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The Waiting Game

How to reduce US interconnection queues and costs

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Editorial

Setting targets for wind power deployment is all well and good, but transmission challenges in the US and Europe are threatening to derail many projects

Having ambitious targets for the development of onshore and offshore wind is one thing, but ensuring proposed wind projects can connect to the grid is another entirely.

As this issue of Tamarindo's *Finance Quarterly* report highlights, the US and Europe are beset by a number of significant transmission-related challenges that are slowing down the speed with which wind projects can be deployed.

In the US, data shows that around 300GW of wind projects are parked in interconnection queues, partly due to the system being clogged up with multiple speculative requests submitted by exasperated developers. Such developers, frustrated with the snail-like pace of the approval process, file a large number of requests merely in the hope that just one will get the green light within a reasonable time frame.

The problem is the adoption of this strategy is exacerbating queues with the result that most of the wind projects stuck in line never actually get developed.

Pondering point-to-point

Meanwhile, in Europe, there are doubts about whether dedicated point-to-point transmission lines – the traditional method of connecting projects to the grid – will be viable for offshore wind projects in future.

European waters are becoming increasingly crowded, with forecasts indicating that, by 2040, they may be home to as much as 180GW of offshore wind. In such a scenario, the point-to-point system of interconnection would become unwieldy. But what's the solution? We look at how transmission may be re-thought to help offshore wind companies.

For example, there is increased talk about new ways to build transmission and offshore wind capacity, including hybrid projects and meshed grids. It is good to see this innovative thinking. However, such methods need to be developed in such a way that developers and investors will gain certainty over both the costs and timelines of transmission links.

Elsewhere, DNV discusses the trend for wind developers in the US to be increasingly focused on wind curtailment amid concerns that the financial impact could affect tax credits. We also talk to Scout Clean Energy about how transmission is one of the main risks it sees in the US wind market right now, and discuss approaches to overcoming community resistance to renewables projects in some areas.

Contents

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Stuck in the queue: The rising cost of US interconnection

With interconnection queues in the US getting longer, and the associated expenses escalting, how can wind developers get plugged into the grid more quickly? BEN COOK REPORTS

While US politicians have set bold renewable energy objectives in an effort to focus minds on speeding up the energy transition, the reality is that practical difficulties – specifically, connecting sources of renewable energy to the nation's electricity grid – are jeopardising efforts to widen the deployment of clean energy.

From the wind industry's perspective, there is no doubt that the political will to turbo boost the US offshore wind sector, in particular, is there. Back in 2021, the Biden Administration set a target of deploying 30GW of offshore wind by the end of the current decade, and then, in September last year, the White House announced a new goal of deploying 15GW of floating offshore wind capacity by 2035. And yet, there is a serious obstacle to achieving these targets, and that is the US' rapidly growing grid connection queues.

So what exactly is the problem? In order to get a wind project connected to the grid, electric transmission system operators – namely, independent system operators (ISOs), regional transmission organisations (RTOs), or utilities – require project developers that want to connect to the grid to undergo a range of impact studies before they get the green light. Simply put, the studies identify what additional transmission equipment or upgrades may be required to enable the project to be connected to the grid, and, crucially, assigns the costs of such equipment and upgrades. It is the backlog of projects going through, or waiting to go through, this process that form the interconnection queues. The problem is that these queues are growing rapidly.

How much capacity is stranded in US interconnection queues?

At the end of 2022, there was 1,350GW of generation capacity in the queues, according to the Lawrence Berkeley National Laboratory (Berkeley Lab), a US DOE Office of Science national laboratory managed by the University of California. With regard to the generation capacity currently queued, 1,250GW constitutes zero-carbon projects, with wind making up 300GW of that total. Just over a third of the wind projects in the queues (113GW) are offshore.

Unfortunately, the interconnection queue is as far as many proposed wind projects will get. Data from Berkeley Lab indicates that the vast majority of the projects in the queue will never be actually built. The statistics show that, only 21% of the projects (and 14% of capacity) seeking connection from 2000 to 2017 had been built as of the end of 2022.

High interconnection costs forcing projects to withdraw from queues

In some instances, projects will simply withdraw from the queues, partly because of high interconnection costs. Research by Berkeley Lab shows that, in the ISO New England regional transmission area, for example, "high interconnection costs appear to be a driver of withdrawal decisions". However, the Berkeley Lab study concluded that average interconnection costs have grown across all regions of the US. Notably, the research showed that, while such costs have doubled in some regions for projects that had completed the impact studies, they have increased even more for active projects currently moving through the queues. Furthermore, the study showed that projects that withdraw have the highest interconnection costs of all, strongly indicating that costs may indeed be a significant factor in withdrawal decisions.

In some regions, the burden of interconnection costs is having a greater impact on wind farms than it is on other forms of renewable energy. The Berkeley Lab study concluded that renewables and storage often face higher interconnection costs than natural gas. Alarmingly, if we take the example of the ISO New England region, the average interconnection cost for the period 2018 to 2021 was around $100 per kilowatt for natural gas, which compared to $1,200 per kilowatt for onshore wind. One hypothesis put forward by the Berkeley Lab for the higher interconnection costs imposed on renewables projects is that renewables are often located in more rural areas where the existing transmission system is weaker, and therefore costlier network upgrades are required.

Queues made worse by speculative requests

Problems for the wind industry are exacerbated by the fact that information about interconnection costs is not made available prior to projects entering the system. Another issue is that, given the extended timeframe for the processing of interconnection requests, developers are submitting multiple speculative requests in the hope that one of them will be processed quickly. The typical duration from connection request to commercial operation increased from less than two years for projects built in the period 2000-2007 to nearly four years for those built in the period 2018-2022, with a median of five years for projects built in 2022, according to Berkeley Lab. Cornelis Plet, vice president, power system advisory at DNV, says that 80% of the projects entering interconnection queues are "duds". He adds: "This is, to some extent, due to developers entering speculative queue positions thinking 'why don't we just try 10 places at the same time?' And then if one of them is good, then they'll go with that one, which is fair enough from a developer perspective."

But Plet points out that speculative applications use up valuable resource like every other application. "All these positions have to be studied with very extensive impact studies, loading up the utilities with simulation work," he explains. Another issue is that a lot of developers enter the queues before they have actually developed a project proposal. "This is one of the rules that is now being implemented in a lot of the queue reform processes, that is, you need to either have proof of having some sites and some projects, or put down a deposit to show that you're at least serious about making a queue position work for you," says Plet.

Joe Rand, energy policy researcher in the Electricity Markets and Policy Group at Berkeley Lab, has some sympathy for the developers' position. "Developers wouldn't feel the need to submit multiple requests if they thought that they would get results of interconnection studies within a six-month time frame rather than three years," he says. However,

High interconnection costs appear to be a driver of withdrawal decisions

Rand adds that the US is not building new transmission at the same rate that it's trying to interconnect new generation. "It's just really hard to site and build and permit new transmission lines in the US," he says.

Potential fixes for the interconnection problem

So, what's the solution? Rand's first proposal is to reconstruct existing transmission corridors. "We already have transmission lines, we can put new cables that have higher capacity ratings to move more power – we can use those existing towers and corridors, so you don't have to site and permit new corridors," Rand says.

There also calls for making use of existing rights of way, like railway lines and highways, to site new transmission lines. "Then you don't run into issues such as delays in siting and permitting existing corridors," says Rand. "Use the existing corridors with other infrastructure that is there for other purposes." Meanwhile, it's also proposed that the US could also make better use of technology such as dynamic line rating (DLR), which refers to the varying of presumed thermal capacity for overhead power lines in response to environmental and weather conditions. The International Renewable Energy Agency has extolled the virtues of DLR, saying it facilitates the varying of presumed thermal capacity in real time, based on changes in ambient temperature, solar irradiation, wind speed and wind direction "with the aim of minimising grid congestion".

> "We already have transmission lines, we can put new cables that have higher capacity ratings to move more power – we can use those existing towers and corridors, so you don't have to site and permit new corridors"
>
> **Joe Rand, Berkeley Lab**

The use of DLR is backed by Rand. "I think this is a really good example of a way in which we can squeeze more juice out of our existing transmission lines," he says. "If we were to install sensors along the grid network that measure things like temperature, ambient conditions, how much power is flowing through the line, and so on, then you can dynamically adjust the rating of that line based on the ambient conditions." Rand argues that, currently, the rating of transmission lines is not done in a particularly sophisticated way. "I think there's a real opportunity to take advantage of dynamic line rating to enable us to move more power more efficiently," he says.

Make use of surplus interconnection service

Developers are also advised to consider opportunities for making use of surplus interconnection service. "If there are any existing power plants, or power plants that are in the interconnection queue but ultimately seem like they're not going to use all of the interconnection limit that they initially requested, there might be what's called surplus interconnection service that could be utilised," Rand says.

Meanwhile, developers are also looking to identify locations where fossil fuel power plants are being retired, which would open up available capacity on transmission networks. Rand highlights the example of the Colstrip Transmission System in Montana. "There's a really big coal power plant there that's slated to be retired and mothballed," he says. "In the interconnection queues, we see lines and lines of wind and solar plants trying to connect there because they know, as soon as that coal plant shuts down, there's going to be available capacity."

Wind developers seeking interconnection can, in most US regions, either opt for a Network Resource Interconnection Service (NRIS) or an Energy Resource Interconnection Service (ERIS). While an NRIS gives more certainty regarding transmission capacity, it also costs more – inversely an ERIS means less expense up front but it providers fewer guarantees regarding transmission capacity. "Across the US, in regions that offer ERIS and NRIS, we're seeing more than 90% of wind and solar developers choosing NRIS," says Rand. "The trade-off is you pay higher interconnection costs if you're choosing an NRIS, so developers are weighing up the economics of paying more up front, but having higher revenue potential as the plant operates – I think most generators are saying that's a worthwhile investment."

Despite all the obstacles, Rand says it should be acknowledged that at a federal level – and in the private sector – substantial effort is being put into trying to address and resolve interconnection issues.

Developers looking to hedge transmission costs

Rob Gramlich, founder and president of clean energy consultancy Grid Strategies, says that transmission planners are trying to address the issue of limited capacity with new transmission lines and plans. He adds that, in this context, renewable energy developers are trying to determine where transmission capacity will be available in a few years' time. "There are a number of transmission lines that appear promising and, for the most part, these are known to the market, so generation developers can try to develop projects in areas that can be served by new transmission lines," Gramlich says. However, he adds that in some cases, the wind developer has taken it upon themselves to build the required transmission.

Gramlich says developers are looking for ways to hedge transmission costs. Approaches could involve securing a long-term transmission service, or "working the risk out between counterparties", he says. "For example, the PPA off-taker may be able to take on some of the risk and the generator may absorb some as well, so they can work that out between themselves contractually." Gramlich says that wind developers could sign up for a long-term transmission service – for multiple years from the transmission provider. But there's a catch. "We don't have very good long-term transmission services here, it's not generally required by the regulator and it can be expensive," Gramlich says. "The markets are thin, they're not very liquid, so it's challenging." He adds that sometimes developers will work with "third-party power marketers" who structure their own hedges, but that can be challenging because it needs to fit with the interconnection service and transmission service that the generator needs.

On the flipside, short-term transmission services have significant challenges in that they can result in exposure to physical curtailment. "In most regions you can buy your way through a physical constraint, but it's expensive – you're essentially paying for the re-dispatch of the generation fleet in order to enable transactions, but that can be very expensive and unpredictable, so therein lies the risk," explains Gramlich. Consequently, basis risk – that is, the risk associated with imperfect hedging – is currently a massive issue for investors in renewable generation.

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>
> **Rob Gramlich, Grid Strategies**

Transmission problems deterring investors

Transmission issues such as these are acting as a deterrent for wind investors in the US. Congestion costs are rising dramatically, projects are running the risk of extremely low, or negative energy power prices, as well as potential curtailment, and these are all factors being considered when assessing the viability of potential wind projects.

However, there are grounds for some optimism. After a decade-long hiatus, there are signs that transmission investment is picking up, according to Gramlich. "The problem has become so acute that the value of transmission has increased," he says. That said, any optimism should be tempered slightly. "There are also a lot of estimates about what the Inflation Reduction Act is going to accomplish, but there's also a lot of analysis showing that we're not going to achieve the widely reported results of that act if we don't build a lot of transmission," argues Gramlich. He adds: "I think there's a very broad recognition now that transmission is really important and I'm pretty sure that every single Democrat in the US House and Senate would say transmission is really important. Some Republicans would also say that, but, thus far, we've not been able to include meaningful transmission policies in legislation."

Gramlich proffers similar solutions to those proposed by Rand, such as making better use of the existing network with grid-enhancing technologies and high performance cables, making use of existing rights of way – "by stringing a new wire on the same towers or bigger stronger towers to carry a bigger line" – and developing new rights of way. But he says this use of existing rights of way is a partial solution to the significant challenges involved in developing new rights of way that can take up to 15 years. Gramlich considers dynamic line ratings, topology optimisation and power flow control to be vital tools when seeking to enhance the grid, but he adds that implementing such technologies is not straightforward. "We have more challenges with the grid-enhancing technologies because transparency is a problem," he explains. "There's not a lot of good information available to the public, or the market participants, about where on the system certain technologies could apply."

A further problem is that the incentives for utilities are misaligned with the public interest, as Gramlich puts it. "The utilities' incentives, as structured by their regulators, rewards them for bigger capital investments, but grid enhancing technologies tend to be lower capital cost."

Signs of progress?

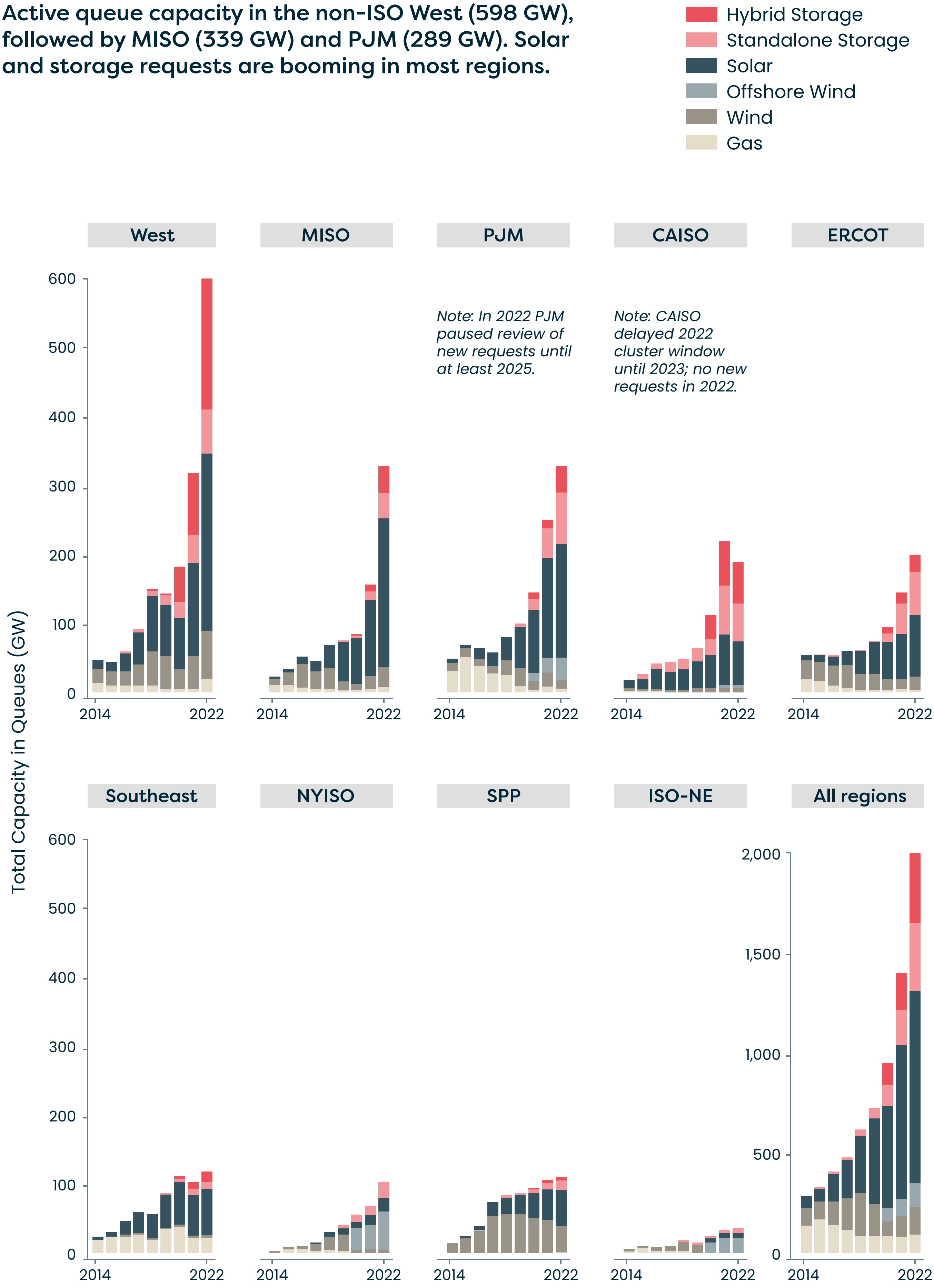
The good news is that with regard to making use of existing rights of way, there are signs of progress. In July last year, the Midcontinent Independent System Operator (MISO) approved a $10.3 billion transmission plan that could support about 53 GW of wind, solar, hybrid and stand-alone battery projects. As Gramlich highlights, the 18 transmission projects approved as part of the plan, would, on the whole, make use of existing rights of way. "I think when the utilities and the regional planners are motivated to get a lot of transmission built, they will look for those opportunities," he says.

In July this year, Federal Energy Regulatory Commission (FERC) issued a new rule aimed at speeding up the grid interconnection process. Key changes included a "first ready, first served" cluster study process, the establishment of penalties if transmission providers fail to complete interconnection studies on time, as well as a requirement that transmission providers allow more than one generating facility to "co-locate on a shared site behind a single point of interconnection and share a single interconnection request". FERC said the latter reform would create a "more efficient standardised procedure for these types of generating facility configurations".

It's early days, but hopes are high that the new FERC rule will mark the beginning of significantly more streamlined interconnection processes. That said, this is only the first step in that direction and time will tell how effective the new rule will be. Sceptics say the new rule is merely codifying bests practices currently used in many interconnection queues, but there is a belief that the "first ready, first served" cluster approach will ease interconnection backlogs in regions that don't currently adopt that strategy.

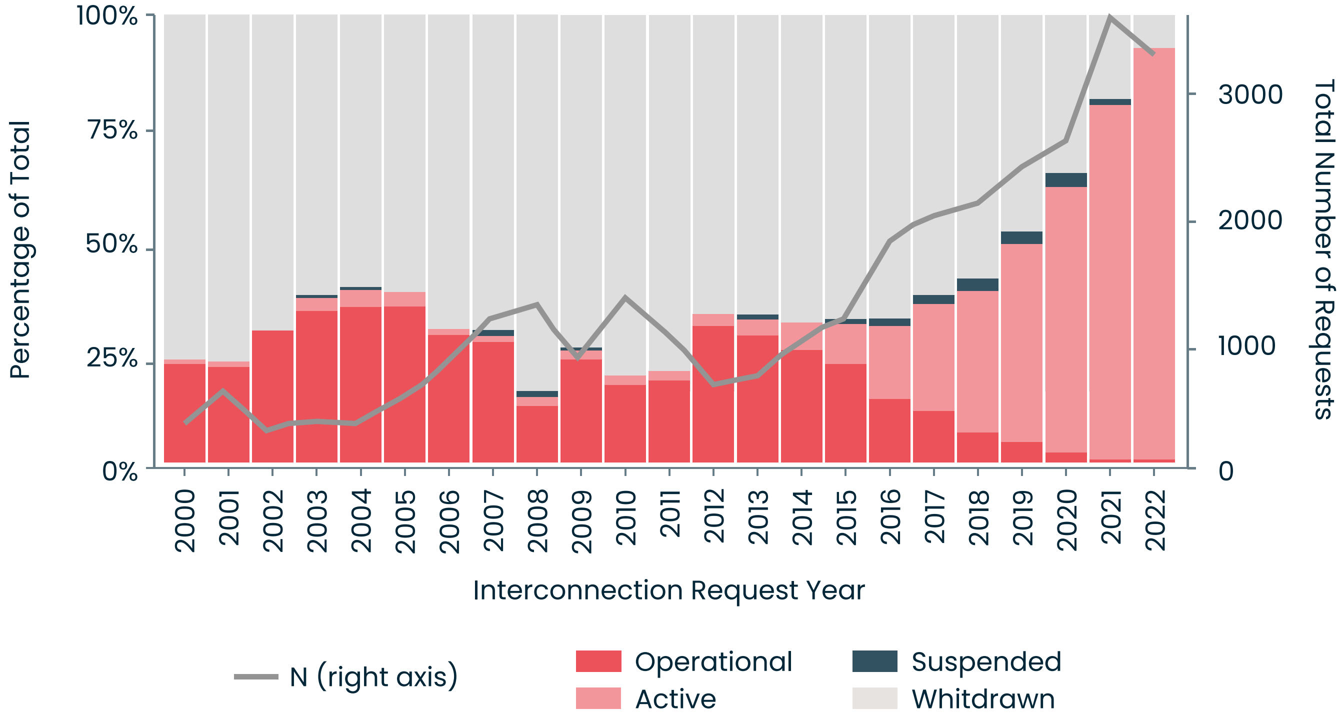
Transmission development in the US has stagnated for too long, and it is vital that such work is kick-started again if US states are to make significant progress in their attempts to add more renewables into the energy mix. If the new FERC rule fails to speed up interconnection, the prospects for deploying wind energy on the scale envisaged by some of its leading proponents look decidedly bleak.

Active queue capacity in the non-ISO West (598 GW), followed by MISO (339 GW) and PJM (289 GW). Solar and storage requests are booming in most regions.



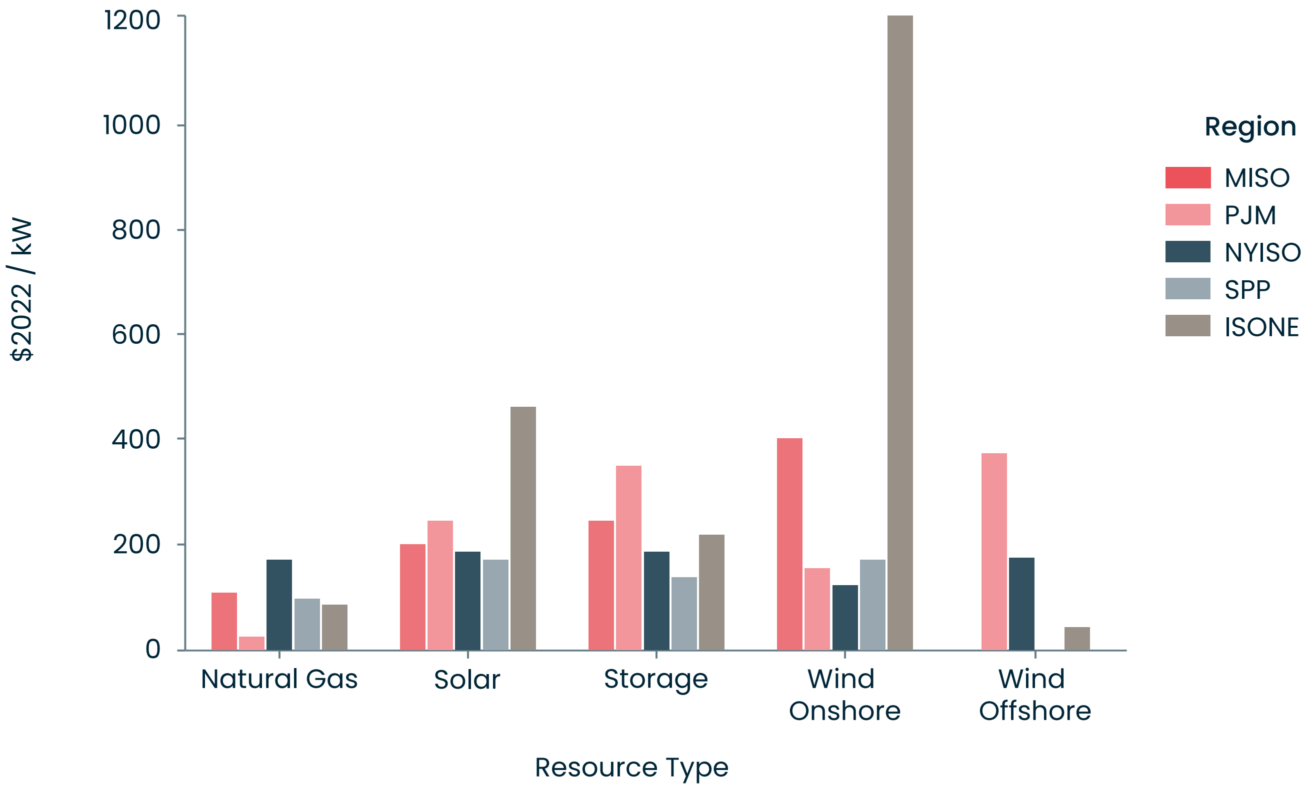
Source: https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf

Only 21% of all projects proposed from 2000-2017 had reached commercial operations by the end of 2022 – 72% had withdrawn from queues



Source: https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf

Average Interconnection Costs in Recent Years (includes projects that withdraw application)



Offshore Wind costs exclude transmission investments offshore

Source: https://www.dropbox.com/sh/uwk2381fyzysqtr/AABwIWH4QKIMjGFOwvjRojZia?dl=0&preview=berkeley_lab_interconnection_cost_webinar.pdf

JOHN CLAPP Q&A

“We support all moves to reduce delays”

John Clapp, Chief Financial Officer at Scout Clean Energy

John Clapp, Chief Financial Officer at Scout Clean Energy, reflects on the year since Brookfield bought the company for over $1bn, and wider market challenges.

Has Scout changed since the Brookfield buyout?

We remain a standalone IPP under Brookfield’s $15bn Global Transition Fund. We’re not merged into Brookfield Renewables, but we work closely and integrate with them on financing, equipment procurement, PPA contracting strategy and so on.

Where do you see the biggest opportunities?

The demand side has changed dramatically with the rise in importance of ESG on Wall Street. A decade ago, we used to only have utility buyers running annual or biannual solicitations, but that’s all changed with the massive in-flow of corporates into the buying universe. The scarce resource now is high-quality projects that can be built in a determined timeframe.

On top of that, the Inflation Reduction Act (IRA) has brought in new buyers, like data centers and green hydrogen operators. They’re what I call the ‘new economy’ buyers.

Has the IRA changed the mix?

There’s tremendous promise in the IRA, including the long-term extension of renewable tax credits. That gave a lot of certainty to an industry that had been living on short-term tax credit economics. The IRA is also helping to create more of a domestic manufacturing base, which shortens our supply chains and gives us as a developer more options around procuring equipment and managing risk.

> There’s tremendous promise in the IRA, including the long-term extension of renewable tax credits.

What are the biggest market challenges?

I see five main ones.

First, interconnection queue delays and associated reforms. The Regional Transmission Operators were set up to analyse maybe a dozen fossil fuel projects each year, but now they have to analyse hundreds of renewable projects. We support all moves to reduce delays.

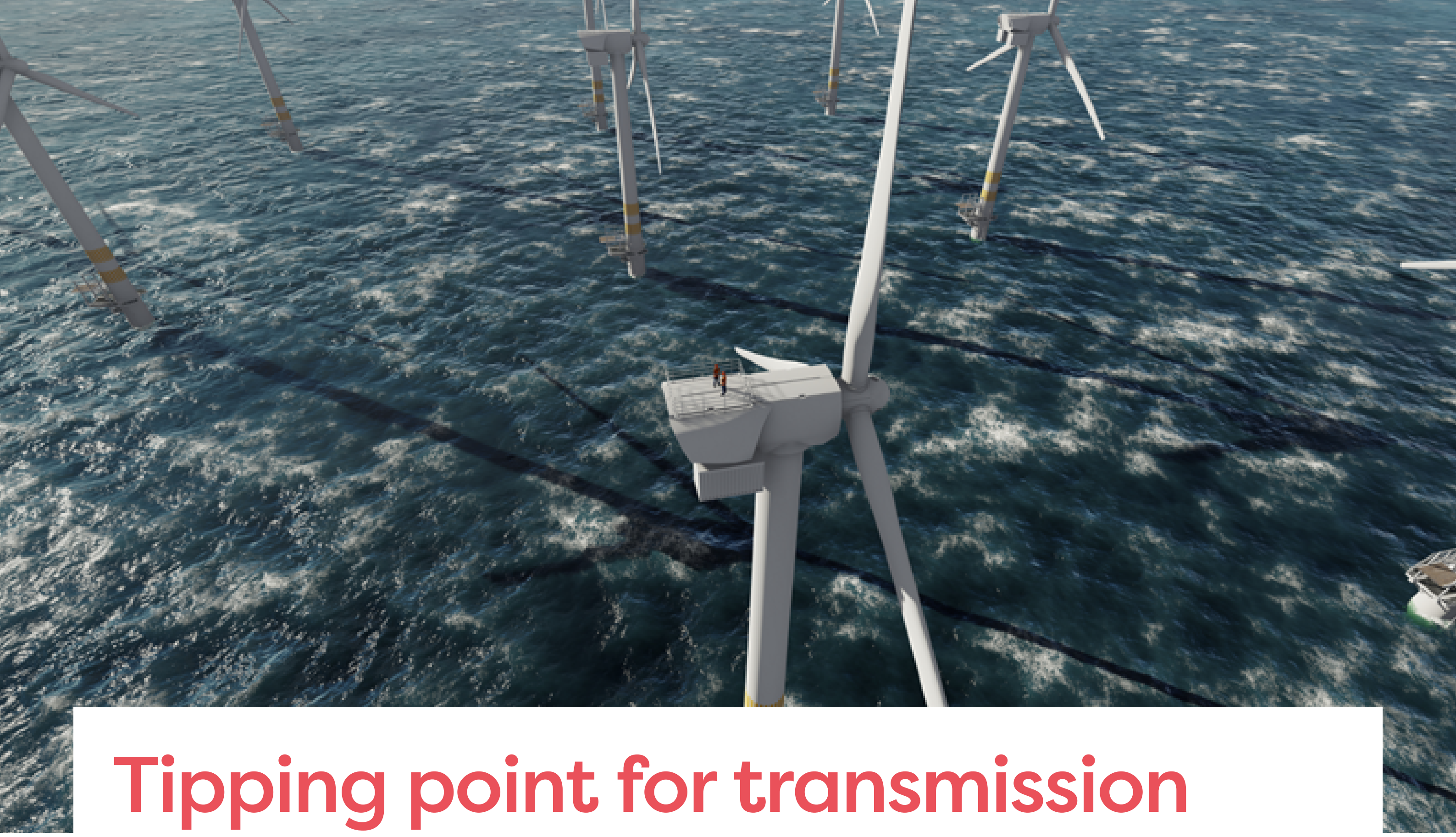
Second, transmission development and access. We need more transmission, but some of the entities that have control over the system regionally have a conflict of interest: the more they build transmission to help renewables, the faster they have to retire or take writedowns on their own fossil fuel assets.

Third, supply chain issues. Delays in deliver times are continuing to lengthen. This was happening post-Covid, and the war in Ukraine exacerbated the situation. The industry is now forced to sign long-term supply agreements to guarantee equipment well in advance of project financial close.

Fourth, permitting. There’s still resistance to renewables in some areas. We look to form long-term partnerships with the communities we develop in, because we are an owner-operator as opposed to a ‘develop and flip’ platform and plan to be a part of the community for years to come. Local objections kill a lot of projects.

And the fifth challenge is financing. The good thing about the IRA is a lot more projects – electric vehicles, green hydrogen and so on – can tap into tax credits, but the demand for tax credits is outstripping supply. A shrinking number of sponsors have access to large tax equity suppliers. For us, the Brookfield transaction came at a great time because they have strong relationships with banks in North America and globally.

> Delays in deliver times are continuing to lengthen. This was happening post-Covid, and the war in Ukraine exacerbated the situation.



Tipping point for transmission

The European offshore wind sector is poised for huge growth that will change how projects connect to the grid. Richard Heap looks at the future of transmission in the European offshore market and whether the era of 'point-to-point' links is ending.

Europe's offshore wind sector is into its fourth decade. With 32GW of installed capacity at the end of June 2023, the sector is unrecognisable from that first project in 1991.

Yet the sector's approach to connecting offshore wind farms to the onshore grid has changed little over that period. The technology and installers are more sophisticated, but nearly every offshore wind farm is connected to the grid via a 'point-to-point' (or 'radial') connection. This has given offshore wind farm operators the certainty that they will be able to export power from their projects and clarity on transmission cost.

However, there is now a great deal of debate in the industry about the best ways to connect offshore wind farms to the grid in the coming years. The system of point-to-point connections has worked so far, but it has weaknesses too.

First, Europe's seas are set to become increasingly busy. By 2040, the International Energy Agency has forecast there could be as much as 180GW of offshore wind in European waters. The European Union is targeting for 300GW in operation by 2050. This would make the current approach increasingly unwieldy, and load extra pressure on the supply chain. Policymakers are looking at collaborative approaches with shared connections, such as hybrid projects, energy islands and meshed grids.

Second, dedicated point-to-point transmission links are an expensive solution, due to the fact that capacity factors of new offshore wind farms are 40%-50%, according to WindEurope. This means that point-to-point transmission lines spend long periods of time without being used. Shared approaches could enable operators to divide the cost of transmission lines between them, and support firms through the value chain as they grapple with tight profit margins. How much companies should pay to develop, deliver and operate these links is a hot topic in the industry.

And third, some industry onlookers are concerned that emerging European offshore wind markets, particularly in the Nordics and southern Europe, are planning to copy the UK's Offshore Transmission Owner (OFTO) regime. Under this regime, it is the wind farm developer that builds the transmission line to their project, before selling it on completion. Only a limited number of offshore developers have the skills to deliver new transmission lines themselves, which could increase the risks associated with projects.

The UK's OFTO approach is in contrast to the way offshore links are developed by third-party Transmission System Operators (TSOs) in the rest of Europe.

In this article, we will look in greater depth at the key trends that are shaping industry debate on the future of Europe's offshore grid; and share insights on how developers and investors can mitigate their financial risks as the system continues to evolve.

Mimicking OFTOs

The UK implemented its OFTO regime in 2009 to give offshore wind developers the responsibility to design, fund and build transmission links to their schemes. They sell the link on completion to a specialist operator, such as Blue Transmission, Diamond Transmission Partners or Transmission Capital Partners. The most recent such sale was Ørsted and AXA's disposal of the £1.1bn Hornsea 2 grid link to Diamond in July.

The benefit of this approach is that it has given the developer certainty about when the transmission line to their project will be built, so that they can be synchronised. The challenge is that developers need to fund and deliver a transmission line along with the rest of their project, which exposes their investors to additional risk, but it has not stopped the UK growing to 13.9GW of installed offshore wind capacity.

In the rest of Europe the responsibility for building and paying for grid upgrades sits with TSOs such as TenneT and Elia. Despite teething problems in the early 2010s, this approach now works well. In March, TenneT awarded contracts totalling €30bn for 14 offshore grid connection systems in the German and Dutch North Sea.

However, other countries are now looking to mimic the OFTO approach, including Norway in its delayed first offshore wind tender where results are due in early 2024.

> "Making offshore wind farm operators responsible for the cost of transmission upgrades for projects is the only way you get the real cost of offshore wind"
>
> **Quentin Le Noac'h, Voltiq**

Quentin Le Noac'h, partner at financial advisor Voltiq, says including the transmission link in the scope for offshore wind farms in more markets will increase costs and risks for investors.

"It's only in new markets, where most projects are really early development stage that the grid is coming back into the project scope. In Germany, Denmark and France, it's completely out of the scope, so it hasn't been a concern historically," he says. "But now you are seeing this in new markets, and it is a concern because, as it's only been on UK projects so far, a lot of developers have only limited experience with actually building or managing transmission links."

The scale of offshore grid connections needed in Europe in the coming decades is also a concern for the supply chain. There is still a small number of players with the experience of installing high-voltage direct current (HVDC) cables, including ABB, Hitachi Energy and Siemens Energy. This limited pool of suppliers could result in delays with the delivery of new grid connections, and have knock-on effects on the financial side of offshore wind projects. In addition, transmission experts face similar workforce constraints as the wider offshore wind industry.

Le Noac'h says it is not only the UK and new offshore markets where developers and investors are at risk of being exposed to the costs of developing transmission lines. He says discussions are afoot in other European countries about whether the developers of offshore wind farms should take on more of the cost of building new transmission lines, even if the responsibility for building them stays with the TSOs.

He says developers and investors need clarity from policymakers over how the cost of building transmission lines will be treated in individual markets.

"It's not a major concern, but it is a new thing and it's unclear because many of the countries haven't decided yet. Is it going to be the TSO or not? Who's going to pay for it or will it be a separate revenue stream? It's the uncertainty and the novelty that creates concern," he explains.

Le Noac'h adds that making offshore wind farm operators responsible for the cost of transmission upgrades for projects is "the only way you get the real cost of offshore wind". It will not be easy for countries and companies to make these changes—but the discussion over who pays for transmission upgrades is far from over.

Another impact of the huge predicted growth of offshore wind in Europe is that

The current system of point-to-point grid connections will continue to evolve as the European Union introduces new reforms for the EU electricity market.

there will be increased levels of curtailment at offshore wind projects when the grid is too busy. WindEurope says it is vital for the European Commission to implement clear market rules about curtailment, so operators know the financial risks to projects.

The current system of point-to-point grid connections will continue to evolve as the European Union introduces new reforms for the EU electricity market.

Long-term grid planning

The discussion about curtailment also demonstrates a bigger transmission challenge for Europe's offshore wind industry: the need for long-term grid planning. The current system of individual ad hoc transmission lines will become increasingly unwieldy.

The European Commission has shown it is aware of the issue. The next Commission is set to be appointed in mid-2024, and WindEurope says that the need for offshore and onshore grid upgrades to support wind projects will be high on its agenda. The European offshore wind sector has grown almost fivefold over the last decade, from 6.6GW in 2013 to over 32GW now. This has mainly been driven by national policies.

However, the future of offshore wind in Europe is set to rely on greater cooperation between countries.We can see this in recent cross-border partnerships. In September 2022, the nine members of the North Seas Energy Cooperation pledged to roll out at least 260GW of

offshore wind in the North Sea by 2050; and, in August 2022, eight countries neighbouring the Baltic Sea committed to 19.6GW of offshore wind in the Baltic by 2030. We will also see offshore wind farms developed in the Celtic and Mediterranean Seas in the coming years too.

WindEurope and Hitachi Energy discussed what this would mean for the European offshore grid in the report 'Offshore Grids: The next frontier', which was published in April 2023. The report said that transmission equipment in point-to-point connections was" designed and installed to transmit 100% of the output from the wind farms but remains unused in low or no wind conditions", which meant there was "significant under-utilisation" in Europe's offshore grid with load factors of 40%-50%.

The report argued that European offshore wind should embrace three technologies to ensure the grid is fit for purpose. They are:

Energy island: An energy island is an offshore renewable power hub that links to multiple offshore wind farms, and then sends power to the onshore grid in one or more countries; or uses some or all of the power to create green fuels. Examples include the 3GW Bornholm energy island project linked to Denmark and Germany.

This summer, four countries - Belgium, Denmark, Germany and the Netherlands - committed to build four of these 'islands' to transmit power and green hydrogen to multiple countries.

Offshore hybrid projects: An offshore hybrid project, sometimes known as a 'multi-purpose interconnector', enables multiple wind farms to connect to multiple markets by merging offshore wind generation and transmission assets in a single asset. The report gave examples of the Triton Link between artificial energy islands in Danish and Belgian waters; and the Nautilus interconnector between Belgium and the UK.

Meshed grid: A meshed grid would connect several offshore wind farms to the grid in several countries. Proponents of the technology say it would be more reliable and have higher utilisation rates than current point-to-point links. Countries around the North Sea and Baltic

Sea have started work to jointly plan these grids, while the European Network of Transmission System Operators for Electricity (ENTSO-E) is due to publish a regional network development plan by January 2024.

These collaborative approaches present opportunities for companies in the offshore wind sector: shared transmission schemes could help reduce the financial exposure of developers and investors to the cost of building individual point-to-point connections.

However, finance experts warn that there will be financial risks for firms to overcome as well, due to their exposure to multiple electricity grids and power markets. This is set to increase the complexity of their energy trading strategies.

Udo Schneider, managing director at Green Giraffe Advisory and head of the firm's Hamburg office, says it is a good idea to build stronger transmission links between offshore projects as it can help stabilise grids, decrease the levelised cost of offshore wind power, and open up opportunities for energy arbitrage across multiple countries.

"If Ireland wants to play a role in European markets, it's going to have to develop its own offshore transmission system to feed into the European super grid."

Cathal Ryan, Inis Offshore Wind

"Interconnecting projects and countries would also increase the resilience of the system, which is important since such projects are considered to be of strategic significance." he says. "You want to build more meshed networks, but that's much easier if done in one balancing market only."

He says offshore wind operators would need some level of long-term off-take certainty and curtailment protection, as otherwise the business case becomes more dynamic and more difficult to predict. WindEurope says offshore wind farm owners need a 'transmission access guarantee' to ensure they would be able to export the power from their project in competition with other offshore wind farms. It has called on the European Commission to include this in its energy market reforms.

Schneider says he likes the idea of more collaboration on transmission "but it gets exponentially more difficult if you combine two, three or four markets, none of which is perfect". He adds that getting the legal framework for such a project right would also keep lawyers busy.

Another concern is that the size of these shared transmission projects, as well as the involvement of governments in their development, could mean that contracts need to be tendered via official European Union processes. This could increase the time and uncertainty associated with these projects, as well as leaving them more exposed to short-term political decisions. The regulatory approach will need to evolve to give the developers and investors in offshore wind farms the confidence they need.

For operators in Europe's emerging offshore wind markets, there are also potential benefits for linking into the grids in more than one country. Cathal Ryan, regulatory analyst at Irish developer Inis Offshore Wind, said that creating links with the rest of Europe would be crucial for the growth of offshore wind in Ireland, for example.

You want to build more meshed networks, but that's much easier if done in one balancing market only

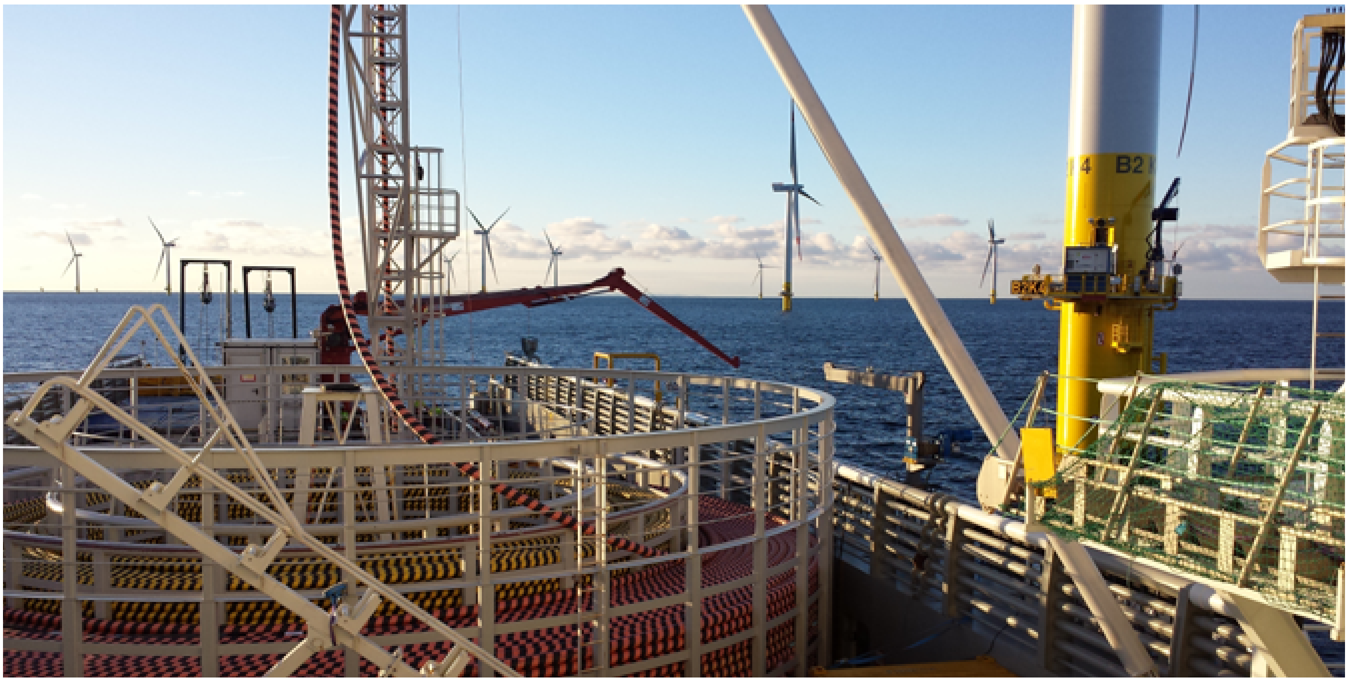
Construction work is underway on the €1.6bn Celtic Interconnector between Ireland and France; and Irish policymakers are also exploring links with Belgium, Spain and the UK as well. Ryan says this will expose operators to risks in the energy markets in more than one country, but that this is a huge opportunity to meet demand.

"If Ireland wants to play a role in European markets, it's going to have to develop its own offshore transmission system to feed into the European super grid," he says.

This will likely present short-term economic challenges in new markets that have not reached the scale and sophistication of offshore wind in the North Sea. He says: "It's more expensive to generate offshore wind power in Ireland compared to the North Sea, but I think over time that will come down. That's the hope, and the government taking the lead on building offshore infrastructure will be critical to enable that."

Ryan adds that one difficulty with long-term transmission planning is that these plans can be outdated by the time they are due to be implemented, particularly if they are over a 10-year time horizon. This suggests that transmission planners will need to take a longer-term view if Europe is to get the offshore and onshore grid it needs.

The era of point-to-point connections is not over. This is the most established way of linking offshore wind farms to the onshore grid, which means the model is trusted by developers and investors. But new approaches to transmission will be needed as the seas in Europe become busier, and the job now is for regulators, policymakers and TSOs to build investor confidence by providing clarity over timelines and costs. This work is essential as Europe's offshore wind sector heads to its fifth decade.



DNV Q&A:

Interconnection costs ‘won’t come down soon’

Wind developers in the US are increasingly focussed on the economic impact of curtailment, according to DNV’s Tim Pearce (head of resource integration & market analytics) & Cornelis Plet (vice president, power system advisory)

Why are US transmission interconnection costs increasing for wind farms?

Tim Pearce: It’s related to the remoteness of wind farms. Increasingly you’re seeing the comparison with, say, a combined-cycle gas turbine where the costs are dramatically lower than those for a wind farm. Firstly because of the footprint and location, and then when you do the math on the capacity factor, it makes the cost that much higher for a wind farm. If you’re building out transmission for a 1,000MW wind farm that has a lower capacity factor than a natural gas facility, that is in a smaller footprint and has a higher capacity factor, it costs more because of that.

How can wind developers mitigate high grid interconnection/transmission costs?

TP: Onshore wind developers look at the curtailment new wind farms will experience upfront. They look at the financial impact and how it will affect tax credits, for example. Developers are also trying to enter into power purchase agreements that will guarantee a revenue stream. They’re now more focussed on the economic impact of the congestion curtailment based on the existing grid. They are also lobbying hard for upgrades to the current transmission grid.

So, curtailment analysis studies are important?

Cornelis Plet: By doing your homework and running these congestion curtailment analysis studies for different POIs [points of interconnection], you can identify the economic risk for each one. The other thing that we see is developers building large loads close to their generation sites in the form of electrolyzers. We see several projects where developers are basically saying ‘we don’t need the transmission grid anymore, we’ll just go straight from wind into hydrogen’.

What’s your forecast for interconnection costs?

CP: If policy can get changed to stimulate new transmission, and get it built out at a faster rate, then those costs might come down. It also depends a little bit on how those costs are allocated. For example, in Europe, the costs of the connection of an offshore wind farm are born by the ratepayers. It’s different over in the US where it’s borne by the developer. So, depending on what policy choices are made, costs could come down. But things are moving quite slowly in the US so I don’t think they’re going to come down very soon.

Is there a solution?

CP: In some cases, the Department of Energy (DOE) is saying they are going to step in and buy 50% of the transmission capacity for the lifetime of the line, basically giving the transmission projects the financial security they need to go out to the market to get a construction loan and go ahead and bid. Then the idea is that, before the line is actually completed and constructed, the DOE will have sold off their transmission rights to the renewable developers who are now also building their wind farms and solar farms because now they know that the transmission line is going ahead.

> ”We see several projects where developers are basically saying ‘we don’t need the transmission grid anymore, we’ll just go straight from wind into hydrogen’”.

Cornelis Plet, DNV

Get in touch

hello@tamarindo.global

+44 (0)20 7100 1616

www.tamarindo.global

Tamarindo