Department for
Business, Energy
& Industrial Strategy

Contracts for Difference

Methodology used to set Administrative Strike Prices for CfD Allocation Round 5

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Any enquiries regarding this publication should be sent to us at:BEISContractsForDifference@beis.gov.uk

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Introduction

This document explains the methodology for determining the Contracts for Difference (CfD) Administrative Strike Prices (ASPs) for Allocation Round 5 (AR5). ASPs represent the maximum strike price (the per MWh price for generating electricity) that a project of a particular technology type can receive. Should an auction be triggered, ASPs continue to limit the maximum price that projects of a particular technology type can receive, even if the auction clears at a higher price.

The ASPs included in the Core Parameters publication[1] are presented in Table 1 (below). A single ASP applies across each technology's applicable Delivery Years.

Table 1: Administrative Strike Prices (£/MWh in 2012 prices)

Pot	Applicable Delivery Years	Technology Type	Administrative Strike Price (applicable in each Delivery Year)
1	2025/26, 2026/27 and 2027/28	**Energy from Waste with CHP**	116
		Hydro (>5MW and <50MW)	89
		Landfill Gas	62
		Offshore Wind	44
		Onshore Wind (>5MW)	53
		Remote Island Wind (>5MW)	53
		Sewage Gas	148
		Solar PV (>5MW)	47
2	2026/27 and 2027/28	**ACT**	182
		Anaerobic Digestion (>5MW)	136
		Dedicated Biomass with CHP	162
		Floating Offshore Wind	116
		Geothermal	119
		Tidal Stream	202
		Wave	245

[1] https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-5-core-parameters

Section 1: Objectives for setting ASPs

The ASPs set out the maximum price, presented on a price per MWh basis, that the Government is willing to offer developers for each technology type, otherwise known as the reserve price. Should there be sufficient bidders for an auction to be triggered, the clearing price (the price paid to successful projects) is set by the bid made by the last project allocated a contract before the auction closes, subject to no project receiving a higher strike price than its technology-specific ASP[2].

The Government identified several policy objectives at the outset of the scheme and these continue to frame our approach to setting ASPs. For this allocation round, the Government has set ASPs using the same principles and overall analytical framework for ensuring value for money. ASPs should be based on robust cost information, set to encourage participation in the allocation round, and set using an approach which ensures value for money, whilst being consistent with Government's policy and deployment ambitions. More detail on these three objectives and the implications for how ASPs have been set is included in Table 2, below.

Table 2: Objectives for setting draft ASPs

	Objective	Implications for setting ASPs in AR5
1	**Based on robust cost information**	
	ASPs should draw on the latest generation cost data, while also considering market conditions, policy considerations and other technology-specific factors to ensure value-for-money for consumers.	Use latest evidence on renewable electricity generation costs to produce a supply curve for each technology in each year.
2	**Set to encourage participation in the allocation round**	
	ASPs should be set at the minimum level necessary to encourage new investment from a significant proportion of the supply curve.	Target 25% of the supply curve when setting reserve prices, unless there is a clear rationale otherwise.
3	**Set using an approach which ensures value for money and is consistent with Government policy and deployment ambitions**	

[2] Technologies subject to a maximum set their own clearing price (see the Allocation Framework for more detail).

	In general, the methodology for ASPs should take a consistent approach across all technologies. However, different sections of estimated supply curves may be targeted to improve value for money and/or ensure consistency with wider ambitions on decarbonisation, and to derive secondary benefits such as innovation and investment, where there is a clear rationale for doing so.	Target the same proportion of the supply curve (25%) for each technology, except for Offshore Wind, Floating Offshore Wind, Onshore Wind and Solar PV, which will have a target of 50% (see section 4 for more information on the rationale for this decision).

Section 2: Factors considered in setting ASPs

In light of the objectives set out in Section 1, in setting ASPs the Government has considered a range of factors, including:

- **Technology specific factors** such as capital and operating costs, financing costs as well as any build constraints.

- **Market conditions** such as estimated wholesale electricity prices and the discount which generators may face when signing a Power Purchase Agreement (PPA).

- **Policy considerations** such as the statutory purpose of the scheme to encourage low carbon electricity generation and the need to have regard to meet Carbon Budget 6 (CB6) and Net Zero targets, the likely cost to consumers, and ensuring security of supply. In addition, we can consider other factors including driving technology cost reductions and deployment scalability. ASPs have also been set to encourage a significant proportion of potential projects to come forward and compete in the allocation round – for this allocation round, this level has been set at 25% of the modelled supply curve for each technology, with Offshore Wind, Floating Offshore wind, Onshore Wind and Solar PV set at 50% of the modelled supply curve.

These factors mean that an ASP for a particular technology is different to the 'levelised cost' – the average cost over the lifetime of the plant per MWh generated. Relative to this levelised cost, an equivalent strike price could be higher or lower for several different reasons, all of which are taken into account in the setting of these ASPs:

- **Costs not included in BEIS's standard levelised costs:** CfD top-up payments will be paid based on generation after taking account of the generator's share of transmission losses, known as the Transmission Loss Multiplier, so the ASPs need to be increased to account for this.

- **PPAs:** The revenue received by the generator is a combination of the estimated wholesale market price and the CfD top-up, which is the difference between the strike price and the reference price. Where the generator is assumed to not be able to achieve the reference price because it sells its power through a PPA at a discount to the market price (or faces equivalent transaction costs within a vertically-integrated utility), the ASP must be increased to compensate for this. PPA discounts therefore reflect route to market costs including the costs of trading and imbalance costs.

- **Contract length:** The levelised cost is defined over the operating life of a project. Assuming the CfD contract length of 15 years is shorter than the operating life, and wholesale market revenues and any relevant heat sale revenues (for CHP plants) post-contract are lower than the levelised cost then, all other things being equal, the ASP must be increased above the levelised cost to compensate for this. Therefore, the ASP calculation factors in the remainder of project life revenues post-CfD expiry.

- **Pipeline specific information:** In modelling supply curves for each technology publicly available information relevant to potential applicants in the allocation round has been used to inform cost assumptions for pipeline projects, where possible. As a result, some project cost assumptions may differ from the technology-wide assumptions used in levelised cost estimates.

- **Other relevant information specific to setting ASPs:** This includes policy considerations such as CfD eligibility criteria for each technology, technology-specific estimates for decommissioning costs and scrappage values not included in BEIS's definition of levelised costs, and other relevant evidence of developments within industry.

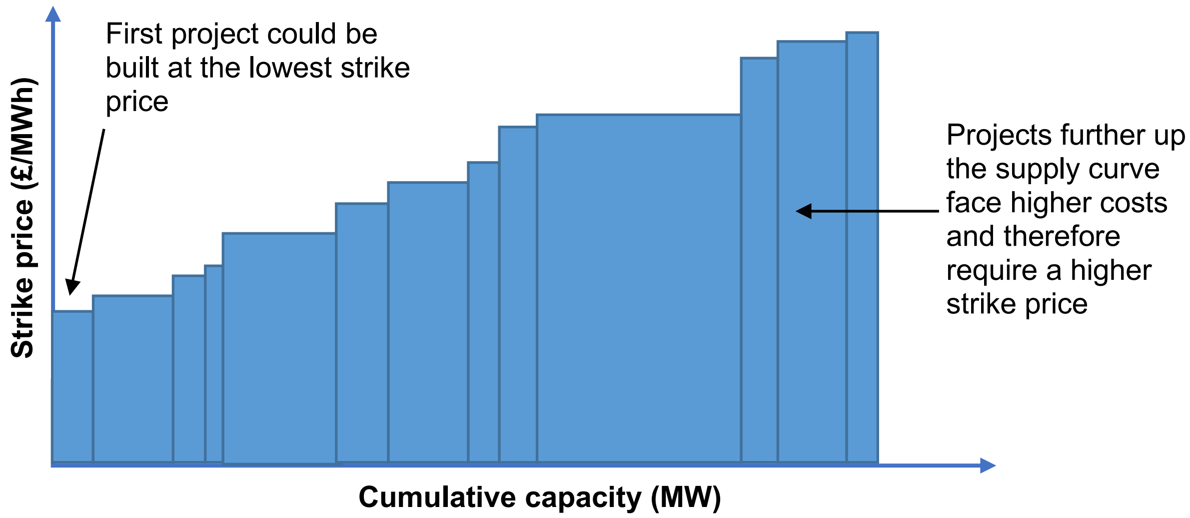
Further, ASPs are set to bring forward the most cost-effective projects, which may not be the same as the estimates of typical project costs. For all these reasons, the ASPs presented here may be significantly different from the levelised costs for each technology.

Section 3: Approach to setting ASPs

The methodology for setting ASPs draws on BEIS's latest view on generation costs to produce a modelled 'supply curve' for each technology in each delivery year. The supply curve represents the estimated volume of capacity in MW that could be built at different strike prices, ranked from cheapest to most expensive. This is represented graphically as an upward-sloping curve, with more projects expected to be financially viable as the ASP is increased, as illustrated in Figure 1.

Where possible these supply curves use publicly available information relevant to real-world projects likely to be able to apply for CfDs in Allocation Round 5 ('pipeline' projects). Examples include project capacities and estimated load factors based on project characteristics, and are factored in so as to more accurately reflect costs associated with the pipeline.

Figure 1: Illustrative supply curve



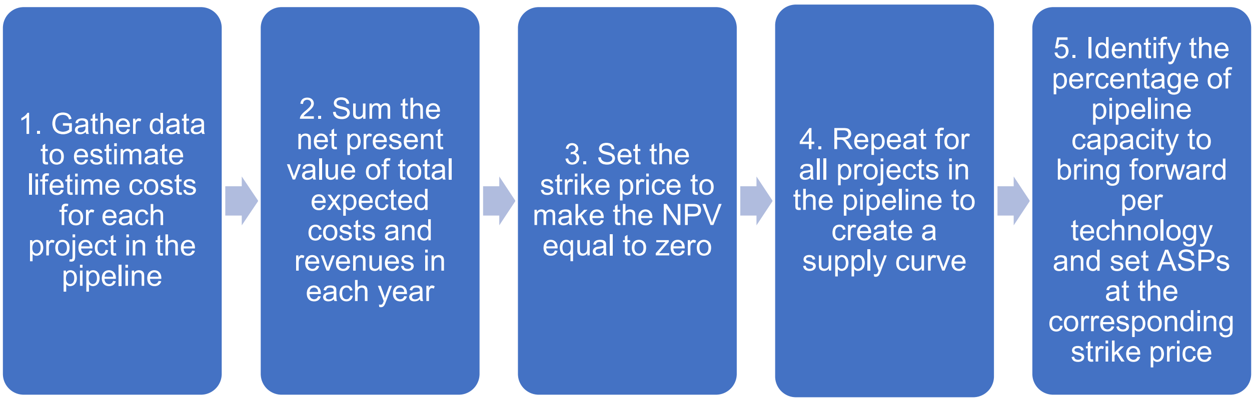
The ASP that is expected to incentivise a certain capacity of deployment is determined through a discounted cash-flow calculation for each project in the supply curve. The 'marginal project' is then identified as the most expensive project within the targeted deployment range (the cheapest 25% or 50% of the supply curve). The ASP is determined as the price that sets the net present value of this project's cash-flows equal to zero, taking account of the revenues in the wholesale market and from other relevant sources (such as the sale of heat produced by projects deploying with Combined Heat and Power) throughout the project lifetime and after the end of the CfD. The project cash-flows are discounted at BEIS's latest view on central hurdle rates.

For AR5, as with AR4, the calculated ASPs for each Delivery Year relevant to that technology have been compared, and a single ASP has been taken based on the maximum across the relevant years. This simplifies the allocation process and aligns with the use of a single clearing price, whilst reducing the risk that an individual project is unable to participate in the auction.

3.1 Approach Overview

Figure 2 provides a high-level summary of the approach used to set ASPs. Further detail is provided in Section 3.2.

Figure 2: Approach overview



3.2 Step-by-step approach

Step 1: Gather data to estimate lifetime cash-flows for each project in the pipeline

Table 3 outlines the key data inputs for estimating project lifetime cash-flows. The primary sources used for these inputs are BEIS's latest view on generation costs and market price projections, supplemented by pipeline project specific information where available. Further details on data sources can be found in Section 5.

Table 3: Key data and assumptions for each pipeline project

Capex costs	Opex costs and revenues	Decommissioning costs	Generation and other key data
Pre-development costs	Fixed opex	Financial security costs	Capacity of plant
Construction costs	Variable opex	Cost of decommissioning	Availability
Infrastructure costs	Insurance		Efficiency
	Connection costs		Load factor
	Heat revenues		Hurdle rate
	Fuel costs/gate fees		
	Strike price revenue (determined in Step 3)		

Step 2: Sum the net present value of total expected costs and revenues in each year

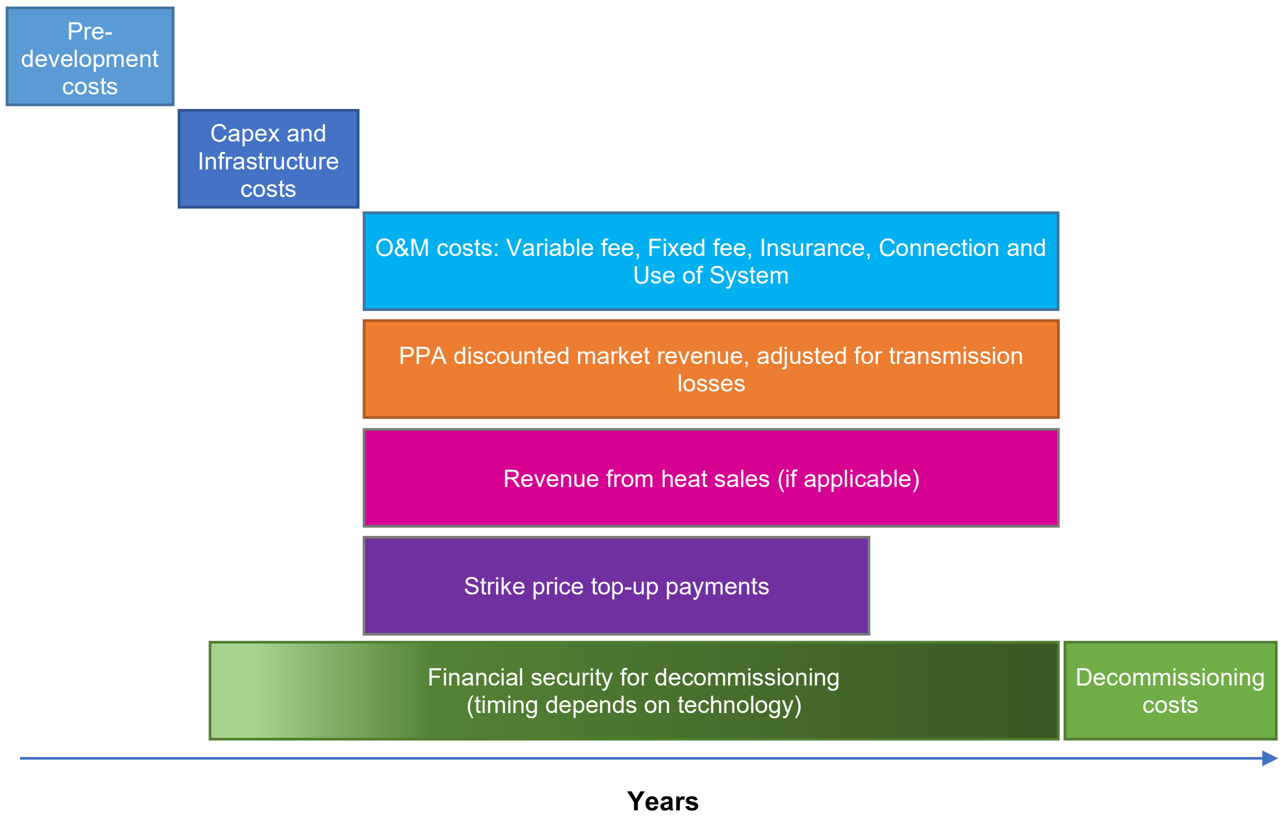
Costs and revenues are summed in each year over the lifetime of the project, and discounted by the hurdle rate for the technology (which accounts for relevant financing costs) to give the net present value (NPV) of lifetime cash-flows:

$$\mathrm{NPV} = \sum_{\mathrm{n}} \frac{\text{Total capex, opex, decommissioning costs and revenues}_{\mathrm{n}}}{(1 + \text{discount rate})^{\mathrm{n}}}$$

$$\mathrm{n} = \text{years}$$

Figure 3 illustrates how the timings of these costs and revenues are accounted for in the calculation.

Figure 3: Illustrative timings of project costs and revenues



Step 3: Set the strike price to make the NPV equal to zero

The strike price is set at the level at which the NPV of the project's lifetime costs and revenues is equal to zero. The strike price therefore represents the level of total revenue under the CfD required for the relevant project to achieve a rate of return equal to the BEIS latest view on central hurdle rates.

Step 4: Repeat for all projects in the pipeline to create the supply curve

Where information is publicly available on specific projects in the pipeline the supply curve is constructed from those individual projects, based on bespoke cost and generation assumptions as far as possible. This approach is currently used for Offshore Wind and Remote Island Wind.

Where limited information on pipeline projects is available, the range of viable strike prices has been estimated by assuming that pre-development, construction, and infrastructure costs increase linearly from the first project to the last project in the supply curve, where the low point on the supply curve assumes that low pre-development, construction and infrastructure cost apply to this particular project. Operating costs and all other cost and non-strike price revenue assumptions (for example load factors, hurdle rates and fuel costs where applicable) are assumed constant across the length of the supply curve.[3]

Technologies that are grouped together in a single category under the CfD are combined into a single supply curve based on the estimated total pipeline capacity across the variants that would be viable at each strike price.

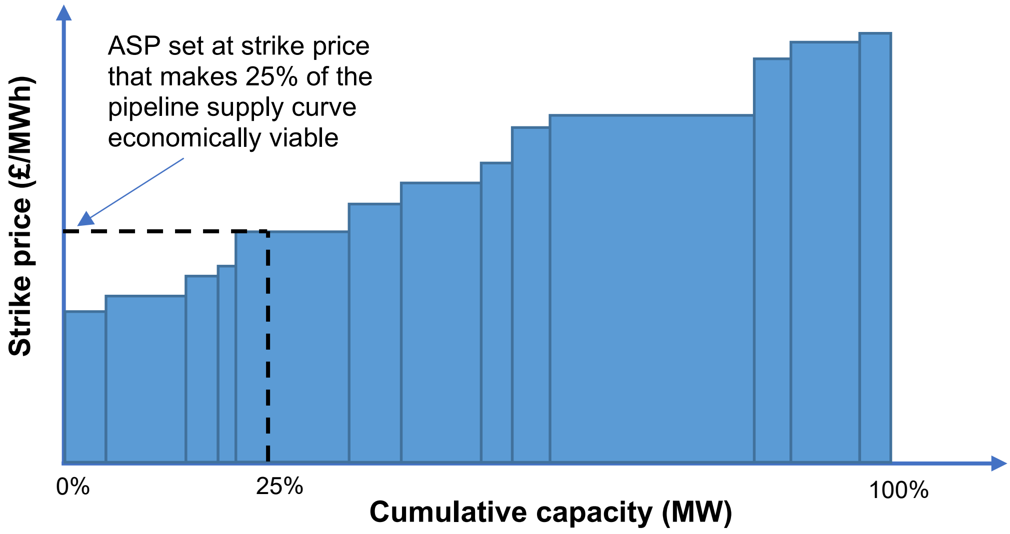
Step 5: Identify the percentage of pipeline capacity that would enable a high level of participation and set ASPs at the corresponding rate

A point on the supply curve is chosen to encourage participation in the auction, ensure competition and fulfil policy objectives. For this allocation round, it has been set at 25% of the supply curve for all technologies, except Offshore Wind, Floating Offshore Wind, Onshore Wind and Solar PV which are set at 50%, i.e. the ASP for each technology and delivery year corresponds to the strike price that is estimated to make 25% or 50% of pipeline projects economically viable, as illustrated in Figure 4.

In line with the methodology used in AR4, the calculated ASPs for each Delivery Year relevant to that technology are compared, and a single ASP is then taken based on the maximum across the relevant years. The ASP is then rounded to the nearest £1/MWh.

[3] The variation in overall levelised costs across these supply curves, due to the variation in capital costs assumed, is intended to proxy the variation in overall levelised costs across the potential new projects, which itself will reflect variations across all cost components.

Figure 4: Setting the Administrative Strike Price



Section 4: Technology Specific Approaches

The following technology-specific approaches have been applied to reflect the best evidence available when estimating project costs and technology supply curves.

Offshore Wind and Remote Island Wind

For these technologies, we have constructed supply curves consisting of specific known projects in the pipeline, informed by information included in planning consents. Project-specific costs have been estimated where possible using the following approaches:

- **Project capacities:** These assumptions are based on capacities stated in planning consents.
- **Capex:** Capital costs are assumed to vary with the size of turbine. This is in line with a range of external sources and BEIS's latest view on generation costs. As the MW capacity of each turbine increases, it is assumed that the £/MW capital costs decrease due to economies of scale.
- **Load factors:** These have been estimated using internal models generating power curves (the relationship between the power output of a turbine based on its size, and wind speed) and combining these with site-specific wind speed distribution data from the Met Office.
- **Transmission Network Use of System (TNUoS) charges:** These have been estimated for each pipeline project using tariffs and network charging assumptions for each location, provided by National Grid.
- **Decommissioning costs for offshore wind**: Decommissioning costs have been estimated using BEIS's decommissioning cost model[4] (developed by ARUP).

Floating Offshore Wind

Floating offshore wind is an emerging technology. In line with AR4, we have used a bespoke approach to estimating generation cost assumptions. This includes incorporating evidence from a combination of sources, including but not limited to the Department's own estimates, information from the Offshore Renewable Energy Catapult (OREC) and industry intelligence. Where appropriate, we have made amendments to generation costs to reflect the relatively nascent characteristics of AR5 pipeline projects (e.g. to reflect their smaller size).

[4] Cost estimation and liabilities in decommissioning offshore wind installations: https://www.gov.uk/government/publications/decommissioning-offshore-wind-installations-cost-estimation

Anaerobic Digestion (AD) and Geothermal

Both AD and Geothermal technologies have the option to deploy with or without CHP, and these two variants have different generation costs associated with them. These variants have been combined based on an assumed breakdown of pipeline projects informed by information in the Renewable Energy Planning Database (REPD)[5], the responses to the 2016 Call for Evidence on fuelled and geothermal technologies in the Contracts for Difference scheme[6], and published information on projects. Based on these sources, we assume that 80% of Geothermal projects will deploy without CHP and 20% with CHP and so a combination of the generation costs for each variant have been used. For AD, we assume that all projects will deploy without CHP and so only 'without CHP' generation cost estimates have been applied.

Tidal Stream

Industry estimates supplied to BEIS on capex and pre-development costs have been incorporated into our modelled supply curve.

Targeted proportion of the supply curve for Offshore Wind, Floating Offshore Wind, Onshore Wind and Solar PV

For Offshore Wind, Floating Offshore Wind, Onshore Wind and Solar PV, a greater proportion of the supply curve is targeted than other technologies (50%, versus 25% for others). This approach is consistent with the Government response to the AR4 consultation in November 2020[7], which expressed a need for greater flexibility when setting ASPs for specific technologies.

This is an increase compared with AR4 for Floating Offshore Wind, Onshore Wind and Solar PV, which were all 25% in AR4.

This approach better reflects Government's decarbonisation objectives to meet Carbon Budget 6 (CB6) and Net Zero, and is line with the public statements included in The British Energy Security Strategy[8] (BESS) and the Net Zero Strategy[9] (NZS).

Meeting these commitments requires deploying significant quantities of Offshore Wind, Floating Offshore Wind, Onshore Wind and Solar PV capacity, and the change is designed to enable greatest participation whilst seeking to retain sufficient levels of competitive tension.

[5] https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract
[6] https://www.gov.uk/government/consultations/call-for-evidence-on-fuelled-and-geothermal-technologies-in-the-contracts-for-difference-scheme
[7] https://www.gov.uk/government/consultations/contracts-for-difference-cfd-proposed-amendments-to-the-scheme-2020
[8] https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
[9] https://www.gov.uk/government/publications/net-zero-strategy

Section 5: Assumptions

The key data source used in setting ASPs is BEIS's latest view on electricity generation costs, which builds on the evidence base from the 2020 Electricity Generation Costs report.[10] This includes assumptions on pre-development costs, construction costs, operating and maintenance costs, connection and use of system charges, load factors and efficiencies, and project timings.

Remote Island Wind is not included as a separate technology from Onshore Wind in BEIS's generation cost estimates, and therefore assumptions from Baringa's Scottish Islands Renewable Project Final Report[11] have been incorporated, updated in line with cost reductions estimated for onshore wind since 2013, from BEIS's latest generation cost assumptions. As noted in Section 4, these are supplemented by project specific estimates for a range of items.

Hurdle Rates

These are sourced from a BEIS commissioned report from Europe Economics (EE)[12], updating the Department's financing cost assumptions for projects starting development from 2018 in a range of technologies.

Connection and Use of System Charges (UoS)

For Offshore Wind and Remote Island Wind, Transmission Network Use of System (TNUoS) charges have been estimated for each pipeline project using forecast tariffs and network charging assumptions for each location, provided by National Grid. For all other technologies, connection and UoS charges estimates are sourced from BEIS's updated generation cost assumptions.

The UoS charge estimates have been updated for AR5 to reflect the OFGEM decision to move BSUoS charges from generation and demand to Final Demand only[13]

Revenues

Market price assumptions (including forecasts of wholesale prices and PPA discount factor assumptions) have been modelled using the Department's Dynamic Dispatch

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

[11] Scottish Islands Renewable Project: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/199038/Scottish_Islands_Renewable_Project_Baringa_TNEI_FINAL_Report_Publication_version_14May2013__2_.pdf

[12] 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.pd

[13] https://www.ofgem.gov.uk/publications/cmp308-removal-bsuos-charges-generation

Model (DDM)[14]. Different market prices are assumed to be captured by baseload technologies (such as ACT) compared to intermittent technologies (such as Offshore Wind).

For baseload technologies this uses the modelled season ahead price (average wholesale). For intermittent technologies, day ahead hourly prices are estimated based on intra-day half-hourly prices. An individual wholesale reference price series is estimated for Offshore Wind, Onshore Wind, Solar PV and Hydro. These prices reflect the estimated average price which each technology could achieve in the market based on when they are expected to generate. For technologies other than those listed above, a suitable proxy capture price is used. Schedule 2 Appendix 2 of the Allocation Framework sets out the reference price series used in the valuation formula, with Schedule 3 setting out which technologies each series is applied to[15]. The same series are applied to the same technologies for the purposes of informing ASPs.

Heat revenues are calculated based on the avoided retail cost of gas needed to be purchased. This approach estimates the cost that would have been incurred by the heat off-taker (the buyer of the heat produced by the CHP plant) if they were to produce the same amount of heat using a boiler. This would incur fuel costs at the retail gas price, which are avoided by buying heat from the CHP plant. Geothermal is assumed to have 40% heat demand (the proportion of time when generated heat would be sold) given the geographical location restrictions and seasonal considerations for this technology. This assumption is based on responses to the 2016 Call for Evidence on Fuelled and Geothermal Technologies in the CfD Scheme.[16] For all other technologies deploying with CHP heat demand is assumed to be 100% in line with BEIS's levelised cost estimates.

Decommissioning costs and scrappage value

For Offshore Wind, decommissioning costs have been estimated using BEIS's decommissioning cost model[17] (developed by ARUP). For other technologies, decommissioning cost assumptions have been informed by information included in planning applications, decommissioning plans submitted to BEIS, independent cost assessments of decommissioning plans (commissioned by BEIS) and internal BEIS expertise.

For all technologies it is also assumed that developers must provide a financial security during the lifetime of the project to cover the costs of decommissioning at end of project life. Internal BEIS commercial expertise has been used to inform

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[14] BEIS Dynamic Dispatch Model: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/65709/5425-decc-dynamic-dispatch-model-ddm.pdf

[15] These reference prices are used for the purposes of informing ASPs, and in the valuation formula to estimate monetary budget during the Allocation Round. They do not influence or predicate the reference prices used by the Low Carbon Contracts Company (LCCC) to calculate payments in-life.

[16] https://www.gov.uk/government/consultations/call-for-evidence-on-fuelled-and-geothermal-technologies-in-the-contracts-for-difference-scheme

[17] Cost estimation and liabilities in decommissioning offshore wind installations: https://www.gov.uk/government/publications/decommissioning-offshore-wind-installations-cost-estimation

estimates of the cost of these financial securities. Timings of financial securities have been informed from BEIS decommissioning guidance and internal BEIS expertise.

Scrappage value assumptions have been informed by decommissioning plans submitted to BEIS, independent cost assessments of decommissioning plans (commissioned by BEIS) and internal BEIS expertise.

Other assumptions

Since the 2020 Generation Costs Report, BEIS has commissioned new research into the costs associated with the eligible technologies outlined below. This has informed BEIS' latest view of generation costs for the purposes of determining ASPs in this allocation round.

- **ACT and Energy from Waste with CHP:** BEIS commissioned a review into the generation costs associated with ACT and EfW capacity. Evidence from this review has been incorporated into ASP calculations to more accurately reflect the likely costs associated with generation eligible to bid into the CfD scheme. The outcomes of this review will be published in due course.

- **Solar PV and Onshore Wind:** BEIS commissioned a review into the generation costs associated with Solar PV and Onshore Wind. Evidence from this review has been incorporated into ASP calculations to reflect a more up to date view of likely generation costs for these technologies. The outcomes of this review will be published in due course.