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Offshore Revolution?
Decoding the UK Offshore Wind Auctions and What the Results Mean for a "Zero-Subsidy" Future

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Overview

In this paper, we review the outcome of the latest UK auction for "less established" low-carbon generation technologies, such as offshore wind. The auction resulted in record low costs, with prices paid for offshore wind in the mid-2020s now not much higher than the government's expected wholesale price. The results are in line with other auctions in Europe, where the costs of renewable power have fallen sharply, owing to cost efficiencies. Such lower prices raise the prospect of a "zero subsidy" future, in which solar, onshore wind, and offshore wind compete directly against each other and against other forms of power generation. These developments will bring with them increasing costs of integration, and increased risk for both governments and investors—for example, the risk that projects will not be delivered, as well as the risks associated with greater exposure to market prices.

The paper is set out in four parts. First, we describe the results of the UK auctions and consider the extent to which price outcomes for offshore wind projects imply that they are competitive with other technologies. Second, we compare UK auction prices for offshore wind with prices across Europe: we observe a broad downward trend in costs, but describe and analyse the significant variations between countries. Third, we assess the bid strategies observed in the auction—both the successful and the seemingly less successful. Finally, we consider what these results mean for offshore wind investors and governments, and the implications for market design as the transition to low-carbon energy sources continues.

Is wind generation now competitive with other technologies?

Renewable subsidy auctions are forcing down the cost of renewables at an astonishing rate, bolstering hopes that some forms of low-carbon electricity will soon be able to compete against gas-fired generation. The results of the latest UK auction for "less established technologies" were published on 11 September, with subsidy contracts awarded to 3.2 GW of offshore wind and 150 MW of bioenergy projects.[1] The lowest clearing price, £57.50/MWh, was approximately half the lowest bid in the 2015 auction (£114.39/MWh)—even though the new projects will be delivered only four years later (for the delivery year 2022/23). These auctions are being hailed as a success for the government's Contract for Difference (CfD) and renewable auctions policy, as well as for the offshore wind industry, which has exceeded expectations by moving down the cost curve so quickly. The successful offshore wind projects of the 2017 auction are shown in Table 1 below.

Table 1. **UK offshore wind auction 2017 results**

Project	Owners	Size (MW)	Strike Price (GBP (2012)/MWh)	Delivery Year
Triton Knoll Offshore Wind Farm	innogy and Statkraft	860	74.75	2021/22
Hornsea Project 2	DONG Energy	1,386	57.50	2022/23
Moray Offshore Wind Farm East	EDPR and ENGIE	950	57.50	2022/23

Notes: Projects may be commissioned over three years. "Delivery Year" refers to the first year of commissioning. Full results can be accessed at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/643560/CFD allocation_round_2_outcome_FINAL.pdf

The UK auction format sets a single strike price for all offshore wind projects scheduled for delivery in the same year. That price is based on the highest bid among all projects winning in that delivery year. Thus, the price generally differs between delivery years. (The price may be set by an offshore wind project, or by another winning project of a different technology, with some exceptions as discussed below.)

The auctions have driven cost efficiencies in three main areas:

- *Technology costs have come down faster than many expected*, and innovations like larger turbines have meant fewer towers have to be built, saving on foundations, steel, construction, and maintenance costs. Market leader DONG Energy has said it believes 13-15 MW turbines will be available in 2024. These turbines are nearly twice the size of those currently being installed. Turbine and blade improvements developed to harvest more wind energy have also led to higher load factors. Additionally, cost efficiencies have been achieved in foundation design and cable capacity.[2]
- *Economies of scale have contributed to greater cost efficiency*, with project sizes increasing from a few hundred MWs to Hornsea Project 2's 1.4 GW. Offshore wind projects involve significant fixed costs, such as cables and installation vessels, so spreading these costs over larger projects helps decrease per-unit expenditures. Also, as more projects are completed, infrastructure and operation and maintenance costs can be spread across a wider base, leading to additional efficiencies.
- *Financing costs have fallen*. With any large infrastructure project, the return that must be paid to capital investors represents a significant share of the overall cost. In a wider investment climate where yields remain very low, debt costs for offshore wind have fallen over the last few years as lenders have grown more comfortable with projects and the associated risks (for example, through the work of the Green Investment Bank in the UK). The cost of equity has also fallen through a combination of financial engineering and increased competition among financial investors buying stakes in wind farms.[3]

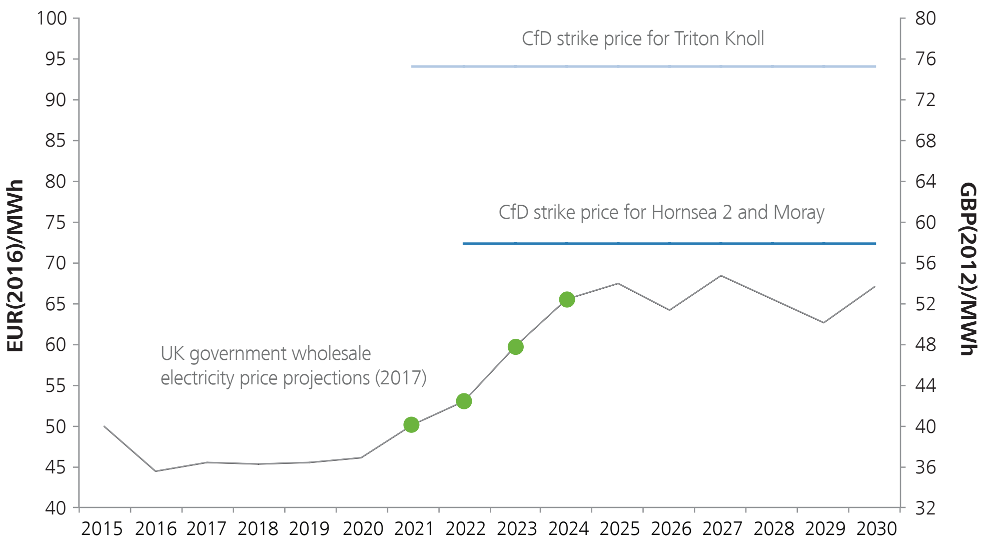
The UK offshore wind strike prices imply levelised costs of energy (LCOE) in line with or below new gas plants (once carbon cost are included).[4] The strike prices are also significantly below the roughly £80/MWh for onshore wind and solar awarded in the last UK auction in 2015, though the costs of these technologies have also fallen since that auction. (In Germany in 2017, onshore wind auctions awarded over 1 GW at an average price of €43/MWh, or a mere £34/MWh in 2012 prices. The UK has not held an auction for solar or onshore wind since 2015.) The offshore wind strike prices are also significantly below the CfD strike price granted to the planned Hinkley Point C nuclear project's £92.50/MWh (awarded without competition, for 35 years).

However, a full comparison of the competitiveness of the different technologies must account for the fact that wind-powered generation is not always available at times when power is needed, and is therefore less able to capture market prices. System integration costs (SICs) accounting for the need for back-up generation and higher balancing costs have been estimated in several recent studies.[5] Nevertheless, even adding SICs of £10-15/MWh, the strike prices of the lowest-cost offshore wind CfDs are significantly below the price awarded to Hinkley Point C.

Drawing the conclusion that offshore wind is nearing "grid parity" and able to compete with new gas plants on a merchant basis seems premature, however. Merchant plants bear the risk that future prices turn out to be lower than expected, whereas CfD projects are protected from this risk (by shifting it to the government and consumers). If CfD projects were forced to bear the risk of uncertain and volatile power prices this would increase their costs. (One way to deal with such risk would be to obtain a power purchase agreement (PPA) with a fixed or "floor" price, but such price insurance would come at a cost.)

Figure 1 shows the strike prices awarded to each of the winning offshore projects alongside the UK's projected wholesale market price, which determines how much top-up support the government expects to pay. The figure reveals that the difference between the strike price awarded to Hornsea 2 and Moray and the BEIS wholesale price projection is very small. However, as discussed above it is not just the expected level, but also the risk associated with the power price that will determine when projects can compete on a truly unsubsidized basis.

Figure 1. **Electricity wholesale prices and offshore wind strike prices**



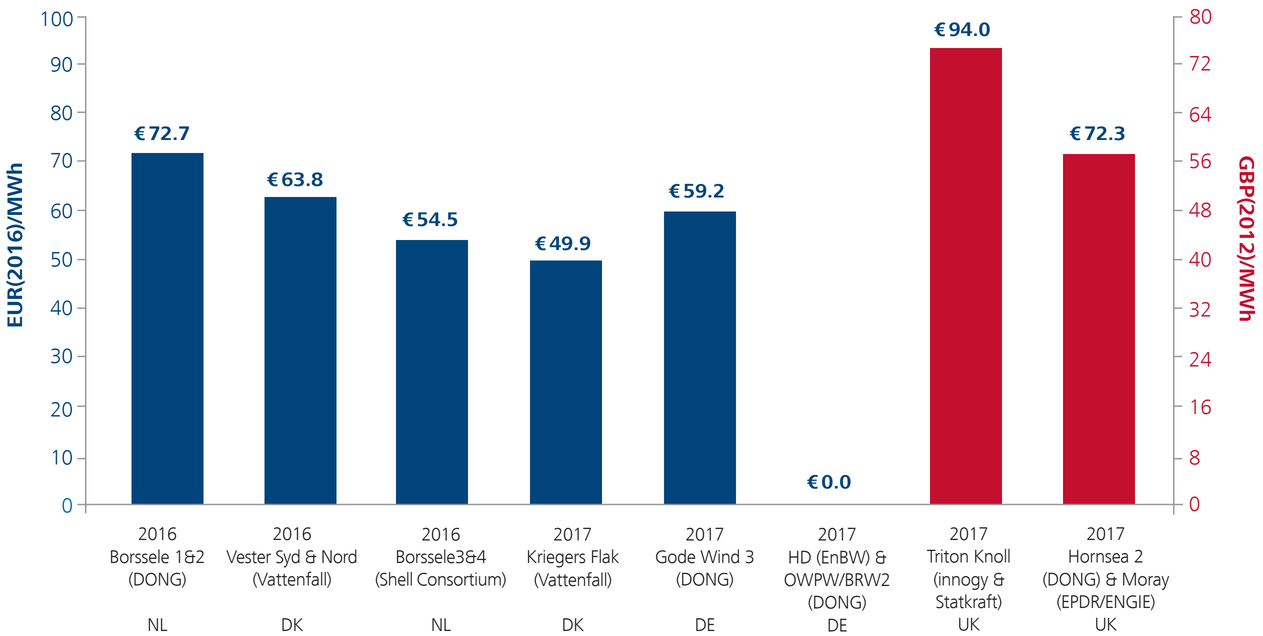
Source: NERA analysis based on BEIS UEP (2017) and CfD Allocation Framework 2017.

Are UK offshore wind prices low compared to prices in other countries?

How do the UK results compare to recent outcomes in other EU countries, where the costs of offshore wind have also been plummeting? Auctions in the Netherlands and Denmark saw strike prices for offshore wind drop to €50-55/MWh in 2016 (around £40-45/MWh in 2012 prices). In Germany, the 2017 auctions produced some bids at "zero-subsidy" levels (i.e., developers said they were willing to build their wind farm relying only on revenue from wholesale electricity prices, though the cost of connecting to the electricity grid is paid by the transmission operator and ultimately borne by consumers, which many consider a form of subsidy).[6] The UK auction prices are part of a downward trend across Europe, but there are significant variations between countries.

Figure 2 shows recent offshore wind auction prices in both euros and in pounds sterling. The results are arranged in order of when the auctions were held. The figure shows the results for the UK auctions (red bars) converted into 2016 euros for ease of comparison with the euro-denominated auctions. The right-hand axis of the figure shows the equivalent values in pounds (in real 2012 terms) to facilitate conversion of the euro-denominated results into the terms used in the UK auctions.

Figure 2. **Recent prices awarded in European offshore wind auctions**

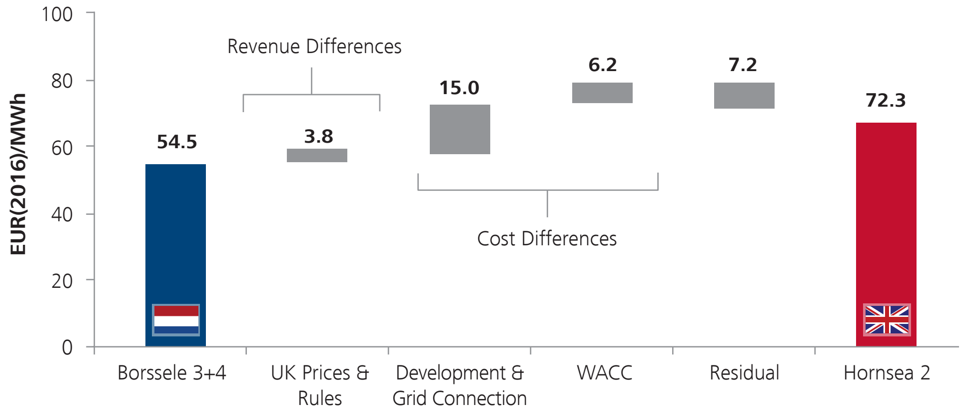


Source: NERA analysis.
Notes: For illustration we have applied an exchange rate of 1.20 to convert GBP (2016) to EUR (2016). As discussed below, support regimes differ, so direct comparisons must be made with caution.

Comparing the strike prices in different regimes and using them to draw conclusions about underlying project costs requires care for a number of reasons. First, different projects have different characteristics—wind speeds, water depth, distance from shore—that influence cost (and strike price required). Second, projects commissioning in later years are able to benefit from continued technological progress and innovation. Third, there are differences between subsidy regimes. For example, in the Netherlands, Denmark, and Germany, wind farms do not pay the cost of transmission connection, so their bids do not reflect these costs. The Dutch and Danish auctions are also for specific, pre-developed sites, so bidders do not need to cover any development costs. Also in the Netherlands, Denmark, and Germany, the prices awarded are not indexed to inflation, whereas the UK CfD contracts are inflation-indexed. On the other hand, the UK auction is for a "two-sided" CfD, eliminating beneficial exposure to upside moves in the wholesale price, whereas other countries offer "one-way" CfDs, which provide a floor, but do not cap the upside. Finally, some subsidy regimes also place a limit on the number of production hours to be subsidised (e.g., Denmark limits subsidy payments to 50,000 full load hours, corresponding to approximately 11–12 years of operation at historical load factors).

We have carried out a decomposition analysis of differences between the recent Netherlands auction for the Borssele 3&4 sites and one of the two lowest-priced UK projects (Hornsea 2), accounting for divergence between the support regimes, such as indexation and the nature of the CfD offered. The results of our analysis are shown in Figure 3.

Figure 3. **Decomposition analysis: required strike price for Borssele 3&4 vs Hornsea 2**



Source: NERA analysis

Once differences between the revenue streams, as well as project scope and risk, are taken into account, the figure suggests UK costs that are even lower than those from the 2016 Netherlands auction. The most material differences are as follows:

- **UK Prices and Rules:** We find that a project bidding under UK wholesale price expectations and endowed with a UK-style two-way, inflation-indexed CfD would require almost €4/MWh more than Borssele 3&4. This is because the two-way CfD (which removes market price "upside"), along with lower expected UK wholesale prices in the post-subsidy period,[7] is not fully compensated by the UK's advantage, namely, the indexation of the strike price.
- **Development and Grid Connection:** The site development and grid connection costs (which, in the Netherlands, projects do not pay for) could add around €15/MWh.
- **WACC:** Because UK projects are established at the developer's risk (with no guarantee of subsidy allocation), projects are likely to require a higher return to compensate for the risk that a subsidy contract will not be secured. We have assumed this increases the project weighted average cost of capital (WACC) by one percentage point,[8] which results in a €6/MWh increase in the required strike price.

These three adjustments alone imply that Hornsea 2 would have required a strike price of around €79/MWh, which is well above the €72/MWh equivalent the project actually secured. Moreover, these estimates do not take into account the fact that Hornsea 2 is in deeper water and further from shore than Borssele. This suggests further cost reductions—whether due to technical progress or acceptance of lower returns—of at least €7/MWh, which are reflected in the "Residual" bar in Figure 3.[9]

Comparing the UK results to the April 2017 German "non-subsidy" bids requires similar analysis. The viability of the German bids depends critically on assumptions about future power prices and the extent to which these can be captured by the project, taking account of the revenue "cannibalisation" that occurs when wind farms all generate at once and depress the wholesale power price. It is also necessary to consider the significantly higher financing costs associated with the increased exposure to merchant price risk (e.g., NERA (2013) suggested this could add as much as 300 bps to the WACC).[10]

Exposure to merchant price risk will also affect capital structure, gearing levels, tenor, and other lending conditions. Lenders are likely to require a PPA with some price protection and may still reduce the debt shares they will accept. Equity providers will seek a premium on their return requirements to reflect greater risk. DONG Energy's press release following the publication of the German results confirmed they had increased their hurdle rate to account for the greater risk associated with full exposure to the market price,[11] and market analysts are already discussing implications for project financing structures. In theory, PPAs can be used to manage merchant risk, but if someone is bearing the risk, they will ultimately need to be compensated. This will increase project costs and reduce returns.

In both Germany and the UK, the question of non-delivery also looms large. The penalties for not delivering projects are fairly low in both countries. In the UK, the project company would simply be excluded from the next CfD auction round. In Germany, it would forfeit some portion of a bid bond. With a low cost for non-delivery, the auction structures clearly incentivise very competitive bidding. In the 1990s, the UK Non-Fossil Fuel Obligation (NFFO) scheme also achieved very low per-MWh prices for renewable energy, but delivery levels for projects in the final round were very low.[12] Hopefully history will not repeat itself.

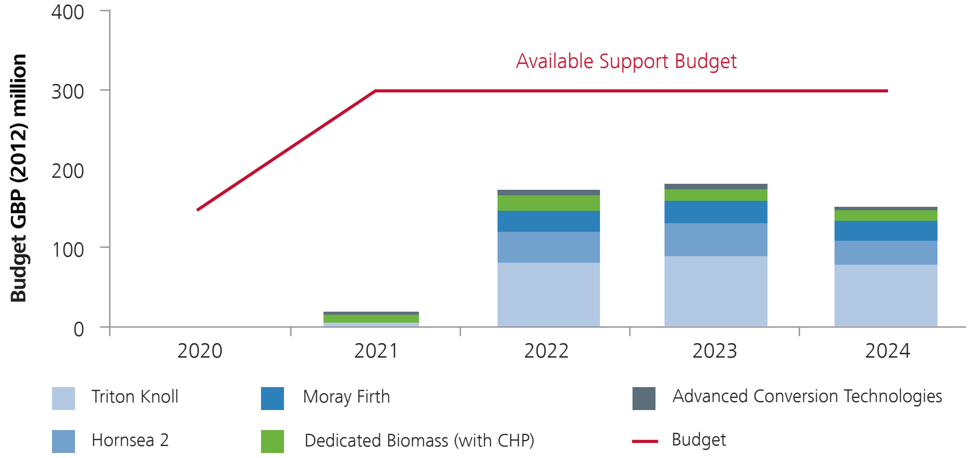
Smart bids, blind luck, and "winner's curse"

The results of the UK auctions show there can be clear benefits to careful planning of bid strategy based on competitor analysis and simulation modelling.[13] By simulating the likely bids of rival offshore wind projects and other bidders (in particular bioenergy projects), offshore wind bidders can estimate the likelihood of winning, as well as the likelihood of benefitting when more expensive projects set the price.

Figure 4 below shows the budget impact from successful projects in the 2017 auction. Due to the 30% higher strike price it received by virtue of winning in 2021/22, Triton Knoll has a far greater call on the support budget than Hornsea 2 or Moray, both of which won contracts to deliver in 2022/23. Under UK auction rules, all projects had the option of submitting up to four bids, varying their strike price, year of delivery, and capacity. The auction rules stipulate that bids are ranked in order, from lowest to highest price, regardless of delivery year. Figure 4 also shows there was a substantial amount of unused budget remaining.

Examination of the auction results makes it clear that Triton Knoll achieved a higher strike price than the other offshore wind projects because the clearing price in 2021/22 was set by a higher-cost bioenergy project. Although a single bioenergy project also secured a contract in the later year alongside Moray and Hornsea 2, its bid was below those of the offshore projects, so it did not set their price.[14]

Figure 4. **UK CfD auction results: budget impact**



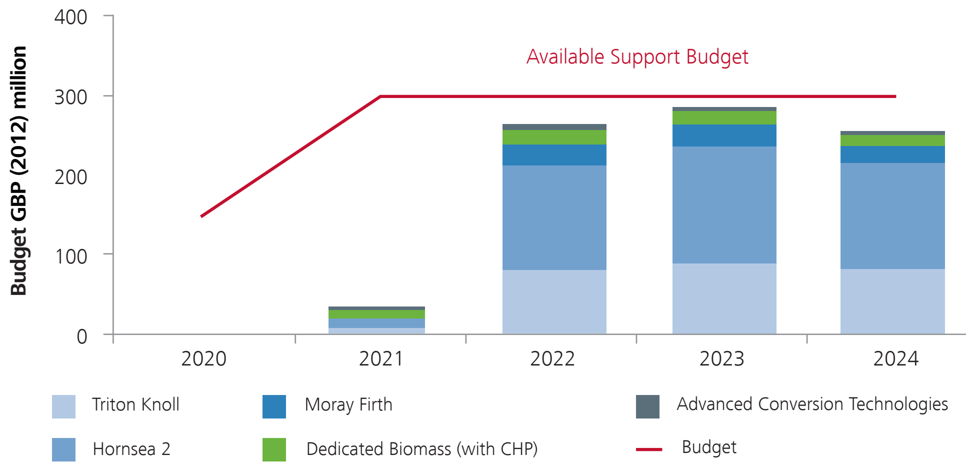
Source: NERA analysis
Note: To match the budget commitment results published by National Grid, we have assumed certain start dates and sizes for the phasing of each project.

In reviewing these results, there are at least two puzzles. First, why did the auction only allocate contracts to projects covering 60% of the available budget, given that the auction was reported to be heavily over-subscribed? Second, why did the offshore wind projects in 2022/23 not benefit from higher clearing prices set by bioenergy bids?

One possible answer to both questions is that the 2022/23 delivery year was "closed down" (i.e., the budget was exceeded and, as such, no further bids for that year were considered) by a fourth large offshore wind project bidding in above £57.50/MWh (the price at which Hornsea 2 and Moray were allocated). Closing 2022/23 would have prevented any further bioenergy projects from being allocated in that year, but still would have left 2021/22 open.As a result, following the success of the three offshore projects, the remaining budget was spent on 2021/22 bioenergy projects, up to the point at which the 150 MW volume cap was reached. This led to relatively high prices in 2021/22, low prices in 2022/23, and significant budget under-spend.[15]

Could Hornsea 2 (and/or Moray) have secured higher strike prices? Figure 5 shows what would have happened if Hornsea 2 (the larger of the two) had put in a 2021/22 bid at a price below its 2022/23 bid. In this scenario, Hornsea 2 would have been allocated at the clearing price of £74.75/MWh without breaking the budget.

Figure 5. **Estimated budget impact if Hornsea 2's leading bid had been in 2021/22 rather than 2022/23**



Source: NERA analysis

Analysis shows that Hornsea 2 (or Moray) could have been accommodated at the higher 2021/22 strike price, but for some reason it elected to submit a lower bid in the second delivery year, making the 2022/23 bid its primary bid. Once this bid had been accepted as affordable, the project's place and year were fixed and it could only have benefitted from a higher clearing price *in that year.* As explained above, no higher-priced bioenergy bids in that year were successful.

If Hornsea 2 had anticipated the fiercer competition in 2022/23, it could have avoided the more crowded field and fit comfortably in 2021/22. However, this would have depended on accurately predicting that their co-winner(s) in 2022/23 (i.e., Moray) were leading with the later year, and that another large offshore wind project would bid and close out the auction in 2022/23, preventing any higher priced bioenergy bidders in that year from setting the price. Even if Hornsea 2 had identified this as a possibility, it is also possible that the 2022/23 winners considered a range of different scenarios and, given the uncertainties, concluded that the best overall option was still to prioritize the 2022/23 bid. Still, the fact remains that Hornsea 2 could have secured more than £100 million annually, or well over £1 billion in total over the full CfD period.

Bidding without taking into account the full range of potential auction outcomes may carry significant risk. A case in point may be one of the successful bioenergy projects in the auction. Bidding as low as £40/MWh,[16] it presumably hoped that the clearing price would be set by another bidder at a much higher level (in essence, this was a "price taker" bid). However, due to the auction rule preventing offshore bids from setting the price for bioenergy projects, the strategy appears to have backfired. Since this bioenergy project ended up as the only successful bioenergy project in 2022/23,[17] it set its own price at a low £40/MWh, apparently falling victim to a form of the "winner's curse." Similar low bids for solar photovoltaic projects were observed in the 2015 auction. Those projects subsequently abandoned their CfD contracts.

Implications for investors and policymakers

Investors and policymakers may need time to analyse these results and understand the implications for future regulation and investment decisions. We highlight here a few inter-related questions that merit consideration.

Question 1: Are we ready for technology neutrality?

With offshore wind strike prices now approaching those of onshore wind and solar, calls may intensify for greater technology neutrality. In 2015, NERA's report for Citizens Advice found consumers could save around £1 billion if onshore wind were included in the next UK auctions.[18] Now that offshore wind prices have fallen dramatically, the savings could be lower, though increased competition could also lead to even greater cost reductions. The UK Competition and Markets Authority 2016 Energy Market Investigation emphasized these potential cost savings and called on the government to be more transparent about why it was allocating budget to some technologies but not others. The rationale for awarding a contract to nuclear power without competition and for more than twice the duration at the relatively high price of £92.50/MWh should be clearly explained.

The CfD auctions could be reformed to be more technology-neutral, allowing greater competition between technologies. The government should seriously consider the case for allowing more technologies to compete against each other—or set out reasons for not doing so, if it so chooses. They might even bid at strike prices *below* the long-term average expected electricity price, giving the market and government a signal about the value of revenue stabilization and possibly stimulating the further development of markets for long-term PPAs. Others may advocate for a shift to a premium feed in tariff (FIT) system, which would expose all generators to market price signals and would better account for whole system costs, facilitating the development of projects with the highest net value to consumers and society.

To move even further toward technology neutrality, the government could revert to allowing carbon pricing to direct investments in generation technologies. At the start of the Electricity Market Reform in 2010, a carbon price on its own (whether via emissions trading or via a carbon tax) was not considered sufficiently bankable for long-term infrastructure investments. However, there are ways in which the carbon price could, in theory, be strengthened and made more bankable, including offering long-term carbon price contracts. Upcoming reviews of the cost of energy for the UK government, and the Clean Growth Plan, will need to address these issues.

Question 2: Should renewables pay for their integration costs (and if so, how)?
Integrating large amounts of variable renewable energy generators has significant cost implications (e.g., costs for back-up capacity, balancing services, and network expansion and reinforcement), which are largely socialised across electricity consumers. More efficient integration of those renewable assets would mean exposing them to the SICs. In many parts of the electricity system, this already happens (e.g., in the balancing market, where recent reforms have sharpened the price faced by out-of-balance generators). The falling cost of offshore wind will lead to calls from the industry to deploy greater volumes. Unless projects are exposed to SICs, there will be a growing wedge between what is good for projects and what is good for consumers and society as a whole. In this context, it is important to understand the impact of greater penetration of variable renewables on wholesale market dynamics and how this might affect the efficient deployment of flexible generation (of all types) and storage (e.g., hydro, hydrogen, batteries), as well as the role of demand response. Technological changes are increasing the ability of wind and solar to respond to price signals. Clear market price signals will help the deployment of storage and other forms of flexibility. Subsidy regimes that expose generators to power prices (e.g., premium FITs, or simply changing the reference price within the CfD) would provide greater incentives for renewables generators to respond to market conditions and consumer demand.

Question 3: An end to subsidy… and an end to risk transfers?
Widespread deployment of offshore wind without subsidy in the UK would be a revolutionary development. It would also loosen the control that government currently has over the electricity technology mix. Exposure to merchant price risk, however, weakens project economics by increasing projects' cost of capital and potentially affecting debt provision and conditions. Current financial and PPA markets are not set up for such projects at scale, but would no doubt evolve to meet the challenge.

As noted, the prospect of technology neutrality raises the question of whether—and how—one can really compare the various low-carbon technologies. LCOE does not take account of the full integration costs, nor does it reflect the difference between a guaranteed, contracted revenue and exposure to market price risk. Being at "grid parity" (i.e., with a cost at or below the expected wholesale price) or being cheaper than gas CCGT in terms of LCOE is not the same as being competitive in the electricity market without government contracts. If we really have entered an era of non-subsidy offshore wind farms, there will need to be adjustments to wholesale and PPA markets, policy, and among investors and financial markets.

Question 4: Is it time to sharpen delivery incentives?

In assessing the extent to which low auction bids represent a revolution in cost reduction for offshore wind, we must also bear in mind that it will be a long time before these projects are delivered. There were similar renewables auctions in the UK in the 1990s (the NFFO auctions), which were very successful at producing low bids, but rather less successful at producing actual projects. Due to bidders placing their bids at a very early stage of project development, before planning permission had been secured, the vast majority of projects in the later auction rounds fell victim to winner's curse and only a small proportion of the winning projects were actually built. In the German and Dutch auctions, the authorities have required the posting of bid bonds, which will be forfeited in the event of non-delivery of the project. In the UK, the non-delivery penalty is exclusion from further auction participation for 24 months (although there are likely to be further incentives to proceed once the first milestone is reached, 12 months after accepting the CfD). Time will tell whether these sanctions are sufficient to deter over-aggressive bidding.

Notes

1 Winners in the auction (those who bid the lowest strike prices) receive a 15-year subsidy contract known as a "contract for difference", or CfD. The "less established technologies" classification or "pot" contains offshore wind, advanced (waste) conversion technologies (ACT), biomass with CHP, wave and tidal, and other technologies. Projects with planning permission and grid connection agreement offers from all of these technologies compete against each other, bidding down the strike prices (subsidy) required in one of a number of future delivery years (for this auction, the delivery years were 2021/22 and 2022/23). The government sets the maximum budget for the auctions and other parameters, such as maximum strike prices for each technology.

2 See reports by ORE Offshore Wind Catapult: "Transmission Costs for Offshore Wind: Final Report," Offshore Wind Programme Board, April 2016, https://ore.catapult.org.uk/wp-content/uploads/2016/05/Transmission-Costs-for-Offshore-Wind.pdf.

3 "The wind has changed," Offshore Wind Industry 2017, http://www.offshorewindindustry.com/sites/default/files/owi_03_2017_the_wind_has_changed.pdf.

4 LCOE is based on new combined cycle gas turbine (CCGT) costs of £66-90/MWh reported in the UK government's recent cost of electricity generation study: "BEIS electricity generation cost report," Department for Business, Energy & Industrial Strategy, 9 November 2016, https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016. Our financial modelling suggests an offshore wind strike price of £57.50/MWh is consistent with an LCOE of less than £50/MWh.

5 See Daniel Radov and Alon Carmel, "UK Renewable Subsidies and Whole System Costs: The Case for Allowing Biomass Conversion to Compete for a CfD," 16 February 2016, http://www.nera.com/publications/archive/2016/NERA_Imperial_Feb_2016_Renewable_Subsidies_and_Whole_System_Costs_FINAL_160215.html; and Philip Heptonstall, Robert Gross, and Florian Steiner,"The costs and impacts of intermittency—2016 update," UK Energy Research Centre, February 2017, http://www.ukerc.ac.uk/programmes/technology-and-policy-assessment/the-costs-and-impacts-of-intermittency-ii.html, or Clara F. Heuberger, Iain Staffell, Nilay Shah, et al., "A systems approach to quantifying the value of power generation and energy storage technologies in future electricity networks," Computers & Chemical Engineering, 18 May 2017, http://www.sciencedirect.com/science/article/pii/S0098135417302119?via per cent3Dihub.

6 See Dominik Huebler, Daniel Radov, and Lorenz Wieshammer, "Method or Madness: Insights from Germany's Record-Breaking Offshore Wind Auction and Its Implications for Future Auctions," NERA, May 2017, http://www.nera.com/content/dam/nera/publications/2017/PUB_Offshore_EMI_A4_0417.pdf.

7 Because the wholesale price projections for the two markets come from different sources, they are not necessarily based on identical underlying assumptions.

8 This information is based on analysis set out in Richard Hern, Daniel Radov, Alon Carmel, et al., "Electricity Generation Costs and Hurdle Rates," Department of Energy and Climate Change, 9 November 2015.

9 It is possible that grid connection costs for Hornsea 2 will actually be lower than typically estimated for offshore wind farms, given that it lies next to the Hornsea 1 offshore wind farm, which is currently under construction, allowing Hornsea 2 to benefit from economies of scale.

10 Richard Hern, Daniel Radov, Mauricio Bermudez-Neubauer, et al., "Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime," Department of Energy and Climate Change, 9 December 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267606/NERA_Report_Assessment_of_Change_in_Hurdle_Rates_-_FINAL.pdf.

11 "DONG Energy awarded three German offshore wind projects," DONG Energy, 14 April 2017, http://www.dongenergy.com/en/investors/company-announcements/company-announcement-detail?omxid=1557851.

12 Michael G. Pollitt, "UK Renewable Energy Policy since Privatisation," EPRG Working Paper, University of Cambridge, January 2010.

13 For a discussion of simulation modelling as an important planning tool for bid strategy, see Daniel Radov, Alon Carmel, and Clemens Koenig, "Gale Force Competition? Auctions and Bidding Strategy for Offshore Wind," NERA, 2016, http://www.nera.com/content/dam/nera/publications/2016/PUB_Offshore_Wind_A4_0916.pdf.

14 The auctioneer (National Grid) follows rules set by the government in calculating the auction clearing price and budget impacts. National Grid uses government-mandated assumptions about load factors and electricity wholesale prices to calculate the amount of subsidy implied under each CfD contract, and compare that to the total budget released (£295M per year for this auction, in 2012 prices). It is worth remembering that the actual budget impact, and impact on consumer bills, will depend on actual wholesale prices and load factors. In addition to the budget constraint, the government also imposed a cap (150 MW) on the amount of bioenergy capacity that could be awarded a CfD. To prevent capped bioenergy projects from securing high prices set by other technologies, bioenergy prices are allowed to set the price for other technologies, but not the reverse—as we discuss later in this paper. The bioenergy cap appears to have been binding in the auction, as nearly 150 MW of bioenergy projects were successful and significant amounts of budget remained unused.

15 This is not the only explanation for the auction outcome. Another possibility is that a bioenergy bid for 2022/23 in the low-to-mid £70/MWh range led to a budget breach that closed the 2022/23 commissioning year to further bidding, leaving 2021/22 free to accommodate more projects. This is consistent with the observed auction outcome as long as one is willing to assume that (i) there were no bioenergy bids for 2022/23 between £40/MWh and the budget-breaking bid and (ii) there was at least one bioenergy bid for 2021/22 slightly below the budget-breaking bid that caused the strike price for 2021/22 to be sufficiently high (thus setting up the broken budget constraint in 2022/23).

16 This project must have bid £40/MWh in 2022/23, as there are no other successful bioenergy projects, and bioenergy cannot benefit from the clearing price set by offshore wind.

17 As discussed above, it is likely that among the bidders for 2022/23 there was another large offshore project that could not be accommodated within the budget. Delivery year 2022/23 was therefore closed, preventing any other bioenergy projects from being awarded and setting the price for the project having bid £40/MWh.

18 See Daniel Radov, Alon Carmel, et al., "Modelling the GB Renewable Electricity CfD Auctions" NERA, October 2015. The cost savings for consumers of merging Pot 1 and Pot 2 into a single auction including onshore wind was estimated as £1bn (undiscounted over the lifetime of the CfD contracts), equivalent to £650m in net present value (NPV) terms.

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