Wind Power Economics – Rhetoric and Reality

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4th November 2020

It is difficult to make predictions, especially about the future. [Attributed variously to Niels Bohr (Nobel Prize in Physics) and Sam Goldwyn (movie mogul)]

The theme of my talk is the disparity between predictions about the future costs and performance of wind power (especially offshore wind) - the Rhetoric - and the actual evidence that is available on what it costs to build and operate wind farms and the amount of power they produce over their lifetime – the Reality.

As background, I was co-author of one of the first studies of climate change produced by an international organization in 1992. I have written or co-written several studies of adaptation to climate change. My academic field is applied statistics and economics, but much of my work has been on the interface between economics and engineering. I have worked on energy and infrastructure policies for more than three decades. For example I was responsible for developing a set of international environmental standards for power plants while I was at the World Bank.

In the UK and most of Europe, both policymakers and investors have adopted the rhetoric around renewables as the basis for very costly transformations of our economy and society to meet the goal of low or zero carbon emissions. In doing so, they have accepted the claims of dramatic improvements in costs and performance made by wind operators for new projects now and in the future. Unfortunately, the propensity of both governments and companies to understate the costs and overstate the performance of new projects has a history that is long and inglorious. The ongoing record of HS2 – and, indeed, the whole history of railways in the UK – should be sufficient warning not to believe the rhetoric.

There is a core idea that is crucial for proponents of renewable technologies across a wide range. This is that costs – or specifically capex costs – will decline over as installed capacity grows due to what are called economies of scale and learning. The issue then is how rapid the decline, usually measured as the % reduction for each doubling in capacity, is likely to be. There is no doubt that such a decline in unit costs has occurred in specific cases – notably the manufacture of aircraft, the production of solar PV modules and the cost of environmental controls such as FGD for power plants. However, the pattern is far from universal - the unit costs of nuclear, coal and LNG plants have tended to increase rather than decline. It is much more plausible for manufactured capital goods than for large projects involving complicated sites and civil works. In the case of offshore wind, the parallel experience of offshore oil & gas is not encouraging.

The reality of what will happen to the costs of key renewable energy and other low carbon technologies is critical. The UK Government's strategy for meeting its Net Zero target at an affordable cost rests on the core assumption that the costs of wind power have fallen - and will continue to fall. There is, however, a major problem with all of the projections produced by official agencies, academics and other organisations. Put bluntly, they are the product of wishful thinking applied to notional projects in the future with little or no connection to commercial reality.

Hence, in my work I have adopted a completely different approach. My starting point is the actual data reported by companies in their accounts over the last two decades. This is possible because the standard commercial arrangement is that solar, wind and other projects are operated via legal entities known as Special Purpose Vehicles whose accounts are usually audited and are filed with Companies House. I have collected data for more than 350 SPVs responsible for wind projects that have filed accounts since 2005. The dataset is unique and provides the basis for a detailed analysis of the actual costs of wind power.

Figure 1 shows the evolution of capex costs for onshore wind since the early 2000s when the modern technology using turbines with a capacity of 2+ MW became standard for utility scale projects of 10+ MW. There are large variations in unit capex costs across sites but overall the dashed line shows that there has been a significant increase in the average capex cost per MW as the amount of installed capacity has increased. Onshore wind generation has been a mature technology for at least 15 years. Global installed capacity was about 58 GW in 2005 and reached 540 GW in 2018. If actual capex costs per MW in the UK have been rising for 15 years, there is no reason to believe that the trend will abruptly change.

Figure 2 shows the equivalent data for UK offshore wind projects. In this case the average capex costs include the cost of the offshore transmission system, since this is an essential element of any project. There are two points to note. First, offshore wind is a pan-European industry with the major operators having projects spread over North-West Europe. Hence, I have used installed offshore capacity in Europe as my capacity variable. Second, the outlier with a very high capex cost per MW is the Hywind floating turbine project. Capex costs for floating turbines are typically 50% to 100% more expensive than for turbines fixed to the sea bed.

Offshore wind is less mature with global capacity of 3 GW in 2010 reaching 24 GW in 2018. The trend line shows that, leaving out the Hywind project, actual offshore capex costs for UK projects have increased by 15% for each doubling in European capacity. Figure 3 shows the same results but over time with markers that indicate the typical water depth for each wind farm. Statistical analysis confirms that one factor contributing to the increase in costs over time has been the need to use deeper water sites as offshore capacity has grown. This is a more powerful influence than distance from the coast. Underlying costs are likely to continue to increase because the number of suitable offshore sites with shallow or medium depths is limited. As for offshore oil & gas the costs of building and operating offshore wind farms located at deep water sites in hostile marine environments will inevitably be higher than for the initial set of shallow water projects.

But there is worse to come. Figure 4 and 5 shows the evolution of average opex costs for typical onshore and offshore projects. The graphs are based on analyses of large samples spread over 15 years which allow for turbine size, water depth, OFTO status and other factors. In each graph the blue line shows the costs for a project commissioned in 2008. Note that opex cost is reported in £000s per MW per year at 2018 prices. The reason is that the expected load factor for new projects has increased over time. The grey line shows the costs for a project commissioned in 2018. For the offshore wind farms the 2008 project is assumed to be in shallow water with no OFTO while the 2018 project is in deep water with an OFTO. The operating costs allow for OFTO charges in the latter case.

For both onshore and offshore wind the base level opex cost has shifted up significantly over time and costs increase with year of service. I will focus on offshore wind because this is central to the whole Net Zero strategy. Converting offshore opex costs to £ per MWh using an expected load factor of 35% for the 2008 project and 50% for the 2018 project we get initial opex costs of £17 per MWh for the 2008 project and £44 per MWh for the 2018 deep water project. By age 12 the opex cost for the 2008 shallow water project will be £30 per MWh and it will be £82 per MWh for the 2018 deep water project. The wind-weighted average market price of power in 2019-20 was £35 per MWh. This means that at market prices – i.e. without subsidies - offshore wind from deep water projects cannot even cover operating expenses at age 1, let alone earn an adequate return on capital.

In the case of offshore wind the initial average opex cost of £44 per MWh for the 2018 deep water project, which is typical of the future for the sector, exceeds the average revenue per MWh in 2019-20 at market prices weighted by wind output. The average opex cost of £82 per MWh for this project after 12 years of service either equals or exceeds the guaranteed strike for all offshore projects awarded contracts from Allocation Round 2 (2017) onwards.

These results for capex and opex costs run completely counter to the wishful thinking put out by BEIS. The opex estimates, in particular, prompt the question of why costs are so high and have been increasing over time. To investigate this issue I have examined detailed data on the performance of 6,400 turbines in Denmark. This is a substantial update of my previous work published in 2012 using satellite data that allows me to control more reliably for variations in wind conditions.

The first part of the study examines equipment failures and major breakdowns. Figure 6 shows the failure curves by turbine category focusing on the time to the first equipment failure. The results are similar if alternative failure indicators are used. The conclusions are that (i) offshore turbines are less reliable than onshore turbines, and (ii) the older small (< 1 MW) onshore turbines were much more reliable than the 2+ MW turbines that dominate wind farms constructed since 2005. Nearly 60% of offshore turbines will experience an equipment failure in their first 5 years of operation. The reliability of 2+ MW onshore turbines deteriorates over time, so that the risk of failure increases sharply once they have been operating for more than 10 years. Finally, there are strong locational differences within Denmark with the expected number of months affected by equipment failure over a 20-year operating life increasing from 8 months in the west of the country to 15 months in the east. The reason seems to be a combination of site choice and wind turbulence caused by wind flows over land for the prevailing westerly winds.

The second part of the Danish study looks at the evolution of the average load factors for onshore and offshore turbines with age after allowing for variations in the distribution of wind speeds and other factors. One major conclusion is that the 2+ MW turbines that were introduced in the early 2000s experienced major performance problems in the period from 2002 to 2010. This is very obvious when such turbines are compared with the smaller turbines of less than 1 MW installed up to 2000. In Denmark – and probably in the UK – the new generation of 2+ MW turbines experienced major teething problems for 5 to 8 years after they were introduced on a large scale. That is an important warning about the effects of generational shifts in turbine technology.

The third major conclusion is that the average load factor for onshore turbines declines at about 3% per year as turbines age, while the average load factor for offshore turbines declines at about 4.5% per year. This means that an onshore wind turbine installed in a location where its load factor, standardised for wind conditions, at age 1 should be 35% can be expected to achieve a standardised load factor of 25% at age 12 years. For an offshore wind turbine the decline might be from a standardised load factor of 55% at age 1 to one of only 33% at age 12.

There is an important corollary when the analysis of the performance of Danish turbines is combined with the actual opex costs for UK wind farms. Once the decline in load factor with age is taken into account, the average opex per MWh for an onshore wind farm installed in 2018 rises from £24 per MWh at age 1 to £42 per MWh at age 12. The equivalent figures for an offshore wind farm are £41 per MWh at age 1 and £125 per MWh at age 12. The increases in opex costs have a drastic impact on the expected economic life of wind farms.

If wind farms do not receive offtake prices that are higher than the market price – or very much higher in the case of offshore wind – their expected revenues will not cover opex costs after 12 or 15 years. Operators will either cease production or drastically cut operating costs leading to closure within a relatively short period. There is no way out of this trap because opex costs are linked to reliability; the decline in reliability with age means that high opex costs must be incurred to maintain production. The consequence is that the assumption made by BEIS and many investors that the expected operating life of new wind farms will be 25 or 30 years is completely at odds with the underlying economic reality. Few modern wind turbines operate for more than 20 years and many offshore wind turbines are likely to be decommissioned before they reach an age of 20 years.

Pulling these threads together I have examined the overall economic prospects for some specific projects and for offshore wind in general, focusing on the separate perspectives of investors and policy makers.

In the Danish study I have carried out a detailed risk analysis of the Kriegers Flak offshore wind farm being built by Vattenfall. This has all of elements of a financial disaster. It is unclear whether Vattenfall – a state-owned Swedish company underwritten by Swedish electricity consumers – understands what it is doing. Implicitly it has placed a huge speculative bet on the market price of power in Germany in the period from 2033 onwards, after the expiry of the initial power purchase agreement (PPA).

The breakeven price for the PPA is €75-85 per MWh excluding transmission charges whereas the actual PPA price is €50 per MWh. To recover its initial losses and offset the expected decline in the average load factor the market price in Germany would have to be roughly 6 times in real terms the average price over the last 12 months – equivalent to about €130 per MWh at 2018 prices. This is far higher than current plans for increasing carbon taxes would imply.

It is standard practice for offshore wind operators to refinance completed projects, in part by bringing in passive investors such as an infrastructure funds or groups of pension funds. This allows the operator to recoup some of its investment, thus realising part of its expected profit or limiting its potential losses. However, investors might be well-advised to steer well clear of Kriegers Flak. The fundamental problem is that the gross cash flow is likely to be consumed by debt service for the initial 12 to 15 years. Any cash extracted by Vattenfall will merely increase the risk borne by the passive investors.

The story is similar for offshore wind projects in the UK supported by CfD contracts awarded in 2017 or 2019. Figure 7 shows a simplified version of the cash flows for the Triton Knoll wind farm based on its CfD contract using alternative performance scenarios. The blue solid line shows gross revenue for a constant load factor of 50% over its lifetime, while the green solid lines shows gross revenue for a load factor of 55% at age 1 with a performance decline of 2% per year thereafter. This decline is much lower than the actual experience in Denmark. The red dashed line is total opex, while the mauve dashed line is the sum of opex and a finance charge for a real WACC of 4% with an asset life of 15 years. The economic life would be 15 years with the constant load factor and only 12 years for the declining load factor. Operating profit – gross revenue minus opex – is less than the finance charge in every year under both revenue scenarios. The project is clearly a dud for both lenders and investors if we base projections for revenues and costs on actual experience. So, what we have is the usual bromide "this time things will be different" – a variant of Samuel Johnson's triumph of hope over experience.

Figure 8 shows average strike prices and my estimates of breakeven prices for the CfD contracts in different allocation rounds together with the assumption necessary to achieve the breakeven prices. For onshore wind the average AR1 strike price is very close to the breakeven prices in the 2018 cost and performance scenario. For offshore wind the Investment Contract strike price of £161 was slightly more generous than the 2018 breakeven price of £152 per MWh. For projects in operation the CfD prices are reasonably close to breakeven prices and no-one should lose a lot of money.

However, for Allocation Rounds AR1 and AR2 it is necessary to make very ambitious assumptions about costs and performance to match the average CfD strike prices. In AR1 the average CfD strike price was £112 per MWh. For a breakeven cost at that level projects would require a constant load factor of 58% over 15 years if costs are similar to the 2018-19 actual costs. No offshore project, even with 8-10 MW turbines, has got close to achieving that performance. In AR2 the average CfD strike price was £65 per MWh. To get the breakeven price down to that level it is necessary to assume a constant load factor of 60% and operating costs equivalent to those for shallow water projects completed in 2008-09. This is pure fantasy!

There is a larger issue behind the story of individual project risks. This concerns the stability of the financial sector. In the UK and several other European countries governments, central banks and financial regulators have actively promoted green finance. They argue that banks, money managers and pension funds should increase their lending to and investment in wind farms and similar projects as part of their wider social responsibility. However, if many such projects are very risky – as is clearly the case – this pressure is a betrayal of their fundamental duty to protect the stability of the financial system. It is no different from urging financial institutions to finance speculative property developments at the beginning of a property crash.

The likely response is that general advice does not override the obligation of lenders and investors to identify good and bad projects. That position highlights the central problem. There are no good offshore wind projects without either huge subsidies or much higher market prices. Government policy is based on assumptions that can be shown to be wrong with any reasonable amount of due diligence. Financial institutions that do their job properly are likely to be condemned for failing to support the shift to green energy. Most of them will prefer not to look too hard and to go along with the short term pressure.

This is an old and disreputable story with only one outcome, so everyone should face up to what will happen. Financial institutions will do as they are told and join the party. In roughly a decade the likelihood of large future losses will become all too obvious and asset write-downs will jeopardise both loan security and investment returns. Governments will blame financial institutions for irresponsible behaviour. They will bail out all parties via a large increase in market prices. Apart from a few people who get fired – no doubt with ample compensation - the ultimate patsy in all of this will be electricity customers.

So far I have focused on the costs and performance of wind power. There is an equally important issue concerning the economic value of the output produced from wind farms. It is well known that both wind and solar power give rise to significant system costs that are paid by customers in general. To economists these are known as negative externalities and, just as for CO_2 and other pollution, their cost should be covered by the producer. That is the standard case for a carbon tax. If we follow that logic, wind and solar generators should be required to pay a charge equal to the marginal system costs of additional wind or solar output.

In a forthcoming study I have estimated the marginal cost of balancing supply and demand in the UK which covers some but not all of these system costs. The marginal balancing cost is closely related to the level of wind output, varying from £11 per MWh at the 5th percentile to £31 per MWh at the 95th percentile. Figure 9 shows the effect of allowing for this element of system costs on the cumulative distribution of the net values of wind and solar output in 2019-20. Net value in this context means the market value of the power **minus** the extra system costs incurred in handling wind or solar output. The solid black line is the cumulative distribution of market prices, while the dashed blue line shows the cumulative distribution of the net values of wind output. There is a large difference between the two: 50% of all wind output in the year had a net value of less than £13 per MWh and 20% of all output had a negative net value, i.e. it made everyone worse off. To be clear, Figure 9 shows that the breakeven cost of producing wind output with a net value of less than £13 per MWh is between £91 and £152 per MWh.

In stark terms a significant portion of wind output is expensive to produce and of no value in terms of its contribution to national wellbeing. Other than sheer ignorance there is no excuse for policymakers tolerating, let along promoting, this outcome.

I will conclude with some general lessons from the study:

1. Stop pretending! The projections of the costs of achieving Net Zero put out by government bodies and many others rely on cost estimates that are just wishful thinking. They have no basis in actual experience and a realistic appraisal of trends in costs. As a very broad brush calculation the cost of meeting the Net Zero target by 2050 is much more likely to be 10+% of annual GDP than the claimed 1-2% of GDP.
2. Accelerating arbitrary targets is very expensive. If the Government persists with the goal of building 30 GW of extra offshore wind capacity by 2030 the costs discussed here are likely to be significant under-estimates. This will be reinforced by the adoption of similar targets elsewhere in NW Europe. The offshore wind sector does not have the capacity to build new projects at a rate of 3 to 4 times the last decade. Any familiarity with the history of offshore oil & gas and other energy projects tells us that the consequence will be a gold rush. It is plausible to assume that capex and opex costs will rise by a minimum of 20% and probably closer to 50% above the already high costs that we observe in the audited accounts.
3. Bailouts of wind farms and financial institutions are inevitable. The Government is creating a situation in which it will have no option other than to bail out failed and failing projects simply to ensure continuity of electricity supply. There will be a game of pass the parcel over how the losses will be distributed but ultimately they will fall largely on taxpayers and energy customers. Any business investor outside the renewable energy sector should plan on the basis that electricity prices in 2030 will be 3-4 times in real terms what they are today.
4. Remember that not everyone has the same priorities. The UK and the EU are very minor bit players in what happens about climate change. The outcome will depend on choices made in China, the US and India. Focusing on China and India, they are only interested in options that are consistent with both economic growth and other environmental goals. Offshore wind is expensive and of limited interest in most of Asia.
5. As a rich country, the UK can afford Net Zero by 2050 at the aggregate level. However, it will mean allocating the proceeds of 10 or 15 years of economic growth to that single goal. Past experience shows that the UK's political system cannot handle the structural and redistributive consequences of following that path. A strategy that acknowledges the real economic costs and difficulties of trying to make the transition too quickly is much more likely to be accepted and implemented.

Figure 1 - UK onshore wind: actual capex cost vs installed capacity

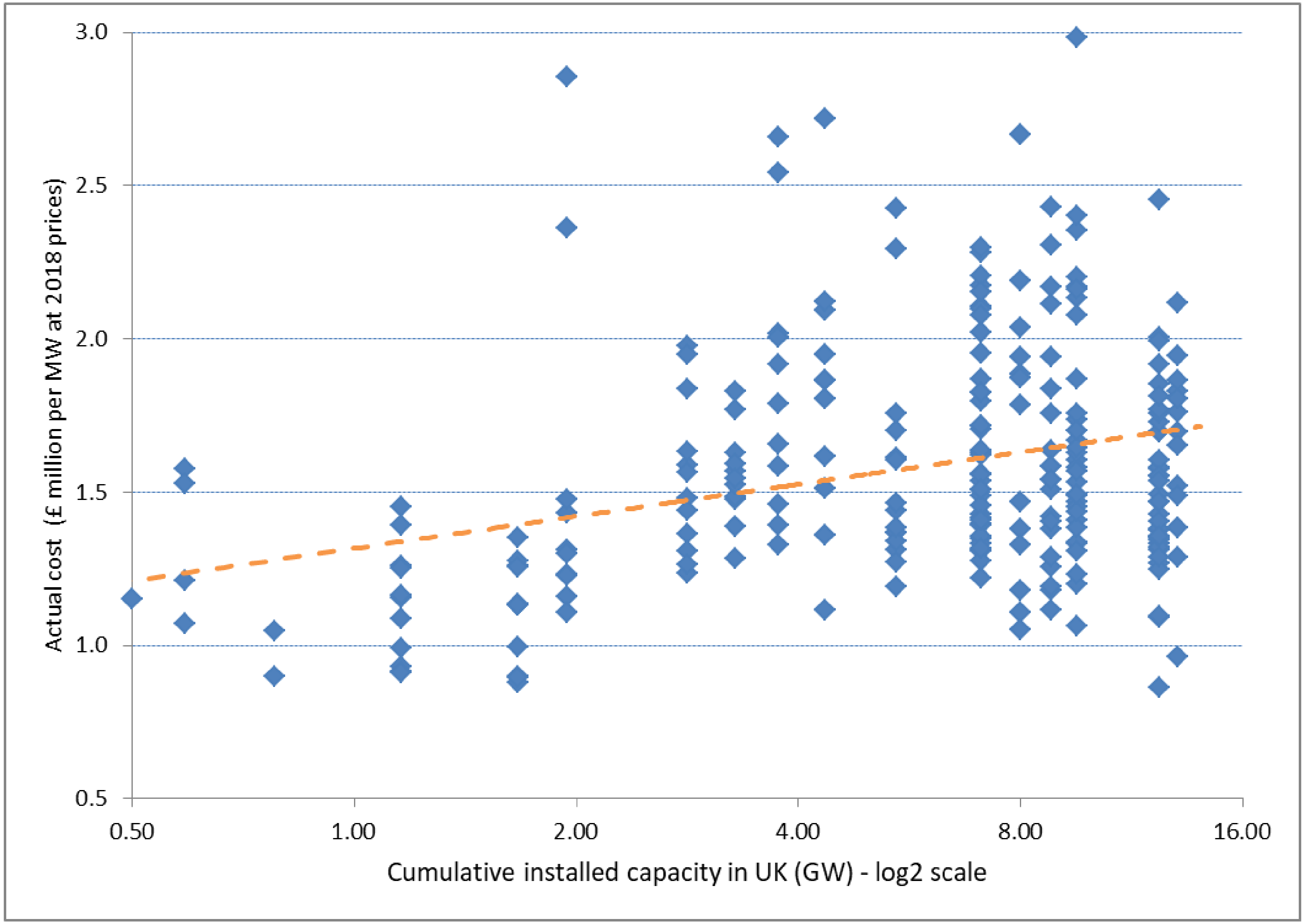

Figure 2 - UK offshore wind: actual capex cost vs installed capacity in Europe

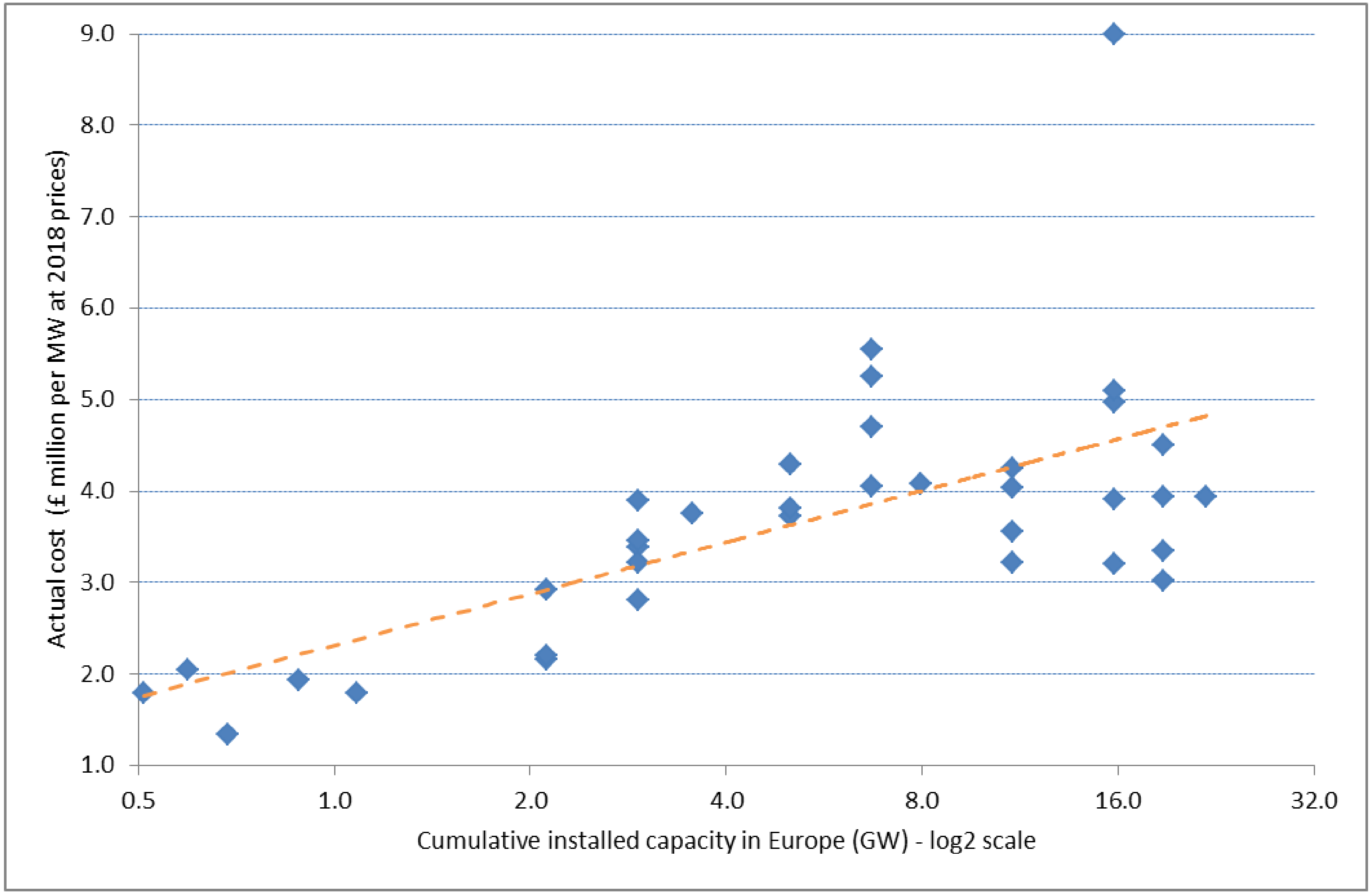

Figure 3 - UK offshore wind: actual capex cost by depth and year

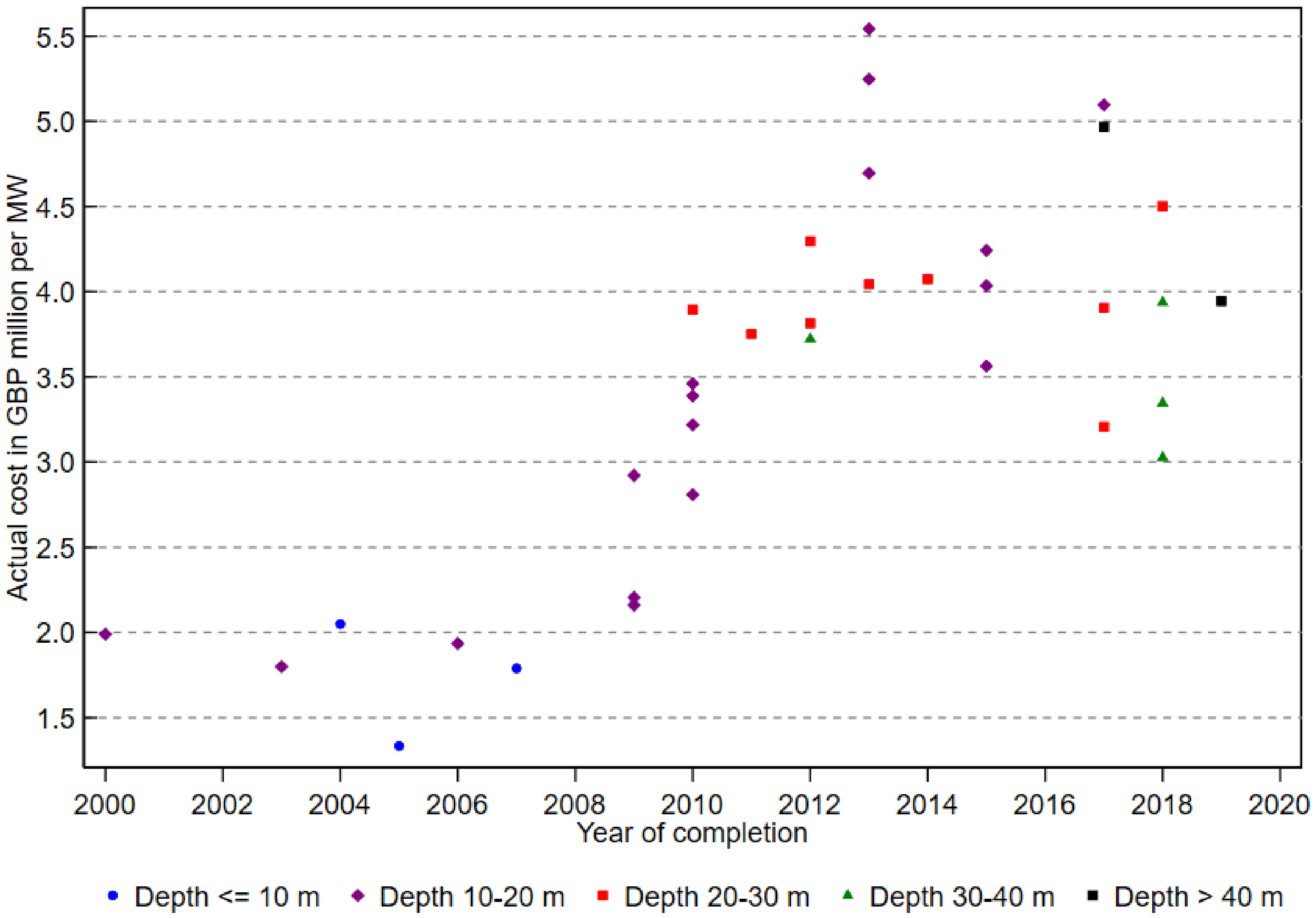

Figure 4 - UK onshore wind: average opex costs vs year of service

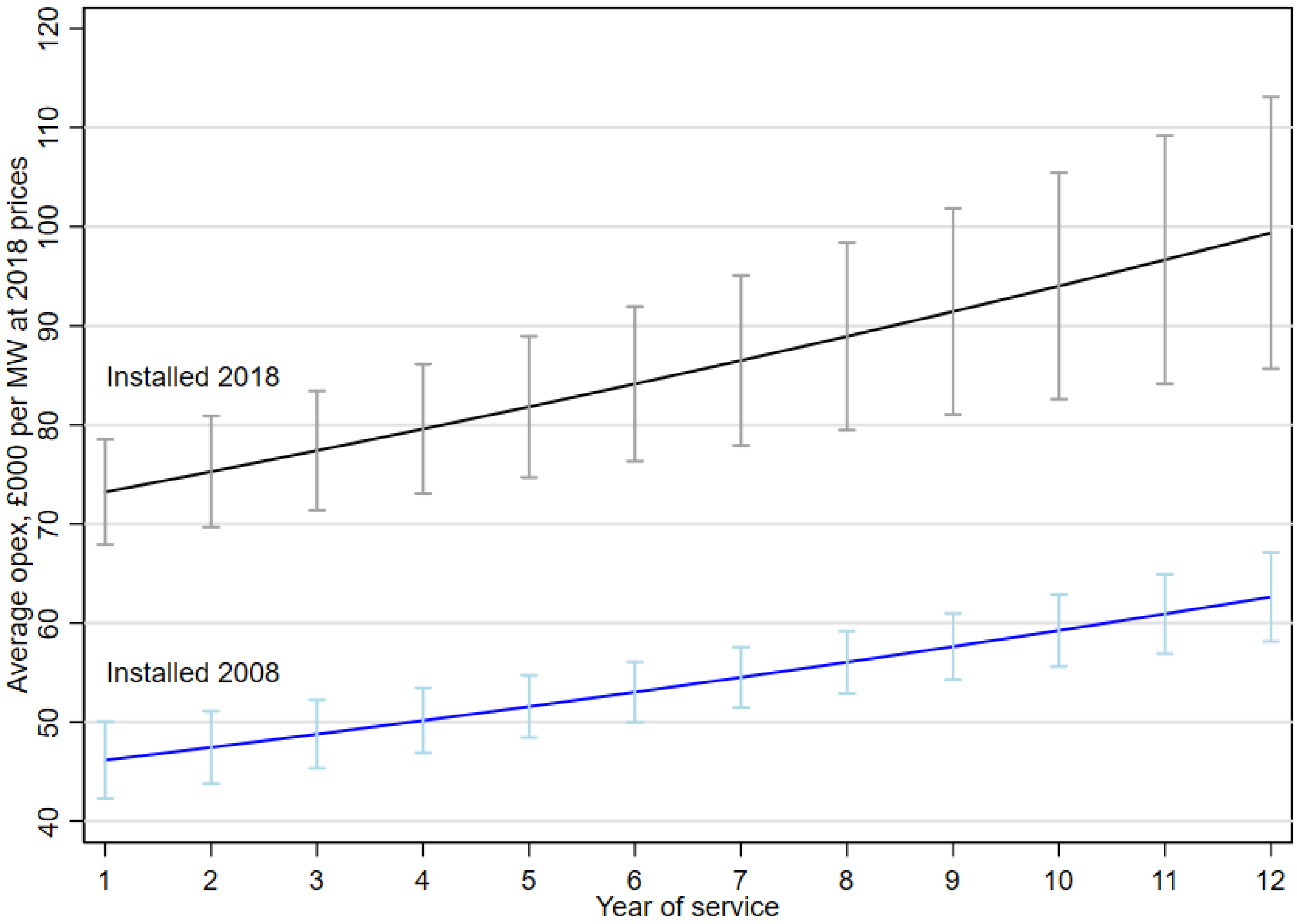

Figure 5 - UK offshore wind: average opex costs vs year of service

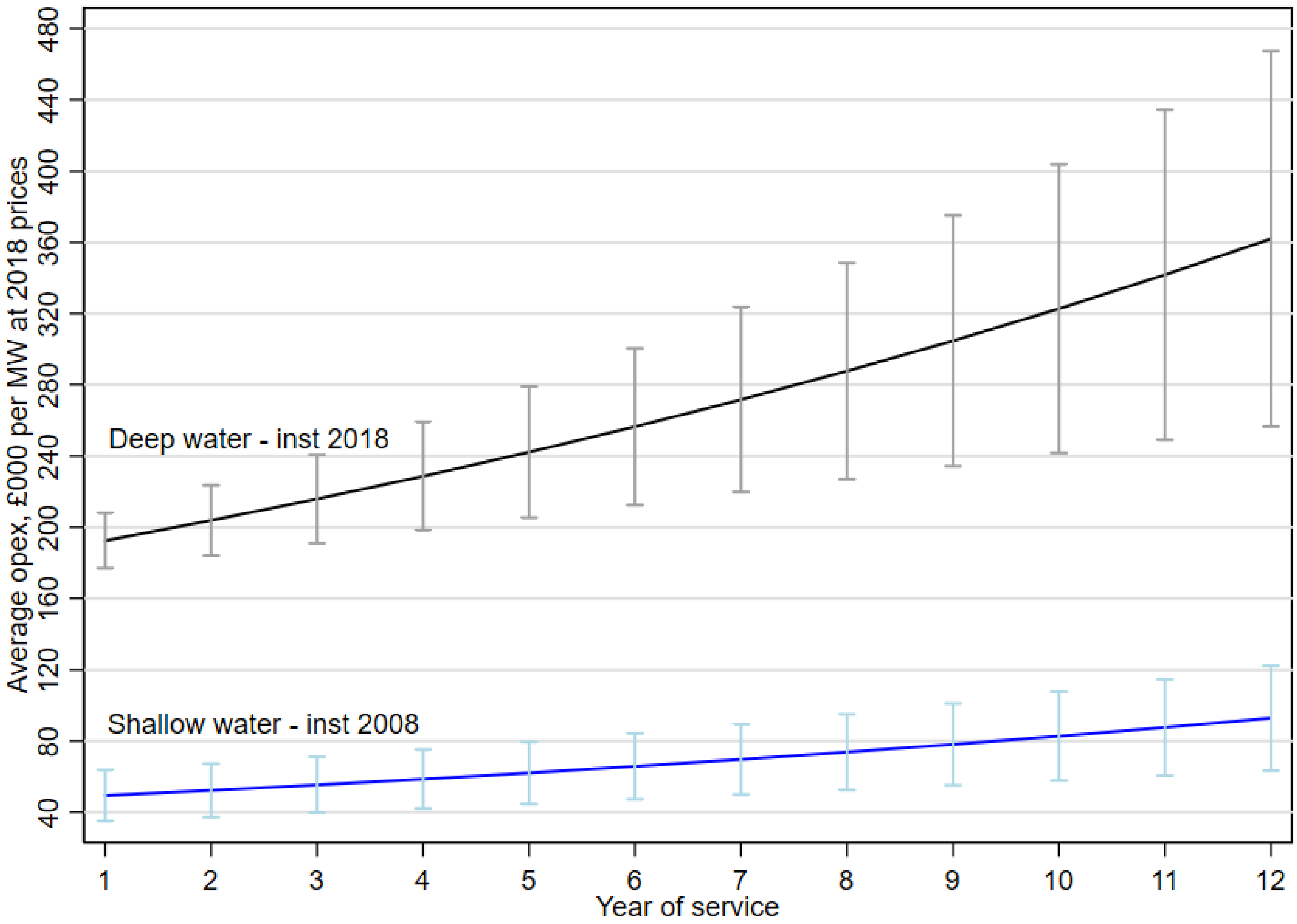

Figure 6 – Denmark turbines: failure curve for time to first equipment failure

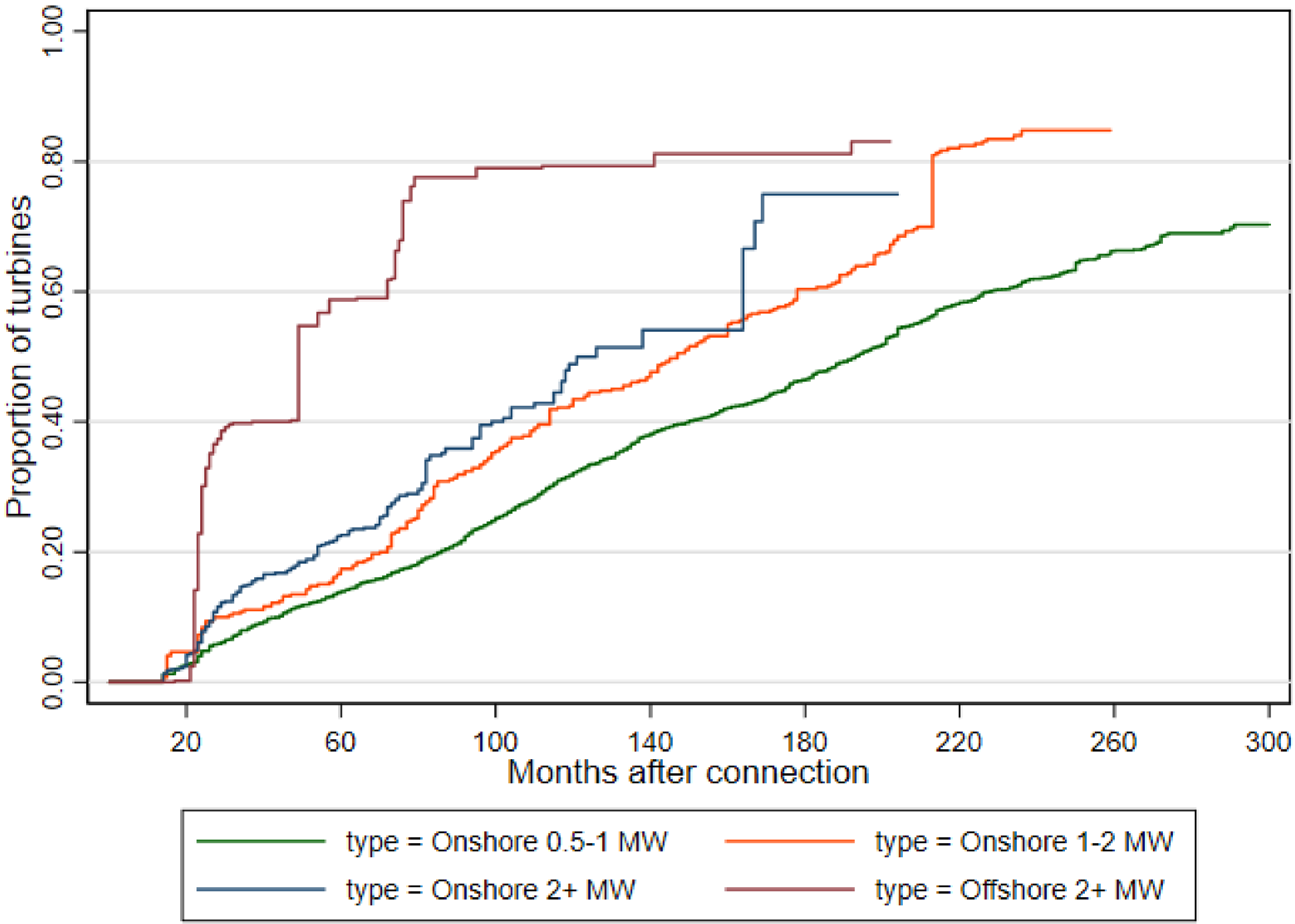

Figure 7 – Prospective cash flows for Triton Knoll project

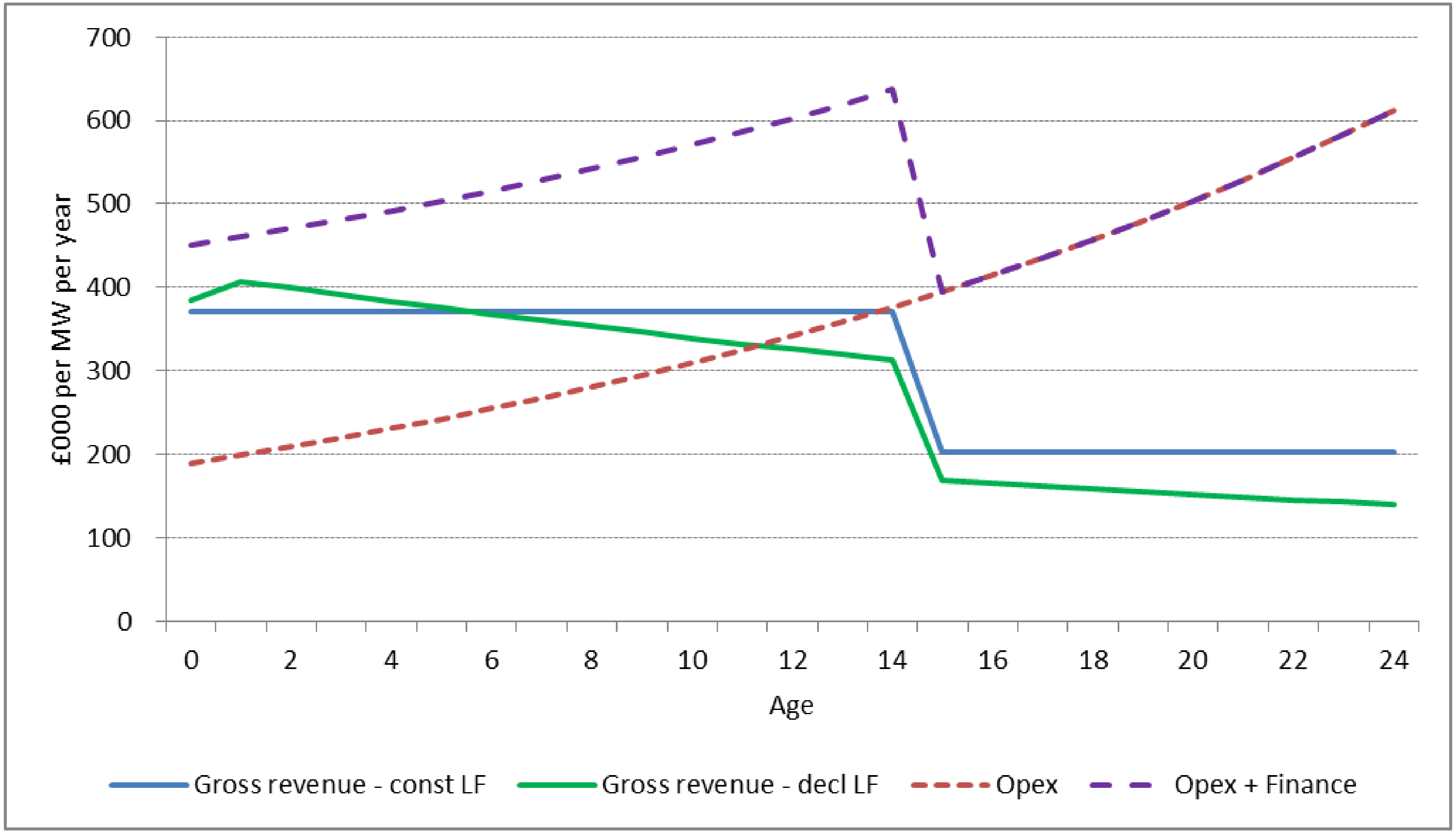

Figure 8 – Breakeven prices for CfD projects

	CFD Allocation Round	Average CfD strike price (£/MWh)	Breakeven Prices		
			Built 2008-09 (£/MWh)	Built 2018-19 (£/MWh)	In progress (£/MWh)
Onshore wind (actual costs)	Allocation Round 1	£92	£92	£91	
Offshore wind (actual costs)	Investment Contract	£161	£125	£152	
Offshore wind (Model A)[a]	Allocation Round 1	£112			£114
Offshore wind (Model B)[b]	Allocation Round 2	£65			£68

Notes:

(a) Model A: the breakeven price of £114 / MWh assumes a constant load factor of 58% with other parameters based on actual values

(b) Model B: the breakeven price of £68 / MWh assumes a constant load factor of 60% plus operating costs for shallow water projects completed in 2008-09

Figure 9 – Effect of system costs on the net value of wind & solar generation