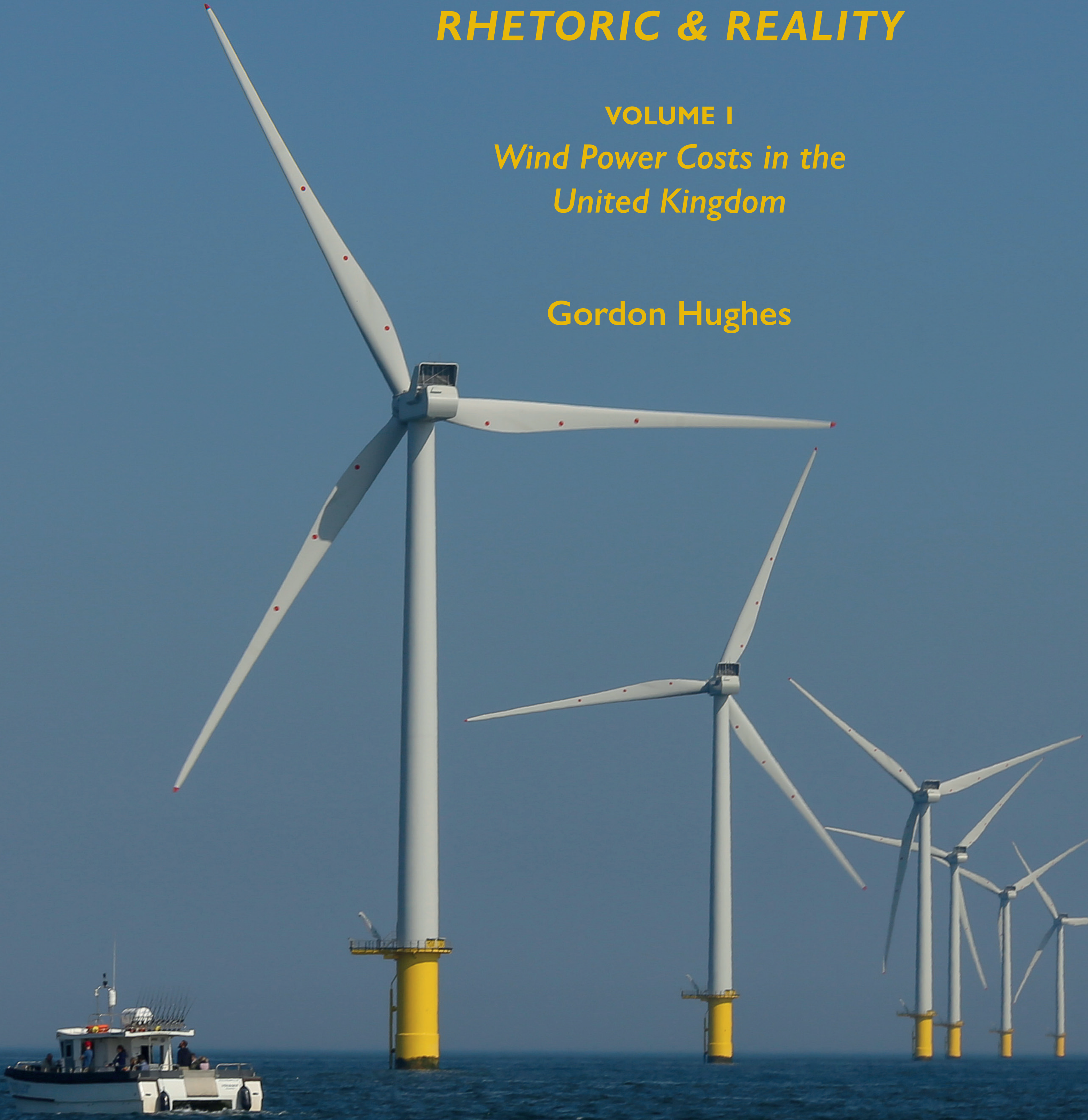
WIND POWER ECONOMICS
RHETORIC & REALITY

VOLUME I

Wind Power Costs in the United Kingdom

Gordon Hughes



REF
Renewable Energy Foundation

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Gordon Hughes
School of Economics, University of Edinburgh

REF
Renewable Energy Foundation

Published by Renewable Energy Foundation
Registered Office
Unit 9, Deans Farm
Stratford-sub-Castle
Salisbury
SP1 3YP

The cover image (Adobe Stock: 263859897) shows Rampion windfarm off the coast of Brighton, UK.

www.ref.org.uk

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WIND POWER COSTS IN THE UNITED KINGDOM

Summary: Are the costs of wind generation really falling in the UK?

Almost every report or lengthy article on the future role of renewable energy is accompanied by a chart which claims to show the rapid decline of the costs of renewable electricity generation over the last one or two decades, perhaps with projections forward to 2030 or 2040. The problem for any non-technical reader is simple: Are these claims and projections plausible? We should note as a warning sign that these optimistic scenarios almost always come from corporate or governmental sources that have no personal wealth at stake and cannot be taken on trust. This leads us to the obvious and most important substantive question: *Do those asserting large and likely further reductions in the cost of wind generated electricity, rely on empirical data about present or past circumstances which they have compiled and manifestly understand?* As anyone familiar with the literature will know, it is extremely rare to find a study that presents any, let alone an adequate, quantity of primary data and attempts serious analysis on that basis.

This paper attempts to remedy that unsatisfactory situation and presents findings based on a statistical and econometric analysis of a database compiled by the author of the actual capital and operating costs for a large majority of the onshore and offshore wind farms built in the United Kingdom since 2002 and with a capacity of at least 10 MW. The database covers more than 350 wind farms, all commissioned before or in 2019 – a much larger sample than for any previous study.

The findings are complex but sobering:

(1) **The actual costs of onshore and offshore wind generation have not fallen significantly over the last two decades and there is little prospect that they will fall significantly in the next five or even ten years.**

(2) While some of the components which feed into the calculation of costs have fallen, the overall costs have not. For example, the weighted return for investors and lenders has declined sharply, especially for offshore wind, because of a fall in perceived risk. In addition, the average output per MW of new capacity may have increased, particularly for offshore turbines. However, these gains have been offset by higher operating and maintenance costs (O&M).

(3) **Far from falling, the actual capital costs per MW of capacity to build new wind farms *increased* substantially from 2002 to about 2015 and have, at best, remained constant since then.** Reports discussing the construction of new offshore wind farms in the early 2020s imply that their costs may fall by 2025, but such reports are consistently unreliable as

well as being incomplete. Final costs tend to be significantly higher, so little weight can be attached to forecasts of future costs.

(4) **Far from falling, the operating costs per MW of new capacity have increased significantly for both onshore and offshore wind farms over the last two decades.** In addition, operating costs for existing wind farms tend to increase even more rapidly as they age. The cost increase for new capacity seems to be due to the shift to sites that are more remote or difficult to service. Much of the increase with age is due to the frequency of equipment failures and the need for preventative maintenance, both of which are strongly associated with the adoption of new generations of larger turbines – both onshore and offshore.

(5) Turbine manufacturers and wind operators appear to be relying on an increase in load factors via (i) an increase in hub heights to take advantage of higher wind speeds, and (ii) changes in the engineering balance between blade area and generator capacity. However, the inferior reliability of new turbine generations leads to a more rapid decline in performance with age, so that the ultimate effect on average performance over the lifetime of new turbines is unclear.

(6) **The combination of increasing operating and maintenance costs with lower yields with ageing means that at current market prices the expected revenues from electricity generation will be less than expected operating costs after the expiry of contracts guaranteeing above-market prices**. The length of these contracts has been reduced, implying a need to recover capital costs over a shorter economic life, which pushes up the effective capital charge.

There is an important corollary to these findings. The current set of offshore projects being constructed and planned in North Western Europe are closely akin to speculative property development. They are high risk projects that will only be able to repay lenders and offer a return to equity investors if the average wholesale market prices of power rise to at least 3 to 4 times their current level throughout NW Europe. Such a price surge would require either a large and permanent increase in the market price of gas, which experience suggests is very unlikely, or carbon taxation at 8 to 10 times current levels, rising to at least €200 per tCO_2 at 2018 prices in 2030. Such a tax would place an insupportable burden on the economy and therefore also seems very unlikely.

This has consequences for financial regulation. To discharge their responsibilities, financial regulators ought to impose a heavy risk weighting on loans to offshore wind farm operators, while also advising that green equity investments are too risky for pension funds and small investors. Instead, the chiefs of the European Central Bank (ECB), the Bank of England and other regulators have urged more investment in green assets.

This leads to the prospect of what is not so much a car crash as a motorway pile up in the fog of ignorance. The looming crisis will require that those who finance wind power and its related ecosystem of companies are bailed out by either taxpayers or electricity consumers. The scale of the bailout would be large: about £30 billion is at risk in the UK wind sector alone, with significantly more in Germany, the Netherlands and Denmark.

There was widespread public anger over banking bailouts after the 2008 crisis, but this is likely to be exceeded in intensity by criticism of bailouts for wind farms, not least because the public has been told repeatedly that wind power is now the cheapest form of electricity generation. Some companies and institutions may lose their shirts. Rather than wait passively for the resulting collapse it is time to think urgently about how to limit the scale of the eventual problem and how to clear up that part of the mess that cannot now be prevented.

Overview and Policy Conclusions

Introduction

It is accepted by all that the costs of adopting renewable energy were high in the past, from the late 1990s up to the early 2010s. Yes, we are told, wind and solar, for example, required large subsidies extending to the mid-2030s for early projects to cover heavy capital and operating costs. In addition we are told that costs have not only been falling rapidly but will continue to fall, so that an economy powered by wind and solar power will involve little or no sacrifice in terms of living standards and welfare.

The evidence to support this vision of the future is scanty, and consists principally of the assumption that a combination of economies of scale together with learning by doing will bring down both capital and operating costs. However, while this has happened in some industries it is far from being a universal pattern. Consider, for example, nuclear power, where the imposition of ever more stringent safety standards has offset any prospect of lower costs. One should not assume that sector growth and experience will always reduce costs. In the case of the wind sector there is one powerful reason warning against such an expectation. Namely, the modern wind turbine is now a mature technology, and has been so for some time.

This maturity is readily demonstrated. More than 1,750 turbines of at least 0.5 MW were installed in Denmark in the period 1995-1999, and the global total installed capacity for wind generation was 17 GW in 2000, reaching 181 GW in 2010 and 622 GW in 2019.[1]

The classic period for early cost reductions was over by 2010 and did not work out quite as expected, as this study will show. Bearing this history in mind, the forecast of additional dramatic reductions in cost in the period after 2020 is both surprising and implausible. Admittedly, the situation for offshore wind might be different as global installed capacity only reached 1 GW in 2007 and was 28 GW in 2019. However, this too is unlikely because offshore wind is the combination of two mature technologies, namely onshore wind and offshore oil and gas operations. One would expect that any further cost reductions specific to offshore wind would be modest at best, which is in fact what the empirical evidence suggests.

The second type of evidence in support of the view that offshore wind is becoming dramatically less costly is based on the results of auctions in NW Europe, and more recently the United States, for "contracts" offering guaranteed prices (in effect subsidies). But the very scale of the effect is an indication that extreme caution is needed when interpreting the facts. Consider the history:

Many countries in Europe – especially the United Kingdom – have offered extremely generous subsidies for offshore wind since the early 2000s, in some jurisdictions effectively offering up to

1 See: IRENA (2020) – *Renewable Capacity Statistics 2020.*

three or four times the wholesale price. A significant fraction of those subsidies were pure profit for the operators – as much as £40–£60 per MWh for some UK projects commissioned up to 2020.

However, guaranteed offtake prices for new projects have fallen very significantly in UK auctions since 2015. East Anglia 1, which was commissioned in 2019-2020, has a strike price of about £140 per MWh (at 2020 prices). However, Dogger Bank, Seagreen and Sofia, due for completion in 2024-2025, all have guaranteed prices of about £45-£50 per MWh.

That is indeed remarkable, but such a striking reduction requires a special explanation. Even those most committed to the prospects for offshore wind might wonder what factors could possibly explain a 68% fall in the guaranteed price for projects that are, without question, more difficult and expensive to build and operate.[2] It is relevant also to bear in mind that these are marine and coastal projects which will cost £4–£5 billion each. Marine construction and operation has, due to physical realities inherent in the location, a very poor record of cost control. The history of LNG projects provides a clear warning.

Furthermore, it is elementary that one cannot equate prices with costs, and equally fundamental to recall that extraordinarily expensive mistakes are sometimes made by participants in auctions or other bidding mechanisms.

Consequently, if we wish to know about either the level of or trends in *costs*, the starting point has to be an investigation of data on costs, not prices.

In preparing this paper I have compiled a database of the actual capital and operating costs for a large majority of the onshore and offshore wind farms built in the UK since 2002 with a capacity of at least 10 MW. This is possible because of the structure of the industry. In most cases, the assets of each wind farm are held by a special purpose company (Special Purpose Vehicle, SPV) which takes on debt to acquire the wind farm assets, receives generating revenues, contracts with service companies to operate and maintain the wind farm, and distributes any profits. Through such arrangements wind farms are converted into tradeable assets with frequent changes in ownership. Because of their operational structure, SPVs almost never employ staff, so it is straightforward to determine actual operating costs. Similarly, actual capital costs can be obtained by examining the SPV balance sheet. All of these figures are then adjusted for inflation to give costs at 2018 prices. The database covers more than 350 wind farms, all commissioned before or in 2019 – a much larger sample than that employed by any previous study.

Reported and Actual Capital Costs

In the case of offshore wind farms it is possible and instructive to compare *actual* capital costs with costs *reported* in public announcements before or during construction – both adjusted for inflation. On average, *actual* costs are 18% higher than *reported* costs and in a third of cases the cost overrun was at least 30%. Reported capital costs are clearly affected by "optimism bias", but even so, it is important to note there has been a large increase in the reported capital cost per MW of capacity for

2 As an illustration of the difficulty of drawing conclusions from offshore auctions, some may point to the apparently lower – supposedly "subsidy-free" - prices for offshore projects in the Netherlands, Germany and Denmark. However, the headline prices do not include transmission costs whereas the UK prices do cover transmission, which can account for a third of total costs. There are also critical differences between CfD prices and option prices. Finally, there are large differences in water depth, distance offshore, and other factors.

offshore wind farms in NW Europe over the last two decades, with the main change being between projects completed up to 2009 and those completed in the period 2015-2018. A part of the increase is due to a move to installing turbines in deeper waters, but reported costs have increased even when adjustments are made for depth and other factors. It appears, therefore, that the industry, and not just its accountants and senior management, is broadly aware of the rising cost trend.

In fact, the analysis of the *actual* costs for UK offshore wind farms completed up to 2019 shows an even worse picture than that visible in reported costs. In real terms the average capital cost per MW of capacity has more than doubled since 2008. The claim that average costs will fall significantly in future requires a complete reversal of a trend that has prevailed over the last decade, and can hardly be regarded as a probable forecast.

Actual capital costs for onshore wind farms also increased significantly in real terms from 2002-2004 to 2012-2014. Since 2014 onshore capital costs have been roughly constant with no sign of any systematic decline. For a handful of individual projects, the switch to larger turbines – of greater than 3 MW in capacity – has reduced capital cost, but the average capital cost of all onshore rojects with these larger turbines has actually increased since 2012. The median capital cost at 2018 prices of all projects completed in 2018 was over £1.6 million per MW as compared to a median of £1.0 million per MW in 2006. Again, there is little or no reason to believe that average actual capital costs have fallen over the last decade or will fall in future.

Operating Costs

There is extremely strong empirical evidence of a powerful rising trend in operating costs per MW of wind farm capacity. Two factors affect the overall pattern:

As wind farms age, the average cost of operating and maintaining the turbines tends to increase because equipment failures and breakdowns become more frequent, requiring greater expenditure on repairs and on preventative maintenance. The average increase in operating costs with age is 2.8% per year in real terms for onshore wind and at least 5.0% per year for offshore wind. The estimate for offshore wind is affected by the way in which offshore transmission costs are treated. Because of the structure of offshore transmission contracts, operating costs including separate transmission charges have increased at an average of 5.9% per year for offshore wind.

The average cost of operating and maintaining new wind farms in their first or second full year of operation has also been increasing rapidly over time. For onshore wind farms this increase, linked to their year of commissioning, has been an average of 4.4% per year. For offshore wind farms the average increase in the main analysis was 5.5% per year together with substantial additional costs for working at depths of either 10–30 metres or greater than 30 metres. After allowing for the combination of the underlying increase in costs plus greater depth and changes in the regime for offshore transmission, the initial operating cost per MW of capacity for a typical offshore project quadrupled between 2008 and 2018.

The increase in operating costs dominates all of the other influences on the cost of wind generation for a reason that may not be obvious to those outside the industry. The reason lies in the answer to a key question: *How long will it be worth operating a new wind farm?* This focuses attention on the expected economic life of the installation rather than its physical life. Most wind turbines have a physical life of

25-30 years but almost all of them are decommissioned before they reach an age of 25 years and many of them before an age of 20 years. This means that their initial capital cost must be recovered over 15 or 20 years rather than 25 or 30 years, so that the capital charge is correspondingly higher.

Economic Lifetime

Operating costs are critical to wind farm economics because it is uneconomic to operate a wind farm if the expected operating costs exceed the expected revenue from generation either (a) at a guaranteed above-market price (for as long as that is paid), or (b) at market prices.

If we make the wholly unrealistic assumption that output does not decline with age, a new onshore wind farm supported by a Contract for Difference (CfD) or a corporate Power Purchase Agreement (PPA) (both lasting for 15 years) will have an economic life of 16 to 18 years. If we allow for evidence on the decline in performance with age in the paper on Denmark that accompanies the present study, then the economic life falls to no more than 15 years. This is because the expected revenues at market prices cannot cover the increase in operating costs.

The question is more acute for offshore projects. The Beatrice project in the Moray Firth in North-East Scotland is guaranteed a high CfD strike price of £162 per MWh in 2020. This will cover the project's operating costs for the 15-year life of the CfD contract but as soon as the contract expires the expected revenues at market prices will fall below its operating costs from year 16 onwards, even if there is no decline in performance with age. It will incur large losses if it continues to operate after the expiry of its CfD contract in 2033. The market price would have to increase by nearly 200% over the next 13 years – about 9% per year – in real terms to warrant continuing to operate the wind farm past 2033.

The Triton Knoll wind farm, due to be completed in 2021-22, is one of the projects cited as evidence for the decline in offshore wind costs. It has a CfD strike price of £87/MWh in 2020. Even if there is no decline in performance with age, the generation revenues will fall below expected operating costs in year 14. If there is a decline in performance comparable to the experience in Denmark, then generation revenues will be less than expected operating costs from year 11. There is no likelihood that the project will continue to operate after the expiry of the CfD contract, since it would incur a loss of about £170 million per year.

Based on these figures no reasonable investor should assume an economic life greater than 15 years for offshore wind and a prudent, risk-averse view might imply an economic life of no more than 12 years. For onshore wind the economic life might be between 15 and 18 years depending on what assumption is made about future market prices, but a prudent assessment would imply an economic life of 15 years.

Cost of Capital

The one component of the overall cost of wind generation that has clearly declined over the last decade is the cost of capital. Based on the evidence available the Weighted Average Cost of Capital (WACC) has fallen from about 8% in 2009 to about 4% in 2019. The WACC for subsidized wind generation is somewhat higher than the WACC for regulated network assets, such as offshore or onshore transmission lines, because the risks relating to costs and performance are greater.[3] However, the benefits of a lower cost of capital have been largely offset by the reduction in the economic life of wind assets. The Renewables Obligation scheme provided a subsidy for 20 years, and expectations for future market prices in 2009 were much higher in real terms than in 2019. Thus, it would not have been unreasonable in 2009 to assume an economic life of 20-25 years.

The combined effect of the reduction in the cost of capital from 8% to 4% and a reduction in the economic life from 20 to 15 years is a fall of 12% in the overall capital charge per £1 million of capital expenditure. This is just enough to offset the increases over 2009 to 2019 in average capital costs per MW of capacity for onshore wind, while the increase in average capital costs for offshore wind greatly exceeds any reduction in the capital charge. If the reduction in the economic life were from 25 years to 15 years the reduction in the overall capital charge would only be 4%, significantly lower than the increase in capital costs per MW of capacity, even for onshore wind.

Putting this together, **when capital costs, economic life and the cost of capital are combined, the overall capital element of the cost of wind generation per MW of capacity rose substantially during the decade from 2000 to 2010 for both onshore and offshore wind.** The trend has, at best, flattened out for onshore wind since 2010 with the effect of a large fall in the cost of capital offset by a reduction in economic life and an increase in average capital costs. **For offshore wind the overall capital element of the cost of wind generation per MW of capacity increased by at least 20% from 2009 to 2019.**

Increasing Average Output?

Notwithstanding the increase in capital and operating costs per MW of generation capacity, it is possible that investors and policymakers are relying upon a large increase in average output per MW of capacity. This would be reflected in the average load factors for new onshore and offshore wind farms.[4] There are two factors that might lead to higher load factors.

Improvements in turbine design that enable turbines to make better use of the available wind resources. While this is possible in principle and to some degree in practice, the yield of any wind turbine is constrained by the physical processes described by Betz's law as well as the need to limit mechanical stresses at high wind speeds. Modern turbine designs have been close to the Betz limit for some time, and recent designs get very close, so the scope for increasing yields by future changes in turbine design is quite small.

An increase in the hub height of turbines leads to an increase in the average wind speed at hub height and permits the use of longer blades with a larger swept area. Longer blades permit an increase in the rated capacity of turbines, whereas higher wind speeds lead to an increase in average

3 My assumptions about the WACC for wind investment are on the low side relative to official estimates. Shortly after this paper was written Ofgem proposed that the WACC for regulated transmission assets should be below 3% per year in real terms. Allowing for the much greater risk of investment in wind generation assets suggests a WACC closer to 5% than 4%. BEIS (2020) uses even higher hurdle rates of 5.2% for onshore wind and 6.3% for offshore wind.

4 The average load factor for a wind turbine is calculated as the total output per MW of capacity in a month, quarter or year divided the number of hours in the same period. This represents the actual output in the period as a proportion of the maximum possible output for the period.

output per MW of capacity. The increase in average wind speed due to higher hub height is a function of what is known as *wind shear* – the gradient of wind speeds as the height above surface level increases. Detailed analysis of actual wind conditions for Denmark show that the median increase in yield for onshore turbines from an increase in hub height from 80 metres (typical for recent projects) to 120 metres (proposed for some new projects) is a little below 10% with further increases in hub height offering even smaller gains. The benefits of equivalent increases in hub height are lower for offshore turbines, offering a median increase of less than 7% for a move from a hub height of 100 metres to 150 metres. At the same time, the increase in hub heights brings a clear penalty in the form of substantial increases in capital and operating costs.

It appears from public sources that wind farm operators and turbine manufacturers believe that (a) average load factors for new turbines have increased, and (b) the trend will continue in future. However, the actual performance of wind farms over the last decade provides only ambiguous support for that belief. At an aggregate level for the UK there has been no significant trend in the average load factor for onshore wind farms since 2010 once allowance is made for variations in annual wind speeds. The average load factor has been 26–27% in years with normal wind speeds. The evidence for offshore wind is more promising, with the average load factor for UK offshore wind increasing by 0.6 percentage points per year, rising from 35% in 2010 to 41% in 2019, holding wind speed constant.

The data for Denmark discussed in the accompanying paper can be used to compare load factors for onshore turbines installed in the late 2000s and a decade later. The analysis tests for differences between the average load factors for turbines with a capacity of at least 2 MW installed in 2008-2010 and those installed in 2016-2018 after controlling for differences in wind speed, location and age. The results are somewhat surprising but they are statistically quite strong. The average capacity of the turbines installed in 2016-2018 was 3.3 MW vs an average of 2.6 MW for the turbines installed in 2008-2010, and the later set of turbines has an average hub height of 87 metres vs 80 metres for the earlier set, so that one would expect the newer turbines to have higher load factors. However, the average load factor at age 2 years (typically the peak age) for the newer machines is 29% as compared with 34.5% for the older group. The statistical probability that this is a chance result is less than 1%. In other words, *in Denmark the more modern turbines, which are both taller and have greater capacity, have a substantially lower load factor once we take account of differences in wind speed and other factors*. This is a surprising result, and must be regarded as tentative and questionable. The finding may not apply in all countries or periods but it is at least a check to any naïve assumption that larger and more modern turbines will *certainly* have higher load factors and thus lower costs. They may, but this requires demonstration.

The evidence for offshore wind turbines in Denmark is limited. The only offshore wind farm developed since 2013 was completed in 2018. The data available for this project only refers to its first year of operation and has clearly been affected by outages during commissioning and other one-off factors. A simple comparison of the recent load factors for turbines installed in 2009-10 and 2011-13 shows that the latter group has an average load factor that is about 9% higher than the earlier group. This is consistent with the difference in average hub heights – 68 metres for the earlier group and 82 metres for the latter group.

One clear conclusion from the analysis of offshore turbines in Denmark is that they experience much higher rates of equipment failure and, thus, a more serious decline in performance with age than is the case for onshore turbines. Thus, even if offshore turbines can achieve an average load factor of 55% in their early years, their lifetime average is likely to be little better than 40–45%. The combination of rising operating costs and declining yields is extremely damaging to the viability of offshore wind farms when required to operate as merchant generators – i.e. selling their output at market prices rather than much higher subsidized prices.

Policy Implications

Table S1 summarises the implications of the findings of the study. While many commentators refer to the Levelised Cost of Electricity (LCOE), the calculation is misleading when there are large changes in operating costs and performance that affect the economic life of a generation unit. Instead, the table reports the long term breakeven prices required to justify proceeding with an investment in a wind farm with an uncertain operating life.

Table S1 – Project breakeven prices (£ per MWh at 2018 prices)

	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

Source: Study estimates.

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

The table shows that the breakeven prices for onshore wind were very similar in 2008-2009 and 2018-2019, with the CfD strike price for projects finished in 2018 being between the two values. This provides a clear pattern that is consistent with there being no reduction in the overall costs of onshore generation over the decade. The benefit of a large reduction in the cost of capital has been offset by the increase in operating costs and their impact on the economic life of a wind farm. The breakeven price for offshore wind increased substantially from about £125 per MWh in 2008-2009 to about £152 per MWh in 2018-2019. The main reasons for the increase were:

(a) a significant increase in capital costs (even after allowing for the transfer of Offshore Transmission Owner (OFTO) assets) as a consequence of a shift to deeper waters, and

(b) an even larger increase in operating costs.

The average offshore CfD strike price for projects supported in the Investment Contract round, the first round of the CfD process, which were completed between 2017 and 2019 was £161 per MWh, a little more than the breakeven price.

The next set of projects from Allocation Round 1 (AR1) due for completion in 2020-22 have an average strike price of £112 per MWh. To achieve a breakeven price close to that it is necessary to assume that the annual load factor will be 58% over the 15 year life of the CfD contract (Model A), which is extremely optimistic.

Projects from Allocation Round 2 (AR2) due for completion in 2021-23 have an average strike price of £65 per MWh. For the breakeven price to get close to that it is necessary to have both (i) a constant load factor of 60% over the 15 year life of the CfD contract, and (ii) operating costs identical to those for shallow water projects completed in 2008-2009 (Model B). These assumptions are outside the bounds of what is reasonably possible.

Finally, to justify the Allocation Round 3 strike prices of about £48 per MWh it is necessary to add the assumption that market prices after the end of the CfD contract are sufficiently high to offset the large losses made during the life of the contract. These projects are a high stakes gamble on market prices in the late 2030s. The gamble will only pay off if the average market price exceeds £120 per MWh – a real increase of 8.5% per year for 15 years – and even that relies on implausible assumptions about load factors and operating costs.[5]

In summary, the analysis based on the evidence from the actual costs incurred by offshore wind projects shows that offshore costs have increased substantially over the last decade. **The belief that costs have fallen at all, let alone by the amount implied by CfD bid prices, requires assumptions that are entirely inconsistent with evidence on actual performance and operating costs for offshore wind farms in the UK and Denmark.**

Conclusion

We are left with a final question. If the empirical evidence is so clear, why are large companies committing substantial capital to very large projects that are almost certain to make a loss under anything like current market conditions? There are three factors that may explain this behaviour:

The offshore wind sector is dominated by large, often state-controlled, companies that can deploy large cash flows from existing generation and/or network businesses, and which are under little pressure to return cash to either their customers or their shareholders.

Operators may expect to be able to sell on a large portion of the shares in their projects to over-optimistic investors with little appreciation of the risks involved. In addition, projects rely heavily on debt provided by equally naïve lenders.

Operators and financial investors may expect to be bailed out. Once the financial consequences of the underlying economic reality become undeniable, there will be a huge lobby to pass on the full costs of offshore wind to either electricity consumers or taxpayers. The obvious instrument is carbon taxation, but the increase required will be extremely contentious and the process will be difficult, to say nothing of the harmful consequences to the wider economy. The behaviour of a government trapped between political opposition and the wider ramifications of the financial collapse of the offshore wind sector cannot be predicted.

5 The Kriegers Flak project examined in the paper on Denmark is another high stakes gamble on future market prices. Other offshore projects under development in Germany and the Netherlands are likely to break even only if there is some fundamental shift in the real level – and variability – of market power prices. This seems to be a consistent pattern in which offshore developers have been assuming that market power prices (weighted by wind output) in NW Europe will increase at 8-10% per year in real terms. The actual trend in market prices since 2015 has been quite different with a real decline in the average price weighted by either onshore or offshore wind output.

WIND POWER COSTS IN THE UNITED KINGDOM

Gordon Hughes
School of Economics, University of Edinburgh

1. Introduction

In the endless search for attention and support, the general public and policymakers are bombarded with claims that the costs of wind generation are either falling rapidly or will soon reach "grid parity", a term rarely defined with any precision. Such claims rest primarily on the results of auction bids that are subject to contracts whose provisions are obscure and which may be interpreted in very different ways. In the United Kingdom, much emphasis is given to the successive rounds of Contracts for Differences (CfD) auctions even though the contracts are **not** firm commitments to supply fixed volumes of electricity at the contract price. For example, contracts can – and will - be terminated with the supplier incurring a relatively modest penalty if the market price rises above the contract strike price on a sustained basis in future.

Within the European Union there have been auctions for offshore power purchase agreements in Denmark, Germany and the Netherlands, each with different provisions concerning transmission costs, price support and contractual terms. Many of these agreements allow the supplier to sell their output at whichever is the higher of the guaranteed price or the market price. This is what is meant by describing the contracts as option contracts, in the sense that the supplier can choose between selling at the contract price or the market price if/when that is advantageous. More recently, there have been auctions for offshore wind in the United States which involve (relatively) firm supply obligations but which incorporate unpublicized tax benefits. In practice, the actual revenue per megawatt-hour (MWh) that will be earned by the generator is considerably higher than the headline price.

The lesson is that auction prices tell us little about the actual costs of building and operating offshore wind farms. As we will see, the auction price in the UK and NW Europe tell us more about expectations of future power prices. No-one should be surprised about this. Exposure to even the most elementary course in microeconomics should warn anyone that prices are not a reliable guide to costs, especially in markets dominated by strategic behaviour by large companies that are often highly protected from conventional market pressures.

Almost all of the "successful" bidders are companies that are either state-owned or have large cash flows from monopoly energy businesses. As an illustration, one of the more aggressive bidders is Vattenfall, which is both state-owned and obtains much of its revenues from a regulated distribution business in Sweden. Shell Energy has made a substantial commitment to offshore wind in the US, but this accounts for a very small proportion of the cash flows from its gas business. The larger picture, therefore, is one of a group of potential bidders who appear to apply a very low or even zero cost of capital in evaluating projects and who have the balance sheets to absorb a few bad investments justified internally on the grounds of either learning or good public relations.

The pattern is all too familiar to anyone with experience of property booms, especially those fuelled by periods of lax monetary policy and low interest rates. Such booms almost always end badly and the more sanguine property developers know that. The problem for them is that it is never obvious when they should take their money off the table – if it were obvious, the boom would already be over. That is why development options are more attractive than firm contracts requiring future investment. As in property booms, some of the speculative wind farm projects will be constructed and will prove to be bad bets. In consequence, the developers or the financiers, or both, will eventually have to write down a part or all of their investment. Such is the nature of asset markets in times of excess capital and low rates of return, but it means that data from these projects is unlikely to provide a reliable guide to the long term costs of wind generation.

As an illustration of the madness that has overtaken the renewables sector, one might cite the fact that in 2020 the regulator Ofgem published as part of a public consultation a document prepared by the National Grid, Electricity System Operator (NG ESO) on the levelised cost of electricity, but redacted almost every single substantive number (ESO 2020). In many of the tables the source given was the Department of Business, Energy and Industrial Strategy (BEIS), which cannot claim grounds of commercial confidentiality for insisting that its data be witheld. For whatever reason, BEIS was clearly so concerned about the reliability or implications of its own data that it was unwilling to allow that data to be included in a public document.

The purpose of that consultation was to inform a decision on whether Ofgem should authorise the construction of a transmission line from Shetland to the North of Scotland, the line being required to serve a large proposed onshore wind farm in Shetland itself. How anyone was supposed to comment on the value for money offered by the project when the government department responsible was unwilling to allow any of the data to be published is, of course, a mystery. It reminds one of the company that was floated during the South Sea Bubble whose business plan was: "For carrying on an undertaking of great advantage; but nobody to know what it is". Unsurprisingly, a member of the public involved in the Shetland consultation submitted a Freedom of Information request, and Ofgem and the Department have been compelled to reveal some of the data hidden by the redactions, as well as the Department's analysis cited by the ESO (discussed in the Addendum below), but much remains obscure, both in regard to the Shetland project and more widely in the wind industry. The present paper attempts to shed some light on the matter.

It is essential to ground any assessment of claims about trends in the cost of wind generation on the analysis of data on actual outcomes. For this purpose I have compiled a large dataset extracted from the accounts, often audited, of wind operators for both onshore and offshore wind farms in the UK commissioned from 2000 onwards.[6] The reason for not extending the sample further back

6 I should gratefully acknowledge the work of Aldersley-Williams et al (2019) who first proposed the use of data extracted from SPV accounts filed with Companies House as a way of examining the costs of offshore wind generation. I have built upon and extended their example to cover a much larger number of offshore and onshore projects.

in time is that there was a fundamental shift in technology at the turn of the century with the adoption of turbines with a capacity of 2 MW or greater. Earlier wind farms mostly used turbines with a capacity of less than 1 MW, and the data on reliability shows that these were more robust and had much lower maintenance costs than the larger turbines that followed them. The shifts to 3+ MW turbines onshore and 6+ MW turbines offshore have reinforced the change in the engineering balance between capital costs, operating costs and performance. A similar shift is apparent for offshore transmission which is crucial for the costs of offshore wind projects.

There are five elements that determine the long run cost of wind generation: (a) the investment cost of building wind farms (capex); (b) the costs of operating and maintaining the capital equipment (opex); (c) the cost of capital to fund the investment that is required; (d) the expected economic life of the wind farm, a matter which depends on the balance between revenues from power sales and the costs of operating the farm; and (e) the expected profile of the annual yield from the wind farm over time (load factor). We have evidence derived from operating experience over the last 20 years for each of the elements that provides the basis for assessing trends in long run costs over the last decade. While such trends may change in future, wind turbines are now a relatively mature technology. The turbines themselves account for less than 50% of offshore capex costs and that share will diminish in future. Hence, it is possible to draw on the lessons from other generation technologies to set plausible limits on the extent to which the trends in total costs may change in the next 20 years.

2. The costs of building new wind farms

Onshore capex costs. It seems to be widely believed that the capital costs per megawatt (MW) of nameplate capacity of building new onshore and offshore wind farms have been falling and will continue to fall in future. This belief is simply wrong: the evidence, based on the actual costs of wind farms built over the last two decades, shows a quite different pattern.

I will start with onshore wind farms in the UK. The data used for the analysis is described in Appendix A. The most important point to note is that the estimates of capex costs have been obtained from the company accounts filed by the Special Purpose Vehicles (SPVs) that own and operate the wind farms. In most cases these accounts are audited and they form the basis for corporation tax returns, so there are significant penalties for misreporting. The data is likely to be considerably more reliable than other reports of capex costs. Needless to say, coverage is not complete, but the available sample of wind farms is very substantial, comprising 80% of the wind farms with a nameplate capacity of at least 10 MW which were commissioned between 2002 and 2019. The remaining 20% of such wind farms are not covered because the projects are owned by a parent company that does not report figures for individual projects or that is registered outside the UK.[7]

Figure 1 shows the distribution of actual capex cost by year – measured in £ million per MW of capacity at 2018 prices - with different markers indicating projects for four turbine size categories:

7 The main parent companies that do not rely on SPVs for onshore wind farms were Scottish Power Renewables (23 projects), SSE Generation & SSE Renewables (11 projects), E-ON UK (9 projects) and Innogy Renewables (6 projects).

(i) <1 MW, (ii) 1-2 MW, (iii) 2-3 MW, and (iv) 3+ MW. Over 70% of projects have turbines in the 2–3 MW size category. Almost half of the projects are located in Scotland. The graph shows that there was a clear increase in real capex costs from 2002 to 2010. There is no obvious trend in capex costs after 2011, though the distributions by size category suggest that projects using turbines of 3+ MW have a lower capex cost than those using turbines of 2–3 MW. There are very few projects that used turbines smaller than 2 MW after 2010. Weighted by capacity, average capex per MW in 2018 prices for the whole country increased from £1.07 million per MW in 2002-05 to £1.65 million in 2011-15 and then fell marginally to £1.55 million in 2016-19.

Figure 1 – Distribution over time of actual capex costs for UK onshore wind farms

(£ million per MW of rated capacity at 2018 prices by turbine size)

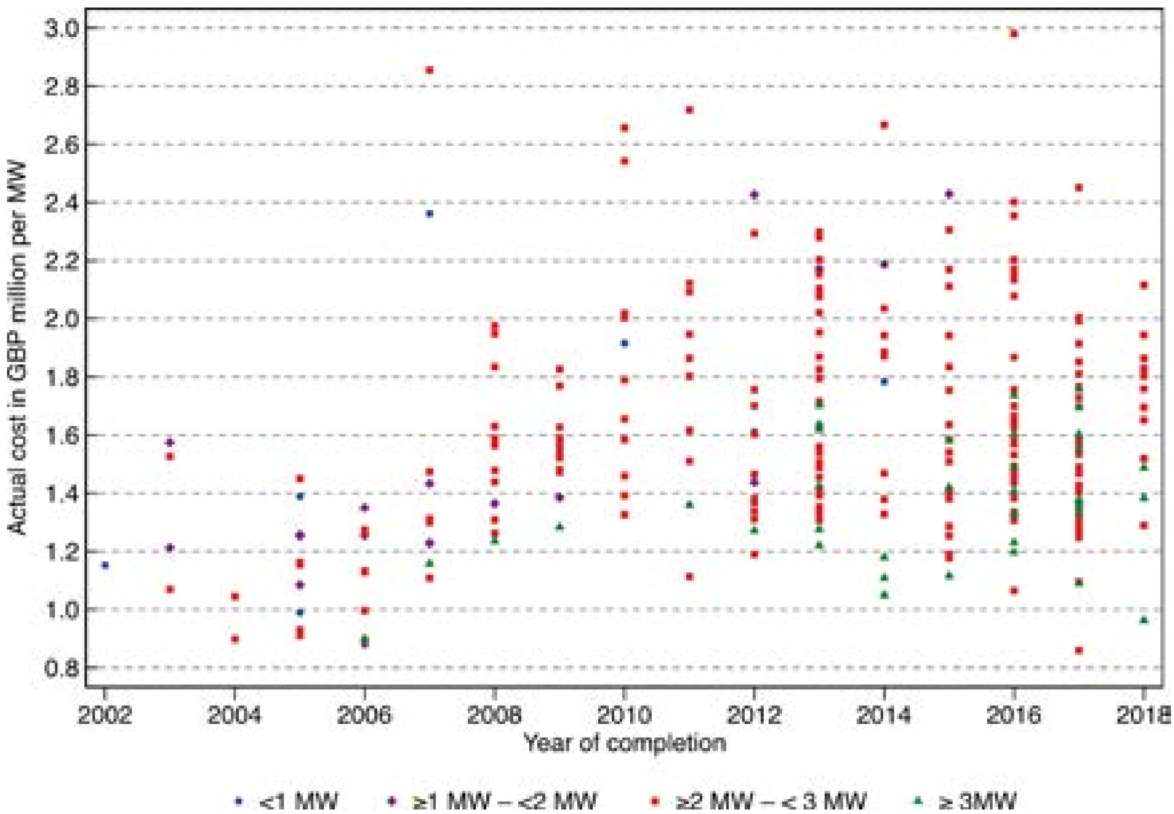


Table 1 shows the results of two regression models for the wind farms shown in Figure 1. Each wind farm is weighted by its capacity so that the results reflect the average capex per MW for all wind farms in the UK. An increase in turbine size reduces capex costs but because the relationship is logarithmic the effect of a 1 MW increase in turbine size diminishes as turbines get larger. In Model 1, a shift from 2 MW turbines to 3 MW turbines reduces average capex by 9.5%, while an increase from 3 MW turbines to 4 MW turbines only reduces average capex by 6.9%.

Model 1 shows the differences across time periods with 2002-05 as the default category. Relative to this baseline there was a large increase in average capex during the period 2006–2010 and an even greater increase for both 2011-15 and 2016-19. However, there is no significant difference between 2011–2015 and 2016–2019. Model 2 offers an alternative way of presenting the same pattern using the year 2002 as the baseline and contrasting the period 2002-10 with 2011-19. Between 2002 and 2010 average capex increased at 9% per year, but there was no significant time trend in capex costs over the period 2011-19. Overall, the average capex cost in 2011-19 for a wind farm with 2 MW turbines was more than the average for 2002.

If we take the long view, average capex per MW for onshore wind farms has increased substantially, even allowing for the increase in turbine size. Most of this increase occurred in the decade of the 2000s but the change in the trend in the last decade has not come close to reversing the previous increase. The reasons for the increase in capex costs are not clear, but it runs directly counter to naïve assumptions that investment in new technologies will inevitably bring lower costs. The adoption of larger turbines, perhaps 5-6 MW units, in future may reduce capex costs by 10-15% but this will still leave capex cost significantly higher than they were in the first decade of this century.

Table 1 – Regression models for onshore capex

Variable	*Log(Actual capex)*	
	Model 1	Model 2
log(Turbine size)	-0.247*** (0.061)	-0.264*** (0.060)
Time periods		
2006-10	0.338*** (0.045)	
2011-15	0.469*** (0.044)	
2016-19	0.442*** (0.049)	
2011 onwards		0.869*** (0.104)
Time trends		
Time 2002-10		0.090*** (0.013)
Time 2011-19		-0.006 (0.008)
Observations	258	258
Adjusted R-squared	0.313	0.353
*Notes: (a) * p < 0.05, ** p < 0.01, *** p < 0.001.*		

Source: Author's estimates.

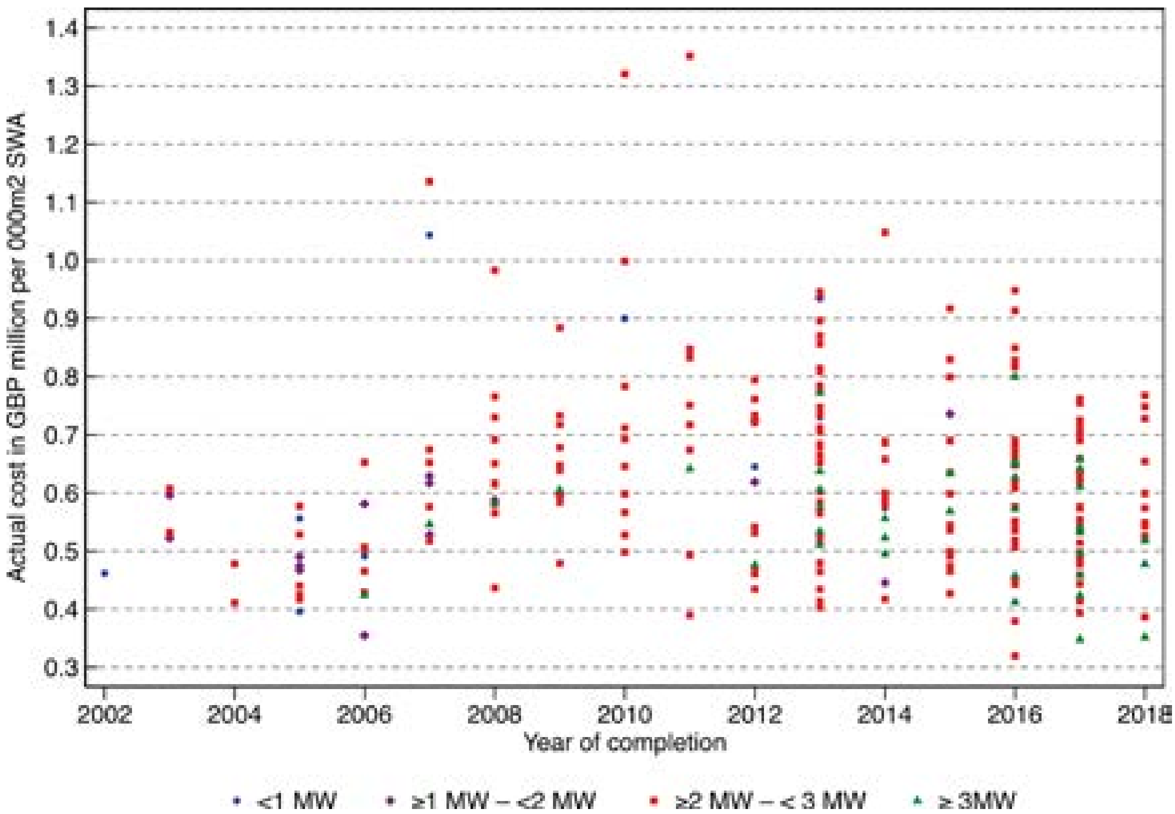
The absence of a significant downward trend in capex costs for 2011-19 when turbine size is held constant is particularly striking. Advocates of new generation technologies rely heavily on the assumption that costs will decline at 10–15% for each doubling of installed capacity. The installed capacity of onshore wind in the UK went from 0.5 GW in mid-2002 to 14 GW in mid-2019, or just under 5 doublings. For a 10% reduction per doubling, average capex costs should have declined by 40% from 2002 to 2019 if this assumption were correct. Even if we discount the cost increase from

2002 to 2010, the assumption implies a reduction of at least 15% from 2010 to 2019, whereas the observed fall in costs was about 5%. This is consistent with the view that cost reductions due to economies of scale and learning for a new technology have been largely exhausted because of the global growth in onshore wind installations.

While the reasons for the observed trends in capex costs for onshore wind in the UK may be complex and are certainly not fully understood, it is essential to discard assumptions that are not supported by the evidence. For clarity, it seems that a move to wind farms with fewer but larger turbines – currently 3–4 MW but perhaps 5–6 MW in future – brings economies of scale and a modest reduction in capex costs. On the other hand, there are other considerations that may prompt substantial resistance to the adoption of such large turbines – especially their impact on neighbours and the landscape. Any shift is likely to be slow and will not bring a substantial reduction in capex costs.

Figure 2 – Alternative distribution over time of actual capex costs for UK onshore wind farms

(£ million per 000m² of swept area at 2018 prices by turbine size)



Source: Author's estimates.

Most commentators focus on the rated capacity of a wind farm but this may not be the best indicator of its potential output. Turbines operate at less than their rated capacity for a substantial fraction of the year because wind speeds are below those required to reach rated output. In such conditions the area swept by the blades of a turbine may be a more useful measure. Average swept area per MW of rated capacity increased at a rate of 1.9% per year (on a capacity-weighted basis) from 2002 to 2018. This will partially offset the increase in average capex per MW, but it should be noted that the within-year variance in swept area per MW across projects has also greatly increased over time.

As a contrast, average capex costs per MW for gas-fired capacity have fallen at an average of 3-5% per year in real terms over the last 3 decades.[8] The different paths illustrate the difficulties of transferring technological assumptions across disparate generating technologies. One reason is that as the cost of wind turbines per MW of capacity has fallen, it is mundane items such as civil works (including turbine towers), transformers and transmission equipment, and other electrical equipment which dominate the overall cost of constructing new wind farms. These are not subject to the same technological and cost trends as the products of new manufacturing technologies.

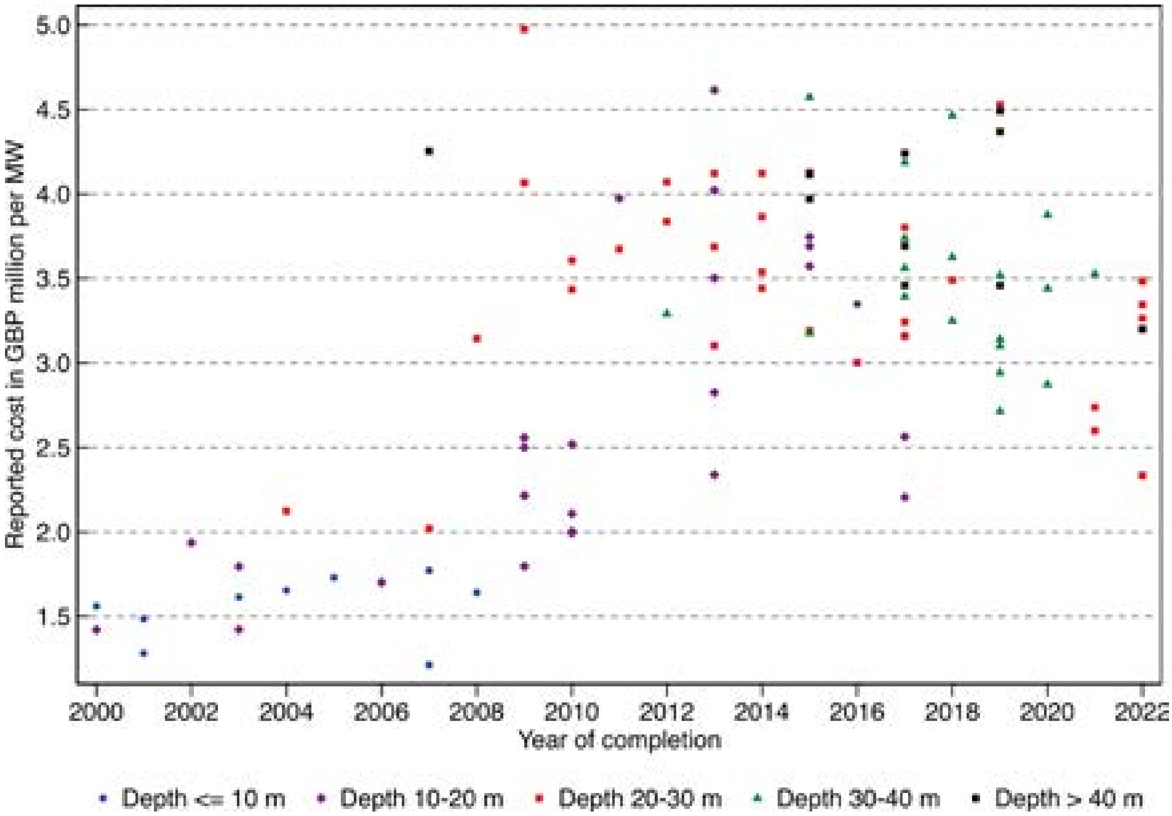
Offshore capex costs. I have written an earlier paper on trends in offshore capex costs – see Hughes, Aris & Constable (2017) – which showed that the reduction in real capex per MW of capacity due to the adoption of large turbines was being offset by the costs of installing turbines at great depths. For the current analysis I have added more projects to our original database but, equally important, I have added data on actual (ex-post) rather than anticipated (ex-ante) capex costs. The comparison between actual and reported cost turns out to be rather revealing for what it tells us about the reliability of most of the figures that are cited at conferences and in industry publications.

Figure 3 shows a scatter plot over time of reported offshore capex in £ million per MW at 2018 prices for all projects in North-West Europe with commissioning dates up to 2022. Colours and markers indicate the water depth for the projects. It is clear that there was a very substantial increase in capex costs when the period to 2010 is compared to the period from 2011 onwards. This mirrors what happened for UK onshore capex. The figure suggests that reported capex costs have been falling since the late 2010s. However, this inference depends heavily on reported costs for projects that have not been commissioned and depends on information on capex costs that is incomplete. For example, there are a group of projects in Belgium, the Netherlands and Denmark (Seamade, Borssele 1&2, Borssele 3&4, Kriegers Flak) which all report capex costs of less than £3 million per MW. In each case there is almost no information about the level and allocation of transmission costs.

8 I know of no academic study which has documented this trend, but it reflects the views of power sector consultants who provide advice on the replacement costs of power plants around the world. Further, it is consistent with the evolution of US EIA (Energy Information Agency) estimates of the costs of building new power plants in the US over the last 20 years.

Figure 3 – Distribution of estimated capex costs for offshore wind projects in NW Europe

(£ million per MW of rated capacity at 2018 prices by water depth)



Source: Author's estimates.

Figure 4 shows a rather different picture for actual capex costs (including transmission) obtained from Special Purpose Vehicle (SPV) accounts for UK projects that have been commissioned.[9] On average, actual costs are 18% higher than reported costs. There are two cases in which the actual costs were more than 10% lower than the reported costs – Kentish Flats (commissioned in 2005) and Dudgeon (commissioned in 2017). Kentish Flats is a project in very shallow water (a depth of 5 metres) with an estimated cost that was similar to that of other projects developed in the period 2003-06. The actual capex cost was the lowest for all of the projects in the dataset.[10] In the case of Dudgeon the project developer specifically announced that they had found ways of reducing the cost of development by about 15%. In the other direction, about 40% of all offshore projects exceed their anticipated capex cost by more than 25%. For two projects – Gunfleet Sands 1 and Burbo Bank

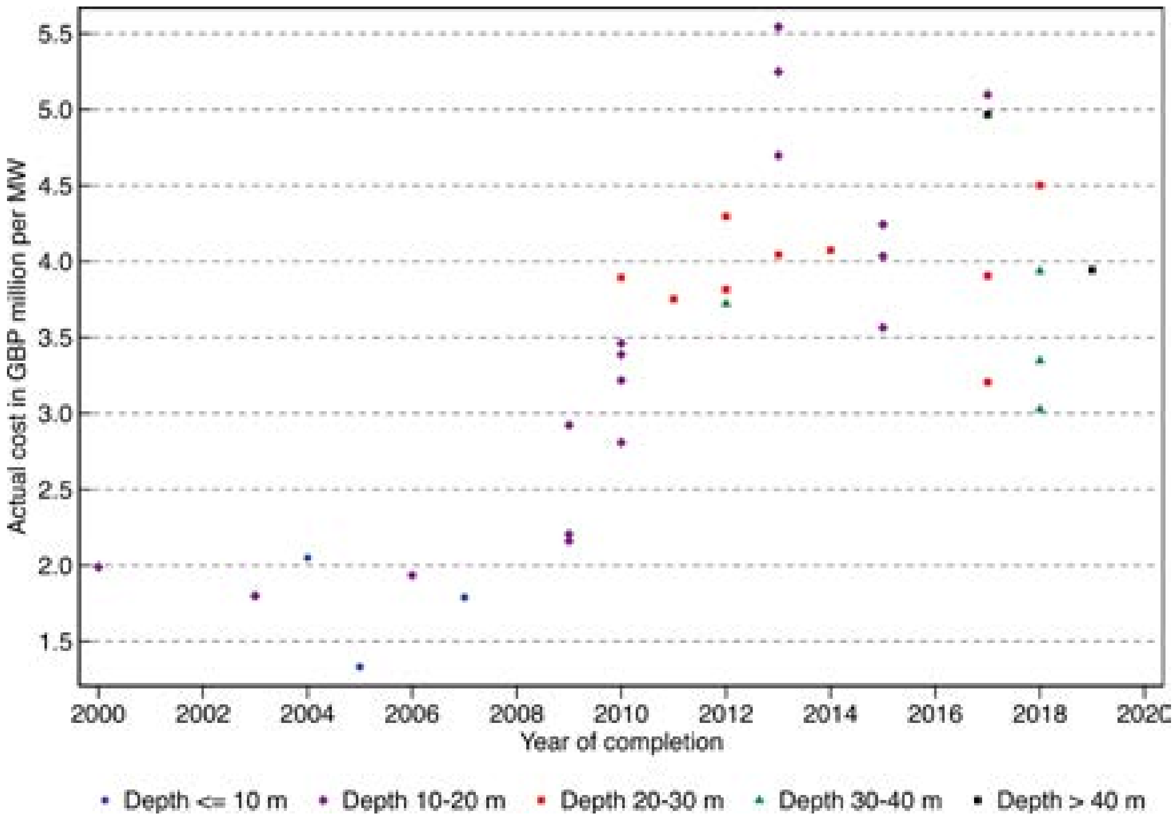
9 Current practice in the UK is that the project developer builds the offshore transmission network along with the wind farm. After the project is commissioned the transmission network is separated from the wind farm and transferred to an Offshore Transmission Operator (OFTO) at a price determined by a bidding process managed by Ofgem. For various reasons the OFTO transfer value may not be equal to the cost of building the transmission network. OFTO transfers can be tracked in SPV accounts and the implications for operating costs are discussed below. Actual capex costs used for the analysis are based on total project costs including the cost of building the transmission network.

10 The original Kentish Flats wind farm was extended in 2015 with the addition of 15 3.3 MW turbines at an actual cost of £151 million. This illustrates the increase in costs which has occurred as the actual cost of the Kentish Flats Extension in £ per MW at 2018 prices was more than 2.4 times the actual cost of the original wind farm.

Extension – the cost overrun was more than 60%. This is a warning that the anticipated capex costs for offshore projects are often optimistic, to put the point no more strongly.

Figure 4 – Distribution of actual capex costs for offshore projects in the UK

(£ million per MW of rated capacity at 2018 prices from SPV accounts by water depth)



Source: Author's estimates.

It is difficult and potentially misleading to fit crude trends to the data shown in Figures 3 and 4. Two points stand out:

- There was some kind of fundamental shift in costs for projects completed in or around 2010. For example, in Figure 3 nearly all of the projects completed up to 2009 had a reported cost of £2.5 million per MW (at 2018 prices) or less. The exceptions were projects at depths of greater than 20 metres, which was relatively deep water up until 2010. The transition occurred in 2010, and for projects completed from 2011 onwards more than 90% had reported costs of more than £2.5 million per MW, even for projects at the shallower depths up to 20 metres. The pattern is similar for actual costs in Figure 4 but with the dividing line shifted up to £3.0 million per MW.

- Within each group of years – up to 2010 and 2011 onwards – the average cost of projects increases with water depth. Projects at a depth of less than 10 metres tend to have lower costs than projects at depths between 20 and 30 metres, with projects at a depth of greater than 40 metres being even more expensive. In the UK, the average depth of projects has increased from 12 metres for 2000–2005 to 43 metres for 2016 onwards. The average distance from shore has also increased from 9 km in 2000-05 to 28 km for 2016 onwards. The tendency to move into deeper water and further offshore has been much less marked for projects in the rest of North West Europe. In Germany, for example, the average depth has increased from 27 metres for 2006–2010 to 33 metres for 2016 onwards, while the average distance offshore has remained constant at about 55 km. This large difference between the UK and the rest of Europe means that claims about trends in costs based on evidence from projects in continental NW Europe may not apply to the UK.

Table 2 – Regression models for offshore capex

Variable	Log(Reported Capex)		Log(Actual Capex)	
	Model 1	Model 2	Model 3	Model 4
Depth (m)	0.010*** (0.003)	0.010*** (0.002)	0.002 (0.004)	0.001 (0.003)
Location				
Baltic	-0.141** (0.051)	-0.142* (0.060)		
Irish	0.011 (0.060)	-0.008 (0.064)	0.336*** (0.062)	0.350*** (0.049)
North	0.010 (0.052)	0.002 (0.057)	0.298*** (0.044)	0.290*** (0.040)
Time period				
<= 2005	-0.384*** (0.069)		-0.727*** (0.117)	
2006-2010	-0.144 (0.085)		-0.313* (0.152)	
2011-2015	0.200*** (0.056)		0.023 (0.074)	
2011 onwards		0.853*** (0.093)		1.315*** (0.191)
Trends				
Time 2000-10		0.050*** (0.011)		0.109*** (0.023)
Time 2011-22		-0.032*** (0.009)		-0.001 (0.013)
Observations	103	103	36	36
Adjusted R-squared	0.528	0.569	0.535	0.652
*Notes: (a) * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.*				

Source: Author's estimates.

Table 2 shows regression models for the logs of reported (in NW Europe) and actual project costs (in the UK) measured in £ million per MW using (i) different period, and (ii) separate time trends for

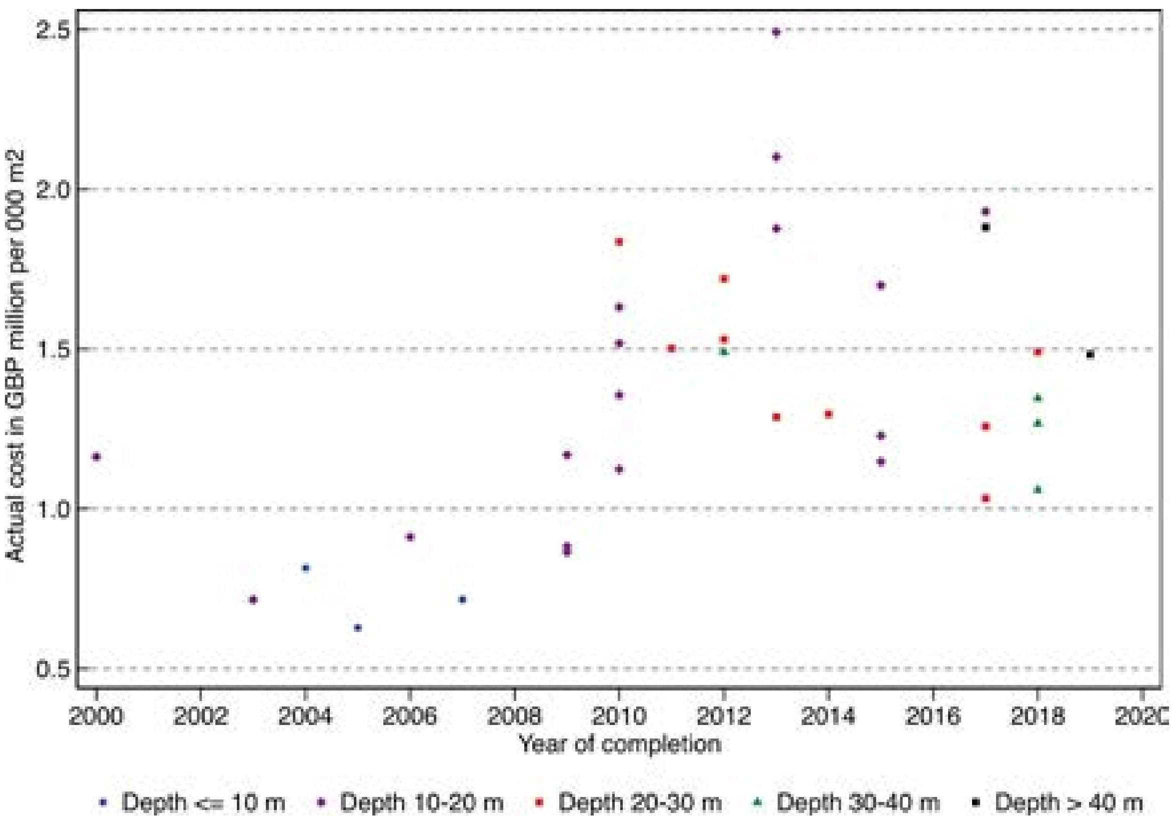
2000-10 and 2011 onwards. The sample for reported project costs in NW Europe is much larger than for actual costs in the UK, but the latter figures are more reliable. In carrying out the regression each observation is weighted by project capacity, so the results reflect average costs per MW of capacity rather than per wind farm.

Water depth has a significant impact on reported costs but not on actual costs in the UK. Location has no significant effect on reported costs but does affect actual costs with projects in the North and Irish Seas costing 30–35% more per MW than those in the Channel (the default location). These differences suggest that the costs reported in industry publications are generic rather than specific.

The regression models using period averages – with 2016 onwards as the default period – confirm that reported costs were relatively low for 2000–2005 and relatively high for 2011–2015, so that there was a significant reduction in reported costs after 2015. However, that conclusion is not borne out for actual costs as there is no significant different between actual costs in the periods 2011–2015 and 2016 onwards. This reinforces the observation that any decline in reported costs may be largely due to the influence of projects that were due for completion between 2019 and 2022 for which no data on actual costs are available. The estimates of the time trends in reported and actual costs for 2000–2010 and 2011–2022 are consistent with this pattern. There was a particularly rapid increase in actual costs in the UK during 2000–2010 but no significant trend since then.

Figure 5 – Distribution of actual capex costs for offshore projects in the UK

(£ million per 000 m² of swept area at 2018 prices from SPV accounts by water depth)



Source: Author's estimates

Figure 5 matches Figure 4 but showing actual costs per 000 m2 of swept area rather than MW of rated capacity. The step change in capex cost which occurred between 2009 and 2012 is slightly less marked for swept area than for rated capacity but the overall pattern is similar. Again there is no significant trend in actual capex costs per unit of swept area from 2011 onwards.

Overall, there is no evidence that offshore capex costs have actually been falling. The level of actual offshore capex costs in the 2010s was much higher than in the previous decade. There is limited evidence that costs were slightly higher in the first half of the 2010s than in the second half of the decade. However, in statistical terms there was no consistent and significant downward trend in actual capex costs. It is clear that operators believe that offshore capex costs will fall in future, which gives rise to the downward trend in reported anticipated costs. However, the systematic discrepancy between anticipated and actual costs for completed projects suggests that operators are not very good at forecasting. Little weight should be given to reports anticipating lower costs until there is a stronger track record of confirmation by actual project outcomes.

3. The costs of operating wind farms

Onshore opex costs. The dataset on onshore opex costs has been compiled by extracting data from the accounts for onshore wind farm SPVs going back either to the accounting year which covers the majority of 2010 or to the first full year after the wind farm was commissioned. The full dataset contains 955 observations from 2010 to 2019 for 199 wind farms that were commissioned between 2002 and 2018.[11] The composition of the dataset means that it is possible to estimate cost equations that take account of both age and date of commissioning without the coefficients being affected by a high level of multicollinearity.

Opex costs are measured as £000 per MW of capacity, taking the capacity as reported to Ofgem's RO/REGO database. In cases where the reported capacity of a wind farm has either increased (due to the addition of wind turbines) or decreased (due to turbine failures) this is taken into account. In a small number of cases, opex costs are averaged over a group of wind farms that report aggregated results.

Table 3 shows the results for alternative regression models explaining the evolution of onshore opex costs over time. The crucial issue examined in these models is whether opex costs are either (a) purely a function of the date of the observation (Model 1), or (b) they vary with both the year of installation and the age of the wind farm (Model 2). Model 1 is a restricted version of Model 2 with equal coefficients on year of installation and age. This restriction can be tested by goodness of fit tests as well as tests on the coefficient values.[12] In all cases the restriction implied by Model 1 is

11 The number of wind farms reporting opex costs is smaller than the number reporting capex costs because of the small company exemption which allows some companies not to publish an income statement. The estimates of the coefficient standard errors are adjusted for the correlation between observations on the same wind farm for a sequence of years – technically, clustering on wind farms over time.

12 It is also possible that age and year of installation are sufficiently highly correlated in the data that it is not possible to obtain unbiased estimates of the coefficients on each variable. One standard test for multicollinearity is the VIF test. The values of the VIF statistics are below the threshold for concern about possible bias.

rejected at a confidence level of 99%, so it is safe to conclude that year of installation and age have independent influences on opex costs.

Table 3 – Regression models for onshore opex

	Log(Opex per MW)	
	Model 1	Model 2
Year	0.039***	
	(0.005)	
Year of installation		0.044*** (0.006)
Age (years)		0.028*** (0.005)
Turbine size		
1-2 MW	-0.155 (0.090)	-0.147 (0.084)
2-3 MW	-0.270*** (0.076)	-0.311*** (0.073)
3+ MW	-0.277** (0.084)	-0.339*** (0.088)
Observations	955	955
Adjusted R-squared	0.120	0.144
Notes: (a) * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$.		

Source: Author's estimates.

To understand the results in Table 3 suppose that we compare two onshore wind farms, one commissioned at the beginning of 2005 and the other a decade later at the beginning of 2015. Both wind farms have turbines in the 2-3 MW size category. To hold the influence of age constant the comparison is when each wind farm is 2 years old, i.e. in 2007 for the first wind farm and 2017 for the second one. Then, the results tell us that the average annual opex cost – measured in £ per MW at 2018 prices at age 2 years - for the wind farm commissioned in 2015 will be 54% higher than for the wind farm commissioned in 2005, i.e. a growth of 4.4% per year. This is very striking because it means that the underlying cost of operating and maintaining wind farms has increased rapidly in real terms when we hold age and turbine characteristics constant. It is entirely contrary to what one would expect from the story that the costs of wind generation are falling significantly.

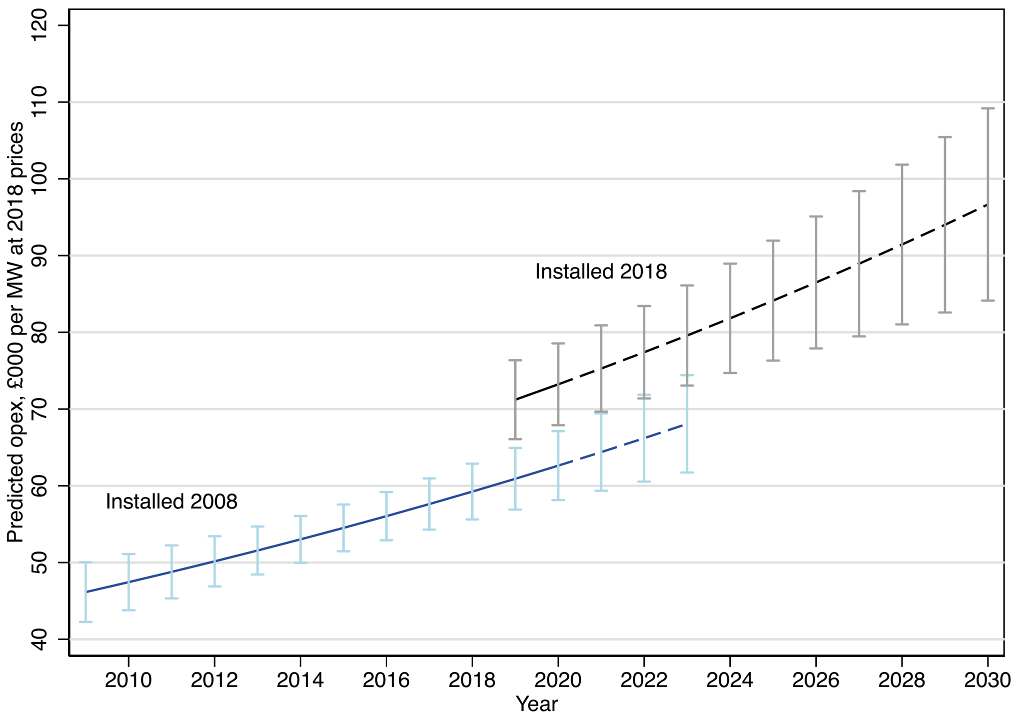
Once the influence of the year of commissioning is stripped out, there is a separate effect linked to turbine size. The average cost per MW of operating and maintaining turbines of less than 1 MW is significantly higher than for turbines of 2-3 MW. However, this economy of scale seems to run out at this size as the average opex cost per MW for turbines of 3+ MW is not significantly lower than that for turbines of 2-3 MW.

The reason for this systematic and rather large upward trend in opex costs with date of commissioning is unclear. I have tested a number of variables such as the number of turbines and total wind farm capacity without identifying any that might account for the trend. The most plausible explanation is that over time developers have moved to more remote and less favourable sites with an associated increase in annual opex costs, but it is difficult to test this hypothesis in a systematic manner.

Once an onshore wind farm has been commissioned, its opex cost will continue to increase as it ages at a rate of 2.8% per year (the coefficient on age in Model 2 of Table 3). Hence, the opex cost for a wind farm that is 11 years old will be nearly a third higher in real terms than its opex cost when it was only 1 year old. As we will see, this increase has a substantial impact on the expected economic life of a new wind farm. For the operator the key calculation that determines economic life is a comparison between expected revenue – from sales of electricity and subsidies received – and the cost of keeping the wind farm in operation. Under various scenarios it is straightforward to compute a break-even load factor at each age and compare that with the average load factor for onshore wind farms of different ages.

Figure 6 – Average opex costs for onshore wind farms in UK

(£000 per MW at 2018 prices)



Source: Author's estimates.

Note: The dashed segments are projected costs derived from the regression analysis.

Figure 6 shows the average opex cost with confidence intervals for (i) a wind farm using 2–3 MW turbines commissioned in 2008, and (ii) a similar wind farm commissioned in 2018. Each curve represents the effect of age on opex costs for an existing wind farm, while the shift from the 2008 curve to the 2018 curve represents the impact of installation year on the starting level of opex costs for new wind farms. A new wind farm with 2–3 MW turbines installed in 2018 had an expected annual opex cost of £71,200 per MW at 2018 prices in 2019 and that is expected to increase with age to £105,000 per MW at age 15 in 2033.

In this case, there can be no doubt that opex costs for onshore wind farms are not falling in real terms over time. Opex costs per MW of capacity measured at 2018 prices have been increasing at a substantial rate by year of commissioning. Notwithstanding the large increase in the number and the cumulative capacity of onshore wind farms in the UK, this trend has continued for more than 15 years. There seems to be no reason to expect that it will change in the near or even medium term. All of the evidence points to a systemic and substantial increase in average operating costs for new installations during the 2020s. The small advantage from using larger turbines will be far outweighed by the underlying trend that has pushed opex costs upwards. Further, after a wind farm has been commissioned, so that its site and equipment characteristics are fixed, the evidence shows that opex costs increase with the age of the wind farm, though at a rate that is somewhat lower than the underlying increase for new installations.

Offshore opex costs. The analysis of offshore opex costs is somewhat more complicated than that of onshore opex. The reason lies in the treatment of offshore transmission costs. In the UK it is standard for offshore wind farms to construct dedicated transmission links from their wind farm to an onshore substation where the transmission link connects to the onshore national grid. The cost of building the offshore transmission link is borne by the developer. This is different from the arrangement in the Netherlands and Germany where it is national or regional grid companies that are responsible for constructing offshore transmission links.

Each model has its advantages and disadvantages for wind farms developers and energy customers. There may be cost savings from building and operating shared offshore transmission networks, but individual projects may be delayed and less well served because of constraints on what the grid company can finance and build. One important consequence is that transmission costs for offshore wind are likely to be socialised – spread over all customers – rather than being allocated to specific wind farms. This tendency is particularly important in Germany where the average distance from wind farm to an onshore landing point is more than 50 km.

While offshore wind farm developers in the UK retain responsibility for building offshore transmission links, there was a change in 2009–2010 in the arrangements for the ownership and operation of offshore transmission after the wind farm and its transmission network have been commissioned. In response to an EU Directive requiring the unbundling of generation and transmission, offshore transmission networks for some (but not all) offshore wind farms have been transferred to separate entities known as OFTOs.[13] What happens is that Ofgem prepares a cost valuation of the transmission network to establish the Regulatory Asset Value (RAV) for the OFTO, which is used in setting transmission charges. Then, it manages a bidding process for the disposal of the transmission network by the wind farm SPV to an independent SPV (the OFTO) that will own and operate the unbundled network. In all cases, the OFTO is primarily a financial vehicle that contracts out the

13 The first transfers – for Barrow, Gunfleet Sands, Robin Rigg and Walney wind farms – took place in 2011. At the end of 2019 only 834 MW out a total of 9110 MW of offshore capacity was outside the OFTO regime.

operation and maintenance of the transmission network to specialised contractors, often those who were responsible for the original construction. Technically, the OFTO is providing transmission services to National Grid Electricity Transmission (NGET) in England or SPT/SHETL in Scotland.[14] NGET, in turn, recharges the transmission costs to the wind farm.

As a consequence, the opex figures reported in SPV accounts fall into two categories.

- Offshore opex measure 1 (Opex1) – This excludes transmission charges for offshore transmission but it includes direct expenditures on operating and maintaining offshore transmission cables and related infrastructure. This measure is reported by (a) offshore wind farms that do not have an OFTO, or (b) new offshore wind farms with an OFTO but in the period prior to the transfer of the offshore transmission network to that OFTO.

- Offshore opex measure 2 (Opex2) – This includes transmission charges for offshore transmission but it excludes direct expenditures on operating and maintaining offshore transmission cables and related infrastructure. This measure is reported by offshore wind farms that have an OFTO in the period after the transfer of the transmission network to the OFTO.

Using the accounts of each OFTO it is possible to make an estimate of the conversion from Opex2 to Opex1 by deducting the OFTO's transmission service revenues – reported in their regulatory accounts as operating income and finance income – and adding back the OFTO's operating costs which exclude depreciation.[15] Hence, there are two ways of estimating trends in offshore opex costs. The first is to combine data for the Opex1 and Opex2 measures and then include a shift parameter for the cases in which OFTO charges are included in the value of opex costs per MW as shown in models 1–3 of Table 4. The inclusion of OFTO charges increases the average opex per MW by about 28% relative to the opex cost incurred by wind farms without an OFTO. The second method is to pool the actual and adjusted estimates of Opex1 to estimate the regression coefficients as shown in models 4 and 5 of Table 4. The first approach yields much better results when judged using either the adjusted R-square or the Akaike/Bayesian Information Criterion (AIC/BIC) indicators of model performance.[16] On this basis I will concentrate on models 1–3 in Table 4 which use actual opex costs with a shift to allow for OFTO charges.

Models 1 & 2 compare the specification with a single time variable, covering both year of installation and age, with the specification with separate time trends for year of installation and age. In contrast to the models for onshore opex there is no significant difference between the time coefficients for year of installation and age. In both of these models wind farms in water depth of 30 metres or greater have significantly higher opex costs than those in water depth of less than 10

14 Since April 2019 the financial counterparty for OFTO charges is National Grid Electricity System Operator (NGESO) but I will refer to NGET for the whole period as that company remains the physical counterparty.

15 This calculation can be confirmed using data published annually by Ofgem from 2013 to 2016 in a table called Offshore Transmission Operator Revenue Report covering the accounting years 2012–2013 to 2015–2016. For some reason Ofgem stopped publishing this data after 2016 but apart from minor deviations due to timing noted in the report it is possible to confirm that the calculations can be replicated using data from the annual regulatory accounts of each OFTO.

16 The AIC/BIC statistics are generally viewed as better indicators of overall model performance than the adjusted R-square statistic, especially for the purpose of assessing which variables should be included in the equation.

metres. The coefficients on intermediate depth categories are barely significant. Model 3 shows that turbine size does not seem to have a significant effect on average opex costs.

Table 4 – Regression models for offshore opex

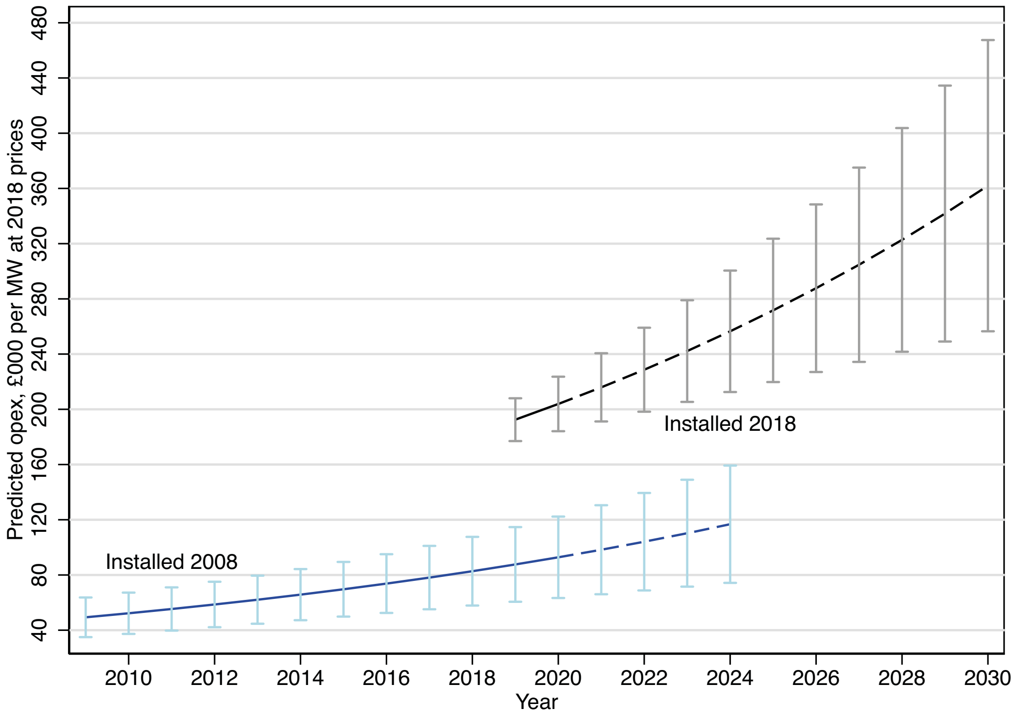
Variable	Log(Opex per MW)			Log(Adjusted Opex per MW)	
	Model 1	Model 2	Model 3	Model 4	Model 5
Year	0.057***			0.044**	
	(0.011)			(0.012)	
Year of installation		0.055***	0.061***		0.036**
		(0.013)	(0.015)		(0.013)
Age (years)		0.059***	0.061***		0.050***
		(0.011)	(0.010)		(0.013)
OFTO included	0.276***	0.278***	0.236***		
	(0.063)	(0.062)	(0.062)		
Depth category					
10-20 m	0.350*	0.361*	0.361*	0.306	0.348
	(0.149)	(0.163)	(0.157)	(0.151)	(0.174)
20-30 m	0.328*	0.344	0.331	0.108	0.166
	(0.152)	(0.175)	(0.175)	(0.177)	(0.198)
30+ m	0.511**	0.531**	0.530**	0.337*	0.412*
	(0.150)	(0.181)	(0.176)	(0.160)	(0.197)
Turbine size category					
3-6 MW			0.057		
			(0.122)		
6+ MW			-0.112		
			(0.251)		
Observations	199	199	199	199	199
Adjusted R-squared	0.581	0.579	0.582	0.222	0.225
*Notes: (a) * p < 0.05, ** p < 0.01, *** p < 0.001.*					

Source: Author's estimates.

Using Model 1 as the baseline, offshore opex costs have been increasing in real terms at a rate of 5.7% per year over a period of nearly 20 years, which translates to 74% per decade, after controlling for the transition to OFTOs and the shift to locating offshore wind farms in deeper water. This is an astonishing rate of increase sustained over a long period. Figure 7 illustrates the average opex costs derived from the model for two types of offshore wind farm: (i) a project such as Burbo Bank in shallow water (6 metres) that was commissioned in 2008 and has no OFTO; and (ii) a project such as Galloper in relatively deep water (36 metres) that was commissioned in 2018 and has an OFTO. For the first wind farm, the average annual opex cost rises from £50,000 per MW in 2009 to £117,000 per MW in 2024. For the second wind farm, the average annual opex cost including OFTO charges rises from £192,000 per MW in 2019 to £362,000 per MW in 2030. The large difference between the two paths reflects the combination of OFTO charges and the penalty for moving into deeper water.

Figure 7 – Average opex costs for offshore wind farms in UK

(£000 per MW at 2018 prices)



Source: Author's estimates.
Note: The dashed segments are projected costs derived from the regression analysis.

Again, the evidence on actual offshore opex costs as recorded in wind farm Special Purpose Vehicle accounts is of a rapid increase both for new wind farms and as those wind farms age. In addition, the OFTO regime has led to a substantial and long run substitution of opex costs for capex cost. This is not a neutral change because, as I will show, it is likely to have a large impact on the economic life of offshore wind farms. The effect does not appear to have been recognised either by Ofgem or by wind operators and investors in OFTOs. This impact would not arise if opex costs were stable but the combination of an increase in base opex costs plus the sustained rise in opex costs means that many projects will have an economic life that is far shorter than the 20–25 years assumed in company accounts and by financial investors.

4. Financial costs

Up to this point the evidence on actual costs of building and operating wind farms runs entirely counter to the belief that the cost of wind power has fallen and will continue to fall in future. It is clear that some operators and investors believe that such costs will fall in future, but such beliefs seem to represent a – probably expensive – triumph of hope over experience. It takes a very strong variety of optimism to sustain the conviction that trends sustained over 20 years will miraculously be reversed in the next 5 years. As a well-known epigram goes, "the race is not always to the swift, nor the battle to the strong, but that is the way to bet".

However, wind generation is capital-intensive and there is no doubt that the cost of the capital required to finance new wind farms has fallen substantially. Since both interest rates and risk-adjusted rates of return have been at historically low levels for more than a decade, it is not the underlying financial environment that explains the fall in the cost of capital. The key factor has been the reduction in the risk premia for wind projects that are applied by lenders and equity investors as the scale of wind generation has grown. To this factor we should add the development of specialised investment vehicles that cater for institutional and private investors wishing to allocate funds to green investments.

This is, at best, a one-off change in market conditions. The cost of capital for new wind projects in developed countries is as low as it is likely to get, so there is no room for further reductions in the costs of financing new projects. Even more important, the reduction reflects assumptions about risks and asset lives that may be seriously wrong, in which case financial costs will rise.

To understand this it is necessary to consider some basic financial mathematics. As a starting point the median first year OFTO finance charge as a percentage of the Regulated Asset Value (RAV) for the offshore transmission network has fallen from 8.1% for OFTO contracts awarded in 2011 to 3.3% for contracts awarded in 2018.[17] OFTO contracts are regulated with RPI indexation and secure income streams so that their cost of capital is lower than would be required to fund wind farm investments.[18] The decline suggests that the weighted average cost of capital (WACC) for offshore wind generation may have fallen by 4-5 percentage points over the decade from 2010 to 2019.

In its RIIO-2 draft determination published in July 2020 Ofgem has proposed a real WACC of about 2.75% for National Grid Electricity Transmission after allowing for expected out-performance. Regulated transmission assets have longer asset lives and are much safer investments than offshore wind generation. Allowing a modest margin for the additional risk, the real WACC for offshore wind is likely to be 4%-5%.

A survey carried out by Grant Thornton and the Clean Pipeline Initiative – Grant Thornton (2019) – gave an average unlevered discount rate (equivalent to the cost of capital) of 7.25% nominal in 2018 for offshore wind projects receiving subsidies. Allowing for expected CPI inflation that estimate translates to a real WACC of 5.25%. The equivalent real WACCs for Germany and Scandinavia fall in the range 4.5% to 5.25%. For unsubsidised onshore wind projects, the real WACCs ranged from 3.5% in Germany to 5% in the UK.

17 The figures for 2018 are based on pro-rating data for OFTO SPVs that operated for at least 3 months in the financial year 2018-19.

18 There is an important difference in indexation provisions between the original OFTO contracts and CfDs. The former use RPI indexation while the latter use CPI indexation. Since RPI inflation has been consistently 0.6-1.0 percentage points higher than CPI inflation, this means that generators with CfD contracts will face a fall in net revenue due to OFTO charges rising more rapidly than the CfD strike price. In 2016 Ofgem considered whether to switch to CPI indexation but chose to retain RPI indexation on the grounds that there is a more liquid market for RPI indexed bonds.

Table 5 – Financing costs for onshore and offshore wind farms

Expected life	Capital charge in £000 per MW for WACC of:					Capital charge in £ per MWh for WACC of:				
(years)	8%	7%	6%	5%	4%	8%	7%	6%	5%	4%
A. Onshore wind farm £1.6 million per MW with load factor of 30%										
15	£187	£176	£165	£154	£144	£71	£67	£63	£58	£55
20	£163	£150	£139	£128	£118	£62	£57	£53	£49	£45
25	£150	£138	£125	£114	£102	£57	£52	£47	£43	£39
30	£142	£130	£117	£104	£93	£54	£49	£44	£40	£35
B. Offshore wind farm £4.0 million per MW with load factor of 50%										
15	£468	£440	£412	£384	£360	£107	£100	£94	£88	£82
20	£408	£376	£348	£320	£296	£93	£86	£79	£73	£68
25	£376	£344	£312	£284	£256	£86	£79	£71	£65	£58
30	£356	£324	£292	£260	£232	£81	£74	£67	£59	£53

Source: Author's calculations.

Table 5 shows the costs of financing an onshore wind farm costing £1.6 million per MW of capacity and an offshore wind farm costing £4.0 million per MW of capacity under combinations of the cost of capital and expected economic life of the assets. The calculations assume a mortgage repayment schedule and are very basic in order to illustrate the magnitude of the changes in financing costs due to the fall in the cost of capital and an assumption of longer asset lives.[19] The columns showing the cost of financing per MWh of output are based on extremely optimistic assumptions about annual load factors. These load factors are representative of what operators claim to expect in future; they do not reflect the reality of the load factors that have actually been achieved by any wind farm that has operated for a reasonable period. In the case of onshore wind farms the average annual load factor for the UK varied during the period 2010–2019 in the range from 21.8% to 29.3%.[20] The average over the 10-year period was 26.5%. Since total capacity has grown rapidly, the average is skewed to represent wind farms in the early years of operation. The lifetime average is very unlikely to exceed 25% in reality. The picture is similar for offshore wind farms. The 10-year range is 30.5% to 41.5% and the 10-year average is 37.6%. Even focusing on wind farms in deeper waters with better wind conditions the average load factor is only a little over 40%.[21]

The fall in the real cost of capital from 8% to 4% reduces the annual cost of financing by 23% for an expected life of 15 years and by 32% for an expected life of 25 years. The effect is bigger the

19 It should be emphasized that the figures are highly simplified. The actual financial structure for most wind farms – and especially large ones – will usually involve combinations of senior and junior debt with different maturities as well as equity and sometimes mezzanine finance. In most cases, any payments to equity investors are likely to be deferred until certain financial targets are met.

20 Data from Energy Trends Table 6.1 published in March 2020.

21 There is one exception worth noting. This is the Hywind project that uses floating platforms and has achieved a load factor of nearly 54% over two years. However, the higher load factor is far from sufficient to offset its much higher capex cost - nearly £9 million per MW at 2018 prices.

longer the expected life, so with a lower cost of capital there is a strong incentive to assume a longer economic life. Moving from a combination of a 8% cost of capital and a 15 year asset life to a 4% cost of capital and a 30-year asset life reduces the overall cost of financing by 50%. This incentive is reflected in the decisions made by some wind farm SPVs to increase the typical depreciation life from (usually) 20 years to 25 or even 30 years.

The scope for further reductions in the cost of financing is limited except under an assumption of long asset lives. Thus, the critical question for the future is whether the combination of low risk and long asset lives, which underpins the low cost of financing for regulated network and similar assets, is appropriate for wind generation. On the evidence in this paper this combination can only be sustained when wind farms are guaranteed above-market prices for much longer periods than those available under either the main support mechanisms for renewable generation in the UK over the last decade.

- Renewable Obligation Certificates (ROCs) are paid for a maximum of 20 years, after which period the operator has to rely on the wholesale market price.
- Contracts for Differences (CfDs) are offered for a maximum of 15 years, after which the operator has to rely on the wholesale market price.

Under both arrangements, a conservative financial structure will ensure that all debt is paid off and a substantial part of the equity is recovered within the life of the support contract, meaning that the effective asset life for the purpose of the cost of financing is the same as the 15- or 20-year contract length. The reason for this lies in the factors that determine the economics of asset lives.

5. The economic life of wind farm assets

In purely physical terms, wind turbines can operate for 25 years or longer, but very few wind farms actually operate this long. Even in Denmark, where turbines are well maintained, more than 90% of turbines are retired before they reach an age of 25 years. Older turbines tend to be less reliable on average and usually operate at lower load factors than newer turbines. Even so, the motivation for the retirement of turbines is economic rather than physical. The reason for this is best understood by thinking of a wind farm as a land use project similar to forestry. In the case of forests the decision that has to be made by the landowner is whether in any given year the trees should be allowed to continue to grow or whether they should be cut down and sold as timber. The age at which the trees are harvested is then a balance between the net increase in the saleable volume of timber from allowing the trees to grow for one more year versus the opportunity cost (sacrifice) of waiting one more year to realise the value of the timber. That gives rise to an equation by which the net value of the extra timber from allowing the trees to grow for one more year must exceed a notional land rent for the forest which reflects the opportunity cost of keeping the forest for one more year.

Translated to a wind farm, the calculation involves three components:

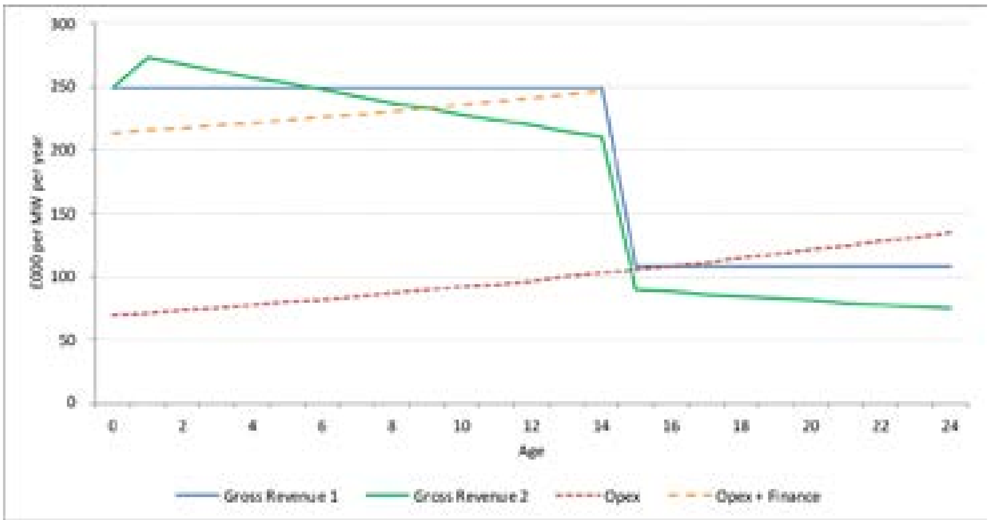
(a) Gross revenue from power sales (at guaranteed or market prices) plus any other services;

(b) Total opex costs including transmission charges, maintenance and other operating expenses; and

(c) The opportunity cost of using the site with its existing turbines rather than redeveloping with newer turbines.

Figure 8 shows the summary cash flows at 2018 prices for an illustrative onshore wind farm commissioned at the end of 2018 with a 15 year CfD contract at a strike price adjusted to £94.67 per MWh at 2018 prices, reflecting the CfD contracts for Kype Muir and Middle Muir wind farms in Scotland. Based on the analysis presented earlier in this paper the capex cost is £1.6 million per MW and the opex cost increases from £69,300 per MW per year at age 0 to £101,500 at age 15. At the end of the CfD contract the wind farm is expected to sell its output at the average day-ahead market price for wind output which was £46.3 per MWh at 2018 prices for the period 2015–2019.[22] The solid blue line marked Gross Revenue 1 assumes that the expected load factor is constant at 30% over a physical life of 25 years.

Figure 8 – Cash flow projections for a new onshore wind project: based on Kype Muir and Middle Muir



Source: Author's estimates.

The wind farm will earn an operating profit – defined as gross revenue minus opex costs – until age 16 but this operating profit is very small once the CfD contract expires. If an asset life of 15 years is assumed to match the life of the CfD contract, then the operating profit is sufficient to cover the cost of financing for a real cost of capital of 4% over that period. This means that the economic life of the asset is 15 years if the cost of capital is no greater than 4%. If the real cost of capital were, for example, 5% the cost of financing would exceed the operating surplus at age 12, so it is necessary to recover the capex over a shorter asset life. Even if the cost of capital is less than 4% the operating

22 GBP day-ahead prices for the UK in this analysis were obtained from the NB2EX power exchange operated by NordPool. EUR day-ahead prices for other countries were obtained from power exchanges operated by NordPool (Scandinavia), EEX (Germany, France, Switzerland & Benelux), EXAA (Austria and Germany), GME (Italy), OMIE (Spain & Portugal), and HunPX (Eastern Europe).

profit from age 15 onwards is so low that all of the original investment must be recovered during the life of the CfD contract.

However, this graph gives a very optimistic view of the viability of operating the wind farm past the end of the CfD contract. There are three reasons why the future economic life will be no more than 15 years.

- The average day-ahead price of £46.7 per MWh for 2015–2019 is skewed by the high prices that prevailed from the middle of 2017 to early 2019. The average price for 2018 was £56.8 per MWh but the "normal" price over the period was below £42 per MWh – the average prices for 2015, 2016 & 2019 were £41.6, £40.7 & £41.7 respectively. The higher prices in 2017–2018 were caused by a temporary increase in gas prices that lasted for about 18 months. As a consequence, an operator will not be able to cover its O&M costs in most years and the prospective profits from the occasional good year may not justify incurring significant operating losses in other years.
- Power prices in the GB market are high relative to those in neighbouring European countries. Expressed in Euros the average price for 2015–2019 was €54.3 per MWh as compared with €41.0 for France, €40.6 for the Netherlands, €30.7 for Germany, and €28.9 for Denmark (DK1). The only reason that a gap of €13 or more per MWh can be maintained between GB and nearby countries is limited transmission capacity.[23] The long run cost of transmission from France or the Netherlands to the UK is €5-6 per MWh. That is why flow along the interconnectors is almost all towards GB. Further, the gap between average prices in Germany and those in France and the Benelux countries is due to constraints on transmission capacity from Germany to France and the Netherlands. Large investments are being made or planned in interconnectors, so the gap between GB prices and those in Western Europe will narrow. A reasonable forecast of future market prices in the GB market would be significantly lower than their 2015–2019 average – perhaps €40-45 (£36-40) per MWh by 2025.
- No sensible wind operator should assume that it will be able to achieve a constant 30% load factor from an onshore wind farm that is more than 15 years old. Even the most optimistic estimates of the decline in performance with age indicate that the average load factor for a 15-year old wind farm is likely to be no better than 75% of its average load factor when it was less than 5 years old. The average load factor for onshore wind farms in the UK for the period 2015–2019 was 26.9% (Energy Trends Table 6.1). That is a simple average without adjustment for age composition or location. The line marked Gross Revenue 2 in Figure 8 shows gross revenue over time on the assumption that the initial load factor is 33% with a decline in performance of 2% per year from age 2 onwards. In that scenario the operating profit is negative after the end of the CfD contract, though the project is able to recover its full costs over the life of the contract if the real cost of capital is 4%.

23 The relative gap in gas prices is much lower than that for power prices because the combination of LNG trade and large pipelines across the North Sea from Norway means that the North Sea area of Western Europe forms a single market for gas.

Under current market conditions the economic life of the wind farm is 15 years – or the life of any contract guaranteeing above-market power prices – and no longer. In the future, it may be worth keeping the wind farm in operation for a few more years but only on the basis that it has recovered its initial development and capital costs and that there is no better use for the site at that time.

The economic life of the wind farm would, of course, be longer if the market price of power at the end of the CfD contract were expected to be much higher than the level for 2015–2019. If the expected market price for 2034 and beyond were £90 per MWh in real terms, in other words double the recent level, then the project would have an economic life of at least 20 years. The implication is that the assumption of an economic life longer than the CfD contract term is, in effect, a high stakes gamble on the real level of electricity prices in the mid-2030s and beyond. For that gamble to pay off the market price received for wind generation must increase at an average of at least 5% per year in real terms up to 2034.[24]

As noted above, the logic of increasing integration between the GB power market and power markets in neighbouring countries points to a decline rather than an increase in the real price of power. The average price of £46.3 per MWh for 2015-19 is higher than the "normal" price level of about £41.0 per MWh in years when gas prices are not well above their average level. This highlights the fundamental issues that have to be considered in assessing any assumption of an economic life that is longer than the length of a guaranteed price contract. What would be the economic factors underpinning much higher power prices in future?

The key determinant of power prices throughout Europe is the marginal cost of running gas plants – either Combined Cycle Gas Turbines (CCGTs) if the expected load factor is above 50% or gas turbines (GTs) for backup and peak demand. Older CCGTs operate for small numbers of hours per year and are mostly being retired because they cannot meet new environmental standards. New CCGT can achieve a thermal efficiency of 62–65%, while new GTs can achieve a thermal efficiency of 45% – in both cases with a rapid ramp rate and relatively low start-up costs. It is these plants that will set the cap on power prices in Europe in the late 2020s and beyond. They will recover their capital and annual fixed costs through contracts for capacity and frequency response (acting as spinning reserve). As a consequence, they will be dispatched whenever market prices are sufficient to cover their fuel and start-up costs.

I have built a model to calculate the marginal costs of dispatch for new CCGTs and GTs – see Hughes (2020). It takes account of start-up costs and the choice between operating units under different regimes – including base load, day + evening, separate morning + evening shifts, and peak only – with different regimes for weekdays and weekends as well by month. This gives a reasonable basis for estimating the response of average power prices to future changes in gas prices and the carbon price.

24 The combination of low demand and windy or sunny weather during 2020 has driven market power prices in the UK to even lower levels. The Intermittent Market Reference Price calculated by the Low Carbon Contracts Company for day-ahead market prices was £26.50 per MWh for June 2020 and £28.50 per MWh for January-June 2020. While the circumstances were special, the long run trend to lower wind-weighted market prices is well-established throughout NW Europe. Thus, the increase in market power prices required to support an economic life of even 20 years may be close to 8% per year in real terms.

Using actual data on prices and system loads for the period 2015–2019 the low-high range of the average marginal cost for new CCGTs in Great Britain is £32–£35 per MWh, while for new GTs this range is £46–£51 per MWh. The equivalent ranges for nearby countries in Western Europe are €34–€38 per MWh for new CCGTs and €49–€55 per MWh for new GTs. In general, it is significantly cheaper to trade gas than to transmit electricity, so the differences between countries in the marginal costs of running new gas plants are smaller than current differentials in power prices.

Stepping back from these estimates it is clear that the energy policies of European and other countries over the last 10–15 years have been little more than a complicated, and ultimately very expensive, hedge on gas prices. Any energy economist with an open mind has known that the cheapest way – at past and current prices – of reducing carbon emissions from energy consumption is to promote the use of gas wherever possible as a substitute for coal and oil. In due course, gas could be displaced by even lower carbon options, which might, perhaps, include nuclear, renewables, fossil fuels with carbon capture and alternative gas cycles. That, indeed, has been the route followed in the United States, though largely by accident.

The only coherent reason for departing from this strategy rests on the belief that the increase in gas prices that occurred in the late 2000s would accelerate through the next two decades. Gas – and oil – prices have a history of being strongly cyclical. Unfortunately, many policymakers and commentators are prone to assume that cyclical up- and down-swings signal long run trends and draw erroneous conclusions about the future of energy markets and prices.

There is no reason to expect the real level of power prices in the 2030s to be double those of the last 5 years because of some transformation of the world gas market. Gas is not scarce now and is not going to be fundamentally scarce at any time in the next two decades, though, naturally, there will be cyclical variations in its price. Hence, the notion that the European power price will reach £90 per MWh in real terms because of a change in the gas market is not a basis for serious business planning.

That leaves the carbon price. How large would the price of EU-ETS permits have to be to increase the marginal cost of gas generation by enough to warrant an assumption that the real power price will double in 10–15 years? The answer is that the ETS price would have to increase to about 8 times its 2019 average of €24.50 per tonne of carbon dioxide (tCO2), i.e. roughly to €200 per tCO2.[25] At this permit price the range of marginal costs for CCGTs in the UK would be £85–£92 per MWh. While a policy intervention of this magnitude cannot be entirely ruled out, its visibility and consequences would be so large that it is hard to believe that any UK government would have the inclination to adopt and, crucially, persist with such a policy. The lesson from all previous attempts to make such large changes is that none last for very long.

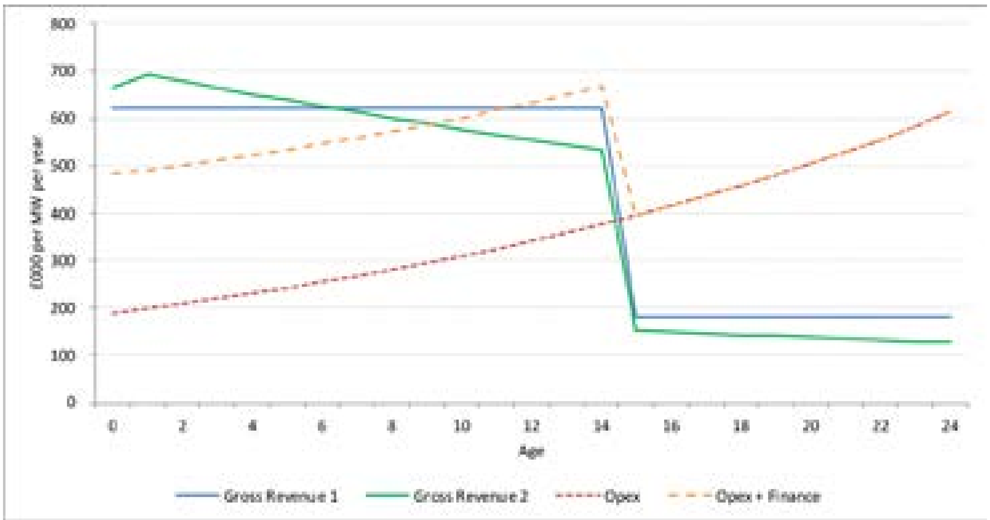
In summary, all evidence and experience indicate that the economic life of an onshore wind farm in the UK is not likely to be any longer than the length of the contract for which an above-market level of power prices is guaranteed. Under current policies, that is 15 years for CfDs. Based on actual data for operating wind farms the annual opex costs for a wind farm that comes to the end of a CfD contract will exceed the expected gross revenue from power sales in the day-ahead market. After making a very conservative allowance for the decline in

25 The UK floor price is £18 per tCO2 which was higher than the EU-ETS price up to mid-2018.

performance with age, the operator would require a price of at least £58.5 per MWh at 2018 prices to cover opex costs alone in year 20 even if all finance costs are paid off within the life of the CfD contract. Any investor who uses a depreciation period that is longer than the length of the original CfD contract will be both disappointed and substantially out of pocket.

The story is similar for offshore wind projects. Figure 9 illustrates the cash flows for hypothetical project completed in 2019 with capex costs similar to those for the Beatrice project in North-East Scotland. The lifetime constant load factor is assumed to be 45%, consistent with offshore projects completed in the late 2010s which use the current generation of 6–8 MW turbines, and the CfD price is £158 per MWh at 2018 prices. That is far higher than the prices for later CfD rounds. The project should cover a 4% cost of capital but opex costs after 15 years will exceed prospective revenues from power sales at the market price, even if the average load factor remains constant over time. There is no reasonable prospect that the project would continue to operate after the expiry of the CfD contract that guarantees a very high power price.

Figure 9 – Cash flow projections for a new offshore wind project: based on Beatrice

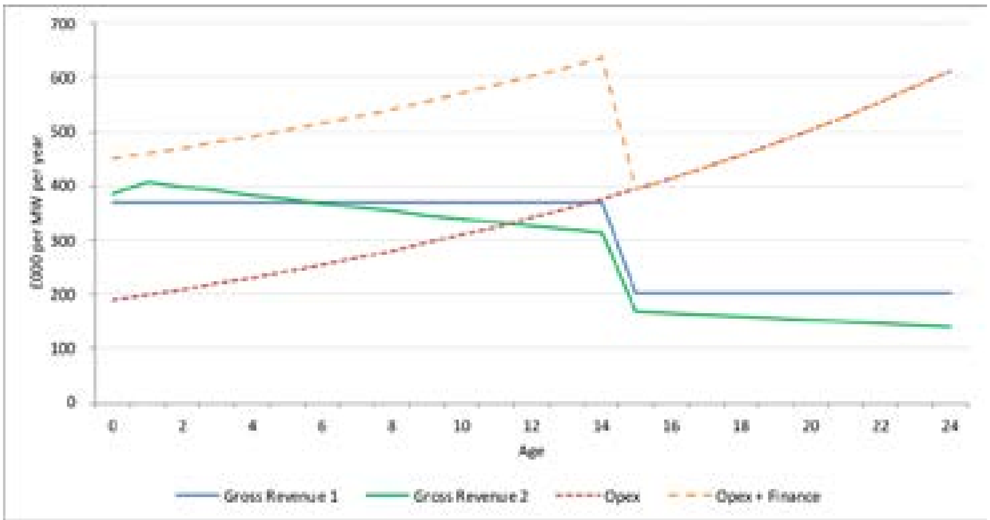


Source: Author's estimates.

Figure 10 illustrates an even more extreme case. It is based on the Triton Knoll offshore project currently under construction with an expected completion date of 2021–2022. This has a CfD that guarantees an offtake price of £84.50 per MWh at 2018 prices. The capex cost is assumed to be £2.9 million per MW excluding the transmission network. This is consistent with the figures reported for Triton Knoll and is below the trend of actual costs for a wind farm at a water depth of 30 metres. The turbines are 9.5 MW MHI-Vestas units and I have examined two scenarios: one with a constant average load factor of 50%, and the other with a peak load factor of 55%, declining at 2% per year. In both cases there is little that can be said other than that the project has all the signs of being a financial disaster. It is unable to cover its cost of financing in any year and will make a cumulative loss of more than £2.5 million per MW over the life of the CfD contract. Even if the cost of capital is reduced to 0% in real terms, the cumulative loss over the life of the CfD contract is about £1.5 million per MW. In slightly different terms, the project is only able to recover half of its capex costs even if it pays no interest or return on equity to those who provide the funds.

Thus, the economic life of offshore wind farms is likely to be shorter than that of onshore wind farms because the higher load factors will not be sufficient to offset the increase in annual opex costs as the wind farms age. It is possible that projects which received CfDs in Allocation Round 2 – Hornsea 2, Moray East and Triton Knoll – will find that their opex costs exceed generation revenues at the CfD strike price after 10-12 years. In such cases the projects will be unviable on a cash flow basis, even if all residual debt and equity is written off. There will be no option other than a bailout or some other intervention.

Figure 10 – Cash flow projections for a new offshore wind project: based on Triton Knoll



Source: Author's estimates.

There are two conclusions that follow from this analysis of the factors which determine the economic life of both onshore and offshore wind farms.

- No prudent investor should assume an economic life that is longer than the period of any contract which guarantees offtake prices that are significantly higher than those which can be earned in the day-ahead market. The crucial point is that the average length of such contracts has tended to fall rather than rise over time. As already noted, RO contracts last for 20 years while CfD contracts expire after 15 years. In Denmark the length of guaranteed price contracts is tied to the volume of production and is expected to be no more than 12 years for the Kriegers Flak offshore wind farm that is currently under construction. The consequence is that capex and finance costs have to be recovered over a shorter period and thus will be higher than in the past if all other factors are held constant. This reduction in the effective economic life of wind farms substantially offsets the impact of the fall in the cost of capital on the total cost of a project.

- When investors assume an economic life that is significantly longer than the length of the guaranteed price contract, as many SPVs do when using amortisation lives from 20 to 30 years, they are making a large bet on the future path of market power prices. The evidence discussed suggests that this may be a much riskier bet than many investors realise. To compensate for the increased level of risk, the cost of capital should be significantly higher than the 4% assumed for current wind farm projects. For a wind farm there is little difference between the cost of finance and amortisation at 4% over 15 years and at 6% over 20 years. The assumption of a general operating life of 25+ years is not reasonable on the basis of actual experience, even in Denmark. Thus, the cost of capital should be even higher, thus increasing rather than reducing the overall cost of finance and amortisation.

The logic of an inverse correlation between assumed economic life and the cost of capital is an unavoidable consequence of the limited period for which guaranteed or hedged power prices at above market levels are available. The risks that are associated with uncertainty about market power prices in the 2030s or 2040s cannot be eliminated. At best, they can be shifted. Understandably, governments and power purchasers are reluctant to expose themselves to large liabilities 15 or 20 years into the future. This means that any wind farm investor that wishes to amortise its wind farm over a period of more than 15 years must factor the cost of bearing those risks into their calculations.

To summarise, the costs of wind generation are not falling. Certainly there is an effort to shift costs onto different parties, hiding the true risks by assuming long operating lives instead of covering these risks out of lengthy price guarantees. In part this is an issue of ignorance and accounting disclosure. Any SPV that adopts an amortisation life that is longer than the period for which it has a contract guaranteeing above-market prices should be required to explain why it has done so, and what measures it has taken to mitigate the risks that follow its decision. Of course, the issue does not arise if an SPV sells all of its power in the day-ahead market, but despite all the rhetoric there have been no significant investments in pure merchant wind farms.[26]

6. Output and load factors

In discussing the economic life of wind farms I have adopted assumptions about output or load factors that reflect current assumptions for new projects, mediated by a dose of realism from the actual performance achieved by wind farms over the last two decades. However, there is an argument that is relevant to assessing claims that the costs of wind generation are falling. In general terms, it is asserted that modern turbines are capable of extracting greater output from given wind resources. For the most part, this rests on a simple application of the physics of wind shear, namely that wind speeds tend to increase as you move up from the surface of the earth. By increasing the hub height of wind turbines they are able to take advantage of higher average wind speeds. Since the amount of wind energy is proportional to the cube of wind speed, taller turbines should achieve higher output for longer periods of time.

Inevitably, things are not quite that simple. First, taller turbines must be spaced at greater distances in order to minimise "wake effects". This means that output per square kilometre of land area

26 For the avoidance of doubt, wind farms supported by corporate PPAs are **not** merchant plants. They rely upon a guarantee of above-market prices, usually for a period of 15 years but occasionally for longer. Further, they are **not "subsidy-free"** as the rhetoric suggests. The subsidy is hidden but it arises because a significant part of the extra cost is transferred to taxpayers via a reduction in corporation and other tax liabilities. For analytical purposes wind farms supported by corporate PPAs are almost identical to those supported by CfDs funded by the Low Carbon Contracts Company.

occupied by turbines may even decrease from switching to taller turbines even though output per turbine may increase. For onshore wind farms, where land with planning consent and a reasonable wind speed is scarce, the primary concern of operators may be to maximise output per unit of land rather than per turbine. Second, even when land is not a constraint, wind speeds increase less than proportionately with hub height, whereas the costs of building and operating turbines may increase more than proportionately with hub height. Third, the increase in output is not proportional to the increase in average wind speed because turbine power curves are S-shaped, with peak output reached at 12–14 m/s, so there is a complex set of trade-offs involved in designing and choosing wind turbines for specific sites based on the distributions of wind speeds at different heights above ground or sea.

Figures 11A and 11B show the proportional increases in load factors for onshore and offshore turbines for increases in hub height. The derivation of the estimates is described in Appendix B and the figures are based on calculations for turbines in Denmark based on the complete register of Danish wind turbines. Since Denmark is relatively flat, the effects of turbulence caused by hills and other topographical features is minimised for this dataset.

For onshore turbines, increasing the hub height from 80 to 120 metres leads to a median increase in the expected annual output of 9.6%, while increasing the hub height from 120 to 160 metres leads to a further increase of 5.8% in the expected annual output. These estimates translate to an increase in the expected annual output from 30% at a hub height of 80 metres to 32.9% at a hub height of 120 metres and to 34.8% at a hub height of 160 metres. Clearly, increases in hub height yield a diminishing return while the increase in capex and opex costs get larger as the hub height increases.

There are a number of onshore wind projects in the UK with proposed tip heights of 150 to 180 metres. The hub heights for these turbines would be 80 to 100 metres, giving at most an increase of 5% in the expected annual output. This is already built into the projected cash flows for the onshore project shown in Figure 8. Going to a tip height of 200 metres with a hub height of 120 metres would only increase the yield by an extra 4% and would bring no substantial improvement in the cost of onshore wind relative to gas plants or other forms of renewable generation, but it would greatly increase the visual impact of onshore turbines in most locations.

Figure 11B shows that the increase in annual output from increases in hub height are even less significant for offshore wind farms. Going from a hub height of 100 metres to one of 150 metres leads to an increase of less than 7% in the expected annual output and this is likely to involve large costs.[27] This translates to an increase in the expected annual output from 50% at a hub height of 100 metres to 53.5% at a hub height of 160 metres. A more realistic increase to 120 metres will only increase the expected annual output by 3%. Again, this has been incorporated in the cash flow analysis based on the Triton Knoll project shown in Figure 10.

Since any increase in hub heights will involve higher capex and opex costs, the net impact of such change on the overall costs of wind generation is likely to be small or negligible.

27 General Electric claims a considerably larger relative increase in annual output for its Haliade-X 12 MW turbine which has a planned hub height of 150 metres – from a load factor of about 55% to about 63%. Whether and how it will achieve this in actual operation remains unproven. It relies on an exceptionally large rotor blade (a diameter of 220 metres); the difficulties of manufacturing and maintaining such large items have proved to be very great for other manufacturers.

Figure 11A – Onshore turbines - relationship between hub height and load factor

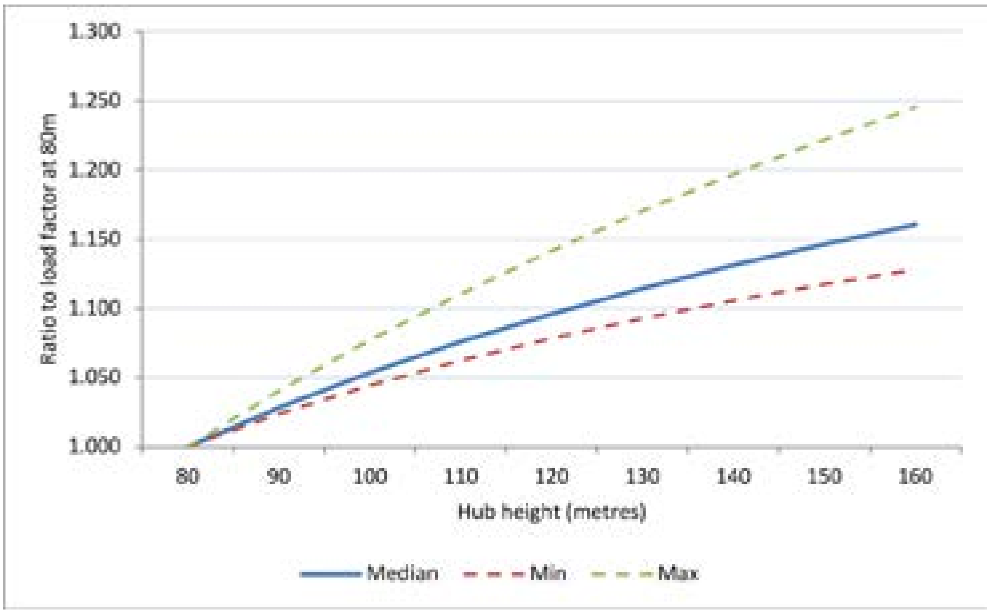
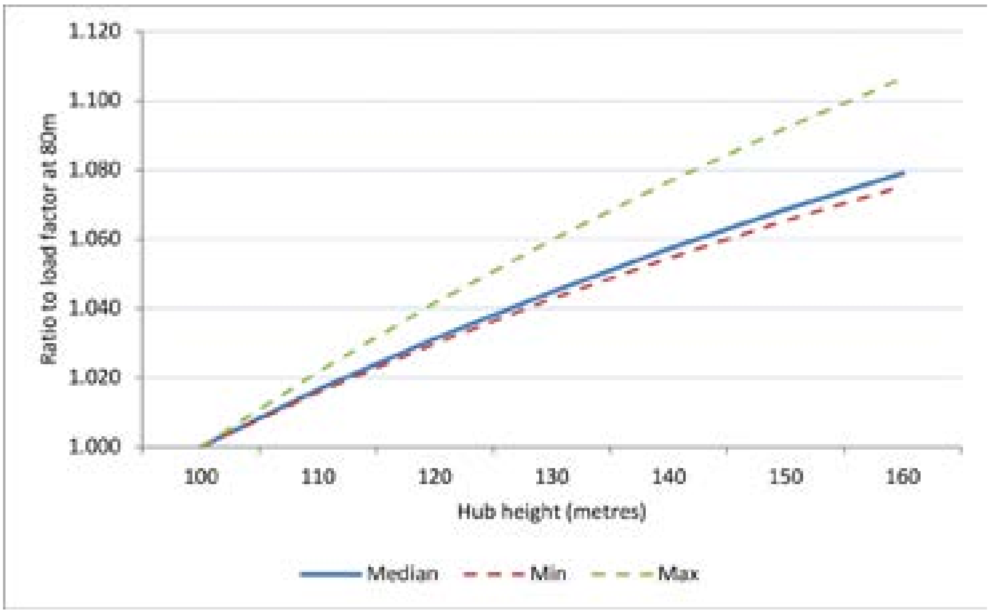


Figure 11B – Offshore turbines – relationship between hub height and load factor



Source: Author's estimates.

7. Pulling the elements together

The story that the costs of wind generation in the UK, especially offshore wind, are falling rapidly rests on the assumption that, notwithstanding the actual evidence, the bidders at auctions for offshore wind contracts know what they are doing. No one with experience of auction bidding in many other sectors would make that assumption. It is quite possible that the Winner's Curse is alive, thriving, and directly applicable to the outcome of offshore wind auctions.

This paper has shown that on the figures reported in the accounts of a large number of SPVs for wind farms:

- Capex costs per MW of capacity at 2018 prices for new onshore or offshore wind farms rose rapidly up to the early 2010s and then stabilised. Capex costs for onshore wind may be falling at a low rate, but the evidence is mixed and costs vary greatly across sites.
- Opex costs for both onshore and offshore wind farms have been rising at a significant rate in real terms both for new projects and for existing projects as they age. This increase has been particularly striking for offshore wind.
- The cost of capital for new projects has fallen substantially but there is little scope for further falls. On the other hand, the economic life of wind farms has fallen too, because the length of contracts guaranteeing above-market prices has been reduced and the expected revenue from both onshore and offshore wind projects at market prices is not sufficient to cover expected opex costs after the end of guaranteed price contracts.
- The combined effect of a lower cost of capital and a shorter amortisation period is a small one-off fall in the cost of financing new projects. There is no reason to expect that the cost of financing will or can fall significantly in future unless governments or other parties are willing to hedge the risks inherent in uncertainty about future power prices.
- Manufacturers and operators are adopting new designs of turbines with larger rotors and greater hub heights. These take advantage of the greater wind wind speeds at higher elevations due to wind shear. Even so, after allowing for the higher capex and opex costs of using larger and taller turbines there is no evidence that such changes will result in substantial reductions in the unit costs of wind generation. They are equivalent to the marginal improvements in efficiency and performance that characterise many generating technologies.

When all of this is pulled together the dominant factor is the continuing increase in opex costs. This outweighs all of the small reductions in the costs of wind generation due to lower capex costs, higher load factors and a lower cost of financing. At the same time, the trends in opex costs examined in this paper are the element which is most firmly grounded in actual data for a large number of wind farms over a period of more than 15 years.

The response from those with an optimistic view of the future of wind generation is that some fundamental change in the level of opex costs is just around the corner and that this will reverse the adverse trends that are apparent in company accounts for the last decade and longer. However, this is not a new story. There have been frequent reports of radical changes in O&M costs over the last decade. These have not materialised. Investors and government decision makers should ask whether there is any reason for thinking that things will be different this time round.

Anyone who is familiar with both the development of wind power and thermal generating plant, especially gas turbines and combined cycle units, must be struck by the similarities between them. Initially, gas plants were expensive and relatively inefficient. Over time, manufacturers reduced the capital costs and improved their efficiency. By the early 2000s the introduction of new models with lower costs and higher efficiency had become an established pattern, and this will doubtless continue. The same pattern is apparent for wind turbines with generational shifts from < 1MW turbines to 1–2 MW turbines and then 2–3 MW turbines. Currently there is a shift taking place to 3–5 MW onshore turbines and 6–10 MW offshore turbines. The point is that wind turbines are a mature technology whose performance and costs improve in a series of regular but modest increments. It would be naïve to expect major changes bringing radical improvements in either performance or costs. Such expectations are the product of wishful thinking rather than engineering and economics.

There is, however, one critical difference between the economic characteristics of gas plants (both gas turbines and gas combined cycle units) and wind turbines. Gas plants have low capital costs and relatively high operating costs, but they can be designed to provide high levels of flexibility. Gas is simply a form of energy storage – much cheaper and more flexible than batteries or pumped storage. On the other hand, wind generation is highly capital-intensive; offshore wind is considerably more capital intensive than onshore wind. The economic reality is that offshore wind competes with nuclear power as it has an even higher capital cost per MWh of expected output. As turbines get larger in order to capture a higher proportion of wind energy they become more capital-intensive and less flexible.

One of the consequences of the technical naiveté that characterises discussions of energy policy and renewable technologies is the assumption that the economics of electricity generation is solely or largely concerned with the levelised cost per unit of energy. Power system engineers and economists have known for many decades that this is a mistake, especially since large transmission grids were developed. The supply of electricity involves a combination of services, and different modes of generation offer different packages of those services – either on their own or with complementary investments.

Capital-intensive, inflexible (must-run), and often remote generation units can play a useful role in electricity systems, provided that (a) the power they generate is sufficiently cheap, and (b) they do not form too large a share of the overall generation mix. Occasionally, as in France, large nuclear units are adapted to run in load-following mode (though at a significant cost in terms of higher maintenance requirements). This allows a higher proportion of total demand to be met from nuclear power.

The issue for wind power is clear. Offshore wind, in particular, is highly capital-intensive, has a short economic life due to its high operating costs, and does not operate in load-following mode. To play a large role in any electricity system it must either be very cheap – with a cost per unit of energy that is significantly below that of alternative, more flexible, sources of generation – or it must be heavily subsidised. To date, wind generation has relied on the second option. There is no real evidence that the first condition can be met.

This is not a conclusion for all times and all places. In locations with good wind resources and abundant land – e.g. Texas, Brazil or Western China – large onshore wind turbines may be able to generate power that is sufficiently cheap to warrant the investment in ancillary transmission, storage and integration services required to match the requirements of large power systems. In such circumstances, a limited proportion of onshore wind will provide a useful addition to a portfolio of generation technologies that can be used when and where appropriate.

It is harder to see an unsubsidised role for offshore wind on a large scale, simply because the stresses and costs of operating in a marine environment are so high. The requirement will be (a) the capability to operate at a constant level of performance for a minimum of 30 years with no significant increase in O&M costs, and (b) contracts which pay for load-following rather than just dumping electricity into the network.

The publicity that surrounds wind generation and other forms of renewable energy is too often characterised by a simplistic moral agenda and wishful thinking. Putting these aside, the truth that remains is that wind power is expensive under most conditions, and there is little prospect that this will change in the next one or two decades. The size of the premium price that is warranted for renewable generation is a wider social and economic decision. At the moment there is little evidence that either the social cost of carbon or any of the other benefits of using renewable energy come close to covering the higher costs of wind power in most locations.

The fundamental costs of wind generation have not fallen in real terms since 2010 and are not falling in the early 2020s. The fact that governments have unwittingly encouraged the playing of contractual games via the cost of capital, together with hidden tax subsidies and system integration charges, has no bearing on the real costs that have to be borne by society. If anything, these are rising over time and seem likely to continue to rise for years into the future. This has important implications for the role of wind energy in any politically and economically sustainable low-carbon agenda.

Acknowledgements

A. NASA daily weather data by grid square used to analyse the effect of hub height on output were obtained from the NASA Langley Research Center (LaRC) POWER Project funded through the NASA Earth Science/Applied Science Program – see **https://power.larc.nasa.gov/**. I am grateful to members of the POWER project for facilitating access to the detailed data that they have compiled.

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ADDENDUM: COMMENTS ON THE DEPARTMENT OF BUSINESS, ENERGY & INDUSTRIAL STRATEGY (BEIS) *ELECTRICITY GENERATION COSTS* (AUGUST 2020)

On the 24th of August 2020, when the paper above was complete and being typeset, the United Kingdom government's Department of Business, Energy and Industrial Strategy (BEIS) published its latest set of electricity generation cost estimates, *Electricity Generation Costs*, together with a number of related documents.[1] This is an astonishing publication for many reasons. According to the introduction it was completed in January 2020 and appears to have been kept in limbo for seven months, from well before the coronavirus lockdown, until being published without fanfare in the middle of the summer holiday period. Release of this material may have been stimulated by the need to disclose some of its findings as part of a Freedom of Information (FoI) request made to Ofgem by a member of the public wishing to see cost data in National Grid ESO documents published as part of the regulator's consultation on the proposed interconnection between the Shetland Islands and the Scottish mainland.[2] Ofgem's decision letter of the 25th of August accepting that they were obliged to reverse their redaction and to release some of this data strongly suggests that this is the case. Ofgem wrote:

> "Our review of Ofgem's engagement with the consultees shows that our officers provided constructive challenge on the application of the various exceptions in play. BEIS agreed to publish some of the information in their Electricity Generation Costs Report, which was released on 24 August."[3]

It therefore seems possible that BEIS did not initially intend to publish *Electricity Generation Costs* and only did so because National Grid ESO had inadvertently revealed its existence, and exposed it to FoI. Nevertheless, the material in *Electricity Generation Costs* presumably forms the basis of government thinking on the costs of offshore wind, and of other generation technologies, and indeed National Grid ESO relied on it in its own assessment of the economics of wind power on

1 BEIS, *Electricity Generation Costs* (24 August 2020). **https://www.gov.uk/government/collections/energy-generation-cost-projections?utm_source=2deef6b5-8bc2-4b0b-a6a7-eecc4f289432&utm_medium=email&utm_campaign=govuk-notifications&utm_content=daily#2020**

2 Consultation documents: **https://www.ofgem.gov.uk/publications-and-updates/shetland-transmission-project-consultation-proposed-final-needs-case-and-delivery-model**. Freedom of Information request information.

3 Letter from Ofgem to [Name witheld] 24 August 2020. I am grateful to the member of public for allowing me to see this document.

and around Shetland. As I shall show in my brief comments below the BEIS analysis is wholly inadequate, and its optimistic assessment of the costs of wind power cannot be relied upon for any purpose whatsoever.

Before making more detailed observations, attention should be drawn to two general aspects of the study. First, it purports to provide estimates or forecasts of generation costs for projects commissioning in 2025, 2030, 2035 and 2040. While costs at the nearest of these dates can be estimated rationally, costs a decade or more in the future are radically uncertain, and to attempt even moderately precise costings, as BEIS does, suggests naivety or hubris. Who in 2000 – or even in 2010 - had any realistic basis for forecasting the capex and opex costs for projects that are being commissioned in 2020?

Furthermore, on examining the spreadsheet which contains the detailed assumptions, it turns out that 94% of the model parameters for the various technologies, conventional and renewable, do not change from one period to the next. This is implausible, since it must presume that there is no technological progress in those fields. In other words, no fall in costs is projected for the majority of the generation types discussed. Where costs do vary they are for either (a) wind and solar, or (b) a range of minor (Geothermal CHP) or novel (wave, biomass with CCS) technologies. This is not reasonable. If there are cost reductions in the renewable sector, why rule out cost reductions in the conventional sector, which has in any case a very strong record of technological progress?

Looked at in more detail this underlying bias is quite extraordinary. The rates of decline in capex and opex costs or increases in operating performance for offshore wind – now a mature technology – are greater and more sustained than the decline for CCGT+CCS – a new and potentially critical technology.

It is obvious, therefore, that the BEIS projections of short-term generation costs are almost trivial, being merely generic costs for the middle of the current decade. Consequently, the estimates of the relative costs of conventional and renewable generation in the medium and longer term are at best meaningless and at worst misleading.

A second general point that should be noted is that the data used in the BEIS model is almost entirely derived from work conducted by or for the department itself. With the exception of a single reference to a National Grid ESO report, all of the sources cited for the data are BEIS publications or BEIS-commissioned reports. No attempt has been made to draw upon the growing academic and policy literature on the *actual* costs of building and operating various kinds of generation. There is not even a single reference to the extensive studies undertaken by the Energy Information Agency (EIA) in the US and various of the research laboratories funded by the US Department of Energy (DoE) – for example the Lawrence Berkeley National Laboratory (LBNL), the National Renewable Energy Laboratory (NREL) or the Oak Ridge National Laboratory (ORNL). Such a narrow focus is hard to justify, and indeed begins to look like a deliberate blindness in which all data is selected to fit with a pre-determined narrative.

Bearing these general remarks in mind, I will compare some of the specific assumptions in the BEIS study with the results of the data that I have compiled for this and other studies. Conveniently BEIS has adopted the same base year (2018) for real prices as that used in my own work, so there is no need for adjustment. I will start by examining capex costs and then opex costs before looking at load factors and financial parameters. In all cases I will use the BEIS assumptions for projects commissioning in 2025, since, as noted above, the BEIS estimates for later dates are mere speculation. I will focus on onshore wind, offshore wind and large scale solar as those are the primary technologies for which BEIS has updated its assumptions and for which comparisons with actual data from company accounts are possible.

A. **Capex costs**. The BEIS assumptions imply total capex costs (including capitalized interest) in 2025 of £1.30 million per MW for onshore wind, £2.16 million per MW for offshore wind (or £1.82 million excluding transmission), and £0.55 million per MW for large scale solar. Comparison with the actual costs reported in audited accounts is stark. The average value of the actual capex costs reported for onshore wind farms completed in 2016-19 was £1.61 million per MW, for offshore wind it was £4.49 million per MW (including transmission) or £3.99 million if the very expensive Hywind project is excluded. For large scale solar the average of actual costs was £0.98 million per MW. Hence, the BEIS assumptions are only 50%-80% of the actual capex costs reported in audited accounts for recently commissioned projects. Since BEIS provides no evidence in the data of any rapid reduction in capex costs per MW of peak capacity, their assumptions reflect little more than wishful thinking. The bias is particularly egregious in the case of offshore wind as most future projects will necessarily be at greater depths and distance from shore, thus incurring significantly higher capex costs for both turbines and transmission.

B. **Opex costs for onshore wind**. The BEIS assumptions imply opex costs for onshore wind of £47,000 per MW per year for a wind farm commissioning in 2025. Incredibly, these are assumed to be constant over an operating life of 25 years. My analysis, again from audited accounts, shows that actual opex costs for a new onshore wind farm commissioned in 2016 were £77,000 per MW at age 1 and that this will increase to £114,000 at age 15, and £149,000 per MW at age 25 if it were to continue to operate that long (which is very unlikely). The analysis also shows that the *initial* opex cost for *new* wind farms has been increasing at 4.3% per year, so the expected opex cost for a wind farm commissioned in 2025 at age 1 would be £112,000 per MW, more than double the BEIS estimate. Overall, the BEIS estimates of opex costs are about one-third of the best estimate based on actual data for the last two decades.

C. **Opex costs for offshore wind**. The BEIS assumptions imply annual opex costs for offshore wind of £109,000 per MW for a wind farm commissioned in 2025, constant over an operating life of 30 years. It is hard to make sense of the BEIS numbers. Their table 2.4 gives a fixed O&M cost of £36,300 per MW per year for 2025. This is implausible if it is supposed to cover Offshore Transmission Operator (OFTO) costs. Indeed, there isn't a single reference to OFTO transmission costs in the whole document yet the methodology requires that OFTO costs must be included. Again, my analysis of audited accounts shows that actual opex costs (including OFTO costs) for a new offshore wind farm commissioned in 2018 were £184,000 per MW per year at age 1, with an expectation that this will rise to £426,000 per MW per year at age 15. Actual offshore opex costs have been increasing at an average of 5.9% per year in real terms for the last two decades, so the lifetime average for a new wind farm commissioning in 2025 would be at least £450,000 per MW per year, or over four times the figure assumed by BEIS.

D. **Opex costs for large solar**. The BEIS assumptions imply opex costs for large solar plants of £10,000 per MW per year, constant over an operating lifetime of 35 years. Since most large solar plants were built between 2012 and 2017 the data on lifetime opex costs is limited, but my analysis shows an average of actual operating costs of £19,000 per MW at age 1 rising to £33,000 per MW at age 5. It is unclear whether these costs have been increasing with year of commissioning as well as age. Nonetheless, the pattern is clear. The BEIS assumptions about large solar opex costs are typically one-quarter to one-third of the actual costs incurred by real plants operating today.

E. **Load factors for onshore wind**. The BEIS estimates assume constant load factors of 34% over relatively long operating lives for new plants. This is implausible, and it would be surprising if even the most committed advocates of renewable generation believed it to be correct. Even the most optimistic academic analyses imply a decline of 1.5% to 2% per year in annual output of onshore wind farms, holding wind conditions constant. My analysis of the extensive data for Denmark, published together with the present study, shows that while the rate of decline in performance was lower for early generation turbines in the 0.5 MW to 1 MW category, which are no longer installed, the current generation of onshore turbines of greater than 2 MW exhibits a rate of decline of about 3% per year. The BEIS failure to recognise any decline in performance is a serious defect in the analysis. There can be no justification for this. BEIS's own figures show that the actual load factor for onshore wind farms has been constant at about 27% over the last decade after controlling for variations in wind conditions. In practice, what has happened is that the higher load factor for larger turbines at new wind farms, which lies behind their estimate of 34%, has been offset by the decline in performance for older wind farms.

F. **Load factors for offshore wind**. BEIS assumes a constant average lifetime load factor of 51% for conventional offshore turbines (i.e. not floating devices such as Hywind). However, for offshore turbines the rate of decline in performance is much worse than for onshore wind, a fact which underlies the rapid increase in opex costs per MW. The average load factor for offshore wind has increased, but this is purely a function of the skewed age distribution in the wind fleet. The BEIS assumption of a 51% load factor relies upon a belief that the future will be radically different from the past. That is unreasonable. The average load factors for offshore wind farms less than 5 years old in NW Europe mostly fall in the range 40-45%. That is the best they will achieve over their lifetime, and as they age their performance will decline. The advantages of turbine size and hub height referred to in the BEIS analysis are not remotely sufficient to account for the difference between the BEIS assumption of a constant 51%, and the reality of an initial 45% declining steadily over time.

G. **Load factors for large solar**. Proponents of large solar generation may be somewhat aggrieved by the BEIS assumption of average lifetime load factor of 11%, which is in fact typical of recent experience. Indeed, solar developers may have a stronger case for arguing that their relatively new technology may allow higher load factors in future. This is partly a matter of definition. Peak output is rarely achieved by most solar plants, whereas wind turbines are increasingly designed to achieve rated output at lower wind speeds, by adjusting the balance of swept area to generator capacity. Nonetheless, US EIA estimates of generation costs have assumed a significant increase in solar load factors for new plants commissioned in 2023-2024 relative to those commissioned in 2019-20, holding location and solar conditions constant. That may prove to be wrong, but BEIS's failure to note this possibility, while exaggerating the prospects for wind, brings the peculiar bias of their analysis into sharp focus.

H. **Operating lifetime**. As explained above, the operating lifetime of a new wind farm or solar plant is a complex economic issue and not simply a physical one, though the effect of age on operating costs and performance is critical. The BEIS assumption of an operating life of 25 years for onshore wind is optimistic but not completely outside the bounds of reason. My analysis suggests that the upper bound with current contractual arrangements and market conditions will be no more than 20 years. On the other hand, assuming an operating life of 30 years for offshore wind – note, with a constant load factor - is completely at odds with any of the actual evidence. The same is true for the 35-year lifetime for large solar plants. After all, even mature and reliable technologies such as Combined Cycle Gas Turbines and super-critical coal plants require major refits after about 20 years.

I. **Future market prices and lifetimes**. A possible interpretation of the implausibly long economic lifetimes projected for wind and solar is that BEIS is tacitly assuming that market power prices in the late 2030s will be 3 to 4 times their current level in real terms. Indeed, it is hard to explain the lifetime assumptions on any other basis. If that is BEIS's assumption, the failure to spell this out in the analysis illustrates the lack of transparency and arbitrary nature of the whole exercise.

J. **Hurdle rates**. The BEIS assumptions with regard to hurdle rates are based on a study by Europe Economics carried out in 2018, but only published on the 24th of August 2020 as part of the *Electricity Generation Costs* package.[4] The Capital Asset Pricing Model used in the study is employed by some economists and regulators, but it has, at best, only an accidental relationship to the way in which real investors determine the hurdle rate of return of investment in generation or other businesses. Putting that problem aside, it is still surprising that BEIS appears not to have carried out any kind of sanity check on the numbers in the Europe Economics report. For example, if BEIS had examined a financial model for any of the offshore wind CfD projects in Allocation Round 2 (AR2) or Allocation Round 3 (AR3), they would have discovered that every project would be a financial disaster on the cost of capital assumptions made in the Europe Economics analysis. It would be impossible for Hornsea 2, Moray East or Triton Knoll – all AR2 projects which I have examined in detail – even to cover debt service costs, let alone produce a reasonable return on equity if their CfD strike prices are taken at face value. The cost of capital for each project would have to be close to zero simply to cover the announced levels of debt that have been incurred for each project, and even that may not be sufficient.

Reviewing the deficiencies of the UK government's latest estimates of generation costs we are left with a puzzle. The assumptions which underpin the BEIS estimates of the cost of generation for wind and solar power are fanciful, and do not withstand even cursory scrutiny; under close analysis

4 **https://www.gov.uk/government/publications/cost-of-capital-update-for-electricity-generation-storage-and-dsr-technologies**

they disintegrate. Indeed, they are so far from the *actual* costs incurred by current operators and recorded in audited accounts that they are not worth further consideration. The question is how a government department in a major economy can have strayed so far from the real world.

One hypothesis is that the civil servants working within BEIS take the validity of their policies for granted and do not subject them to empirical criticism. In which case the report is an instance of policy-based evidence-making of the kind discussed at length in the recent book by John Kay and Mervyn King titled *Radical Uncertainty* (2020), which observes that the technical models of economics are frequently corrupted by those seeking support for specific policy narratives in a context of great uncertainty. Kay and King are understandably dismayed at the way in which almost all of the costs of such behaviour fall on outsiders, electricity consumers for example.

An alternative hypothesis suggests that far from being wilfully blind BEIS is attempting to defer the embarrassing admission that the much vaunted Contracts for Difference (CfD) system is being gamed by developers who fully expect to be bailed out in future. Indeed, there are clear signs in *Electricity Generation Costs* that BEIS is acutely sensitive to the discrepancy between the prices bid at recent CfD auctions and even their own implausibly low estimates of levelised costs (see pp. 23–24).[5]

If that is correct, the poor quality of the obfuscation exposes the Department and its ministers to ridicule. The *Electricity Generation Cost* estimates published by BEIS are not merely unreasonable, they are indefensible. As John Kay and Mervyn King repeatedly say in similar cases: *What is going on here?*

5 It is worth noting that this discrepancy occurs only in relation to offshore wind, since the strike prices for earlier *onshore* wind auctions were not absurdly low.

APPENDIX A
ESTIMATING CAPEX AND OPEX COSTS

Offshore capex costs. I have updated the analysis of offshore capex costs in Hughes, Aris & Constable (2017). The dataset now covers additional projects with planned completion dates up to 2023. More importantly, I have compiled data from audited accounts on the actual rather than the reported costs of wind farms. This follows the approach pioneered by Aldersley-Williams et al (2019) in taking advantage of the standard financial structure for most projects which involves the creation of a Special Purpose Vehicle (SPV) that owns and, thus, reports financial data for individual projects. There are a few projects with more complicated structures involving joint ventures between SPVs, each of which has a share in the wind farm, but it is usually possible to aggregate data for multiple SPVs to calculate the actual costs for the whole project.

One element of capex costs for offshore projects requires careful treatment because reporting conventions differ across countries, a point of particular importance in relation to the cost of the transmission network running from the wind farm to the point at which power is delivered to the onshore grid. The transmission cost is clearly part of the overall cost of the project, but it is not always included in the costs that are reported in press releases or even financial accounts. For example, in the Netherlands it is standard for the grid company TenneT to pay for the transmission network and that is the case for some projects in Denmark – e.g. Kriegers Flak. Since 2010 in the UK, the SPV responsible for most projects has been required, on completion, to spin off the transmission network into a separate company called an OFTO (Offshore Transmission Operator), though in practice the OFTO may contract with the wind farm owner for maintenance and other services. Not all offshore wind farms in the UK have spun off transmission into a separate OFTO. The exceptions are mostly wind farms that were commissioned prior to 2010 and special cases with very short transmission lines – e.g. Teesside and Aberdeen offshore wind farms.

To put all projects in the database on the same basis, I have added estimates of offshore transmission capex for projects in countries outside the UK where regular reports quote capex figures that exclude transmission. For the UK I have used SPV accounting figures for tangible assets before the disposal of transmission network assets to an OFTO. In total there are 45 offshore projects in the UK and 64 projects for Western Europe ex-UK, with reported total capex obtained from a wide range of sources in the public domain. Of the UK projects, some 36 were completed before or in the year covered by the most recent set of SPV accounts for the project.[1]

1 No SPV was formed for the Beatrice Demo project, which was a joint venture between Talisman Energy and SSE that was constructed to meet the electricity requirements of the Beatrice offshore oilfield.

Onshore capex costs. These were derived by examining all of the SPV accounts that could be located for a population of 317 onshore wind projects commissioned between 2000 and 2018 with a minimum capacity of 10 MW. There are 247 SPVs that could be identified and a further 10 projects for which capex figures were identifiable in parent company accounts, giving an overall sample of 258 projects for the analysis of trends in onshore capex.

The cost of connecting an onshore wind farm to the grid is a standard component of onshore capex and is rarely identified separately. There are, however, some minor issues arising from the way in which information is presented in the accounts of different SPVs. Some operators capitalize lease contracts and development costs as intangible assets but in an apparently inconsistent manner. For example, the accounts of Stroupster Caithness Wind Farm Ltd for the year 2015 include £7 million of intangible assets defined as follows: "intangible assets comprise contracts, rights and benefits associated with the wind farm site which were capitalized during the construction of the wind farm". By 2018 the description of intangible assets was changed to "intangible assets relate to capitalized fees associated with long term operating lease arrangements" but with no change in the original book value of these assets. For clarity and consistency, the value of intangible assets has been excluded from capex costs, while on the other side the depreciation of intangible assets is included in opex costs.

There is a separate point highlighted by the Stroupster Caithness accounts. In 2015 the accounts state that tangible assets are estimated to have a remaining useful life of 19 years. By 2018 the remaining useful life of the same assets is assumed to be 26 years. This reflects a change in the assumed operating life of the wind farm from 20 years in 2015 to 30 years in 2018.[2] While the original assumption matched the period of eligibility for ROCs, the assumption of a 30-year operating life for the wind farm seems difficult to justify on the basis of historical experience and economic reality. Any rational and sceptical reader familiar with accountancy is likely to ask whether this is little more than an accounting change to increase the apparent profitability of the wind farm. In this case the owner is Greencoat UK Wind PLC which bought the wind farm from the developer (BayWa) at end of 2015. A number of other wind farms have increased their asset lives to 30 years without providing any clear reasons or explanation.

Opex costs. The basic formula for calculating opex costs from SPV accounts is:

Opex = Cost of sales + Administrative costs – Depreciation of tangible assets.

A small number of the earliest offshore wind farms received government grants which are written off over the expected life of the wind farm, usually as a deduction from administrative costs, so these grants are added back into the calculation of opex.

Transmission costs for offshore wind farms require special treatment. When there is no OFTO, or the OFTO has not commenced operation, total opex includes the operating and maintenance (O&M) costs of the offshore transmission network while the capital costs of the transmission

2 In the accounts for 2016, the summary of principal risks states: "wind turbines may have shorter lives than their expected life-span of 25 years". This is consistent with the use of a depreciation life of 20 years in those accounts but is hard to reconcile with the increase in the depreciation life to 30 years in later accounts. The overriding impression is one of muddle or manipulation in preparing the accounts.

network are reflected in other parts of the accounts. Once an OFTO is operating, the OFTO SPV has two sources of revenue: (a) a charge for asset management and maintenance, and (b) a finance charge which is effectively a mortgage payment on the transmission asset transferred from the wind farm to the OFTO. The calculation of these charges is based on regulatory provisions in the licence for each OFTO and includes performance incentives that may be recovered over more than one year. Technically, the OFTO SPV charges National Grid Electricity Transmission (NGET) for the asset management and finance services; NGET recharges its costs to the offshore wind farm. Up until 2016, Ofgem published an annual report on the allowed revenue for each OFTO as well as the actual revenue recorded in the regulatory accounts for each OFTO. For accounting reasons the actual revenue tends to be less than allowed revenue but the differences are relatively small.

On this basis it is possible to construct an alternative measure of opex costs for offshore wind farms that puts wind farms with and without OFTOs on approximately the same footing. This is done by deducting OFTO revenues from the opex cost reported by the wind farm which they serve and adding back the OFTO opex cost. The alternative opex measure indicates what the level of opex for the wind farm would have been if the transmission network had not been separated to create the OFTO. In addition, there are detailed adjustments that have been made to allow for multiple OFTOs serving one wind farm SPV (Walney 1 and Walney 2) and a single OFTO serving two wind farm SPVs (Gunfleet Sands 1 & 2, Robin Rigg East & West).

In the case of onshore wind farms it is not possible to obtain opex figures for all of the wind farms for which capex figures are available. This is because (i) some SPVs take advantage of a small company exemption that spares them the requirement of including an income statement in their annual accounts, and (ii) for companies that operate more than one wind farm it is usually possible to infer the capex cost of a new wind farm but the opex costs are pooled.

In most cases SPV opex costs for both onshore and offshore wind farms are understated by the standard practice of not charging management costs and central overheads for a group to each SPV. It is normal for SPVs to report that (a) they have no employees and (b) accounting and management costs are borne by the ultimate owner of the SPV. This means that opex covers the cost of contracted and other outsourced services but not a pro-rated portion of group overheads. For this reason the opex costs examined here tend to be understated. The extent of the understatement is difficult to quantify but it may be 10% or more. It is important to bear this in mind when considering suggestions that the opex charges in SPV accounts cannot be relied on. In reality, they are more likely to be too low rather than too high.

APPENDIX B
THE EFFECT OF INCREASING TURBINE HUB HEIGHT ON AVERAGE LOAD FACTOR

The analysis is based on NASA's Power database which provides estimates of daily average, minimum and maximum wind speeds from 1981 to 2019 at heights of 10 metres and 50 metres above surface level. The steps involved are:

1. Calculate wind shear coefficients for minimum, average and maximum wind speeds and use them to estimate the same parameters for wind speeds at hub heights of 80 metres, 90 metres and so on up to 160 metres above surface level.

2. Assume that the distribution of wind speeds within each day can be described as a Rayleigh distribution with the observed minimum wind speed and a shape parameter derived from the average wind speed.

3. Use the Rayleigh within-day distribution of wind speeds with the turbine power curve to calculate daily output at each hub height by taking random draws for 10-min average wind speeds from the Rayleigh distribution and adjusting so that the average of the 10-min wind speeds is equal to the mean daily wind speed for each day.

4. Average the daily output over 10 years to derive the average annual output and hence the expected load factor at each hub height assuming 100% annual availability.

5. The calculation is repeated for each grid square in which there are at least 10 wind turbines so as to allow for spatial differences in wind shear coefficients and other parameters.

6. The average load factor over 10 years is calculated for each hub height in each grid square. These values are standardised to a value of 1 for a hub height of 80 metres for onshore turbines and 100 metres for offshore turbines, so the results reported show the increase in the expected average load factor from increasing the hub height of turbines.

One complication is that Staffell & Pfenninger (2016) argue that a bias correction should be applied to the NASA estimates of wind speeds, which correspond to what they refer to as the MERRA 2 reanalysis dataset. They correctly point out that the computed load factors using the NASA wind speed estimates are substantially higher than the actual load factors for wind farms by country. However, they then proceed to assume that the discrepancy is entirely due to biased estimation of wind speeds in the NASA dataset. This assumption must be mistaken. The computed load factors do not make any allowance for availability – i.e. downtime for maintenance or because the marginal cost of running a turbine exceeds the expected revenue. Further, as Staffell reports in an earlier paper – Staffell & Green (2014) – the load factors of wind turbines decline with age, so that a part of the discrepancy must be due to the age composition of the turbine fleet. There are reporting and other factors that will contribute to the discrepancy between theoretical and actual load factors.

Nonetheless, it is possible that using the NASA estimates of wind speeds introduces a bias into the calculation of the improvement in average load factors due to an increase in hub height. To get an idea of the potential overstatement I have recalculated the estimates using the wind speed corrections proposed by Staffell & Pfenninger. These are:

Adj wind speed = 2.846 + 0.595 x NASA wind speed for Denmark

Adj wind speed = 2.628 + 0.642 x NASA wind speed for the UK

The analysis has been carried out using the power curves for 13 models of onshore turbines and 7 models of offshore turbines. The onshore turbines range in size and capacity from the Vestas V90-2000 (blade diameter 90 metres, capacity 2 MW) to the General Electric GE158-5300 (blade diameter 158 metres, capacity 5.3 MW) and the Enercon E126-7580 (blade diameter 127 metres, capacity 7.58 MW). Some of the larger turbines can only be installed at hub heights of more than 100 metres but a hub height of 80 metres is used as a reference height for onshore turbines.

Wind shear tends to be greater for onshore sites, so the benefits of increasing hub height are greater while the costs of installing larger foundations to support the taller towers may be relatively less than for offshore wind farms. On the other hand, blade tip height is usually more of a concern for onshore sites, which may limit hub height except in the most remote locations. The Enercon E126-7580 can only achieve its rated capacity by being installed at a hub height of 135 metres, which means that its blade tip height is 198 metres. The largest turbines, such as the GE158-5300, are usually designed for low or medium wind conditions; they use a combination of blade diameter and hub height to achieve their rated output. The GE158-5300 can have a hub height of up to 161 metres with a blade tip height of 240 metres, but in current applications the hub height is 121 metres so that the tip height keeps within a height limit of 200 metres.

The offshore turbines range from the Areva M5000-116 (blade diameter 116 metres, capacity 5 MW) to the Vestas V164-9500 (blade diameter 164 metres, capacity 9.5 MW). There are a number of larger wind turbines under development, including the General Electric Haliade-X model with a capacity of 12 MW, but certified power curves for these models are not available. Most large offshore turbines have a minimum hub height of 100 metres; this is used as the reference turbine height. The Haliade-X model will have a hub height of 160 metres. It is not yet economic to go to hub heights of more than 160 metres because of the extra cost of the foundations required relative to the gain in average wind speed.

The results show that the Staffell & Pfenninger bias correction does not have a substantial or consistent effect on the expected increase in the load factor from increasing the hub height. For example, the median increase in load factor for onshore turbines due to an increase in hub height from 80 to 120 metres is 9.6% with regular NASA wind speeds and 9.1% with the Staffell & Pfenninger bias-corrected wind speeds. For offshore turbines the increase in load factor due to an increase in hub height from 100 to 140 metres is 5.7% for the uncorrected wind speeds and 6.4% for the bias corrected wind speeds. The conclusions in the main text are valid even if one were to accept the Staffell & Pfenninger bias correction to the NASA estimates.