EFFICIENT INTEGRATION OF MIXED CONNECTION CONCEPTS FOR OFFSHORE WIND AND HYDROGEN PRODUCTION

A report for AquaVentus

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EXECUTIVE SUMMARY

Unlocking Germany's offshore wind potential and deploying domestic electrolysis are critical to achieving affordable, secure energy and meeting Germany's 2045 climate neutrality target. However, cost expectations for connecting offshore wind with undersea electricity cables have been exploding recently: The latest electricity Network Development Plan expects offshore transmission costs of €158 billion by 2045, on top of a similar number for the onshore transmission network (which is partly also driven by offshore wind expansion). To reduce connection costs, the latest Spatial Offshore Grid Plan by the Federal Maritime and Hydrographic Agency (BSH) invites sector feedback on 'overplanting' of offshore electricity cables in the German North Sea, particularly in far-offshore zones 4 and 5 of the North Sea.

This study evaluates how combining electricity grid connections with hydrogen pipeline connections and offshore hydrogen production – referred to as offshore sector coupling – can complement the BSH proposal of electricity-only overplanting to minimise the cost of integrating offshore wind.

Our analysis covers two offshore wind deployment scenarios to 2045: 70 GW reflecting Germany's statutory target, and 55 GW representing a more conservative expansion constrained by wake effects. For each scenario, we compare three configurations:

- **Baseline**: Current plans with equal offshore turbine and electricity cable capacity, with; electrolysers to produce hydrogen located onshore,
- **Electricity-only overplanting**: Excess turbine capacity relative to cables and electrolysers located onshore,
- **Sector Coupling:** Excess turbine capacity relative to grid connection; offshore electrolysis with a hydrogen pipeline complementing electric connections.

We assess these three configurations using an optimisation model that determines the cost-minimising capacity of transport infrastructure required to integrate offshore wind and hydrogen production in zones 4 and 5 of the North Sea (while connection infrastructure in nearer-shore zones 1-3 are not varied).

Key findings at a glance

1. **Offshore sector coupling enables cost savings of up to €1.7 billion per year in Zones 4 and 5 of the German North Sea**

   Electricity-only overplanting does already reduce net infrastructure costs compared to the 'current build-out' baseline by €778 million per year in the 70 GW offshore wind scenario, and €116 million in the 55 GW scenario, respectively. However, substantially higher savings are achieved if offshore sector coupling is applied: savings of €1,664 million per year in the 70 GW scenario and €477 million per year in the 55 GW scenario.

2. **Cost-effective transport infrastructure explains the economic advantage**

   Offshore sector coupling is a valuable option for connecting far-from-shore wind areas, due to lowest costs by combining efficient energy transport and flexible use of offshore generation. Despite higher costs for offshore electrolysis compared to onshore electrolysis, the use of hydrogen pipelines significantly reduces transport costs. And the flexibility to produce and export either electricity or hydrogen improves generation and transmission infrastructure utilisation and minimises curtailment of offshore wind electricity.

   In particular, power grid utilisation increases from 52 % with electricity-only overplanting to 65 % with offshore sector coupling in the 70 GW scenario, and from 55 % to 64 % in the 55 GW scenario. Curtailment falls from 14 % to 11 % at 70 GW, and from 5 % to 3 % at 55 GW, resulting in about 2.5 TWh more total energy delivered to the system in 2045 in the 70 GW scenario and about 1 TWh more in the 55 GW scenario, combining electricity and hydrogen outputs.

3. **Results remain robust across key sensitivities on electrolyser capacity, electricity prices and offshore electrolyser costs**

   Offshore sector coupling delivers the lowest net infrastructure costs across key sensitivities. Moreover, the relative advantage a) increases with higher electrolyser capacity, b) remains stable across electricity price variations of ± 20 %, and c) persists even when offshore electrolysers are assumed to be twice as expensive as onshore electrolysers. This confirms that the economic case for offshore sector coupling is not dependent on narrowly defined parameter ranges but holds under a broad set of future market conditions.

4. **Required action to enable offshore sector coupling**

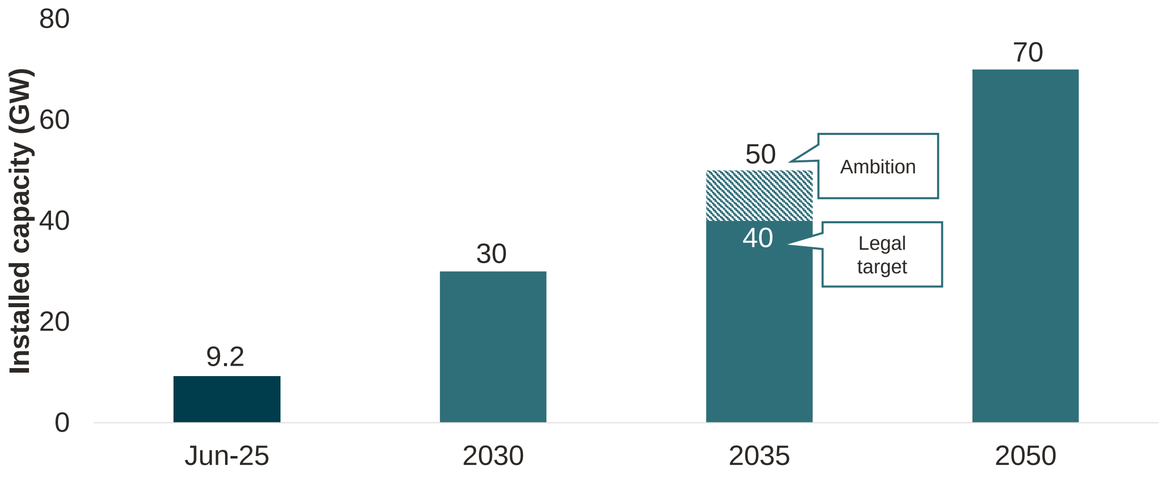
   Key regulatory elements are to be addressed in order to enable offshore sector coupling in Germany and realise the potential to cost-efficiently deploy offshore wind energy. The regulatory elements include a) expanding site designations beyond the current 1 GW for offshore electrolysis planned at pilot area SEN-1 and allowing mixed offshore power-and-hydrogen connection concepts, b) advancing planning for both power and hydrogen transmission in parallel, c) granting same status of public interest to offshore electrolyser projects as to onshore electrolyser projects, and d) implementing mechanisms to mitigate investment risks.

Contents

1 Introduction

Germany aims to achieve climate neutrality by 2045, with offshore and renewable hydrogen on the basis of electrolysis with renewable electricity as central elements. Targets include 30 GW of offshore wind electricity generation capacity by 2030, 50 GW by 2040, and 70 GW by 2045 (Figure 1).

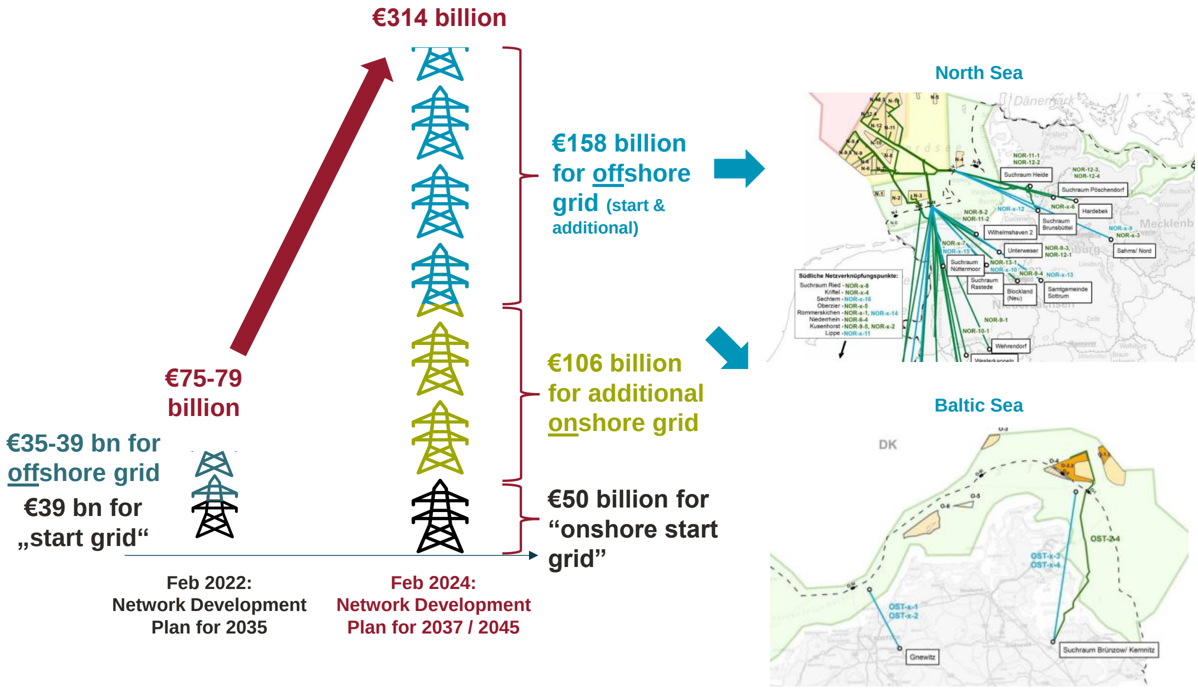
Figure 1 German legal targets for offshore wind generation capacity



Source: Frontier Economics based on Deutsche WindGuard (https://www.offshore-stiftung.de/en/status-quo-offshore-windenergy.php) and WindSeeG (www.gesetze-im-internet.de/windseeg)

Until today Germany's planning principles are based on the assumption that every offshore wind park receives a 100 % electricity cable connection, with the exception of a 1 GW pilot area (SEN-1) where alternative connection concepts such as offshore hydrogen are supposed to be trialled. However, cost expectations for connecting offshore wind with undersea electricity cables have been exploding recently: The latest electricity Network Development Plan expects offshore transmission costs of €158 billion by 2045, on top of a similar number for the onshore transmission network.

Figure 2 Development of expected electricity transmission network expansion cost between 2022 and 2024



Source: *Frontier Economics based on Network Development Plans (NDP) 2022 and 2024*

In line with recent monitoring, cost-efficient domestic electrolysis should complement large-scale hydrogen imports and be developed in a system-serving manner. Ensuring cost efficiency in reaching these targets is necessary so that energy supply remains competitive and affordable.

In this context, the Federal Maritime and Hydrographic Agency (BSH)'s latest Spatial Offshore Grid Plan (FEP) has revived discussion on overplanting offshore wind capacity relative to grid connections, particularly in Zones 4 and 5 of the North Sea, i.e. the zones farthest away from the German coast in the so-called duckbill ("Entenschnabel"). This alternative has been explored before, for instance in the UK, Ireland and the Netherlands.[1]

The BSH proposal entails a trade-off between lowering costs of offshore electricity grid connection and reducing electricity volumes of offshore wind parks transported to consumers: On the one hand, sizing the cable below offshore peak generation capacity lowers costs, as peak output is seldom reached. On the other hand, it limits the maximum power deliverable

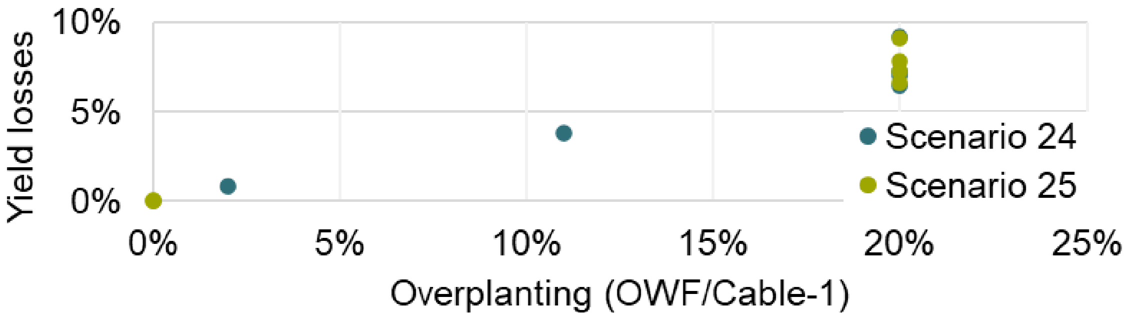
1 For example: UK Round 3 leasing process (2008), Ireland's decision to raise its cap by 20 percent above maximum export capacity, and the Netherlands' approach allowing up to around 8 percent additional capacity in the Borssele tender. Following Borràs Mora et al. (2019) in *Journal of Physics Conference Series 1356* and Wolter et al. (2016) in the 15th Wind Integration Workshop, *Overplanting in Offshore Wind Power Plants in Different Regulatory Regime*s. The latter refers to studies in Ireland suggesting optimal overplanting at 8-20% above the transmission capacity for onshore wind and 2-5% optimal overplanting for offshore wind in the United Kingdom

and requires curtailing energy, thereby constraining revenues and increasing the need for subsidies for offshore wind.

Several factors shape this trade-off. Overplanting is more economically beneficial when turbine availability is lower (due to wind speed distribution, wake effects, or faster blade degradation) or when turbine costs are relatively low compared to electrical grid infrastructure. Since these conditions vary across contexts and concrete offshore park sites, each proposal requires an empirical assessment tailored to the specific location.[2]

Recent studies provide evidence specific to Germany. An analysis by Fraunhofer for the BSH indicates that 20 % overplanting in Zones 4 and 5 without sector coupling will lead to 2.8 % lower available offshore wind electricity (yield losses) at the aggregate level of the German Exclusive Economic Zone (EEZ) under area-aggregated peak-load capping, with a further 1.4 % yield losses under area- or farm-specific capping.[3] At the area level, yield losses are higher, between 5-10 % as shown in the figure below.

Figure 3 Yield losses under different levels of overplanting in the German North Sea at area level



Source: Frontier Economics based on Vollmer & Dörenkämper (Fraunhofer, 2025)

Notes: Scenarios 24 and 25 are alternative offshore wind expansion pathways defined by BSH (see Footnote 3). The scenarios differ in total offshore wind capacity: 75 GW in scenario 24 and 70 GW in scenario 25. Each dot represents results for North Sea wind offshore areas N-14, N-16, N-19, N-9E, N-12E, and N-13E.

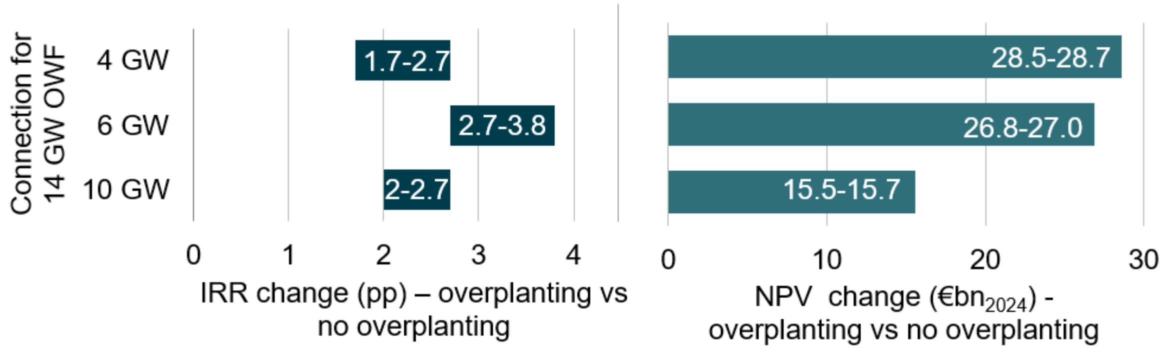
Likewise, a study by E-Bridge for AquaVentus found that allowing (electricity-only) overplanting in Zones 4 and 5 of the German North Sea improves both the internal rate of return (IRR) and the net present value (NPV) of offshore wind projects compared to a no-

2 See Borràs Mora et al. (2019) and Wolter et al. (2016)

3 Vollmer, L., & Dörenkämper, M. (Fraunhofer, 2025) Ad-hoc analysis: yield modelling of expansion scenarios 24 and 25. Scenarios 24 and 25 are alternative offshore wind expansion pathways defined by BSH. S24 assumes merged areas N-14/N-15, enlarged N-17, and a new zoning of N-5 (4.4 GW), leading to slightly lower capacity than in the baseline scenario. S25 keeps the same layouts as S24 but models existing wind farms in N-5 instead of replanning, with adjusted capacity allocations. The study differentiates between two forms of peak-load capping in response to overplanting. Under area-aggregated capping, spare grid capacity can be shared between wind farms within the same area. Under area- or farm-specific capping, each wind farm is limited to its own share of the grid connection, with no balancing across farms.

overplanting case where turbine capacity matches grid capacity.[4] The next chart summarises these findings.

Figure 4 Increases in IRR (pp) left and NPV (€bn$_{2024}$) right relative to no overplanting



Source: Frontier Economics based on E-Bridge (2024) for AquaVentus

Notes: The study evaluates multiple scenarios with differing assumptions on total demand and energy mix. The ranges presented indicate the variation in results across these scenarios.

AquaVentus aims to advance the understanding of how offshore sector coupling through mixed power and hydrogen connections can make use of overplanting to strengthen project economics and lower overall system costs. This study examines how offshore electrolysis, co-located with wind generation and connected to shore via both power cables and hydrogen pipelines, can enhance the efficient use of Germany's offshore wind potential.

4 E-Bridge (2024) for AquaVentus *Assessment of connection concepts for Germany's far out North Sea offshore wind areas for an efficient energy transition*

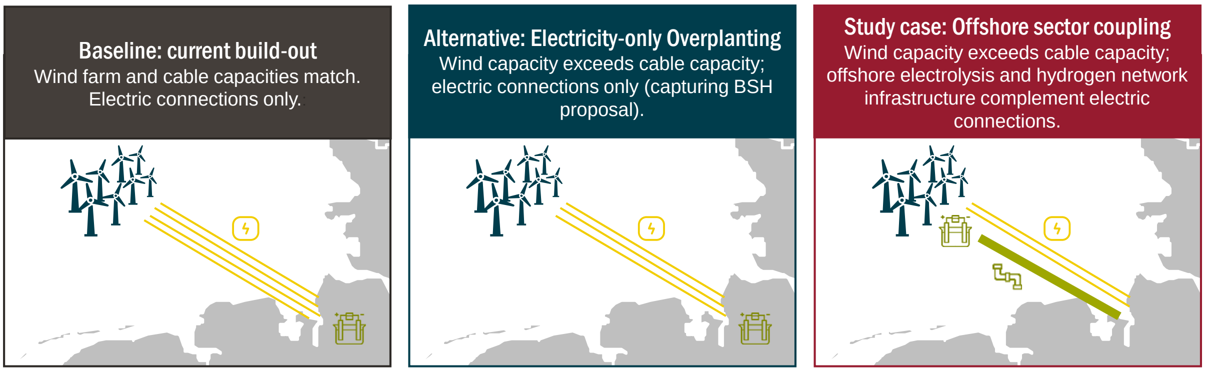
2 Model results show that offshore sector coupling delivers the most cost-effective use of offshore wind potential

In this section we first set out the analytical approach used to compare offshore sector coupling with alternative configurations for integrating offshore wind energy, including key assumptions, scenarios, and modelling design. We then present the main results under central assumptions, followed by sensitivity analyses that test the robustness of these findings.

2.1 Approach: Setting up the comparison of offshore sector coupling and alternative configurations

We examine offshore sector coupling with mixed power and hydrogen offshore connections as an alternative to the BSH proposal of electricity-only overplanting in zones 4 and 5 of the German North Sea. In the BSH proposal, offshore wind capacity exceeds cable capacity and all connections to shore are electricity-only. We compare both options against a 'current build-out' baseline where cable capacity equals turbine capacity (that is, no overplanting) and all connections are electricity-only. Figure 5 illustrates how our analysis defines the three configurations.

Figure 5 Overview of infrastructure configurations



Source: Frontier Economics

Notes: 1) All configurations assume identical wind farm capacities and identical electrolyser capacities within each offshore wind deployment scenario (70 GW and 55 GW). Capacities vary between offshore deployment scenarios but are the same across configurations within each offshore deployment scenario. In baseline and overplanting configuration, the electrolyser is located onshore at the coast while in the offshore sector coupling configuration the electrolyser is located offshore next to the wind farms. Across all configurations and both scenarios the power connection for offshore and coastal electrolysers is bidirectional, implying that electrolysers can also use grid-electricity in situations with low offshore wind generation but low electricity prices (e.g. driven by high solar power infeed).
2) The model optimises offshore cable, electrolysis, and hydrogen transport given the planned turbine capacity, allowing overplanting of turbine capacity relative to cable capacity and of electrolyser capacity relative to hydrogen pipeline capacity.

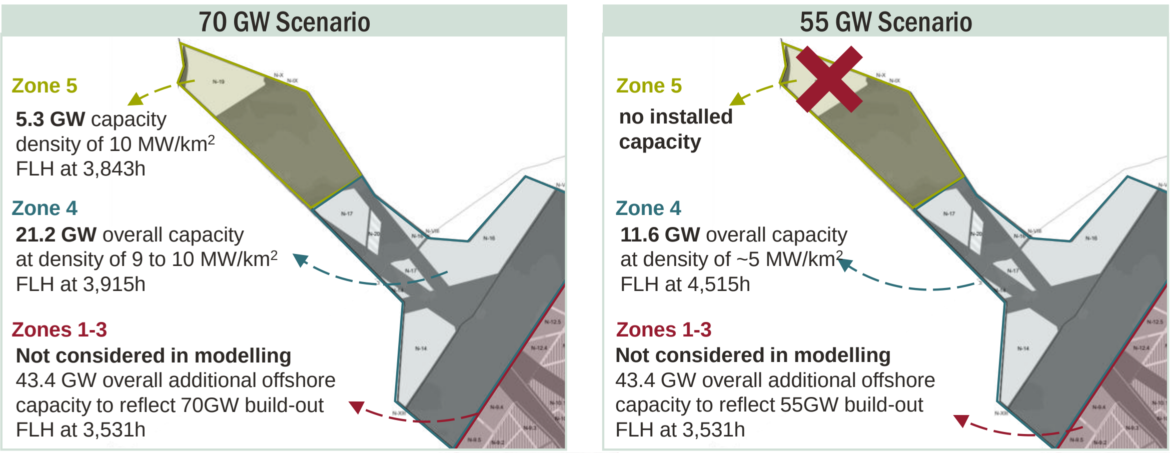
We conduct our comparison of different configurations for two offshore wind deployment scenarios to 2045 (see Figure 6):

- The first is **70 GW**, reflecting Germany's statutory wind offshore expansion target, with the current FEP providing the layout to achieve it. In this scenario, electrolyser capacity is set at 10 GW across configurations, with only the location (on- or offshore) differing between configurations.[5]
- The second is **55 GW**, reflecting a constraint of limiting offshore wind capacity to mitigate wake effects. In this scenario, we set electrolyser capacity at 4 GW across configurations.

We assume the same electrolysis capacity across configurations within each offshore wind deployment scenario (10 GW in the 70 GW scenario and 4 GW in the 55 GW scenario), rather than optimising it within each configuration. This is consistent with the design of our **stand-alone offshore system model which, for each wind offshore capacity scenario and each configuration, identifies the offshore connection set-up (i.e. the capacity of electricity cable and hydrogen pipeline) that minimises the net infrastructure costs of integrating offshore energy**.[6] Unlike a generalised energy system model, the stand-alone model does not account for wider interactions with end-use sectors or the overall energy mix. It therefore does not optimise hydrogen demand or its sourcing between imports and domestic production.

The assumption of 10 GW electrolysis capacity in the 70 GW offshore wind scenario is consistent with AquaVentus vision of developing 10 GW offshore electrolysis capacity in the German Exclusive Economic Zone by 2035. The 4 GW assumption in the 55 GW scenario reflects the lower offshore wind capacity in Zones 4 and 5 (11.6 GW compared with 26.5 GW in the 70 GW scenario, see Figure 6, maintaining consistency between scenarios.

Figure 6 Overview of two different offshore build-out scenarios



Source: Frontier Economics, full load hours based on wind model simulations.

5 Baseline and overplanting configurations assume capacity located onshore at the coast while in the offshore sector coupling configuration 10 GW electrolyser capacity is located offshore next to the wind farms.

6 See Annex B for a more detailed model illustration.

Within each configuration and scenario, we optimise the net infrastructure costs of integrating offshore energy, defined as the difference between all transport and production infrastructure costs and the revenues from electricity and hydrogen sales at wholesale market prices:

- **Costs** consist of Capital Expenditures (CAPEX) and Operating Expenditures (OPEX) for the Offshore Wind Farm (OWF), the electricity cable connection offshore and onshore, the electrolyser and the hydrogen pipeline connection. See Annex B for an overview of technical and cost assumptions.
- **Electricity revenues** are calculated by valuing the hourly electricity volumes transported from offshore to the mainland with hourly electricity prices that we get from two separate runs of our cross-sector energy system system-wide model COMET (one run for the 70 GW and one for the 55 GW offshore expansion scenario).[7] **Hydrogen revenues** are calculated by valuing hydrogen outputs with hydrogen price estimates from a Fraunhofer assessment.[8]

As part of our analysis, we evaluated alternative locations for onshore electrolysis in the electricity-only overplanting configuration to identify the most suitable reference for comparing offshore sector coupling. We tested coastal and inland (southern Germany) locations. We found that coastal electrolysis performs generally better, as it avoids additional onshore electricity grid integration costs, and therefore use it as our reference scenario.[9] For transparency, we include the inland location as a sensitivity in Annex C.

In assessing how to minimise net infrastructure costs for offshore energy integration, **our analysis addresses the guiding question of which configuration makes best use of Germany's offshore energy potential**. This provides a consistent basis for comparing configurations, without dealing with how costs and benefits are distributed among stakeholders. The analysis is not intended as a cost-benefit assessment, as it does not extend

7 We conduct hourly runs for the year 2045. To reflect correct offshore capacity in modelling electricity, we model prices individually for the two OWF build out scenarios assuming 70 GW and 55 GW installed offshore capacity. More information on our COMET model can be found under: https://www.frontier-economics.com/uk/en/hot-topics/collection-i21808-comet/. Our model in this focuses only on offshore wind generation and the onshore power and hydrogen infrastructure needed to use offshore potential, unlike a system-wide sector model. In treating power prices as exogenous, our model does not capture the feedback loop between electrolysis deployment and electricity prices. As the electrolyser capacity is identical across all configurations, this affects all options equally and therefore does not constitute a relevant limitation for assessing the most economical option.

8 We take a median of 110 €/MWh as our central case from a range of 90–130 €/MWh. The HyPAT Working Paper 01/2023 (Wietschel et al., 2023) explains that "*price regions below 90 €/MWh and lower are hardly to be expected. Even pure cost considerations show that this is currently only feasible at very favourable locations worldwide. But on top of the production costs identified in these studies come, among other things, transport costs, profit margins, capital costs reflecting country risks, distribution costs, R&D costs etc*." (translation of the German original, p. 26). On the demand side, the study notes that "at high hydrogen prices it is cheaper to expand renewables further, accept electricity surpluses and use more electricity in district heating networks. Therefore, demand for hydrogen can become very low at high prices." (translation of the German original, p. 26).

9 In the coastal reference scenario, we allow overplanting of offshore wind and offshore network capacity relative to the onshore cable in the current build-out configuration.

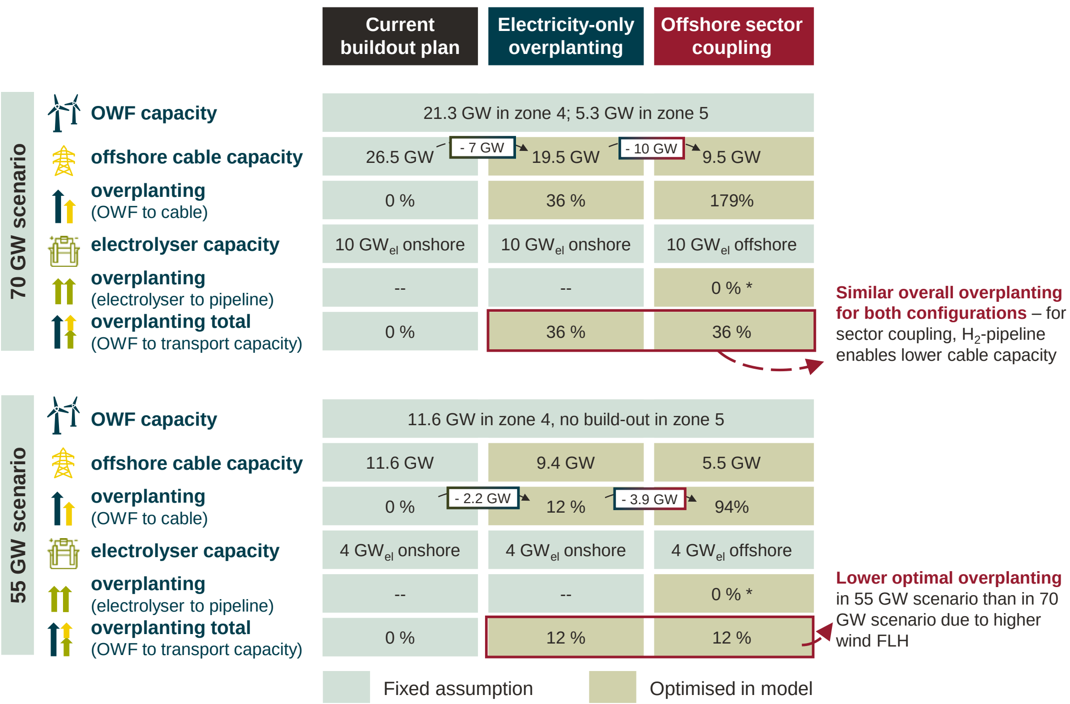
to system-wide considerations such as alternative pathways to net zero, the value of different decarbonisation trajectories, or the contribution of offshore potential to security of supply.

We begin by setting out the main findings under our central assumptions before turning to sensitivities that test how robust these results are to changes in key variables.

2.2 Key results: Offshore sector coupling enables the most economical case of using offshore wind

Figure 7 summarises the optimal infrastructure set-up identified by our model, showing the installed capacities that minimise the net infrastructure costs of integrating offshore energy in the electricity-only overplanting and offshore sector coupling configurations across the offshore wind deployment scenarios.

Figure 7 Cost-minimising infrastructure capacities across configurations and offshore wind deployment scenarios



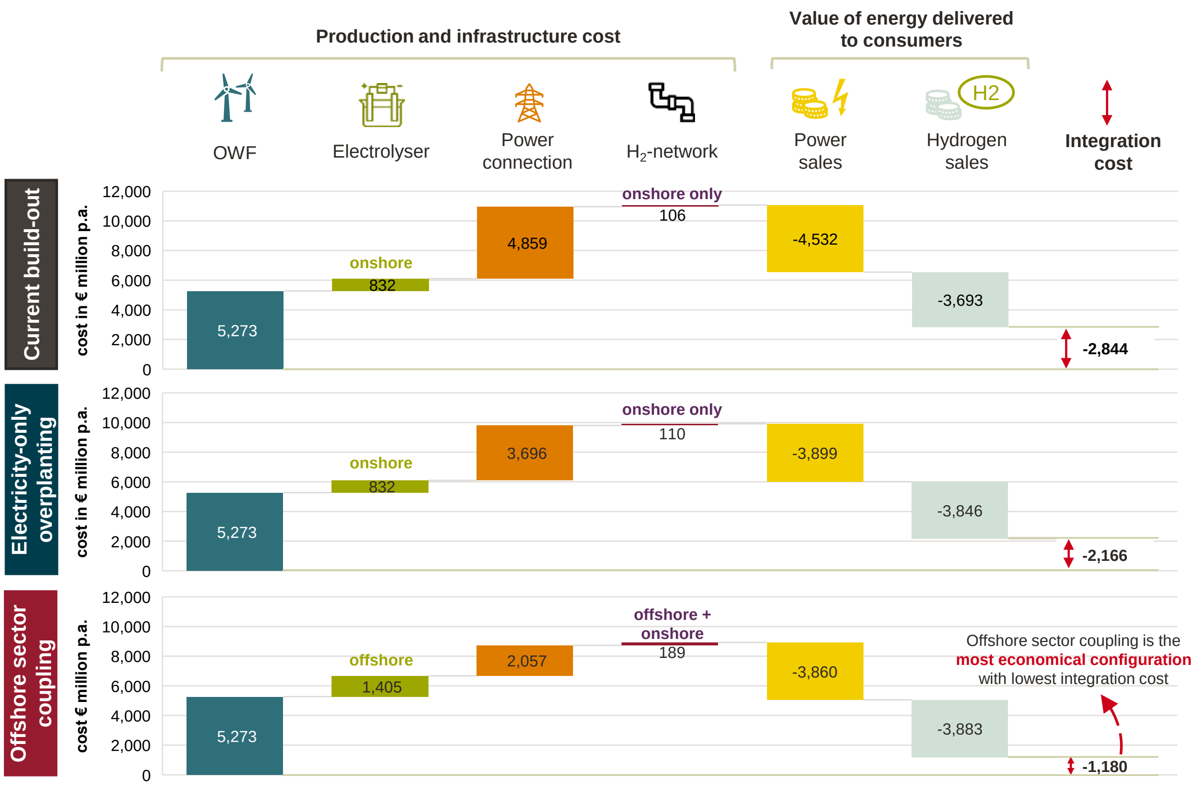
Source: *Frontier Economics*

Note: ** Due to 68 % electrolyser efficiency, a pipeline capacity of 68 % electrolyser capacity is sufficient to transport 100 % of energy from the electrolyser. Therefore, overplanting is at 0 % for electrolyser to pipeline capacity.*

In the electricity-only overplanting and offshore sector coupling, we find an optimal 36 % overplanting of offshore wind capacity relative to total offshore transport capacity (see *Overplanting total)*. In the offshore sector coupling case, where a hydrogen pipeline complements the power cable, it is cost-optimising to install a smaller cable capacity than in electricity-only overplanting, as the pipeline provides an additional, cost-efficient transport route. The optimal pipeline capacity is equivalent to the electrolyser capacity suggesting that, given the cost-effective transport of energy at scale in the form of hydrogen, the cost-saving rationale that supports overplanting turbine capacity relative to cable capacity does not apply to electrolyser capacity relative to the hydrogen pipeline, even within an integrated power-and-hydrogen configuration.

We also find that **offshore sector coupling is the most effective means of harnessing offshore wind potential in zones 4 and 5 of the German North Sea** (see Figure 8). Both electricity-only overplanting and offshore sector coupling reduce the net infrastructure costs of integrating offshore energy potential compared to a no overplanting baseline configuration, with sector coupling delivering most economical result in both offshore wind deployment scenarios.[10]

Figure 8 Annual costs for integrating offshore energy across configurations in 2045 (70 GW scenario)



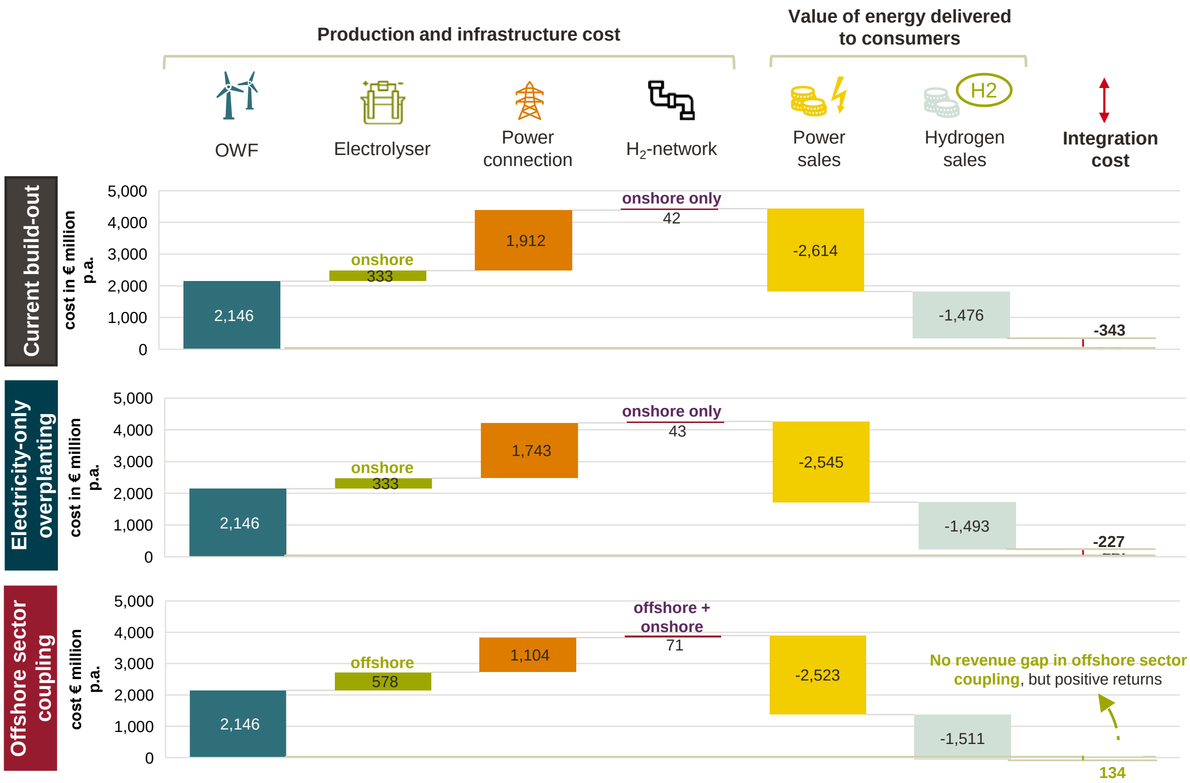
Source: Frontier Economics

Note: Analysis only considers costs and revenues from offshore zones 4 and 5 (while zones 1-3 are not varied).

10 In the 55 GW scenario, the net integration costs even turn to a positive profit. This occurs even though the revenue side of the model captures only part of the system's potential income (electricity and hydrogen sales at wholesale market prices), without including possible network tariffs or other remuneration mechanisms that could further support the financing of transport infrastructure.

Lower net infrastructure costs for integrating offshore energy arise from a reduced capacity of offshore electricity cables. While this reduction slightly decreases revenues from the sale of electricity valued at wholesale market prices and electrolyser costs are higher offshore than onshore, the savings in investment and operation costs are substantially larger. Due to the possibility of transporting energy to shore as hydrogen, electricity cable capacity can be reduced even further in the offshore sector coupling configuration.

Figure 9 Annual costs for integrating offshore energy across configurations in 2045 (55 GW scenario)



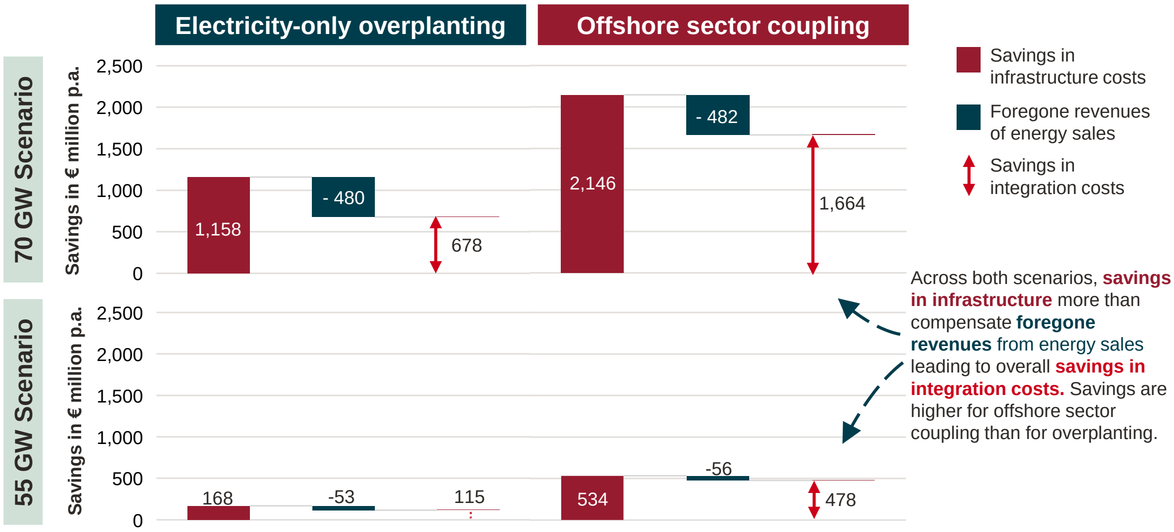
Source: Frontier Economics

Note: Analysis only considers costs and revenues from offshore zone 4. No build-out of zone 5 in 55 GW scenario

Offshore sector coupling leads to lowest net infrastructure costs for integrating offshore energy

Specifically, offshore sector coupling reduces net infrastructure costs for integrating offshore energy by approximately €1,664 million per year relative to the baseline (current build-out) in the 70 GW scenario and by €477 million per year in the 55 GW scenario (see Figure 10). Electricity-only overplanting, for comparison, reduces these costs by only €678 million and €116 million per year, respectively. The larger relative savings in the 70 GW scenario show that offshore hydrogen becomes particularly valuable for integrating the final 15 GW, particularly the capacities located at the far shore in zone 5.

Figure 10 Savings in annual net infrastructure costs for integrating offshore energy in 2045 for electricity-only overplanting and sector coupling relative to current build-out



Source: Frontier Economics
Note: The baseline is current buildout with coastal electrolysis

The advantage of offshore electrolysis is driven by most cost-effective transport of energy compared to electricity

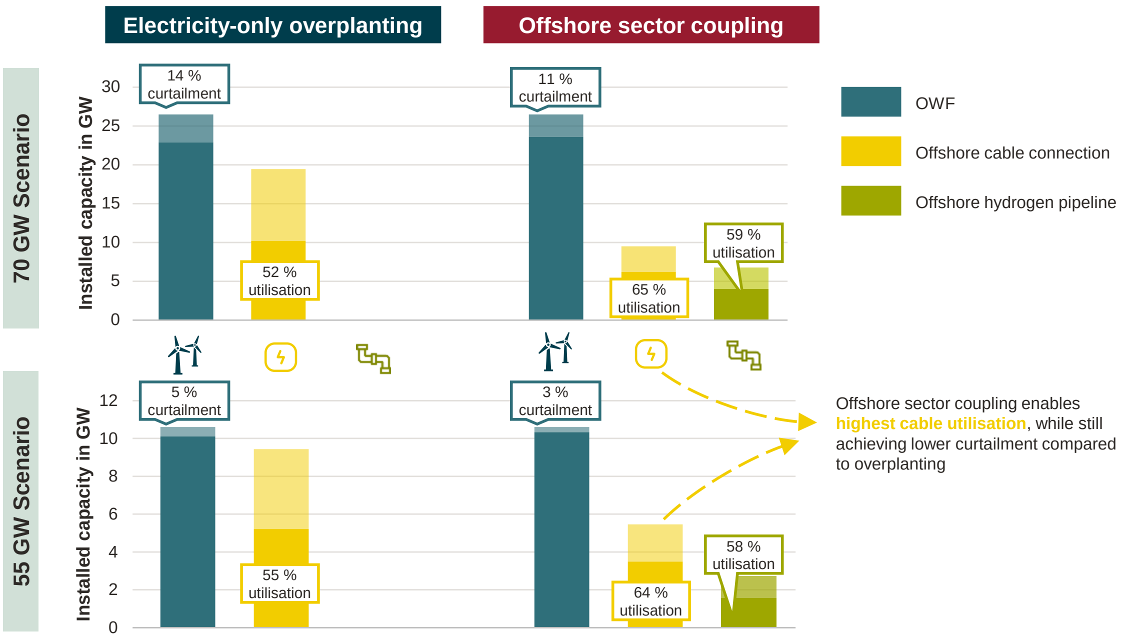
The advantage of sector coupling arises from three factors:

- First, **overall costs are lowest** for offshore sector coupling. While offshore electrolysis entails higher investment and operating costs than onshore electrolysis and requires the construction of a hydrogen pipeline, these disadvantages are outweighed by saved cable investments and the efficiency gains in energy transport. Hydrogen pipelines offer a significantly more cost-effective means of transferring large amounts of energy over long distances than power cables, so that overall system integration costs are lower despite the higher cost of offshore electrolysers.

- Second, flexibility to transport either electricity or hydrogen **improves utilisation of offshore electrical transmission infrastructure**. The offshore cables are utilised 65 % under sector coupling compared with 52 % under electricity-only overplanting in the 70 GW scenario, and 64 % versus 55 % in the 55 GW scenario (see Figure 11).

- Third, **offshore sector coupling also reduces curtailment** compared to overplanting by allowing offshore wind generation to be used flexibly for either electrolysis or electricity. This in turn increases the total amount of energy made available to the system, combining electricity and hydrogen output. This effect is most pronounced in the 70 GW scenario, which involves a stronger expansion into far-from-shore areas: curtailment amounts to 11 % under offshore sector coupling compared with 14 % under electricity-only overplanting. This corresponds to 2.5 TWh more energy delivered to the system per year. In the 55 GW scenario, curtailment is 3 % with offshore sector coupling versus 5 % with electricity-only overplanting (see Figure 11). The smaller difference in this case reflects the shorter distance of wind farms from the coast (resulting in lower cable requirements for power transmission) as well as a lower wind farm capacity density, which leads to higher full-load hours and makes lower levels of overplanting economically optimal. In this case, the total energy made available to the system increases by around 1 TWh compared to electricity-only overplanting.

Figure 11 Installed capacities and infrastructure utilisation

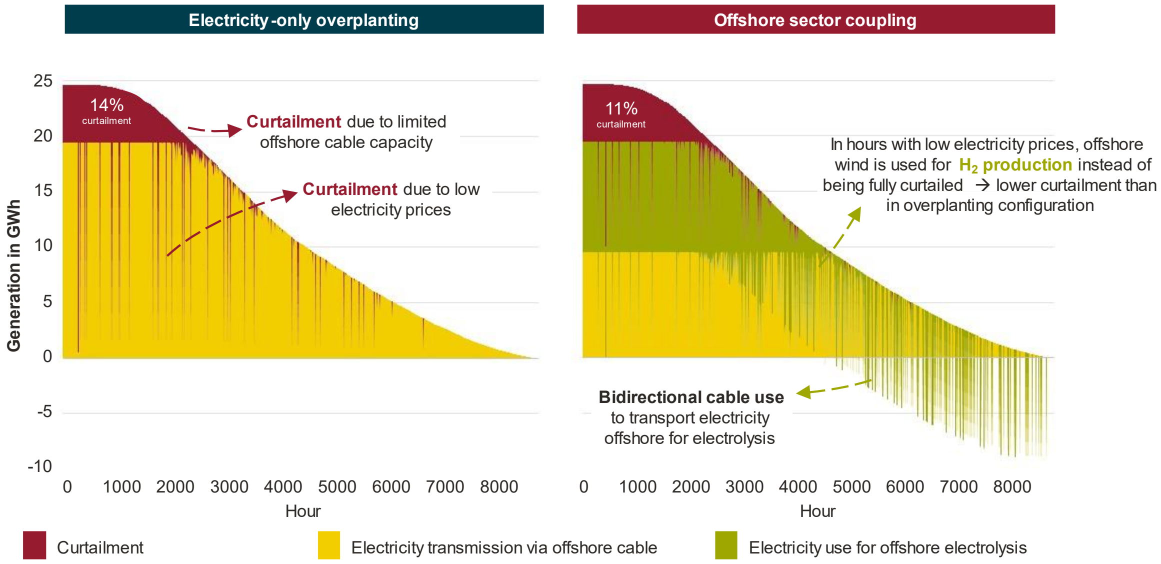


Source: Frontier Economics

Note: Lighter coloured areas indicate share of capacity that is curtailed (for OWF) or not utilised (for cable and pipeline)

Due to its parallel infrastructure of power and hydrogen connection, offshore sector coupling enables system-beneficial utilisation of offshore wind energy. In hours of high electricity prices, power is preferentially transported to shore, maximising the value of electricity generation. When electricity prices are low or negative, offshore power is instead used directly for electrolysis and transported to shore as hydrogen. In these periods, the bidirectional offshore power connection also allows offshore electrolysers to utilise surplus electricity from the onshore grid, increasing the energy system value of offshore sector coupling. During periods of high wind output, both electricity and hydrogen are exported simultaneously. By combining both transport routes, the system can make full use of available offshore generation capacity and keep curtailment of offshore wind farms to a minimum.

Figure 12 Hourly use of offshore electricity generation (70 GW scenario)



Source: Frontier Economics

2.3 Sensitivity analysis: The advantage of sector coupling is robust to changing uncertain assumptions on future energy market development

We test sensitivities on the variables most likely to affect the advantage of offshore sector coupling. The objective is to assess the robustness of our results against key drivers of offshore energy economics, in particular the installed electrolyser capacity, the level of electricity prices, and the cost difference between offshore and onshore electrolysers.[11]

[11] We did not include a sensitivity to hydrogen prices because the model assumes a fixed (exogenous) level of installed electrolysis capacity. This means that changes in wholesale hydrogen prices would only affect revenues from hydrogen sales, not investment decisions or costs, and as such does not impact on the comparison of net infrastructure costs to integrate offshore wind across configurations.

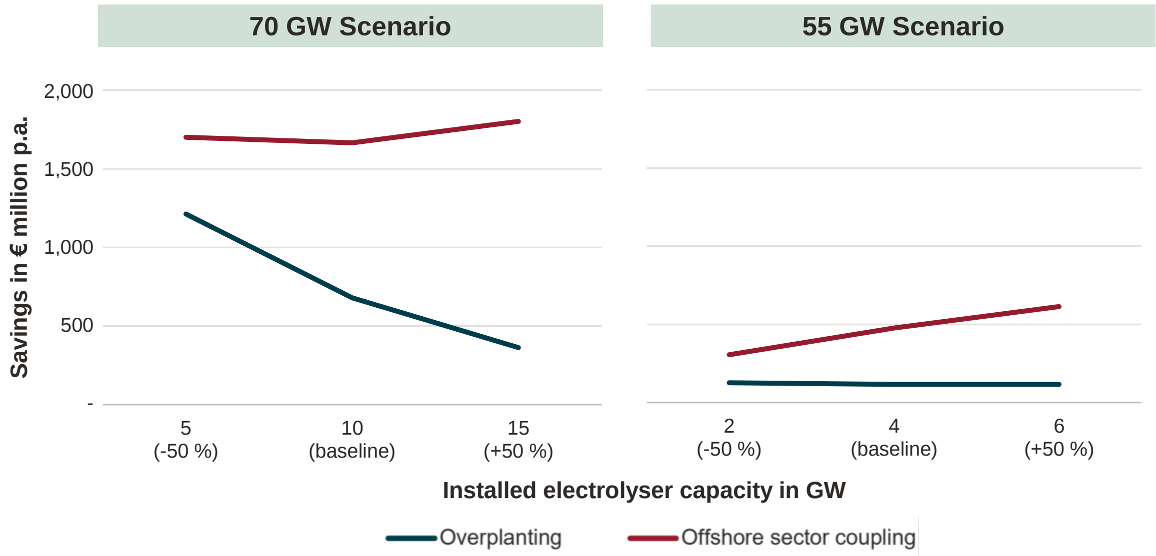
In reality, hydrogen prices would influence several factors at once — the scale of installed electrolysis capacity, the volume of hydrogen produced, and the revenues earned per unit sold. Production would only occur when it is profitable given wholesale electricity prices or when electricity would otherwise be curtailed.

Given lower cost for energy transport, advantages of offshore hydrogen production increase with installed electrolyser capacity

Our default analysis assumes 10 GW of electrolyser capacity in the 70 GW scenario and 4 GW in the 55 GW scenario as a baseline. We test sensitivities by varying electrolyser capacity by ± 50 %. The results show that offshore sector coupling remains the most economical configuration under all variations (Figure 13). Moreover, its economic advantage over alternative configurations increases with higher electrolyser capacity.

For offshore sector coupling, net integration costs decline as electrolyser capacity increases, reflecting more efficient use of offshore generation and transport infrastructure. By contrast, in the overplanting configuration, net integration costs increase with higher electrolyser capacity. This is because additional offshore cable capacity is required to connect the larger onshore electrolyser capacity, and corresponding cost increases are not offset by revenue gains. In this context, **offshore sector coupling represents the most effective way to enable a larger and more efficient deployment of domestic electrolysis.**

Figure 13 Sensitivity of savings in net integration cost to installed electrolyser capacity



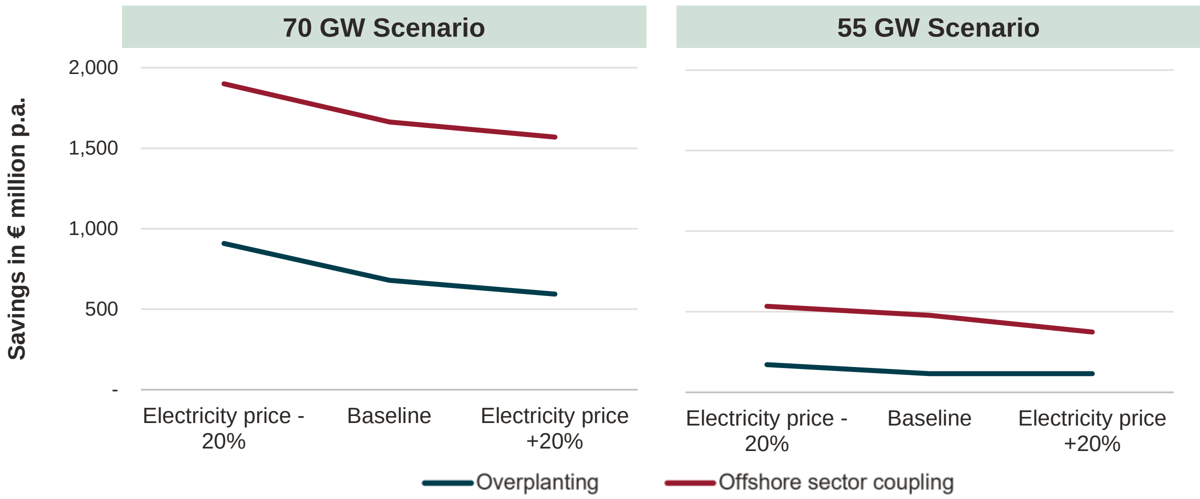
Source: Frontier Economics

Note: Savings relative to current build-out.

Sector coupling option is the most robust configuration against uncertain electricity prices

For electricity prices, we test sensitivities in a range of -20 % to +20 % around the default wholesale price level, while keeping the price distribution constant (see Figure 14). Lower electricity prices reduce revenues from power sales, increasing the net infrastructure costs for offshore energy integration of electricity-only overplanting relative to offshore sector coupling, thereby strengthening the benefits of the latter. Higher electricity prices narrow this difference, but in both the 70 GW and 55 GW offshore wind scenarios offshore sector coupling continues to show lower net infrastructure costs for offshore energy integration across the tested range, indicating robust results.

Figure 14 Sensitivity of savings in net integration cost to changes in electricity prices



Source: Frontier Economics

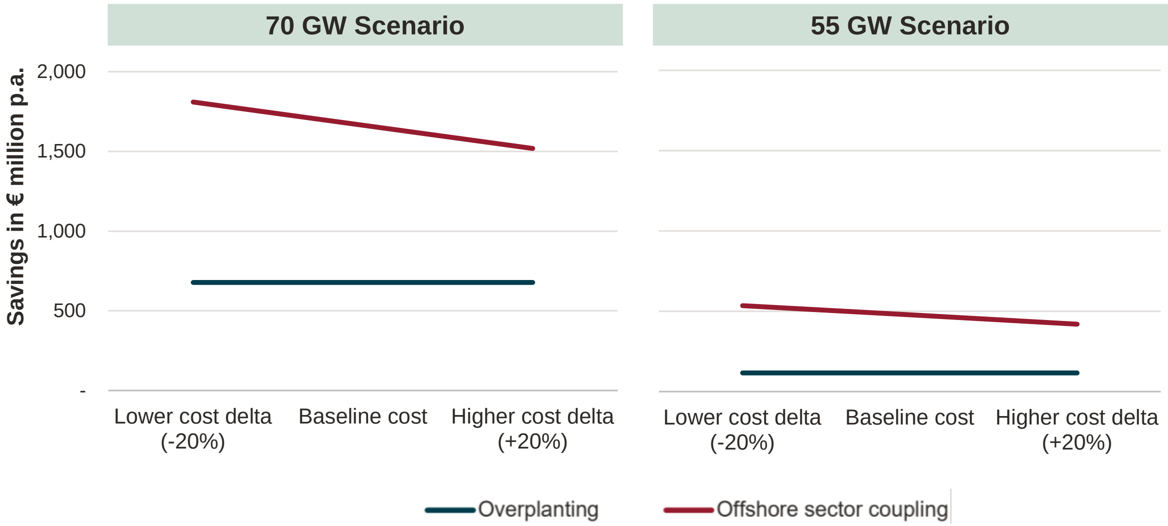
Note: Savings relative to current build-out. Electricity price numbers reflect average prices. The model uses a full hourly electricity price curve with varying prices.

Additional costs of offshore electrolysis compared with onshore are not a significant driver of results: offshore sector coupling remains the most economical option under substantial cost differences

Finally, we test the sensitivity of results to the additional cost of offshore electrolysis compared with onshore. Faster cost convergence, with smaller cost differences, increases the advantage of offshore sector coupling. Across the full range, however, the advantage in minimising net infrastructure costs for integrating offshore energy remains largely unchanged, confirming the robustness of the results. Even when assuming significantly higher costs for offshore electrolysers:

- offshore hydrogen production is the most economical option for domestic hydrogen generation from offshore wind and therefore
- offshore sector coupling is the most economical option of integrating offshore wind potentials.

Figure 15 Sensitivity of savings in net integration cost to the additional cost of offshore electrolysis relative to onshore



Source: Frontier Economics

Note: Savings relative to current build-out. Under baseline assumptions, offshore electrolyser CAPEX is around 80 % higher than onshore electrolyser CAPEX. This is a conservative assumption given literature and experts estimate the additional cost of offshore electrolysers compared to onshore electrolysers to be between 20 % and 50 % (see Guidehouse and Berenschot, 2021).

3 Enabling mixed connection concepts to tap offshore wind energy potential

Different challenges continue to hinder the deployment of offshore sector coupling in Germany. Existing site designations, allocation procedures and permitting frameworks limit the development of offshore electrolysis and integrated power-and-hydrogen connection concepts. Ongoing discussions on tender design, regulatory frameworks and support mechanisms will shape how and when such projects can help realise Germany's offshore wind potential, and through it, contribute to achieving the country's climate and environmental goals.

3.1 Expanding areas hosting offshore electrolysis and allowing mixed offshore hydrogen-and-power connections

At present, BSH has designated one zone (SEN-1) for other energy production, which is generally expected to host electrolysis. This pilot area, with a planned capacity of at most 1 GW, is currently the only offshore hydrogen area foreseen in the German EEZ. All other areas are reserved for electricity-only projects, which limits the scope for scaling offshore hydrogen.

These areas are defined as not connected to the electricity grid.[12] As such, SEN-1, and any zone that could be designated to host offshore electrolysis in the existing framework, would not have a mixed power-and-hydrogen connection, limiting the potential for sector coupling and system integration. Instead, hydrogen transport is anticipated via ship or pipeline, with pipeline transport viewed as the preferred option.

The allocation of SEN-1 has been repeatedly postponed. Debate continues over whether the area should host a single large project or be divided into smaller sub-areas. The 2023 draft FEP suggested a possible three-part division, but no final decision has been made. The current FEP 2025 does not introduce new provisions compared with FEP 2023.

The allocation mechanism remains under discussion, and the final tender rules, initially expected in mid-2023, have not yet been published. A draft of the funding guidelines consulted by BMWK in January 2023 sets out a two-stage process:[13] one tender for the allocation of the area, based on qualitative criteria such as efficiency, scalability and environmental impact (§ 9 SoEnergieV), and a separate funding tender by BMWK based on price. Industry feedback has indicated that the sequencing of these tenders and the short interval between them could

[12] WindSeeG § 3 No. 8

[13] BMWK, *Eckpunktepapier zur Förderrichtlinie Offshore-Elektrolyse – Marktkonsultation*, Jan 2023.

create challenges. Developers may obtain funding without securing the area, or may need to prepare business cases without clarity on support levels.[14]

3.2 Advancing joint power and hydrogen network planning

Joint planning of power and hydrogen transmission infrastructure is important both from a system and an investment perspective. From a system viewpoint, it enables coordinated development of networks that will increasingly interact as hydrogen production, storage and use expand alongside electrification. Shared spatial planning and consistent modelling can reduce duplication, lower overall system costs and improve resilience. From an investor perspective, an integrated approach provides clearer visibility of future capacity, connection points and network priorities, reducing uncertainty and supporting timely private investment.

The EU and Germany have taken initial steps in this direction by harmonising the process flow for electricity, gas and hydrogen network development. This reform aligns scenario frameworks, timelines and consultation procedures, so that network plans are based on consistent assumptions and developed in parallel.[15]

Possible next steps towards integrated planning could include developing a single spatial plan to identify shared corridors and complementary infrastructure, establishing joint governance across transmission operators, and introducing common cost–benefit and investment assessment frameworks.

3.3 Extending legal prioritisation to offshore electrolysis projects

A final permitting and legal status concerns the draft Hydrogen Acceleration Act. The Act limits the status of overriding public interest to electrolysers onshore and in coastal waters, excluding offshore projects in the EEZ from this provision.[16] In practice, this means offshore electrolysis does not receive the same legal prioritisation. While not prohibitive, the absence of such status could make permitting and approval processes comparatively more challenging, with implications for planning certainty for investors.

3.4 Mitigating investment risk

Investment risks remain a central challenge in the emerging hydrogen sector, including for offshore projects. The cost of electrolysis, including offshore electrolysis, is expected to reduce

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14 BWO, Stellungnahme zur Marktkonsultation Eckpunkte Förderrichtlinie Offshore-Elektrolyse, Jan 2023, p. 2. BDEW, *Stellungnahme zum BMWK-Eckpunktepapier Offshore-Elektrolyse*, Jan 2023. BDEW Stellungnahme zur Marktkonsultation „Förderrichtlinie Offshore-Elektrolyse". Jan , 2023

15 *Netzentwicklungsplan (2025). "Network Development Plan 2037/2045 (2025)".* https://www.netzentwicklungsplan.de/en/nep-aktuell/netzentwicklungsplan-20372045-2025

16 BMWE. (2024). *Wasserstoffbeschleunigungsgesetz (Anhörungsfassung)* (p. 31). Retrieved from https://www.bundeswirtschaftsministerium.de/Redaktion/DE/Downloads/W/wasserstoffbeschleunigungsgesetz-bmwe-anhoerung.pdf?__blob=publicationFile&v=8

through scaling and learning effects. Early investments contribute to this process and create benefits for the wider sector, although individual investors may not capture this value.

Hydrogen networks face similar challenges. They require large upfront investment, while costs decline as utilisation increases, leaving early users with higher unit costs. On the demand side, uptake is constrained by the cost gap with conventional fuels and by the expense of adapting existing equipment for hydrogen use.

Incomplete carbon pricing and the cost advantage of existing fuels (with matured markets) further increase investor exposure, as low-carbon hydrogen remains less competitive. Combined with limited scale in production and transport, this leads to the familiar “chicken-and-egg” problem: demand depends on lower costs and reliable supply, while investment depends on assured demand.

Together, these factors create significant uncertainty for investors in both onshore and offshore hydrogen, highlighting the need for targeted measures to mitigate investment risk and strengthen market confidence, including for hydrogen network development.

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Annex B Model framework & assumptions

This annex summarises the analytical framework supporting the offshore system modelling. The first part describes how the model operates and the second sets out the detailed techno-economic assumptions applied in the analysis. These include costs, efficiencies and price parameters.

Model framework and optimisation approach

We use a stand-alone offshore system model to determine cost-effective infrastructure set-up for integrating offshore wind energy in Zones 4 and 5 of the German North Sea. For each configuration (namely, current build-out, electricity-only overplanting and offshore sector coupling) and scenario (70 and 55 GW offshore wind deployment in the German North Sea), the model minimises the net infrastructure costs for integrating offshore energy. We define this net cost as:

- Costs of offshore energy production and transport infrastructure, *minus*
- Revenues from electricity and hydrogen sales at wholesale market prices.

Figure 16 illustrates how the model operates. It takes as inputs the exogenous capacities of offshore wind farms and electrolysers, hourly generation profiles, technology costs, efficiencies and transmission losses, and exogenous hourly prices for electricity and hydrogen.

The model identifies the combination of cables, converters, electrolysers and pipelines that minimises total system costs while meeting technical and operational constraints. In doing so, it determines the most cost-effective infrastructure configuration for each configuration and scenario.

Offshore wind generation can serve either the electricity or hydrogen market:

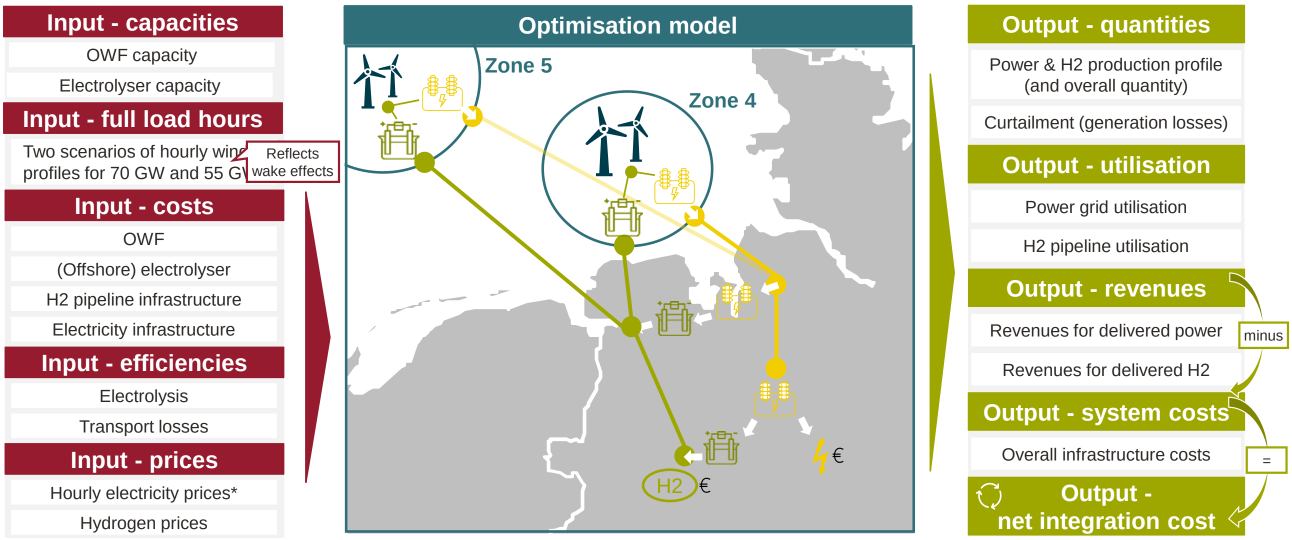
- To serve the electricity market, power is transmitted directly to demand centres in central Germany through offshore AC/DC and onshore DC/AC conversion.
- In the hydrogen pathway, electricity powers electrolysers, which is then transported by pipeline to the same demand centres. Electrolysis locates either offshore or onshore (coastal or inland, depending on the configuration).

The optimisation determines how these two pathways interact and which balance between electricity export and hydrogen production minimises overall system costs.

All costs and revenues are annualised[17] and expressed for 2045, reflecting steady-state operation once capacity is deployed.

[17] We annualise costs using an annuity approach, which calculates annualised costs for each infrastructure element based on its lifetime and the assumed weighted average cost of capital (WACC). The approach assumes that costs and returns are constant across all years of operation.

Figure 16 Model illustration



Source: *Frontier Economics*

Note: *Optimisation problem under multiple constraints. For given H2 and power prices, the model optimises supply and corresponding transport infrastructure. As prices reflect market needs the model automatically supports the overall energy system. Solved in GAMS (tool for solving large constrained optimisation problems).*

Techno-economic assumptions

The techno-economic assumptions assume that zone 4 and onshore infrastructure is built in 2040, ahead of zone 5 in 2045. We model hourly electricity price curves using our sector-coupled European energy system model *COMET*[18] using input load-factor profiles for offshore wind for each of the two wind deployment scenarios separately.[19] Resulting average electricity prices are 81.5 €/MWh_{el} for the 70GW scenario and 84.4 €/MWh_{el} for the 55GW scenario in 2045. Higher prices in the 55 GW scenario result from a reduced low-variable cost electricity supply (which is partly offset by higher full load hours due to lower wake effects as a consequence of a reduced density of offshore wind farms in zone 4).

The hydrogen price is set to 110€/MWh_{H2} based on Wietschel et al., (2023) as explained in more detail in Section 2.

18 More information on our COMET model can be found under: https://www.frontier-economics.com/uk/en/hot-topics/collection-i21808-comet/

19 The EnBW team (as member of AquaVentus) provided the full-load hour profiles used in the model for the 70 GW and 55 GW offshore wind deployment scenarios.

Table 1 Power infrastructure

Infrastructure component	CAPEX €/kW$_{el}$	OPEX % CAPEX / Year	Lifetime Years	Efficiency %	WACC %	Source
Offshore windfarm zone 4	1,702	2.4	35	44.7-51.5*	9	[1],[4],[5]
Offshore windfarm zone 5	1,541	2.5	35	43.5*	9	[1],[4],[5]
Offshore HVDC converter	625	1.5	35	100	7	[2],[4],[5]
Onshore HVDC converter	275	1.5	35	100	7	[2],[4],[5]
Onshore AC substation	215	1.5	35	100	7	[2],[4],[5]
Offshore HVDC cable**	2.34 / km	2.5	40	100	7	[2],[4],[5]
Onshore HVDC cable***	433 -1,356	-	40	100	7	[3],[4],[5]

Sources:

[1] IEA 2024, World Energy Outlook 2024, Announced Pledges Scenario, https://www.iea.org/reports/world-energy-outlook-2024

[2] ENTSO-E (2024),TYNDP 2024 Offshore Network Development Plans – Methodology, Cost Set 2, eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/ONDP2024-methodology.pdf

[3] Frontier based on EnBW Aurora (2025), Systemkostenreduzierter Pfad zur Klimaneutralität im Stromsektor 2040, https://www.enbw.com/media/presse/docs/gemeinsame-pressemitteilungen/2025/zusammenfassung-systemkostenstudie-aurora-zzgl-enbw-ableitungen.pdf

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[5] WACC is based on internal assumptions

Notes:

**Average capacity factor, accounting for wake effects. For zone 4 the average capacity factor is higher for the 55GW scenario (51.5%) than the 70GW scenario (44.7%).*

***Offshore HVDC converter includes platform costs. Offshore HVDC cable lengths are assumed to be 300 km to zone 4 and 450 km to zone 5 based on E-Bridge (2024), Figure 29. CAPEX for the offshore HVDC cable is expressed in €/kW$_{el}$ per km.*

****Onshore HVDC cable CAPEX is calculated as gap between grid infrastructure cost in the model and final grid connection numbers in EnBW Aurora (2025). CAPEX increases linearly with installed capacity, from €433/kW at 45 GW to €1,357.5/kW at 70 GW.*

Click or tap here to enter text.

Table 2 Hydrogen infrastructure

Infrastructure component	CAPEX €/kW$_{el}$	OPEX % CAPEX / Year	Lifetime Years	Efficiency %	WACC %	Source
Offshore electrolyser zone 4	1,995	3.7	25	68	9	[1],[5],[6]
Offshore electrolyser zone 5	1,695	3.9	25	68	9	[1],[5],[6]
Onshore electrolyser	1,121	4	25	68	9	[1],[2], [5],[6]
Offshore H_2-pipeline*	0.374 / km	2	50	100	7	[3],[4], [5],[6]
Onshore H_2-pipeline**	-	0.00315**	50	100	7	[3],[5],[6]

Sources:
[1] E-Bridge (2024), Assessment of connection concepts for Germany's far out North Sea offshore wind areas for an efficient energy transition, Table 4,https://aquaventus.org/wp-content/uploads/2024/09/240829_AQV_ShortStudy_EN.pdf
[2] ENTSO-E (2025), TYNDP 2026 Draft Scenarios Input Data and Methodologies,https://2026.entsos-tyndp-scenarios.eu/download/
[3] EHB (2023) Implementation Roadmap - cross border projects and cost update, [EHB-2023-Implementation-Roadmap-Part-1.pdf]()
[4] OPEX are based on ENTSO-E and ENTSOG (2025), TYNDP 2024 Scenarios Methodology Report – Final Version,https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2025/01/TYNDP_2024_Scenarios_Methodology_Report_Final_Version_250128.pdf

[4] Overall project lifetime assumption and efficiencies based on E-Bridge (2024) Assessment of connection concepts for Germany's far out North Sea offshore wind areas for an efficient energy transition, https://aquaventus.org/wp-content/uploads/2024/09/240829_AQV_ShortStudy_EN.pdf
[5] WACC is based on internal assumptions

Notes:
**The offshore H_2-pipeline lengths are assumed to be 300 km to zone 4 and 450 km to zone 5 based on E-Bridge (2024) . CAPEX for the offshore H2-pipeline is expressed in €/kWh$_{H2}$ per km. OPEX are retrieved from ENTSO-E and ENTSOG (2025) plus additional OPEX for compression.*

***The onshore H_2-pipeline is assumed to be 500 km long, and OPEX is expressed in €/kWh$_{H2}$.*

Annex C Assessing coastal electrolysis vs onshore electrolysis at the south of Germany

Instead of locating electrolysis onshore at the coast, electrolysers could alternatively be connected to the grid further inland, for example in southern Germany. This option would have both advantages and disadvantages in terms of costs and revenues. On the one hand, it requires a stronger expansion of the onshore electricity grid to transmit offshore wind power to the southern demand centres, leading to higher infrastructure costs. On the other hand, it offers greater operational flexibility, as the additional onshore grid capacity allows electricity either to be directed to electrolysis or to be sold directly in the power market.

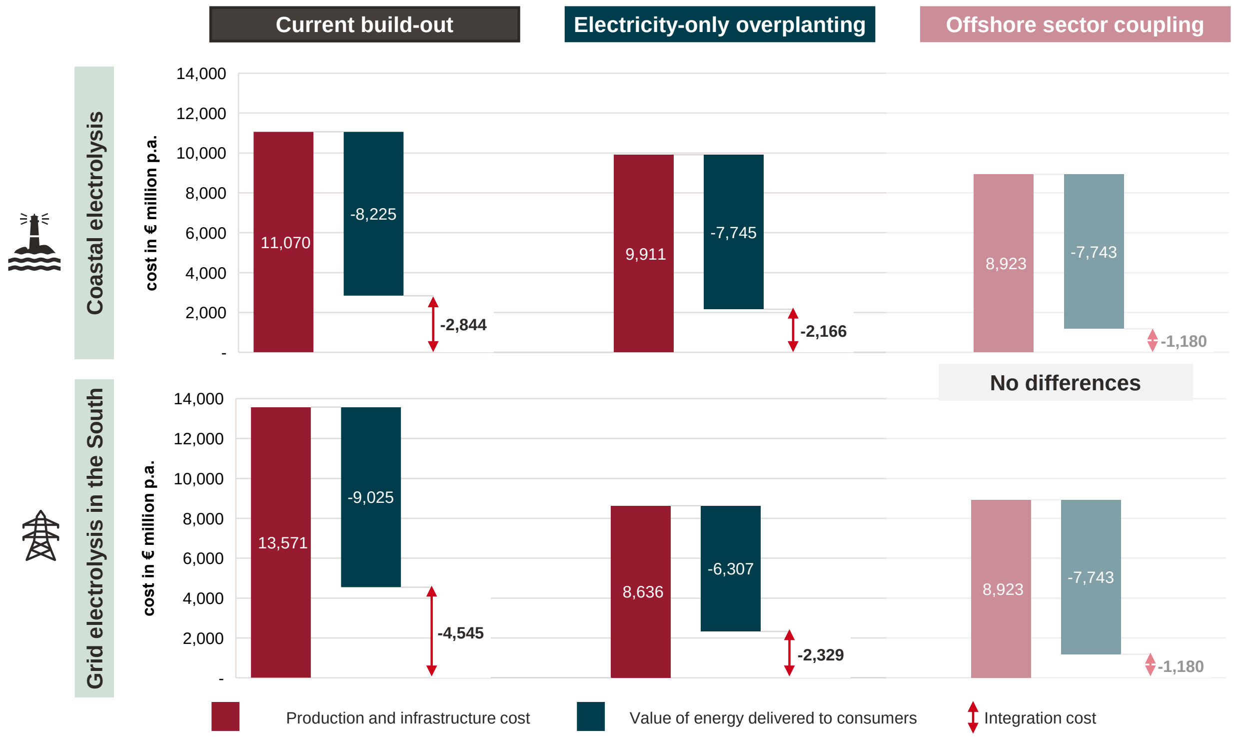
Figure 17 compares coastal and grid electrolysis for the 70 GW scenario.

- In the current build-out configuration, the full onshore grid connection required for grid electrolysis leads to substantially higher infrastructure costs than coastal electrolysis. Although the value of energy delivered to consumers is higher, it increases less than the corresponding costs, resulting in higher net integration costs of €4,545 million per year.

- In the electricity overplanting configuration, the model reduces onshore connection capacity to lower costs. This also decreases the value of delivered energy, leading to net integration costs of about €2,329 million per year.

Overall**, coastal electrolysis constitutes the more economical form of onshore electrolysis in the 70 GW scenario,** as locating the electrolyser at the coast avoids long and capital-intensive north-south electricity transmission cables.

Figure 17 Comparison of coastal and grid electrolysis (70 GW scenario)



Source: *Frontier Economics*
Note: *There are no differences in results for offshore sector coupling configuration where electrolyser location is always offshore.*

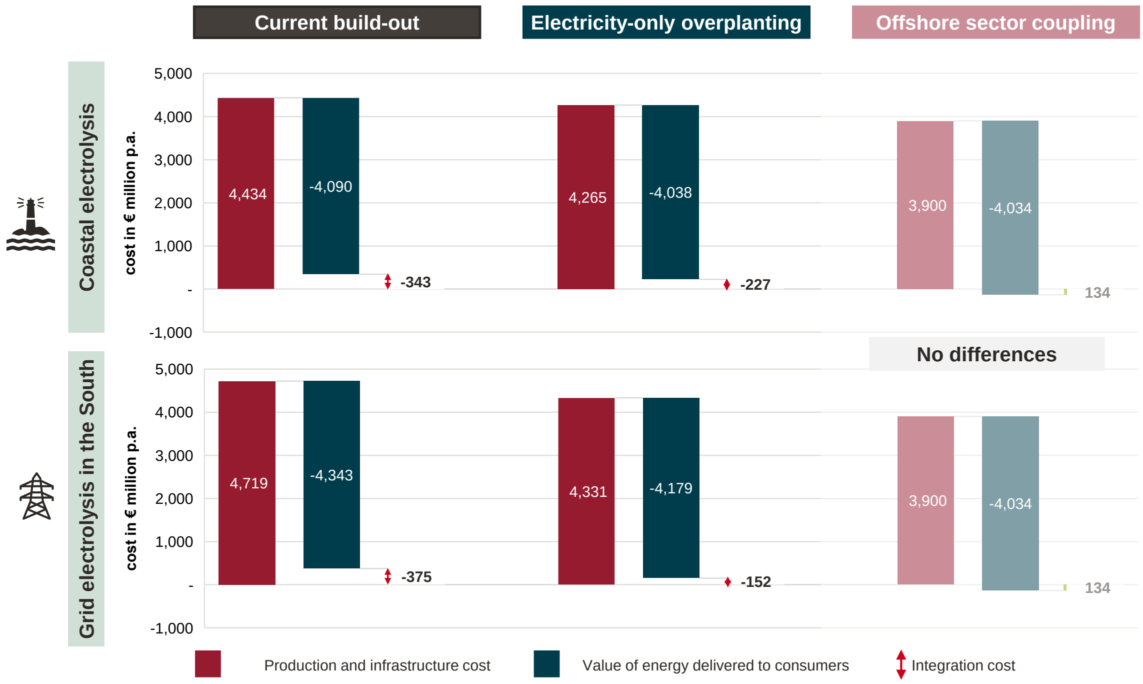
In the 55 GW scenario (see Figure), the differences are less pronounced. Two factors explain this:

1. higher full-load hours due to lower capacity density improve utilisation of the transmission infrastructure; and
2. As there is no build-out of zone 5, the average distance from shore of the OWFs decreases, which leads to lower offshore connection costs.

As a result, grid electrolysis (with higher onshore transmission capacity) performs better than in the 70 GW scenario:

- In the current build-out, grid electrolysis shows slightly higher production and infrastructure costs but also a slightly higher value of energy, resulting in similar overall net integration costs.
- For electricity-only overplanting, grid electrolysis even shows a small advantage, with net integration costs of €152 million per year compared with €227 million per year for coastal electrolysis.

Figure 18 Comparison of coastal and grid electrolysis (55 GW scenario)



Source: *Frontier Economics*

Note: *There are no differences in results for offshore sector coupling configuration where electrolyser location is always offshore.*