UK Government

# Electricity Generation Costs 2025

First published January 2026

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# Contents

## Acronym glossary

| | |
|---|---|
| ACT | Advanced Conversion Technologies |
| AD | Anaerobic Digestion |
| AMR | Advanced Modular Reactor |
| ASP | Administrative Strike Price |
| BECCS | Bioenergy with Carbon Capture and Storage |
| BSUoS | Balancing Services Use of System |
| CAPEX | Capital Expenditure |
| CCGT | Combined Cycle Gas Turbine |
| CCHT | Combined Cycle Hydrogen Turbine |
| CCUS | Carbon Capture Utilisation and Storage |
| CfD | Contract for Difference |
| CHP | Combined Heat and Power |
| CPF | Carbon Price Floor |
| CPS | Carbon Price Support |
| DESNZ | Department for Energy Security and Net Zero |
| DPA | Dispatchable Power Agreement |
| DSA | Demand-Side Aggregators |
| DUoS | Distribution Use of System |
| EEP | Energy and Emissions Projections |
| EfW | Energy from Waste |
| EPC | Engineering, Procurement, and Construction |
| EU ETS | European Union Emissions Trading System |
| UK ETS | UK Emissions Trading Scheme |
| FLOW | Floating Offshore Wind |
| FOAK | First of a Kind |
| GW | Gigawatt |
| GWh | Gigawatt-hour |
| HHV | Higher Heating Value |

| | |
|---|---|
| H2P | Hydrogen to Power |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| LCOE | Levelised Cost of Electricity |
| LHV | Lower Heating Value |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NOAK | Nth of a Kind |
| NPV | Net Present Value |
| OCGT | Open Cycle Gas Turbine |
| OCHT | Open Cycle Hydrogen Turbine |
| OPEX | Operating Expenditure |
| O&M | Operations and Maintenance |
| PPA | Power Purchase Agreement |
| PV | Photovoltaic |
| RAB | Regulated Asset Base |
| SMR | Small Modular Reactor |
| T&S | Transport and Storage |
| TNUoS | Transmission Network Use of System |

# Introduction

Electricity generation costs are a fundamental part of energy market analysis, and a good understanding of these costs is important when analysing and designing policy which ensures electricity security and decarbonisation in a cost-effective way.

This report presents estimates of the costs and technical specifications for different generation technologies based in Great Britain.

Since the publication of the Generation Costs Report 2023, we have updated key assumptions for a wide range of technologies. The information in this report reflects a significant update to the evidence base. The underlying research reports with full details of individual updates can be found on the Generation Costs series on gov.uk[1].

## Updates in this report

The following assumptions have been updated:

- The Department commissioned an external provider to review assumptions for hurdle rates across 30 power sector technologies.
- The Department commissioned external providers to update cost and technical assumptions for:
    - Onshore wind
    - Large-scale solar photovoltaic (PV)
    - Fixed offshore wind
    - Geothermal for power (and for heat)
    - Unabated gas (CCGT, OCGT, gas reciprocating engines)
    - Hydrogen to power (CCHT, OCHT, hydrogen reciprocating engines)
- The Department carried out internal analysis and updated the methodology to estimate net load factors for wind technologies.
- Assumptions have been updated where available from other published updates, including fossil fuel price projections, hydrogen fuel projections, carbon price projections and inflation series[1].

All other assumptions remain the same as in the Generation Costs Report 2023, unless otherwise stated. The discussion and Annexes in this report do not include costs for technologies updated prior to the previous report. Assumptions for these technologies and can be found in previous Generation Cost Reports.

[1] Energy generation cost projections - GOV.UK

## Scope of the report

In scope:

- The costs of pre-development (e.g. planning), construction, operation, and carbon emissions, reflecting the cost of building, operating and decommissioning a generic plant for each technology.

Out of scope:

- Potential revenue streams accruing to generators, such as revenue from electricity markets or via policy support schemes (except for heat revenues for Geothermal technologies).
- Wider system costs beyond those faced by the developer, and wider system benefits of deploying generation assets. These cannot be assessed without whole power system modelling.

The report summarises some of the key results and findings from the updated cost and technical assumptions. The underlying research reports contain further information and background.

The department undertakes comprehensive whole-system modelling of the power sector to understand how the power sector could evolve in future while meeting security of supply and legally binding emissions limits. LCOEs are not used directly in the department's modelling, but underlying generation cost assumptions, such as CAPEX and OPEX, along with other assumptions on demand, capacities, and financial incentives (such as Contracts for Difference) are used in the department's power system models to explore how the sector might evolve in the future.

## Report structure

- **Section 1** provides an overview of generation costs.
- **Section 2** outlines how the Department uses generation cost data in its modelling, including the differences between generation costs and administrative strike prices.
- **Section 3** outlines levelised costs of electricity (LCOE) given this metric is then used in subsequent sections.
- **Section 4** outlines the changes to cost assumptions that we have made in our most recent review.
- **Section 5** presents selected LCOE estimates generated using the department's LCOE Model.
- **Section 6** presents sensitivity analysis on LCOE for specific uncertainties.
    - **Annex A**: Further generation cost data and assumptions are published alongside this report in Annex A. Annex A also contains updated LCOE estimates for a range of technologies commissioning from 2025 to 2050.
    - **Annex B** provides example calculations of LCOE for each technology updated.

## Uncertainty

As with any projection, estimating current and future electricity generation costs involves uncertainty. This report presents ranges of generation cost estimates that the Department considers robust for the Department's analysis. These estimates should be treated with appropriate regard to the uncertainties, and users must account for these uncertainties when using the data.

These uncertainties include the potential for unanticipated cost reductions or increases in less mature technologies, greater uncertainty for technologies where the Department has access to less detailed evidence and uncertainty around fossil fuel prices and carbon prices. The assumptions in all generation cost parameters are not project specific. The assumptions are intended to provide a broad order of magnitude to reflect a generic plant of each technology. To illustrate the potential effects of these uncertainties, the report presents ranges and sensitivity analysis on the effects of changes in parameters.

# Section 1: Overview

This section outlines the components that comprise generation costs and how these are evaluated.

## Presentation of costs

Generation costs include a range of cost and technical assumptions covering all stages of a plant's lifetime along with future projections for cost trajectories. Depending on the cost component, costs can be presented as an overall cost, as a cost per capacity or as a cost per unit of generation. Many costs within the written report are presented as the levelised cost of electricity (LCOE) which is a measure of the average cost per MWh generated over the full lifetime of a plant and enables generation costs to be presented as a single metric.

LCOEs provide a straightforward and transparent way of consistently comparing the costs of different generating technologies with different characteristics, focusing on the costs incurred by the generator averaged over the lifetime of the plant. However, the simplicity of the measure means that there are factors which are not considered, including a technology's impact on the wider system given the timing, location, and other characteristics of its generation. For example, a plant built a long distance from centres of high demand will increase transmission network costs, while a 'dispatchable' plant (one which can increase or decrease generation rapidly) will reduce the costs associated with grid balancing by providing extra power at times of peak demand. Full power system modelling is required to evaluate the system costs of different power sector capacity mixes.

While LCOEs have their limitations, at a high-level they remain an effective tool to use to communicate generation costs and changes associated with different technologies and the Department will continue to use them in this context.

All cost estimates are in 2024 real values unless otherwise stated. GDP deflators are used to convert costs in other years unless otherwise stated.

## Generation cost components

Generation costs include all costs and technical assumptions that a developer is liable for and, as such, are generally those associated with the generator and site itself and not the wider electricity system. Precise definitions for each technology can be found within the underlying research reports.

***Capital costs***: These are costs relating to all elements of the construction of the power plant and include pre-development costs and infrastructure costs as well as the plant construction costs. Infrastructure costs include on site civil works and any buildings, cabling and grid connection and costs associated with supporting systems. Capital costs are generally assessed on a £/kW basis, other than infrastructure which is presented in £ basis.

***Operational costs***: These are all costs associated with the operation of a plant once built and include both fixed costs assessed on a £/kW/year basis and variable costs assessed on a £/MWh basis. Fixed operating costs include staffing costs and routine maintenance and any equipment contracts. Variable costs include any costs that increase with operating hours. For plants that require fuel, such as gas or nuclear plants, this includes the cost of fuel.

***Technical assumptions***: These include the capacity of the plant and assumptions including availability, efficiency and load factor. These are required to estimate the expected generation from a plant. The load factor is the ratio of actual operational hours over maximum operational hours and relates to the characteristics of an individual technology and also assumed operation within the system. This is discussed further in Section 3.

***Phasing***: The timescales for pre-development, construction and operational periods are part of generation cost and technical assumptions. These inform overall costs as a plant that operates for longer period than another with the same cost will be cheaper over its lifetime.

***Cost projections***: For less established technologies there will generally be some learning associated with increased deployment that is factored into future cost estimates.

***Financing costs***: Hurdle rates are the minimum internal rate of return for a project to proceed and are used in a wide range of analysis. When used in the presentation of LCOEs these are applied as the discounting rate and not as a separate cost component.

***Not included***: the generation costs we present do not include the cost of renting or purchasing land although an indication of these costs can be found in the underlying research reports. Similarly, community benefit payments are not presented in the report or Annex A but are discussed in the underlying research.

## Technology maturity

When generation costs are reviewed for a technology, an assessment is made of the level of technological maturity of projects deployed in the UK. In general, technologies are categorised into first-of-a-kind systems (FOAK) or nth-of-a-kind systems (NOAK). If relevant, very early projects are described as demonstration projections (DEMO). Depending on the technology, this can progress as a step-change from FOAK to NOAK, for example where the progression assumes some fundamental change in the technology, such as a step increase in efficiency, whereas many technologies are assumed to progress from early examples to established more gradually. We would generally expect greater uncertainty in cost estimates for technologies which are nascent than those which are more established.

Of the technologies updated or discussed in this report, offshore and onshore wind, large-scale solar, and all unabated gas technologies are established (NOAK) technologies whereas deep geothermal for power, tidal stream energy, floating offshore wind and hydrogen to power are assumed to currently reflect more nascent (FOAK) technologies and their potential trajectory to NOAK is discussed. While gas with post-combustion carbon capture and storage (gas CCUS) is a nascent generation technology in the UK, it combines two separate mature technologies. Therefore, for this report, it is considered neither FOAK or NOAK, and assumptions have been made accordingly.

## Sensitivity of generation costs

Generation cost and technical assumptions each have an associated uncertainty. LCOE estimates are modelled estimates that are sensitive to the underpinning data and assumptions. Different technologies have different characteristics and their LCOE will be affected, to a greater or lesser extent, by specific assumptions. For example, capital intensive technologies are relatively more sensitive to hurdle rate assumptions whereas those with proportionally higher operational costs will generally be more sensitive to assumptions like fuel costs.

This report captures some of these uncertainties through ranges presented around key estimates in section 5 and 6: load factors, hurdle rates, CAPEX, fuel costs, and carbon costs with additional ranges in Annex A. However, not all uncertainties are captured in these ranges. It is often more appropriate to consider a range of costs rather than point estimates.

Generation costs are estimated for a generic plant, rather than site-specific. Land costs are typically not included, and use of system charges are calculated on an average rather than a site-specific basis.

## Current cost environment

We are in a different environment to when the last Generation Costs Report was published in 2023 and have seen a range of pressures that have impacted on cost estimates including the pandemic and Ukraine war. The updated costs presented within this report have sought to factor in macroeconomic pressures appropriately in the assessment of current and future cost estimates.

Most of the cost updates presented in this report reflect data collected around 2024 and so post-date the recent period of significant price spikes due to macroeconomic pressures. For technologies or generation cost components where baseline costs were collated prior to this, the numbers published are in real prices (converted using a GDP deflator) and therefore do account for general price inflation. There is significant uncertainty about how long commodity price increases and short-term economic pressures persist and this analysis will not capture all future uncertainty on costs. We will monitor these assumptions where appropriate in future to ensure they remain accurate.

The department periodically commissions research to update assumptions. We would welcome views on the angles that future research should take.

# Section 2: Generation costs: how the department uses generation costs

Generation costs can be used to inform a range of different analyses. This section briefly outlines the main use cases of generation costs metrics by the Department.

## Power sector modelling

The estimates outlined in this report provide a high-level view on the costs of different generating technologies. Because LCOEs are a simplified metric, this means that not all relevant issues are considered.

The department's full power system modelling, including the Dynamic Dispatch Model (DDM) and BID3 power sector model use generation cost assumptions, such as CAPEX and OPEX, along with other assumptions on demand, capacities, and financial incentives (such as Contracts for Difference) to explore how the power sector might evolve in the future. Here the profitability of any individual plant is dependent on the wider capacity mix, its cost relative to other plants, network constraints, flows of power between GB and interconnected markets, and any subsidies received.

## Renewable auction administrative strike prices (ASPs)

Generation cost assumptions, including capex costs, opex costs, technical assumptions, load factor estimates and hurdle rates, are one set of inputs into setting administrative strike prices – the maximum strike price applicable to a technology in a Contracts for Difference (CfD) allocation round.

However, neither generation cost assumptions, nor these assumptions summarised in the form of LCOE estimates, provide an indication of potential future administrative strike prices (ASPs) for technologies in Contracts for Difference (CfDs) allocation rounds due to other important inputs relevant to a specific round or technology. Each of these metrics is used in specific contexts although both are presented in £/MWh.

Other inputs to ASPs, including market conditions and policy considerations, may include:

- Revenue assumptions (which aren't accounted for in LCOE estimates)
- Other costs not included in our definition of LCOE (for example the generator's share of transmission losses, route to market costs reflected in Power Purchase Agreement (PPA) discounts, and technology-specific estimates for decommissioning costs and scrappage values)
- CfD contract terms including length (during which the CfD revenue will be received), risk allocation, and eligibility requirements within technologies.
- Other relevant information such as studies or data published by industry
- Developments within industry
- Wider policy considerations (for example the relevant ambitions for different technologies)

The generation costs data presented in this report may be different from that used as part of the ASP-setting process. This is particularly true where information relevant to potential bidders in a particular allocation round is used to inform cost assumptions for pipeline projects. Further, ASPs are normally set so as to bring forward the most cost-effective projects, which may not be the same as the estimates of generic project costs estimated in this report.

For all these reasons, the LCOEs presented here may be significantly different from the ASPs that are set for CfDs and therefore should not be seen as a guide to potential future administrative strike prices.

# Section 3: Generation costs: Levelised Cost of Electricity

This section goes into further detail on the levelised cost of electricity (LCOE) given the use of this metric throughout later sections of this report as a tool to present updated generation costs across technologies.

## Definition

The LCOE is the discounted lifetime cost of building and operating a generation asset, expressed as a cost per unit of electricity generated (£/MWh). It covers all relevant costs faced by a generic generator, including pre-development, capital, operating, fuel, and financing costs. This is sometimes called a life-cycle cost.

The LCOE of a generation technology is the ratio of the total costs of a generic plant to the total amount of electricity expected to be generated over the plant's lifetime. Both are expressed in net present value terms. This means that future costs and outputs are discounted, when compared to costs and outputs today. Because the financing cost is applied as the discount rate, this means it is not possible to express it as an explicit part of the LCOEs in £/MWh.

## Purpose

LCOEs provide a straightforward and transparent way of consistently comparing the costs of different generating technologies with different characteristics, focusing on the costs incurred by the generator averaged over the lifetime of the plant. They are an effective tool for capturing generation costs and reflecting changes associated with different technologies, and the Department continues to use them in this context.

## Limitations

There are some factors which are not considered in LCOEs, including a technology's impact on the wider system given the timing, location, and other characteristics of its generation. For example, a plant built a long distance from centres of high demand will increase transmission network costs, while a 'dispatchable' plant could reduce the costs associated with grid balancing by providing extra power at times of peak demand, but could also run less frequently than a given LCOE assumes depending on the wider power mix in which it is integrated. That is why full power system modelling is required to evaluate the system costs of different power sector capacity mixes.

The capacity mix will impact the load factors of plants in the system. A system with higher levels of renewables would decrease average load factors for wind and solar capacity, for example. Unabated gas capacity is expected to play an increasingly important role in maintaining security of supply but is likely to operate at lower average load factors in a decarbonised system, with the extent of this reduction dependent on the composition of the wider capacity mix and patterns of demand. Broadly, technologies with different characteristics are complements, rather than substitutes, therefore a direct comparison of LCOEs between different classes of technologies is not appropriate.

LCOE estimates do not consider revenue streams available to generators (e.g. from sale of electricity or revenues from other sources). One exception to this is heat revenues for Combined Heat and Power (CHP) plants (including Geothermal). As the cost of the owning and operating the CHP technology is included in the capital and operating costs of the plant, heat revenues are also included so that the estimates reflect the net cost of electricity generation only.

The electricity system is a dynamic and complex system, and a simple LCOE metric is unable to capture all the complexities. To assess power sector policies, and the role that a specific technology plays in the system a comprehensive power system model is required. A full system model captures costs, reliability, emissions, and market behaviour, to allow for robust policy assessment.

## How to estimate

Figure 1 demonstrates at a high level how LCOEs are calculated and what is included. For further information on how LCOEs are calculated, details on the categories, and the department's LCOE Model, please refer to section 4.2 of Mott MacDonald (2010).[2]

Annex B contains example LCOE calculations for a sample of the technologies updated in this report, to illustrate how the department calculates LCOEs in more detail.

[2] UK Electricity Generation Costs: Mott MacDonald update (2010) - GOV.UK

### *Figure 1 - Overview of levelised cost calculation*[3]

**1: Gather plant data and assumptions**

| | |
|---|---|
| **Capital expenditure (CAPEX) costs** | Pre-development costs*<br>Construction costs*<br>Infrastructure costs<br>**adjusted for learning over time* |
| **Operating expenditure (OPEX) costs** | Fixed operating costs*<br>Variable operating costs<br>Insurance<br>Connection costs<br>Carbon transport and storage costs<br>Decommissioning costs<br>Fuel prices<br>Carbon costs, including both ETS carbon prices, and the Carbon Price Support (CPS)<br>Heat revenues<br>**adjusted for learning over time* |
| **Expected generation data** | Capacity of plant<br>Expected availability<br>Expected efficiency<br>Expected load factor |

**Step 2: Sum the net present value of the total expected costs and net generation for each year**

$$\text{NPV of Total Costs} = \Sigma_n \frac{\text{total capex and opex costs}_n}{(1+\text{discount rate})^n} \qquad n = \text{time period}$$

$$\text{NPV of Electricity Generation} = \Sigma \frac{\text{net electricity generation}_n}{(1+\text{discount rate})^n} \qquad n = \text{time period}$$

**Step 3: Divide total costs by net generation**

$$\text{Levelised Cost of Electricity Generation Estimate} = \frac{\text{NPV of Total Costs}}{\text{NPV of Electricity Generation}}$$

[3] Note that in this table, net electricity generation refers to gross generation minus any internal plant losses/use before electricity is exported to the electricity network.

# Section 4: Generation costs: updates since the previous report

The introduction section outlined updates since the Generation Costs Report 2023. This section steps through each of these updates in further detail.

*Table 1: Updates since the Generation Costs Report 2023 and Links to Underlying Reports*

| Update | Link to underlying report |
| --- | --- |
| **Cross-cutting Assumptions** | |
| Hurdle Rates | Hurdle rate estimates for electricity sector technologies |
| Turbine Trajectories | Internal Analysis |
| Load Factor Methodology for renewable wind technologies | Load factors for renewable wind technologies |
| Fossil Fuel Price Assumptions | To be published in due course |
| Carbon Price Assumptions | To be published in due course |
| Hydrogen Fuel and Production Costs Assumptions | To be published in due course |
| **Technology Specific Assumptions** | |
| Solar | Onshore wind and solar cost and technical assumptions |
| Onshore Wind | Onshore wind and solar cost and technical assumptions |
| Fixed offshore Wind | Offshore wind cost and technical assumptions |
| Geothermal | UK geothermal energy review and cost estimations |
| Unbated Gas | Unabated gas cost and technical assumptions |
| Hydrogen to Power | Hydrogen to power cost and technical assumptions |
| Gas CCUS | Gas carbon capture plant capital expenditure benchmarking: methodology |

## Cross-cutting assumptions

This section covers updates to any assumptions that apply to multiple technologies.

### *Hurdle Rates*

#### *Overview*

DESNZ commissioned CEPA to develop hurdle rate estimates for a range of different electricity generation technologies, numbering 30 in total. These hurdle rate estimations are used as inputs in a range of analysis within the department and reflect a consistent approach across all power sector technologies. The research also included advice on the future updating of estimates.

Hurdle rates reflect the minimum internal rate of return (IRR) for a project investment. For example, if the net present value of the discounted (using the hurdle rate) future cashflows of a project are equal to or greater than zero, a project investment will proceed.

***Key results***

Hurdle rates have been updated for 30 power sector technologies with a general increase of 1-2 percentage points since the previously published research. In this report, we publish updated hurdle rates for the subset of power sector technologies with accompanying cost and technical updates. The updates for the other technologies (which are not published in this report) can be found in the underlying research. All LCOE estimates in this report use updated hurdle rate assumptions directly from the CEPA study, except for Hydrogen to Power (H2P) hurdle rates. H2P hurdle rates were adjusted based on internal expertise within the range quoted in the underlying research. This led to reduced hurdle rates for 50% fuel blending for CCHT plants to 2030[4], but increased hurdle rates for OCHT plants pre-2030[5].

### *Turbine trajectories for wind generation technologies*

Future load factors depend on the turbine sizes and their locations. Hence, establishing estimates for turbine size trajectories is required to feed into the methodology to produce load factor estimates. Turbine size trajectories are developed by a combination of reviewing historic trajectories and policy judgement based on industry knowledge. In reality, there will be a range of turbine sizes for any single year. Turbine size trajectories have been slightly updated from the previously published trajectories, new assumptions are shown in Table 2.

*Table 2: Turbine trajectories for wind technologies for different commissioning years*

| Technology | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| Onshore wind | 5MW | 6MW | 6.5MW | 7MW | 7MW |
| Offshore wind[6] | 13MW | 15MW | 17MW | 20MW | 20MW |

### *Load factor methodology for renewable wind technologies.*

***Overview***

An internal DESNZ update was carried out to update the methodology to estimate net load factors for renewable wind technologies.

A load factor measures actual electricity generated by a generation technology over the maximum possible if it ran continuously at full capacity, expressed as a percentage.

For wind turbines, the gross load factor is the theoretical value calculated from the turbine's power curve and wind resource without accounting for any losses. The net load factor is an adjustment to the gross load factor; accounting for real-world losses such as turbine downtime, internal wake effects, electrical transmission losses, turbine performance degradation, and environmental losses. Locational balancing and economic curtailment have not been included

[4] Many newbuild unabated gas CCGTs will be 30-50% hydrogen capable from the outset with no technical issues expected. Plants can dispatch like an unabated gas CCGT and can alternate between gas/hydrogen interchangeably with limited impact on operating costs.

[5] 100% hydrogen capable turbines are available today at small scale(<100MW). These are expected to carry an OPEX increase due to increased water demand, and have reduced efficiency (35% vs c. 38%).

[6] This offshore wind turbine trajectory is used in calculations for both fixed and floating offshore wind.

as losses for the purposes of the generation costs report, as the extent of curtailment is dependent on the rest of the energy system.

Please see the underlying research report[7] for further details of the updated estimation methodology.

The methodology uses satellite data and wind power curves to simulate the load factor of existing sites in Great Britain on an hourly basis. These simulated load factors are then calibrated against real generation data, to correct for errors in the simulations and additional losses.

***Key results***
Net load factors for selected turbine sizes are displayed below for different commissioning years. Incorporation of the full suite of loss factors, other than locational balancing and economic curtailment, reduces net load factors by 7-9 percentage points. The final load factors depend on a range of variables including but not limited to, the assumed wind turbine generator size and height (given that wind speeds vary with height).

*Table 3: Net load factor estimates for different commissioning years*

| Technology | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|
| Onshore wind | 36% | 37% | 37% | 37% | 37% |
| Offshore wind[8] | 48% | 49% | 50% | 50% | 50% |

## Fossil fuel price assumptions

***Overview***
Updated LCOE estimates for dispatchable technologies use, soon to be published, fossil fuel price assumptions[9]. The impacts on LCOE estimates of low, central and high fuel price projections are explored in section 6.

***Key results***
The previous report used the 2019 fossil fuel price assumptions, which were the most recent publication at the time. These are updated annually so we are now using the 2025 fuel price projections. Compared to the previous report, in real terms, central fossil fuel prices have decreased slightly, largely due to lower projected future demand due to increased electrification.

## Hydrogen fuel and production costs assumptions

Hydrogen production costs used DESNZ's internal Long Run Variable Cost (LRVC) appraisal values, due to be published in the next HM Treasury Green Book update. These do not include hydrogen transport and storage costs because values may differ depending on the H2P archetype.

7 Load factors for renewable wind technologies - GOV.UK
8 This offshore wind load factor is used in calculations for both fixed and floating offshore wind.
9 Link available shortly

### *Carbon price assumptions*

#### *Overview*

LCOE estimates in this report use, soon to be published, UK ETS carbon price assumptions[10]. The impacts on LCOE estimates of low, central and high carbon price assumptions are explored in section 6.

#### *Key results*

The 2023 report was prior to publication of the UK ETS price assumptions and used the published UK ETS price for the most recent year available in the short-term, whilst previous departmental modelling assumed carbon prices would reach the published appraisal cost of carbon (traded + social costs) by 2040. In this report, we use the 'soon to be published' ETS assumptions. The latest assumptions show a small change in carbon prices in the short-term, with reductions past 2040 as the estimates no longer converge to the appraisal cost of carbon.

This change in the department's carbon price assumptions means that any comparison of LCOEs with those in the 2023 Generation Costs for generation technologies that pay for their greenhouse gas emissions must be considered carefully. If the carbon price was assumed to reach the appraisal cost of carbon (as it was in the 2023 report) the LCOE of unabated gas technologies would be higher, in real terms, in the 2025 report than it was in the 2023 report for equivalent commissioning years.

Carbon costs used for generation technologies throughout this report include UK ETS carbon price assumptions and the Carbon Price Support (CPS).

## Renewable technologies

Key renewable technology costs have been updated from the 2023 Generation Costs Report. These are published in the underlying research reports:

- Costs for onshore wind and solar were commissioned in 2024 to Arup to update current cost estimates. Please see the combined research report published in October 2025.[11]
- Fixed offshore wind cost assumptions were commissioned to Arup in 2024[12] and subsequently peer reviewed in 2025.[13]
- Geothermal costs were commissioned to Arup in 2024, reviewed in May 2025 and published in August 2025.[14]

### *Large-scale solar photovoltaic (PV)*

#### *Overview*

In 2024, Arup were commissioned to update key renewable energy generation costs including large-scale solar photovoltaic (>5 MW). Small scale solar PV, including rooftop solar is not included. Solar PV is an established renewable technology and considered NOAK.

[10] Link available shortly
[11] Onshore wind and solar cost and technical assumptions
[12] Offshore wind cost and technical assumptions
[13] Offshore wind cost and technical assumptions peer review
[14] UK geothermal energy review and cost estimations

***Key results***

There have not been significant changes to the total LCOE estimates however, some individual component costs have changed. For example, solar project sizes for a generic plant are significantly larger than previously assumed. Furthermore, underlying hurdle rates have changed[15]. Please see the full report[11] for detail on macroeconomic trends impacting supply chains and input prices, contributing to LCOE estimate changes. The LCOE estimate in this report differs from the Arup report because of updated hurdle rate assumptions. CAPEX, OPEX, technical (including load factor), use of system, and phasing assumptions are taken from the Arup research.

### *Onshore wind*

***Overview***

In 2024, Arup were commissioned to update key renewable energy generation costs including onshore wind. Onshore wind is an established renewable technology and considered NOAK.

***Key results***

Total LCOE estimates have not experienced substantial changes from previous estimates, although individual components have. Changes are largely due to commodity price changes (notably steel), macroeconomic trends and supply chain impacts as well as hurdle rate changes. Onshore wind learning rates are not expected to be as steep as previously estimated. Please refer to the full report[11] for more detail. The LCOE estimate in this report differs from the Arup report because of updated hurdle rate and load factor assumptions. Capex, opex, technical and phasing assumptions as well as connection and use of system fees are taken from the Arup research.

### *Fixed offshore wind (including peer review)*

***Overview***

In 2024, Arup were commissioned to update key renewable energy generation costs including fixed offshore wind. The fixed offshore wind results were then subject to a peer review process in line with standard practice. The peer review assessed the approach taken by Arup as valid, but with access to a large database, suggested some adjustments were made to account for the small sample size from the surveyed developers. Fixed offshore wind is an established renewable technology and considered NOAK.

***Key results***

Overall, total LCOE estimates have seen an increase. Similarly to other renewable technologies, changes are due to commodity price changes, macroeconomic trends and supply chain impacts as well as hurdle rate changes. Fixed offshore wind capital costs vary significantly with distance from the shore.

The LCOE estimate in this report differs from the Arup report due to updated hurdle rate and load factor assumptions. CAPEX, OPEX and technical and phasing assumptions are based on the figures presented in the Arup research but modified as recommended by the subsequent peer review. The peer review concluded that the original Arup analysis relied on a relatively small sample size, which was skewed towards higher-cost projects. This resulted in inflated

[15] Hurdle rate estimates for electricity sector technologies

low and central cost estimates. To address this, low and central estimates were revised downward to provide a more representative and balanced view. The Use of System assumptions are taken from the Arup research.

## Geothermal

### Overview

Deep geothermal technologies offer the potential to deliver continuous baseload heat and power. In 2024, DESNZ commissioned Arup to conduct research to update electricity generation cost estimates and provide DESNZ's first heat generation cost estimates for geothermal technologies, along with consideration of lithium extraction potential and carbon intensity assessment[14]. The research consisted of data collection from both literature and stakeholders. This report focuses on the LCOE for geothermal. Deep geothermal was modelled as a combined heat and power (CHP) system to allow heat revenues to be accounted for within the LCOE.

The cost estimates in this report are restricted to geothermal granite figures. However, the full report[14] considers a range of deep and shallow geothermal technologies.

### Key results

Overall, deep granite geothermal technologies were found to have lower LCOE values than sedimentary LCOEs. This is due to the higher capacities that geothermal granite projects offer. LCOE estimates were found to be extremely sensitive to hurdle rates and drilling costs.

Revenue assumptions are very significant to overall LCOE. Geothermal plants for power also produce heat that can be utilised and sold, without needing to run in either heat or power mode as per some other combined heat and power plants. Costs reduce once heat revenues are incorporated into the LCOE. This report uses an avoided cost methodology for heat revenue assumptions as discussed in the previous Generation Costs Report and updated and discussed in the underlying research report. A heat to power output ratio of 3.8 is estimated and the avoided cost methodology assumes a conservative estimate for heat revenues, with 20% of heat assumed to be sold.

The Arup geothermal review and cost estimation research published in August 2024 presents LCOE throughout[14]. These results may differ from estimates in this report due to modelling differences between the ARUP's bespoke geothermal model and DESNZ analysis.

## Non-renewable technologies

Non-renewable technologies were updated via external research, and the underlying research which will be published accompanying this report are as follows:

- Unabated gas by CEPA and GHD[16]
- Hydrogen to power by Baringa[17]
- Gas CCUS Technologies[18] – Internal analysis, in collaboration with WSP consultancy, combining generic unabated gas capex and opex with generic carbon capture plant *capex*.

### *Unabated gas*

#### *Overview*

In 2025, DESNZ commissioned CEPA and GHD to update estimates of unabated gas generation costs. This was carried out in two phases, firstly via technical modelling with subsequent developer surveying via focussed interviews.

The following unabated gas technologies were included in the update:

- Combined cycle gas turbines (CCGT) – approximately 1700MW
- Open cycle gas turbines (OCGT) – 299 MW and approximately 770 MW
- Gas reciprocating engines – 20 MW
- Combined heat and power gas plants (CHP)[19]

An adjustment was applied by DESNZ to the unabated gas capex costs to account for the difference between modelled (lower) and survey (higher) results, and higher expected turbine prices supported by industry insight (see below). This adjustment was applied to the specialised component of capex.

#### *Key results*

Capex estimates are higher than the previous generation cost report. This is attributed to a lower supply of gas turbines worldwide linked to an increased demand for usage by data centres and countries transitioning from coal to natural gas as a source of flexible power. Technical modelling conducted by CEPA and GHD was based on data available in July 2024. Capex estimates were adjusted in June 2025 (see above) following additional insights from industry experts to reflect up-to-date knowledge on evolving market conditions. Connection and use of system fees were not updated as part of this research. Connection and use of system fees for gas are the same as the previous generation costs report, which have been deemed within a reasonable range of expected current gas connection and use of system fees, by internal experts.

As discussed in Section 4 above, LCOE calculations for greenhouse gas emitting technologies in this report use the department's updated carbon price assumptions, which no longer converge to the appraisal cost of carbon in the long-term. If the carbon price was assumed to reach the appraisal cost of carbon (as it was in the 2023 report) the LCOE of unabated gas

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[16] Unabated gas cost and technical assumptions
[17] Hydrogen to power cost and technical assumptions
[18] Gas carbon capture CAPEX benchmarking
[19] Not included in the Generation Costs Report or annexes.

technologies would be higher, in real terms, in the 2025 report than in the 2023 report for equivalent commissioning years.

This is demonstrated in Table 4, below. Table 4 compares the LCOE of a gas CCGT from the 2023 report, with the LCOE of a gas CCGT from this report, both commissioning in the year 2030 and operating at a 93% load factor. It compares the total LCOE for both using the carbon price assumptions from the 2023 report (which include the social cost and trend to the appraisal cost of carbon in the long-term) and the department's updated carbon price assumptions used in this report. Underlying figures are in Annex A of each report. All figures are in 2024 prices, with figures from the 2023 Generation Costs Report updated for inflation.

Dispatchable plants are expected to operate at a range of load factors in the future system, likely well below 93% presented in Table 4 below. This load factor is presented in Table 4 to provide a comparison with the LCOE presentation in the 2023 report. CCGTs in Great Britain currently run at a range of load factors, though can generally be considered mid merit order. Data from DUKES Table 5.10.B shows that the average load factor of the UK's CCGT fleet over the last 5 years has been between around 30% - 40% and has been broadly decreasing over the last 10 years. Newer, more efficient CCGTs run at load factors greater than the fleet average, but considerably lower than baseload. Dispatchable load factors presented in this report are not intended to make any assumption about the role a technology will play in the system.

*Table 4: A comparison of Gas CCGT LCOEs from the previous Generation Costs Report with the 2025 Generation Costs Report, under the carbon price assumptions used in each report. Figures are presented in 2024 prices, for projects commissioning in 2030, and operating at a 93% load factor.*

| | Gas CCGT LCOE<br>2023 Generation Costs Report | Gas CCGT LCOE<br>2025 Generation Costs Report |
|---|---|---|
| 2023 Carbon Price Assumptions | £163/MWh | £165/MWh |
| 2025 Carbon Price Assumptions | £107/MWh | £109/MWh |

## *Hydrogen to power*

### ***Overview***

In 2025, DESNZ commissioned Baringa[17] to update Hydrogen to Power (H2P) cost estimates. Baringa collected baseline unabated gas cost estimates and applied uplifts to estimate hydrogen cost components. This research resulted in estimates for co-firing or 'blended' CCHTs as well as hydrogen firing OCHT cost estimates.

100% hydrogen firing capable gas turbines are expected to be commercially available from the early 2030s. CCGT developers in the short term could design new CCGT systems so that they can be 'hydrogen ready' with the capability to initially utilise hydrogen at lower blend ratios, up to 50%, and could later be upgraded to operate on 100% hydrogen with minimal hardware changes[20]. The 2025 update therefore includes a set of assumptions for co-firing or 'blended' CCGTs, i.e. unabated gas CCGTs that can generate at a 50% hydrogen blend, with 100% hydrogen capability assumed from 2030. 100% capable CCGTs (CCHTs) are expected to be able to burn up to 100% hydrogen and any blend of natural gas.

This is reflected in the analysis as a shift from FOAK plants assumed at 50% blending up until 2035, and NOAK with 100% hydrogen fired after 2035. The 2025 update covers four hydrogen-fired generation archetypes:

- 100% hydrogen capable Combined Cycle Gas Turbines (CCHT) – large-scale units adapted for 100% hydrogen firing capability.
- Hydrogen ready Combined Cycle Gas Turbines (CCGTs) – large-scale methane fuelled units adapted for 50% hydrogen firing capability.
- Open Cycle Gas Turbines (OCHT) – peaking plants configured for 100% hydrogen firing capability.
- Gas reciprocating engines – medium- to small-scale hydrogen-capable engines configured for 100% hydrogen firing capability.

***Key results***

The generation costs for hydrogen turbine systems were benchmarked against the equivalent unabated natural gas archetypes, for which some assumptions were updated as part of the commissioned research, but some were assumed to be the same as other generic gas plants (e.g. variable operational costs and informed by the CEPA GHD 2025 research gas estimates). The benchmarking resulted in an uplift to the original hydrogen to power capex costs consistent with expected trends. Connection and use of system fees were not updated as part of this research. Estimates are the same as the previous generation costs report, which has been deemed acceptable and within a reasonable range of expected current gas connection and use of system fees.

*Table 5: Example of uplifts applied based on industry expertise to estimate expected CCHT capex.*

| | | % Increase vs new build natural gas baseline | | |
|---|---|---|---|---|
| | | Newbuild H2 ready CCGT | Newbuild 100% H2 capable CCGT | New build 100% H2 capable CCGT (2040s) |
| Earliest Commissioning Year | | 2026 | 2030 | 2040 |
| DEVEX (not in capex) | % | 0% | 5% | 0% |
| Main Mechanical Equipment | % | 0% | 10% | 5% |
| Main Mechanical BoP | % | 5% | 5% | 5% |
| Instrumentation, Control & Safety Equipment | % | 5% | 5% | 0% |
| Civils & Installation | % | 5% | 5% | 0% |

[20] Based on OEM feedback, retrofitting a hydrogen-ready turbine to enable full 100% hydrogen firing could be expected to cost 5% of total system CAPEX

100% hydrogen-capable turbines are expected to be commercially available by the early 2030s, carrying a CAPEX premium of approximately 5-10% relative to natural gas systems. Deployment of large-scale hydrogen to power is dependent on large scale hydrogen storage. Analysis from Baringa indicates that hydrogen turbines will likely require natural gas for some operational processes e.g. start up.[21]

## *Gas CCUS Technologies*

### *Overview*

To calculate capex costs for a CCGT with CCUS post combustion, we have paired an assumption for generic capture plant capex with generic gas power plant capex assumptions. Generic carbon capture plant capex has been benchmarked by drawing on a curated set of projects across different emitter types and locations, normalising all costs, and adjusting for inflation, regional cost differences, scale, and project scope. The primary metric used was engineering, procurement, and construction (EPC) cost per tonne of $CO_2$ input capacity, with uncertainty ranges applied based on the maturity and quality of the underlying cost data. More information on the methodology used to benchmark capital expenditure for carbon capture plants has been published[18].

All other cost components, including transport and storage costs, use the data in the 2020 Generation Costs Report. We have assumed CCUS projects to be mature, with a hurdle rate of 8.9%. This reflects market trends where lower hurdle rates have been observed due to the guarantees provided by the DPA.[22] For more information, please refer to the hurdle rates underlying research[15].

The figures published in this report for gas CCUS technologies are not those used for the Department's internal modelling of the power sector. The department uses data based on real-world information for modelling, appraisal and wider analysis. This data cannot be published in this report as it is subject to non-disclosure agreements (NDAs). For this reason, cost components from the 2020 Generation Costs Report have been used where appropriate for the 2025 report, as above.

### *Key results*

DESNZ did not update cost estimates for gas CCUS technologies in the 2023 Generation Costs Report. Costs for first development of this technology in the UK are commercially confidential, subject to non-disclosure agreements, and not available for use in the generic cost assumptions in this report.

Where updated, the figures presented here are a significant increase from the figures last published in the 2020 Generation Costs Report. This is due to the increased level of knowledge about deployment of CCUS globally, from which capture plant capex has been benchmarked, and the same cost pressures experienced by unabated gas plants are assumed to apply to the non-capture capex components.

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[21] Most 100% hydrogen capable systems expected to be available in the early 2030s will still require natural gas for start-up due to the increased technical complexity associated with maintaining combustion stability during the start-up phase.

[22] Underlying risks for gas CCUS technologies is not that it is an emerging, immature technology, but that two relatively mature technologies are being combined at a greater scale than they have before.

### *Nuclear*

In June 2025, the Government announced that Rolls-Royce SMR has been selected as the preferred bidder to partner with Great British Energy – Nuclear (GBE-N) to build the UK's first small modular reactors (SMRs), subject to final government approvals and contract signature. The following month, the Energy Secretary signed the final investment decision for Sizewell C. Project-specific and confidential costs and technical assumptions were used by DESNZ analysts for both projects but cannot be made available in this report because of their commercial sensitivity.

High-level cost assumptions for both Hinkley Point C and Sizewell C are in the public domain. GBE-N's SMR Programme is in the early stages of development and cost estimates are expected to mature.

## Technologies that have not been updated for cost and technical assumptions

### *Floating offshore wind and tidal stream (updated in 2023 report)*

LCOE estimates for floating offshore wind and tidal stream were included in the Generation Costs Report 2023 with further details published in the underlying, externally commissioned research reports.[23]

Given the recency of this update, floating offshore wind and tidal stream is included in Annex A of this report to incorporate the most recent cross-cutting updates, including hurdle rates and load factors.

### *Other technologies*

Cross-cutting assumptions will impact the costs for all technologies even those where capital and operational costs have not been updated as part of this report, for example including inflation, fuel projections, load factor estimates for wind plants and hurdle rates for all power sector technologies. However, unless cost and technical assumptions have been updated within the last 2-3 years these technologies are not included in this report without further review. These costs can be accessed from previous Generation Cost reports on the department's Generation Cost series and the calculator in Annex B enables evaluation of the impact of updated cross-cutting assumptions.

DESNZ keep technology costs under review and will commission research to review or update all technologies as appropriate.

[23] Review of power generation costs for floating offshore wind and tidal stream energy technologies

# Section 5: LCOE estimates

In this section, we present the LCOE estimates for each technology. All cost estimates are in 2024 real values unless otherwise stated.

Technologies are separated into two groups based on the broad role they play in the system: renewables and dispatchable technologies. It is not appropriate to present LCOEs comparatively when technologies play very different roles in the power system.

## Renewable technologies

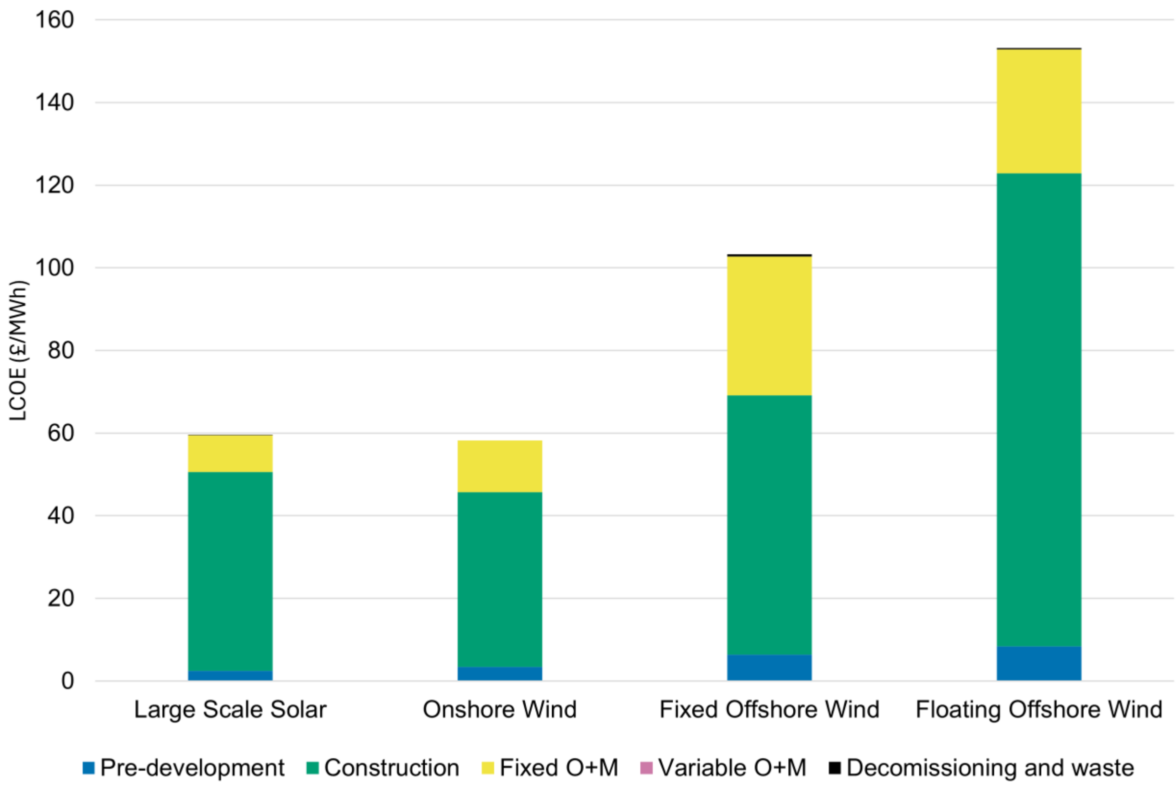
This section shows LCOE estimates for large scale solar PV (>5MW), onshore wind, and offshore wind technologies. The charts show LCOE estimates for projects commissioning in 2030, 2035 and 2050, to show how, for some technologies, cost projections vary over time.

Floating offshore wind LCOE estimates are based on data collected in 2023. Updated hurdle rates and load factor assumptions (for wind technologies) are incorporated into these updated estimates. These technologies are presented as operating at their net load factor, incorporating all loss factors except locational balancing and economic curtailment, as described in Section 4 above.

### *Key Renewables: 2030 Commissioning*

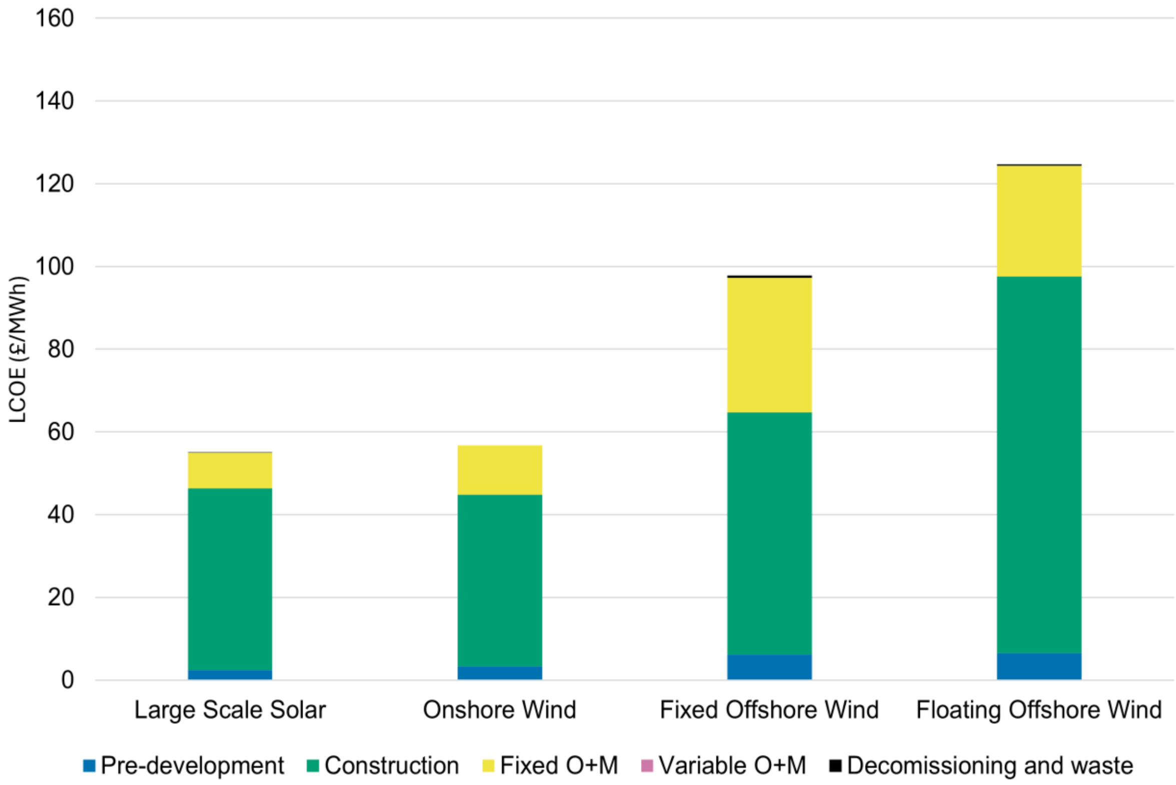
Floating offshore wind is considered a FOAK technology in 2030, below, and NOAK in subsequent charts.

**Figure 2: Key Renewable LCOE Estimates - Projects Commissioning 2030**



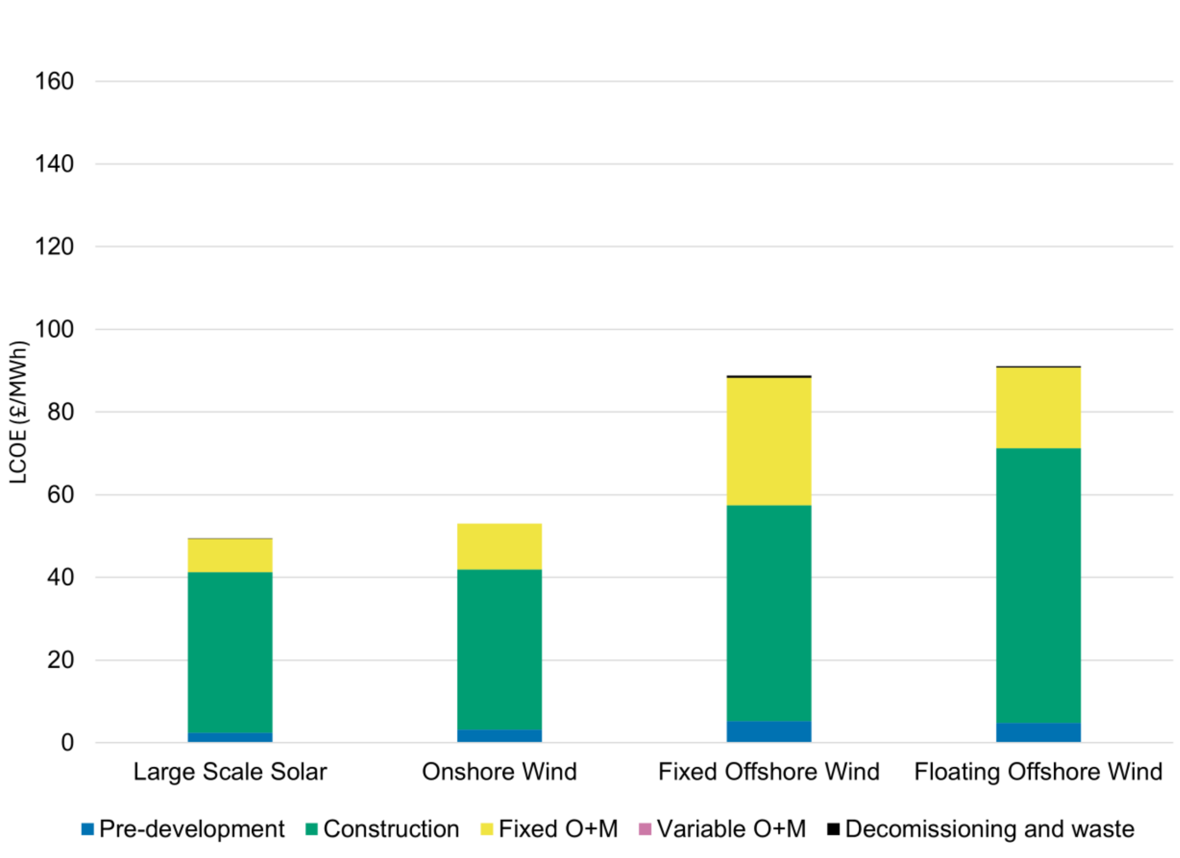
## *Key Renewables: 2035 Commissioning*

**Figure 3: Key Renewables LCOE Estimates – Projects Commissioning 2035**



### *Key Renewables: 2050 Commissioning*

***Figure 4: Key Renewables LCOE Estimates – Projects Commissioning 2050***




## Dispatchable technologies

This section shows LCOE estimates for dispatchable technologies, including unabated gas CCGT, H2P, and gas CCUS. The charts demonstrate projects commissioning in 2030 and 2035 to show how LCOE estimates, for some technologies, vary overtime. 2050 estimates are not presented as central underlying assumptions remain largely unchanged between 2035 and 2050, due to limited credible evidence of how future costs may change in the long term.

Importantly, the different commissioning years also reflect H2P LCOE estimates assumed to change from 50% blending (up until 2035) to 100% hydrogen fired (beyond 2035).

These LCOE results use a combination of hurdle rates from the recent research[15], and adjusted hurdle rates for H2P projects, based on the ranges presented in the hurdle rate research report, according to internal expertise.

A range of load factors are presented to reflect different load factors that may be expected from dispatchable generation capacity in future years. However, dispatchable plants are expected to operate at a range of load factors in the future system, likely well below the maximum presented below. The load factors presented here are not intended to make any assumption about the role a technology will play in the system.

As discussed in Section 4 above, LCOE calculations for greenhouse gas emitting technologies in this report uses the department's updated carbon price assumptions, which no longer converge to the appraisal cost of carbon in the long-term. If the carbon price was assumed to reach the appraisal cost of carbon (as it was in the 2023 report) the LCOE of unabated gas technologies would be higher, in real terms, in the 2025 report than it was in the 2023 report for equivalent commissioning years.

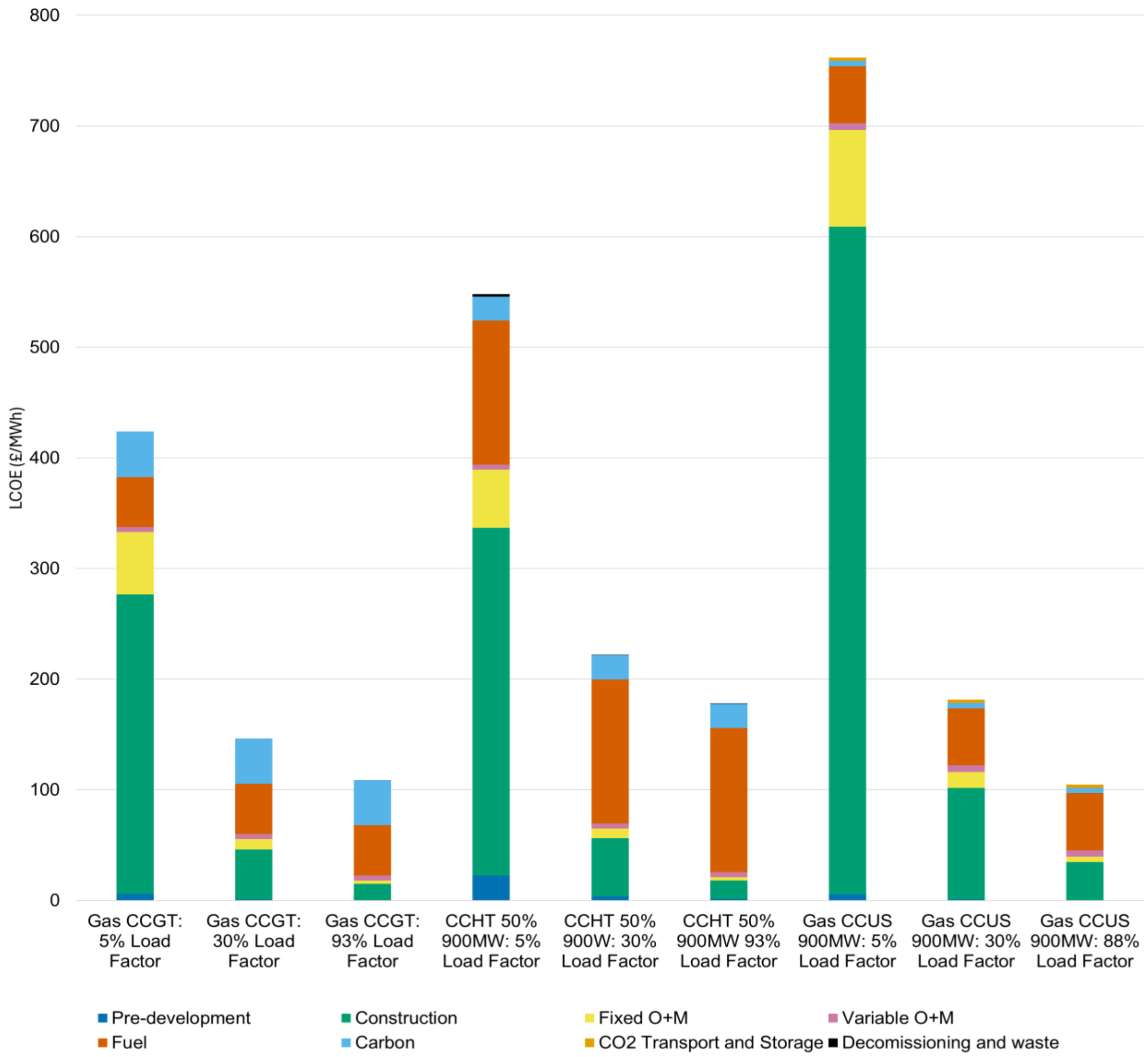
### *Dispatchable technologies: 2030 commissioning*

The charts below display LCOE estimates for dispatchable technologies. These results are presented at illustrative average load factors of 5%, 30%, and 93% (Gas and Hydrogen) and 88% (gas CCUS), to represent a range of possible future system roles. These have been chosen to represent illustrative peaking (5%), mid-merit (30%) and baseload (93% and 88%) operation[24]. For 2030 estimates, we display FOAK hydrogen estimates – with blending level capability of 50% hydrogen fuel.[25]

[24] The difference in load factor for assumed baseload operation of unabated gas and H2P compared to gas CCUS is due to assumed availability of the CCUS T&S network.

[25] Some categories of costs are not directly comparable across technologies (e.g. pre-development costs for CCGT vs CCHT) as there are differences in the definition and/or methodology used in the underlying research reports.

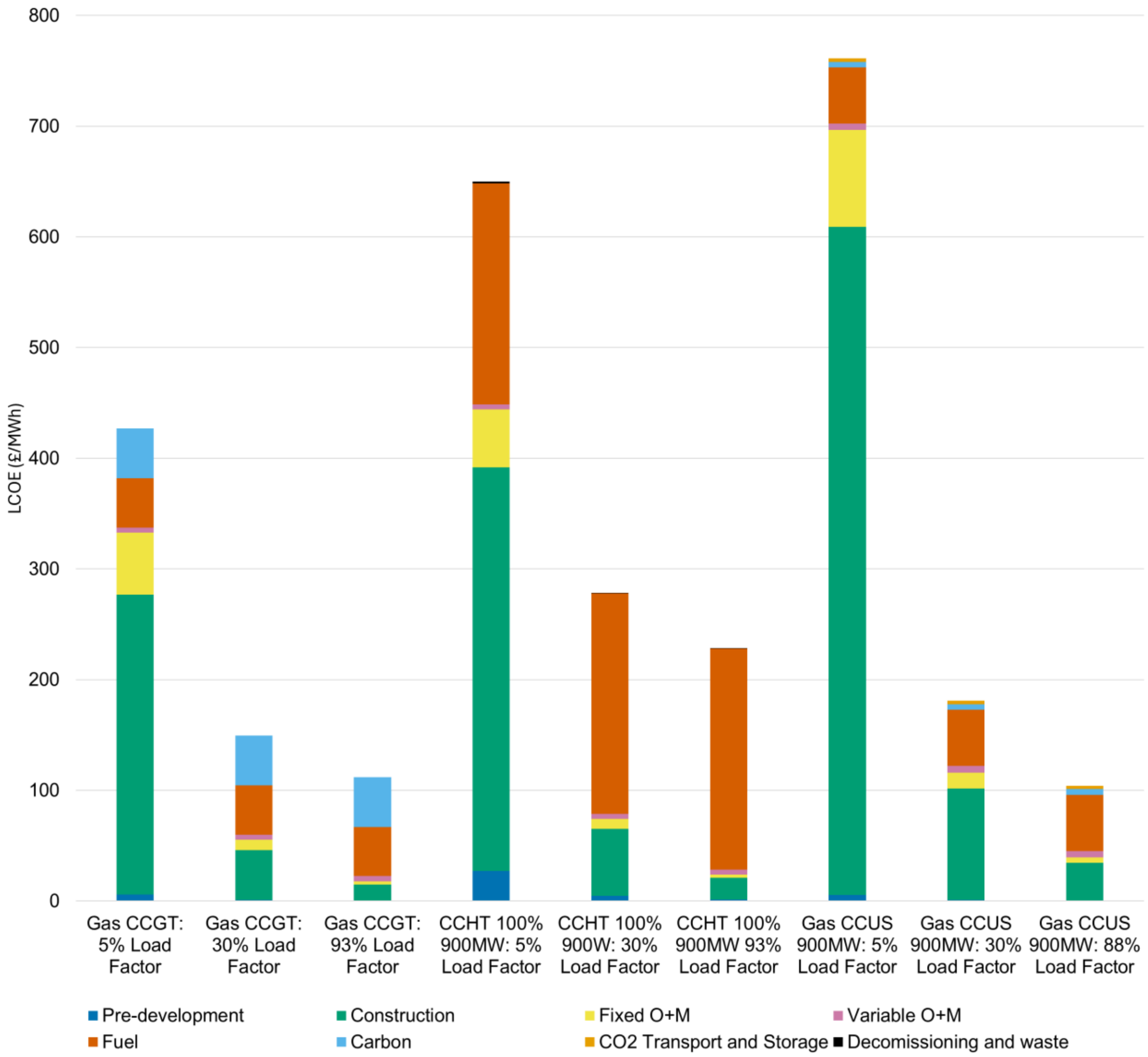
***Figure 5: Dispatchable Technologies LCOE Estimates - Projects Commissioning 2030***




## *Dispatchable technologies: 2035 commissioning*

Post 2035, hydrogen technology LCOE estimates are presented as NOAK with 100% hydrogen fuel blending capability. Currently, estimates suggest that as hydrogen blending levels increase, LCOE estimates increase. This is due to the higher projected costs of hydrogen fuel compared to natural gas.

***Figure 6: Dispatchable Technologies LCOE Estimates – Projects Commissioning 2035***




## *Dispatchable technologies: 2050 commissioning*

Central underlying assumptions remain largely unchanged between 2035 and 2050, due to limited credible evidence of how future costs may change in the long term and so are not presented.

# Section 6: Sensitivity analysis

Understanding the cost of different electricity generation technologies is critical for informed decision making. However, these costs are influenced by a range of uncertain input parameters. Sensitivity analysis provides a systematic approach to assess how variations in these key parameters affect overall generation costs and relative comparisons across technologies.

In this section, we examine the uncertainty of our LCOE estimates by varying assumptions within plausible ranges. By exploring these sensitivities, we aim to outline the uncertainty in our estimates. This analysis shows that LCOE estimates should be interpreted as a range, as opposed to a single central value. We present sensitivity analysis for the technologies that have been updated in this report. The sensitivities we present in this section are:

- Hurdle Rates
- CAPEX
- Fuel Costs
- Carbon Costs

## Hurdle Rates

LCOE estimates are sensitive to hurdle rates assumptions because the chosen hurdle rate directly affects the discounting of future costs and generation output. Hurdle rates are subject to uncertainty and reflect specific assumptions, including how the revenue model for each technology mitigates risk. Technologies like nuclear, fixed offshore wind, and solar PV have high upfront capital costs and relatively low operating costs. These technologies are particularly affected, as when the hurdle rate increases the present value of future generation falls sharply, but the initial capital cost remains relatively unchanged.

The charts below present LCOE estimates using the low, central or high hurdle rate, established in the Hurdle Rates Report[15].

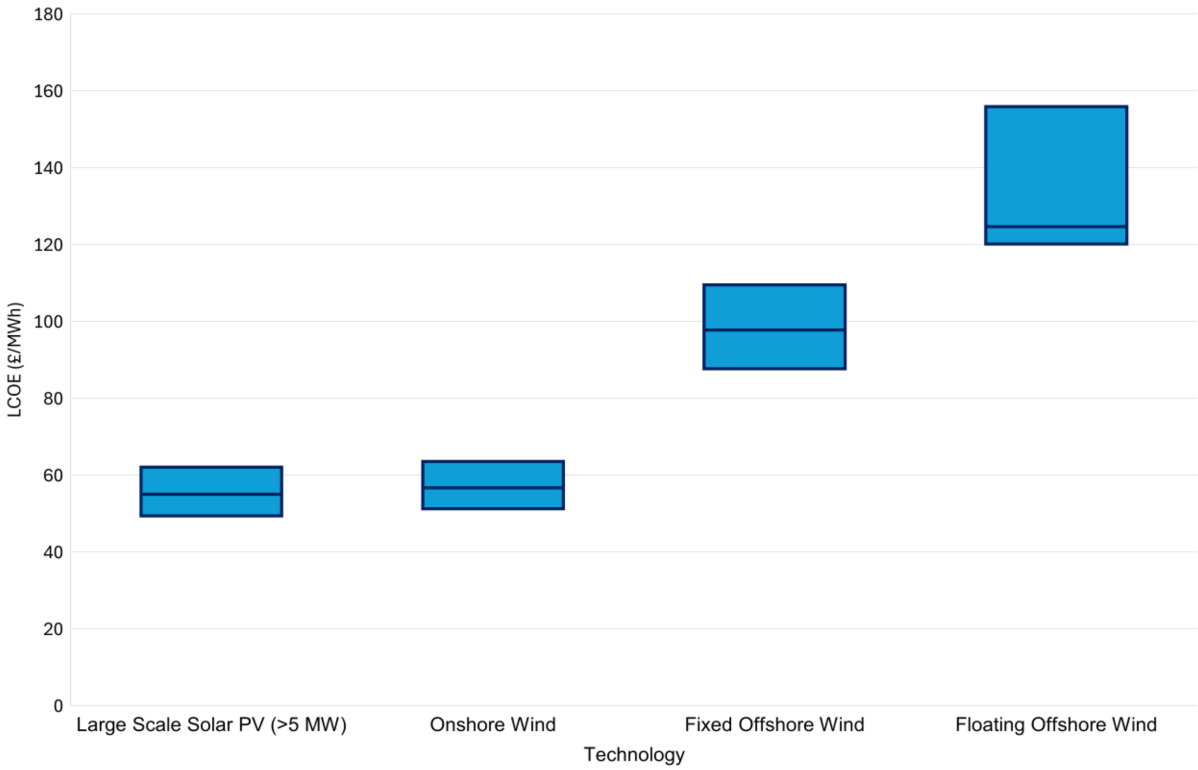
### *Renewable Technologies*

The below chart shows how LCOE estimates for key renewable technologies commissioning in 2035 vary depending on hurdle rates used. The table below shows the hurdle rate range for each renewable technology.

*Table 6: Hurdle rate sensitivities for renewable technologies*

| Renewable Technology Hurdle Rates | Low | Medium | High |
|---|---|---|---|
| Large Scale Solar PV (>5 MW) | 6.5% | 7.6% | 8.9% |
| Onshore Wind | 6.5% | 7.6% | 8.9% |
| Fixed Offshore Wind | 7.3% | 8.9% | 10.6% |
| Floating Offshore Wind | 9.6% | 10.1% | 13.3% |

***Figure 7: Key Renewable Technologies: Hurdle Rate Sensitivities – Projects Commissioning 2035***




*Inner blue lines show central LCOE estimates for the central hurdle rate. The upper and lower boundary of the box plot show LCOE estimates for the high and low hurdle rates.*

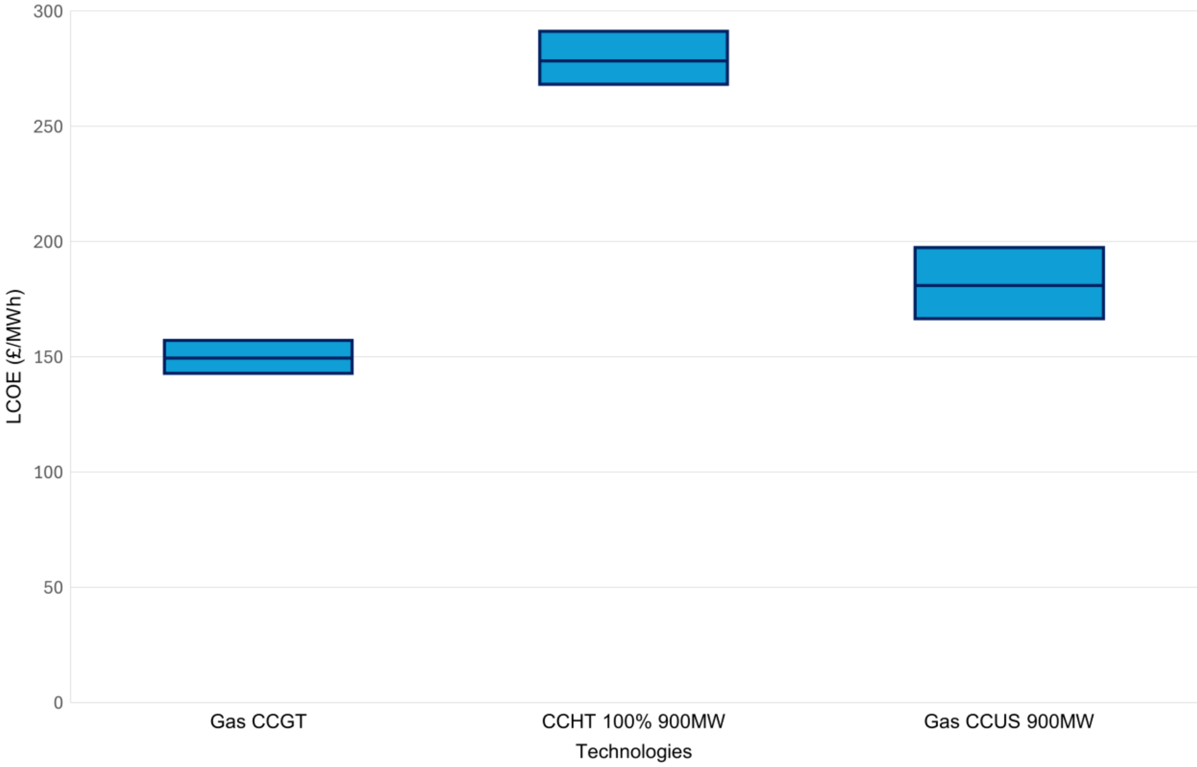
## Dispatchable technologies

The below chart shows how LCOE estimates for hydrogen to power, gas CCUS, and unabated gas vary depending on hurdle rate used. Estimates are for projects commissioning in 2035 and assume 100% hydrogen firing for H2P technologies. Hurdle rate sensitivities for dispatchable technologies are presented with a 30% load factor.

*Table 7: Hurdle rate sensitivities for dispatchable technologies*

| Dispatchable Technology Hurdle Rates | Low | Medium | High |
|---|---|---|---|
| Gas CCGT | 7.3% | 8.9% | 10.6% |
| CCHT 100% 900MW | 8.5% | 10.1% | 12% |
| CCUS 900MW | 7.3% | 8.9% | 10.6% |

***Figure 8: Dispatchable Technologies: Hurdle Rate Sensitivities – Projects Commissioning 2035, 30% load factor***




*Inner blue lines show central LCOE estimates for the central hurdle rate. The upper and lower boundary of the box plot show LCOE estimates for the high and low hurdle rates.*

CAPEX Costs

LCOE estimates are sensitive to construction cost assumptions. Uncertainty in these costs can be driven by project specific characteristics, construction delays, supply chain risks or fluctuations in material costs. We demonstrate the impact of a low, medium or high capex cost on LCOE estimates. As shown in the charts below, the LCOE estimates for high capex technologies such as renewables are most sensitive to these assumptions.

***Renewables Technologies***

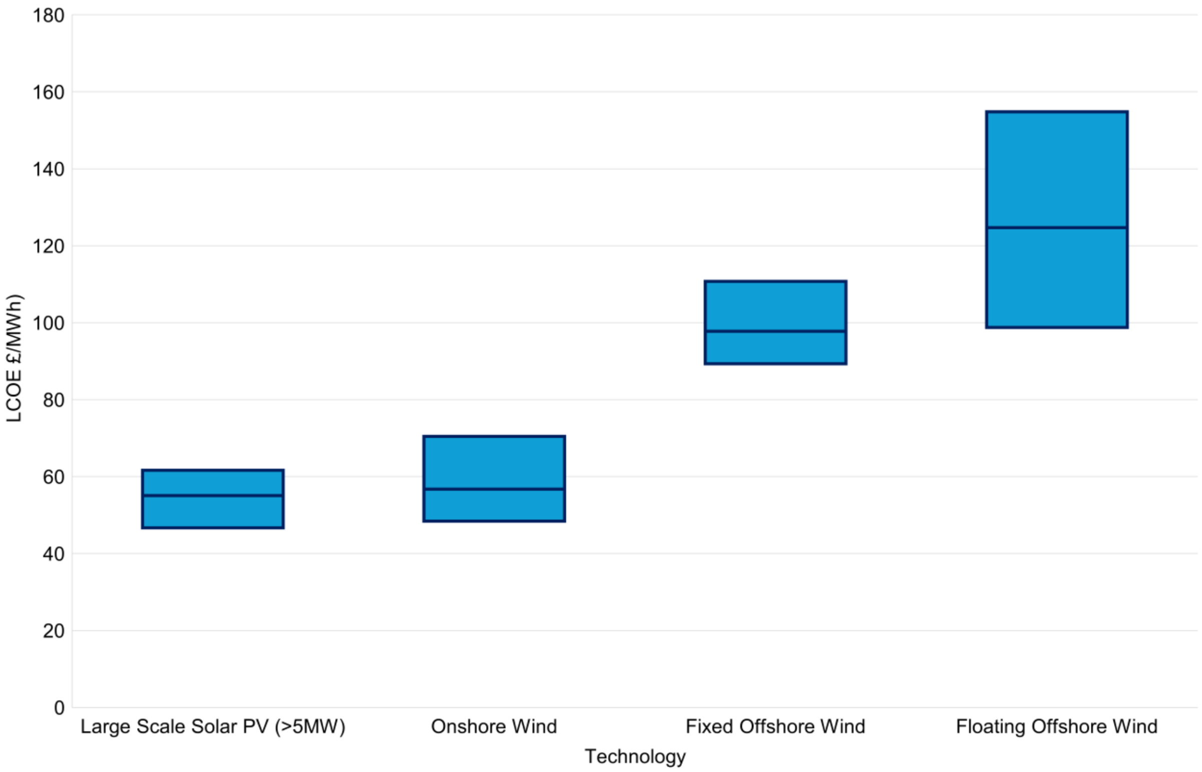
The chart below presents key renewables LCOE capex sensitivities, to reflect underlying capex assumption uncertainties.

The table below shows the underlying capex sensitivity assumptions. See the underlying reports for individual technologies for more detail[11] [12] [23].

*Table 8: Capex sensitivities for renewable technologies*

| Capex Sensitivities Renewable Technologies (£/MWh, 2024 Price Base, Projects Commissioning 2035) | Low | Medium | High |
|---|---|---|---|
| Large Scale Solar PV (>5MW) | 36 | 44 | 50 |
| Onshore Wind | 33 | 41 | 55 |
| Fixed Offshore Wind | 50 | 59 | 72 |
| Floating Offshore Wind | 65 | 91 | 121 |

***Figure 9: Key Renewable Technologies: Capex Sensitivities – Projects Commissioning 2035***




*Inner blue lines show central LCOE estimates for the central capex estimate. The upper and lower boundary of the box plot show LCOE estimates for the high and low capex estimates.*

### *Dispatchable Technologies*

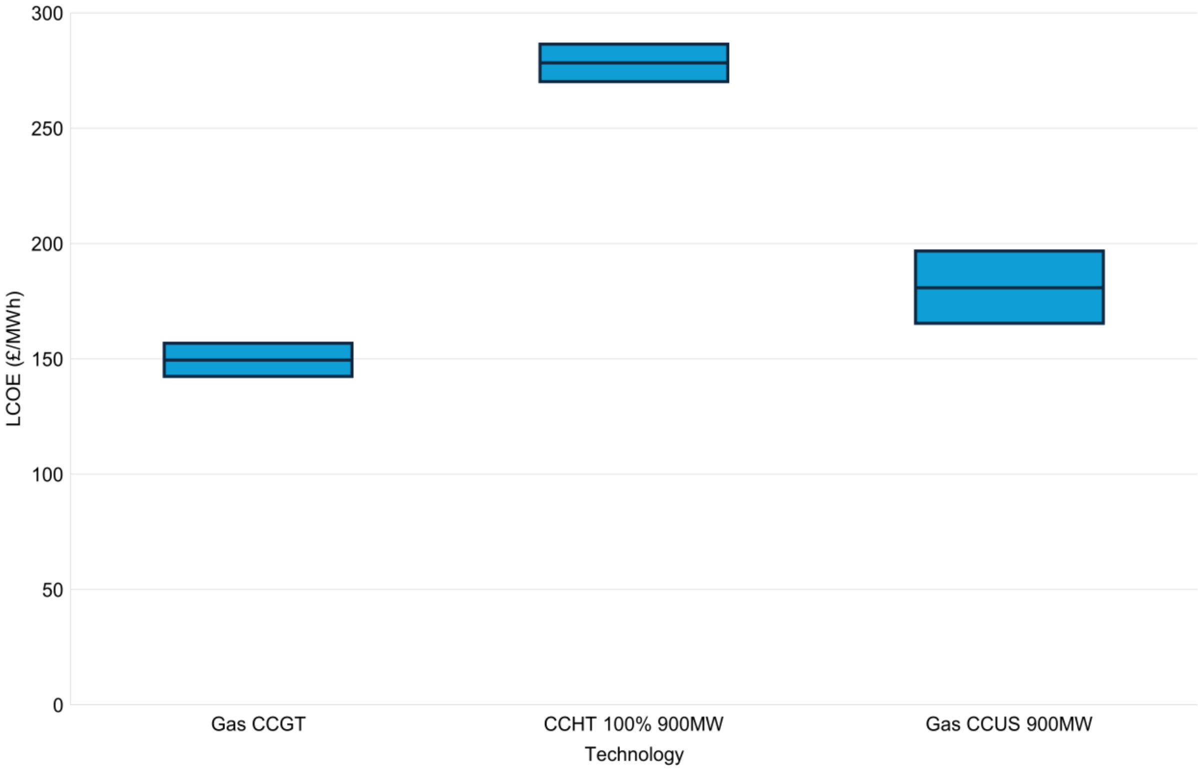
The chart below shows a range of LCOE estimates for dispatchable technologies under low, medium and high capex cost scenarios.

The table below shows the underlying capex sensitivity assumptions. See the full report for more detail[16] [17] [18].

*Table 9: Capex sensitivities for dispatchable technologies*

| Capex Sensitivities Dispatchable Technologies (£/MWh, 2024 Price Base, Projects Commissioning 2035, 30% load factor) | Low | Medium | High |
|---|---|---|---|
| Gas CCGT | 38 | 45 | 53 |
| CCHT 900MW | 53 | 61 | 69 |
| CCUS 900MW | 85 | 101 | 117 |

***Figure 10: Dispatchable Technologies: LCOE Capex Sensitivities – Projects Commissioning 2035, 30% load factor***




*Inner blue lines show central LCOE estimates for the central capex estimate. The upper and lower boundary of the box plot show LCOE estimates for the high and low capex estimates.*

## Fuel and carbon price variations

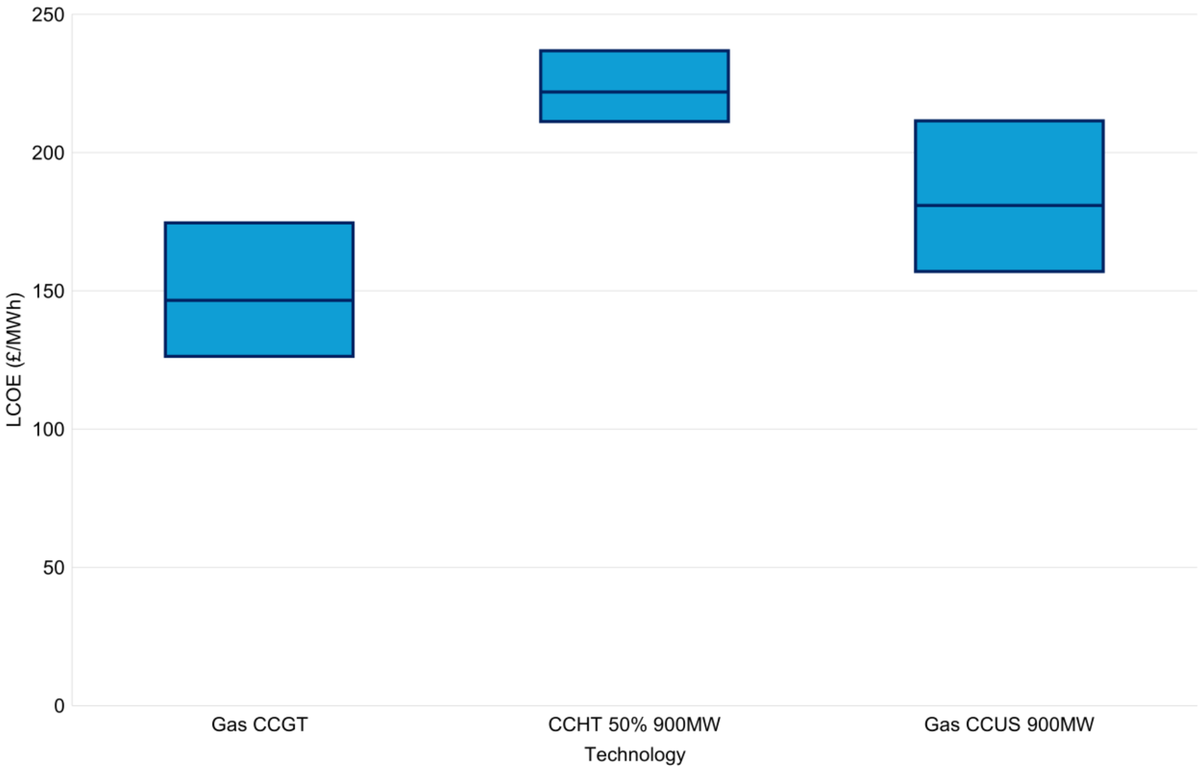
LCOE estimates for specific technologies are sensitive to fuel and carbon price assumptions. Some technologies incur fuel costs for every unit of electricity produced. If fuel prices rise (e.g. natural gas or hydrogen), the operating costs over the project lifetime increase, increasing the LCOE. Technologies that emit greenhouse gases incur an additional cost per unit of carbon emitted; this increases operating costs and results in higher LCOE estimates.

This section explores the impact of a range of fuel and carbon prices on the LCOE for hydrogen to power, gas CCUS and unabated gas. To find out more about the underlying low and high scenarios related to fuel and carbon price sensitivities, see the underlying reports.

### *Gas Fuel Price Sensitivities*

The LCOE estimates for plants using gas or blends of gas and hydrogen are sensitive to gas price projections[16]. The below figure explores this sensitivity for each technology under low, medium and high gas price scenarios. This sensitivity is presented for 2030 commissioning to present H2P which is assumed to be operating with 50% gas blending.

***Figure 11: Dispatchable Technologies: Gas Fuel Price Sensitivities – Projects Commissioning 2030, 30% load factor***



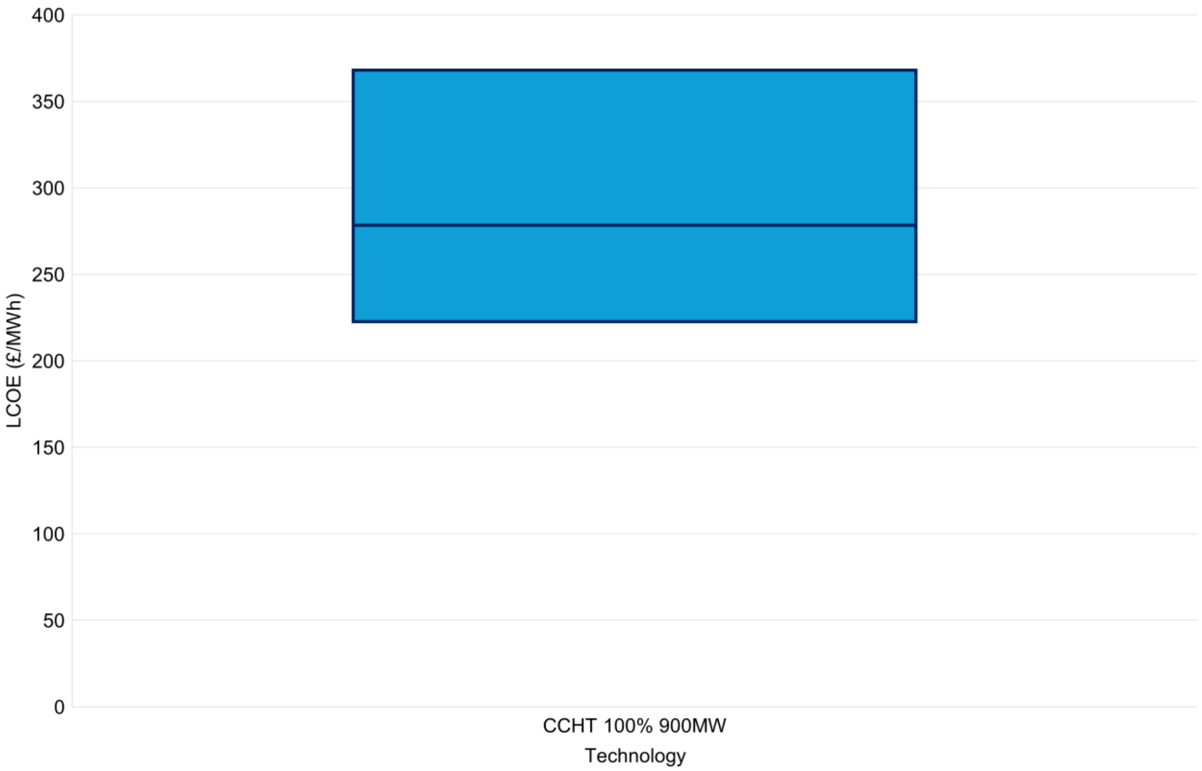

*Inner blue lines show central LCOE estimates for the central fuel price assumptions. The upper and lower boundary of the box plot show LCOE estimates for the high and low fuel price estimates.*

### *Hydrogen Fuel Price Sensitivities*

Similar to gas fuel prices, the LCOE estimates for projects that use hydrogen fuel are sensitive to the hydrogen fuel price assumption. Hydrogen fuel cost assumption use appraisal values, not including transport and storage costs[26]. Transport and storage costs are not used due to these aspects of the future system being at a very early stages of development and subject to significant uncertainty. The chart below shows a range of LCOE estimates under low, medium and high hydrogen fuel prices.

[26] Link available shortly

***Figure 12: Hydrogen to Power: Hydrogen Fuel Price Sensitivities – Projects Commissioning 2035, 30% load factor***

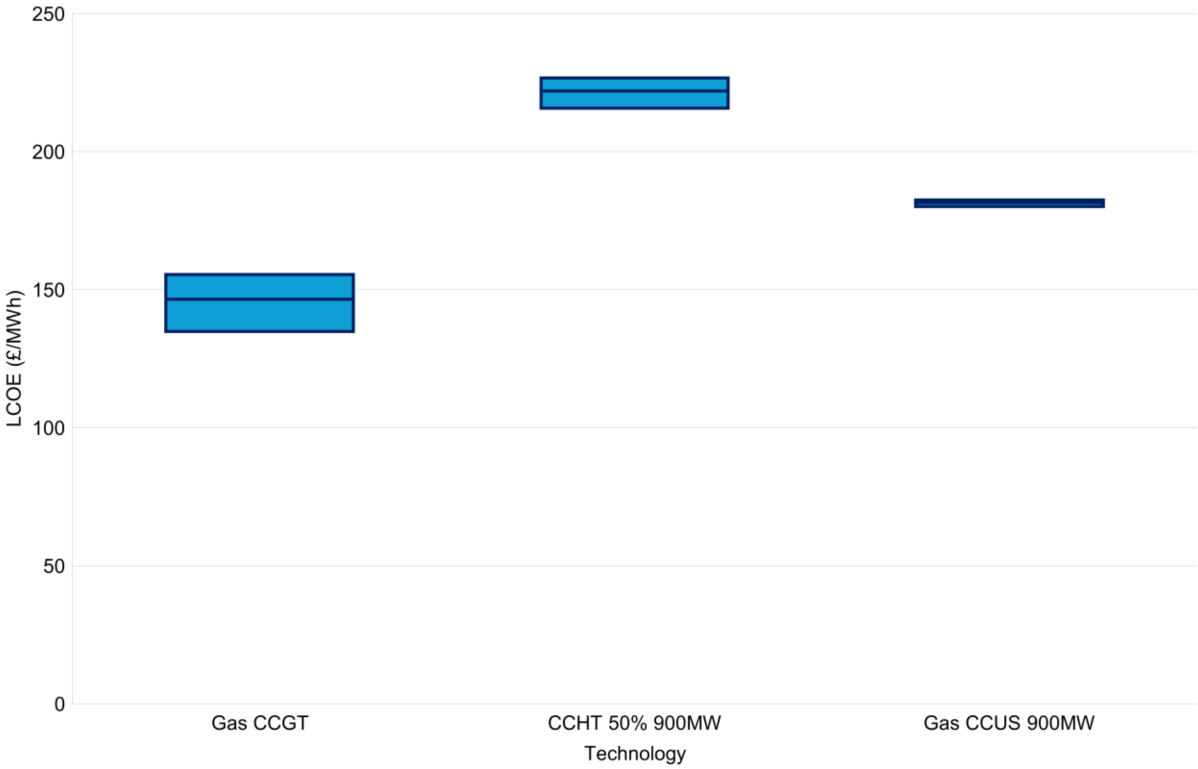



*Inner blue lines show central LCOE estimates for the central hydrogen fuel price assumptions. The upper and lower boundary of the box plot show LCOE estimates for the high and low hydrogen fuel price estimates.*

***Carbon Price Sensitivities***

The LCOE estimate for emitting technologies are sensitive to the carbon price assumption. For gas CCUS or hydrogen projects using a mix of natural gas and hydrogen, the level of emissions is relatively less than an unbated gas plant therefore the carbon price has a much smaller impact on LCOE. Carbon price assumptions are taken from the, soon to be published, UK ETS carbon price assumptions[10]. The chart below demonstrates carbon price uncertainties and their impact on LCOE estimates. The LCOE range is explored in 2030 commissioning years where H2P is assumed to be using 50% gas blending.

***Figure 13: Dispatchable Technologies Carbon Price Sensitivities – Projects Commissioning 2030, 30% load factor***




*Inner blue lines show central LCOE estimates for the central carbon price assumptions. The upper and lower boundary of the box plot show LCOE estimates for the high and low carbon price estimates.*

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