North Sea Energy

Dossier files

Empowering & decarbonizing Europe: an international grid compass for North Sea Energy system integration

Towards an affordable, reliable and decarbonized energy system

Prepared by:	TNO	Aravind Satish, Hamid Yousefi, Joris Koornneef, Janaki Mohanan Nair, Merel Laarhoven
	Arcadis	Diederik van Hogendorp, Moreno Derespinis, Nico van Roden, Isabel Cremers, Rob van Damme
	Aquaventus	Robert Seehawer
	BP	Anya Hoff
	MSG Strategies	George Wurpel
	Net Zero Technology Centre	Ana Almeida, Luca Corradi
	Norce Research	Anthonie Oosterkamp
	New Energy Coalition	Rob van Zoelen, Nathanial Dooley, Marije Vos
	Subsea7	Wilfrid Merlin, Stian Sande, Babasola Ogunnaike, Christophe Brice
Checked by:	[Party]	[Person]
Approved by:	TNO NSE coordinator	Madelaine Halter
		Signature Madelaine

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The European transition to renewable energy sources

Worldwide, the energy sector is responsible for 40% of global CO_2 emissions[1], whereas in the EU, this figure is an outstanding 75%[2]. The transition from fossil fuels to renewables energy is therefore seen as a key driver for combating climate change. Within the EU, 42.5% of the total electricity supply needs to be produced from renewable energy sources by 2030, with the goal of reaching a 100% by 2050.

Energy independence has become a key topic after the invasion of Ukraine. The REPowerEU plan has been launched to decrease energy dependence on Russia by saving energy, diversifying sources and increasing the production of clean energy[3]. The energy independence on countries outside of Europe goes hand in hand with an increase of energy trade between the European countries. When looking at the energy system from a cross-border perspective, various sources and demand clusters could be coupled, thereby increasing the efficiency of energy infrastructure and driving down costs.

Next to this, as outlined in the Draghi report, European industrial competitiveness could be increased by expanding its domestic renewable energy production[4]. The combination of decreasing CO_2 emissions, increasing energy independence and increasing European competitiveness, makes increasing the production of renewable energy one of the spearheads of EU policy.

The role of the North Sea in the European energy transition

Since the 1960s, offshore production of natural gas, and later oil, marked the first offshore energy activities in the North Sea[5]. The area has developed into a crucial energy production region and has been critical for the supply of natural gas to mainland Europe. In the past two decades, the production of offshore hydrocarbons is in decline and decommissioning efforts are intensifying. This provides opportunities for newcomers in the offshore energy transition, such as hydrogen and CO_2 transport and storage, where existing assets can be reused for new energy carriers,.

The decrease of hydrocarbons is offset by an increase in renewable energy sources. Offshore wind is expected to play a pivotal role in the future energy supply, accounting for approximately 30% of the total European electricity production by 2050[6]. The North Sea is designated as one of the most important areas for the offshore energy transition due to its shallow waters and existing infrastructure. Next to this, it is surrounded by 9 European countries, foreseeing a high need for international collaboration. In February, the EU published an action plan on affordable renewable energy, highlighting the important role for offshore energy infrastructure[7]. This suggests that the North Sea will fulfil a crucial role in the European energy system, focused on energy production, import and hydrogen and CO_2 storage.

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[1] Understanding CO2 emissions from the global energy sector
[2] Renewable energy targets - European Commission
[3] REPowerEU
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Due to the intermittent nature of renewable energy sources, energy storage becomes more important. Hydrogen is foreseen to play a major role here, with separate targets and infrastructure plans already being developed and approved. Next to this, in the foreseeable future, natural gas is still expected to play an important role in the energy supply. When combined with carbon capture and storage and hydrogen production, another low-carbon energy carrier is created. This means that when talking about the offshore energy transition, we are considering four key commodities: electricity, hydrogen, CO_2 and natural gas. In the coming decades, their role within the energy transition will change, with key differences between the North Sea countries. Understanding the interaction of each commodity with the others, will help the proper timing of infrastructure, supply, and demand developments.

EU Action plan for affordable energy

Even though the EU managed to decrease its reliance on other countries for its energy supply in the past few years, energy prices have increased drastically, decreasing the competitiveness for European industry and hurting the most vulnerable citizens. The European Commission recently launched an ambitious program on affordable, efficient and clean energy for all to tackle this; the EU Action Plan for Affordable Energy. It aims to lower energy bills in the short term, while strengthening the current and future energy system. Even though the EU already has the most integrated grid in the world, more needs to be done in terms of energy system integration to boost the integration of cheaper and cleaner energy sources. Critical parts of this action plan focus on the role of offshore energy production and infrastructure, due to its vast potential of offshore wind production.

Integration of the offshore energy network

The action plan proposes the establishment of an extensive international offshore network, to balance supply and demand, reduce energy losses and enhance grid stability. By interconnecting areas with high renewable energy production to high energy demand regions, such as industrial clusters, an efficient energy flow can be realized on a much larger scale than individual countries, while mitigating energy price peaks. Several actions are proposed for this.

First of all, significant investments are required for the expansion and strengthening of the electricity and gas grids. More international interconnections are required to optimally make use of the international integration concept. For this, the action plan calls for anticipatory investments to enhance the grid capacity and reduce overall costs by approximately 18% (12bn annually).

Next to this, cross-border collaborations is crucial, with a key focus on decreasing the permitting process. The action plan therefore proposes streamlined permitting procedures to increase the implementation processes. National deadlines for permitting need to be decreased to less than two years for offshore wind, with a focus on digitizing permitting processes. The Commission is therefore preparing a legislative proposal to accelerate grid permitting procedures, in combination with the European Grid Package. Individual perspectives and procedures can be a bottleneck when improving the overall system, calling for improved cost and benefit sharing among countries. Therefore, the action plan calls for strengthened regional cooperation.

Lastly, technological innovation for flexibility in energy systems is boosted by supporting projects that combine energy generation and storage. In order to stimulate the deployment of more renewable energy projects, the European Investment bank launches a ‘grids manufacturing package’ to support the European supply chain and derisk investments on clean energy projects. Next to this, more granular data on the offshore wind and solar potential will be mapped to increase the designation options of renewable acceleration areas. Together, these measures hope to strengthen the offshore electricity grid.

Challenges within the offshore energy transition

Although the development of the North Sea renewable energy system could provide many opportunities, there are various challenges with establishing a proper international offshore energy system. A proper understanding of these challenges can provide holistic solutions on how to deal with them.

Use of space & ecological boundaries
Since the North Sea is one of the most busiest seas in the world, it faces significant spatial challenges due to the multi-use of the area. Although this whitepaper focuses mainly on the 'energy system' of the North Sea, the 'total system' also includes fisheries, shipping routes, military activities and protected marine areas, as visualized in **Figure 1**. Even though there are quite some ecologically protected areas in the North Sea, many parts still share their space with other sectors such as fisheries, transportation routes or wind farms. This highlights that currently, there is already a multi-use of space, where various needs and interests have to coincide. The increasing demand for energy developments further constraints the use of space, focusing on previously built oil and gas platforms and new-built wind parks, PV and hydrogen infrastructure. Efficient multi-use of available space is essential, where ecological boundaries simply cannot be neglected. A full analysis on this multi-use function can be further explored in D6.4 Multi-use in the North Sea[8].

Due to the multi-use of the area, the North Sea has different functions for various stakeholders. The ecological, societal and economic functioning of this area can result in conflicts among various stakeholders. Adequately managing these interests, possibly prioritizing them and reaching consensus on the various functions is crucial for smooth collaboration and alignment, but can be highly complex.

[8] A. Satish, M. de Respinis, J. Breuer, O. Khatraoui and P. Marcus, "White paper – multifunctional spatial use at the North sea and the implications of future energy infrastructure," North Sea Energy, 2025

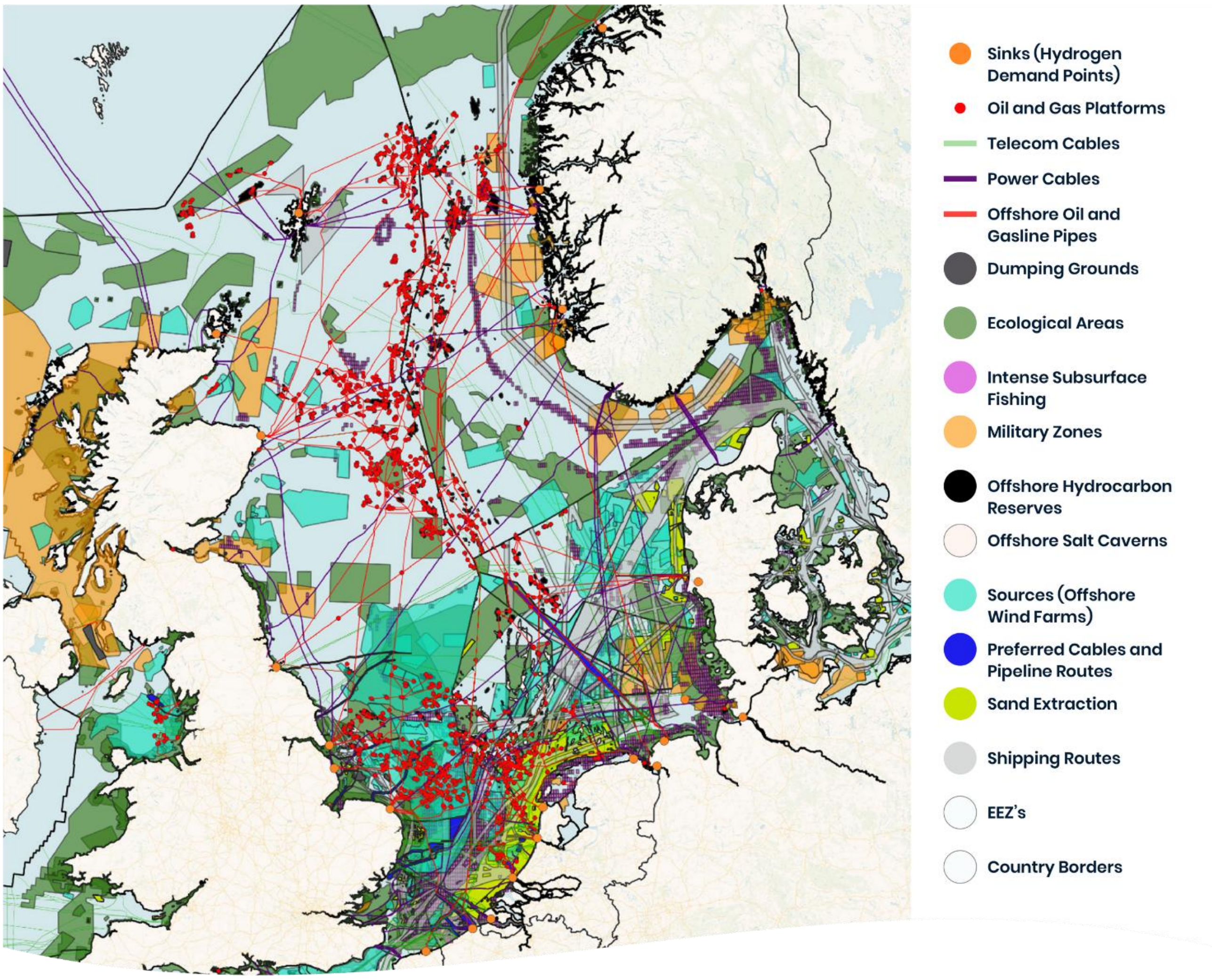

Figure 1 The various functions of the North Sea such as nature, transport, food and energy[9]

Governance

The international and system-level character poses various challenges for a smooth deployment of the offshore energy system. Due to a lack of international regulatory frameworks and definitions, several unclarities and delays persist.

First of all, legislation is currently designed individually for the four commodities (electricity, hydrogen, CO_2 and natural gas), making the interaction between them highly complicated. As is highlighted later in this report, the interrelation, and thereby the information dependencies, between the various commodities is large. Next to this, due to the relatively new development of CCS and hydrogen production and transport, international markets and regulations are still under development. Since regulation and target-setting is currently not done from a system perspective, there are many uncertainties in policy development between the commodities, challenging timely decision-making for all four of them.

[9] Use of Space — North Sea Energy

Beside the sectoral frameworks, international frameworks are also lacking. Each country has its own targets and policies for offshore energy development, challenging international alignment, which is crucial for a system-level perspective. Standardization is also lacking. This suggests that the governance framework for the North Sea energy system is currently underdeveloped, challenging a timely deployment. A full analysis on the international collaboration can be further explored in the D7.3 International Collaboration whitepaper[10].

Parallel development of supply, transport and storage, and demand
With the increased supply of intermittent renewable energy, the matching of supply and demand becomes more challenging. Sufficient wind or solar energy cannot be supplied at all times. Next to this, the electrification of industrial processes and thereby an increase of electricity demand, needs to be developed in parallel to the increase of renewables, otherwise providing uncertainties for sufficient demand. The increased electricity production needs to be transported through adequate electricity grids. This strengthening needs to be happen at the same time and is a costly investment. Next to the strengthening of the electricity grid, ports need to invest heavily on additional capacity to adequately land the generated wind power[11]. This value chain dependence highlights the challenging interaction between energy supply, transportation and storage, and demand.

Supply chains are under pressure
The rapid deployment of offshore renewable energy technologies poses significant challenges on her supply chain and OEM'ers. Several key items of the supply chain are under pressure. Geopolitical factors have highlighted the importance of domestic production and the vulnerability on imports, since both solar and wind require quite some rare earth materials (for further info see the D4.5 Material Flow Analysis report[12]). There is currently limited manufacturing capacity in Europe for the rapid expansion of offshore wind, relating to both the actual industrial capacity and a shortage of skilled labour. Besides this, the transportation of large components to offshore sites is highly complex and time-consuming (for further info see the D6.3 Logistics report[13]). Lastly, international competition of offshore energy components can further strain the supply chains.

Price increases
Related to the supply chain challenges are the price increases in the offshore energy industry. In the past year, it became clear that the costs of all offshore energy technologies (f.e. wind turbines and electrolyzers) were higher than expected. This is mainly due to supply chain disruptions, increased interest rates and increasing inflation[14]. This could result in a more hesitant attitude of offshore energy developers, thereby slowing down further deployment. Next to this, the decommissioning of oil and gas wells is facing delays as well, due to financial hurdles and volatile costs, impacting the reuse of existing assets[15].

Human capital
As previously stated, the large deployment of additional energy assets requires sufficient human capital. The growth of the offshore energy sector will create more and more jobs and require a skilled workforce. Currently, the development of the energy technologies already faces significant production challenges,

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[10] N. Dooley, R. van Zoelen and M. Vos, "International North Sea Collaboration: from buzzword to concrete actions," North Sea Energy, 2025
[11] Studying port infrastructure needs for offshore wind energy | Royal HaskoningDHV
[12] M. Kamps and R. Elbing, "Material Flow Analysis and Criticality Assessment," North Sea Energy, 2025
[13] V. Uritsky, J. Mohanan Nair, "Logistics", North Sea Energy, 2025
[14] Expensive Offshore Wind Is in Trouble - IER
[15] North Sea decommissioning grapples with delays despite government incentives - Offshore Energy

posing even more challenges with further deployment in the future. Besides the equipment manufacturing, extensive human capital is required for the construction, operation and maintenance of the energy system. An additional challenge is here that the offshore environment is often perceived as harsh by the general public. With an ageing workforce over the next decade, the challenge of finding sufficient workforce is expected to increase even more in the future. A full analysis on the challenges related to the human-capital agenda can be further explored in the WP2 Human Capital report.

A brief graphical overview of the type of challenges the future North Sea energy system faces is depicted in **Figure 2**. A division is made between techno-economic challenges and social challenges, although the barrier between the two can be blurred.

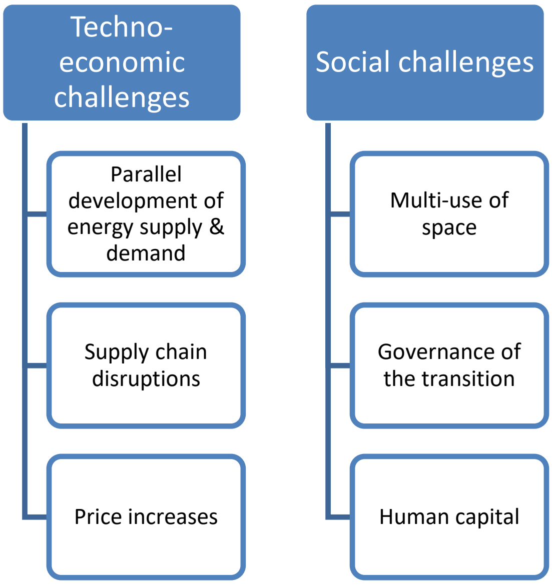

Figure 2 Graphical overview of the offshore energy system transition

System integration as a solution for the North Sea

Many of the before-mentioned challenges can be tackled by taking a system perspective on the North Sea energy system. Offshore system integration is defined as a set of sector coupling activities including: oil & gas platforms combinations with CCS and hydrogen, CO_2 storage, Power2Gas (P2G) and energy storage. It includes the strategically coupling of offshore sectors by integrating infrastructure, services and logistics, and making a multifunctional use of space. From the energy perspective, this suggests to not individually consider the energy carriers, commodities and infrastructure assets, but regard them as part of one holistic energy system.

One of the most familiar concepts of system integration is the combination of electricity generation and energy storage, for example in the form of hydrogen. By directly converting electricity into hydrogen, the issue of intermittency could partly be tackled. Next to this, existing pipeline infrastructure and platforms from the oil and gas sector could be converted to hydrogen transportation infrastructure, and depleted oil and gas fields could be used to store hydrogen. This drastically decreases the need for new materials and has a lower impact on the environment than new infrastructure instalments. Oil and gas platforms that are still in use for fossil fuel production could be electrified and CO_2 emissions could be captured and stored in depleted fields or salt caverns. A visualization of these concepts can be seen in **Figure 3**.

A specific example of offshore integration is the concept of energy hubs, where various functional systems are closely integrated within specific geographical locations, to reduce overall spatial needs. Energy hubs are defined as multi-carrier offshore energy systems consisting of production, conversion and/or storage. The energy hubs are connected to the shore via national (transport) corridors or interconnected internationally to other countries. In this way, energy hubs are search areas for offshore system integration opportunities.

Although this is just a brief overview of possible integration solutions, the interaction between various energy commodities is apparent. By approaching the North Sea as an integrated system, the costs of the energy transition can be reduced, security of supply can be ensured, the spatial claim and impact on nature can be mitigated, and energy system development times can be decreased.

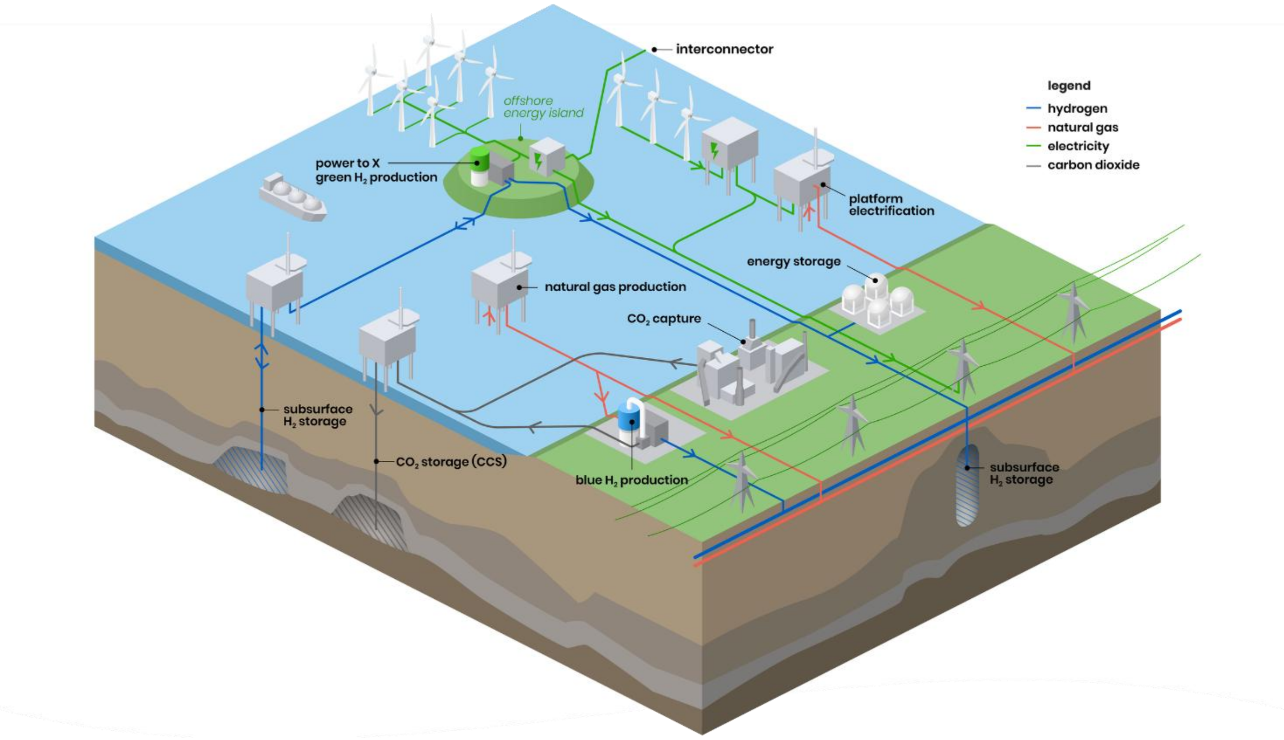

Figure 3 System integration concepts in the North Sea[16]

Pathways towards 2050

This whitepaper examines the electricity, hydrogen, CO_2 and natural gas trends foreseen for the North Sea in the coming decades. More in depth information on the results of these four commodities can be read in Chapter 2, 3, 4 and 5. This subchapter examines the pathways of the future energy system. The scenarios that form the basis of the 2050 pathways are the Distributed Energy (DE) scenario and Global Ambition (GA) scenario from ENTSO, of which more information can be read in the textbox below. **Figure 4** provides a possible pathway overview for the offshore commodities, based on the DE and GA scenario outcomes and additional sources.

[16] System Integration Concepts — North Sea Energy

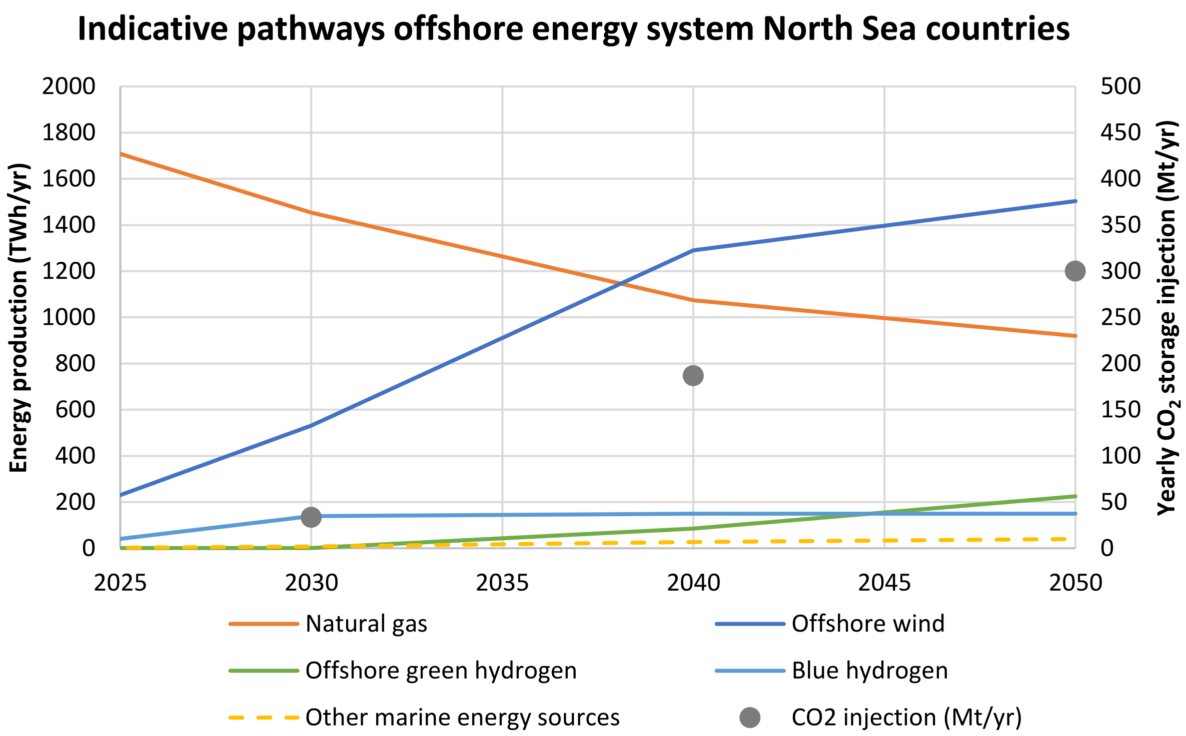

Figure 4 Indicate pathways for the offshore energy commodities for all North Sea countries, combining various sources[17],[18]

[17] Pathway sources: natural gas → country specific pathways, offshore wind → average of the modelled scenarios & ONDP Sea Basin report, offshore green hydrogen → NSWPH - Pathway 2.0, blue hydrogen → average of the calculated DE & GA scenarios, other marine energy sources → North Sea Energy, yearly CO_2 injection in the North Sea → Xodus report.

[18] Compared to the current production of offshore wind (110 TWh in 2024), a doubled growth is already foreseen towards 2025. Even though this might not be realistic, it is still visualized in this graph to linearly achieve the 2030 target

Scenario description

The future North Sea energy system is modelled with the integrated energy market model I-ELGAS. It provides cost-optimal market production numbers for electrons and molecules, given a certain energy system. The input data of this model consists of the Ten Year Network Development Plan 2024 (TYNDP2024) scenarios developed by the European network operators, ENTSO-E and ENTSO-G. These scenarios describe two contrasting pathways towards climate neutrality in 2050 and are used to investigate the associated infrastructure needs. Two TYNDP scenarios are available for 2050: the **Global Ambition (GA)** and the **Distributed Energy (DE)** scenario**.** For 2030, the **National Scenario (NT)** from II3050 is implemented.

For 2030, the National Scenario (II3050) was chosen to provide the most suitable pathway for the near future. This scenario assumes national leadership with an extensive role for governments in guiding the transition, together with a national instead of international character in terms of energy supply. The scenario assumes a strong electrification and extensive renewable energy production, together with a limited decline of domestic industrial sectors. The focus is on national self-sufficiency.

For the longer term, the TYNDP scenarios were investigated to provide an energy system pathway with a European character. The GA scenario assumes centralized generation, offshore wind and Power-to-X with imports, whereas DE takes a decentralized approach with small scale solutions and circularity approaches. The DE scenario foresees high European autonomy with a renewable and decentralized focus. The Global Ambition scenario assumes more centralized (large scale) low carbon and renewable energy options. The latter entails typically higher levels of offshore wind, more import of low carbon energy and more CCS deployment. The demand for natural gas is rapidly declining in both scenarios and has similar outcomes in 2050. In comparison to each other, the Global Ambition scenario has higher natural gas demands and the Distributed Energy has a higher production and import of biomethane. Both scenarios include a rapid system transition from molecules to electricity, resulting in a general push for technologies that provide energy flexibility options, such as hydrogen. Next to this, the subsurface will increasingly provide services such as CO2- and hydrogen storage. Lastly, the current import of oil and coal will be replaced by the import of hydrogen and biomethane, resulting in a different import-export system. In general, the GA scenario assumes a higher role for molecules, whereas the DE scenario is richer in electrons. In the remainder of this report, we will most commonly refer to the GA scenario as the 'high' scenario and the DE scenario as the 'low' scenario.

Shortcomings of the scenarios

The assumed rapid level of decarbonization in the GA scenario requires rapid technological advancements and high investments, amongst others for infrastructure. Since this should go hand in hand with international cooperation and policy development, this is most likely overambitious and unachievable, especially for 2030. Next to this, the DE scenario relies more on small-scale decentralized solutions, which could pose greater challenges on the grid stability. In general, the scenarios provide a very optimistic point of view, with high offshore wind installed capacities, high offshore hydrogen production and significant CO2 storage. Additionally, it needs to be noted that ACER has criticized the TYNDP2024 scenarios for providing only 'high hydrogen' pathways compared to the member states' energy outlooks (ACER, 2024).

The modelled energy system focuses on the nine countries surrounding the North Sea. This means that the wider international context (import with other European countries or even countries outside of Europe) is not accurately taken into account. The outcomings should therefore mainly be used for relative comparisons between the North Sea countries and not be directly coupled to a wider context.

It should be noted here that the pathways presented in this report only serve as indicative pathways for a future energy system in which we rely heavily on renewable energy sources. They should by no means be considered as the truth, but only serve as possible future developments. Where possible, a comparison with other scenarios, targets or prospected pathways is given in the dossiers of this whitepaper, in order to present a more realistic pathway.

Rapid increase of offshore wind and a slow increase of other marine energy sources
Offshore wind shows a rapid increase and steep growth towards 2050. The steepest growth occurs between 2030-2040, which is required to meet the ambitious European targets. This means that the yearly production of the North Sea countries will increase almost tenfold in 2050 towards 1500 TWh, accounting for approximately 60% of total European installed capacity.

Comparing this to the expected production of 1300 TWh in 2050 in the ONDP North Sea Basin report, highlights the overestimation of the calculated GA and DE scenario. On one hand, this could be due to the neglection of inter-farm wake effects between wind turbines. On the other hand, it could be due to a too high estimation of total installed capacities. To provide a more realistic overview, the pathway figure depicts the average between the calculated scenarios and the ONDP forecast.

Figure 4 also depicts a trendline on electricity production from other marine energy sources, such as floating solar, wave and tidal energy. Although it is not a direct result from the calculated scenarios, its share in the offshore energy system will most likely increase in the future.

Decrease in natural gas production
The increase of offshore wind production can nearly directly be coupled to the decrease in natural gas production. This trend is expected to decrease more until 2030, after which it will eventually decrease to approximately 50% of the current production. However, this is greatly dependent on new policies that might be developed in the coming years to decrease energy dependence. The four major producing countries are the UK, Norway, the Netherlands and Denmark. The Netherlands and Denmark will completely phase out their natural gas production in 2050, the UK is expected to produce only 5% of her current production in 2050, whereas Norway will continue natural gas production until the 2050s, with only a minor decline (from 1300 TWh in 2023 to 900 TWh in 2050). Next to the depletion and thereby phase-out of current oil and gas fields, platform electrification could result in a reduction in emission intensity of extraction activities. However, it should still be investigated where this is technically and economically feasible on the North Sea.

The mix of green and blue hydrogen
From our calculated scenarios, offshore and onshore hydrogen production could not be split apart. The North Sea Wind Power Hub (NSWPH) Pathway 2.0 was conducted as a forecast on how offshore green hydrogen could develop, mainly related to the rapid increase of offshore wind. The percentage of offshore blue hydrogen production was assumed to be approximately 40% of total blue hydrogen production in the calculated scenarios.

At the moment, offshore hydrogen currently represents only a minor fraction in the energy commodities. It is expected that blue hydrogen foresees a somewhat quicker developed in the next five years, due to its incorporation with current natural gas platforms. However, it is currently still in the demonstration phase. After the 2030s, the blue and green hydrogen pathways could converge and have comparable production in the 2030-2040 decade. Green hydrogen is expected to take off drastically after that, with rapid expansion in parallel to offshore wind developments. The synergy between both technologies is quite apparent and go hand in hand. Blue hydrogen, other hand, has peak production in 2030, after it will slowly decrease. However, it is foreseen to still have a role in the energy transition until 2050. When coupled to CCS, blue hydrogen is produced and used as an energy commodity as long as there is still oil and gas production.

The estimate of blue hydrogen production is somewhat low in the calculated scenarios. For 2050, its share is even expected to be 0. However, this is not deemed realistic, since investments required for 2030-2040 cannot be profitable if the technology is expected to be phased-out by 2050. That is why in the pathway figure, a similar production for 2050 as 2040 is foreseen.

CO_2 storage
Currently, there are only two operational CCS sites in Europe, both in Norway. In the coming years, various demonstration projects are expected to start, after which a significant increase in capacity is expected in the coming decades. In the near future, CCS will mostly be used for CO_2 capturing from oil and gas production activities. However, in the long-term, CCS could have a role in achieving negative emissions when used with biomass. The EU has the ambition to capture 50 Mt of CO_2 by 2030, 280 Mt by 2030 and 450 Mt by 2050[19]. Even though there is not a direct number stated for the North Sea, this region is expected to host the majority of the storage sites. The depletion and abandonment of gas fields in the coming years will allow for an increase in storage capacity. Next to this, storage in aquifers is likely to be deployed as well.

System interdependencies within the coming decades

The offshore commodities (natural gas; offshore wind; CO_2 transport and storage; hydrogen production, transport and storage) do not develop in isolation. They are strongly intertwined and these dependencies govern to a very large extent the possibilities and challenges for offshore system integration in time and space on the North Sea.

The interdependencies – either positive or negative feedback – provide insight into how the sketched pathways affect each other. A graphical overview with the key system interdependencies is depicted in **Figure 5**. One example is that the production of green molecules from the North Sea region would require a faster development of offshore wind to ensure enough electricity is available for electrolysis.

Blue hydrogen production requires natural gas and a CO_2 transport storage network. However, strategies for reducing import dependency may limit the import of natural gas for the production of blue hydrogen. This could result in blue hydrogen only being produced from local sources of methane. Next to this, the CO_2 transport and storage infrastructure may re-use certain offshore hydrocarbon assets (pipelines, platforms, wells and reservoirs) for the transport and storage of CO_2. This requires these assets to be available for this purpose and that the natural gas production has ceased. However, this could also compete with offshore hydrogen that could re-use the same assets for hydrogen production, transport and storage.

On one hand, green and blue hydrogen could compete for offshore assets and for the offtake of the hydrogen market. On the other hand, there are strong synergies as the production profiles and price setting behavior for the commodities are much different. Together they can provide security of hydrogen supply for large demand sectors and provide the volume needed to develop markets and infrastructure efficiently.

[19] In focus: Industrial carbon management

Figure 5 System interdependencies between the four commodities. A positive relation is described by a (+) and a negative relation by a (-)

Examples of current system integration concepts
Currently, there are already quite some demonstration projects centered around the concept of system integration. The first platforms electrification programs are starting up, such as the N05-A platform. The Sealhyfe platform has produced its first kilograms of green hydrogen in 2024, consisting of an offshore electrolyzer coupled to a floating wind farm near the French coast. In 2025, the PosHYdon project started demonstrating a 1MW of offshore green hydrogen electrolyser at the electrified Q13a-A hydrocarbon production platform near Scheveningen. The Porthos project will most likely start in 2026 to store 2.5 Mt/yr of CO_2 from industrial processes and transport it to an offshore depleted gas reservoir. The OranjeWind program will combine offshore wind with floating solar, electricity storage and onshore flexible assets. The Zeevonk wind park will combine offshore wind with floating solar and onshore hydrogen production, and is expected to be operational by 2029. Lastly, among various other examples, Germany has reserved an area of the North Sea for exclusive green hydrogen production from offshore wind, which will be transported to shore via a hydrogen pipeline. These demonstration projects in the coming years will pave the way for future expansion and rapid take of renewable energy system integration. A simplistic overview of some of these key projects is visualized in **Figure 6**.

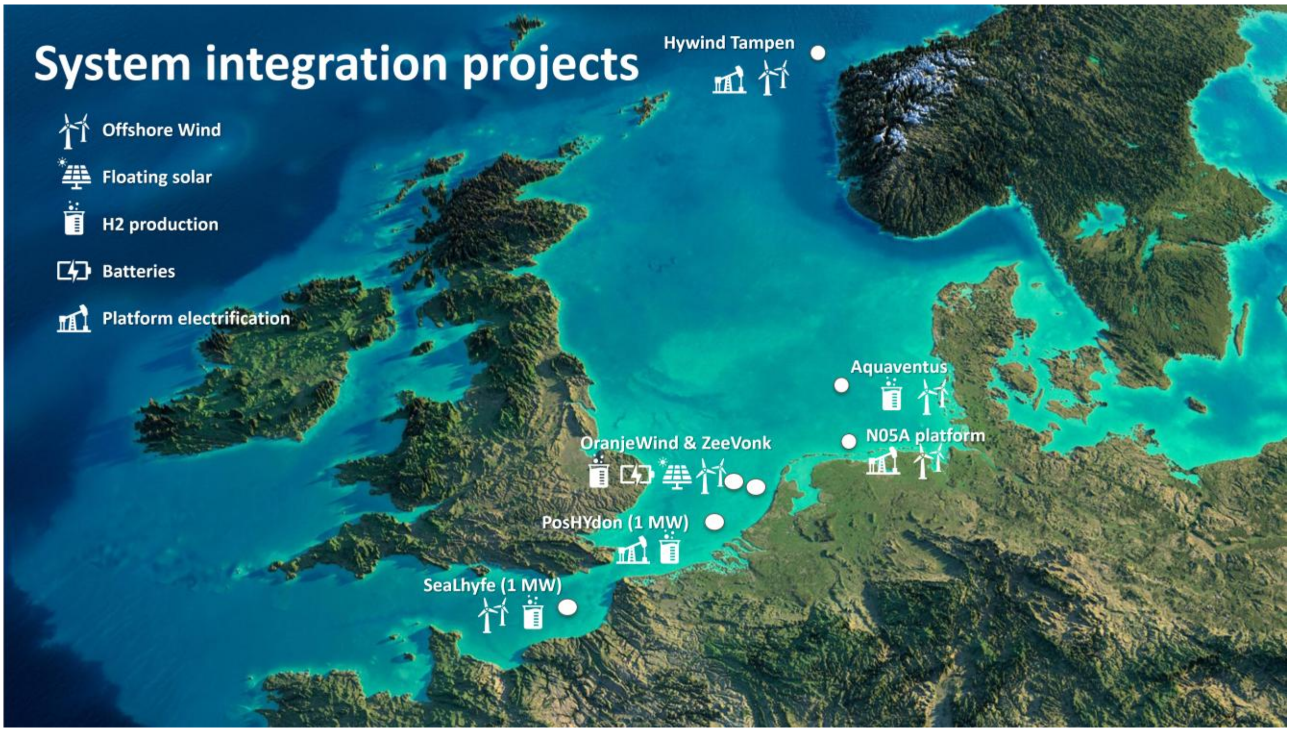

Figure 6 Graphical overview of key system integration projects on the North Sea, where various energy commodity functions are combined

Action agenda

To fully make use of system integration as an implementation strategy for the energy transition on the North Sea, an action agenda is proposed that addresses the key challenges. Eight main themes have been identified, next to the commodity specific actions that are further highlighted in the proceeding four chapters.

Goal setting: international, spatial and integral
In the past years, ambitious targets have been set on offshore wind and total hydrogen production. Although this is a step in the right direction, no targets have been set on all offshore key commodities yet. Targets on

offshore hydrogen production, transport and storage are lacking, despite its major foreseen role in combination with offshore wind. Next to this, policies and targets on CCS, together with blue hydrogen, have not been developed yet, even though it has been seen as an inevitable part of the future energy system. Lastly, even though the majority of the North Sea countries has pledged to decrease its natural gas production, no targets on actual demand or import have been set yet. This means that a clear pathway for the North Sea energy system has not been developed at this moment, obstructing a clear vision and way forward.

The development of an integrated strategy is needed to guide public and private strategies, and decrease the spatial impact of the transition. It is advised that this vision is as spatially explicit as possible, in order to align stakeholders' perspectives and minimize negative impacts. Next to this, the targets and strategies should focus on infrastructure planning in an international context, to provide long-term pathways for the commodity developments.

The vision for the North Sea's energy transition should be integrated into national energy and climate plans and align with the infrastructure visions of ENTSO-E and ENTSO-G. The Dutch government's "Energy Infrastructure Plan North Sea 2050" will most likely be published in 2025 and can serve as an input for the international vision.

Governance of the transition
Next to the absence of clear targets, a general good governance of the transition is required to smooth deployments and creating investment certainties. The integration can be hampered by inconsistent national regulations or the absence of standardization. It is crucial that legislation quickly and adaptively follows innovation, since system integration is still a relatively recent concept.

Firstly, it is crucial that the concept of system integration is clearly defined, after which standardization can be developed, which is crucial for safety, interoperability and cost reductions. Secondly, to align spatial planning and increase permitting processes, a proper governance structure is required for quick and adaptive decision-making across the North Sea Countries. Several initiatives are already running, such as the OSPAR Commission, North Sea Basin Task Force, Greater North Sea Basin Initiative and North Seas Energy Cooperation. Further advice can be read in the WP7 whitepaper on International Collaboration.

Collaboration, engagement, dissemination and communication
Besides adequate collaboration between countries, broader stakeholder engagement and collaboration are crucial for a successful rollout of the offshore energy system. Due to the multi-faceted approach and intertwinement of the various commodities and sectors, it is essential to engage with stakeholders spanning all actors from the public, private and civil society. Early engagement can help in faster decision-making and avoid potential delays.

For organizations that are directly involved in the development of the energy system, international collaboration and knowledge sharing should be improved. Due to the quick technological developments and complicated spatial planning, smooth knowledge sharing is of the utmost importance. This can be strengthened by the establishment of a dissemination platform.

Public awareness and engagement can be improved by effective communication on what the North Sea's role will be in the future energy system. The key message should emphasize the replacement of old fossil-fuel systems with new sustainable solutions. Additionally, raising awareness about the benefits and costs of an integrated energy system compared to individual systems is important. Strategic tools like VR tours, live streams, bird cams, and video/board games can help make the offshore energy system a part of public life and discourse.

Economic stimuli & market development of offshore system integration
Besides the international alignment of regulatory frameworks, the alignment of market frameworks is crucial for the future energy system. Since the four system integration commodities are highly intertwined, it is likely that the market development of one commodity will affect the others. This means that project developers of offshore wind, hydrogen, natural gas and CO_2 will most likely operate in an international and intersectoral system.

Currently, the offshore system integration is hampered by the lack of long-term certainty in terms of offtakers, infrastructure development and uncertain business cases. For example, the development of offshore wind needs to run in parallel with electricity demand, the green hydrogen market needs to be de-risked for investors (on demand, supply and infrastructure side) and CCS needs support until the price of emission allowances can close the business case. It is advisable that various support mechanisms will be put in place in the coming decade that serves a level playing field across the North Sea basin.

Minimize negative impacts and seek positive impacts on the ecosystem
The North Sea is an ecologically sensitive area, with various protected species and important marine ecosystems. It is important to minimize the impact of disruptive activities and actively pursue positive impacts on the environment, while developing our future energy system. The requires the embodiment of ecological principles into the design of this energy system, so-called nature-inclusive design, instead of only considering it as a separate aspect. A good example here is the GSNBI has a separate track on nature conservation, aimed to 'better align current and future conservation' and upscale the international cooperation in this regard[20]. A robust research and monitoring program must be established to study the environmental and ecological impacts of new offshore energy systems. Furthermore, better funding and financing options must be extended to projects with lower ecological impacts or positive environmental externalities. This can be done by embedding ESG (Environmental, Social, and Governance) into the evaluation criteria for financing. Lastly, standardization of offshore systems will also support the efforts to build with nature more effectively. Further advice can be read in the WP6 report on Nature-inclusive design.

Human capital agenda and supply chain
One of the central pillars of making this energy transition succeed, is the availability of a skilled and motivated workforce. The growth of the offshore renewable energy sector will create many new jobs, while the declining fossil fuel production poses a difficult situation for the experienced oil and gas workers. Significant efforts are needed to transition these workers to a decarbonized energy sectors, by providing proper trainings to work on hydrogen, CCS and electricity, and by integrating ecological principles. By offering a multi-faceted skillset, these workers could become employable in the integrated energy system.

Secondly, the offshore renewable energy sector should become more attractive to the general public. While currently being perceived as a 'far away', it is often not on people's top of mind when searching for job opportunities. More effort needs to be done on communicating the excellent job opportunities in the offshore energy sector.

Lastly, automation and digitization can lessen the pressure on the required workforce. Labour reducing technologies such as autonomous vehicles, unmanned monitoring systems, logistic optimization models and

[20] Establishment of the Greater North Sea Basin Initiative (GNSBI) | The European Maritime Spatial Planning Platform

predictive maintenance with AI can effectively decrease the pressure on the required workforce. It is strongly advised that the implementation of these technologies is closely followed. Further recommendations can be read in the WP2 Human Capital report.

The upscaling of the renewable energy system goes hand in hand with sufficient availability of materials. For this it is important that adequate resources will become available in Europe, that recycling technologies are developed further and that the key bottlenecks on the supply chain are identified in time, such that bottlenecks can be identified in time. Further recommendations can be read in the WP4 Material Flow Analysis.

Technical improvements

Many of the offshore energy technologies are still in an early stage of (scale-up) development. Onshore electrolyzer innovation processes currently focus on the scale-up from the MW to GW scale. Learnings must be translated to the offshore electrolyzer development, which requires more piloting due to its different environment. Many scale-up projects for offshore hydrogen have already been announced, focusing on both the implementation on existing platforms, as well as the integration with wind turbines. A great learning potential can be achieved by combining the knowledge of all demonstration projects, paving the way towards standardization and de-risking the technologies.

A similar story holds for the other offshore technologies. Currently, the North Sea region lacks an integrated approach to share best practices and innovation learnings for various offshore system integration concepts. A North Sea offshore demonstration Flagship program could align national and regional innovation programs, setting clear goals for technology improvement, scale-up, and deployment. The NSEC framework or European Technology & Innovation Platforms could serve as starting points for this program.

Energy security and defending energy infrastructure

Since the war in Ukraine, security threats of critical offshore energy infrastructure became realistic, resulting in energy security and safety becoming a major theme in Europe. It is strongly advised that the security and resilience of the future offshore energy system are properly assessed, together with the development of multi-use sensor networks for monitoring environmental, operational and security conditions in the North Sea. This also relates to building a robust cybersecure network of both the assets as well as the international interconnections.

Besides the monitoring and cybersecurity, it is important that the system itself is resilient. This relates to the diversification of the energy sources, the interconnectivity levels between countries and sources, and the amount of storage and storage locations for the various energy carriers. For this, adequate system planning is required again.

Dossier 1 – Electricity

1.1 State of play and ambitions

Over the past decade, there has been gradual shift from fossil fuel-based energy to renewable energy, a trend that is expected to accelerate in the future. For the North Sea region, offshore wind is the key driver in this trend. Next to this, the transition to a fossil-free future will result in increased electrification and consequently a higher overall electricity demand. This section will explain the current state of electricity production, consumption, storage and infrastructure development in the nine North-Sea countries, and present an outlook on how this could develop in the future.

Current state of play

Increase of electricity production from renewable energy sources, most notably offshore wind
2023 showed a record high share of 24.5% renewables in Europe's energy mix[21]. 59% of Europe's total electricity production originated from the North Sea Countries[22]. Although total electricity production has remained relatively constant over the past decade, there has been a significant shift from fossil-fuel sources to renewable sources, predominantly offshore wind. In the Netherlands, renewables accounted for the first time for approximately 50% of the total electricity production in 2024[23]. **Figure 7** shows the electricity production from offshore wind in the nine North Sea countries for the past decade, whereas **Figure 8** depicts the total electricity production from all sources except offshore wind.

Within offshore wind production, there is a significant difference in scale between the North Sea countries. Germany and the UK lead this development, with their annual production already exceeding 25 TWh. Next to this, the Netherlands has seen a rapid increase in offshore wind production capacities over the past decade of more than 2000% (from 0,7 TWh in 2015 to 15 TWh in 2024). Other countries have production levels below 10 TWh in 2024. Of all the North Sea countries, Denmark has the highest contribution of offshore wind in its energy mix with 56%, followed by Sweden (31%) and Germany and the UK (both 30%)[24].

[21] Share of energy consumption from renewable sources in Europe | European Environment Agency's home page
[22] Statistics | Eurostat
[23] Half of electricity is produced from renewable sources | CBS
[24] Wind energy in Europe: 2024 Statistics and the outlook for 2025-2030 | WindEurope

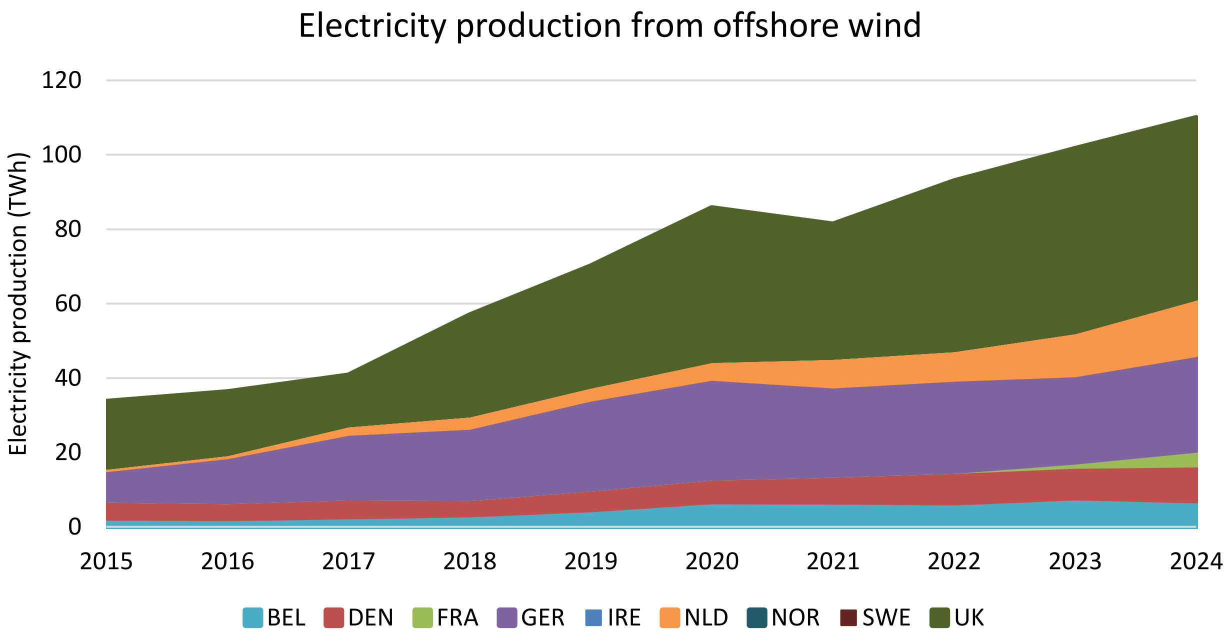

Figure 7 Historic offshore wind production of the nine North Sea countries[25,26]

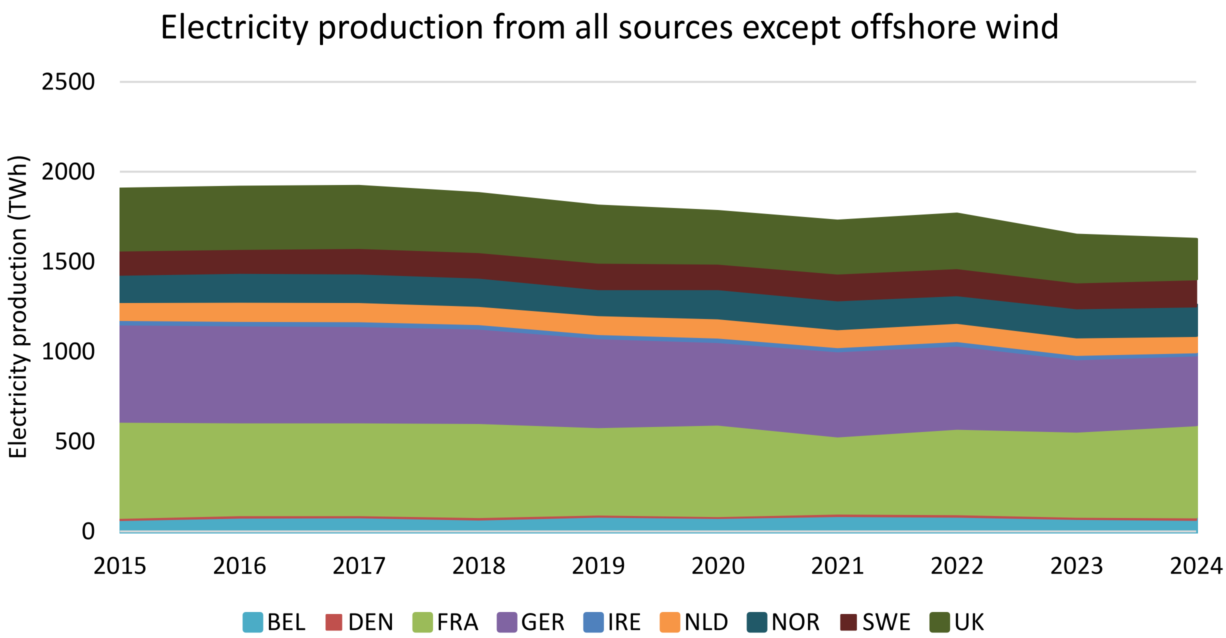

Figure 8 Historic electricity production from all sources except offshore wind[27, 28]

Challenges for offshore wind developments and trends towards new forms of marine energy

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[25] Column charts on electricity generation | Energy-Charts
[26] Energy Trends: UK electricity - GOV.UK
[27] Column charts on electricity generation | Energy-Charts
[28] Energy Trends: UK electricity - GOV.UK

The expansion of offshore wind started to take off after 2017, with **Figure 9** representing the installed capacity of offshore and onshore wind for all North Sea countries. In 2024, 9.4 GW of new wind power capacity was installed in the this region, of which approximately 25% was offshore[29]. As is seen in this graph, the relative share of offshore versus onshore wind is increasing over the years. In order for the EU to reach its 42.5% renewable target by 2030, an annual increase to 23 GW of newly installed total wind capacity is needed for Europe as a whole.

Recently, the wind sector started to face major challenges. Increased inflation and commodity prices resulted in increased investment cost for wind farms (especially offshore), sometimes even resulting in failed tenders for offshore wind farms in the North Sea basin[30]. Next to this, the business case for large offshore wind farms is getting more uncertain with a lagging industrial demand for electricity and the issue of onshore grid congestion. Lastly, restrictions in vessel and port capacity further complicate the further development. This makes the value chain surrounding further expansion quite uncertain.

Next to offshore wind, there is a slow development towards other forms of marine energy. At the moment, floating solar is still in the piloting phase, whereas for wave and tidal energy there was an increase of around 800 kW installed capacity in Europe in 2023, adding up to a total of 44 MW installed capacity[31]. Comparing this to the total installed capacity of 37 GW of offshore wind in Europe, this is still a minor fraction.

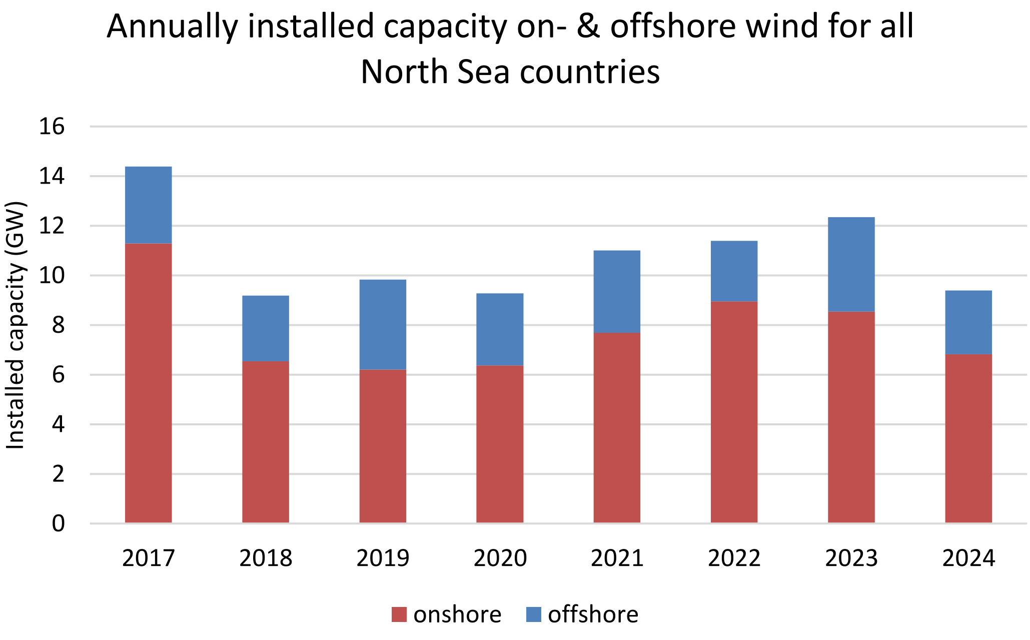

Figure 9 Annually installed on- & offshore wind capacity of the North Sea countries[32]

The past decade shows relatively constant electricity demand in the North Sea region, with significant differences between countries

[29] WindEurope-European-Stats-2024.pdf
[30] No offshore bids in Denmark - disappointing but sadly not surprising | WindEurope
[31] Ocean-Energy-Stats-and-Trends-2023.pdf
[32] WindEurope-European-Stats-2024.pdf

In the past decade, electricity demand has been relatively constant for the North Sea countries, adding up to 1700 TWh in 2023, as visualized in **Figure 10**. France and the UK lead this demand with each approximately 400 TWh in 2023, whereas the other North Sea countries account for a much smaller fraction of the region's total electricity demand. In Europe, industry covers the largest share of electricity demand with 36.5%[33]. There was a slight reduction of electricity demand in 2022 and 2023, primarily due to increasing electricity prices because of the war in Ukraine and a relatively warm winter and hot summer[34].

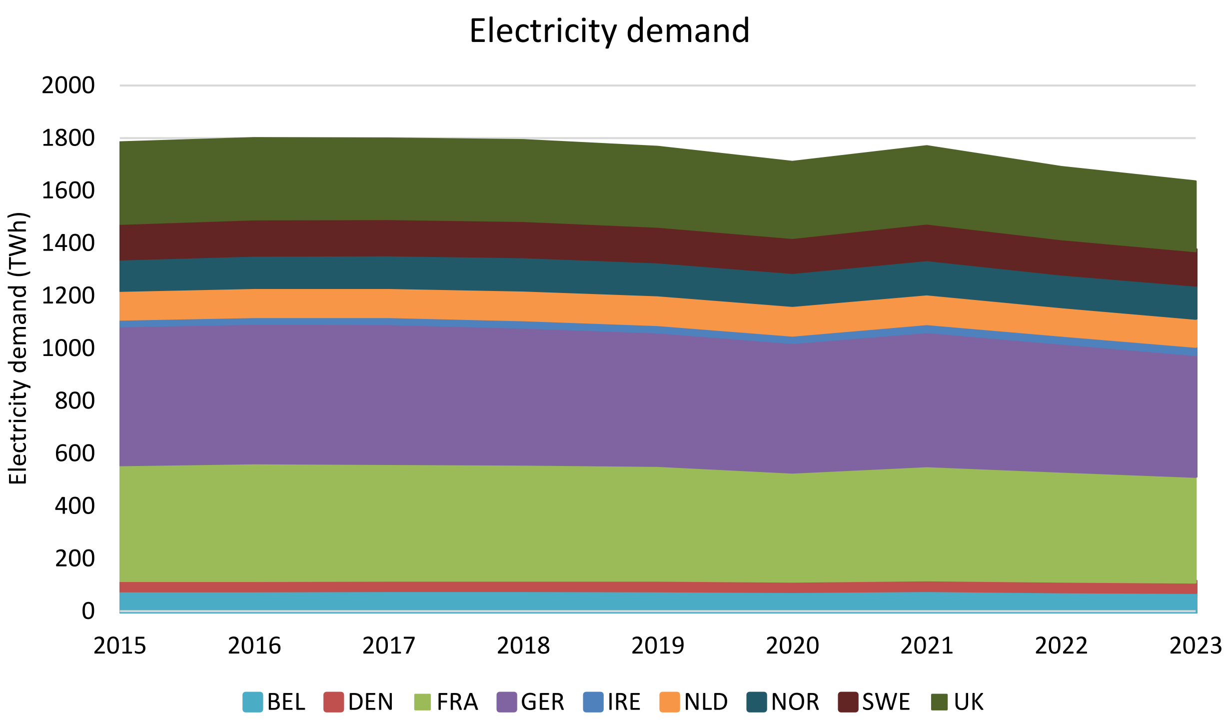

Figure 10 Historic electricity demand [35, 36]

The North Sea region as a net export area

An analysis of the electricity import-export dynamics, as illustrated **Figure 11**, reveals significant differences between the North Sea countries. Norway and France are principal exporters, primarily due to their surplus of hydro- and nuclear energy. On the other hand, the UK imported a significant volume of 26 TWh in 2023 to meet its electricity demand. Together, the North Sea countries function as a net-export area for Europe[37].

[33] Europe – Countries & Regions - IEA
[34] Europe's energy crisis: Understanding the drivers of the fall in electricity demand – Analysis - IEA
[35] Statistics | Eurostat
[36] UK electricity consumption 2023 | Statista

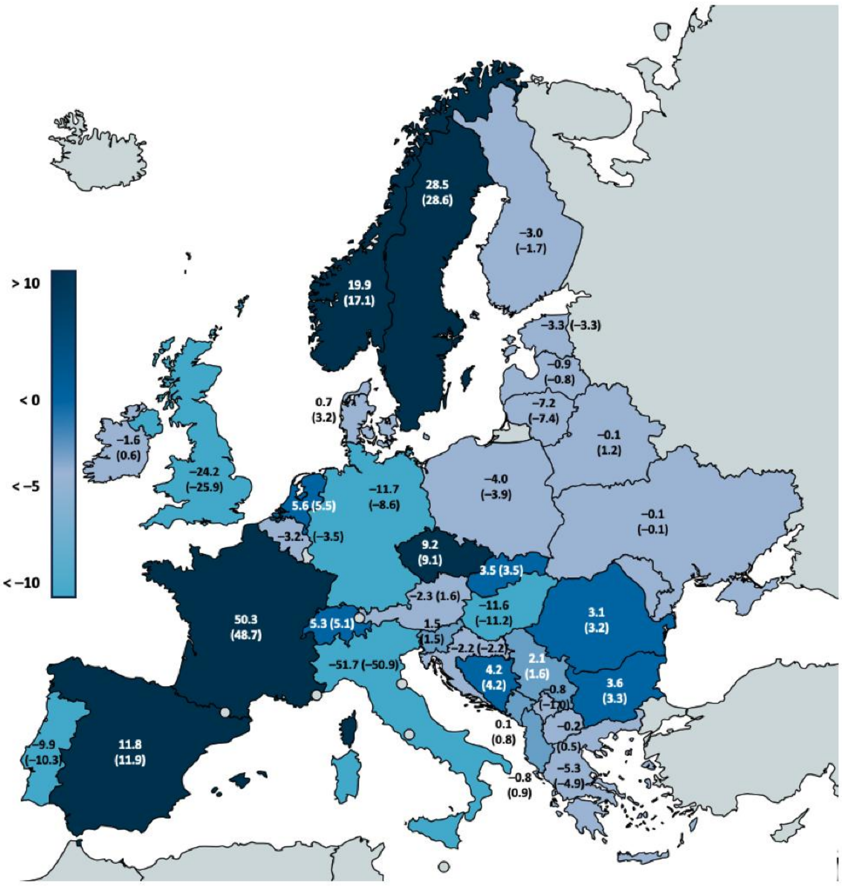

Figure 11 Net electricity export trading volumes and physical flows (between brackets) in TWh/yr of European countries in 2023, where positive numbers represent export and negative numbers represent import[38].

Future state of play

The North Sea region's ambitious offshore wind developments

The North Sea countries collectively have a target of 120 GW offshore wind installed capacity by 2030 and 300 GW by 2050, representing a very large share of the total EU ambition by 2050[39,40]. Figure **12** illustrates the a possibly pathway for the total electricity production from the modelled TYNDP scenarios for offshore wind versus all other electricity sources, whereas **Figure 13** depicts the total installed capacity of offshore and onshore wind, broken down for the nine North Sea countries.

A 65% increase of total electricity production is foreseen between 2030 and 2050. For offshore wind, an impressive 200% increase is foreseen, highlighting the rapid development anticipated in the coming decades. As shown in **Figure 13**, the UK and Germany account for the majority of offshore wind production, however, after 2040, the Netherlands is expected to have a rapid expansion of offshore wind as well, becoming the third largest producer.

[38] Trend Analysis of Cross-Border Electricity Trading in Pan-European Network
[39] Ostend Declaration
[40] The North Seas Energy Cooperation

The general trend in the calculated scenarios is comparable to the explored pathways in the NSWPH. However, the total installed capacities for the North Sea are larger, suggesting that the modelled scenarios in this analysis are rather optimistic[41]. Next to this, the production per installed capacity for offshore wind amounts to approximately 4.5 TWh/GW installed, which is significantly larger than the historic Dutch production of 3.2 TWh/GW[42]. This is most likely due to the fact that intra-farm wake-effects are not taken into account in the model. Despite these shortcomings, lessons can still be drawn from the development trends between 2030-2040 and 2040-2050 and the differences between countries.

According to the scenario outcomes, the biggest increase of offshore wind installed capacity is expected to occur between 2030-2040 with approximately 18 GW/year. Between 2040-2050, this decreases to 8 GW/year. Furthermore, the ratio between off- and onshore wind is expected to significantly change in the coming decades. In 2030, around 28% of total installed wind capacity arises from offshore wind parks, whereas in 2050 this adds up to 47%. For both the UK and the Netherlands, offshore wind installed capacities could exceed onshore capacities.

As visible in **Figure 13**, Norway has a minor contribution for offshore wind installed capacity. However, the country has the ambition to install 30GW in 2040, suggesting that its contribution to the North Sea offshore wind production will be larger than depicted here[43]. Most likely this is a result from our scenario analysis where the current contribution of Norway with its hydropower on the renewable energy mix is cheaper than installing more offshore wind capacity.

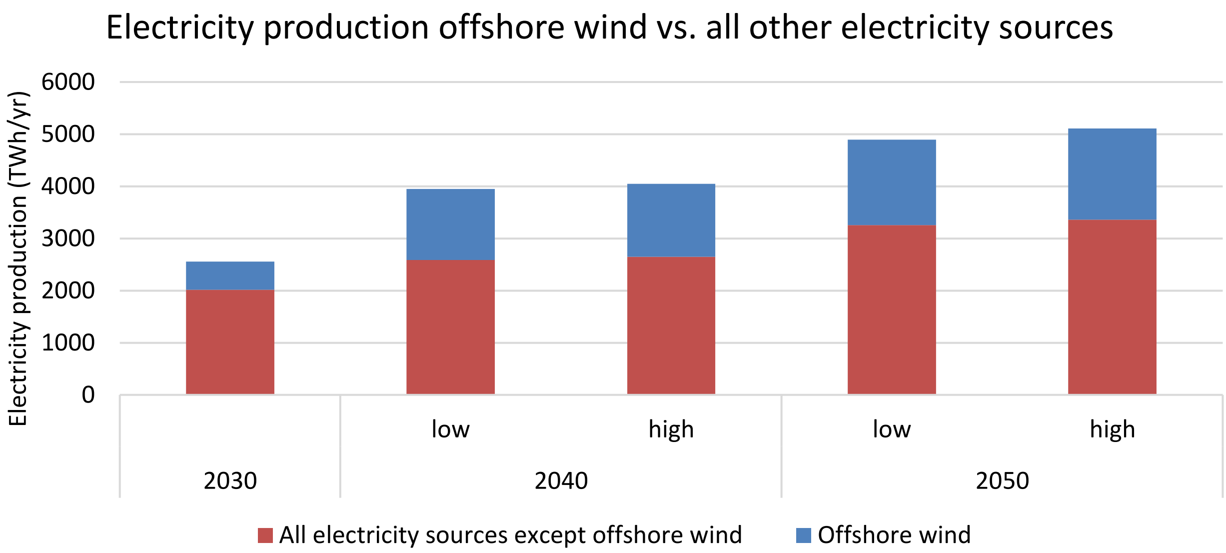

Figure 12 Estimated electricity production from wind energy and all other electricity sources. The low and high values represent the outcome of the modelled Distributed Energy and Global Ambition TYNDP scenarios

[41] NSWPH - Pathway 2.0
[42] Netherlands_IEA_Wind_2022.pdf
[43] Offshore wind - regjeringen.no

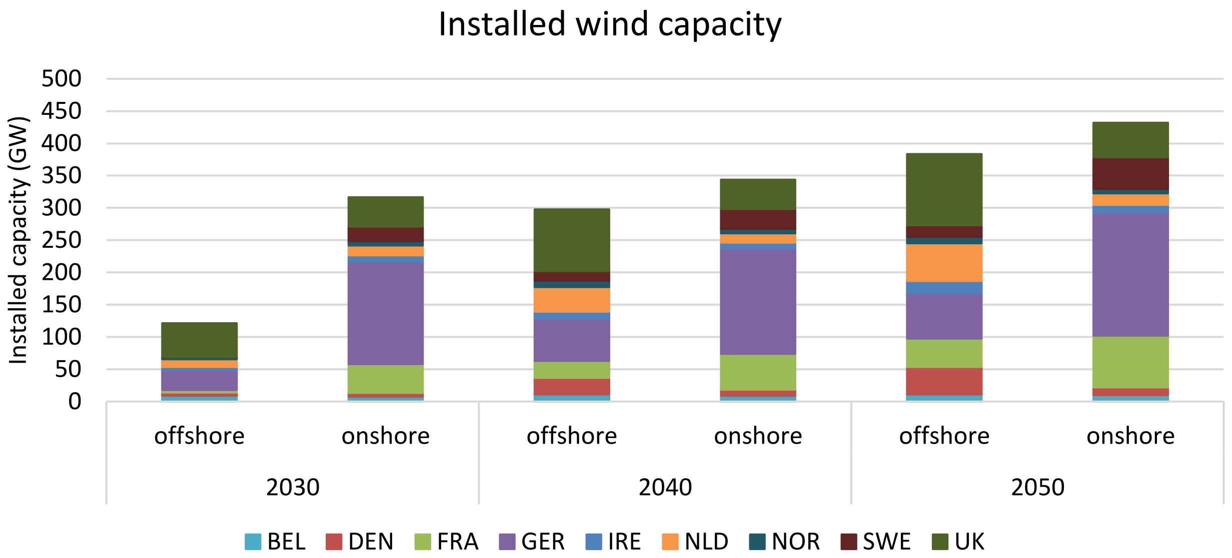

Figure 13 Estimated installed capacity of offshore and onshore wind, averaged over the national, Distributed Energy and Global Ambition scenarios

Doubled electricity demand between 2030-2050

The transition away from fossil-fuels is inherently linked to an increased electricity demand, as is illustrated in **Figure 14**. This demand is expected to double in 2050 compared to 2030, with again a slightly larger increase between 2030-2040, than 2040-2050. This trend in increased electricity demand is in line with the NSWPH Pathway 2.0[44]. The largest electricity producers - Germany, the UK and France - also account for the largest electricity demand.

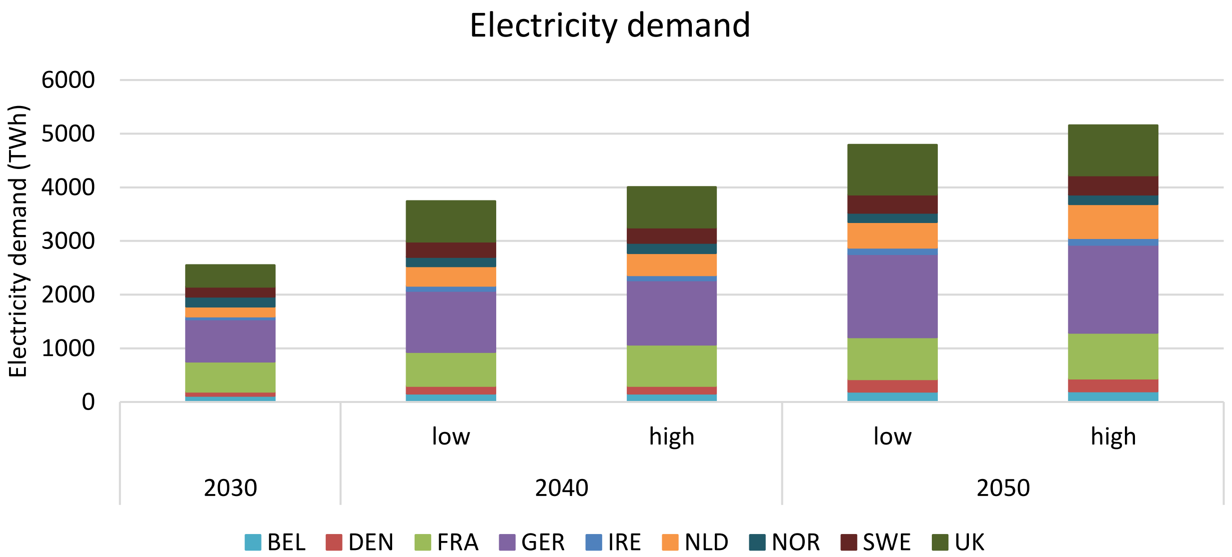

Figure 14 Estimated electricity demand, where the min and max values represent the outcome of the modelled Distributed Energy and Global Ambition TYNDP scenarios

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[44] Netherlands_IEA_Wind_2022.pdf

Import dependency of the North Sea region reduces and countries with significant offshore wind capacities become net exporters of electricity

There is a significant difference between the level of electricity import and export among the North Sea countries, as visualized in Figure **15**. Due to the geographical scope of the model, the overall production and consumption levels balance out across the North Sea countries, indicating minimal need for electricity import or export with other regions. However, it is probably more realistic that trading with other (European) countries occurs as well. The scenario results highlight the importance of cross-border electricity trade to fulfill electricity demand in a renewable way for the North Sea region.

In the calculated scenarios, France and Norway remain net exporters of electricity, similar to the current state of play. However, a decrease in their export volumes is projected towards 2050, most likely due to increased renewable developments in other countries, reducing the reliance on France's nuclear power and Norway's hydro power. A similar trend is observed for Sweden and Denmark, although in smaller volumes.

Although the UK is projected to be a net exporter in 2030, it transitions to being a net importer of electricity by 2040 and 2050. An explanation for this could be the abundance of cheap renewable electricity from other European countries, which could increase the share of electricity import. The same principle applies to Germany. Even though this country is projected to have one of the largest offshore wind production volumes, Germany's substantial electricity demand makes it a net importer. Lastly, the Netherlands is expected to be a key transit country in all calculated scenarios, with import volumes adding up to an outstanding 390 TWh in 2050 and export volumes adding up to 330 TWh. The significant role as a transit country is in line with the NSPWH projected pathways[45].

The scenario differences are quite apparent in **Figure 15**. Although the net import of the North Sea countries is zero in both the DE and GA scenarios for 2040 and 2050, the level of import and export varies significantly. Since the DE scenario assumes enhanced regional corporation and extensive renewable electricity production, more renewable energy is exchanged with overall more trade between the North Sea countries.

[45] NSWPH Key Messages_Pathway Study_0.pdf

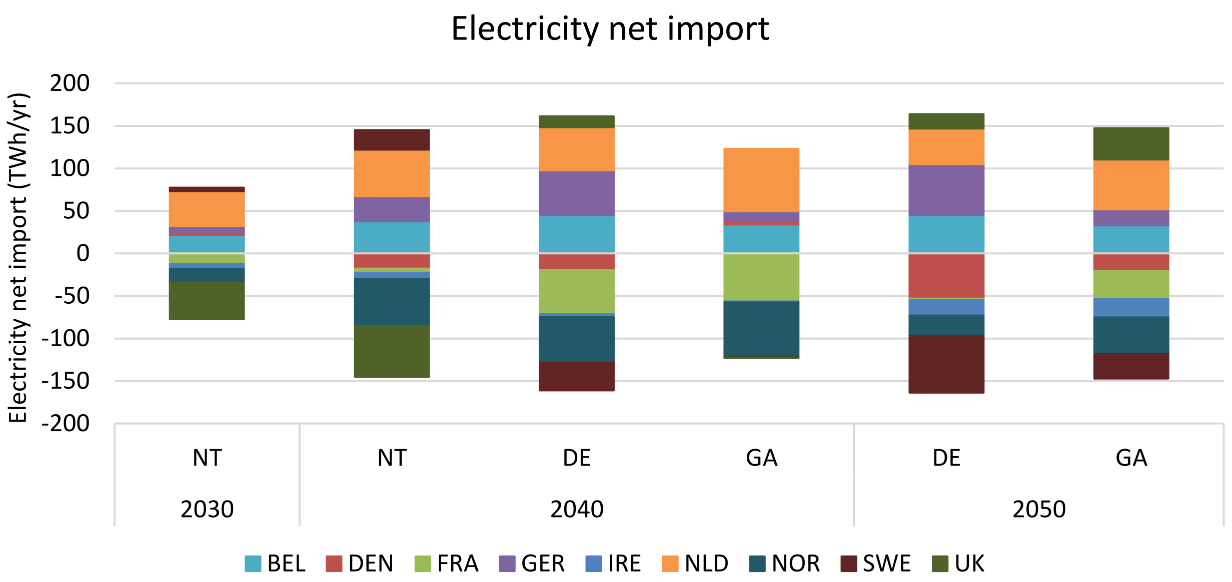

Figure 15 Net import of electricity for the North Sea countries, where NT represents the outcomes from the National scenario, DE from the Distributed Energy scenario and GA from the Global Ambition scenario

Expansion of offshore wind requires technological development

In the future, the offshore wind farms will be located further from the shore, due to, next to space restrictions, a more reliable and powerful wind supply. This means that the generated electricity will have to be transported over larger distances to shore. For this, high voltage direct current (HVDC) connections will be deployed, which result in lower transport losses. In the coming years, technological development and standardization on both the on- and offshore converters, switching stations and meshed grids is foreseen[46].

Offshore electricity storage developments

The rapid development of the offshore electricity grid runs parallel with the development of offshore electricity storage technologies. Recent developments include the integration of batteries in wind farms, compressed air energy storage, pumped hydro storage and the conversion of electricity into hydrogen by electrolyzers (as further explained in Dossier 2 – Hydrogen). The OranjeWind project is a good example where various storage technologies will be incorporated, such as onshore lithium iron phosphate batteries, offshore lithium-ion batteries and a pumped hydro storage plant[47]. In offshore UK waters 3 MW of battery storage capacity is co-located with offshore wind and much more capacity (600 MW) is consented.[48]

Floating solar expansion with a leading role for the Netherlands

Next to the offshore wind development, other types of offshore renewable energy production are undergoing significant technological advancements as well. Even though floating solar is still in the research and piloting phase, the North Sea countries with Netherlands and Belgium are taking a leading role in its development and the first has the ambition to install 3 GWp[49]. Due to combined wind tenders in the Netherlands, several MW-scale offshore solar projects have been granted recently (f.e. Crosswind, Zeevonk and OranjeWind).

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[46] North Sea Wind Power Hub_Vision Paper 2024.pdf
[47] System integration
[48] Offshore wind co-location -integrating offshore wind with flexibility
[49] Floating solar panels | TNO

Pilot projects in Belgium and Netherlands are moving from hundreds of kW scale to multi-MW scale. The focus in the coming years will be on standardization and integration with other technologies.

Marine energy sector foresees significant expansion
Marine energy technologies, such as tidal and wave energy converters, can be a stable and reliable form of renewable electricity supply in the North Sea. Currently, both technologies are in the research and piloting phase, similar to floating solar. The European ocean energy industry expects to install 100GW of marine energy by 2050[50], whereas the EU has set a target of 40 GW by 2050[51]. In order to make this happen, the EU has set cost-reduction targets for these marine energy technologies, to secure its further expansion in the coming decades.

1.2 Grid vision 2050

Increment in offshore wind capacity needs to be accompanied by increase in electricity transmission infrastructure.
The findings from the Ten Year Network Development Plan (TYNDP)[52] prepared by the European Network of Transmission System Operators for Electricity (ENTSO-E) suggest that 119 GW of offshore wind capacity will be operational in the Northern Seas by 2030 [53]—greater than a 4-fold increment in comparison to the operational capacity in 2023 (27 GW). This expansion has to be accompanied by an increase in associated transmission infrastructures as well. The TYNDP study also expects that, as a result of this increase, an additional cable route length of approximately 7000 km will be needed in the EU Member states and Norway[54]. This number assumes that 2 GW cables will be used and the windfarms are connected radially to the home-countries of their exclusive economic zones (EEZ).

For 2040, the same study predicts a 274 GW operational offshore wind capacity in the Northern Seas. Once again, with an assumption that ~2 GW sized cables will be used to connect the windfarms radially to the home countries in their EEZs and that DC circuit breakers will be used, an additional 21,140 km of route length (90% of which is offshore) will be required in the EU Member States and Norway (route lengths in the UK are not included).

For 2050, the study assumes that 330 GW operational wind capacity will be realized in the Northern Seas. To connect the additional ~60 GW radially to the home-countries in their EEZ, an additional 8000 km of offshore route length will be required in the EU Member States and Norway (route lengths in the UK are again not included). As mentioned before it was assumed that ~2 GW sized cables will be used to connect the windfarms radially to the home countries in of their EEZs and DC circuit breakers will be available.

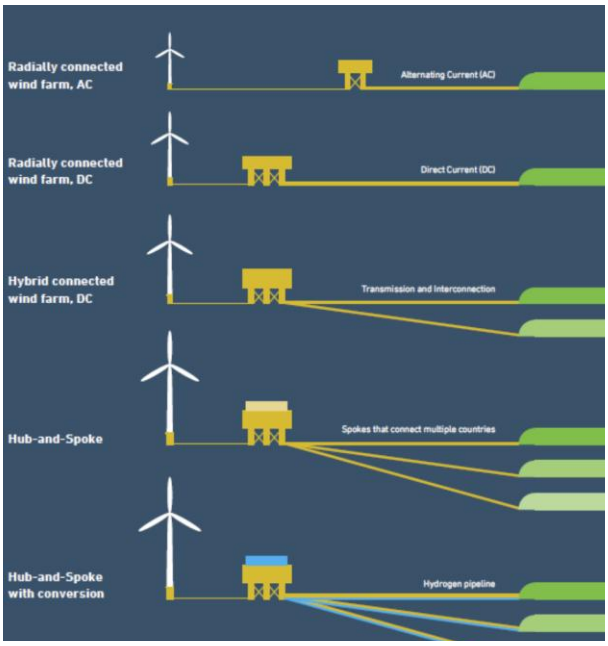
DC circuit breakers enable a larger number of grid expansions and larger transmission capacities
With the use of HVDC circuit breaker technology, the interlinking of offshore power supply and demand nodes can be done at lower costs because the circuit breakers avoid the need for expensive converter

[50] Powered by the ocean - Ocean Energy Europe
[51] Offshore renewable energy
[52] ENTSO-E TYNDP 2024: Sea-Basin ONDP Report—Northern Seas Offshore Grids available at eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/web_entso-e_ONDP_NS_240226.pdf#page=26.09
[53] Comprised of exclusive economic zones of Belgium, Denmark, Germany, Great Britain, France, Ireland, Netherlands, Norway and Sweden
[54] Route length does not refer to cable length. The latter might be 2-3 times the former depending on the whether a DC monopole or bipole with dedicated metallic return or and separated AC cables are used.

stations at each node. According to the ENTSO-E TYNDP 2024 scenarios for the Northern Seas, DC circuit breakers will allow for larger number of grid expansions. Therefore, during the 2030-2040 horizon, an additional transmission capacity of 21.5 GW is expected to be reached, compared to only 7.5 GW which could be achieved without DC circuit breakers. Similarly, during the 2040-2050 horizon, an additional transmission capacity of 8.5 GW is expected to be reached, compared to only 3 GW which could be

Radial and hybrid connections

In radially connected offshore systems, electrical connections used to link wind farms to shore differ from those used for interconnections between different countries. However, in a hybrid connection, a wind farm can be connected to more than one country, serving both as a means of transmitting power to shore and as an interconnection between countries, effectively fulfilling both functions. The following conceptual image produced by the [North Sea Wind Power Hub program] visualizes the distinction between radial and hybrid connections.



achieved without DC circuit breakers.

Increase in transmission system infrastructure will mostly be shouldered by radial connections in 2030 but a spike in hybrid connections can be expected in the 2040-2050 horizon.
The offshore renewable energy integration in 2030 will mostly be facilitated by radial connections. In 2050, the proportion of renewable energy sources connected to more than one country increases as a result of increments in hybrid connections. The development of hybrid interconnections will increase flexibility for the renewable electricity system through its cross-country pathways. This future development is visually highlighted in **Figure 16**. The yellow bubbles represent the proportion of radial connections in the transmission system, the blue ones represent hybrid connections and the green ones represent radial connections with the possibility to be transformed to hybrid ones.

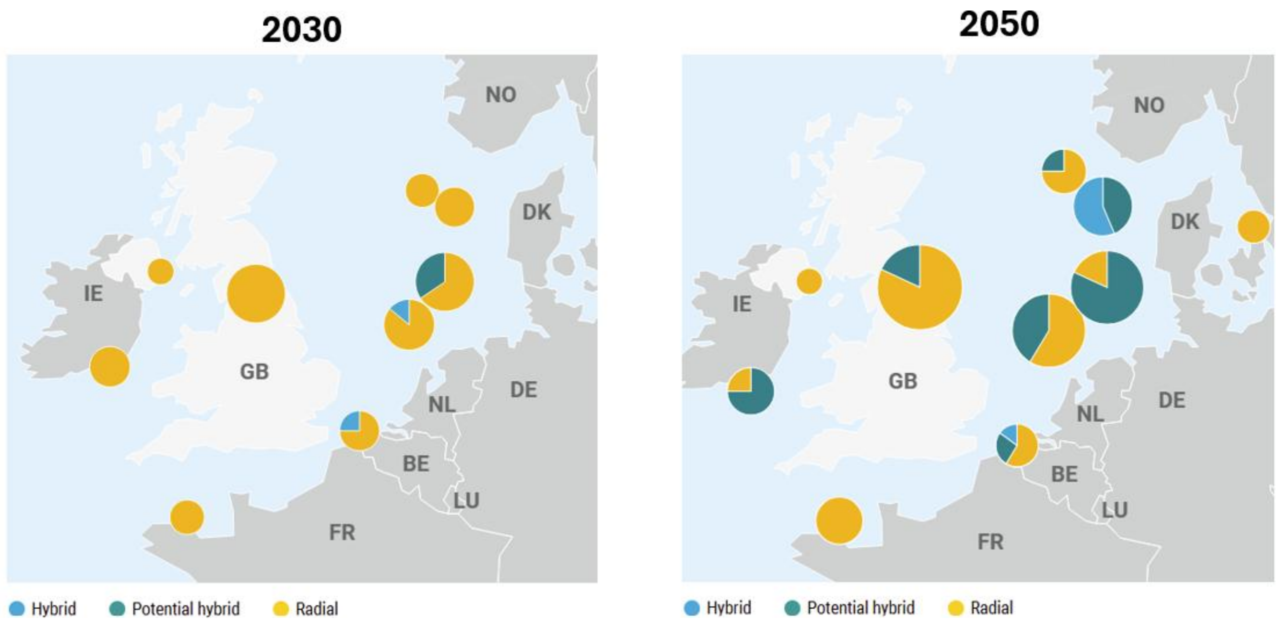


Figure 16: Generation capacities per country in the Northern Seas differentiated by connection type - radial and hybrid - in 2030 (left) and 2050 (right), the size of the bubble represents the relative generation capacity[55]

Predictably, in 2030 offshore renewable energy sources will be linked by radial connections but hybrid connections are already appearing on the map

Nautilius and LionLink are two hybrid system projects in the North Sea currently in their planning phases. Nautilus aims to connect the UK and the Princess Elisabeth Island located in the Belgium EEZ[56]. The LionLink will create a hybrid interconnector between the UK and the Netherlands. The TritonLink is currently in a feasibility study phase and could potentially connect two energy islands—the Princess Elisabeth Island in Belgium and a Danish Energy Island. An upcoming radial connection is the NeuConnect HVDC cable that is well under construction in the North Sea. It will connect Germany and Great Britain. Its construction began in 2023 and is expected to be operational in 2028. NeuConnect and the remaining operational/existing interconnectors in the North Sea are mapped out in **Figure 17**.

[55] ENTSO-E TYNDP 2024: Sea-Basin ONDP Report—Northern Seas Offshore Grids available at eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/web_entso-e_ONDP_NS_240226.pdf#page=26.09

[56] More about the Princess Elisabeth Island can be read at https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/princess-elisabeth-island

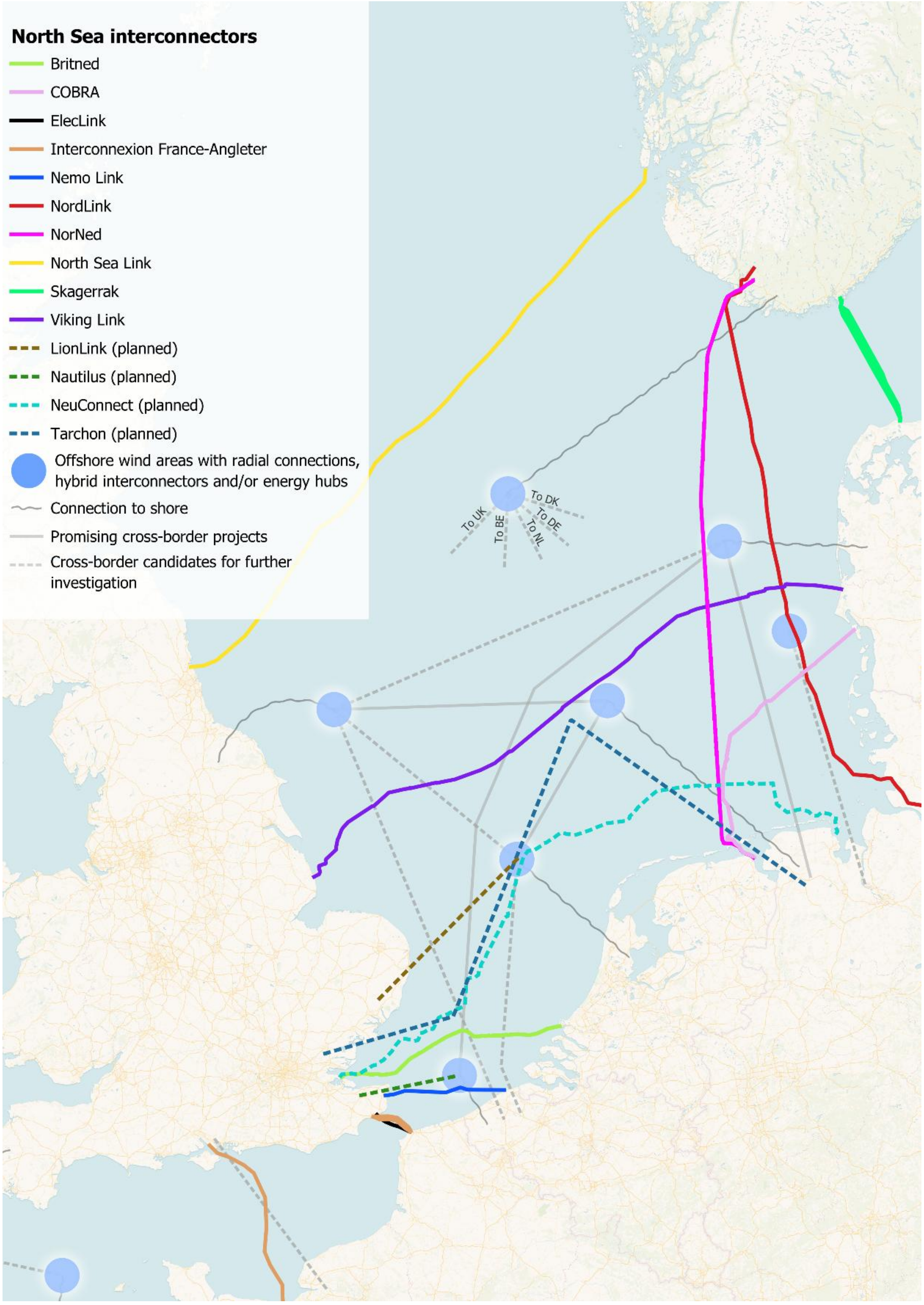


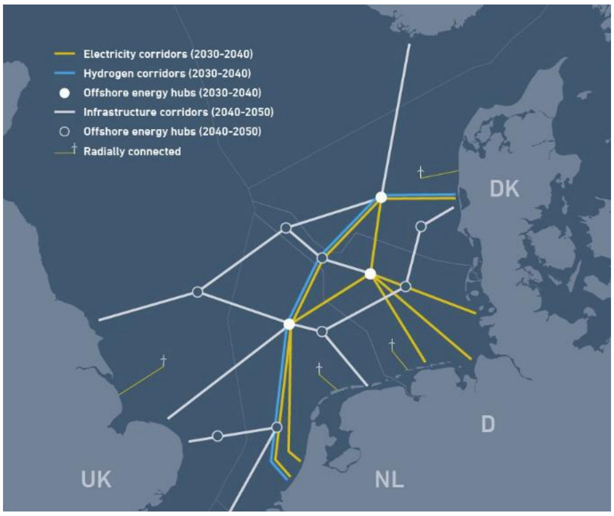
Figure 17 This map shows the existing and planned electricity interconnectors in the North Sea[57]. The existing/operational interconnectors are represented by bold lines and planned projects are represented by dashed-lines. Items in grey colour and the blue areas are collected from the 'OTC

Grid Map 2025 – Cross Border Projects Around 2040' displays the vision of an integrated-offshore-grid prepared by the Offshore TSO Collaboration (OTC)[58] Disclaimer: maps are a representation of announced and envisioned plans and projects in the public domain and therefore subject to frequent updates and may not always reflect the most recent information. For more detailed spatial information and updates see: North Sea Energy Atlas

Multi-terminal HVDC (MTDC) grids offer efficient ways of transporting offshore wind energy
The interconnected network resulting from MTDC grids could potentially offer economic benefits by converging the electricity prices in the North Sea region since it connects different markets. It can also offer more energy security by increasing the network redundancy. MTDC grids also helps utilize the offshore renewable energy sources better, especially if there is network redundancy. Higher utilisation of offshore RES also helps to reduce CO_2 emissions and emission costs[59]. The Transmission System Operators (TSOs) in working in the North Sea are engaged in efforts to develop such interconnected offshore electricity networks[60].

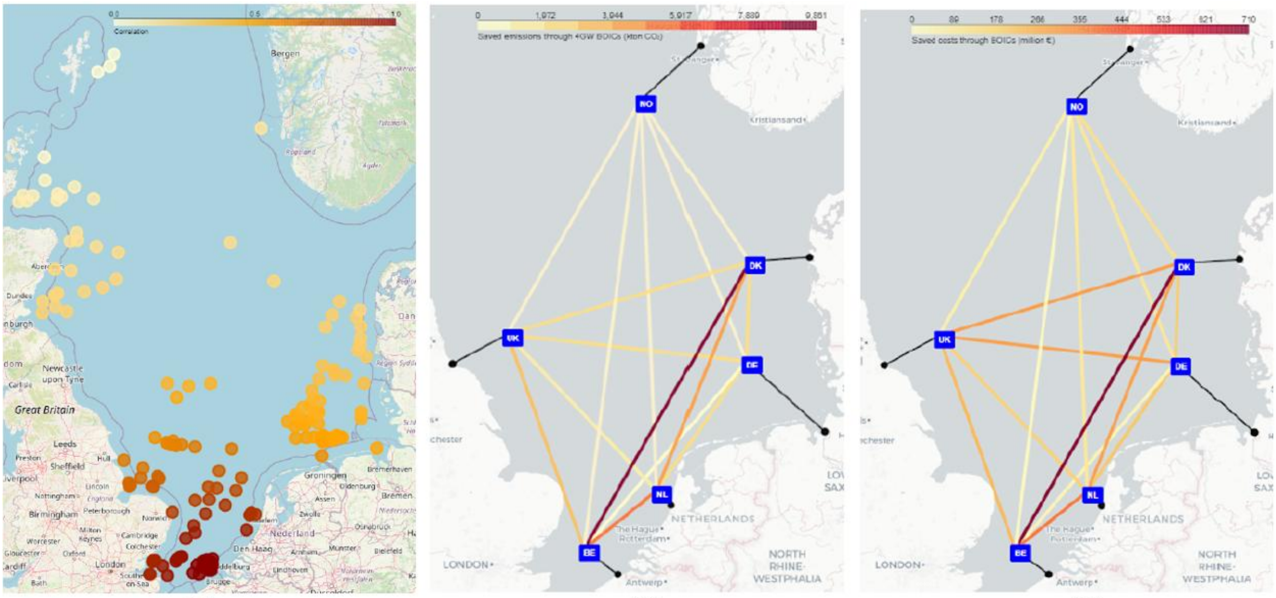
[57] North Sea Energy Atlas
[58] The elements of the OTC grid integrated grid map has been adapted from 12 Offshore TSOs are striving for integrated offshore grid to strengthen European energy independence
[59] More about the impacts of an offshore interconnected system can be read in the ENTSO-E TYNDP 2024: Sea-Basin ONDP Report—Northern Seas Offshore Grids available at eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/web_entso-e_ONDP_NS_240226.pdf#page=26.09
[60] An example of one such effort is the involvement of the transmission system operators in the InterOPERA project, more about which can be read at https://interopera.eu/

In comparison to point-to-point HVDC grid connecting a single power source to a single load, a MTDC grid allows the connection of multiple source and load nodes. DC circuit breakers enable the development of MTDC grids as they avoid the costs of expensive offshore converter stations as mentioned above. The North Sea Wind Power Hub (NSWPH) concept conceives of a large MTDC grid connecting offshore wind farms in the North Sea to several surrounding countries. A visual description of MTDC grids can be seen in the following conceptual image produced by the North Sea Wind Power Hub program which describes its blue print of the energy highways built for 2050.

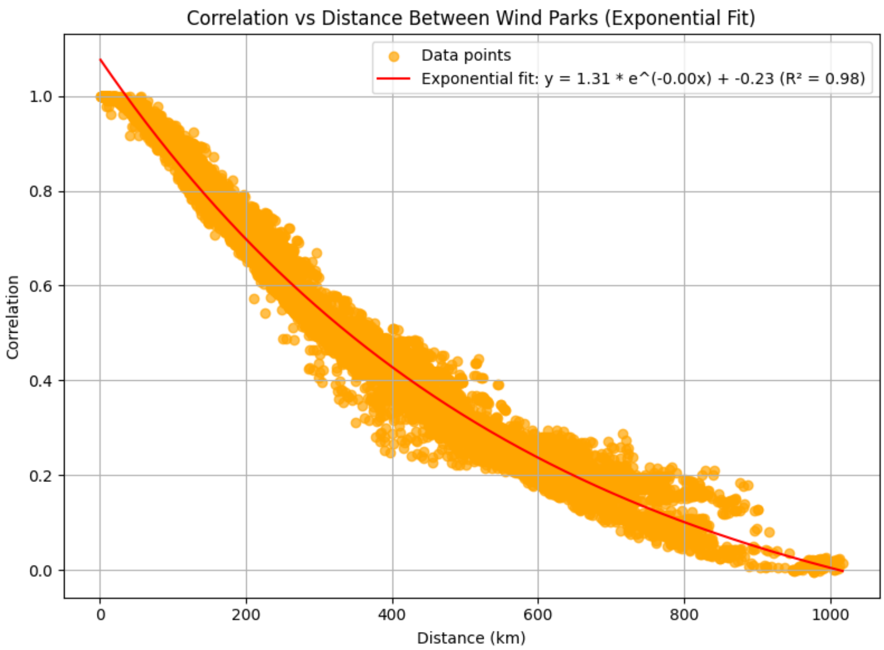


Bilateral offshore interconnectors (BOIC) between countries far apart increase utilization of offshore renewable energy sources and consequently save costs and emissions

When two windfarms are separated by hundreds of kilometers, moments of high windspeed in one geographical regions can coincide with moments of low windspeed in another. During moments of that energy disparity, transport of surplus wind energy from the former to the latter through a BOIC helps to balance the load—thereby increasing the utilization of surplus renewable energy which otherwise would have been curtailed. This concept is visualized in **Figure 18** which correlates the wind profiles of the Rental offshore windfarm in Belgium to that of the other North Sea wind farms. Evidently the windfarms in Denmark bares the least correlation with the ones in Belgium. As a result the costs and emissions are saved by trading surplus offshore renewable energy across 2 electricity market.



(a) (b) (c)



(d)

Figure 18 Correlations between the wind profiles of Belgium's Rentel offshore wind farm and the other wind farms in the North Sea are shown in image (a)— the darker the bubbles, the higher the correlation. Hence there is remarkable complementarity between Belgian and Danish windfarms. The benefits of this complementarity was studied using annual simulations of the BOICs with a 4 GW capacity limit. The resulting quantity of emissions saved in kton CO_2 is shown in image (b), and

costs saved in million € in image (c)—the darker the lines, the larger the savings. (d) shows the yield correlation between wind farms plotted vs their distance in km (including an exponential fit)[61].

1.3 Commodity specific actions

Actions on offshore wind

Appoint areas for future development and deployment
To meet the ambitious targets for offshore wind, the appointment of areas and coordination on marine-spatial planning is crucial to facilitate the required large deployment. The appointment of areas acts as a starting point for stakeholder discussions and planning procedures, that need to start early in order to reach the 2030-2040 targets. It is important to note that this should not only focus on offshore wind, but consist of an adaptive approach with co-functions such as hydrogen production, energy storage and CCS. Further insights on spatial planning advices can be read in the WP6 Offshore multi-use in the North Sea area.

Acceleration and security of demand by industry electrification
In order to have an attractive business case for offshore wind development, the demand for electricity and flexibility of the energy system should grow at the same speed of the increase of installed wind capacity. A key point in here is the electrification of large industrial demand clusters, either through process electrification or indirect electrification through power-to-X solutions.

Investments in infrastructure and sources for flexibility
To optimally make use of the increase offshore wind's potential, the strengthening of the electricity grids and development of energy flexibility sources is crucial. This requires very high investments in infrastructure, which take time to plan and deploy, making it one of the top priorities on the action agenda. This also consist of increasing the permitting processes. Large investments on storage, (industrial) flexible demand and energy conversion are also required, suggesting that an alignment on offshore wind, infrastructure and flexibility solutions is critical.

Secure long-term investment climate & supply chain
An appropriate market framework for the integrated offshore market design should be developed in parallel to the physical deployment, with for example a focus on offshore bidding zones with hybrid interconnectors and offshore hubs[62]. Next to this, it is important to take a full value chain perspective on the development of offshore wind, with sufficient port capacity, vessels and human capital available for the future deployment.

Actions on offshore marine energy (solar, wave and tidal)

Accelerate the scale-up and deployment of offshore ocean energy
Besides offshore wind, the scale-up of other offshore renewable energy sources such as floating solar, wave and tidal energy, is widely recognized as a critical part of the energy system development. The EU has set ambitious targets on offshore renewable energy of a 100MW by 2025, 1 GW by 2030 and 40 GW by 2050. For this, rapid scale-up and replication is needed, together with adequate planning and support schemes to increase the learning potential for these technologies. For floating solar it is important that sufficient demonstration projects are deployed, with preferably a focus on recycled materials to reduce the impact on critical raw materials,

Develop integrated offshore energy tenders
Because of the synergistic effects between offshore wind and other marine energy sources, the deployment of the latter should beneficially coincide with the quick development of offshore wind. This could be achieved

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[61] The images and results were taken from Blokhuis, N. (2024) *Spatial Modelling of International Offshore Energy Scenarios and Investigating Offshore Interconnections* (Master's thesis). Utrecht University & TNO
[62] Expert Paper II Offshore TSO Cooperation

through integrated offshore tenders that allocate certain areas to multiple energy sources, resulting in a reduced variability of energy supply and an optimal use of the available infrastructure.

Derisk support for multi-energy demonstration areas
in order to accelerate the scale-up of marine technologies and implement the proposed hybrid tenders, any regulatory barriers on the co-use of wind areas should be removed. An option would be to include the efficient use of space and offshore infrastructure as part of the evaluation criteria for offshore demonstration and deployment areas.

Actions on the electricity grid

The key outline of the action plan on the North Sea electricity grid, has been designed in 2024 by ENTSO-E, with the following simplistic timeline[63]:

- **2030**: Focus on radial connections and the first offshore hybrid elements to achieve faster deployment speeds
- **2040**: Development of the first interlinked offshore clusters, with further increases towards 2050
- **2050**: Continued expansion of offshore wind capacity and other marine energy sources, with a focus on reinforcing existing transmission corridors.

Furthermore, there are several key themes that should be addressed:

Cost sharing and financing
Significant investments are required for the strengthening of the offshore electricity network, with estimated costs of over €50 billion by 2030, €150 billion by 2040, and an additional €60 billion by 2050[64]. Due to this enormous scale, it becomes more important to share costs and benefits between countries developers, such that the hosting countries are not solely responsible for the cost bearing. When this infrastructure would not be built, the future development of offshore renewables is at risk. In the coming decade, the European Commission is mandated under the new TEN-E Regulation to develop guidelines for a cost-benefit cost sharing system (CBCS) at the sea basin level, which can act as a starting point to facilitate collaboration between countries. Next to this, market conditions should be adjusted such that hybrid interconnections between countries are supported.

Technology development and standardization
To accommodate the transportation of GWs of offshore wind over long-distances, it is crucial that new technologies are developed such as high voltage direct current (HVDC) circuit breakers and hybrid interconnectors that combine offshore wind connections with interconnections between countries. Next to this, standardization is crucial for the interoperability between different systems, technologies and countries. Lastly, in order to learn quickly and adaptively, pilot projects are important for testing and demonstrating interoperability solutions in real-world scenarios.

Regulatory framework
In relation to the technology development and cost-sharing of the infrastructure roll-out, appropriate regulatory frameworks should be developed in parallel. Especially the development of hybrid interconnectors and energy hubs requires a supportive regulatory framework. This includes clear guidelines for cost allocation, revenue sharing, and operational responsibilities among the various involved parties.

Minimize supply chain stress

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[63] ENTSO-E TYNDP 2024 Sea-Basin ONDP Report – Northern Seas Offshore Grids
[64] ENTSO-E TYNDP 2024 Sea-Basin ONDP Report – Northern Seas Offshore Grids

Similar to the action under offshore wind deployment, the challenge of sufficient human capital, port availability and vessel capacity is crucial for the massive expansion of the electricity grid. Smart solutions should be investigated where various grid and project plannings are aligned to optimally schedule further deployment.

Incorporate environmental and spatial planning
Spatial conflicts should be managed right from the beginning of the design of grid expansion. Both for the cable and platform installment as well as during operation. Maritime spatial planning is crucial here, since it operates in an ecosystem of fishing, shipping, military activities and ecological protected areas. Next to this, ecological principles should be incorporated in the design process of grid expansion, where the environmental impact is assessed and mitigated.

Dossier 2 – Hydrogen

In Chapter 0 it was seen that the offshore wind capacity in the North Sea will increase substantially. Furthermore, section 0 described the expansions required in the offshore electricity grid to absorb this offshore wind energy into the North Sea energy system. However, absorbing this offshore energy as electricity in the electricity system can congest the electricity network. There are price volatility risks for power due to simultaneous onshore renewable energy supply. Fortunately, converting North Sea's offshore wind energy partly to hydrogen can help alleviate the issue of network congestion and price risks. Once converted to hydrogen, part of the wind energy can be transported via pipelines and hence mitigates electricity network congestion. Moreover, introducing hydrogen as another energy carrier increases revenue potential and decreases prices through flexible revenue streams.

The North Sea region is expected to take a leadership role in the development of the hydrogen value chain in Europe. With its proximity to offshore wind resources, existing natural gas infrastructure, and industrial hubs, the North Sea is well-positioned to become a key hydrogen production and distribution center. This section explores the significance of hydrogen development in this strategic region and examines its potential impact on the global and European hydrogen markets. The North Sea countries inspected in this section are France, Belgium, the Netherlands, Germany, Denmark, Sweden, Norway, UK and Ireland.

2.1 State of play and ambitions

Developing a comprehensive hydrogen value chain enables North Sea countries to meet their decarbonization targets and create new economic opportunities. A strategic roadmap to 2050 should focus on essential elements such as targeted investments, international collaboration, and technological advancements to establish a viable business case. Understanding the current status of hydrogen production, distribution, and consumption, along with predictions for its future trajectory, will provide valuable insights into where we stand today and identify the necessary steps to achieve our ambitions. This section will explore the present landscape of hydrogen in the region and outline the future outlook.

Current state of play

Current Hydrogen Backbone and Storage: Limited to Onshore
Currently, hydrogen production is predominantly onshore, with only a few pilot-scale initiatives for offshore hydrogen production. However, producing hydrogen at sea using offshore wind can reduce transmission costs and provide energy security. Therefore, interest in offshore production is expected to grow significantly in the coming years, particularly with new projects and plans emerging from the North Sea countries.

The present hydrogen demand among the nine countries surrounding the North Sea stands at approximately 4.4 Mt/year, equivalent to 145 TWh of lower heating value (LHV), as illustrated in **Figure 19**. Germany and the Netherlands lead this demand, each at around 40-45 TWh/year, while the other countries each report demands below 20 TWh/year. Refineries and the ammonia industry account for 75% of this demand, with the remainder used in methanol production, the chemical industry, and industrial heat. Emerging uses for clean hydrogen, such as mobility and e-fuels, represent less than 0.1%.

The existing hydrogen pipeline infrastructure is entirely onshore, consisting of separate (not-connected) segments concentrated in Belgium and the Netherlands, with a smaller segment in Germany. These pipeline systems mainly servicing chemical industry end-users and is owned mostly by Air Liquide and Linde, with a total length of around 1,400 km[65].

Currently, underground hydrogen storage projects are also limited to onshore facilities. Several pilot projects have already been completed in salt caverns in the Netherlands[66], France[67], and Germany[68]. Full-scale storage facilities are now under development and are expected to be operational before 2030.

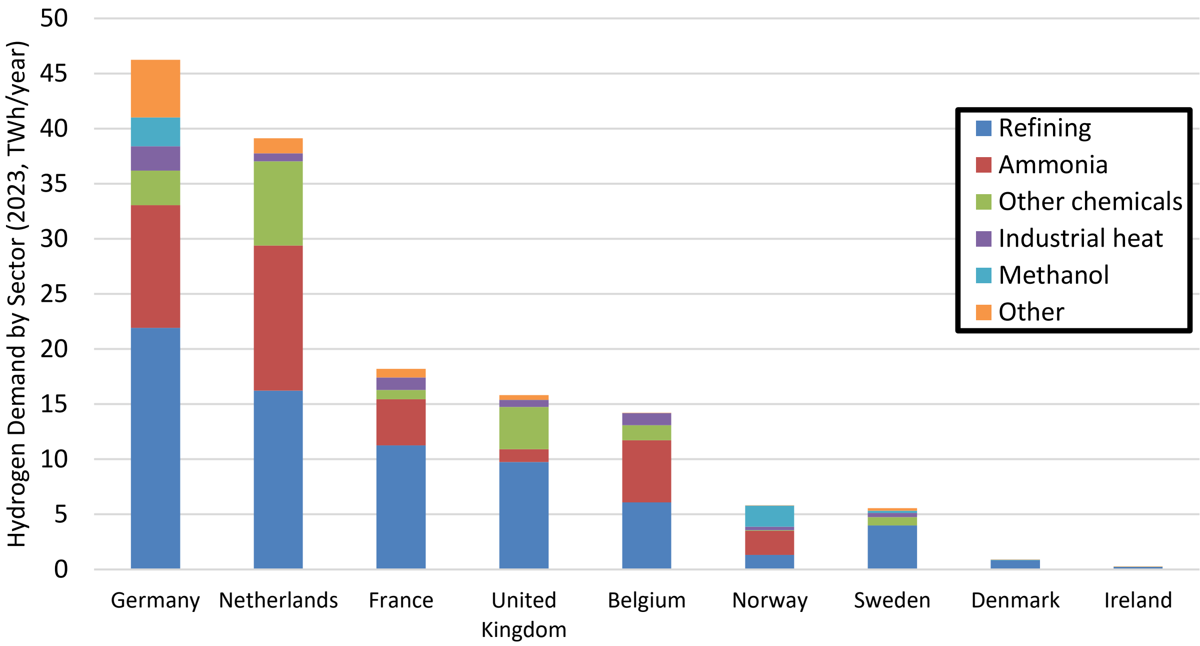

Figure 19 Hydrogen demand in North Sea countries by sector[69]

Building a Portfolio of Offshore Hydrogen Projects in North Sea Countries with New Pilot Projects
Offshore hydrogen production is gaining attention, with several ongoing and planned pilot projects for hydrogen generation in the North Sea such as Sealhyfe, PosHyDon, BLPH, Demo1, Demo2, Alpha Ventus, AquaVentus (SEN-1) and HOP2, as illustrated in **Figure 20**. This region could significantly contribute to

[65] Hydrogen infrastructure May2024.xlsx
[66] HyStock hydrogen storage › Gasunie
[67] HyPSTER | 1st demonstrator for H2 green storage
[68] H2CAST Etzel – Making energy transition work. | H2CAST Etzel
[69] https://observatory.clean-hydrogen.europa.eu/hydrogen-landscape/end-use/hydrogen-demand

hydrogen generation and help meet the increasing market demand in the future. A brief explanation of these projects is given in the textbox below.

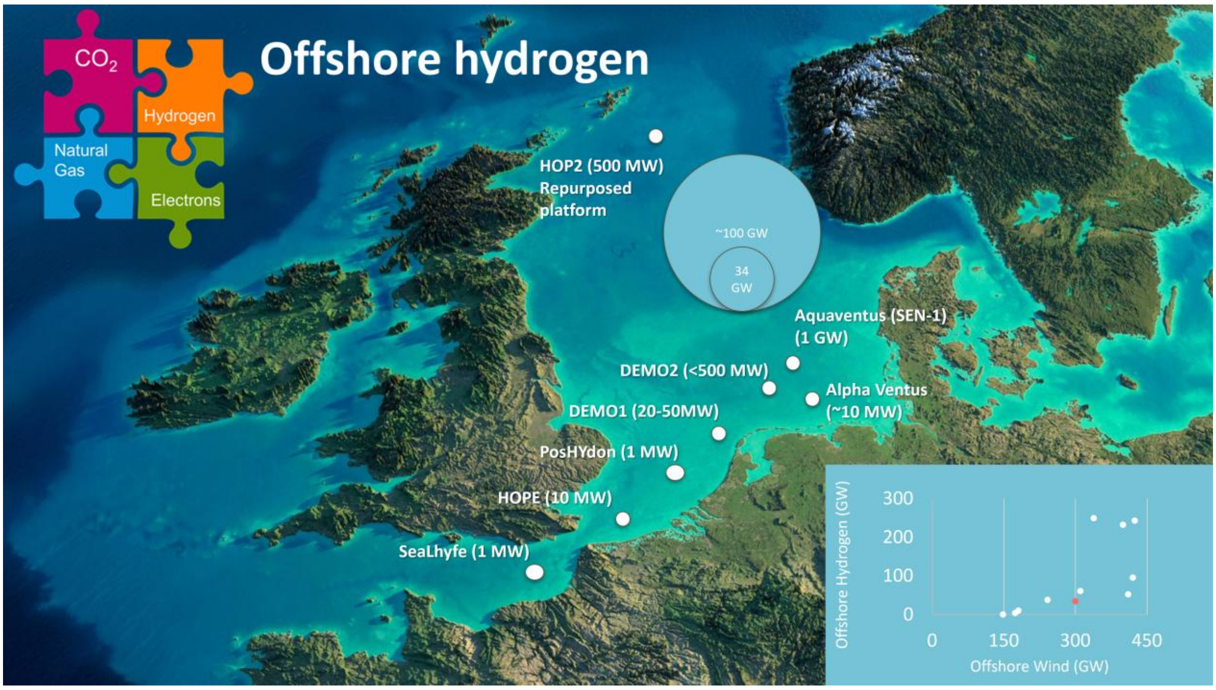

Figure 20 Offshore hydrogen projects in the North Sea. This figure shows (forthcoming) pilot and demonstration projects for offshore hydrogen production in the North Sea region. Graph bottom right indicates the relationship between installed offshore wind capacity and offshore hydrogen (in GWe) in future scenario studies[70],[71],[72]. Bubble graph in the centre highlights potential offshore hydrogen installed in 2050 as quoted in the ONDP (34 GWe) and typically in peer-reviewed literature of up to ~100 GWe and towards even 243 GWe in extreme scenarios.

[70] https://northseawindpowerhub.eu/knowledge/pathway-20-study
[71] Benefits of an integrated power and hydrogen offshore grid in a net-zero North Sea energy system
[72] https://www.sciencedirect.com/science/article/pii/S0301421522006012?via%3Dihub

Offshore hydrogen pilot and demonstration projects

Sealhyfe

In 2023, the first kilograms of hydrogen have been produced near the French coast, at a 1 MW electrolyzer from Lhyfe. Its main aim was to prove technical feasibility and gain experiences for further offshore deployment. This will be further expanded within the HOPE projects.

PosHydon (NL)

PosHyDon, considered the first pilot project to integrate offshore wind, gas and hydrogen, is based on the Q13a-A platform of Eni, 13 km off the coast of The Hague. In this project, hydrogen is produced via electrolysis powered by offshore wind from the Luchterduinen wind farm. The 1 MW electrolyser will produce up to 400 kg/day of green hydrogen, which will be blended with natural gas (up to 0.5% hydrogen) and transported to shore using existing pipelines. The project is expected to be start offshore hydrogen production by 2025, with plans to scale up to large-scale hydrogen production between 2030 and 2035. This makes it one of the first operational offshore hydrogen production plants.

HOPE (BE)

Most likely, HOPE (Hydrogen Offshore Production Europe), will be one of the first 'large-scale' offshore hydrogen production units in the North Sea. Located 1-km off the coast of Belgium, the 10 MW electrolyzer is expected to reach full operation mid-2026. In contrast to other demonstration projects, this electrolyzer is not directly coupled to one wind farm but receives electricity through a renewable Power Purchase Agreement (PPA). This project is a direct follow-up to the Sealhyfe project.

Demo1 & Demo2 (NL)

The Dutch offshore hydrogen production scale-up demonstration projects Demo 1 (20-50 MW) and Demo 2 (<500 MW) are planned to be operational by 2031 and 2033, respectively. These demonstration projects aim to provide valuable insights for scaling up hydrogen production at sea, and with its two distinct phases, aim to demonstrate a capacity scale-up with a factor 10 within a few years from each other. Demo 1 will produce hydrogen at the existing Hollandse Kust wind farm, while Demo 2 will be located at the Ten Noorden van de Wadden wind farm.

AquaVentus SEN-1 (DE)

As part of the AquaVentus program, the SEN-1 pilot projects of 250-300 MW will pave the way towards large-scale offshore electrolysis. The total size of the SEN-1 area is about 1GW. Therefore, it is recommended to split this area into at least three parts to allow a variety of auteurs engagement and learning curves. It will be one of the first German offshore hydrogen parks and first green hydrogen transport to shore is expected to take off in 2028.

Alpha Ventus – electrolyzer (DE)

In the coming years, an electrolyzer of 10 MW will be deployed at the Alpha Ventus offshore wind farm near the coast of Germany. It is directly aimed at testing the feasibility of offshore hydrogen production, and being part of the NORTHSEA Hydrogen project, can serve as a starting basis for further expansion.

HOP2 Scotland/UK

Initiated by the Net Zero Technology Centre, the HOP2 project recently started its next phase focused on the design of a 500 MW offshore electrolyzer integrated on an existing oil platform. This repurposing is a key aim of the project, together with investigating future upscaling towards 1 GW electrolyzers.

Industry and Government: Unlocking Offshore Hydrogen's Potential
While several studies highlight the potential value of offshore hydrogen production, particularly for the whole energy system, the financial viability for individual offshore hydrogen projects is still challenging (for further information see NSE D3.4 results[73]). A key issue is building a business case that can address the current costs and risks. Both industry and governments need to work together to address these challenges, which could unlock mutual benefits for both sectors and society.

Future state of play

Powering the Future: North Sea's Ambitious Hydrogen Goals
The North Sea countries have set an ambitious target of producing 40 GW of green hydrogen by 2030, which represents nearly half of the European Union's overall goal. While it is unclear how much of this production will come from offshore sources, the North Sea is expected to play a key role in this production. However, onshore production is anticipated to remain dominant by 2030.

In the coming years, the region is expected to begin the early stages of large-scale hydrogen projects. By 2050, hydrogen could account for a significant portion of the region's energy mix. This development would position the North Sea as a global hydrogen hub, driving innovation and competitiveness in the European market.

Offshore Hydrogen: A Key Component of the Future Energy System
Offshore hydrogen production is set to play a crucial role in the future energy system by leveraging vast offshore renewable resources, particularly wind energy, to produce green hydrogen at scale. Given the large scale of this energy production, transporting it through pipelines becomes economically more efficient than using cables. Therefore, plans for after 2030 include offshore-electrolysis, where hydrogen is produced at sea, collected from multiple wind farms, and transported to shore via large pipelines. By utilizing existing offshore infrastructure, such as repurposed gas pipelines and platforms, offshore hydrogen can facilitate efficient transport and storage to the shore. It is estimated that by 2050, offshore electrolysis could contribute up to 34 GW[74] or potentially up to 100 GW[75] to hydrogen production. Results from the North Sea Wind Power Hub foresee that approximately 20% of offshore wind is directly converted to hydrogen via offshore electrolysis[76].

From Blue to Green: North Sea's Ambitious Hydrogen Transition from 2030 to 2050, Aiming for 1,200 TWh of 100% Green Production
According to scenario outcomes, hydrogen production and demand in the North Sea countries are projected to grow rapidly. However, these estimates represent target levels and are highly ambitious, making them not realistic in the short term; project delays are expected due to technical and financial challenges, as well as market uncertainties. For example, the Norwegian-German blue hydrogen project has been shelved owing to

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[73] R. van Zoelen, S. Mahfoozi, S. Blom and I. Gonzalez Aparicio, "White paper – Offshore Energy System Value and Business Cases: Aligning Project Decisions with Societal Objectives," North Sea Energy, 2025
[74] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/web_entso-e_ONDP_PanEU_240226.pdf
[75] https://repository.tno.nl/SingleDoc?find=UID%2004edcc85-55bf-42ed-84b1-017f28d458f7
[76] NSWPH - Pathway 2.0

lack of customers for its hydrogen as well was feasibility issues with the pipelines to transport the hydrogen that was to connect Norway and Germany[77].

By 2030, total hydrogen production in the nine countries is expected to reach 300 TWh/year (9 Mt/year), with about 55% coming from green hydrogen and 45% from blue hydrogen. As shown in Figure 2, In 2030, Germany and Norway are expected to lead in green and blue hydrogen production. Grey hydrogen production is expected to be minimal according to our modelled scenarios.

Looking ahead to 2040, hydrogen annual production is expected to triple, exceeding 900 TWh/y (30 Mt/year), with a significant shift towards green hydrogen and a reduced contribution from blue hydrogen. By 2050, total production is anticipated to surpass 1,200 TWh, with Germany still leading the production, followed by France and England. Interestingly, Norway's hydrogen production is projected to be zero, as offshore wind and hydropower are assumed to be the main sources of their renewable energy.

Technology trends: Rising electrolyzer capacities
The estimated growth in green hydrogen production implies that a growth in installed electrolyzer capacity can be expected. This growth has been visualized in **Figure 21**. As expected, Norway will have the least amount of electrolyzer capacity. The largest capacities will be seen in Germany followed by Denmark, France and the Netherlands. However, it is important to note that these projections are extremely ambitious and may not be fully realized within the expected timeframe due to technological, economic, and regulatory challenges.

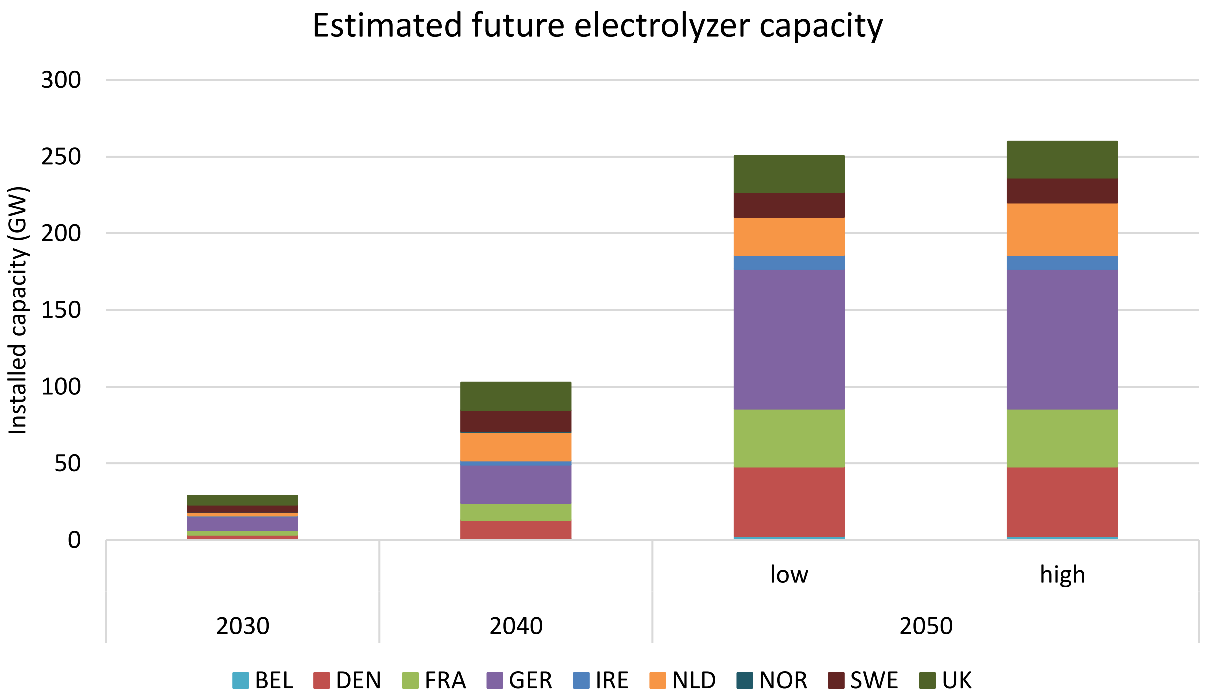


Figure 21: Estimated future electrolyzer capacity

[77] More about the discontinued Norwegian-German blue hydrogen project can be read at [Equinor reportedly shelves Norwegian-German 'blue hydrogen' project | Offshore]

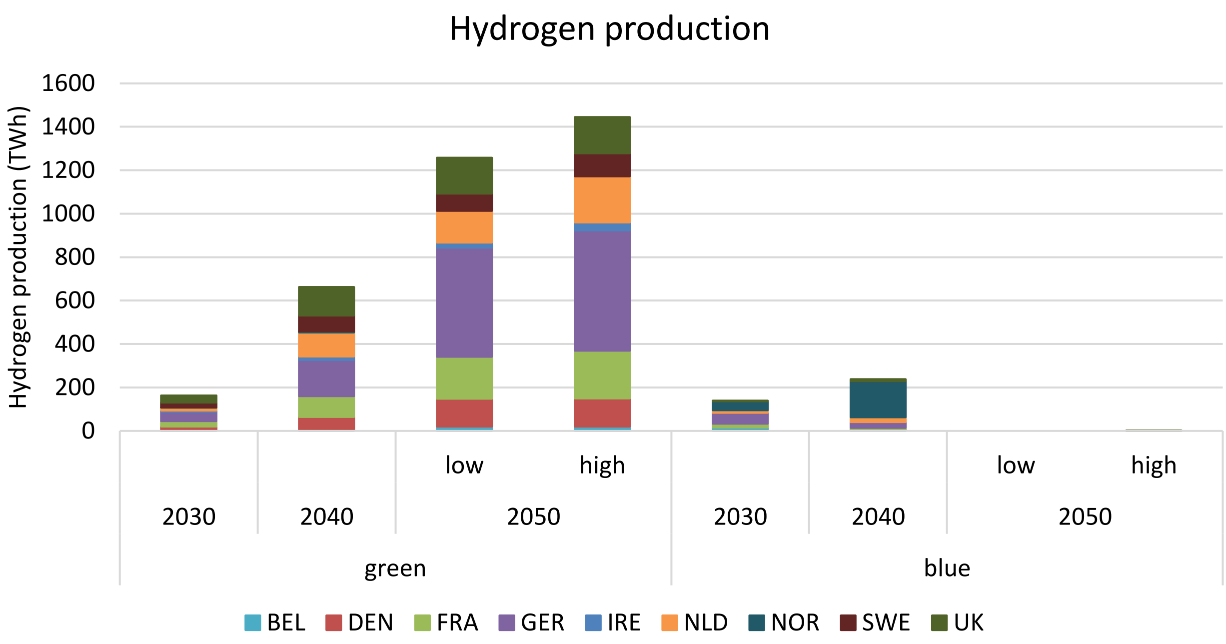


Figure 22: Estimated hydrogen production in the North Sea countries

On the demand side, total hydrogen consumption in these countries is projected to be relatively comparable to production levels, as shown in **Figure 23**. In 2030, total demand is expected to reach 330 TWh, increasing to 1,010 TWh by 2040, and further rising to 1,290 - 1,420 TWh by 2050. However, the distribution of demand will vary significantly among the countries, with Germany expected to have the highest hydrogen demand, followed by France and England. Consequently, import and export strategies will be essential within the North Sea region, along with the potential for trade with countries outside of this area.

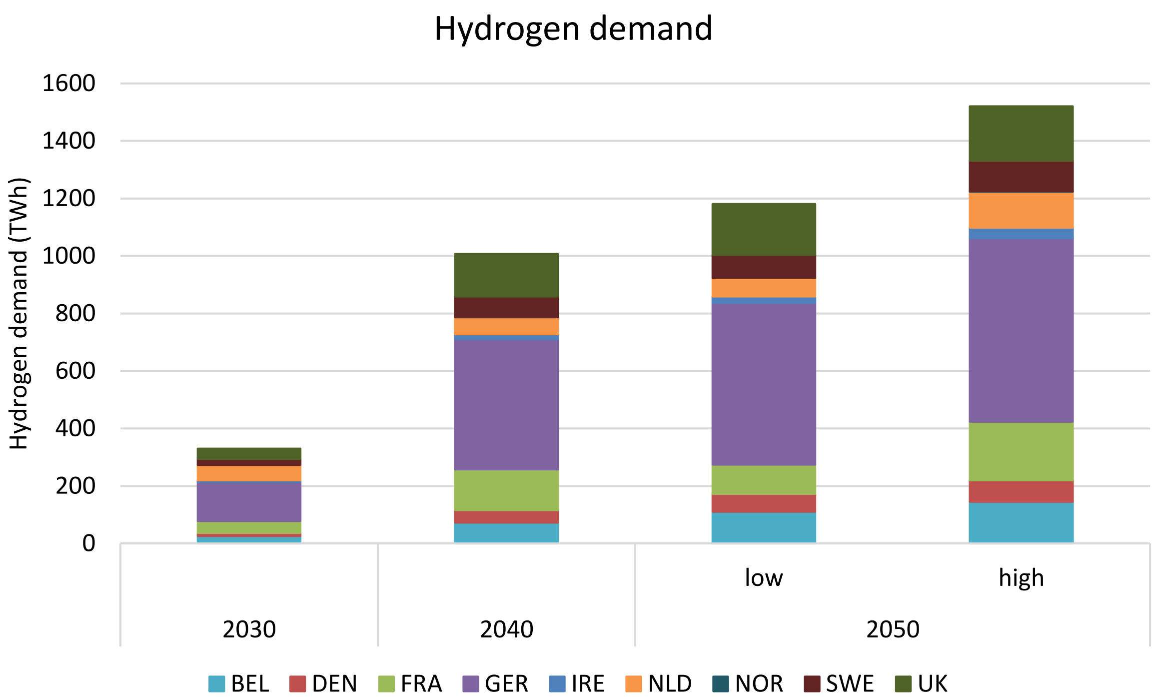
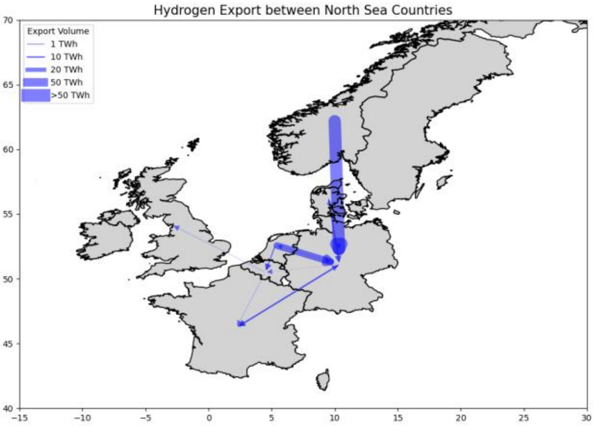
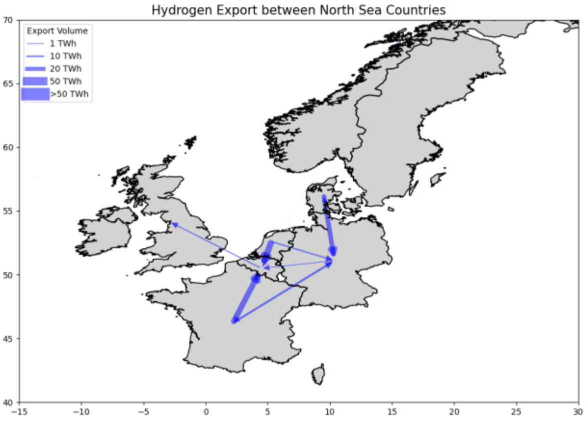


Figure 23: Hydrogen demand in the North Sea countries

Cross-Border Hydrogen Trade: Exporters and Importers in the North Sea

Cross-border trading agreements and consistent regulations will play a crucial role in developing a robust hydrogen distribution market.



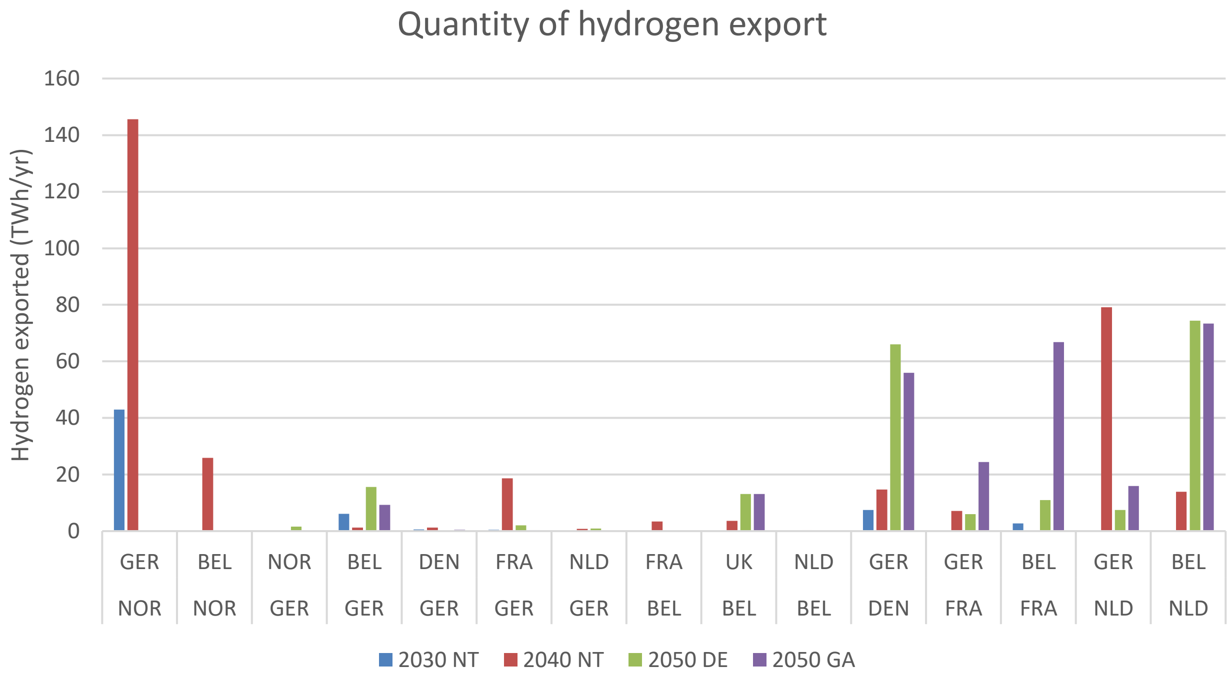


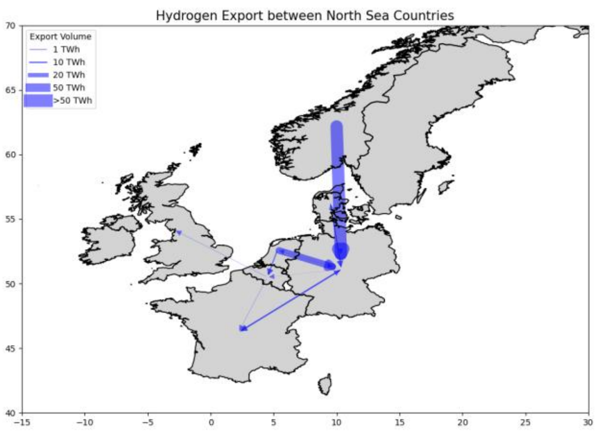
(a) 2040 (b) 2050

Figure 24 highlights the hydrogen export volumes from North Sea countries. With substantial renewable energy potential, countries like Norway, Denmark, the Netherlands, and France are likely to become net exporters of hydrogen. On the other hand, countries such as Germany and Belgium may rely on imports to meet their high industrial demand.

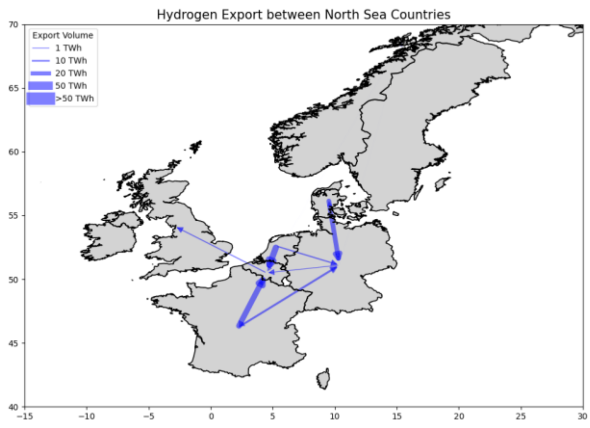
North Sea Ports as Gateways for Hydrogen Imports to Europe

The ports of North Sea countries are well-positioned to facilitate hydrogen imports into Europe, leveraging their infrastructure and strategic location. As hydrogen demand grows across the EU, imports via carriers such as ammonia, liquid hydrogen, and LOHC (Liquid Organic Hydrogen Carriers) will complement domestic production and help balance supply. Major ports in the region, including Rotterdam, Antwerp, and Hamburg, are planning facilities for large-scale hydrogen import, conversion, and distribution. These ports will act as key entry points, allowing hydrogen to be transported efficiently to inland European markets through existing and repurposed infrastructure.





(b) 2040



(b) 2050

Figure 24: Hydrogen export volumes from North Sea countries (on the x-axis, the countries in upper tier are the exporters and the ones in the lower tier are the importers)

Combining the export-estimates with the expected trends in installed electrolyzer capacities and hydrogen production and demand, the following insights were obtained:

- Norway's export dominance early on (2030–2040) tapers off by 2050, likely due to future reliance on blue hydrogen production, and other clean energy sources such as offshore wind and hydropower.
- Despite its significant production, Germany relies heavily on imports, reflecting a potential mismatch between its domestic production and industrial demand.
- Denmark and The Netherlands emerge as future export powerhouses by 2050.
- Belgium imports from exporters like Norway and The Netherlands, while also exporting to England and France, indicating its pivotal role in balancing hydrogen supply and demand across the region.

Hydrogen Transport and Storage: Key Infrastructure for North Sea Production

To facilitate the cross-border transport of hydrogen from exporters such as Norway, Denmark and the Netherlands to importers such as Germany and Belgium, large-scale hydrogen transport infrastructure is essential. The existing natural gas pipeline infrastructure could be repurposed for hydrogen transport, reducing the need for new investments. Additionally, new hydrogen pipelines and shipping routes will connect production centers in Norway, the UK, and the Netherlands to industrial hubs across Europe. More on the transport of hydrogen with cross-border pipelines is addressed in section 0

As hydrogen production scales up, the North Sea countries will also need to address the challenges of storage. Developing large-scale hydrogen storage in salt caverns and porous reservoirs is essential for balancing supply and demand fluctuations, as well as ensuring security of supply. Countries such as the United Kingdom and the Netherlands, which have numerous depleted gas fields and existing offshore facilities, could play a pivotal role in this area as shown in **Figure 25**. Additionally, countries like Germany, France, Denmark, and Belgium have potential for hydrogen storage in salt caverns and aquifers. This region offers significant opportunities for various types of underground hydrogen storage, both onshore and offshore, making it a good candidate for advancing hydrogen infrastructure. Based on the work from the HyUsPRe project[78], approximately 250 TWh of hydrogen storage capacity could be available in existing underground gas storage sites across seven countries if they are fully repurposed. This includes both salt caverns and porous reservoirs.

Currently, all planned underground hydrogen storage projects are located onshore and only in salt caverns, with a total capacity of up to 5 TWh by 2035. Porous reservoirs are less mature for hydrogen storage and are expected to play a role from 2040.

[78] https://www.hyuspre.eu/wp-content/uploads/2023/04/HyUSPRe_D1.5_Classifying-hydrogen-storage-potential_incl.-Supplement_2023.03.31.pdf

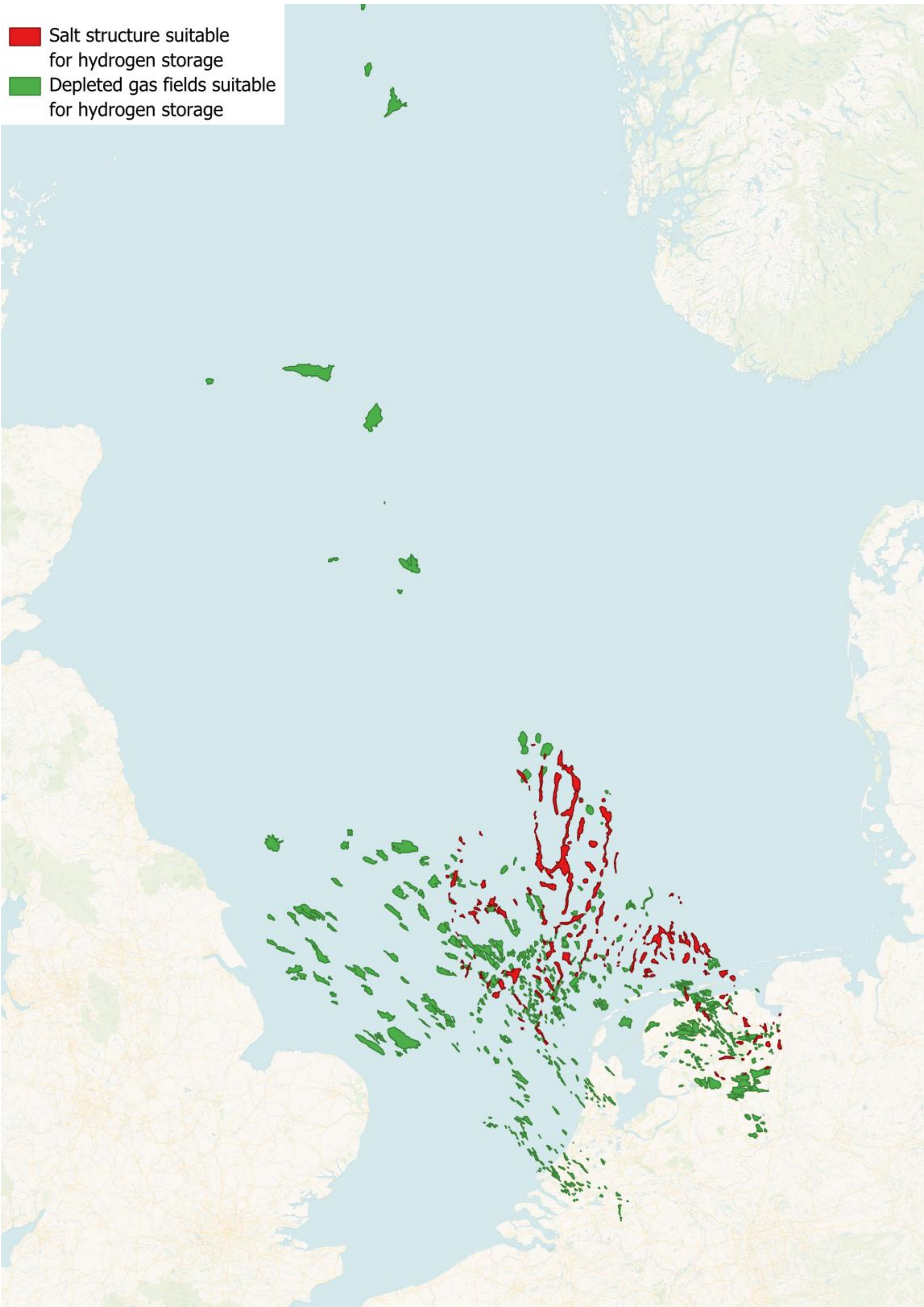


Figure 25: Potential hydrogen storage sites salt caverns and depleted gas fields in the UK and the Netherlands (source: [North Sea Energy Atlas](#) and Peecock et al. (2023)[79])

2.2 Grid vision 2050

Mapping the Future: a North Sea Hydrogen Grid vision towards 2050
The 320 GW of offshore wind capacity envisioned in the North Sea in 2050 cannot be brought to shore by electric cables alone. This is because the costs of cables, the space they will consume and the limitations of the onshore grid capacity makes it difficult for this renewable energy to be absorbed in the onshore electricity grid[80]. The North Sea energy system will thus benefit from converting this offshore wind energy to hydrogen which can then by transported to shore via new or existing pipes. This calls for the development of a North Sea hydrogen grid, connecting offshore wind farms to onshore industrial hubs through an integrated network of pipelines and storage facilities.

Work in the North Sea Energy program revealed five elements that very important for the future North Sea hydrogen grid:

- Nature inclusivity involves incorporating measures into the design of the future hydrogen backbone to protect the habitat of native species[81]. In addition to preserving natural environments, nature-inclusive designs can reduce spatial stress of the hydrogen grid in the North Sea. By allowing energy infrastructure and marine ecosystems to coexist or minimizing their interference with each other, such designs—like those implemented at the Hollandse Kust West windfarm in Dutch North Sea[82]—demonstrate how infrastructure and ecology can be harmonized.
- A fully meshed network of hydrogen pipelines interconnects multiple national transmission systems, unlike the limited bilateral connections of a point-to-point transmission grid[83]. Every production centre is connected to multiple, if not all, demand clusters and vice versa. This design supports the reuse of existing pipelines and offshore platforms and enables the development of a few centralized offshore hydrogen hubs or islands to manage production, transport, and storage across multiple countries. A fully meshed network also creates redundant hydrogen transport infrastructure—assets that can be availed when energy security in the is threatened among the North Sea countries.
- Similar to a meshed-grid, an internationally optimized grid also serves multiple national transmission system and takes it a step further by connecting supply and demand centres based on the most efficient production, cost, and consumption of hydrogen. This approach ensures that pipeline infrastructure is used without redundancy.
- An optimally reused hydrogen grid focuses on repurposing existing oil and gas pipelines for hydrogen transport. This approach offers several benefits, including lower capital costs, reduced environmental impact by avoiding unnecessary new infrastructure, and delayed decommissioning of current pipelines.
- A future-proof hydrogen grid should be able to support both large industrial consumers and smaller, decentralized users, such as hydrogen filling stations and logistics centres. The design should focus not just on current needs, but also be adaptable for future scenarios, ensuring flexibility as demands evolve.

Although a North Sea hydrogen grid that incorporates all five key characteristics would be preferred, its implementation comes with several challenges. Before constructing such a grid, international cooperation is needed to agree on regulations, such as hydrogen purity standards for pipelines, political buy-ins, cost-sharing arrangements, and nationally defined hydrogen supply and demand targets. Without established agreements on these issues, there will be concerns about the risks of redundancy in the hydrogen grid.

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[79] Peecock, A., Edlmann, K., Mouli-Castillo, J., Martinez-Felipe, A., & McKenna, R. (2023). Mapping hydrogen storage capacities of UK offshore hydrocarbon fields and exploring potential synergies with offshore wind.
[80] More about the benefits of an offshore hydrogen grid can be read at https://www.gasunie.nl/en/expertise/hydrogen/offshore-hydrogen/our-offshore-activities#:~:text=This%20is%20cheaper%20than%20laying,the%20possibility%20of%20storing%20hydrogen.
[81] Nature inclusive design-a catalogue of offshore wind infrastructure, Witteveen + Bos 518699 (wur.nl)
[82] Innovations - Ecowende Wind Farm Hollandse Kust West
[83] Baltic InteGrid: Towards a meshed offshore grid in the Baltic Sea; 10-Baltic_InteGrid_HighLevelConcept.pdf (interreg-baltic.eu)

Parallel to that is the 'not in my back yard' mentality towards the pipeline infrastructure crossing through various Exclusive Economic Zones (EEZ)[84].

Hydrogen Backbone Initiatives: Key Infrastructure Projects Shaping the North Sea's Future
Several significant projects are currently underway, designed to create hydrogen pipeline routes connecting the North Sea countries. The proposed routes are displayed in **Figure 26**. The Aquaductus project in the German North Sea aims to connect the hydrogen production site SEN 1, with a capacity of 1 GW, to the German mainland. This connection will tie into other pipelines and hydrogen demand centers, facilitating the distribution of hydrogen across the region. Spanning over 400 km in length, the project will feature a transport capacity of 20 GW, playing a crucial role in Germany's transition to a sustainable energy future.

Another key initiative is the Hydrogen Backbone Link, which will connect Germany with Scotland over a distance of 1,400 to 1,500 km. With a capacity of up to 10 GW, it will enable the efficient transport of hydrogen between the two countries.

In the Dutch North Sea, research is currently going on concerning the technical and economic feasibility of repurposing (parts of) the NGT and NOGAT pipelines, each with a capacity of 14 GW. In 2025, an Environmental Impact Assessment will be published that assesses the impact of re-use and potential consequences of required rerouting of natural gas production infrastructure. These pipelines can support demonstration projects in the Dutch offshore regions. The benefits of reusing these pipelines include a lower environmental impact compared to installing new pipes, a faster transition to a hydrogen economy and cost reduction. It can also connect to international gas networks by leveraging the existing international connections to Denmark via the Tyra-Nybro pipeline or to the UK. Similarly, the HyONE hydrogen network aims to connect Dutch production from demonstration projects—Demo 1 and Demo 2, wind areas 6-7 as well as international flows.

The remaining pipelines are part of the European Hydrogen Backbone (EHB) initiative. The EHB initiative shows The EHB outlines the vision of 32 European network operators, based on national analyses of existing natural gas infrastructure, future natural gas and hydrogen market developments, under an accelerated and ambitious climate scenario.

[84] An Exclusive Economic Zone (EEZ) is a maritime zone established by the United Nations Convention on the Law of the Sea (UNCLOS), where a coastal state has special rights regarding the exploration and use of marine resources

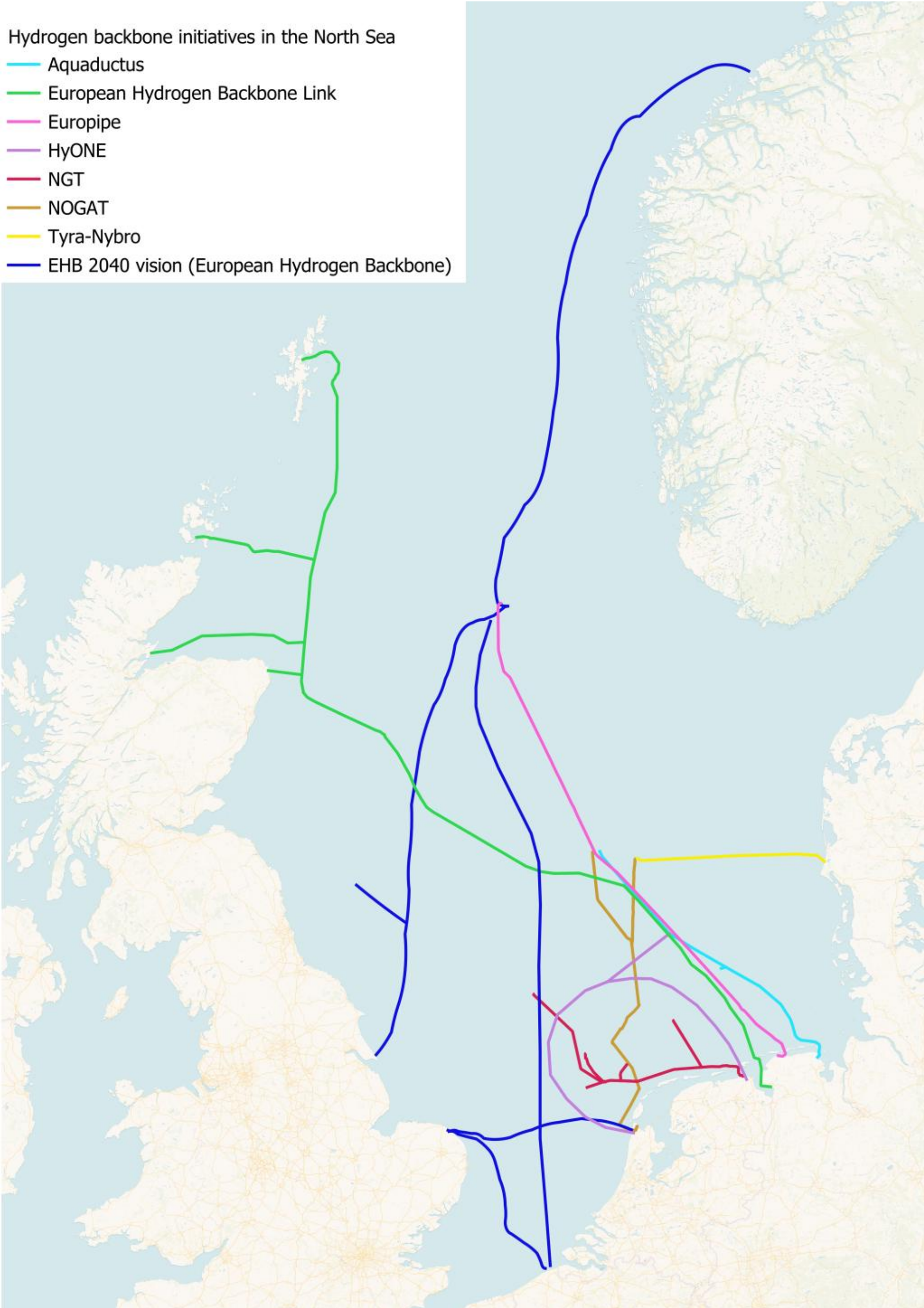

Figure 26: Hydrogen backbone initiatives in the North Sea[85] Disclaimer: maps are a representation of announced and envisioned plans and projects in the public domain and therefore subject to frequent updates and may not always reflect the most recent information. For more detailed spatial information and updates see: [North Sea Energy Atlas]

[85] The development of the pipeline between Germany and Norway has been cancelled due to high costs and lack of demand, so it is not included on the map anymore [Planned hydrogen pipeline between Norway and Germany scrapped by Equinor | Hydrogen Insight]

2.3 Commodity specific actions

Actions on green hydrogen

Create a deployment plan for offshore hydrogen value chains
At the moment, various green hydrogen production targets have been set by numerous countries, however, the offshore production is still in its first infancy. With only a handful of current pilot projects, there is still a lot to be tested before a full offshore green hydrogen value chain can be developed. Examples on how green hydrogen can develop are electrolysis on platforms, in- or near-turbine electrolysis, hydrogen transport through existing and new offshore pipelines, and hydrogen storage in compressed vessels or underground structures. In the near-term, more pilot projects are needed to develop them to higher TRLs. At the same time, the development should go at a very quick pace in order to reach the set targets. For this, stakeholder coordination and deployment plans are required to provide clarity and align visions. Regulation needs to be harmonized across commodities and countries, together with increased permitting and standardization. Long-term planning across sectors and borders is crucial.

Secure offtake and a market framework
Since hydrogen is not a widely traded commodity yet, the market still has to develop. Security of demand by potential off-takers and the establishment of a market framework are crucial to remove uncertainties and attract investments for further hydrogen deployment. An interesting development in this respect is the H2Global initiative, which is a support scheme designed to facilitate the market ramp-up of import of renewable hydrogen and its derivatives. Under this initiative a double tender scheme is designed for both long-term Hydrogen Purchase Agreements (HPAs) for suppliers and short-term Hydrogen Service Agreements (HSAs) for buyers. The difference between supply prices and demand prices will be compensated by grants (Contracts for Difference auctions). Next to this, integrated tenders with subsidization across various commodities could be beneficial for the parallel development of hydrogen with for example offshore wind.

Plan and develop an offshore hydrogen backbone
Next to the production and demand development, the transportation infrastructure is a crucial part of the value chain as well. The spatial planning on transport and storage needs to advance, similarly to the current development of the onshore backbone plan. It is crucial to align marine spatial planning with the other commodities. A critical element in these plans is the addressing of the potential and need for offshore production, transport and storage assets. This includes the careful and early appraisal of the role of legacy infrastructure (platforms, wells, reservoirs and pipelines) in these future plans to ensure timely planning of the repurposing of offshore assets for the hydrogen infrastructure.

Actions on blue hydrogen

Provide investment security for blue hydrogen production assets
Blue hydrogen is mainly seen as a transition option for many of the North Sea countries. Still, for its role in the energy system in the coming years, large investments are required. It is important that a long-term vision is developed, to provide solid business models for blue hydrogen producers. As part of this, the timeline of this ‘transition period’ needs to be clearly defined.

Provide clarity on the taxonomy and priority setting of blue hydrogen in gas demand
Since the war in Ukraine, there is a strong push for a reduction of natural gas demand in European countries. However, for the production of blue hydrogen, net more primary energy is needed per kg of

hydrogen produced, which conflicts with the push for energy security and natural gas reduction. Clarity is needed on how blue hydrogen fits in the priority setting for natural gas reduction.

Plan and develop an on- and offshore hydrogen and CO_2 backbone
Similar to the development of an offshore infrastructure network for green hydrogen, the same applies for blue hydrogen, except for the fact that it also requires CO_2 transportation and storage infrastructure. Plans have to be developed on the North Sea region scale for long-term security of sufficient and timely CO_2 storage potential under the seabed. There might be a conflict of repurpose; assets (pipelines, wells, platforms, reservoirs) are in some situations of value for both the CO_2 and hydrogen infrastructure. Such conflicting functions need to be identified early and resolved by public and private stakeholder discourse.

Actions on hydrogen grid

Pathway to Progress: Actions for a Robust Hydrogen Grid in the North Sea
To ensure the successful future of the hydrogen grid in the North Sea, several specific actions must be undertaken. These actions will collectively pave the way for a robust and sustainable hydrogen grid in the North Sea:

Short-term actions (< 1 year)
- Establish standardized environmental monitoring systems to assess impacts across production, transport, and storage phases, starting before project rollouts
- Strengthen international collaboration among governments to align strategic planning and decision-making for a fully meshed hydrogen grid
- Establish a centralized institution or regulatory framework to drive hydrogen infrastructure in the North Sea, promoting multi-country collaboration and incentivizing cross-border investments.
- Conduct research to identify eligible parties in infrastructure reuse projects and assess the technical feasibility of reusing subsea infrastructure
- Research on large-scale, grid-connected renewable energy production demonstrations and conduct] system modelling for business case evaluations

Mid-term actions (< 5 year)
- Create a basin-scale spatial plan to guide the long-term integration of offshore hydrogen infrastructure, focusing on minimizing environmental impacts and sustainable spatial allocation.
- Coordinate EU and regional measures to support hydrogen infrastructure development in the North Sea.
- Strengthen European leadership and cross-border agreements on safety, market standards, and supply security for hydrogen infrastructure
- Identify no-regret investments and develop an integrated TSO model for CO_2, hydrogen, gas and electricity to enhance collaboration in optimal infrastructure reuse
- Focus on harmonizing long-term national grid plans across countries to ensure cohesive infrastructure development and conduct technology pilots and demonstrations particularly for storage.

Dossier 3 – CO_2

3.1 State of play and ambitions

CCS is a key technology for achieving deep decarbonization in the EU, especially for North Sea countries. Given the high concentration of industries in North Sea countries that need to become carbon neutral, CO_2 is expected to be captured from sectors such as steel, cement, and chemicals. The North Sea has extensive offshore storage capacity (50-250 Gt) in depleted gas fields and aquifers, along with existing infrastructure like pipelines and platforms. This combination offers a unique opportunity for North Sea countries to lead in CCS deployment.

With many projects in the North Sea expected to begin by 2030, this section explores the current and future state of CCS development, outlines the 2050 vision for a CCS grid in the region, and highlights the short- and mid-term actions needed to build a robust CCS backbone.

Current state of play

Decarbonizing the North Sea Countries: A 40% Reduction in CO_2 Emissions by 2023
The North Sea region's emissions vary significantly by country, reflecting differences in industrial activities, energy mixes, and policy priorities. Germany has the highest CO_2 emissions in this region, followed by the UK, France, and the Netherlands. Most countries show a decreasing trend compared to 1990 levels, except for Norway and Ireland, which have maintained similar emission levels, albeit small compared to the total CO_2 emissions of these nine countries. **Figure 27** shows the trend of CO_2 emissions in these countries over time, showing a 40% reduction in 2023 compared to 1990 levels. Currently, the region collectively produces a significant portion of the EU's emissions (1.51 out of 2.51 billion tons). This also provides insight into the emission reduction pathway needed to meet 2030 and 2050 targets. By 2030, emissions should decrease by approximately 380 Mt, with an additional 1,130 Mt (compared to current emission levels) reduction required by 2050 to achieve carbon neutrality. CCS could play a crucial role here, with estimates suggesting that CCS can address up to 15–20% of the region's emissions, particularly in hard-to-abate sectors[86]. Besides decarbonizing industry, CCS is also interesting in enabling blue hydrogen production, the potential re-use of existing infrastructure in the North Sea for geological storage and unlocking negative emissions potential.

[86] https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf

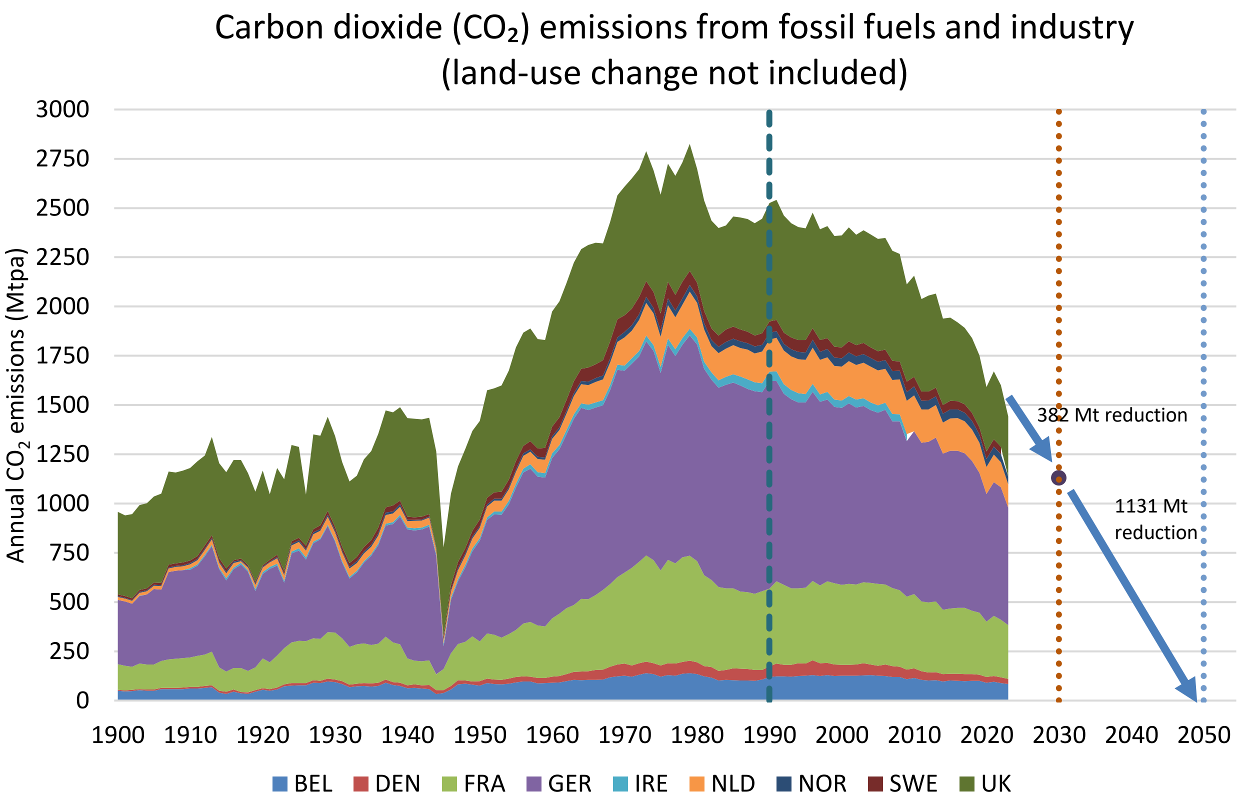

Figure 27 CO_2 emissions in North Sea countries[87]

CCS Development in the North Sea: First Operational Projects on the Horizon
CCS is gaining momentum in the EU/EEA, particularly in the North Sea region, with numerous projects already underway or planned to start soon. As of mid-2024, There are 191 large-scale projects currently progressing through different phases of development in EU[88]. Significant efforts have been made by the European Commission and several countries to facilitate policies, financial incentives, and regulations for CCS. Additionally, international collaboration such as the North Sea Basin Task Force (NSBTF) and cross-border CO_2 transport, especially among North Sea countries, are advancing, with many Memorandums of Understanding (MoUs) signed for cross-border transport of CO_2 for offshore storage.

CCS has a long history in Europe, particularly in the North Sea countries. Norway has been a pioneer in this field, introducing a carbon tax in 1991 and initiating CO_2 storage operations with the Sleipner project in 1996 and the Snøhvit project in 2008. Following these initiatives, several countries have made significant progress towards ratifying the 2009 amendment to the London Protocol, which regulates the export of waste, including CO_2, for offshore geological storage. Additionally, some nations have developed roadmaps and strategies for carbon management. Currently, the construction of several CCS projects is underway, with full-scale operations expected by 2030 in Norway, Denmark, the Netherlands and the UK. **Figure 28** illustrates the key milestones and highlights in the timeline of CCS projects in the North Sea countries since 1990.

[87] https://ourworldindata.org/co2-emissions
[88] https://www.globalccsinstitute.com/wp-content/uploads/2024/11/PLR-Review-Report_15-November.pdf

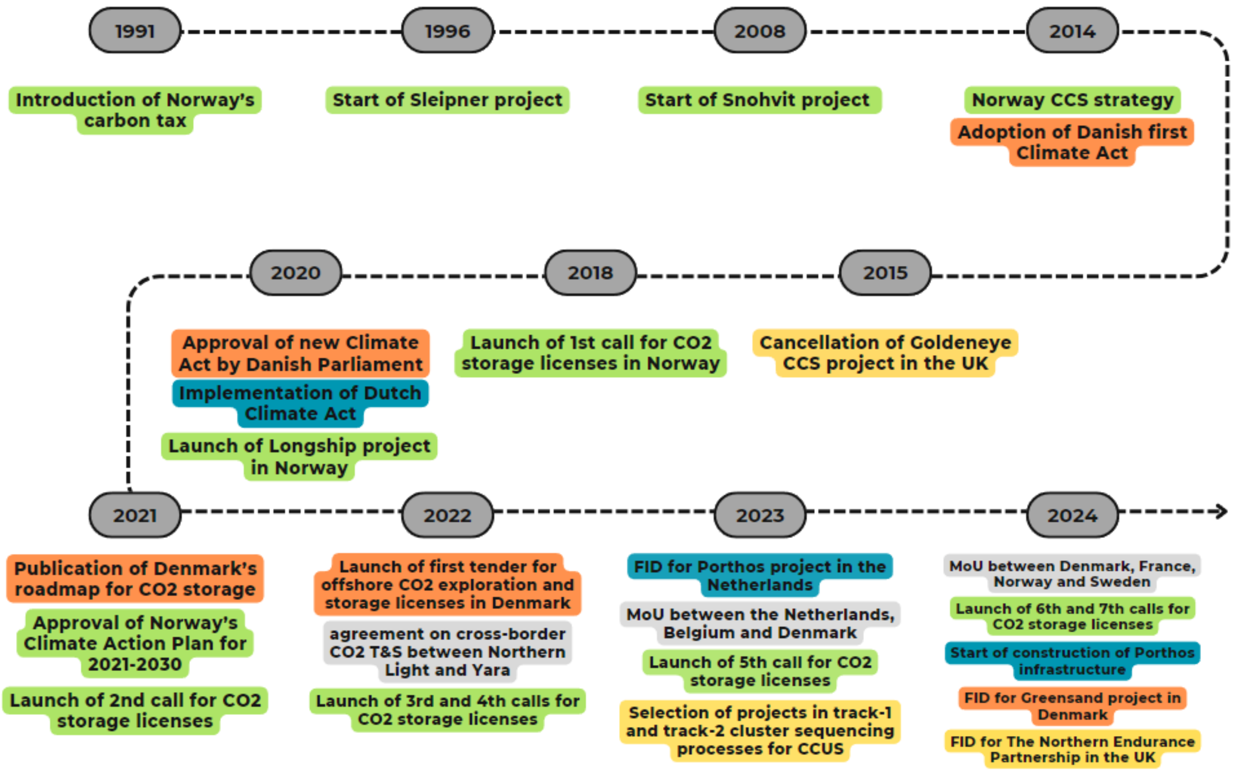

Figure 28 Timeline of key milestones and developments in CCS projects in North Sea countries since 1990 – Green: Norway, Orange: Denmark, Yellow: UK, Blue: Netherlands, Grey: inter- cross-border agreements[89]

Exploration and Storage Licenses in the North Sea: Regional Insights

In line with these historical developments, the current CO_2 licenses, whether for exploration or storage, are mainly awarded in the North Sea region, specifically in the offshore areas of the UK, Norway, the Netherlands, and Denmark. **Figure 29** illustrates the areas where these licenses have been applied for or awarded. The UK has issued 27 active exploration licenses, a higher number than in other countries such as the Netherlands, Norway, and Denmark[90] (status Summer 2024). Many of these licenses are not yet linked to specific projects, reflecting the UK's strategy to explore multiple potential storage sites, even though not all will necessarily be suitable or selected for storage permits.

In terms of proximity, the UK and the Netherlands are closer to countries like Belgium, Germany, and France for CO_2 storage. However, these countries can also connect to Norway via Equinor's 'CO_2 Highway Europe'[91].

[89] https://www.globalccsinstitute.com/wp-content/uploads/2024/11/PLR-Review-Report_15-November.pdf

[90] https://www.catf.us/2024/08/carbon-dioxide-without-borders-connecting-uk-eu-create-more-resilient-lower-cost-co2-storage-network/

[91] https://www.equinor.com/energy/smeaheia

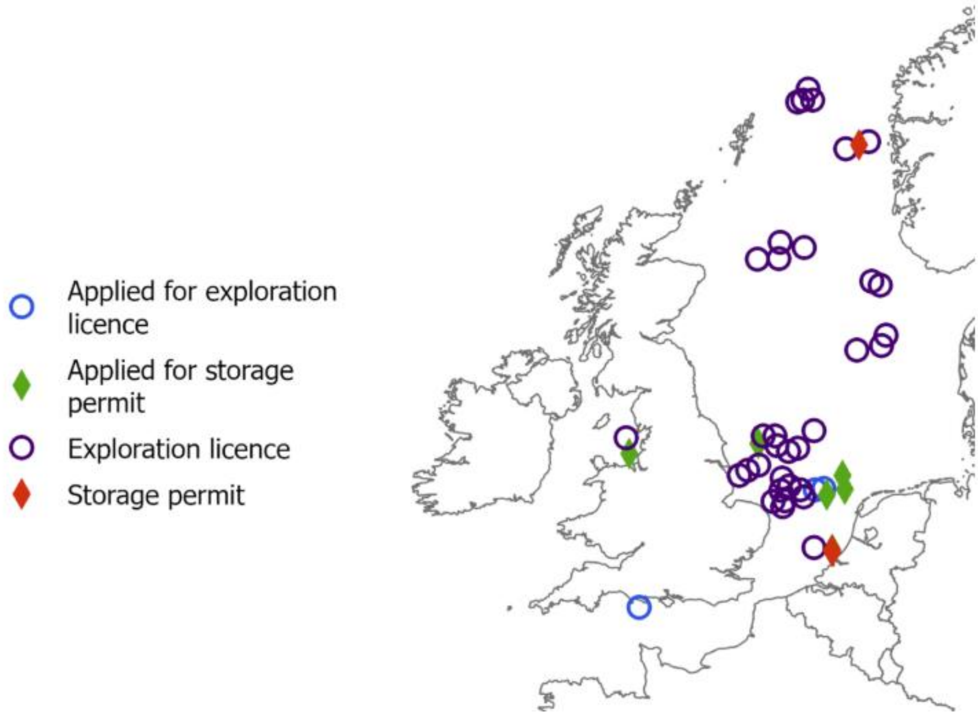

Figure 29 CO_2 storage licenses and permits awarded in the North Sea[92]

CCS Initiatives in the North Sea: Key Projects and Timelines; Longship and Porthos Lead the Way
Looking at the ongoing CO_2 transport and storage projects in the North Sea region, several notable projects are currently in early development or construction phases and are expected to become operational in the coming years. Excluding Sleipner and Snøhvit, which are primarily natural gas processing projects with CO_2 storage components in Norway, no dedicated CCS projects are operational in this region yet. Longship (captured CO_2 from Brevik and Northern Lights' transport and storage) is expected to become operational in 2025, followed by Porthos in 2026, marking them as pioneers in the area. Other projects, such as Aramis in the Netherlands, Greensand and Bifrost in Denmark, and HyNet and the East Coast Cluster Northern Endurance Partnership (NEP) in the UK, are still in development, with some set to start construction and anticipated to launch in the near future[93]. Some of these projects are included in the Union list of Projects of Common Interest (PCI) and Projects of Mutual Interest (PMI), which are key infrastructure initiatives shaping Europe's future energy landscape[94].

Progress in Carbon Capture: 80 Announced Projects Across North Sea Countries
An essential component of the CCS value chain is CO_2 capture. Capture technologies, such as membrane and amine-based methods, depend on the CO_2 concentration in the gas stream, which varies by industry, as well as the pressure at which the gas is produced. Currently, there are approximately 100 carbon capture projects in Europe, with around 80% located in North Sea countries, due to the region's diverse industrial portfolio. The majority of these projects in the North Sea region are in sectors such as cement, hydrogen,

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[92] https://www.catf.us/2024/08/carbon-dioxide-without-borders-connecting-uk-eu-create-more-resilient-lower-cost-co2-storage-network/
[93] https://res.cloudinary.com/dbtfcnfij/images/v1700717007/Global-Status-of-CCS-Report-Update-23-Nov/Global-Status-of-CCS-Report-Update-23-Nov.pdf?_i=AA
[94] See section 13 of the report: https://energy.ec.europa.eu/document/download/944b96b9-4efd-44a3-bbfe-45b752b0b55f_en?filename=Technical_document_1st%20PCI_PMI%20list_15.05.2024_FINAL.pdf

ammonia, fertilizer production, and power and heat generation. A map of the locations of these projects can be found on the CATF website[95].

Future state of play

North Sea's Ambitious CO_2 Storage Target: Up to 80-100 Mtpa by 2030
With the development of current and ongoing CCS projects, the North Sea has the potential to store up to 100 million tonnes of CO_2 per year (Mtpa). **Figure 30** illustrates the growth in CO_2 storage capacity as proposed by CATF, reaching up to 150 Mtpa by 2035. At the EU level, the CCUS Vision Working Group has proposed tentative CO_2 storage targets of 80 Mtpa by 2030[96], which is roughly in line with CATF's projections. In their analysis, the majority of storage capacity by 2030 is expected to come from reservoirs in the North Sea region. In practice, however, these numbers represent high estimates assuming all projects reach commercial scale. A more realistic projection for 2030 is likely below 50 Mtpa in terms of storage capacity[97]. Note that the EU's target for CO_2 storage by 2030 is also 50 Mtpa, as outlined in the Industrial Carbon Management Strategy (ICMS) and the Net Zero Industry Act (NZIA)[98].

In terms of country target, to date, only a few countries, such as the United Kingdom, have established clear national targets. The UK, for instance, aims to capture and store 20–30 Mtpa of CO_2 by 2030, with ambitions to exceed 50 Mtpa by 2035[99].

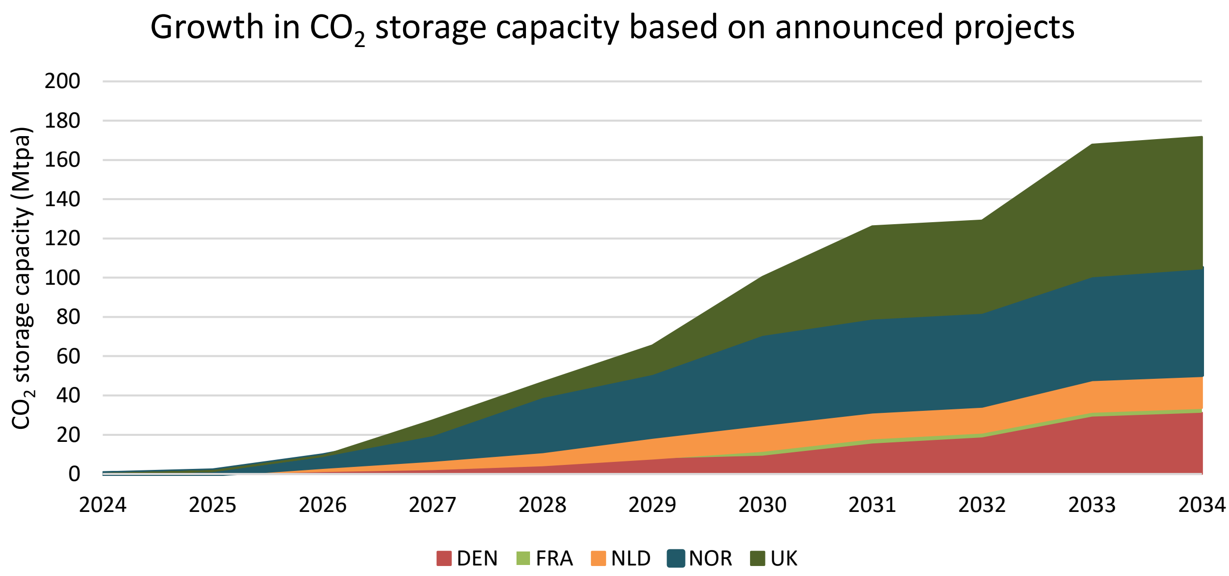

Figure 30: Growth in CO_2 storage capacity based on announced projects till 2034 (assuming successful implementation)[100]

North Sea's Ambitious CO_2 Goals: 150 Mtpa by 2040, 300 Mtpa by 2050

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[95] [Europe Carbon Capture Project Map – Clean Air Task Force]
[96] Read more about the CCUS roadmap made for the European Union's CCUS Forum by the CCUS Vision Working Group at Circabc
[97] https://papers.ssrn.com/sol3/papers.cfm?abstract_id=5067953
[98] Currently, this target applies to the EU. If countries like Norway join, the 50 Mtpa target will be expanded to include the EEA. Projects under development in the UK do not contribute to the EU or EU/EEA targets.
[99] More about UK's CCS targets can be found at Carbon Capture and Storage - The Move to Net Zero - The North Sea Transitioning Authority
[100] https://www.catf.us/carbon-capture/storage-project-capacity-europe/

After 2030–2035, projections mainly depend on the availability of storage space. Most estimates are derived from scenarios developed by various organizations. Other regions in Europe, beyond the North Sea, are expected to play a role in achieving the 2040 and 2050 targets.

The CCUS Vision Working Group has set ambitious targets of 300 Mtpa by 2040 and 500 Mtpa by 2050 for the entire EU[101]. Of the 300 Mtpa target for 2040, approximately 150 Mtpa is projected to originate from the North Sea region. By 2040, international collaboration is anticipated, as some countries have limited storage potential while others have surplus capacity, allowing CO_2 from other countries to be transported to North Sea nations such as the Netherlands, Denmark, the UK, and Norway. This growth highlights the importance of cross-border efforts in achieving climate goals. Xodus forecasts a high-case scenario of up to 130 Mtpa by 2040 and 300 Mtpa by 2050[102] in the North Sea. Note that the EU's CCS targets set forth in the ICMS are 200 Mtpa for 2040 and 250 Mtpa for 2050.

North Sea CO_2 Storage: 8-30 Mtpa from Blue Hydrogen by 2040
The NSE program does not provide a specific prediction for the total amount of CO_2 stored in the North Sea. However, it estimates that, based on different scenarios for 2030 and 2040, up to 20% (8-30 Mtpa) of the stored CO_2 could come from blue hydrogen production (via the SMR + CCS process). This estimate is based on the lower heating value (LHV) of hydrogen and an 80% efficiency for the capture plant (see **Figure 31**).

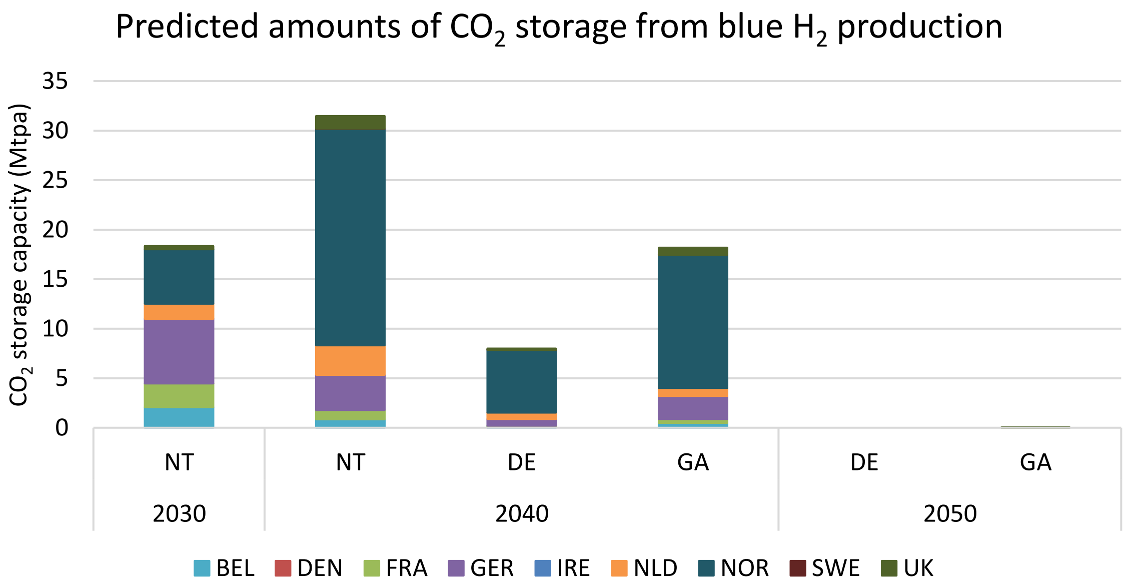

Figure 31 Predicted amounts of CO_2 stored from blue hydrogen production in different scenarios where NT represents the outcomes from the National scenario, DE from the Distributed Energy scenario and GA from the Global Ambition scenario

Technology trends: Learnings from unique fit-for-purpose designs employed in different CCS projects in the North Sea
CCS projects offer various solutions for injecting CO_2 into reservoirs and aquifers. Current projects show that each uses fit-for-purpose designs to accommodate varying geological, infrastructural, and regulatory conditions. Various engineering methods and technologies have been developed in each project to address the unique challenges faced by operators. Each new storage project contributes to

[101] Read more about the CCUS roadmap made for the European Union's CCUS Forum by the CCUS Vision Working Group at Circabc
[102] https://www.xodusgroup.com/this-is-what-we-do/forecasting-the-north-sea-ccus-infrastructure-to-2050/

the portfolio of engineering solutions or partial solutions used to develop CO_2 storage. This combined knowledge should be made available to new project developers. The following outlines several opportunities and challenges associated with these projects.

Repurposing Existing Infrastructure: Viable in Some Cases, but Not Always the Best Choice
The repurposing of existing infrastructure, such as oil and gas platforms, wells, and pipelines, has been investigated in several projects. For example, the Porthos project in the Dutch North Sea plans to reuse platform P18-A and five wells for CO_2 injection into the subsurface[103]. Similarly, the Bifrost and Acorn CCS projects are assessing the feasibility of converting existing gas pipelines to transport CO_2 from shore to platforms for injection[104],[105]. However, reusing infrastructure is not always the most cost- or time-efficient solution. Conversely, other projects in the Dutch offshore plan to build new infrastructure, such as the K14 and L10 projects of Shell and ENI, respectively[106]. Each project must be evaluated individually, as infrastructure may sometimes be unsuitable or could reduce the flexibility needed for effective CO_2 storage.

Engineering Solutions for Injecting Cold CO_2 into Ultra-Depleted Reservoirs
Hydrocarbon fields in the North Sea have been depleted from initial pressures of several hundred bar to very low pressures in some cases (below 20 bar). Injecting CO_2, transported via dense-phase pipelines at seafloor temperatures, into a low-pressure, high-temperature (over 100°C) reservoir presents several engineering challenges. These include significant Joule-Thomson cooling during CO_2 expansion, which can cause freezing of fluids in the well and reservoir, thermal fracturing near the wellbore, hydrate formation, salt precipitation, and complex phase changes[107].

To address these challenges, it is essential to maintain CO_2 within acceptable temperature and pressure ranges throughout the CCS supply chain (including pipelines, wells, and reservoirs). Various engineering methods have been implemented to achieve this. For example, the Porthos project uses an insulated pipeline to transport warm gas-phase CO_2 during the early phases of injection, to maintain safe temperatures in the well and reservoir and reach targeted injection rates[117]. In cases where the distance from shore to the platform exceeds that of Porthos, insulated pipelines are not useful. Non-insulated pipelines also offer higher capacity. Therefore, the L4-A CCS project, which faced similar challenges, chose to modify the well and tubing designs to enable injection of dense-phase CO_2[108].

Alternative CO_2 Transport Methods in CCS Projects: Ships
The Greensand[109], Bifrost[110] and L10 CCS projects are exploring CO_2 transport by ships, rather than using pipelines from shore to platforms. Although this method had not been previously attempted, Greensand

[103] Aanvraag CO2-opslagvergunning reservoir P18-2 - Porthos Transport en opslag van CO2 - fase 2
[104] Bifrost, an Innovative CO2 Transportation and Storage Project in Denmark by Mathieu Prevost, Alexia Genin, Jacob Ladenburg, Jesper Kok Frost, Ugur Soytas, Rasmus Lang, Malene Hein, Malene Rod Vest, Simon Ivar Andersen, Hamidreza M. Nick :: SSRN
[105] Acorn Carbon Capture and Storage (CCS) feasibility studies Project | Genesis
[106] https://www.rvo.nl/sites/default/files/2022-06/Concept-NRD-Aramis.pdf
[107] https://ieaghg.org/publications/managing-the-transition-of-depleted-oil-and-gas-fields-to-co2-storage/
[108] Aramis CO2 storage Case Study – A Geomechanical Assessment of Containment by Peter Shotton, Sandrine Vidal-Gilbert, Sylvain Thibeau, Nicolas Agenet, Anne Lesueur, Clémence Manhes, Capucine Ninet :: SSRN
[109] energy.gov/sites/default/files/2023-07/7c. Building industrial clusters and CO2 infrastructure - Greensand Project.pdf
[110] Bifrost, an Innovative CO2 Transportation and Storage Project in Denmark by Mathieu Prevost, Alexia Genin, Jacob Ladenburg, Jesper Kok Frost, Ugur Soytas, Rasmus Lang, Malene Hein, Malene Rod Vest, Simon Ivar Andersen, Hamidreza M. Nick :: SSRN

successfully completed a pilot injection of 4,000 tonnes in 2023[111]. Both Greensand and Bifrost are also investigating offshore systems for offloading CO_2, unlike projects such as Northern Lights and Aramis, which rely on onshore offloading systems.

Innovative Approaches to Monitoring CO_2 Storage Sites
During and after CO_2 injection, it is crucial to monitor the subsurface for potential leakage. Bifrost is testing two advanced monitoring techniques to ensure the safe and effective storage of CO_2[124]. One method uses a machine-learning-enabled digital twin to automate monitoring and verification of CO_2 storage in the subsurface. The other involves highly sensitive stationary chemical sensors that continuously monitor the seafloor above the storage site. Currently, such marine monitoring is carried out using equipment suspended from ships that need to scour the waters above the storage site. Additionally, Greensand utilized the SpotLight technique to detect the presence of CO_2 in areas where migration was expected, or its absence where it was not. This method could eliminate the need for large-scale seismic surveys in the future[112].

3.2 Grid vision 2050

Mapping the Future of CCS Networks: 2030 and Beyond
Based on ongoing and announced projects, the envisioned CCS grid for 2030 in the North Sea is illustrated in **Figure 32**, which shows the planned pipelines, shipping routes, storage locations, and associated injection capacities. By 2050, the CCS network is expected to have expanded significantly, comparable in scale and complexity to the current natural gas grid. However, two key aspects distinguish CCS from natural gas networks: internationalization and flexibility.

Toward a Flexible and International CCS Network: Connecting Emitters to Storage
International collaboration and flexible infrastructure will be essential for building a reliable and efficient CCS network that supports Europe's decarbonization goals:

- Collaboration across borders will play a crucial role in the North Sea CCS network. CO_2 captured from emitters in several north European countries will likely be transported to the North Sea reservoirs and aquifers. For instance, the Aramis pipeline is expected to carry CO_2 from Belgium and Germany in addition to CO_2 from the Netherlands. Similarly, shipping is expected to be another key mode of transport. Numerous MoUs are already in place for cross-border transport and delivery CO_2 to storage locations. Already by 2040, it is expected that CCS in the North Sea will be fully internationalized, with robust cross-border cooperation.
- Ensuring sufficient pipeline capacity to transport CO_2 from multiple emitters to multiple storage sites is critical. The flexibility of the network must consider variations in supply rates (e.g., daily and seasonal variations in captured volumes), as well as planned and unplanned downtime at both capture locations and storage sites. Such flexibility may be created by linking CCS networks, potentially across borders, to create back-up transport and storage capacity. In addition, CO_2 composition may vary over time, within limits defined by the CO_2 specifications used by the transport and storage system. This requires careful network design from the beginning to meet both capture and storage requirements, ensuring the CCS grid can adapt to varying conditions and effectively connect emitters to storage reservoirs across the North Sea.

[111] INEOS led project Greensand and Royal Wagenborg sign agreement on CO2 carrier
[112] 22_08_22_EAGEGET_Abstract_Greesand-seismic.pdf

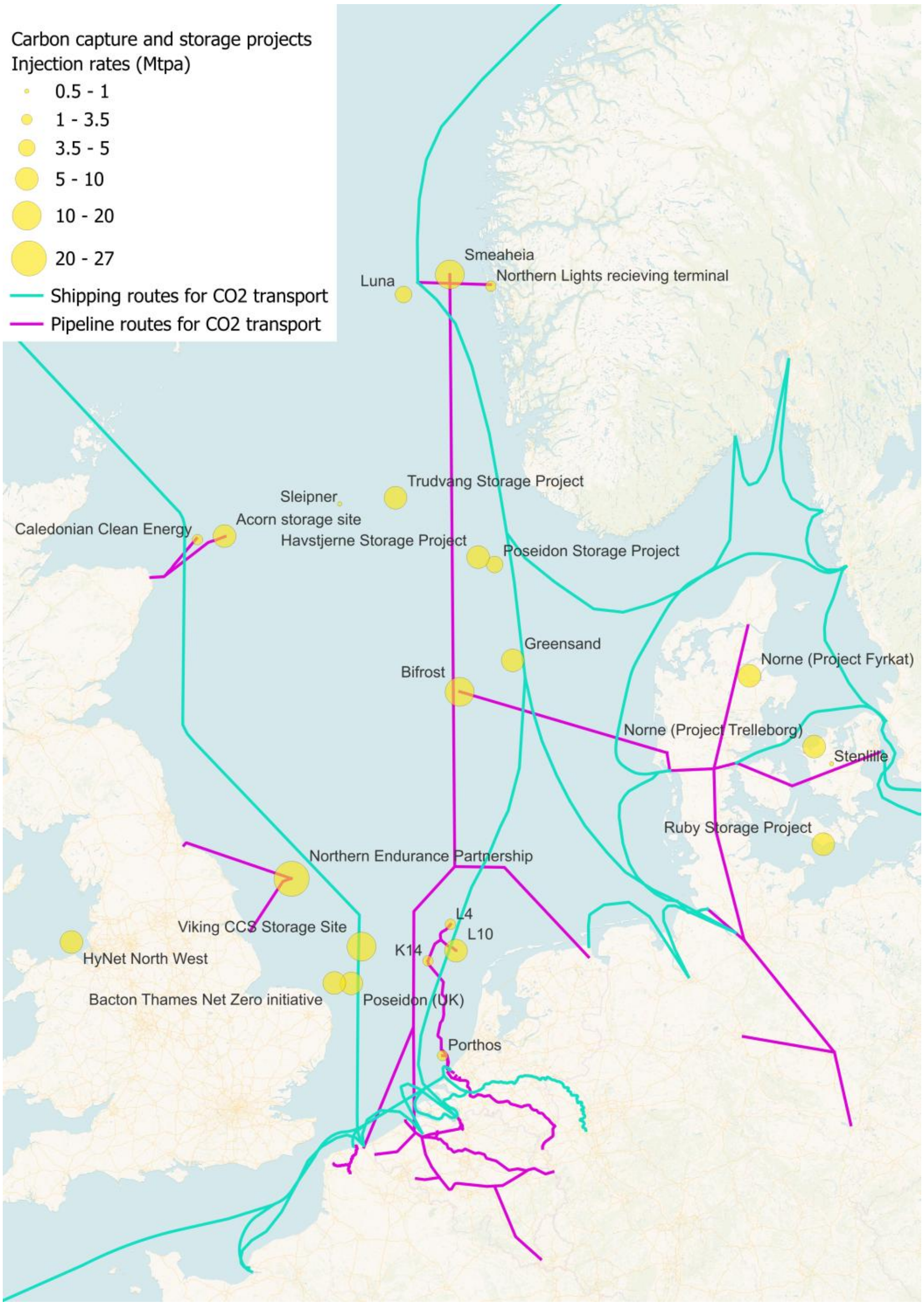

Figure 32 CCS grid envisioned for 2030, showing announced projects and including both pipeline and shipping transport networks Disclaimer: maps are a representation of announced and envisioned plans and projects in the public domain and therefore subject to frequent updates and may not always reflect the most recent information. For more detailed spatial information and updates see: [North Sea Energy Atlas]

Aramis is a first-of-its-kind backbone pipeline designed to transport CO_2 at high capacity, initially to depleted gas fields, with the potential to include saline aquifers in future phases. What sets the Aramis project apart is its innovative open-access infrastructure, enabling a multi-emitter and multi-storage system—an approach not previously implemented at this scale. The pipeline is built with significant overcapacity (22 Mtpa) to support future expansion in the early phases.

The Greensand project represents an international CCS value chain. During its pilot phase, CO_2 was captured in Antwerp and transported to the Nini field in Denmark by ship. This marks a breakthrough in the development of larger cross-border CCS initiatives. A bilateral agreement between Belgium and Denmark was in place to enable the transport of CO_2 for this project.

3.3 Commodity specific actions

Actions on CCS development

Resolve long-term liability and cross border challenges
The key business case opportunity for CCS lies within the EU and UK Emission Trading Schemes (ETS). These framework consider CO_2 that is captured and safely stored as 'not emitted'. However, the topic of long-term liability is still a challenge, especially when this relates to cross-bored international CO_2 projects. Next to this, CO_2 transport by ships is currently not included in the EU ETS Directive, resulting in the fact that emitters that transport their CO_2 by ships cannot qualify their CO_2 as being captured. This should therefore be better regulated. Cross-border permitting of CCS projects is thus expected to require streamlining by national authorities where possible to prevent any delay in the project deployment.

Provide long-term market incentives
Due to a lack of clear CCS policy and limited long-term targets, investors are hesitant on the economic viability of CCS in the long-term. Next to this, CCS business models are very different to what offshore operators of hydrocarbon reservoirs are experienced with. The CCS business model is not a 'high risk, high reward' model, but requires long term investments in repurposing assets for CO_2 transport and storage with a limited reward model. Building a CCS network requires much involvement and dependency of additional parties in the value chain (e.g., collaborative model with suppliers of CO_2). This makes the investment climate quite reluctant. Actions towards alignment and a long-term outlook of support and taxing schemes would be beneficial to mobilise private capital in developing CCS projects.

Develop a CO_2 transport and storage basin strategy North Sea
In line with this limited CCS long-term policy, more governmental initiative is required. A broadly supported strategy has to be developed, where public and private parties are involved in the decision-making. The strategy should describe under what conditions CO_2 storage is available, how much storage is needed, how much CO_2 can be imported from other regions and what the role of CCS will be in achieving negative emissions. Next to this, it should become clear to which extent existing hydrocarbon assets such as pipelines and gas fields can be used for CCS.

Actions on CO_2 grid

Advancing CCS Infrastructure: Key Actions for a Sustainable Future in the North Sea

To ensure the continued growth and expansion of CCS in the North Sea, a series of strategic actions are crucial. These steps aim to establish an international CCS backbone, utilizing both existing and new infrastructure for long-term CO_2 storage.

Short-term actions (< 1 year)

- Identify suitable fields and locations for CO_2 storage, taking into account other offshore activities by conducting pre-competitive assessment of storage readiness levels .
- Begin developing a supportive regulatory framework and standards for CCS, with a focus on cross-border collaboration.
- Facilitate and coordinate the re-use of existing infrastructure for CCS applications.
- Continue research on the behavior and impact of CO_2 impurities on the storage backbone.
- Initiate the development of trade and cooperation agreements between the UK and EU on CO_2 transport and storage.
- Conduct spatial modelling for route optimization and network architecture to enhance international CCS synergies.

Mid-term actions (< 5 year)

- Establish a pan-North Sea body to coordinate CCS operations and system architecture.
- Facilitate the sharing of technology and best practices among North Sea countries.
- Develop regional market mechanisms (in the EEA), aligning the UK with these frameworks to facilitate international CCS projects.
- Expand cross-border CO_2 infrastructure, supported by funding mechanisms such as the Innovation Fund and CEF[113].
- Adapt the EU Emissions Trading System (ETS) to recognize CO_2 storage sites in the UK, ensuring that storage needs of EU countries can be met. This requires linking the EU and UK ETS to allow CO_2 captured under one system to be stored under the other.
- Create North Sea-wide agreements on nature-inclusive design and the mitigation of negative environmental impacts.

[113] https://cinea.ec.europa.eu/programmes/connecting-europe-facility_en

Dossier 4 – Natural gas

4.1 State of play and ambitions

Natural gas is still a key part of the energy mix in the EU. For decades, the North Sea has been a producer of natural gas, but production is now in decline as many reservoirs near the end of their operational life. While some new developments may emerge, natural gas is the only commodity facing an inevitable reduction.

This section examines the current and future state of natural gas demand and production and explores coming decommissioning plans as well as opportunities and challenges for repurposing oil and gas infrastructure.

Current state of play

Trends in Domestic Natural Gas Production in North Sea Countries: Rising in Norway, Declining in the UK and the Netherlands
Natural gas is a key contributor to the economy and industry of North Sea countries and Europe. In 2022, 77% of Europe's domestic gas production came from North Sea countries. **Figure 33** shows the domestic natural gas production for NS countries since 2000. Norway, the UK, and the Netherlands are the leading producers, with the UK and Netherlands showing a declining trend, while Norway continues to increase production.

Current Natural Gas Demand and Import: Germany and UK at the Forefront
On the demand side, **Figure 34** shows natural gas consumption in these countries, primarily used for electricity generation, heating for buildings, industry, and other sectors such as transport and agriculture. Unlike natural gas production, which is declining, demand remained relatively stable until 2021, followed by a decrease in 2022 due to the energy crisis. The distribution of gas demand differs significantly from production, leading to import and export dynamics among these countries. Germany and the UK are the largest consumers, with Germany being the biggest gas importer in Europe. Both countries also have the highest CO_2 emissions from natural gas. **Figure 35** show the net import of natural gas for North Sea countries since 2000. Germany, France, and Belgium have consistently been net importers, while Norway has remained a net exporter. The Netherlands and the UK were net exporters previously but are now net importers.

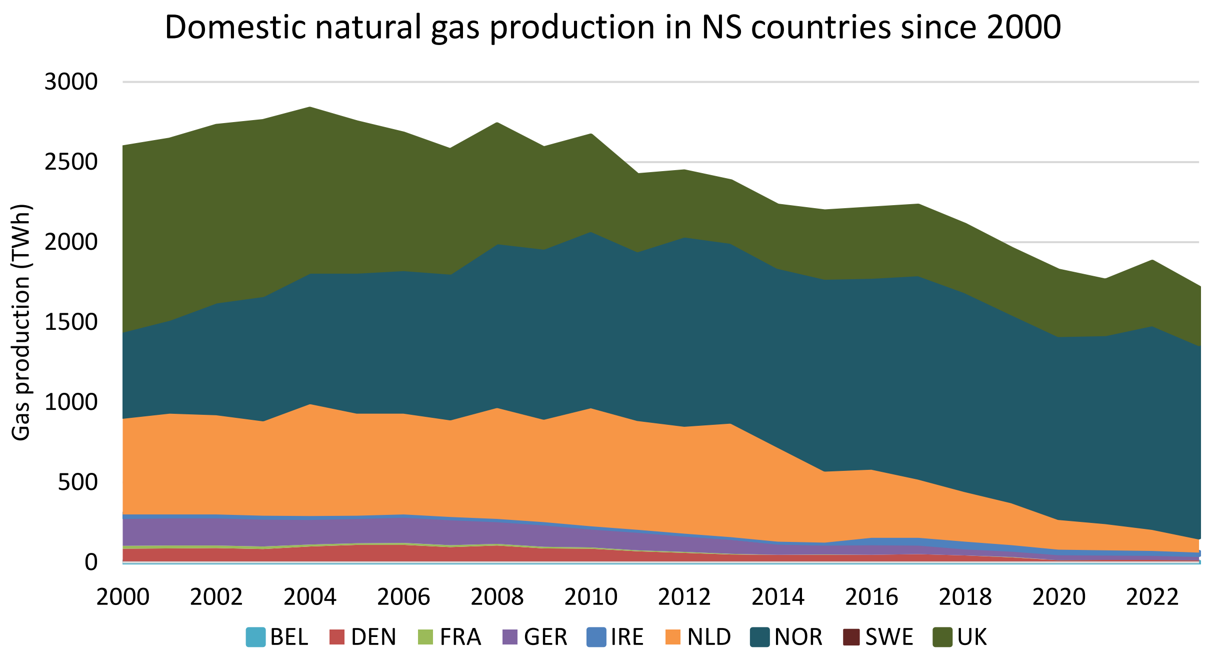

Figure 33 Domestic natural gas production in NS countries from 2000 to 2023 (no data available for Sweden). Source of data: IEA World Energy Statistics and Balances[114]

[114] https://www.iea.org/data-and-statistics/data-product/world-energy-statistics-and-balances

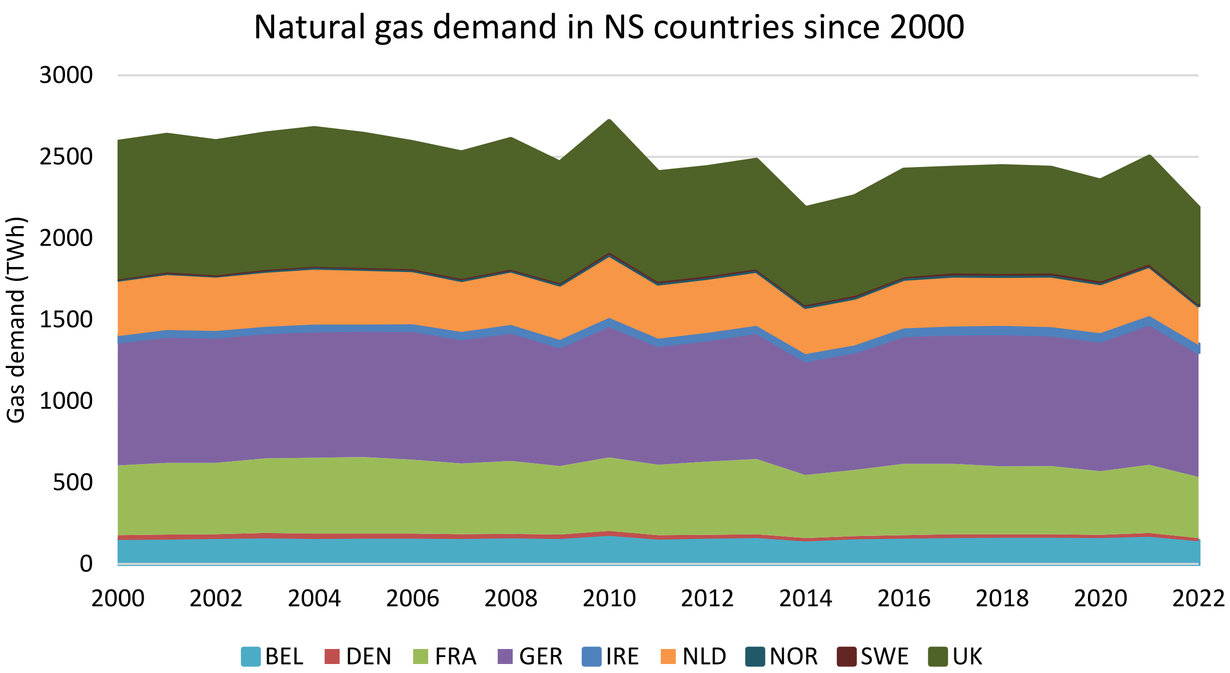

Figure 34 Natural gas demand in NS countries from 2000 to 2023. Source of data: IEA World Energy Statistics and Balances[115]

[115] https://www.iea.org/data-and-statistics/data-product/world-energy-statistics-and-balances

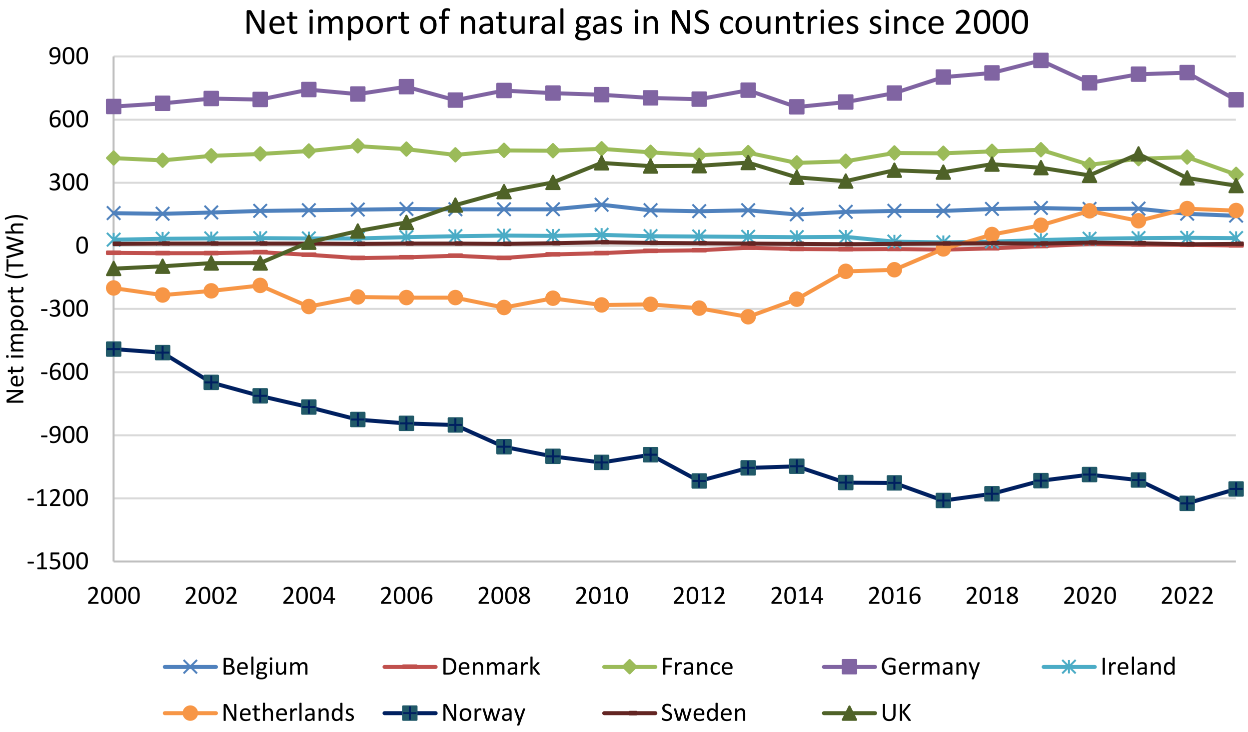

Figure 35 Import and export of natural gas in North Sea countries. The values represent imports (+) and exports (-), where positive numbers indicate net imports and negative numbers indicate net exports. Source of data: IEA World Energy Statistics and Balances[116]

Future state of play

Declining Natural Gas Demand: Outlook for 2030, 2040, and 2050
Natural gas demand is expected to decline in the coming years. The extent of this decline depends on different scenarios. By 2030, total demand could remain high at 1,900 TWh. In 2040, it could range between 850–1,250 TWh, and by 2050, between 400–550 TWh (**Figure 36**). Germany, the UK, and France are projected to have the highest natural gas demand among North Sea countries. As domestic natural gas production declines significantly in most countries—except Norway—these nations will increasingly rely on gas imports from Norway, LNG imports, or gas production through methanation.

[116] https://www.iea.org/data-and-statistics/data-product/world-energy-statistics-and-balances

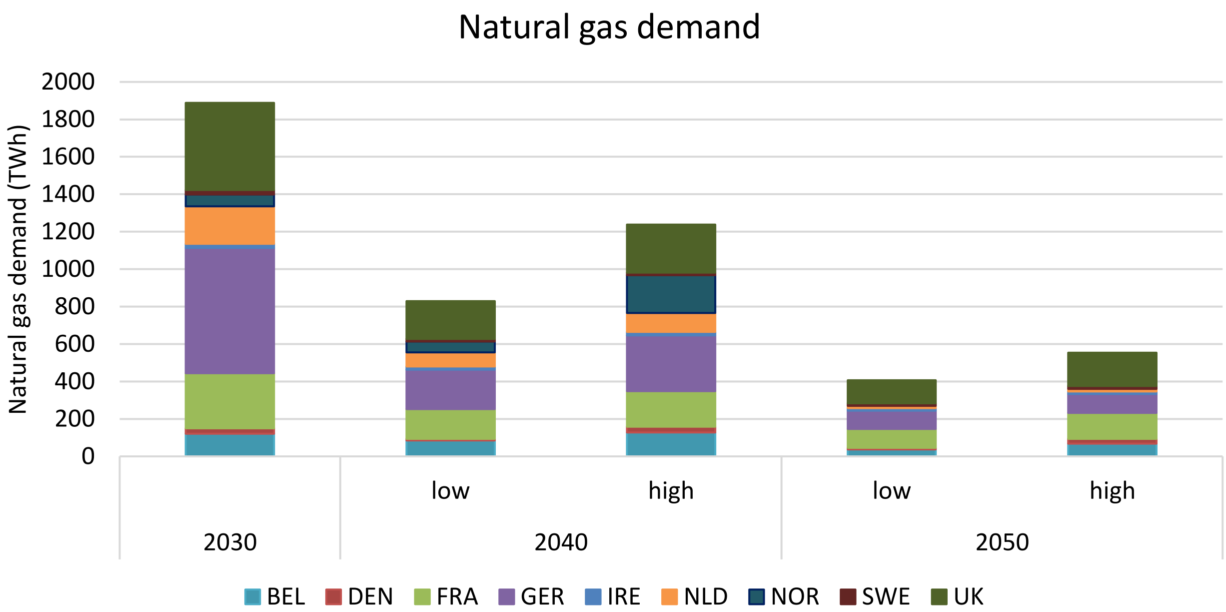

Figure 36 Estimated natural gas demand in the North Sea countries

Declining Offshore Gas Production in the North Sea: Preparing for a Sustainable Transition and Repurposing Infrastructure

Currently, offshore reserves in the North Sea are the main source of natural gas for countries like Norway, the UK, the Netherlands, and Denmark. However, gas extraction in the North Sea is expected to decline between 2030 and 2050 as many gas fields reach the end of their operational lifetime and exploration efforts to replace these volumes will decrease with the goal of reaching no production in 2050. On the other hand, European production stays important to avoid energy dependencies on other countries. The recently approved Sector Agreement on Gas Extraction in the Netherlands, for example, emphasizes the continued role of natural gas as a transition fuel until at least 2045, to reduce import dependency and ensure energy security[117]. **Figure 37** shows that natural gas production, currently at 1850 TWh across the five depicted countries, is expected to decrease to 900 TWh by 2050. Norway will see a slight decline in production, while all other countries will experience a significant reduction after 2040. These numbers are for the maximum production potential based on current reserves, as well as contingent and undiscovered resources. If, for any reason, these undiscovered resources fail to contribute to production, the decline will be even faster. In that case, gas production will drop to approximately 550 TWh by 2050, as indicated by the red dashed line.

[117] Sectorakkoord gaswinning in de energietransitie

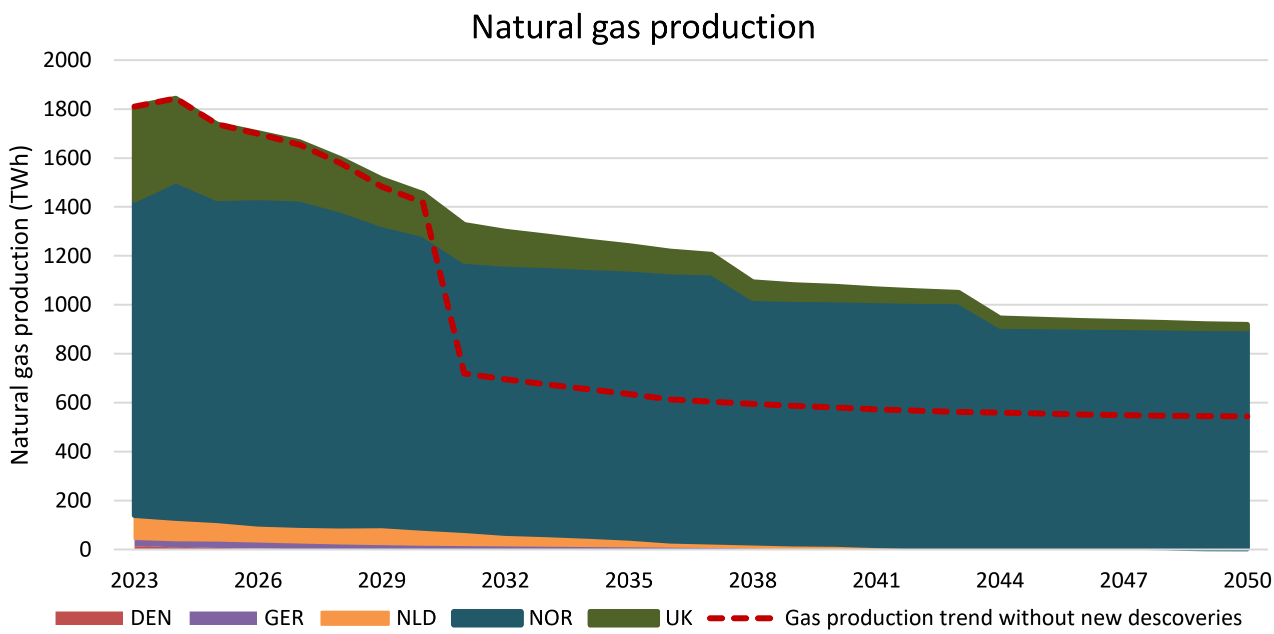

Figure 37 Natural gas production trend (reserves + contingent + undiscovered) until 2050 for the UK, Netherlands, Germany, Denmark, and Norway. The red dashed line represents the trend excluding undiscovered resources.

Decommissioning North Sea Oil and Gas Infrastructures: Over 2,700 Wells to be Decommissioned by 2033

As natural gas will see a gradual phase-out in the coming decades, a key element of offshore system integration will be the investigation of potential re-use of existing infrastructure—such as oil and gas reservoirs, platforms, pipelines, and wells—for new energy applications. These could include CO_2 and hydrogen storage and transport, as well as using platforms for green hydrogen production at sea. When this is not feasible, wells will be decommissioned, equipment dismantled, and materials will be recycled wherever possible.

Focusing on the main oil and gas producers in the North Sea—UK, Norway, the Netherlands, and Denmark—current plans and strategies forecast significant decommissioning of wells, platforms, and pipelines over the next decade. **Figure 38** shows the estimated number of wells to be decommissioned between 2024 and 2033. During this period, over 2,700 wells are expected to be decommissioned, with the majority in the UK (74%), followed by the Netherlands (14%), Norway (10%), and Denmark (2%)[118].

A similar distribution is expected for topsides and substructures. **Figure** highlights estimates for the same period, including the decommissioning of wells, topside mass, substructure mass, and pipeline distance. In total, approximately 1,200 million tons of topsides, 700 million tons of substructures, and 3,100 km of pipelines are projected to be decommissioned.

[118] https://oeuk.org.uk/wp-content/uploads/2024/11/OEUK-Decommissioning-Report-2024.pdf

UK Leads North Sea Decommissioning: GBP 2.4 Billion Annually and 200 Wells Per Year Over the Next Decade

The UK is a leader in decommissioning activities in the North Sea, with estimated expenditures exceeding GBP 2.4 billion annually over the next decade. It is predicted that decommissioning could account for one-third of total oil and gas expenditures by 2030. On average, 200 wells will be decommissioned each year, with well decommissioning representing nearly 50% of total spending during next decade. A key challenge for the UKCS in the coming decade is the potential clash between decommissioning plans and wind turbine installations, leading to competition for resources and personnel. This presents a significant opportunity for collaboration, where sharing work programs, assets, and expertise can help ensure efficient execution and mutual benefit.

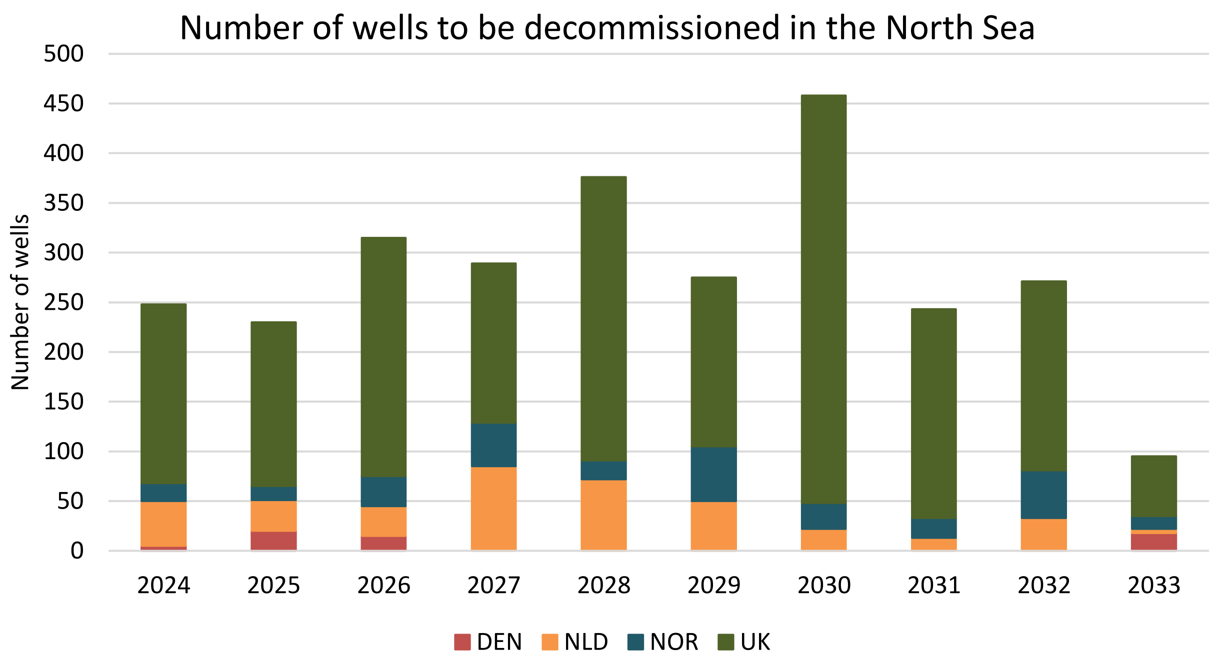

Figure 38 Predicted number of wells to be decommissioned by country in the North Sea between 2024 and 2033[119]

[119] https://www.nexstep.nl/wp-content/uploads/2024/06/NEXSTEP-Re-use-Decommissioning-report-2024.pdf

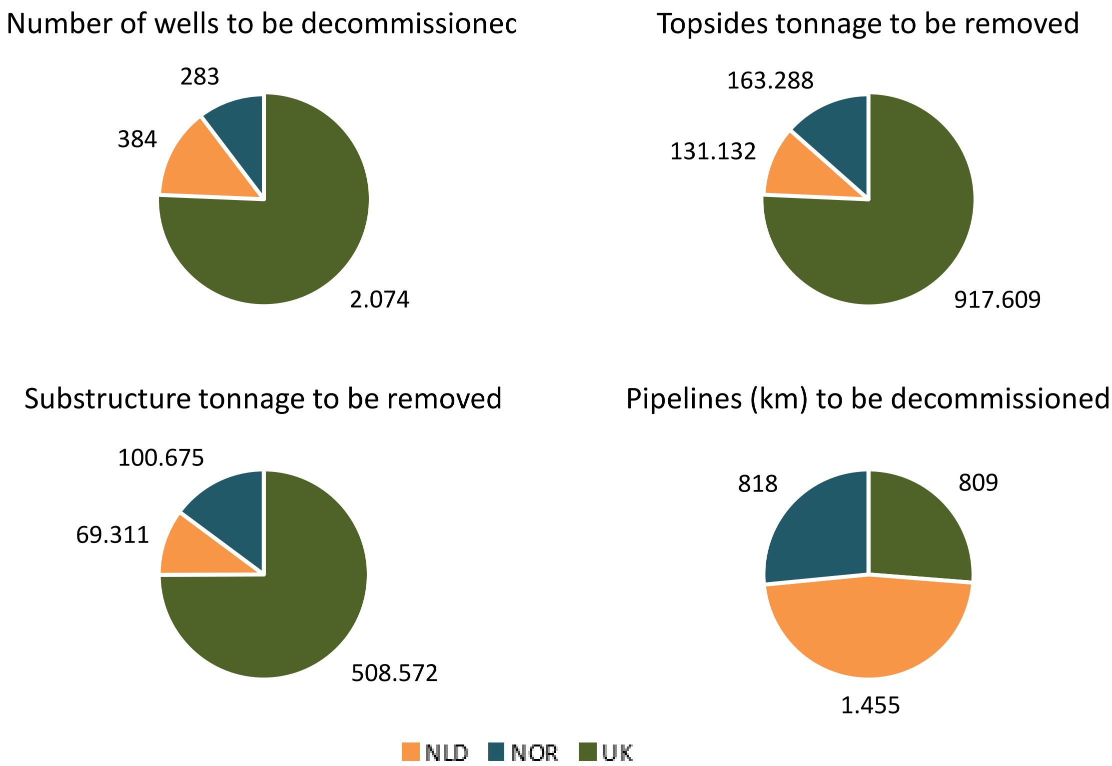

Figure 39 Decommissioning of offshore infrastructure in the North Sea by the three main oil and gas producers—Norway, the UK, and the Netherlands—during the period 2024-2033. The infrastructure includes wells, platforms (topsides and substructures), and pipelines[120]

Dutch Sector Decommissioning: EUR 300 Million Per Year and Two-Thirds of remaining Wells to be Decommissioned in the Next Ten Years

The Netherlands has also seen an increasing trend in decommissioning activities in recent years, which is expected to continue. However, the scope of decommissioning in the Dutch sector is relatively small compared to the entire North Sea portfolio, as the tonnage to be removed is approximately 10% of the regional total. Over 60% of all offshore wells drilled in the Netherlands have already been decommissioned. It is expected that two-thirds of the remaining wells will be decommissioned over the next decade, with an average of 40 wells per year. The average annual expenditure on decommissioning in the Netherlands is projected to reach EUR 300 million over the next decade, with well and platform decommissioning each comprising 40% of the total[121].

Repurposing Oil and Gas Infrastructure: Opportunities and Challenges

Oil and gas infrastructure suitable for repurposing or reuse could include terminals, platforms, subsea structures, pipelines, and wells. These assets can be repurposed for applications such as CCS, offshore hydrogen, and renewable energy sources. Operators intending to repurpose these assets

[120] https://www.nexstep.nl/wp-content/uploads/2024/06/NEXSTEP-Re-use-Decommissioning-report-2024.pdf

[121] https://www.nexstep.nl/wp-content/uploads/2024/06/NEXSTEP-Re-use-Decommissioning-report-2024.pdf

must assess the repurposing option prior to initiating decommissioning plans. This evaluation must address constraints and challenges across various dimensions, including technical and engineering feasibility, regulatory compliance, commercial viability, and economic considerations[122]. While repurposing can reduce waste and offer time and cost efficiencies for new users, ongoing projects have shown that reuse is not always feasible or straightforward. For example, platforms and wells may be too old, or reuse may be more technically challenging when platforms are still in use, making simultaneous operations—such as gas production and CO_2 injection—quite complicated. Liability poses a common challenge in the decision process as well. Additionally, conversions can sometimes be more expensive than building new facilities, as new builds often provide greater flexibility for project requirements.

Electrification of Offshore Platforms: A Path to Emission Reduction. Norway Leads, Netherlands and UK to Follow

Electrification has the potential to significantly reduce emissions from offshore assets and plays a vital role in advancing net-zero ambitions in the North Sea. While it is already being implemented in Norway, the Netherlands and the UK are also planning to adopt this concept in the near future. Electrifying hydrocarbon production platforms involves meeting their energy requirements, primarily for processing and compression, using electricity. At present, most of this energy is generated by gas-fired turbines, which are relatively inefficient. By transitioning to electrification, these turbines or engines are replaced, leading to reduced energy consumption and significant cuts in CO_2 and NO_x emissions. Connecting platforms to a renewable energy hub via cables ensures a stable and reliable power supply while enhancing energy security[123]. However, it might not always be technically and economically feasible to electrify platforms, especially when they are close to their end of life.

Platform Electrification Projects: Three Case Studies from Norway, the Netherlands, and the UK

In Norway, Equinor has begun power-from-shore operations at the Troll B and C platforms since September 2024. Electricity is supplied from Kollsnes, northwest of Bergen, via a 132-kV power cable. The platforms' processing and energy-intensive systems now run entirely on electricity, though the large export compressors remain gas-powered. This shift reduces CO_2 emissions from the Norwegian Continental Shelf (NCS) by 250,000 tonnes annually under the Troll West Electrification (TWEL) project. The next step is full electrification, starting with the Troll C platform and potentially followed by Troll B. Troll A (Troll East) was the first platform on the NCS to use shore-based power, operating this way since its start in 1996[124].

In the Netherlands, the first offshore platform powered entirely by wind energy will be N05-A, operated by ONE-Dyas. The platform is located about 20 kilometers north of Borkum Island, and its

[122] https://www.nstauthority.co.uk/Regulatory-Information/decommissioning-and-repurposing/repurposing/
[123] https://publications.tno.nl/publication/34636747/ENOdsN/NSE-2020-unlocking.pdf
[124] https://www.equinor.com/news/20240911-reducing-emissions-troll-field

electricity will come from the nearby Riffgat Wind Farm. This initiative will make natural gas extraction cleaner and more sustainable. The project is expected to start in 2025[125].

Figure 40 The N05-A platform in the Dutch part of the North Sea, with the nearby German offshore wind farm Riffgat in the background. [ref: the same as one days website]

In 2022, power generation accounted for 79% of emissions from UK offshore production, highlighting the significant potential for reducing power-related emissions. Electrifying both new and existing platforms could result in carbon savings of up to 22 million tonnes by 2050[126]. One of the demonstration projects is TotalEnergies' pilot, which involves a 3 MW floating wind turbine to provide renewable energy to the Culzean offshore platform in the UK North Sea. The turbine will supply around 20% of the platform's energy needs, with the remaining power coming from the existing gas turbines[127].

4.2 Grid vision 2050

The natural gas grid in the North Sea by 2050 is expected to be significantly smaller than it is today. Many platforms, wells, and pipelines will likely be decommissioned in the coming years, although some may be repurposed for alternative offshore activities. A limited number of facilities will remain for oil and gas operations, primarily in Norway, as hydrocarbon production in the UK and the Netherlands is projected to decline significantly after 2040. However, if contingent and prospective resources are

[125] https://onedyas.com/wp-content/uploads/2024/08/20240814-PR-Planfeststellungsbeschluss-N05-A-EN-website.pdf
[126] https://www.nstauthority.co.uk/news-publications/nsta-convenes-collaborative-workshop-on-platform-electrification-to-cut-north-sea-emissions/
[127] https://totalenergies.com/news/press-releases/united-kingdom-totalenergies-launches-floating-offshore-wind-pilot-project?utm_source=chatgpt.com

brought into production, the decline in hydrocarbon output could slow and potentially extend beyond 2040.

Some pipelines can be repurposed if they overlap with future offshore activities. One solution is to reroute natural gas into a single pipeline, making the other available for hydrogen or CO_2 transport. Note that there is no clear indication of what the grid will look like in 2050. However, by removing decommissioned and repurposed pipelines from the current natural gas grid, the remaining infrastructure could represent the natural gas grid for 2050.

4.3 Commodity specific actions

Actions on natural gas

Set targets for natural gas

There has been significant uncertainty on the production and consumption of natural gas in the North Sea countries. A long-term strategy defining country-level outlook and targets for the production, import, storage and consumption of natural gas is needed to remove the volatility currently surrounding the role of natural gas in the energy mix. This is especially relevant since the production timeline impacts the decommissioning possibilities of the natural gas assets is a required input for the further development of CCS and hydrogen. Reliable policies should be developed that provide clarity for at least the next two decades.

Enable the electrification of offshore hydrocarbon production

As long as hydrocarbon assets are still active within the North Sea, electrifying its assets decreases the carbon footprint of natural gas production and transport. Several pilot and demonstration projects are already being put in place, such as Neptune Energy's Q13a-A platform and ONE-DYAS N05 platform, but large scale deployments still have to develop. Technical and economic feasibility studies should provide clarity when electrification is feasible.

Actions on natural gas grid

Key Actions for a Sustainable Future in the North Sea

Short-term actions (< 1 year)

- Certification of existing pipelines for hydrogen and or CO_2 transport and preparing the existing infrastructure and pipelines for reusing in terms of market and legal arrangements
- Importance of safety measures and dynamic lifetime assessments for reused pipelines.
- Enhance monitoring of existing natural gas infrastructure for security and integrity monitoring against external threats and suitability for reuse.
- Early phase pipeline ownership structures for repurposed pipelines
- Improve data availability of decommissioning timelines for centralized grid planning in the North Sea basin
- Phase out and preservation planning for existing pipelines

Mid-term actions (< 5 year)

- Develop strategy for de-commissioning and re-use of legacy infrastructure: As gas production declines in the future, the re-use and co-use of existing gas assets like platforms and infrastructure like pipelines can extend the life of assets and reduce the overall system cost needed to develop an integrated offshore energy system. However, the absence of a clear strategy about which assets are to be necessarily decommissioned and which can be re-used for other purposes, adds an additional layer of uncertainty for investors and asset owners in planning their investments. Such a strategy needs to be designed with a special focus on the timelines of when the assets and infrastructure are planned to be decommissioned so that decisions about potential re-use/co-use can be made in a timely manner. Next to this, the strategy should focus on commercial and legal aspects to make re-use economically viable for the asset owner.

- Develop a strategy to evaluate and implement re-routing requirements of natural gas infrastructure for CO_2 and hydrogen reuse.
- Capacity mapping of supply chain issues for decommissioning peaks in the next decades