Ea Energy Analyses

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Offshore wind and its relationship to transmission and hydrogen infrastructure in Northern Europe

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Forward

The purpose of this report is to inform all those interested in wind energy economics (including IEA Wind Task 53 members) on the potential synergies between offshore wind generation and hydrogen infrastructure in the European context.

The report is a Work Package 5 deliverable of IEA Wind Task 53 (2022-2026): “How does transmission infrastructure and hydrogen affect the cost and value of offshore wind energy?”. While published in March 2026, methodology and assumptions have been developed over the period from April 2024 - October 2025.

1

Introduction

The offshore wind energy sector continues to grow around the world, with global capacity reaching 83 gigawatts (GW) by the end of 2024[1] (references can be found at the back of the report). This capacity is located almost exclusively in China and Europe, which tend to have shallow coastlines and strong costal winds. In Europe in particular, thanks to the high winds and shallow depth of the North Sea, offshore wind stands to play a key role in the energy transition.

Over the last five years, the offshore wind sector has experienced headwinds, namely due to the increase of interest rates, as well as higher costs of raw materials and supply chain constraints. Offshore wind energy projects are particularly sensitive to interest rates as they are very capital-intensive investments, with most of the lifetime costs incurred upfront. These factors have caused the cost of offshore wind to increase about 30% between 2021 and 2023 in Denmark[2] and by ~50% since 2020 in the US[3]. This increase in cost has led to a number of large offshore wind tenders in Europe that received no competitive bids.

Annual additions of offshore wind have remained at ~3 GW/year over the past 10 years (2015-2024) in Europe (including UK)[4]. Even though annual additions of offshore wind in Europe have not meaningfully grown since 2015, it is expected to increase rapidly in the future, already reaching 10 GW/year by 2030 based on accepted and expected actions as of February 2025[4].

Due to the need to decarbonize both the existing hydrogen demand and a number of hard-to-abate sectors including shipping, aviation, steel and cement production, hydrogen demand is expected to increase over the coming decades if Europe is to become carbon neutral[5]. In order to produce this future hydrogen in a sustainable manner, the use of electrolysers is expected to accelerate, due to their ability to convert water and electricity into hydrogen via electrolysis[5].

If electrolyser capacity accelerates to the levels needed to decarbonize the hydrogen sector, it is expected that electrolysis will also facilitate the integration of variable renewable energy (VRE) because during times of high wind and solar generation, surplus electricity can be used to produce hydrogen, and vice versa[6].

Furthermore, the transmission of hydrogen across very long distances via pipeline is estimated to be cheaper than HVDC power lines over the same distances[7]. This suggests that, if some future offshore wind is to be built for the main purpose of generating green H2, offshore wind farms could produce hydrogen (H2) on site and transport it to shore via a pipeline instead of sending electricity to shore via an HVDC line, assuming the H2 is not converted back into electricity. This option is the main motivation for this report.

The aim of this report is to analyse the impact of hydrogen infrastructure configurations on the value of offshore wind energy.

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Methodology

The Balmorel Energy System Model

To analyse the impact of transmission and hydrogen infrastructure on offshore wind energy, the Balmorel Energy System Model was used. Balmorel was originally developed to model the district heating and power system of the Baltics in the early 2000s and has since been actively developed and used across the Northern Europe, primarily at the Technical University of Denmark (DTU) and at Ea Energy Analyses.

Balmorel is used to model a future energy system and produce outputs such as hourly electricity prices, optimal solar and wind buildout, and revenue from individual infrastructure projects. The purpose here is to use it to determine the potential relationships between offshore wind energy, electricity transmission, and hydrogen infrastructure based on a possible future European energy system that is based upon a set of assumptions including but not limited to future fuel prices, future grid buildout, potentials for renewable energy and future energy demand growth.

In an attempt to keep this report succinct, this section focuses on key assumptions of the modelled energy system. The Balmorel model itself is open source and available at: https://github.com/balmorelcommunity/Balmorel. However, the detailed input data has not been presented in order to keep the report short. That being said, any further inquiries about input data used in the work can be sent to phs@eaea.dk.

The Modelled Energy System

A key assumption which drives asset investment in Balmorel is the EU’s goals of being carbon neutral by 2050. Demand

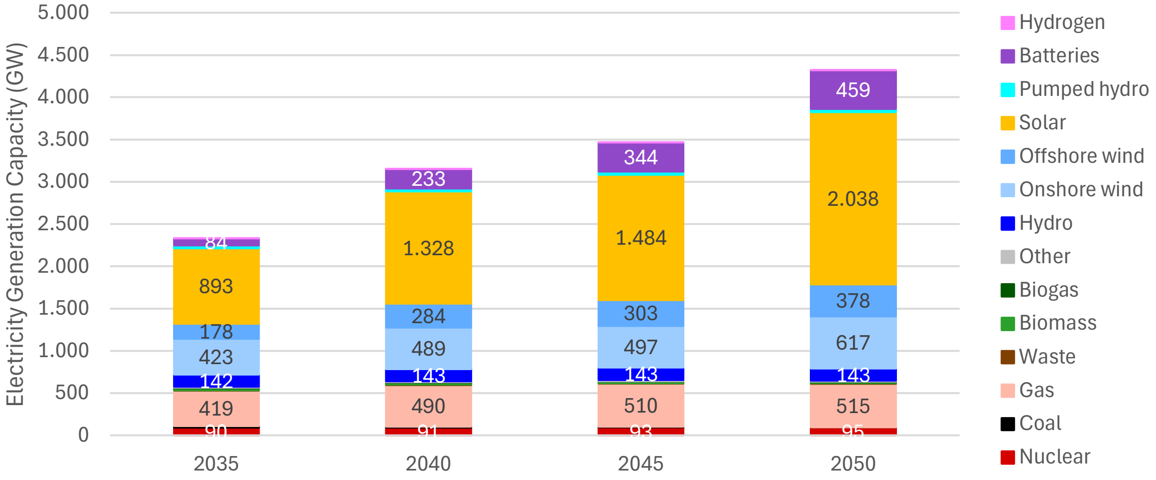

Figure 1: Total European electricity supply capacity by year

assumptions are developed with ENTSO-E's Distributed Energy scenarios in TYNDP 2024[8] as a starting point.

To pursue carbon neutrality by 2050, we assume carbon taxes rising from 95 €/ton in 2035 to 130 €/ton by 2050 as an important driver for the energy supply. These prices come from CO2 futures markets in the short term (through 2027) and in the long-term we expect CO2 prices to not raise drastically as this would be politically unacceptable, thus raise eventually to 130 €/ton in 2050, (an estimate based on internal evaluations within Ea Energy Analyses). This assumption, along with decreases in the cost of VRE and battery storage (assumptions which come from the Danish Energy Agency's Technology Catalogues[9]), results in a European energy system with wind and solar dominating the supply of electricity (Figure 1). In this system, thermal generation capacity makes up only 22% of supply capacity in 2035 and falls to 15% by 2050.

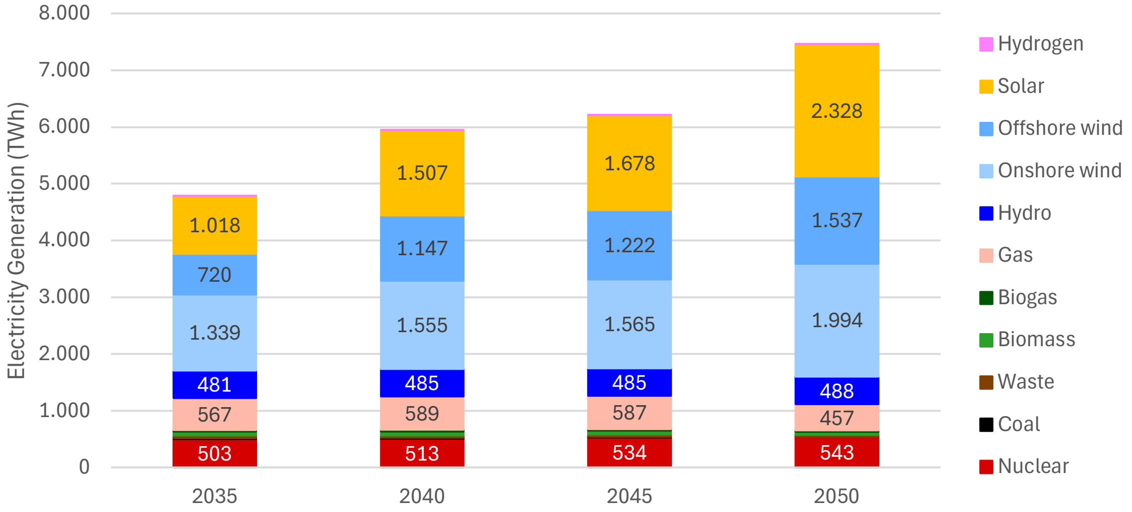

Figure 2: Total European electricity generation by year

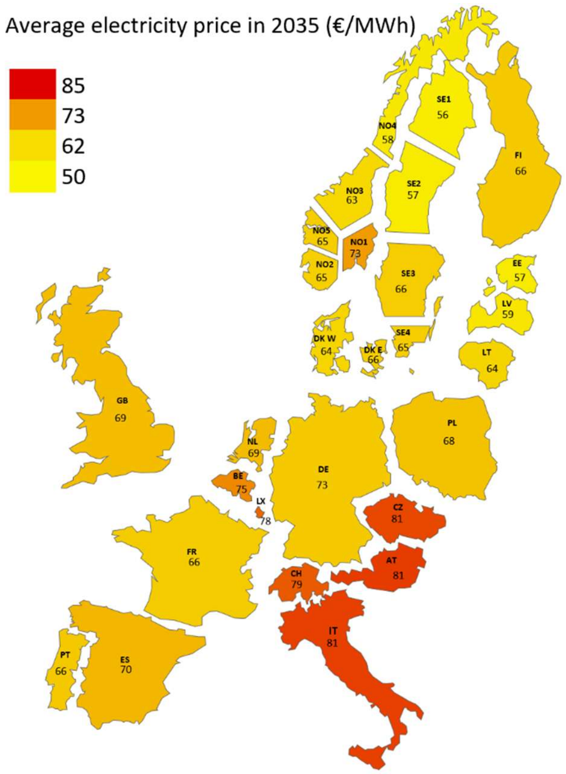

Figure 3: Average electricity price in 2035. 2050 numbers have a similar pattern, but 5-10% lower

The system is still able to balance supply and demand through a number of investments. On the demand side, the use of energy storage (namely batteries) and flexible demand (namely price responsive EV charging and electrolyser demand) generate power system flexibility. Transmission expansion decreases the need for additional thermal capacity.

Similar to today, electricity in 2035 tends to be generally cheaper to produce in Northern Europe than in Southern and Central Europe where most of the demand is located (Figure 3).

Offshore wind and interconnection hubs

Five proposed offshore wind energy areas in the North Sea were used in this study. Each location chosen is at least under consideration to become an international hub for offshore wind energy. We chose projects which plan to connect to two or more countries, either directly or indirectly via other interconnected hubs. Each hub, their associated potential interconnector project, and their real-world location can be seen in Table 1.

Table 1: Modelled offshore wind and interconnection hubs (see footnotes at the bottom of this page)

Offshore Hub	Associated Interconnector Project	Location
Danish Hub	Triton Link[1]	Nordsøen III area
Belgian Hub	Nautilus[2]	Princess Elisabeth Island
Dutch Hub	LionLink[3]	Nederwiek 3 area
German Hub	North Sea Wind Power Hub (NWSPH)[4]	EN11 offshore zone
UK Hub	HansaLink[5]	Dogger Bank area

Each hub has an associated amount of wind capacity, which can be seen in Table 2. The size of each farm comes from the associated project's information, or internal assumptions where the information was unavailable.

Table 2: Installed offshore wind capacity in each hub (GW)

Hub Name	2035-2045	2050
Danish Hub	3	6
Belgian Hub	1.4	2.8
Dutch Hub	2	4
German Hub	2	4
UK Hub	2	4

Scenarios and Sensitives

To analyse the impact of transmission and hydrogen infrastructure development on the economics of offshore wind energy, we investigated three different infrastructure scenarios: Case I, Case II, and Case III.

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[1] https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/tritonlink
[2] https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/nautilus
[3] https://www.tennet.eu/nl-en/projects/lionlink
[4] https://northseawindpowerhub.eu/
[5] https://www.windgrid.com/

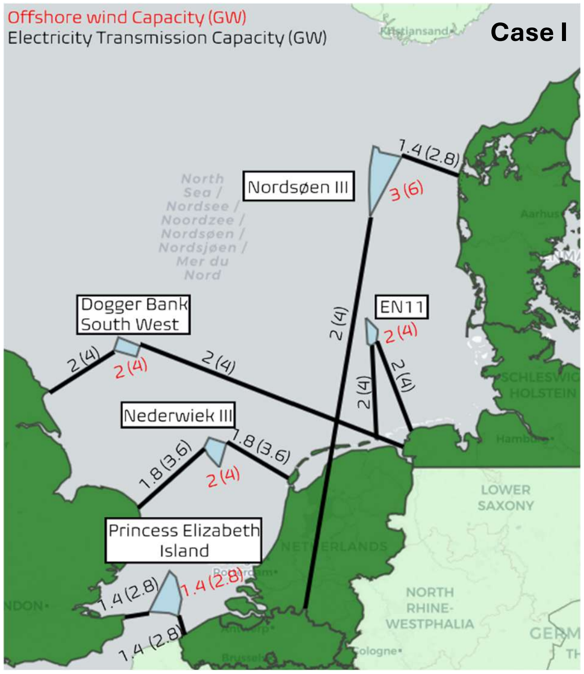

Figure 4: Case I setup (100% electrical connection to shore). Numbers outside parentheses are for 2035, numbers inside parentheses are for 2050

Table 3: Scenario overview

Scenario Name	Transmission Infrastructure
Case I	100% electric transmission
Case II	50% electric transmission, 50% H2 transmission
Case III	100% H2 transmission

The purpose of modelling these three different cases (Figure 4, Figure 5, Figure 6, Table 3) is to analyse the impact of various types of energy transmission infrastructure on offshore wind energy.

The years 2035, 2040, 2045, and 2050 were modelled, and in each run, these five offshore hubs were exogenously defined (i.e. they are fixed), and the surrounding system was able to be optimized endogenously in the model. This means that when analysing and comparing these scenarios, it is important to remember

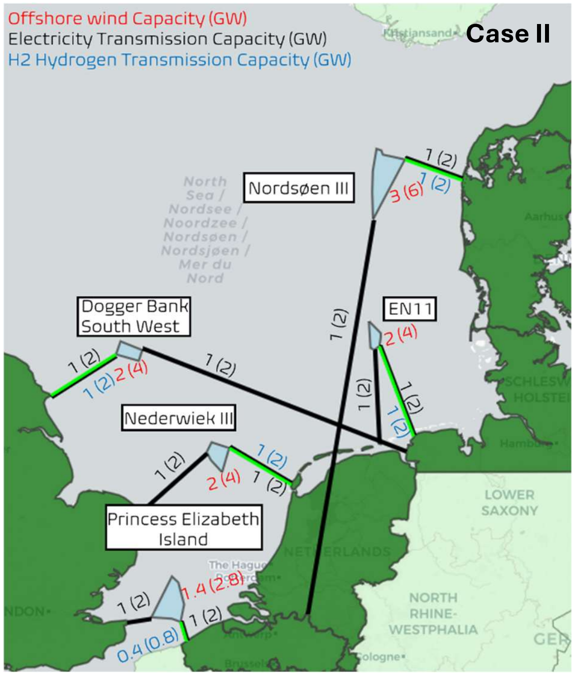

Figure 5: Case II setup (50% electrical connection to shore, 50% H2 connection to shore). Numbers outside parentheses are for 2035, numbers inside parentheses are for 2050

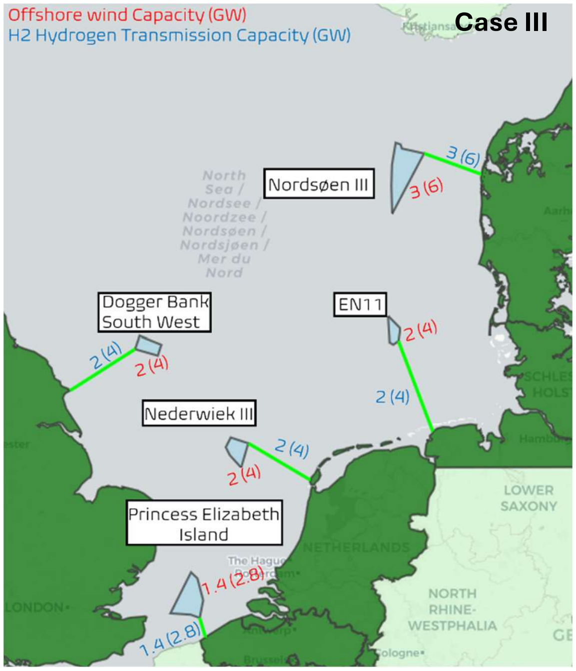

Figure 6: Case III setup (100% H2 connection to shore). Numbers outside parentheses are for 2035, numbers inside parentheses are for 2050

the energy system surrounding these hubs are not identical (although overall they are very similar).

H2 Demand Sensitivities

For each scenario, two additional sensitives were modelled, one with lower H2 demand and one with higher H2 demand. These H2 demands were derived from an internal literature review at Ea Energy Analyses. This means there is a total of nine model runs, as each of the three cases are modelled at three different H2 demand levels. An overview of the H2 demands modelled can be seen in Table 4 and Figure 7, which are inputs to the model.

Table 4: Overview of H2 demand sensitivities (TWh[6]) (Annual European demand), see footnote

Sensitivity	2030	2040	2050
Low H2 demand	68	237	721
Default H2 Demand	137	475	1443
High H2 Demand	274	950	2886

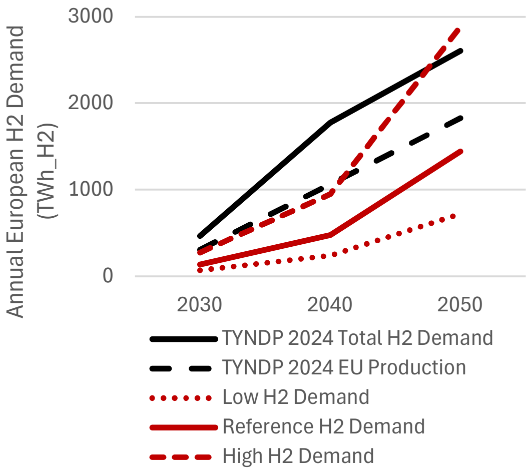

Figure 7: Overview of the three H2 demand sensitivities (in red), with the assumptions from TYNDP 2024 as a comparison.

H2 demand was chosen for a sensitivity analysis because it has a significant impact on the modelled results. The higher H2 demand is, the higher electricity demand becomes and thus the amount of clean energy in the system increases. H2 demand is also one of the inputs with the highest uncertainty, as it is unclear how much more H2 demand will increase, which makes it an important parameter to understand further.

Another key assumption relating to H2 are the options to import H2 from outside the EU, which are considered in the modelling performed during this study and come from internal calculations based on potential H2 production costs in North Africa and globally. There are two import options assumed, one being a pipeline from North Africa, which enters Europe via Spain. The size of the pipeline from North Africa to Spain is capped at 1 GW_H2. Another option is import via shipping, with hydrogen that can be received in any country with a coastline in the model. An overview of

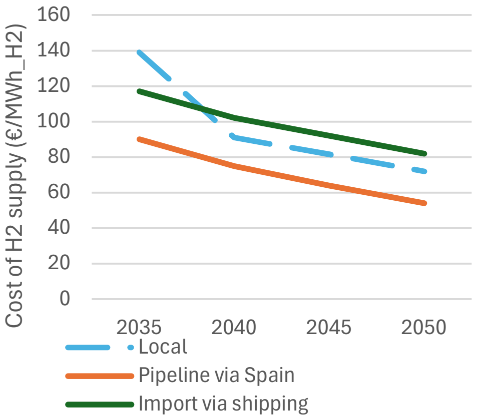

Figure 8: Cost of H2 supply from import options and domestic European (local) production

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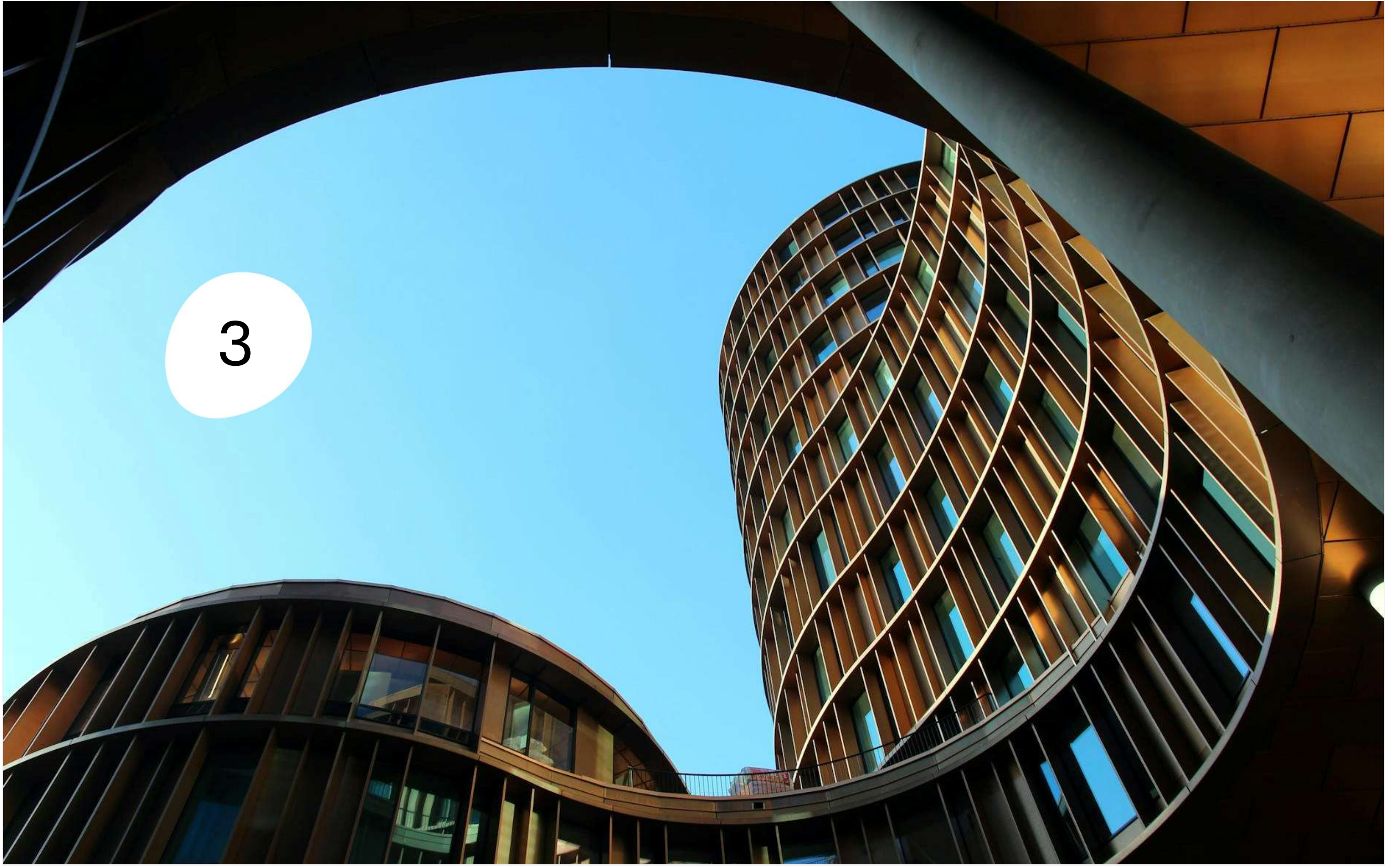
[6] Note: We've assumed the LHV of H2 here, meaning 120 MJ/kg or 33.3 kWh/kg

the marginal cost of H2 supply in the model is shown in Figure 8.

The cost of importing hydrogen is an exogenous assumption; however, the cost of local European hydrogen production ("Local" in Figure 8) is endogenous (i.e. optimized in the model), with the cost of electricity and the timing of production dictating the cost to produce H2. Local represents producing H2 via electrolysis in Europe, and its cost is the average cost to produce hydrogen in the default H2 demand scenario (Case I), and is technically a result from the modelling, and hopefully gives the reader a better idea of what options the model has to meet its hydrogen demand.



Results

This study is focused on the impact of new H2 and energy transmission infrastructure on the system value of offshore wind. System value here is measured based on the revenue earned by the assets in question, which are the offshore wind farms in the hubs, the electrolysers in the hubs, and the transmission assets between the hubs and shore. Results that are not directly related to this system value focus are not discussed in this report.

Results have been organized into three sections. The first group of results focuses on the offshore wind capture price, the second group of results focuses on curtailment, and the last group of results focuses on the system value of the modelled offshore wind energy hubs.

Offshore wind capture price analysis

In each of the three cases, the offshore wind farm capacity is the same, the only parameter which is varying is the hub's transmission system to shore and how much offshore electrolyser capacity each hub is equipped with. One method to measure the value of offshore wind is to calculate the capture price of offshore wind, which is the average revenue from the sale of electricity from one MWh of electricity generation (including curtailed generation). An overview of capture prices in each hub can be seen in Table 5 and 6.

Table 5: Offshore wind farm capture price (in offshore bidding zone) at the reference H2 demand in each case in 2035 (€/MWh)

	Case I	Case II	Case III
BE_Hub	61	61	46
DE_Hub	52	52	36
DK_Hub	52	49	36
GB_Hub	52	52	38
NL_Hub	55	55	36

Table 6: Offshore wind capture price in the low and high H2 demand sensitivities in 2035 (€/MWh)

	Case I		Case II		Case III	
H2 Demand:	Low	High	Low	High	Low	High
BE_Hub	61	62	61	63	39	49
DE_Hub	48	54	48	54	30	38
DK_Hub	50	54	43	52	31	38
GB_Hub	48	54	48	54	31	40
NL_Hub	52	57	52	57	30	38

The offshore wind capture price is virtually the same between Case I and Case II, as there is an electric connection to shore in both scenarios, meaning that the electricity price at the hub is similar to that of the connected onshore bidding zones. Meanwhile in Case III, there is no electric connection to shore, thus the price of electricity is dictated by the onshore H2 price. From the perspective of the wind farm assets, Case I and Case II perform much better than Case III when it comes to the revenue earned by the wind farm asset (i.e. not including electrolysers), as the average cost of electricity used for hydrogen production is lower than the total average value of electricity.

Predictably, increasing H2 demand (which increases electricity demand due to higher amounts of EU H2 production) increases electricity and H2 prices, which benefit the capture price of the offshore wind assets in the hubs (Table 6). Similarly, the decrease in H2 demand lowers the capture prices across the hubs.

The model can import H2 from abroad (see section on methodology), meaning that changing H2 demand does not necessarily translate 1:1 to changes in local H2 production. Table 7 shows the electricity demand from electrolysers, indicating that local production generally follows H2 demand. However, due to the option to import H2, there is a point where H2 demand gets so large that the model no longer increases local production and instead imports H2 via shipping. For example, this clearly happens in 2050 in the High H2 scenario, where H2 demand is 1443 TWh higher than in Ref H2 in 2050, but the added electrical load only increases by 332 TWh. This means that in 2050, the reference and high H2 demand scenarios are more similar than they might first appear.

Table 7: Electricity demand from electrolysers for H2 production in Case I across the three H2 demand sensitivities (TWh). The percent shown is the share of total electricity demand.

	Low H2	Ref H2	High H2
2035	4 (0.1%)	231 (5.6%)	317 (7.6%)
2040	66 (1.5%)	233 (5.0%)	833 (15.9%)
2045	224 (4.5%)	463 (8.9%)	822 (14.9%)
2050	548 (9.8%)	1,451 (22.5%)	1,783 (26.3%)

Curtailment analysis

Another area of interest is the analysis of energy transmission and hydrogen's influence on offshore wind curtailment. In energy systems with high amounts of wind and solar energy, curtailment of wind and solar energy occurs when residual load (demand minus wind and solar generation) falls to zero due to high amounts of wind and solar generation in a given hour. When there is too much VRE generation in the system, wind and solar assets need to curtail their production as there is nowhere for their electrons to go (and negative wholesale prices might arise). This subsection analyses how electricity transmission and H2 transmission could

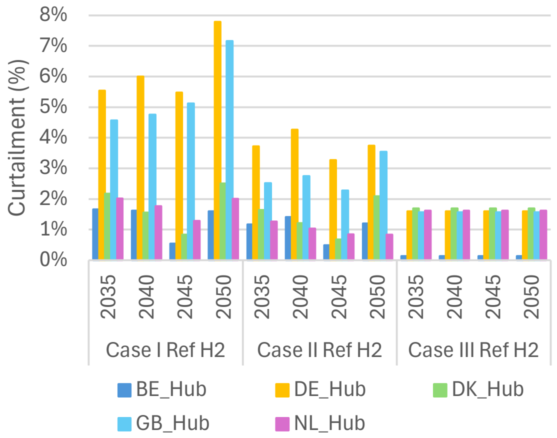


Figure 9: Offshore wind curtailment in the hubs in the reference H2 demand model runs

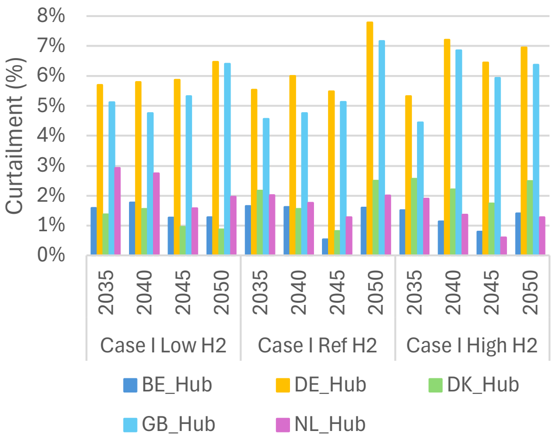


Figure 10: Offshore wind curtailment in the hubs in the Case I model runs

impact offshore wind curtailment in a hub setup.

Figure 9 shows the amount of offshore wind curtailment in each hub. As the amount of electrolyser capacity increases in the hubs, the lower the curtailment becomes. H2 demand is much more flexible than electricity demand as is it relatively inexpensive to store, so the more electrolyser capacity there is in the hub, the less curtailment occurs as there are fewer hours where the system cannot absorb excess H2 production. This also causes hydrogen to have a much higher price floor than electricity (see discussion below). Interestingly, there is still curtailment in Case III in most of the hubs, meaning that even in a 100% H2 offshore setup, the H2 system can still get oversupplied by VRE (now depending on the offtake options for H2).

While the various cases tested have a significant impact on offshore wind curtailment in the hubs, the H2 demand sensitivity is much less conclusive. Increasing H2 demand leads to more electrolysers in the system, which in theory should allow the system to absorb more excess VRE. However, as the H2 demand was increased, the model chose to install more VRE in the system, and thus the ratio of VRE capacity to electrolyser capacity did not change meaningfully, leading to similar levels of curtailment in all three H2 demand levels in Case I, which is shown in Figure 10. While there is a slight drop in curtailment in 2035 as H2 demand is increased, and a slight increase in curtailment in the later years as H2 demand increases, the overall takeaway here is that increasing H2 demand did not meaningfully change the amount of curtailment in the hubs. This is due to the additional generation from variable renewable energy increasing and a new optimal buildout level - also including curtailment – being established.

System value

In this analysis, revenue will be used as a proxy for value, as a perfect market is assumed. To better understand how sensitive the value of offshore wind is to H2 and transmission infrastructure, we analysed three different perspectives:

1) The perspective of the wind farm in the hubs
2) The perspective of the total energy supply at the hubs (wind + electrolyser)
3) The perspective of the entire hub infrastructure (wind + electrolyser + transmission infrastructure).

Table 8: Wind farm value generated in 2035 (million €)

	BE_Hub	DE_Hub	DK_Hub	GB_Hub	NL_Hub	**Total**
Case I Low H2	421	457	746	438	516	**2,578**
Case I Ref H2	420	503	798	472	544	**2,737**
Case I High H2	422	515	809	482	553	**2,781**
Case II Low H2	419	457	661	442	520	**2,499**
Case II Ref H2	420	503	770	477	547	**2,717**
Case II High H2	423	516	787	486	555	**2,768**
Case III Low H2	307	351	527	332	354	**1,871**
Case III Ref H2	384	430	661	426	433	**2,332**
Case III High H2	401	446	684	446	452	**2,429**

Table 8, Table 9 and Table 10 show the revenue generated by the various assets included in each perspective.

The first perspective is that of the windfarm asset. While the value of the windfarms has already been partially explored via capture prices earlier in the results section, they will be analysed in slightly more detail here to use as comparison to the other two perspectives. Table 8 shows the revenue generated by each hub's windfarm in 2035 in each model run. As observed previously, the wind farm's value is higher in Case I and II than in Case III and increasing H2 demand results in a higher offshore wind value by a modest amount (~10%), having the largest effect in Case III.

When only accounting for the revenue generated by the wind farm assets, Case III (100% H2 transmission) appears to be the worst setup for maximizing the value of offshore wind. While the H2 system provides a price floor and lower curtailment, it misses out on hours of high electricity prices. However, if the revenue from the electrolysers is included, the story changes.

Table 9 shows the value generated from the energy supply in the hubs, meaning the value generated by the combination of the wind farm and the electrolysers. Including the revenue from the electrolysers will not change the value generated in Case I, as there are no electrolysers present in the hubs in this case, and thus will only benefit cases II and III.

Shifting to the energy supply perspective (wind farm + electrolysers) changes the value generated in Case III most significantly, and it becomes the case which produces the most value within the hub (for Ref and High H2). This is because the average value of H2 is much higher than the average value of electricity during most hours. Of course, the cost of the

Table 9: Energy supply (wind + electrolyser) value generated in 2035 (million €)

	BE_Hub	DE_Hub	DK_Hub	GB_Hub	NL_Hub	**Total**
Case I Low H2	421	457	746	438	516	**2,578**
Case I Ref H2	420	503	798	472	544	**2,737**
Case I High H2	422	515	809	482	553	**2,781**
Case II Low H2	459	598	799	556	631	**3,042**
Case II Ref H2	472	643	909	614	684	**3,322**
Case II High H2	476	656	927	627	694	**3,381**
Case III Low H2	380	539	831	499	538	**2,787**
Case III Ref H2	461	649	995	607	653	**3,365**
Case III High H2	482	678	1,034	641	687	**3,522**

hub energy supply in Case III is much higher than that of Case I, as it has the 10.4 GW of offshore wind which Case I has, as well as 10.4 GW of electrolysers. However, total transmission infrastructure to shore would be cheaper in Case III compared to Case I, as H2 transmission is cheaper than electricity transmission (for large capacities).

Whether or not Case II and Case III show an overall better economic case compared to Case I depends on:

- The cost of offshore electrolysers
- The cost of H2 infrastructure (pipelines and storage or access to onshore storage)
- The savings on electric infrastructure

Case II also benefits from the inclusion of the revenue generated by the hydrogen supply. While its generated value is lower than Case III, it is not far behind. Furthermore, there is one aspect of the hub infrastructure which has not yet been accounted for, which is the value of electricity infrastructure connecting different bidding zones. This value is reflected in the congestion rent earned by the transmission infrastructure, which would benefit Case I and Case II. Case III does not generate any electricity congestion rent due to the lack of electricity infrastructure.

This leads to the third perspective explored in this analysis, which is the perspective of the entire hub infrastructure, meaning the wind farm, the electrolysers, energy transmission assets (both HVDC and H2 pipelines). What is new in this perspective is the inclusion of the congestion rent earned on transmission assets. The total value generated by the offshore hub setup can be seen in Table 10, which shows that the perspective of the entire hub infrastructure. From this perspective, Case II produces the most value to the system, as it benefits from the congestion rent from the electric transmission assets, the high price electricity hours, and the high price floor of the H2 system.

Lastly, by dividing the total value generated in by the hubs by the potential generation (actual generation + curtailed generation) we can measure the total value per MWh of wind. This can be seen in Table 11.

Table 10: Total system value generated by the hubs in question in 2035 (million €)

	BE_Hub	DE_Hub	DK_Hub	GB_Hub	NL_Hub	**Total**
Case I Low H2	488	551	932	617	615	**3,203**
Case I Ref H2	482	577	957	623	634	**3,273**
Case I High H2	486	590	972	628	639	**3,314**
Case II Low H2	514	653	975	655	691	**3,489**
Case II Ref H2	525	688	1,025	700	742	**3,680**
Case II High H2	530	699	1,039	708	748	**3,725**
Case III Low H2	380	539	831	499	538	**2,787**
Case III Ref H2	461	649	995	607	653	**3,365**
Case III High H2	482	678	1,034	641	687	**3,522**

Table11: Total value generated per MWh wind generation in each hub in 2035 (€/MWh)

	BE_Hub	DE_Hub	DK_Hub	GB_Hub	NL_Hub	Average
Case I Low H2	72	57	63	68	63	64
Case I Ref H2	71	60	64	68	65	65
Case I High H2	72	61	65	69	65	66
Case II Low H2	76	68	66	72	71	70
Case II Ref H2	78	71	69	77	76	73
Case II High H2	79	72	70	78	77	74
Case III Low H2	56	56	56	55	55	56
Case III Ref H2	68	67	67	67	67	67
Case III High H2	71	70	69	70	70	70

The system value analysis thus far has only focused on 2035. This is simply because the trends seen in 2035 generally remain in 2050, with only subtle changes over time in most cases. The total value generated per MWh in 2050 can be seen in Table 12, which can be compared to Table 11 to see how the value changes over time.

The 2050 modelled system differs from the 2035 system in several aspects, namely by the amount of H2 demand, which is much higher in 2050, the share of dispatchable generation in the system which roughly halves between 2035 and 2050, and the price of hydrogen falls as the electrolysis industry matures.

While average electricity prices are slightly lower in 2050 relative to 2035, they are more volatile, which means that exposure to the electricity market in Case I and Case II remains very beneficial. As the price of hydrogen is much lower in 2050, the value added in Case III falls significantly, both relative to its 2035 value and relative to the other two cases in 2050.

Table12: Total value generated per MWh wind generation in each hub in 2050 (€/MWh)

	BE_Hub	DE_Hub	DK_Hub	GB_Hub	NL_Hub	Average
Case I Low H2	73	54	64	63	60	62
Case I Ref H2	72	58	66	64	62	64
Case I High H2	75	59	68	65	63	66
Case II Low H2	75	58	59	64	63	63
Case II Ref H2	76	63	65	68	68	67
Case II High H2	78	63	66	68	68	68
Case III Low H2	44	42	42	42	42	42
Case III Ref H2	56	54	53	54	54	54
Case III High H2	57	55	55	56	56	56

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Conclusion

There are a number of key takeaways from this work, which focuses on the value generated from offshore wind at the specific five sites and how that value generation is sensitive to transmission and H2 infrastructure.

Mixing electric and H2 infrastructure leads to higher total system value

When analysing the total value generated by the 5 hubs and their respective transmission infrastructure, Case II (50% Electric – 50% H2) clearly generated the most value, especially in 2035 when there is a higher H2 price than in the later years. Case II provides more value because it benefits from both the electric and H2 infrastructure.

Electric infrastructure gives the hubs access to high electricity price hours, and congestion rent from interconnecting two onshore bidding zones. H2 infrastructure provides a high price floor, which is helpful during hours with high wind and solar generation when electricity prices onshore are suppressed. Since the marginal benefit of these infrastructures are not linear, having half electric and half H2 infrastructure is better than having 100% of only one of them. The optimal mix of hydrogen and electricity infrastructure depends on the cost and savings for different hub setups. For instance, if the high cost of electric transmission assets experienced over the past 2-3 years prevails, the balance might shift towards higher shares of hydrogen assets as the optimal hub setup.

Relative value of H2 infrastructure declines over time

We assume in our modelling that cost of electrolysers will fall between now and 2050, leading to reductions of the cost (and value) of hydrogen production.

Average electricity prices are also estimated to fall as a result of reduced supply cost, but by a smaller amount. In total, the value added by hydrogen infrastructure is higher in the short term, but the cost of realising the hydrogen infrastructure (electrolysers and pipelines) is also higher.

H2 infrastructure can be an advantage or disadvantage depending on whose perspective you consider

From the perspective of the wind farm only, H2 infrastructure increases the price floor of the hub, which positively benefits capture price. However, the price of H2 is much less volatile than electricity because it is much cheaper to store. This means that without an electricity connection to shore, the hub loses access to above average electricity prices, and overall, this loss is greater than the benefit from increasing the price floor. Comparing Case I (100% electricity) to Case III (100% H2) from this perspective, Case I produces 17% more value in the reference H2 demand scenario in 2035 (Table 8).

However, if the wind farm and offshore electrolyser are owned by the same stakeholder, then H2 infrastructure can increase value generated, at least in 2035 when the price of H2 is high. Comparing Case III to Case I from this perspective, Case III produces 23% more value in the reference H2 demand scenario in 2035 (Table 9).

Lastly, when the value generated by the electricity transmission assets is accounted for, then the value generated in 2035 between Case I and Case III is very similar (65 €/MWh vs. 67 €/MWh) in the reference H2 demand scenario (Table 11). However, over time system H2 supply cost decrease, which impacts Case III negatively, and by 2050 Case I generates 19% more value than Case III (Table 12).

When designing energy transmission infrastructure to hubs, potential congestion rent earnings must be considered

The value generated from the electric transmission infrastructure is not insignificant. By comparing Table 9 and Table 10, it can be observed that in Case I in 2035, congestion rent makes up over 16% of the total system value provided in the reference H2 demand scenario. Whereas in Case II, where the capacity of the electricity transmission is halved relative to Case I, congestion rent still provides 10% of the total value generated. This also indicate that increasing the size of the transmission line to other markets could have diminishing returns.

The point is that, in this study, total value generated increased 10-16% from additional connection to another market, meaning that when designing offshore hub infrastructure, connecting to multiple bidding zones can provide significant value to the energy system and thus should be considered.

As the amount of H2 infrastructure increases, the hub system becomes more sensitive to H2 demand

One large aspect of this study was analysing the sensitivity of offshore wind value to H2 demand. What can be seen across our results is that as the amount of offshore infrastructure increases in the hubs, the more sensitive the hubs are to H2 demand levels. For example, Table 10 shows that Case I's total value generated only increases 3% in 2035 when total system wide H2 demand is increased from 153 TWh to 612 TWh, whereas in Case II and Case III, value increases by 7% and 26% respectively. This also shows that Case III is particularly sensitive to H2 demand levels.

Offshore H2 infrastructure decreases offshore wind curtailment

As stated earlier, H2 increases the price floor of the hubs as the price of H2 does not fluctuate as much as electricity does due to larger amounts of longer-term storage. This means that during hours of high VRE generation, even though the energy system is flooded with cheap electricity causing the curtailment of VRE assets, offshore wind farms connected directly to electrolysers can continue producing.

Comparing the three Cases in 2035 (Figure 9), total curtailment across the five hubs fell from 3.2% in Case I to 2.1% in Case II to 1.4 % in Case III. A related finding is that the German and UK hubs benefited the most, as they had the highest curtailment to begin with.

Figure 10 on the other hand shows that increasing system wide H2 demand did not have an impact on offshore wind curtailment in the hubs. This is because the model was able to invest in the rest of the system in the various H2 demand sensitivities and thus elects to invest in not only more electrolyser capacity, but also more VRE capacity. If the model could not invest in more VRE capacity, the expectation is that only then would increasing H2 demand lead to lower curtailment.

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