Rising US offshore wind costs and what it could mean for 2023 UK bid rounds

A Conversation with ORE Catapult Energy Economist Ken Kasriel & Shashi Barla, Director/Head of Research (Renewables), Brinckmann Group

Date: 30 March 2023

INTRODUCTION

- After years of falling offshore wind (OSW) costs, inflationary pressures which have been accumulating since 2021 are now forcing developers outside of China to ask for new project terms, as the prices they had agreed to sell power for no longer make the projects economic, or as economic as first thought.
- In a series of public statements since mid-2022, and accelerating since December, four developments in the US – the world's largest OSW emerging market - have given off distress signals, with a further two reportedly facing trouble. Total capacity involved is 7.4 MW, or 25% of the US goal for 30 GW of OSW operating by 2030.
- All but one are close neighbours in what is arguably Americas' best OSW real estate, from a wind- and water depth-perspective.
- In the first major public trans-Atlantic echo of this trend, on 3 March 2023, Ørsted publicly asked the UK Government, via a news interview, for improved fiscal terms, without which its planned 2.8 GW Hornsea 3 "would have to go on hold," due to cost pressures since it agreed to a fixed power tariff in July 2022. This would be unprecedented for a project of this scale, and from such a big developer.

We talked with Sashi Barla, Director and Head of Analysis and Renewables Intelligence at Brinckmann Group, about:

- What's behind these signals,
- Whether these problems are an unfortunate series of one-offs, or rather symptoms of something of which we might see more;
- The implications for price / acreage bidding behaviour in 2023,
- Whether these trends look to be mid- or longer-term.

Projects under pressure

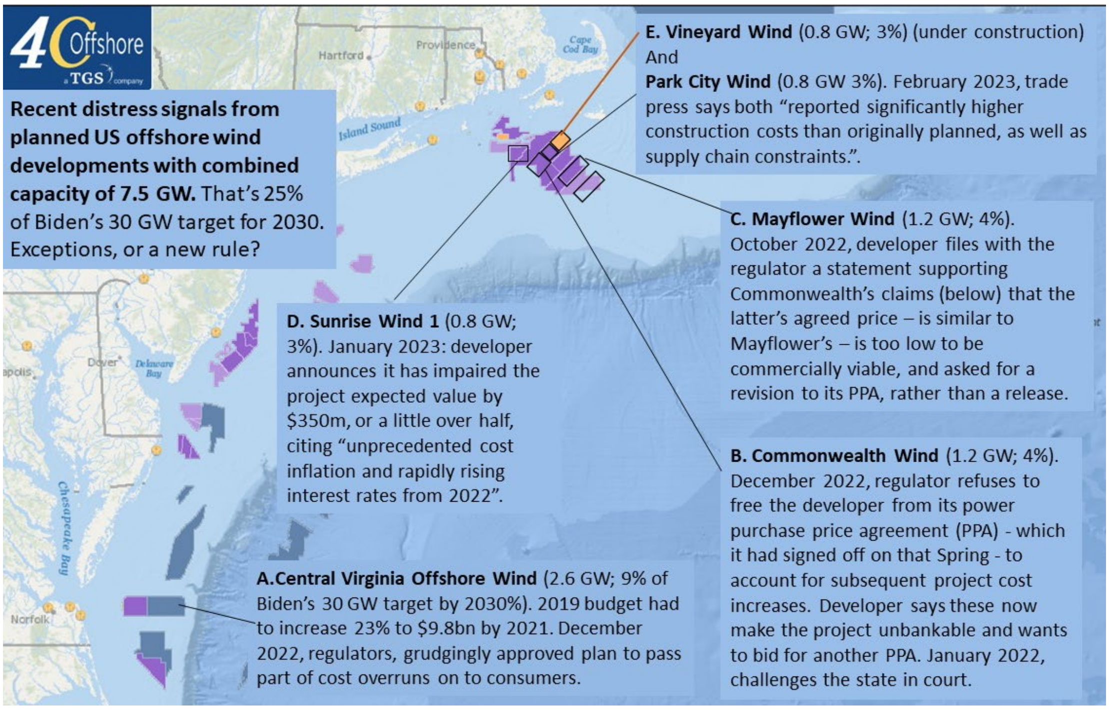

Figure 1 : Recent distress signals from planned US offshore wind developments. Sources: map, 4COffshore online map ; capacity estimates, 4COffshore Database; **A.** S&P Global Market Intelligence, 5 November 2021 , AP News, 16 Dec 2022 **B.** Avangrid 21 October 2022, State House News Service, 31 December 2022, ; **C.** Mayflower filing, 20 October 2022 **D.** Ørsted analyst call slides and transcript, 20 January 2023 **E.** Seatrade Maritime News, 23 January 2023

In late 2021, Coastal Virginia Offshore Wind became the first US offshore wind project to ask state regulators for new terms to recover unanticipated costs overruns, which would increase total project spend the total from the approximately $8 bn Dominion had stated in 2019, to $9.8 bn.

The State agreed in August 2022 to let Dominion share with consumers 50% of any future overruns which boosted the total to $10.3-11.3 bn; for Dominion to absorb all additional overruns which would push it to $11.3 bn; and to consult the state again if it exceeded that. It is the first such terms revision in the US, the world's largest emerging market for OSW.

This signals a State's pragmatism in the face of industry cost pressures. Dread of the failure of such a flagship development with a large local supply chain footprint likely led Virginia regulators to revise to keep the project afloat.

Yet one might sense some exasperation in its public statements, chiding Dominion for having used "stale economic assumptions," noting that "the electricity produced by this Project will be among the most expensive sources of power — on both a per kilowatt of firm capacity and a per megawatt-hour basis — in the entire United States."

Massachusetts has been less forgiving than Virginia. In this case the proposal to revise came from Avangrid, developers of Commonwealth Wind, part of a cluster of planned developments in the technically promising Nantucket area.

Last October it said the project was no longer financeable, asked the state regulator to pause to "assess measures that would return the project to economic viability including, but not limited to, modest changes to the PPAs" (power purchase agreements).

The request was "in response to the unprecedented economic challenges facing all major infrastructure projects, including historic price increases for global commodities, sharp and sudden increases in interest rates, prolonged supply chain constraints, and persistent inflation."

In late December, the state refused. In January Avangrid said it will appeal in court. "We have to be able to finance it," a senior Avangrid said, "and frankly, we can't do that with the current contract." It also said it will bid for a new PPA this spring.

Whether it can participate is unknown. This leaves an uneasy standoff in the meantime. "There simply isn't any precedent for an offshore wind project that's hit an impasse between the developer and the utilities," one Massachusetts-based industry observer tells ORE Catapult.

Ørsted's impairment of Sunrise in January prompted many analyst questions on the conference call. Management said it remains committed to the project and that "we are not expecting that we will need to impair more going forward. But as you know, this is of course, depending on, among other things, the development in the interest rates".

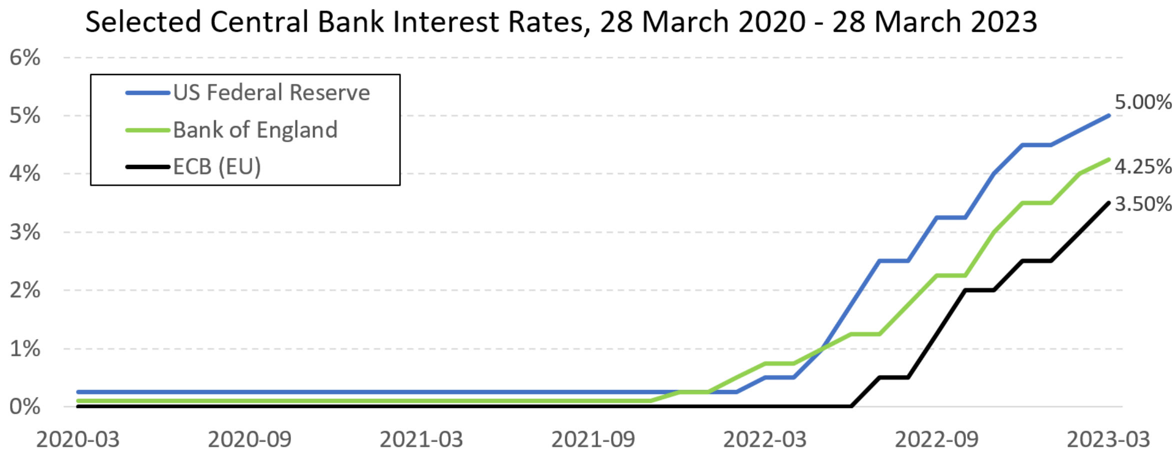

Figure 2: Selected central bank interest rates. Sources: GlobalRates.com , Bank of England

Crown jewel acreage

All but one of the projects shown in Figure 1 are clustered in what is, from a technical wind resource perspective, America's prime territory for conventional OSW development. Meaning, using bottom-fixed turbines in around 60m or shallower water depths, which is well-proven at the utility scale. As opposed to floating offshore wind, which is still an emerging technology.

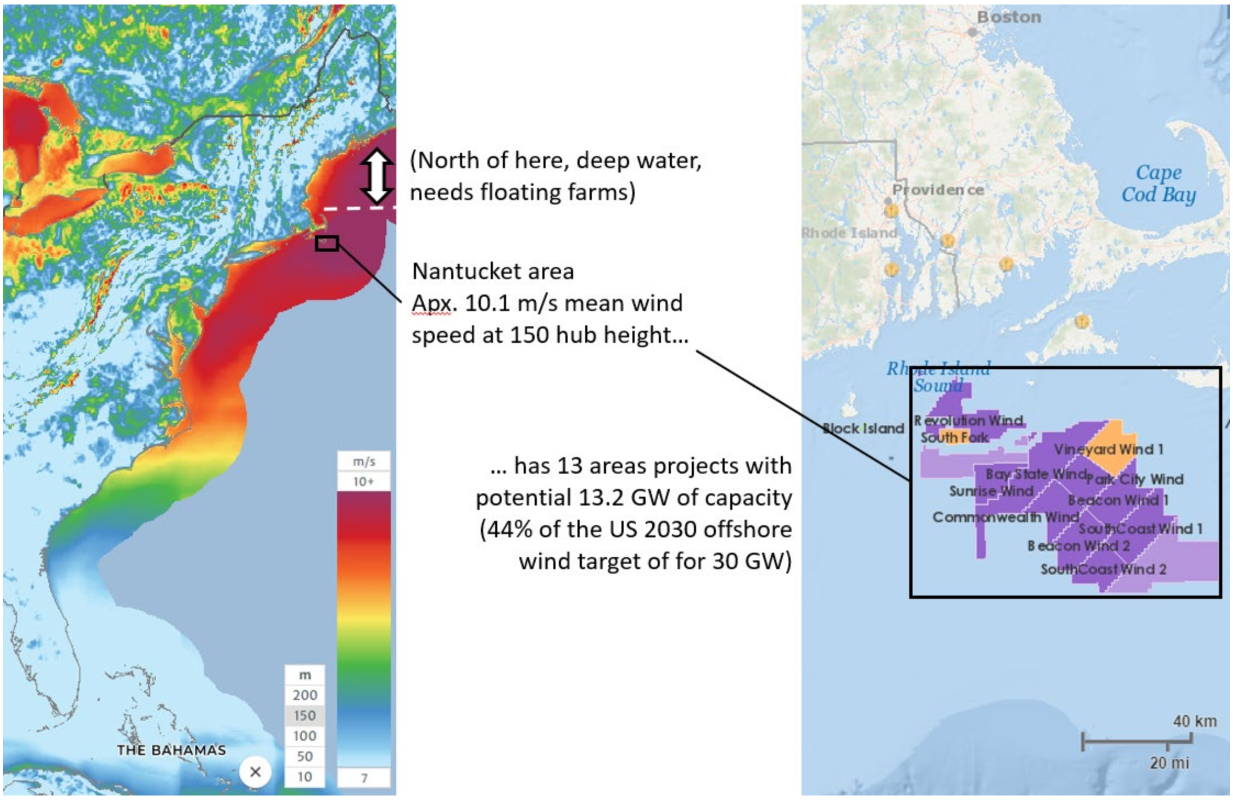

Figure 3: Nantucket Area (Massachusetts, Rhode Island) and mean wind speed in metres per second (m/s) at a 150 m hub height, approximated by ORE Catapult from the interactive version of the Global Wind Atlas Locations approximated from the 4COffshore,where orange means under construction; dark purple, consent application submitted; and light purple, concept/early planning phase. Capacity data from the 4COffhsore subscription database.

From a raw wind resource perspective, the US East Coast is blessed with a broad, approximately 1000 km long margin of windy acreage in shallow water, close to shore and demand centres. The only comparable area is the Chinese coast.

This US margin starts off about the middle of the east coast, off South Carolina, and gets windier as it goes north. It stops at the windiest part at the Nantucket area, off Massachusetts and Rhode Island.

Much north of that is still very windy, but deep, requiring floating wind.

Here, all inside an area approximately four times the size of Greater London, annual wind speeds average just under 10 m/s at a hub height 150 m, which is very good by global standards. This is where polar jet streams and tropical jet streams converge.

This helps explain intense developer interest there, with no less than 13 projects, with planned capacities totalling 15 GW, according to 4Coffshore’s database. This would be equal to half of Biden’s 30 GW target by 2030 in this area alone if all materialise.

The issues facing developers here raise some questions. One such is, if projects struggle here, might developments in other US areas, with weaker technical wind resources, do the same?

DISCUSSION

Ken Kasriel: Discussing these and other recent events and their implications for new OSW acreage and price bidding this year is Shashi Barla.

Shashi is a Director and Head of Analysis and Renewables Intelligence at Brinckmann, a Denmark-based advisory consultancy. Prior to that he worked five years as a wind supply chain and technology principal at consultant Wood Mackenzie; and before that, six years with LM Wind Power, also in Denmark.

Shashi, what are we seeing?

Shashi Barla: Thanks for having me. To answer your question, I think that in the past few quarters, there has been cost pressure and commodity inflation. The different geographies are impacted slightly differently. It's more severe here in Europe than in any other part of the world.

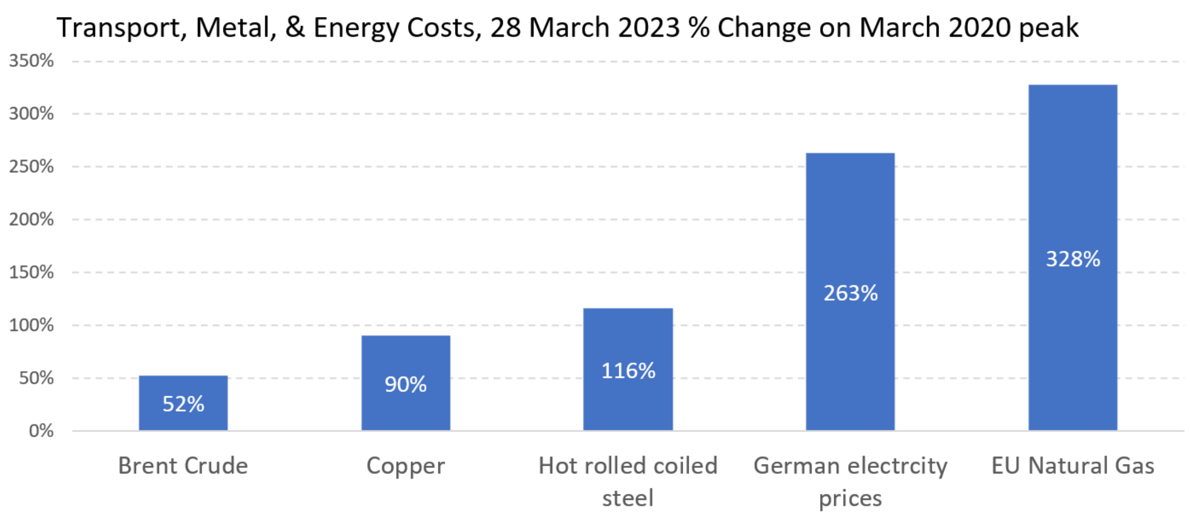

Figure 4: Selected Indicative Input Cost Inflation. Source : Trading Economics, ORE Catapult Analysis

If you look at how things have evolved in the last two and a half to three years, we were hit by COVID; immediately followed by commodity inflation, and then logistics costs have increased by multiple folds, those have actually quintupled in most cases. And then the EU energy crisis. One after the other. That's been adversely affecting the industry as we go along.

And that's clear from wind turbine makers' financial results.

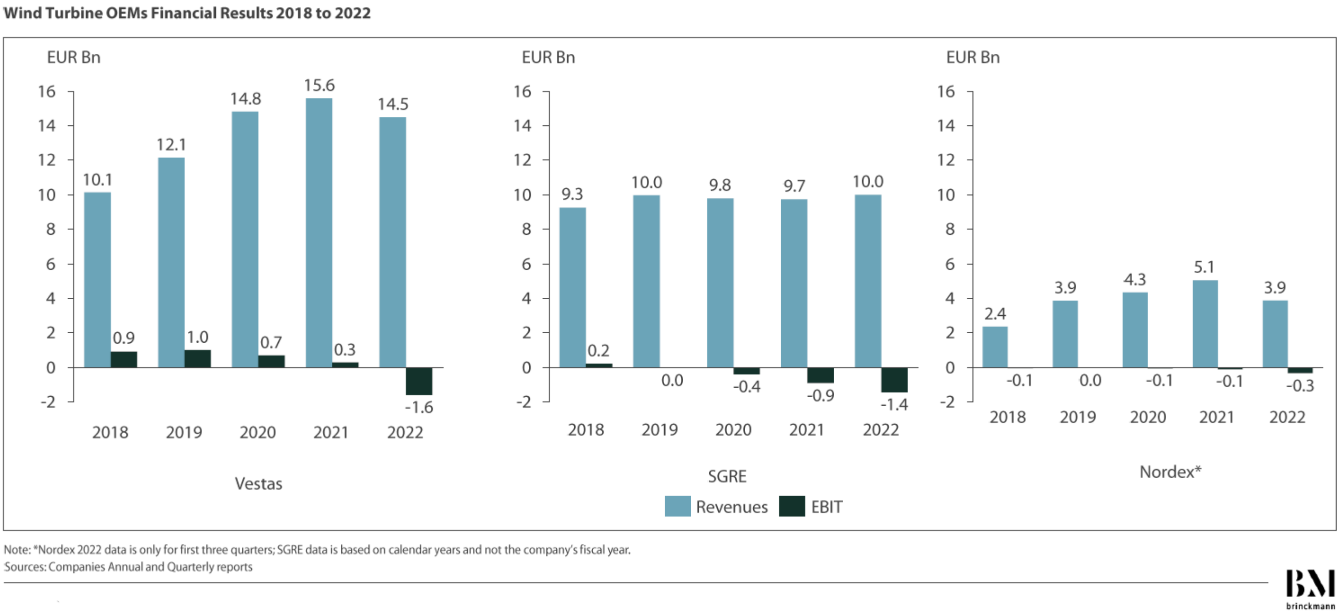

Figure 5: All Wind turbine OEMs' losses balloon in 2022 due to commodity inflation and EU energy crisis. EBIT is Earnings before Interest and Tax. Nordex 2022 data is only for first three quarters. SGRE data is based on calendar years and not the company's fiscal year. Sources: Companies' annual and quarterly reports, Brinckmann Group analysis

Last year, in consecutive quarters, these companies were making huge operating losses, and now they're trying to mitigate that.

Ken Kasriel: You mentioned quintupling of logistics costs. Can you be a bit more specific? Would it be installation vessels? Or rather, the shipment of raw materials?

Shashi Barla: The shipment of the raw material. First there was a shortage of the vessels to transport the components and the raw materials. And even when the vessels were available, the lead times were significantly longer. So the logistics prices were much, much higher. They quadrupled or quintupled in a few cases.

Some of the companies even had to air-freight the materials, paying 10 times more than the business-as-usual scenario, because otherwise they'd have to pay the liquidated damages[1] to their clients.

Ken Kasriel: So, with costs soaring, and strike prices[2] agreed to *before* they soared, it doesn't surprise me to see these projects, in the absence of full project financials, showing, symptoms of economic distress.

1 "Liquidated damages" is a term often used in project finance, and are penalties for not honouring the relevant part of a contract

2 The price a generator receives for sale of electricity

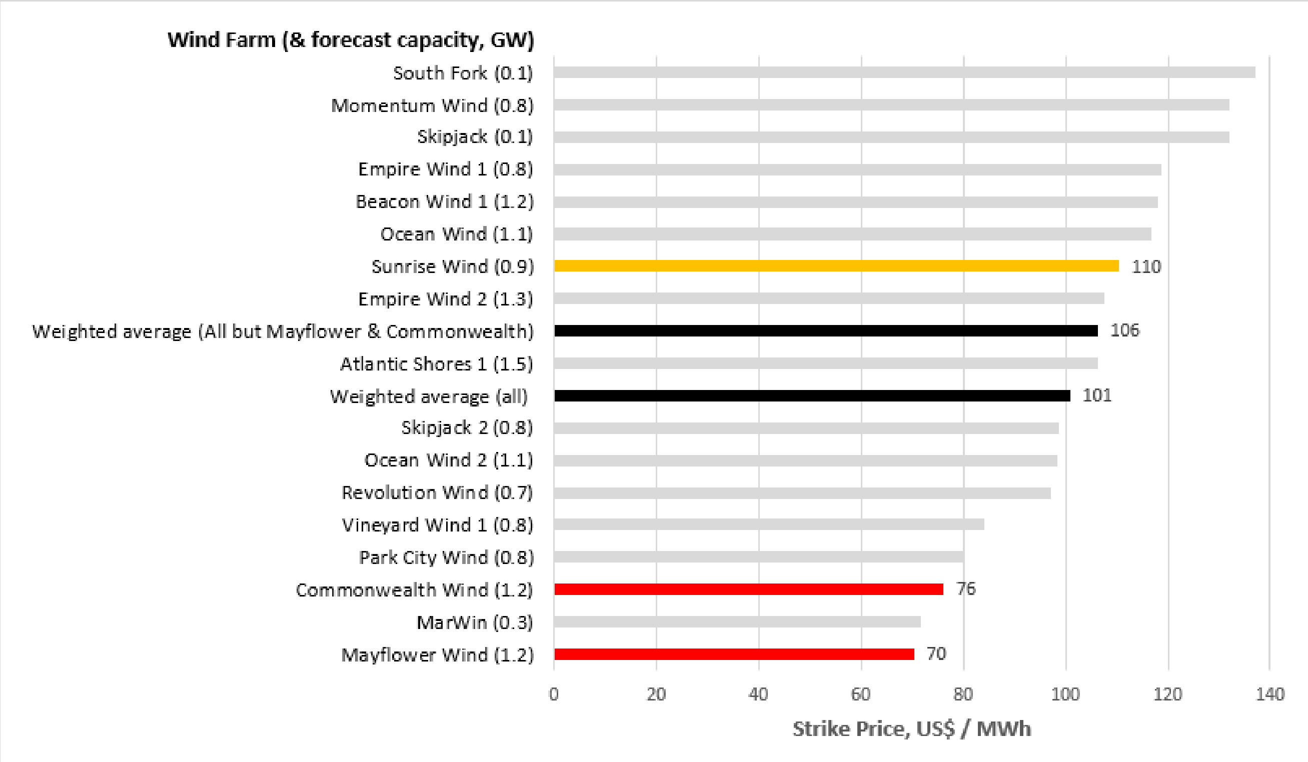

Figure 6: US offshore wind strike prices. Weighted by expected farm capacity. ORE Catapult calculations and analysis, using 4COffshore data.

After the problems with Dominion's Virginia farm emerged, towards the end of last year we saw two new cases, Mayflower and Commonwealth. these two projects are exceptional, in that the strike prices they'd agreed to - in the low-to-mid $70/MWh range - were amongst the lowest of the 17 post-2020 US projects for which 4COffshore has these data. One developer active in the region even went so far as to call them "ridiculously low".

In light of that, the reports of troubles with Vineyard Wind and Park City Wind made apparent sense too, as their prices are in the same neighbourhood, in the low $80/MWh range.

But then, this January, Ørsted said it had taken an impairment charge on Sunrise Wind, which despite having a reported a strike price of $110/MWh is not necessarily enough to keep trouble at bay. The day after the news, their closing share price fell around 9%, and as at 7 March 2023, still hadn't returned to where it was on

Does this signal that we could perhaps see more PPAs under strain?

An inflexion point for OSW costs outside China

Shashi Barla: Absolutely. If we look at what's happening onshore, globally outside of China, where we've seen multiple projects either abandoned, or there's a lot of project attrition – I'd have a very compelling reason to believe that that would also happen for the offshore, a trend percolating down to many markets, as we've now seen in the US.

Project timing is of the essence here. When developers proposed their PPA strike prices, their views of future costs are based on future wind turbine technology evolution. However, considering the inflation now, most of these projects will not be financially viable if the PPA prices are not renegotiated.

Ken Kasriel: And as we'll get to later, across the pond, Ørsted's announcement that its massive planned 2.6 GW Hornsea 3 project could look unviable under its agreed strike price is a maybe ominous sign that these problems aren't US-specific.

Shashi Barla: One of the biggest reasons for historic cost *reductions* - which led the industry to expect them, only to be taken by surprise now - was the turbine original equipment manufacturers' - or OEMs' - ability to scale up the technologies and achieve economies that way. That also resulted in lower costs for the balance of plant - because with larger turbines, you need fewer foundations, cables etc.

So the biggest factor that developers were considering was the technology evolution in the turbines and the balance of plant, since they had this history of continuous cost reduction to go by. And so they assumed the cost reductions would continue into the future.

Now, here a major thing is that the future time frames involved are long. You have to get consents to secure financing; that takes a while; and then for onshore, typically after financing is closed, then it's about two to three years, and for offshore, four to five years, for the wind farm to get built and come online.

Basically the developers had expected that within this long timeframe, there would be continued technology evolution-led cost reduction they could tap into.

Most of these projects that you look at today, the ones that were awarded, are to be commissioned between 2025 and 2028. And that's one of the biggest reasons why they were aggressively bidding these low strike prices.

But we can only generalise so much. The differences amongst strike prices will be site-specific, depending on things like size and so economies of scale, as well as variance in the wind speeds.

A difference of even half a metre per second in the average wind speeds can make a significant difference to the business case. Considering that, and generation losses due to blade degradation, over a 20 year life-span, that will have a huge impact on project financials.

Ken Kasriel: This is why developers sweat so much over anything which can boost overall farm "captured" wind speed, such as farm layouts to minimise wake losses, as well as ways to fight blade erosion, or degradation as you call it.

I think it's fair to summarize that basically the PPA prices which have been agreed, were agreed anticipating a world somewhat different than what we live in now.

Shashi Barla: Yes.

OEMs push back

Ken Kasriel: So, before wind farm input costs started rising to threaten PPAs to the bursting point, developers had said “Ok, I can win PPAs by having the lowest bid!” And then turned around and asked the OEMs, “So, can you do it cheaper?”

And for a while, in a battle for market share, the OEMs complied, until last year, when they found themselves stuck with promises to deliver turbines based on the old, lower cost estimates.

And now the OEMs, as we saw in your chart (Figure 5), have been running operating losses, and have decided to pursue profits over market share, and so are raising prices. Basically, transferring the disadvantage of higher input costs back to the developers (again, this is outside of China, like all of our discussion about offshore wind cost inflation).

And so now we see developers like Dominion and Avangrid (Iberdrola), which is behind Commonwealth, having to go to ratepayers, by way of their public representatives (the utility boards) to renegotiate. So the cost increases are like a bubble in a tube of fluid – it can’t be gotten rid of, only moved somewhere else. Is that fair?

Shashi Barla: Absolutely. You hit the nail on the head, that's exactly what's happening, because the cost inflation from the upstream - by upstream, I mean the turbine OEM and the component suppliers, and raw material suppliers - is passed on to the downstream, which is the developers, the asset owners.

So eventually they need to pass it on to somebody, whether it is the rate payers or the energy regulators, they need to renegotiate those.

If the industry is to survive, all the major stakeholders will have to share their burden. You can't penalize the turbine OEM or you can't penalize the developers or single out anybody in the value chain, so everybody should be assured that they share the burden equally. And that's how the industry will thrive.

And that's what they're trying to do, because components suppliers are pushing costs on to the turbine OEMs, who are partly absorbing this cost, but still forced to pass some of it on to the asset owners and the developers, and so it goes down the value chain.

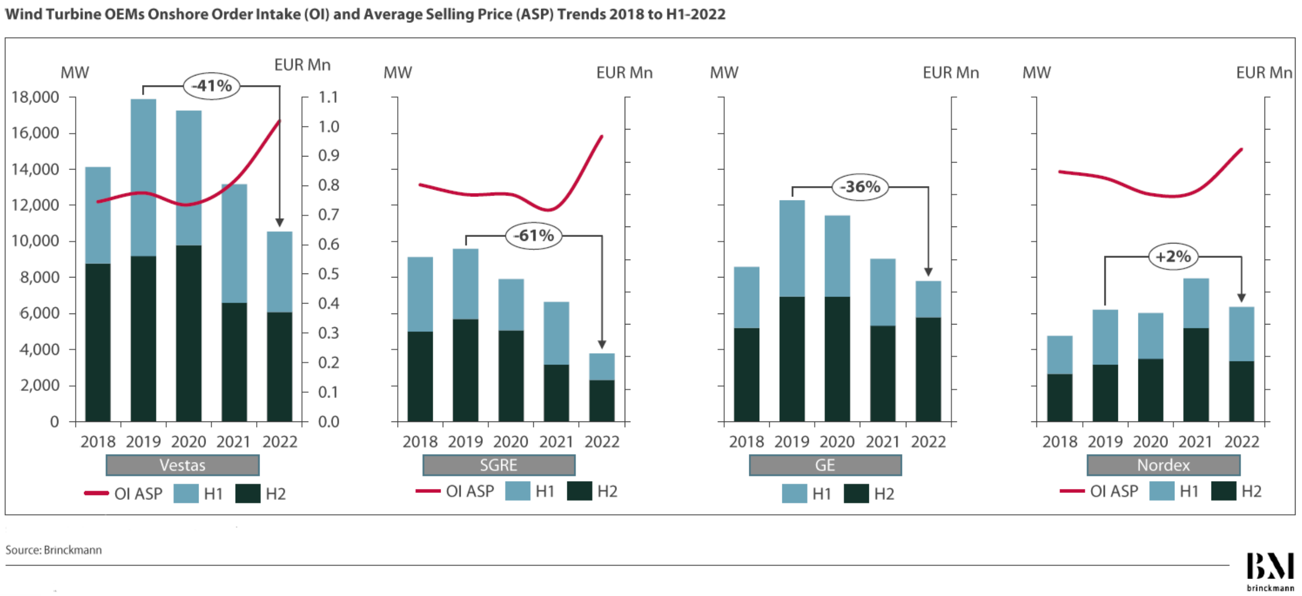

Figure 7: Turbine prices rising. Note: GE ASP (average selling price) data is not available. Source: Brinckmann Group

We saw the OEM financial results earlier. Here, you can see they've been pushing back with higher prices, the red lines. This isn't perfect for our purposes, as these are for onshore turbines, but what those turbine price lines show, directionally, is happening in the offshore too.

Outlook for bidding in 2023

Ken Kasriel: This year in the US, there's going to be some new lease auctions, where developers bid for site exclusivity.

And there will also be new biddings for PPA prices developers would be able to sell their existing developments' generation from, once they are online. In fact, Avangrid has said they want to do that for Commonwealth, even though the Massachusetts regulator has said they have to stick with their old one. Now that Avangrid has appealed, we'll have to see how that plays out – it might end up having some sort of significant precedent value somewhere down the line, who knows.

Do you think we might see more caution around the upcoming US bids for leases, or PPA prices, than we've seen so far? Might we see more on the $100s/per MWh side of our strike price chart? (Figure 6, above)

Shashi Barla: In the hundreds, yes.

Developers are trying to look at the current dynamics in raw materials and turbine prices with an eye on the implications on projects that are to be developed in the next three to four years. Because if you plan to start generating by 2026, then you'd already have started working on that by now. So those projects will slightly be impacted.

But the new projects that are awarded, considering what's happened with Commonwealth where the regulators outright rejected the request to raise the existing PPA price, the developers will be very, very cautious on what is the price point. Because regulators are sending a signal that after you have signed a PPA you can't renegotiate it.

Of course, in other parts of the world, I can give a good number of examples of where the regulators are backing down and *increasing* the PPA prices. But that's not happening in all the cases.

Back to the US, developers who are bidding for those projects will be cautious of that. They'll try to bake those costs into their bids, depending on when the projects will be operational, what sort of technologies will be available, what oil prices will be, and as a consequence, what will be the prices of steel and other commodities, and thus of components.

They'll look at all those elements, plus an element of an extra cushion, for contingency, and of course a profit margin. Because if the world turns out to be worse than what we are expecting today, they need to be well-protected. So, adding all that cushion into the equation will certainly elevate the prices they bid in the subsequent rounds.

Ken Kasriel: So again, are we looking at more three-digit US PPA prices?

Shashi Barla: Possibly, but again a large part of that depends on when these projects are expected to be operational. And of course, as we have seen, delays - Vineyard Wind is a good example, in permitting, as opposed to the other developer problems we've been discussing.

Because if we focus a little bit far out in the future, then there's ample room for the developers, as well as the turbine OEMs and component suppliers, to work out and *lower* their costs -- both in terms of supply chain and procurement, and also, enhancing the performance of the of the turbine technologies.

In other words, if generation starts far enough out in the future, it gives time for technology improvements to lower the LCOE [levelised cost of electricity, or notional discounted breakeven price] of a project.

Ken Kasriel: That might be, but when you look at the discounting effects, the further out generation starts, the *higher* the LCOE, and thus the strike price you'd ask for today, all other things being equal.

Shashi Barla: Well, there are discounting effects, but I don't think all are other things will be equal. I think the cost savings of a project using more efficient - because it is later - technology will more than compensate for discounting effects. So from that perspective, the further out generation starts, then the lower the strike price that the developers would bid, and sooner its starts, the higher they'd bid.

Costs pressures to ease longer-term?

Ken Kasriel: We've been talking about a bounce, an inflexion point in costs, moving from years of steady decline to this new quintupling of some items which you've mentioned. Yet are you saying that further out, technology gains will take over and drive down costs again? In other words, do I understand you to mean that that this upwards cost bounce is more of a mid-term than long-term thing?

Shashi Barla: I would say more of a mid-term thing. As you rightly put it, we have almost reached an inflection point now. Costs are going up for both onshore and offshore measured on a per MW basis.

For onshore, the turbine pricing is roughly about 70% of the capex. For offshore it's about 50%. They aren't all of the capex costs, as you also have cost pressures on the balance of plant – foundations, cables, substations and so forth -- but taking turbine costs as a proxy, they determine how the costs on a project level will evolve. Right now, the costs are rising for both onshore and offshore, which implies that in the near term, the developer's bids for power tariffs will also increase.

But will that continuously increase in the next three to four years? It's hard to digest that it will, because the whole success story of the industry itself is due to its ability to lower the cost and build a comparative source of power generation which is competitive with any of the other forms of power generation.

So, I'd say costs will increase, and so developers will need to bake that into forecasts of what you'd foresee for the next three to four years. But it won't keep rising. It has to start declining. I mentioned technology-led efficiency gains. We can forecast these using industry-specific learning rates.

Ken Kasriel:

There are two forces at play. On the one hand, you have learning rates[3], pushing the cost of energy down. It's an idea with empirical corroboration from many industries, offshore wind included, that assumes that you get smarter and more efficient with what you have to work with.

But what if the costs of *what* you have to work with -- copper, steel, logistics and other cyclicals – are rising? That's the other force. Even if you're getting hyper-efficient, there's only so much you can do.

Shashi Barla: You also touched upon some other commodities. I mean it's hard, even developers try to hedge power prices to a certain extent. But it's hard to have an overview because of the many macroeconomic factors driving those costs. What will oil, steel and copper prices be? All these commodities have a huge influence on the input costs of those projects.

I'm not a commodities expert, but it's hard for us to imagine what the prices will turn out to be, because that's a confluence of multiple factors. So considering those, if you take 2020 as the base, before COVID, now in 2023, the input costs have at least risen by about 30-40% in many areas. So if we use that as a proxy, you can determine the project level cost have escalated in the last 3-4 years.

Ken Kasriel: This is offshore wind, excluding China, correct?

Shashi Barla: Yes. And by the way, China has gone the other way. Looking at the combined offshore and onshore, turbine costs have plummeted, by 50-60% in China during the same time frame.

Ken Kasriel: I'd come across this, published by S&P Global last autumn. Note that this combines both onshore and offshore data, whereas the reduction amounts you mentioned were offshore only. So they are not going to match. It's a rough measure for our purposes, but if nothing else, again, directionally it seems right.

3 the rate by which, as one produces more of something, the cost of producing falls, as producers get better, i.e. learning by doing

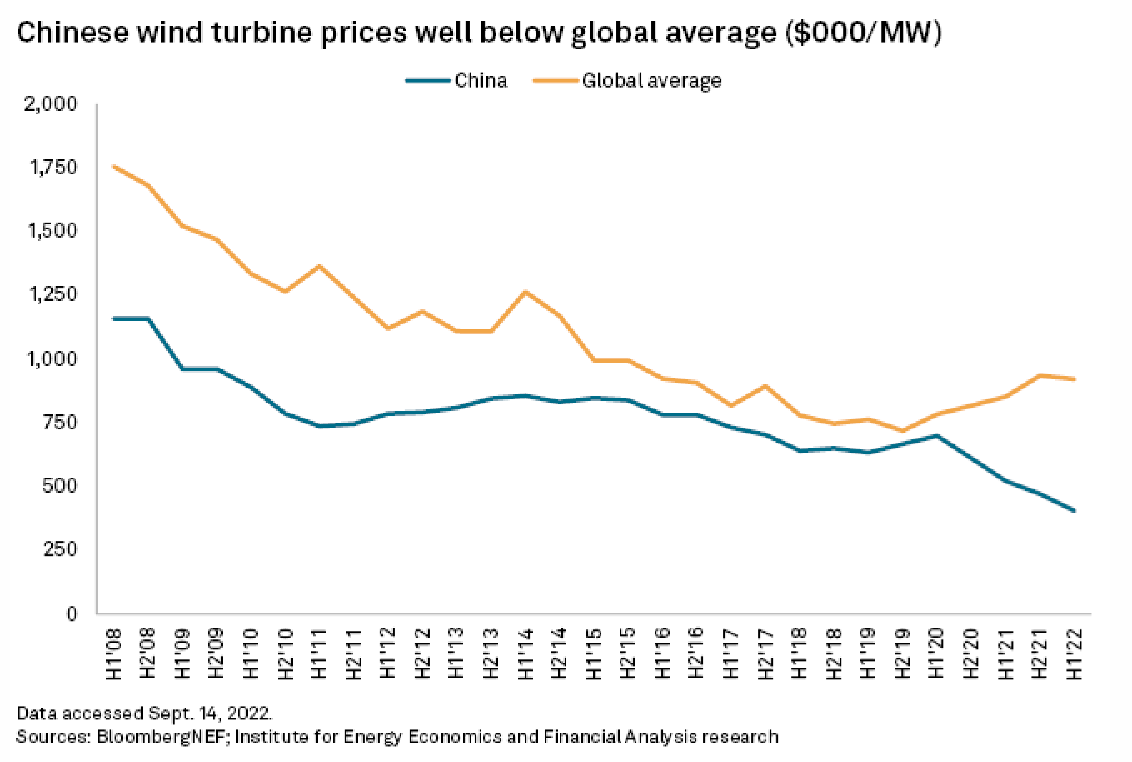

Figure 8, Source: S&P Global Market Intelligence, 22 September 2022

That orange line bouncing up towards the end, to my mind, captures the shape of the inflexion in point in costs we've discussed pretty well. I only wish they had shown the global average ex-China, Rather than China and the global average. Because if China is down and the world including China is up, then ex-China must be way up.

Lease-bidding behaviour

Ken Kasriel: we'll be seeing some leases being bid for in the Central Atlantic area later this year. Let's examine how they might compare to the US bids we saw last year.

US lease area auction results, 2022

Month of Auction	Area	Approximate Mean Wind Speed (m/s) at 150 m Hub height	Approximate Water Depth (m)	Offical name of Lease Area	Winning bid value per estimated megawatt of capacity ($1,000s)
February 2022 (1 day before invasion of Ukraine)	New York Bight	9.0 - 9.3	20 - 25	OCS-A 0544	$545
				OCS-A 0537	$881
				OCS-A 0538	$825
				OCS-A 0539	$793
				OCS-A 0541	$844
				OCS-A 0542	$691
May 2022	Carolina Long Bay	8.5	10 - 15	OCS-A 0545	$240
				OCS-A 0546	$231
November 2022	California (floating wind)	9.4 - 9.7	250 - 460	OCS-PO561	$205
		9.8 - 10.4		OCS-PO562	$207
		9.0 - 9.3	530 - 565	OCS-PO563	$134
				OCS-PO564	$154
				OCS-PO565	$149

$0 $200 $400 $600 $800 $1,000

Figure 9. ORE Catapult analysis of bid values and capacities - US Department of Energy, US Bureau of Ocean Management, including the assumption that all areas have 3 MW of capacity per square kilometre. Wind speeds and water depths approximated visually from the Global Wind Atlas (DTU/ ESMAP) https://globalwindatlas.info/en

This analysis is using the Global Wind Atlas and US Department of Energy and US Bureau of Ocean Energy Management data. It's slightly crude, in that the last two assume the same capacity per unit of area – specifically, 3MW per square kilometre – for all sites. These have been combined with their data for total site size to provide estimates for the chart.

You can see that last year's New York auction bids were a lot higher than the others. Without getting too side-tracked with detail, I'd point out that the auctions later in the year were for qualitatively different sites. The Carolina ones were for two states with weaker wind speeds and offshore wind promotion policies than New York.

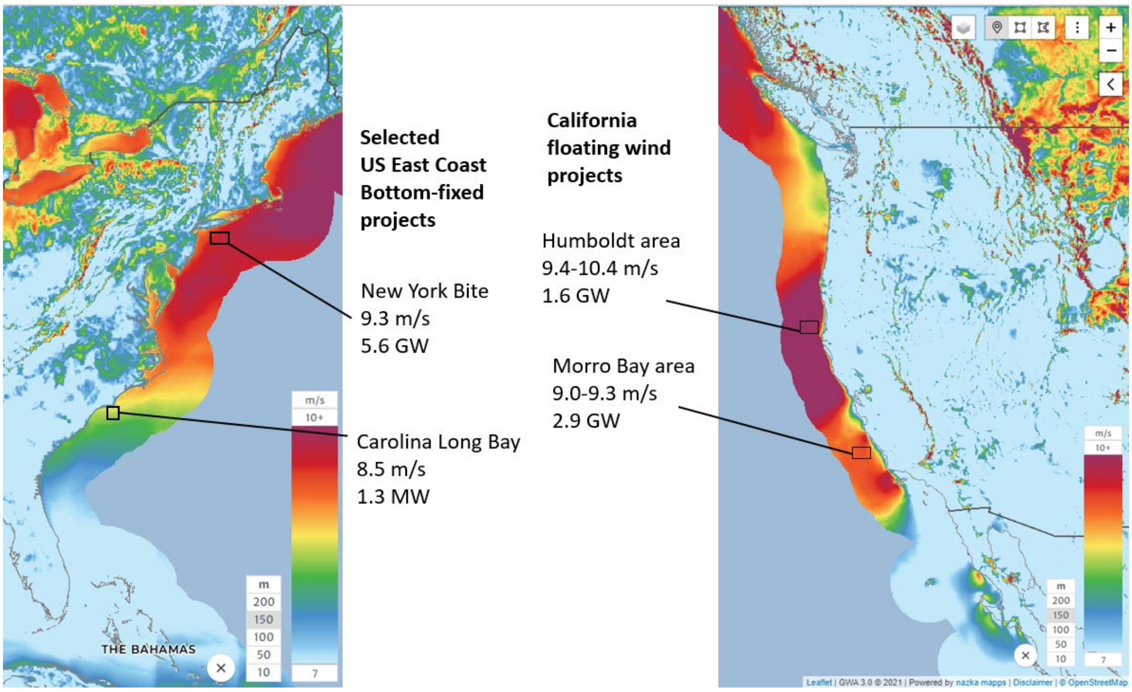

Figure 10. Approximate mean wind speeds at 150m hub heights, and planned capacities, of US offshore wind areas lease-auctioned in 2022. Maps by 4cOffshore. Windspeed and capacity data as per Figure 9, above.

The California lease areas have very nice mean wind speeds, but are for floating offshore wind, which is a much less proven technology; and they are in deeper water than any existing floating sites. So in that respect, California's deepwater makes its floating ambitions sort of a frontier within a frontier. That I think explains part of the discount.

There are other factors. For one, California needs a while to build a supply base from scratch; and also, the California auctions were in December, by which time cost pressures for the segment as a whole, outside China, were already increasingly evident whereas the New York auctions took place in a more fizzy atmosphere, one day before the invasion of Ukraine.

So, for the US, my guess is that we will see more restrained bidding this year – not only for the newest US lease auctions this year, but also for the Nantucket area PPA round planned for April. What do you think?

Shashi Barla: I certainly think that they will be lower than what we saw a year ago, simply because the lease prices will primarily be a function of the prospects on offer. New York is good territory. It's targeting about 9 GW by 2035. And it's also one of the biggest demand centres.

Not to say that California isn't. It's by far the biggest economy within the US, but there is the matter of extreme water depths, I mean, which you also mentioned with regard to floating offshore wind, increases the complexity and also the cost. So the developers will always try to pay lower for those lease areas because of the complex nature in the site characteristics, as opposed to what you pay in New York with fixed bottom turbines.

Also, floating wind is a young technology -- today's global floating market itself, is less than about 200 megawatts, let's say, for the sake of simplicity here, versus global offshore capacity of about 58,000 megawatts. That's kind of far apart.

As for what will be the level of the new, upcoming east coast bids, compared to the New York Bight auction last year -- I believe they'll be lower than this time.

Ken Kasriel: Why lower?

Shashi Barla: Number one, the biggest reason is the cost evolution we've seen. If developers will pay higher for the lease auctions, at the start of the project, they would also have to bear in mind, that will lower total project returns at a later stage. So they'll be cautious about paying a higher price for those lease auctions to begin with.

Secondly, for the New York Bight, competition was very high. I mean you know it's a simple supply and demand equation when the competition is very high. They were outcompeting each other and the bid prices were skyrocketing.

But now the world has changed in the last 12 months. I would believe that now there won't be a cut-throat competition, in terms of increasing the prices that they pay for those lease auctions; and considering the inability or the inflexibility to renegotiate the PPAS, they'll be cautious about the strike prices they propose, because they'll be mindful of the impact on the project IRR's once they're operational.

Ripples across the Pond

Ken Kasriel: Speaking of reticence when bidding – here across the pond in the UK we might well see the same.

As I mentioned in the January episode of our Re-Energise podcast , I'd already expected to see a muted response when bidding starts this month, with winners to be announced probably this summer, for the 15-year guaranteed fixed strike prices, under the mechanism known here as contracts for differences (CfDs). Recent news makes me double-down on that prediction.

Then, I'd noted some tension. On the one hand, I mentioned how the costs of raw inputs and finished products, like those we've seen in our charts, were all trending up.

On the other hand, the new maximum allowable strike price, announced in December, for the upcoming Round 5 CfD bidding, is down from Round 4. Not by much, but the opposite of what might be expected, if all we're hearing about cost pressures is to be believed.

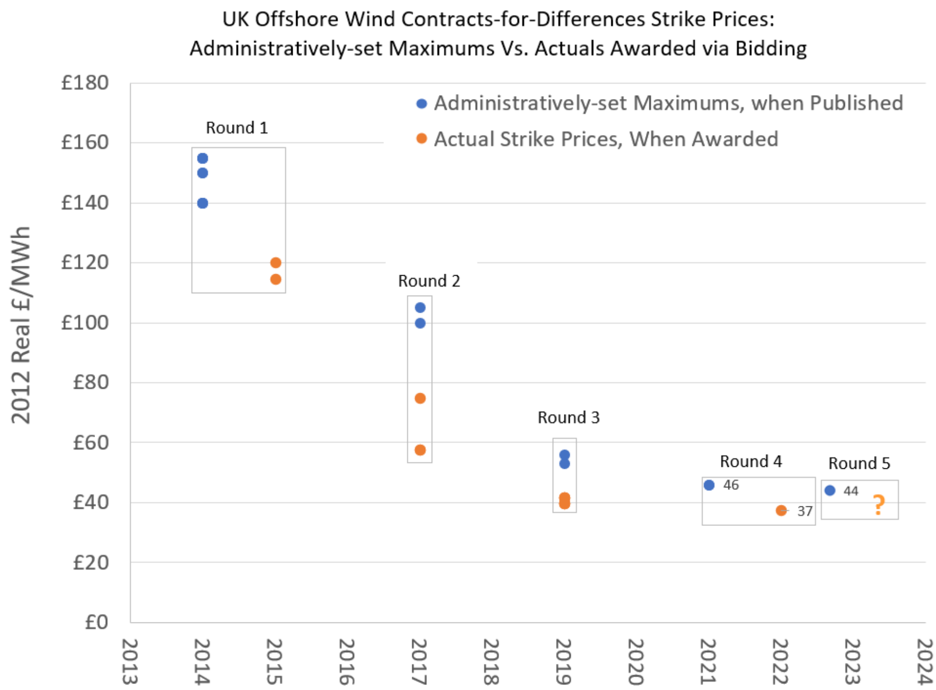

Figure 11.ORE Catapult analysis, drawing on: Low Carbon Contracts Company I and II, and UK BEIS (now Department for Energy Security and Net Zero), 5 December 2022.

A few things jump out here, especially as we look ahead to the results, probably this summer, of the Round 5 bidding to start this month.

One is the winning, i.e. actual strike price bids have come down rapidly. This reflects the historical lowering of offshore wind project-basis LCOE we've discussed.

Also, developers have always been willing to accept less than the administrative maximum. Last summer, the winning Round 4 developers' bid hit their lowest ever: a bid of £37 per MWh (in 2012 terms, as is customary in the UK) – the last orange point on the right of the chart - or around £47 in todays' money.

But the *slope* of the decrease in both the blue and orange points, from round to round, has flattened out. They used to fall in big steps, but, for the blue dots, the last one, from £46 to £44, was a baby step.

To an extent this is understandable, because once you get to a certain low absolute price, you can't keep falling by large percentages, compared to the previous round, indefinitely, otherwise you'll soon be approaching the limit of £0.

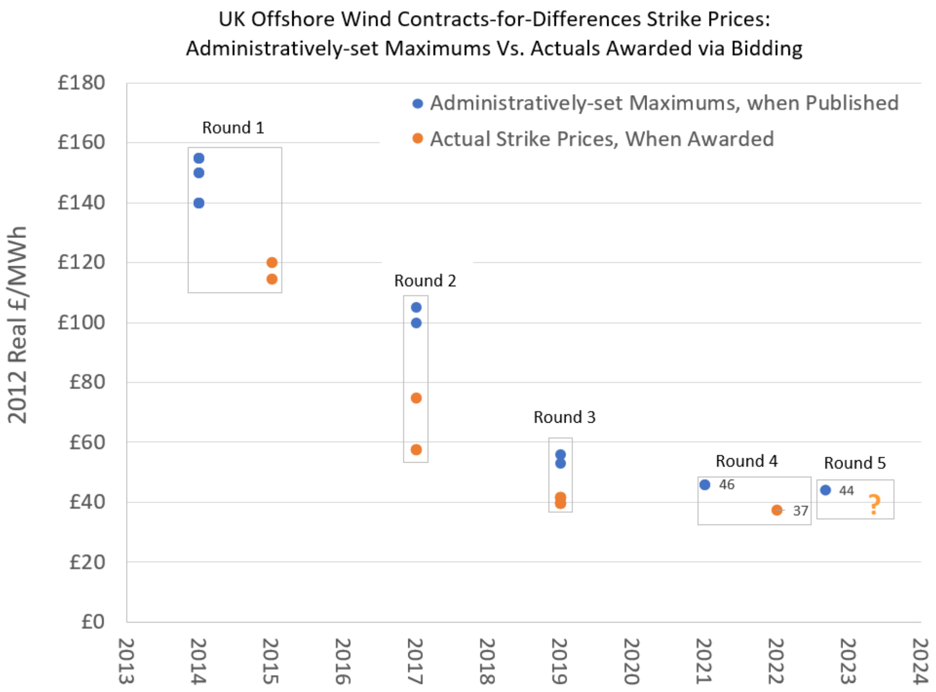

Figure 11, repeated from above.

But the thing is, there is no inflexion point to be seen.

Bear in mind, that Round 5 administrative max of £44, set in December 2022, was the first one to be published after the invasion of Ukraine.

The prior one, £46, was published in September 2021. In hindsight it seems like a date from such a golden era - when input costs were starting to rise but had not rippled through project economics in the public way we've seen in the US in second half of 2022, as we've discussed.

I wonder whether that Round 5 baby step down from £46 to £44 was, to some extent a cautious, politically constrained compromise "nod" to the current toughening cost climate.

It would have been interesting to have been a fly on the wall when this Round's £44 maximum was decided. My hunch is that to have *raised* the administrative max, for the first time in the CfD history - and also at a time when Britons face high power prices, when the price cap here ends in April - would have sent out the wrong signal. Plus, it would be an admission that renewables don't always get cheaper. So, they settled for the baby step.

My guess in January was that £44 as a maximum price for the upcoming Round 5 doesn't take fully consider the new, more expensive macro environment, so we'd see a somewhat muted developer response, expressed as a lower number of bids then in past rounds, and/or the discount to the administrative maximum they'll be willing to bid this time. I wouldn't have been surprised to see the discount shrink to around £0 – meaning, we'd see bids at or very near to £44.

Then came this month's news of US-style requests for revised terms in the UK, suddenly bubbling into the open here in the UK.

First, Ørsted called into question the viability of its planned massive 2.9 GW Hornsea 3 development, for which it had won a fixed £37 strike price only last summer, in Round 4.

Its Head of UK Region, Duncan Clark, told the press that if the UK doesn't introduce fiscal relief in the form of tax-deductible capital allowances, Hornsea 3 "would have to go on hold," and Ørsted would have to forgo its right to develop under that price.

"Since the auction there has been an extraordinary combination of increased interest rates and supply chain prices," he said. "Industry is doing everything it can to manage costs on these projects, but there is a real and growing risk of them being put on hold or even handing back their CfD." ReNews.biz, 3 March 2023 . One day after the budget passed, Orsted again reiterated its concerns. Sky News 16 March 2023.

Nor is it alone. The *FT* this month reported that "several" other developers were "seeking tax breaks from the UK government or enhanced subsidies as a sharp rise in costs puts British projects at risk."

Vattenfall's director of its planned 1.8 GW Norfolk Vanguard development – another which had won a £37 Round 4 CfD - confirmed that "given the challenging macroeconomic circumstances, [the offshore wind] industry has been discussing the delivery of [Round] 4 projects with government… Other parts of the world have announced major support for the offshore sector in the face of dramatically increasing costs. The UK government must do the same so we can build the clean, secure power generation we need here." Financial Times, 3 March 2023

As late as last month, 4Coffshore had forecast that Hornsea 3 and Norfolk Vanguard – both of which have already secured development consents and fixed CfD prices – would start construction in 2026. How this might affect the schedules, I don't know.

I can say their combined capacity would be 4.7 GW, which for context is equal to a full 35% of the UK's 13.6 GW total installed OSW capacity at the end of 2022. World Forum Offshore Wind, February 2023 . And of course, when a country says it wants 50 GW in the water by 2030, every little bit counts.

It's hard to draw conclusions from these two data points, but they sure get one's attention. As I said, I suspect that we won't see Round 5 developers competing to go below the maximum strike price. Does that make sense?

Shashi Barla: Absolutely. I completely concur, considering cost inflation, I wouldn't really be surprised if they almost arrive at a price that's closer to the max ceiling strike price for these upcoming UK CfD auctions.

Ken Kasriel: Shashi, we've covered lots of ground here. Thanks very much for your insights and your time!

Shashi Barla: My pleasure.

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