand is higher, which would have to be meet in the event of the drought.

Source: Aurora Energy Research

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