The future of dispatchable generation in GB

Commissioned by:
The Independent Generators' Group (IGG)

13 December 2021

Agenda

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Context

- In October 2021, the Government announced a target to fully decarbonise the power sector by 2035. Whilst the Government's ambitions are clear, the pathways and policies required to achieve this target are not yet fully defined.
- GB's operational dispatchable capacity currently stands at 56 GW, which delivered over 50% of GB's electricity in 2020, contributing heavily to both GB's energy security and affordability for consumers. The lack of clarity on how Net Zero targets are to be achieved threatens the future of dispatchable capacity and thus GB's energy objectives.
- Most of the existing dispatchable capacity fleet is made up of ageing thermal assets which are coming towards the end of their operational life and require critical investment decisions in the near term to secure their future.
- In the current climate, this investment is not assured, as investors' confidence has been dented by the lack of clarity on the assets' future in a decarbonised system, as well as by the practicalities surrounding conversion to CCUS and/or hydrogen and their route to market.
- This report has been produced by Aurora Energy Research ("Aurora") for The Independent Generators' Group (IGG) to identify and explore the potential solutions or pathways for flexible, dispatchable generation to achieve Net Zero in GB within the timeframes outlined by government.
- This report is intended for approved recipients only and may not be forwarded or distributed. Receipt of this report does not confer reliance, nor the acceptance of liability by Aurora Energy Research. Other legal conditions apply as outlined at the back of this document.
- For the purpose of this report, dispatchable generation is defined as asset classes with the following properties:
  - Ability to produce more or less power on demand and is not linked to weather
  - Economics which incentivise dispatch in response to system needs
  - Duration sufficient to contribute to security of supply

Sources: Aurora Energy Research, IGG

The future of dispatchable generation in GB: Key insights and executive summary

Key insights from the analysis

30 GW

de-rated low carbon dispatchable capacity needed by 2035 to meet system requirements and achieve Net Zero power

Immediate policy action

required to meet 2035 decarbonisation targets with low carbon dispatchable generation

14 $MtCO_2e$

reduction in power sector emissions by 2035 as a result of policy supported dispatchable generation

£54 billion

savings in total system costs through to 2050 relative to a system with policy inaction

Executive summary of the report

- Net Zero power by 2035 will require c.30 GW of de-rated low carbon dispatchable capacity. Without action to incentivise investments, **there will be an undersupply of this critical dispatchable capacity** in the near future as the power sector decarbonises.
- Existing thermal assets are **critical for providing system security and flexibility requirements** to support the low-carbon transition up to 2035 and in abated form (CCS, Hydrogen, BECCS) will form a large-scale part of the Net Zero system in 2035 and beyond.
- Asset owners will require clear signals for investments, and **critical decisions will be required as early as in the 2020s** to ensure sufficient capacity is decarbonised and available by 2035. No clear policy pathway currently exists for these assets so **they may have to close**.
- **CCS and hydrogen are the front-running decarbonisation pathways** available for existing thermal assets and conversions will depend on **key considerations of policy support, costs, timing and location**.
- Current policies have secured firm capacity and reduced emissions but **need to adapt for Net Zero.** The proposed dispatchable power agreement (DPA) will further **require a suite of complementary policies and holistically reformed markets** to incentivise low carbon capacity.
- **Immediate policy action is required** to incentivise the deployment of low carbon dispatchable generation. Without policy action, **the UK may miss its decarbonisation targets** by c.14 $MtCO_2e$ in 2035 and incur a £54bn increase in total system costs.
- Conversion of existing assets are currently the **most cost effective option** and a lack of policy support for them could **cost at least 65% more in investments** to ensure security of supply.

Source: Aurora Energy Research

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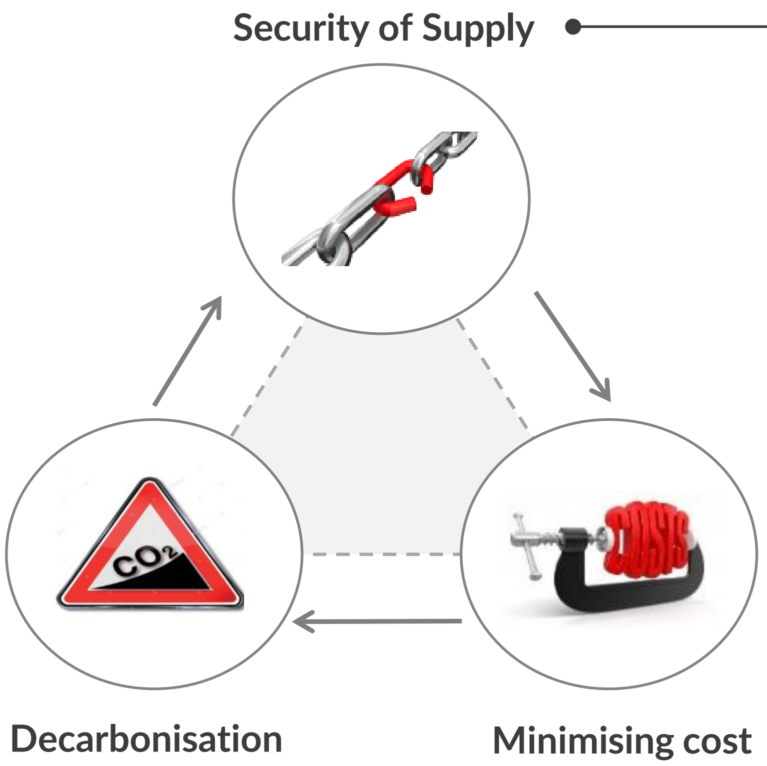
UK energy policy aims to meet three main objectives including security of supply which entails specific system requirements

UK energy policy aims to meet three overarching objectives, often referred to as the 'energy trilemma'. Of the three, ensuring security of supply is most complex with several key requirements.



1 Firm Capacity

- Dispatchable assets are those that are able to produce power more or less on-demand, without being linked to the weather, and whose economics incentivise them to produce in response to the system needs. In addition, they have sufficient duration to have a sustained contribution to energy security at peak times.

2 Flexible Dispatchable Capacity

- Capacities that are able to ramp flexibly (i.e rapid warm start times) will be required to guarantee energy security as more intermittent renewable capacity comes on the system. This could see output vary significantly between settlement periods, increasing the need for balancing actions.

3 Frequency Response and Inertia[1]

- Deviations in system frequency can be detrimental to the grid resulting in blackouts. Inertia is critical to prevent sharp movements in system frequency and helps make the grid resilient to energy imbalances.
- Frequency response is equally essential to counteract sharp deviations if they occur. This is mitigated by generators that are able to react instantaneously to changes in system frequency by ramping generation up or down.

4 Voltage[1]

- It is essential to keep the voltage on the grid stable to prevent damage to grid infrastructure and blackouts. Maintaining grid voltage is dependent on reactive power and Short Circuit Levels which can come from a variety of assets and technologies.

1) The challenges with system requirements already exist and National Grid currently have a suite of products to procure ancillary services as required to manage the grid and have laid out plans for future procurement.

Sources: Aurora Energy Research, BEIS, National Grid

Meeting the system requirements for security of supply will become increasingly challenging in a Net Zero world

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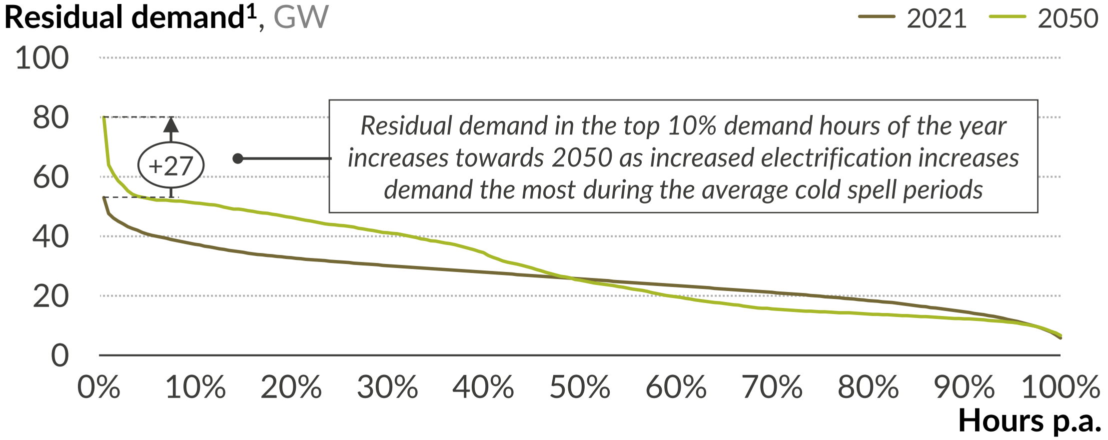
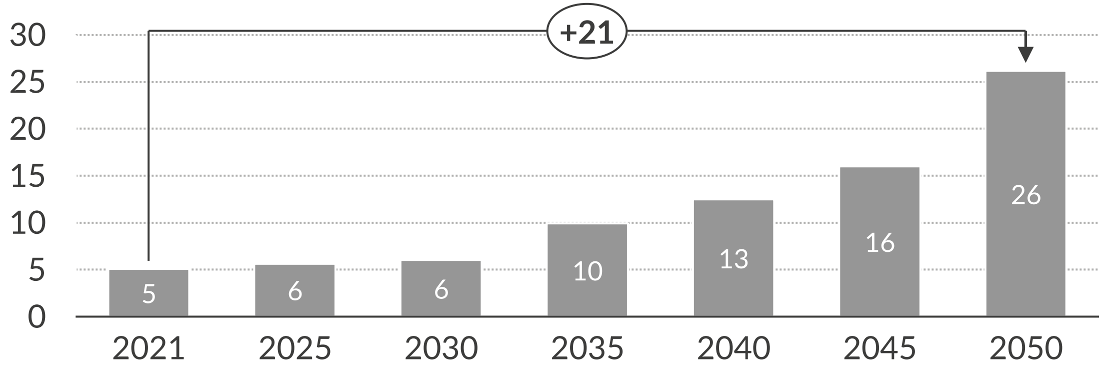
1 As demand increases from higher levels of electrification, the need for firm capacity to maintain system security will increase

Residual demand[1], GW



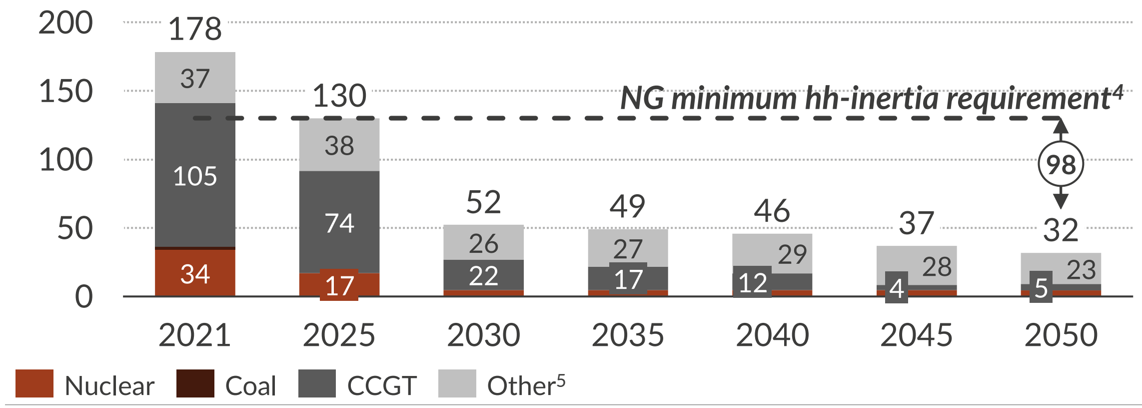
2 The need for fast-ramping generation increases by over 20 GW from now until 2050 as supply volatility increases with renewables buildout

System maximum ramping requirements[2], GW/hour



3 Inertia contribution from conventional assets is set to fall by more than 80% to 32 GVA.s by 2050, well below National Grid requirements

Yearly average inertia contribution from existing capacity, GVA.s[3]



4 In a high renewables power system, CCGT load factors will be lower than today, leading to greater requirement for alternate sources of voltage

- COVID lockdowns provided a preview into a high-RES system where CCGTs were running at **less than 20%** load factors. Reactive power procurement and voltage constraints costs rose to **£59m** in Q2 2020, 47% higher than in Q2 2019 where CCGTs were at c.40% load factors

A system where these system requirements are not met will suffer a lack of operability and threaten energy security. This could result in potentially frequent power outages and blackouts.

1) Residual demand is calculated as the difference between demand and generation from intermittent renewables. 2) Difference in residual demand from one half-hour to the next. 3) Giga volt amp seconds. 4) National Grid has previously published that the lowest amount of inertia the system can manage at any given half-hour is 130 GVA.s. However, the system has on a few occasions already seen system inertia fall below this level. 5) Includes biomass, pumped storage, run-of-river and OCGTs.

Sources: Aurora Energy Research, National Grid

Dispatchable generation is key to ensuring security of supply; several asset classes exist that can contribute to system requirements

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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 Contribution to inertia	4 Contribution to voltage	5 Minimising cost to consumer	6 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 how asset contributes to system inertia, via synchronous generation (and not procured separately)	Measure of the technology's contribution to maintenance of system voltage at a steady value	Measure of the cost today of a technology in terms of its LCOE and it's contribution to reducing balancing costs	This metric considers the technology's current (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	Metric scored considering the asset's technological inertia contribution as well as its average running hours	This metric considers the ability of an asset to provide a sustained supply of power to the grid	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 = Asset has inertia contribution of less than 2 GVA.s/MWh and load factors less than 10%* *5 = Asset has inertia contribution of greater than 7 GVA.s/MWh and load factors more than 30%*	*1 = Asset generation is intermittent and non-synchronous* *5 = Asset generates a consistent supply of synchronous electricity to the grid*	*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)*

Dispatchable assets provide vital system services but will need adequate remuneration if they are to remain available in a Net Zero world

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

Sources: Aurora Energy Research, National Grid

Traditional thermal assets currently serve a unique purpose on the power system, fulfilling niche system requirements

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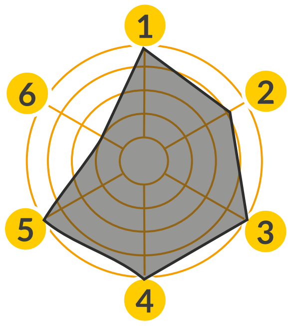
All metrics are scored based on technology performance today. Further considerations for abatement of thermal assets are explored in a later section of this report.

Unsuitable for Net Zero without conversion

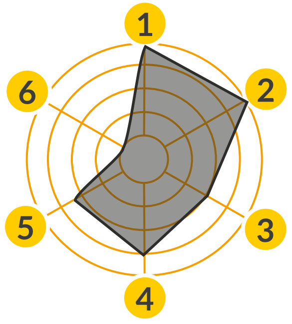
Unabated CCGTs

- *Generates electricity via combined gas and steam turbines*
- *Low capex and high efficiency have enabled CCGTs to run at baseload capacity historically*



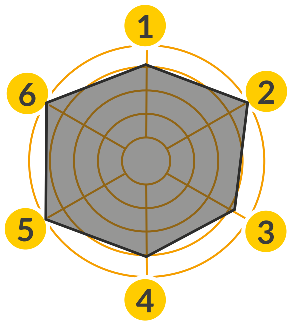
Gas peakers/OCGTs

- *Similar to CCGTs but without the steam cycle, these technologies are cheaper but less efficient*
- *Typically smaller capacity and operate as peakers*



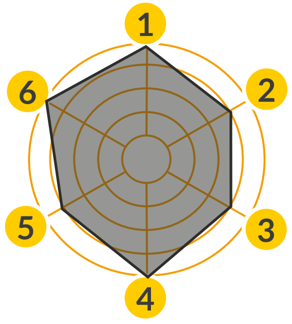
Pumped hydro

- *Pumps water uphill using excess electricity, to be stored until needed for regeneration of power*
- ***Finite capacity available**, most sites already exploited in UK*



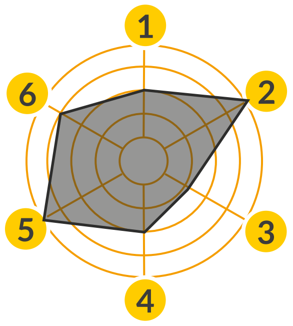
Biomass

- *Combustion of biomass[3] to generate steam which turns a turbine to generate electricity*
- *Slow ramp times means that biomass operates at baseload capacity*



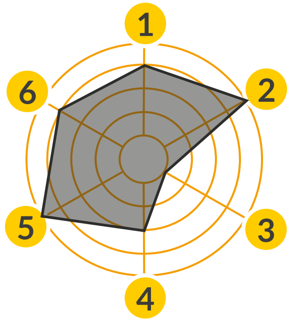
Battery storage[1,2]

- *Typically lithium-ion technology, batteries provide several services to the grid, including energy arbitrage, operation in the CM and BM, and ancillary services*



Interconnectors[2]

- *High voltage power lines connecting different power markets, in order to allow transfer of electricity from low to high demand*



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	5	6
Metric	Duration / continuous supply	Ramping speed	Contribution to inertia	Contribution to voltage	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.

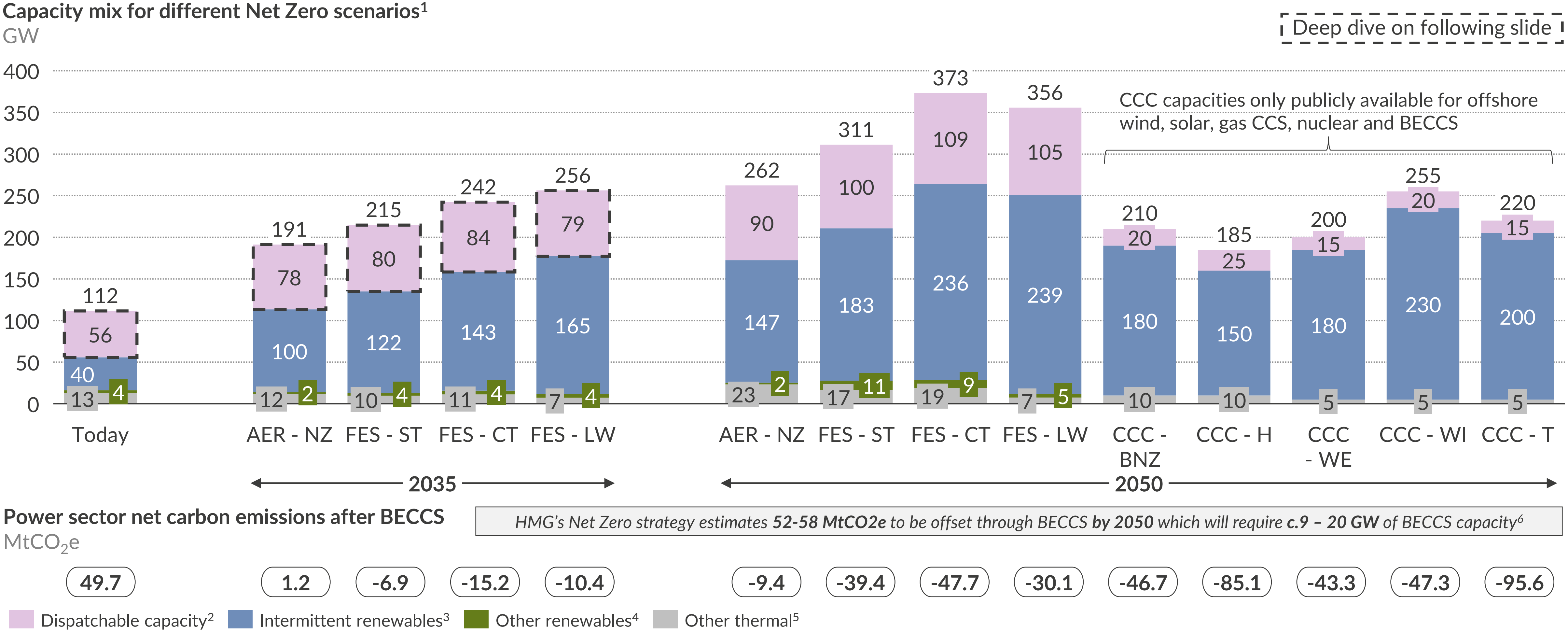
Sources: Aurora Energy Research, EMR, BEIS, National Grid

Generation capacity in a Net Zero world will feature a strong buildout of renewables supplemented by dispatchable capacity

We explore the evolution of GB's capacity mix towards Net Zero as forecasted by Aurora, National Grid and the CCC. The following scenarios are presented: Aurora Net Zero (AER – NZ): National Grid Future Energy Scenarios (FES): Leading the Way (LW); System Transformation (ST); Consumer Transformation (CT); Climate Change Committee UK Sixth Carbon Budget scenarios (CCC): Balanced Net Zero (BNZ); Headwinds (H); Widespread Engagement (WE);Widespread Innovation (WI); Tailwinds (T).

Capacity mix for different Net Zero scenarios[1]

GW

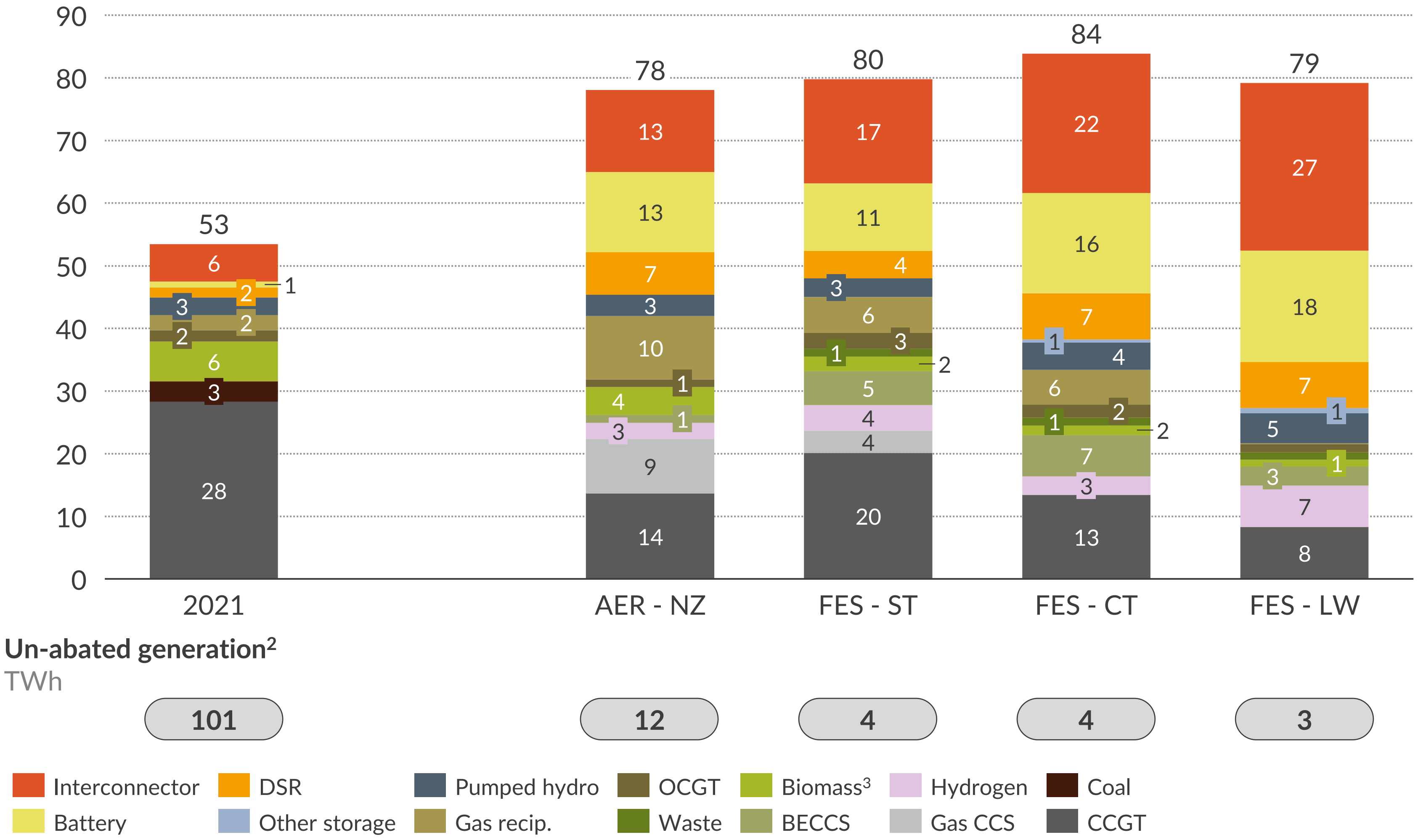


1) Based on publicly available data. Data from CCC scenarios not available for 2035. 2) Includes CCGT, OCGT, gas recip., coal, biomass, waste, fuel oil, pumped hydro, battery, other storage, interconnector, BECCS, hydrogen and CCS. 3) Includes solar, onshore wind and offshore wind. 4) Includes hydro, tidal and energy from waste. 5) Includes nuclear, lignite and thermal CHP. 6) Capacity requirement will vary based on the operational profile and running hours of the BECCS plants .

Sources: Aurora Energy Research, National Grid, CCC

Dispatchable assets will be vital but without policy action, unabated thermal will be needed beyond 2035 to guarantee system security

Dispatchable capacity in 2035 for different Net Zero scenarios[1]
GW



1) AER – NZ: Aurora Net Zero (Oct 2021); FES – XX: National Grid Future Energy Scenarios (2021) [LW: Leading the Way; ST: System Transformation; CT: Consumer Transformation]; 2)Includes CCGTs, OCGTs and gas recips. 3) Biomass is considered a dispatchable technology for this report, while also being a renewable source of energy.
Sources: Aurora Energy Research, National Grid

- The dispatchable capacity mix features low carbon capacities however, **there is no guarantee under current policy frameworks that there will be investment to deploy them**
- Without policy action, unabated thermal assets are still required to ensure security of supply across all scenarios by 2035
- However, these unabated assets will run at low load factors, with total generation <12 TWh
- Residual emissions from unabated generation are expected to be offset by negative emissions technologies, including BECCS
- Batteries and interconnectors are seen to dominate the dispatchable capacity mix however it is crucial for the GB market itself to have enough inland dispatchable generation to guarantee system security

Owners of existing dispatchable thermal assets are facing a number of imminent key decisions as the UK looks towards Net Zero

Dispatchable asset owners today are facing important near-term decisions as they look to decarbonise, to align with targets for a Net Zero power system by 2035.

Current UK policy is geared towards a Net Zero power system by 2035…

- The UK is mandated to achieve Net Zero carbon emissions across all sectors by 2050, and the government recently announced its intention to fully decarbonise the power sector by 2035
- Looking towards Net Zero, dispatchable thermal generation assets will face an uncertain future with several challenges:

1 Declining operations and profitability

2 Commodity price volatility

3 Policy support and incentives uncertainty

4 Dwindling investment signals

- **As decarbonisation efforts intensify, thermal asset owners will need to make several key decisions in the immediate future as to whether and how to stay relevant in a Net Zero world.**

…accelerating the decision-making process for thermal asset owners in the near-term future….

- Operators of dispatchable thermal assets face several key near-term decisions, with many assets due major and costly overhauls as they come to the end of their theoretical lifetimes
- Policy inaction risks un-ordered exit of gas assets, thus clear investment signals are needed well ahead of delivery, to inform key decisions for asset owners and the system operator
- At the overhaul date, asset owners will decide if to:

1 Cease operations, or

2 Extend asset lifetimes

- **Clear and urgent policy action will be required to inform the decision making process in order to achieve the best outcome for asset owners and for the system.**

…as conversions to low carbon alternatives present an opportunity to feature in Net Zero

- There remains a clear need for dispatchable generation in a Net Zero world which presents an opportunity for existing assets to remain relevant, provided they decarbonise
- **CCS and hydrogen are currently the front-running decarbonisation options for these assets**; the choice will depend on key factors such as:

1 Policy support

2 Plant technology and properties

3 Plant and site location

4 Conversion costs and timing

No clear policy pathway exists to support low carbon conversion of existing assets so they may be forced to close

Source: Aurora Energy Research

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Unabated thermal dispatchable assets will have two key pathways to adapt to a Net Zero world - CCS and hydrogen

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This section explores the conversion options available to carbon intensive dispatchable assets in operation today that are incompatible in a net zero world. *Costs presented reflect Aurora's internally consistent assumptions based on publicly available data, as well as discussions with key stakeholders.*

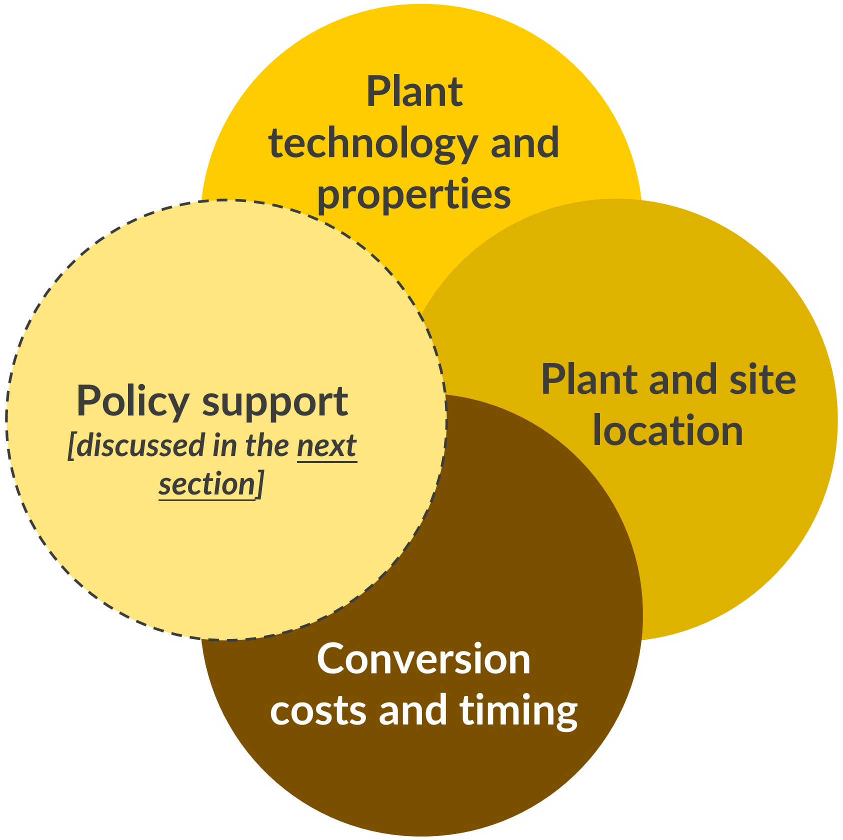
Unabated gas CCGT	Power CCS plant	Hydrogen CCGT	Unabated gas peakers	Hydrogen peakers
CH_4 CH_4	CH_4 CH_4	H_2 H_2		
Conventional gas-powered turbines	*Thermal plant with carbon capture and storage*	*Hydrogen powered turbines (mixed to full firing)*	*Conventional gas-powered peakers*	*Hydrogen powered OCGTs/recips*
CAPEX (new build):	*CAPEX (retrofit – new):*	*CAPEX (retrofit – new):*	*CAPEX (new build):*	*CAPEX (new build):*
£500 - 600/kW	**£500-1,800/kW**	**£100-700/kW**	**£300-600 /kW**	**£350-600/kW**
Efficiency:	*Efficiency[1]:*	*Efficiency:*	*Efficiency:*	*Efficiency:*
57% HHV	**44-50% HHV**	**50-57% HHV**	**38% HHV**	**38% HHV**
Carbon intensity:	*Carbon intensity[2]:*	*Carbon intensity[3]:*	*Carbon intensity:*	*Carbon intensity[4]:*
320 gCO_2/kWh	**20 - 25 gCO_2/kWh**	**0 - 55 gCO_2/kWh**	**480 gCO_2/kWh**	**0 - 80 gCO_2/kWh**
UK installed capacity:	*Example UK projects:*	*Example UK projects:*	*UK installed capacity:*	*Example UK projects:*
30 GW	**Keadby 3 (910 MW)** **Immingham[4] (800 MW)**	**Saltend (400 MW)** **Immingham[4] (400 GW)**	**6 GW**	**N/A**

Majority of hydrogen conversions are expected to proceed via progressive blending (mixed hydrogen and gas firing) before conversion to full hydrogen firing[5]

1) Assumes CCS efficiency penalty of 7 p.p. 2) Assumes capture efficiency of 95% and reflects range for retrofits (upper end) and new builds (lower end). 3) Reflects carbon intensity of Hydrogen production and range for Green to Blue H_2. Hydrogen is a zero emissions fuel at point of use. 4) Immingham will be a hybrid project, with both a hydrogen and a CCS conversion. 5) Hydrogen blends are only expected as part of full hydrogen conversions, and will still require key decisions to in the immediate future.
Sources: Aurora Energy Research, IGG, BEIS, SSE and Equinor (non IGG members)

Decarbonisation of thermal dispatchable assets will be dependent on key considerations like policy support, costs and location

Developers will need to consider several key elements when deciding on a pathway for conversion



Plant technology and properties

- Additional energy requirement and intensity of CCS process imposes efficiency penalties of 6–9 percentage points on the host plant
- Parasitic nature of CCS further imposes capacity penalties[1] of about 10%
- High operational costs of hydrogen
- Expected generation profiles i.e. baseload or flexible or peaking

Plant and site location

- Need for relevant hydrogen and CCUS infrastructure
- Transport and storage (T&S) infrastructure including shipping ports, onshore and offshore pipelines, carbon storage sites
- Lack of hydrogen/CO2 network dictating proximity to supply infrastructure

Conversion costs and timing

- Large upfront CAPEX outlay, with limited financing options, and high operational costs for hydrogen-fuelled assets
- Downtime required for asset overhaul and conversion
- Lack of policy certainty and support for assets transitioning between policy support schemes

1) In addition to CCS efficiency penalties which impact power output, capacity penalties impact the usable capacity of a plant

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

Technology specifics and policy support will determine the applicable decarbonisation pathways for different asset classes

A large number of factors and plant specifics must be carefully considered before deciding on an appropriate pathway for decarbonisation

1 Unabated gas CCGTs

CCS

- Additional energy load from CCS equipment creates an efficiency and capacity penalty on the host plant **reducing overall power output**
- CCS plants in a Net Zero world will be expected to shift from typical baseload operations today above 40% load factors to more **flexible dispatchable operations above 20% load factors**
- **At load factors beyond 20%, CCS becomes cost competitive** on an LCOE basis as its high capex cost is mitigated and spread out

Hydrogen

- Despite low capex costs, **hydrogen as a fuel costs significantly more than gas**[1]
- Hydrogen's lower energy content by volume means **higher fuel volumes will be required** to deliver similar energy levels as unabated assets
- At load factors beyond 20%, hydrogen turbines become very expensive to operate due to high fuel costs and **baseload margins will be insufficient to close the missing money gap** dictating subsidy support[2]

2 Unabated gas peakers – gas recips, OCGTs

CCS

- The energy intensive and parasitic nature of CCS **negatively impacts asset performance reducing ramp rate and start times** thus rendering peaking plants less suited to fast response
- The efficiency penalty from CCS also **penalises already low peaker efficiencies** e.g. a 38% HHV gas recip could fall to c.30%HHV
- The high capital outlay for CCS equipment makes relevant assets **competitive only at higher load factors** thus making it too expensive at load factors typical of peaking plants c.10%

Hydrogen

- A combination of relatively low capex costs for hydrogen and its high fuel costs mean that hydrogen assets are the **most cost effective at load factor of less than 20%**
- Peak period operation of hydrogen assets at load factors c.10% means that they are **able to capture top prices in the market reducing the missing money gap** and requiring less subsidy support overall
- CCGTs can operate at different load factors, making them flexible to run a peaking operational profile more suited to a hydrogen conversion

1) Hydrogen fuel cost could be lowered through fuel subsidy support, however the cost of subsidy would still be passed through to consumers bills through low-carbon levies. 2) If approriate fuel subsidies were put in place, hydrogen-converted CCGTs would be enabled to run competitively at baseload capacity.

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

Availability of CCS and hydrogen infrastructure and proximity to plant sites will be paramount to deliver low carbon thermal assets

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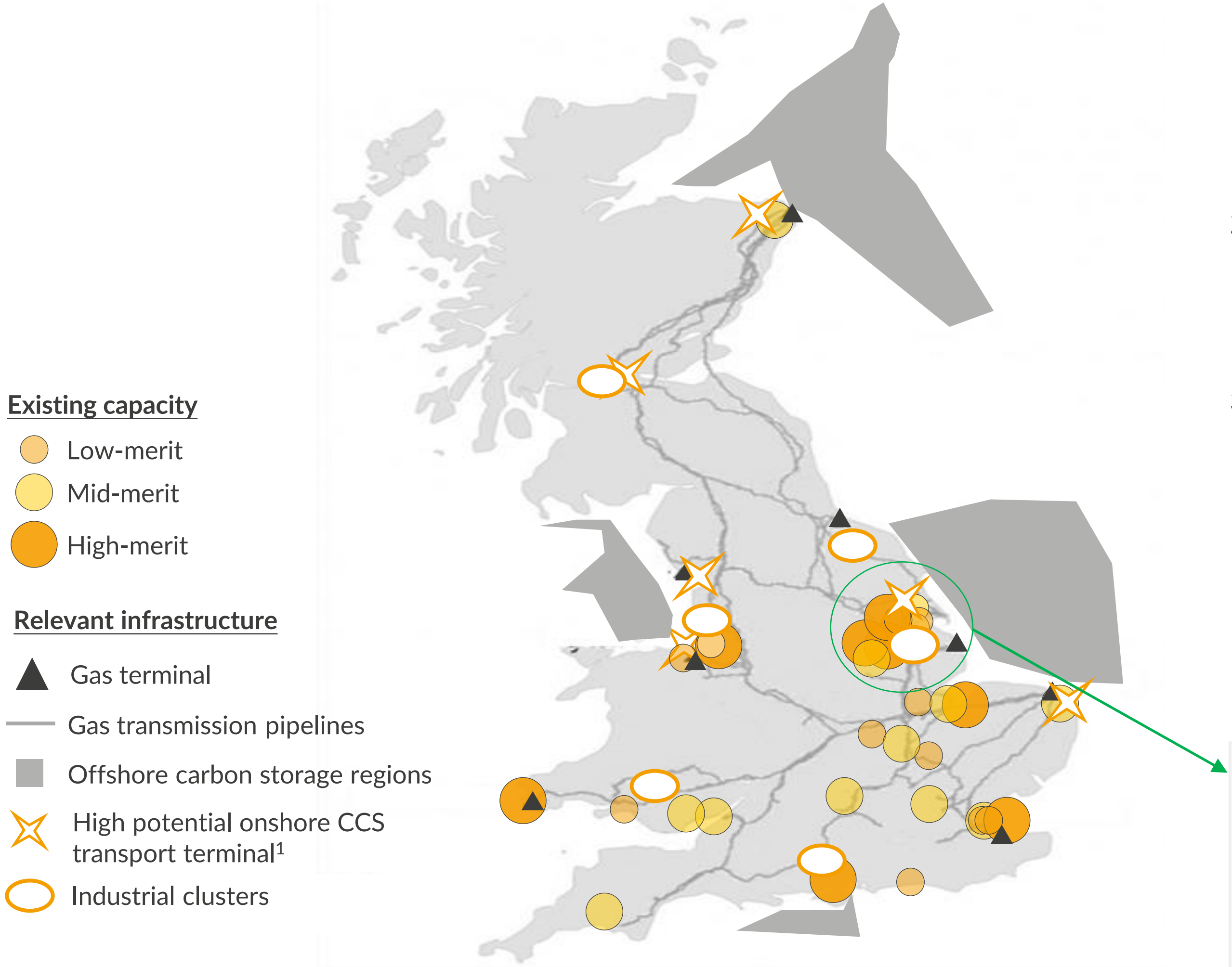
Existing CCGT capacity and relevant infrastructure locations in UK



Location will play a key role in determining plant conversions

1. **Proximity to potential offshore carbon storage sites**

   This is key for CCS plants, as distance will determine transport and storage requirements and costs. Alternatively, proximity to ports could be beneficial due to potential development of H_2/CO_2 shipping hubs.

2. **Proximity to industrial clusters**

   With policy currently focused on deployment of CCS and hydrogen in industrial clusters, low carbon plants in close proximity may benefit from potentially useful infrastructure in these clusters.

3. **Proximity to supply infrastructure**

   Proximity to hydrogen production infrastructure will be key for hydrogen burning plants. Proximity to gas terminals and transmission pipelines will also be relevant as they could be repurposed for hydrogen use in the future.

4. **Proximity to electricity demand**

   The dependency of network charging on distances to demand e.g. TNUoS incentivises capacity deployment near high demand centres so proximity to demand will be key for asset conversions to remain relevant.

Optimal asset locations will feature a combination of some or all of the above listed factors e.g. ***plants in the Humberside region*** *will be well suited for a conversion or new build asset due to availability of all the key factors.*

Sites with existing assets that are not suited for conversion based on other factors could be repurposed for new build assets.

1) Hydrogen Supply Chain Evidence Base – Element Energy.

Sources: Aurora Energy Research, Element Energy, National Grid

The range of reasonable existing thermal conversions lies between 7 GW and 17 GW; new build assets will be required

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Potential capacity for retrofitting existing CCGTs[1]
GW

Location →

Efficiency/age ↓

	Poor location	OK location	Good location
Low-merit	0.9	2.2	8.0
Mid-merit	3.0	5.8	2.9
High-merit	0	3.5	3.5

Rating scale Low potential — High potential

Context for ranking

Location
- Good: close proximity to offshore storage
- OK – bit further inland but within 50 km of suitable storage
- Poor – greater than 100km away from suitable storage

Efficiency / age
- Low-merit – <50% HHV CCGTs
- Mid-merit – 50 - 53% HHV CCGTs
- High-merit – >53% HHV CCGTs

- Our analysis shows a shrinking volume of existing assets available and suitable for low carbon conversions
- Due to CCS penalties and high hydrogen fuel costs, low merit assets become unviable with efficiencies less than 50%
- Assets with poor locations could also be unviable due to expected high CO_2 and hydrogen transport and storage costs feeding into their marginal costs
- Based on these factors, the reasonable range for CCGT conversions lies between 7 GW and 17 GW
  - Green: The newest of GB's fleet will probably be a prime candidate for conversion due to high efficiency, newer age and prime location in the Humberside region - one of two projects selected in phase 1 of the Government's CCS cluster decision and with good proximity to potential CO_2 storage in the South North Sea
  - Yellow: Older plants located in industrial clusters will probably be suitable for site conversions due to prime location and close proximity to key infrastructure. Low efficiency and old age of the plants might hinder the plant conversion but can be mitigated with adequate refurbishments.
  - Red: Old, low efficiency plants in far inland locations away from infrastructure, demand and offshore storage will probably be unsuitable for conversions without further refurbishment.
- **Plant efficiencies and age could be upgraded as part of the overhaul and repowering process to mitigate performance issues (albeit at higher costs), which could increase the reasonable range of conversions to 7 - 25 GW.**

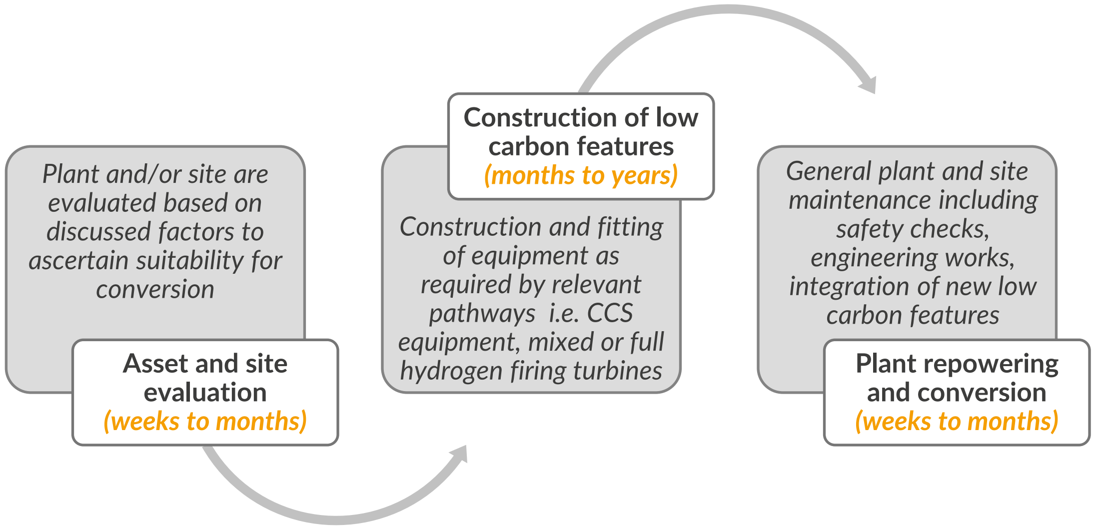
1) Includes Keadby 2 which is currently under construction and set to come online in 2022.

Sources: Aurora Energy Research, Elexon, SSE

Low carbon conversions of dispatchable assets will take up to several years to complete and costs will vary across the different pathways

AURORA

1 Conversion process and timing

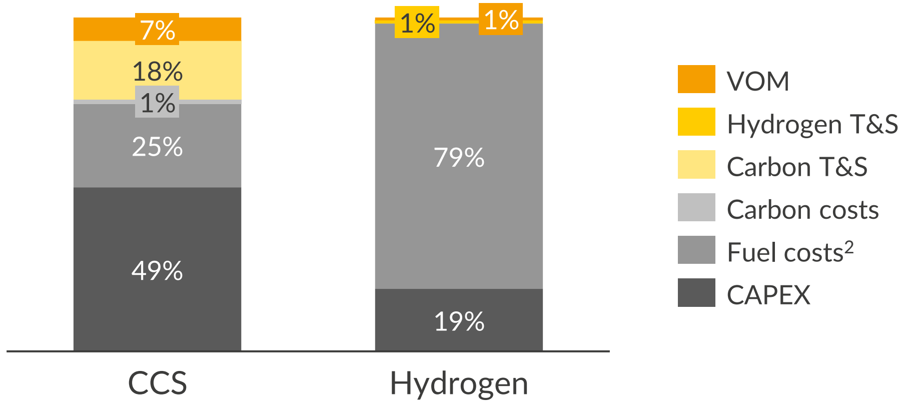


- The **total duration** for low carbon conversions of dispatchable assets **could range from a few months** for hydrogen pathways **to several years** for CCS pathways
- While conversions could last several years, the **downtime** from the system for integration and repowering **will be shorter,** ranging from weeks to months
- Careful thought will be required to manage asset downtimes and their impact on system flexibility and dispatchability during the transition
- **Asset owners will require clear signals for investments, and critical decisions will be required as early as in the 2020s to ensure sufficient capacity is decarbonised and available by 2035**

2 Conversion costs

- Conversion costs across the decarbonisation pathways are expected to vary with CCS being capital intensive and hydrogen subject to high operational costs
- Capex for CCS conversions could range between **£500-1,000/kW** for while capex for hydrogen conversions range between **£100 – 400/kW**
- Operationally, CCS will be subject to low gas and carbon costs between **£30-45/MWh** while hydrogen plants will be subject to much higher fuel costs between **£80-100/MWh**
- Both pathways will also be subject to transport and storage costs dependent on asset/site location and fuel supply

Cost components for low carbon conversions of thermal assets[1]
£/MWh



1) Indicative representation of cost breakdown on an LCOE basis. 2) Hydrogen fuel costs represent the LCOH blue hydrogen.

Sources: Aurora Energy Research, IGG

Low carbon thermal assets could cost over £250/MWh on an LCOE basis, conversions will outcompete new builds

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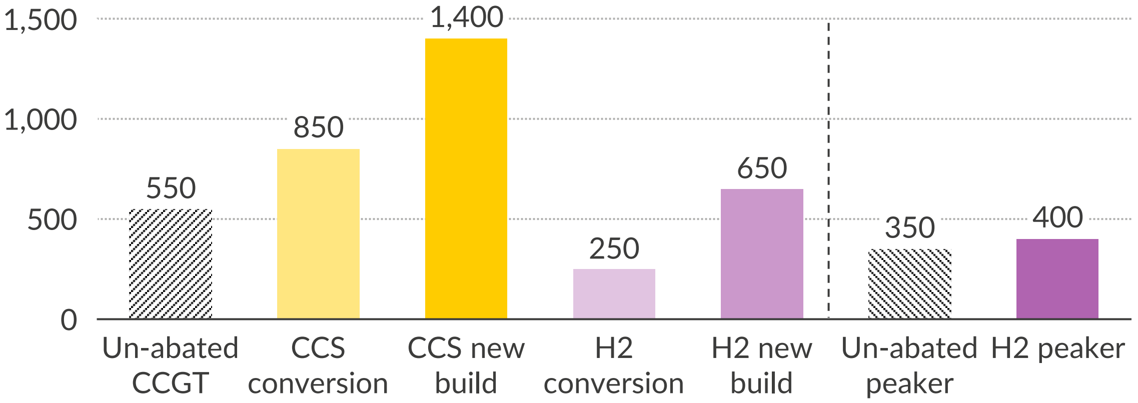
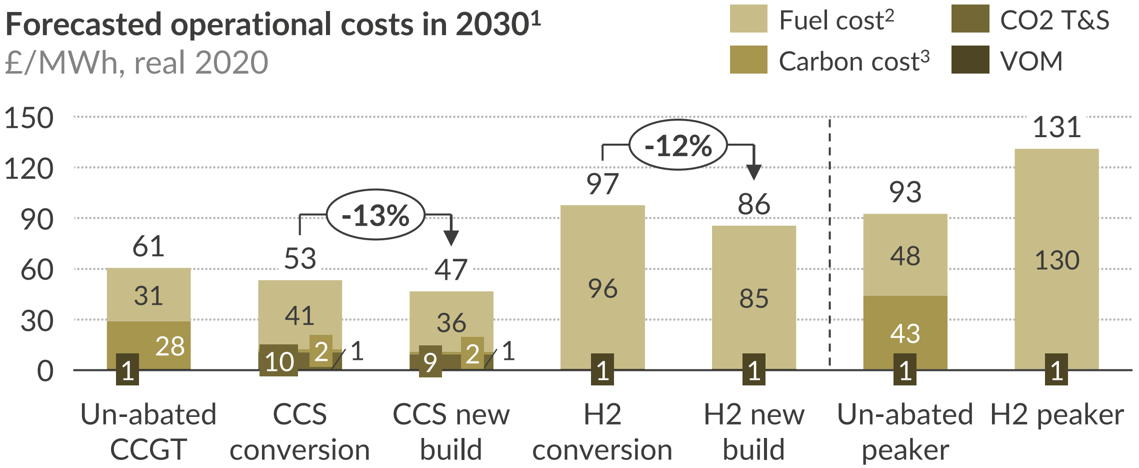
1 Existing asset conversions benefit from lower capex requirements

Forecasted CAPEX in 2030
£/kW, real 2020



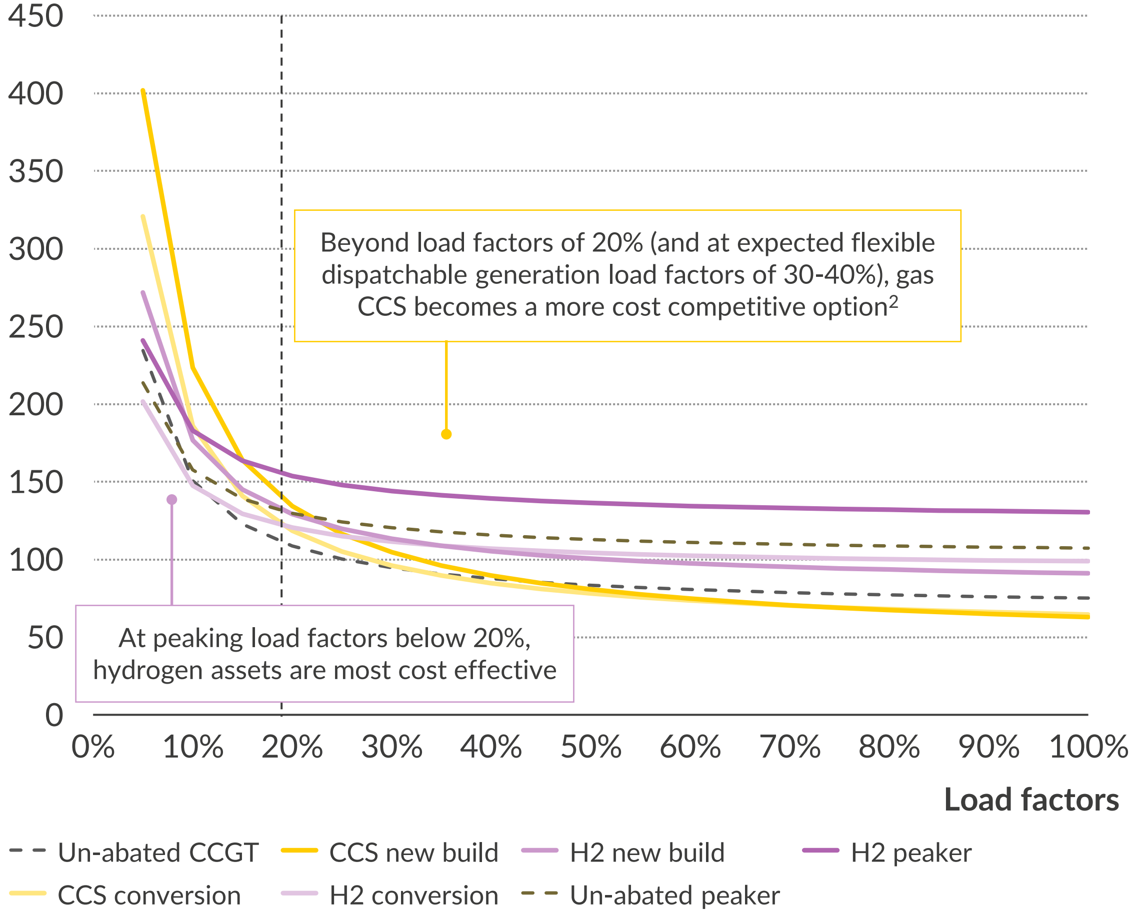
2 New builds benefit from lower operational costs due to higher efficiencies

Forecasted operational costs in 2030[1]
£/MWh, real 2020



3 Conversions outcompete new builds on an LCOE basis

LCOE[4] (assuming entry in 2030)
£/MWh, (real 2020)



1) Analysis shows all numbers excluding any subsidies. Note that costs other than those shown may be included, such as hydrogen transport and storage costs. 2) Fuel cost for hydrogen plants calculated using levelised cost of blue hydrogen and excluding any fuel subsidies. 3) Calculated using Aurora's October 2021 net zero forecast of UK carbon prices. 4) Assumed lifetimes: 30 years for newbuild CCGTs, 20 years for conversions and 25 years for new build peakers.

Source: Aurora Energy Research

Agenda

Decarbonisation of the power sector is crucial, but security of supply during the low-carbon transition must be maintained

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Inaction could have severe and wide-reaching implications on the power sector

Security of supply

- Rising carbon prices and increasing penetration of renewables create hostile market conditions for dispatchable thermal assets, limiting operations and dampening margins
- Without adapting to Net Zero, these assets could be forced to close before their end of life, **reducing the availability of firm capacity on the grid and ability to meet system operability needs**

Minimising cost

- Failure to convert current dispatchable flexible generation technologies will make them unprofitable in a Net Zero world with high carbon prices
- Alternatives would be to significantly **oversize the renewable system, or to employ other low-carbon dispatchable technologies**, both of which Aurora analysis[1] has shown **typically come at a higher cost to the consumer**
- Inaction which could threaten security of supply and **lead to loss of load or other operability failures also translates to additional costs to consumer**

Decarbonisation

- Failing to convert dispatchable assets to low-carbon alternatives could slow the pace of power sector decarbonisation, **ultimately hindering the UK's Net Zero commitment**

A lack of policy support for existing dispatchable thermal capacity could result in an undersupply of critical capacity in the near future

- There is currently a disjoint between government policies for decarbonisation and security of supply
  - New policy focusses on supporting new-build abated dispatchable assets but gives little direction to existing, unabated dispatchable assets
  - Existing policy like the CM that support unabated dispatchable assets face uncertainties as the UK looks towards Net Zero
- **Low-carbon dispatchable technologies have the benefit of contributing to both security of supply requirements and decarbonisation objectives** thus, policy makers must work to secure the future of existing unabated assets

Policies to incentivise low carbon conversion of dispatchable assets must satisfy certain requirements to be able to support these technologies

1. **Incentivise low carbon capacity –** *policy should be able to support upfront costs of the relevant technologies*
2. **Incentivise low carbon flexible dispatch** – *policy should be able to send price signals to incentivise flexible dispatch ahead of unabated assets but without competition with other zero carbon technologies*
3. **Integration with wider market** – *policy should be able to support assets without creating market distortions or direct competition with other policies*
4. **Investor confidence –** *policy should alleviate merchant risk and provide revenue certainty*

1) Aurora 'Out of Gas' report (available to subscribers).

Source: Aurora Energy Research

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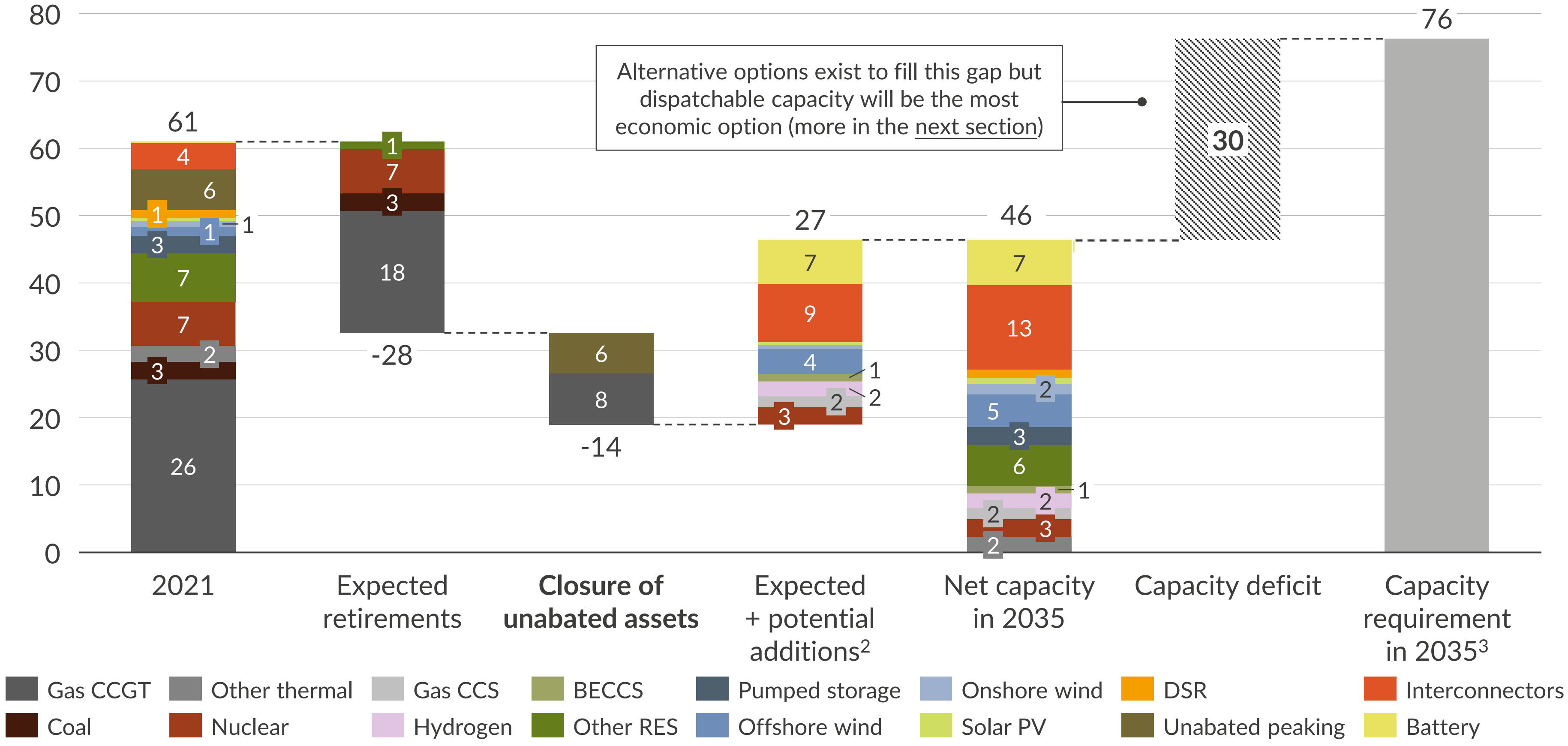
Without urgent policy action, Net Zero power by 2035 could result in a 30 GW (de-rated) undersupply of critical capacity

The analysis presented here explores the impact of the Government's Net Zero power by 2035 on energy security. It is based on the existing GB fleet and pipeline and presupposes that there is no new build of any carbon intensive capacity. Existing unabated assets are also estimated to be phased out without sufficient policy in place to support low carbon conversions.

Expected capacity retirements and additions by 2035[1]

GW, de-rated



1) Expected retirements reflect publicly announced dates for nuclear plant closures, policy mandated closure of coal assets and retirements of existing CCGTs based on a 30 year technical lifetime. 2) Expected and potential additions reflect confirmed and announced projects in the GB pipeline. 3) Estimated capacity requirement in 2035 (de-rated) based on Aurora's Net Zero scenario.

Sources: Aurora Energy Research, REPD, EDF, Drax

- GB's security of supply will be challenged by the impending retirements of ageing nuclear and large thermal plants and forced closure of unabated assets
- As these highly de-rated firm dispatchable capacities come off the system much faster than the deployment of other capacities, there could be a **capacity deficit of 30 GW (de-rated) by 2035**
- **This deficit could be further exacerbated based on actual market outturns** e.g. biomass is unable to stay on the system without subsidies or not all of the expected additions come through
- Decarbonising all existing gas assets on the system could fill this gap but not all assets will be suited for conversion so new builds will also be required
- **Given the timescales involved, policymakers need to take urgent action to incentivise deployment of low carbon dispatchable capacity to ensure energy security**

A suite of policy options is available to support the conversion of thermal assets, however they must satisfy certain requirements

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Assessment criteria[1] ○ Low ● High

	Policy option	Description	*Incentivise low carbon capacity*	*Incentivise low carbon flexible dispatch*	*Integration with wider market*	*Investor confidence*
Existing policies and potential modifications	A Capacity Market (CM)	▪ Design could be modified to a 2-stage auction, with low-carbon technologies able to access higher CM prices in earlier bidding rounds to incentivise dispatchable capacity	◕	◔	◑	◕
	B Contracts for Difference (CfD)	▪ Existing CfD auctions can be expanded to include a new pot for firm low carbon dispatchable technologies to enable cost reductions as seen in the renewables sector	◕	◔	◔	◕
	C Carbon pricing	▪ Higher carbon prices to price gas burning assets out of merit and incentivise low carbon alternatives	◔	◕	◕	◔
New policies	D Carbon Contracts for Difference (CCfD)	▪ A CfD that rewards emissions reduction with a fixed carbon strike price paid for every unit of carbon displaced	◔	◕	◔	◑
	E Dispatchable power agreement (DPA)	▪ Provide an availability payment to subsidise upfront costs and a variable payment to incentivise flexible dispatch ahead of unabated plants but after renewables and nuclear	◕	◕	◑	◕

Individual policies may be insufficient to incentivise low carbon dispatchable assets in isolation. Some combinations of policies could work well, although double subsidies will not receive government backing. Further details on the policies presented here are available in appendix.

1) Existing policies are assessed based on assumed versions which have the potential modifications implemented.

Sources: Aurora Energy Research, EMR, BEIS

Agenda

We have designed a scenario under the status quo policies, where there is no support for low carbon dispatchable generation

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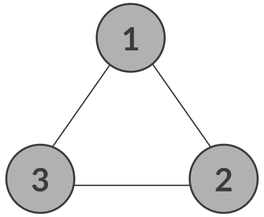
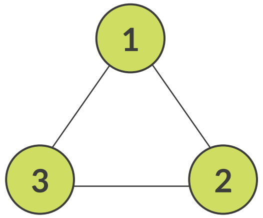
The Aurora Net Zero scenario sees all energy policy objectives achieved, driven by significant policy support. The Status Quo scenario designed for this report however fails on two of three objectives due to policy inaction to support the conversion of dispatchable assets.

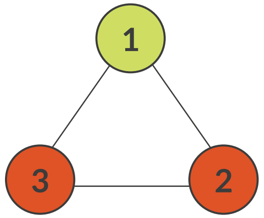


UK Energy policy objectives

1. Security of supply
2. Decarbonisation
3. Minimise cost to consumer

Objective met   Objective not met





Scenario design inputs	Aurora Net Zero - NZ (reference case)	Status Quo - SQ
Policy support to enable deployment of low carbon dispatchable capacity	?	?
Policy support to enable dispatch of low carbon dispatchable assets	?	?
Continued policy support and subsidies for renewables in line with government ambition	?	?
Ban on un-abated thermal assets[1] beyond 2035	?	?
Carbon price continues to increase in line with Net Zero targets	?	?
Capacity Market persists in its current form	?	?

Both scenarios presented here solve for estimated system capacity deficits (e.g. as presented in section IV) albeit in different ways. The Net Zero scenario features policy supported low carbon dispatchable assets while the Status Quo scenario features unabated dispatchable assets.

1) Subject to security of supply - peaking plants such as OCGT and gas recips are assumed to be exempt.

Sources: Aurora Energy Research, BEIS

Policy inaction will see 38 GW of unabated assets still required by 2035, but prevalence of gas will support merchant renewables

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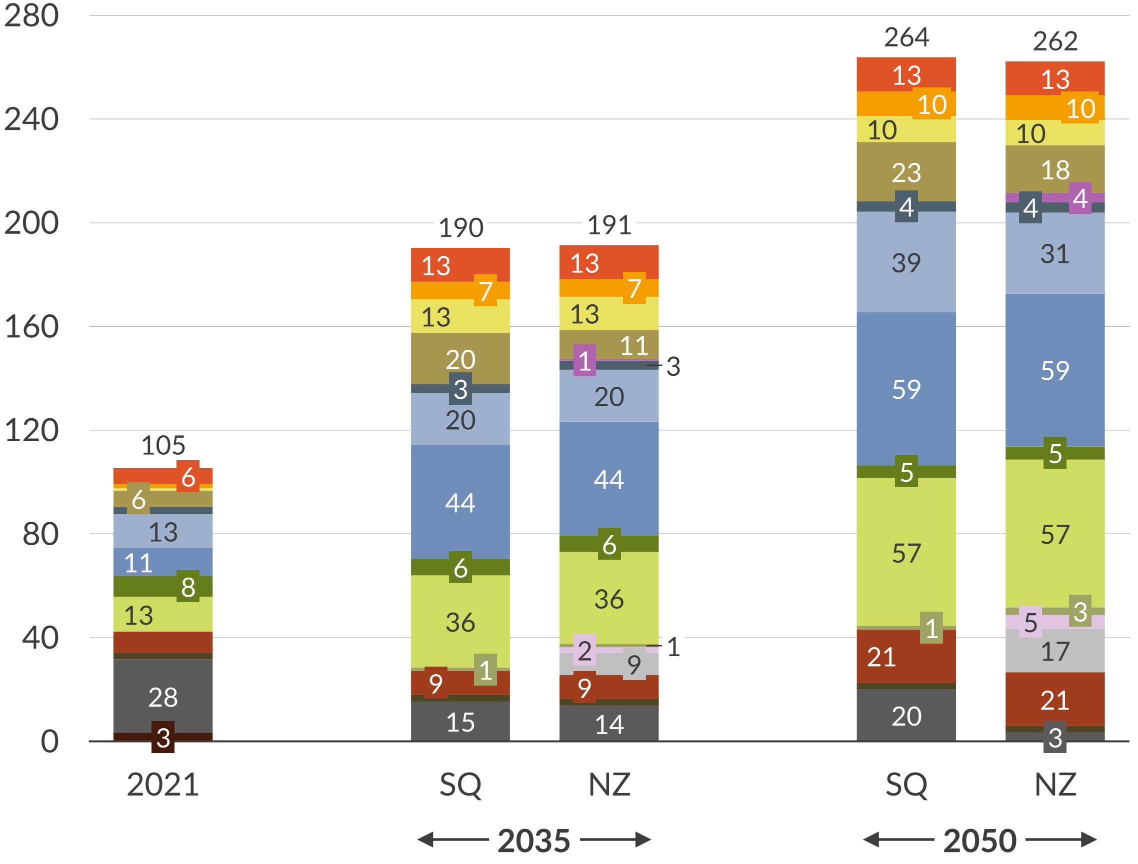
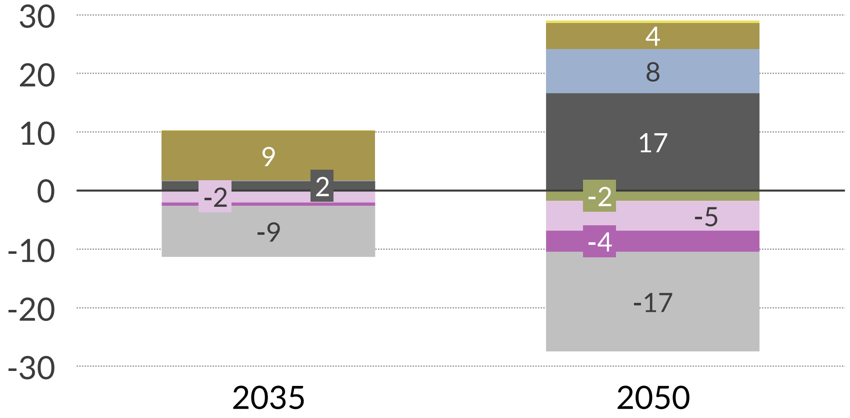
Total installed power generation capacity in modelled scenarios[1]

GW



Difference in Status Quo capacities relative to Net Zero

GW



Key trends emerge in the scenario with policy inaction for dispatchable assets:

- Unabated thermal capacity will continue to thrive, mainly supported by the CM[5], resulting in 17 GW additional capacity by 2050 (*there is a high risk that these gas assets will not be available without clear signals for investments today*)
- High price environment driven by continued gas generation helps facilitate the deployment of merchant renewables, resulting in 8 GW additional capacity by 2050
- The economics for low carbon dispatchable assets (gas CCS and H_2 assets) remain unfavourable and they are unable to deploy without policy support
- BECCS capacity remains flat at 1.2 GW without further policy support

1) SQ – Status Quo; NZ – Aurora Net Zero scenario. 2) Includes OCGT, gas recips and oil. 3) Includes biomass, energy from waste, hydro and tidal. 4) Includes CHP. 5) CCGTs will be necessary for security of supply and be supported through the CM, albeit at high clearing prices. See appendix.

Source: Aurora Energy Research

Without policy action, unabated gas generation will make up 9% of total demand in 2035 and set prices 85% of the year

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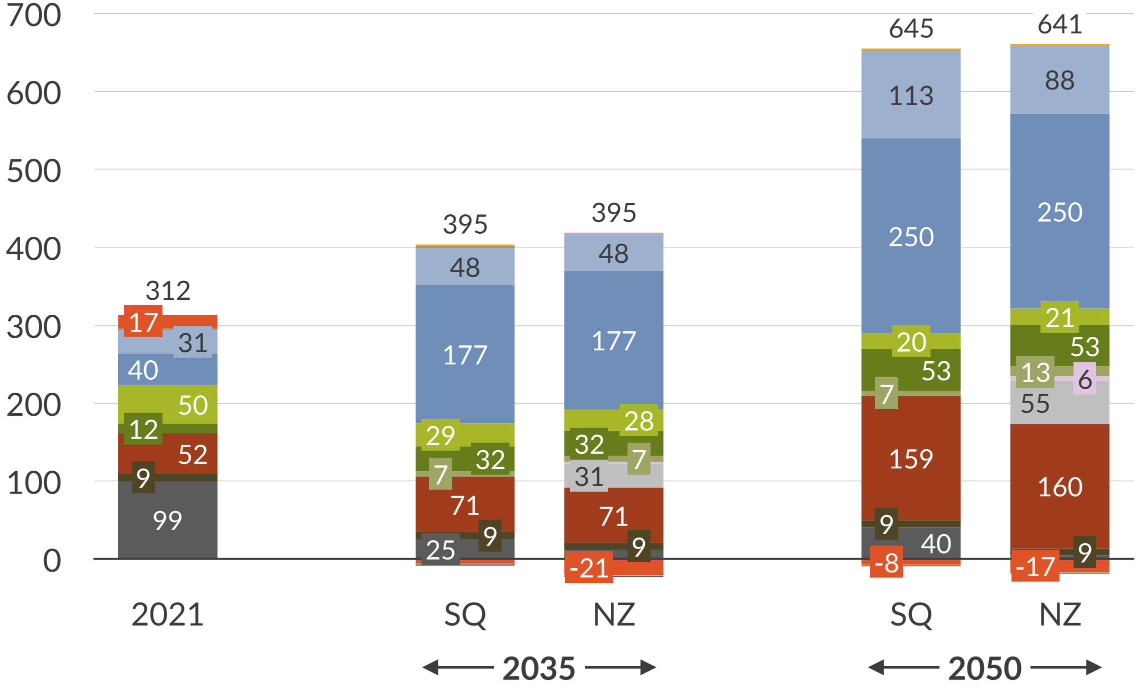
Electricity generation

TWh



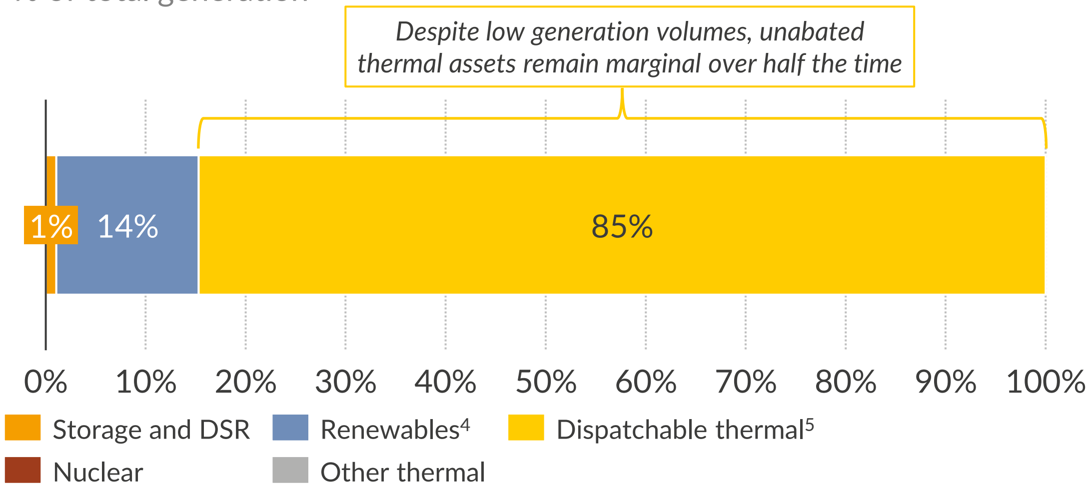
	2035 SQ	2035 NZ	2050 SQ	2050 NZ
Low-carbon generation %	91%	95%	92%	98%
Un-abated generation %	9%	5%	5%	2%

Lack of policy action in the Status Quo scenario results in a share of un-abated generation that doubles the share in a policy-supported Net Zero scenario

Interconnectors | Battery storage | Pumped storage | Offshore wind | Solar[2] | Hydrogen CCGT | Gas CCS | Other thermal | Coal
DSR | Peaking[1] | Onshore wind | Other RES | BECCS | Hydrogen peaking | Nuclear[3] | Gas CCGT

Marginal generation technology in 2035 (Status Quo)

% of total generation[4]



- Despite making up just 9% of total generation in 2035, unabated dispatchable thermal assets are price setting in the majority of hours
- These gas assets provide uplift to the power price – **supporting renewable capture prices and driving capacity deployment on a merchant basis** (*there is a high risk that these gas assets will not be available without clear signals for investments today*)

1) Includes OCGT, gas recips and oil. 2) Includes biomass, energy from waste, hydro and tidal. 3) Includes CHP. 4) Includes wind and solar. 5) Includes CCGTS and peaking plants

Source: Aurora Energy Research

Failure to convert unabated thermal dispatchable capacity will see GB miss its target of Net Zero in Power by 2035

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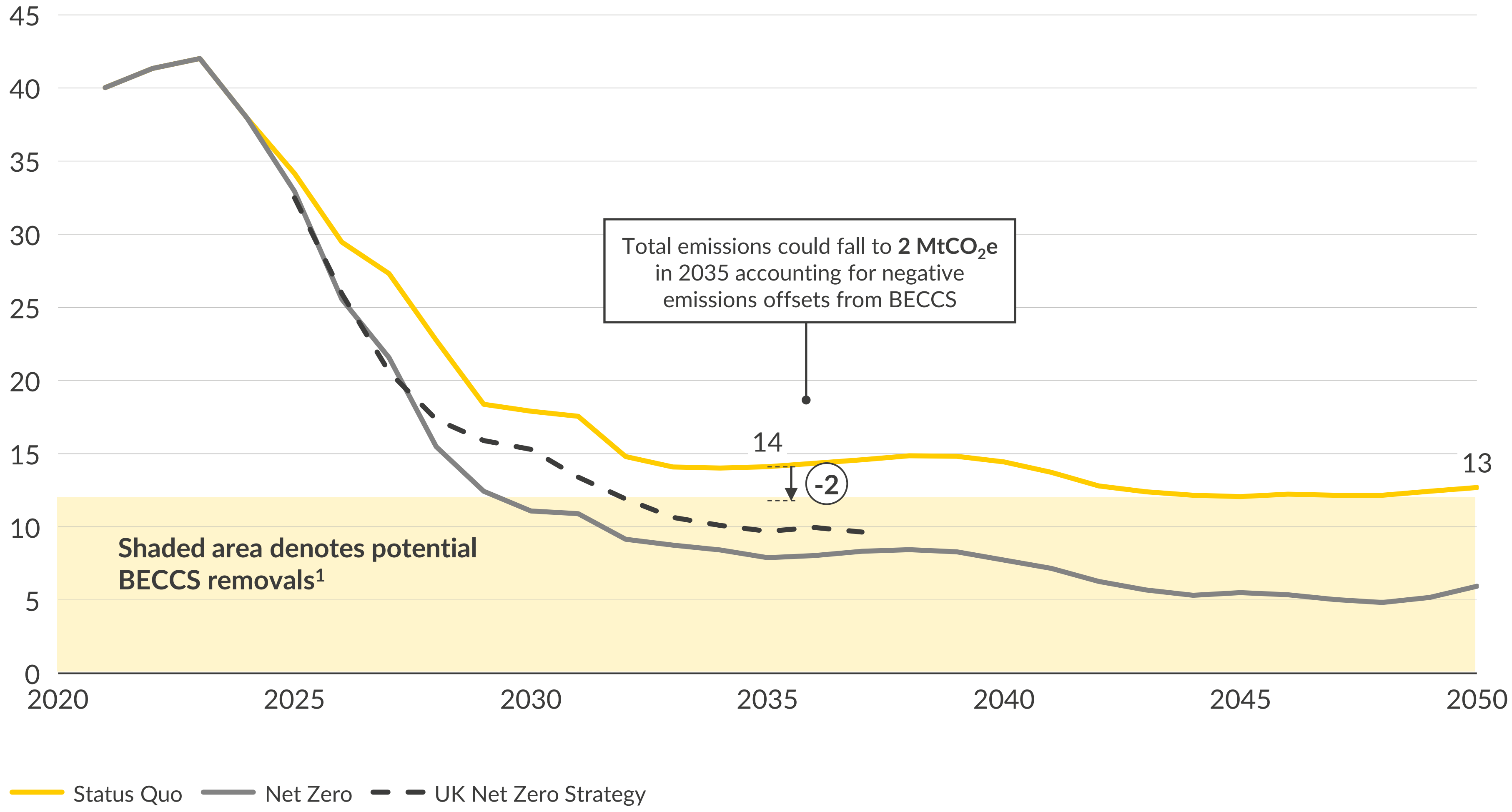
Total power sector carbon emissions (before BECCS)
$MtCO_2e$



1) Removals calculated using an assumption of 3 GW of BECCS capacity running at 47% load factor, using a carbon intensity of -941 gCO2/kWh.

Source: Aurora Energy Research

- A strong growth in renewables, driven by Government ambition depresses short term CCGT load factors and enables rapid decarbonisation in the 2020s
- The rate of decarbonisation however slows in the 2030s as demand picks up and power becomes harder to decarbonise
- Total emissions in the Status Quo scenario then falls to **14 $MtCO_2e$ by 2035**, 4 $MtCO_2e$ higher than the trajectory set in the UK Net Zero strategy
- Emissions could however fall further to **2 $MtCO_2e$** in 2035 after accounting for negative emissions offsets from BECCS[1]
- **Across all trajectories, BECCS will be required to achieve Net Zero and so will require policy support**

Total system costs could increase by £54bn without further policy action adding £58/year to the average household bill

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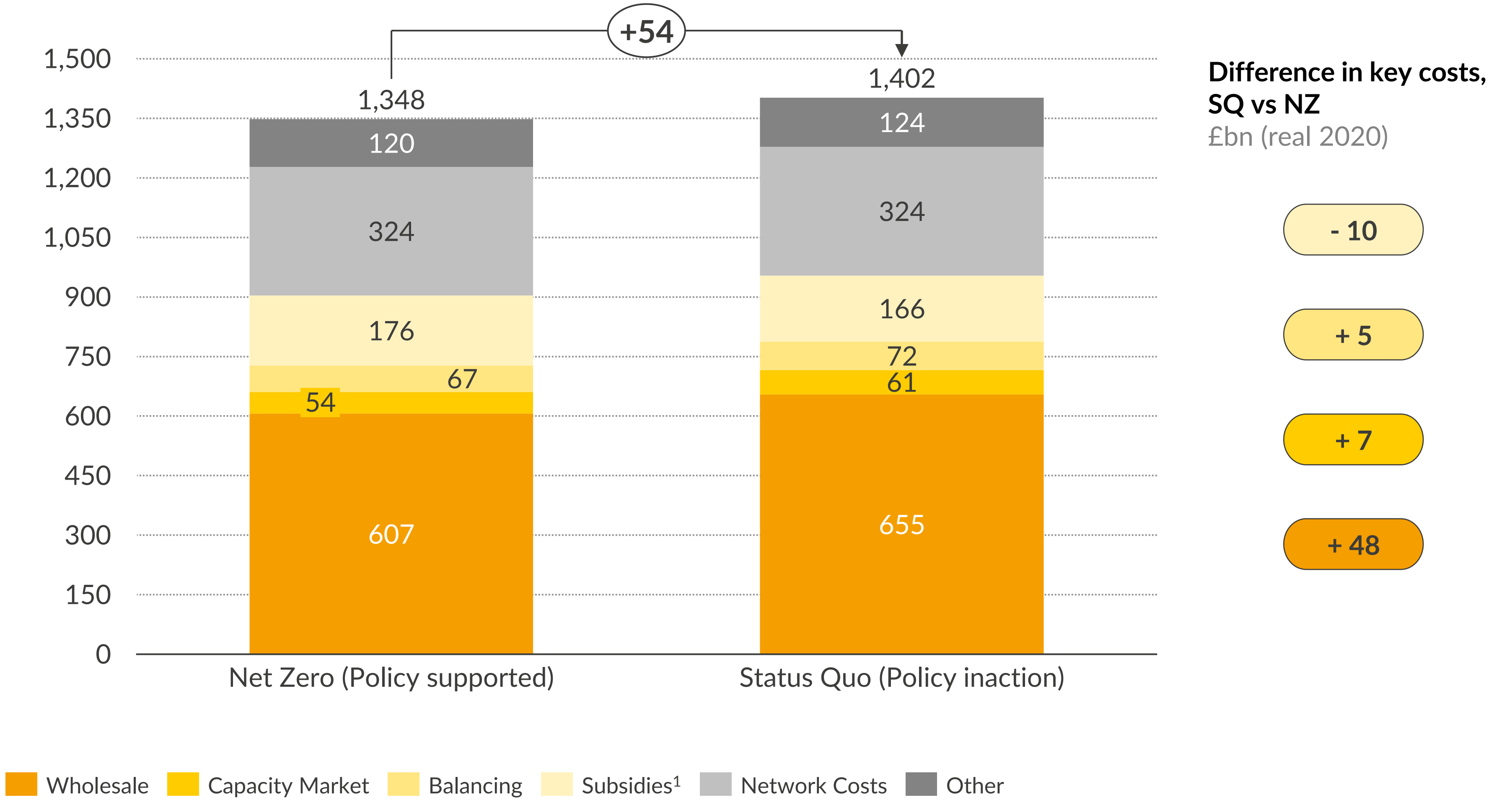
Cumulative power system costs (2021-2050)
£bn (real 2020)



- In addition to missing emissions reductions targets[4], the Status Quo scenario results in a higher total system cost
- Relative to the policy supported Net Zero scenario, total system costs are £54 billion higher in the Status Quo scenario
- This translates to an additional £58/year in energy costs to the average household in UK **failing the objective of minimising costs to consumers**
- Majority of the increase comes from higher wholesale costs, driven by higher baseload prices due to more unabated gas capacity in this scenario, which drive up power prices
- Costs arising from the Capacity and Balancing Markets are also slightly higher, while subsidy costs are lower due to reduced subsidised capacity and higher power prices lowering the spend on top-up payments

1) Includes forecast cost of FiT, ROC and CfD payments. 2) Includes electricity, gas and hydrogen network costs. 3) Includes storage and transportation costs for hydrogen and carbon dioxide, as well as the cumulative cost of the hydrogen wholesale market. 4) Costs of missing emissions targets and potential carbon tax revenues not included in analysis.
Source: Aurora Energy Research

Inaction on dispatchable generation policy could cost at least 65% more in investments to ensure security of supply

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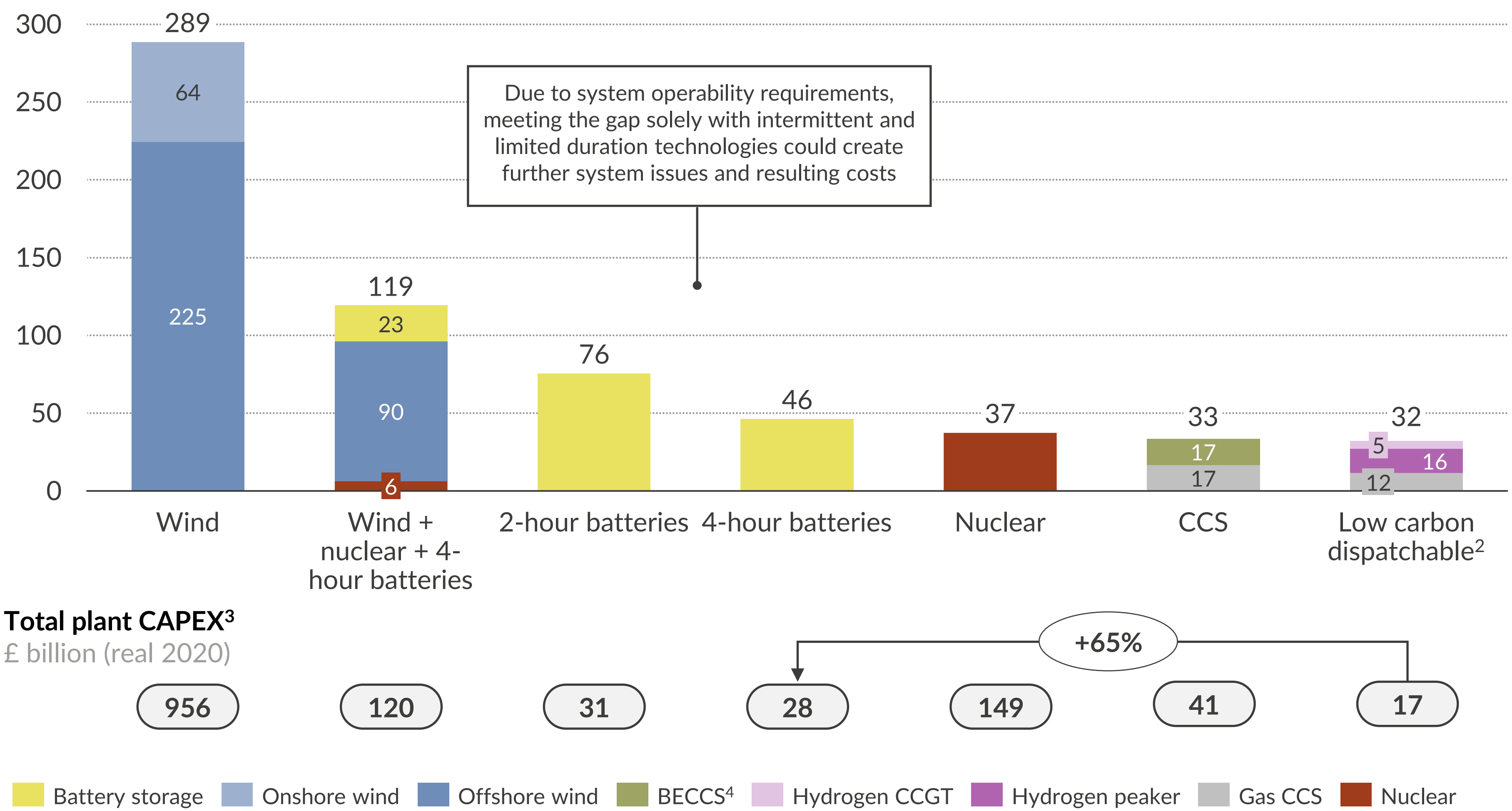
Capacity required to fill estimated 2035 deficit (30 GW de-rated capacity)[1]
GW, nameplate capacity



- Low-carbon dispatchable capacity will be the most economic option to guarantee security of supply and achieve decarbonisation objectives
- A combination of hydrogen and CCS plant conversions could supplement the capacity deficit at an economical cost of **£17bn**
- Batteries also present an economical option at c. £30bn but technological limitations make this option less viable
- The intermittency of wind and low contributions to security of supply means any options focused on wind will require over 90 GW by 2035 costing north of £100 billion
- Although more expensive at **£41bn**, a CCS focused strategy including 17 GW BECCS would **benefit from negative emissions** however, this would require at least 7 GW new build capacity based on the existing pipeline of potential conversions

1) Capacity deficit estimated based on known and planned capacity additions and retirements on a de-rated basis as shown in Section IV here. 2) Assuming conversions of existing assets for CCGTs and new build peakers. 3) Includes capital costs for the plants only. Other cost considerations not included e.g. infrastructure costs. 4) Includes EfW. 5) Estimated emissions removals of c.55 $MtCO_2e$ by 2035[4] in line with the Net Zero strategy assuming a 40% load factor and carbon intensity of -941 gCO2/kWh.

Sources: Aurora Energy Research, CCC, UK Net Zero Strategy

Agenda

Current policies have been effective at securing firm capacity and decarbonising the grid but will need to adapt to a Net Zero world

A Capacity Market (CM)

- The CM was introduced to ensure national energy security by procuring a sufficient level of firm capacity to meet peak electricity demand and security of supply standards (< 3 hours Loss of Load Expectation (LOLE) per year)
- It operates by providing the necessary payments to enable plants to deploy or remain operational and contracts are awarded in durations of up to 1, 3 and 15-years for existing, refurbishing and new build respectively
- Since the first auction in 2014, the CM has successfully met this goal and has procured an average of 52 GW de-rated capacity through the T-4 auctions, dominated by gas assets

Policy limitations

- The CM is effective at deploying capacity but **does not incentivise dispatch on its own**
- **Low clearing prices** will not support the deployment of low carbon dispatchable assets
- **Loose emissions limits** allows unabated dispatchable assets to deploy

Potential modifications

- **A 2-stage auction with separate bidding and higher prices for low carbon technologies could support deployment of low carbon dispatchable assets**
- Stricter emissions limits could incentivise abated capacity over unabated assets

B Contracts for Difference (CfD)

- The CfD scheme was introduced to support the deployment of renewables capacity in line with the Government's decarbonisation agenda
- It is secured via competitive auctions and operates as a two-way floating premium, guaranteeing a price for generators
- There have been three competitive CfD rounds to date which including the initial FIDER[1], have procured 16 GW of renewables capacity
- The CfD allocations have resulted in steady decreases in strike prices across all RES technologies and been instrumental in driving investor confidence so could support low carbon dispatchable technologies in a similar manner

Policy limitations

- The CfD auctions are **limited to specific technologies** and new build assets, potentially excluding technologies that will be critical in a Net Zero world
- CfDs would **incentivise baseload dispatch** of dispatchable assets which has knock on impacts to the wider market system through excess dispatch signals in competition with other low carbon technologies

Potential modifications

- **Similar to offshore wind, existing CfD could be expanded to include a new pot for firm low carbon dispatchable technologies**
- Higher strike prices could be set as required by the low carbon technologies

1) Final Investment Decision Enabling for Renewables (FIDER)

Sources: Aurora Energy Research, EMR, BEIS, LCCC

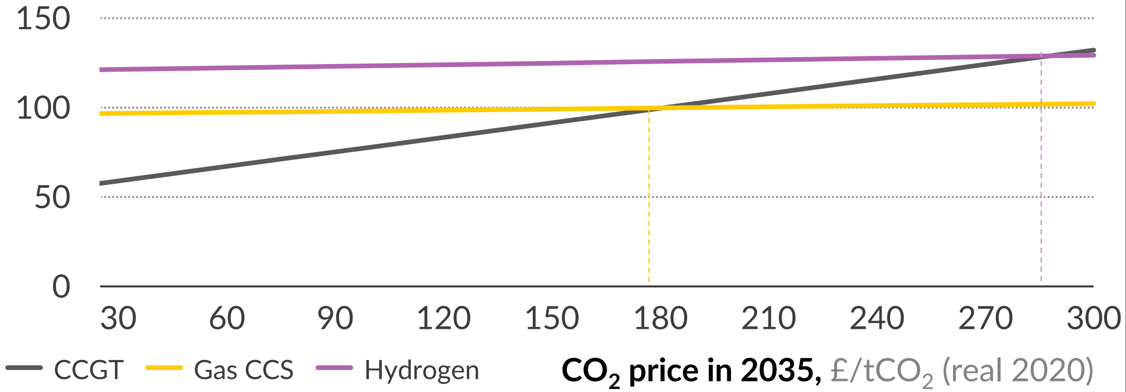
Total carbon prices above £150/tCO_2 by 2035 will be required to make low carbon thermal assets competitive

AURORA

C Carbon pricing

- Carbon pricing operates by imposing prices on carbon emissions to disincentivise carbon intensive energy and processes in favour of lower carbon alternatives
- It has proven to be an effective policy tool for phasing out carbon intensive generation and incentivising lower carbon generation
- The introduction of the EU-ETS and carbon price support in the 2000s helped phase out significant amounts of coal generation as well as gas generation in favour of renewables over the last decade
- **Carbon pricing as a policy tool could incentivise both CCS and hydrogen assets but at different price levels**

LCOE of dispatchable thermal assets in 2035[1], £/MWh (real 2020)



Policy limitations

- Current carbon price levels are still favourable to unabated assets and would not incentivise low carbon dispatchable generation required for Net Zero
- Carbon prices alone are not bankable thus unable to drive investor confidence
- The effectiveness of carbon pricing as a policy tool in power runs out after a certain level as fewer thermal assets remain on system

Potential modifications

- **Stricter total carbon prices** could price unabated assets out of merit and incentivise flexible operations of low carbon dispatchable generation
- The bankability of carbon prices could be addressed via the introduction of **a Carbon Contracts for Difference (CCfD) scheme**

D Carbon Contracts for Difference (CCfD)

- A CCfD is a long-term contract that would pay the difference between the contractually-fixed CO_2 strike price and the actual carbon price. It could be adopted to support the deployment of low-carbon technologies, but would require a high strike price.

CCfD Payment = (**Carbon strike price** – **Actual carbon price**) × **Avoided carbon**

- **Key advantages** of CCfD mechanism include its bankability and ability to remunerate avoided carbon. This could be leveraged to support deployment of BECCS or other negative emissions technologies.
- **Potential limitation** is that it will likely be needed in conjunction with another policy to fully incentivise flexible dispatch of low carbon assets.

1) LCOE's shown for existing assets and likely conversions. Assumes average 30% load factors for all assets and the following asset efficiencies: CCGT - 50%, CCS – 44%, Hydrogen – 50%

Sources: Aurora Energy Research, BEIS

The proposed DPA would incentivise low carbon capacity and flexible dispatch but requires amendments to be fully effective

E Dispatchable power agreement (DPA)

The Government is planning to implement the Dispatchable Power Agreement (DPA) business model for Power CCS plants as part of its Net Zero strategy. This is designed to incentivise power CCS to operate flexibly, dispatching after renewables and nuclear, but ahead of unabated thermal. The DPA will consist of two payments:

1. **Availability payment** – to subsidise upfront capital costs
   - This payment is intended to provide investors with a regular payment based on the availability of capacity
   - The payment will be based on a fixed monthly Availability Payment Rate (APR), with settlement adjusted to reflect the availability of generation and availability of capture that the plant is able to achieve
   - The APR will be set through either a negotiated or competitive allocation process and contracts will be awarded to projects based on their choice of an appropriate term length that is between 10 and 15 years

Availability payment = Availability of generation × Availability of capture × Plant capacity × Availability payment rate

2. **Variable payment** – to incentivise dispatch
   - This payment will be given as an incentive for power CCS plants to generate ahead of unabated plant when demand cannot be met by renewables and nuclear
   - The variable payment will be calculated by considering the difference in short run marginal cost between the power CCS plant as agreed in the DPA contract and a reference unabated plant
   - The payment will however only be made at times where the market conditions are not sufficient to incentivise CCS dispatch ahead of unabated plants

Variable payment = Gas cost differential + Carbon cost differential + T&S volumetric payment rate + Additional variable cost

Key advantages

- Its ability to **incentivise the deployment of low carbon capacity and flexible dispatch** of the deployed capacity
- The DPA will **mitigate merchant risk and provide sufficient investor confidence** to unlock private sector investment and expertise

Potential limitations

- Lack of competition could also stunt otherwise rapid innovation, development and cost reductions of abated gas assets – **adopt a competitive approach and grant open access to the scheme**
- Assets with CM contracts are restricted from negotiating DPAs - to avoid potential capacity gaps, **a mechanism would be required to allow the contracted assets to transition to the DPA**

An amended DPA addressing the potential limitations will sucessfully support low carbon dispatchable technologies through the transition

Sources: Aurora Energy Research, BEIS

A 2-stage CM auction coupled with stricter carbon pricing could send adequate market signals to incentivise dispatchable thermal assets

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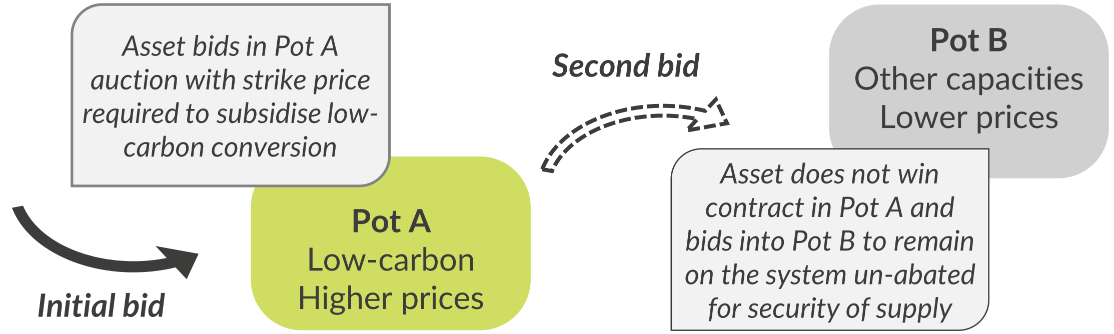
A new 2-stage CM auction with separate bidding for low carbon technologies could support the deployment low carbon assets

- At present the CM is technology neutral and all types of capacity are eligible to participate, providing they can demonstrate their contribution to security of supply
- This has resulted in high levels of participation from gas-fired generation which provided c.two-thirds of capacity in the 2024/25 auction
- To align with net zero targets, BEIS is considering introducing split auctions to enable low carbon alternatives to deploy, whilst continuing to support unabated thermal for its contribution to system security
- **Split auctions could allow a price to be set to support refurbishments on a competitive basis**, by allowing existing plants to bid in both auctions: an initial bid in the low carbon auction (Pot A) in anticipation of converting, and if unsuccessful, a second bid in to the other bucket (Pot B)

Illustrative bidding strategy in a two-stage CM for an existing asset



Policy limitations

- A modified CM could prove effective at supporting the deployment or conversion of low carbon capacity, however it would not provide price signals to incentivise low-carbon flexible dispatch

Potential modifications

- A combination of a 2-stage auction with higher carbon prices or subsidised H2 prices would incentivise both the deployment and dispatch of low carbon flexible assets

- **To incentivise low-carbon dispatch, hydrogen price support or a CCfD could be implemented alongside the modified 2-stage auction**, although care would be required to avoid the appearance of double subsidies
- Higher carbon prices would support abated gas, by pushing unabated gas out-of-merit, however high prices would be required (see page 29). High carbon prices may also be insufficient to attract investment as investors may not have confidence in the long term carbon price trajectory
- An alternative to higher carbon prices would be to adopt a CCfD scheme where a guaranteed carbon strike price would drive investor confidence and incentivise low carbon assets to deploy ahead of unabated plants
- Subsidised hydrogen prices could also bring hydrogen plants below unabated gas in the merit order, whilst remaining higher than RES and biomass, incentivising the flexible dispatch of hydrogen assets

We have presented one potential policy combination that can incentivise low carbon dispatchable assets, other options exist that could be as effective.

Sources: Aurora Energy Research, BEIS

Agenda

Aurora's outlook for the GB power market is shaped by the evolution of four key fundamentals

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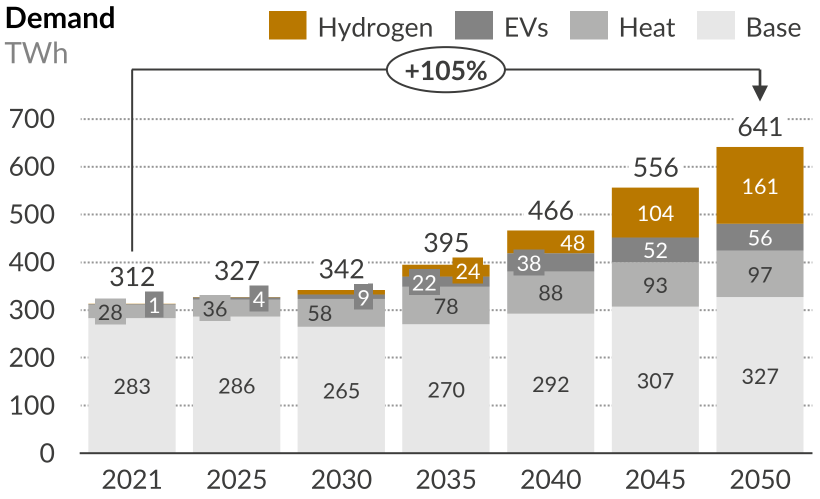
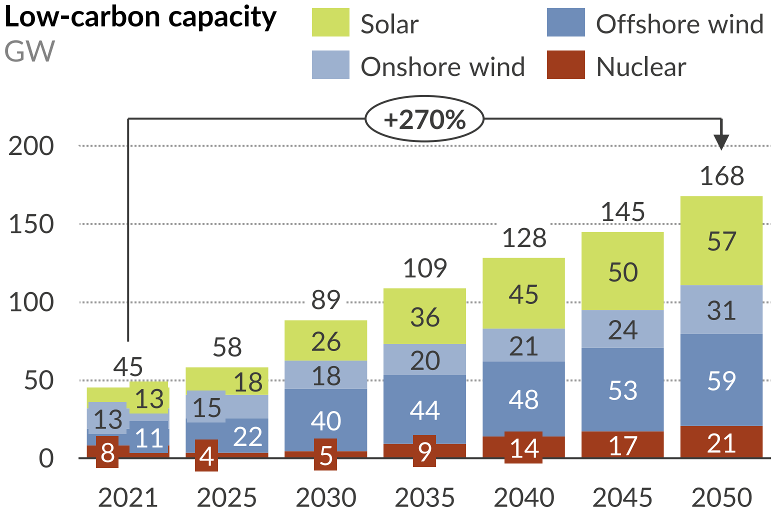
1 Power demand

- Stringent decarbonisation efforts see demand increase by 105% from today to 2050
- This is driven mainly by rapid electrification of heat and transport as well as hydrogen production via electrolysis



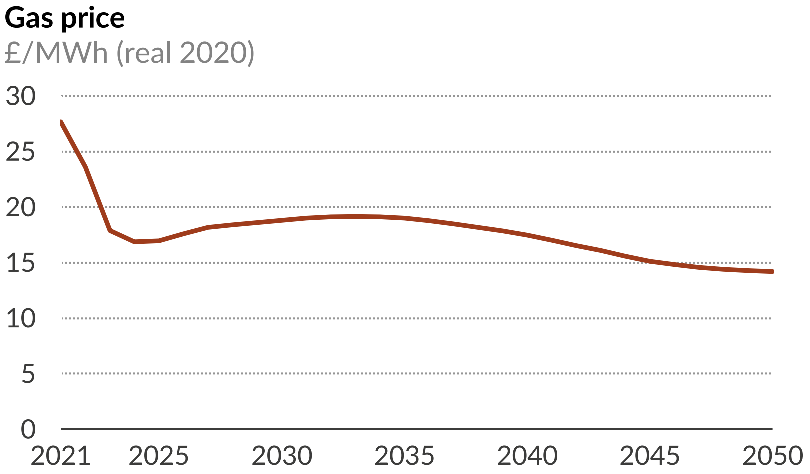
2 Low-carbon capacity

- In order to meet increasing power demand, low-carbon capacity increases three-fold by 2050
- Much of the increase comes from offshore wind which reaches 40 GW by 2030, in line with government ambition



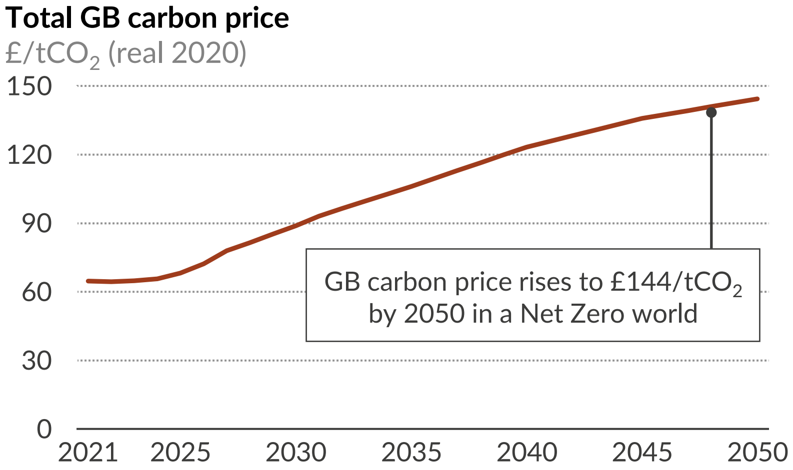
3 Gas prices

- Our GB Net Zero scenario assumes that efforts are made globally to limit warming to 2-degrees
- Gas prices are expected to fall from today's highs and rise slightly in the 2030s due to strong Asian demand, before falling to a low of £14/MWh in 2050



4 Carbon prices

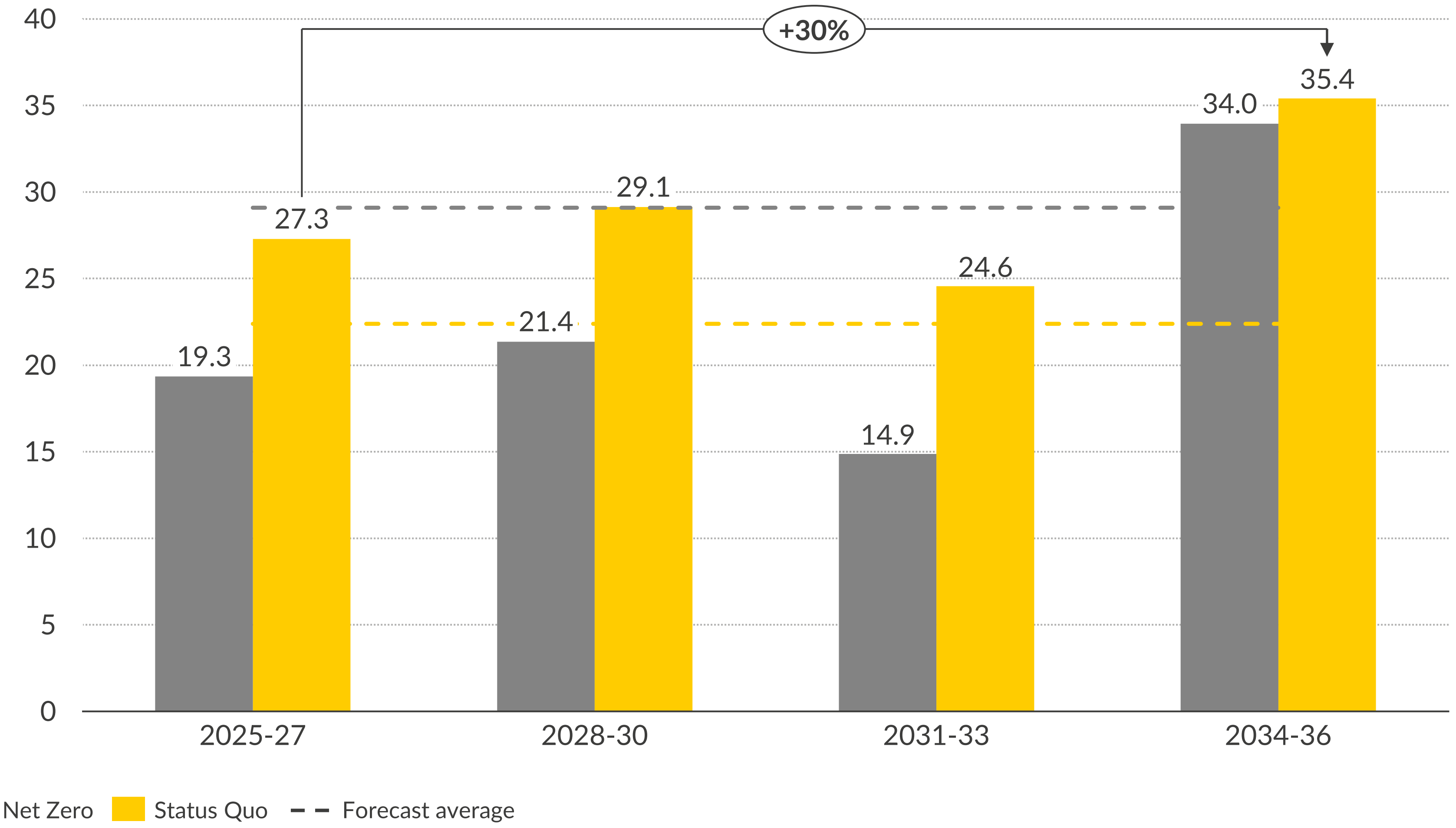
- Higher carbon prices are expected with stringent Net Zero targets
- We assume a rise in carbon prices to £144/tCO_2 by 2050, reflecting the required marginal abatement across most sectors to decarbonise



Source: Aurora Energy Research

Capacity Market prices average £29/kW between 2025 – 2036, a £7/kW increase relative to our Net Zero scenario

Average CM clearing prices[1]
£/kW (real 2020)



- Capacity Market (CM) prices are expected to increase in the future due to the retirements of ageing CCGTs and nuclear capacities, plus the mandatory closure of coal which necessitate the entry of new build firm-capacities.
- With the continued deployment of renewables and other low carbon firm capacity eroding the load factors for firm capacities, the 'missing money' problem for thermal assets increases – further driving higher CM prices
- Relative to our Net Zero scenario, CM prices are £7/kW higher - this is due to the high amounts of otherwise subsidised low carbon dispatchable capacity in the Net Zero scenario which do not feature in the Status Quo

1) The Capacity Market is modelled assuming current policy and regulatory set-up, and does not include any potential changes to the mechanism which BEIS/Ofgem are looking at through their consultations, such as BEIS' Net Zero review.
Sources: Aurora Energy Research

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