Financing Offshore Wind

September 2022

WORLD FORUM OFFSHORE WIND

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This document relies on content from presentations prepared by the author while with Green Giraffe, which are still available online on he Green Giraffe website, in particular „Recent trends in offshore wind finance“, presented in April 2019 at the WindEurope 2019 conference in Bilbao.

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Photo courtesy of DEME Group

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Content

1

Introduction

1

Introduction

In the context of the energy transition, with countries and major corporations both in the energy sector and outside looking to reach net-zero, offshore wind is increasingly seen as one of the ways to help meet these targets, and features more and more in public discourses and corporate plans. Quarterly results by quoted companies focused on the sector give investors and the wider public certain information but not always enough context to fully understand the wider picture. In fact, the increased scrutiny by the general public brings back old arguments (intermittency, impact on fauna, relationships with fishermen, localisation of jobs) that have been discussed over the past 15 years and which the industry may consider as "resolved" but which need to be explained in more detail again.

In particular financing plays a huge role in renewable energy infrastructure projects, especially offshore wind. This report helps understand better the different financing structures used and risks involved in financing an offshore wind energy project. By discussing early projects and comparing them with the current projects, it highlights the changes that have happened in recent times in the offshore wind energy space.

This report also tackles and discusses wider energy topics, including economics, policies, regulatory frameworks, but always from the perspective of how the offshore wind industry is impacted, or can play a role, or can be compared to other technologies.

In the online-version of this report – published on our blog – you can find further links to certain sources.[1] This document relies on content from presentations prepared by the author while with Green Giraffe which are still available online on the Green Giraffe website, in particular „Recent trends in offshore wind finance", presented on April 2019 at the WindEurope 2019 conference in Bilbao.[2]

1 https://wfo-global.org/financing-offshore-wind-part-1/
2 https://green-giraffe.eu/wp-content/uploads/2019/04/190411_green_giraffe_bilbao_-_trends_in_ow_finance_final.pdf

2

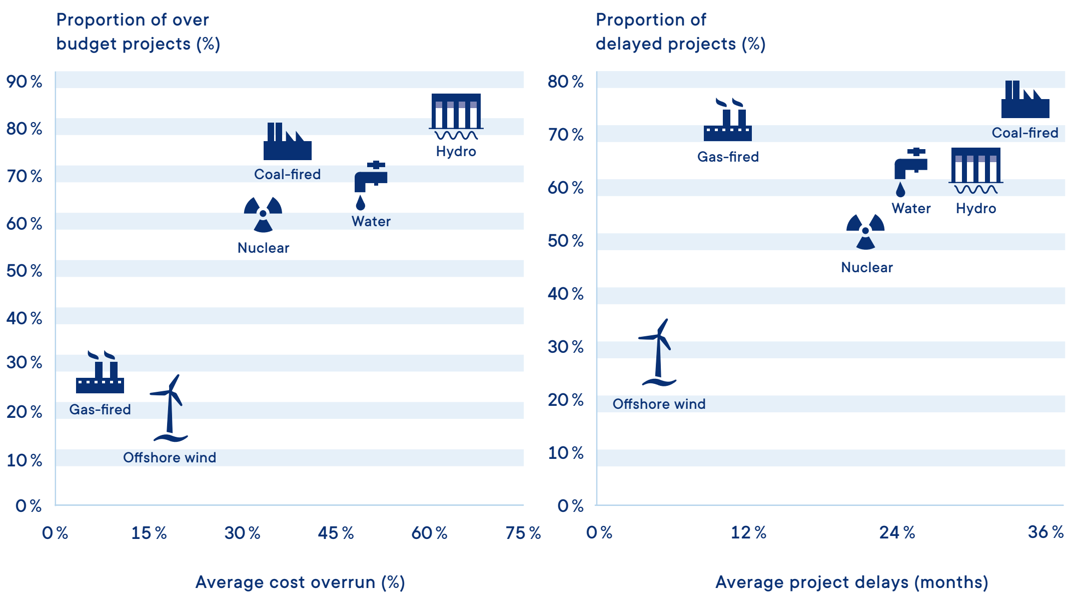
Beginning of offshore wind

2.1 A miracle on the sea ...

In late 2016, EY, the professional services firm, published a report on large power sector projects and how well they were being built (*Spotlight on power and utility megaprojects – formulas for success*).

Proportion of 100 megaprojects with reported delay and cost overruns

Cost overruns and delays in power sector mega–projects

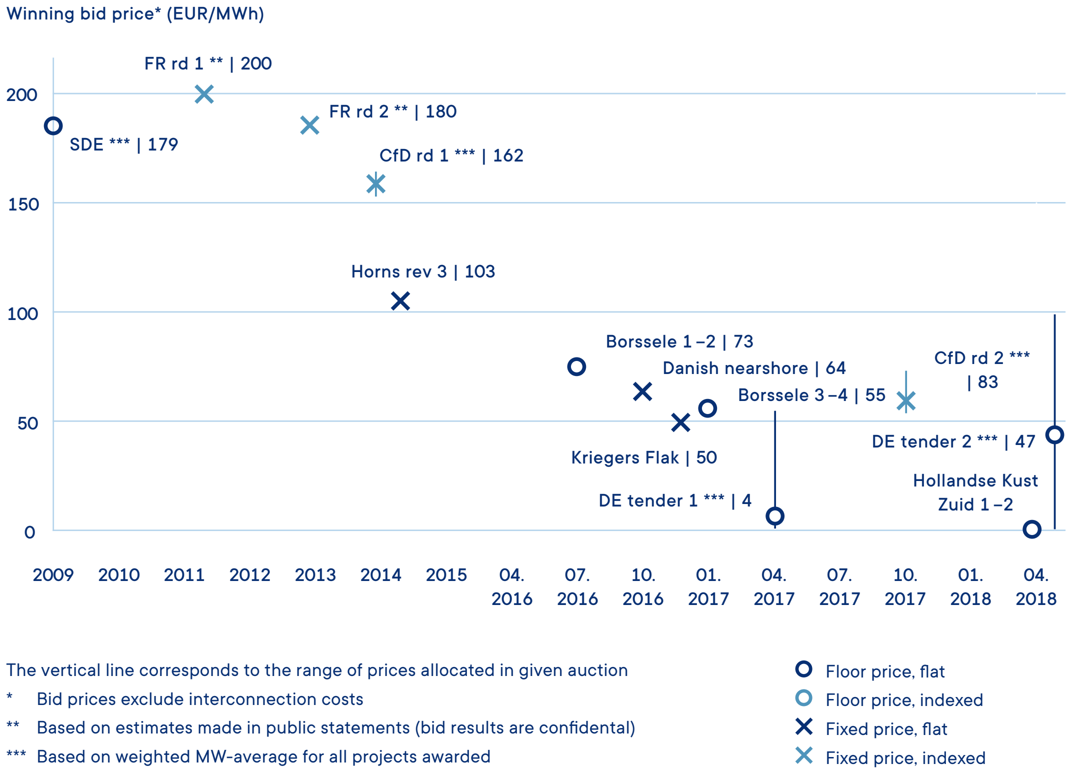


Source: EY research, *Spotlight on power and utility megaprojects — formulas for success*
The Report is no longer available on the EY website but a copy will be sent upon demand to the author. Other technologies (oil, onshore wind, geothermal, solar and T&D) are not shown as they represent a small fraction of the 100 megaprojects analyzed).

Unsurprisingly, it noted that most of these very large projects suffered from cost overruns and delays, sometimes on a quite massive scale. However, what stood out was how much better offshore wind projects seemed to be faring, with the lowest delays and cost overruns by far, despite being a relatively new and immature sector, and despite the obvious intrinsic difficulty of installing large industrial facilities in a very hostile and inaccessible location – the open sea.

Not long after that, Ørsted, the Danish utility that was one of the pioneers in offshore wind and still is the market leader, stunned the world with a bid to build the Borssele 1–2 project in the Netherlands for a record low tariff of 72.7 EUR/MWh, at a time when most countries were still offering feed–in tariffs (FiTs) around 150 EUR/MWh for offshore wind projects. A few months later, the next Dutch project, Borssele 3–4 was awarded at the even lower tariff of 54.5 EUR/MWh to a consortium led by contractors Van Oord and MHI Vestas, and the Danish nearshore tender was won by Vattenfall with a tariff of 49 EUR/MWh. And soon afterwards, Germany awarded the first "zero-bid" project, where the sponsors effectively saying they could build projects on the basis of ongoing market prices, without any medium-term revenue stabilisation mechanism. An industry that had until then required substantial subsidies to get projects built was suddenly confident that it was fully competitive against all other power generation technologies and could provide cheaper electricity than the market.

Offshore wind tender prices, 2009 – 2018



Offshore wind tender prices, 2009–2018. Source: Green Giraffe (https://green-giraffe.eu/wp-content/uploads/2021/02/180509_windforce_auction_design_guillet_sent_to_organisers.pdf)

This section of the report will discuss how the industry managed this feat, and the prominent role that project finance lenders, a rare breed of financiers, played in that success. It thus tells the story of how early projects were financed, what was learnt along the way, and what this means for today's projects. In particular, it will underline how financial engineering was critical in (i) getting a lot of things right during the early generation projects and (ii) bringing the net cost of electricity (the "LCoE" – levelised cost of electricity) down.

2.2 "Stuff happened" on the early projects

A collapsed crane in the [Ijmuiden] port

Source: picture from author archives (provided by project team)

In the summer of 2007, an accident took place on the quayside of the Ijmuiden port. The crane on an offshore installation barge fell on the quay and crashed. There was only limited damage to the wind turbine components; however, the crane itself could not be repaired anymore.

That made the installation barge inoperative and prevented for some time the transport of wind turbine nacelles from the quay to the "Q7" offshore site at sea where a 60-turbine, 120MW offshore wind farm was under construction in Dutch water. The accident took place in July, precisely the period when the weather is calmer, and it is much easier to do construction work at sea.

Just a year later, in July 2008, another project, the 6-turbine, 30 MW C-Power phase 1 in Belgium reported an incident: while pouring sand into the concrete foundations at sea, the plastic "J-Tube" that was supposed to house the cable connecting the turbine to the rest of the project was crushed by the pressure. Quickly identified as a design error (the plastic used for the tube was strong enough for water but not for packed sand), the incident threatened to prevent the connection of the project's turbines to the grid altogether.

The Q7 wind farm (also known as the "Prinses Amalia" wind farm) and the C-Power phase 1 projects being the first two offshore wind projects to be financed by banks on a non-recourse basis (respectively in October 2006 and May 2007), this in each case became an immediate and severe test of whether their financial structures were sturdy enough to resist to such events, and whether the industry could hope to continue to be financed using "project finance".

Other early offshore wind projects also had to face severe problems during construction or early operations, such as Horns Rev (serial defects on the gearboxes leading to their eventual full replacement at sea), Greater Gabbard (flaws in the welding of the foundations, leading to delays in their production and the installation of the turbines), but as these were built on balance sheet, the problems were kept between the project owner(s) and the contractors, and much less public or semi-public information was made available about them.

Offshore wind has been tough for oil & gas contractors

For oil & gas contractors, the temptation to get involved in the nascent offshore wind sector was strong – no obvious competitors from the wind industry side with experience working at sea, familiarity, and experience with the main area where projects are built (the North Sea), attractive size of contracts. And indeed, players like KBR, Fluor, Bechtel, and Technip, who have long experience offering "EPC" ("engineering, procurement, construction") contracts in the oil & gas sector, tried to get involved. Unfortunately, it quickly appeared that offshore wind was quite different from offshore oil & gas – serial construction rather than large bespoke structures, a capped revenue structure that means that cost discipline is a lot more important than simply getting things done (in oil & gas, the cashflows from a producing well are such that it is almost always worth it to spend more to get things done faster; in offshore wind, this is not the case), and the technical features of the turbines themselves, requiring specific design and installation for each individual generator. The early attempts by oil & gas contractors to build offshore wind farms (KBR on the Barrow project (UK, 90 MW), Fluor with Greater Gabbard (UK, 504 MW)) were therefore quite challenging, leading to losses and / or long disputes with project owners or sub-contractors. As a result, most of the large oil & gas contractors quit the market in the early 2010s or focused on very specialised tasks (like cable installation) and the marine construction work ended up being dominated by another breed of offshore contractors: the dredgers, led by DEME and Van Oord.

2.3 Dealing with problems

In the end, both Q7 and C-Power were built within the timetable and funding the banks had allocated for in their pessimistic scenarios, thanks to massive efforts by the project teams to resolve the unexpected problem:

- → For Q7, construction work was delayed by several months. A temporary solution was found by using a mobile crane on the installation barge, but that was less efficient and slower, and it was already autumn by then. This meant being able to work fewer days of work each month as weather conditions became more difficult and there was an increase in delays. Thankfully, as no work had originally been scheduled at all during these harsher winter months, the project was able to slowly catch up on its original schedule.
- → For C-Power, the project team, with the help of contractor DEME, quickly designed an external steel "robe" to be installed on the outside of the foundation to carry the cable that could no longer be pulled through the J Tube inside the foundation. The team managed to design, manufacture, and install this within a few months, allowing the consequences of the accident to be mitigated. The cost of that effort was fully borne by insurance – the insurers were quickly convinced by the solution proposed by the project and saw it as a much cheaper alternative than waiting and litigating as they were clearly on the hook in any case for the loss of production that would have happened otherwise.

Installing the external "robe" on a C-Power foundations

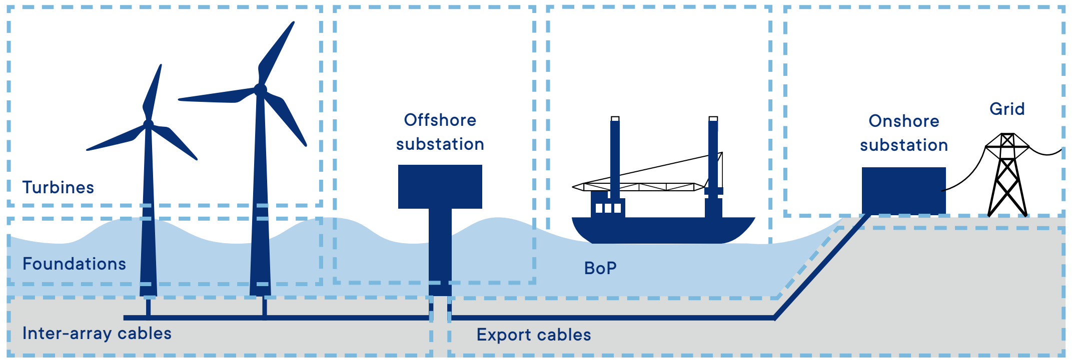
*Source: Giants on the Thornton Bank, Jan Strubbe

These two incidents confirmed what had been a core assumption of the banks funding the projects: problems will inevitably happen in such projects, what matters most was the ability by the project to withstand the consequences and solve them. That meant, in practice, having (i) enough time and funding buffers to be able to deal with the unexpected, and (ii) the right people to understand issues, identify solutions and implement them.

Now that the offshore wind industry has moved to another dimension, it is important to remember these principles, as they still underpin the fundamental philosophy of how projects are built, and how they are financed.

2.4 Offshore wind construction complexity

Main components of an offshore wind project



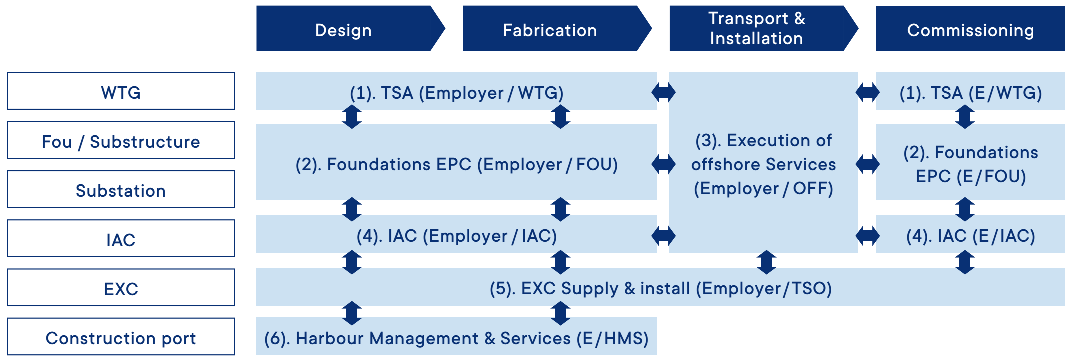
Source: Green Giraffe, S9
(https://green-giraffe.eu/wp-content/uploads/2019/02/190212_offshore_wind_energising_an_industry_vfinal.pdf)

Beyond the inherent difficulty of erecting heavy structures at sea, the offshore wind industry is remarkable in that it brings together industrial sectors that have nothing to do with each other and cannot easily sub-contract work to each other. Turbine manufacturers and marine installation companies have very little to do with each other, and steel foundations, cables and heavy electrical equipment are all quite separate. More importantly, not a single component dominates in terms of overall cost or ultimate responsibility to make the project happen – all elements are critical, but none of them usually represent more than 30% of the construction budget. And the necessity to build at sea requires a very carefully choregraphed construction schedule, as most tasks can only be done in a very specific order.

BEGINNING OF OFFSHORE WIND

This creates interdependencies between multiple contractors and a large number of “interfaces” – points where the responsibility for the work needs to be transferred from one party to another – and these are physical interfaces between very different tasks or components. Even if it is possible to find one party responsible for both, it will need to manage the interface between these tasks carefully.

A simplified overview of interfaces in an offshore wind project



WTG = wind turbine generators FOU = foundations A = Inter-array cables EXC = external cable (to grid)

Source: Green Giraffe, Recent trends in offshore wind finance, April 2019, S6

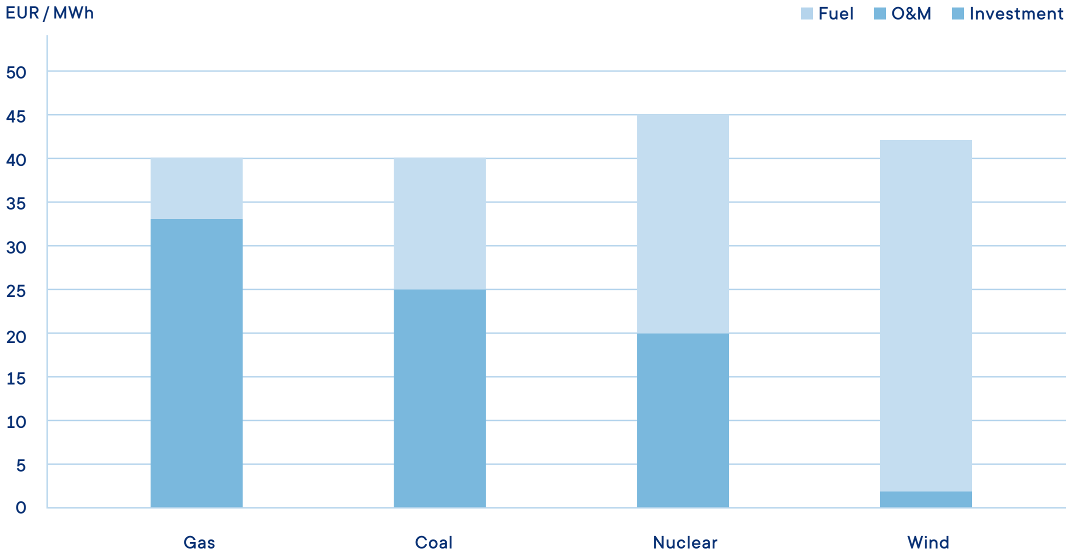
So, in short – even if the industry has learnt to do it better, installing wind turbines at sea (at increasing distances from shore) is never going to be an easy undertaking and it will always require a lot of planning and precautions.

Wither Project Finance?

It is in that context that it should be noted that offshore wind, like most infrastructure projects, is capital-intensive: most of the money needs to be spent upfront to build the equipment, which then costs relatively little to operate and maintain. That means that once operational, the main cost is the repayment of the initial investment (whether as interest and principal on loans, or dividends to equity providers) and, as such, offshore wind's long term cost base is (i) largely fixed from day 1, and (ii) highly dependent on the cost of capital.

Long term generating costs

The relative composition of the cost of electricity for different types of plants

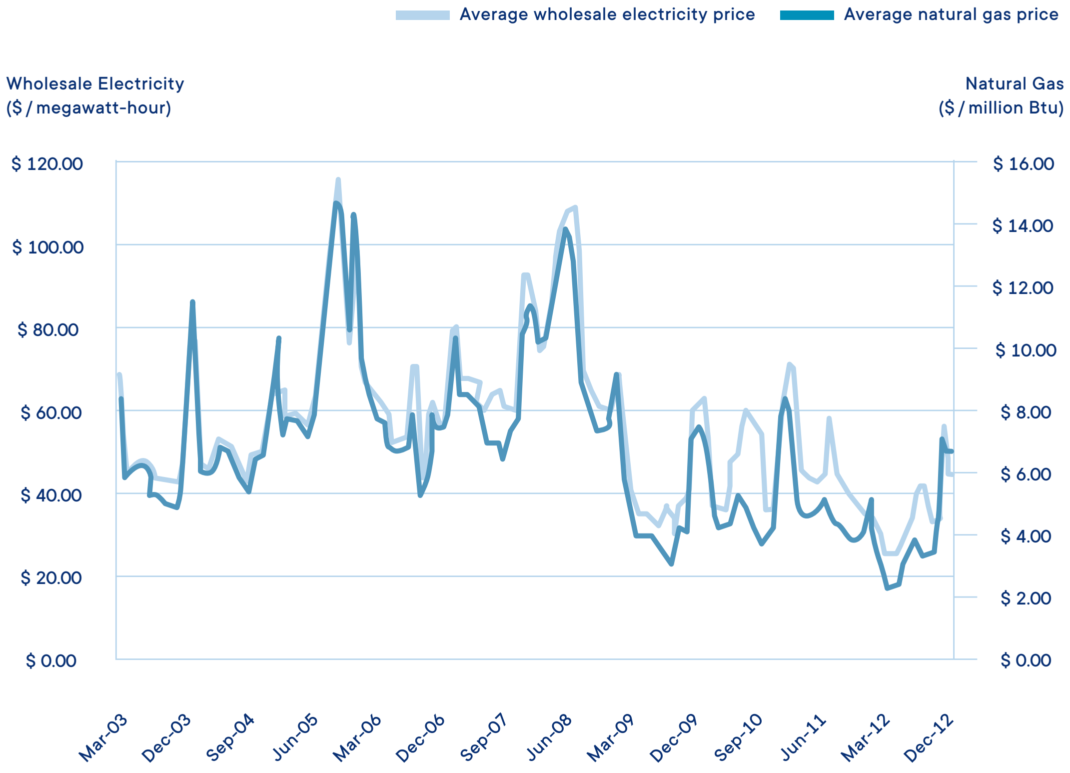


*Source: IEA World outlook 2004, adapted by the author. An old source is used on purpose, to remind us that wind has been competitive against traditional power generation sources for close to two decades, but its economics are fundamentally different, and thus policies have struggled to integrate them easily into market designs.

In one case, most of the cost is linked to the fuel that is burnt, i.e., it is avoidable but unpredictable, whereas in the other the cost is fixed, predictable and unavoidable. That means that fossil fuel plants, unless prevented for technical reasons, will choose at any point in time whether to produce power or not – they burn fuel only if it is profitable to do so. Their marginal cost of power is high, and they are "price-makers" i.e., they will help determine the market price most of the time, as the most expensive plant required to balance the market will typically be such a plant, based (partly) on its technology and (largely) on the cost of the fuel required at that time.

Power prices closely track gas prices in liberalised markets

Electricity prices track natural gas prices



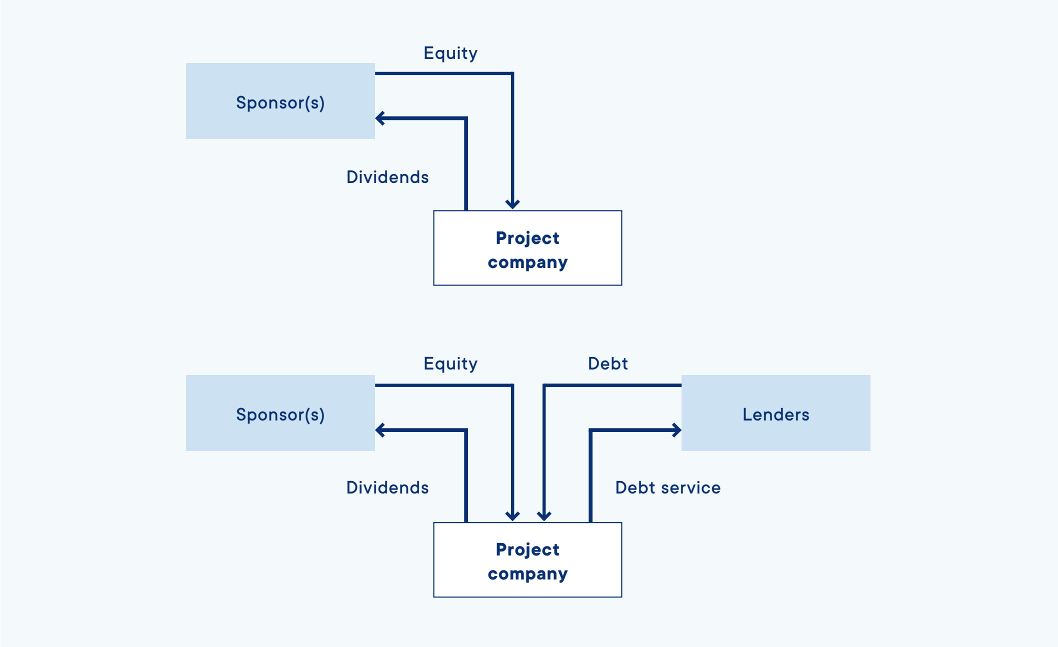
Source: Power prices closely track gas prices in liberalised markets (https://neutroneconomy.blogspot.com/2013/01/wheres-real-bottleneck-for-natural-gas.html)

Conversely, renewables (like nuclear) are "must run": it costs very little to produce an additional MWh (their marginal cost of production is very low), so they will do it as much as they can – as long as the underlying resource, wind or solar, is available, of course. They always bid a generation price of zero in the market (i.e., any price above that generates cashflow and is thus worth it): they are "price takers". That means that they are almost always dispatched before fossil fuel plants. The exception are lignite plants, which are very inflexible, and hard to stop and restart, and will typically bid negative prices to be sure they are not taken off the grid at any point in time.

In terms of economics, it means that the single biggest driver of the cost of electricity for renewables is the cost of capital. The lower the cost of capital, the cheaper it is to spread the initial investment over future production years. That explains why solar was cheaper in Germany than in Spain for a long time despite the obviously weaker resource.

The cheapest form of capital is debt, so the more debt you can raise for a project, and the longer the maturity, the cheaper the electricity will be. This is where "project finance" or "non-recourse finance" comes in. This is debt provided directly to a project, and repaid only by such project's revenues, and not guaranteed by the project's owners.

Balance sheet finance vs project finance

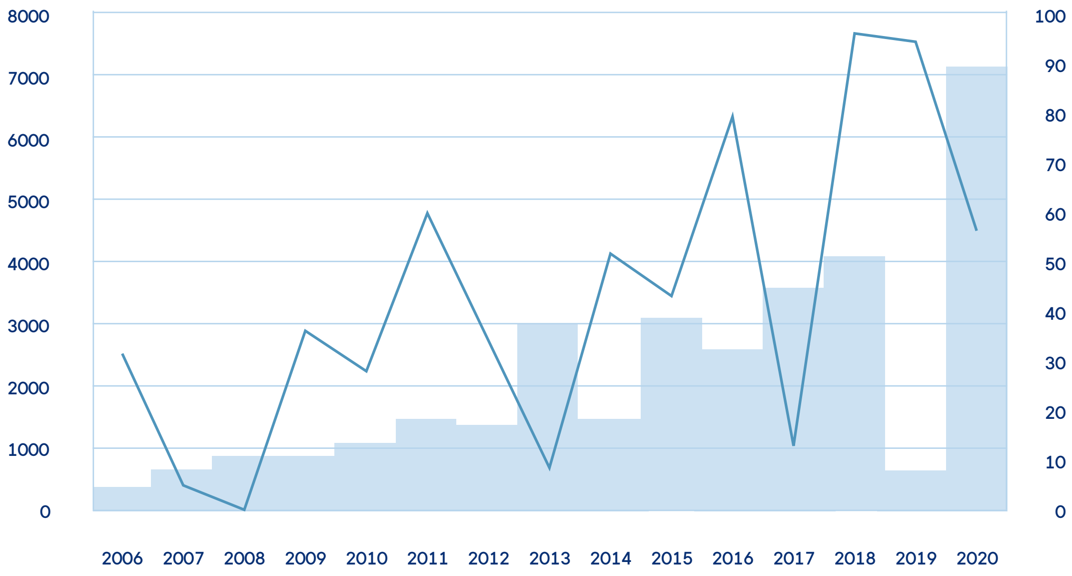


Source: Green Giraffe, S4
(https://green-giraffe.eu/wp-content/uploads/2019/04/190411_green_giraffe_bilbao_-_trends_in_ow_finance_final.pdf)

The cost of capital for a project-financed project is the weighted average of the cost of equity (over the life of the project) and the cost of debt (over the duration of debt), which makes it structurally lower than if you only invest with equity, and thus highly attractive for capital intensive projects. The cost of capital for a project funded on the balance sheet of an investor is itself the weighted average of the cost of the equity of that investor, and that of its corporate debt. The cost of equity for investors using non-recourse debt is a bit higher than the cost of equity for sponsors investing directly in projects, but this is more than compensated for by the lower cost of the non-recourse debt specifically provided to the project.

As the graph below shows, the proportion of projects using non-recourse debt has increased over the years, as the volume of projects built was increasing. The trend is not linear as projects are "lumpy" (they are very larger and a small number of projects in each category each year can change the data for that year materially) but the overall trend is clear.

Offshore wind construction (MW, left), share using PF (%, right)



Source: Derived from "Offshore wind debt 15 years on", PFI Yearbook 2022

Given that lenders will only be repaid by the project itself and not by anyone else, they want to make sure that the project actually gets built with the funds allocated for that purpose, and then generates enough revenues to service the debt. If they are further asked to take construction risk (which is not always the case – there are many infrastructure sectors where the investors prefer to keep that risk, and in offshore wind it has not been the case for all projects, as shown in the graph above), they will want to make sure that construction will happen on time and on budget. In any case, they will want the project to be operated properly for a duration at least as long as the debt maturity, and to have enough revenues, i.e., enough production is sold at a high enough price. In order to take these risks, they will want the different tasks and commitments to be allocated to the right parties and contracted in enough detail to cater for most circumstances.

That typically means intrusive involvement in the contractual set up of the project and extensive “due diligence” i.e., technical, legal, and other verifications by third party experts of every aspect of the project (its permits, technology, schedule, budget, personnel, and the markets it sells into). Not all investors are comfortable with such active participation of outsiders, let alone bankers, in what is usually their core area of competence.

In many sectors, investors use project finance to cover very narrow and specific risks: for instance, oil & gas companies use limited-recourse debt to share political and operational risk with banks, but not construction risk for projects in difficult countries. So, they guarantee the repayment of debt in case of delays or cost overruns, but they ask the banks to shoulder some of the risk in case of expropriation, currency convertibility or transfer restrictions, or inability of the local governmental entities to fulfil their commitments.

Offshore wind is actually one of the few sectors where the banks have regularly been asked from the start to take complex construction risk on a non-recourse basis. To some extent, this is a quirk of history – in several countries, small developers were able to get their hands on the first offshore wind sites and quite simply did not have the financial capacity to fund the projects in full themselves, so they were willing to give potential lenders a lot of say in how the projects would be structured, as long as it actually made them happen.

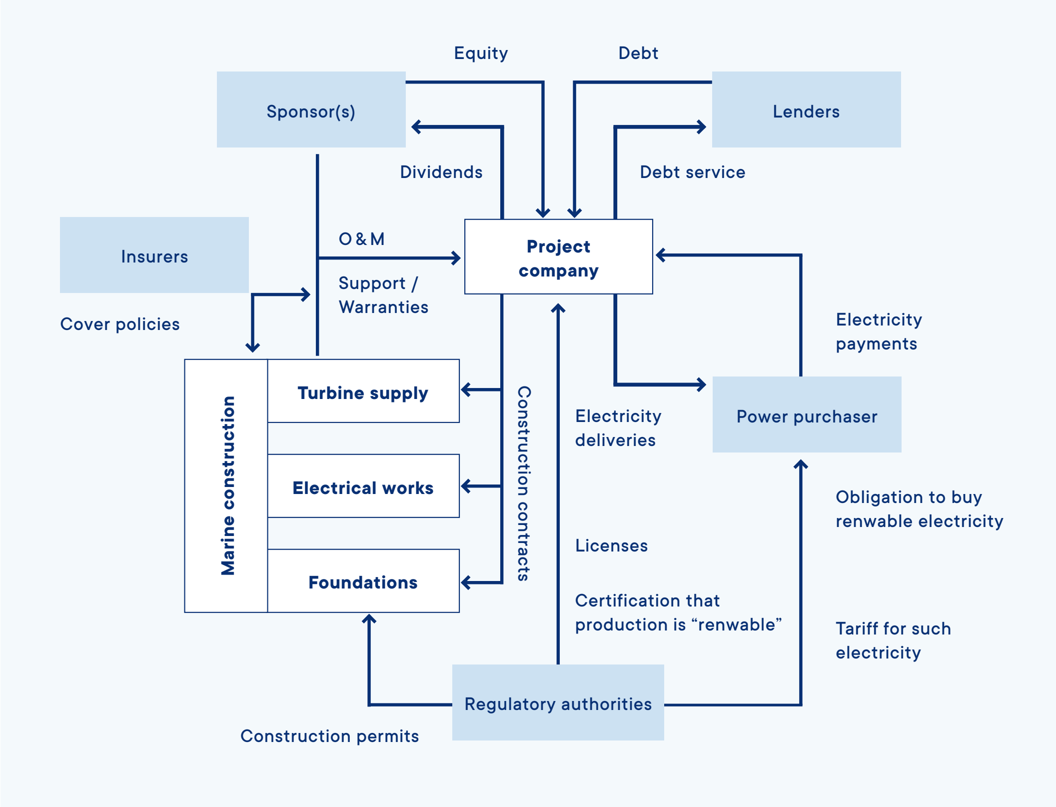
This usually makes the construction contracts more expensive than when managed by balance sheet investors, as banks expect to see stronger warranties and commitments by the contractors, and costs such as project management are explicitly passed on to the project rather than being partly hidden or buried in the internal costs of the sponsors, but this is usually an acceptable trade-off against the lower overall cost of capital mentioned above.

In a stroke of luck for the sector, the first projects were financed in 2006 – 2007, before the financial crisis, at a time where banks were already quite enthusiastic about financing renewable energy (then a relatively new sector) but were not as constrained by the restrictions and the increased risk aversion that came after the crisis. That meant that the early transactions, which acted as precedents for the future market, were set in relatively favourable conditions, and this made the next projects post-crisis much easier, as there were already existing projects that could be used as (positive) reference points. It also helped that offshore wind started in the countries around the North Sea, which are all highly rated, stable democracies where banks were keen to do more business and have a tradition and the expertise of non-recourse lending.

In any case, that meant that banks were asked, from the very beginning, to take considerable risk on the construction side, in addition to all the traditional risks of such projects, in a sector where there was very little visibility and very few precedents. That meant very intrusive due diligence and

direct involvement in all the contracts of these projects. The picture below summarises the major contractual and / or regulatory relationships that exist in a project. In the case of project finance, banks want to make sure that every single one of the material contracts is fit for purpose and in place at the time they commit the fund. As many of these relationships are conditional upon each other (the financing requires contracts to be effective, construction contracts become effective when proof of funding is provided) this usually means that all contracts need to be signed and confirmed at the same time: this is what is called “financial close” (or “FC”) in bank parlance. For balance sheet projects, things are a bit simpler as investors can commit the funding themselves towards contractors and not all contracts need to be in place on day one; their decision to go ahead with the project is called “final investment decision” (or “FID”).

Simplified contractual structure for an offshore wind project



Source: Green Giraffe. “Recent trends in offshore wind finance”, April 2019? S7

3

The early financings

3.1 Q7

Name	Q7 (later renamed "Prinses Amalia")
Size	120 MW
Sponsors	ENECO, Econcern, EIH
Turbines	60 Vestas V80 – 2 MW
Country	The Netherlands
Financial Close	25 October 2006
Debt amount	EUR 219 M
Initial lenders	EKF, Dexia, Rabobank, BNP Paribas
Key contractors	Vestas, Van Oord
Project completion	2008

In 2005, when Dexia and Rabobank started working on the financing of the Q7 offshore wind project in the Netherlands, two things were clear: (i) this has never been done before (technically, the very first offshore wind project to benefit from non-recourse debt was North Hoyle (60 MW), as a part of the wider refinancing of a much larger operational wind portfolio operated by RWE/nPower in the UK. The project represented roughly 15% of the capacity of the portfolio and 25% of its production, and was operational at the time of the transaction) and (ii) the banks would need to bear construction risk, as the project owners were simply not able to finance the project otherwise, not having the requisite funds (half of the project was owned by a consortium of Econcern and EIH, both relatively small developers, while the other half was owned by ENECO, one of the four main Dutch utilities). With that precondition in mind, the bankers set out to identify what could make it possible to take the risk on reasonable terms.

Project finance lenders are generally not interested in the "normal" scenario – they want to make sure that the project can survive adverse circumstances and still pay off the debt. So, a key part of the initial work, together with independent technical advisors, was to think about what could go wrong, how that could be solved or mitigated if it happened, and what it meant in terms of delays or extra costs. The idea was to identify what additional period, and what contingency budget (i.e., a supplementary budget available only in case of problems) would be sufficient to cater for most adverse scenarios, and make sure that such additional time and budget were available from the start and would still allow the debt to be repaid.

This led to work over a period of a year with the project team, the technical advisors, and the contractors, plus the insurance brokers, to go through construction planning, to identify critical paths (items that constrain the timetable: if they are delayed, the whole project is delayed), knock-on effects (tasks that are dependent on an earlier one to take place), possible buffers, potential backups and alternatives for a wide variety of circumstances. A lot of "what ifs" where brought up, and those that were deemed plausible were analysed extensively.

In the end, it was quickly identified that work in the winter months was difficult – with work at sea possible maybe one day in ten statistically in the worst months, as opposed to eight or nine days out of ten in the summer, and that such period should be excluded altogether from all construction planning. That meant that if work was not completed by October, it could only be restarted by April the following year: tasks that required several days at sea could not reliably be planned in the winter season. Any adverse scenario thus needed to be able to absorb a delay of six months in addition to the time actually required. In terms of cost, this might mean having the funds to mobilize the requisite vessels twice (i.e., two consecutive warm seasons) to complete the task of installing the turbines.

The analysis was obviously a lot more detailed, but the simplified description above brings the essential substance of it, and the focus on the worst possible risk to size the necessary reserves of money and time made sense and was sufficient (in Germany a few years later that would be delays in the construction of the grid connection by the grid operator).

The financing structure thus included a "base case" scenario of things going according to plan, and a "downside scenario" including various delays and problems, and the project needed to be able to repay its debts in both – obviously it would be less profitable for investors in the second case, but it would not go bankrupt and would still show some minimal level of return in that case.

In this project, Vestas, the Danish turbine manufacturer, was involved, and this allowed EKF, the Danish export credit agency (ECA), to participate to the financing. ECAs are usually involved in project to cover political risk or local counterparty risk, but in this case, EKF actively helped make the Vestas contract happen by providing a substantial portion of the contingent funding to the project, thus justifying its mission of supporting exports from Denmark. This helped create larger buffers for adverse scenarios and allowed the commercial banks to be more comfortable taking the overall construction risk: with no funding beyond the committed buffers available to solve possible problems, having these buffers mainly funded by EKF provided substantial additional comfort to all (including Vestas).

The incident of the crane falling on the quayside was not identified as such during that structuring process, but the buffers and precautions that had been put in place to cater for other incidents proved sufficient to manage the aftermath of that particular event and the project was successfully completed with some of the contingent funding and time to spare.

3.2 C-Power Phase 1

Name	C-Power phase 1
Size	30 MW
Sponsors	DEME, EDF, SRIW, Socofe, Nuhma (originally)
Turbines	6 Repower 5 M (5 MW)
Country	Belgium
Financial Close	25 May 2007
Debt amount	EUR 126 M
Initial lenders	Dexia, Rabobank
Key contractors	Repower, DEME
Project completion	2009

The financing of the first phase of the C-Power project took place not long after that, essentially involving the same participants (Dexia and Rabobank as lenders, and several advisors which had been involved in Q7), with the same principles followed. As a lot of the lessons learnt in the Q7 process were brought forward, the negotiations went quite fast, carried forward by a strong project team and a committed group of investors including industrial groups and local Belgian public investment bodies. It helped that 2007 was a year of general optimism and lenders and investors were willing to take risks that they would not necessarily have taken in other periods. With strong competition and a quest for yield, financing a partly new sector was seen as a way to get better remuneration while still taking understandable risks.

The project was in a different country, with a different tariff mechanism, and used a completely different turbine, the Repower 5 MW, which at that time had only been deployed 4 times, with two prototypes installed onshore and two more offshore. This was quite important for future transactions as it ensured that the precedents created by the first projects were not too narrowly defined.

For a lot of reasons, lenders love (successful) "precedents". Part of that is that once you have made the effort to understand a particular technology, or regulatory framework, or category of risk, it is much easier to assess a project that falls in the same basket. Other part is that a history of profitable transactions in a sector is more conducive to doing more business in that same sector than if losses have been incurred. A less flattering reason is that banks prefer to be wrong in groups than right alone – so doing something that a lot of other peers are doing already is seen as reputationally safe.

In any case, here, it meant that just before the great financial crisis of 2008 struck, there had been two separate offshore wind transactions, in different countries, with different contractors and turbine models, and different price mechanisms. The sector was therefore "real", validated by serious players in the market, and not seen as something completely alien, and that validation applied without restrictions to a single country, or player, or other narrow criteria that could conceivably be applied. (Ironically, the one narrow criterion that remained for years was that only one technical advisor, involved in both transactions, was seen as acceptable by lenders as it was the only one with experience – that only changed when an individual involved in these transactions changed employer and brought his recognized track record and reputation on these transactions to that new company).

Despite the J-tube incident mentioned earlier in the section, the C-Power (phase 1) project was also built on time and within the contingent budget allocated by lenders, thus setting a second successful reference point for the sector.

3.3 Belwind

Name	Belwind
Size	165 MW
Sponsors	Econcern, SHL, Parkwind
Turbines	55 Vestas V90 (3 MW)
Country	Belgium
Financial Close	24 July 2009
Debt amount	EUR 219 M
Initial lenders	EKF, EIB, Dexia, Rabobank, ASN
Key contractors	Vestas, Van Oord
Project completion	2011

By 2009, when the next project to be financed came to the final contractual negotiations, the financial environment had completely changed. Projects financed using non-recourse debt were faring quite well in general (i.e., their performance and business models were usually not affected by the financial crisis), but the lenders in the sector had to cope with adverse circumstances across the board, and some of them were in difficult situations themselves, so project finance volumes were significantly reduced, with banks focusing much more narrowly on core countries, key clients, and strategic sectors.

This applied to renewable energy in general, and offshore wind was inevitably impacted. What helped was that (i) projects were mostly in North European countries that were seen as amongst the safest, (ii) the investors in the sector, utilities, and infrastructure funds, were seen as safe and solid clients for the most part, and (iii) green energy was already becoming something that lenders and investors wanted more of rather than less. So overall, within a much less favourable financing environment, offshore wind was still seen as something that could be done by banks.

Belwind replicated a lot of what had been done in the earlier two projects (it was in Belgium like C-Power, and used Vestas and Van Oord as key contractors, like Q7). The main novelty, other than its larger size, was the proposed participation of the European Investment Bank (EIB) in the financial structure, alongside Danish ECA EKF, allowing to reach the requisite level of funding, which at approximately EUR 500 million, was substantially larger than previous transactions.

The financing was largely agreed in early 2009, despite the fact that one of the key participants, Dexia, had been one of the most visible victims of the financial crisis and had to be bailed out in September 2008. For Dexia, the project was in its home market of Belgium, and infrastructure financing being its core activity, this particular transaction was something that fit the substantially narrower criteria applying to the bank and why it was still allowed to finance after benefitting from massive public support. Then, in May 2009, the leading sponsor, Econcern, itself went belly up, in one of the most high-profile bankruptcies in the Netherlands, after overextending itself across too many projects.

It is a testament to the robustness of the proposed financing structure that the project was nevertheless able to go forward soon afterwards, and the financing closed in July 2009. A new group of investors was put together to take over the project from Econcern, led by the investment arm of Belgian retail group Colruyt, which already had extensive experience in renewable energy. The commercial and financial structure was essentially unchanged, with the main requirement to transfer key personnel from Econcern to the project company to make sure that it had the requisite core competencies in house without depending on a now unavailable parent. Together with the technical and legal advisors, the banks identified the relevant people and contracts – it turned out that just 7 people were deemed essential to the project and the transaction.

Closing a transaction when one of the stakeholders was the judiciary administrator of the estate of the bankrupt (and highly scrutinized) Econcern was not simple – given their role, it is very hard to convince such administrators to provide the necessary additional funding to bring the transaction forward (paying for advisors, among others), but in this case, it was quite obvious that the project was worth a lot more if it could be financed right away than if it was sold without the financing and later redeveloped by a new owner, and the administrator agreed to keep the process alive in order to get a reasonable sale price at financial close. It did manage to get an across-the-board reduction in fees by all advisors, including lawyers and bankers, of 20% as a contribution to the overall effort. The financing finally happened, with painful final haggling over who had the pay the last 50,000 euros required to close the budget when the swap rate moved in the wrong direction by a few basis points on the day of signing.

The project was duly built on time and on budget, despite a spectacular incident when one of the foundations sank in the middle of the main Zeebrugge shipping lane when being towed to site.

A foundation sank in the Zeebrugge channel, 2010

Source: picture from author archives (provided by project team)

Colruyt, via the entity called Parkwind, has since become one of the savviest independent developers and investors in European offshore wind, building on the experience of that early project.

3.4 BARD 1

Name	BARD 1
Size	400 MW
Sponsors	BARD (then UniCredit)
Turbines	80 BARD 5 MW
Country	Germany
Financial Close	N/A
Debt amount	N/A
Initial lenders	UniCredit
Key contractors	BARD
Project completion	2013

BARD1 is a project that is partly forgotten by the offshore wind community, as it is an orphan project in many ways, with a bankrupt developer, a defunct turbine, and a secretive bilateral funding, even though it was the first 400 MW project to get built in German waters.

Its developer, BARD, was one of the many smaller players that participated to the first generation of projects in Germany, but it was unusual in that it was a fully integrated operation, including design and manufacturing of its own turbine, its own foundation concept (a tri-pile structure which was meant to be serial-produced), its own installation vessel, as well as project development. Founded by an immigrant Russian engineer who had played a prominent role in the Russian gas industry (heading Gazpromstroy, the construction arm of the gas giant), Arnold Bekker, it tried to do everything in-house and almost succeeded.

The distinctive BARD tri-pile, in the Cuxhaven harbour, before installation

photo by author

The project got lucky in that it received a EUR 200 million bridge financing from UniCredit's capital markets team in the summer of 2008, just before the financial crisis, which closed financial markets and any hope of the "real" financing to be raised on the public markets (which had quite different requirements than project finance lenders) and the bank was then left with the unpalatable decision to either write off the loan or continue to fund the project on its own to the end, requiring at least another billion euros. It did decide to continue with the project (at the time it still had credible buyers for it, once it was built) but unfortunately the project's installation vessel suffered from delays in construction and then design defects that prevented it from fulfilling its job. Construction was delayed by over 2 years, and cost overruns, while never fully made public, probably reached above EUR 1 billion, largely borne by UniCredit.

Active construction of the BARD1 project, June 2013

photo by author

The saga saw UniCredit take over the projects as well as the company, completing the project, selling the other BARD projects (including what became Gemini in the Netherlands and Veja Mate in Germany) after multiple complications.

After the death of the founder and the delayed completion of the project (at the time, the first of the multiple 400 MW utility-scale offshore wind projects in Germany to actually get built, beating to the punch the largest utilities), it still suffered many operational difficulties, including serial defects with the turbines, harmonics issues with the grid, while having to manage orphaned technology (the turbine was not used on any other project), suppliers no longer committed to the (defunct) manufacturer, and the perception in the market that it was a troubled project. A dedicated project team managed to solve most technical issues after several years of effort, and finally bring the project to almost 100% technical availability, allowing the project to be sold as a viable concern to and finally selling it in 2019 to Green Investment Group (the Macquarie-owned successor to the UK Green Investment Bank), an experienced offshore wind player.

3.5 Global Tech 1

Name	Global Tech 1 (also known as “wetfeet”)
Size	400 MW
Sponsors	SWM, Axpo, Entega, Windreich
Turbines	80 Multibrid (Areva) M5000-116
Country	Germany
Financial Close	July 2011
Debt amount	EUR 1,047 M
Initial lenders	KfW, EIB, EKF plus 16 commercial banks
Key contractors	Areva
Project completion	2015 (operations) – 2018 (financial)

Global Tech was the first 400 MW project in Germany to receive standard non-recourse construction finance (it was the second project in Germany to be so financed, after the 200 MW Borkum West II a few months earlier), and the first, alongside Meerwind, (288 MW, project financed almost at the same time) to benefit from the public KfW offshore wind financing programme. Promoted by another colourful pioneer of the offshore wind sector, Willi Batz-run Windreich, it managed to bring together the largest bank consortium ever put together for what was then the largest financing of an offshore wind project. Together with Borkum West and Meerwind, it heralded the arrival of Germany in the offshore wind sector and the industrialisation of the sector.

Unfortunately, these projects, like the others built at that time by utilities (Riffgat, Dan Tysk, Nordsee Ost), had to face a major obstacle: delays in the construction of the grid connections to shore. In Germany, the choice was made to allocate all grid connection construction and ownership to the grid operator, and to coordinate that via offshore wind hubs – massive sub-stations that would collect power from several offshore wind farms and then transport the power to shore via high voltage direct current lines (HVDC). That made sense given that projects in Germany need to be quite far from shore and this would avoid building too many parallel cables to shores through environmentally sensitive coastal areas. The problem was that not a lot of HVDC lines and transformer stations had been built in the past, and TenneT, the grid operator, was suddenly obligated to build several almost at the same time. The technical challenges of that task led to severe delays, and forced projects to delay construction (or, if they had started, to find costly ways to maintain their installed turbines with no power available on site). Global Tech I, like Meerwind and Borkum West, was a victim of that situation, and the contingency budgets were stretched beyond breaking point. A combination of complex financial engineering and limited additional support from the sponsors was required to get the projects through. There was an implicit commitment by the grid operator to pay penalties in case of delays, but this situation forced the government to make that commitment explicit and provide a detailed formula to calculate the exact amount – this was put into law in early 2013, after an accelerated process.

Tasks that had been scheduled at certain dates could not be performed, and vessels that had been reserved for such tasks could not be used at the time; substitutes needed to be found at the later dates when the tasks could be performed. Managing these delays, and the full reorganization of the construction schedule, was a full-time job for the project and its lenders. All projects became fully operational at least a year beyond the scheduled date, and definitely beyond the expected date of maximum tolerable delay.

Banks could have decided that this was the sign that offshore wind was too risky, and stopped lending to the sector, or at least made terms a lot more conservative, but the lessons the banks drew from this incident was that problems in offshore wind could be resolved, and what mattered was to have good project management teams, who were proactive and transparent, willing to listen to past experience and learn the lessons from it.

The project became fully operational in 2015 but was only declared complete by the banks (which allowed dividends to be paid to owners) in 2018. It was successfully refinanced in 2020, after having had to deal with the fact that its turbines had also become de facto “orphaned” (Owner Areva ceased activities and was dismantled, with operations and maintenance (O&M) for the small existing fleet transferred to a Siemens entity).

3.6 Lincs

Name	Lincs
Size	270 MW
Sponsors	DONG, Centrica, Siemens
Turbines	75 Siemens 3.6 MW
Country	UK
Financial Close	June 2012
Debt amount	GBP 425 M
Initial lenders	BNP Paribas, BTMU (now MUFG), DnB Nor, HSBC, KfW Ipex, Lloyds,
	Nordea, Santander, SEB, UniCredit
Key contractors	Siemens, multiple others
Project completion	2013

In parallel to the negotiations for the first financing of Global Tech I, Centrica, and DONG (now Ørsted) were also trying to raise financing for their 270 MW project in the UK. That financing effort, started in 2009, only reached a conclusion in 2012, when construction was already well under way, after painful negotiations between the investors (two utilities) and their project finance lenders. At the heart of the conflict between the two was how to manage construction risk – utilities wanted to do it their way, with minimum interference, but asking banks to bear some of the risk, while lenders wanted more scrutiny and more say on how the contracts were structured. The very different approaches to construction risk were never really reconciled and left a bitter taste to all, with London based bankers and investors saying publicly and wrongly, for several years, that construction risk could not be financed even as their continental colleagues were doing multiple transactions where it was. The “curse” was finally lifted when the Galloper project was financed on a non-recourse basis, with construction risk, in late 2015.

The two different approaches to allocating construction risk both work, but they are largely incompatible and the decision to go for one or another must be taken quite early in the development of the project, as it influences the construction strategy and the negotiation of all corresponding contracts.

4

The offshore wind project cycle

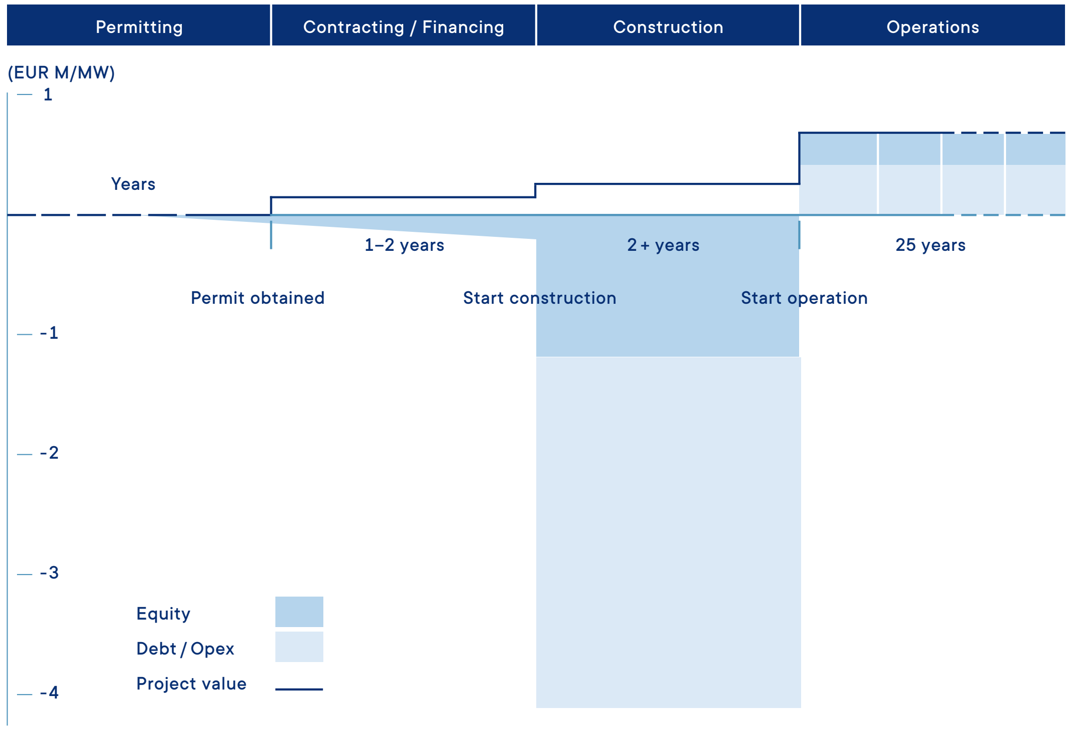
4.1 Project development cycle

Like all large infrastructure and power projects, the development of an offshore wind farm (OWF) includes several phases which are worth describing in detail to identify the important milestones. These milestones correspond to increase in a project's value.

The broader phases in the life of a project are:

→ **Early development** (site identification and control, permits)
→ **Late development** (contract negotiations, financing)
→ **Construction** (installation of foundations, turbines, internal cabling, grid connection)
→ **Operations** (power is generated, the facilities are operated and maintained over 25 years or more)

Project development cycle



*Source: Green Giraffe, "Recent trends in offshore wind finance", April 2019, S11
The first two phases are often called the "development phase", with the project moving to construction when FC or FID is reached

4.2 Early development phase: permitting

This phase requires relatively little capital but is time consuming – typically taking several years. For an OWF, it requires obtaining the following:

→ **Site control**
The right to exclusive use of a defined area at sea (or in a lake), including the right to put an OWF on that location.

→ **Permits**
The full suite of permits making makes it possible to build and operate an OWF. This will include a license to operate, the relevant construction permits, environmental reviews and may include more specific requirements in certain locations (approval by military authorities, shipping authorities, fisheries, certification of the proposed design, etc.) as well as the permits required for onshore works (usually the cable landing and connection to the main grid). These permits can only be considered as final or in place when they are no longer subject to any potential appeals process.

→ **Revenue regime**
Access to some form of price support under the relevant regulatory framework that makes offshore wind economical on such site. This can take the form of a feed-in tariff (FiT), a contract for difference (CfD), a long-term fixed price power purchase agreement (PPA) with the local utility or another party or "green certificates" / renewable obligations (RO). The revenue regime allows a project to be economical given the upfront investment costs and the need to finance or amortise such upfront investment over a long enough period to make the average cost of electricity over the period low enough. For OWF projects, such price support will ideally take the form of a long-term regime which provides pricing visibility over 10 to 20 years; at the very least, the project should have the right to sell production on the wholesale market and get access to the spot price; and

→ **Grid access**
Access to the high voltage grid, whether at the project's location or at an onshore sub-station. Such grid connection may need to be built by the project or by the grid operator and may be subject to a parallel permitting process.

A project with all 4 items above is usually described as "fully permitted."

THE OFFSHORE WIND PROJECT CYCLE

A project generally does not start the contracting and financing phase without being fully permitted or having sufficient comfort that it can achieve that status in a predictable timeframe. The reason is that the above four items are substantially driving the nature and main features of an offshore wind project (such as number of turbines, tip height, maximum generation capacity, siting constraints, etc.), upon which the contracting and financing structures rely.

The cost to get to a fully permitted project would typically be 0.05 – 0.1 M EUR/MW, i.e., in the order of EUR 50 – 100 M assuming a 1,000 MW nameplate capacity. A substantial part of this cost is linked to environmental studies and the geotechnical and geophysical studies, which are required to understand seabed conditions to identify the exact locations for the foundations for the wind turbines and finalise their detailed design. Timing can go from a few years to many years, depending on how settled the permitting process is and whether there is any legal action against the project. The numbers above represent a "best in class" level for projects with experienced developers.

Main risks

→ Delay to permits, or failure to obtain them all
→ Changes in regulatory framework that make the project unviable

Timing and funding required

→ Several years
→ EUR 50 – 100 M for an approximately 1,000 MW project

4.3 Late development phase: contracting and financing

A fully permitted project is not yet ready to be built. In what is traditionally called the "late development phase", the developer must set up the full contractual and financial package to build the project. This involves the negotiation of a number of separate and complex construction contracts.

That number can be anywhere from two to several hundred, depending on how much integration is done at the project level. Utilities will often go for a fairly large number of contracts that they manage in-house through their experienced procurement and project management teams; debt financed projects will typically have only a handful of contracts as banks are not willing to let developers take the project management risk over a large number of contracts. It also requires the negotiation of complex funding documents for equity and debt. Those documents require the preparation of several due diligence reports by external experts, typically for technical matters, legal review, tax, accounting, and insurance issues.

To some extent, this phase can be done in parallel with the previous one, but most counterparties (contractors, investors, lenders) will want to see a project with a high likelihood of being built before they commit negotiation teams and commercial resources. Contractors and lenders will be willing to work with a project that has a permit under appeal if the appeals process is well understood and has a clear maximum period to be settled, or that needs to complete certain studies (also if they are well defined, or cover a pre-agreed period), or where certain regulatory approvals are only provided at a later stage (for instance, in Germany, where the irrevocable commitment by the grid operator to set up a connection to the wind farm is subject to certain construction contracts being signed and financing being in place). But a project still in early stages of permitting, or stuck in unpredictable appeals procedures, or going through that process for the first time in a country, will probably fail to attract the attention of counterparties and will not be able to begin detailed negotiations until fully permitted, let alone receive binding commitments.

Small developers can try to negotiate the construction contracts on their own and then raise equity, and then debt, to fund the project as they have designed it. This has been done successfully by a small number of projects (such as Gemini, Nordergründe and Veja Mate) but there are also a substantial number of developers who have tried this route and failed (examples include MEG 1 – as will be described in a later section – Cape Wind, or Nordergründe and Veja Mate with their previous owners). The alternative is to bring in new investors prior to negotiating the commercial and financial structure, but such transactions typically involve investors that are keen to take charge of these processes altogether, with the original developer keeping a minority stake only (or a milestone-based success fee) and having little influence on the rest of the development. As a result, developers who wish to retain full ownership and control over a project will have to provide their own equity funding.

The development phase ends at "financial close" (FC) for projects with non-recourse debt (or „levered" transactions) or "final investment decision" (FID) in the case of projects without non-recourse debt (or „unlevered" transactions). At that point in time, all construction contracts are signed and effective (i.e., all conditions precedent to their effectiveness have been fulfilled), the financing is signed and irrevocably committed, and construction can start.

This last part of the development phase will typically require spending something in the range of 0.05 – 0.1 M EUR/MW for overall negotiations for a utility-scale project (mainly in advisor fees, some of which can be delayed to financial close) but may require substantially higher commitments from the sponsors if certain long lead items need to be ordered in advance so as to stick to the proposed timetable. For instance, down-payments to order steel, or cable manufacturing, are often required long before financial close. The alternative is to make these orders at financial close only but have the overall construction schedule delayed by a number of months since even a short delay in the availability of foundations or cables can cause the project to miss those available installation windows either because of the weather (most installation activity takes place in the summer when work conditions in the water are easier) or regulatory constraints (limitations on construction activities linked to migratory patterns, nesting periods, or fish spawning areas, for instance).

Main risks

→ Changes in regulatory framework that make the project unviable
→ Inability to negotiate the construction contracts
→ Inability to raise the equity for the full development costs
→ Inability to raise equity and debt for construction

Timing and funding required

→ Several years
→ 0.10 – 0.15 M EUR/MW for pure development expenses (including early development costs), and up to an additional 0.1 M EUR/MW in commitments for long lead items

4.4 Construction phase

At FC/FID, the full amount required to build a project needs to be committed – typically around 2 – 2.5 M EUR/MW nowadays, including the previously spent development costs – but obviously that amount is going to be site specific. That money can be provided by debt and equity (on terms as discussed below) and equity is often provided at that point in time by new parties that did not want to take development risk, but are willing to take fully contracted construction risk, especially if the project has been vetted in parallel by the debt providers, and buy into the project at that moment.

Within the overall budget, FC/FID is the moment where the development premium materialises, i.e., the profit that the developer can earn from completing the development cycle by bringing the project to FC/FID. That premium is the difference between the value of the project accepted by the new investors, and the overall development and construction budget – if positive. That amount can be paid out to the developer (in addition to the reimbursement of actual development costs) at that point in time but is more usually partly subject to full completion of the project. It is determined by the price of acquisition of a stake in the project by new investors, if they enter at that moment, or it is an amount requested by the developer and validated by the banks, if there is no equity transaction. Banks accept to recognize a reasonable market standard premium at that point in time, and to include it in the overall project budget they are funding.

Main risks

→ Construction delays (linked to weather, contractor failure, accidents, etc.)
→ Cost overruns
→ Unavailability of grid connection on the planned date
→ Non-performance of turbines to specs

Timing and funding required

→ Typically, 2 years to complete the project from FC/FID
→ Full construction budget, i.e., 2 – 2.5 M EUR/MW, of which the equity should be fully funded upfront, and the debt committed at FC/FID

4.5 Operations phase

At completion ("commercial operation date", or COD) a project is fully operational and starts generating cash flow at full rate. Many investors are only willing to take operational risk and buy stakes in offshore projects at this point in time (or rather, after a few months of operations once performance is demonstrated). Naturally, return expectations are lower than for investors willing to take construction risk.

Main risks

→ Lower production than expected, due to less wind or lower technical performance
→ Lower prices than planned, for production sold on wholesale markets (this includes the period beyond the original PPA or FiT contract – investors now use a 30 to 35-year operational life to evaluate projects and will need to make assumptions about wholesale power prices to evaluate revenues after the PPA period; given that project debt has always been repaid at that point, these cash flows represent a material portion of the value of the project)
→ More expensive O&M
→ Grid unavailability

Timing and funding required

→ Long term operations for 20 – 30 years (projects in 2011 would typically have assumed a 20-year operational life, but the industry has moved towards 35 years as a standard and some players now even expect that 40 years is achievable)
→ Operating expenses typically represent 20 – 25% of revenues under price regimes that make offshore wind possible. The rest is available for debt service and/or equity remuneration

5

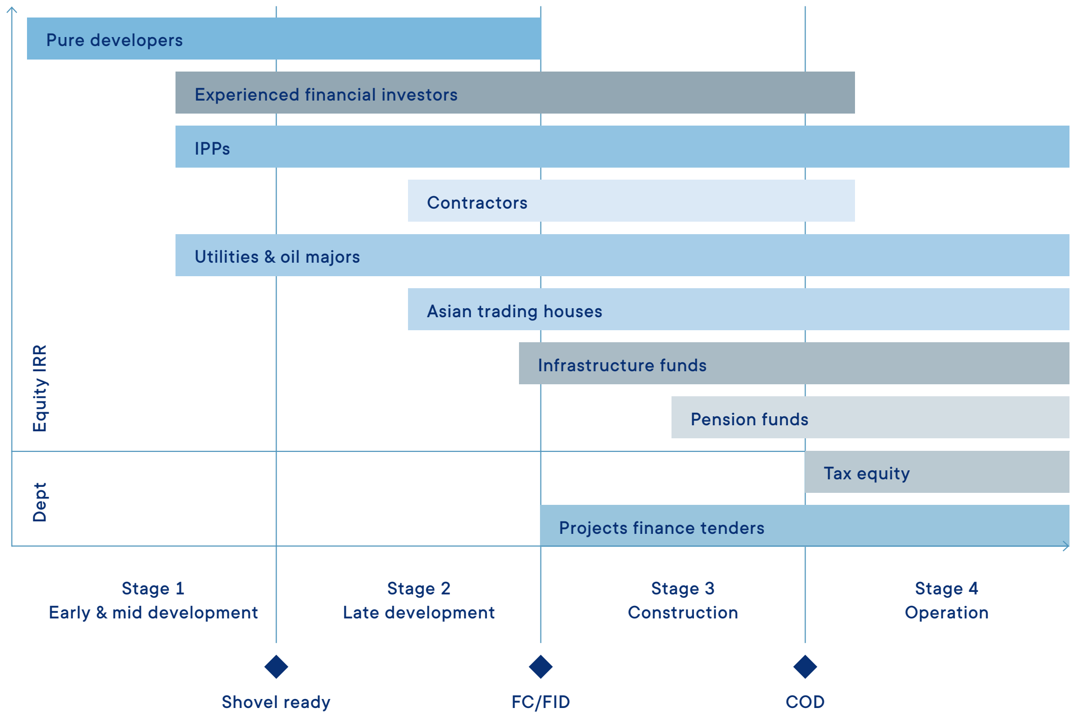
Investors in offshore wind

5.1 Investor profiles

Given the very different profiles of each phase, in terms of time, money to be invested, and risk, investors often focus on different parts of the cycle.

Project development phases and investors

Investor profiles and appetite depending on the stage of development



Source: Green Giraffe, "Recent trends in offshore wind finance", April 2019, S12

→ The most risk adverse investors will only come in when a project is built and operational – they also have the lowest return expectations and offer the most attractive "home" to such capital intensive projects. A minority stake in a recently completed OWF operated by a big utility with a fixed price tariff is the safest possible investment in offshore wind and the equity return expected by such passive investors represents the floor for returns in offshore wind – and any other investment proposal will involve more risk and thus, potentially higher returns.

→ Industrial players are typically involved across the value chain, but will focus on late development and construction, their core areas of competence, and will usually sell down their projects (at least partly) after completion.
→ Smaller developers will focus on the early phases (site identification, permitting, stakeholder management) and tend to sell out once the required investments become larger – so either when they manage to bring projects to the "fully permitted" stage, or at FC/FID.
→ Financial investors can typically be involved at most stages of development; individual players tend to focus on a given phase and sell out as a project moves to the next stage.

Auctions are transforming the development period as in some cases (like in the Netherlands) the winning bids obtain a fully permitted project – but in other countries the development risk remains with the project owners (like in the UK or US), and auction participants closely match the "late development" stage in the graph above.

→ Debt providers ("project finance lenders") never take development risk and only come in at FC/FID – they will negotiate the terms of their participation during the late development period but will only provide funding once the project is fully permitted and all construction contracts are effective.
→ Tax equity providers are a US peculiarity linked to the fact that support for renewable projects has come through tax policy, in the form of tax credits linked to actual production, which can be deducted from profits of the owner. As projects will typically not have taxable income for a long time (as they amortise their initial investment over several years), this can only be captured by otherwise profitable owners, which is not necessarily the case of wind project developers. So, an industry has developed whereby the ownership of the project (at least from a tax perspective) is transferred to profitable parties who can make use of the tax credit and pay the corresponding amount (minus their remuneration) back to the "real" project owners. The tax credit beneficiaries only take operating risk on projects.

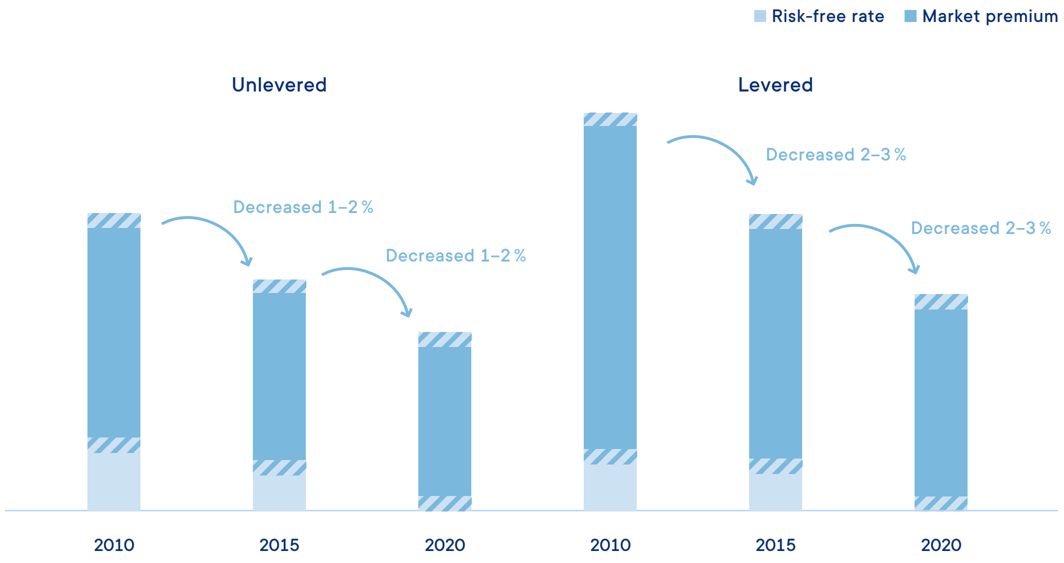
5.2 Equity returns

Expected returns on investment (ROI) have followed a slowly declining trend over the past ten years, with both the underlying long-term rates (unrelated to the industry) and the risk premium for offshore wind going down over the period.

The slow decline in the risk premium reflects the better understanding of the industry by external investors, combined with a solid track record of projects being built largely on time and on budget, and operating as expected or even slightly better overall (at least compared to the expectations, which were prudent to start with but have also become more aggressive over time as said track record has been available).

Return expectations for operational offshore wind farms 2010–2020

Evolution of investor return expectations (2010–2020)



Source: Green Giraffe, "Recent trends in offshore wind finance", April 2019, S13

For parties willing to take more risk than operations, the returns are higher, as discussed in a later section, but have followed the same gentle downwards trend over the years. The extra yield compared to the base operational investment is generally proportionate to the additional risk taken, i.e., the market has been consistent in its pricing of the various risks.

That downwards trend in financing costs is what explains, more than anything else, how the industry was able to bring power prices down and bring the remarkable bid prices mentioned at the beginning of this report.

In a sense, the industry benefits from the fact that it is both inherently risky (construction in an unfavourable location, with multiple contractors that are relatively lesser-known names) and perceived to be risky. This has led to continuous efforts to understand risks, mitigate them, and price them correctly. And in fact, it is a rare project where nothing has gone wrong – and indeed as this is expected, what matters to lenders and investors is the ability to react to incidents and prevent them from leading to actual serious delays or cost overruns.

6

Risk analysis

6.1 “Normal” infrastructure / structured finance risks

Offshore wind project finance presents 3 categories of risks

→ Those that are common to all infrastructure projects (regulatory, macro-economic)
→ Those that are common with other wind projects
→ Those that are specific to offshore, during construction and operations

The first category of risks applies to all sectors that use non-recourse financing and more generally attract infrastructure investors like specialised funds. That means that these risks are well known to financiers and thus well understood.

6.1.1 Political risk

Political risk is, broadly speaking, the risk of regulators or legislators changing the rules that apply to a project once the investment has been made, or even during its development phase, with an adverse impact on its ability to repay its debts or turn a profit. That can include changes in taxation or regulations that apply to the sector or to the project specifically, and macro-economic policy decisions such as restrictions on currency exchange or cross-border capital movements.

In project finance, political risk is usually associated with oil & gas or mining projects in emerging markets, where big infrastructure projects can have a material impact on the overall economy of the country and are thus negotiated at the highest levels of power of the country, with the corresponding potential for arbitrary decisions. In these countries, investors like the big oil majors typically bring in lenders to share that risk, and in particular, they bring multi-lateral lenders and ECAs, who usually have deeper relationships with these countries, and specific tools to mitigate political risk. Commercial lenders usually take a relatively small portion of the risk alongside the public lenders, but they assess it carefully.

It may seem a bit strange to compare such emerging market projects to wind projects, but the reality is that renewable energy projects, like all infrastructure projects, heavily depend on the applicable regulatory framework, and any change to the rules can have an impact. And the projects have the same financial profile, which is to see most of the investment done upfront, with operations showing large gross operating profit before debt repayment. Such cash flows always constitute a tempting target for governments that are looking for new funding. In the case of renewables, and as opposed to oil & gas or mining projects which rely on exporting the production to the global market, the revenues are generated locally, creating additional macroeconomic risks, like inflation or reduced demand, which can translate into lower revenues (if funds need to be converted from the local currency into dollars or euros).

The risk was specifically acute in the early days of the sector, when projects relied on tariffs that were clearly out of the market and needed these subsidised tariffs to repay their debts. The question was whether such tariffs were sustainable both politically and economically for the country.

As it were, there have been a number of countries, in particular after the financial crisis of 2008, that took retroactive decisions with respect to renewable energy tariffs (to reduce them), forcing a number of projects into bankruptcy or at least serious financial stress. So, the risk certainly exists.

The risk is also acute during the development phase, when investments are not fully committed but developers are making efforts (and spending money) to make their projects viable – by identifying suitable sites, running the relevant environmental studies, and submitting permit applications. If the rules change during that period (to give a simple and real example: rules on the minimum distance between a turbine and a house, onshore, or between a turbine and navigations lanes, offshore), some sites may no longer be viable and earlier development efforts will have been lost.

Developers, investors, and lenders understand these risks, and behave accordingly. That means, for instance, avoiding countries that have a history of decisions detrimental to existing assets and preferring those that have predictable and stable regulatory frameworks; it can mean avoiding projects that offer too high remunerations (because they are not economically justified nor politically sustainable, and have a higher chance of triggering a backlash and adverse decisions later on), and it also means that countries perceived as less predictable will suffer a discount in the form of higher interest rates or higher expected returns on capital invested.

It is important to note here that lenders in particular do not like tariff regimes that are too far out of the market, unless there is a really strong strategic justification for these, and subsidised projects are seen as inherently riskier than projects that have a price regime close to what market prices are.

Similarly, while lenders do not take development and permitting risk (they will only provide funding once all permits and licenses have been granted without risk of appeal), they are sensitive to the transparency and professionalism of the process – a permit that has been granted by an arbitrary decision of a minister can be revoked just as easily and would be seen as less valuable than a permit that has been granted following explicit or regular procedures that provide stakeholder involvement. This can be relevant in countries where offshore wind is a nascent industry and the overall vetting and permitting process has not been fully defined and may be subject to jockeying by various domestic bodies, such as those responsible for aviation, fisheries, navigation, the military, industry, and many others. A stabilised permitting and supervisory regime is essential for an investment that will take 20+ years to be repaid.

Overall, this is a critical risk for investors and lenders, and one which is always closely assessed.

RISK ANALYSIS

6.1.2 Commodity price (merchant) risk

“Merchant” is the term used to describe price risk on the sale of electricity on the wholesale market. For offshore wind projects, there is also an element of commodity price risk with respect to steel and copper as projects use substantial quantities of these, as well as, prior to FC/FID, risk on the interest rates that will apply. Even when projects have power price regimes set by regulation, there is an element of merchant risk – at least for the period beyond the regulated tariff (which is relevant for investors and to a lesser extent for lenders when the tenor of debt is longer than the tariff) but also during the regulated period – for instance it is possible for projects to sell their production on the spot market if prices are higher than the regulated tariff. It is obviously even more relevant for projects that are developed without a long-term tariff regime.

Investors and lenders are familiar with merchant risk in that they have long taken price risk for gas fuelled projects, and as we have seen, there is a close link between power prices and gas prices (even as the difference between the two, known as the “sparkspread” is closely watched). The economics of these gas projects are very different, they don’t produce if they are not competitive, and their running costs are otherwise relatively low, but the requirement to have an opinion on future power prices is the same.

This is not a risk that either investors or lenders like much (power prices can be very volatile and stay away from expectations for long periods) so they try to be careful about how much of the risk they will take: this is typically done by taking fairly low price assumptions, or requiring high returns on capital to take more risk, or whenever possible, by transferring the risk to a third party via long-term PPAs with price formulas that typically offer a minimum price and thus, guarantee some minimum revenues.

The unavoidable consequence is that merchant risk translates into less debt (as lower revenues are considered to calculate the amount that can be safely repaid), more expensive equity (as it receives more volatile income) and overall, more expensive capital. Even when a PPA can be procured, this is seen as riskier than a fixed price regime, as the contract creates counterparty risk and potentially mismatches between the profile of generation sold and what is actually produced. For capital-intensive projects like renewables, it means that the cost of electricity produced is higher. It is actually a sign of how far renewable energy production costs have fallen that these projects can now be built on a merchant basis in some countries.

For offshore wind, the volumes they are generating (several TWh per year for a typical utility scale project) means that it is difficult to find PPAs for their full production volumes and thus, merchant projects remain a questionable proposition, and the industry is now lobbying hard to avoid these as much as possible and have access to long-term price regimes that afford price stability, even if the prices are very low.

This is one of the key risks for projects and is treated as such by financiers.

6.1.3 Counterparty risk

The final traditional risk is borne on the third-party stakeholders in the projects. Construction contractors, suppliers, electricity off takers all make industrial and financial commitments towards the project, and these can be endangered if the company fails – or the guarantees backing these commitments can become void if the relevant company is unable to back them. Any stakeholder going bankrupt is a risk for the project – at the very least a source of delays and potential new costs to solve the problem if it appears. Evaluating the financial strength of project parties is a core competence of banks and investors, and it is as relevant for renewable projects as it is for other sectors.

Indeed, it may even be more critical for several reasons

→ Certain project components are highly specialised, or manufactured specifically for the project (for instance, turbine foundations are each individually designed for their specific location) and may not be easily replaceable.
→ Given the requirement to build turbines in a specific order, bringing a very different supplier is a delicate dance. A failure to manufacture or install one of the components can have knock-on effects on the rest of the installation schedule and severely delay the project – and can cause cost overruns as other suppliers need to have their own deliveries delayed.
→ As a relatively new industry, it has tended to rely on suppliers that have often been smaller and less tested companies, without the strong balance sheet of contractors in other sectors. There have indeed been multiple failures of key suppliers over recent years, sometimes during the construction of projects, and these have led to serious complications for projects.

This is a risk that banks understand and try to cater for as much as possible in the financial structuring of projects, and they can impose quite strict requirements on projects and on the contracts that are negotiated, for instance by including financial guarantees backed by the contractor's banks, by asking the project to identify alternative suppliers (and, in the most critical cases, to procure options for such alternatives as back up plans).

This is a risk that is always carefully monitored by investors and lenders.

Example – the Senvion bankruptcy

Senvion, the German turbine manufacturer, went bankrupt in 2019. This had an impact on multiple wind projects across the globe, in particular for those that had reached FC/FID, made down payments to the contractor, but had not seen the turbines built yet. For projects with operational turbines, it created mostly short-term disruption as Senvion's role as operator was taken over by Siemens Gamesa and the existing long term maintenance contracts could be taken over.

In offshore wind, where Senvion was involved in a handful of projects, it generated massive roadblocks on several projects, and in particular on two that were project financed: C-Power (already in operations), and TWB II (under construction).

C-Power benefitted from a long-term O&M contract, which suddenly became void, and had to build new operations set up that made economic sense and could be accepted by the lenders. That meant contracting directly with a number of core sub-contractors (more than 20) of Senvion to ensure continuity of supply and services, and build a team to take over the tasks and coordination previously done by Senvion – and get the banks to validate the new setup.

TWB II was in an even tougher situation, as the bankruptcy happened in the middle of construction, with some turbines delivered but not installed, and others not yet manufactured – but paid for to a significant extent. The only way forward was for the project to take over the installation of the turbines and enter into direct relationships with suppliers for them to continue to provide components, while entering a new contract with the now-under-administration Senvion entity to perform the actual turbine assembly (but without the guarantees that were previously included in the contract and could no longer be provided by the bankrupt entity) using the components supplied under now–separate contracts.

This was made possible by "step–in" rights in the existing contracts (that precisely allow the project to enter into direct relations with key suppliers in such circumstances) and other contractual features, including the contingency budgets and buffers in the project financing that allow to survive the unavoidable chaos and delays that such an event can cause.

In both cases, the project successfully navigated the bankruptcy, with the support – and ultimate approval – of the banks during the negotiations, but this was time consuming and complex to manage.

6.2 Wind sector risks

Wind sector related risks include the uncertainty on wind measurements and production estimates, and the risk on new technology as projects tend to want to use the most recent turbine models.

6.2.1 Wind estimates

Electricity production estimates – as well as estimates of the likely seasonality and variability of such production – are obviously a critical aspect of the economics of a project, and these depend for the most part on the wind measurements made onsite or near the site. It turned out a few years ago that production estimates for onshore sites had been structurally over estimated by technical experts (to the tune of 8 – 10 %) and banks and investors had to deal with projects that were generating quite a bit less of electricity than expected and have been even more sensitive to the topic since that.

The good news is that wind speeds at sea are a lot easier to measure than onshore, as the surrounding area is completely flat and does not have obstacles like hills, trees, etc., that complicate wind patterns, and estimates made to date on offshore projects have proven to be quite accurate. The further good news is that it is possible to use different methodologies such as "mesoscale models" using atmospheric data (as the US National Oceanographic and Atmospheric Administration (NOAA) provides) or interpolation from existing meteorological masts, even if they are some distance away, and combine them to reduce overall uncertainty. Investors and financiers are thus quite comfortable with estimates made by reputable experts.

One point of attention has been the "wake effect" and associated "blockage effect" i.e., the fact that turbines situated behind other turbines in the prevailing wind direction tend to have lower output. On a windfarm level, the impact on net production can reach 10 – 15 % of the gross number, so it is a significant factor and projects rightfully spend a lot of effort to try to optimize site layout so as to minimise this effect. From the banks' perspective, this effect is also correctly estimated by experts, so it is not a source of uncertainty as long as it is taken into account from the start.

Overall, the estimate of the wind resource for offshore wind projects is seen as a low risk by financiers.

RISK ANALYSIS

6.2.2 Wind turbine technology

Wind turbines are relatively mature technology – large mechanical and electrical equipment, with mostly incremental improvements but putting them offshore has created new challenges as there is a specific additional requirement for reliability, as you cannot simply drive down to the turbine and replace a component in case of failure. The quest for size as a way to reduce costs has also meant that new industrial processes have become necessary to test and manufacture components at a scale never seen before (such as 100+ meter blades, or multi-hundred ton nacelles that need to be transported to site and installed at 100+ meter heights).

With projects keen to use the most recent and largest turbine models, it has also meant that offshore wind projects often use relatively untested products, without a long track record of use at sea.

Lenders have nevertheless been quite relaxed about that risk, thanks to a methodology that was applied on the early projects with independent experts to assess turbine design, testing procedures and expected performance. The fact that offshore wind turbines have been manufactured by a relatively small number of players (never more than 3 – 4 at any point in time, in fact) has helped by creating a relatively small universe of players that have shown their commitment to the sector and "stood by" their turbines when technical issues were identified.

Lenders understand that all turbines will experience teething problems and know that these will be solved by the turbine manufacturers – and they trust those that have had problems and have been transparent about what happened and how they solved it. Financiers do expect strong contractual commitments by turbine manufacturers through warranties, availability guarantees over long period of operation (up to 20 years), and a commitment to repair their equipment. And as this is what has happened since the early projects in 2002 – 2005, the manufacturers have strong credibility on that front and are trusted for any new turbine they bring to production. Conversely this would not apply to newcomers, and it seems unlikely that Chinese manufacturers will be seen as credible parties in the foreseeable future without first demonstrating the same commitment in a consistent and transparent manner, towards banks at least.

Technology risk is thus considered low, provided that the right processes are followed.

6.3 Offshore wind specific risks

Wind sector related risks include the uncertainty on wind measurements and production estimates, and the risk on new technology as projects tend to want to use the most recent turbine models.

6.3.1 Construction risk

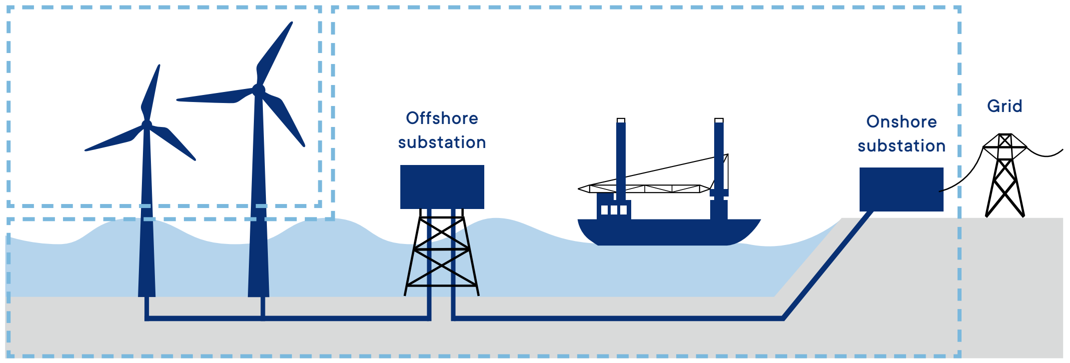
Construction risk is seen as the critical risk for the sector, with the lenders specifically asked to bear that risk and thus required to understand it and price it correctly. Construction of offshore requires the participation of very different contractors, starting with turbine suppliers and marine contractors, and including suppliers of foundations, cables, and other equipment. This means many physical and potential commercial interfaces which need to be managed, and that has led lenders to follow several strategies to mitigate such risk:

Reduced number of contracts

The first one has been to try to limit the number of contracts as much as possible and make such interfaces internal to the scope of broader contracts and thus the responsibility in the first place of the corresponding contractor. Items that can be bundled together can be the procurement and installation of part of the wind farm (such as foundations, or cables, or turbines); or the successive installation of various items (by having a single marine contractor in charge of all installation, for instance). The industry has been able to converge on a typical number of contracts ranging from two to eight, focusing on the four major "packages" (turbines, foundations, cables, and sub-station), with their procurement and installation regrouped in various ways. Turbine supply is always a separate contract, given how critical it is to the performance of the project (and it is typically linked to a long-term O&M contract), but everything else can be bundled into a "balance of plant" contract, usually with a marine contractor, covering procurement of all other equipment and installation of everything.

In Germany, having four separate contracts for the design, procurement, and installation of each of the packages has been a fairly traditional structure as well, with installation of some of these sometimes treated as separate contracts.

Two-contract structure



Source: Green Giraffe, "Recent trends in offshore wind finance", April 2019, S8

Four EPCI contract structure

Turbine	Foundations	Cables	Substation
Design	Design	Design	Design
Engineering	Engineering	Engineering	Engineering
Fabrication	Fabrication	Fabrication	Fabrication
Installation	Installation	Installation	Installation
Turbine EPCI	**Foundation EPCI**	**Cable EPCI**	**Substation EPCI**

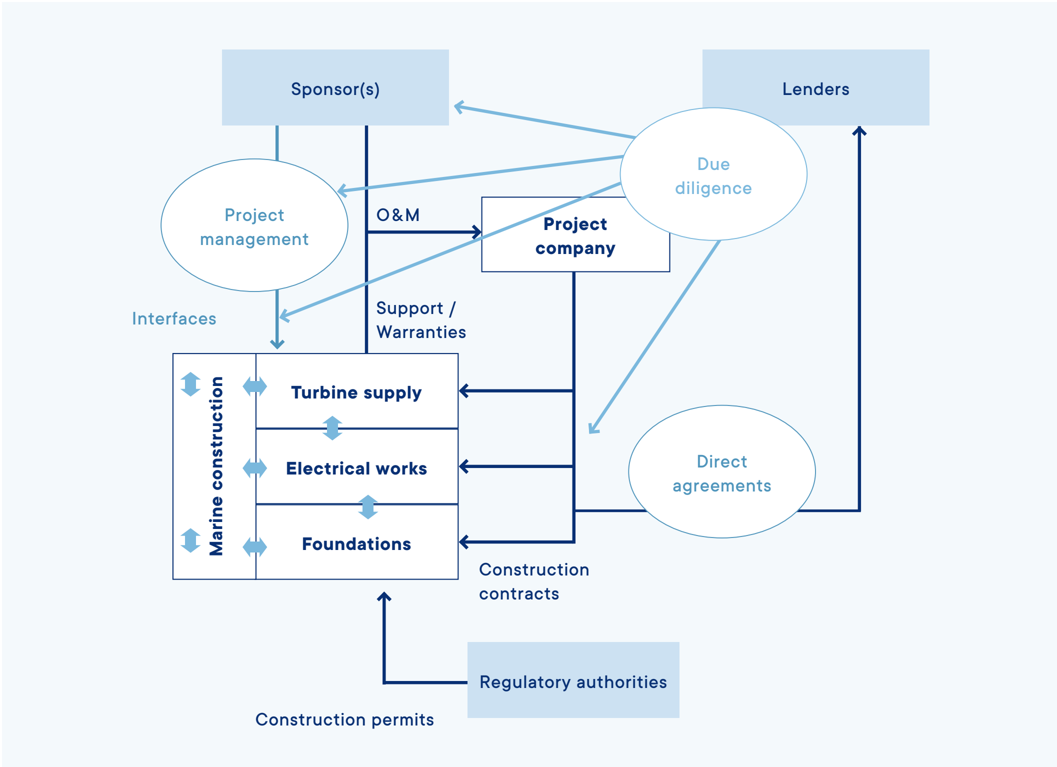
Source: Green Giraffe, "Recent trends in offshore wind finance", April 2019, S8

The advantage of broad contracts is that the counterparty takes contractual responsibility to manage the technical interfaces (and contractual ones with their sub-contractors) and make commitments to that respect, with (i) an obligation to perform the works to the standard agreed, with warranties in case of failure, and (ii) penalties in case of delays (including for quality problems) as penalties are typically expressed as a percentage of the value of the underlying contract, the absolute amount that can be triggered in case of problems is larger, if the contract amount is larger (and this does make a difference in a set up where multiple contractors and sub-contractors are on the "critical path" – i.e., delay caused by any one of these triggers domino-effect delays on subsequent tasks – problems caused under a small contract will only trigger small penalties even if they slow down the whole construction).

Project management

The second has been to focus on project management skills by ensuring that the project team had enough experience to manage the contractors and ensure that they did their work without mishaps, and with as much coordination between them as possible. This means having experience managing the key contractors, understanding the project tasks inside out (even when they are within the scope of contractors), and understanding what backup plans can be used in any circumstance. People that have actually done it before have a real edge and the industry has wisely tended to allocate project leadership roles to people that had done it before – or were closely involved – on previous offshore wind projects. The core teams can be quite small.

Construction risk mitigants



Source: Green Giraffe, The different options to finance offshore wind, May 2012

Transparency

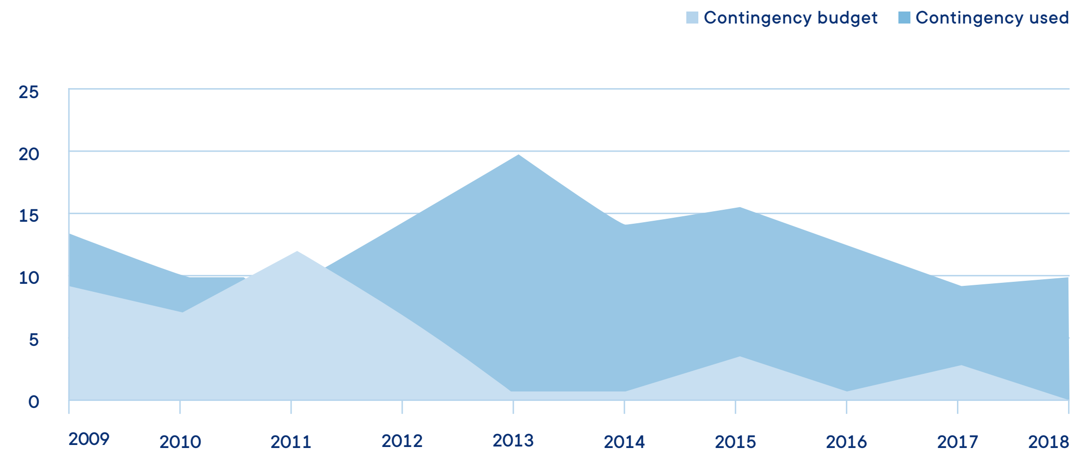
The third has been to push for maximum transparency across all items – contractors are expected to provide visibility about their sub-contractors and how they manage the interfaces within their scope; contractors are kept informed of overall progress of work of the project and can adapt their own work more easily as a result (such as managing the exact timing of their work better); explicit handover procedures between contractors are negotiated and made transparent so that, even if two contractors do not have a direct commercial relationship, they can coordinate their work better, and so forth. This also applies to the "due diligence" – that design is sound, that budgets and timing are realistic, and that warranties and palliatives are adequate.

Contingency planning

Further, the banks rely on the availability of additional funding (and time buffers) in the form of contingent funding. These are funds that the project owners do not expect to have to spend, but which are available in case of delays or other unexpected problems, in addition to the guarantees provided by the contractors, and do not require a new funding decision by either the owners or the lenders to be made available – they are part of the budget.

Contingency budgets, as allocated and spent (year indicates date of FC/FID)

Offshore wind PF projects – Contingency budgeted an used



Source: author calculations

The track record of projects that have been built with non-recourse debt funding shows that, up to now, most projects have been built within the contingency budget allocated. The one exception happened when the first generation of German projects (all financed in 2010–11) bumped against the same problem: the delay by TenneT, the grid operator, in building the offshore grid connections, as a result of technical difficulties with the HVDC cables and sub-stations. The direct current technology allows to transmit power over long distances with smaller losses, but it is more complex and less rarely used than alternative current (AC) cables, and the requirement to build several connections in the same year proved to be more difficult than expected. That meant that the projects which relied on such grid connections found themselves stranded and either had to delay the construction of the project or the commissioning of the turbines already installed. The delays had a cost, which together with the other 'normal' problems the projects faced, meant that they exhausted their available funding. The sponsors chose to provide additional funding to keep the projects on track – funds that they eventually recovered, as TenneT owed the projects compensation for the delays (following these delays, the law was changed to make the compensation amounts explicit and unambiguous).

The good news is that lenders and investors saw these problems as things that could be solved without destroying the long-term economics of the projects, and lessons were learnt along the way as to how to deal with such situations. As the graph shows, this led to a temporary increase in the contingency budgets required for new projects, but these trended back to the 10% budget that seems to be the standard the market has converged to, even as actual funds needed have fallen to very low levels in recent years. Recent difficulties with projects in Taiwan (not visible yet on the graph above) suggest that new markets need to learn some of the same lessons in how to build projects and to face higher contingency spending in the beginning.

Insurance

Finally, the lenders tend to require an insurance package (to cover accidents and "acts of God") which is more extensive than investors (particularly utilities which tend to self-insure) typically purchase. In particular, lenders will expect to see "contingent business interruption" coverage i.e., insurance for lost revenue for events caused by third parties (like the cable connection not made available by the grid, or damaged for any reason). That has a cost, which is considered worthwhile as it allows to increase the volume of cheap debt funding.

Part of the risk of building at sea is the weather risk – i.e., the risk that wind, wave, or other local site conditions do not allow for work to be performed. In principle, that risk can be assessed statistically, on the basis of past weather patterns, and can be mitigated by planning for central, best case and worst-case weather scenarios. The industry uses "P10", "P50" and "P90" numbers representing the scenarios that have a 10% chance of happening (aggressive planning), respectively 50% (central scenario) and 90% (conservative scenario). The P90 scenario requires more time for construction as

vessels and equipment must wait longer for the relevant weather windows when work can be done, and this is typically the reference scenario for the lenders, which are more conservative and want a high probability that the budget will be met. Given that vessels are usually contracted out based on daily rates, there is an additional cost in booking the option to use them for the longer period, which may not be necessary.

As this is quite predictable statistical risk, there are various ways to carry that risk – the project can keep it (planning for a P50 or even P10 scenario but agreeing to pay the difference if it takes longer), it can be passed on to contractors (by paying for a fixed price which is above the P50 cost but below the P90 cost – the contractor can then decide on how to optimise installation, or take insurance for the weather risk), or it can be insured. Lenders care that the budget for the worst scenarios is available in any case, but do not mind if some of it is included in the contingent budget (usually, as a well identified amount) rather than the base budget.

Altogether this means that lenders impose quite a lot of scrutiny and constraints on the construction contracts, and require a lot of scenario planning to test, sometimes to extremes, all possible outcomes. Monte-Carlo simulations (where thousands of scenarios are tested to see the full range of outcomes and assess their probabilities) are typically required to be run with the help of independent technical advisors. A lot of these scenarios are extreme and unrealistic, but the mere fact of asking "what if this or that happened?" sometimes help ensure that simple backup solutions are available, just in case – and these can end up helping in other, unexpected, circumstances. Identified risks are rated according to (i) probability of happening, and (ii) impact in case it happens, and risk mitigation naturally focuses on ensuring that those with a "high" or "medium" rating for both items can be fully avoided or absorbed. Low probability, high impact risks should be insured, and high probability, low impact items need to be incorporated and managed as part of the construction process.

While effective, this level of intrusion is not acceptable to all investors, and in practice, offshore wind developers need to decide early on if they will internalise construction risk (in which case they can manage contracts and project management on their own and avoid external scrutiny) or if they want third party debt, in which case they need to accept some level of "backseat driving" in how they run the project. This has led to two quite different routes to managing constructions of offshore wind projects, each with its pitfalls and advantages. While the market is "lumpy", both routes typically represent half of the projects to be built, on average.

As shown above, the track record of project financed wind farms, for which there is more available data, is quite excellent overall, in line with the EY study mentioned in the beginning of the report.

6.3.2 Operation risk

Operation risk is the risk that the project ends up producing less electricity than expected or requires more (and more expensive) maintenance to perform.

This is not about the wind risk, nor the technology risk per se, but the wider combination of performance at sea, ability for the O&M teams to intervene when required, and any unexpected losses or costs to be incurred by the project.

The harsh reality is that most projects and turbine models have to face “teething problems” – technical issues that appear in the early days of operation and require some level of intervention. It can be faulty equipment, sub components that were not correctly installed and break down and need to be replaced, or serial defects (identical problems appearing on multiple turbines) of varying magnitude that require a more extensive campaign of intervention.

The industry has a good record of dealing with these issues. They have not been costless, but they have all been solved with responsibility and funding shared between the project owners, contractors, and insurance companies, when possible. Most turbines and most projects perform at very high levels of technical availability within 2 years of installation and often much earlier. The serial nature of the power plants, and the fact that the installation of wind turbines is largely done sequentially allows to learn lessons from the early turbines and anticipate problems in subsequent turbines (for instance doing any replacement of identified faulty parts onshore, before the turbines are actually installed).

Some projects had severe serial defects on major components like the main axis or the gear box (which require a large installation ship to replace the part) and, in the worst case known to the industry, the lowest availability measured over a 12 month period was 50–55%, and that is the standard of under performance that lenders want projects to be able to withstand for at least one year while still managing to service their debt. This is done by a combination of the natural buffer used in debt sizing (more revenues are expected than just the funds required to service debt), warranty payments by the turbine manufacturers (they typically guarantee an availability level of 90–95% with a contractual commitment to pay for the lost revenue if turbine performance is below that level without an excusable reason) and reserve accounts.

Lenders have shown strong trust in the industry even when severe problems appeared, and the problems have indeed been solved without any project going into insolvency or administration. More positively, a recent project in Germany was financed by lenders even though the turbine selected by the project was experiencing a major serial defect on a key component on existing projects (which the banks had financed and thus were aware of). The turbine manufacturer was able to convince both its clients and the lenders that it had a plan, involving a partial redesign of the turbine for the new project, a fix for the turbines not yet installed on existing projects under construction, as well as a replacement campaign for the turbines already at sea on operating projects, with a budget and a timetable. This was deemed solid enough to allow the new project to go ahead with that upgraded turbine.

A good part of the solution always involves the turbine manufacturer and long-term commitments from them backed by financial warranties. It is telling that on the early projects, the manufacturers were wary of offering such long-term “all inclusive” contracts, as they themselves were not completely sure of the long-term performance of their machines at sea, since there was so little track record beyond a few years. After agreeing to do so for the first projects to be financed (under strong pressure from the lenders, who said they would not finance the projects, and thus the turbine supply contracts), they realised that such long-term contracts, typically with pre-agreed prices, were actually quite advantageous to them, as (i) the performance of the turbines was even better than they warranted, and (ii) the cost for them of maintaining them was lower than the price the projects agreed to pay, and was actually on a downward trend, making these long-term contracts quite attractive. So, they began to offer them quite spontaneously to projects, which made them easier to finance. Naturally, investors started negotiating the price of these contracts more carefully as well, and occasionally pushing back the banks’ requirement for such long-term contracts.

Altogether, the performance of European OWFs has been consistently strong, with availability numbers above 95% for most turbine models, and no surprises on the O&M cost side. Most of the incidents that have taken place in offshore wind tend to have been insurable events (for instance a cable damaged by the anchor of a vessel) with limited direct cost repercussions for project investors or lenders. The insurance market has had to bear a number of events but so far insurers have continued to accept to provide relatively standard coverage to projects on competitive terms.

Overall, as the EY report flagged upfront, and as was noted by investors and lenders, offshore wind has been quite a successful story on both the construction and operation fronts, and this has made it a very attractive asset class, leading to increasing competition amongst financial players and thus more attractive term for both debt and equity.

This is what has led to lower financing costs, as well as lower contingency budgets, both at the project level and within contractors’ scopes, bringing about reduced budgets.

7

Current market structures and terms

7.1 Balance sheet construction

7.1.1 Utility investors

Under this strategy, investors (usually the leading utilities in the sector) keep the construction risk on their books but finance or refinance the project by bringing in passive third-party investors who take the long-term operation risk. Such third-party financing can take place before construction is actually completed, with the support of construction guarantees provided by the leading investor and can include non-recourse debt funding for that third party (what is called “Hold co. financing”, as described below).

The core principles of this strategy are for the utility leading the project to keep full control over construction, with minimal interference from outsiders like lenders, and consolidate the project revenues (and generation capacity) on their books, while gaining access to cheaper long-term capital to improve the overall economics of the project.

The utilities take the final investment decision (FID) on their own, without depending on external funding, but they will typically anticipate the terms of such funding in their business planning. The sale of a stake in the project will typically take place either after completion or after FID (in that case, including completion guarantees). Such stake is typically 50% minus one share, so that the utility can keep control and consolidate.

Utilities selling minority stakes

DONG (now Ørsted) pioneered the sale of non-controlling stakes (typically 49%, or 50% minus one share) in their offshore wind projects and have made it a systematic strategy. By keeping a controlling stake, they can consolidate the projects in their accounts, and be credited the full generation capacity while recycling some of the capital invested in the projects. By selling operating projects (or, if not yet built, selling them with a completion guarantee), they can attract cheaper capital and obtain a better price for the asset than it cost them to build it. For instance, in 2016, they sold 50% of the 258 MW Burbo Bank expansion project, a project benefitting from a government-set power price (via a CfD) at a level of 150 GBP/MWh, to LEGO and PKA for a price of GBP 660 M. That represents a value of 5.1 M GBP/MW, when construction costs at the time were typically in the 3 M GBP/MW (i.e., they would have built the full project for something around GBP 800 M), thus creating a substantial profit. The high purchase price was driven by the nature of the asset, generating highly predictable revenues (without volume or price risk, and limited operational risk) for a long time, which made it very attractive to pension funds and similar long-term investors.

A few months afterwards, Ørsted bid a price of 72.7 EUR/MWh for the Borssele project in the Netherlands. One of the key reasons it was able to bid such a record-low price (at the time) was by giving up the windfall profits made possible by the sale of projects with high tariffs set by governments, and identifying the tariff that still would allow to build the project, and sell half of it to a risk-adverse investor at a "normal" price (i.e., the investors would still pay a good price for very low risk long-term revenues, but as the absolute level of revenue generated would be lower, the net price per MW would be correspondingly lower). Ørsted sold half of Borssele 1 2 in 2020 to Norges at a price of 3.6 M EUR/MW. (Note that price is higher than it would have been in 2016 for the same asset, as risk perception went down in the meantime, and the equity return requirements of investors similarly went down, allowing them to bid more for the same kind of cashflows. If the project had benefitted from a tariff similar to Burbo, it would certainly have sold for more than double the price). The sale is still useful for Ørsted, as the cost of capital of the new investors is lower than its own, and thus they value the project's cashflows more than Ørsted, but the difference between the price at what it could have sold the project if it had had a high tariff and the price they actually received was converted into a lower tariff. Ørsted was able to reduce the tariff level at which the project was still profitable for them, taking into account the low cost of capital for half the project, the requisite return on capital for their own half of the project, ancillary revenues linked to their role as operator of the asset, and the actual construction costs. As the numbers show, the mere fact of having an auction for the tariff instead of a pre-set price led to the disappearance of such windfall profits.

7.1.2 Holdco financings

The buyers will typically be financial investors who either invest the full amount directly or use a combination of equity and debt raised at the investment vehicle level and not at the project level.

Under holdco financings, lenders do not have direct access to project revenues and contracts, so they cannot take the kind of security that they usually enjoy when lending directly to the project, such as rights or mortgages over project contracts and assets. Nevertheless, given the fact that the project company is almost always an entity that only owns and operates the one asset, being the wind farm, and distributes its incomes to the maximum extent to its shareholders, lenders generally accept that they bear a fairly similar economic risk as if they were lending directly.

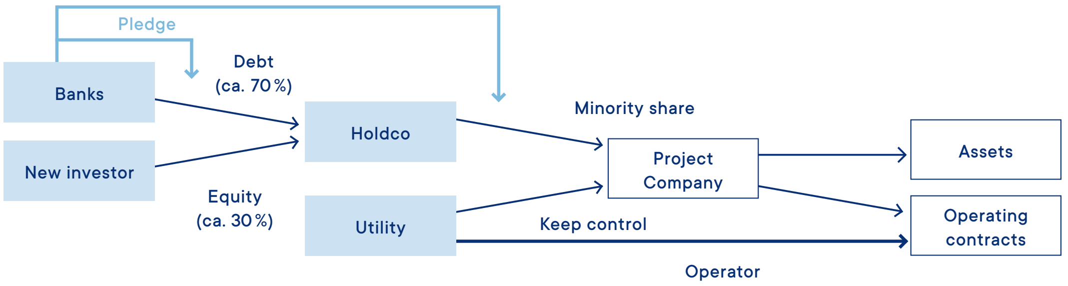
They have security on the shares of the new owner in the project and typically ask for a "direct agreement" with the operator utility, i.e., a contractual relationship whereby that utility provides a certain number of commitments as to its behaviour as an owner and as the operator of the project that gives comfort that the project will be run in a sensible and fair way (for instance, if the utility

provides O&M services to the project, which is usually the case, that contract and any subsequent modifications would be subject to the agreement of the lenders to ensure that it is done on an "arms' length basis" i.e., that the utility provides a competitive price for its services and does not use that contract to siphon a larger fraction of the income of the project than warranted).

So, in practice, in the absence of construction risk and in the context of projects operated by strong experienced parties, the terms for such hold co. debt facilities have been very similar to those provided as direct refinancing of operating assets, as presented below.

The advantage of a hold co. structure for the operating utility is that they can still consolidate the generation capacity and assets of the project without having to consolidate the debt. It also allows them to tap a larger universe of buyers, and potentially find a better price (if the average cost of capital of the buyer, taking into account the debt component, is lower than that of a buyer that does not use non-recourse debt).

Holdco non-recourse financing structure



Source: Jérôme Guillet

7.1.3 Equity returns

Investing in an already built OWF with a long-term tariff and a major utility as the key shareholder and operator is the least risky option in the sector, and risk adverse financial investors have typically looked at such assets to enter the sector and have compared the returns they offer to whatever else they could invest in – so the IRR requirement for such an investment (without debt) is the benchmark for the sector (to which more riskier opportunities within the sector like bearing construction risk, or including leverage, are compared) and it is also a number which provides an external benchmarking of the risk and attractiveness of the sector compared to other investment opportunities (whether similar like infrastructure assets, or any other like equities, bonds, commodities, etc.).

As noted earlier in the construction and operation phases section, this benchmark IRR has gently gone done over time, and today it is considered that it is in the 5–6% range for unlevered investment (i.e., without debt). From that number, the returns expected for riskier assets in the sector, whose additional premium has also shrunk gently over time, can be seen in the table below.

Return expectation for offshore projects at various stages

Investment	Expected Return
Operating wind farm with an experienced operator	5% unlevered
Operating wind farm with an experienced operator, holdco levered structure	7% levered
Construction risk (construction period only)	8–9% levered
Late development (permitted projects)	12–15% (no debt yet)
Early development	20–25% (no debt yet)

Source: Author's estimate

The numbers above are naturally quite meaningless without understanding what the key underlying assumptions are, and what "standard" set of assumptions is used. Some categories of investors seek lower or higher return than those mentioned above but will correspondingly use more conservative (respectively more aggressive) assumptions to calculate future cashflows. Amongst assumptions that can influence things, one can note the duration of the asset, operational performance (availability levels, technical losses), wind resource used (P50, P75, P90), debt terms, long-term power prices, evolution of operating costs and insurance costs, etc. It is important to harmonize those to compare return expectations properly.

7.1.4 Debt refinancings

Projects that are built on balance sheet can be refinanced with debt. As noted above, this is often done only for the part of the project owned by new investors via a hold co. financing, but it can also be done at project level. At that point, lenders are much less stringent in terms of requirements on the contracts and due diligence, so typically the main issue is one of consolidation – industrial investors that consolidate the projects would need to consolidate the debt as well, and they typically try to avoid that. But some projects are owned by consortia where no party has an outright majority or control, and in that case consolidation issues are much less relevant. The terms for such debt financings are essentially similar to those for project re financings after an original non recourse financing.

7.2 Project finance construction

Under this strategy, debt is provided prior to construction and banks take construction risk fully – project owners are not obliged to contribute any additional funding beyond the agreed equity commitments and do anything beyond the contractual commitments they take in respect of project management, operations or, if relevant, PPAs.

This is the "full risk" approach for the banks (and investors, who take construction risk and bear the volatility of returns that rely on dividends that can only be paid after debt service has taken place). Accordingly, the terms for the earlier transactions were quite conservative, regarding debt sizing methodology, securities, and other mitigating factors, and have improved over time as lenders have become more comfortable with the industry and its risks.

7.2.1 Debt sizing metrics

Lenders typically use two criteria to define the amount of debt they are willing to provide to a project:

→ A metric linked to the cost of the project, reflecting the fraction of the investment they are willing to provide. This is called "leverage" and measured by the "debt-to-equity ratio", typically expressed as a fraction: "70:30". The logic here is that lenders want some commitment from investors to ensure that they will make all the necessary efforts to ensure the project gets built and operated properly.

→ A metric linked to expected revenues, and more specifically to operating revenues (gross revenues minus expenses that are absolutely required for the project to keep on functioning, such as O&M costs, taxes, etc.). Such revenues are what is available to repay the debt (they are often also explicitly called "cash flow available for debt service") and lenders want such revenues to be sufficient in every period to repay the corresponding debt service (interest first, then principal).

Cash Waterfall

Step	Revenues
1	Operational expenses and taxes
2	Interest on debt
3	Principal
4	Repayment of shareholder loans
5	Dividends

Source: Author's estimate

Obviously, the numbers used for revenues and operating costs depend on a number of assumptions, and these can be more or less favourable to the project or not:

→ Revenues are based on wind levels, derived from probabilistic wind studies – different probability levels can be used – sponsors usually refer to the central "P50" case, while lenders will typically use the lower "P90" level (the level that has a 90% chance of happening – and even that offers further opportunity to be more conservative, as one can use the "P90 1 year" which is the probability that any given year wind levels are above that number) or the "P90 10 year" (the probability that the 10 year average wind levels are above that number). The production level under the first standard is naturally lower than the second.

→ Revenues also depend on the assumed availability of the wind turbines (which can be linked to the number guaranteed by the turbine manufacturer, but can also be lower, or higher), and associated assumptions for various losses (for things like voltage conversion, transmission within the wind farm, transmission to shore, etc.).

→ Costs are linked to what is budgeted for O&M, of the planned kind and the unplanned kind (reaction to incidents). Depending on the scope of the operating contracts, which can be all inclusive or less inclusive, these numbers will be highly predictable (if the operator offers a fixed price full scope contract including all unplanned maintenance, replacement of major components, if needed) or dependent on assumptions about the frequency of interventions, their nature (whether they require heavy lift equipment to replace components) and their expected cost. If the budget is not fully contracted, banks will typically expect to see buffers to cater for unexpected interventions.

→ Another important cost item is the insurance budget, which can represent 20–30% of the operating costs depending on the nature of the coverage, the maximum amounts insured and the deductibles. Lenders typically require a fairly extensive insurance coverage. Insurance can usually be taken only on a yearly basis, with renewals that can be subject to price modifications based on the costs borne by insurers in previous years (i.e., if they have to pay for unusually expensive incidents in any given year, they will usually try to increase yearly premiums in subsequent years).

Once all assumptions are agreed, the lenders and the project agree on a coverage ratio, which is the ratio of available cash for a given period to the amount that lenders are willing to consider as debt repayment for that period. For OWFs, the coverage ratio was initially set, for early projects, at 1.35, using long-term P90 wind assumptions, and has trended down slowly over time, as shown in the table below.

7.2.2 Pricing and other commercial terms

Naturally, the pricing of the debt (called the "margin") is an important commercial factor. Interest for corporate (and project finance) debt is calculated as the sum of two components – an underlying index, like EURIBOR, which reflects the cost for banks to borrow money themselves on the interbank market, plus the margin itself. The margin is the remuneration of the bank.

The index is variable over time and borrowers like offshore wind projects, which have largely fixed revenues, and do not want to bear interest rate uncertainty, so project owners typically choose to "hedge" that variable interest rate by "swapping" it for a fixed long-term number. The market for interest rates of all maturities is one of the most liquid financial markets and it is possible to swap variable interest rates even over the very long term. This is typically done on financial close – that calculation also drives the final amount of debt given that the exact amount of interest to be paid (from the amount of cash flow available from debt service, divided by the cover ratio) will only be determined then. Given that swap markets are quite liquid, it is at least possible to have a good idea of where the interest rate will be in advance, but they do vary from day to day.

The total cost of debt for the project is derived from the fixed rate of the swap plus the margin. The swap is an element that neither the project nor the lenders control, but the margin is something they negotiate. Another important pricing item is the upfront fee, i.e., a commission paid to the lenders to agree to lend money and spend the time required to assess the project and get the loan approved internally.

Naturally, the duration ("maturity") of debt is also an important element – the longer the debt, the easier it is to spread repayment of principal over a larger revenue stream and increase the overall debt amount.

Finally, given the size of the projects and the risk involved, banks rarely want to lend on their own and prefer to be part of a group of lenders (a "syndicate") that all lend smaller amounts, all on the same terms (and who share all risk and income equally). In order to simplify the negotiations, projects try to negotiate with a smaller number of banks, called "underwriters", who commit to lend bigger amount and then share the risk with other banks on the terms they have agreed (this is called "syndicating" a transaction). The amounts that banks are willing to underwrite are an important commercial element as it drives the number of banks that are required to reach the requisite amount of debt.

The debt syndication markets in project finance stopped functioning properly in 2007 (before the financial crisis struck, it was one of the harbingers of doom, actually), and took a very long time to start again, so offshore wind deals have mostly been negotiated as "club deals" – transactions where no underwriting or syndication takes place, and the transaction must be negotiated with all the lenders that eventually contribute funding to the project. This has meant more complex negotiations with large banking groups, and occasionally the risk that individual lenders would hijack the process to ask for better terms for the financing, because they were all indispensable to its successful conclusion.

The table below shows how these different terms have evolved over time in the sector (based on actual transaction closed):

Refinancing debt terms

Typical lending terms*	Leverage	Maturity	Pricing	Contingency budget
2006–2007	60:40	10–15 years	150–200 bps	12–15%
2009–2013	65:35	10–15 years	300–350 bps	10–12%
2014–2015	70:30	10–15 years	200–250 bps	15–20%
2016–2017	75:25	15–17 years	150–225 bps	12–15%
2018–2019	75:25	15–18 years	125–175 bps	8–12%
2020–2021	80:20	15–20 years	125–175 bps	8–10%

*Greenfield offshore wind

Source: Offshore wind debt 15 years on, Jérôme Guillet, PFI Yearbook 2022

As the tables show, the trend is one of long-term improvement in terms for borrowers over the years, apart from the immediate period after the financial crisis when things tightened a bit (mostly on pricing and available funding), but the market never closed. After a crisis, banks tend to focus on key clients, core countries and selective sectors, and offshore wind, which developed in Northern Europe, ticked all the boxes – projects were in highly rated, stable countries, the investors (clients) are experienced IPPs or infrastructure funds that banks favour, and the sector is at the heart of the transition towards clean energy and thus viewed as something that the banks "should do".

As the track record built up and was very positive, banks became more comfortable with the risks and slowly offered more competitive terms. It is important to note that, like equity investors, nothing lowbrow has been done by lenders: terms have slowly improved, but without any drop in standards. The sector is like a high plateau – transaction that do not meet the standards (in terms of contractual structure, due diligence and economics) simply do not happen, but if you reach the requisite level of quality, then liquidity becomes plentiful and banks compete on commercial terms like pricing or, increasingly, underwriting.

7.2.3 Structures and lenders

The market was built around a few sectorial pioneers (Dexia, Rabobank) and experienced project finance lenders (see below), and slowly attracted a wider universe of banks that have less experience but are willing to follow the lead of the core banks. In that sense, the sector has followed the traditional route of growing maturity that new sectors typically do – a relevant comparison is to the LNG sector, which followed a very similar path 10-15 years earlier.

Banks active in offshore wind

Banks with experience and active in the market	Banks with a bit less experience*
BTMU, BNPP, Rabobank, KfW-IPEX, Natixis	Caixa, NIBC, ASN, Mizuho, ING, BNG
Deutsche Bank, SMBC, SocGen, Goldman Sachs	Lloyds, Barclays, RBS, Bank of Ireland, RBC, HSBC, NAB (UK focus)
Santander, Commerzbank, SEB, ABN-Amro	Bayern LB, DZ Bank, Deka Bank, HSH, NordLB, UniCredit (German focus)
Crédit Agricole, Helaba	DnB Nor, KBC, Investec, Sabadell, BBVA
	Canadian banks (with the relevant angle)

* but involved in recent deals or having expressed appetite

Following banks, institutional investors and debt funds have also joined the market and have either joined directly bank transactions or have participated to specifically designed transactions. Debt funds tend to have slightly different lending capabilities than traditional banks, with a preference for fixed rates, and ability to do longer maturity but less flexibility on the timing of drawdowns. In practice, this has meant that institutional tranches have been focused mostly on post-construction refinancings, where they provide an additional pool of liquidity. In terms of structures and risk assessment, they are quite close to banks (and their teams are often built up from traditional project finance bankers with similar backgrounds and expertise to those in banking teams).

A handful of transactions have been structured as capital market bonds, which can more easily be traded and get ratings from the leading rating agencies. These target a different universe of funders but in practice, the terms have not been materially different from those provided by commercial banks, and they tend to focus on post-construction refinancings (or financings with completion guarantees). There have not been capital market bond transactions with full construction risk to date as bond tranches tend to be "fire and forget" (funding is provided and then lenders get out of the way), whereas the construction period usually requires active involvement from lenders to deal with the inevitable unexpected turn of events during that period which can range from incidents that delay construction to the reverse, such as when unusual weather conditions lead the project developer to accelerate construction to take advantage of that fact, for instance by mobilising more vessels, thereby spending the budget on a different schedule, something which typically requires a nod from the lenders.

We now see transactions that have parallel bond and debt tranches, on identical terms, to tap multiple pools of funders – this has been the case for the large financings such as that for Hornsea 2.

Ultimately, we see two essential categories of debt transactions: those with construction risk, and refinancings of projects post-construction that do not bear construction risk. The terms of the first category were presented above, those for refinancings have the following characteristics:

- → More aggressive debt sizing, based on a lower cover ratio (typically 1.15) and improved assumptions for a number of project parameters (taking advantage of the fact that real data is available for the project once it is actually operating – for production levels, technical losses, ongoing insurance premia, etc.), usually with no leverage requirement
- → Better pricing, given that the construction risk is gone
- → Less intrusive commitments with respect to project ownership, the right to modify ongoing contracts, etc.

These refinancings often allow the investors to receive special dividends as the amount of debt is increased from the original construction financing, or in replacement of equity altogether in the case of balance sheet funded projects.

Refinancing debt terms

Typical lending terms*	Implied Leverage	Tail beyond regulated tariff	Pricing
2009–2013	70:30	No	200–250 bps
2014–2015	80:20	No	175–200 bps
2016–2017	85:15	1–2 years	150–225 bps
2018–2019	>100	1–3 years	125–175 bps
2020–2021	>100	2–5 years	100–175 bps

*Refinancing offshore wind

Source: Offshore wind debt 15 years on, PFI Yearbook 2022

Altogether, there is a full suite of financing tools available to projects at every stage of their life, providing cheap funding for the development, construction, operation of OWF, on predictable and competitive terms, and allowing to optimise the cost of electricity. The availability of funds is not, and has actually never been, an obstacle to the development of the sector.

A few notable transactions

Year	Project	Loc.	Notable feature	Greenfield?
2004	North Hoyle	UK	First non-recourse financing of an operating asset (as part of a larger onshore portfolio)	No
2006	Q7	NL	First non-recourse construction financing	Yes
2010	C-Power	BE	First billion-euro transaction. First 6 MW turbine to be financed	Yes
2012	Gunfleet Sands	UK	First hold co. financing	No
2014	Westermost Rough	UK	First hold co. financing with residual construction risk	No
2014	Gemini	NL	Largest project to be financed (600 MW, EUR 2.2 bn debt)	Yes
2015	Block Island	US	First US project	Yes
2015	Veja Mate	DE	First greenfield financing without any multilateral lender (KfW, EIB, ECAs)	Yes
2015	Belwind	BE	First refinancing of a greenfield financing	No
2015	Gode Wind	DE	First bond refinancing & first refinancing with institutional investors	No
2015	Meerwind	DE	First bond refinancing with public rating	No
2015	Galloper	UK	First full greenfield financing in the UK	Yes
2018	Blauwwind	NL	First greenfield project with low tariff (54.5 EUR/MWh)	
			from competitive tender	Yes
2018	Formosa 1	TW	First project in Taiwan	Yes
2018	Hornsea 1	UK	Largest refinancing, with multiple parallel debt and bond tranches (1,218 MW, GBP 3.5 bn)	No
2019	Yunlin	TW	First utility-scale project outside Europe	Yes
2019	St Nazaire	FR	First transaction with full underwriting and "real" syndication	Yes
2020	Akita/Noshiro	JP	First non-recourse financing in Japan	Yes
2020	Dogger Bank A/B	UK	Largest non-recourse construction financing (3,200 MW, GBP 4.8 bn). First 12 MW turbine to be financed	Yes
2020	Hohe See	DE	"Holdco squared" refinancing	No
2021	Vineyard Wind	US	First utility-scale financing in the US	Yes

Source: Offshore wind debt 15 years on, PFI Yearbook 2022

8

Floating offshore wind

8.1 Why floating offshore wind?

The notion of installing turbines on floating structures rather than foundations set on the seabed has been promoted for two main reasons:

→ The first practical one is that there are actually not many places like the North Sea, where relatively low-depth waters extend for hundreds of kilometres from the coasts, offering a very large area where fixed bottom foundations can be installed. Alongside most coasts, waters get deep quite quickly, and turbines can either be installed very close to shore with all the problems that can cause as they are visible and occupying areas at sea that are typically very busy with other activities, or not at all. This is particularly true in places like Japan, California, or the Mediterranean, where fixed-bottom turbines have limited potential. So, to do offshore wind at scale (and that is the main advantage of offshore wind after all), floating becomes the only route.

→ The second argument is that floating offers the prospect of avoiding construction at sea altogether – an activity which is both inherently risky and expensive. Floaters can be built onshore; the turbine can be erected in the port and the structure can then simply be towed to its location, an activity requiring much simpler vessels (tugboats) than offshore installation of fixed-bottom turbines and much less sensitive to weather conditions. Additionally, this offers the possibility to do serial production of the floaters rather than having to manufacture multiple ad-hoc foundations (as each fixed bottom structure needs to be tailor-made to the water depth and the soil conditions of its exact location).

Floating wind thus offers the hope of a very large-scale renewable power production away from the eyes of coastal populations and with the efficiency of an industrialised onshore supply chain.

8.2 Technology and risks

Several concepts of floaters exist and they each have different constraints (such as minimum water depth to be installed, or quayside surface required).

These technologies are generally considered to work from a technical point of view, but none have been tested in full as regards to large scale manufacturing and installation, and their cost on a serial basis is not necessarily fully identified yet.

Floating platform technologies

Source: NREL

In any case, the risks are fairly similar (and to a reasonable extent, conceptually similar to the risks faced by the fixed-bottom offshore wind industry 15 years ago):

→ It is again bringing together industries that have no experience working together – in this case, the specialised construction industry for floating structures with the wind turbine manufacturers, neither able to take responsibility for the scope of the other.

→ It creates new interfaces, in this case more during operations than construction. What is the envelope of conditions (particularly regarding verticality of the installation) where turbines will perform normally, and who is responsible if the turbine performs below expectations, or suffers more wear and tear? Are the contractors willing to provide guarantees backed by financial commitments, in case of deviations?

→ There are specific questions about "dynamic cables" that would connect the platforms and collect the power generated – they will need to "hang" from the floaters before reaching down to the seafloor, and potentially again to reach a floating sub-station – with the high voltage cable bringing the power to shore facing a similar constraint from such sub-station. The vulnerability of these cables and potential risks of damage or failure are not fully measured yet.

FLOATING OFFSHORE WIND

→ Finally, it generates new questions about potential bottlenecks in the supply chain. Large specialised vessels are no longer required, but very large quayside installations are needed to manufacture and store the floaters before the turbines are installed on them and they are shipped to see – such space is at a premium in many port facilities. With large scale deployment expected in the coming two decades, rapid growth will be necessary and not all parts of the supply chain may move at the same pace, potentially creating unbalances and slowing down some projects.

Ideol floater under construction in St. Nazaire

Source: Ideol

Conceptually, these are questions that resemble those that banks asked 15 years ago about offshore wind: what could go wrong, what will it cost to correct it, and who is responsible? We are at a stage where everybody expects that all these questions have satisfactory answers, but the exact answers are not fully available, and the uncertainty has a cost in terms of the availability of debt and the terms under which it can be provided.

Banks crave precedents, and we are back to a situation where there simply is not enough information available. The early prototypes have demonstrated that turbines work on floaters, and can produce electricity at high capacity factors (Hywind Scotland, a 5 turbine pre commercial project off Scotland, announced a capacity factor of 57% for its second year of operation), but they have not really provided insights on what happens once serial production and installation is the norm.

Ironically, the fact that prototypes have been performing really well has not given information on what downside scenarios could look like (how much time does it take to tow a faulty turbine back to shore and repair it, how much does it cost, and how often it is likely to happen?) making it difficult for banks to assess the worst-case situations that they would want the projects to be able to cope with.

8.3 Debt finance is critical

Just like other renewables and fixed-bottom offshore, floating wind is a capital-intensive technology where most of the money is spent upfront and running costs are relatively low, which means that ultimately, the cost of electricity will be driven as much by the cost of capital as it will be by the cost savings generated by economies of scale and both will only go down if projects happen.

The virtuous circle of any developing sector is as follows:

→ R&D to prove that the technology works is typically funded by governments, providing grants to universities or the R&D teams of industrial players. They usually try to build prototypes (often at reduced scale) and get them to work (1 turbine project, budget typically in the low double digit million euros).

→ The next step is to build pre commercial projects at scale, that can generate revenues with government support in the form of construction subsidies and/or specific revenue regime (5–10 turbine project, budget typically in the low triple digit million euros); these projects can be financed on a commercial basis but this will likely mean quite conservative terms; this generates more data on the technology, allows the supply chain to grow and to start working on manufacturing at scale (even if for small series to stat with).

→ After that, the goal is to have larger fully commercial projects, ideally generating power at a price which is not too far from competitive technologies, to limit the support they receive, for instance via technology specific tariff auctions that do not force them to compete against more mature technologies. Such projects will be financed on terms that will slowly increase as the track record grows (and remain satisfactory); this allows to test manufacturing and installation on a serial basis and build up the supply chain accordingly.

→ Subsequent projects can grow from that basis, benefitting from improved economies of scale, less conservative assumptions/buffers as risks become better understood, and improved financing terms.

The big question is how quickly can the circle of increasing scale and decreasing costs (both physical and financial) happen? Governments now see that onshore wind, solar and traditional offshore wind can be built with tariff levels that are comparable to spot market prices and may wonder why they should force ratepayers to provide higher prices to another technology. Even if they are willing to give support to a new sector, they may get impatient if the cost reduction is not as spectacular as it has been for offshore wind in the 2015–2020 period.

That question is still open today, even if it seems likely that countries like Japan, that simply have no other alternative to deploy renewable energy on a large scale, will support the sector long enough for it to become competitive. The recent Scotwind tender, where half the capacity was awarded to floating projects, should help accelerate the answers.

9

Conclusion

9 Conclusion

The history of offshore wind is quite intertwined with the history of how the projects were financed, and it is a rare sector where risks are quite significant (construction at sea will never be an easy task), where they have been taken willingly by banks, and where they have been successfully navigated by the industry, with an enviable track record of projects built on time and on budget.

This means that funding is available for the industry, on highly competitive terms, and is not a bottleneck for the further development of the sector – and the same will be true of the nascent floating offshore wind sector. Rather than being an obstacle, smart financial engineering has been one of the driving factors for the substantial drop in the cost of electricity generated by offshore wind farms, as the excellent risk management by the industry, prodded by careful financiers, has allowed to attract low-cost capital, an important feature for a capital–intensive sector.

As offshore wind becomes one of the dominant new sources of generation of clean electricity, it is worth celebrating this example of financiers doing their job of supporting an industry while understanding the risks that they are taking.

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