Department for Energy Security & Net Zero

Electricity Generation Costs 2023

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Acronym glossary

ACT	Advanced Conversion Technologies
AD	Anaerobic Digestion
ASP	Administrative Strike Price
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy and Industrial Strategy
BSUoS	Balancing Services Use of System
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture Usage and Storage
CfD	Contract for Difference
CHP	Combined Heat and Power
CPF	Carbon Price Floor
CPS	Carbon Price Support
DSR	Demand-Side Response
EEP	Energy and Emissions Projections
EfW	Energy from Waste
EU ETS	European Union Emissions Trading System
FiT	Feed-in Tariff
FOAK	First of a Kind
HHV	Higher Heating Value
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
O&M	Operations and Maintenance
PPA	Power Purchase Agreement
PV	Photovoltaic
WRAP	Waste and Resources Action Programme

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 to make progress towards net zero.

This report, produced by the Department for Energy Security and Net Zero presents estimates of the costs and technical specifications for different generation technologies based in Great Britain.

Since the department's last report, BEIS Electricity Generation Costs (2020)[1], we have updated key assumptions that underlie our analysis.

The department has:

- Commissioned an external provider in 2020 to review assumptions for onshore wind and large-scale solar photovoltaic (PV).
- Commissioned an external provider in 2020 to review assumptions for Energy from Waste (EfW) and Advanced Conversion Technologies (ACT), including with Combined Heat and Power (CHP).
- Commissioned an external provider in 2023 to review assumptions for Floating Offshore Wind (FOW) and Tidal Stream Energy (TSE).
- Collected evidence on costs for hydrogen-fired combined cycle gas turbines (H2 CCGT).
- Updated other cross-cutting assumptions, such as fuel costs, gate fees and carbon prices.

All other assumptions remain the same as in the 2020 report unless otherwise stated.

In this report we consider the costs of planning, construction, operation, and carbon emissions, reflecting the cost of building, operating and decommissioning a generic plant for each technology. Potential revenue streams are not considered, except for heat revenues for CHP plants (see section 3). Most costs in this report are presented as levelised costs, which is a measure of the average cost per MWh generated over the full lifetime of a plant. All estimates are in **2021** real values unless otherwise stated.

Levelised costs provide a straightforward way of consistently comparing the costs of different generating technologies with different characteristics, focusing on the costs incurred by the generator 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

[1] BEIS Electricity Generation Costs (2020) https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

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. An analysis of the impact of these wider ‘enhanced levelised costs’ were presented in our 2020 report.

Generation costs are used as inputs to the department’s analysis, including the setting of Administrative Strike Price setting for Contracts for Difference allocation rounds. These assumptions are reviewed at each allocation round. However, it is important to note that levelised costs are not the same as strike prices. Strike prices include additional considerations, such as market conditions, revenues for generators, and policy factors, which are not considered in levelised costs. To date, they have also typically been expressed in 2012 prices, whereas the levelised costs reported here are in **2021** prices. For further details on the differences between strike prices and levelised costs, please see Section 3.

This report is structured as follows:

- Section 1 provides an overview of how levelised costs are calculated, as well as some of the uncertainties around projecting the costs of future generation.
- Section 2 outlines the changes to cost assumptions that we have made in our most recent review.
- Section 3 outlines how the department uses generation cost data in its modelling, including the links between generation costs and strike prices.
- Section 4 presents selected levelised cost estimates generated using the department’s Levelised Cost Model and technology-specific hurdle rates.
- Section 5 discusses peaking technologies, presenting an alternative metric to levelised costs on a £/kW basis.

Further detail on the data and assumptions used can be found in the Key Data and Assumptions spreadsheet published alongside this report in Annex A. Annex A also contains levelised cost estimates for a range of technologies for 2025, 2030, 2035 and 2040.

Uncertainty

As with any projection, there is inherent uncertainty when estimating current and future costs of electricity generation. While the department considers that the ranges of levelised cost estimates presented in this report are robust for the department’s analysis, these estimates should also be used with care given uncertainties around the future cost of generation.

These uncertainties include the potential for unanticipated cost reductions in less mature technologies, greater uncertainty for technologies where the department have access to less detailed evidence, uncertainty around future network costs, and uncertainty around fossil fuel prices and carbon values. The assumptions in all generation cost parameters are not project specific. Instead, they are intended to provide a broad order of magnitude to compare technologies. To illustrate the potential effects of these uncertainties, the report presents ranges and sensitivity analysis on the effects of changes in parameters.

This report does not account for some of the potential effects of short-term increases in commodity prices and macroeconomic circumstances on project costs. However, the numbers published are in real prices (GDP deflator) and therefore do account for general price inflation. The purpose of the Department's generation cost modelling is to look at the longer-term outlook for generation cost estimates over the lifetime of a plant. There is significant uncertainty about how long commodity price increases and the current economic pressures will persist and therefore this is not factored into our modelling at this stage. We continue to have confidence in our assessment. We will monitor these assumptions going forward to ensure that it is still accurate.

The department continuously commissions research to update assumptions where the department feels necessary. As a result, updates in this report have been made to improve assumptions from earlier than BEIS's 2020 publication, reflecting a longer-term development in cost assumptions than just since 2020. We would welcome views on what angles future research should take.

Section 1: How levelised costs are calculated

The Levelised Cost of Electricity (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 the generator, including pre-development, capital, operating, fuel, and financing costs. This is sometimes called a life-cycle cost, which emphasises the “cradle to grave” aspect of the definition.

The levelised cost 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 levelised costs in £/MWh.

The main intention of a levelised cost metric is to provide a simple “rule of thumb” comparison between different types of generating technologies. However, the simplicity of this metric means some relevant issues are not considered. Further details on the considerations included and excluded from levelised costs can be found in Section 3.

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

Annex B, contains sample LCOE calculations for an unabated gas CCGT and an offshore wind farm, to illustrate how the department calculates levelised costs in more detail.

[2] https://www.gov.uk/government/publications/uk-electricity-generation-costs-mott-macdonald-update-2010

Figure 1 - Overview of levelised cost calculation[3]

Step 1: Gather plant data and assumptions	
Capital expenditure (CAPEX) costs	Pre-development costs* Construction costs* Infrastructure costs *adjusted for learning over time
Operating expenditure (OPEX) costs	Fixed operating costs* Variable operating costs Insurance Connection costs Carbon transport and storage costs Decommissioning costs Heat revenues Fuel prices Carbon costs *adjusted for learning over time
Expected generation data	Capacity of plant Expected availability Expected efficiency 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 2: Changes to generation cost assumptions

Where assumptions and technologies have not been mentioned, please assume that there have been no changes since the previous report.

Renewable technologies

Onshore wind & solar PV

The department commissioned a report by WSP[4] to review the current estimates for onshore wind and solar PV. This has been supplemented with internal modelling and research. As a result, this new information has been used to update the following for onshore wind:

- Capital costs learning rate.
- Load factors.

Capital costs learning rates and load factor increases are now both linked to turbine size growth, reflecting WSP's recommendations and following the same method as used or offshore wind. However, the department has altered the suggested turbine trajectory from WSP, instead limiting maximum turbine size at 6 MW. The department also used internal updates to model onshore load factors[5].

Table 1 - Turbine assumptions for onshore wind

Commissioning year	Projected turbine size MW	Projected load factor[5] (net of availability)
2023	5	45%
2030	6	48%
2035+	6	48%

Load factors, defined as expected annual generation as a percentage of theoretical maximum generation, are modelled to increase with turbine size. Larger turbines are expected to produce higher load factors for several reasons, most importantly that larger turbines can access higher winds due to their increased height, and that a wind farm with fewer, larger turbines has

[4] Onshore wind and solar cost review https://www.gov.uk/government/publications/review-of-power-generation-costs-for-technologies-eligible-for-contracts-for-difference
[5] The first version of this report (published 4th August 2023) had a lower onshore wind load factor that was updated in this version (published October 2023) to reflect internal modelling used within the department. This reduces the LCOE.

increased efficiency. Detailed discussion of these relationships can be found in a report for the department by DNV GL Energy[6]. Future load factors were calculated by combining a theoretical turbine power curve (power output as a function of wind speed, modelled using turbine specifications provided by manufacturers) with hourly wind speed data from existing offshore wind sites. The pre-development and construction costs are the total cost of construction.

Table 2 - Main cost assumptions for onshore wind

	2025	2030	2035	2040
Total Pre-development (£m)	6	6	6	6
Total Construction (£m)	56	54	54	54
Fixed O&M (£/MW/year)	25,400	25,500	25,700	25,900
Variable O&M (£/MWh)	6	6	6	6
Load factor[5] (net of availability)	45%	48%	48%	48%
Operating period (years)	25	25	25	25

For solar PV, the following assumptions have been updated, reflecting WSP's recommendations:

- Plant capacity.
- Construction timings.
- Construction and infrastructure costs.
- Pre-licensing, technical and design costs.
- Variable operating costs.

Table 3 - Main cost assumptions for solar PV

	2025	2030	2035	2040
Total Pre-development (£m)	1	1	1	1
Total Construction (£m)	7	6	5	4
Fixed O&M (£/MW/year)	6,000	5,600	5,300	4,900
Variable O&M (£/MWh)	-	-	-	-

[6] https://www.gov.uk/government/publications/potential-to-improve-load-factor-of-offshore-wind-farms-in-the-uk-to-2035

Load factor (net of availability)	11%	11%	11%	11%
Operating period (years)	35	35	35	35

Offshore wind

The department has analysed recent changes in offshore technology and updated turbine assumptions and load factors for offshore wind, increasing both the expected load factors and turbine sizes in comparison to the previous Electricity Generation Costs Report publication.

As with onshore wind modelling, capital costs learning rates and load factor increases are both linked to turbine size growth. We have assumed that the £/MW capital costs decrease over time with the size of the turbine due to economies of scale.

Table 4 - Turbine assumptions for offshore wind

Commissioning year	Projected turbine size	Projected load factor (net of availability)
2025	14 MW	61%
2030	17 MW	65%
2035+	20 MW	69%

Table 5 - Main cost assumptions for offshore wind

	2025	2030	2035	2040
Total Pre-development (£m)	130	410	460	460
Total Construction (£m)	1,500	1,400	1,300	1,300
Fixed O&M (£/MW/year)	43,300	42,100	42,200	42,400
Variable O&M (£/MWh)	1	1	1	1
Load factor (net of availability)	61%	65%	69%	69%
Operating period (years)	30	30	30	30

The Crown Estate Leasing Round 4

In February 2021, the Crown Estate closed their Leasing Round 4 (LR4), in which developers bid into a competitive auction for an ‘option’ to develop a project on their chosen site in the future. This resulted in 8 GW of capacity being awarded leasing rights across six projects and four developers.

The option fees resulting from this auction are paid annually in the pre-development phase of the project, for a minimum of 3 and a maximum of 10 years, from developers to the Crown Estate. Once construction begins, construction rent is paid in place of option fees. These option fees were significantly higher than the department's previous estimates of pre-development costs. In addition, projects due to come online through LR4 made up a significant portion of the offshore wind pipeline. Therefore, the department has adjusted pre-development costs.

This means that there is a sharp increase in pre-development costs as LR4-related projects come online in the early 2030s and become more representative of 'typical' project costs. It is uncertain at this point whether the high option fees are indicative of future seabed leasing rounds to come. As further seabed leasing occurs, the department will continue to monitor these costs and update estimates as necessary.

Floating Offshore Wind and Tidal Stream research.

Floating Offshore Wind (FOW) and Tidal Stream Energy (TSE) technologies have been updated[7] to align with two DESNZ-commissioned research reviews by Frazer-Nash Consultancy (FNC)[8] [9]. FOW projects are categorized into demonstration (Demo), FOAK and NOAK categories8 above[8]. TSE projects are similarly categorised with additional sub-categories[9] with medium Demo and medium FOAK selected as most representative here. For FOW, data is adjusted from the FOAK category applying the central learning rate assumption in the FNC review across capital and operational cost components to result in assumed NOAK costs[8]. For TSE, data is adjusted from the large FOAK category applying learning rates based on the profiled learning rate presented in the FNC report[9]. The assumed learning rates are based on global National Renewable Energy Laboratory (NREL) assumptions[10]. Demo status is assumed for projects commissioning pre-2030, FOAK in 2030 and NOAK for 2040 onwards. For FOW load factor assumptions used are in line with internal modelling, consistent with modelling used for OFW and ONW. For Demo projects, a 12 MW turbine size is assumed, smaller than for OFW, but as the industry develops turbine sizes are assumed to align with the projected trajectory for OFW. The hurdle rate assumed is as per the European Economic 2018 report[11] as a baseline, with subsequent analysis to produce an average[12]. For TSE the costs

[7] This reflects a November 2023 update to the original publication alongside publishing the Frazer-Nash Consultancy reviews of cost and technical assumptions for Floating Offshore Wind and Tidal Stream Energy
[8] Floating Offshore Wind. https://www.gov.uk/government/publications/review-of-power-generation-costs-for-floating-offshore-wind-and-tidal-stream-energy-technologies
[9] Tidal Stream Energy. https://www.gov.uk/government/publications/review-of-power-generation-costs-for-floating-offshore-wind-and-tidal-stream-energy-technologies
[10] A Systematic Framework for Projecting the Future Costs of Offshore Wind Energy. (2022). National Renewable Energy Laboratory (NREL). https://www.nrel.gov/docs/fy23osti/81819.pdf
[11] Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/910814/Cost_of_Capital_Update_for_Electricity_Generation_Storage_and_Demand_Side_Response_Technologies.pdf
[12] Contract for Difference Administrative Strike Price Methodology Note https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-6-administrative-strike-prices-methodology-note

presented are aligned with FNC supplied data[9]. The hurdle rate assumed is as per the European Economic 2018 report[11].

There is significant uncertainty in these assumptions given the nascent nature of these technologies, and that cost assumptions were based on a limited number of data points. The uncertainty increases over time. The Department will review assumptions as the technologies develop. Further discussion of the methodology can be found in the cover note and underlying research reviews[9] [9].

For both technologies, given the uncertainties in the cost assumptions, the LCOEs presented should be regarded as illustrative.

Table 6 - Main cost assumptions for floating offshore wind

	2025 (Demo)	2030 (FOAK)	2035 (NOAK)	2040 (NOAK)
Total Pre-development (£m)	50	170	160	140
Total Construction (£m)	570	3,000	2,700	2,500
Fixed O&M (£/MW/year)	112,700	108,200	98,200	89,000
Variable O&M (£/MWh)	-	-	-	-
Load factor (net of availability)	56%	As per offshore wind		
Operating period (years)	24	28	28	28

Table 7 - Main cost assumptions for tidal stream energy

	2025 (Demo)	2030 (FOAK)	2035 (NOAK)	2040 (NOAK)
Total Pre-development (£m)	4	4	2	2
Total Construction (£m)	60	70	60	50
Fixed O&M (£/MW/year)	240,400	107,500	60,400	47,300
Variable O&M (£/MWh)	-	-	-	-
Load factor (net of availability)	38%	37%	33%	33%
Operating period (years)	25	25	25	25

Non-renewable technologies

Hydrogen-fired CCGTs

For 100% hydrogen-fired CCGT technologies, we rely on internal departmental analysis to estimate the capital and operational cost of hydrogen-fired CCGTs. The department has also carried out internal analysis to arrive at a set of illustrative price series under different scenarios, based on methodology explained in the Hydrogen Production Costs Report 2021[13]. Hydrogen prices are highly uncertain and dependent on the development of the hydrogen economy and market, so the LCOE of hydrogen CCGTs is also highly uncertain.

This is the first time hydrogen-fired CCGTs have been introduced into the Generation Cost Report. The department will continue to commission further research to obtain more certainty in the data since it is a nascent technology. This aims to include retrofitted hydrogen turbines. In this report, hydrogen CCGTs are presented as both baseload plant (Annex A) and a peaking plant (Section 6: Peaking technologies) to illustrate both modes of operation. The role of hydrogen in the power system is still uncertain and we are researching further into this area. There remains some uncertainty around exact deployment timeframes, and the technology remains at the first of a kind (FOAK) stage of development. The department considers hydrogen CCGTs commissioning before 2040 to be FOAK. We therefore present FOAK costs for 2025, 2030 and 2035 in this report, and Nth of a kind (NOAK) costs for 2040.

Table 8 - Main cost assumptions for 100% hydrogen-fired CCGTs

	2025	2030	2035	2040
Total Pre-development (£m)	20	20	20	20
Total Construction (£m)	830	830	830	740
Fixed O&M (£/MW/year)	15,500	15,500	15,500	14,000
Variable O&M (£/MWh)	2	2	2	2
Load factor (net of availability)	93%	93%	93%	93%
Operating period	25	25	25	25

[13] https://www.gov.uk/government/publications/hydrogen-production-costs-2021

Energy from Waste & Advanced Conversion Technologies

The department commissioned a report by NNFCC[14] to review the technical and cost assumptions for the following technologies:

- EfW with CHP.
- ACT.
- ACT with CHP.

As a result of the recommendations in the report, the following technical and cost assumptions have been updated for Energy from Waste:

- Construction period.
- Plant operating period.
- Net efficiency.
- Availability.
- Capital costs.

For ACT, the following technical and cost assumptions have been updated:

- Plant operating period.
- Net power.
- Net efficiency.
- Capital costs.

Further details on how these costs were reached can be found in the NNFCC report.

Power CCUS and power BECCS

We have not updated cost estimates for power generation with carbon capture, usage, and storage (power CCUS) and power generation from bioenergy with carbon capture and storage (power BECCS). Costs for first deployment of both technologies in the UK are expected to be revealed through bilateral negotiations which relate to specific projects, informed by project-specific analysis. The information and analysis used for this purpose is commercially confidential. Therefore, it is not available for generic cost assumptions.

Nuclear technologies

For nuclear, we continue to use assumptions from the 2016 Generation Costs Report and from publicly available data from the Hinkley Point C project - the only nuclear power plant currently under construction in GB. Currently our assumptions only refer to large-scale nuclear plants. However, the department is in the process of updating assumptions for large-scale nuclear

[14] Review of BEIS assumptions underlying power generation costs for ACT and EfW with CHP www.gov.uk/government/publications/review-of-power-generation-costs-for-technologies-eligible-for-contracts-for-difference

plants, as well as obtaining generation cost estimates for advanced nuclear technologies, including Small Modular Reactors (SMRs) and Advanced Modular Reactors (AMRs).

Nuclear costs are revealed through bilateral negotiations which relate to specific projects. Project-specific analysis is used to inform the Government's approach to these negotiations. Because the information and analysis used for this purpose is commercially confidential, it is not available to be used to update our generic cost assumptions.

Cross-cutting assumptions

Fuel costs & gate fees

Fossil fuel price assumptions have been updated in line with the figures used in the 2019 Fossil Fuel Price Projections[15] and updated to fit our internal assumptions.

As part of the EfW and ACT review performed by NNFCC, gate fees have also been updated. Our new assumptions are listed in the Table 9.

Table 6 - Gate fee assumptions, 2021 prices.

Technology	Gate fee, current report (£/MWh)	Gate fee, 2020 report (£/MWh)
EfW	-35	-34
ACT	-18	-14

Carbon prices

For fossil fuel plants, the total carbon price initially uses published UK ETS prices[16] as a base but then tracks towards the carbon appraisal price[17], noting that this represents a modelling assumption rather than a government projection.

Carbon prices are significantly higher than assumed in the previous 2020 report, which has resulted in an increase in LCOE for fossil fuel plants.

Balancing Services Use of System (BSUoS) charges

In April 2022, Ofgem published their decision CMP308[18], which moves BSUoS charges away from generation and demand to Final Demand only. This change is due to take effect from April 2023 onwards.

[15] https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2019
[16] https://www.gov.uk/government/publications/determinations-of-the-uk-ets-carbon-price
[17] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal/valuation-of-greenhouse-gas-emissions-for-policy-appraisal-and-evaluation
[18] https://www.ofgem.gov.uk/publications/cmp308-removal-bsuos-charges-generation

Therefore, these costs are no longer incurred by the generator and are no longer part of the levelised cost framework. They are no longer presented as part of the estimates in this report. Previously this cost fell under the variable operating costs.

Deflator assumptions

The prices presented in this report are all in 2021 prices unless stated. Where necessary, prices have been converted from other years' price bases using the GDP deflator series as published by HM Treasury. For this report, the March 2022 Quarterly National Accounts series have been used[19].

Fuel emissions factors

Fuel emissions factors (mass of CO2 released per relevant quantity of fuel burned) were updated from the UK Greenhouse Gas Emissions Inventory[20].

Heat revenues

A simplified method based on the avoided boiler cost approach has been used to estimate the heat revenue per MWh of electricity generated. This approach estimates the cost that would have been incurred by the heat off-taker (the buyer of heat produced by the CHP plant) if they were to produce the same amount of heat using a boiler. This assumes that 100% of the heat is purchased. This would incur fuel costs at the retail gas price, which are avoided by buying heat from the CHP plant.

[19] https://www.gov.uk/government/statistics/gdp-deflators-at-market-prices-and-money-gdp-march-2022-quarterly-national-accounts
[20] https://naei.beis.gov.uk/

Section 3: How the department uses generation cost data in modelling

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

In practice, the department's electricity market modelling, including the Dynamic Dispatch Model (DDM), does not use levelised cost estimates directly. Instead, it models private investment decisions using the same capital expenditure (capex) and operating expenditure (opex) assumptions incorporated in the levelised cost estimates reported here. The DDM also includes assumptions on investors' expectations over fossil fuel, carbon, and wholesale electricity prices that are CB6 compliant assumptions, as well as the financial incentives from policies such as Contracts for Difference (CfDs) and the Capacity Market. The DDM models the investment decision by comparing the internal rate of return with a technology specific hurdle rate.

Levelised cost 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. 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.

Levelised costs do not cover wider costs to the electricity system as they only relate to those costs accruing to the owner/operator of the generation asset. Further analysis on Wider System Impacts, including illustrative scenarios, can be found in Section 7 of the 2020 Electricity Generation Costs Report.

Levelised costs are less suitable for peaking technologies where the most relevant consideration is the cost of capacity rather than the cost per MWh. A £/kW measure covering fixed costs for peaking technologies is presented in **Section 5**.

Levelised costs are sensitive to the assumptions used

Levelised cost estimates are highly sensitive to the data and assumptions used. Within this, different technologies are sensitive to different input assumptions.

This report captures some of these uncertainties through ranges presented around key estimates. A range of costs is presented for capex and fuel, depending on the estimates. However, not all uncertainties are captured in these ranges and estimates should be viewed in this context. It is often more appropriate to consider a range of costs rather than point estimates.

Levelised costs are generic, 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.

Levelised cost estimates can be reported for different milestones associated with a project including the project start, the financial close and the commissioning year. In this publication, the department reports levelised cost estimates for projects commissioning in the same year.

Pre-development and construction durations will vary by technology and therefore estimates reported for 'project start' or 'financial close' for different technologies may not be commissioning in the same year as each other. Central estimates for pre-development and construction timings are presented for key technologies in the accompanying spreadsheet to this publication.

Levelised costs are not strike prices

The levelised cost estimates in this report do not provide an indication of potential future Administrative Strike Prices (ASPs) for technologies under Contracts for Difference (CfDs) allocation rounds.

Generation cost assumptions, such as that summarised here in the form of levelised costs, 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.

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

- Revenue assumptions
- Other costs not included in our definition of levelised cost (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, risk allocation, and eligibility requirements within technologies
- Other relevant information such as studies or data published by industry
- Developments within industry
- Wider policy considerations

The generation costs data used here may be different from that used as part of the administrative strike price-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 typical project costs estimated in this report.

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

Section 4: Generation cost estimates

This section summarises the analysis of the levelised cost of electricity generation at technology-specific hurdle rate for a selection of technologies. All values presented are in 2021 real prices[21].

Projects commissioning in 2025

Figure 2 – LCOE estimates for projects commissioning in 2025, in real 2021 prices

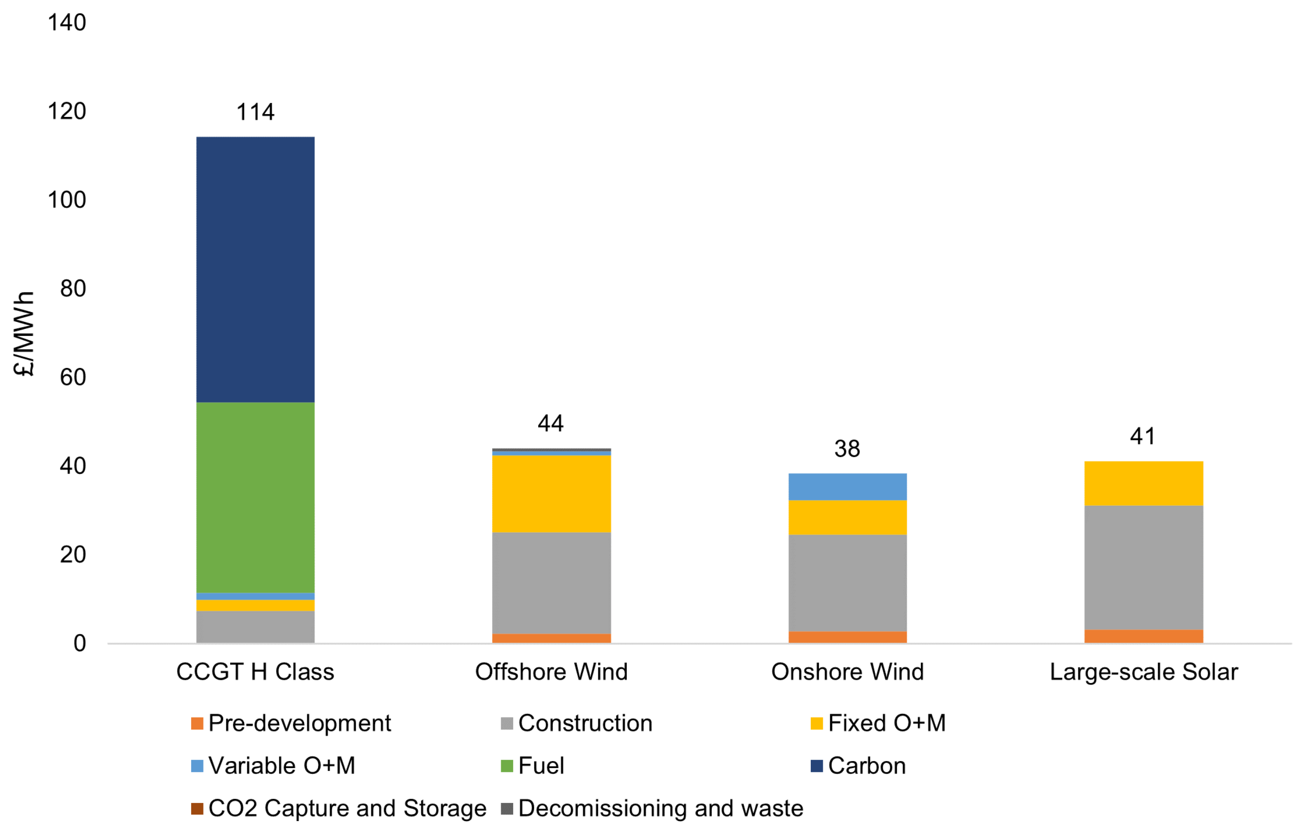


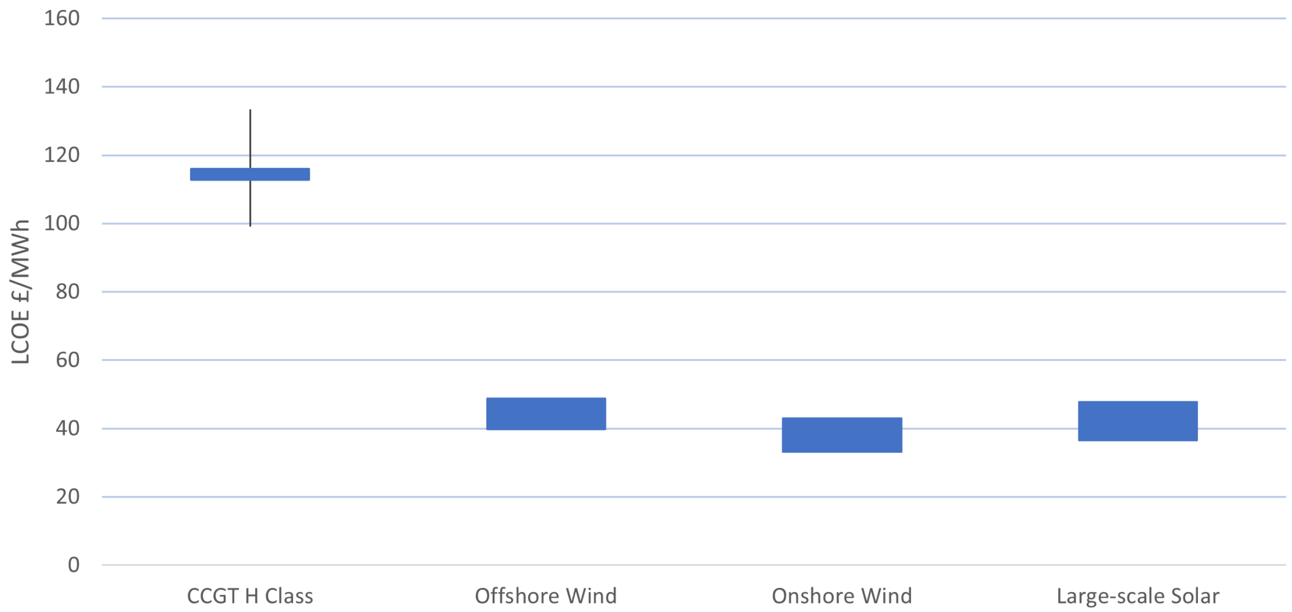
Table 10 - LCOE estimates for projects commissioning in 2025, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
Pre-development costs	<1	2	3	3
Construction costs	7	23	22	28
Fixed O&M costs	2	17	8	10
Variable O&M costs	2	1	6	0

[21] Please note that these estimates should be viewed in the context of the sensitivities and uncertainties highlighted in the text of this report.

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
Fuel costs	43	0	0	0
Carbon costs	60	0	0	0
CO2 Transport and Storage	0	0	0	0
Decommissioning and waste	0	1	0	0
Total	**114**	**44**	**38**	**41**

Figure 3 - LCOE sensitivities for projects commissioning in 2025, in real 2021 prices



Boxes represent capital expenditure variation, and whiskers represent fuel expenditure variation.

Table 7 - LCOE sensitivities for projects commissioning in 2025, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
High capex	116	49	43	48
Central	114	44	38	41
Low capex	113	40	33	37
High capex, high fuel	133	n/a	n/a	n/a
Low capex, low fuel	99	n/a	n/a	n/a

Projects commissioning in 2030

Figure 4 - LCOE estimates for projects commissioning in 2030, in real 2021 prices

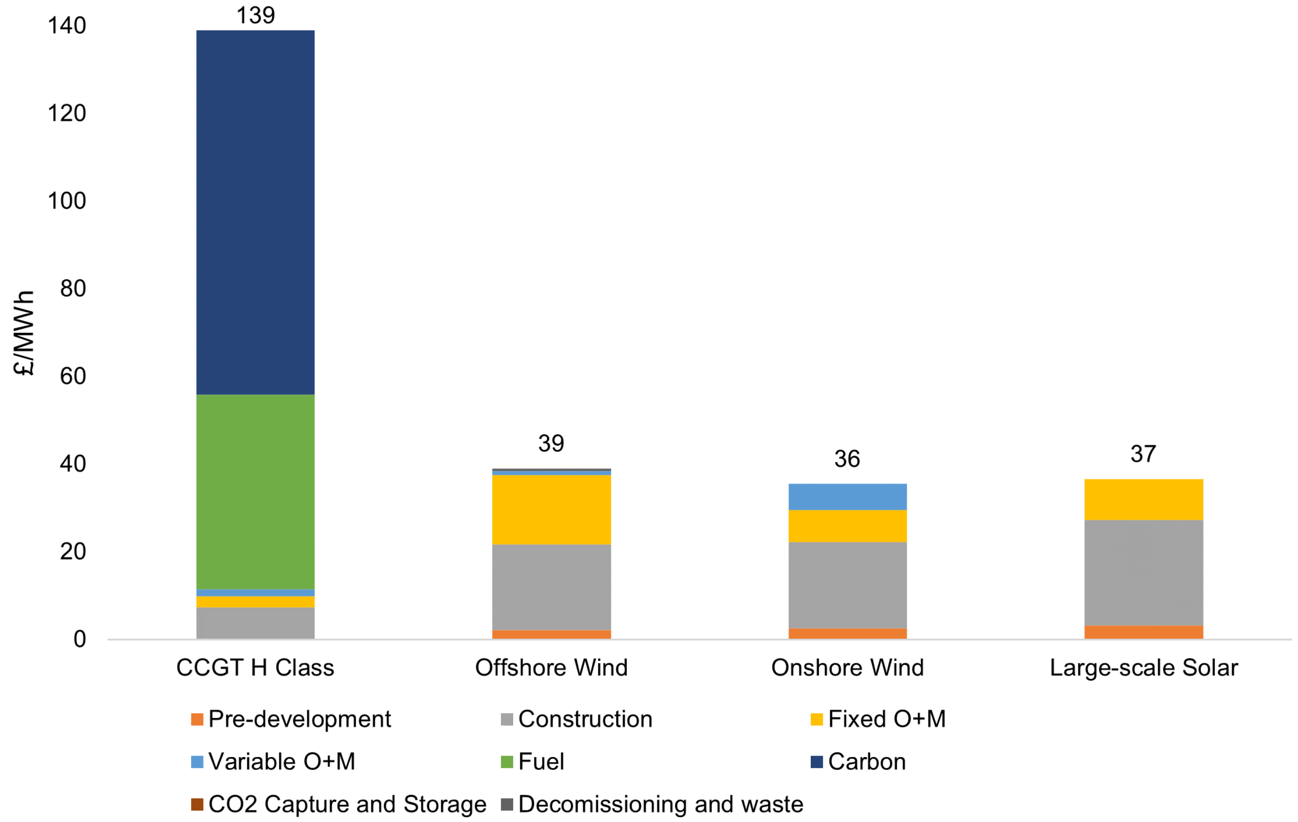
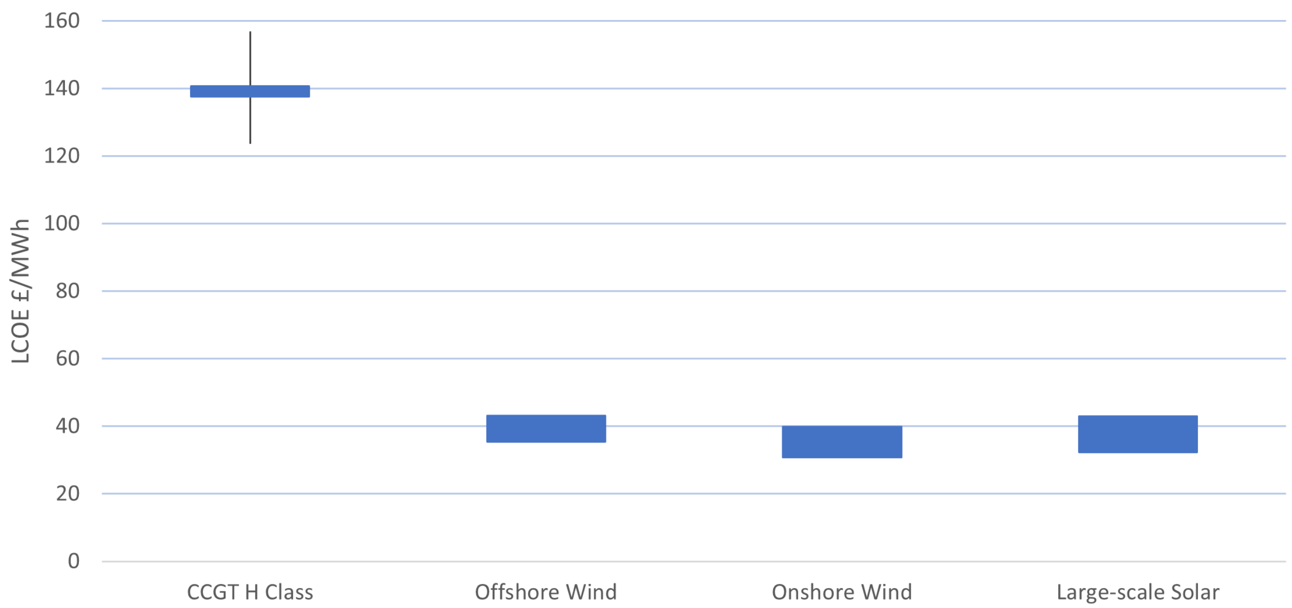


Table 128 - LCOE estimates for projects commissioning in 2030, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
Pre-development costs	<1	2	3	3
Construction costs	7	20	20	24
Fixed O&M costs	2	16	7	9
Variable O&M costs	2	1	6	0
Fuel costs	44	0	0	0
Carbon costs	83	0	0	0
CO2 Transport and Storage	0	0	0	0
Decommissioning and waste	0	1	0	0
Total	**139**	**39**	**36**	**37**

Figure 4 - LCOE sensitivities for projects commissioning in 2030, in real 2021 prices



Boxes represent capital expenditure variation, and whiskers represent fuel expenditure variation.

Table 13 - LCOE sensitivities for projects commissioning in 2030, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
High capex	141	43	40	43
Central	139	39	36	37
Low capex	138	35	31	32
High capex, high fuel	157	n/a	n/a	n/a
Low capex, low fuel	124	n/a	n/a	n/a

Projects commissioning in 2035

Figure 6 - LCOE estimates for projects commissioning in 2035, in real 2021 prices

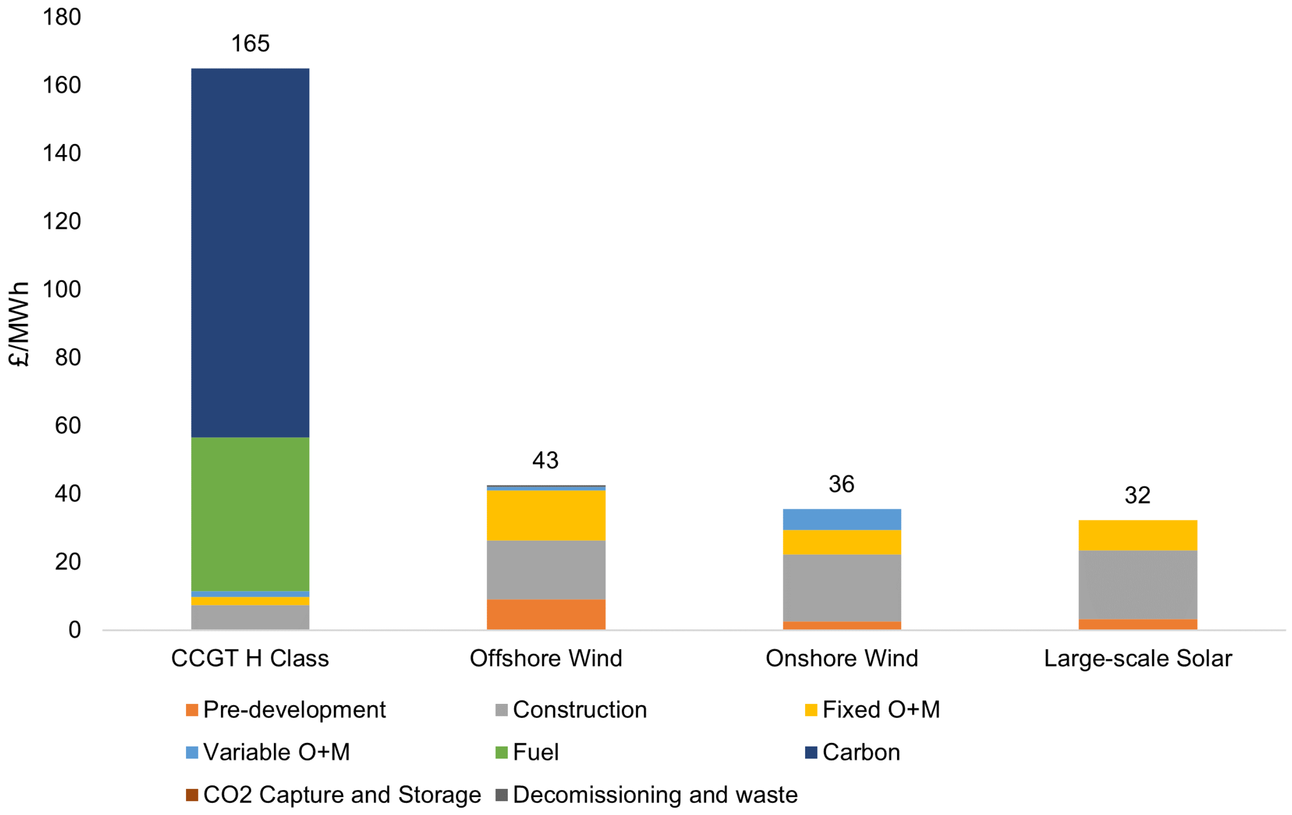


Table 149 - LCOE estimates for projects commissioning in 2035, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
Pre-development costs	<1	9	3	3
Construction costs	7	17	20	20
Fixed O&M costs	2	15	7	9
Variable O&M costs	2	1	6	0
Fuel costs	45	0	0	0
Carbon costs	108	0	0	0
CO2 Transport and Storage	0	0	0	0
Decommissioning and waste	0	1	0	0
Total	**165**	**43**	**36**	**32**

Figure 5 - LCOE sensitivities for projects commissioning in 2035, in real 2021 prices

Boxes represent capital expenditure variation, and whiskers represent fuel expenditure variation.

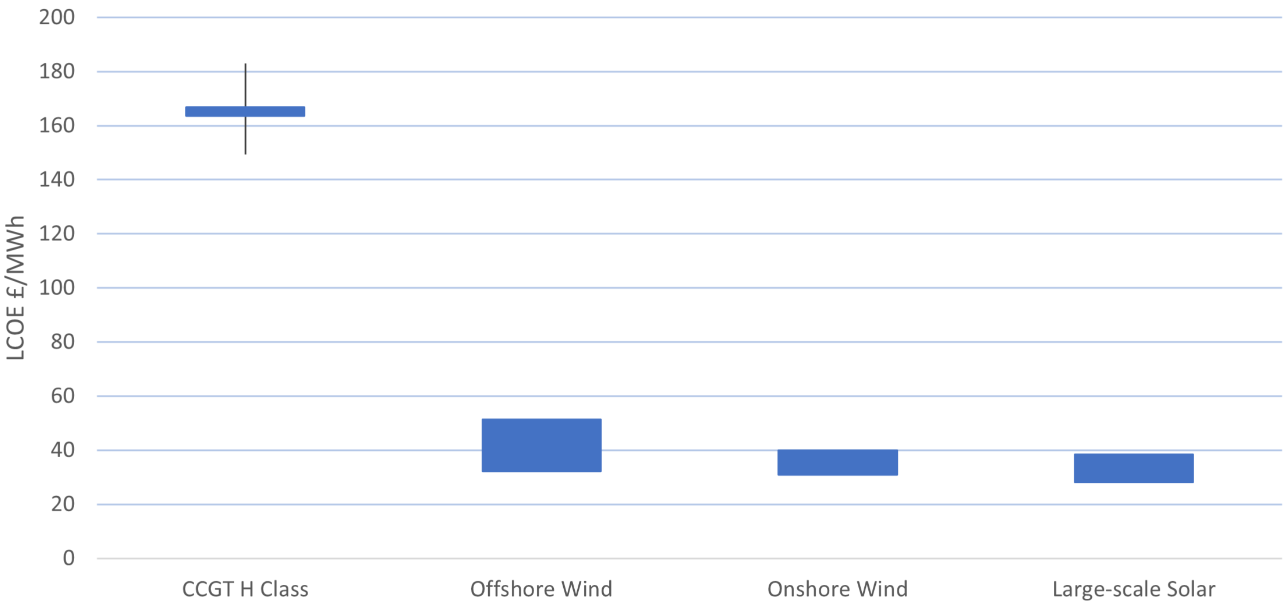


Table 1510 - LCOE sensitivities for projects commissioning in 2035, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
High capex	167	51	40	38
Central	165	43	36	32
Low capex	164	32	31	28
High capex, high fuel	183	n/a	n/a	n/a
Low capex, low fuel	149	n/a	n/a	n/a

Projects commissioning in 2040

Figure 8 - LCOE estimates for projects commissioning in 2040, in real 2021 prices

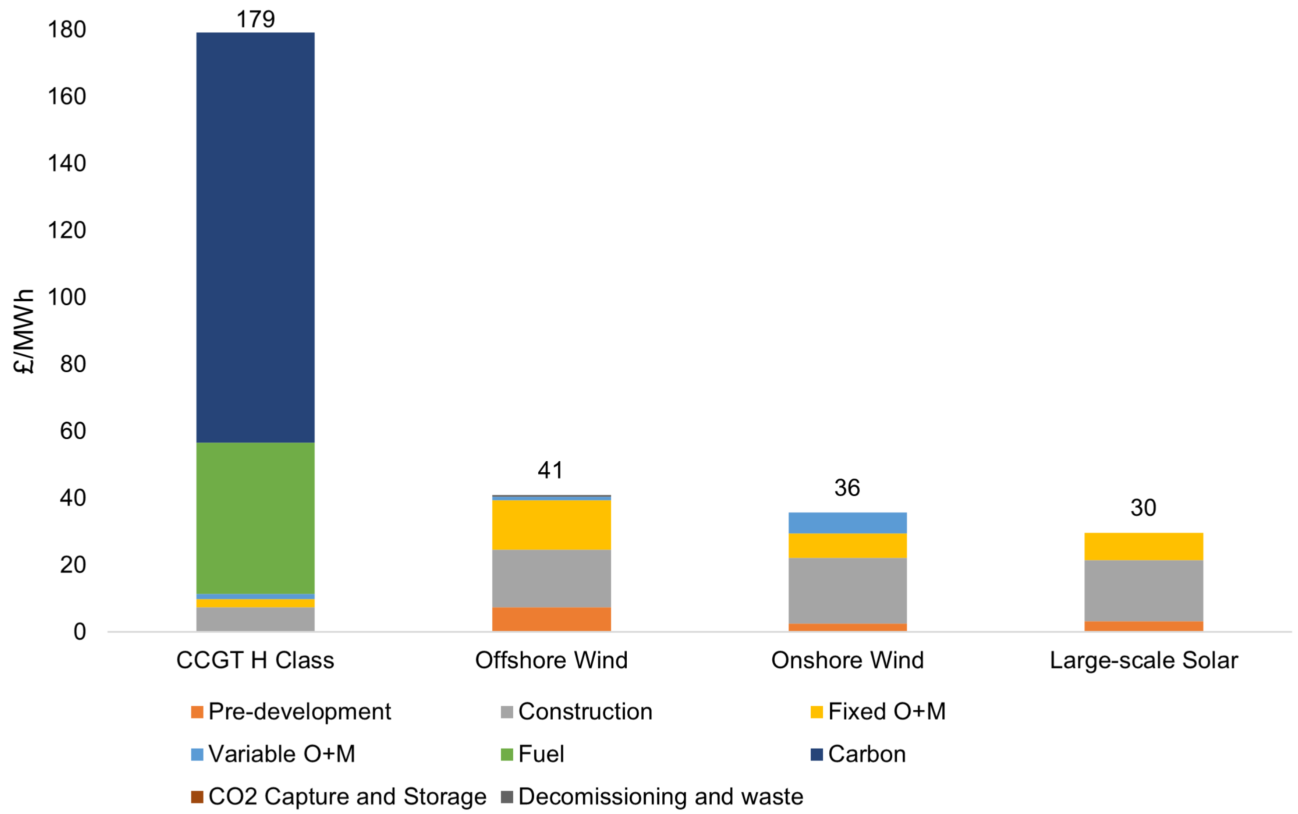
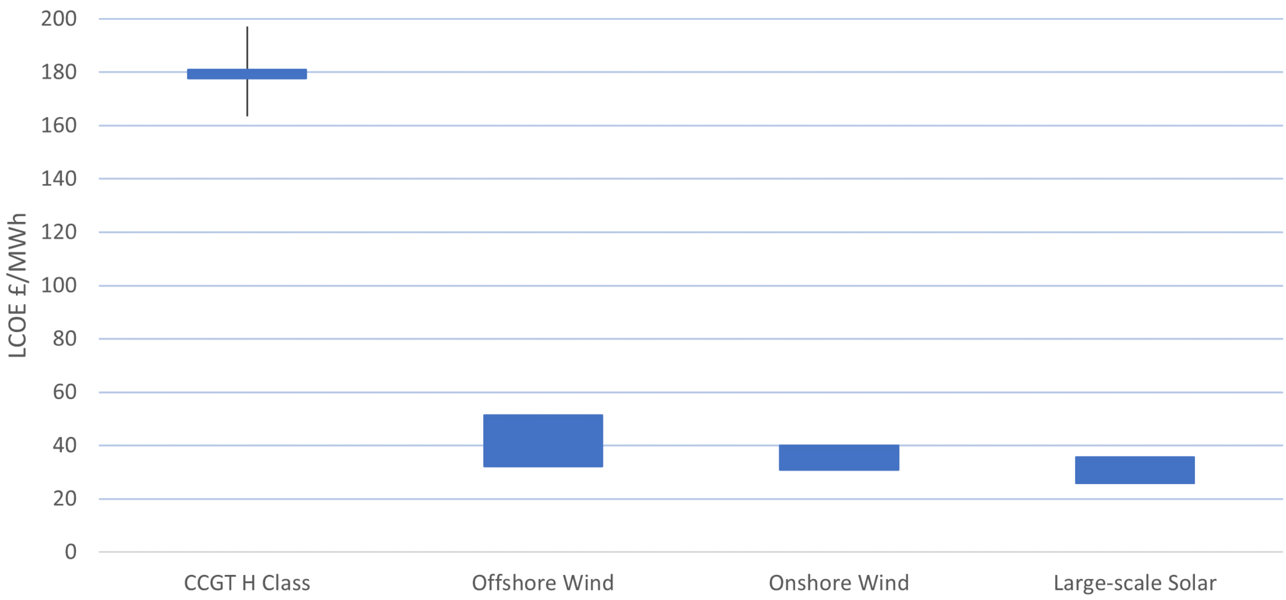


Table 1611 - LCOE estimates for projects commissioning in 2040, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
Pre-development costs	<1	7	3	3
Construction costs	7	17	20	18
Fixed O&M costs	2	15	7	8
Variable O&M costs	2	1	6	0
Fuel costs	45	0	0	0
Carbon costs	123	0	0	0
CO2 Transport and Storage	0	0	0	0
Decommissioning and waste	0	1	0	0
Total	179	41	36	30

Figure 6 - LCOE sensitivities for projects commissioning in 2040, in real 2021 prices



Boxes represent capital expenditure variation, and whiskers represent fuel expenditure variation.

Table 127 - LCOE sensitivities for projects commissioning in 2040, £/MWh, in real 2021 prices

	CCGT H Class	Offshore Wind	Onshore Wind[5]	Large-scale Solar
High capex	181	51	40	36
Central	179	41	36	30
Low capex	178	32	31	26
High capex, high fuel	197	n/a	n/a	n/a
Low capex, low fuel	163	n/a	n/a	n/a

Comparison between technologies over time

Table 138 - Levelised Cost Estimates for Projects Commissioning in 2025, 2030, 2035 and 2040, £/MWh, highs and lows reflect high and low capital and pre-development cost estimates, in real 2021 prices

Commissioning		2025	2030	2035	2040
CCGT H Class	High	116	141	167	181
	Central	114	139	165	179
	Low	113	138	164	178
Offshore Wind	High	49	43	51	51
	Central	44	39	43	41
	Low	40	35	32	32
Onshore Wind[5]	High	43	40	40	40
	Central	38	36	36	36
	Low	33	31	31	31
Large-Scale Solar	High	48	43	38	36
	Central	41	37	32	30
	Low	37	32	28	26

Comparison to previous levelised cost estimates

The below table summarises the changes made to the previous departmental estimates (BEIS 2020)[22] with the revised estimates in this report for 2025, 2030, 2035 and 2040 commissioning. All values below are in 2021 prices.

The reduction and then increase in Offshore wind costs comes from the pre-development costs because of the AR4 leasing round and resulting projects coming online.

Renewables costs have seen further declines due to increased deployment, and decreased costs as they progress further along the learning curve. Further improvements in turbine technology for offshore and onshore wind have driven down per MW capital costs, as well as increasing annual energy generation. For solar technologies, decreases in capital costs and increases in plant capacity, as informed by research, has also driven down the LCOE.

LCOE estimates have reduced for all transmission network connected technologies as they no longer have to pay BSUoS charges, which reduces their variable operating & maintenance fees.

[22] https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

CCGT has seen increases aligning to the increase in gas prices.

Table 19 - Change in Levelised Cost Estimates for Projects Commissioning in 2025 and 2030, £/MWh, highs and lows reflect high and low capital and pre-development cost estimates. All in real 2021 prices.

Commissioning		**2025**		**2030**	
		BEIS 2020	**This report**	**BEIS 2020**	**This report**
CCGT H Class	High	93	116 (+23)	109	141 (+32)
	Central	91	114 (+23)	107	139 (+32)
	Low	90	113 (+23)	105	138 (+33)
Offshore Wind	High	68	49 (-19)	56	43 (-13)
	Central	61	44 (-17)	51	39 (-12)
	Low	55	40 (-15)	46	35 (-11)
Onshore Wind[5]	High	55	43 (-12)	55	40 (-15)
	Central	49	38 (-11)	48	36 (-12)
	Low	42	33 (-9)	42	31 (-11)
Large-Scale Solar	High	55	48 (-7)	49	43 (-6)
	Central	47	41 (-6)	42	37 (-5)
	Low	42	37 (-5)	37	32 (-5)

Table 20 - Change in Levelised Cost Estimates for Projects Commissioning in 2035 and 2040, £/MWh, highs and lows reflect high and low capital and pre-development cost estimates. All in real 2021 prices.

Commissioning		**2035**		**2040**	
		BEIS 2020	**This report**	**BEIS 2020**	**This report**
CCGT H Class	High	125	167 (+42)	137	181 (+44)
	Central	123	165 (+42)	135	179 (+44)
	Low	122	164 (+42)	133	178 (+45)
Offshore Wind	High	52	51 (-1)	48	51 (+3)
	Central	47	43 (-4)	43	41 (-2)
	Low	42	32 (-10)	39	32 (-7)
Onshore Wind[5]	High	54	40 (-14)	53	40 (-13)
	Central	48	36 (-12)	47	36 (-11)
	Low	41	31 (-10)	41	31 (-10)
Large-Scale Solar	High	45	38 (-7)	42	36 (-6)
	Central	38	32 (-6)	35	30 (-5)
	Low	34	28 (-6)	30	26 (-4)

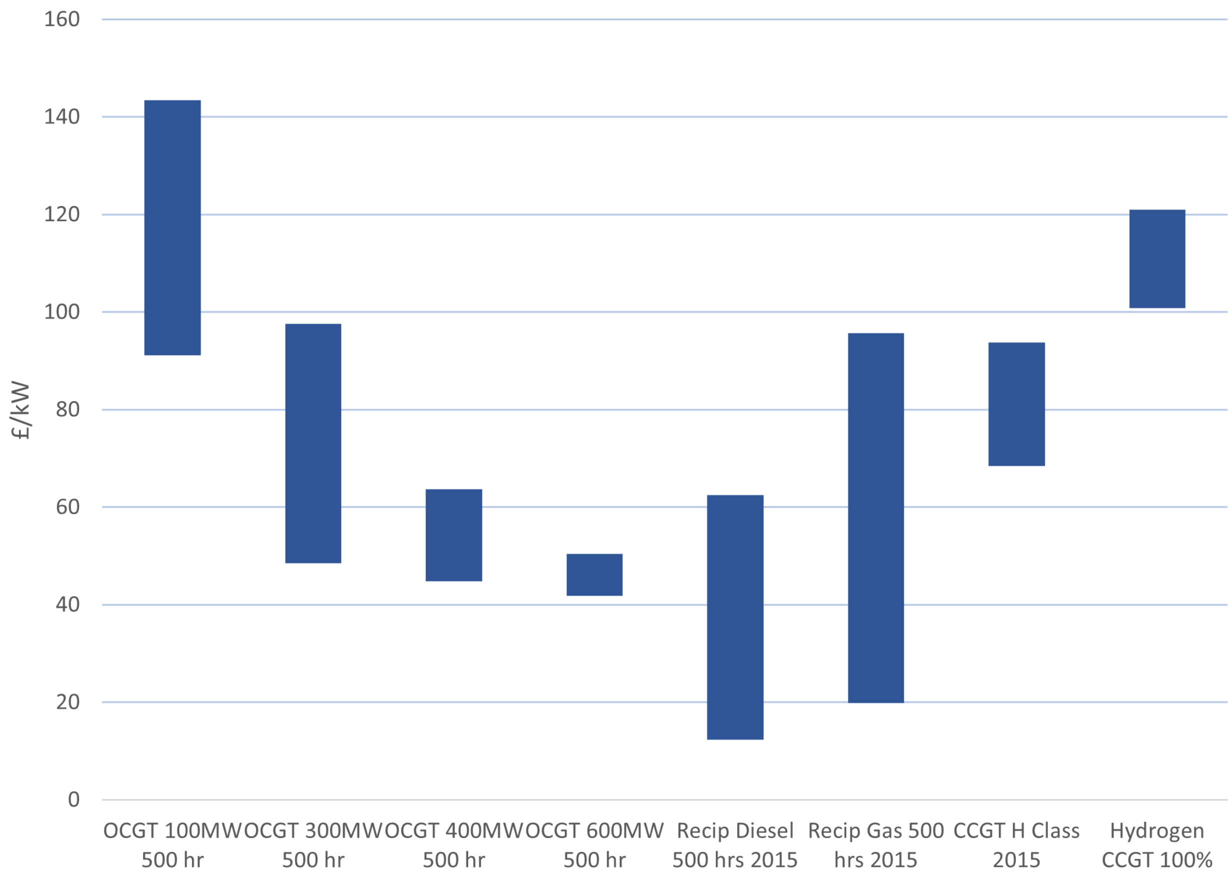
Section 5: Peaking technologies

This section presents a £/kW measure for peaking technologies (OCGT, reciprocating engines, H2 CCGT), as well as an unabated gas CCGT H Class for comparison. This measures the cost of capacity rather than the cost of generation – it therefore ignores fuel costs, carbon costs and other variable costs. This measure is more suitable for comparing technologies where generation varies with demand.

Figure 6 represents the annual cashflows required to finance the pre-development, construction, and fixed costs for a generic plant. These cashflows are assumed to be paid over the operating lifetime of the plant. The range of costs is created by varying capital expenditure to the high and low values.

All technologies are assumed to run for a fixed 500 hours per year, except unabated natural gas CCGT, which is assumed to run at baseload. This metric is not meant to illustrate likely capacity market outcomes, which reflect a range of other factors, including different contract lengths, load factor and wholesale price expectations and other sources of revenue.

Figure 10 - Peaking technologies (reciprocating diesel and gas, OCGT and Hydrogen CCGT 1000MW at 500 hours per year) and unabated gas CCGT (at normal load factors). £/kW per annum presented for construction and fixed operating costs, with technology-specific discount rates. 2025 commissioning dates.



This publication is available from: www.gov.uk/government/publications/electricity-generation-costs-2023