OFFSHORE WIND IN A ZERO BID CLIMATE

THE RESULTS OF THE RECENT DUTCH AND GERMAN OFFSHORE WIND TENDERS SEEM TO HAVE SPARKED CONCERN FROM LENDERS THAT THERE WOULD BE MUCH LESS BUSINESS FOR THEM IN OFFSHORE WIND IN THE FUTURE. ARE SUCH CONCERNS JUSTIFIED? BY **JÉRÔME GUILLET**, MANAGING DIRECTOR AT **GREEN GIRAFFE**.

The first wave of disquiet followed DONG Energy's victory in the Borssele 1-2 tender in the Netherlands, announced in July 2016, and Vattenfall's subsequent wins in the Near Shore and Kriegers Flak tenders in Denmark.

Previous tenders had seen prices in the €150/MWh range in the UK – £119.89/MWh for East Anglia and £114.39/MWh for NNG, corresponding roughly to €162/MWh and €154/MWh at the then prevailing rate of £1 = €1.35 in February 2015 – while the Horns Rev 3 tender, won at €103/MWh by Vattenfall, was dismissed at the time as a special case.

The Borssele bid and the subsequent Danish prices stunned the industry as they were much lower than previous bids, and much lower than anybody expected at the time. They naturally generated a lot of questions about the changing economics of offshore wind. But for project finance lenders, the bigger question was: is the project finance model dead? If tenders were to be won only by utilities financing projects on their balance sheet, what deals would remain for debt providers?

There have been a few holdco transactions, whereby owners of minority stakes in projects refinanced their stakes on a non-recourse basis at the holdco level, but banks generally dislike these structures as they have no direct control of the project and its contracts and must rely on upstreamed revenues and indirect commitments by the other project shareholders to reasonably manage the project and its costs.

While some limited construction risk has been borne by lenders under such structures, they are not seen as being truly fit for greenfield projects. Holdco financings tend to apply to fractions of projects, ie, less generation capacity, and thus the amounts raised only reach a few hundred million euros or pounds, compared with the billion-euro/pound greenfield financings.

A future where all new projects were to be built by utilities, with partial refinancings of the minority stakes then sold to financial investors, is rather unattractive to project finance lenders both in terms of the risk profile and of the volumes to be raised.

The victory of the Van Oord/Eneco/Diamond/Shell consortium in the Borssele 3-4 tender briefly reassured lenders. It is widely believed that the consortium will be using project finance and its victory in the tender suggested that the IPP/PF model could also be competitive. And indeed the price proposed by that consortium (€54.49/MWh) was even lower than what had been previously reached.

However, comments by the Dutch government suggesting the likelihood that no support would be required by the project after a few years of operation underlined the fact that such a bid price was extremely low and that the bidders were likely to rely on revenue scenarios based on merchant prices even before the end of the fixed tariff period.

For financiers, these developments brought merchant risk to the fore, a topic they had largely managed to avoid in offshore wind, to-date.

Investors have had to worry about merchant risk for a while already, as they need to take into account revenue streams beyond the period of the regulated tariff regime in their valuation efforts, given the lifetime of turbines extends beyond these regimes. This is especially true in onshore wind and solar, where a number of transactions now include assets with a long operational history and only short periods of regulated tariffs remaining.

The price risk there is essentially similar to that in offshore wind. The precedents set in onshore wind on that front, including the fact that the proportion of merchant revenues in such onshore wind projects has steadily increased, are definitely also relevant for offshore wind.

Lenders, on the other hand, have largely limited their exposure to merchant prices in offshore wind until now, save for a few Belgian and UK deals where a relatively small portion of electricity revenues was subject to merchant risk.

This limited merchant exposure was offset by a majority of fixed/contracted revenues, either thanks to floors/fixed-price formulas under the green certificate support mechanisms and floor prices in long term PPA contracts such as the

TABLE 1 - THE FIRST SHOCK

Tender	Country	Date of announcement	Winner	Price (€/MWh)
Borssele 1-2	NL	July 2016	DONG Energy	72.7
Nearshore	DK	September 2016	Vattenfall	63.8
Kriegers Flak	DK	November 2016	Vattenfall	50.0

fixed price Green Energy Certificate in Belgium, or the de facto floor provided by "buy out" price under the old ROC system in the UK.

With a majority of revenues at a certain fixed price, the residual variable revenues could be taken into account by using prudent price assumptions and higher coverage ratios. For example, in UK deals the standard was to use a 1.45 debt service cover ratio (DSCR) for fixed revenues anda 1.90 DSCR for merchant revenues with conservative price forecasts.

Gemini, the Dutch project tendered back in 2010 with a contract-for-difference structure at a strike price of €168.9/MWh, actually also carried some merchant risk, as the top-up payment by the public authority is capped if underlying prices fall below €44/MWh. The risk was accepted by lenders as the mechanism implied an absolute minimum price of €124.9/MWh at all times (which offered a still acceptable worst-case scenario) and included other protective features. Incidentally, the same top-up cap structure also applies to the more recent Borssele tenders, with slightly lower thresholds of €29/MWh and €30/MWh for Borssele 1-2 and Borssele 3-4, respectively.

So, after worrying about not having any deals, lenders suddenly had to start thinking about deals where there might be a substantial merchant risk component. Then came the second shock, with the results of the German auction, in April 2017, where all the winning bids except one were "zero-bids", de facto accepting full merchant risk on revenues.

A lot has been written about the specific factors that drove bids in this auction, such as the very limited capacity available against the large number of potential bidders and the fact that the winning projects will only need to be built several years from now and can thus expect further turbine and construction technology progress in the meantime.

Some analysts have interpreted these bids as options bought on future projects, with a relatively modest upfront payment, lower than the full development costs of similar projects without the auction mechanism. There is therefore still some doubt whether such prices can be replicated – and the answer will come from subsequent tenders.

The next tender results to be made public were those of the second UK CfD auction, on 11 September. As expected, this tender did not lead to zero-bids given that the tender rules de facto created a floor: bidders were known and limited in number, and they were bidding for a known amount of top-up payments so could conceivably all win if they bid below a number which allowed all of them to share that pot of money. And indeed the three bidding projects, Hornsea Zone 2, Moray Firth and Triton Knoll won, with prices at £57.50/MWh for the first two and £74.75/MWh for the last project.

So the next real test will be the next Dutch tender, for the HKZ 1 zone. The government, taking into account the German results, has actually organised a specific first round to test the appetite for "zero-bid" tenders, to be followed by a second round of "normal' bidding" if the first one fails, scheduled near the end of this year.

This means that investors, and some lenders, are busy considering what it would take to submit such zero-bids, and how to manage the resulting merchant risk exposure.

- The first, obvious, option is for investors to keep the project on their balance sheet and take the merchant risk. Utilities, with their permanent presence in power markets and large portfolios of clients, would seem to be the best placed under such a scenario;
- A second option will be to find a third party willing to bear some of the merchant risk (but not the project risk) by providing a power purchase agreement including some form of price comfort to the investors, whether through a fixed price or a floor

The involvement of lenders seems quite unlikely in the first case, unless the investors provide some form of support or guarantees to lenders, or lenders themselves agree to consider a predominantly merchant transaction. It is also quite unclear that any investor will be ready to go for a zero-bid today for a project that needs to get built almost right away, given the state of technology and available alternative investment opportunities.

Lenders do not like merchant risk, but there is a history of project finance for purely merchant projects. Most of that history took place around the turn of the century, when a big wave of construction of merchant gas-fired CCGTs took place, mostly in the US.

A number of projects did go bankrupt due to low prices, but the track record is not entirely negative for the banks as in many cases they ended up as the owners of the projects and were actually able to make substantial profits when prices picked up again. So there is at least a history of lenders analysing merchant prices and dealing with the risk, and we believe that a number of banks will be willing to take some merchant risk exposure for offshore wind projects, be it through conservative-enough electricity price assumptions or higher coverage ratios.

Of course, the additional complication today is that power prices in Europe are no longer directly correlated to natural gas prices as they were then in the US, and everybody needs to take into account the additional "merit order effect" – the more renewables in the system, the lower the spot prices, as renewables have a zero marginal cost – which lowers prices for everybody but especially for renewable energy producers.

TABLE 2 - THE SECOND SHOCK, THE GERMAN AUCTION

Project	Capacity (MW)	Winner	Bid price (€/MWh)
He Dreiht	900	EnBW	Zero-bid
OWP West	240	EnBW	Zero-bid
Borkum Riffgrund West 2	240	DONG	Zero-bid
Gode Wind 3	110	DONG	60.0

Taking such merchant risk is likely to limit the volume of debt to be raised, which in turn will actually make the other risks associated with offshore wind easier to bear for lenders, as lower leverage will mean a higher equity contribution and thus more buffer from the banks' perspective.

As long as the cost of debt is lower than the cost of equity, such debt financing will still help make bids more competitive for new projects, even if the terms are less aggressive than on the most recent tariff-backed projects. The jury is still out as to whether this will be sufficient to win tenders, but there is no reason to be pessimistic, as utilities also do not like merchant risk much, and tend to have quite conservative long-term price outlooks.

In any case, we still expect plenty of activity for lenders in offshore wind in the coming years, as there is still a large backlog of projects with solid tariff structures to be financed, including for instance Neart na Gaoithe in the UK (450 MW), most of the projects under the first two rounds of French tenders - 2,500 MW between the EDF/Enbridge and the Engie/EDPR projects which are all expected to be project financed - and some of the projects under the UK CfD round. At least Triton Knoll and Moray Firth are likely to use project finance.

Meanwhile, merchant risk will start to be borne by lenders to a limited but steadily increasing extent on various renewable energy transactions – refinancings of old assets, winners of onshore or solar tenders at low prices – and this creates a body of precedents that will be useful when the first "real" merchant projects need to be financed in offshore wind, if that actually happens.

Ultimately, as the volume of investment required is large, and project finance debt is cheaper than the alternative sources of funding, investors and lenders will make it work in a way that is useful for the industry and safe for lenders. ■

TABLE 3 – THE FULL LIST OF TENDERS

Tender	Country	Date of announcement	Winner	Price (€/MWh)
Gemini	NL	December 2010	BARD	168.9
FR Round 1	FR	April 2012	EMF/Ailes Marines	180-200*
FR Round 2	FR	May 2014	LEM	180-200*
East Anglia	UK	February 2015	Iberdrola	162**
Neart na Gaoithe	UK	February 2015	Mainstream	154**
Horns Rev 3	DK	February 2015	Vattenfall	103.1
Borssele 1-2	NL	July 2016	DONG	72.7
earshore	DK	September 2016	Vattenfall	63.8
Kriegers Flak	DK	November 2016	Vattenfall	50.0
Borssele 3-4	NL	December 2016	–	54.5
He Dreiht	DE	April 2017	EnBW	Zero-bid
OWP West	DE	April 2017	EnBW	Zero-bid
Borkum Riffgrund West 2	DE	April 2017	DONG	Zero-bid
Gode Wind 3		April 2017	DONG	60.0
And forthcoming				
CfD R2	UK	Q4 2017	Up to 4GW	
HKZ 1	NL	Q1 2018	700MW	
Dunkerque (FR R3)	FR	Q2 2018	250-750MW	
Germany 2018	DE	Q2 2018	1,550MW	

* The final bid prices are not public. EMF was the joint venture of EDF and DONG and won three projects (Fécamp, Courseulles and St Nazaire). DONG has now exited the project and has been replaced by Enbridge. wpd has stakes in two of the three projects. Ailes Marines is the joint venture of Iberdrola and RES for the St Brieuc project with CDC having acquired a small stake. LEM is the joint venture between Engie and EDPR, with CDC also having a minority stake, winning two projects (Noirmoutier and Tréport)

** CfD strike prices are £119.89/MWh for East Anglia and £114.39/MWh for NNG and have been converted into euros at a rate of £1 = €1.35 which was the then prevailing rate in February 2015. Note that the UK CfD strike price is indexed, but it does include transmission, contrary to those in DK, NL or DE