Department of Energy Security and Net Zero

Renewable Energy Generation Cost and Technical Assumptions – Onshore Wind and Solar PV

Cost of Electricity Report Update 2024

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Glossary

Acronym	Term
AEP	Annual Energy Production
AI	Artificial Intelligence
AR6	Allocation Round 6
BloombergNEF	Bloomberg New Energy Finance
BoP	Balance of Plant
Capex	Capital Expenditure
CfD	Contract for Difference
COD	Commercial Operations Date
DCO	Development and Consent Order
DESNZ	Department for Energy Security and Net Zero
Devex	Development Expenditure
DUoS	Distribution Use of System
EBITDA	Earnings Before Interested, Tax, Depreciation, and Amortisation
EPC	Engineering, Procurement, and Construction
EU	European Union
FID	Final Investment Decision
FX	Foreign Exchange
GB	Great Britain
GDP	Gross Domestic Product
GW	GigaWatt
GWp	GigaWatt-Peak
IEA	International Energy Agency
IoT	Internet of Things
IRENA	International Renewable Energy Agency
kW	KiloWatt
kWp	KiloWatt-Peak
LCOE	Levelised Cost of Electricity
LPA	Local Planning Authority
MW	MegaWatt
MWh	MegaWatt-Hour
MWp	MegaWatt-Peak
NDA	Non-Disclosure Agreement

NSIP	Nationally Significant Infrastructure Project
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
ONS	Office for National Statistics
ONW	Onshore Wind
Opex	Operational Expenditure
PINS	Planning Inspectorate
PPA	Power Purchase Agreement
PV	Photovoltaic
REA	Renewable Energy Association
SGRE	Siemens Gamesa Renewable Energy
SRMC	Short-Run Marginal Costs
TNUoS	Transmission Network Use of System
TSO	Transmission System Operator
UK	United Kingdom
UoS	Use of System
WTG	Wind Turbine Generator

1. Executive summary

1.1 Context

In February 2024, Arup was commissioned by the Department for Energy Security and Net Zero (DESNZ) to update the Levelised Cost of Electricity (LCOE)[1] for onshore wind and large-scale solar PV (>5MW) technologies in Great Britain out to 2050. The purpose of this study was to collect up-to-date costs and technical assumptions to enable the update of LCOE figures which inform DESNZ's policy decisions and its energy system modelling.

The LCOE for solar and onshore wind has been falling since 2010; however, there has been upward pressure on the LCOEs of both technologies since 2022. This has been driven by macroeconomic global price shocks, the lingering effects of COVID-19 (particularly in China), volatile commodity costs, supply chain issues, rising labour costs, elevated interest rates increasing the cost of capital, and persistently high inflation.

Arup conducted an independent assessment using data from stakeholder engagement, published sources, and internal benchmarks. This study builds on previous cost and technical assumption studies, including the Electricity Generation Costs Report 2023 (DESNZ, 2023a), the Onshore Wind and Solar PV Costs Review by WSP in 2020 (WSP, 2020), and the Review of Renewable Electricity Generation Cost and Technical Assumptions carried out by Arup in 2016 (Arup, 2016).

The LCOE estimates presented in this report were calculated using DESNZ's published LCOE tool along with technology-specific data which were gathered over 2023 and 2024 using a standardised methodology. The LCOEs Arup has estimated do not necessarily reflect the final results adopted by DESNZ for its future publications; DESNZ may choose to apply different assumptions for some parameters. The figures presented in this report should therefore be interpreted as key inputs into DESNZ's broader cost and technical analysis rather than final forecasts adopted by the department.

1.2 Stakeholder engagement

To inform this study, Arup undertook a targeted stakeholder engagement process, contacting over 100 organisations across the renewables sector. This included developers and key technology suppliers, with participation further encouraged through engagement with relevant trade associations.

The stakeholder survey formed the backbone of this research, given the importance of evaluating costs and assumptions most relevant to future UK projects. Hence, a range of measures were applied to maximise reach across relevant developers and to facilitate their provision of a high-quality return.

Solar Energy UK distributed our communications and invited us to attend their industry sessions, including a Solar Energy Scotland member discussion and a Solar working group meeting. These sessions allowed us to speak directly with developers, encourage their participation, and address any questions. Other trade associations such as the Renewable Energy Association (REA), RenewableUK, Scottish Renewables, and Energy UK also shared our communications with their members helping to increase the number of responses. Additionally, Arup arranged a virtual drop-in session during which developers could ask questions about the questionnaire and raise concerns.

To further enhance the legitimacy of the study and encourage participation, Arup provided Non-Disclosure Agreements (NDAs), recognising that much of the requested information was confidential. Once signed, Arup shared a standardised questionnaire with developers (see Appendix A.1).

A key enhancement since the 2016 Arup led study was the involvement of a dedicated stakeholder engagement specialist, who refined the survey approach to better align with the needs of the renewable

[1] LCOE can be defined as 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 predevelopment, capital, operating, fuel, and financing costs. It should be noted that the definition of LCOE applied in this report only takes into account the costs borne by developers in relation to construction and operation of a renewable generation project. It does not account for the impact on the wider electricity network, revenue or support mechanisms such as contract for difference (CfD), capital grants, taxes, land leases or property and business rates.

energy sector. This contributed to a higher response rate. In 2024, 9 solar developers responded, compared to 6 in 2016; 14 onshore wind developers, up from 8 previously. The overall participation in this study is summarised in Table 1 below.

1.3 Summary of responses

Arup's analysis relied on responses provided by stakeholders (primarily renewable energy project developers), in combination with the assessment of benchmark data and in-house expert judgement. The stakeholder engagement process encouraged participation from project developers, which resulted in a sample of projects covering both technologies. Arup received responses from 20 developers (noting that some respondents covered multiple technologies), covering 45 projects across both technologies. A summary of these responses is illustrated in Table 1 below, highlighting the number of responses received, total capacity, and geographic regions covered across each technology type.

Arup aimed to test the information provided by developers with that from suppliers. However, only four responses were received from suppliers, and these did not include detailed cost information for benchmarking. This limitation restricted our ability to compare developer data with supplier data.

Table 1: Summary of responses by technology type

Category	Large Solar	Onshore Wind
Responses received	18	27
Number of developers	9	14
Total MW	1,856	1,566
Regions	England and Scotland	Scotland and Wales

1.4 Criteria for identification and inclusion of data

Arup applied a rigorous, multi-stage process to ensure the integrity and representativeness of the cost and technical data used to estimate LCOE values. An initial review of all questionnaire responses assessed the stakeholder interpretation, consistency across responses, and standardisation of cost data to 2023 prices. Responses were checked for completeness, correct units, formatting consistency, and outliers. Clarifications were sought directly from stakeholders where values did not align with benchmarks.

Following this, a structured framework was implemented to determine the inclusion of data. This comprised six scenarios, each applying progressively more selective filters. These were used to define the final dataset for cost and technical assumptions. The scenarios applied a combination of the following inclusion criteria:

- **No duplicates or zeros:** No zeros and no duplicate responses from the same developer.
- **Technology-specific:** Responses must be technology-specific and within scope, ensuring that the data provided pertain to one of the technologies assessed (e.g. only solar farms >5 MW were included).
- **Reasonable response:** Data points must pass Arup's test for reasonability, where internal experts validated the data based on their expertise. Where data points were removed using this filter, explicit notes have been included in the report to ensure the rationale is clear and to ensure traceability of the results.
- **Current cost:** Data points must reflect costs that are as current as possible, thus omitting costs heavily influenced by recent macro-economic pressures. A more detailed explanation is provided in Subsection 3.3.5.

- **Arup's benchmark:** Data points must fall within the range of Arup's benchmark. Details on the type and number of projects used to calculate this benchmark are provided in each technology chapter.
- **External benchmark:** Data points must fall within the range of the externally published industry benchmarks~~,~~ which included reports from reputable sources. Where applicable, these are included in each technology chapter.

Subject matter experts assessed each scenario and, through discussion with DESNZ, selected the most appropriate data subset to provide robust low, medium, and high estimates for each category.

Crucially, Arup defined **"current costs"** as those accurate at present, as of 2023-2024. In particular, costs which are up-to-date and are based on presently valid assumptions (i.e. if developers were to request quotes in the market between 2023 and 2024). The intention of focusing on this timeframe was to (i) attempt to remove or reduce the impact of the macroeconomic shocks between 2020 and 2022 and (ii) focus on the current technology rather than future scenarios dependent on hypothetical innovations.

To determine if project costs are recent and aligned with the years 2023 to 2024, Arup utilised the COD provided by developers in their questionnaire responses to estimate when costs had been derived. By subtracting the typical construction period range (as provided by stakeholders) and the likely time needed to negotiate contract prices (assessed with input from subject matter experts), Arup calculated a range of CODs which have been assumed to represent current costs, see Subsection 3.3.5 for more detail. This approach allowed Arup to isolate costs aligned with the present market and technological environment, ensuring the LCOE estimates are both timely and credible.

Table 2 below presents the number of project responses, highlighting how many were classified as reflecting "current costs" based on their Commercial Operations Dates (CODs).

Table 2: Project responses identified as satisfying the definition of "current cost"

Technology	COD range	Project responses	Projects with COD in current cost range
Onshore Wind	2025 to 2029	27	18
Solar	2024 to 2028	18	16

1.5 Summary of results

1.5.1 Costs and technical assumptions

The tables below present the current costs[2] and technical assumptions for the low, medium and high scenarios of the two technologies. The cost figures represent the current costs for 2023-2024 and are in real terms 2023, with no adjustment made to capital or operational expenditure to account for future learning rates[3]. In this study, Arup aimed to ensure costs are up-to-date and are based on presently valid assumptions (i.e., the costs if developers were to request quotes in the market between 2023 and 2024 prior to reaching project financial close[4]).

Table 3: Summary of 2023-2024 current costs and technical assumptions for onshore wind in this study

Category	Unit	Onshore wind		
		Low	Medium	High
Costs				
Pre development	£/kW	36	81	199
Capital costs during construction	£/kW	963	1,204	1,603
Infrastructure costs	£/kW	242	303	403
Total Capex	£/kW	1,241	1,588	2,205
Insurance	k£/MW/a	2.2	3.6	4.4
Connection and UoS charges[5]	k£/MW/a	0.4	17.0	45.3
O&M	k£/MW/a	14.8	19.5	22.8
Total Opex	k£/MW/a	17.4	40.1	72.4
Technical assumptions				
Net load factor[6]	%	33.0%	38.1%	41.3%
Operating lifetime	years	25	35	40
Additional assumptions				
Hurdle rate[7]	%	5.8%	5.8%	5.8%
Predevelopment timescale	years	5	8	13
Construction timescale	years	1	2	3

[2] For solar, Arup considered current costs to be those from projects with CODs between 2024 and 2028. For onshore wind, current values were based on projects with CODs between 2025 and 2029. See Subection 3.3.5 Current Costs for more details.

[3] For more information on data precision and the intended use of the results presented in this report, please refer to Section 3.10 of the methodology.

[4] In this context, financial close refers to the process of formalising all financial agreements, contracts and commitments. It represents the end of the procurement phase of the project and the point in which the project moves into the construction phase. Arup has assumed that there is between 0.5 – 1 year between final quotes being received and financial close. When accounting for a technology specific period of construction, the current costs have been derived from responses received with COD of 2024-28 for Solar PV and 2025-29 for onshore wind. See Section 3.3 for more details.

[5] Due to limitations in stakeholder responses for Use of System (UoS) charges for onshore wind and solar PV, a proportional approach has been used to derived UoS charges for these technologies. See Subsections 5.3.4.3 and 6.3.4.3 for further explanation.

[6] As part of this study, Arup calculated net load factors based on survey results. However, it is understood that DESNZ will use its own internal data and modelling to inform the net load factors applied in in their LCOE calculations.

[7] Hurdle rates were calculated by Arup using BloombergNEF's H2 2023 LCOE data, published for the UK (BloombergNEF, 2024a) post-tax nominal debt and equity assumptions. These were converted from post-tax nominal to pre-tax real terms, following the methodology set out in BEIS's 2018 Cost of Capital report and assuming 2% inflation and a 25% corporate income tax rate. Hurdle rates were assessed through literature review only and were not included in the survey, as DESNZ was undertaking separate work on this topic, the results of which were not available at the time. Note that Hurdle rates may vary over time depending on specific asset dynamics, where the asset is in its development lifecycle or movements in the macro-economic environment including cost of capital or changes to the regulatory environment. Therefore, rates now may be different to those referenced through a desktop review from BloombergNEF's H2 2023 data.

Table 4: Summary of 2023-2024 current costs and technical assumptions for Solar PV (>5MW) in this study

Category	Unit	Solar PV (>5MW)		
		Low	Medium	High
Costs				
Pre Development	£/kWp	12	24	59
Capital Costs During Construction	£/kWp	423	522	601
Infrastructure Costs	£/kWp	91	112	129
Total Capex	£/kWp	526	659	788
Insurance	k£/MWp/a	0.8	1.6	2.7
Connection And UoS Charges[5]	k£/MWp/a	1.1	1.6	2.0
O&M	k£/MWp/a	4.5	6.1	7.6
Total Opex	k£/MWp/a	6.5	9.3	12.3
Technical assumptions				
Net load factor[6]	%	11.5%	12.2%	14.5%
Operating lifetime	years	35	38	40
Additional assumptions				
Hurdle rate[7]	%	5.0%	5.0%	5.0%
Predevelopment timescale	years	1	3	4
Construction timescale	years	1	1	1

1.5.2 LCOE results

Arup has utilised the DESNZ LCOE calculator, published online as Annex B to the Electricity generation costs 2023 report (DESNZ, 2023a) to produce low, medium, and high LCOE scenarios. These scenarios represent the central (medium) case as well as the effective minima (low case) and maxima (high case) by combining the relevant low, medium and high data inputs. As described in Section 3.7, LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital and operating cost. Therefore, it is the standard approach to consider a range of scenarios rather than a single point, allowing the modelling to capture uncertainty.

The LCOE values presented are derived from low, medium, and high capital and operating cost estimates, as well as low, medium, and high technical assumption estimates. It is important to note that in most cases, the low values of costs and technical assumptions were used for the low LCOE scenario, with medium and high values used accordingly. However, for net power output and plant operating period, these were used inversely (e.g. the high net power output and high operating lifetime values were used to calculate the low LCOE value). This approach is based on the understanding that larger projects benefit from economies of scale and that a longer project lifetime will lead to greater total energy production.

The results are shown below in Table 5. These scenarios are designed to be indicative and to offer a range of LCOE estimates for comparison with current LCOE scenarios in industry literature. Arup notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

Table 5: LCOE based on current costs 2023-2024 (2023 real prices £/MWh)

Case	Onshore wind	Solar PV (>5MW)
Low	27.2	30.3
Medium	45.8	46.5
High	90.6	65.2

1.6 Assessment of data confidence, uncertainty and limitations

Arup's primary objective was to produce current central LCOE values that reflect current costs and deployment trends. Given the specific nature of the responses, the findings inherently include uncertainty and may not fully represent projects in other geographies or with different characteristics. To mitigate this, Arup employed internal and external benchmark data, alongside insights from subject matter experts, to validate all results. This ensured that even when results were inconsistent with projects reviewed by Arup or found in the literature, internal experts could assess their accuracy based on specific characteristics and recent trends.

The pool of survey respondents must be considered when assessing the risk of bias in survey responses leading to higher cost estimates. While we have sought to validate developer responses and compare them against industry benchmarks and data, some positive bias may remain. While the data points do sit within benchmarks, caution should be applied when considering the central case result, as it may not be representative of a generic future project. Arup recommends applying a range of results and provide sensitivities cases around this central view.

Despite the successful gathering of valuable data for LCOE modelling, certain challenges influenced the scope and detail of the analysis. These included:

1. Number of responses received.
2. Potential bias in the data provided.
3. Limited engagement from suppliers.

Cost and technical assumptions provided by stakeholders were carefully validated to mitigate potential bias. All data supplied by developers were cross-checked against internal and external benchmarks to ensure reliability. Arup also looked across the responses to determine whether any of respondent provided consistently above-average costs, which could potentially skew results. In cases with limited responses, Arup relied more on internal expert judgement, industry understanding, and assessment of the latest literature and benchmarks.

Ensuring geographical representativeness was another challenge. Arup received data from projects in England, Wales and Scotland, but these varied depending on the technology. For example, due to the timing of the stakeholder engagement, this study does not capture potential geographic changes to onshore wind developments since policy changes made on 8 July 2024.

It is also important to note that, in any survey, responses may be influence by human factors such as differences in individual interpretation of questions, optimism or pessimism bias, or strategic positioning. Such factors are inherent in qualitative research and should be considered when drawing firm conclusions from the data. We have aimed to present the results transparently, without attributing motive; we encourage the reader to consider the broader context when interpreting the findings.

1.7 Future outlook

The future outlook of renewable energy costs is important when assessing the LCOE. The understanding of future cost trends can help policymakers and investors make informed decisions about energy infrastructure investments, subsidies, and long-term planning.

As part of this research, Arup asked stakeholders for their views on how costs have evolved since 2021, their expectations up to 2035, and from 2035 to 2050. Responses were largely qualitative in nature and covered predevelopment costs, construction costs, and operational costs.

As described in the report's Section 4, historical cost reductions experienced across the renewable energy industry do not reflect the evolving macro-economic situation since 2021, which has resulted in increased cost for renewable energy projects.

For onshore wind, the analysis is based on a combination of qualitative and quantitative data provided by stakeholders, supplemented with industry views and Arup's in-house expertise.

For large scale solar PV, Arup has utilised BloombergNEF (BloombergNEF, 2024a) to develop learning curves at a subcomponent level (modules/panels, inverters, electrical BoP and structures, civil works) which have been used to estimate the cost reduction as a function of installed capacity (global and regional). Arup's long-term view on solar PV global capacity expansions was collated from the IEA's World Energy Outlook and National Grid Future Energy Scenarios 2023. Ultimately the subcomponent cost reductions are combined to provide an overall cost reduction curve up to 2050.

1.7.1 Onshore wind

The future outlook of onshore wind is represented by a range of possible scenarios based on quantitative and qualitative views provided by stakeholders. It appears that although technological advancements are continuing in the wind industry, driving efficiencies and higher performance, there is uncertainty related to the impact of other factors such as supply chain constraints, inflationary pressures and increased financing costs. This is reflected in the stakeholder responses and has resulted in underlying uncertainty of achieving short-term cost savings, hence for onshore wind, immediate cost reductions are not considered to be the medium case. Operations and maintenance (O&M) cost reductions for onshore wind is expected to continue based on review of industry literature, which forecasts continued efficiencies relating to technology advancements.

In the tables below, Arup has presented low, medium and high scenarios representing stakeholder views for onshore wind technology.

Note that the years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured and costs finalised, prior to a project reaching financial close[4]), unless stated otherwise. These years do not correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years. For example, an onshore wind project securing costs in 2025 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close), should apply 100% of the "current costs" (as defined above) for capital costs and 96.2% of the Fixed O&M costs. This project may not become operational for a number of years after securing the costs, following time taken to reach financial close[4] and then for the site to be constructed.

Another example could be a project securing costs in 2030 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close) where a 97.5% Capital Cost factor and 80.0% Fixed O&M cost factor should be applied through multiplication, to the "current costs" (as defined above) resulting in a lower capital and operating cost.

Table 6: Learning rates for capital and fixed O&M costs based on stakeholder views – onshore wind

Learning rate	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Capex projections						
Low case	100.0%	97.5%	91.3%	85.0%	81.7%	75.0%
Medium case	100.0%	100.0%	99.3%	97.5%	95.0%	90.0%
High case	100.0%	101.7%	105.8%	110.0%	108.3%	105.0%
Opex projection						
Fixed O&M	100.0%	96.2%	85.4%	80.0%	76.5%	71.2%

1.7.2 Solar PV

For Solar PV, short-term and long-term decreases are forecasted using a bottom-up global deployment model based on the application of learning curves at a sub-component level. Solar PV differs from onshore wind, in that costs are expected to fall from the "current costs" immediately. This is based on responses provided by stakeholders, Arup literature review as well as trends seen in the solar PV market. In 2021, solar PV module prices increased as supply chain disruptions and limited polysilicon capacity in China led to lower availability and inflated commodity prices, which caused a sharp increase in LCOE in 2022. Since then, the downward trend has resumed, appearing to be driven by decreasing commodity prices and supply chain stabilisation, with the LCOE for large-scale solar projects falling back to 2020 levels.

In the table below, Arup has presented the central case learning rates for large-scale solar projects.

Table 7: Learning rates for capital and fixed O&M costs based on stakeholder views – solar PV(>5MW)

Learning rate	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Capex projection	100.0%	91.9%	79.2%	72.4%	68.6%	63.4%
Fixed O&M projection	100.0%	96.3%	89.8%	85.7%	83.0%	78.8%

1.8 Comparison of LCOE estimates

1.8.1 Approach

Arup has carried out a comparison of the LCOE for onshore wind and solar PV based on Arup's 2023-2024 cost and technical assumptions analysis against a blended average of LCOEs from global and UK literature and the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a). The comparison reveals variations across the different sources, highlighting recent trends and regional impacts on LCOE.

The LCOE values presented are derived from low, medium, and high capital and operating cost estimates, as well as low, medium, and high technical assumption estimates. It is important to note that in most cases, the low values of costs and technical assumptions were used for the low LCOE scenario, with medium and high values used accordingly. However, for net power output and plant operating period, these were used inversely (e.g. the high net power output and high operating lifetime values were used to calculate the low LCOE value). This approach is based on the understanding that larger projects benefit from economies of scale and that a longer project lifetime will lead to greater total energy production.

Note that for the low, medium, and high scenarios the hurdle rate was kept consistent (see individual technology chapters for details), therefore further sensitivity cases exist based on this financial metric and should be considered as required. This approach allowed Arup to assess the impact of changes in cost and technical assumptions on LCOE.

To reflect the inherent uncertainty in these inputs, Arup developed low, medium, and high scenarios for each cost and technical parameter. These input scenarios were then used to calculate corresponding low, medium, and high LCOE estimates for each technology. The resulting range illustrates the potential variability in generation costs and highlights that the central case should not be interpreted as a definitive value. Arup suggests that, when considering generation costs, sensitivities should be assessed within this range, as the central/medium case alone does not represent the full breadth of possible outcomes.[8]

As discussed in Section 1.6, whilst we have sought to validate developer responses and compare them against industry benchmarks and data, some bias may remain.

1.8.2 Results

Table 8: Onshore wind LCOE comparison (2023 real prices)

Onshore wind	Arup 2023 - 2024	Literature	DESNZ 2023[9]
Low LCOE (£/MWh)	27.2	30.9	37.1
Medium LCOE (£/MWh)	45.8	46.0	42.8
High LCOE (£/MWh)	90.6	60.8	48.4

For onshore wind, Arup's medium LCOE is 45.8 £/MWh. This is well aligned with the blended literature, which is less than 1% higher at 46.0 £/MWh. The Arup LCOE is 7% higher than DESNZ's estimate (DESNZ, 2023a) of 42.8 £/MWh.

Table 9: Solar PV LCOE comparison (2023 real prices)

Solar PV	Arup 2023 - 2024	Literature	DESNZ 2023[9]
Low LCOE (£/MWh)	30.3	30.7	41.6
Medium LCOE (£/MWh)	46.5	48.4	46.1
High LCOE (£/MWh)	65.2	66.5	54.0

For solar PV, Arup's medium LCOE is 46.5 £/MWh, which is 4% lower than the literature average of 48.4 £/MWh and less than 1% higher than DESNZ's estimate of 46.1 £/MWh. This is in line with the expectations based on Arup's literature review.

[8] Arup notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

[9] DESNZ projection for commissioning year 2025 was used, as this aligns best with Arup's "current cost" filters.

2. Introduction

In February 2024, Arup was appointed by the Department for Energy Security and Net Zero (DESNZ) to undertake a comprehensive Levelised Cost of Electricity (LCOE) study. LCOE is per unit cost of electricity generated over a project's life, taking into account costs, electricity generation, asset life, and discount rate[10]. The objective of this study was to estimate current generation costs and technical assumptions that enable the update of LCOE for onshore wind and large-scale solar PV technologies in Great Britain. This report specifically focuses on onshore wind and solar technologies. In addition, the outlook of costs has been considered up to the year 2050 reflecting the current state of the supply chain as well as technology variations and advances.

Arup's work involved an independent assessment, drawing upon data obtained through stakeholder engagement processes, as well as leveraging both published and internal sources. The analysis conducted as part of this study enabled the development of new estimates for generation costs and the LCOE associated with renewable electricity generation projects spanning the next three decades.

The findings from this study will play a crucial role in informing DESNZ's policy decisions and strategic planning related to renewable technology support by the UK government. We compared this review and assessment be compared to previous work, including DESNZ's last published review of generation costs conducted in the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a), along with explanation of where methodology or assumptions may have changed. In some areas, this new research is wider than previous work, as it focuses solely on renewable energy (large scale solar PV >5MW and onshore wind) which allowed a more tailored response to these sectors.

2.1 Context

The renewable energy sector has seen significant growth in recent years, with solar and onshore wind technologies playing a pivotal role. Over the past decade or more, the LCOE for these technologies has generally been on a downward trajectory, making them increasingly competitive with traditional energy sources. However, recent macroeconomic global price shocks following the lingering effects of COVID-19 (particularly in China), volatile commodity costs, supply chain issues, rising labour costs, elevated interest rates, capital and persistently high inflation have increased costs and placed pressure on renewables developers. This has resulted in LCOE increases across both technologies since 2021.

The impact of these price spikes has varied per geography, and in scale and length per technology, with solar LCOEs reducing in 2024, whilst wind developers are still dealing with inflated prices and elevated LCOEs (BloombergNEF, 2024a; IEA, 2023; IRENA, 2023; Lazard, 2024).

Onshore wind technology has historically seen a downward trend in its LCOE. However, the extent of the decrease has been variable, with some regions experiencing increases in LCOE in recent years 2022-2023 (BloombergNEF, 2024a) due to volume and commodity price volatility, including high steel prices, which has particularly impacted the price of wind turbines in the UK and Europe.

Solar energy has seen a substantial decrease in LCOE, falling 89% globally and 87% in the UK from 2010-2022 (IRENA, 2023). This decline is primarily driven by volume, along with improvements in technology and efficiency. However, recent macroeconomic pressures and commodity price volatility led to short-term LCOE increases in 2022, with the UK experiencing a more significant uplift than the global average (BloombergNEF, 2024a).

In summary, although the LCOE for solar and onshore wind technologies has historically been on a downward trend, recent macroeconomic factors have caused short-term increases across both technologies. This context will inform the costs and technical assumptions used for the analysis in this report.

[10] LCOE can be defined as 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 predevelopment, capital, operating, fuel, and financing costs. It should be noted that the definition of LCOE applied in this report only takes into account the costs borne by developers in relation to construction and operation of a renewable generation project. It does not account for the impact on the wider electricity network, revenue or support mechanisms such as contract for difference (CfD), capital grants, taxes, land leases or property and business rates.

2.2 The project

The primary focus of this study was to update the costs and technical assumptions necessary for generating LCOE estimates. Arup undertook a comprehensive approach, beginning with an extensive review of industry literature to summarise the latest developments in renewable energy technologies. This review provided a foundation for gathering new project costs for each renewable technology, considering the critical information related to capital expenditure, operating expenditure, and load factors. Additionally, supplementary data, including land costs, property and business rates, taxes, and specific technology details such as turbine information, were collected to ensure a robust analysis aligned with DESNZ's objectives.

A significant aspect of the study was the stakeholder engagement process, which played a crucial role in the analysis. The stakeholders involved in this project included developers of onshore wind and solar farms, as well as technology suppliers and trade associations which helped extend our reach to more developers. Arup received strong engagement from project developers, with help from trade associations; however, there were no responses from technology suppliers that could be used in the analysis.

Arup relied on stakeholders to provide their most accurate estimates of costs for new renewable projects. While the data from stakeholders served as the primary source, they were tested against published benchmarks and internal knowledge to validate their suitability for LCOE estimation. Chapter 3 of this report details the methodology used to analyse and generate a representative set of costs and technical assumptions.

Data for the study were gathered from various sources. Over 100 stakeholders across different technology groups were contacted using a standardised questionnaire, the details of which are provided in Appendix A.1.

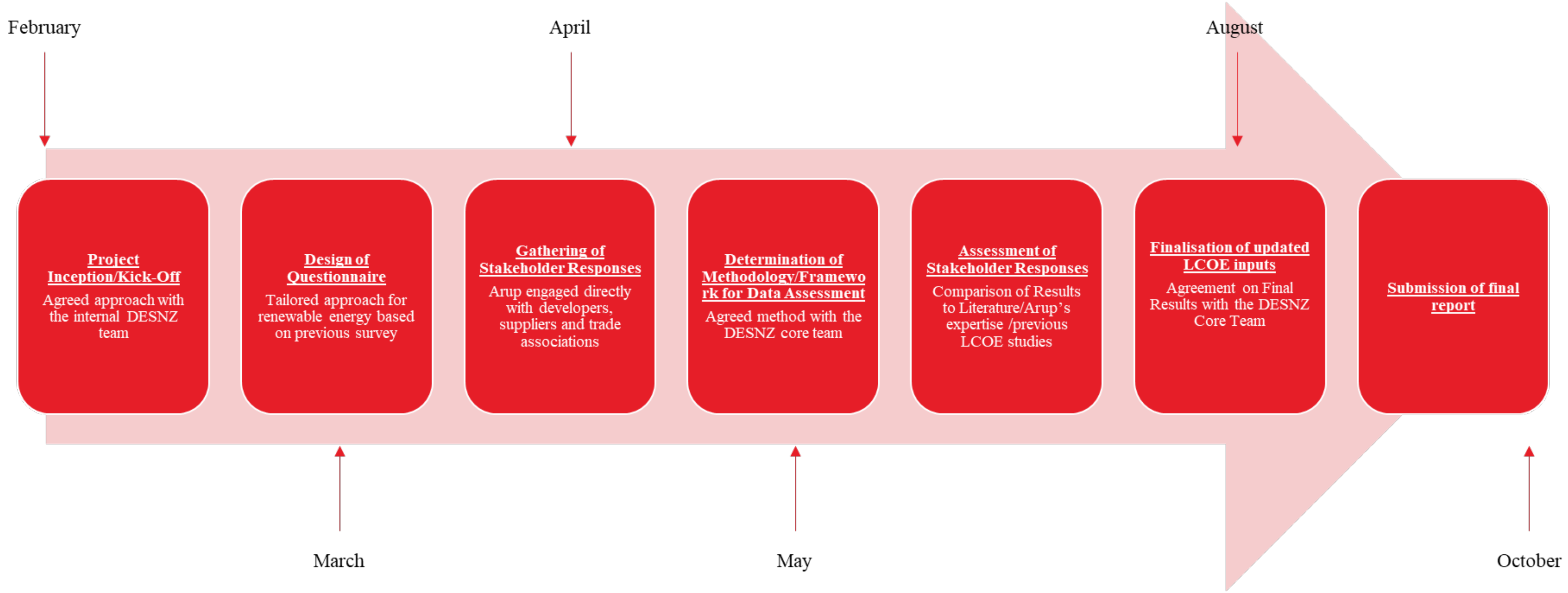
Additionally, Arup utilised insights from external entities such as Bloomberg New Energy Finance (BloombergNEF), the International Renewable Energy Agency (IRENA), the International Energy Agency (IEA), and Lazard. Arup also reviewed internal data on renewable generation costs and performance to supplement the analysis.

Lastly, to assess how LCOE might change over time, Arup developed a future outlook for capital and operating costs for each technology. This forecast was primarily informed by stakeholder views for onshore wind. For solar PV, the methodology involved an assessment of potential technical changes resulting from deployment and learning effects on a sub-component level. The analysis considered both increasing and decreasing cost trends to provide a comprehensive outlook on future LCOE.

3. Methodology

This chapter provides a summary of the Arup methodology used to develop a representative set of renewable data. The objective is to outline the approach and logic employed to derive the cost and technical assumptions presented in this report. The main steps in the methodology are shown in the diagram below:

Figure 1: Arup's 2024 study methodology timeline



3.1 Research design

This section provides an overview of the method for collecting primary data via stakeholders which are active in the development of renewable generation technology, specifically onshore wind and large solar PV (>5MW) projects.

Stakeholders were asked to provide data via a questionnaire regarding the cost, timeline, and technical assumptions for bringing a project from predevelopment (i.e. the planning stage) through to construction and operation. This allowed Arup to form a view of the lifecycle cost and performance of each technology. Arup used the methodology from the Arup (2016) study as a basis, tailoring it to focus solely on renewable generation technology by including specific questions relating to onshore and solar and updating where necessary. This approach enabled Arup to gather more granular data, specifically identifying views around supply constraints in the near future, such as for panels, inverters, and transformers.

The survey was split between Part A, which focussed on collecting new data, and Part B, which focussed on collecting stakeholder views on future developments in technology, cost, and performance. The aim was to collect sufficient reliable data for a representative lifecycle cost for each technology to be produced.

To ensure consistency in the responses, Arup verified the integrity and validity of the stakeholder data. This involved verifying values were entered correctly, reviewing figures against internal knowledge, and raising follow-up questions with stakeholders where necessary.

Part B of the questionnaire asked stakeholders to provide commentary (both qualitative and quantitative) around their expectations for future changes in cost as well as the key drivers behind these changes. Examples of cost drivers include supply chain effects, commodity prices, and labour.

For the levelised cost calculations, Arup maintained consistency with previous Electricity Generation Cost studies, by employing the template provided by DESNZ. This common template was used across technologies to capture data consistently for each cost category. It is important to note that, three values (low, high, and medium) were calculated for each key timing and technical datum needed for determining the cost of electricity in order to ensure consistency and coverage of the range of potential outturn results. Further elaboration on this topic can be found in Section 3.3.

3.2 Stakeholder engagement process

As part of the stakeholder engagement process, Arup contacted over 100 organisations, including developers of renewable energy projects and suppliers of key components for these projects. To increase participation and response rates, Arup also engaged with trade associations representing these developers and suppliers. The contacted developers spanned across solar and onshore wind technologies, ensuring a comprehensive representation of the sector.

Arup shared a standardised questionnaire with developers (see Appendix A.1), aiming for a balanced input with a similar proportion of each technology group, although slightly more developers from the solar sector were successfully engaged. Suppliers received a tailored set of questions (see Appendix A.1), designed to address the specific context of their contributions to the sector. Over 30 technology suppliers were contacted, including wind turbine manufacturers, cable suppliers, inverter manufacturers, and PV module producers.

Four responses were received, covering cables, inverters, mounting structures, and solar panels; however, the information provided did not include cost details that could be used for benchmarking. This limited our ability to contrast the information provided by developers with this data. This may have been due to the commercial sensitivity of product costs and prices, lack of incentives for the suppliers to respond, or because suppliers were contacted later in the process, with less time to respond.

Some trade associations agreed to share our communications with their members. Notably, Solar Energy UK not only distributed our communications but also invited us to attend their industry sessions, including a Solar Energy Scotland member discussion and a Solar working group meeting. These sessions allowed us to speak directly with developers, encourage their participation, and address any questions. Additionally, Arup arranged a virtual drop-in session during which developers could ask questions about the questionnaire and raise concerns. Other trade associations such as the Renewable Energy Association (REA), RenewableUK, Scottish Renewables, and Energy UK also confirmed that they had shared our communications with their members.

To further enhance the legitimacy of the study and encourage participation, Arup provided Non-Disclosure Agreements (NDAs), recognising that much of the requested information was confidential. We were flexible in using either our own NDA as a standard or those provided by specific respondents if they so wished.

A main difference between the 2016 and 2024 studies has been the involvement of an Arup stakeholder engagement expert with experience in participatory design, who formulated the surveys to maximise the benefit for all parties. The questionnaire focused solely on renewable energy technologies, rather than across a wide range of generating technologies (as previously) and was tailored to effectively engage stakeholders.

Arup received questionnaire responses from 20 developers (noting that some respondents covered multiple technologies), regarding 45 projects across both technologies: 18 solar projects and 27 onshore wind projects.

3.3 Criteria for identification and inclusion of data

Prior to using the cost and technical assumption data for LCOE modelling, an examination of the questionnaire responses was carried out to ensure the dataset's integrity. The evaluation included:

- **Stakeholder interpretation:** Correct interpretation of the questionnaire. For example, verifying that the respondent provided a response that is in line with the question asked.
- **Data range and consistency**: Consistency across different datasets was checked using data plots to view the range of responses. This enabled extreme values to be more readily identified and examined as potential outliers.
- **Cost uniformity:** To enable meaningful comparisons, the cost base was standardised by inflating or deflating where necessary.

Note that at this stage, no data were excluded. Subsequently, the questionnaire data were reviewed following a framework for data utilisation to ensure accurate and representative results, free from bias and based on current costs, not influenced by recent macro-economic pressures.

- **Framework for data utilisation:** This is the defined framework for assessing the data, presenting a range of scenarios and ultimately the final subset of data to be included within the cost and technical assumption estimates.

The points below summarise our approach in more detail.

3.3.1 Stakeholder interpretation

A review of the questionnaires indicated that most stakeholders provided the requested data accurately. However, in a small number of instances where values did not align with internal and external benchmarks, clarification was sought via email exchange directly with the stakeholders. Arup has reviewed each questionnaire and established its overall usefulness to the study in terms of providing accurate information for cost and LCOE modelling.

3.3.2 Data range

Arup's initial step was to generate a scatter plot of the cost and technical assumptions collected. This was presented in a dashboard, facilitating the identification of extreme values and allowing Arup to assess the range of responses. Outliers were identified through evaluation against data points from other suppliers, whether other responses from the same developer aligned, and the degree to which they were outside benchmarking range; otherwise, these data were retained.

3.3.3 Cost uniformity

Arup’s approach involved reviewing each questionnaire to ensure consistency across the dataset. This included verifying the data were in the same format, currency, and cost base. For cost-related questions, Arup expressed a preference for receiving data that is as current as possible, based on firm offers, contracted prices, or incurred amounts. Developers were also asked to provide the base year and describe the indexation mechanism assumed if the cost base year was not 2023. This allowed us to adjust nominal terms to real 2023 where necessary. Predevelopment, capital, and infrastructure costs were expressed in £/kW, and operating costs in k£/MW/a. For indexing, the GDP deflation factors from December 2023 published by the Office for National Statistics (ONS) were used. Note that developers primarily responded in real terms 2023, meaning minimal adjustment was required.

3.3.4 Framework for data utilisation

After the initial evaluation of the data, Arup developed a framework to determine which data points would be utilised for the study. This framework consisted of six scenarios, each with minimum requirements for data inclusion, and was applied to all costs and technical assumptions provided as outputs to DESNZ.

For each scenario, Arup subject matter experts assessed the range of scenarios and subsequently recommended which results should be used for the calculation of the LCOE.

The scenarios were developed using a defined set of filters.

- **No duplicates or zeros:** No zeros and no duplicate responses from the same developer.
- **Technology-specific:** Responses must be technology-specific and within scope, ensuring that the data provided pertain to one of the technologies assessed (e.g. only solar farms >5 MW projects were included).
- **Reasonable response:** Data points must pass Arup's test for reasonability, where internal experts validated the data based on their expertise. Where data points were removed using this filter, explicit notes have been included in the report to ensure the rationale is clear and to ensure traceability of the results.
- **Current cost:** Data points must reflect costs that are as current as possible, thus omitting costs heavily influenced by recent macro-economic pressures. A more detailed explanation is provided in Subsection 3.3.5.
- **Arup’s benchmark:** Data points must fall within the range of Arup’s benchmark. Details on the type and number of projects used to calculate this benchmark are provided in each technology chapter.
- **External benchmark:** Data points must fall within the range of the externally published industry benchmarks~~,~~ which included reports from reputable sources. Where applicable, these are included in each technology chapter.

Table 10: Scenarios considered

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
No duplicates or zeros	X	X	X	X	X	X
Technology specific	X	X	X	X	X	X
Reasonable response		X	X	X	X	X
Current cost			X	X	X	
Arup benchmark				X		X
External benchmark					X	

Arup subject matter experts reviewed each of the scenarios and, through discussions with DESNZ, determined the most appropriate scenario to use, providing a single estimate of the low, medium, and high values for each of the cost and technical assumptions to be used in the subsequent LCOE modelling.

This approach ensured that data points outside our internal benchmarks or external industry benchmarks, yet sufficiently close to be considered possible by experts, were still considered in the analysis.

It is important to note that even though different scenarios were selected depending on the category and technology, most of the scenarios selected were either scenario 2 or scenario 3.

3.3.5 Current costs

In recent years, there have been global price shocks (see Section 4) that have directly influenced the cost to develop renewable energy projects. Considering the main objective of this research – to determine the "**current costs**" that influence the LCOE of renewable energy projects – it was deemed essential to develop a method to identify **"current costs"** from within the stakeholder responses.

The aim was to remove data points from historical cost data (prior to 2022), attempting to ensure that costs are as current as possible and are therefore as free as possible from the price-shocks caused up to 2022. To do this, it was decided to use the projects' Commercial Operations Date (COD) to determine if the costs are potentially historical in nature and thus potentially influenced by the price shocks. The detailed explanation of what constitutes current costs and how they were determined is provided in this subsection.

Arup defined **"current costs"** as those accurate at present, as of 2023-2024. In particular, costs which are up-to-date and are based on presently valid assumptions (i.e. if developers were to request quotes in the market between 2023 and 2024). The intention of focusing on this timeframe was to (i) attempt to remove or reduce the impact of the macroeconomic shocks between 2020 and 2022 and (ii) focus on the current technology rather than future scenarios dependent on hypothetical innovations.

To determine if project costs are recent and aligned with the years 2023 to 2024, Arup utilised the COD provided by developers in their questionnaire responses to estimate when costs had been derived. By subtracting the typical construction period range (as provided by stakeholders) and the likely time needed to negotiate contract prices (assessed with input from subject matter experts), Arup calculated a range of CODs which have been assumed to represent current costs (see Figure 2).

Methodology for Determining COD Ranges

Arup followed a systematic approach to determine the COD ranges for each technology:

1. **Review of responses**: Arup first reviewed the stakeholder responses to ensure they were robust and reliable.
2. **Calculation of COD ranges**: Using the typical time required to negotiate prices and the typical construction period range from the surveyed responses, Arup employed a bottom-up approach to calculate the COD ranges.
3. **Assessment of data points**: Arup then assessed the number of responses within the identified COD ranges to determine the sufficiency of data points for cost calculations.
4. **Adjustment of COD ranges**: If too few data points were identified, the upper end of the dataset was checked to see if additional data points could be included, ensuring the results were consistent with the existing data within that category. In these cases, this suggests that projects in the near future beyond current costs would have a similar cost in this category.

As a result, the COD range was extended by one year to ensure a sufficient number of data points. These CODs vary by technology:

- **Large-Scale solar projects**: Solar project construction periods range from 0.5 – 1.8 years, with final price negotiations occurring approximately half a year to a year before construction starts. Therefore, Arup considered current costs to be those from projects with CODs ranging from 2024 to 2028. This estimation aligns with costs defined between 2023 and 2024.
- **Onshore wind projects**: Onshore wind projects typically have construction periods of 1 – 3 years, with final price negotiations occurring approximately half a year to a year before construction begins. Based on this, Arup considered current values to be those from projects with CODs ranging from 2025 to 2029. This estimation aligns with costs defined between 2023 and 2024.

Some of the project information received did not represent current costs. Consequently, these costs do not accurately reflect the industry landscape for the years 2023-24. The data outside of this COD range were still analysed and may prove useful for other purposes, but they were not used to inform the LCOE.

Note that through this process, the CODs were rounded to the nearest integer and the upper end of the COD range was informed by the stakeholder responses and Arup subject matter experts. This approach ensured that sufficient data was processed, and that the results reflected current technology trends, rather than extrapolating too far into the future.

This methodology differs from previous data selection methods used in Arup's earlier studies, wherein macroeconomic pressures and the resultant price fluctuations were of a lesser concern.

Figure 2: COD ranges used to derive current costs

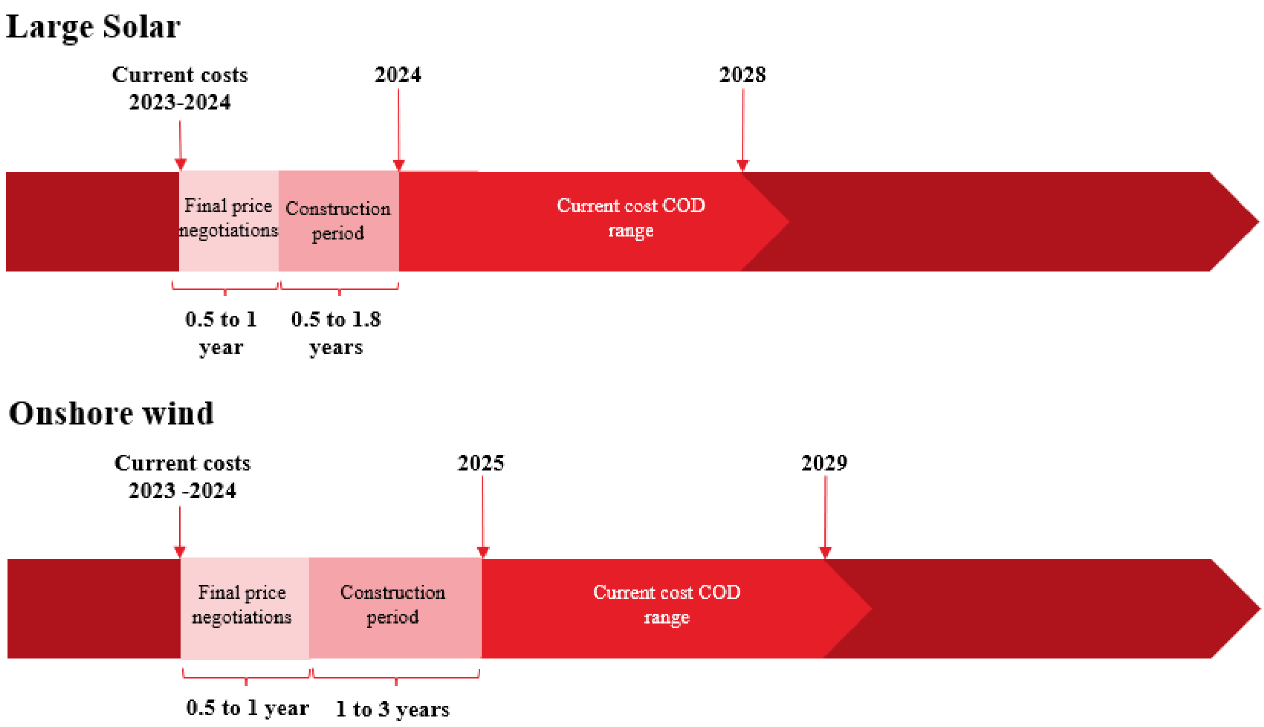


Table 11 below presents the number of project responses, highlighting how many were classified as reflecting "current costs" based on their Commercial Operations Dates (CODs).

Table 11: Project responses identified as satisfying the definition of "current cost"

Technology	COD Range	Total number of project responses	Projects with COD in current cost range
Onshore Wind	2025 to 2029	27	18
Solar	2024 to 2028	18	16

3.4 Categorisation of outputs

Cost and technical assumptions were categorised into low, medium, and high values based on the designated scenario and dataset used.

The medium value was determined using either the mean or median of the dataset, depending on the total number of data points available for the analysis. If the dataset contained fewer than ten data points, the mean was chosen. For datasets with ten or more data points, the median was used. Although the Arup-derived method recommended using the mean for smaller datasets, an evaluation of the underlying distribution and expert judgement were also considered to ensure accuracy. In one instance, this rule was overruled in favour of the median. Specific details on the method used for each category are provided in the respective technology chapters.

This approach was chosen with the aim of finding a "middle" or "typical" value. The median can be a better measure of the "typical value", when a large dataset is being measured (i.e. the middle point) and is less susceptible to being skewed by outliers. Conversely, for smaller datasets, the mean can serve as a more reliable central indicator. For example, with values of 1, 5, and 20, the median would be five, while the mean would be nine, which may provide a more representative central value.

Arup calculated the 5th and 95th percentiles of cost figures based on the survey responses. Using percentiles was necessary to derive low and high values and to anonymise the cost data provided by the developers. However, for time periods and other technical assumptions, Arup chose not to apply a 5th or 95th percentile because these are less easily identifiable metrics than cost; instead, minima and maxima were used. Each technology chapter explains in detail which cost or technical assumptions used the minimum or 5th percentile, and which used the maximum or 95th percentile.

3.5 Assessment of data confidence, uncertainty and limitations

This section evaluates the confidence and uncertainty of the data gathered from developers in this study, reflecting the diversity of responses in technology and geography.

3.5.1 Summary of responses

Arup's analysis relied on responses provided by stakeholders (primarily renewable energy project developers), in combination with the assessment of benchmark data and in-house expert judgement.

The stakeholder engagement process encouraged participation from project developers, which resulted in a sample of projects covering both technologies. Arup received responses from 20 developers (noting that some respondents covered multiple technologies), covering 45 projects across both technologies. A summary of these responses is illustrated in Table 12 below, highlighting the number of responses received, total capacity, and geographic regions covered across each technology type.

Table 12: Summary of responses by technology type

Category	Large solar	Onshore wind
Responses received	18	27
Number of developers	9	14
Total MW	1,856	1,566
Regions	England and Scotland	Scotland and Wales

Arup has presented a range of results (low, medium and high), reflecting the uncertainty of the findings and the range of possible outcomes. Arup suggests that, when considering generation costs, sensitivities are assessed within this range, as the central/medium case alone does not represent this broad range of results.

Capex is susceptible to bias due to the impact of a project's characteristics on its construction cost. Whilst factors such as water depth, distance from port and onshore grid connection point, and transmission system also affect Opex, the implications for Capex are more significant.

As discussed in Subsection 3.3.5, data were filtered to ensure only "current costs" were considered for the assessment of Capex, which further reduced the number of data points.

3.5.2 Mitigating uncertainty in the updated costs, technical assumptions and resulting LCOE calculation

Arup's primary objective has been to produce cost and technical assumptions to enable current central LCOE values ("medium" or "typical" case) that reflect current costs and deployment trends in terms of location, technology, and other technical characteristics.

Given that the responses received are specific to particular renewable energy generation sites, or in some cases generic sites, the findings from the modelling inherently include uncertainty and may not fully represent projects in other geographies or with different characteristics.

Arup employed internal and external benchmark data, alongside insights from subject matter experts, to validate all results. This ensured that even when the results were inconsistent with projects reviewed by Arup or found in the literature, our internal experts could assess their accuracy based on specific characteristics (e.g. site size) and recent trends known or expected by the experts.

As described above in Section 3.4, to reflect the range of stakeholder responses, Arup has provided low and high values for each of the updated cost and technical assumptions that are used within the LCOE analysis.

In addition, effective minima (low case) and maxima (high case) scenarios have been established by combining the relevant low and high data inputs. This enabled us to present the full range of uncertainty surrounding the LCOE figures. This approach generated a broad range of results, ensuring that costs and assumptions from projects at both ends of the spectrum were considered and utilised.

3.5.3 Overcoming data collection challenges

Despite the successful gathering of valuable data for LCOE modelling, certain challenges influenced the scope and detail of the analysis. These included the number of responses received, the potential for bias in the data provided, and the limited engagement from suppliers. With these variables, a range of strategies were employed to ensure the robustness of the findings. These are outlined below.

- **Limited number of responses in some categories:** As is typical in stakeholder engagement exercises, certain data limitations were encountered in specific categories with limited responses. In these cases, Arup relied more on internal expert judgement, understanding of the industry along with assessment of latest literature and industry benchmarks.

  In certain cases, where a subcategory had insufficient data, a proportional approach (i.e. a % of total capex or opex category) was taken to derive suitable allocation of costs. For example, this approach was applied for the Solar PV Connection and UoS charges where limited and inconsistent responses made it difficult to rely on stakeholder responses.

  All cases where expert judgement, benchmarks or proportional approach were used are detailed in the relevant technology subsections. In addition, the total quantity of data received, as well as the data points used to calculate each cost and technical assumption, have been included in each technology chapter for clarity.

- **Mitigating potential bias in responses:** Cost and technical assumptions provided by stakeholders were carefully validated to mitigate potential bias. All costs and technical data supplied by developers were crosschecked against internal and external benchmarks to ensure reliability. Arup applied its judgment to stakeholder data to establish representative cost and technical parameters for each technology. The rigorous approach to data inclusion is described in Section 3.3. Arup's internal benchmarks consisted of projects located across the United Kingdom and other relevant markets with Commercial Operations Dates within the ranges considered current, as outlined in Subsection 3.3.5. To further enhance the validity of the data, internal experts were consulted, especially when benchmarks were limited.

- **Addressing limited supplier engagement:** Arup aimed to test the information provided by developers with that from suppliers. However, only four responses were received from suppliers, and these did not include detailed cost information for benchmarking. This limitation restricted our ability to compare developer data with supplier data. To mitigate this, Arup relied on internal and external industry benchmark data and performed an in-depth literature review to test and ensure the robustness of the stakeholder data and the resulting analysis.

  It is important to note that supplier perspectives are generally limited to specific parts of projects (e.g. PV mounts, or inverters), rather than the holistic view that developers have, and thus we believe their restricted engagement did not materially impact results.

- **Ensuring geographical representativeness:** From the stakeholder data, 23 onshore wind projects were located in Scotland, three in Wales and one did not disclose its location. For solar, the distribution included three projects in Scotland and 15 in England. Due to the timing of the stakeholder engagement, this does not capture the potential geographic changes to developments of onshore wind since policy changes were made in 8 July 2024. This geographical distribution provided valuable insights and is considered to be representative of the project locations currently under development in Great Britain. Despite these challenges, Arup undertook thorough data validation, employed internal benchmarks, and engaged subject matter experts to assure data quality and robust analysis. Cross-checking results with recent literature and benchmark data ensured alignment with the industry, taking into account broader trends. This comprehensive approach reinforced the robustness of the LCOE calculations and provided a solid foundation for the findings in this study. Nevertheless, Arup remained cognisant of potential bias and the influence of site-specific characteristics on a project's LCOE ultimately resulting in a range of low, medium, and high sensitivities, reflecting to some extent the uncertainty in the findings.

3.6 Levelised cost of electricity

The levelised cost of electricity (LCOE) generation is a metric used to analyse the average cost of electricity generation by different technologies over their lifetime for a generic plant. It can be defined as 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 predevelopment, capital, operating, fuel, and financing costs.

It should be noted that the definition of LCOE applied in this report only takes into account the costs borne by developers in relation to construction and operation of a renewable generation project. It does not account for the impact on the wider electricity network, revenue or support mechanisms such as contract for difference (CfD), capital grants, taxes, land leases or property and business rates.

Project timing is an important dimension for the development, delivery and operation of a project. The following were factored into the calculation:

- The estimated time it takes for a project to go through design, construction, and delivery.
- The expected operational life of the technology in question.
- The discount rate which allows the valuation of future values to be brought back to present values i.e. the value today of a future stream of costs. The discount rate was not derived through stakeholder responses but through external literature, as described in Chapter 4.

Arup produced low, medium, and high estimates for input into an LCOE model (the Model) as described in Section 3.7. LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital. and operating cost. Therefore, it is the standard approach to consider a range of scenarios rather than a single point, allowing the modelling to capture uncertainty.

Please note that a review of learning rates has been carried out to provide a future outlook for each technology under review. A summary of the analysis is presented in Section 3.9.

3.6.1 Components of LCOE

This subsection outlines the main components of LCOE (cost or technical assumptions) and provides an approach which is consistent with the approach previously adopted by DESNZ. The calculation comprises the following items:

- **Devex:** The development cost of a project, which includes achieving planning permission and compliance with regulatory requirements.
- **Capex:** The capital cost of bringing a generator to operation, including any associated infrastructure costs for grid connection.
- **Opex:** On-going costs of operating a renewable generator and keeping it available for generation. These also include costs relating to operations and maintenance, insurance, connection. and Use of System (UoS) charges.

- **Load factor:** Load factor, which is defined as the ratio of average annual output to the total potential output if a plant were to operate at full capacity over its lifetime, when accounting for all site-specific loss adjustments. For LCOE specifically, net load factor should be utilised as this typically provides a central estimate of the actual annual energy yield. Arup considers this approach more representative compared to that of the Electricity generation costs report from DESNZ (DESNZ, 2023a), where LCOE has been calculated using the gross load factor with an availability loss adjustment only. There was a higher response rate in the survey for net load factor compared to gross annual load factor and a lack of detailed responses regarding loss factors. Below are the net load factors per technology:
  - **Net load factor for wind energy**: Typically accounts for all relevant loss factors, including system availability (Wind Turbine Generator (WTG), Balance of Plant (BoP), and Grid), wake losses (internal and external), electrical system losses, turbine performance losses, and other secondary factors. Definitions of typical loss factors can be found at the European Academy of Wind Energy website (EAWE, 2021)). Specific details of site-specific loss factors such as locational grid curtailments are not provided; however, the net load factors provided are expected to include any constraint losses, particularly those that are not compensated. For compensated losses it is likely that developers do not include these in the net load factor, but this cannot be known definitively.
  - **Net load factor for solar energy**: Typically considers relevant loss factors such as soiling losses, irradiance losses, ohmic wiring losses, transformer losses and system availability losses (PVsyst, 2024). For solar energy, a degradation profile has been applied to this net load factor to include additional losses (such as light induced degradation) due to gradual panel degradation.
- **Time periods:** Predevelopment (from project initiation, through the design and permitting phase, to final investment decision (FID) and start of construction), construction (through to COD) and operational time periods (up to decommissioning), along with how costs are distributed across these periods.
- **Gross power:** The gross power output, which represents the total electrical power that a renewable farm can produce under ideal conditions, without factoring in inefficiencies or other losses. This is used, along with the net load factor, to determine the annual energy production.
- **Operational life:** The plant's operational life, which refers to the duration for which a generation plant remains active and produces electricity.
- **Plant availability[11]:** The plant's availability, which is an energy-based measure of the maximum potential time a plant is available to generate electricity annually. This factor varies depending on how the plant is operated and the amount of downtime required for maintenance.

3.6.1.1 Predevelopment costs

In the context of this study, predevelopment costs refer to expenses incurred before the construction of a renewable energy farm. These costs are critical for project planning and include the following components:

- Pre-Licensing Costs and Technical Design:
  - Expenses related to obtaining necessary permits, approvals, and licenses from regulatory authorities.
  - Costs associated with engineering design, feasibility studies, and technical assessments.
- Regulatory, Licensing, and Public Inquiry Costs:

[11] Note that plant or system availability is already accounted for as a loss within the net load factor and therefore is not used directly within the LCOE estimation.

- Fees for complying with legal and regulatory requirements specific to the renewable energy project.
- Expenses incurred during public consultations and local community engagement processes.

In this analysis, we aggregated these two cost categories to present a singular total predevelopment cost. This decision was influenced by the higher response rate from developers regarding total development expenditure. Detailed information on the number of responses per subcategory and the overall development expenditure will be provided in each technology chapter.

Exclusions: Note that predevelopment costs do not include land lease, acquisition expenses, property and business rates, tax costs, rental fees, or community benefit payments. These were asked independently and the results of these are included in each technology chapter. This is understood to be consistent with the approach taken in previous LCOE analyses carried out on behalf of DESNZ.

3.6.1.2 Capital costs

Capital costs for a renewable energy farm encompass the total expenses required for construction and bringing the facility into operational status. Based on the stakeholder questionnaire, capital costs for LCOE modelling were assumed to include two main components:

- Capital cost, which includes project design, procurement, and EPC expenses. In addition, other capital costs such as site works, roads, and utility connections were also captured here.
- Infrastructure cost, which is a separate line item within the LCOE model. It comprises grid connection expenses (e.g. underground cable costs), the local substation, and transformer stations. It is important to mention that in the future outlook, the infrastructure cost is assumed to remain constant; due to the maturity of this technology, no further learning is anticipated. The focus of the future outlook analysis is therefore on the generating technologies. The boundary of infrastructure is assumed to include the site where the generator is located, associated electrical infrastructure and connection to the nearest point on the grid.

The capital costs include contingency; however, specific values were not always provided by survey respondents.

Exclusions: capital costs do not include land acquisition expenses, property and business rates, tax costs, rental fees, interest costs during construction or community benefit payments. These were asked independently and the results of these are included in each technology chapter.

3.6.1.3 Operating costs

Operating costs represent the ongoing expenses associated with the day-to-day operation of a renewable energy farm. These costs encompass the following:

- O&M costs:
  - Fixed O&M costs: These include labour, planned maintenance, a limited number of unplanned maintenance activities, spares, and consumables.
  - Variable O&M costs: These costs are related to output and include additional O&M expenditures, although these are generally not significant to renewable energy projects.

  In this study, fixed and variable O&M costs have been combined into a single O&M figure, based on the responses received. This is due to a combination of not receiving a sufficiently detailed breakdown of costs from the stakeholder responses. This could also reflect that stakeholders do not cost projects using the variable £/MWh metric. This combined approach aligns with the analyses of other industry bodies, such as BloombergNEF and Lazard.
- Insurance costs: These cover the cost of insuring the generation plant, protecting against risks associated with its operation and maintenance.

- Network Use of System (UoS) charges: These are the costs associated with connecting to and using the distribution and transmission networks. The UoS cost reported in Arup's analysis includes local and wider Transmission Network Use of System (TNUoS) and Distribution Use of System (DUoS) costs, calculated as a £/MW/annum. It should be noted that the UoS charges are highly site-specific and are heavily dependent on location and grid connection. This analysis does not take into account or estimate system-wide costs.

Exclusions: operating costs do not include land acquisition expenses, property and business rates, tax costs, rental fees, or community benefit payments. These were asked independently and the results of these are included in each technology chapter.

3.7 LCOE scenarios

DESNZ had previously developed a Microsoft Excel-based LCOE model specifically for calculating the LCOE. This is published online as Annex B to the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a). The Model's flexibility allowed sensitivity scenarios to be undertaken against the key cost and technical assumptions outlined above. It has been used to produced low, medium, and high LCOE estimates based on the data inputs developed by Arup.

Arup's primary objective was to produce current central LCOE values (medium case) that reflect current costs and deployment trends. In addition, effective minima (low case) and maxima (high case) are presented by combining the relevant low and high data inputs which illustrates the uncertainty surrounding the LCOE figures. For this analysis, no adjustment to Capex or Opex based on future learning rates has been applied, as the primary objective is to present LCOE results based on current, up-to-date assumptions.

By using the collected cost and technical data, Arup generated the following:

- **Medium LCOE:** This estimate used the mean or median values for all costs and technical assumptions.
- **Low LCOE:** This estimate was based on the following combination of inputs:
    - The lowest values for predevelopment, construction, and operating expenditure.
    - The lowest value for predevelopment, construction, and operational time periods.
    - The highest net power output and net load factor.
    - The highest value of plant operating period.
- **High LCOE:** This estimate was based on the following combination of inputs:
    - The highest values for predevelopment, construction, and operating expenditure.
    - The highest value for predevelopment, construction, and operational time periods.
    - The lowest net power output and net load factor.
    - The lowest value of plant operating period.

LCOE estimates for each technology are presented at the end of their respective technology chapter, along with a comparison of this study's LCOE results and the assumptions detailed in the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a). An overall comparison across technologies with the published Generation Costs 2023 assumptions and Literature can be found in Chapter 7.

To ensure consistency, all costs were reported in 2023 prices, using the GDP deflator figures from December 2023 published by the ONS.

Additionally, Arup calculated hurdle rates based on factors such as cost of debt, debt ratio, cost of equity, and equity ratio, using BloombergNEF's 2023 2H values for each technology[12]. Note that for the low, medium, and high scenarios the hurdle rate was kept consistent (see individual technology chapters for details), therefore further sensitivity cases exist based on this financial metric and should be considered as required. This approach allowed Arup to assess the impact of changes in cost and technical assumptions on LCOE.

Arup notes these results may not reflect the final LCOE that DESNZ adopts; the LCOE derived in this report is a key component of the findings but are not the sole factor likely to be considered. In a separate report, *Hurdle Rate Estimates for Electricity Sector Technologies*[13] DESNZ intends to provide an updated view on hurdle rates in the industry (DESNZ, 2023c).

3.8 Other costs and technical assumptions not included in LCOE

In addition to the direct costs considered in the LCOE calculation, there are several other factors that impact the overall economics of renewable energy projects. Arup gathered the following information through a questionnaire:

- Decommissioning cost: This cost pertains to dismantling and removing infrastructure at the end of the farm's operational life. It includes disposal and recycling expenses, net of earnings from the sale of scrap. This is not included within the DESNZ LCOE calculation tool used and has therefore been excluded from the LCOE calculations.
- Land Costs: These are the expenses related to acquiring or renting land for renewable energy infrastructure development and operation. It is important to note that land costs and lease fees are not included in the Opex used within the LCOE calculations.
- Property and Business Rates as well as other Taxes.
- Wake Loss (onshore wind only): Wake losses are caused by upwind turbines from within the project ("internal") or from neighbouring projects ("external"), resulting in reduced wind speeds and, therefore, energy production.
- Turbine Information (onshore wind only): Technical parameters such as turbine size and hub height were also asked.
- Community benefit payments: These are voluntary contributions made by the developers of the solar or wind farm to support local communities.

Additionally, through the stakeholder questionnaire Arup asked specific questions concerning the following aspects:

- Assessing the cost variations associated with co-located storage in large solar projects.
- Cost differences between developing a fully repowered onshore wind farm compared to constructing a new onshore wind farm.
- How short-run marginal costs (SRMC) influence developers' dispatch behaviour for renewable generators.
- Costs associated with turning down or self-curtailing when the renewable asset could otherwise be generating.

[12] Hurdle rates were calculated by Arup using BloombergNEF's H2 2023 LCOE data, published for the UK (BloombergNEF, 2024a) post-tax nominal debt and equity assumptions. These were converted from post-tax nominal to pre-tax real terms, following the methodology set out in BEIS's 2018 Cost of Capital report and assuming 2% inflation and a 25% corporate income tax rate. Hurdle rates were assessed through literature review only and were not included in the survey, as DESNZ was undertaking separate work on this topic, the results of which were not available at the time. Note that Hurdle rates may vary over time depending on specific asset dynamics, where the asset is in its development lifecycle or movements in the macro-economic environment including cost of capital or changes to the regulatory environment. Therefore, rates now may be different to those referenced through a desktop review from BloombergNEF's H2 2023 data.

[13] The report will be published at the following address: *https://www.gov.uk/government/collections/energy-generation-cost-projections*

- Qualitative views from developers on how costs will change between 2035 and 2050.

3.9 Future outlook

3.9.1 Introduction

The future outlook of renewable energy costs is important when assessing the LCOE. The understanding of future cost trends can help policymakers and investors make informed decisions about energy infrastructure investments, subsidies, and long-term planning.

As part of this research, Arup asked stakeholders for their views on how costs have evolved since 2021, their expectations up to 2035, and from 2035 to 2050. Responses were largely qualitative in nature and covered predevelopment costs, construction costs, and operational costs.

As described in the report's Section 4, historical cost reductions experienced across the renewable energy industry do not reflect the evolving macro-economic situation since 2021, which has resulted in increased cost for renewable energy projects.

3.9.2 Overall methodology

For large scale solar PV, Arup has utilised BloombergNEF (BloombergNEF, 2024a) to develop learning curves at a subcomponent level (modules/panels, inverters, electrical BoP and structures, civil works) which have been used to estimate the cost reduction as a function of installed capacity (global and regional). Arup's long-term view on solar PV global capacity expansions was collated from the IEA's World Energy Outlook and National Grid Future Energy Scenarios 2023. Ultimately the subcomponent cost reductions are combined to provide an overall cost reduction curve up to 2050.

For onshore wind, the analysis is based on a combination of qualitative and quantitative data provided by stakeholders, supplemented with industry views and Arup's in-house expertise.

This report provides a variety of estimations of capital cost developments up to 2050. The analysis considers short- and long-term estimations and sets out potential scenarios (low, base, and high cases) to reflect the range of views observed.

Note that this methodology assesses the outlook of construction and operational costs. However, infrastructure cost (i.e. cost of grid connection infrastructure) is assumed to remain constant; this technology is mature and no further learning is anticipated. The focus of the future outlook analysis is therefore focussed on the generating technologies.

3.9.3 Future outlook Summary

For large-scale solar PV (>5MW) projects, it is Arup's view that recently observed increases in capital costs, driven by macroeconomic factors, have fallen in line with global deployment back to pre-2021 levels. Arup has derived a bottom-up learning curve based on adjustments to subcomponent costs, up to 2050. More detail is provided in Section 6.6.

For onshore wind, the direction of future cost in the short-term is uncertain; although, based on a combination of stakeholder responses and recent experience, project costs are not expected to fall. In the short-term, costs could also increase from current levels. Therefore, unlike for solar PV, a bottom-up method, wherein global and regional deployment drives cost reductions, would not capture the short-term expectations of cost. Arup has therefore separately assessed the short- and long-term cost fluctuations, based on a qualitative analysis of stakeholder responses. The result is a range of scenarios: low, base, and high. High and low can be considered sensitivity cases. More detail is provided in Sections 5.6 and 6.6.

For fixed O&M, limited responses were received from stakeholders. As a result, Arup has used a combination of published industry views (BloombergNEF, 2024a) and inhouse knowledge to derive a fixed O&M cost adjustment curve for each technology.

3.10 Precision of data results

In this report, we have updated the costs and technical assumptions to facilitate the calculation of the Levelised Cost of Electricity (LCOE) for onshore wind and large solar projects. The values presented in the tables and figures are derived from detailed analyses and are intended to provide a clear and accurate representation of the data.[14]

Rounding and Precision

- **Rounding Methodology**: Costs are reported to one decimal place for values less than ten; values greater than ten are reported to the nearest integer. Technical assumptions have been rounded to the nearest integer.
- **Exceptions**: Operating expenditure, capacity factors, and hurdle rates retain one decimal place as these are metrics to which the LCOE is highly sensitive. LCOE itself is reported to one decimal place.
- **Underlying Data**: The unaltered figures are available in the underlying spreadsheets. These should be used for precise calculations and analyses.
- **Interpretation of Results**: The rounded values are intended to provide a general understanding of the data trends and should be interpreted with an awareness of their precision and uncertainty. The precision that the results are reported to does not necessarily represent the precision for which the results can be confidently used but instead reflects the numerical analysis of the survey results. Section 3.5 of this report provides further details on data confidence, uncertainty and limitations of the results.

By adopting this approach, we aim to balance the need for clarity in presentation with the accuracy required for detailed analysis.

[14] Results have been rounded to one decimal place, which does not reflect the certainty in the values and may not be adequate precision for certain purposes.

4. Literature review

This literature review sought to provide an overview of key developments in the LCOE of solar and onshore wind over the last five years, paying particular attention to the recent price shocks which have impacted LCOE trends. The information gathered was used to inform the data assessment framework, assess stakeholder responses, and to benchmark Arup's LCOE calculations and underlying assumptions.

The impact of recent price increases has varied per geography, and in scale and length per technology. Solar LCOEs have fallen in 2024, whilst wind developers are still encountering inflated prices and increasing LCOEs (BloombergNEF, 2024a; IEA, 2023a,b; IRENA, 2023; Lazard, 2024).

4.1 Summary

The review considered key literature from the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA), Bloomberg New Energy Finance (BloombergNEF), and Lazard. The IEA and IRENA have provided views up until 2022 but have not yet updated their findings to capture developments in 2023 and 2024, so BloombergNEF and Lazard have been used to provide a more recent view.

The *IEA Renewable Energy Market Update* (IEA, 2023a) published in June 2023 analyses trends in renewable energy markets, including how the energy crisis, market dynamics, and financing will impact the LCOE of renewables. The report covers market developments up until April 2022, with forecasts for 2023 and 2024, and provides insights on a global and EU basis.

The International Energy Agency (IEA, 2023b) *World Energy Outlook 2023* builds on the Renewable Energy Market Update report and examines global energy trends more broadly, offering insights into future energy supply and demand. The 2023 edition focuses on the effects of geopolitical tensions, particularly the energy crisis following the Russian invasion of Ukraine, and how this has impacted market dynamics and project economics. The report focuses on the market in 2022 and developments up to 2030 and 2050, providing insights on a global and EU basis.

The International Renewable Energy Agency (IRENA) *Renewable Power Generation Costs in 2023* analyses global trends in renewable energy costs up to the end of 2022 (IRENA, 2023). The report considers the LCOE of renewable technologies and the economics of renewable deployment. The report has a global focus but also provides UK-specific data.

The *Lazard Levelized Cost of Energy+* is a US-focused report which analyses the levelised cost of energy for renewables against conventional technologies and considers the impact of macro-economic pressure on the build-out of renewables, providing a view up to 2024 (Lazard, 2024).

Bloomberg New Energy Finance (BloombergNEF) *Historic LCOE Benchmarks* and the *LCOE 2H 2023 Data Viewer* have been used to inform our understanding of trends in LCOE and provide insights on a global and UK scale (BloombergNEF 2023a, 2024a).

In addition to this, we have reviewed BloombergNEF reports including *2H 2023 LCOE Update: An uneven recovery* (BloombergNEF, 2023b), and *Solar Supply Chain Index* (BloombergNEF, 2024c). These reports provide insight on renewables deployment, LCOE trends, commodity prices and installation costs and provide both global and UK insights.

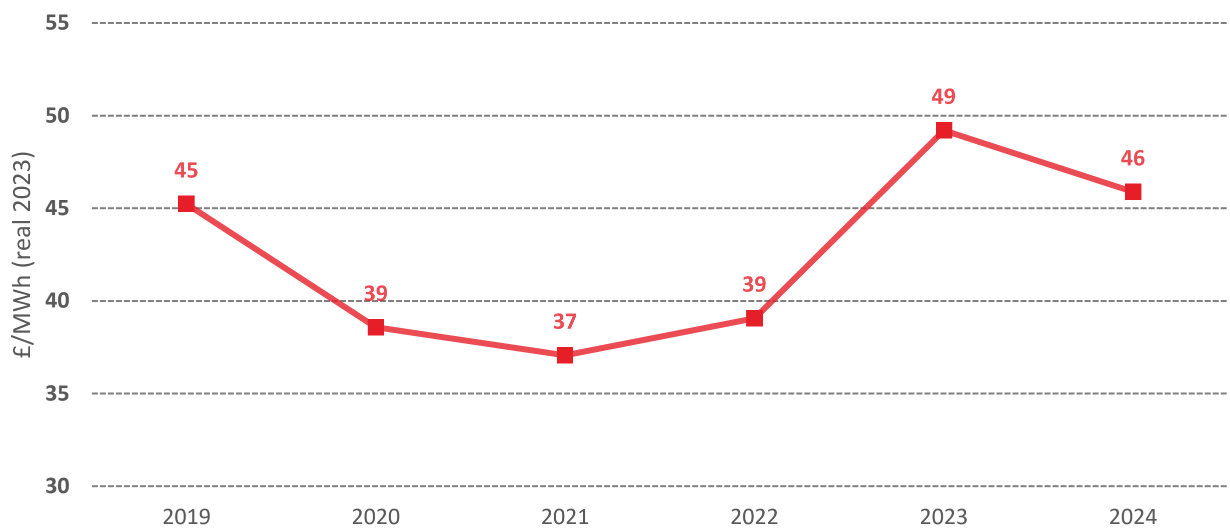
4.2 Literature review: onshore wind

4.2.1 Historical trends

Historically, onshore wind LCOE has followed a downward trajectory since 2010 with LCOE falling 69% globally and 68% in the UK between 2010-2022, driven in part by increased turbine size, reducing O&M costs, and competitive procurement. (IRENA, 2023).

The chart below shows a blended average of onshore wind LCOE data from the key literature over the period 2019-2024. Where provided, Arup has taken UK figures, and where these are not provided Arup has taken global figures to create a blended average. The LCOE of onshore wind began to trend upwards in 2022, with a more significant uplift in 2023. Forecast figures for 2024 show a slight reduction, however the LCOE remains elevated compared to 2021. The drivers behind these trends are explored in the following subsections.

Figure 3: Blended Average of Onshore Wind LCOE from 2019 to 2024[15] (2023 real prices)



In their *June 2023 Renewable Energy Market Update* (IEA, 2023a), the IEA noted that the LCOE of onshore wind in 2024 was expected to remain 10-15% above 2020 levels.

4.2.2 Commodities

Commodity prices drive a key portion of onshore wind project costs, particularly impacting the cost of turbines, with approximately 70% of turbine material composed of steel and approximately 1% of copper and aluminium. Significant rises in the costs of these raw materials in 2022 have played a key role in the increase of onshore wind LCOE in the short term.

Steel: The price of steel rose significantly in 2022 following Russia's invasion of Ukraine, which resulted in increased gas and electricity prices, lifting the cost of steel production in turn. In addition, exports from Ukraine, which is a key player in the steel market, were limited. Increased demand for steel following the pandemic also caused prices to rise. Prices remained elevated in 2023, with the IEA (2023a) reporting that the price of steel in Europe was 270% higher in 2022 than in 2020, and remained 200% higher in Q1 2023. Steel prices have reduced significantly in 2024 sitting ~38% below their 2022 peak, due in part to increased steel production in China and subdued global demand; however, the price remains volatile.

Copper: The price of copper experienced a sharp drop in early 2020 as the COVID-19 pandemic led to reduced demand and mining disruptions in the early months. The price began to rise in July 2020 with a significant peak in May 2021 and has since remained elevated, reaching a new all-time high in May 2024, sitting ~80% above the average price in 2020.

Aluminium: Aluminium prices have followed a similar trend to those of copper, with prices initially declining during the pandemic before rising in late 2020 and peaking in 2022 at over double 2020 levels, before stabilising in 2023 and 2024.

There appears to be a lag between material price increases and the impact on LCOE for onshore wind, with commodity price increases in 2022 having a more notable effect in 2023, as shown in Figure 3. This is

[15] Note that literature sources did not consistently specify the years their LCOE results correspond to.

assumed to be in part due to the timing of securing turbine pricing and the manufacturers' forward hedging of steel prices, producing a lag in the realisation of these increases in the supply chain.

In addition, recent reductions in steel price are not expected to be immediately reflected in turbine prices, as wind turbine manufacturers are currently readjusting prices to ensure profitability across the supply chain. Therefore, in 2024, despite a significant decrease in steel prices, manufacturers are maintaining elevated prices in order to recover losses and stabilise their financial positions; this reduction is not reflected in the LCOE.

4.2.3 Capex

Total installed costs for UK onshore wind decreased 41% between 2010 and 2022, driven by technology advancements such as increased turbine size, component standardisation, economies of scale, and supply chain improvements (IRENA, 2023). Turbine supply, transportation, and installation form the majority of the project costs for onshore wind at around 63% of total capital costs and have historically followed a downward trend on a per MW basis. However, in 2021 turbine prices increased due to rises in the price of raw materials, such as steel, and supply chain disruption following the pandemic. These issues were exacerbated in 2022 following the Russian invasion of Ukraine. Turbine prices have remained elevated with developers in Europe paying 14% more on average in 2H 2023 than 1H 2023, with a more pronounced increase experienced in the UK (BloombergNEF, 2023b). It is expected that turbine prices will remain elevated in 2024 and uncertainties remain around the price of turbines in long term.

High interest rates and inflation have increased the cost of capital in most markets since 2022, affecting the overall economics of new onshore wind projects. In many cases, increases in the weighted average cost of capital have offset gains from technology advancements and falling commodity prices (IEA, 2023a).

BloombergNEF (2023b) reports that in the first half of 2023, onshore wind equipment costs increased by 30% in the UK. Alongside a weaker pound and a decrease in average project size, this has left developers unable to leverage economies of scale, leading to higher turbine costs per MW.

4.2.4 Technology advancements

Onshore wind turbine scale has increased from an average of 2.6MW in 2018 (IRENA, 2019) to turbines of up to c.7MW today (Vestas, 2024). Rotor diameters have increased considerably to over 170m in diameter (Siemens Gamesa, 2024; Vestas, 2024), significantly expanding the swept area and the annual energy production compared to the smaller turbines installed around 2018 which had rotors around 120m in diameter. The increases in turbine hub heights ensure turbines can access higher wind speeds with reduced turbulence, which contributes to improved capacity factors and increases in annual energy production. The average onshore wind capacity factor in the UK increased from 30% in 2010 to 38% in 2022 (IRENA, 2023).

Capacity factors have also been improved by advances in remote sensing and computing, which have aided in the selection of sites and the optimisation of wind farm layouts for increased output (IRENA, 2023).

4.2.5 Operations and maintenance costs

O&M costs contribute to around 10-30% of the LCOE for onshore wind projects and have followed a downward trend historically, with reductions driven by technology improvements, increased competition between service providers, and improved operator and service provider experience (IRENA, 2023). Lazard forecasts an 18% increase in O&M costs between 2023 and 2024 (Lazard, 2024); however, the downward trend is expected to resume, falling on average 2% per year out to 2030 (BloombergNEF, 2024a).

4.2.6 Conclusion

Historical downward trends in LCOE have been driven largely by increased turbine sizes leading to increased energy yield. Onshore wind has also reaped the benefits of economies of scale as larger production volumes and manufacturing hubs reduce costs, whilst larger projects support amortisation of project development and O&M costs. Competitive procurement processes such as the CfD auction in GB have historically driven efficiency and lower prices across the supply chain.

However, the onshore wind industry continues to face high prices for raw materials, increased financing costs, and supply chain issues. These factors have somewhat offset the technology advancements and economies of scale that have historically driven costs down. This has led to an increase in LCOE from 2022 onwards, and whilst onshore wind prices are potentially falling from their peaks, they still remain high, with increases in LCOE in the UK and Europe. The return to a downward trend in the long term will depend on when the cost of capital, supply chain issues, and commodity prices stabilise.

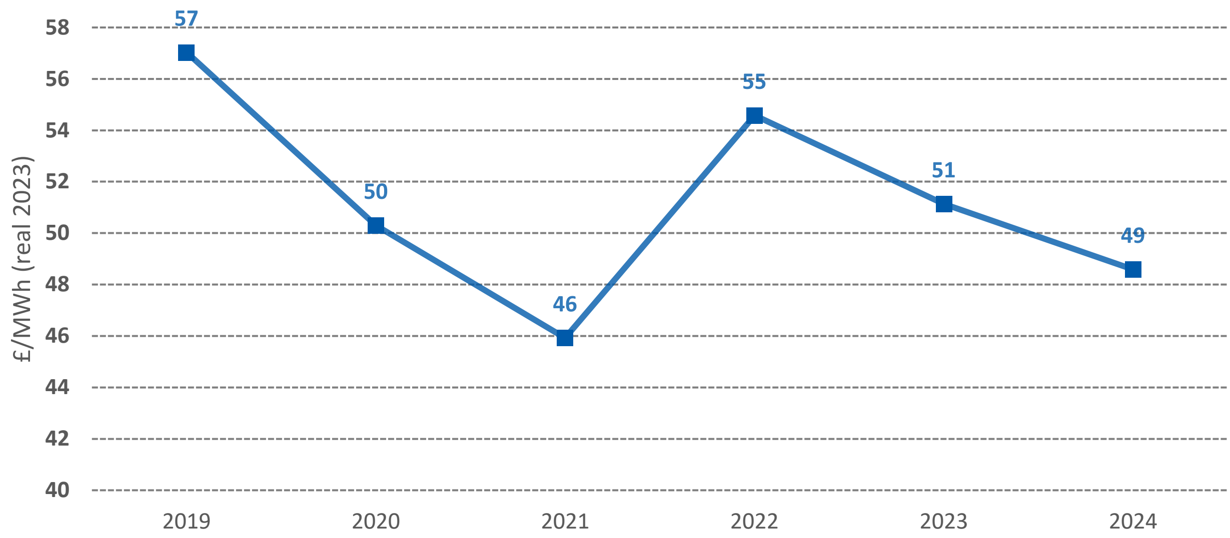
4.3 Literature review: solar

4.3.1 Historical trends

Solar has followed a significant downward trend since 2010, driven by technological and efficiency improvements, falling 89% globally and 87% in the UK from 2010-2022 (IRENA, 2023). However, solar has recently faced short-term LCOE increases driven largely by commodity price volatility.

The chart below shows a blended average of solar LCOE data from the key literature over the period 2019-2024. Where provided in literature Arup has taken UK figures, and where these are not provided Arup has taken global figures to create a blended average. The LCOE of solar rose sharply in 2022 due to price shocks, including a significant increase in polysilicon prices. Solar LCOE has since trended downwards, largely driven by falling polysilicon prices and other factors which are explored in the following subsections. The LCOE for large scale solar projects has fallen back to 2020 figures, as shown below.

Figure 4: Blended Average of Solar LCOE from 2019 to 2024[16] (2023 real prices)



4.3.2 Commodities

Commodity prices have played a key role in the short-term uptick in solar LCOE. The price of polysilicon, a key material in the production of solar PV modules, began rising in 2020, reaching a peak in August 2022 with high prices due in part to extended lockdowns in China, which dominate the global polysilicon supply chain. The IEA (2023) reported that, compared to 2020, the price of polysilicon was four times higher at the 2022 peak and remained about 200% higher in Q1 2023. The price of polysilicon has since fallen, with the March 2024 price sitting 78% below its peak in August 2022. (BloombergNEF, 2024c). Unlike wind, commodity price changes appear to have fed through to the LCOE much faster, as shown in Figure 4, where significant LCOE increases quickly followed the uptick in polysilicon prices.

[16] Note that literature sources did not consistently specify the years their LCOE results correspond to.

Solar has also been impacted by the price rises in steel, copper, and aluminium described above. These materials are used in the manufacturing of components including inverters, structures, and electrical balance of plant such as protection equipment and cables for grid connections.

4.3.3 Capex

Total installed costs for utility-scale solar PV decreased 86% between 2010 and 2022 in the UK driven by technology advancements and economies of scale (IRENA, 2023). Module and inverter costs form a significant proportion of total installed costs and have followed a downward trajectory in the UK falling 48% between 2018-2022.

However, in 2021 solar PV module prices increased as supply chain disruptions and limited polysilicon capacity led to lower availability and inflated prices. The price of mainstream and high efficiency modules increased globally between 2021 and 2022, but has since returned to a downward trend, driven in part by polysilicon production capacity in China increasing 43% in the first half of 2023, leading to excess supply (BloombergNEF, 2023b; IRENA, 2023).

Higher interest rates and inflation have increased the cost of capital in most markets since 2022, affecting the overall economics of new solar PV projects. In many cases, increases in the weighted average cost of capital have offset gains from technology advancements and falling commodity prices (IEA, 2023a).

4.3.4 Technology advancements

Advances in photovoltaic technology in recent years has led the average panel conversion efficiency to increase from 15% to well over 21%, partially driven by a shift towards higher-grade n-type silicon cells with improved temperature coefficients and lower rates of degradation (Sharma & Mishra, 2025). This large jump in efficiency resulted in the power rating of the standard-size panel increasing from 250W to over 400W. Recent developments also include the increased use of bifacial and tracking technology (IRENA, 2023).

These technology advancements and higher deployment in areas with higher irradiance have typically resulted in improvements in capacity factors which can help reduce the LCOE of solar. IRENA (2023) reports that the global weighted average capacity factor increased from 13.8% to 17.2% between 2010 and 2022, before slightly declining to 16.9% in 2022. This is slightly above the EU average of 14% reported by the IEA for 2022, which has only increased by one point since 2020.

4.3.5 Operations and maintenance costs

O&M costs contribute to around 10-20% of the LCOE for solar projects and have followed a downward trend historically, with reductions driven by improvements in solar PV technology, including enhanced module efficiency, system design optimisation, and improvements in monitoring and diagnostic tools (IRENA, 2023). Lazard forecasts a 25% increase in O&M costs between 2023 and 2024 (Lazard, 2024); however, the downward trend is expected to resume, falling on average 1% per year up to 2030 (BloombergNEF, 2024a).

4.3.6 Conclusion

Historical downward trends in LCOE have been driven largely by the reduction in capex and O&M costs, alongside increased capacity factors. In 2021, solar PV module prices increased as supply chain disruptions and limited polysilicon capacity in China led to lower availability and inflated commodity prices, which caused a sharp increase in LCOE in 2022. Since then, the downward trend has resumed, appearing to be driven by decreasing commodity prices and supply chain stabilisation, with the LCOE for large-scale solar projects falling back to 2020 levels.

It is expected that the LCOE will follow a downward trend in the long term due to increased polysilicon production capacity, increased global deployment and the benefits of economies of scale which solar has historically benefited from.

4.4 Literature review conclusion

Both onshore wind and solar PV have historically followed a downward trend in LCOE. However, 2022 saw this trend reverse, with commodity price volatility, increased cost of capital, and supply chain issues leading to notable increases in LCOE, somewhat offsetting technology advancements and economies of scale that historically drove costs down. The uplift in LCOE has varied in scale and length per technology, with solar LCOE sharply increasing in 2022 before falling up to 2024, largely following the trend of commodity prices. Onshore wind LCOE rose significantly in 2022 and 2023 and, whilst declining slightly in 2024, the LCOE remains elevated compared to pre-pandemic levels.

Literature is showing that solar LCOE is reducing and is expected to continue falling in future, whereas, for onshore wind, the return to pre-pandemic levels and the resumption of downward trends will depend largely on when the cost of capital, supply chain issues, and commodity prices stabilise.

5. Onshore wind

5.1 Introduction

As of 2024, the UK has approximately 15.6 GW of onshore wind installed capacity (DESNZ, 2024). Onshore wind remains a crucial component of the UK's renewable energy mix, contributing significantly to the country's decarbonisation goals. The UK Government is aiming for a radical increase in onshore wind deployment to 2030 to meet its decarbonisation goals (UK Government, 2024).

Note that Arup collected stakeholder responses in April 2024 prior to the AR6 results being published and the policy surrounding onshore wind development in England changed in July 2024. Therefore, the responses received do not reflect the latest auction results or updated government policy.

5.2 Data collection

Data for our onshore wind energy analysis was collected from renewable energy project developers, with outreach to trade associations and technology manufacturers. In total, we received responses from 14 developers, providing 27 project data points, from which 18 projects had CODs that would classify them as having "current" costs. These 27 data points represented a total installed capacity of 1,566 MW of onshore wind projects at various stages of development, including operational, under construction, and planned. Notably, 23 projects were located in Scotland and four in Wales. This regional distribution reflects the policy landscape prior to July of this year, during which there were restrictions on the construction of onshore wind projects in England. Consequently, most recent onshore wind developments in Great Britain have been concentrated in Scotland. Developers reported that turbine models range in capacity from 4.3 MW to 6.8 MW, with rotor diameters between 117 meters and 163 meters. Mentioned turbine manufacturers include Vestas, Nordex, Enercon, and Siemens Gamesa Renewable Energy (SGRE).

Based on the data selection criteria outlined in Chapter 3, the data points were assessed to include only those that were robust, representative, and current. For cost analysis, only data points identified as current costs, as defined in Subsection 3.3.5, were selected for the analysis. For onshore wind projects, Arup considered current values to be those from projects with Commercial Operations Dates ranging from 2025 to 2029.

To ensure the accuracy of the LCOE results, all findings were compared against internal and externally published benchmarks. Arup's internal benchmark comprised 69 projects located across Europe, with CODs within the ranges considered current. For external benchmarks, we primarily referenced the BloombergNEF and Lazard's LCOE, cost, and technical assumptions for 2023, applying consistent foreign exchange (FX) and inflation factors to enable a fair comparison. Lastly, internal experts reviewed the final low, medium, and high values to ensure these were in accordance with their expectations. For the medium value of cost or technical assumptions, either the mean or median of the dataset was used. The decision on which to use depended on the total number of data points available for the analysis. If the dataset contained fewer than ten data points, the mean was calculated as the central value. For larger datasets, the median was used.

Regarding high and low values, Arup calculated the 5th and 95th percentiles of costs based on the survey responses. Using percentiles was necessary to anonymise the cost data provided by the developers. However, for time periods and other technical assumptions, Arup chose not to apply a 5th or 95th percentile because these metrics are less identifiable than costs; instead, the minimum and maximum values were used. This comprehensive approach ensured the validity and reliability of the data, providing a solid foundation for the subsequent analysis.

5.3 Cost and technical assumptions breakdown

5.3.1 Predevelopment expenditure

As indicated in Chapter 3, predevelopment costs refer to the expenses incurred up to FID, before the construction of the onshore wind farm begins.

Through the stakeholder questionnaire, Arup requested total predevelopment costs, as well as the breakdown of i) pre-licensing costs, ii) technical and design costs, as well as iii) regulatory, licensing, and public inquiry costs, each as separate classifications. It was decided to use the total predevelopment cost for the subsequent analysis due to the larger number of data points in this category (26 data points) compared to the subcategories (seven data points in the first, eight in the second, and six in the third). Utilising the total predevelopment costs rather than considering subcategories ensured all relevant costs were included and a more robust assumption would ultimately be derived.

Following the application of the selection criteria, a dataset of 18 data points remained, from which a medium predevelopment cost (in 2023 real prices) was calculated as £81/kW, with low and high costs at £36/kW and £199/kW, respectively.

It is important to note that predevelopment costs are expected to vary significantly depending on the site-specific conditions, planning hurdles, and requirement for appeals.

Table 13: Current predevelopment costs 2023-2024 (2023 real prices £/kW)

Item	Total data points	Data points used	Low	Medium	High
Predevelopment cost	26	18	36	81	199

5.3.2 Predevelopment timings

After evaluating the provided data against our methodology detailed in Chapter 3, we selected 12 data points to determine the total predevelopment period, which ranged from 5 to 13 years with a medium value of 8 years.

To incorporate the predevelopment costs in the LCOE calculation, we estimated annual phasing based on low, medium, and high values from the predevelopment periods as described by developers. Eight responses regarding the phasing of the costs over the predevelopment period were received. Respondents mostly described the distribution for predevelopment costs as linear. Consequently, we used the low, medium, and high values for the time period of the chosen scenario with the costs evenly split across the years.

The phasing of costs for each scenario is shown below:

- **Low Scenario**: Costs spread evenly across five years (20% per year).
- **Medium Scenario**: Costs spread evenly across the first seven years, with the remaining costs allocated to the eighth year (13.3% in the first seven years and 6.7% in the final eighth year).
- **High Scenario**: Costs spread evenly across 13 years (7.7% per year).

Table 14: Predevelopment periods (years)

Item	Total data points	Data points used	Low	Medium	High
Predevelopment period	12	12	5	8	13

5.3.3 Capital expenditure

5.3.3.1 Construction cost

Construction costs for onshore wind include the costs associated with the supply and installation of wind turbines, foundations, array cables and site preparation. For onshore wind projects, the construction costs were derived from the total Capex provided by stakeholders with a proportion removed which was defined as "Infrastructure" (including grid connection, substations, and other related infrastructure). Specifically, our findings indicate that construction costs constitute 80% of the total Capex, with the remaining 20% attributed to infrastructure costs. This proportion was derived from the responses received, reflecting the average distribution observed in the assessed projects.

The capital costs include contingency; however, specific values were not always provided by survey respondents.

Following the application of the selection criteria, a dataset of 11 data points remained, from which a medium capital cost was calculated as £1,204/kW, with low and high costs at £963/kW and £1,603/kW, respectively.

Table 15: Current construction costs 2023-2024 (2023 real prices £/kW)

Item	Total data points	Data points used	Low	Medium	High
Capital cost	15	11	963	1,204	1,603

5.3.3.2 Capital timings

After evaluating the provided data against the methodology described in Chapter 3, we selected 12 data points to determine the total construction period, which ranged from 1 to 3 years with a median value of 2 years.

Similarly to the approach for predevelopment costs, incorporating construction costs into the LCOE calculation required us to project the timing of costs. These projections were based on the low, medium and high construction durations reported by developers. Although the data on cost phasing during the construction phase was limited, the responses we received indicated a variety of approaches. Among the nine responses, cost distribution during the construction period was described as either linear, front-loaded, back-loaded, or bell curve-shaped.

In the absence of a consistent approach to the annual phasing of capital costs, we adopted a linear approach for projecting costs over the low, medium, and high construction durations of the chosen scenario. This aligns with previous methodologies.

The phasing of costs for each scenario is shown below:

- **Low Scenario**: 100% of costs incurred in one year.
- **Medium Scenario**: 57.1% in the first year and 42.9% in the second year.
- **High Scenario**: Costs spread evenly across three years (33.3% per year).

Table 16: Construction periods (years)

Item	Total data points	Data points used	Low	Medium	High
Construction period	12	12	1	2	3

5.3.3.3 Infrastructure cost

Infrastructure costs include the expenses related to grid connection, substations, and other associated infrastructure elements. Similarly to the method used for calculating construction costs, the infrastructure cost was determined as a proportion of the total Capex. This proportion was derived from the average of questionnaire responses regarding grid connection, substation, and transformer costs, as well as other infrastructure costs. On average, these constituted 20% of the total Capex.

The medium infrastructure cost was calculated to be £303/kW, with low and high costs calculated at £242/kW and £403/kW, respectively. Additionally, the same annual phasing figures used for capital cost were applied to incorporate infrastructure costs into the LCOE calculation.

Table 17: Current infrastructure costs 2023-2024 (2023 real prices £/kW)

Item	Total data points	Data points used	Low	Medium	High
Infrastructure costs	15	11	242	303	403

5.3.4 Operating expenditure

Operating costs refer to the ongoing expenses associated with the day-to-day operation of an onshore wind farm. These costs exclude land expenses, property and business rates, tax costs, rental fees and community benefit payments, as noted in Subsection 3.6.1.3. To align with the DESNZ LCOE methodology, Arup divided the cost forecast into three categories: O&M, insurance, and Connection and UoS Charges.

5.3.4.1 Operations and maintenance

O&M costs for an onshore wind farm include all the maintenance, logistics and monitoring expenses in order to maximise production, maintain asset integrity, and safely operate the generating assets. These costs typically include labour, remote monitoring, maintenance activities, purchase of spare parts, and on-site inspections.

As indicated in Chapter 3, O&M costs were presented as a combined figure rather than separated into fixed and variable costs. This decision was made to ensure consistency, given the variations in data reporting among stakeholders – some reported only fixed O&M, others only variable O&M, and some provided both.

After applying the selection criteria, a dataset of five data points remained, from which a medium O&M cost (in 2023 real prices) was calculated as £19.5k/MW/a, with low and high costs at £14.8k/MW/a and £22.8k/MW/a, respectively. These responses are well aligned with Arup's benchmarks.

Table 18: Current O&M costs 2023-2024 (2023 real prices k£/MW/a)

Item	Total data points	Data points used	Low	Medium	High
O&M costs	10	5	14.8	19.5	22.8

5.3.4.2 Insurance

Insurance for an onshore wind farm is designed to protect against the various risks associated with operation and maintenance. The medium insurance cost (in 2023 real prices) was calculated as £3.6k/MW/a, with low and high costs at £2.2k/MW/a and £4.4k/MW/a, respectively.

It is worth noting that one data point was excluded from the analysis of insurance as it was considered an outlier; it was 20 times higher than the second highest insurance value and therefore deemed unrepresentative.

Table 19: Current insurance costs 2023-2024 (2023 real prices k£/MW/a)

Item	Total data points	Data points used	Low	Medium	High
Insurance costs	10	5	2.2	3.6	4.4

5.3.4.3 Connection and UoS charges

Network Use of System charges are the costs of connecting to and using the distribution and transmission network. In Arup's analysis, the UoS cost includes both local and wider TNUoS and DUoS charges, calculated on a k£/MW per annum basis.

Due to the limited availability of benchmarks in this category, Arup used the National Grid's Five-Year View of TNUoS Tariffs for 2025/26 to 2029/30 to validate the responses. One data point was disregarded as it appeared to be an outlier and did not align with the highest possible value indicated by the National Grid TNUoS charges five-year forecast.

After applying the selection criteria, a dataset of 8 data points remained, from which a medium connection and UoS Charge was calculated as £17.0k/MW/a, with low and high costs at £0.4k/MW/a and £45.3k/MW/a, respectively. Of the eight data points, three included only TNUoS charges, four included only DUoS charges, and one included both.

It is worth mentioning that connection and Use of System charges can vary greatly, depending on site-specific conditions and location, leading to a wide range of costs.

Table 20: Current connection and UoS charges 2023-2024 (2023 real prices k£/MW/a)

Item	Total data points	Data points used	Low	Medium	High
Connection and UoS charges	13	8	0.4	17.0	45.3

5.4 Technical assumptions

Based on the data received from developers, Arup derived up-to-date key technical assumptions, crucial for determining the LCOE. The following provides a summary of the observations.

5.4.1 Gross power

Gross power for an onshore wind farm refers to the total electrical power output that the farm is capable of producing under ideal conditions, without accounting for losses due to the electrical conversion system, inefficiencies, or other factors.

This study defined the medium-sized onshore wind site as having a capacity of 52 MW, with a range of 8 MW to 194 MW.

Table 21: Gross power (MW)

Item	Total data points	Data points used	Low	Medium	High
Gross Power	27	27	8	52	194

5.4.2 Load factor

Load factors for an onshore wind farm can be presented as either a gross or net load factor. The gross load factor reflects the estimated energy output that the wind farm could produce under ideal conditions, without accounting for losses such as system availability (Wind Turbine Generator or WTG, Balance of Plant or BoP, and grid), wake losses (internal and external), electrical system losses, turbine performance losses, degradation, and other secondary loss factors. Stakeholders provided both gross and net load factors, which were assessed. However, since the net load factor accounts for all applicable losses, this should be used to calculate net energy production as part of the LCOE analysis.

Arup calculated a net load factor of 38.1%, with high and low values of 33.0% and 41.3%, respectively. The net load factor for onshore wind is assumed to account for degradation throughout the asset's life, meaning that we present the full-life average load factor.

It is important to note that the net load factor is highly site-specific, and these results reflect only the sample of projects we analysed.

Table 22: Net load factor (%)

Item	Total data points	Data points used	Low	Medium	High
Net Load Factor	18	11	33.0%	38.1%	41.3%

5.4.3 Plant operating period

The operating lifetime of an onshore wind plant refers to the period during which the plant is expected to be functional and generate electricity. Based on the responses received from stakeholders, Arup estimated the medium operating lifetime of an onshore wind site to be 35.0 years, with a minimum of 25.0 years and a maximum of 40.0 years.

Two data points were excluded from the analysis. One was deemed an outlier as it was significantly higher than what is currently feasible (over double the typical design life for onshore wind turbines), and the other was identified to be a second-hand turbine, reflecting a considerably reduced asset life and therefore not in line with current industry views.

Table 23: Operating lifetime (years)

Item	Total data points	Data points used	Low	Medium	High
Operating lifetime	13	11	25	35	40

5.5 Summary of results

5.5.1 Costs and technical assumptions

We have summarised the main costs and technical assumptions for onshore wind projects in this study, including the low, medium, and high cases of each category in the table below.

Table 24: Summary of 2023-2024 current costs and technical assumptions for onshore wind in this study

Category	Unit	Onshore Wind		
		Low	**Medium**	**High**
Costs				
Pre Development	£/kW	36	81	199
Capital Costs During Construction	£/kW	963	1,204	1,603
Infrastructure Costs	£/kW	242	303	403
Total Capex	£/kW	1,241	1,588	2,205
Insurance	k£/MW/a	2.2	3.6	4.4
Connection And UoS Charges	k£/MW/a	0.4	17.0	45.3
O&M	k£/MW/a	14.8	19.5	22.8
Total Opex	k£/MW/a	17.4	40.1	72.4
Technical assumptions				
Net load factor	%	33.0%	38.1%	41.3%
Operating lifetime	years	25	35	40
Additional assumptions				
Hurdle rate[17]	%	5.8%	5.8%	5.8%
Predevelopment timescale	years	5	8	13
Construction timescale	years	1	1	3

5.5.2 LCOE result

Arup has utilised the DESNZ LCOE calculator, published online as Annex B to the Electricity generation costs 2023 report (DESNZ, 2023a) to produce low, medium, and high LCOE scenarios. These scenarios represent the central (medium) case as well as the effective minima (low case) and maxima (high case) by combining the relevant low, medium and high data inputs. As described in Section 3.7. LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital and operating cost. Therefore, it is the standard approach to consider a range of scenarios rather than a single point, allowing the modelling to capture uncertainty.

The LCOE values presented are derived from low, medium, and high capital and operating cost estimates, as well as low, medium, and high technical assumption estimates. It is important to note that in most cases, the low values of costs and technical assumptions were used for the low LCOE scenario, with medium and high values used accordingly. However, for net power output and plant operating period, these were used inversely (e.g. the high net power output and high operating lifetime values were used to calculate the low LCOE value). This approach is based on the understanding that larger projects benefit from economies of scale and that a longer project lifetime will lead to greater total energy production.

The results are shown below in Table 25. These scenarios are designed to be indicative and to offer a range of LCOE estimates for comparison with current LCOE scenarios in industry literature. A comparison between this study's results, a blended average of the literature, and DESNZ current LCOE estimates is provided in Chapter 7.

[17] Hurdle rates were calculated by Arup utilising BloombergNEF's 2023 2H debt and equity ratios

Arup notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

Table 25: LCOE based on current costs 2023-2024 (2023 real prices £/MWh)

Item	Hurdle rate (%)	Low	Medium	High
LCOE	5.8	27.2	45.8	90.6

5.6 Future outlook

The stakeholder respondents provided a range of opinions on the short and long-term trend of costs for onshore wind.

There were limited qualitative and quantitative views on future cost curves, leading to uncertainty around how to reflect this into the short- and long-term cases. Therefore, Arup has considered a range of scenarios (low, base, and high cases) to reflect different possible outcomes based on the small sample of quantitative responses. Stakeholders indicated that from 2030 to 2035, capital cost is forecasted to fluctuate between +10% and -15%. Under an optimistic scenario respondents suggested that costs could reduce by 5-10%, between 2035 and 2050 based on technology innovations. For example, larger wind turbines.

The cost data provided by stakeholders reflects projects with CODs up to 2028. Therefore, in the medium case, Arup assumed that costs will be flat up to 2028. This is a simplified assumption and is based on the details provided by stakeholders and from the review of literature, reflecting the uncertainty of any material short-term cost reductions. Post-2028, Arup has taken the central point of the range of stakeholder views, i.e. a 2.5% reduction to 2035 (central point of +10% and -15%) followed by a 7.5% reduction (central point of -5% and -10%) between 2035 and 2050.

Stakeholders indicated that capital cost are typically divided into the following subcomponents with the corresponding proportions presented in the table below.

Table 26: Proportions for separate components in capital costs (onshore wind)

Component breakdown	Capex proportion
Turbine supply	52%
Turbine transportation & installation	11%
Foundation construction	9%
Electrical Balance of Plant (inter-turbine cables, switch gear, protection equipment, transformers, auxiliary systems)	3%
Civil works (ground works, hardstanding areas, drainage, access roads, substation building, compound areas)	15%
Other Costs	10%

The largest share of cost is the supply and installation of the wind turbine, comprising over 60% of total capex. The main driver of historical cost reduction on a per MW basis stems from the wind turbine, resulting from increases to turbine scale in terms of both physical scale (rotor size and hub height) and generating capacity (MW). The projects considered by stakeholders include turbines in the range of 4.3-6.8 MW. Stakeholders anticipate turbine sizes will increase to around 8 MW, with a maximum tip height in the UK of 260 m. Current costs reflect turbine scales up to c.7 MW. While further increases in turbine scale may occur post-2028, the "learning curve" is not expected to be as steep as in the past. In the long term, stakeholders generally agree that turbine generating capacity will level off at a maximum of 8-10 MW in the UK, constrained by transportation, visual impact, and aviation limitations.

Newer turbines, with larger rotors, higher hub heights and greater generating capacity will ultimately result in an increase in annual energy production generated per turbine. This could result in an increase in load factors over time; however, the average load factor will depend on the geographic deployment of wind farms in future. For example, if more wind farms are developed in England due to a change in planning policy, then the average load factor may reduce over time compared to if development continues to be concentrated in Scotland where average wind speeds are greater.

It is not clear if the impact of Chinese WTG manufacturers entering the market and capturing a substantive market share is factored into the views of stakeholders. Arup expects Chinese manufacturers entering the market may result in a large reduction in future wind turbine costs (potentially up to 40% lower turbine cost per MW), resulting in more significant cost adjustments in the future.

Overall, with turbine supply costs representing a high proportion of Capex (52%), a 40% reduction in turbine costs could result in an overall 20% reduction in total cost. At this point in time, there is uncertainty around their technical performance and the potential reduction in cost, and therefore the impact on LCOE of Chinese-manufactured turbines.

5.6.1 Resulting future price adjustments

For each scenario (low, base, and high case), the capital cost forecast is based on the data provided via the stakeholder survey. For onshore wind, stakeholders indicated that between 2030 and 2035, the change in capital cost is expected to range from +10% to -15%. A further reduction of 5% to 15% is expected between 2035 and 2050.

Short-term: Based on Arup's analysis of data provided via the stakeholder survey, current costs have been estimated based on projects with COD between 2025 and 2028. Regarding the future outlook, stakeholders indicated that capital cost are expected to remain unchanged across this period. Therefore, up to 2028 cost adjustment has been set to 100%. High and low sensitivity cases have been taken as the upper and lower range presented by the respondents.

Long-term: Based on the centre of the range provided by the stakeholders, by 2035 cost is projected to decrease on average by 2.5%, resulting in an overall reduction to 97.5% of 2023 base cost. By 2050, cost is expected to decrease further by an average of 7.5%, bringing cost down to 90% of 2023 levels. High and low sensitivity cases have been taken as the upper and lower range provided by the stakeholders.

The years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close[4]), unless stated otherwise. These years do not correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years.[18]

Table 27: Capital cost forecast for three scenarios (onshore wind) by year of securing costs

Scenario	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Low case	100.0%	97.5%	91.3%	85.0%	81.7%	75.0%
Medium case	100.0%	100.0%	99.3%	97.5%	95.0%	90.0%
High case	100.0%	101.7%	105.8%	110.0%	108.3%	105.0%

5.6.1 Fixed O&M

Limited responses were received from stakeholders regarding future adjustment to onshore wind O&M costs.

[18] For example, an onshore wind project securing costs in 2025 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close), should apply 100% of the "current costs" (as defined above) for capital costs and 96.2% of the Fixed O&M costs. This project may not become operational for a number of years after securing the costs, following time taken to reach financial close and then for the site to be constructed. Another example could be a project securing costs in 2030 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close) where a 99.3% Capital Cost factor and 85.4% Fixed O&M cost factor should be applied through multiplication, to the "current costs" (as defined above) resulting in a lower capital and operating cost.

Arup has assessed the latest available industry views (BloombergNEF, 2024a) to derive a future fixed O&M cost adjustment curve for onshore wind.

Table 28: Fixed O&M cost forecast (onshore wind) by year of securing costs

Learning rate	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Fixed O&M projection	100.0%	96.2%	85.4%	80.0%	76.5%	71.2%

The percentage change in fixed O&M cost is calculated on a yearly basis. The fixed O&M cost is anticipated to decline by an average of 2.2% per annum until 2030. Post-2030, the rate of reduction is expected to slow, averaging 0.9% annually.

Note that Arup's LCOE results in this study are based on the updated current costs and do not reflect the potential fluctuations in Capex or O&M cost presented here. To calculate future LCOE scenarios, the adjustment curves must be applied separately.

The years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close), unless stated otherwise. These years do not necessarily correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years.

5.7 Comparison of previous and current costs, technical assumptions, and LCOE results

In this section, Arup compared the costs and technical assumptions presented in the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a) with the outcomes of our latest study.

5.7.1 Approach

The comparisons are based on medium cost values. Furthermore, Arup's calculations were based on £2023 real values, whereas the Electricity Generation Costs for 2023 by DESNZ were reported in £2021 real values (DESNZ, 2023a). To align these figures, we adjusted them to 2023 values using the GDP deflator figures from December 2023 published by the Office for National Statistics.

The LCOE calculation incorporates Arup's current hurdle rate assumptions and is based on the latest current costs and technical assumptions. The hurdle rate, calculated by Arup and derived from the cost of debt and equity from industry literature for onshore wind, is 5.8%.

The table below provides a comparison between the new and old estimates for predevelopment, capital, and operating costs, as well as the technical assumptions necessary for the LCOE calculation. It is worth mentioning that although the costs and technical assumptions are current at the time of the analysis, for the comparison, Arup selected the scenario from the Electricity generation costs 2023 report from DESNZ (DESNZ, 2023a) that most closely matched our study parameters. For onshore wind, the projects analysed had CODs ranging from 2025 to 2029. Given that DESNZ provided scenarios for projects with commissioning years of 2025, 2030, 2035, and 2040, the 2025 scenario was deemed the most appropriate and relevant for this comparative analysis.

5.7.2 Results

Overall LCOE has increased by 7% from the Electricity generations costs 2023 report from DESNZ (DESNZ, 2023a) which is in line with the expectations based on Arup's literature review. The changes in LCOE are driven by the following key factors:

- **Increased hurdle rate:** LCOE is increased by the rise in the cost of capital through the application of a higher hurdle rate.
- **Increased Capex:** total Capex has increased by 8% in real terms. As outlined in Subsection 3.6.1, Capex comprises three components: pre development, capital cost during construction, and infrastructure. Whilst costs in the predevelopment and construction sub-categories have decreased, this is outweighed by a substantial increase in infrastructure costs, leading to an overall rise in Capex. This overall increase is in line with expectations based on trends visible in the market. The apportionment of costs between sub-categories has also changed, not necessarily in line with expectations. This could be due to respondents' interpretation of the survey questions, in particular how they have assigned costs to each sub-category. Considering this, we recommend focussing on the changes in total Capex.
- **Reduced net load factor:** the updated net load factor (38%) is in line with Arup's expectations and is based on the net load factors provided by stakeholders. The Generation Costs 2023 study followed a different approach, calculating the gross load factor using technical performance and weather data, then reducing it by availability to derive a net load factor. The lower net load factor reported by stakeholders would increase the overall LCOE.
- **Plant operating period:** by increasing the asset operational life from 25 to 35 years, this has the impact of reducing LCOE. This is in line with current typical assumptions for asset life made across industry.
- **Connection and Use of System Charges:** Arup's latest analysis has resulted in an increase in UoS charges. This factor is particularly site specific and, in this analysis, has led to an increased LCOE.

As stated above, Arup has compared this study's medium results with those from the Electricity generation costs 2023 report (DESNZ, 2023a) medium results. This can be found in the table below.

Table 29: Onshore wind – Arup's key study results versus DESNZ's assumptions (DESNZ, 2023a)

Assumption	Unit	Arup (medium)	DESNZ projection for 2025	% Change
Technical				
Hurdle rate	%	5.8%	5.2%	
Net load factor[19]	%	38.1%	45.0%	
Gross power output	MW	52	51	
Plant operating period	Years	35	25	
Predevelopment period	Years	8	4	
Construction period	Years	2	2	
Cost (2023 real prices)				
Predevelopment expenditure	£/kW	81	146	
Capital costs during construction	£/kW	1,204	1,238	
Infrastructure costs	£/kW	303	83	
Total Capex (incl. predevelopment expenditure)	£/kW	1,588	1,468	8%
Insurance	k£/MW/a	3.6	1.9	
Connection and UoS charges	k£/MW/a	17.0	4.1	
Fixed O&M	k£/MW/a	19.5	28.6	
Variable O&M	£/MWh	0.0	6.8	
Total Opex	k£/MW/a	40.1	61.2[20]	-34%
Total LCOE	**£/MWh**	**45.8**	**42.8**	**7%**

It should be noted that for the latest AR6 CfD auction round certain evidence-based adjustments were made to the assumptions used by DESNZ in its energy modelling, such as increases to capital costs (DESNZ, 2023b). These adjustments are not reflected in their latest Electricity Generation Costs report and are therefore not captured in this comparison.

[19] Clarification: The comparison presented is based on two distinct methodologies. Arup's calculation of the net load factor includes all losses. In contrast, the previous report's average load factor (net of availability) does not encompass all losses, resulting in a higher load factor figure. This distinction is essential for an accurate understanding of the data.

[20] Total Opex was calculated by converting all components to a consistent unit.

5.8 Other key findings

Arup gathered additional information that falls outside the scope of the LCOE calculations, on behalf of DESNZ. It is important to note that the same methodology employed above was used to calculate the low, medium, and high values of the findings in this subsection. A summary of these findings is presented in the following subsections.

5.8.1 Land costs

Land costs refer to the financial expenditure associated with acquiring or leasing the land where the wind farm will be located. These costs may include either the purchase price of the land or the rental fees paid to the landowner for the use of their property.

Some developers provided a range of land/rental cost mechanisms typically used to calculate these expenses, such as: (i) fixed rent, (ii) a percentage of revenue, or (iii) a formula based on revenue and/or power prices. Based on eight responses, the range of land costs was reported to be between £9.0k/MW/a and £36.0k/MW/a, with an average of £19.5k/MW/a. It is important to highlight that most of these data points are related to sites in Scotland, with only a few from Wales.

5.8.2 Property and business rates

Data provided by 10 respondents indicated that property and business rates range from £10.0k to £24.0k/MW/a, with an average cost of £12.0k/MW/a.

5.8.3 Tax

Developers were also asked to provide information on any additional taxes they were required to pay. Four respondents reported tax rates, resulting in a range of £10.0k/MW/a to £30k.0/MW/a, with an average of £21.5k/MW/a.

5.8.1 Decommissioning costs

Decommissioning costs involve the expenses related to safely dismantling and removing infrastructure of an onshore wind farm at the end of its operational life. Arup received eight responses regarding these costs, and after evaluating the information received based on the criteria outlined in Chapter 3, five data points were used to calculate an average decommissioning cost of £31k/MW, with a low cost of £15k/MW and a high cost of £62k/MW.

5.8.2 Short-run marginal cost

Short Run Marginal Cost (SRMC) is defined as the change of total cost when producing one more unit of energy (e.g. 1 MWh). In the short-term, when the capacity of the energy system is fixed, the short-term marginal cost only includes the operating costs of the existing infrastructure, without any additional investment.

Developers were asked how these costs impact their dispatch behaviour, and four comments were received on this topic. Respondents indicated that dispatch behaviour is not influenced by SRMC for projects with a Contract for Difference (CfD), but it is influenced by curtailment or bids into the balancing or capacity market when those bids exceed revenue from CfD exports. This aligns with Arup's view. One respondent estimated SRMC at £4/MWh (Real 2023) but noted that it is not included in their valuations.

5.8.1 Self-curtailment

Self-curtailment is the intentional reduction of electricity generation by the wind farm itself. Developers were asked to provide the costs associated with turning down or self-curtailment when the asset could otherwise be producing electricity.

Respondents provided a range of responses that reflect the opportunity costs of the CfD, the project's exposure to day-ahead pricing, negative pricing, and the impact of the balancing mechanism on curtailment periods.

Arup's view is that the cost of self-curtailment is a function of the offtake arrangements of projects and the projects' participation in the balancing market. Given the various approaches to securing CfD, Power Purchase Agreements (PPA), or alternative routes to market, the approach to self-curtailment will vary from project to project.

5.8.2 Availability profile

Availability in this context refers to the maximum potential time that a generation plant can produce electricity annually (energy based – i.e. the proportion of possible energy production). It is important to note that while an availability profile is being presented, it was not used to calculate LCOEs, as the Net Load Factor was being utilised, which already accounts for the availability profile. Moreover, one data point of 100% was excluded from the analysis, as it was considered unrealistic by Arup's subject matter experts.

The average availability for an onshore wind project was calculated to be 96.9%, with minimum and maximum availabilities of 94.1% and 98.8%, respectively.

5.8.3 Community benefit payments

Community benefit packages voluntary contributions made by onshore farm developers to support local communities. According to 12 questionnaire responses, community benefit payments ranged between £3.0k to £10.0k/MW/a, with the most responses stating £5.0k/MW/a.

5.8.4 Wake loss

Wake losses occur when neighbouring wind turbines experience reduced energy yield due to the wake effect caused by other turbines. These can be interactions with turbines within the project or from neighbouring wind farms. According to the nine questionnaire responses received, wake loss estimates range from 2% to 14%, with an average loss of 9% across the projects received. This variation is a result of the site-specific nature of wake losses.

5.8.5 Repowering

Onshore wind repowering takes place when a site reaches the end of its permitted planning period or design life. At a minimum, repowering will involve like-for-like replacement with a view to increasing efficiency and energy output. This process often involves an application to a planning authority, followed by the decommissioning and replacement of the current assets with newer models. Elements of balance of plant replaced could include foundations, array cables, grid connection, and access roads.

Developers were asked whether they anticipated cost differences between developing a fully repowered onshore wind farm and constructing a new onshore wind farm. From the stakeholder responses, there was no clear consensus that repowering would result in notable cost savings. Therefore, as a result, Arup cannot recommend any changes to the repowering report it previously published (Arup, 2022) which recommended no substantial savings. However, in this study, some respondents suggested that the main cost savings could occur in grid capital expenditure, assuming grid capacity remains unchanged, with anticipated savings estimated to be in the region of 10-20% of total Capex. Additionally, one respondent indicated potential savings of £80k/MW for repowered projects, while another noted that lease payments could increase by as much as 50%.

6. Solar

6.1 Introduction

As of 2024, the UK has approximately 16.9 GW of solar installed capacity (DESNZ, 2024). Solar power in Great Britain has seen significant growth, driven by technological advancements, efficiency improvements, and supportive government policies.

Note that Arup collected stakeholder responses in April 2024, prior to the publication of the AR6 results.

6.2 Data collection

Data for our large-scale solar PV (>5MWp) energy analysis was collected from renewable energy project developers, involving outreach to trade associations and technology manufacturers. In total, we received responses from nine developers, resulting in 18 project data points, of which 15 had CODs that would classify them as having "current" costs. In terms of installed capacity, these 18 data points represented a total of 1,856 MWp of solar projects at various stages of development, including ready to build, under construction, and planned. Notably, 15 projects were located in England and three in Scotland. This concentration of projects in England can be attributed to more favourable weather conditions for solar energy generation and greater availability of suitable land. All respondents noted that their projects used fixed-tilt structures, with a range of technologies including bifacial, mono-crystalline P-type bifacial, and mono half-cell. Some developers indicated that their projects were too early in the development process to confirm panel details.

Based on the data selection criteria outlined in Chapter 3, the data points were assessed to include only those that were robust, representative and current. For cost analysis, only data points identified as current costs, as defined in Subsection 3.3.5, were selected for the analysis. For solar projects, Arup considered current values to be those from projects with CODs ranging from 2025 to 2028. One large project with a COD in 2024 was excluded after analysing its construction period, which was atypically long, and as such its costs predated what was considered to be current.

To ensure the accuracy of the LCOE results, all findings were compared against internal and externally published benchmarks. Arup's internal benchmark comprised 30 projects located across the United Kingdom with CODs within the ranges considered current as outlined in Subsection 3.3.5. For external benchmarks, we primarily referenced the BloombergNEF and Lazard’s LCOE, cost, and technical assumptions for 2023, applying consistent FX and inflation factors to enable a fair comparison. Lastly, internal experts reviewed the final low, medium, and high values to ensure these were in accordance with their expectations.

For the medium value of cost or technical assumptions, either the mean or median of the dataset was used. The decision on which to use depended on the total number of data points available for the analysis. If the dataset contained fewer than ten data points, the mean was calculated as the central value. For larger datasets, the median was used, except in some cases where an expert believed another value was more closely aligned with their understanding of the industry. In these instances, this decision was noted in the relevant category.

Regarding high and low values, Arup calculated the 5th and 95th percentiles of cost based on the survey responses. Using percentiles was necessary to anonymise the cost data provided by the developers. However, for time periods and other technical assumptions, Arup chose not to apply a 5th or 95th percentile because these are less easily identifiable metrics than cost; instead, the minimum and maximum values were used. This comprehensive approach ensured the validity and reliability of the data, providing a solid foundation for the subsequent analysis.

6.3 Cost and technical assumptions breakdown

6.3.1 Predevelopment expenditure

As indicated in Chapter 3, predevelopment costs refer to the expenses incurred up to reaching FID, before the construction of the solar farm begins.

Through the stakeholder questionnaire, Arup requested total predevelopment costs, as well as the breakdown of i) pre-licensing costs, ii) technical and design costs, as well as iii) regulatory, licensing, and public inquiry costs, each as separate classifications. It was decided to use the total predevelopment cost for the subsequent analysis due to the larger number of data points in this category (18 data points) compared to the subcategories (four data points in the first, three in the second, and four in the third). Utilising the total predevelopment costs rather than considering subcategories ensured all relevant costs were included and a more robust assumption would ultimately be derived.

Following the application of the selection criteria, a dataset of 15 data points remained, resulting in a medium predevelopment cost (in 2023 real prices) of £24/kWp, and low and high costs of £12/kWp and £59/kWp, respectively.

It is important to note that predevelopment costs are expected to vary significantly depending on the site-specific conditions, planning hurdles, and requirement for appeals.

Table 30: Current predevelopment costs 2023-2024 (2023 real prices £/kWp)

Item	Total data points	Data points used	Low	Medium	High
Predevelopment cost	18	15	12	24	59

6.3.2 Predevelopment timings

After evaluating the provided data against our methodology detailed in Chapter 3, we selected seven data points to determine the total predevelopment period, which ranged from 1 to 4 years with a mean value of 3 years.

Our analysis sought to understand the relationship between the scale of solar farms and the length of their predevelopment phase. We observed that, for projects exceeding 50MWp, there was a positive correlation between predevelopment period and generating capacity. This observation is consistent with Arup's predictions, considering that solar farms with a capacity of 50 MWp or more are classified as Nationally Significant Infrastructure Projects (NSIPs). Such projects have to obtain a Development Consent Order (DCO) from the Planning Inspectorate (PINS) with final decision requiring approval from the Secretary of State for Energy Security and Net Zero, as opposed to a local planning authority (LPA) consent. This typically extends the predevelopment timeframe.

To incorporate the predevelopment costs in the LCOE calculation, we estimated annual phasing based on low, medium, and high values from the predevelopment periods as described by developers. There were limited responses relating to the phasing of the costs over the predevelopment period. However, the responses we did receive described the distribution for predevelopment period costs as being in a straight line, which aligns with previous approaches. Therefore, we used the low, medium, and high values for the time period of the chosen scenario with the costs evenly split. For the medium case, the mean was selected as the number of data points was fewer than 10, as described in Section 3.4.

The phasing of costs for each scenario is shown below:

- **Low Scenario**: 100% of costs incurred in one year.
- **Medium Scenario**: Costs spread evenly across the first two years, with the remaining costs allocated to the third year (36.8% in the first two years and 26.3% in the final third year).

- **High Scenario**: Costs spread evenly across four years (25% per year).

Table 31: Predevelopment periods (years)

Item	Total data points	Data points used	Low	Medium	High
Predevelopment period	7	7	1	3	4

6.3.3 Capital expenditure

6.3.3.1 Construction cost

Construction costs for a solar farm include the costs associated with the supply and installation of solar PV modules, supporting structures, cabling, inverters and electrical equipment. For solar projects, the capital costs were derived from the total Capex provided by stakeholders with a proportion removed which was defined as "Infrastructure" (including grid connection, substations, and other related infrastructure). Our findings indicate that construction costs constitute 82% of the total Capex, with the remaining 18% attributed to infrastructure costs. This proportion was derived from the responses received, reflecting the average distribution observed in the assessed projects.

The capital costs include contingency; however, specific values were not always provided by survey respondents.

Following the application of the selection criteria, seven data points remained, from which a medium capital cost was calculated as £522/kWp, with low and high costs at £ 423/kWp and £ 601/kWp, respectively.

Table 32: Current construction costs 2023-2024 (2023 real prices £/kWp)

Item	Total data points	Data points used	Low	Medium	High
Capital cost	9	7	423	522	601

6.3.3.2 Capital timings

After evaluating the provided data against the methodology described in Chapter 3, we selected seven data points to determine the total construction period, which ranged from 0.5 to 1.8 years (with a mean value of 1.3 years).

Similarly to the approach for predevelopment costs, incorporating construction costs into the LCOE calculation required us to project annual cost phasing. These projections were based on the low, medium and high construction durations reported by developers. The data on cost phasing throughout the construction stage was limited; however, the responses we received suggested a uniform distribution of expenses, similar to prior methodologies. Therefore, in the absence of detail for the annual phasing of capital costs, we adopted a linear approach for projecting costs over the low, medium, and high construction durations of the chosen scenario. For the medium case, the mean was selected as the number of data points was fewer than 10, as described in Section 3.4.

The phasing of costs for each scenario is shown below:

- **Low Scenario**: 100% of costs incurred in one year.
- **Medium Scenario**: 80% in the first year and 20% in the second year.
- **High Scenario**: 54.5% in the first year and 45.5% in the second year.

Table 33: Construction periods (years)

Item	Total data points	Data points used	Low	Medium	High
Construction period	7	7	1	1	2

6.3.3.3 Infrastructure cost

Infrastructure costs include the expenses related to grid connection, substations, and other associated infrastructure elements. Similarly to the method used for calculating construction costs, the infrastructure cost was determined as a proportion of the total Capex. This proportion was derived from the average of questionnaire responses regarding grid connection costs, substation and transformer costs, and other infrastructure costs. On average, these costs constituted 18% of the total Capex.

The medium infrastructure cost was determined to be £112/kWp, with low and high costs calculated at £91/kWp and £ 129/kWp, respectively. Additionally, the same annual phasing figures used for capital cost were applied to incorporate infrastructure costs into the LCOE calculation.

Table 34: Current infrastructure costs 2023-2024 (2023 real prices £/kWp)

Item	Total data points	Data points used	Low	Medium	High
Infrastructure costs	9	7	91	112	129

6.3.4 Operating expenditure

Operating costs refer to the ongoing expenses associated with the day-to-day operation of a solar farm. These costs exclude land expenses, property and business rates, tax costs, rental fees and community benefit payments, as noted in Subsection 3.6.1.3. To align with the DESNZ's LCOE methodology, Arup divided the cost forecast into three categories: O&M, insurance, and Connection and UoS Charges.

6.3.4.1 Operations and maintenance

O&M costs for a solar farm include all the maintenance, logistics, and monitoring expenses in order to maximise production, maintain asset integrity and safely operate the generating assets. These costs typically include activities such as PV module cleaning, labour, remote monitoring, spare parts, and on-site inspections.

As indicated in Chapter 3, a decision was made to present O&M costs as a combined figure rather than separating them between fixed and variable costs. This approach was taken due to variations in the data provided by stakeholders – most of whom only reported fixed O&M, whilst one reported both fixed and variable O&M.

After applying the selection criteria, four data points remained, from which a medium O&M cost (in 2023 real prices) was calculated as £6.1k/MWp/a, with low and high costs at £4.5k/MWp/a and £7.6k/MWp/a, respectively. These responses are well aligned with Arup's benchmarks.

Table 35: Current O&M costs 2023-2024 (2023 real prices k£/MWp/a)

Item	Total data points	Data points used	Low	Medium	High
O&M costs	6	4	4.5	6.1	7.6

6.3.4.2 Insurance

Insurance for a solar farm is designed to protect against the various risks associated with operation and maintenance.

The medium insurance cost (in 2023 real prices) was calculated as £1.6k/MWp/a, with low and high costs at £0.8k/MWp/a and £2.7k/MWp/a, respectively. One outlier was excluded from the insurance analysis as it was approximately 800 times lower than the next lowest value, and therefore considered unrepresentative.

Table 36: Current insurance costs 2023-2024 (2023 real prices k£/MWp/a)

Item	Total data points	Data points used	Low	Medium	High
Insurance costs	7	4	0.8	1.6	2.7

6.3.4.3 Connection and UoS charges

Network Use of System charges are the costs of connecting to and using the distribution and transmission network. In Arup's analysis, the UoS cost includes both local and wider TNUoS and DUoS charges, calculated on a £/MWp per annum basis.

Due to the limited and inconsistent responses for Connection and UoS charges specific to Solar PV (only three data points were provided, with no consistency across TNUoS wider, local, and DUoS), Arup adopted a proportional approach. This involved calculating a ratio between connection and UoS charges and fixed O&M costs, based on relationships found in the previous DESNZ 2023 study and Arup 2016. This ratio was then applied to fixed O&M to determine a range of indicative values.

After applying the selection criteria to fixed O&M, four data points remained, from which a medium Connection and UoS Charge was calculated as £1.6k/MWp/a, with low and high costs at £1.1k/MWp/a and £2.0k/MWp/a, respectively. It is noted that the approach taken by Arup results in UoS charges being a cost, whereas it is possible that the charges could be negative, depending on project location. Negative UoS charges occur in areas where adding more generation helps reduce network constraints. This may be the case for some solar PV projects however has not been factored into this analysis.

It is worth mentioning that connection and Use of System (UoS) charges can vary greatly, depending on site-specific conditions and location, leading to a wide range of costs.

Table 37: Current connection and UoS charges 2023-2024 (2023 real prices k£/MWp/a)

Item	Total data points	Data points used	Low	Medium	High
Connection and UoS charges	6[21]	4	1.1	1.6	2.0

6.4 Technical assumptions

Based on the data received from developers, Arup derived up-to-date key technical assumptions, crucial for determining the LCOE. The following provides a summary of the observations:

6.4.1 Gross power

Gross power for a solar farm refers to the total electrical power output that the solar farm is capable of producing under ideal conditions, without accounting for losses due to electrical conversion system, inefficiencies, or other factors. In recent years, the average installed capacity of photovoltaic developments has significantly increased.

[21] These data points are fixed O&M responses obtained from developers, which were later adjusted using the proportion calculated by Arup.

This study defined the medium-sized solar site as having a capacity of 52 MWp, with a range from 11 MWp to 225 MWp. Arup excluded one very large project of approximately 1 GWp from the Gross Power analysis, as it was considered an outlier; this project was over four times larger than the next largest project and approximately 20 times larger than the average.

Table 38: Gross power (MWp)

Item	Total data points	Data points used	Low	Medium	High
Gross Power	18	17	11	52	225

6.4.2 Load factor

Load factors for a solar farm can be presented as gross load factor and net load factor. The gross load factor for a solar farm refers to the estimated energy output that the solar farm is capable of producing under ideal conditions, without accounting for loss factors such as system availability, electrical conversion losses, panel soiling, inefficiencies, panel degradation, or other factors. Stakeholders provided both gross and net loss factors, which were assessed. However, since the net load factor accounts for all applicable losses, this should be used to calculate the net energy production as part of the LCOE analysis.

Arup calculated a net load factor of 12.2%, with high and low values of 14.5% and 11.5%, respectively. Note that this is before degradation is applied. This load factor is assumed to represent the first-year load factor, accounting for all relevant loss factors, including system availability (Balance of Plant and Grid), electrical system losses, and other secondary loss factors. For Solar PV, it is typical to apply annual degradation as a separate year-on-year loss factor. Respondents provided a range of annual degradation factors – 0.29% (low), 0.3% (medium), and 0.45% (high) – which were applied annually to the load factor to produce an "Efficiency Profile.". These loss factors are in line with Arup's experience.

It is important to note that the net load factor is highly site-specific, and these results reflect only the sample of projects we analysed.

Table 39: Net load factor (%)

Item	Total data points	Data points used	Low	Medium	High
Net Load Factor[22]	11	6	11.5%	12.2%	14.5%

6.4.3 Plant operating period

The operating lifetime of a photovoltaic plant refers to the period during which the plant is expected to be functional and generate electricity. Based on the responses received from stakeholders, Arup estimated the average operating lifetime of a photovoltaic site to be 37.9 years, with a minimum of 35.0 years and a maximum of 40.0 years. This is in line with the latest assumptions for asset life seen by Arup across the industry.

Table 40: Operating lifetime (years)

Item	Total data points	Data points used	Low	Medium	High
Operating lifetime	7	7	35	38	40

[22] This load factor is assumed to represent the first-year load factor. Annual degradation applied separately.

6.5 Summary of results

6.5.1 Costs and technical assumptions

We have summarised the main costs and technical assumptions for large scale solar PV (>5MW) projects in this study, including the low, medium, and high cases of each category in the table below.

Table 41: Summary of 2023-2024 current costs, technical assumptions, and LCOE results for Solar PV (>5MW) in this study

Category	Unit	Solar PV (>5MWp)		
		Low	Medium	High
Costs				
Pre Development	£/kWp	12	24	59
Capital Costs During Construction	£/kWp	423	522	601
Infrastructure Costs	£/kWp	91	112	129
Total Capex	£/kWp	526	659	788
Insurance	k£/MWp/a	0.8	1.6	2.7
Connection And UoS Charges	k£/MWp/a	1.1	1.6	2.0
O&M	k£/MWp/a	4.5	6.1	7.6
Total Opex	k£/MWp/a	6.5	9.3	12.3
Technical assumptions				
Net load factor	%	11.5%	12.2%	14.5%
Operating lifetime	years	35	38	40
Additional assumptions				
Hurdle Rate[7]	%	5.0%	5.0%	5.0%
Predevelopment timescale	years	1	3	4

6.5.2 LCOE results

Arup has utilised the DESNZ LCOE calculator, published online as Annex B to the Electricity generation costs 2023 report (DESNZ, 2023a) to produce low, medium, and high LCOE scenarios. These scenarios represent the central (medium) case as well as the effective minima (low case) and maxima (high case) by combining the relevant low, medium and high data inputs. As described in Section 3.7. LCOE is highly sensitive to the underlying assumptions on load factor, discount rates, capital and operating cost. Therefore, it is the standard approach to consider a range of scenarios rather than a single point, allowing the modelling to capture uncertainty.

The LCOE values presented are derived from low, medium, and high capital and operating cost estimates, as well as low, medium, and high technical assumption estimates. It is important to note that in most cases, the low values of costs and technical assumptions were used for the low LCOE scenario, with medium and high values used accordingly. However, for net power output and plant operating period, these were used inversely (e.g. the high net power output and high operating lifetime values were used to calculate the low LCOE value). This approach is based on the understanding that larger projects benefit from economies of scale and that a longer project lifetime will lead to greater total energy production.

The results are shown below in Table 42. These scenarios are designed to be indicative and to offer a range of LCOE estimates for comparison with current LCOE scenarios in industry literature. A comparison between this study's results, a blended average of the literature, and DESNZ current LCOE estimates is provided in Chapter 7.

Arup notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

Table 42: LCOE based on current costs 2023-2024 (2023 real prices £/MWh)

Item	Hurdle rate (%)	Low	Medium	High
LCOE	5.0	30.3	46.5	65.2

6.6 Future outlook

6.6.1 Bottom-up method

As explained in Section 3.9, for Solar PV, Arup has applied a bottom-up methodology to forecast the future direction of cost.

Capital costs were broken down into separate components. Arup's analysis then focused on how the underlying drivers may change in the future. Based on the stakeholder responses, the capital cost was divided into the main costs of project development, including panels/module, electrical balance of plant, inverter and steel/racking, civil works (Engineering, Procurement and Construction), and other costs for solar PV. The proportion each component represents is presented below in Table 45. The following is a summary of the approach applied:

- Based on the sub-component costs from published literature (BloombergNEF, 2024d), Arup estimated a learning rate for each sub-component, linking the costs to future rates of PV deployment. The capital costs and cumulative installed capacity (2024 to 2040) are combined onto a logarithmic scale (log-log). The slope of the estimated straight line represents the learning rate applied to the PV system components. It was assumed that panels, modules, electrical balance of plant, inverters, and steel/racking cost learning rates are linked to the roll-out of global PV deployment, as detailed in Section 3.9. Civil work costs and others cost learning rates are linked to PV deployment specifically in the UK.

- The proportion of capex relating to each of the subcomponents was derived from data provided via the stakeholder responses. The subcategories were adjusted to align the learning rate with categories observed in industry as shown in Table 43.

- The capital cost forecast up to 2050 was calculated using the derived learning rates, assuming a base year of 2023.

The years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close[4]), unless stated otherwise. These years do not necessarily correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years.[23]

Table 43: Proportions and learning rates for separate components in capital costs (solar PV)

Component breakdown	Capex proportion	Learning rate
Panels/Module	23%	31.3%
Electrical balance of plant, Inverter and Steel/racking	48%	7.2%
Civil works (Engineering, Procurement and Construction)	25%	16.3%
Others	4%	26.8%

Table 44: Capital cost forecast (solar PV) by year of securing costs

Learning rate	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Forecast capital cost	100.0%	91.9%	79.2%	72.4%	68.6%	63.4%

[23] For example, a solar PV project securing costs in 2025 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close), should apply 91.9% of the "current costs" (as defined above) for capital costs and 96.3% of the Fixed O&M costs. This project may not become operational for a number of years after securing the costs, following time taken to reach financial close and then for the site to be constructed. Another example could be a project securing costs in 2030 (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close) where a 79.2% Capital Cost factor and 89.8% Fixed O&M cost factor should be applied through multiplication, to the "current costs" (as defined above) resulting in a lower capital and operating cost.

6.6.2 Stakeholder responses

For Solar PV, Arup assessed the responses provided by stakeholders and compared it with the bottom-up deployment linked approach. Stakeholders indicated that, between 2030 and 2035, capital cost is forecast to reduce by between 10% and 30%. Post-2035 capital costs are also expected to reduce by a further 10% to 20% 2050.

Arup's outlook, based on bottom-up learning curve analysis, aligns closely with the conclusions of the stakeholder responses, albeit at the lower end of the short-term view up to 2030-35.

Based on a review of industry literature, Arup has observed learning curves (BloombergNEF, 2024d) which generally align with the bottom-up deployment-linked approach.

6.6.3 Fixed O&M

Limited responses were received from stakeholders regarding future adjustments to Solar PV O&M costs.

Arup has assessed the latest industry view (BloombergNEF, 2024a) to derive future fixed O&M cost adjustment curves for solar PV.

The years presented for comparison in this study indicate the years in which the costs were established (i.e. the time at which quotes are secured, and costs finalised, prior to a project reaching financial close), unless stated otherwise. These years do not necessarily correspond to the years in which the assets will become operational but rather reflect the market costs as projected for those specific years.

Table 45: Fixed O&M cost forecast (solar PV) by year of securing costs

Learning rate	Year in which the costs are secured prior to financial close					
	2023	2025	2030	2035	2040	2050
Forecast fixed O&M cost	100.0%	96.3%	89.8%	85.7%	83.0%	78.8%

Fixed O&M is expected to decrease at an annual average rate of 1.8% until 2026. Over the long term, up to 2050, the rate of cost reduction is forecast to fall, averaging 0.8% per year.

6.7 Comparison of previous and current costs, technical assumptions and LCOE results

In this section, Arup compared the costs and technical assumptions presented in DESNZ's Electricity Generation Costs 2023 report with the outcomes of our latest study.

6.7.1 Approach

The comparisons are based on medium cost values. Furthermore, Arup's calculations were based on £2023 real values, whereas the Electricity Generation Costs for 2023 were reported in £2021 real values. To align these figures, we adjusted them to 2023 values using the GDP deflator figures from December 2023 published by the Office for National Statistics.

The LCOE calculation incorporates Arup's current hurdle rate assumptions and is based on the latest current costs and technical assumptions. The hurdle rate, calculated by Arup and derived from the cost of debt and equity from industry literature for non-tracking PV systems, is 5.0%.

The table below provides a comparison between the new and old estimates for predevelopment, capital, and operating costs, as well as the technical assumptions necessary for the LCOE calculation. It is worth mentioning that for the comparison, Arup selected the scenario from DESNZ's Electricity Generation Costs 2023 report that most closely matched our study parameters. For solar, the projects analysed had CODs ranging from 2025 to 2028. Given that DESNZ provided scenarios for projects with commissioning years of 2025, 2030, 2035, and 2040, the 2025 scenario was deemed the most appropriate and relevant for this comparative analysis.

6.7.2 Results

Overall, LCOE has increased by 1% which is in line with the expectations based on Arup's literature review. The changes in LCOE are driven by the following key factors:

- **Increased capex:** total capex has increased by 13%, despite reductions in the predevelopment costs. This is in line with expectations.
- **Increased net load factor:** the updated load factor (12.2%) is in line with Arup's expectations and is based on the net load factors provided by stakeholders, this represents a slight improvement in load factor since the previous study (11%) which is expected. This difference has resulted in a reduction in LCOE.
- **Plant operating period:** an increase in operational life from 35 to 37.9 years has reduced the LCOE. This is in line with the latest typical assumptions for asset life made across industry.

The increases in capex have largely been cancelled out by improved load factors and operating period.

As stated above, Arup has compared this study's medium results with those from DESNZ's Electricity Generation Costs 2023 medium results. This can be found in the table below.

Table 46: Large scale solar PV >5 MWp – Arup's key study results versus DESNZ's assumptions (DESNZ, 2023a)

Assumption	Unit	Arup (medium)	DESNZ projection for 2025	% Change
Technical				
Hurdle rate	%	5.0%	5.0%	
Net load factor	%	12.2%	11.0%	
Gross power output	MWp	52	20	
Plant operating period	Years	38	35	
Predevelopment period	Years	3	1	
Construction period	Years	1	1	
Cost (2023 real prices)				
Predevelopment expenditure	£/kWp	24	56	
Capital costs during construction	£/kWp	522	450	
Infrastructure costs	£/kWp	112	79	
Total Capex (incl. predevelopment expenditure)	£/kWp	659	585	13%
Insurance	k£/MWp/a	1.6	2.3	
Connection and UoS charges	k£/MWp/a	1.6	1.5	
O&M	k£/MWp/a	6.1	6.8	
Total Opex	k£/MWp/a	9.3	10.5	-12%
Total LCOE	**£/MWh**	**46.5**	**46.1**	**1%**

It should be noted that for the latest AR6 CfD auction round certain evidence-based adjustments were made to the assumptions used by DESNZ in its energy modelling, such as increases to capital costs (DESNZ, 2023b). These adjustments are not reflected in their latest Electricity Generation Costs report and are therefore not captured in this comparison.

6.8 Other key findings

Arup gathered additional information that falls outside the scope of the LCOE calculations, on behalf of DESNZ. It is important to note that the same methodology employed above was used to calculate the low, medium, and high values of the findings in this section. A summary of these findings is provided in the following subsections.

6.8.1 Land costs

Land costs encompass the financial expenditure required for acquiring or leasing land to install solar panels. These costs include either the purchase price of the land or the rental fees paid to the landowner for the use of their property.

Respondents generally agreed that the total land or rental costs average around £1.0k per acre per year, with estimates ranging from £0.8k to £1.0k per acre annually. Developers did not specify whether they were renting or purchasing the land; however, in general terms, most developers in Great Britain rent the land instead of purchasing it. Some responses also indicated that 5-6% of revenues are typically allocated to land rental costs.

It is important to highlight that most of these data points are related to sites in England, with only a few from Scotland.

6.8.2 Property and business rates

Data provided by four respondents indicated that property and business rates range from £1.0 to £2.5k/MW/a, with an average cost of £1.8k/MW/a.

6.8.3 Tax

Developers were also asked to provide any additional taxes they were required to pay. Respondents highlighted that they incurred a 25% corporate tax as part of their overall tax costs.

6.8.4 Decommissioning costs

Decommissioning costs involve the expenses related to safely dismantling and removing the infrastructure of a solar farm at the end of its operational life. Arup received five responses regarding these costs, and after evaluating the information received based on the criteria outlined in Chapter 3, four data points were used to calculate an average decommissioning cost of £15k/MW, with a low cost of £4k/MW and a high cost of £25k/MW.

6.8.5 Short-run marginal cost

Short Run Marginal Cost is defined as the change of total cost when producing one more unit of energy (e.g. 1 MWh). In the short-term, the capacity of the energy system is fixed, the short-term marginal cost only includes the operating costs of the existing infrastructure, without any additional investment.

Developers were asked how these costs influence their dispatch behaviour. However, no substantial responses were received on this topic, with only one respondent indicating that SRMC has very little influence on their dispatch decisions.

As per onshore wind, Arup's view is that SRMCs do not impact the dispatch behaviour of solar PV operators; however, it is influenced by curtailment or bids into the balancing or capacity market when those bids exceed revenue from CfD exports.

6.8.6 Self-curtailment

Self-curtailment is the intentional reduction of electricity generation by the solar farm itself. Developers were asked to provide the costs associated with turning down or self-curtailment when the asset could otherwise be producing electricity.

No responses on this matter were received. However, respondents noted that the route to market is secured by a Power Purchase Agreement (PPA), which means there is no ability to turn down generation.

Arup's view is that the cost of self-curtailment is a function of the offtake arrangements of projects and the projects' participation in the balancing market. Given the various approaches to securing a CfD, PPA, or alternative route to market, the approach to self-curtailment will vary from project to project.

6.8.7 Availability profile

Availability in this context refers to the maximum potential time that a generation plant can produce electricity annually (energy based – i.e. the proportion of possible energy production). One response indicating 95% availability was excluded from the analysis, as it was considered an outlier.

It is important to note that whilst an availability profile is being presented, it was not used to calculate LCOEs, as the Net Load Factor was being utilised, which already accounts for the availability profile.

The average availability for a photovoltaic project was calculated to be 98.9%, with minimum and maximum availabilities of 98.2% and 99.0%, respectively, which is in line with Arup expectations.

6.8.8 Community benefit payments

Community benefit packages are voluntary contributions made by solar farm developers to support local communities. Developers were asked if they provide such packages. Responses from five developers indicated contributions ranging from £0.2k to £1.0k/MWp/a, with an average contribution of £0.6k/MWp/a.

6.8.9 Co-located storage

Limited responses were received regarding cost variations associated with co-locating solar PV and storage. It was indicated by two developers that potential savings would likely be related to grid infrastructure and could range between 3-8% of Capex. However, one developer noted that there are unlikely to be any savings in O&M costs and Devex.

7. Comparison of LCOE estimates

7.1 Approach

This section presents a comparison of the LCOE for onshore wind and solar PV based on Arup's 2023-2024 cost and technical assumptions analysis to a blended average of LCOEs from global and UK literature and estimates from the Electricity Generation Costs 2023 report from DESNZ (DESNZ, 2023a). The comparison reveals variations across the different sources, highlighting recent trends and regional impacts on LCOE.

The available literature includes a range of sources (see Section 4.1), published between 2022 and June 2024, covering both global and regional views. To ensure a fair comparison, only sources from 2024 were used to calculate the blended average shown in the charts. It is worth noting, however, that whilst these sources were published in 2024, the CODs or FID dates of the underlying projects may differ from those used by Arup in this project.[24]

Arup has utilised the DESNZ LCOE calculator, published online as Annex B to the Electricity generation costs 2023 report (DESNZ, 2023a) to produce low, medium, and high LCOE scenarios. These scenarios represent the central (medium) case as well as the effective minima (low case) and maxima (high case) by combining the relevant low, medium and high data inputs. The hurdle rate is consistent across cases, which provides clarity on how changes in cost and technical assumptions affect the LCOE.

As described in Section 3.7, LCOE is highly sensitive to the underlying load factor, discount rate, and capital and operating cost assumptions. Therefore, in order to capture uncertainty, the standard approach is to consider a range of scenarios rather than a single point. The ranges presented in this report illustrate the potential variability in generation costs, demonstrating why the central case should not be interpreted as a definitive value. Arup suggests that, when considering generation costs, sensitivities should be assessed within this range, as the central case alone does not represent the full breadth of possible outcomes.[25]

7.2 Results

7.2.1 Onshore Wind

The chart below (Figure 5) presents a comparison of LCOE ranges from Arup's 2023-2024 cost and technical assumption analysis, the blended literature average, and DESNZ's 2023 estimates (DESNZ, 2023a).

For onshore wind, Arup's medium LCOE is 45.8 £/MWh. This is well aligned with the blended literature, which is less than 1% higher at 46.0 £/MWh. The Arup LCOE is 7% higher than DESNZ's estimate of 42.8 £/MWh.

The increase compared to DESNZ's estimate is in line with expectations based on Arup's literature review. As described in 5.7.2, the changes in LCOE are driven by the following key factors:

- **Increased hurdle rate:** LCOE is increased by the rise in the cost of capital, represented by the increase in hurdle rate.
- **Increased Capex:** total Capex has increased by 8% in real terms. As outlined in Subsection 3.6.1, Capex comprises three components: predevelopment, capital cost during construction, and infrastructure. While costs in the predevelopment and construction sub-categories have decreased, this is outweighed by the substantial increase in infrastructure costs, leading to a rise in Capex overall. This overall increase is in line with expectations based on trends visible in the market. The apportionment of costs between sub-categories has also changed, not necessarily in line with expectations. This could be due to respondents' interpretation of the survey questions, in particular

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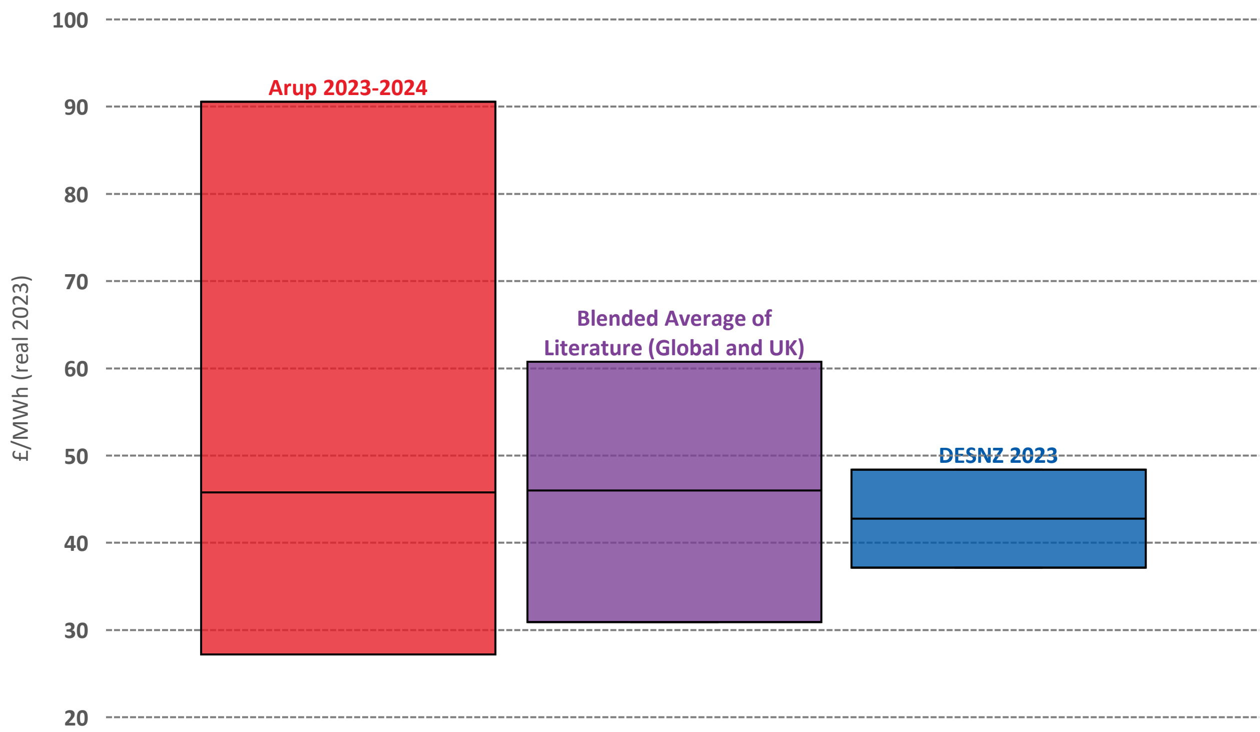
[24] Note that literature sources did not consistently specify the years their LCOE results correspond to.
[25] Arup also notes these results may not reflect the final LCOE that DESNZ adopts; the results are a key component of the findings but are not the sole factor likely to be considered.

how they have assigned costs to each sub-category. Considering this, we recommend focussing on the changes in total Capex.

- **Reduced net load factor:** the updated net load factor (38%) is in line with Arup's expectations and is based on the net load factors provided by stakeholders. The DESNZ's 2023 study followed a different approach, calculating the gross load factor using technical performance and weather data, then applying availability to derive a net load factor. The lower net load factor reported by stakeholders has put upward pressure on the LCOE.
- **Plant operating period:** an increase in the operational asset life from 25 to 35 years has reduced the LCOE. This is in line with current assumptions for asset life across industry.
- **Connection and Use of System Charges:** Arup's latest analysis has resulted in an increase in UoS charges. This factor is particularly site-specific and, in this analysis, has led to an increased LCOE.

Figure 5: Onshore wind LCOE comparison across Arup 2023–2024, literature review, and DESNZ 2023 report



- The maximum line represents the High LCOE, the inner line represents the Medium LCOE, and the minimum line represents the Low LCOE. Refer to Section 3.7 for details on the constituents of these LCOEs.

7.2.2 Solar PV

The chart below (Figure 6) presents LCOE ranges, derived from Arup's 2023-2024 cost and technical assumption analysis, against alongside the blended literature average and DESNZ 2023 estimates (DESNZ, 2023a).

For solar PV, Arup's medium LCOE is 46.5 £/MWh, which is 4% lower than the literature average of 48.4 £/MWh and less than 1% higher than DESNZ's estimate of 46.1 £/MWh. This is in line with the expectations based on Arup's literature review.

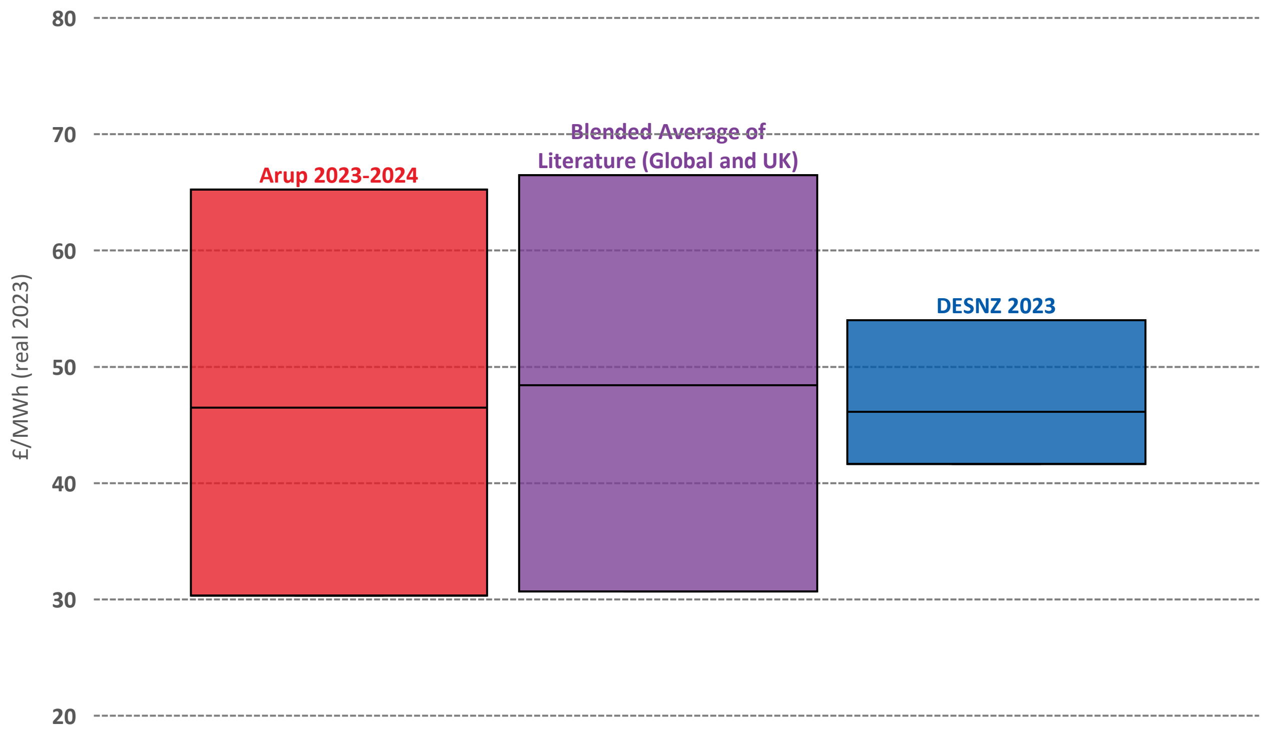
The changes in LCOE are driven by the following key factors:

- **Increased Capex:** total Capex has increased by 13%, despite reductions in the predevelopment costs. This is in line with expectations.

- **Increased net load factor:** the updated load factor (12.2%) is in line with Arup's expectations and is based on the net load factors provided by stakeholders, this represents a slight improvement in load factor since the previous study (11.0%) which is expected. This difference has resulted in a reduction in LCOE.
- **Plant operating period:** an increase in operational life from 35 to 38 years has reduced the LCOE. This is in line with the latest typical assumptions for asset life made across industry.

The increases in Capex have largely been cancelled out by improved load factors and operating period.

Figure 6: Solar LCOE comparison across Arup 2023–2024, literature review, and DESNZ 2023 report



- The maximum line represents the High LCOE, the inner line represents the Medium LCOE, and the minimum line represents the Low LCOE. Refer to Section 3.7 for details on the constituents of these LCOEs.

8. Recommendations to future-proof

To future-proof the LCOE work between procurement cycles and developer surveys, Arup recommends that DESNZ implements an annual benchmarking process, ideally managed by an independent third-party expert. This process should involve reviewing key publications from organisations such as the International Energy Agency, International Renewable Energy Agency, BloombergNEF, and Lazard, focusing on Capex, Opex, load factors, and LCOE. The third-party should also use its internal expertise and knowledge of the latest industry trends to compare to the external industry benchmarks.

The third-party expert should have the relevant know-how to assess the evolution of costs since the previous benchmarking, the consistency of assessments carried out by external organisations, and how the 2024 DESNZ LCOE figures compare to the latest data. This annual desk-based research would provide a partial update on costs without the requirement to carry out regular stakeholder engagement. In Arup's view, there is still a requirement for periodic engagement with stakeholders; however, the frequency could be reduced if there is a robust approach to benchmarking, carried out by experts with access to the relevant data.

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Appendices

A.1 Questionnaire for developers

The following shows copies of the data collection survey sent to developers.

Section A – Project Specific Information

	General project questions	Response
Priority	**Renewable technology,** *please select technology*	*Please select*
	Please specify whether the data provided below pertains to a newly established site or a site that has undergone full repowering*	*Please select*
	Name or title of project	*Insert name*
	Location of project *(e.g. England, Scotland, Wales)*, *please select*	*Please select*
Priority	**Stage of project** *(Earlier than pre-development, pre-development, financial close, ready to build/under construction, operation start, operational)*	*Please select*
Priority	**Operation start year** *(Expected or actual)*	
Priority	**Specify the size for which specific project costs are provided for, in MW(e) net (please provide net electrical capacity.)**	
	How is the land/seabed structured? *(E.g., lease, freehold, rented)*	
	What procurement / contracting strategy is in place? *(E.g., full engineering, procurement and construction contract, EPC wrap or individual sub-contracts)*	
	What is the approximate distance in km to the grid? Is the project connected to the electricity distribution or transmission grid?	
	Is the data provided below commercially confidential? *(Please indicate which aspects of the data are confidential and why.)* ***Important Note: All data will be held securely by Arup, anonymised, and treated as confidential.***	

	Cost Items PLANT ASSUMPTIONS	Unit	Response	Comment
Priority	**Plant capacity MW(e) gross** *(Nameplate capacity of generating assets)*	[MWe]		
	Plant capacity MW(e) net *(Gross capacity minus all electrical system losses and parasitic loads)*	[MWe]		
	Grid Connection capacity *(What is the maximum export capacity at the grid entry point?)*	[MW]		
	CURRENCY ASSUMPTIONS	**Unit**	**Response**	**Comment**
	Currency	[£,$,€]	*Please select*	

	PRE-DEVELOPMENT COST *(Please note: this should exclude land costs, property and business rates, tax costs, rental and community benefit payments. These are requested separately in Additional Data section below.)*	Unit	Response	Comment
	For each cost entry, could you please specify the year the costs relate to? *Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.*	[Yr]		
	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		
Priority	**What is the total Development expenditure (devex)** *e.g. costs incurred up to the point of reaching Final Investment Decision (FID)*			
	Pre-licensing cost *(E.g., development costs including planning, submission fees, survey costs etc.)*	[£]		
	Technical development cost *(Including design)*	[£]		
	Planning cost *(Including regulatory costs, licensing, public enquiry, 'local community engagement' costs)*	[£]		
	Timescale for pre-development *(total pre-development period including pre-licensing, licensing, public enquiry)*	[Yrs]		
	Is a contingency included within the above pre-development costs? If so what % of the above cost is contingency? E.g., 10% of £1m (£100k contingency, £900k pre-development cost) / If no contingency is included what would the typical % included on top of pre-development cost be. *(E.g., for potential cost overrun and development uncertainty)*	[%]		
	Please provide the percentage distribution of costs over the pre-development period by year *(E.g., 50% of the cost upfront and the rest straight line, straight line for the full pre-development period or straight line with 50% of the cost back-ended)*	[%]		
	CONSTRUCTION COST *(Please note: this should exclude land costs, property and business rates, tax costs, rental and community benefit payments. These are requested separately in Additional Data section below.)*	**Unit**	**Response**	**Comment**
	For each cost entry, could you please specify the year to which the costs relate? Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.	[Yr]		
	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		

Priority	**Total capital (overnight) cost** *The cost item covers the projected design, procurement and construction costs, such as EPC costs if applicable. It should include the full capital cost EXCLUDING interest costs, land costs, property and business rates, tax costs, rental and community benefit payments.* *Please include the below costs in this total and list them separately where available. If not available separately, please state if included as part of the total.*	[£]		
	Owner's costs *[please provide total cost]* *(These include procurement cost, project management - owner's engineer, etc.)*	[£]		
	Grid connection costs *(E.g., exclude pre-connection securities, but include any upfront connection payments required)*	[£]		
	Substation and transformer costs *Please separate from EPC, if data is available.*	[£]		
	Other infrastructure costs *[please provide total cost if applicable to the project]* *(If applicable, e.g., water, roads, sites works etc.)*	[£]		
	Is a contingency included within the above construction costs? If so, what percentage of the above cost is contingency? E.g. 10% of £10m (£1m contingency, £9m capex). If no contingency is included, what would be the typical percentage included on top of capex cost? *(E.g., for potential cost overrun and development uncertainty)*	[%]		
	Construction time period	[Yrs]		
	Distribution of costs over the construction period *(E.g., 50% of the costs upfront and rest straight line, straight line for full construction period or straight line with 50% of the costs back-ended)*	[%]		
	OPERATIONAL COST *(Please provide the following operating cost data on a unit cost basis – i.e., per MW or MWh as appropriate. If different from the unit in 'column C', please indicate the unit your cost figures are reported in.*	**Unit**	**Response**	**Comment**
	For each cost entry, could you please specify the year the costs relate to? *Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.*	[Yr]		
	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		
Priority	**What is the total operating expenditure?** *(Includes all operations and maintenance costs, as well as all commercial costs such as asset management, insurance, etc., and excludes connection and UoS charges as these will be requested later on.)*	[£/MW/a]		
	Fixed O&M cost *(Includes operating labour costs, planned and unplanned maintenance, lifecycle capital renewable cost.)*	[£/MW/a]		

	Variable O&M cost (please specify the components being considered)	[£/MWh]		
	Insurance cost	[£/MW/a]		
	Do you pay a community benefit package and if so how much?	[£/MW/a]		
	How does short-run marginal costs (SRMC) influence your dispatch behaviour? Please quantify total SRMC and individual components.	[Text]		
	What costs are associated with turning down / self curtailing when the asset could otherwise be generating?	[Text, £/MW]		
	Connection and UoS charge costs *(E.g., TNUoS, DUoS and OFTO)*	**Unit**	**Response**	**Comment**
	TNUoS (local) cost *(e.g. payment for utilising the local Transmission Network, including local substation charges and local circuit charges.)*	[£/MW/a]		
	TNUoS (wider) cost *(e.g. payment for utilising the wider Transmission Network, including locational and residual charges.)*	[£/MW/a]		
	DUoS cost *(e.g. charge for operating and maintaining local distribution network)*	[£/MW/a]		
	DECOMMISSIONING COST *(Please provide the following decommissioning cost data on a unit cost basis – i.e., per MW or MWh as appropriate. If different from unit in 'column C', please indicate the unit your cost figures are reported in.)*	**Unit**	**Response**	**Comment**
	For each cost entry, could you specify the year the costs relate to? *Our preference is to receive cost data that is as current as possible and based on firm offers, contracted prices or incurred amounts. If the cost base year is not 2023, please provide the base year and describe the indexation mechanism assumed.*	[Yr]		
	What is the source of your cost data? *(e.g., costs incurred, contracted, firm offer, estimation)*	[Text]		
Priority	**What are the total assumed decommissioning costs?**	[£]		
	What are the disposal and recyling costs net of any valuable scrap earnings?	[£]		
	TECHNICAL ASSUMPTIONS	**Unit**	**Response**	**Comment**
	Gross annual expected load factor *(Defined as average operating hours at full load equivalent divided by hours per year.)*	[%]		
Priority	**Average annual expected net load factor** *(Defined as average operating hours at full load equivalent divided by hours per year, net of all losses, e.g., wake losses, availability, electrical system losses, performance, environmental)*	[%]		
	Plant availability during full annual operation % *(Availability is defined as the total proportion of time that a plant is able to produce electricity over a full year.)*	[%]		
	Please describe how you expect plant availability to change over the plants lifetime.	[Text]		
	Average annual degradation in plant performance (if applicable) %	[%]		

Plant operational life (technical life) i.e. expected maximum operational life	[Yrs]		
What is the wake loss as a percentage of annual production (applicable to onshorewind only)?	[%]		
To what extent have you been able to reduce wake loss? And are there any planned technological upgrades or operational strategy adjustments to further reduce wake effects in the future?	[Text]		
What turbine model are you using?	[Text]		
What turbine hub height are you planning to use?	[M]		
ADDITIONAL DATA **Please provide the following costs, if available.**	**Unit**	**Response**	**Comment**
Land / rental	[£]		
Property and business rates	[£]		
Tax	[£]		

Section A - Technology Specific Information

ONSHORE WIND	Units	Response	Comment
What is the average turbine size?	[MW]		
Do you think turbine size in terms of MW rating and physical scale will continue to increase or level off? If level off, what do you consider to be the maximum turbine scale to be reached and by when? *(MW, rotor diameter)*	[MW]		
Are there any current or near term constraints in the supply chain? *(E.g., supply of turbines, transformers, availability of trucks, etc)*	[Text]		
What proportion of Total Capital Expenditure, as presented in cell B38 on the Section A tab, is related to the following:	[%]		
Turbine supply			
Turbine transportation & installation			
Foundation construction			
Electrical BoP (inter-turbine cables, switch gear, protection equipment, transformers, auxiliary systems)			
Civil works (ground works, hardstanding areas, drainage, access roads, substation building, compound areas)			
What, if any, differences in costs would there be between developing a full repowered onshore wind farm compared to a new build onshore wind farm? What elements of project costs might differ and what would be the scale of these costs?* *(E.g., what proportion of the total cost per MW does it cost to repower onshore wind project compared to a new project?)*	[Text]		
SOLAR PV	**Units**	**Response**	**Comment**
What technology is being used in the project? ***(E.g., panel manufacturer, cell material (Mono/Poly-crystalline, Thin-film, etc.), bifacial)***	[Text]		
Is the solar installation using either a tracker or fixed structure?	[Text]		
How do costs vary with advances such as optimised site layouts, improvements in panel efficiency and active output controls?	[Text]		
What country is the solar technology from? ***(E.g., China, Germany)***	[Text]		
Are there any current or near term constraints in the supply chain? ***(E.g., supply of panels, invertors , transformers, etc.)***	[Text]		
What is the average annual expected level of degradation?	[%]		

What proportion of Total Capital Expenditure, as presented in cell B38 on the Section A tab, is related to the following:	[%]		
PV module			
Inverter			
Electrical balance of plant (cables, switch gear, protection equipment, transformers, auxiliary systems)			
Steel Mounting / racking systems			
Civil works (ground works, drainage, access roads and public rights of way, screening, substation building, compound areas)			
How do costs vary with co-located storage? (E.g., generation assets only, including cost synergies with associated infrastructure)	[Text]		

Section B – Future Outlook

Information about your company	Units	Response
Are you a developer, investor or operator?	[Text]	
What is the technology type?	[Text]	*Please select*
Amount of technology/installed capacity deployed by you globally to date:	[MW]	
Amount of technology/installed capacity deployed by you in Great Britain to date:	[MW]	
Amount of technology/installed capacity currently in development by you in GB. What is in your immediate pipeline?	[MW]	
Amount of technology/installed capacity expected to be developed by you in GB. How much new installed capacity do you expect to deploy between now and 2030, and from 2030 onwards?	[MW]	

General questions on your portfolio of renewable generation projects	Units	Response
What do you consider the key drivers to be behind:		
Pre-development costs *(e.g., planning hurdles, licensing, technology, environmental, etc.)*	[Text]	
Construction costs *(e.g., steel, exchange rates, energy costs, labour costs, transportation costs, others)*	[Text]	
Operational costs *(e.g., exchange rates, fuel costs, labour costs, others)*	[Text]	
What percentage change in real terms have you experienced between 2021 to date? How has each category been affected by recent macro-economic factors such as the COVID pandemic, war, energy prices, inflation etc.? (E.g., please provide an overall % estimate for each category and your assumptions behind this. For instance, 'In our project cost modelling, we have seen construction costs increase by 5%'.)		
Pre-development costs	[%, text]	
Construction costs	[%, text]	
Operational costs	[%, text]	
How long do you expect it to take for changes (increases and decreases) in commodity prices to feed through to costs faced by developers?	[Text]	
What are your expectations for the likely percentage change in cost <u>in real terms</u> between 2025 and 2035? *(E.g., please provide an overall % estimate for each category and your assumptions behind this. For instance, 'In our discounted cashflow modelling, we assume fuel costs will increase by 5%' .)*		
Pre-development costs *(e.g., planning hurdles, licensing, technology, environmental, etc.)*	[%, text]	

Construction costs *(e.g., steel, exchange rates, energy costs, labour costs, transportation costs, others)*	[%, text]	
Operational costs *(e.g. exchange rates, fuel costs, labour costs, others)*	[%, text]	
What are your qualitative views on how costs will change between 2035 and 2050? *(E.g., please provide us with your views on what factors will influence longterm costs.)*		
Pre-development costs *(e.g., planning hurdles, licensing, technology, environmental, etc.)*	[Text]	
Construction costs *(e.g., steel, exchange rates, energy costs, labour costs, transportation costs, others)*	[Text]	
Operational costs *(e.g., exchange rates, fuel costs, labour costs, others)*	[Text]	

A.2 Questionnaire for suppliers

<table>
<tr><th>#</th><th>Questions</th><th>Your response</th></tr>
<tr><td>1</td><td>Please describe the technical specification of the [component(s)] that you supply.

Please provide units where appropriate, e.g., MWe, rotor diameter, etc</td><td><table><tr><td>Year:</td><td>Unit:</td></tr></table></td></tr>
<tr><td>2</td><td>Please provide us with any up-to-date costs based on firm project information. Please specify the currency and units,

e.g., £/MW, etc.</td><td><table><tr><td>Year:</td><td>Unit:</td></tr></table></td></tr>
<tr><td>3</td><td>What is the % breakdown of the main materials?</td><td><table><tr><th>Component Name</th><th>% breakdown</th></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr></table></td></tr>
<tr><td>3</td><td>What costs can you provide for the materials or sub-components, prioritising the most costly?</td><td><table><tr><th>Component Name</th><th>Cost % breakdown</th></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr><tr><td></td><td></td></tr></table></td></tr>
<tr><td>4</td><td>What can you tell us about recent changes to costs in the past 3 years? Please consider the prompts below before answering;
What change have you experienced (in percentage terms)?
What do you believe are the drivers for this change? (examples COVID pandemic, war, energy prices, inflation….)
How have you managed these changes? e.g. cost increases, absorption, combination, etc.
e.g., steel costs, exchange rates, energy costs, labour costs, transportation costs, other…</td><td>Response:
<table><tr><td>Year:</td><td>Unit:</td></tr></table></td></tr>
</table>

5	What factors do you anticipate will impact future costs? Please specific the timeframe your answers refer to (e.g., 2024 – 2025, 2024 – 2030, 2030 – 2035, 2035 – 2050) *e.g., steel costs, exchange rates, energy costs, labour costs, transportation costs, others*	Response: Timeframe: | Unit:
6	What do you believe are the cause(s) or driving forces behind these factors affecting future costs?	Year: | Unit:
7	Is there anything else you would like to share with Arup and DESNZ concerning costs?	Year: | Unit: