Policy brief

Headwinds: how seabed leasing risks adding costs to clean energy

Summary

- This policy brief examines how changes to seabed leasing by The Crown Estate (TCE) affect offshore wind financing costs, and may impact project delivery, bills and the UK energy transition.
- Currently, developers must secure a seabed lease from TCE, pay an annual option fee and bid for a Contract for Difference (CfD) guaranteeing a 'strike price' for electricity generated.
- For Leasing Round 4 (LR4, 2021), TCE moved from fixed fees to an uncapped auction, significantly increasing fees.
- Fees are paid years before any revenue, so are funded by equity not debt. Equity costs more, and paying it early compounds costs.
- Our modelling suggests a project able to bid for a CfD at ~£95–97/MWh with no option fees would need a strike price 30–59% higher to earn the same return with LR4-style fees.
- If such prices were struck for all new projects they would equate to £36–72bn in consumer costs during 2035–2054, equivalent to £326–659 per household.
- LR4-style fees imply a seabed cost of at least £31/MWh, six to nine times what onshore wind developers typically pay landowners.
- In 2025/26, TCE received £875 million in LR4 option fees, and distributed £487 million to HM Treasury.
- Government has set the maximum bid for fixed-bottom offshore wind in the next CfD round (AR8) at £113/MWh. Projects with LR4-style fees may not be viable with this cap. Developers may delay or withdraw (as with Morgan, a 1.5 GW project). All outcomes slow deployment and prolong reliance on gas generation.
- Government should reconsider seabed leasing before LR6 in 2027. Reverting to fixed or capped fees needs no new legislation, just action by the Chancellor. Any conditional fees should be capped and paired with strict 'use it or lose it' terms. Faster planning and consenting would also reduce compounding costs.

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Contents

Disclaimer

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The relevance of offshore wind

The growth of offshore wind is one of the UK's most significant energy policy success stories. Between 2010 and 2022, the levelised cost of offshore wind electricity generation fell by around 71%.[1] However, costs have since risen, with recent CfD clearing prices continuing to rise.[2] The UK now has approximately 16.5 GW of operational offshore wind capacity.[3] Wind (offshore and onshore) provided just under 30% of UK electricity generation in 2025.[4]

As the UK decarbonises electricity generation and electrifies its heat, transport and other sectors, offshore wind is likely to form the backbone of its electricity system. Government's Clean Power 2030 Action Plan targets between 43 and 50 GW of offshore wind capacity by 2030,[5] while the Climate Change Committee's Balanced Net Zero Pathway requires 125 GW of offshore wind capacity by 2050, with wind contributing over half of total UK power generation in that pathway.[6]

The advantages of offshore wind are clearest during global energy market volatility.[7] With gas currently accounting for roughly a third of electricity generation,[8] the UK is highly exposed to global gas markets. Gas sets the marginal cost of electricity, and hence the price in the domestic wholesale electricity market, with significant impacts on costs faced by households and businesses.[9] The global nature of fossil fuel markets means that even the UK's domestically produced oil and gas are subject to international pricing, and price shocks are passed through to UK consumers.[10]

Offshore wind strengthens the UK's energy security by providing a domestic alternative insulated from the geopolitical and price risks of fossil fuels.[11] As offshore wind generation grows and displaces gas as the marginal technology for a growing share of hours, it should reduce the influence of gas prices on wholesale electricity prices and improve system-level price stability.[12] Wholesale electricity costs are also projected to be lower as a result of adding offshore wind.[13] How much consumers actually benefit from these trends will depend not only on the unit cost of offshore wind, but also on market and policy design.

Specifically, this brief examines how recent changes to seabed leasing have affected the financing costs of offshore wind, and how those financing costs may influence project delivery, consumer affordability and the UK's wider energy policy objectives.

The role of The Crown Estate

All offshore wind projects require access to the seabed. Under the Energy Act 2004,[14] the Crown Estate (TCE) manages seabed leasing around England, Wales and Northern Ireland, with Crown Estate Scotland performing the equivalent role in Scottish waters. Through leasing rounds allocating development rights over specified areas, TCE controls a critical input into offshore wind development.

Offshore wind development in the UK is carried out through a staged process. The first stage requires developers to secure a lease for rights to develop the seabed. These leases are granted through leasing rounds (LRs) in which developers bid for the right to develop specified areas. Developers that secure seabed rights pay annual option fees to continue to hold the option to lease the land (an Agreement for Lease) during the development period, until the conditions for a fully executed, formal long-term lease (typically planning consent, a grid connection agreement and, in practice, a CfD) are met.

Once seabed rights are secured, along with consent and grid access, developers compete for a CfD, the government's primary support mechanism for low-carbon electricity generation. A CfD is a contract with the Government's Low Carbon Contracts Company (LCCC), generally lasting 20 years, that guarantees the generator an agreed 'strike price' for the electricity produced. When the wholesale market price of electricity falls below the strike price the difference is paid to the generator, and when it is above the strike price, the generator pays the difference back to the LCCC.[15] CfDs are won in Allocation Rounds (ARs) and are funded through a levy on electricity bills paid by electricity suppliers and passed on to household and business bills. Energy-intensive industries are exempt from the levy.[16] To make projects financially viable, developers need to incorporate upstream costs including seabed leasing fees, into their CfD bids.[17] Leasing costs may therefore affect developer returns, as well as CfD auction outcomes and, ultimately, electricity costs for UK users.[18]

TCE operates under the Crown Estate Act 1961, which requires its land to be sold or leased for "the best consideration in money or money's worth which in their opinion can reasonably be obtained…but excluding any element of monopoly value".[19] The seabed is held by the Crown, but is not the Monarch's private property, and some of TCE's surplus revenue is paid to HM Treasury. TCE is a statutory body run by independent commissioners.

TCE's first three leasing rounds for offshore wind (LR1, LR2, LR3) ran in 2000-01, 2003-04 and 2009-10.[20] Sites were awarded on bidders' ability to deliver, and TCE set fixed annual option fees rather than inviting developers to bid.[21] Once operating, Round 3 projects paid a rent based on a percentage of revenue, around 2% of gross revenue.[22] TCE also offered to fund up to half the cost of obtaining planning consent for Round

3 sites, and by 2014 TCE and industry had together invested more than £300 million in zone appraisal and project development, reflecting the sector's early stage and a policy push to encourage investment.[23] Terms for individual sites were not published, but LR4 was the first round in which option fees were set by competitive auction, and the result was fees far higher than anything seen in prior rounds.

LR4, under which leases were awarded in 2021, marked a shift to a multi-round auction, in which developers bid the option fee, with no cap on the amount (referred to in this brief as an 'uncapped option-fee auction'). It generated substantially higher option fee commitments from developers. For example, the 3 GW LR4 project Dogger Bank South (developed by RWE) had winning option fee bids of £76,203 and £88,900 per megawatt (MW) per year, resulting in an annual payment of £247.6 million.[24] The LR4 projects Mona and Morgan each had a winning option fee bid of £154,000 per MW per year, for an annual payment of £231 million each.[25] On a per-unit-of-output basis, Round 4 option fees have been estimated at around £33/MWh for the highest bidder, against roughly £6/MWh for ScotWind.[26] These payments shifted a larger share of project costs into the pre-revenue development phase, when spend is riskier and financing is most dependent on higher-cost equity.

LR4 became a major source of income for TCE by 2024/25, when option fees generated £1,073 million out of a total of £1,632 million of revenue, and supported a distribution of £1,149 million to HM Treasury.[27] In 2025/26, LR4 option fee income fell to £875 million as some projects fulfilled the conditions for their lease, and the rights to the Morgan site were handed back. TCE increased the amount retained for investment from 27% to 60% of gross revenue, resulting in the distribution to HM Treasury falling to £487 million in 2025/26.[28] TCE states that the retained revenue will fund investment of up to £5 billion over the next decade.[29] The assumption that high option fees might translate directly and proportionately into near-term public revenues therefore requires scrutiny.

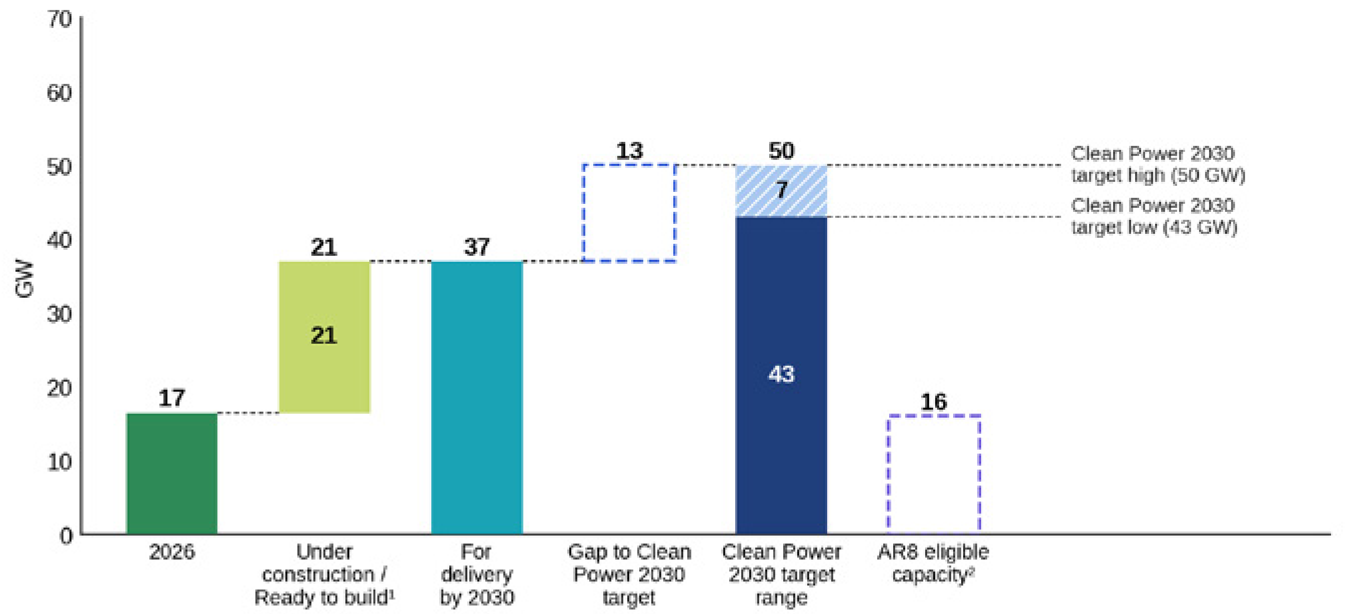
LR5, awarded in 2025 for floating offshore wind sites, also used an uncapped option fee auction, but produced substantially lower bids. This likely reflected its greater development and technology risks versus the fixed-bottom technology used in previous projects, plus weaker competitive pressure. Equinor and Gwynt Glas projects, each with proposed capacity of 1.5 GW, agreed fees of £350 per MW per year, equivalent to £525,000 annually for each project.[30] Floating turbines used in deeper water remain a less mature and more expensive technology, so fewer developers competed for the sites. Since fixed-bottom wind will supply most 2030 capacity, the relevant test of TCE's approach is the next fixed-bottom round, LR6, planned for 2027.

The high fees from LR4 and the upcoming LR6 raise the question of whether future rounds should repeat the LR4 approach or better balance seabed revenue with affordable, secure and rapid deployment.

The offshore wind pipeline: potential, progress and emerging risks

The UK has an active offshore wind pipeline of approximately 95 GW,[31] including around 16.5 GW already operational. On the authors' assessment, approximately 37 GW will be operational by 2030 under the current development pipeline. A further 13 GW would therefore need to be procured to reach the upper Clean Power 2030 target of 50 GW (see Figure 1). The wider pipeline is substantially larger, but much of it remains at earlier stages of planning, consenting and financing, and is not necessarily deliverable by 2030. Even if 50 GW is not delivered fully by 2030, it will need to be procured in the medium term to keep pace with the approximately 4 GW annual average capacity additions to 2050.[32]

Figure 1: UK offshore wind pathway to Clean Power 2030 target (GW) [33]



¹ Projects that have achieved planning consent and a route to market. Includes projects pre- and post-FID and projects currently under construction.
² Fixed-bottom offshore wind eligible for AR8. Around 0.3 GW of floating wind is also eligible; including it does not change the rounded figure. The Clean Power 2030 target covers fixed and floating wind.
Labels are rounded to the nearest GW. Source: authors' analysis based on The Crown Estate Offshore Wind Report 2025, RenewableUK EnergyPulse and DESNZ.

Note: *Labels are rounded to nearest GW. 'For delivery by 2030' figure reflects authors' assessment of realistic delivery against current build rates and commissioning timelines rather than the total of all capacity with an awarded CfD.*

Appendix 1 further breaks down project pipeline by leasing round, and development stage, reflecting the authors' assessment.

Earlier leasing rounds account for almost all operational offshore wind capacity with most projects already holding CfDs (or contracts under the earlier Renewables Obligation) or under construction. LR4, by contrast, includes a significant share of the fixed-bottom projects that could contribute to the remaining 2030 procurement gap but are still progressing through planning, consenting and financing. The economics of these projects are therefore important to delivery of the Clean Power 2030 target and beyond.

Of course, it is not guaranteed that the full pipeline capacity will be built. Morgan (an LR4 project) as well as Norfolk Boreas and Hornsea 4 (LR3 projects) encountered delays when their developers concluded that the expected returns no longer justified continued investment.[34] These decisions reflected a combination of financing costs, supply-chain pressures and inflation. Seabed option fees should be understood as one pressure among several, rather than the sole cause of delivery challenges, but TCE's approach, which awarded sites to the highest bidders at a time of peak market optimism, added a material cost during the pre-revenue development phase. TCE's position is that option fees were set by developers themselves through an open, competitive process.[35]

The Leasing Round 4 effect

The introduction of the uncapped option-fee auction in LR4 changed the timing and scale of offshore wind development costs. Unlike construction expenditure, which can generally be financed through a combination of debt and equity once a project is sufficiently mature, option fees are incurred during the higher-risk development phase.

The early timing of option fees therefore magnifies their financial impact on developers, as fees are normally financed out of developer equity. Equity carries a materially higher required return than secured project debt as it is higher risk, with variable dividends instead of fixed interest rate payments and lower seniority (i.e. equity holders are paid back last) in the event of default. The cost of financing option fees also compounds, as capital committed years before generation begins must be financed for a significant period of time before the project produces revenue. The overall financial impact of the leasing changes on project development therefore depends on four principal factors: the annual option fee level, the number and timing of fee payments, the interval between those payments and first revenue, and the return required on the equity used to fund them.

Developers' reasons for bidding high option fees in LR4 are not publicly observable, but are likely to have included internal strategic priorities, the value of establishing a presence in the UK market, optimistic expectations of falling build costs, and bullish views on future power prices. Developers then reassess project viability as projects progress through leasing, planning, financing and construction. As higher option fees increase the amount of capital exposed before a CfD is secured or revenue begins, developers may respond by accepting lower returns, seeking higher CfD prices, delaying investment or handing back their seabed rights. Our analysis therefore does not assume that option fees are automatically passed through to consumers. Instead, it considers the range of possible developer responses, and examines how fees affect project economics and the CfD strike prices required to preserve commercial viability.

Developer responses to higher leasing costs

Developers facing higher leasing costs have three broad options: accept lower project-level returns, seek to recover the costs through higher CfD prices (including by delaying investment to target a later, less competitive auction round), or cancel projects altogether (which may include redirecting capital to other markets). These responses are not mutually exclusive, and developers are likely to pursue different combinations, depending on project economics, financing conditions and portfolio strength.

As discussed below, all three responses have been observed or signalled within the current UK offshore wind pipeline. Financing conditions, auction design and supply chain costs all impact project economics; this brief isolates the additional effect of uncapped option fees. Below, we examine how these responses influence project economics, consumer costs and offshore wind deployment. In this brief, 'developer' refers to the company or consortium that funds a project through its development phase. These are typically large utilities or infrastructure investors, and the same firm usually provides the development-stage equity.

Absorption into portfolio

One response is to accept a lower project-level return rather than seek full recovery of option fees through a CfD bid or when selling project equity. Large developers with diversified portfolios may be better placed to do this, particularly where a project offers strategic value or complements other assets. However, the extent of any portfolio cross-subsidy is not publicly observable. Moreover, this strategy becomes harder to sustain as a larger share of a developer's pipeline becomes exposed to similarly high leasing costs.

For example, in CfD Allocation Round 7 (AR7), which concluded in January 2026, RWE secured CfDs for 6.9 GW of capacity, including Dogger Bank South (3 GW), which is liable for LR4 option fees.[36] This suggests that the portfolio cross-subsidy model has been adopted by a developer with the scale to deploy it. RWE's position appears unusual however, as few, if any, other developers currently hold a comparable spread of projects across leasing rounds.

Seek higher CfD prices

A second response is to seek a higher CfD price, either by bidding at a level that reflects the project's full cost base or by delaying participation until a later allocation round. Developers may defer entry in the hope of higher administrative strike prices, improved market conditions or a less competitive field. However, delay is not costless as it can extend the period for which development expenditure is carried and expose the project to further financing, supply-chain and policy risks.

The handback by Norfolk Boreas of its AR4 CfD, and by Hornsea 4 of its AR6 CfD, illustrate the broader sensitivity of offshore wind projects to changing costs and financing conditions. Norfolk Boreas originally won a CfD at £37.35 per MWh (in 2012 real terms) before the contract was cancelled amid cost pressures and the project rights sold.[37] Similarly, Hornsea 4 won an AR6 CfD at £58.87 per MWh (2012 prices) before Ørsted returned the project to its development pipeline in May 2025, citing rising supply chain costs and higher interest rates.[38] Neither project was subject to LR4-style option fees. They nevertheless show that developers may withdraw or defer projects when the awarded CfD no longer supports an acceptable return.

Cancellation

The third response is to cancel or discontinue a project where the expected return remains below the developer's investment threshold. Developers with smaller or less diversified portfolios may have less scope to absorb project-level losses, although internal investment decisions are not publicly observable.

Morgan, a 1.5 GW LR4 project, handed back its seabed rights after failing to secure a CfD.[39] As it remained exposed to development costs without contracted revenue, its handback is consistent with the type of financial pressure examined in this paper. Option fees were one of several pressures on the project, but at £231 million a year they were a substantial cost carried with no contracted revenue.

Implications of Leasing Round changes for project economics

The effect of LR4 option fees on individual project economics is not directly observable because CfD bids, internal hurdle rates and detailed project cash flows are not publicly available. As noted above, project decisions cannot be attributed purely to option fees. Our analysis therefore isolates their effect on project economics while holding other influences constant.

We first calibrated a baseline project with no LR4 option fees. Using assumptions chosen to reflect a typical project in current market conditions (Table 1), we set the CfD for the eight-year case at an indicative round-number price close to recent auction outcomes, £95/MWh (AR7 cleared at £91.20/MWh),[40] and identified the equity return this delivered. The resulting pre-tax nominal equity IRR of 13% is consistent with the return expectations of DESNZ's hurdle rates.[41] We held that return fixed, resulting in a no-fee baseline for the 11-year case at £97.3/MWh. We then added LR4-style option fees and solved for the CfD needed to restore the same return of 13%. The difference between the two is the increase reported in this brief. Because option fees are paid from equity years before any revenue, and that equity must earn its required return over the waiting period, the uplift is larger than the fees themselves. Finally, we varied the target return and the development timeline to test sensitivity (Table 2). Both the baseline and the LR4 project are assumed to pay TCE's standard 2% production rent once operating.

Table 1 sets out the key parameters of this indicative project's financing structure. The 13% return is a calibrated benchmark applied to both projects, not a directly observed hurdle rate, and should not be interpreted as an estimate for any individual developer or project.

Under the parameters in Table 1, annual option fees of £112,500 per MW, which is the capacity-weighted average of LR4 fees, are payable during the pre-construction development period. Fees are paid for four years in the eight-year case and seven years in the 11-year case, with the remaining four years in each covering construction. The scenarios illustrate the cost of future rounds run on the LR4 model. Existing LR4 projects that entered their leases after around three years of fees face a burden at or below the lower impact case.[42] In the eight-year case, the strike price would need to rise to £123.6/MWh, an increase of £28.6/MWh (approximately 30% above the £95.0/MWh no-fee baseline). In the 11-year case, it rises to £155.1/MWh, an increase of £57.8/MWh (approximately 59% above the £97.3/MWh no-fee baseline). Measured against the model's no-fee baselines of £95.0/MWh and £97.3/MWh (which are close to the AR7 clearing price of £91.20/MWh), the modelled uplifts represent increases of roughly 30% to 59%.

Both fee-inclusive strike prices sit above the current administrative strike price. For AR8, government has fixed the administrative strike price for fixed-bottom offshore wind at £113/MWh (2024 prices), unchanged from AR7, for all delivery years.[43] That is the maximum any project can bid. The modelled fee-inclusive prices of £123.6/MWh and £155.1/MWh both exceed it. On these figures an LR4 project cannot recover its option fees through AR8 at normal returns. Unless the administrative strike price is raised in later rounds, the realistic outcomes are that developers absorb the fees into lower returns, or that projects are delayed or withdrawn, rather than that consumers pay higher strike prices. The consumer cost figures later in this brief show what full pass-through would cost if the cap were lifted.

Table 1: Scenario parameters and results

Parameter	Lower Impact Scenario	Higher Impact Scenario
Interval from first fee payment to first revenue	8 years (4 years' option fees)	11 years (7 years' option fees)
Option fee payment period	2022-2025	2022-2028
First revenue	2030	2033
Total option fees	£450,000/MW	£787,500/MW
Pre-development expenditure	£71,000/MW	
Option fee financing	100% equity	
Option fee refinancing	None assumed	
Target return (pre-tax nominal equity IRR)	~13.0%	
Construction cost	£4,000,000/MW	
Construction financing	75% debt / 25% equity of construction capex	
Debt interest rate	5%	
Minimum Debt Service Coverage Ratio (DSCR)	1.75x	
Debt repayment	Repayments sculpted to maintain minimum 1.75× DSCR	
Base CfD (excl. option fees)	£95.0/MWh	£97.3/MWh
Cost inflation	3.25%	
Load factor	55%	
Operations and Maintenance	£20/MWh	
TCE production rent	2%	
Results		
CfD inc. option fees	**£123.6/MWh**	**£155.1/MWh**
Incremental CfD uplift (£/MWh; % of base)	**£28.6/MWh (30%)**	**£57.8/MWh (59%)**

Note: Option fees are funded by sponsor equity and are not refinanced at financial close.

The shorter-timeline result in Table 1 is close to the upper end of Aurora Energy Research's separate estimate, at approximately £15–17/MWh increase in real 2024 terms on AR7 CfDs for Dogger Bank LR4 projects (whose option fees are roughly half those of Mona), and approximately £30/MWh for Mona's AR8 bid.[44] Our 11-year result is well above Aurora's range, reflecting the longer fee period and, possibly, a higher equity return than Aurora assumes. Because detailed project economics are not public, these comparisons should be understood as separate scenario estimates rather than empirical validation.

Table 2 examines how estimated CfD increases change with the developer's equity-return benchmark, and with the interval between first option-fee payment and first revenue. Longer pre-revenue periods and higher required equity returns produce larger CfD increases. Similarly, while Table 2 estimates the CfD prices required to preserve project returns, it does not predict the prices at which future ARs will clear.

We model different possible accepted equity returns, from 10% to 15%. As well as our base case of an eight-year interval from first fee payment to first revenue, we show the potential impact of delays out to 12 years. A significantly shorter timeframe than eight years is not seen as realistic, so is not modelled.

Option fee impacts on CfDs are responsive to the equity return requirements of developers. For example, in the 11-year case, increasing the return benchmark from 10% to 12% raises the required CfD uplift from approximately £40.5/MWh to £50.5/MWh, an increase of around 25%. The equity return requirements of developers depend on a wide variety of factors, including policy uncertainty around offshore wind and the cost of capital they face. Appendix 2 lays out calculation details and the sensitivity methodology.

Table 2: Cost of equity sensitivity analysis on required CfD uplift, £ per MWh

Target return (pre-tax nominal equity IRR)	8 years	9 years	10 years	11 years	12 years
10%	£22.9 (29%)	£28.3 (35%)	£34.2 (42%)	£40.5 (49%)	£47.2 (57%)
11%	£23.2 (27%)	£29.6 (34%)	£36.4 (42%)	£43.8 (50%)	£52.3 (59%)
12%	£25.3 (28%)	£33.0 (36%)	£41.3 (45%)	£50.5 (54%)	£60.5 (65%)
13%	**£28.6 (30%)**	£37.4 (39%)	£47.1 (49%)	**£57.8 (59%)**	£69.6 (71%)
14%	£32.2 (32%)	£42.3 (42%)	£53.4 (53%)	£65.8 (64%)	£79.6 (77%)
15%	£36.0 (34%)	£47.4 (45%)	£60.2 (57%)	£74.6 (69%)	£90.8 (83%)

The shift to uncapped competitive auctions under LR4, and the associated policy uncertainty it introduced, could increase not only the accumulated costs but also the required equity return (in other words, the risk premium) on UK wind projects, pushing yet more cost through to future CfDs.

System-level implications

The analysis above identifies three ways LR4 option fees may affect developers: they may recover the costs through higher CfD bids, delay or cancel projects, or absorb the costs internally. We now consider the implications of these different outcomes for consumer bills and the ability to meet UK offshore wind targets.

Calculating impacts on household bills

We estimate household bill impacts by distributing the additional CfD cost across eligible household electricity demand under the current levy. Throughout this brief, 'consumers' refers to all electricity users who pay the CfD levy (certain energy-intensive industries are exempt). Household figures reflect only the residential share of levy-eligible demand, roughly a quarter of the total. Demand projections are taken from NESO's Further Flexibility and Renewables Scenario, and household projections from ONS forecasts. Our calculation applies to the 13 GW gap between expected deployment by 2030 and full achievement of Clean Power 2030 targets. Full assumptions are in Appendix 3.

Scenario One: Higher CfD strike prices

In this scenario, LR4 projects recover option fees through higher bids in future CfD auctions (AR8 to AR10). This requires the administrative strike price to rise above the £113/MWh at which AR8 has been fixed, since the modelled fee-inclusive prices exceed it. If that happened and LR4 projects cleared at prices reflecting full fee recovery, the further 13 GW of added capacity could add around £36 billion to £72 billion to the CfD scheme, or approximately £326 to £659 per household, cumulatively over 2035 to 2054. These figures show what full pass-through would cost. Under current auction rules it is not available.

It is not certain that LR4 costs will be passed through to consumers. Future auction competition may prevent full recovery, but LR4 projects could become price-setting in later rounds if lower-cost projects drop out of the pipeline (for example, by winning contracts), and later projects face similar option-fee burdens.

Scenario Two: Fewer projects and weaker competition

Under current auction rules this is the most likely outcome. Some LR4 projects may fail to secure CfDs and be delayed or cancelled. Around 4 GW of LR4 capacity without a CfD (Mona, 1.5 GW; Outer Dowsing, 1.5 GW; Morecambe, 0.48 GW) is at meaningful risk in upcoming allocation rounds AR8 to AR10 if projects cannot clear at viable strike prices.

Replacing these projects with alternatives in the Scottish pipeline is unlikely to provide a lower-cost route to deployment. Although ScotWind projects benefit from substantially lower seabed fees (around £35–50/kW in total),[45] they face higher and more uncertain Transmission Network Use of System (TNUoS) charges due to greater distance from demand centres.[46] Ongoing reforms to the TNUoS regime, due to continue until at least 2029, add further uncertainty to project financing and investment decisions.[47] Aurora Energy Research estimates that the bid price impact of TNUoS for Scottish projects is broadly comparable to the LR4 option fee burden for English and Welsh projects.[48]

ScotWind projects also tend to be at an earlier development stage. Around four years after ScotWind lease awards, none of the commercial-scale ScotWind projects secured a CfD in AR7.[49] Further, approximately 60% of the ScotWind pipeline is planned as floating offshore wind, which remains a less mature technology with longer and more complex development pathways than fixed-bottom offshore wind.[50] This is reflected in AR7 strike prices, where floating offshore wind cleared at £216.49/MWh compared with around £91/MWh for fixed-bottom projects.[51]

Overall, replacing delayed or cancelled LR4 projects is unlikely to provide a materially cheaper route to meeting Clean Power 2030. While the sources of costs to households differ in each scenario (for example, higher seabed option fees in England and Wales versus higher network costs and a less mature technology base in Scotland) the overall cost burden remains broadly comparable. Cancellation or postponement of LR4 projects is therefore more likely to substitute one set of cost pressures for another than to reduce costs for consumers.

Scenario Three: Option fees are absorbed internally by developers

Under this scenario, the administrative strike price ceiling, together with competitive pressure in AR8 and AR9, forces LR4 developers to absorb some or all of the option fee burden rather than price it into CfD bids. Alternatively, CfD auction mechanisms may be altered to prevent cost pass-through of LR fees. In either case, LR4 developers absorb some or all of the option fee burden rather than price it into bids.

Larger developers with portfolios diversified across leasing rounds may be able to absorb the financial burden, while smaller developers exit and leave the market increasingly concentrated. AR7 already demonstrated concentration toward large developers as just RWE and SSE captured the entire 8.25 GW fixed-bottom award.[52] A less competitive market for developers in future rounds due to reduced participation undermines the dynamics that drove the UK's historic cost reductions.

If option fees are absorbed, developers have a theoretical incentive to accelerate project delivery to reduce the period over which fees accrue. However, the planning and consenting processes driving development timelines are largely outside developer control. There is limited evidence to date that LR4-style fees have in fact shortened development timelines, and the handback of Morgan seabed rights (a project where the fee burden was most acute) suggests the opposite dynamic may be more common.

Policy options: reforming seabed leasing to protect deployment and consumer costs

The cost pressures of LR4 identified here can be addressed through reforms to leasing design, CfD design and project timelines, which are complementary rather than sequential levers. Accelerated consenting and CfD adjustments can be implemented in the current AR8/AR9 cycle, while leasing reform needs a near-term decision before LR6, and a merged leasing and CfD competition would be a medium-term structural change requiring careful design before implementation.

Leasing design: reversion or reform

The most direct intervention is to change how TCE conducts future leasing rounds. The shift from fixed or capped option fees to uncapped competitive auctions in LR4 was an operational choice, and alternatives are possible. Under TCE's own statutory framework, as set out in the Crown Estate Act 1961, section 3(1), the extraction of monopoly value is expressly excluded from the best-consideration obligation. As TCE's then-chief executive acknowledged before the House of Commons Treasury Select Committee in 2010, the Act "expressly says that we may not take advantage of our monopoly position".[53] The legal question of whether section 3(1) imposes a duty to exclude monopoly value, or permits TCE to do so if it chooses, remains contested. Under either interpretation, TCE is not obliged to maximise revenue from the seabed, and the uncapped auction model deployed in LR4 sits uncomfortably with the statutory framework within which it operates.

Importantly, the government does not need new legislation to revise or reform leasing rounds. The Crown Estate Act 1961, section 1(4) provides that "the Commissioners shall comply with such directions as to the discharge of their functions under this Act as may be given to them in writing by the Chancellor of the Exchequer or the Secretary of State".[54] The Act provides that the two act jointly, except that "in matters not relating to Scotland the Chancellor of the Exchequer may act without the Secretary of State".[55] That reference (historically to the Secretary of State for Scotland) is now largely redundant as Scottish Crown Estate functions were devolved to Crown Estate Scotland in 2017.[56] Directions to TCE on offshore wind leasing in England, Wales and Northern Ireland are therefore a matter for the Chancellor. The Chancellor could accordingly direct TCE to return to a capped or fixed-fee structure (for example) for future rounds without any further parliamentary process.

When considering capped leasing fees, onshore wind provides the closest available market benchmark. There is no competitive market price for UK seabed, because TCE is the sole supplier. LR4 auction outcomes reveal what developers were willing to pay for scarce sites, not what site rights would be worth in a competitive market. Land for onshore wind, by contrast, is leased by many competing landowners, so its price gives a reasonable indication of the market value of hosting wind generation.

Onshore rents in the UK are typically around £10,000/MW per year, plus a share of project revenue (equivalent to roughly £3.50–5.10 per MWh of generation), or some 5–10% of onshore levelised costs.[57] The benchmark is also consistent with the statutory framework. Section 3(1) of the Crown Estate Act excludes from TCE's best-consideration obligation any monopoly value "attributable to the extent of the Crown's ownership of comparable land".[58] Because the Crown owns effectively all UK seabed, prices set by competitive supply of land elsewhere offer the nearest indication of what site rights are worth once that monopoly element is removed. If anything, seabed should price below onshore land: it has fewer competing economic uses than farmland, and offshore developers already bear far higher construction costs, leaving less residual value for the landowner.

Under LR4, the land cost embedded in offshore wind is far higher. In the lower impact scenario, four years of option fees total £450,000/MW. Spread across 20 years of generation at a 55% load factor, that is around £4.70/MWh before any financing costs. Adding TCE's 2% production rent (around £2.50/MWh) brings the direct cost to roughly £7/MWh, already above the top of the onshore range.[59] But the fees are paid years before revenue and must be funded with equity, so their effect on the strike price the project needs is much larger: £28.6/MWh, or around £31/MWh including production rent. This represents six to nine times typical onshore rents. These figures use the lower impact case throughout. On the higher case the fees raise the required strike price by £57.8/MWh, which with production rent gives a seabed cost of around £61/MWh, or twelve to seventeen times onshore rents. The comparison is like-for-like in the sense that matters for bill payers: both figures show the revenue each project must earn per MWh to cover its land costs. The difference is that onshore rents are largely paid from operating revenue, whereas LR4 fees must be financed for years before any revenue arrives. Some differential between individual sites is legitimate, and onshore rents contain an element of landowner surplus of their own. However, neither comes close to explaining a multiple of this size.

If future seabed pricing were benchmarked at £3.50/MWh (the low end of the onshore range, on the basis that offshore developers already bear far higher construction costs than onshore) then at a £95/MWh CfD the 2% production rent would account for £1.90/MWh, leaving around £1.60/MWh recoverable through option fees. Spread over a 20-year lease at a 55% load factor, this implies a total option-fee cap of roughly £154,000 per MW. For a 1.5 GW project such as Morgan, the cap would be approximately £231 million payable over the life of the lease, or around £11.5 million per year. For comparison, under LR4 Morgan's developers agreed to pay TCE £231 million per year, before any revenue flowed.

Box 1: How the UK prices seabed rights for oil and gas

Oil and gas rights on the UK Continental Shelf are licensed by the North Sea Transition Authority (NSTA). Its licence fees are set to recover the cost of the regulatory service, not to generate profit: an offshore exploration licence costs £3,630 and a production licence £10,030. These are coupled with escalating rentals based on acreage, designed to discourage companies from sitting on licences they do not develop.[60] The bulk of the value the state captures from oil and gas comes later, through petroleum taxation on production.[61]

The contrast with offshore wind is stark. In 2024/25 the NSTA collected £2.9 million in fees and charges in total,[62] against the £1,073 million TCE received from LR4 option fees in the same year. Rent is captured in wind at the option for lease stage, through the auction of property rights before anything is built, rather than through taxation of output once revenue exists.

Oil and gas developers take price risk on their product, whereas wind developers are in effect relying on prices which are guaranteed by government and paid by consumers through the CfD mechanism.[63] Running seabed leasing as a profit centre in this way passes high rents directly through to bill payers, whereas in oil and gas the state's main take comes from taxing profits once production is under way.

In July 2026, TCE adopted a different structure for the re-tender of the Morgan LR4 site after the site was returned by its developers. Bids in a rising-price auction (in which the price ticks upward until only one bidder remains) will determine a 'Site Exclusivity Fee' payable only once the project enters its lease, bid as a lump sum but paid over 20 years from the start of the lease.[64] TCE has not publicly confirmed whether it intends to use this approach for LR6 or later rounds. If future fixed-bottom rounds instead repeat the LR4 model, the cost pressures identified in this brief would persist in full. TCE has said that option fees for future leasing rounds will continue to be set at auction, although it expects them to be lower than in Round 4.[65]

In this brief, 'option fees' are the annual payments made during development under LR4, and 'conditional fees' are the alternative used in the Morgan re-tender, payable only once a lease is entered. Whilst the removal of upfront fees might address the associated financing burden explored in this paper, two issues must be carefully examined.

First, if conditional fees are set through a competitive auction without a cap, with tight supply of sites, and payable only once a CfD is secured (as this is usually the trigger for the entry into a longer lease), then developers bidding for seabed rights face a fundamentally different incentive. Knowing that the leasing fee will be paid from contracted revenue rather than from equity at risk, they may be willing to bid higher conditional fees in the leasing round than they would under the current structure. Those higher leasing fees would likely flow through into the CfD strike prices that developers need to bid to recover their costs, with electricity consumers ultimately bearing the burden through the CfD levy. A conditional LR fee structure only improves consumer outcomes if the fee level is also constrained. Without an explicit cap on the fee level, the reform risks substituting one form of consumer cost for another.

Second, developers could be tempted to bid high conditional fees in order to secure a site, knowing that they may never have to pay them. Developers may deliberately 'slow walk' a site or determine that they are unlikely ever to get a CfD price high enough to recover the offered fee. A developer might choose to bid in this way for a range of reasons, such as 'neutralising' new sites to drive value into older sites in development, or to stop a neighbouring new wind farm from reducing the wind reaching an existing one (a 'wake effect'), or in expectation of renegotiating the framework from a later position of influence. AR8 has already tightened its eligibility rules to require more commitment from developers before a CfD is awarded, but it is unclear whether the conditional-fee approach used for Morgan includes rules to force developers to 'use or lose' their lease option at earlier stages.[66] If conditional fees are adopted, a cap on the fee level would be needed to protect electricity consumers, together with strict terms (such as 'use it or lose it' provisions) to prevent developers from seeking to 'neutralise' sites.

A more fundamental reform would merge the leasing and CfD processes into a single, integrated competition in which developers bid simultaneously for seabed rights and a strike price, eliminating the multi-year gap during which option fees accrue at full equity cost with no contracted revenue. Several European jurisdictions have adopted such models. Germany's WindSeeG framework,[67] the Netherlands' Hollandse Kust tenders[68] and Denmark's Thor process all illustrate variants of this approach,[69] though each has encountered challenges under current cost conditions. Most notably, this includes the failure of zero-subsidy rounds to attract bids, suggesting that integration is advantageous but not sufficient without appropriate revenue support mechanisms.[70]

The UK's own approach to LR3 allocated sites on delivery criteria rather than price, demonstrating that price-based competition is not the only model available. A merged competition would remove the temporal mismatch that makes LR4-style fees uniquely burdensome, and would allow government to optimise simultaneously across deployment, cost and supply chain objectives rather than treating leasing and contracting as sequential and independent decisions. Merged auctions would however present higher up-front equity requirements. This may price out a significant number of developers and would require close coordination between TCE and DESNZ across two processes that currently operate independently.

With LR6 planned for the first half of 2027, a policy decision by TCE and government on leasing design is required within the current year. In practice, the introduction of such a major change to the UK's offshore wind market might require a lengthy pause, and implications for the Clean Power 2030 Plan objectives and beyond should be taken into account.

CfD auction design: adjusting the CfD to reflect upstream costs

As well as reforming the leasing process itself, CfD auction design could be adjusted to better accommodate LR4 cost realities. Administrative strike price caps could be set to reflect the full development cost stack for different leasing round cohorts, rather than applying a single benchmark across the pipeline regardless of LR. Similarly, the Clean Industry Bonus introduced in AR7 (a top-up payment for projects that invest in UK supply chains and in deprived coastal communities) could be extended to include a leasing cost adjustment,[71] on the basis that part of the higher upstream cost stems from leasing policy rather than developer choices. These changes would not remove the underlying distortion, but they could prevent the current auction structure from systematically pricing out viable LR4 projects. However, both options would likely pass LR4 costs through to bill payers, the outcome costed in Scenario One. They are therefore not a substitute for addressing fees at source.

Adjustments to administrative strike price caps and the Clean Industry Bonus sit within DESNZ's existing powers and could be implemented for AR9 without primary legislation,[72] making them the most immediately actionable near-term protection for LR4 projects.

It is worth being clear about what the AR8 administrative strike price does and does not achieve. Freezing it at £113/MWh caps what consumers can be asked to pay, but it does nothing to reduce the fees themselves. Where a project's cost base sits above the cap, the result is not a cheaper project but a project that does not bid, or bids and fails. A strike price cap therefore protects bills only by shrinking the pipeline. Capping the leasing option fee addresses the cost at source and the authors consider this the most direct route that protects both bills and deployment.

The development timeline: bringing forward the payback of upfront costs

The total cost burden of LR4-style option fees is exacerbated by the length of the project development period. Each year separating lease award from first revenue represents an additional period of fees compounding at equity cost, without any contracted revenue to offset them. Reforms to the planning and consenting regime that shorten development timelines would reduce the cumulative fee burden on LR4 projects still paying option fees, and on any future rounds run on the same model, without any change to the fee structure itself. This represents a policy lever that can be activated independently of, and in parallel with, leasing reform. Accelerated consenting (shorter statutory timelines for planning decisions and fewer opportunities for repeated delay) is well-established as a priority for offshore wind deployment in its own right.

The planning and consenting reforms needed to achieve development timeline changes are already government policy.[73] What is required is prioritisation of offshore wind applications within the existing programme, which sits within DESNZ and the Planning Inspectorate's existing remit and requires no new legislative authority.

Conclusion

Offshore wind remains one of the UK's most cost-effective clean energy tools, but costs have risen sharply due to supply chain pressures, higher interest rates and a development framework that has become structurally more expensive.

This paper has focused on the Crown Estate's decision to run Leasing Round 4 (LR4) as an uncapped option-fee auction. Our analysis suggests that LR4-style option fees raise the required CfD strike price by between £29 and £58/MWh, or 30–59% above the strike price the same project would need without LR4 fees (£95–97/MWh, close to the AR7 clearing price), depending mainly on how long fees are paid before first revenue. These figures put such projects above the £113/MWh administrative strike price fixed for AR8. If that ceiling were raised and all the costs were recovered through CfDs on the remaining capacity needed to reach the upper Clean Power 2030 target, the additional cost could be approximately £36 billion to £72 billion over 2035 to 2054. This is equivalent to around £326 to £659 per household over the contract period (2024 real prices). If not raised, these costs will instead show up as projects absorbed by developers, delayed, or withdrawn.

In July 2026, TCE re-tendered the Morgan site, with a conditional fee payable only once the project enters its lease. It has not confirmed whether it will take this approach more widely in LR6. A conditional fee may ease early financing pressure, but would only improve consumer outcomes if fee levels were constrained and 'use it or lose it' provisions imposed to force developers to move quickly. If future rounds instead repeat the LR4 model, the cost risks identified in this brief will persist. More broadly, reducing costs requires attention to leasing design, planning and consenting timelines, the timing of seabed option fees relative to CfD award, and relaxation of wider supply-chain constraints.

We suggest four main policy directions:

1. Adjust seabed leasing design to avoid passing large upfront option fees into the development phase, whether through capped fees or a different auction structure.
2. If conditional fees are introduced, set a fee cap (which could be done by reference to onshore wind land costs or the NSTA's cost-recovery approach), attach clear development milestones so that developers must progress or surrender sites, and publish the fee terms so that their effect on CfD bids is transparent.
3. Where needed to protect deployment, refine CfD auction design to reflect cohort-specific upstream costs, recognising that this passes costs to bill payers.
4. Accelerate planning and consenting to shorten the period over which early costs must be carried at equity returns.

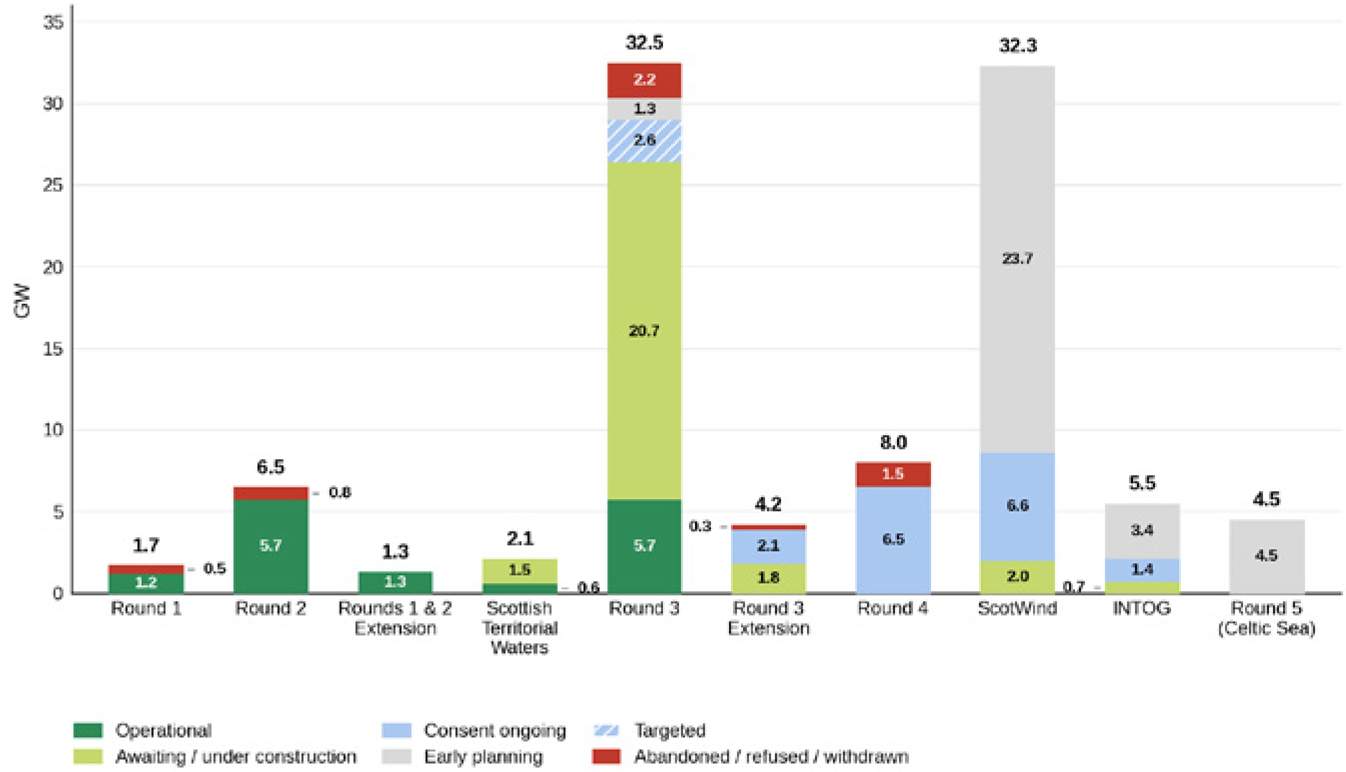
These measures would not eliminate all offshore wind cost pressures, but they could reduce the extent to which seabed leasing costs feed through into higher strike prices and consumer bills. As offshore wind becomes the backbone of the UK's electricity system, keeping deployment costs low is increasingly inseparable from delivering affordable, secure and resilient energy.

Appendices

Appendix 1: UK offshore wind capacity

Figure 2: UK offshore wind capacity by leasing round [74]

LR4 accounts for 6.5GW of capacity waiting to become operational



Note: *Much of the operational capacity in earlier rounds was supported under the Renewables Obligation rather than CfDs.*

Note: *Totals in this figure are gross pipeline capacity by leasing round as reported by The Crown Estate, and do not sum to the figures in Figure 1. Figure 1 combines several sources and reflects the authors' assessment of realistic delivery by 2030, excluding pipeline capacity expected to commission after 2030 or judged unlikely to proceed. The two figures also draw on data snapshots taken at different dates and are rounded to whole GW. Differences between them reflect source data and purpose, not inconsistency in the underlying analysis.*

Appendix 2

- **Project finance model assumptions**

CfD strike prices and O&M assumptions are reported in 2024-price terms. For the cash-flow calculation, these values are escalated at the modelled inflation rate. Financing rates and equity returns are nominal. Construction capex is treated as a stylised nominal expenditure profile across the construction period. Model assumptions combine publicly available evidence with representative industry financing assumptions and are intended to illustrate plausible project economics rather than predict individual project outcomes. The total consumer cost is largely insensitive to the load factor assumed: a lower load factor raises the uplift per MWh but reduces the MWh generated.

The model includes £71,000/MW of pre-development expenditure, spread evenly across the pre-development period. The cost is held constant in the no-fee comparator and the fee-inclusive project and is therefore not treated as an incremental LR4 cost in the option-fee increase. The option-fee schedule itself uses a fixed annual fee of £112,500/MW, which is the capacity-weighted average of fees signed in LR4. Fee payments run for pre-revenue years minus four years, so the eight-year case has four fee years (2022–2025) and the 11-year case has seven fee years (2022–2028).The uplift therefore reflects both the level of the fee and the duration over which it is carried.

Construction debt is held at 75% of construction capex and is re-sculpted in each scenario to maintain a 1.75x debt-service coverage ratio. Consequently, higher CfD revenues accelerate principal repayment relative to the base case. The estimated impact therefore reflects both recovery of the equity-funded option fees and the resulting change in the timing of equity distributions.

Option-fee cash flows are represented in annual periods using a stylised payment schedule. Because financing costs are sensitive to the precise timing of early expenditure, the results should not be interpreted as applying mechanically to projects with different payment dates.

Input	Scenario model	Unit	Source
Construction capex	4,000,000	£/MW total	DESNZ/Arup central offshore wind capex assumptions [75]
Pre-development expenditure	71,000	£/MW total	Representative pre-construction development expenditure assumption
Development timeline (first fee to first revenue)	8–11	years	Sensitivity assumption reflecting alternative delivery timelines
Option fee payment period	2022–2025	2022–2028	Sensitivity assumption reflecting alternative delivery timelines, set at development timeline minus four years
O&M incl. OFTO	20	£/MWh (2024 real)	Representative industry assumption, benchmarked against DESNZ/Arup and operational offshore wind projects [76]
Load factor	55	%	Upper end of the DESNZ/Arup range (approximately 46–56%), representing a conservative assumption for option fee impacts [77]
Revenue period	20	years	Standard 20-year Contract for Difference support period (from AR7; AR1 to AR6 contracts ran for 15 years)
CPI inflation	3.25	% p.a.	Sensitivity assumption reflecting long-run inflation expectations
Base CfD (excl. fees)	95.0–97.3	£/MWh (2024 real)	£95.0/MWh set for the eight-year case, close to the AR7 clearing price (£91.20/MWh)[78]; £97.3/MWh is the model output for the 11-year case at the same return.
Construction debt	75	% of capex	Representative project finance assumption for operational offshore wind projects
Construction equity	25	% of capex	Representative project finance assumption
Debt interest rate	5.0	% nominal	Representative project finance assumption
DSCR	1.75	x	Representative project finance assumption
TCE production rent	2	% of revenue	Standard Crown Estate production rent payable once operational
Target pre-tax nominal equity IRR	~13.0	Equity cost of capital (pre-tax nominal)	Calibrated: the return delivered by the £95/MWh baseline; consistent with DESNZ hurdle-rate estimates[79]
CfD with fees	123.6–155.1	£/MWh (2024 real)	Model output after incorporating LR4 option fee costs while maintaining the target project return

- **Sensitivity analysis**

The sensitivity table was generated using a Python automation that updates the Excel cash-flow model for each combination of the interval from first fee payment to first revenue and the target pre-tax nominal equity IRR. For each combination, the script uses Excel Goal Seek to solve separately for the CfD price required by the full no-fee project and the full fee-inclusive project, including the modelled DSCR-based debt repayment profile. The reported uplift is the difference between these two CfD prices.

The table uses the same harmonised fee rule as Table 1: a fixed annual option fee of £112,500/MW, with the number of fee-paying years set at pre-revenue years minus four. This means the fee period lengthens as the development period extends, while preserving a consistent assumption across scenarios.

Individual results can be reproduced by applying the same assumptions to full no-fee and fee-inclusive project cash flows and using Goal Seek to set the equity IRR in each case to the specified target.

Appendix 3: Household bill impact assumptions

Household bill impacts are calculated by estimating the annual incremental cost imposed on the CfD scheme by higher strike prices and distributing this across eligible electricity demand under the current CfD levy. The resulting unit cost is multiplied by forecast average household electricity demand to estimate the annual impact on household bills.

All monetary values are expressed in 2024 real prices, consistent with the project finance model and CfD strike price estimates in the main text.

- **Methodology**

The annual incremental cost to the CfD scheme is calculated as:

Annual cost (£) = CfD uplift (£/MWh) × capacity (GW) × load factor × 8,760 hours x 1,000

Applied to 13 GW at a 55% load factor, this gives annual incremental costs of between £1.791 billion (eight-year timeline) and £3.620 billion (11-year timeline). These annual costs are held constant in real terms across the 20-year contract period (2035–2054), giving totals of £36 billion and £72 billion respectively.

13 GW represents the gap between expected deployment of offshore wind by 2030, and fully meeting Clean Power 2030 targets of 50 GW of offshore wind.

The per-household cost in each year is calculated by multiplying the annual scheme cost by the household share of eligible demand, then dividing by the number of households. Because eligible demand and the number of households both grow over the contract period, the per-household annual cost declines over time.

Input	Scenario model	Unit	Source
CfD increase	28.6–57.8	£/MWh	Project Finance Model
Time period assumed	20 (2035–2054)	years	Length of typical CfD contract
Eligible Demand	288–489	TWh	NESO Clean Power 2030 Action Plan Further Flex and Renewables Scenario [80] Note: Assumed consistent 8.5% demand share of Energy Intensive Industries (exempt from CfD levies)[81] and linear interpretation between two data points. Household demand is set to be roughly one quarter of levy-eligible demand between 2035 and 2054, according to CPAP Further Flex and Renewables scenario. Total Eligible Demand in 2030 and 2050
Capacity exposed to LR4-style increase	13	GW	NESO Clean Power 2030 Action Plan Further Flex and Renewables Scenario.[82] Gap between approximately 37 GW of operational and procured offshore wind capacity and the upper Clean Power 2030 target of 50 GW.
No. UK Households	26–30.5m	Households	ONS [83]
Load factor	55	%	Project Finance Model
Residential demand	80–118	TWh	NESO Clean Power 2030 Action Plan Further Flex and Renewables Scenario [84]
Total CfD scheme cost due to option fees	36–72	£ billion	Calculated
Lifetime household impact	326–659	£	Calculated

Note: *The eligible demand calculation excludes volumes attributed to Energy Intensive Industries, which are exempt from the CfD levy, and grid electrolysis demand, consistent with current levy operation. The EII exempt share is held at approximately 8.5% of total demand, consistent with historical proportions.*

Note: *These estimates represent the incremental cost attributable to LR4 option fees relative to a counterfactual in which seabed leasing had not shifted to an uncapped competitive model. They do not represent total CfD scheme costs. They also assume the administrative strike price would permit full recovery, which is not the case under current AR8 rules (see main text).*

Note: *The per-household annual cost figures decline over the contract period because both the number of households and total eligible demand grow, spreading the fixed annual scheme cost more widely. The rate of decline reflects the pace of electrification assumed in NESO's Further Flexibility and Renewables Scenario.*

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