Comparison of system variants for hydrogen production from offshore wind power

Short study based on the AquaVentus vision:
10 GW offshore electrolysis capacity in the German exclusive economic zone by 2035

March 2022

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Sponsors

This study was commissioned by a consortium of RWE, Gasunie, Gascade, Equinor and Shell. The consortium acts as part of the AquaVentus association which pursues the goal of promoting climate-friendly hydrogen technologies globally. The AquaVentus association is supported by organisations and research institutes as well as by leading international companies proclaiming a new age of climate-friendly energy based on the production of green hydrogen at sea.

Authors

The study was prepared by AFRY Management Consulting, a leading business and strategy consultancy for the sectors of energy, forestry and bio-industries. AFRY's team of more than 500 consultants in 17 locations on 3 continents provides strategic and operational consulting services along the entire energy value chain, underpinned by deep technical and market expertise and an extensive industry network.

AFRY Management Consulting is part of AFRY ĂF Pöyry Group, an international engineering and consulting firm with over 17,000 experts in the sectors of infrastructure, industry and energy.

Executive Summary

The AquaVentus initiative has defined the vision to establish an electrolysis capacity of 10 gigawatts (GW) in the exclusive economic zone (EEZ) in the German Bight by 2035 to produce green hydrogen.

In this context, the objective of this short study is to evaluate technical system variants for feeding the hydrogen from this production capacity into the future German hydrogen grid. The study compares two systems based on offshore electrolysis and one system with onshore electrolysis. For hydrogen produced at sea, a distinction is made between "Offshore Hydrogen Production & Pipeline Transport" and "Offshore Hydrogen Production & Ship Transport". In addition, a system with "Submarine Cable & Onshore Hydrogen Production" is considered. The comparison of these alternatives is based on three critical success factors:

- Time required for planning and implementation
- Capital expenditure and operating costs
- Environmental impact and permitting complexity

The study is based on the assumption that the entire system will be newly constructed without limitations arising from existing systems such as pipelines in the area or any restrictions that may arise from the political discourse.

The analysis of planning and implementation times shows that offshore electrolysis with pipeline promises a significantly shorter implementation time than the variant with submarine cables and onshore electrolysis. Assuming sequential component procurement/production, installation and commissioning, the pipeline variant results in a project completion after about nine years. In comparison, the submarine cable variant requires just over 13 years until completion and does not achieve the 2035 expansion target.

A similar result is observed for the offshore hydrogen production & ship transport variant. In this variant it is uncertain if the tanker capacity that can be provided by 2035 will meet the required transport capacity. The prototype liquified hydrogen tanker currently in operation carries about one-hundredth of the LNG volume of a typical LNG tanker. The construction of many small tankers from 2023 onwards would tie up a substantial part of existing international shipyard capacity, while waiting for larger tankers would result in significant uncertainty regarding timely availability. The demand would then be clustered over only a few years before 2035 and could potentially not be met by shipyards. In both cases, the expansion target would be endangered.

The time advantage of the pipeline option is mainly due to the significantly shorter pipeline length of 610 km compared with 3,720 km of high-voltage DC lines. In the pipeline variant, the construction of the offshore electrolysis capacity is on the critical path, while in the submarine cable & onshore hydrogen production variant, the construction of the cable system determines the required time.

The parallel construction of up to ten offshore electrolysis platforms per cluster in the two variants with offshore electrolysis poses a significant implementation risk that needs to be minimized by early involvement of suppliers and securing manufacturing and installation capacity.

The calculated total system costs and resulting costs are lowest for the variant with offshore hydrogen production & pipeline transport. The total system costs are about

six billion euros (17%) lower than for the submarine cable & onshore hydrogen production variant. The specific system cost per kilogram of hydrogen is EUR 2.7/kg H_2, which is EUR 0.50/kg H_2 (15%) lower than in the submarine cable & onshore hydrogen production variant.

The cost analysis uses current prices for electrolysers. If stronger cost reductions over the study's timeframe are assumed for this technology, both the total system costs and the specific system costs per kg of hydrogen decrease. However, the cost gap between the variants remains unchanged because the same technology is used in all three variants.

From an environmental and permitting perspective, offshore hydrogen production & pipeline transportation is preferable to the other two variants as well.

For submarine cable & onshore hydrogen production, there is a risk of conflicts of interest with the local population and interest organisations. These conflicts may not just delay the project but fundamentally endanger the implementation success. Prolonged project delays and costly lawsuits are considered likely. In addition, the discharge of brine into the tidelands is unlikely to be approvable. The technical possibilities for further onshore processing of brine are limited in terms of quantity and not economical based on the current state of technology and offtake markets.

The offshore hydrogen production & ship transport variant avoids the conflicts of interest related to large onshore electrolysis sites and the nearshore discharge of brine. However, expansion or additional construction of the necessary port and offloading facilities may lead to local conflicts of interest as well. In addition, shuttle traffic with large tankers burdens the already heavily used traffic area of the German Bight. Unlike the other variants it also carries the risk of disruptions due to maritime accidents and ship averages. Building a large number of tankers is even more complex than procuring the resources for the cables and increases the procurement and ESG risks along the supply chain. Finally, tankers emit sound, CO_2, and/or other particulates depending on the propulsion technology. In contrast, pipelines and submarine cables can be operated free of CO_2emissions using electricity from wind turbines and, in the case of pipelines, hydrogen as a complementary fuel. Their operation is emission-free and typically does not cause direct damage to third parties in the event of a malfunction, unlike a ship average.

Offshore hydrogen production & pipeline transport is free of these risks. Although pile driving for the foundations of the offshore installations will result in increased noise emissions during construction, they can be contained with proven systems.

Overall, offshore electrolysis & pipeline transport emerges as time-efficient, lowest-cost and most environmentally & permit-friendly among the three appraised system variants for the setup of 10 GW of hydrogen production capacity including grid connection by 2035.

From a strategic perspective, this variant offers a further, more fundamental advantage. The expected electrolysis capacity required for the German energy transition significantly exceeds the 10 GW target used for this study. As the Doggerbank area alone offers space for over 100 GW of capacity (including Royal Haskoning DHV, 2017), additional capacity could be developed in close vicinity to the envisaged pipeline route. The assumed pipeline dimension is large enough to accommodate additional hydrogen volumes generated in this area without changing the pipeline itself. In the other two variants, even relatively small additional energy volumes would require additional submarine cables or tankers.

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1 Introduction

1.1 Initial Situation

The AquaVentus initiative aims to use climate-friendly hydrogen technology to support the achievement of Germany's energy and climate goals. As an emission-free alternative to oil and natural gas, green hydrogen is central to the energy transition. To this end, the project envisions to build an electrolysis capacity of 10 gigawatts (GW) by 2035 to produce green hydrogen. With this capacity, up to one million tonnes of hydrogen could be produced annually. The project is to be implemented in the German Exclusive Economic Zone (EEZ) in the North Sea.

The AquaVentus initiative is supported by a wide range of organisations and research institutes as well as international companies aiming to produce green hydrogen at sea to contribute to the transition to a new age of climate-friendly energy. To further advance the initiative, a consortium of five members of the AquaVentus association has mandated AFRY Management Consulting to prepare this short study to evaluate different technical system variants.

1.2 Scope and objectives

The backdrop of this study is set by the debate around offshore and onshore hydrogen generation and which technical setup is best-suited to achieve the AquaVentus vision. To this end, two technical concepts for offshore hydrogen generation and one technical concept for onshore hydrogen generation were analysed and compared with regard to their implementation time, investment and operating costs, as well as their environmental impact and permitting complexity. Based on these comparison criteria, the study outlines the relative advantages of onshore and offshore hydrogen generation in the assumed system setups. The results are meant to contribute to the public discourse on solutions for a successful energy transition in Germany.

1.3 Hypotheses

Based on the study’s objective, three initial working hypotheses were established, which were to be validated or disproved:

1. Hypothesis: The combined use of offshore electrolysis with a pipeline system enables a faster development of offshore wind farms compared to the use of power cables. Thereby, the potential of offshore wind energy can be exploited faster and deliver a higher contribution to the expansion targets for Renewable Energies for 2030 and 2035.
2. Hypothesis: Offshore hydrogen production in the remote wind fields of the German EEZ in combination with pipeline transport or ship transport of the hydrogen offers cost advantages compared to a cable connection of the wind farms in combination with onshore electrolysis.
3. Hypothesis: As submarine cables are typically installed in 2 GW systems, a total transport capacity of 10 GW of electrical power requires multiple cable routes, placing increased strain on the sensitive ecosystem of the North Sea. The construction and operation of a single pipeline with comparable total energy transport capacity has lower environmental impacts along the pipeline route with associated advantages in terms of permitting complexity.

2 Considered technical setups

2.1 Overview

In this study, three basic technical systems for achieving the AquaVentus vision were considered and compared. The reference point is formed by the offshore wind areas N-17 and N-19 in the German EEZ, which are assumed to provide the electricity for the 10 GW of electrolysis capacity. In system 1, sea cables transport the electricity to the mainland where the hydrogen is produced and fed into the proposed initial German hydrogen grid (*"Startnetz H_2"*). System 2 describes the production of hydrogen on offshore platforms and the transport to the German hydrogen grid through a pipeline. In System 3 the hydrogen is also produced offshore, but it is transported to the mainland by ship and then transported from the port to the *Startnetz H_2* via pipeline. The components of all three systems are dimensioned for a total electrolyser capacity of 10 GW. Since the two considered wind areas, N-17 and N-19, are not sufficient at peak load to fully utilize this electrolyser capacity, areas N-18.3 and N-20.1 are additionally included (see Exhibit 1). The resulting cluster was defined as N-17* for the purposes of this study.

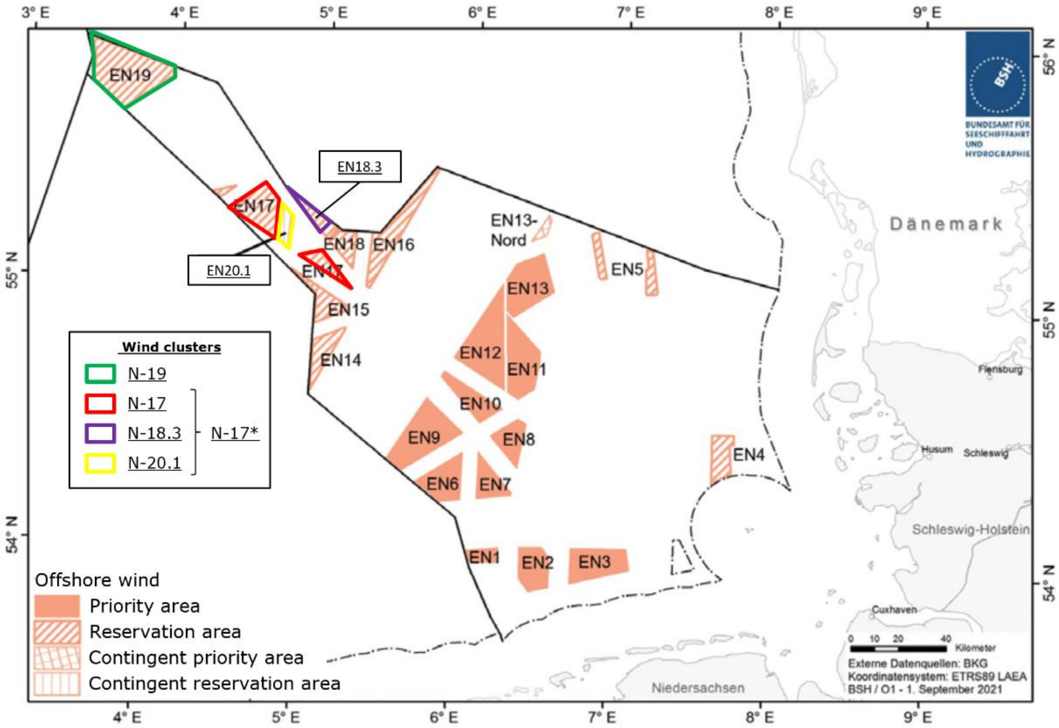


Exhibit 1: Map extract from Offshore-Wind Raumordnungsplan 2021

A greenfield approach was assumed for all three systems, i.e. each entire system is assumed to be newly planned and constructed, without use of potentially existing infrastructure. Potential obstacles constituted by existing infrastructure in the EEZ were ignored. Other potential framework conditions like military training areas of the German Navy were not taken into account either.

The designs of the three technical systems are presented in the following sections. They form the basis for the following chapters. Each system is described with its individual elements along the transport chain and their dimensioning, subdivided into offshore and onshore. It should be noted that the three presented systems are exemplary technical designs and that other designs are conceivable as well.

2.2 Submarine Cable & Onshore Hydrogen Production

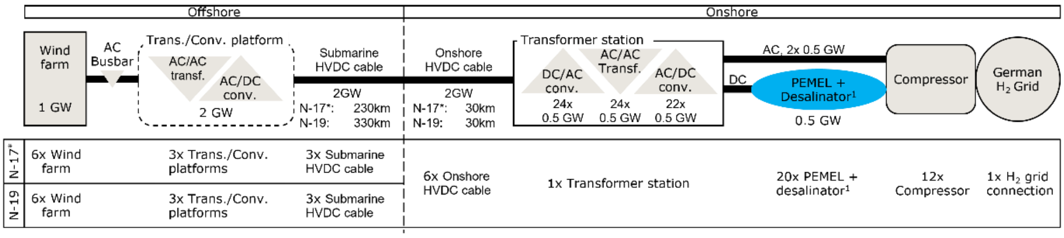


Exhibit 2: Technical setup for submarine cable & onshore hydrogen production

Offshore

The submarine cable & onshore hydrogen production system starts with six wind farms in area N-17* (1 GW each) and six wind farms in area N-19 (1 GW each). The generated electricity from each wind farm is bundled and routed via a busbar to six offshore platforms, three in each area. The platforms are equipped with transformers that adjust the voltage and convert it into direct current. From each platform, the electricity is transported via a high-voltage direct current (HVDC) submarine cable to the landing point in Krummhoern. This connection point was chosen for a pragmatic connection of the system to the proposed *Startnetz H_2*. Other connection points are possible as well but due to the geography of the coastline relative to the wind power fields, the distances would not change in a way that would change the study results.

In the chosen geographical layout, the cables of the N 17* platforms have a length of 230km, while the cables of the N 19 platforms measure 330km.

Onshore

From the landing point, six HVDC underground cables transport the electricity over 30km to the onshore electrolysis site, which is located directly at the feed-in point to the *Startnetz H_2* hydrogen grid. Here, the electricity is converted to AC, transformed to the required voltage level, converted back to DC and transferred to a Proton Exchange Membrane Electrolyser (PEMEL). The PEMEL consists of 20 individual units with a capacity of 0.5 GW each. Water supply is provided by a seawater feed and a desalination plant. To accommodate the volatility of wind power generation and the need for load-flexible operation, a vapour-compression system (*Brueden* compression) is used. The hydrogen is then compressed to the required pressure level of 50 bar using compressors and fed into the hydrogen grid. The compressors are operated with AC that is diverted at the DC-AC conversion stage.

2.3 Offshore Hydrogen Production & Pipeline Transport

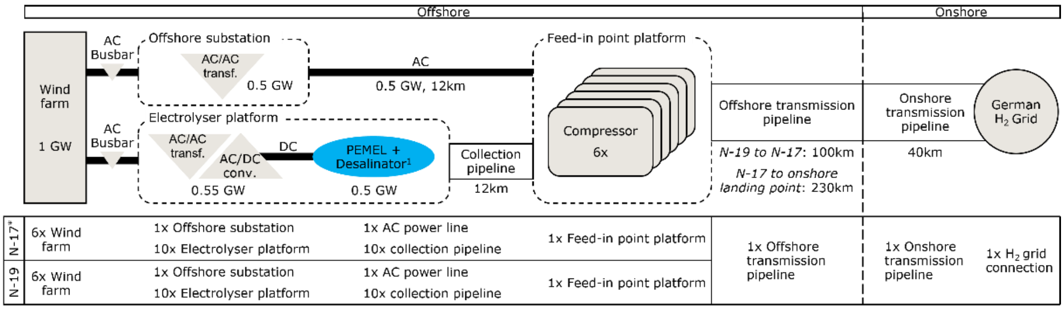


Exhibit 3: Technical setup for offshore hydrogen production & pipeline transport

Offshore

As with the first variant, the transport chain for offshore hydrogen production & pipeline transport starts with six wind farms in Area N-17* (1 GW each) and six wind farms in Area N-19 (1 GW each). The generated electricity is bundled and routed via a busbar to 10 offshore electrolyser platforms, each carrying a transformer with a converter (0.55 GW each), a PEMEL (0.5 GW each) and a vapour-compression seawater desalination plant. A part of the generated electricity is routed to a transformer platform, which transforms the voltage to power the operating equipment at the central offshore feed-in points of the pipeline. Each electrolyser platform feeds the produced hydrogen into a collection pipeline (length 12km) to these central feed points (one each for N-17* and N-19) using the PEMEL exit pressure of 30 bar without additional compression. In parallel, the electricity from the transformer platform flows to the feed-in point via an AC cable to power the required technology. At the feed-in point, the collection pipelines converge into a compressor facility that brings the hydrogen to an operating pressure of 70 bar and feeds it into the transport pipeline.

The central transport pipeline is routed from Area N-19 via Area N-17* to the onshore landing point in Krummhoern. Alternative landing points are possible, as described above, as long as they allow a comparably efficient connection to the hydrogen grid.

In the assessed case, the length of the pipeline from cluster N-19 to cluster N-17* is 100km and the further length from N-17* to the landing point is 230km.

Onshore

From the onshore landing point, an onshore pipeline transports the hydrogen over a distance of 40 km to the feed-in point into the German hydrogen grid where it is fed in without additional compression, with a residual pressure of 50 bar.

2.4 Offshore Hydrogen Production & Ship Transport

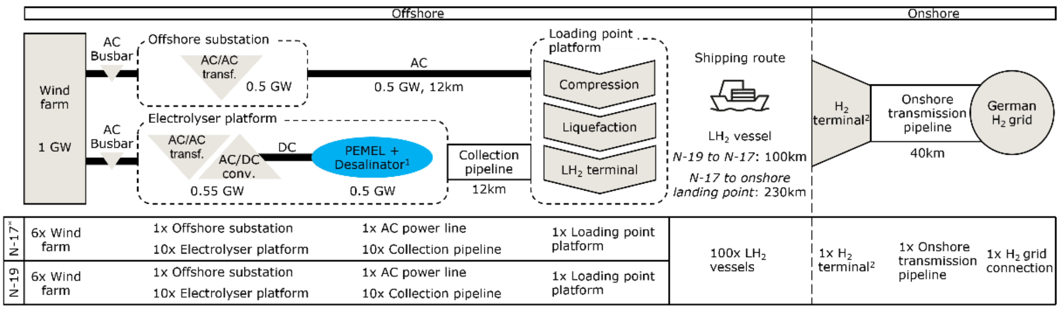


Exhibit 4: Technical setup for offshore hydrogen production & pipeline transport

Offshore
For offshore hydrogen production & ship transport, the transport chain to the central loading points is the same as with of offshore hydrogen production & pipeline transport: the chain starts with six wind farms in Area N-17* (1 GW each) and six wind farms in Area N-19 (1 GW each), from each of which the generated power is bundled and routed via a busbar to 10 offshore platforms, each carrying a transformer and converter (0.55 GW each), a PEMEL (0.5 GW each) and a vapour-compression seawater desalination plant. In parallel, a portion of the generated power is routed to a substation platform, which transforms the voltage to power the operating equipment at the central offshore ship-loading points. From each electrolyser platform, hydrogen is transported at 30 bars via a collection pipeline (length 12km) to a central feed point (one each for N-17* and N-19). In addition, from the substation platform, power is routed via an AC cable to the central loading point to provide power to the equipment. In contrast to the offshore hydrogen production & pipeline transport variant, the central loading point houses a liquefaction plant that compresses and liquefies the hydrogen at -253 °C. Furthermore, a ship-loading terminal is located at the platform to pump the liquid hydrogen onto the tankers. After loading a ship, the hydrogen is transported to the port in Brunsbüttel.

This landing point differs from the one in the two other system variants since landing liquid hydrogen in a deep-water port close to the Elbe mouth seems more plausible than in the shallower vicinity of the Ems mouth, where an existing natural gas pipeline already makes landfall. Since the distances to the N 17* and N 19 are similar and the *Startnetz* H_2 can be reached from Brunsbüttel with a comparable connection distance, the system comparison stays valid with this difference. Alternative landing points are possible, as described above, as long as they allow a comparably efficient connection to the hydrogen grid.

Assuming a transport vessel of the size of *Kawasaki Heavy Industries*' first liquid hydrogen tanker *Suiso Frontier* (1,250 m^3) and the restriction that there is no space for large-scale hydrogen buffer storage on the collection platforms due to limited space availability, tankers are assumed to operate permanently with turnaround times of about four days. Due to the lack of intermediate storage facilities, at least one ship must always be at the loading point of each of the two collection platforms. This results in an estimated requirement of more than 100 tankers. If larger ship sizes are developed, less tankers are needed.

Onshore
In the mainland port, the ship is unloaded at a hydrogen terminal. The liquid hydrogen is converted back into gaseous form using a regasification plant. The hydrogen is then brought to a pressure of 50 bar with compressors and transported over 40 km to the feed-in point at the *Startnetz* H_2 hydrogen grid via an onshore pipeline, where it is fed in without further compression.

3 Description of work packages

3.1 Overview

Based on the three initial hypotheses (see chapter 1.3) and the assumed technical system designs (see chapter 2), the implementation time, investment and operating costs as well as environmental compatibility and permitting complexity of the different systems were compared in three individual work packages. These work packages were defined together with the consortium. Their content is described in the following sub-sections.

3.2 Work package 1: Comparison of implementation period

In the first work package, the implementation times of submarine cable with onshore hydrogen production and offshore hydrogen production with pipeline transport were analysed and compared. To this end, the transport chain was divided into three parts: a) a hydrogen-producing system, b) an interface system, and c) a transport system. For each system component, the technology maturity, supply chain maturity, and resource availability were assessed in a first work step. As second step, the implementation times for design, approval, production, installation, and testing and commissioning were estimated for each system component, based on research and expert interviews. Subsequently, the individual analyses were combined to determine the total implementation time and to identify the critical path per system.

The study scope did not include an appraisal of the implementation time for offshore hydrogen production with ship transport.

3.3 Work packages 2: Comparison of investment & operating costs

In the second work package, the investment and operating costs of all three systems were determined and compared. For the quantitative evaluation of the technical systems, the individual components of each system were evaluated with their specific capital costs and a comparison of the total system costs was made on this basis. In a second step, the specific system costs per kilogram of hydrogen were analysed, taking operating costs and service life of the respective facilities into account. Costs of power generation and decommissioning of the systems were not included in the comparison.

For the offshore electricity production, the N-17* and N-19 clusters were used as reference points. The possibility of pipeline and cable building along suitable routes was assumed. The figures used in the study refer to 2022 as the start year for the project activities and are expressed in EUR of 2021.

3.4 Work package 3: Comparison of environmental compatibility and permitting complexity

In order to analyse the environmental impact of the planned systems and evaluate the approval under licensing law, qualitative criteria relating to construction and operation were considered. For this purpose, existing studies on offshore pipeline construction, offshore cable laying and the results of own studies were compared and evaluated. Additionally, complementing comparison criteria were used for the qualitative examination of the systems.

For a more in-depth assessment of the environmental risk, a biodiversity screening was performed. This screening follows the IFC Performance Standard 6 of the World Bank and checks the project area for the distribution of protected species, designated protected areas and areas of special biodiversity.

4 Comparison of Implementation Times

4.1 Methodology

The system variants for submarine cable & onshore hydrogen production and for offshore hydrogen production & pipeline transport were assessed in terms of technological and supply chain readiness and resource availability. This assessment structure allows a targeted consideration of time buffers, e.g. for licensing procedures or the provision of production capacities.

For offshore hydrogen production with ship transport, the required short-term project start in order to achieve the expansion targets by 2035 would require the co-use or even exclusive use of existing types and technologies for hydrogen tankers. This type of ship is currently still in pilot operation and not scaled to commercially viable size. A known example is the *Suiso Frontier* that runs in pilot operation between Japan and Australia, with a loading capacity of 1,250 cubic metres of liquid hydrogen that is very small compared to current LNG tankers. In the future, the use of tankers with a larger loading capacity is necessary to achieve economies of scale. Due to the large number of tankers required with current technology, the unclear waiting time until technical and constructional availability of larger tankers and the associated limited plannability of appropriate loading and unloading facilities, the implementation perspective of this option appears doubtful with regard to the targeted 10 GW set-up by 2035. This system variant is therefore not considered in the following chapter.

The system variants submarine cable with onshore hydrogen production and offshore hydrogen production with pipeline transport were each divided into three essential system components for the analysis of the implementation time: a hydrogen-producing sub-system, an interface system to the transport system and the transport system itself. Wind farms and the AC busbars leading away from them were not explicitly considered in this chapter since they do not differ among the system variants and are thus not relevant for the system comparison. The implementation time for the analysed components was considered and calculated along five project phases that correspond to the usual sequence of this type of energy infrastructure projects: Design and Planning, Consents and Permits, Production, Installation and, finally, Testing and Commissioning.

The analysis of the implementation time of both schemes follows a bottom-up approach and is based on qualitative and quantitative analysis of publicly available data as well as AFRY internal expertise for the respective sectors, technologies and projects. For the planning, the 10 GW expansion target until 2035 was set as a critical target and all projects were assumed to start in 2023, with all production and installation processes aligned to this start year. For the system components, the earliest possible start of all processes was assumed to build partial capacities as quickly as possible and then commission them consecutively.

4.2 Implementation-critical assessment of technologies, supply chains and resource availability

Before analysing the implementation times for the different systems, the technologies for each system component were analysed, assessing the readiness levels of the technologies as well as the supply chains. In addition, an availability assessment of the necessary resources, such as raw materials, capacities at service providers or production capacities, was performed. This assessment was used to add buffers into the implementation planning, to develop a plausible overall picture of the expected time requirements with regard to the current state of knowledge. The assessments for onshore and offshore hydrogen production are presented separately here-below.

The following rating scales were applied:

- Technology Readiness Level (TRL)
  - 5 – Proof of function in simulated environment
  - 6 – Demonstration in simulated environment
  - 7 – Demonstration of prototype (system) in operational environment
  - 8 – Qualified system with proof of function in operational environment
  - 9 – Qualified system with proof of successful operation
- Supply Chain Readiness and Availability of Resources
  - Red – High risks respectively long delays expected
  - Yellow – Moderate risks respectively delays expected
  - Green – No risks respectively delays expected

Submarine Cable & Onshore Hydrogen Production

In the onshore environment, many system components are used that have already been tested and deployed in other projects and installations in the fields of wind energy or hydrogen generation. Most of the technological and supply chain readiness levels are thus considered to be advanced, meaning that technologies and processes are already established and, taken as a whole, present a comparatively low aggregate risk. This makes planning and implementing the projects easier and more reliable. On the other hand, potentials for future system optimisation and shortening of planning times are expected to be lower.

The onshore hydrogen production system consists of transformers, converters, seawater desalination plants and electrolysers and was rated with an overall technical maturity level 7. A key challenge for this system configuration is the purification and desalination of seawater and the subsequent return of the brine to an environmentally sensitive environment. In addition, there are challenges for suppliers to adapt the use of a seawater desalination plant to the requirements of hydrogen production. A time buffer in the phase of design and system integration is therefore taken into account. As the demand for system components for offshore wind power and hydrogen production will increase in the future, bottlenecks in resources and capacities for services, manufacturing and installation are expected.

System Components	Technology Readiness	Supply Chain Readiness	Availability of Resources
Onshore H_2 System	5 6 **7** 8 9	Yellow	Yellow
Onshore trafo/converter	5 6 7 8 **9**	Green	Yellow
Onshore desalinator	5 6 7 **8** 9	Yellow	Yellow
Onshore electrolyser	5 6 7 8 **9**	Green	Yellow
Onshore H_2 compressor	5 6 7 8 **9**	Green	Yellow
Offshore trafo/converter	5 6 7 8 **9**	Green	Yellow
HVDC submarine cable	5 6 7 8 **9**	Green	Red, Yellow

Exhibit 5: Technology readiness, supply chain readiness and availability of resources of submarine cable & onshore hydrogen production

The technological maturity of the onshore transformers and voltage converters is assessed as mature (TRL 9). The supply chain risks are manageable. However, the project is in competition with other large-scale projects, which may lead to resource and capacity bottlenecks.

Onshore desalination plants are not considered a technological innovation. However, due to the high purity requirements for the water used by PEM electrolysers, additional equipment specifications are necessary. These have been proven in the recent past by prototype tests in the course of the SEA2H2 project in an operational environment (see Schaeffler Deutschland, 2021), so that production lines can be set up (TRL 8). At the same time, risks remain for setting up or ramping up the supply chains. In terms of resource availability, it is also important to note that hydrogen production from saline water represents a significant development potential, leading to an expected increase of use and demand for such technologies.

Onshore electrolysers based on PEM technology are no longer a technological innovation today (TRL 9), so that the maturity of the supply chains is also estimated to be high. However, the demand for electrolysers is already high at present and is expected to increase further. Delays due to bottlenecks in the supply chain can already be observed today and could intensify further.

Onshore hydrogen compressors must meet increased technical requirements due to the physical and chemical characteristics of hydrogen. However, such components are already technologically mature today and are already in operation for the storage, transport or liquefaction of hydrogen or for adaptation to the necessary operating pressure, such as at hydrogen filling stations (TRL 9). No higher risks are currently seen in the manufacturers' supply chains, although capacity bottlenecks may also occur along the supply chain.

Offshore transformers and voltage converters are already in operation in a multitude of cases. This results in a high degree of maturity in the technological assessment as well as in the assessment of the established supply chains (TRL 9). When planning for implementation, it should be noted that due to the increasing number of projects of this or similar types in the offshore environment, the oligopolistic market structure and the resulting strong negotiating position of the suppliers, there is an increased supply chain risk and delays may occur due to resource bottlenecks.

A similar assessment is made for HVDC submarine cables which are also being used in offshore projects already and are based on established supply chains (TRL 9). Due to the higher quantity of cables required for this and other project schemes, the required quantities of raw materials for manufacturing and the complex manufacturing processes, a moderate to increased risk for the availability of cable capacities is assumed. A demand increase for HVDC cables, which has already been observed for some time, also means that production capacities can likely not be taken up promptly, hence a considerable potential for delays is assumed.

Offshore Hydrogen Production & Pipeline Transport

Hydrogen production on an offshore platform as well as transportation of the gas to the German hydrogen grid via pipeline has so far neither been tested nor been in operation on this scale. However, individual components of the system, e.g., hydrogen-ready collection or transmission pipelines, transformers, voltage converters or desalination plants have been running successfully in onshore operation for several years.

System Components	Technology Readiness	Supply Chain Readiness	Availability of Resources
Offshore Platform H_2 System	5 **6** 7 8 9	⚪🟠⚪	⚪🟠⚪
Offshore trafo/converter	5 6 7 8 **9**	⚪⚪🟢	⚪🟠⚪
Offshore desalinator	5 6 **7** 8 9	⚪🟠⚪	⚪🟠⚪
Offshore electrolyser	5 6 **7** 8 9	⚪🟠⚪	⚪🟠⚪
Offshore H_2 compressor	5 **6** 7 8 9	⚪🟠⚪	⚪🟠⚪
Offshore H_2 collection &transmission pipeline	5 6 7 8 **9**	⚪⚪🟢	⚪🟠🟢

Exhibit 6: Technology readiness, supply chain readiness and availability of resources for offshore hydrogen production & pipeline transport

Various concept studies for offshore hydrogen production have already been conducted (TRL 6). An actual design envisages such a platform including the technical components listed here and designs it beyond the dimensioning considered here up to 800 MW (see Tractebel Engineering, 2019 and 2020). A similar but not identical concept for hydrogen production on a designated gas platform is currently being tested by the PosHYdon consortium in a pilot project off the Dutch coast. Accordingly, the level of technological maturity on the scale described here is assessed at the threshold between simulated and real demonstration in an operational environment (TRL 6-7). An increased risk is perceived for the supply chain, as a parallel construction of the platform as well as the involved technical components in a shipyard is assumed and these processes exist in a similar form for offshore projects but are not commonplace. Furthermore, the resource availabilities are considered risky in every respect. One key driver for this is the high utilisation of shipyards in recent years and the high and increasing competition between ship-building and structure building for offshore energy projects.

Offshore transformers and converters are already operational in existing offshore projects such as BorWin 3 and DolWin 3 (TRL 9). Accordingly, no critical risks are perceived regarding both technological readiness and the assessment of supply chain structures. However, the availability of resources is seen as moderately critical here, particularly due to the oligopolistic market structures, the resulting strong negotiation position of the suppliers and associated dependency risks for the project owners.

Desalination plants for electrolysers have been the subject of operational tests for some time (TRL 7). The PosHYdon consortium is piloting offshore electrolysis including seawater desalination. In addition, further plants are being built directly on the coast or on an island. The high purity of the freshwater produced is crucial for the PEM electrolysis considered here. For this purpose, first real-world operational tests were completed in the course of the SEAH2H project and production lines were set up. Serial production for such offshore plants is therefore expected in the medium term at the latest. However, the short-term supply chain availability is categorised as immature since desalination plants as such do not represent a technological innovation but offshore plants have not yet been manufactured and delivered at industrial scale. Furthermore, resource bottlenecks are to be expected due to the upcoming ramp-up of hydrogen infrastructure projects. The German hydrogen strategy and the associated political support for a rapid creation of capacities are intended to counteract this, but delays are plausible, especially in the initial phase.

A similar assessment is made for offshore electrolysers. In onshore operation, PEM electrolysers are not a technological innovation, but they are only just being tested in pilot systems in real offshore environments (TRL 7). Here, too, risks in the development of the supply chain and limited capacities for procurement, production and construction are expected, hence appropriate time buffers are considered reasonable in the time planning for the entire system.

Offshore hydrogen compressors have an increased level of complexity due to the technical requirements arising from hydrogen handling. Tractebel has developed a concept for scalable offshore platforms for the compression and storage of hydrogen (Tractebel Engineering, 2021). In an operational environment, natural gas compressors have been planned or installed for offshore use in various projects like NordStream 1 and Norpipe, but no such operational use case is known for offshore hydrogen compression. In addition, although hydrogen compressors exist as individual products, the system in combination with other systems for offshore hydrogen production has only been simulated so far and not yet tested in a real environment. Accordingly, the compression capacities and dimensions required in the present system for offshore applications are attributed the maturity level of an early-stage technology (TRL 6). This gives rise to uncertainties in the assessment of the supply chain. Offshore operability can be assumed but not demonstrated. Resource availability presents challenges comparable the other hydrogen production systems considered here.

The hydrogen pipelines are no technical innovation in the dimensions of both the DN400 gathering pipelines and the DN1100 transmission pipeline (TRL 9). Even though natural gas pipelines dominate in the offshore environment to date, there are reference projects, e.g., in the Baltic Sea where hydrogen-ready pipeline systems are assumed. Due to these circumstances, no risks are assumed for the supply chains. The assessment of resource availability does not reveal any significant risks either, mainly justified by the less complex construction requirements and efficient production processes. However, the influence of other major projects is taken into account in the form of extended ordering and delivery times.

4.3 Implementation Planning of the System Components

In the analysis of the implementation time paths, the project phases described for the two systems were evaluated for each system component. A distinction was made between the hydrogen-producing part, the transport part and the connector between these two parts. For both systems, a distinction is made between sequential and parallel planning and implementation procedures. Parallel procurement, production, installation and commissioning are assumed for the hydrogen-producing components and for the connector components. This means that completion appears possible within 11 years, i.e. with a project start in 2023, 10 GW of electrolysis capacity could be built by 2035.

For the transport systems (cable and pipeline), sequential procurement, production, installation and commissioning are assumed to ensure comparability of the transport infrastructures. The choice of a sequential approach also reduces the administrative effort for the award of contracts and especially for project management. An approach with parallelised process steps is also conceivable with view to the resources available in the market that can be used in parallel, such as laying ships and the general possibility of carrying out installations in parallel at different locations for both transport systems. However, such parallelisation, which would likely be different for the two systems, would reduce comparability and increase planning complexity. Furthermore, a parallel contracting would reduce efficiency gains through economies of scale and increase the price and thus the overall system costs in the present oligopolistic seller's market. In order to avoid such effects, which would apply unilaterally to the system variant Submarine Cable & Onshore Hydrogen Production, parallel production and installation were not considered for the entire study to ensure a consistent system comparison.

For the calculation of the installation times, different efforts were considered as well as variable installation speeds in onshore, nearshore and offshore areas. In addition to the laying processes themselves, a time requirement extension of approx. 45% of total duration was considered for necessary work steps regarding mine detection and removal, preparation and (de)mobilisation of the laying capacities as well as earthworks. Typical weather conditions for the North Sea were taken into account through corresponding buffer times. The specific installation time for the pipeline was calculated with three times the time factor of the cable system. For the above-mentioned auxiliary processes around the laying, the same speed and time factors were used for both systems.

Submarine Cable & Onshore Hydrogen Production

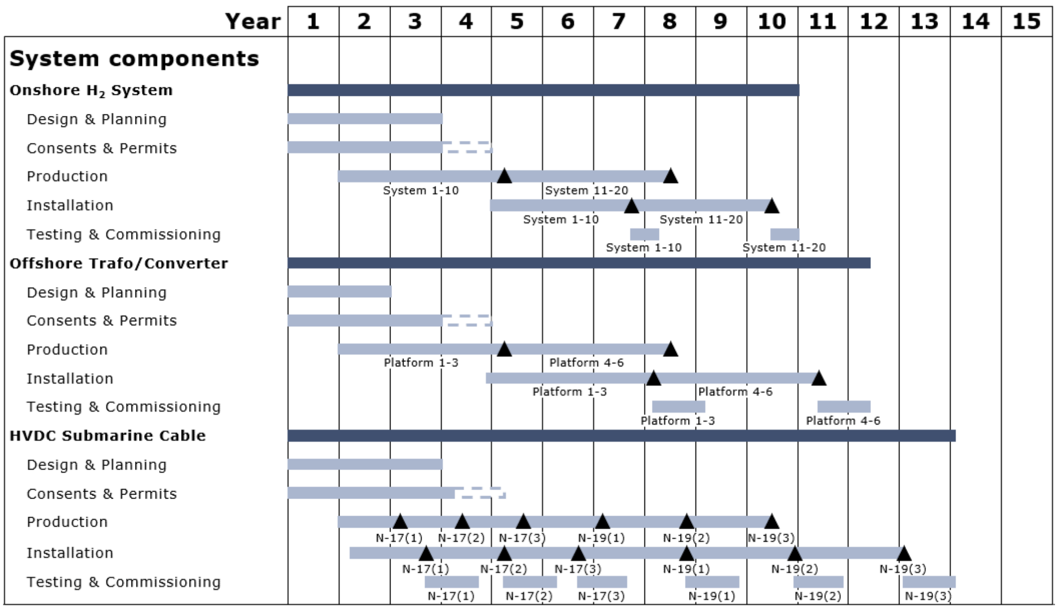


Exhibit 7: Implementation timeline for submarine cable & onshore hydrogen production

The implementation planning for onshore hydrogen production requires ten onshore electrolysis plants to be planned, approved, produced, installed and commissioned simultaneously. Otherwise, the goal of building 10 GW of production capacity before 2035 would not be achieved. Assuming parallel production and installation, we assume that the necessary hydrogen production capacities can be created within ten years.

Similarly, for offshore transformers and converters, parallel processes for design & planning, consents & permits, production, installation and commissioning are assumed to achieve the necessary 12 GW of transformation and conversion capacity within eleven and a half years.

The implementation processes of submarine and land cables are planned sequentially for the reasons described above. The general assumptions are based on AFRY experience from comparable offshore infrastructure projects, ensuring that the assumptions are plausible in comparison with relevant systems already in operation. All processes are assumed for a synchronous system implementation, so all of them are assumed to be conducted by one single consortium for all installations in both N-17* and N-19. The production processes begin one year after project start, as experience shows that the design can be completed by this time. For the production chain, it is assumed that the shorter cables that connect the systems in the N-17* area will be produced before the longer cables required for the N-19 area. The installation process is started as soon as the average loading capacity of a typical contemporary laying vessel of 100 km of cable has been produced. The installation is also calculated in such a way that the installations in N-17* are fully connected, individually tested and commissioned first. After that, the installations in N-19 are connected in parallel to the installations in N-17* operating.

Under these constraints, the timeline shows that provision of the necessary transmission capacity of 12 GW of electrical power to operate 10 GW of electrolysis power is not achieved within the time budget of thirteen years to reach the targets by 2035. If the design and consent processes are started in early 2023, the commissioning of the cable systems would not be completed by the end of 2035. The main reasons for this are the cable lengths required for the desired output and the associated significant production and installation times.

Offshore Hydrogen Production & Pipeline Transport

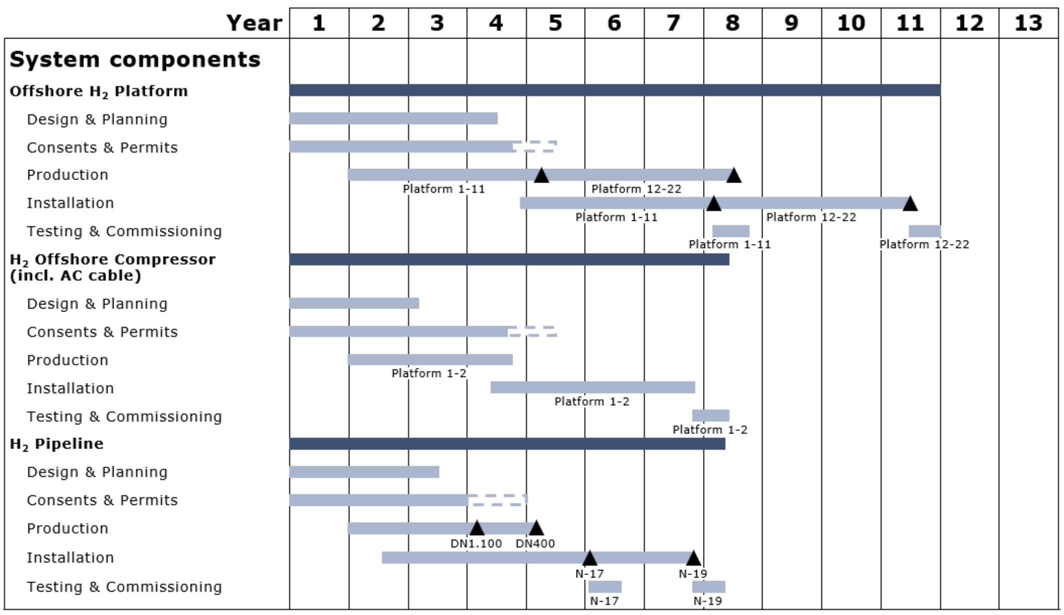


Exhibit 8: Implementation timeline for offshore hydrogen production & pipeline transport

The planning and implementation times for the components of the offshore hydrogen production system differ significantly from the onshore system. For comparability, the assumptions regarding parallel and sequential processing were chosen the same for both systems. Likewise, the different levels of technical maturity, supply chain and resource availability are included in the planning in the form of increased time requirements for the components.

It is assumed that the offshore hydrogen system platforms will be manufactured and installed at sea in two successive phases. Since two additional platforms for further transformers are added in this system, eleven instead of ten platforms are planned for parallel construction. This also assumes a higher production and installation capacity available on the market. Under these conditions, the platforms can be commissioned within eleven years with the required electrolysis capacity of 10 GW.

The two platforms at the two entry points into the central transmission pipeline are also planned in parallel. Both of them are equipped with six compressors to compress 5 GWh/h of hydrogen each. Compared to the onshore variant, only two instead of six platforms for the components have to be built here.

A clear difference emerges for the processes for the transport infrastructure. Here, too, common processes are assumed for design & planning as well as approval procedures for the overall project. To minimise machine set-up times, the production process is assumed in such a way that the DN1100 pipeline is produced completely at first, before starting to produce the DN400 pipes needed for the collection pipelines. Once 100 km of pipeline have been produced, installation of the transmission pipeline to the first feed-in point in area N-17* begins. After this string is completed, sufficient DN400 pipes will already have been produced so that the collection pipelines in N-17* can be fully installed.

Due to the smaller quantities of material that have to be procured, less complex production and the resulting shorter production times, there is a time saving of about 60% compared to the cable variant. The pipe-laying shows a significant difference as well. The entire transport infrastructure can plausibly be installed and commissioned within seven and a half years. The time required is about five and a half years less than for the cable variant.

4.4 Comparison of the critical paths for achieving the expansion targets

A comparison of the two system variants shows significant differences in the implementation times. The critical paths for each system are also quite different.

While the onshore hydrogen production in the considered system structure requires a total length of submarine cables of 3,720 km, the pipeline infrastructure only requires cables with a length of 24 km between the transformer & converter platforms to the compressors, DN400 pipelines with a total length of 240 km and a DN1100 pipeline with a length of 330 km. The differences in the lengths of the transport systems have a significant impact on the critical paths of the overall systems.

Due to the assumed sequential procurement, production and installation of the transport infrastructures, onshore hydrogen production is expected to miss the expansion targets of 10 GW electrolysis capacity by 2035. In this variant, the cable system is on the critical path and causes the capacity targets to be missed. Moreover, the assumed project start in 2023 is very short-term and hence associated with increased feasibility risk. Implementation times could be optimised by a parallel use of production lines and by parallel use of several laying vessels. However, this means an increased administration and coordination effort in production and installation as well as increased cost risks resulting from a multi-supplier strategy in an oligopolistic sellers' market.

In offshore hydrogen production, the expansion of pipeline infrastructure is not on the critical path. Even a sequential, back-to-back production, installation and commissioning of pipelines could be fully completed by 2035. The shorter implementation time of the entire system would even allow a project start delay of up to two years, out to 2025, and still achieve the expansion targets by 2035. In this system variant, the main risks for the completion of the 10 GW overall system reside in the offshore production capacities for hydrogen. For this project part, it must be ensured that system components such as transformers, converters, desalination plants and electrolysers are procured as early as possible, in parallel and, if necessary, from several manufacturers, and that platform construction takes place at several shipyards simultaneously. However, this recommendation also applies to the cable-based system variant.

4.5 Conclusion and Recommendations

Both systems require technical innovations and entail associated risks in the supply chains and the availability of resources. For the offshore hydrogen production & pipeline transport system in particular, some components are not finally tested and in operation yet. The assembly of transformers, converters, desalination plants and electrolysers on a common platform built in port and then installed at sea is a novelty. Hydrogen compression has also not yet been tested and evaluated in the long term in the offshore sector.

For the submarine cable & onshore hydrogen production system variant, the respective system components have already been tested on land. Accordingly, its level of maturity of the technology and supply chain is higher.

A comparison of the two system variants shows significant differences between the respective implementation times, especially in the construction of the transport systems. Cable laying is on the critical path with sequential work and is completed after about 13 years. With equally sequential work, the construction of a pipeline can be completed after about seven and a half years, i.e. with a time advantage of about five and a half years compared to the cable variant. The overall system of offshore hydrogen production & pipeline transport would thus allow a significant time buffer and enable the achievement of the 10 GW expansion targets by 2035 even with if the project start is delayed by up to two years.

For Submarine Cable & Onshore Hydrogen Production, the cable system is on the critical path for the overall project under the above assumptions. For offshore hydrogen production & pipeline transport, the parallel production and installation of eleven platforms is the most time-critical part of the overall system. The availability of resources and capacities appears more critical for the submarine cable & onshore hydrogen production system. Currently, a large number of offshore wind projects is being planned or implemented. As a result, production and laying capacities for submarine cables are already heavily booked worldwide. The market for pipelines has far fewer bottlenecks compared to cables. In the case of the offshore variant, however, it should be noted that the integration of system components into an offshore electrolysis platform does not yet exist and that the construction of the entire platform involves considerable implementation risks for the project owner.

Summarising, a pipeline will expectably have a significant time advantage over a submarine cable solution from a project and implementation planning perspective. The offshore system is characterised by more innovative technology and thus technically riskier overall. In order to reduce the implementation risks, an early selection and integration of all key suppliers into the project and, if possible, parallel commissioning, approval and implementation would support the achievement of the expansion target of 10 GW of electrolysis capacity by 2035.

5 Comparison of investment & operating costs

5.1 Methodology

The variants offshore hydrogen production & pipeline transport and submarine cable & onshore hydrogen production were analysed quantitatively with regard to their total system costs as well as their resulting specific system costs per kilogram of hydrogen. Following a bottom-up approach, capital costs and operational costs of the individual system components were included in the analysis. Furthermore, specific costs for associated services are included for both system variants to ensure an evaluation that is as comprehensive as possible. Costs of power generation and decommissioning costs of the systems were not included.

In the analysis of the specific system costs per kilogram of hydrogen, the contributions of the individual cost elements are allocated to the delivered quantity of hydrogen within the framework of an LCOE[1] approach, taking their specific lifetime into account. An annual production volume of 945 kT hydrogen was used as a basis. Furthermore, the operating costs in the cost calculation for each system element were determined as an annual fixed share of the investment costs. For the operating costs in the system offshore hydrogen production & pipeline transport, a share of 1.9 % was assumed, the assumption for submarine cable with onshore hydrogen production is 1.7 %.

Cost values are denominated in Euros of 2021. The reference year for technology costs is 2021 as well. Future cost degression developments for individual system components were not considered. The system variant of ship transport was only evaluated qualitatively in the comparison of investment and operating costs.

5.2 Cost of Submarine Cable & Onshore Hydrogen Production

The total cost of the submarine cable & onshore hydrogen production variant is approximately 36.5 billion euros. Exhibit 9 Exhibit 9: provides an overview of the contribution of the individual cost elements. With a share of about 45%, the costs for hydrogen supply (16 billion euros) dominate the capital expenditures. The hydrogen supply cost block includes electrolysers, compressors, and seawater desalination plants. Electricity costs are not included in the total costs.

Besides hydrogen supply, the transport system for electrical energy is another major cost driver totalling about 15.7 billion euros. In addition to the necessary offshore

[1] LCOE = Levelised Cost of Energy, discount factor 5% p.a.

converter platforms and HVDC submarine cables, this includes all elements required for the onshore electricity supply of the electrolyser.

In addition, market-standard accruals are taken into account for the individual system components (2 billion euros). The cost analysis also includes design, permitting & compensation, maritime services, route planning and preparation as well as personnel in the block Other Costs (1.5 billion euros). Costs for insurance are set at 1.3 billion euros.

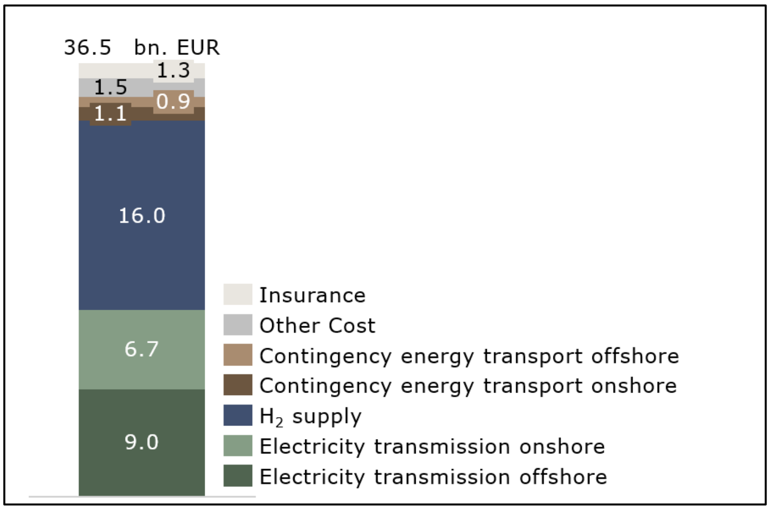


Exhibit 9: Total system cost submarine cable & onshore hydrogen generation (reference year of technology costs 2021)

The specific system cost per kilogram of hydrogen derived from the capital costs and operating costs amount to EUR 3.2/kg, with the electrolyser system and electricity transport being the main cost drivers. The costs for electricity generation are not included here. Exhibit 10 breaks down the contributions of the individual system components.

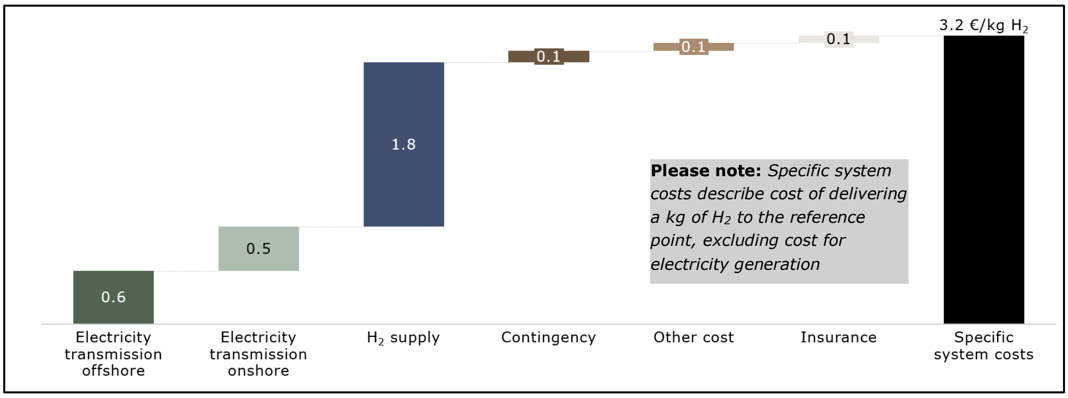


Exhibit 10: Specific system cost of submarine cable & onshore hydrogen generation (reference year of technology costs 2021)

5.3 Cost of Offshore Hydrogen Production & Pipeline Transport

In terms of total costs, the system alternative offshore hydrogen production & pipeline transport is the lower-cost alternative at 30.3 billion euros. Exhibit 11 breaks down the system costs by component. With a contribution of just under 70%, investment for hydrogen supply (21 billion euros) is the main cost driver. Hydrogen supply costs include electrolysers, compressors, and seawater desalination plants as well as the corresponding offshore platform systems. Electricity costs are not included in the total costs.

In the area of transport costs, offshore electricity transport represents the largest cost block at around 3 billion euros, while the pipeline for hydrogen transport at sea and on land requires a total of just under 1.6 billion euros.

In addition to market-standard accruals of about 2.5 billion euros, other costs (design, permitting & compensation, maritime services, and route planning and preparation and personnel) contribute about one billion euros to total system costs. Insurance costs were estimated at around 1.1 billion euros.

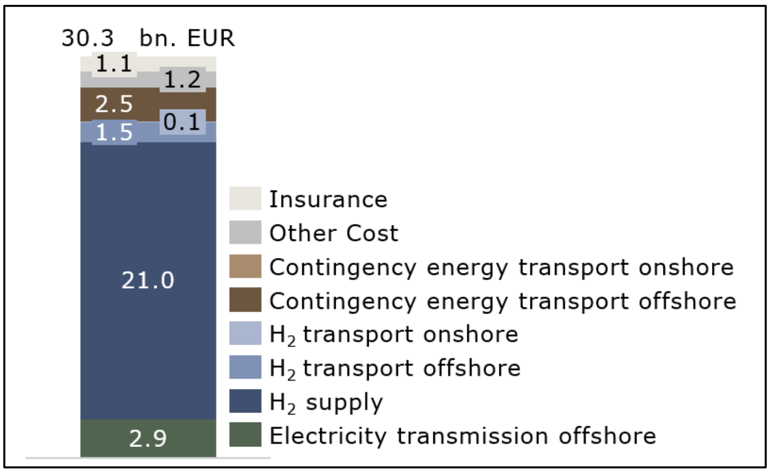


Exhibit 11: Total system cost of offshore hydrogen production & pipeline transport (reference year of technology costs 2021)

The specific system costs per kilogram of hydrogen derived from the capital and operating costs amount to 2.7 EUR/kg in the considered system. As in the submarine cable & onshore hydrogen production variant, hydrogen supply is the main cost driver. Again, costs of electricity generation are not included. Exhibit 12 breaks down the contributions of the individual system components.

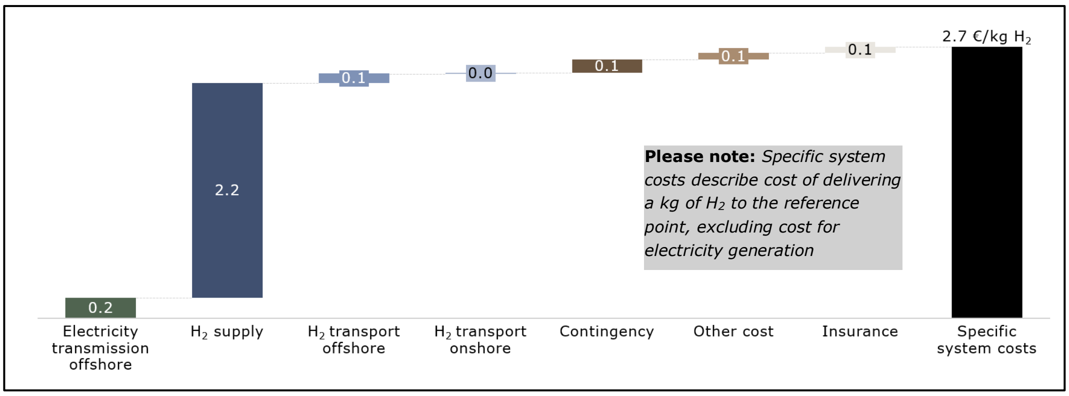


Exhibit 12: Specific system costs of the offshore hydrogen production & pipeline transport variant (reference year of technology costs 2021)

5.4 Cost of Offshore Hydrogen Production & Ship Transport

Due to uncertainties and missing data points for a cost assessment of the offshore hydrogen production & ship transport variant, an appropriate cost comparison of this alternative is not possible at the current time. The transport of hydrogen by ship is currently still being tested. An optimized dimensioning and a suitable technological setup of tankers, loading and unloading infrastructure is not conclusively visible yet. However, it can be expected that the transport costs for offshore hydrogen production with subsequent ship transport will have higher operating costs, but lower capital costs compared to the system alternatives. Compared to cables and pipelines, this would be due to expected lower capital costs for a fleet of future large-size tankers which would decrease significantly with increasing vessel size. The investment requirement for smaller LNG tankers with transport volumes of 30,000 m^3 can be indicatively estimated at around 75 million euro, while a large LNG tanker with 150,000 m^3 cargo capacity costs around 150 million euro indicatively. Over the lifetime of a vessel, total fixed operating costs and fuel costs can be estimated to roughly equal capital requirements, so that a lifetime cost of around 150 to 300 million can be assumed per vessel depending on size (e.g., see US Department of Energy, 2018). Assuming that the costs and transport volumes of mass-produced liquid hydrogen tankers of the future will be of a similar order of magnitude, this results in an approximate lifetime cost for a tanker fleet in the single-digit billions. The costs for the loading and unloading terminals, which are also expected in this order of magnitude, are to be added.

5.5 Conclusion and recommendation

The final comparison of total and specific system costs shows offshore hydrogen production with pipeline transport to be the lowest-cost system that can be built with known technology. The cost advantage for total system costs amounts to approximately six billion euros (17%). The specific system costs per kilogram of hydrogen of 2.7 EUR/kg H_2 are 0.5 EUR/kg H_2 (15%) lower than in the submarine cable with onshore hydrogen production variant. From a cost perspective, the development of an offshore hydrogen production with pipeline transport is therefore recommended for the considered 10 GW expansion stage.

6 Comparison of environmental compatibility and permitting complexity

6.1 Methodology

In general, infrastructure projects give rise to two combinations of environmental and permitting risks: one triggered by the construction phase and another one for the operational phase. The assessment is based on a qualitative estimation of the intensity of the identified impact factors as well as the duration of effects. The environmental and approval risks shown in Table 1 are explained for each individual system hereinafter.

Table 1: Impact factors of the tested systems, divided into construction phase and operation phase

Impact factors - construction phase	Duration of effect
Noise emissions	Temporary
Temporary onshore land use	Temporary
Onshore land-use conflict	Temporary
Disposal of hazardous and construction materials	Temporary
Geological risks	Permanent
Supply chain ESG risk	Temporary

Impact factors - operational phase	Duration of effect
Permanent onshore land occupation	Permanent
Disposal of hazardous and construction materials	Permanent
Water withdrawal & brine discharge	Permanent
Shipwreck risk	Permanent
Noise emissions	Permanent

6.2 Environmental and permitting risks of the submarine cable variant

Construction

For the submarine cable with onshore hydrogen production, environmental and permitting risks caused by noise emissions are avoided by applying the "General Administrative Regulation for Protection against Construction Noise" („*Allgemeine Verwaltungsvorschrift zum Schutz gegen Baulärm*") and the Equipment and Machinery Noise Protection Ordinance ("*Geräte- und Maschinenlärmschutzverordnung*"). The corresponding limits are broken down in the ordinances for day and night work and for individual machines.

Construction sites entail a temporary onshore land use. These can be restored to their original condition with suitable measures after the construction phase. In the offshore area, a wider underwater corridor must be checked during the construction phase compared to the pipeline, resulting in additional effort.

During the planning and approval phase, there is a risk of conflicts of use that have also affected other northern German projects. Examples include the Dieksand Land Station of the Mittelplate A oil platform, the national park expansion in Schleswig-Holstein and various overhead power line projects. It can be assumed that larger greenfield projects can only be implemented against well-organized public resistance.

Contamination of marine and terrestrial ecosystems by operational materials, waste, and hazardous materials that must be used and disposed of during the construction phase poses a fundamental risk. This risk can be avoided by applying current regulations and measures for the proper disposal of these goods and by the safe operation of construction vehicles.

Along the offshore cable route, there is a basic possibility that installations may be damaged or destroyed by geological activity (landslides or similar). To control this risk, the method standard for ground investigation (BSH, 2014) is applied. This working aid sets out the minimum requirements for geotechnical investigations as part of the approval process by the Federal Maritime and Hydrographic Agency.

The production of several thousand kilometers of cable route is resource-intensive and requires an extensive international supply chain for the procurement of the corresponding raw materials. The more raw materials are required, the greater the need for different suppliers. This increases the need to manage potential ESG risks along the supply chain. To minimize these risks, an OECD-compliant screening of social, environmental and governance criteria for high-risk suppliers (e.g., operations in raw material mining, production of materials in countries with low standards for worker safety or similar, see also OECD, 2018) is recommended.

Operation
Assuming a greenfield approach, land is permanently taken up by the construction of the production facilities and along the cable route. On land, this represents a permanent loss of settlement space, agricultural production space, and habitat. The permanent take-up is irreversible and against the German government's goal of limiting daily land sealing to less than 20 ha in accordance with the integrated environmental program (BMUB, 2016). The negative environmental effects could be reduced by co-locating the production facilities with existing industrial and commercial areas.

The risks mentioned for the construction phase in the disposal of waste and hazardous materials, as well as measures for proper handling, can also be applied in the operational phase of the project.

The extraction of water as well as the recirculation of brine with increased salt concentration has to be considered separately from the handling of the remaining hazardous substances. For the onshore electrolysis, this means a withdrawal of significant amounts of brackish water from the Elbe estuary. The water is heavily saturated with suspended particles due to the nearby tidal flats as well as ship operations that stir up the seabed. The exact amounts cannot be determined as part of this study, but it is foreseeable that the abundance of suspended sediment will negatively impact the performance of the onshore facilities.

Furthermore, the recirculation of the brine, even with only a few percent of salinity, poses an environmental risk to the Elbe River and the tidal flats of the Hamburg Wadden Sea National Park that cannot be assessed. The withdrawal as well as discharge of water are highly dependent on tides at this position and the waters are not very deep. Both factors favor a deposition of the brine on the bottom of the Elbe as well as a distribution on the tidal flats near the river, so that these can become salinized and suffer long-term damage during operation. Approval without an appropriate preliminary study and suitable avoidance measures is very unlikely. One possible avoidance measure would be to collect the brine on land. However, considering the quantities and the fact that the methods for brine recycling are neither technically mature nor economical, this measure does not appear to be reliably feasible.

6.3 Environmental and permitting risks of the pipeline variant

Construction

At the onshore connections required for the offshore electrolysis system, environmental risks caused by noise emissions are avoided by applying the "General Administrative Regulation for Protection against Construction Noise" („Allgemeine Verwaltungsvorschrift zum Schutz gegen Baulärm") and the Equipment and Machinery Noise Protection Ordinance ("*Geräte- und Maschinenlärmschutzverordnung*"). The corresponding limits are broken down in the ordinances for daytime and nighttime work, as well as for individual machines.

The construction of offshore platforms releases strong noise emissions, especially during pile driving for the foundations. These can severely injure the hearing of porpoises and other marine mammals that use echolocation for orientation or kill the affected animals. To minimize this risk, the BSH envisions the use of sound mitigation and deterrence measures. These will be developed as part of the permit planning process and may include the use of so-called seal scarers and bubble curtains (ITAP, 2014). Installation is technically and logistically complex but a standard and successful practice, especially during wind farm construction.

The environmental risks triggered by temporary land use, hazardous materials and geological factors, as well as their control mechanisms, correspond to those of the onshore option. The risks along the supply chain also exist for the offshore option. However, the resource consumption for producing the pipeline elements is estimated to be lower in principle than the production of the cables and the raw materials required for it.

Operation

The construction of offshore electrolysers avoids a permanent loss of land on land, or at least minimizes it considerably in the context of the onshore connection. After construction, a positive effect of the project on local biodiversity is possible, as observed in wind farms. Beneficiaries include marine mammals that rest in an area exempt from shipping, fish whose population sizes, species composition, and age structure can recover in an area exempt from fishing, and microorganisms, mussels, and other bottom-dwelling organisms that use the platforms' foundations as artificial reefs (cf. van Deurs et al., 2012).

The risks mentioned for the construction phase for the disposal of waste and hazardous materials, as well as measures for proper handling, also apply in the operational phase. Herein, disposal is more complex for offshore platforms than disposal onshore.

The withdrawal of larger quantities of water on the high seas is harmless. The saturation of the water with suspended matter will be lower than in the Elbe estuary due to the higher water depth. With regard to brine recirculation, the probability of environmental damage is significantly lower compared to onshore electrolysis. To prevent possible contamination of the seabed, it is recommended to additionally enrich the brine with seawater prior to recirculation, to achieve maximum diffusion. Recirculation of the brine is expected to require a preliminary study as part of the environmental permitting process to better understand the potential effects. This study would precede the actual environmental assessment. It is recommended that this issue should be addressed with the permitting authority at the earliest possible time to avoid procedural delays.

6.4 Environmental and permitting risks of the ship transport variant

Construction

The risks of ship transport related to noise emissions, hazardous substances and geological factors correspond to the risks of the offshore hydrogen production with pipeline transport variant. Construction sites for ship terminals entail a temporary onshore land use. These can be restored to their original condition with suitable measures after the construction phase.

The construction of a fleet of ships to transport the hydrogen is resource-intensive and, apart from the production capacities, requires an extensive, international supply chain for the procurement of the corresponding raw materials. The more raw materials required, the higher the need for different suppliers. This increases the need to manage potential ESG risks along the supply chain. To minimize these risks, an OECD-compliant screening of social, environmental and governance criteria for high-risk suppliers (e.g. operations in raw material mining, production of materials in countries with low standards for worker safety or similar, see also OECD, 2018) is recommended. The resource consumption for the construction of the vessels as well as the complexity of the supply chain is estimated to be even higher than for the submarine cable with onshore hydrogen production variant.

Operation

The risks with regards to withdrawal of water and return of brine correspond to the variant offshore hydrogen production & pipeline transport. The risks mentioned for the construction phase with regards to the disposal of waste and hazardous materials, as well as measures for proper handling, also apply in the operational phase of the project. The logistics here are somewhat more complex for offshore platforms than for onshore disposal. Due to the ship operation, the amount of waste, operating materials and emissions will be significantly higher than for the systems with pipeline or cable option. Furthermore, the ship fleet will cause significant CO_2 emissions during operation if conventional fuels are used for propulsion.

Assuming a greenfield approach, land is permanently used by the construction of the terminals. The associated risks correspond to those related to the submarine cable variant.

The operation of smaller tankers will result in increased traffic due to shuttling. Furthermore, it increases the risk of accidents in the area of the wind farms and in the national park areas in the Elbe estuary. This risk increases with potential future tanker sizes at the level of today's large LNG tankers with 200m and more in length, especially in the area of the parks. In addition, these vessel sizes may require tug assistance and ongoing average protection by additional seagoing tugs in the area of the loading points, which would further increase the system complexity.

A further increase in risk results from the loading operations themselves, which are not required in the other options and can only be performed up to a certain sea state. Accordingly, the hydrogen loading is weather-dependent and can be interrupted for several days in the event of sufficiently bad weather, which leads to forced production losses due to the lack of storage facilities on the platforms and is also disadvantageous from the point of view of ongoing supply security. In addition, increased ship traffic in the German Bight results in increased noise emissions. These can additionally harm marine mammals in the pre-stressed North Sea.

6.5 Environmental approval planning

The environmental approval planning and the associated (preliminary) investigations will account for a significant part of the financial and time expenditure for the approval procedure in all three systems. In this context, the map in Exhibit 13 shows the complex protected area landscape of the German North Sea coast, in which the Wadden Sea National Parks are highlighted in green. Especially in the Wadden Sea as well as along the coast, there is an increased risk of being confronted with species protection conflicts and development restrictions. Impairments of the NATURA 2000 site Doggerbank as well as its target species harbour porpoise (Phocoena phocoena) and harbour seal (Phoca vitulina) in the northwestern "duck's bill" are only expected for the construction phase. These can be mitigated with the above measures.

Exhibit 13: Protected areas along the German coast

To better understand and prevent possible causes of procedural delay, the following points merit consideration:

- Approval of the systems will require extensive preliminary investigations, up to a formal requirement to conduct baseline studies to better understand environmental impacts.
- Faunal and ecological surveys are seasonal and tidal and may take more than a year to complete. Generally, surveys such as seabird counts must occur in specific calendar weeks. If a window of opportunity is missed by even a few days, the mapping is usually invalidated by the responsible authority to prevent legal exposure and must be done again the next year.
- For faunistic and ecological surveys, there is a compelling link to the planning area. If the procedure triggers a plan change during the surveys and the area changes subsequently, the ongoing mappings usually have to start over in the following year.
- Contracting the environmental permitting documents to an experienced planning office with onshore and offshore experience is an essential success factor. Planning agencies operate at different levels of experience and

maturity. To minimize the financial risk of a planning delay, a precise definition of the environmental planning steps in the contract and the planning office's formal responsibility for clear definitions of all approval-critical surveys for the bid and for their timely execution can be chosen. The responsibility for the investigation design in compliance with the authorities is best placed with the planning office, whereas a rollover to the developer can jeopardise the approval success.

- Environmental planning also means balancing the extent of the intervention. In order to compensate, sufficient areas must be made available during the procedure for ecological compensation measures (e.g. orchard meadows, rewetting of meadows, creation of hedges and replacement habitats). It is recommended that this area be secured as early as possible. Furthermore, it should be noted that the sum of the impact assessment can change in the event of a change in the plan. A revision of the calculation usually entails a longer processing time of the environmental legal documents. The area to be compensated may also be larger than planned, and completely new measures may be required. A contingency buffer for securing the area reduces this risk.

6.6 Conclusion and recommendations

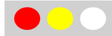
From an environmental and permitting perspective, offshore hydrogen production with pipeline transport is preferable to the other two systems. Onshore production bears a particular risk of conflicts of interest with the local population and associations during the permitting process, which pose an critical risk to the entire project. Prolonged project delays and lawsuits are likely. Furthermore, the discharge of brine in the tidelands area is not likely to be approvable. Onshore brine processing options are currently limited and not economical.

The ship system prevents the discharge of brine close to the coast and part of conflicts of use on land, but the increased ship traffic would carry new risks in the form of noise emissions and possible ship averages. The construction of the vessels is even more complex than sourcing the resources for the cables, increasing ESG risks along the supply chain. Finally, if the vessels use conventional propulsion, ongoing carbon emissions from the transport route would need to be considered.

Offshore hydrogen production with pipeline transportation prevents these risks. Although pile driving for the foundations of the offshore installations will result in increased noise emissions, these can be mitigated using proven systems.

Table 2: Comparison of systems in terms of potential environmental and permitting risks

Impact factors - construction phase	Cable	Pipeline	Ship
Noise emissions			
Temporary onshore land occupation			
Conflicts of interest regarding onshore land use			
Disposal of hazardous and construction materials			
Geological risks			
Supply chain ESG risk			

Impact factors - operational phase	Kabel	Pipeline	Schiff
Permanent onshore land occupation			
Disposal of hazardous and construction materials			
Water withdrawal & brine discharge			
Ship average risk			
Noise emissions			

7 Outlook

The three system variants are realistically workable and designed as simply as possible to ensure comparability and to facilitate the discussion. Comparability is also ensured by using a common reference point for transferring hydrogen to the German *Startnetz H_2* and the *European Hydrogen Backbone*. The technology assumptions reflect the current state of technology and research with the 10 GW electrolysis capacity target as reference.

The offshore electrolysis with pipeline transport has decision-relevant advantages for the provision of effective and efficient energy transmission in a large-scale hydrogen production system. The advantages concern all three considered dimensions of implementation time, economic efficiency and environmental compatibility and are robust in the context of the selected target and system structure as well as the technical developments that are currently expected.

Alternative system designs and implementation assumptions may lead to different results. Examples include:

- Politically driven changes, e.g., expansions of production capacities or reduced permitting requirements
- Parallelisation of further implementation steps or stronger sequential processing of implementation steps
- Assumption of more extensive or faster innovations and/or cost degressions, e.g., for electrolysis technology or size limits of offshore platforms
- Differentiated optimisation of electrolyser locations and grid transfer points
- Change of the economics and capacity profile by postponing implementation to later years, with increased use of expected cost degressions but reduced achievable electrolysis capacity over the considered time period

If the target capacity is increased beyond 10 GW of electrolysis capacity, the advantages of offshore electrolysis with pipeline increase in comparison to the cable variant. The assumed sizing of the pipeline system is sufficient to accommodate higher volumes of hydrogen from larger electrolysis capacities via the possibility of compression increase. Transporting additional volumes of electricity from offshore to an expanded onshore electrolysis system would require additional cables and result in a repetition of all implementation steps and environmental impacts described above.

In each of the relevant Net Zero scenarios for Germany, more CO_2-neutral hydrogen is required than 10 GW of electrolysis capacity can provide. Connecting to offshore wind instead of onshore wind or solar power enables efficient utilisation of CAPEX-intensive electrolysers. Significant exceedings of the 10 GW capacity and a connection to further offshore wind parks in the area are both plausible in the medium to long term. The areas in the "duck bill" and the international areas adjacent to the German EEZ at the Dogger Bank offer considerable additional installation potential for offshore wind turbines which can be used for hydrogen production. Especially with regards to higher national as well as international production volumes of (offshore-produced) hydrogen, this has a reinforcing positive effect on the advantageousness of a pipeline infrastructure for the North Sea.

Another advantage of offshore electrolysis with pipeline can result from an integration of the existing plants in the "duck bill" with future hydrogen volumes from Norway. By increasing the pressure level, the capacity of a large gas transport pipeline can be expanded beyond the H_2 volumes generated in the project. With Norpipe and Europipe I as well as Franpipe and Zeepipe, four natural gas transport pipelines connect Norway with the German North Sea coast and with the Belgian coast, passing through clusters N-17 and N-19. Co-use of the new pipeline considered here as the "last mile" of a possible new hydrogen pipeline from Norway along these routes is conceivable as well as the conversion of an existing pipeline to hydrogen transport. Cross-connections of the system with wind power and/or electrolysis plants in the Danish, English, and Dutch territorial waters at the Dogger Bank are also conceivable. Depending on the system design, such an integration of large international wind power and hydrogen production sites can offer further significant synergy potentials that are not available with the other two variants.

Compared to onshore wind power and photovoltaics, the combination of offshore wind power and offshore hydrogen production offers an advantageous combination of several factors: high and locally concentrated energy potential, high and fast scalability, electrolysis efficiency, storability of the energy carrier, low potential for conflicts of interest, synergy potentials from international integration, and still-acceptable environmental impacts. It is particularly suitable for medium- to long-term substitution of large quantities of imported natural gas.

Under the given set of conditions and assumptions, offshore hydrogen production with pipeline transport is advantageous compared to the considered system alternatives.

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