North Sea Energy offshore system integration

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D1.9

North Sea Energy 2023-2025

Technical Innovation

Navigating the North Sea transition!

For centuries, the North Sea has been a source of economic strength, ecological richness, and international cooperation. Always subject to change, yet steadfast as a connector of nations, cultures, and economies. Today, it once again takes center stage—this time as a lighthouse region for the transition to a sustainable, affordable, and reliable energy system. The North Sea Energy program marks an important step in this development.

North Sea Energy is a dynamic research program centered around an integrated approach to the offshore energy system. Its aim is to identify and assess opportunities for synergies between multiple low-carbon energy developments at sea: offshore wind, marine energy, carbon capture and storage (CCS), natural gas, and hydrogen. At the same time, the program seeks to strengthen the carrying capacity of our economy, society, and nature.

The offshore energy transition is approached from various perspectives: technical, ecological, societal, legal, regulatory, and economic. Our publications provide an overview of the strategies, innovations, and collaborations shaping the energy future of the North Sea. They reflect the joint efforts of companies, researchers, and societal partners who believe in the unique potential of this region as a hub for renewable energy and innovation.

What makes this program truly distinctive is not only its scale or ambition, but above all the recognition that we are operating in a dynamic field of research. The energy transition is not a fixed path, but a continuous process of learning, adapting, and evolving. New technologies, a dynamic natural environment, shifting policy frameworks, and changing societal insights demand flexibility and vision. Within this program, we work together to ensure that science and practice reinforce one another.

This publication is one of the results of more than two years of intensive research, involving over forty (inter)national partners. This collaboration has led to valuable insights and concrete proposals for the future of the energy system in and around the North Sea. All publications and supporting data are available at: https://north-sea-energy.eu/en/results/

We are deeply grateful to all those who contributed to the realization of this program. In particular, we thank our consortium partners, the funding body TKI New Gas, the members of the sounding board, the stakeholders, and the engaged public who actively participated in webinars and workshops. Their input, questions, and insights have enriched and guided the program.

At a time when energy security, climate responsibility, and affordability are becoming increasingly urgent, this work offers valuable insights for a broad audience—from policymakers and professionals to interested citizens. The challenges are great, but the opportunities are even greater. The North Sea, a lasting source of energy, is now becoming a symbol of sustainable progress.

With these publications, we conclude an important phase and look ahead with confidence to the next phase of the North Sea Energy program. In this new phase, special attention will be given to spatial planning in the North Sea, European cooperation, and the growing importance of security in the energy system of the future.

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North Sea Energy 2023-2025

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Executive summary

Energy system modelling plays a crucial role in shaping policy and investment decisions. The outcomes of these analyses are highly dependent on key factors such as initial conditions, boundary constraints, scope, and underlying assumptions. Understanding these dependencies is essential for deriving accurate and meaningful insights. Within the North Sea Energy 5 program, energy system modelling is a fundamental component across various work packages. To ensure transparency and consistency in the modelling efforts, factsheets have been developed to outline the key assumption and numerical values used in the models.

The objective of this report is to provide the background information and justification for these assumption/numbers wherever possible. The factsheets and descriptions in this document vary in detail as not all technologies are in the same Technical Readiness Level (TRL). The aim is to provide guidance to the technology and provide the basis of the assumptions that were used in the analysis.

The fact sheets have been created by different partners withing the NSE program, by means of literature surveys, analyses and stakeholder meetings with experts that are connected to the NSE program. For each of the technologies that are described in the document, scope boundaries, technical parameters, economic parameters and specific considerations are covered.

The report is structured to follow the energy value chain, covering production, conversion, storage, and transport. It discusses the dominant role of offshore wind energy production, the development of offshore hydrogen production through electrolysis, and various battery technologies for offshore energy storage. Additionally, it addresses the ambitious targets set by the Dutch government for offshore wind energy capacity and the role of High Voltage Direct Current (HVDC) systems in energy transmission. The report also highlights the potential of hydrogen transport through repurposed natural gas pipelines and the importance of compressors for hydrogen transport. The appendices include specific deep dives on wind park power density and energy islands.

Disclaimer: The values and information presented in this report have been collected and compiled over a two-year period (2023–2025). Some data points have also been referenced from previous studies such as NSE4 and similar initiatives like NSWPH, which extend the timeline back to 2022 and, in some cases, 2021.

1 Introduction

Energy system modelling plays a crucial role in shaping policy and investment decisions. The outcomes of these analyses are highly dependent on key factors such as initial conditions, boundary constraints, scope, and underlying assumptions. Understanding these dependencies is essential for deriving accurate and meaningful insights.

Within the **North Sea Energy 5** program, energy system modelling is a fundamental component across various work packages. In **Work Package 1**, modelling supports the design of energy hubs through spatial blueprints, determining optimal locations and capacities for power-to-hydrogen conversion. In **Work Package 3**, it is used to evaluate the business case for key infrastructure assets, ensuring economic feasibility and strategic alignment with energy transition goals. In Work Package 5, it is a source of input for the toolkit that is used for the system design and analyses that are performed.

To ensure transparency and consistency in the modelling efforts, the factsheets have been developed to outline the key assumption and numerical values used in the models. The objective of this report is to provide the background information and justification for these assumption/numbers wherever possible. The report is structured to follow the **energy value chain**, covering:

- Production (Chapter 2)
- Conversion (Chapter 3)
- Storage (Chapter 4)
- Transport (Chapter 5)

Each chapter is divided into sections, with each section focusing on a key technology that is expected to play a significant role in the North Sea energy system in the coming decades (as of mid-2024). Additionally, the final section of each chapter highlights **disruptive technologies** that have potential but currently lack sufficient data for integration into the energy system. Each technology section follows a structured format:

1. **Scope Boundary** – Defines the technology, the components included in the factsheet, and the level of detail covered.
2. **Technical Parameters** – Outlines the key technical aspects of the technology.
3. **Economic Parameters** – Provides cost-related data, **where available.**
4. **Other Considerations** – Covers factors such as safety and environmental impact, which may influence the technology's role in the energy system.

It is important to note that not all technologies have data available for every section. Some technologies are still in the early stages of development, making it difficult or even impossible to find publicly available information. In such cases, the report present the best estimates on available literauture or rather left unfilled. By following this systematic approach, the report aims to provide a clear and well-substantiated foundation for energy system modelling in this program.

In addition, the values in this document shall be considered as a snapshot in time. Some cost figures depend heavily on economic or political situations. Costs for certain technologies may be more volatile than others. When using the values from this report, be aware that these are values from 2023 and 2024, and may need updates for future studies.

2 Offshore Energy Production

There are several options of energy source like wind, tidal, wave and solar to harness the energy from an offshore environment. The most dominant source of renewable energy will be offshore wind farms, and to a smaller extent offshore solar farms.

Although tidal and wave technologies could potentially provide renewable power as well, in the current technology, they are expected to play a minor role in developing offshore H2 in the North Sea region[1]. Within North Sea energy 5, they are considered emerging technologies but are not yet considered part of scope as key energy providers in the hubs.

In Section 2.1, offshore wind energy is described, followed by section 2.2 on offshore solar energy. Section 2.3 describes emerging technologies or disruptive innovations.

2.1 Offshore Wind Energy

2.1.1 Introduction

Between 2015 and 2023, the share of electricity produced in the Netherlands by renewable energy has increased from 12% to 53% (Ref: CBS 2024), partially due to a decrease in oil and gas production, as well as increasing development in renewables such as offshore wind. Of those renewable sources, production due to offshore wind specifically, in the same period, has risen from 1.13 TWh to 11.46 TWh, with an installed capacity of 4.7 GW as of the end of 2023.

In the future, installed offshore wind capacity is expected to grow, given plans outlined by the Dutch government to have an installed capacity of 21 GW by 2032, followed by ~70 GW by 2050. These plans indicate high growth in the number of installed units in the Dutch part of the North Sea and necessitate a close look at the economics given expected turbine capacity growth over the coming decades.

2.1.2 Current State of Art

Wind technology is a mature technology at market-scale, with large-scale developers already invested in 2GW projects using conventional designs that have been developed and scaled for decades. As demand for larger capacity turbines grows, design challenges lead to the requirement for further innovation, albeit still in the realm of the conventional 3-bladed pitch-controlled variable-speed design. Other offshore wind concepts, such as vertical axes wind turbines (VAWTs), and multi-rotor designs are still at much lower TRL level, suggesting that future wind North Sea wind farms will likely still be built with conventional technology. Floating wind technology is also at a lower TRL level, and is not expected to play a significant role in the Netherlands due to the shallow nature of the (Dutch part of the) North Sea.

Turbine capacity offshore has been growing steadily since the earliest Dutch wind farms with Egmond aan Zee (2007) and the Princes Amalia (2008) wind farms featuring 3.0 MW and 2.0 MW turbines, respectively. Wind farms constructed in the late 2010s and early 2020s have

[1] Offshore renewable energy (europa.eu)

featured turbines with rated capacities of 8.0 MW (Borssele I + II), 9.5 MW (Borssele III + IV), and 11.0 MW (Hollandse Kust Noord, Hollandse Kust Zuid). The upcoming Ecowende and OranjeWind wind farms (previously known as Hollandse Kust West VI and VII, respectively), are planned to consist of 15.0 MW wind turbines, with an estimated commissioning date of 2026 and 2028, respectively.

2.1.3 Future Lookout

In Europe, wind farms have already been operating with 11.0 MW wind turbines, with models in the 14.0-15.0 MW range already deployed for construction. At the moment, there are no wind farms planned in the next few years that will deploy wind turbines with higher capacities, although prototypes of models that can operate up to 20.0 MW^{+} have already been installed in China. Thus the TRL level for models above 15.0 MW up to 20.0 MW is deemed to be 7-8.

Although a lot of uncertainty remains, trends indicate that rated turbine capacities are expected to grow with project developer demands rapidly over the next few decades. Some Chinese manufacturers have already unveiled plans for 22.0 MW models to be designed over the next few years, and parallel trends in vessels and testing equipment suggest plans to expand further up to 30.0 MW. Growth at this pace, which intends to exploit scale economies at the level of a wind turbine, may be slowed by industry interest in exploiting the scale economies of mass production and standardization or e.g. regulatory restrictions on maximum tip height.

In addition, rated capacity growth presents additional technical challenges which may slow down growth even further as high TRL levels become harder to reach. For example, the physical loading experienced by blades during operation could lead to structural difficulties. A second example relates to the auxiliary wind markets, such as those for wind turbine installation and maintenance vessels, which have high lead times and may not be able to keep up with the ever-increasing masses of these wind turbines. A third example is related to the new innovative equipment that would need to be developed – failure rates with untested technologies are likely to be higher, leading to additional revenue losses and repair costs.

2.1.4 Fact sheets (scope, values)

2.1.4.1 Scope boundaries

The values present for the offshore wind fact sheet are for an entire wind farm, with characteristics deemed reasonable to expect for the appropriate decade. The uncertainty in these values is high and increases quickly towards 2050.

The following technical parameters are included:

- For the wind turbine, the
  - rated capacity
  - rotor power density (RPD)
  - diameter
  - hub height
  - maximum tip speed
  - rated rotor speed

- For the wind farm, the
  - rated capacity
  - number of wind turbines
  - electrical connection type
  - electrical connection voltage
  - water depth
  - spacing between wind turbines

The following economic parameters are included:

- The CAPEX of the turbine
- The CAPEX of the foundation
- The CAPEX of the electric infrastructure
- The CAPEX of the installation costs
- The CAPEX related to fixed project costs
- The OPEX per year related to wind farm operations and maintenance (O&M)
- The DECEX (decommissioning costs)

2.1.4.2 Technical parameters

The following table describes the assumed characteristics for wind farms over the coming decades

Parameter	Unit	2030	2040	2050	Level of Certainty
Rated capacity - WT	MW	17	21	25	Low
Rotor power density	W/m2	350	310	300	Low
Rotor diameter	m	249	294	326	Low
Hub Height	m	149.5	172	188	Medium
Tip Height	m	274	319	351	Low
Max tip speed	m/s	85	85	85	Low
Rated rotor speed	RPM	6.52	5.52	4.98	Low
Rated capacity - Farm	MW	2006	2016	2000	Medium
Number of WTs		118	96	80	Low
Electrical Connection Type		HVDC	HVDC	HVDC	High
Electrical Connection Voltage	kV	525	525	525	Medium
Water Depth	m	40	40	40	High
Spacing	D	8	8	8	Medium

Most of the parameters related to the characteristics of the wind turbine have a low certainty, stemming from the fact that it is highly uncertain how turbine rated capacity will continue to evolve over the decades. Rated farm capacity is slightly more certain, as that will be mainly limited by the evolution of the cable or pipeline technology, as well as the level of risk that the developer is willing to take on. The electrical connection type is likely to remain HVDC, as costs reduce, and losses remain below those of HVAC systems. The voltage level depends on the evolution of the HVDC technology. The water depth is set to a standard consideration for the North Sea. The spacing between wind turbines depends on how the progress of wake recovery techniques.

2.1.4.3 Wind turbine cost data (€ 2024)

Parameter	Unit	2030	2040	2050
CAPEX – Rotor Nacelle Assembly	MEUR/WT	12.3	13.8	16.3
CAPEX – Support structure	MEUR/WT	8.3	13.2	16.9
CAPEX – Power Electronics + export system	kEUR/MW	957	908	879
CAPEX - Installation	kEUR/MW	245	211	185
CAPEX - Project owners Costs	kEUR/MW	313	314	334
Total CAPEX	M€/MW	2500	2500	2400
ABEX/DECEX	kEUR/MW	211	196	184
OPEX	kEUR/MW/yr	52	37	33.2

Individually, the uncertainty of these estimates can be assumed to be ~15%. If taken together, the total uncertainty can be assumed to be ~10%.

2.2 Offshore Solar PV

2.2.1 Introduction

Offshore floating solar power is steadily gaining recognition as a viable addition to the renewable energy landscape, with the technology currently in a piloting stage. Several countries across Europe and Asia, such as the Netherlands, Norway, France, Greece, Italy, Belgium, China, and Singapore, are implementing support mechanisms for offshore solar projects. By harnessing solar energy overseas and oceans, this approach helps to address land limitations and represents a natural evolution following the recent success of inland floating solar installations. Offshore solar offers a valuable opportunity to diversify and strengthen global renewable energy sources.

This approach offers several key advantages, such as the ability to build larger installations offshore and share space and infrastructure with offshore wind farms, providing mutual benefits. Additionally, offshore solar has typically a smaller visual impact from the shoreline than offshore wind farms, allowing installations closer to the coast. offshore PV-modules may benefit from a lower operating temperature and therefore perform better than onshore PV-systems.

However, specific challenges remain. Further advancements are required to address soiling and module mismatch, which demand cost-efficient cleaning and maintenance strategies. Improvements in dynamic power cables and electrical infrastructure—particularly in integration with offshore wind systems—are also necessary. As the technology is still in early phases, the costs are relatively unknown. Balancing technical integrity, standardization, and cost-effectiveness across different environments and floater types will be key to the successful scaling of this technology.

2.2.2 Current State of Art

Offshore floating solar system developments have now reached Technology Readiness Level (TRL) 5, meaning a prototype has been demonstrated in a relevant environment but is not yet at full scale. The most notable advancements in the North Sea offshore environment come from Oceans of Energy (OOE) and SolarDuck. OOE positions its PV panels just above sea level, while SolarDuck places its panels much higher, above the highest waves. OOE is planning to install a system with a 3 MW capacity at the Blue Accelerator test site off the coast of Oostende, Belgium. Meanwhile, SolarDuck, in collaboration with RWE, has installed a 0.5 MW system at the North Sea Farmers near-shore test site off the coast of Scheveningen, Netherlands. Because so far none of the offshore pilots have been grid connected, there is limited experience with deploying and operating dynamic power cables. Also for that reason, there is limited knowledge available on the energy performance of offshore solar power plants.

2.2.3 Future Lookout

The offshore environment poses significant challenges for solar systems, particularly when waves can reach the solar panels. While raising PV panels above the waves can mitigate this issue, it also increases structural costs. In the coming years, companies will focus on enhancing system and structural integrity while driving down costs. The next phase involves upscaling (from TRL 6 to 7) to achieve installed capacities between 100 MW and 1 GW, optimized for integration with offshore wind farms. Following this, certification will be the next critical step. This entire process, particularly for offshore wind parks in the North Sea, is expected to take 3 to 8 years. However, smaller projects, such as those for island electrification or in less harsh environments, may be feasible in the nearer term.

2.2.4 Fact sheets (scope, values)

2.2.4.1 Scope boundaries

Oceans of Energy and SolarDuck, understandably protective of their Intellectual Property (IP), do not permit the sharing of technical details. To navigate this, DMEC has developed two comparable platform designs, each with different but realistic structural configurations. Similar designs have also been published by some international developers. These DMEC designs are conceptual rather than fully engineered, providing one option for PV panels positioned just above sea level and another for panels placed higher above the water. The key advantage of this approach is that it allows access to all structural technical details without IP concerns. The electrical systems need to be able to withstand the dynamics and corrosive environment of the North Sea. Additionally, special measures are necessary to protect the PV-system systems from the harsh North Sea environment when mounted just above the sea level.

Figure 1: PV panels just above the sea level l

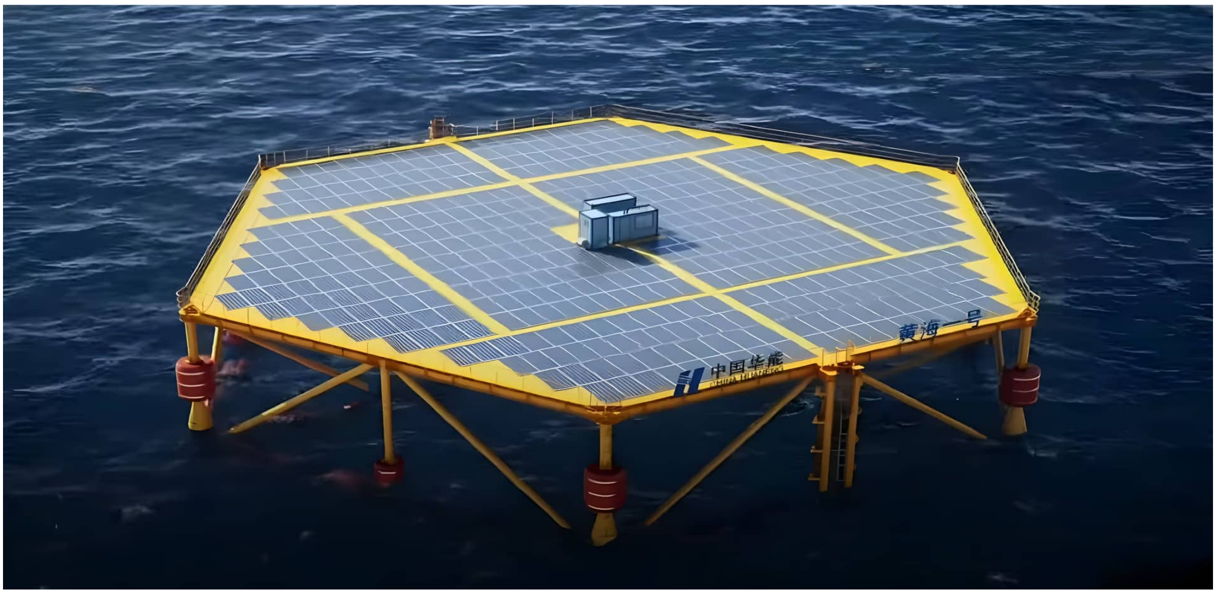


Figure 2: PV panels higher above the sea leve

2.2.4.2 Technical parameters

The modelling results are based on two DMEC concept designs—one with PV panels just above sea level and one with panels higher above sea level—combined with a PV system using research cell efficiencies[2] to estimate future performance for 2030, 2040, and 2050:

- **2030**: Standard crystalline silicon (2023 research cell efficiency: ~26%)
- **2040**: Crystalline silicon and perovskite tandem cell (2023 research cell efficiency: ~34%)
- **2050**: Other developments (non-concentrator research cell efficiency: ~40% in 2023)

[2] NREL Best Research Cell Efficiency Chart 2023

The efficiency of floating modules will be slightly lower than research cell efficiency due to industrial cell limitations and electricity losses in the panels, cabling, and inverters. These modules can be interconnected to form larger floating platforms, which are moored to the seabed. The size of these parks can range from MW to GW scale. For park efficiency, the results from Papadopoulos' 2015[3] thesis have been used.

2.2.4.3 Economical parameters

Operational and capital expenditure for offshore solar energy have been estimated based on DMEC's in-house modelling and expertise. Publications from the EU-SCORES project have provided insights into the levelized cost of energy (LCOE) for this technology.

While the solar energy industry—particularly for roof-mounted and ground-mounted systems and inland floating solar—has grown rapidly, offshore solar will require more robust infrastructure to withstand the marine environment. Nevertheless, offshore solar offers significant opportunities, such as larger installations and synergies with offshore wind energy through shared infrastructure.

According to EU-SCORES, the LCOE is expected to range from €60 to €110/MWh (considered optimistic), especially for larger installations in the 1,500 MW scenario. This cost reduction is primarily driven by economies of scale, though it excludes the cost of electrical infrastructure.

Before accurate estimations on CAPEX and OPEX can be obtained, more practical experience on manufacturing, deploying, operating and maintaining OFPV plants is needed.

Regarding CAPEX, for several components, cost estimates can be relatively accurate, such as PV-modules, cables and electronics, because these can be derived from inland PV-system cost calculations. For offshore-specific components, but not specifically designed for OFPV, cost estimates are relatively accurate, such as anchors and mooring cables. While the OFPV system designs are still in evolution, we do not know which mooring layout choices are most cost-effective.

For OFPV-specific components, like the floating substructure and the dynamic export cable, no transparent cost estimations are available. Because we expect these components to account for large fraction of the total system cost, the uncertainty in the cost of these components greatly affects the overall cost estimate uncertainty.
Other important cost drivers are the offshore installation procedures for OFPV plants, operation and maintenance actions, and end-of-life decommissioning costs. Also for these cost components, no transparent cost estimations are available.

For LCOE calculations, the lifetime of the systems is a crucial parameter. Although the current OFPV have a design lifetime, very limited experience is available to confirm whether these projected lifetimes are feasible.

[3] Modelling of collection and transmission losses of offshore wind farms for optimization purposes, A. Papadopoulos, TUD Thesis, Feb 2015

2.2.4.4 HSE parameters

As with all structures that are placed into the sea, it is important to consider their impact on the environment. Large arrays of floating solar platforms will have effects on the local ecosystems which must be monitored.

- **Loss of sunlight to lower pelagic zones**: introducing large arrays of floating solar panels will reduce the incident sunlight on areas of the sea which could lead to a decrease in biodiversity in the area. However, due to ocean currents, it is hard to estimate if this will actually have a considerable impact on local biodiversity. Testing water eDNA (environmental DNA) could be a potential solution to track the health of the ecosystem before, during and after installation. It is expected that roughly 150MW could be installed per sq km on a system level, excluding mooring.

- **New habitats for wildlife**: These large structures could be used as refuge or a resting place for several species in the North Sea. Birds will likely rest and nest on the floating platforms leading to biofouling which will have to be cleaned regularly to avoid efficiency losses. Fish could use the floaters for safety and the added weight of algae and molluscs growing on the floaters will need to be considered. Having to remove biofouling will add an expense to the lifetime maintenance of the arrays and wildlife populations will need to be monitored to ensure no net loss.

Another important consideration is the safety aboard the structures. To perform operation and maintenance activities in a safe manner, guard rails, walkways and connection points have been included in all three designs. Similar to the maintenance of offshore platforms like oil rigs and wind turbines, weather windows determine when and for how long work can be conducted. The panels should also be cleaned in regular intervals to prevent salt deposition and biofouling and this could potentially be done by robots reducing risks.

2.3 Disruptive/emerging innovations

2.3.1 Offshore Wind

The design of offshore wind turbines stems largely from the technological convergence that wind turbines experienced onshore, before large-scale offshore wind farms started to be developed. Modern offshore wind turbines are mostly based on a standard 3-bladed, pitch-controlled, variable-speed horizontal-axis design.

Figure 3: Standard three blade wind turbine

This design was adapted for offshore purposes through installing a foundation to the seabed and mounting the wind turbine on top. This has been feasible for sea depths of up to around 60m. Developments to extend to deeper waters is foreseen. For deeper waters the turbine can be mounted on a floating platform which is demonstrated already at a smaller scale. There are several platform and anchoring concepts for different site conditions. In the Dutch part of the North Sea, however, where depths don't exceed much more than 50m, it is unlikely that floating wind turbines will appear in the energy generation mix.

For the Mediterranean and Atlantic coast or the northern parts of the North Sea there is an increasing interest in floating wind energy. Although at the moment most of these developments assume a horizontal axis Wind Turbine (HAWT) there is still some interest in using a Vertical Axis Wind Turbine (VAWT) due to the fact that the center of gravity is much lower which has a positive effect on the stability of the platform and thus on the performance of the system. Some companies developing multi-rotor wind turbines have also started to appear, attempting to develop radically different designs that may not be currently economical, but in the future may find a niche market.

Figure 4: Vertical Axis (left) and multi rotor (right) Wind turbines

3 Conversion

The conversion of electricity into molecules plays a crucial role in preventing grid congestion. Renewable energy-generated electricity can be utilized in multiple ways: it can either be converted into molecules offshore and then transported to shore, or it can be transmitted as electricity to onshore facilities where it is subsequently used for molecular production. Each approach presents distinct advantages and challenges in terms of feasibility, energy efficiency, transmission losses, and overall system integration.

The following section will explore different hydrogen production methods derived from electricity, alongside hydrogen purification technologies. Specifically, the focus will be on two primary types of hydrogen production:

1. **Green Hydrogen** – Produced through water electrolysis using renewable electricity.
2. **Blue Hydrogen** – Derived from natural gas with carbon capture and storage (CCS) integration.

These production pathways, along with their associated purification technologies, will be analyzed in detail to assess their role in the future energy landscape.

3.1 Green Hydrogen

3.1.1 Introduction

Green hydrogen production at sea represents a promising avenue for additional demand to utilize the produced electricity when there is a lack of electricity demand onshore The production of hydrogen without any carbon emissions is called green hydrogen. Conversion of electricity offshore to hydrogen presents a method by which hydrogen can be produced locally at the offshore wind farm location. Ambitious growth targets for offshore wind farms in the North Sea also increase electrical infrastructure requirements and therein hydrogen presents itself as a suitable energy carrier that can be produced at sea, and in turn, reduce grid dependency on offshore developments. This section provides an overview of the wind farm configurations, and the considerations made in the reported fact-sheets.

3.1.2 Current State of Art

The Technology Readiness Level (TRL) is a design parameter for hydrogen production platforms. While green hydrogen production has been established as a reliable system for several years, with multiple original equipment manufacturers (OEMs) offering standardized packages for onshore applications, these packages are typically limited in scale, with current capacities reaching a maximum of 10 to 20 MW for Proton Exchange Membrane (PEM).

In contrast, offshore hydrogen production remains in the development phase, and large-scale systems have not yet been deployed in marine environments. Several pilot projects operating in the megawatt range are currently being tested offshore. The insights gained from these projects will provide important data in scaling up the electrolyzer capacity, ultimately paving the way for the transition to gigawatt-scale offshore hydrogen production. An overview of relevant pilot projects is presented below:

- **ERM Dolphyn** Pilot **Project** – Production unit size unknown
- **Lhyfe –** Sealhyfe - 1 MW hydrogen production unit
- **PosHYdon** – 1 MW hydrogen production unit

3.1.3 Future Lookout

The future outlooks on hydrogen production systems do not see any technical showstoppers. However, it must be noted that certain equipment in large offshore hydrogen production systems are in the development phase. Currently, demonstration and deployment of hydrogen production is in place, therefore from a TRL standpoint, a complete operational unit is expected to be available within the upcoming years.

3.1.4 Fact sheets (scope, values)

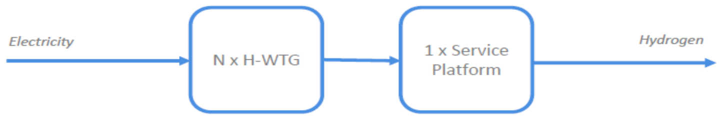
The fact sheets outline two key approaches to offshore wind-powered hydrogen production: hydrogen production at the turbine and hydrogen production in a centralized manner. The first system focuses on a 15 MW off-grid hydrogen production system integrated directly in the wind turbines, while the second involves a 100 MW centralized hydrogen production platform powered by a wind farm.

Three further system variants for centralized hydrogen production were evaluated, with varying electrical connection system configurations. An overview of the relevant parameters, assumptions, and system boundaries considered to generate the fact sheet numbers is provided below.

3.1.4.1 Scope boundaries

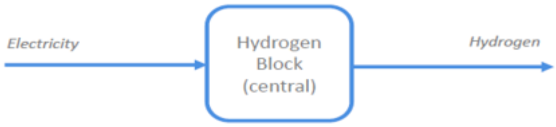
Scope boundaries & Assumptions for the fact sheets for each case are presented in Figure 5 and Figure 6 are further described below:

- 15 MW Definition



INPUT	Unit	H WTG	Service Platform
Power	MW	15 MW WTG / 12 MW Electrolyzer	N x H-WTG
Operational mode		Wind following H2	Only compression service (?)
Voltage	kV	66 kV AC	
Electrical Grid	-	Grid Forming Local (TRL 7)	
Electrolyser Type	-	Pressurized PEM	
Cooling Method		Seawater	
Purified Water		Local from seawater	
Water Depth	m	40	40
H2 Export		30 bar	90 bar
H2 Quality		Gasunie spec (98%)	Gasunie spec (98%)
E Export		-	-
Life time		30 years	30 years

Figure 5: Hydrogen Block 15MW - Input variables



INPUT	Unit	100 MW AC – Off Grid	100 MW AC – Grid Connected	100 MW AC – Grid HVDC
Power	MW	100 MW Electrolyzer	100 MW Electrolyzer	100 MW Electrolyzer
Operational mode		Wind following H2	Wind following H2	Wind following H2
Voltage	kV	66 kV AC	66 kV AC	**132 kV AC**
Electrical Grid	-	Off Grid	**Grid Connected , stability**	**Upstream HVDC, stability**
Electrolyser Type	-	Pressurized PEM	Pressurized PEM	Pressurized PEM
Cooling Method		Seawater	Seawater	Seawater
Purified Water		Local from seawater	Local from seawater	Local from seawater
Water Depth	m	40	40	40
H2 Export		90 bar	90 bar	90 bar
H2 Quality		Gasunie spec (98%)	Gasunie spec (98%)	Gasunie spec (98%)
E Export		-	-	-
Life time		30 years	30 years	30 years

Figure 6: Hydrogen Block 100MW - Technical Input Variable

Overview sources:

Data presented in the value and estimates are based on internal engineering practices from projects and vendor provided information.
Relevant Inputs have been derived <u>but are not limited to</u> the following:

1. **Cummins. (n.d.).** Electrolyser Module KPIs. Retrieved from https://www.cummins.com
2. **International Renewable Energy Agency (IRENA)**. (2020). Making the breakthrough: Green hydrogen policies and technology costs. Retrieved from https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_Hydrogen_breakthrough_2021
3. **Eaton. (n.d.). Transformer Distribution Catalog**. Retrieved from https://www.eaton.com/content/dam/eaton/products/low-voltage-power-distribution-controls-systems/transformer/files/transformer-distribution-catalog-volume-2-tab-ca08100003e/

15 MW Decentral Hydrogen Production:
The Offshore Wind Turbine Hydrogen Production System combines wind energy capture, HV & LV electrical systems, PEM electrolysis technology, and on-site postproduction technology to produce hydrogen gas for consumption purposes onshore. This system functions by allowing wind turbines to operate in a wind-following mode, capturing varying wind energy - without any operational mode changes of the wind turbine taking into consideration the hydrogen production system. The (green) electricity generated is used to power a Proton Exchange Membrane (PEM) electrolyser, which uses the electricity to separate purified water into its components, hydrogen and oxygen. Local cooling and auxiliaries are made available to ensure the reliability and longevity of the system. Systems are designed such that unmanned operation is attained.

Key points overview:

- Wind turbine only hydrogen producing 15 MW Wind / 12 MW electrolysis unit
- Grid Forming wind turbines will be available
- Voltage levels of Wind turbine output 66 kV AC
- Requirement of a Service Platform for further compression
- H_2 export at 90 bar
- Wind turbine modifications are considered out of the scope | Hydrogen production system is treated as an add-on to standard WTG designs

Electrolysis PEM 100MW AC – Off-grid Hydrogen Production:
It's configured to generate hydrogen when the wind farm is operational, utilizing 100 MW of power generated by the wind farm. It's important to note that the platform is non-operational when the wind farm is down, and it will automatically shut down in the absence of wind farm power generation. To achieve operational readiness, the system's startup and availability depend not only on the ramp-up and down capability of the electrolyser but also on the auxiliary energy storage systems integrated into the platform.

- Wind farm Array connected to centralized hydrogen production platform
- Grid forming turbines assumed | No grid connection is available for support
- Voltage Level intra array cable system – 66 KV AC
- H_2 export at 90 Bar
- No electrical connection to shore, energy storage, e.g. solar PV panels plus a battery, is required for support.

Electrolysis PEM 100 MW AC – Grid connected to shore Hydrogen Production
This Offshore Hydrogen Production Platform also integrates high-voltage electrical systems, Proton Exchange Membrane (PEM) electrolysis technology and on-site post-production capabilities. It is purpose-built to generate hydrogen gas efficiently from electricity sourced from a 66 kV wind turbine array / string. The PEM electrolyser, a key component, converts electrical energy into hydrogen gas with a decreasing efficiency over the lifetime of the electrolyser. Additionally, the platform incorporates local cooling and auxiliary systems to ensure the system's reliability and longevity.

- Wind farm array connected to a centralized hydrogen production platform
- Grid forming turbines assumed, as grid connection is only available for system support
- Voltage Level intra array electrical system – 66 kV AC
- H_2 export at 90 bar
- Electrical system connection to land via HVAC is considered out of scope along with electrical system modifications prior to electrical feed into electrolyser input.

Electrolysis PEM 100MW AC – Grid-connected Hydrogen Production via nearby HVDC SS:
This Offshore Hydrogen Production Platform integrates high-voltage electrical systems, (PEM) electrolysis technology, and on-site post-production capabilities. It is purpose-built to efficiently produce hydrogen from electricity sourced from the intra array grid, be it from the wind turbine electrical array or the substation. The PEM electrolyser converts electrical energy and water into hydrogen with a high efficiency. Additionally, the platform

incorporates local cooling and auxiliary systems to ensure the system's reliability and longevity.

- Wind farm Array connected to centralized hydrogen production platform
- Grid forming turbines assumed as grid connection is only available for system support
- Voltage Level grid connection – 132 kV AC
- H_2 export at 90 bar
- Electrical system connection to land via HVDC SS is considered out of scope along with electrical system modifications prior to electrical feed into electrolyser input.

For all hydrogen production systems, the breakdown in the system set-up as follows:

Electrical Power:

- Transformers
- Rectifiers
- Energy Storage Units

Electrolyser:

- Electrolyser Stacks
- Power rectifiers
- Control Panels
- Ultra-pure water circulation loop
- Rectifier Cooling Systems

Balance of Plant:

- Water Purification System
- High Voltage Alternating Current (HVAC)
- Cooling systems
- Aux. Instrumentation
- Hydrogen compression
- Hydrogen dewatering

Focussing on the three electrical systems, i.e. the transformers, rectifiers and energy storage units are established technology and therefore little improvement is foreseen for these components. Electrolyser module improvements are foreseen soon, and standardization of balance of plants to support electrolyser modules with specific size will lead to optimal sizing of auxiliary units for service to groups of electrolyser modules. Aggregation of larger electrolyser modules leads to a more efficient sizing balance of plant units.

3.1.4.2 Technical parameters

Electrolyser module parameters as presented in the factsheet are identical for centralized and decentralized. This is due to the assumption that there will not be a difference in stack design between the central or decentral systems. Stack performance and other KPI as described in the fact sheet, can be used for modelling. The relevant certainty of the parameters are highlighted in the fact sheet, no showstoppers are foreseen in the increase in module reference capacities. An improvement in the electrical performance of the stack is expected, which is the driver for improvements in system energy efficiencies.

Difference can be noticed in balance of plant metrics for centralized and decentralized cases, aggregation of large modules leads to optimized usage of Balance of plant components in the central concept, whereas in the decentral case component efficiencies are lower due to a reduced utilization of each of the described auxiliary unit systems. Data quality for balance of plant systems are developed in-house but based upon vendor data.

Electrical system inputs prior to the feed into electrolysis units in the form of transformers and rectifiers are established technology. Little improvements are foreseen given the high efficiency ratings of electrical power units.

3.1.4.3 Economical parameters

The major capital expenditures for offshore generation of hydrogen are determined by the conceptual design decisions. Current systems being tested for offshore applications are standardized vendor packages for onshore applications that have had various design adjustments to make them suitable for the offshore environment. This technique is viable for small-scale hydrogen production and thus the first demo projects, but it is not cost-effective for large-scale offshore hydrogen generation.

A cost difference in both capital and operational expenditures is seen between decentral and centralized cases due to the increase in operation requirements for individual hydrogen production turbines offshore both during the installation and commissioning phase and during the operational lifetime of the platform and windfarm.

A cost discrepancy exists between the three centralized hydrogen production platforms, this arises due to the varying electrical power rectification requirements in the case of off-grid, grid connected AC and grid connected via a HVDC SS. While the variants do not impact technical performance parameters due to high electrical efficiency economic costs are considered.

3.1.4.4 HSE parameters

For the design of an offshore hydrogen production platform, several critical HSE (Health, Safety and Environment) factors need to be considered to ensure safe and efficient operations. Hydrogen safety is paramount, requiring the thorough management of risks related to leakage, ignition, and explosion, given hydrogen's properties. Fire and explosion protection, integrated through active and passive systems designed to detect, suppress, and contain incidents. Additionally, the design accounts for the unique risks associated with Battery Energy Storage Systems (BESS) and other electrical power equipment, such as thermal runaway and fire. Using early detection methods and implementing mitigation measures the safety can be ensured.

HSE principles serve as checks and barriers to platform design which will also include the necessary safety aspects including but not limited to emergency response systems, human factor design principles and environmental protection.
Hydrogen production at sea introduces environmental challenges that need to be carefully managed to safeguard both the marine and atmospheric ecosystems.

Emissions to sea: Focus on preventing oil discharge, brine dilution, and regulating cooling water temperatures. All discharge into the sea is conducted in a controlled manner. The impact is likely to be reduced with improvement in technology. Reverse Osmosis requires chlorine, sodium bi-sulphite, and anti scalants; alternative fouling prevention methods will expand in time.

Emissions to air: Management of continuous and discontinuous emissions, including hydrogen and NOx, with sensors and venting systems are considered.

3.1.4.5 Offshore Brine Disposal[4]

In addition to hydrogen, electrolyzer systems generate several by-products, including oxygen, heat, and brine (saltwater). If these by-products are not repurposed for other applications, they are classified as waste streams, necessitating appropriate disposal measures. Effective utilization or safe management of these outputs is essential to minimize environmental impact and enhance overall system efficiency.

Any water treatment process would need to remove approximately 35g/l of dissolved matter from sea water. An Reverse Osmosis (RO) process requires between 1,4 and 1,8 litres of seawater for every litre of purified water produced, meaning that for every litre of water produced, between 400-800 ml of additional wastewater is produced. This would also mean that the resulting wastewater concentration is around 44 – 88 g/l. Any salt concentration higher than 50g/l is defined as brine, meaning that for every 1 litre of water produced, there will be up to 2 litres of brine produced.

Currently, the plans of bigger project developers are to pump the brine back into the ocean. This could cause an increase in salinity, which leads to decreasing dissolved oxygen content in the ocean, causing potentially hypoxic conditions that can threaten marine life.

Future Outlook: Brine could be valorised (for instance., mineral recovery). The North Sea contains Critical Raw Materials (CRM) in varying quantities of elements such as lithium, strontium and magnesium. There is potential for combining CRM recovery from offshore brines, although there is no research done yet.

Ecological Impact of brine disposal[5]: Marine life is negatively affected by brine discharge. Osmotic imbalance, changes in habitat quality, effects on food chains, disruption of reproductive cycles, shifts in species diversity are some of the factors that has impact of the ecology. Brine discharges primarily affect benthic communities due to its heavy weight, which causes it to sink to the seafloor. Studies show that the ecological effects of brine discharges are complex, with the main contributing factors being high salinity, the presence of heavy metals, oxygen depletion and high temperatures (typically between 30 and 50 degrees Celsius).

[4] State_of_art_in_Offshore_Hydrogen_production.pdf
[5] Environmental effects of brine disposal and seawater usage for offshore green hydrogen production and storage in the Dutch North Sea.

3.2 Blue Hydrogen

3.2.1 Introduction

Blue hydrogen, valued at USD 2 billion in 2023[6], is expected to grow significantly, driven by its role in reducing carbon emissions while leveraging existing natural gas infrastructure. Produced through steam methane reforming (SMR), partial oxidation (POX) or auto-thermal reforming (ATR) combined with carbon capture and storage (CCS), blue hydrogen is seen as a crucial bridge towards a low-carbon economy. Although green hydrogen is emphasized as the ultimate future energy source, its current technical and economic limitations make blue hydrogen a more viable option in the short to medium term[7,8].

Centralized production of blue hydrogen is key to meeting immediate hydrogen demand and ensuring secure supply chains. With capture rates exceeding 90% in some facilities, blue hydrogen technology demonstrates the potential to significantly reduce greenhouse gas emissions[9]. National infrastructures, like hydrogen backbones, are essential to connect production with consumption and accelerate the adoption of CO_2-free hydrogen[10]. As blue hydrogen gains traction, it will play a critical role in achieving the 2030 emission reduction targets, setting the stage for a sustainable hydrogen economy.

The primary objective of this chapter is to give an overview of the status of technology development and a techno-economic and environmental parameters of the production of natural gas-based hydrogen with accompanying carbon capture and storage (CCS) technology that will be used in the North Sea Energy models.

3.2.2 Current State of Art

Steam reforming production can utilize small-chain hydrocarbons, ranging from natural gas to naphtha. These plants, typically sized between 10–170 kt/year, account for nearly 50% of the world's hydrogen supply[11]. There are a few different carbon capture options for the SMR process, see Figure 7:

- **Option 1**. Capturing CO_2 from the syngas prior to the PSA (typical efficiency 78%$_{HHV}$, Overall Carbon Capture rate (CCR) = 54%)
- **Option 2**. Capturing CO_2 from the tail gas after the PSA (typical efficiency 79%$_{HHV}$, Overall CCR = 52%)
- **Option 3**. Capturing CO_2 from the flue gas exiting the furnace(typical efficiency 69%$_{HHV}$, Overall CCR= 91.1%)
- **Option 4**. Combined option 1 and 3, (typical efficiency 79.5%$_{HHV}$, Overall CCR= 91.2%)

[6] https://www.gminsights.com/industry-analysis/blue-hydrogen-market#:~:text=The%20blue%20hydrogen%20market%20size%20exceeded, last visit 04/09/2024
[7] Newborough M, Cooley G. Developments in the global hydrogen market: The spectrum of hydrogen colours. Fuel Cells Bulletin. 2020, 2020(11):16-22.
[8] El-Emam RS, Özcan H. Comprehensive review on the techno-economics of sustainable large-scale clean hydrogen production. Journal of Cleaner Production. 2019;220:593-609.
[9] Blue hydrogen in a low-carbon energy future, DNV report, 2023.
[10] Poort naar een CO_2-vrije waterstofeconomie,H2 gateway
[11] Kalamaras and Efstathiou 2013, Hydrogen Production Technologies: Current State and Future Developments

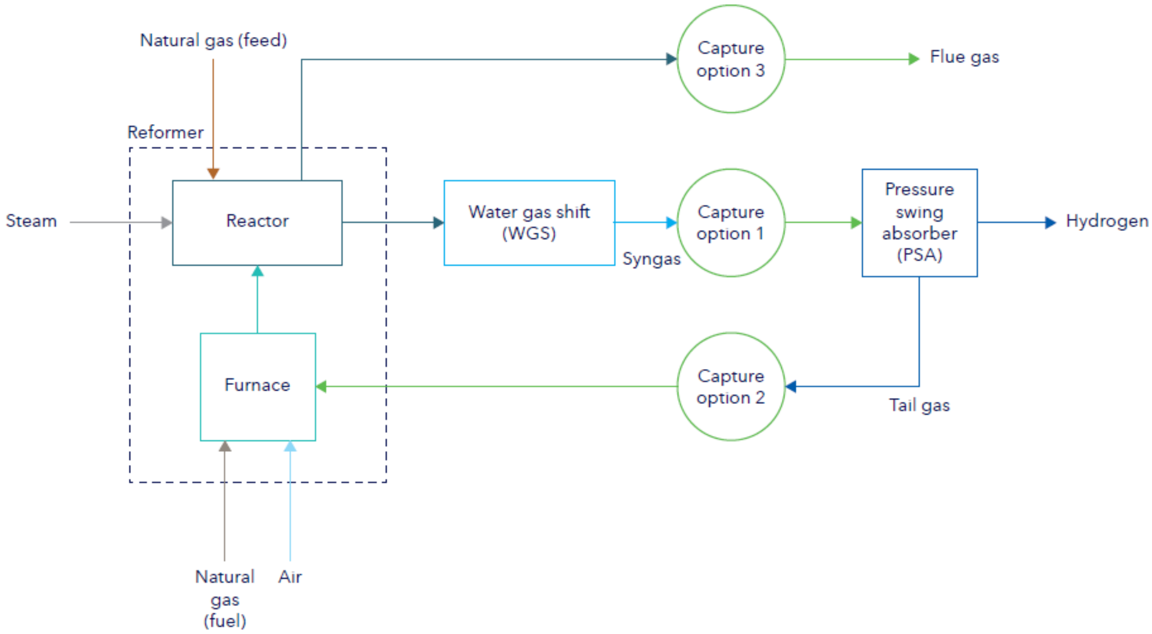


Figure 7 SMR with 3 different options for CO_2 capture[12]

The SMR process is not optimized for carbon capture due to the difficulty and cost of capturing CO_2 from flue gases. This limitation is driving interest in alternatives like Partial Oxidation (POX) and Autothermal Reforming (ATR), which enable more efficient carbon capture. POX, operating at high pressures and without external heat, is widely used in industry with enhanced CO_2 capture potential. ATR combines POX and SMR advantages, offering scalability and efficiency, particularly with CCS integration.

These technologies are established in industry, with ATR commonly used in methanol (oxygen-blown) and ammonia (air-blown) production from natural gas. ATR's efficiency can reach up to 80% HHV with a CCR of 94%. Due to these efficiency gains, investing in POX and ATR for blue hydrogen is critical for future hydrogen demand and carbon reduction goals.

Figure 8[13] outlines the TRLs of low-emission hydrogen technologies, which differ mainly by process conditions and requirements for feedstock purity, steam, and electricity. Optimal technology selection depends on specific site and boundary conditions.

[12] Blue hydrogen in a low-carbon energy future, Exploring what it takes to produce low-carbon blue hydrogen, DNV report
[13] The future of Hydrogen, Seizing today's opportunities, Report prepared by the IEA for the G20, Japan, 2019

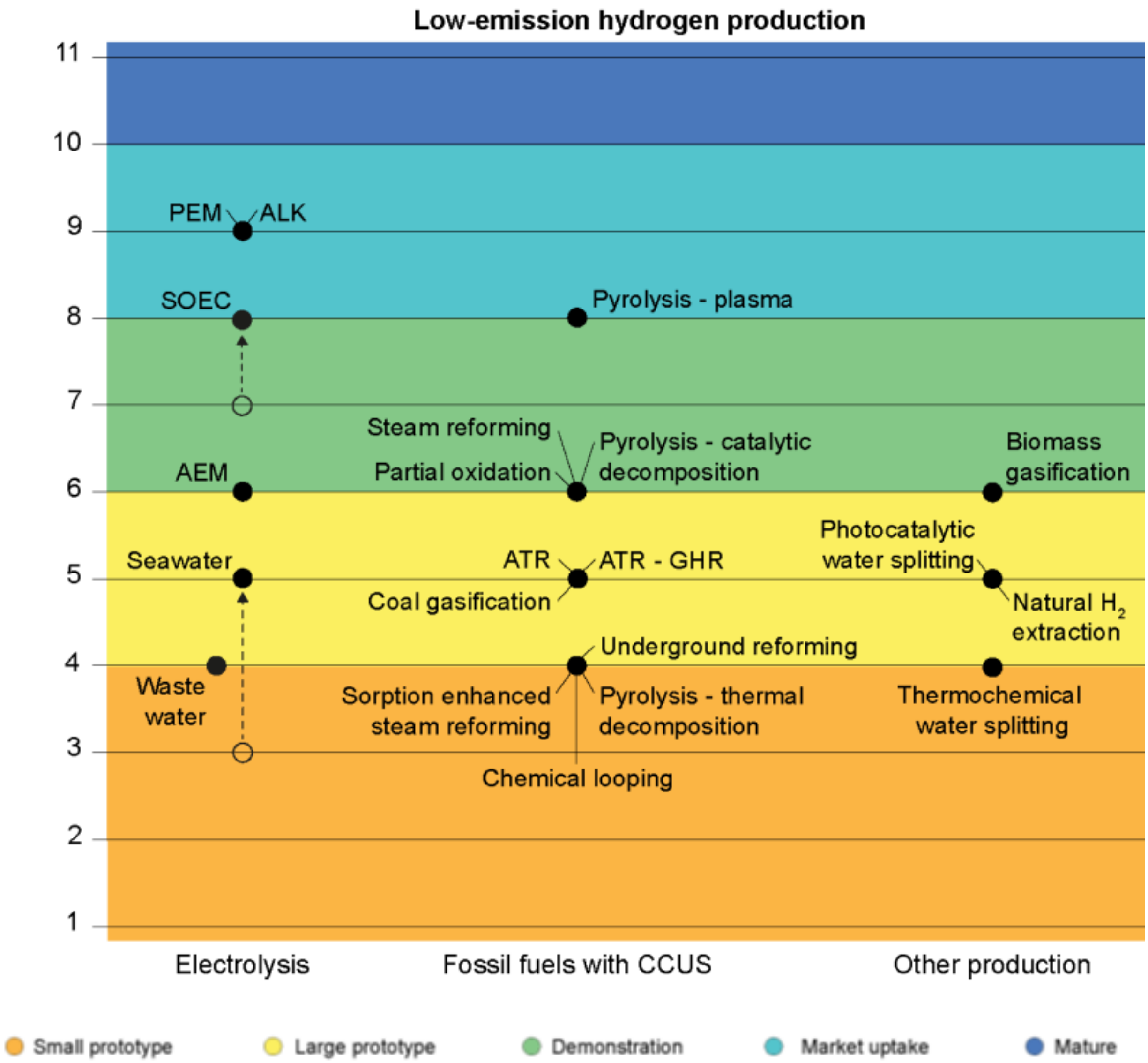


Figure 8 An overview of technology readiness level for different low-emission H_2 production technologies. Notes: AEM = anion exchange membrane; ALK = alkaline; PEM = proton exchange membrane; SOEC = solid oxide electrolyser cell. Biomass refers to both biomass and waste. Arrows show changes in technology readiness level as a consequence of progress in the past year. For technologies in the CCUS category, the technology readiness level refers to the overall concept of coupling production technologies with CCUS and high CO_2 capture rates.

The North Sea region is well-suited for scaling and decarbonizing hydrogen supply, especially in coastal industrial hubs. Key factors include a robust industrial base with nine major hubs, strong climate policies promoting low-carbon investment, existing hydrogen pipelines, proximity to CO_2 storage sites, and potential for offshore wind power. The region is politically motivated to use hydrogen to sustain industrial activity.

The North Sea has some of the EU's most advanced CO_2 storage sites. Since 1996, Norway’s continental shelf has stored CO_2 at a rate of 1 $MtCO_2$ per year—over double the emissions from a large-scale hydrogen plant. While progress has been slow, multiple North Sea projects are now leading European CCUS initiatives. These projects vary: some aim to store CO_2 under territorial waters using local natural gas, others to import gas for hydrogen production with CO_2 export for storage (e.g., to Norway's shelf), and some propose importing hydrogen from overseas production sites with nearby storage. Policy and funding will heavily influence which of these pathways gain support, with certain policies potentially favoring local hydrogen production[14].

The IEA[15] has an interactive map that details Europe's low-emission hydrogen projects, covering technologies and development stages from conceptual to operational. Currently, Europe has 43 fossil fuel-based hydrogen projects with CCUS, totaling an expected production of 9,380 kt H_2 per year. Most projects remain in feasibility or conceptual phases, with only four operational or in advanced stages, totaling 160 kt/year. The largest, Shell's 100 kt/year Pernis gasification plant in the Netherlands, will fully utilize CCUS once the Porthos project is active.

In the UK, BP's Teesside project, still conceptual, aims to produce 3,033 kt H_2 annually, potentially becoming the country's first hydrogen transport hub. It plans to capture up to two million tonnes of CO_2 per year, leveraging proximity to North Sea storage.

In the Port of Rotterdam, German energy provider Onyx Power intends to build a low-carbon hydrogen plant producing 300 kt H_2 per year, with CO_2 stored in offshore fields to cut emissions by 2.5 million tonnes annually. Air Products and Chemicals, Inc. also plans a blue hydrogen plant in Rotterdam by 2026, supplying ExxonMobil and others via a connected pipeline and linked to the Porthos CO_2 transport and storage system.

3.2.3 Future Lookout

The technology readiness level (TRL) for blue hydrogen production is particularly linked with CCS (Carbon Capture and Storage) technologies, remains in the early to mid-stages of development (TRL 4-6)[16]. Many aspects of the blue hydrogen supply chain require further advancement, particularly in cost-effective CO_2 separation technologies, such as chemical looping and hydrocarbon pyrolysis. Although some CCS technologies can currently capture 80-95% of CO_2, they are not yet efficient or cost-effective enough for large-scale commercial application[17,18]. The outlook for the next decade indicates that steam reforming of fossil fuels will likely remain the dominant method of hydrogen production, with ongoing efforts to improve efficiency through integrating chemical looping and CO_2 sequestration.

However, several factors could hinder the scale-up of blue hydrogen production. A significant challenge is the immaturity of CCS technologies, which are not yet capable of capturing enough CO_2 to meet future emission reduction targets. Furthermore, methane emissions associated with the extraction and processing of natural gas present environmental concerns, and controlling these fugitive emissions will be critical for blue hydrogen to be

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[14] The future of Hydrogen, Seizing today's opportunities, Report prepared by the IEA for the G20, Japan, 2019

[15] Hydrogen production projects interactive map – Data Tools - IEA, last visit 05/09/2024

[16] AlHumaidan FS, Halabi MA, Rana MS, Vinoba M. Blue hydrogen: Current status and future technologies. Energy Conversion and Management. 2023; 1;283:116840.

[17] Moliner R, Lázaro MJ, Suelves I. Analysis of the strategies for bridging the gap towards the Hydrogen Economy. International journal of hydrogen energy. 2016;41(43):19500-8.

[18] Ozawa A, Kudoh Y, Murata A, Honda T, Saita I, Takagi H. Hydrogen in low-carbon energy systems in Japan by 2050: The uncertainties of technology development and implementation. International Journal of Hydrogen Energy. 2018 Sep 27;43(39):18083-94.

viewed as a low-carbon solution[19,20]. Another major hurdle is the high cost of implementing CCS technologies at scale, which remains prohibitively expensive, especially when aiming to reduce emissions to acceptable levels. To enable the large-scale industrialization of blue hydrogen, it is crucial to increase research and development efforts in CCS technologies. This will require greater government support, stronger collaboration between industry and research organizations, and the scaling of CCS pilot projects toward commercialization.

3.2.4 Fact sheets (scope, values)

The NSE5 factsheets were created for the production of grey hydrogen, blue hydrogen via SMR route with amine (MEA) absorption for CO_2 removal from flue gases, and blue hydrogen production using the ATR route. Data for the grey hydrogen and blue hydrogen production via SMR route are mostly based on literature[21] in which standalone state-of-art "greenfield" plant operating in merchant plant mode (no integration with other industrial processes within industrial complex) was assumed.

3.2.4.1 Scope boundaries

The system boundaries for the grey H_2 production are given in Figure 5. Natural gas enters the pretreatment unit, where it undergoes hydrotreatment. This is achieved by recycling a small amount of product hydrogen back to the hydrotreatment unit. Afterward, sulphur and chlorine compounds are removed. In the pre-reforming stage, an adiabatic reactor removes light hydrocarbons. In the reforming step (without CO_2 capture), the syngas produced is fed into a High-Temperature (HT) water-gas shift (WGS) unit, where remaining CO reacts with steam to form H_2 and CO_2, resulting in syngas with 2-3% CO by volume. This gas is then sent to a PSA unit, where hydrogen is produced at 99.999% purity with a recovery rate of 85-90%. The off-gases from the PSA unit are used as fuel for the reformer. High-pressure (HP) steam is generated by recovering heat from the convection section of the flue gases from the reformer unit and cooling the syngas from the HT-WGS unit. Any excess heat is utilized for power production in the steam turbines.

Blue hydrogen production plant via SMR route presented in Figure 9 has same process steps as grey H_2 production route. CO_2 is captured from the flue gas using MEA solvent. To meet the steam demand of the CO_2 capture plant, natural gas consumption has been increased and several of the heat exchangers and steam generating coils of the reformer are enlarged. Due to the requirement to extract low pressure steam, instead of condensing a back pressure steam turbine is installed. The mass and energy balance, and costs estimate for SMR cases are taken from literature[21] . Level of certainty of the values reported, and their comparison to other literature data will be discussed in the following chapters. For SMR route, H_2 product is produced at pressure of 25bar, thus additional compression step is required for grid injection.

[19] Howarth RW, Jacobson MZ. How green is blue hydrogen?. Energy Science & Engineering. 2021;9(10):1676-87.

[20] Longden T, Beck FJ, Jotzo F, Andrews R, Prasad M. 'Clean'hydrogen?–Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen. Applied Energy. 2022;306:118145.

[21] Collodi G, Azzaro G, Ferrari N, Santos S. Techno-economic evaluation of deploying CCS in SMR based merchant H_2 production with NG as feedstock and fuel. Energy Procedia. 2017;114:2690-712.

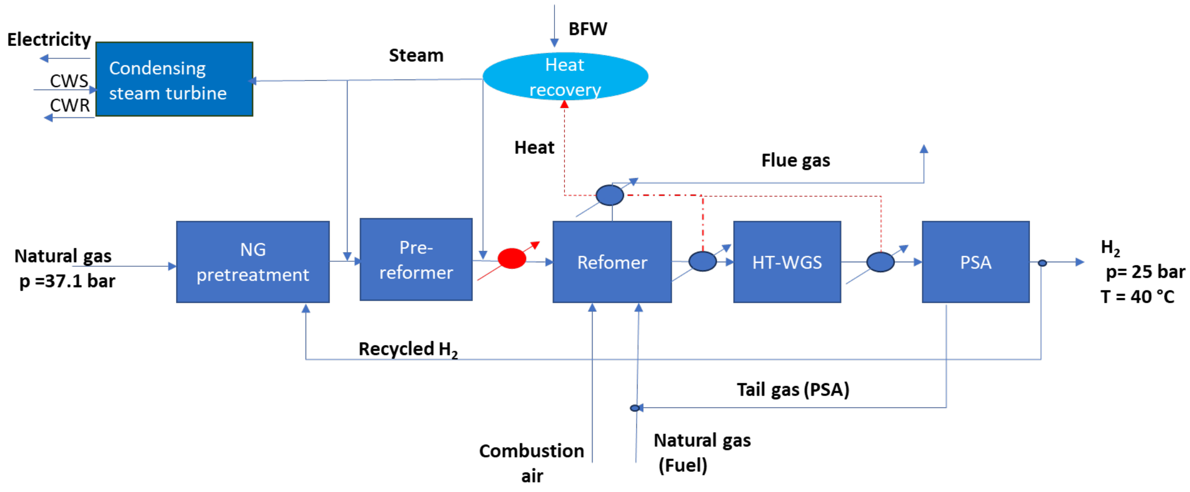

Figure 9 Hydrogen production steam methane reforming route without CO_2 capture, CWS =cooling water system, CWR= cooling water recycle

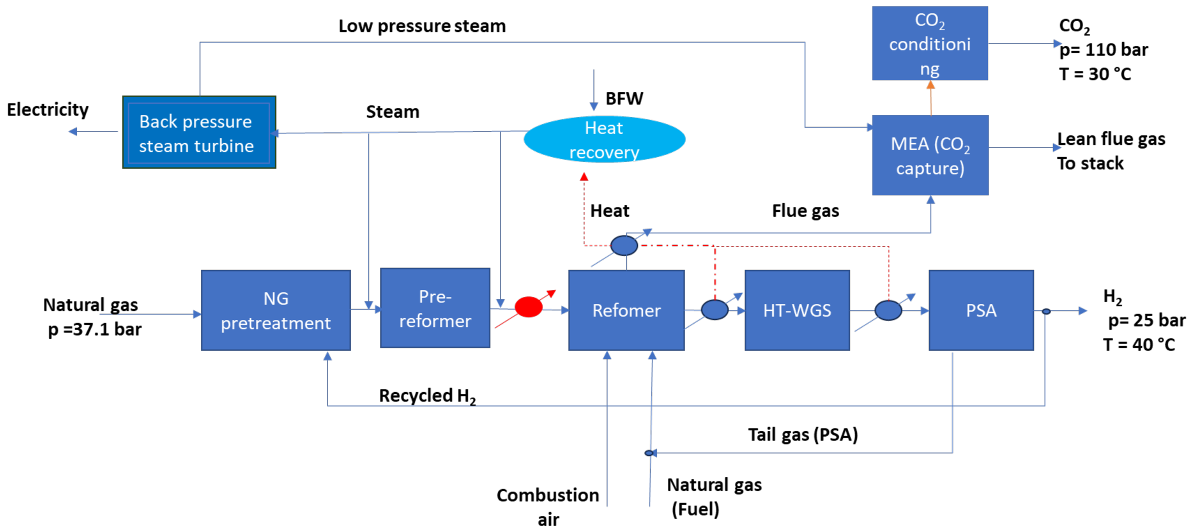

Figure 10 Hydrogen production steam methane reforming route with CO_2 capture using MEA

Blue hydrogen production scheme via ATR route is given in Figure 11. The autothermal reformer uses oxygen and steam to combine a partial oxidation reaction in the top of the reactor (the combustion section) and steam methane reforming in the reforming section accounting for the other 90% of the reactor. The three reactions that take place are partial oxidation, steam methane reforming and the water gas shift. The oxidation reaction generates the heat necessary for the endothermic reforming reaction, making the reactor thermally neutral. CO2 is captured using MDEA amine absorption process. Pure hydrogen stream is produced in PSA unit. Tail gas from PSA unit is combusted for heat generation purposes. The mass and energy balance, and costs estimate for SMR cases are taken from literature[22]. Level of certainty of the values reported, and their comparison to other

[22] Jakobsen D, Åtland V. *Concepts for large scale hydrogen production* (Master's thesis, NTNU).

literature data will be discussed in the following chapters. For ATR route, H_2 product is produced at pressure of 20 bar, thus additional compression step is required for grid injection.

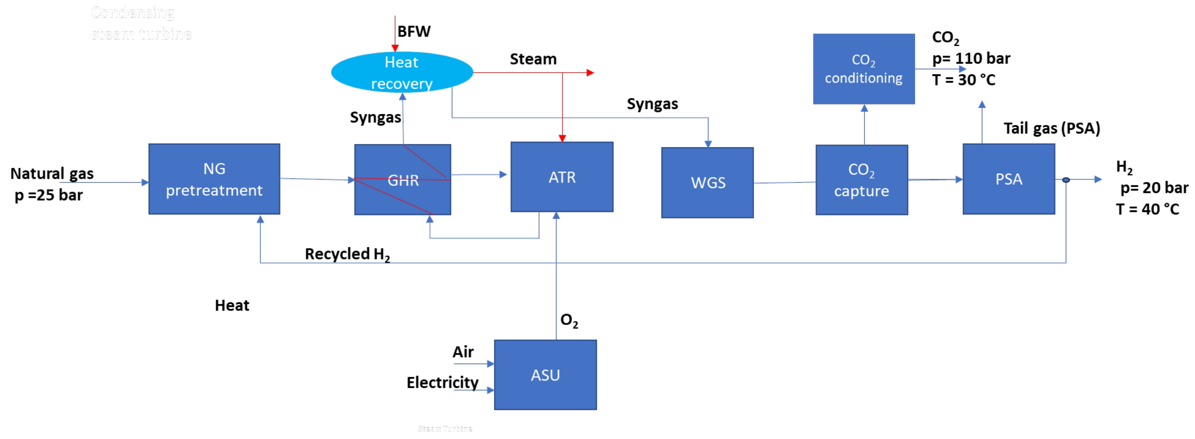

Figure 11 Hydrogen production ATR route with CO_2 capture, GHR = gas heated reformer, ASU= air separation unit

3.2.4.2 Technical parameters

Important technical parameters to include in the modelling work of hydrogen production technologies are:

- **Stream conditions at system boundaries**: natural gas (flow, pressure, temperature), CO_2 product stream (flow, purity, pressure and temperature), H_2 product stream (flow, purity, pressure and temperature). This will determine conditions at which streams need to be supplied at the system boundaries and if additional pretreatment needs to be performed. For the product streams it is important to determine if additional conditioning needs to be done before supplying to the next process steps. For example, H_2 stream will typically needed to be compressed to the grid pressure.
- **Utilities demand, and if relevant utilities export**. This will include demand for natural gas as fuel, electricity demand or electricity export, cooling water demand and demand for other utilities. These data will be used for calculation of the operating costs.

The high quality of data are expected for SMR system without CO_2 capture and SMR system with CO_2 capture. According to literature [21] PROMAX v3.2 was used to simulate the CO_2 capture from the fuel gases, Aspen HYSYS v7.3 was used for modelling of SMR based H_2 production and CO_2 compression and dehydration unit, and gate Cycle v6.1 for simulation of the power island used by steam turbine.

Mass and energy balances for ATR case are generated with the chemical process software Aspen HYSYS version 8.6[22]. It is expected that the mass and energy data will be of good quality. However, there may be some deviations in overall energy consumption because separation units, such as the ASU and CO_2 capture, were modelled as separator blocks with attached energy demand (from open literature). The PSA unit was also modelled as a separator block with an assumed H_2 recovery. Some deviations in energy use or total H_2

produced might occur when more detailed models are applied. For example NOE (2018)[23] reports an efficiency of 79.7% while literature[22] indicates efficiency value of 82%. Both efficiencies are given in the factsheet for sensitivity study purposes.

3.2.4.3 Economical parameters

The costs reported for either SMR case (without or with CO_2 capture) are from literature[21]. For either case the TCR consists of the Total Plant Cost (TPC), interest during construction, owner's costs (covering feasibility studies, land purchase, permitting, legal fees, and engineering), spare parts costs (typically 0.5% of the TPC), working capital (inventories of fuel and chemicals sufficient for 30 days of operation), and start-up costs (including personnel training, initial inefficiencies during start-up, and materials consumed).

The SMR case without CO_2 capture assumes a CAPEX of €170.95 million, with a total capital requirement (TCR) of €222.89 million. The SMR case with CO_2 capture has a significantly higher CAPEX of €305.33 million and a corresponding TCR of €398.48 million. Both cases assume an operational plant lifetime of 25 years, which is standard for such economic evaluations. The fixed OPEX for the SMR case without CO_2 capture represents about 3.39% of the TCR, while for SMR case with CO_2 capture, the fixed OPEX accounts for approximately 2.89% of the TCR. Both cases use the AACE Class IV estimate, with an accuracy range of +35% to -15%, indicating the level of certainty in the CAPEX figures.

The CAPEX for an SMR plant with CO_2 capture, according to various sources [24],[25] is estimated to be in the range of $400 million to $600 million for capacities comparable to those discussed in literature source[21]. The total capital expenditure (CAPEX) for the autothermal reforming (ATR) system with CO_2 capture, transportation and storage, a production capacity of 500 tonnes of hydrogen per day, is €972 million[22] from which €446.8 million is for the facility for capture, transportation of CO_2, and well drilling for storage. The lifetime of the ATR facility is assumed to be 25 years, with the plant operating 347 days annually, based on an operational reliability of 95%. Additionally, installation and engineering costs are considered to represent 20% of the overall investment, which includes auxiliary components as 20% of the total cost.

The IEA estimates the cost for an ATR system with a capacity of 500 tonnes of hydrogen per day at approximately 600 million, including CO_2 capture[26]. Similarly, the NREL report suggests a CAPEX range of €670 million for a similar production capacity, also accounting for CO_2 capture[27]. The Hydrogen Council offers a CAPEX estimate of €500-€600 million for a plant producing 500 tonnes of hydrogen per day, although this estimate includes CO_2 capture but excludes transportation and storage costs for the captured CO_2[28]. Finally, the Global CCS Institute estimates that an ATR plant with a 500 tonnes per day capacity would require a CAPEX of around €550 million, which includes CO_2 capture but does not cover transport and storage expenses.

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[23] NOE (2018). H21 North of England Report v1.0 - Northern Gas Networks
[24] https://www.icf.com/insights/energy/comparing-costs-of-industrial-hydrogen-technologies, 2023
[25] IEAGHG report: Blue Hydrogen: Beyond the Plant Gate,2022
[26] The Future of Hydrogen: Seizing Today's Opportunities, IEA, 2019.
[27] Hydrogen Production Cost From Autothermal Reforming (ATR) of Natural Gas with Carbon Capture and Storage (CCS). NREL/TP-6A10-72740, October 2020.
[28] Path to Hydrogen Competitiveness: A Cost Perspective. Hydrogen Council, January 2020.

3.2.4.4 HSE parameters

Typical footprint for SMR plant without CO_2 capture was taken from reported size for the SMR-X plant of Air Liquide[29] and scaled with scale factor = 1 for the capacity reported in the factsheet. The value for the footprint of the SMR plant with CO_2 storage comes from literature [30]. However, the value calculated for the plant with CO_2 capture is almost 5.5 times larger than one reported for SMR without CO_2 capture. These values appear disproportionate, and since literature reports overall land use[30], it can be assumed that the footprint includes areas required for utilities and other auxiliary units, such as wastewater treatment facilities, buildings.

3.3 Separation

3.3.1 Introduction

In 2021, the natural gas consumption in the Netherlands was 1307 PJ (44% of its primary energy consumption). This amount of natural gas is partly supplied by offshore production in the North Sea to locations such as Den Helder and Uithuizen. Since the production of natural gas from smaller offshore fields has been recently declining, part of the infrastructure will become available in the coming decades for other functions. This could include the transport of captured carbon dioxide for offshore storage, or the transport of hydrogen produced offshore.

The transport of carbon dioxide will support the development of large-scale CO2 storage in depleted gas fields, as planned in Rotterdam (Porthos, Aramis). Other projects are currently under development for blue hydrogen production from natural gas or residual gases from refineries, where captured CO2 will need to be stored to minimize the CO2 intensity of the hydrogen produced, such as in Rotterdam (H-vision), Groningen (H2M4) and Den Helder (H2Gateway).

The development of hydrogen production from renewable electricity at the offshore wind parks is underway, and a significant increase in capacity is expected. It is envisaged that hydrogen produced offshore can be injected into the hydrogen backbone currently proposed by Gasunie once transported onshore.

A transition pathway must be created to ensure that the existing gas pipelines remain viable and thrive in the energy transition. The challenge is to develop a pathway in which existing offshore infrastructure is modified to transform the North Sea from a fossil to a renewable energy source. One promising strategy is to admix hydrogen produced offshore into existing natural gas pipelines, and separate it onshore to the quality sufficient for injection into the hydrogen backbone, while natural gas is injected into the natural gas infrastructure. There is currently insufficient information to make an informed decision regarding the technologies required and their ability to deal with dynamic situations.

[29] Air Liquide celebrates next generation SMR-X (Steam Methane Reformer) hydrogen plant start-up in Antwerp Belgium - Hydrogen Central (hydrogen-central.com)
[30] 41467_2024_50090_MOESM1_ESM.pdf (springer.com)

3.3.2 Current State of Art

All technologies for hydrogen purification can be divided into physical and chemical methods:

- **Physical methods**: pressure swing adsorption (PSA), temperature swing adsorption (TSA), vacuum swing adsorption (VSA), cryogenic distillation, low-temperature adsorption, membrane separation.
- **Chemical methods**: metal hydride separation, electrochemical compression, catalytic purification.

From all technologies, the only ones that are currently mature are the physical methods:

1. PSA, polymeric membranes, cryogenic distillation.

The combination of membranes and a PSA unit seems to be a standard and cost effective combination to approach gas separation with the strict requirements on the purity levels. When the purity is relaxed, membrane technologies are sufficient. Cryogenic separation of H2 at low concentrations is energy intense and not economically attractive.

PSA is a well-established separation technology. The systems are typically produced in sizes of 50–200,000 Nm^3/h. An overview of technology providers, typical volumetric flows, hydrogen purity and recoveries, and turndown ratios is given in Table 1. The working principle of PSA is given in Figure 12. Separation by adsorption is based on one of the following three effects: steric, kinetic or equilibrium. Steric effects refer to separation based on physical size, where a molecule is able to enter the adsorbent due to its size and shape. This is generally applicable for separation with molecular sieves and zeolite. Kinetic separation functions on the principle of differences in diffusion rates of different molecules, where some molecules are able to move through the bed rapidly, while others are slowed and kept inside the bed. Finally, equilibrium separation occurs due to affinity of the target molecule to the adsorbent. The specific mechanism of affinity depends on the target molecule for separation. Since CH_4 and H_2 are sufficiently different in size and diffusion rates, both steric and kinetic separation can be used[31]. When contacting the gas stream with a solid adsorbent, everything except hydrogen is adsorbed. A remarkably high hydrogen purity can be achieved by purging an adsorbent bed with product reflux (which leads to a loss of product). Hydrogen is produced at high pressure, while all other species are recovered at significantly reduced pressure.

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[31] Ritter, J. A., & Yang, R. T. (1987). Equilibrium adsorption of multicomponent gas mixtures at elevated pressures. *Industrial & engineering chemistry research*, *26*(8), 1679-1686.

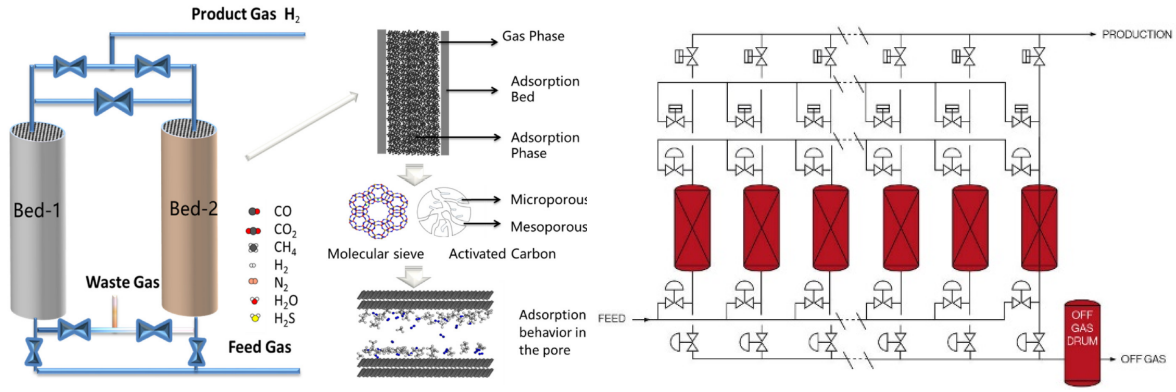

Figure 12 - Work principle of a Pressure Swing Adsorption (PSA) unit for H_2 separation.

Table 1 - Overview of PSA technology suppliers, typical feed capacities, and technology performance

Company	Typical volumetric flow [MMNm3/d]	H_2 purity [%]	Recovery rate [%]	Turndown [%]
Air Products	0.16 - 240	99.999	not mentioned	< 50
Air Liquide	0.12 – 4.8	99.9999	60 – 90	25
Linde	0.02 – 9.6	99.9999	not mentioned	not mentioned
UOP	0.02 – 6.4	99.999	not mentioned	not mentioned

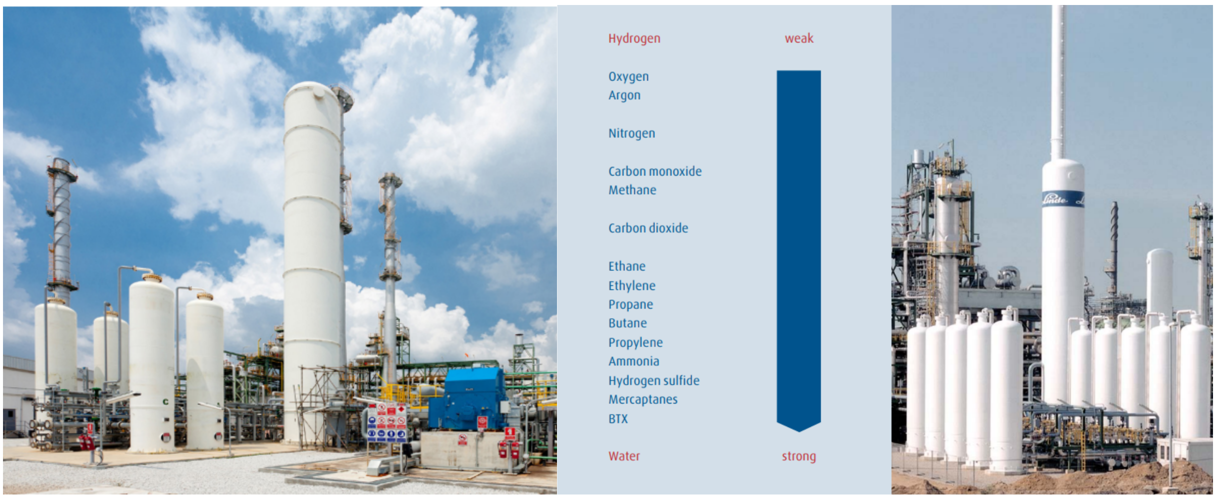

Figure 13 - Industrial PSA installations. (left) Air Products; (right) Linde.

The cost of PSA units falls into four areas: valving and flow controls, vessels, packing materials and compressors. Many design factors impact a PSA bed embodiment. Some crucial factors to consider are its size vs. level of impurities, hydrogen recovery vs. number of beds.

Membrane separation functions by introducing a barrier that is able to selectively let H_2 pass through and limit (or prevent) the transport of other species. This creates two streams, one rich in H_2 and another dilute in H_2 (see Figure 14). The following streams can be differentiated: feed, retentate, permeate and sweep. The feed gas contains the gas mixture for separation and is at high pressure when the pressure difference is used as the driving force for separation.

Figure 14 – Schematic principle of membrane separation.

The properties of the most important membranes that can be used for hydrogen separation processes are given in Table 2. The membranes deployed at commercial scale for this application are dense polymeric membranes. They offer a low-cost solution, compared to other membrane options, but suffer from low H_2 permeance and selectivity. Operating temperatures are limited to 90-100 °C. Polymeric membranes for hydrogen separation are commercially available from gas producing companies like Air Products, Linde, BOC, and Air Liquide. Figure 15 shows a picture of commercial membrane modules provided by two different suppliers.

Other types of hydrogen separation membranes at relatively high TRL (TRL6-7) are microporous and dense metallic membranes. Microporous membranes offer higher flux and moderate selectivity compared to polymeric membranes.

Table 2 An overview of different types of membranes for H_2 separation and their characteristics[32]

	Dense polymer	Microporous	Dense metallic	Porous carbon	Dense ceramic
Temperature range [°C]	<100	200-600	300-600	500-900	600-900
H_2 selectivity	low	5-139	>1000	4-20	>1000
H_2 flux (10^{-3} mol/m^2/s at Δp=1bar)	low	60-300	60-300	10-200	6-80
Stability issues	Swelling complication, mechanical strength	Stability in water	Phase transition	Brittle/oxidizing	Stability in CO_2
Poisoning issues	HCl, SOx, (CO_2)		H_2S, HCl, CO	Strong adsorbing vapors, organics	H_2S
Materials	Polyimide, cellulose acetate	Silica, alumina, zirconia, titania, zeolites, MOF, HybSi	Palladium alloy	Carbon	Proton conducting Ceramics (mainly SrCeO3-δ, BaCeO3-δ)
Development status	Commercial (TRL 9)	Prototype tubular silica membranes available up to 90 cm. Other materials on lab scale. (TRL 7)	Pilot/Demo scale (TRL6)	Lab scale (TRL 4)	Lab scale (TRL 4)
Relative cost	Low	Low - moderate	Moderate - high		

[32] S. Kluiters, Status review on membrane systems for hydrogen separation, Energy Center of the Netherlands, Petten, The Netherlands, (2004).

Polymer hollow fiber SEPURAN Noble (Evonik)

Polymer membrane BORSIG Hydrogen Separation Unit

Figure 15 - Polymer membrane modules provided by Evonik and BORSIG Membrane Technology Gmbh

3.3.3 Future Lookout

Both technologies polymeric membranes and PSA are mature and available on the market. However, the best configuration is always optimized towards a certain concentration of the separated component. As the future projections assume that offshore H2 production will grow, it will increase the H2 concentration on the stream. That requires the separation system to be flexible towards the change in composition and robust to deliver required quality. That is the challenge that needs to be tackled before this solution is commonly offered off-the-shelf.

3.3.4 Fact sheets (scope, values)

3.3.4.1 Scope boundaries

The scope of the factsheet includes the elements outlined in Figure 16 i.e. polymeric membrane modules, compressors, and a PSA unit.

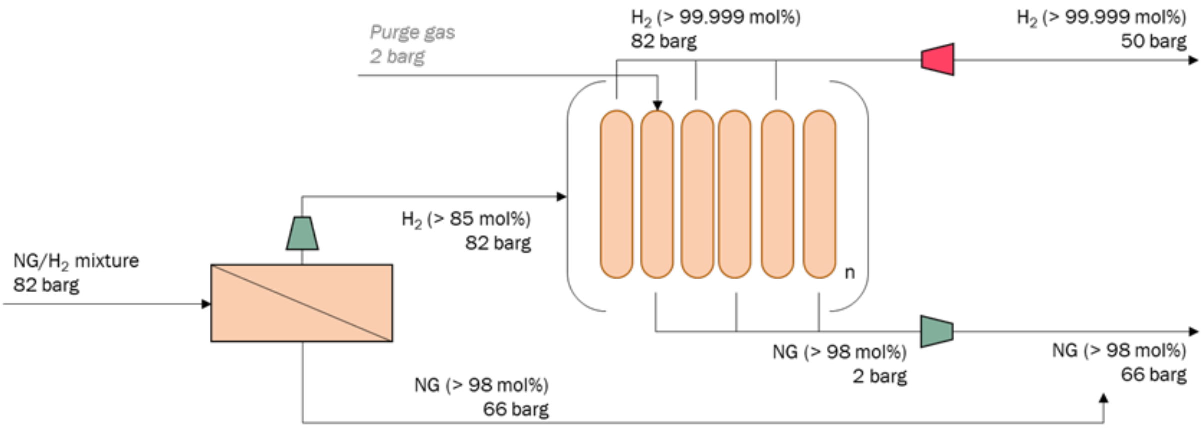

Figure 16 – Model for Ch4/H2 separation using a combination of a 1 stage membrane and a PSA unit

3.3.4.2 Technical parameters

Typical data scouted in publicly available domain is used to define operating conditions. Modelling exercise was done based on the technical assumptions that fall into a high variability window, therefore, the certainty of the results is moderate. The assumptions and boundary conditions are listed below.

Green H2 is admixed into natural gas in concentrations of 5 and 20 %vol. and transported at 83 bar(a) via a pipeline. The mixture initially passes through a membrane separation where enriched natural gas is collected on the retentate side at 83 bar(a) and decompressed till 67 bar(a) while H2-rich gas is collected on the permeate side at 1 bar(a)and sent to the compressor. When recompressed to 82 bar(a), H2-rich stream is sent to a pressure-swing adsorption (PSA) unit. Natural gas is adsorbed and regenerated at 1 bar(a) to be recompressed to 67 bar(a) and admixed to the natural gas stream from the membrane stage. H2 is collected at 51 bar(a) delivery pressure. Such parameters of a membrane unit are assumed: perm selectivity: 56 mol(H2)/mol(CH4); permeability: 0.27 Nm3/m2/h/bar; H2 recovery: 90%. For the PSA units the following parameters are assumed: H2 recovery: 90%; bed voidage: 0.4; sorbent: activated carbon. Recycling is excluded.

3.3.4.3 Economical parameters

The lifetime of the plant is assumed to be 20 years with interest rate of 8%. However, the lifetime of the membranes and sorbents is assumed to be 5 years for each, therefore they need to be replaces three times during the plant operation. Main cost assumptions are: (1) electricity price = 100 EUR/MWh ; (2) membrane cost = 200 EUR/m2, membrane module costs 5 times higher than the membrane costs; (3) sorbent cost = 1.5 EUR/kg.

3.4 Disruptive innovations

3.4.1 Blue Hydrogen

To enable large-scale deployment of blue hydrogen, further advancements in CO_2 capture technologies are crucial. Traditional post-combustion methods, while mature and widely used, are energy-intensive and expensive. However, emerging technologies such as solid sorbents, membranes, chilled ammonia (NH_3), and hot potassium carbonate offer the potential to lower costs and improve energy efficiency, making blue hydrogen a viable solution in the transition to a low-carbon economy.

Solid sorbents are emerging as a promising alternative to liquid solvents for CO_2 capture from flue gases. Their lower regeneration energy requirements and high selectivity for CO_2 make them suitable for both large-scale industrial applications and blue hydrogen production. Several companies are actively developing solid sorbent technologies. Different types of solid sorbents are considered for CO_2 capture.

Metal-Organic Frameworks (MOFs) adsorb CO_2 molecules onto their porous surfaces, offering high capacity and tunable properties. MOFs are in the early commercialization stages, with research focused on improving stability and reducing sensitivity to flue gas impurities. Companies like Svante[33] and MOF Technologies[34] are developing MOFs for industrial CO_2 capture. Typical CCR can exceed 90% under optimal conditions. Challenges for MOFS are high cost of production and susceptibility to moisture in the flue gases.

Zeolites use their crystalline pore structures to adsorb CO_2 based on size and polarity. Zeolites are well studied, particularly for low-pressure applications. Typically CCR that is achieved is 80-90% CO_2. The challenge for these type of sorbents is that their performance degrades in the presence of water vapor.

In amine-functionalized sorbent CO_2 chemically reacts with amine groups on the surface of the sorbent, forming bonds that can be broken during regeneration. Advanced laboratory and pilot demonstrations have shown promise, with companies like Carbon Clean[35] exploring commercialization. CCR achieved is over 90%. Typical challenges are long-term stability in humid or high-temperature environments needs improvement.

Solid sorbents offer lower energy requirements for CO_2 regeneration compared to liquid solvents. The expected cost for CO_2 capture using solid sorbents ranges between \$20 - \$60 per ton of CO_2[36],[37] depending on the material and scale of deployment. Companies like Calera and Carbon Clean Solutions are scaling up these technologies.

Membrane technologies offer a compact and energy-efficient solution for CO_2 separation, particularly in modular applications. These systems are easy to integrate with existing industrial processes, including blue hydrogen production. Several companies are pushing the development of both polymeric and inorganic membranes.

In polymeric Membranes CO_2 selectively permeates through the membrane based on differences in gas diffusivity. Polymeric membranes are already being used at smaller scales, but further optimization is required for large flue gas streams. Air Products and Membrane Technology and Research (MTR)[38] are working on improving polymeric membrane technology. Typical CCR for polymeric membranes is in range of 80-90%, but requires multiple stages for higher purity. These membranes have limited CO_2/N_2 selectivity, especially in low-pressure applications.

Inorganic Membranes often ceramic or metallic, use physical or chemical interactions to separate CO_2 from flue gas. Inorganic membranes are under active research, with companies like Ionada[39] developing scalable solutions. CCR is typically over 90%, but high capital costs and scaling challenges remain.

Mixed Matrix Membranes (MMMs) combine polymeric and inorganic materials, balancing the strengths of both for improved selectivity and performance. MTR[38] and research

[33] Forward-Thinking Carbon Capture Technology | Svante (svanteinc.com)
[34] MOF Technologies | novoMOF
[35] Carbon Capture Technology Company | Carbon Clean
[36] Global CCS Institute Report 2020: "Solid Sorbent-based CO_2 Capture Technologies.
[37] IEA Clean Coal Centre, "Sorbents for CO_2 Capture, 2021.
[38] MTR Carbon Capture | A Cleaner Approach To Carbon Capture (mtrccs.com)
[39] Home - ionada

institutions are investigating MMMs for CO_2 capture. Reported CO_2 capture rate is between 80-90%. However, durability under real-world conditions is still being evaluated.

Membranes offer a modular, scalable approach to CO_2 capture with lower operating costs compared to solvent-based systems. Costs are currently around $30 to $100 per ton of CO_2 captured[40],[41], depending on the membrane material and operating conditions. Further development in selectivity and durability is crucial for widespread adoption.

The chilled ammonia process (CAP) is a post-combustion CO_2 capture technology that uses ammonia as a solvent at low temperatures. This technology offers higher CO_2 absorption capacity compared to traditional amine solvents and is particularly suited for flue gases with low CO_2 concentrations. In the chilled ammonia process, ammonia reacts with CO_2 to form ammonium carbonate or bicarbonate. Cooling the solvent enhances CO_2 absorption, while heat is applied during regeneration to release the captured CO_2. The chilled ammonia process has been tested in several pilot projects, such as Alstom's pilot plant at AEP's Mountaineer plant in the U.S.[42], [43], showing promising results for high CO_2 capture rates. Over 90% CO_2 capture has been demonstrated in pilot-scale tests. GE Power and Alstom have been key players in developing and testing this technology.

The chilled ammonia process offers several advantages, including lower solvent degradation, reduced energy consumption, and the ability to handle large volumes of flue gas. Costs range between $30 and $70 per ton of CO_2 captured though ongoing research aims to lower energy demands and reduce ammonia slip (loss of ammonia into the atmosphere).

Hot potassium carbonate (K_2CO_3) is an established technology for CO_2 capture, particularly in gas sweetening processes, and is now being explored for flue gas CO_2 capture. It offers high thermal stability and lower regeneration energy than amine-based systems. Potassium carbonate reacts with CO_2 to form potassium bicarbonate ($KHCO_3$), which is later decomposed to release CO_2 during regeneration. This technology is being tested in pilot-scale projects for CO_2 capture from industrial sources, including power plants and hydrogen production. Typical CCR is 80-90%, depending on process conditions. Mitsubishi Heavy Industries (MHI)[44] and Thyssenkrupp are developing advanced potassium carbonate-based capture systems. Hot potassium carbonate systems are highly stable under harsh operating conditions, such as high temperatures and acidic flue gases. The cost per ton of CO_2 captured is estimated between $30 and $60 [45],[46] with further optimization expected to reduce costs.

Dense metal membranes can offer high hydrogen flux in combination with high selectivity. Metallic palladium (palladium-alloys) can dissociate hydrogen into atoms and hence produce a very pure hydrogen product. The retentate (which contains all species except hydrogen) is recovered at high pressure, while the hydrogen product is at significantly reduced pressure. The main advantages are ultra-pure hydrogen (99.99999% purity) and low energy penalty.

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[40] IEA Report, Carbon Capture Technology: Costs and Performance,2021.
[41] DOE NETL Report, Membrane-based CO_2 Capture, 2019.
[42] Alstom Chilled Ammonia Process selected for leading CO2 Capture plant in Romania | Alstom
[43] U.S. Department of Energy Mountaineer Commercial Scale Carbon Capture and Storage Project, DOE/EIS-0445D, 2011.
[44] Mitsubishi Heavy Industries, Ltd. Global Website | CO2 Capture Technology: CO2 Capture Process (mhi.com)
[45] Mitsubishi Heavy Industries, White Paper, CO_2 Capture, 2020.
[46] Thyssenkrupp's ,CO_2 Capture Solutions, 2021.

Ceramic-supported Pd - porous supports allow to reduce metal membrane thickness below 1 µm, with a consequent very large increase in hydrogen flux and a large decrease in price, without compromising the structural integrity of the membrane. TNO develops ceramic supported Pd/Pd alloy membranes in HYSEP membranes technology development line and present TRL is 6.

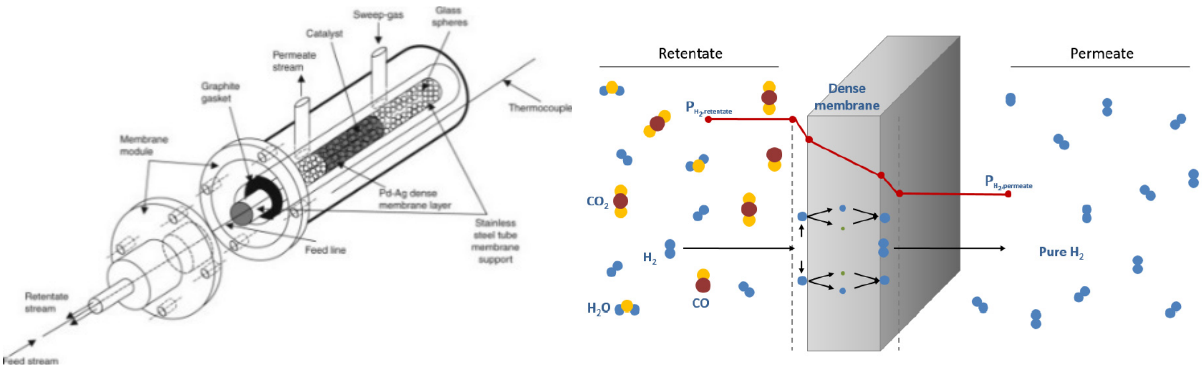

Figure 17 Schematics Pd membrane module and Pd membrane principle[47]

Dense ceramic and porous carbon membranes are at TRL4. In dense ceramic membranes, hydrogen is transported by coupled transport of protons and electrons. The permeability of hydrogen depends on the conductivities of the protons and the electronic devices. If there is no deformity in the membrane layer, 100% hydrogen selectivity can be achieved. Although they offer hydrogen purities comparable to dense metallic membranes, the obtained flux is order of magnitude lower.

Two types of carbon membranes with a different transport mechanism can be differentiated, i.e. molecular sieving and surface diffusion membranes. Molecular sieving membranes are identified as promising, both in terms of separation properties and stabilities. The pore sizes of these membranes are in the order of the size of H_2-molecules, with a selectivity in the range of 4-20. Adsorption selective carbon membranes separate non- (or weakly) adsorbable from adsorbable gases (such as H_2S, NH_3 and CFCs). The main disadvantage of carbon membranes is that they are brittle and thus difficult to handle.

3.4.2 Direct Seawater Electrolysis (DSE)

3.4.2.1 Introduction

Direct Seawater Electrolysis (DSE) encompasses all power-to-hydrogen conversion technology in which seawater is directly used as a resource for the conversion to hydrogen gas. Essentially, in DSE the seawater is untreated and will be fed to the electrolyzer-stacks without altering the chemical composition.

In conventional forms of electrolysis (alkaline, PEM, AEM), it is not feasible to use resource water directly from the source due to membrane poisoning effects. As such, the ions in the untreated water are negatively affecting the durability and lifetime of several stack components, thus increasing the associated OPEX. This is overcome by making use of water

[47] Review of Supported Pd-Based Membranes Preparation by Electroless Plating for Ultra-Pure Hydrogen Production

pretreatment processing steps. The current state-of-the-art integrates water desalination in a two-step membrane process (reverse osmosis and electro de-ionization), followed by an ion exchange polishing step to produce the necessary ultra-pure water that can reach the guaranty specifications of electrolyzer manufacturers[48]. To produce 1 kg of hydrogen, SotA electrolyzers require 9 kg of ultra-pure water[49]. If sufficient water is available, ultra-pure water treatment and supply roughly translate to 1% of the production costs of hydrogen[1]. For these electrolyzer configurations, the cost savings of feeding untreated source water into the electrolyzer system is not likely to outweigh the surplus in OPEX costs[50]. However, in the case of offshore hydrogen production, this picture potentially can be vastly different.

Regarding hydrogen production in the offshore environment, direct seawater electrolysis is considered as a viable alternative to offshore PEM electrolysis in combination with aforementioned pre-treatment steps. The argument for investments in DSE is three-fold, besides potential cost reductions linked to simplified processing steps, eliminating the necessity for pre-treatment hardware on an offshore operation platform will magnify the hydrogen production potential per platform, as current designs are limited by either weight or footprint requirements. Finally, the implementation of DSE has the potential to radically rethink offshore hydrogen production design concepts by introducing the possibility for submerged electrolysis. As such, DSE could unlock the utilization of the ocean advantageous characteristics (water pressure, temperature gradient, consistent environment).

3.4.2.2 Current State of Art

In principal, electrolysis of seawater is identical to electrolysis of other water sources, though higher activation energy (external electricity) is required to overcome the slow kinetics initiate the conversion. Generally this activation energy is 1.23 V for water electrolysis, but the reaction mechanisms vary with the electrolyte's PH. As seawater has a neutral PH of 8.0 – 8.3, this poses challenges for decomposition and requires higher overpotential (1.29 V) compared to acidic or basic solutions[51]. Moreover, untreated seawater has sluggish reaction kinetics due to the lack of naturally conductive molecules, leading to the vast potential losses and requiring usage of conductive catalysts (e.g. noble metals).

Additionally, impurities, microorganisms, and particles in seawater complicate hydrogen production[3]. For instance, the generation of OH^- during hydrogen production can lead to the precipitation of Mg(OH)2 and Ca(OH)2, blocking the catalyst's active sites and reducing catalytic activity. The oxidation of chloride ions at the anode also harms the system and shortens the lifespan of hydrogen production. If the electrolyzer stack is not adapted for, direct seawater electrolysis will lead to internal membrane poisoning and rapid degradation of the system.

Submerged electrolyzers have the potential to overcome limitations faced by 'emerged' electrolyzers in the offshore environment. The design could allow for direct placement on the seabed, omitting the construction of new offshore platforms, and synergizes with decentralized wind energy production. In this way, the ocean can act as a heat sink, thus

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[48] Pure Water Group: Electrodeionization processes for ultrapure water production in green hydrogen generation - Water Alliance
[49] 6442816bc919500faa19707b_Green Hydrogen Production White Paper V1.3.pdf
[50] Review of next generation hydrogen production from offshore wind using water electrolysis - ScienceDirect
[51] Direct seawater splitting for hydrogen production: Recent advances in materials synthesis and technological innovation - ScienceDirect

limiting internal cooling requirements, and shave mechanical compression costs of the output hydrogen gas due to the natural water pressure. Moreover, environmental conditions at the seabed are very consistent and predictable, and sea life could benefit from the presence of the electrolyzer if the design is nature-inclusive. Simultaneously, studies on the environmental impact of (large-scale) offshore electrolysis still are to be conducted to assess the quantitative impact of byproducts and system degradation on the local ecosystem. In addition, submerging man-made structures also encounters new challenges, such as corrosion, scouring and biofouling.

Depending on the design concepts of (submerged) DSEs, the TRL varies from 2 to 6, implying scarcely any demonstrations have yet been realized. In China, the Chinese Academy of Engineering (CAE) conducted DSE on the Dongfu No.1 floating platform in 2023[52]. Current companies involved in the technological scale up of these designs include Dongfang Electric Corporation[53] (China), sHYp[54] (Scotland) and Evolve Hydrogen[55] (United States).

3.4.2.3 Future Lookout

In terms of conversion efficiency, DSE cannot compete with SotA offshore electrolysis due to inherent properties of seawater[56]. To overcome these challenges, significant adaptations to the DS electrolyzer design (e.g. membrane less or different reaction process) are to be tested, incorporated and validated[3]. As a result, the CAPEX of a DSE is expected to be significantly higher and this implies it would be irrational to replace SotA offshore electrolyzers by DSE in commonly used design architypes (centralized platform, floating, energy island). However, DSE has the inherent properties to radically breakthrough the limitations of the presented architypes. Submerged DSE allows rethinking the infrastructural architecture and could enable deployment of electrolyzers in hard-to-reach bodies of water.

DSEs are not expected to be commercially available before 2030. Financial incentives to invest in DSE are scarce, as this design poses high-risk, high-reward and the market for SotA offshore electrolyzers is not yet mature and still developing.

3.4.3 Flexible Electrolyzer with integrated battery capacity:

Disclaimer – All of these information's are taken from the company website. Fact and data checking has not been done by TNO

Battolyser systems[57] is an innovative electrolyzer producer enabling 100% green hydrogen at lowest LCOH. Battolyser technology is a 100% flexible electrolyser with integrated battery capacity. It can follow highly volatile renewable energies and switch instantly and safely between hydrogen production and electricity discharge, leading to the lowest LCOH.

[52] China tests hydrogen production through direct seawater electrolysis at Xinghua Bay OWF - Offshore Energy
[53] Dongfang Electric reports successful test of direct seawater electrolysis for hydrogen production - Green Car Congress
[54] sHYp
[55] Affordable green hydrogen electrolysis directly from seawater.
[56] Seawater electrolysis for hydrogen: here are the numbers | World Economic Forum
[57] Technology — BATTOLYSER SYSTEMS

Some key technical advantages of the technology:

- **Operating** Range – That can go below 0%. The system can be turned down to zero to prevent producing hydrogen, but also revert it and sell power back to grid.
- Conversion **efficiency:** Stack efficiency of up to 85% at 30 barg outlet pressure. Produces pressurized hydrogen at a system efficient of 50,1 kWh/kg
- **Low** cost **raw materials –** The electrolyzer uses only iron and non-battery grade nickel electrodes, which are both abundant low-cost materials.
- Product **Lifetime:** The technology uses proven stable nickel and iron electrodes with a regenerative catalyst that is not subject to electrochemical degradation reducing the efficiency and expected lifetime, common in conventional electrolyzers.

4 Offshore energy storage

Offshore energy storage plays an important role in integrating renewable energy sources, ensuring grid stability, and supporting decarbonization efforts. There are various offshore energy storage mechanisms. For the focus of this study, the upcoming section will focus on three primary offshore energy storage including:

1. **Hydrogen storage** – Offshore produced hydrogen can be stored in subsea salt caverns, depleted oil and gas reservoirs, or pipelines systems for later uses.
2. **Electricity storage** - Electricity storage in offshore is mostly relies on batter storage. Different types of battery solutions are discussed here.
3. **CO_2 storage** - Carbon Capture & Storage (CCS) involves capturing CO_2 emissions from various sources, transporting it offshore and sequestrating them in depleted O&G fields or deep saline aquifers.

4.1 Hydrogen

4.1.1 Introduction

Underground Hydrogen Storage (UHS) will be a key part of future energy system to balance the mismatch between supply and demand and to integrate renewable energy into the grid. Underground Hydrogen Storage (UHS) in depleted gas fields and salt caverns could offer this flexibility to the energy system. This section focuses on describing main design variables of UHS offshore.

4.1.2 Current State of Art

The TRL levels for salt caverns and depleted gas fields (DGFs) differ significantly in the context of UHS. Hydrogen storage in salt caverns has been operational for years in countries like the UK and the US, though primarily for static storage rather than dynamic cycling. In contrast, UHS in depleted gas fields is at an earlier stage, with some pilot projects completed and ongoing.

A key challenge is that there is no experience with offshore UHS or even underground gas storage (UGS). While UGS is a well-established technology onshore with a TRL level of 9, the absence of offshore experiences makes UHS offshore particularly challenging. This adds complexity and risk to developing UHS in offshore environments. However, it is technically feasible to store both gas and hydrogen offshore.

For DGFs, the current TRL is 3-5 for pure hydrogen, indicating that in-field demonstrations are ongoing while the technology continues to develop, building on lessons learned from pilot projects.

For salt caverns, the TRL is 5-7, with numerous projects announced for completion before 2030. Pilot phases for small-scale hydrogen injection and withdrawal have been conducted in countries like Germany, the Netherlands, and France, preparing the technology for larger-scale commercial deployment by 2030.

4.1.3 Future Lookout

Both DGFs and salt caverns will play critical roles in the future energy grid. DGFs offer a TWh-scale storage capacity, though they come with more significant technical challenges. In contrast, salt caverns represent a more mature technology, well-suited for storage on the scale of several hundred GWh, with commercial deployment expected before 2030.

Beyond technology development, comprehensive research is underway to ensure that UHS is developed safely and is socially, economically, and environmentally accepted. This includes studies on business model development and economic viability, regulatory frameworks, societal awareness and acceptance, and the management of environmental impacts. These topics aim to facilitate the widespread adoption of UHS across the EU.

The future development of UHS will require in-depth studies on well integrity, material compatibility, and the potential for reusing existing infrastructure. Additional laboratory research is necessary to address UHS-specific challenges, such as the chemical interactions between hydrogen, water, residual gas (in DGFs), and rock or salt. Developing advanced monitoring, measurement, and verification technologies is also essential to ensure the safe and effective storage of hydrogen. In the context of offshore storage, further studies should focus on the space available on existing or new platforms, or alternative options like energy islands. This is crucial, as installing all surface facilities—such as compression units, auxiliary systems, and gas purification units—on a single platform with limited space and topside weight presents significant challenges.

4.1.4 Fact sheets (scope, values)

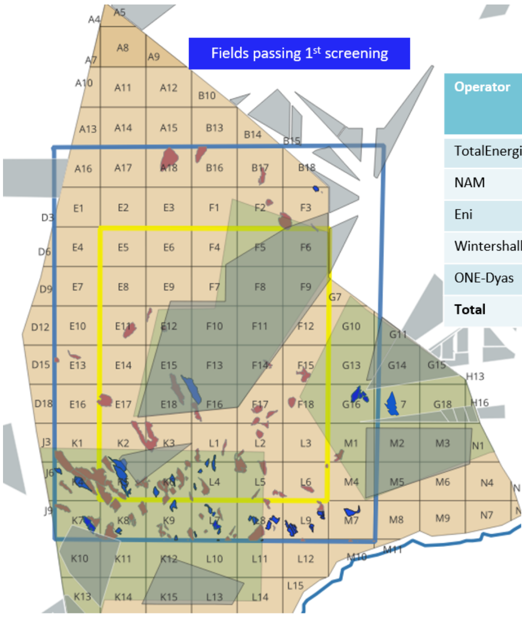
This section describes the factsheets for UHS in both salt caverns and DGFs. Due to the significant variability in design parameters, creating a general factsheet is challenging. Therefore, we have designed a storage facility connected to a wind farm in Hub North, assuming that the wind farm is dedicated entirely to hydrogen production. We also assume a constant demand for hydrogen, which is transported by pipeline to the shore. The storage facility will function as a buffer to meet this demand and balance any supply-demand mismatches. This approach provides a more realistic design by focusing on a specific scenario rather than a broad range of input parameters. We use a single value for each parameter, relying solely on the mid-range inputs without considering high or low extremes. Additionally, we do not predict timeframes or numbers for different years such as 2030, 2040, or 2050. This method ensures a more straightforward and practical design for the storage facility.

Note that the factsheet includes one use case for a salt cavern and one for a DGF. For a more detailed analysis, we first need to conduct a screening study to identify the most suitable salt cavern structures and depleted fields in the Dutch offshore. This study was included in the Hubs Design report. The final results for DGFs and salt caverns within 40–60 km of Hub North are shown in Figure 18.

Out of the initial 122 gas fields in the region near Hub North, 47 fields remain as candidates after applying the initial criteria. The exclusion criteria include:

- Oil fields
- Abandoned and undeveloped fields
- Reservoirs with very large (> 5 bcm) or very small (< 0.5 bcm) GIIP
- Areas within shipping lanes, wind farm (search) areas, ecological (protected) zones, or defence zones.

In the second screening step, additional criteria were applied, narrowing the selection to 9 fields, primarily due to many fields having too low Kh values (<500 mD.m). Figure 18 (right map) shows the locations of the gas fields that remain after the second screening step, along with the operators of these fields, highlighting that:



Operator	No. fields passing 1st screening	No. fields passing 2nd screening
TotalEnergies	18	3
NAM	13	1
Eni	8	5
Wintershall	5	N.A.
ONE-Dyas	3	0
Total	**47**	**9+**

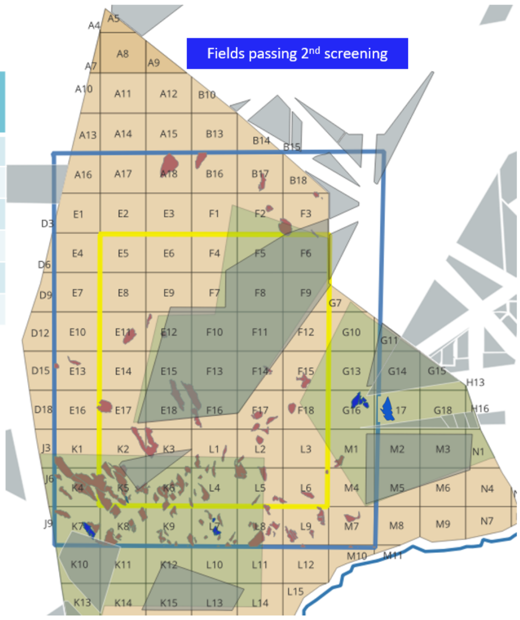


Figure 18 Results of the 1st and 2nd screening of gas fields. All blue fields meet the screening criteria.

4.1.4.1 Scope boundaries

The design basis for both caverns and gas fields is similar, including the following components:

- Electricity supply: A wind farm in Hub North, fully dedicated to hydrogen production
- Buffer: Underground storage (salt cavern and DGF)
- Demand: Constant demand for hydrogen transported via pipeline to the shore

The focus is mainly on the storage aspect, providing technical design inputs for underground storage, including working and cushion volumes, withdrawal and injection rates, pressure, temperature, etc. For the wind farm and pipeline, only the capacity numbers are provided.

4.1.4.2 Technical parameters

Table 3 shows the technical parameters for a salt cavern and depleted gas field assumed in Hub North (Shell and EBN in-kind contribution). These data provide the main design inputs for the storage facility. More detailed information is available in the factsheets.

The key assumptions in Table 3 in are the wind farm's installed capacity and the electrolyser efficiency, which together determine the required storage capacity based on the maximum constant hydrogen demand. This storage capacity, along with assumptions about depth, cavern (or reservoir) temperature, and the minimum and maximum working pressure, will then establish the working and cushion volumes, as well as the injection and withdrawal rates.

Table 3 Technical parameters for salt cavern and depleted gas field in Hub North

Subject	Parameter	Salt cavern (Shell case)	Salt cavern (EBN case)	Depleted gas field (Shell case)
Location	Away from shore [km]	250	200	300
Supply	Windfarm capacity [GW]	2	10	8
Supply	Electrolyser efficiency [-]	0.70	0.70	0.70
Demand	Export pipeline capacity [GW]	1.4	7.0	3.5
Storage	Working volume [GWh/mln nm^3]	864 / 244	5100 / 1700	2782 / 854
Storage	Working volume/total volume rato [-]	0.59	n/a	0.38
Storage	Injection rate [GW, mln nm^3/day]	0.40 / 2.7	3.6 / 29	2.10 / 14.2
Storage	Withdrawal rate [GW, mln nm^3/day]	0.95 / 6.4	3.3 / 26	3.33 / 22.5
Storage	Leaching time [years]	2.5	10	---
Storage	Top depth [m]	1800	1200	1800
Storage	Cavern (reservoir) height [m]	300	300	200
Storage	Cavern diameter [m]	90	70	---
Storage	P_{min}-P_{max} [bar]	122-325	100-200	150-250
Storage	Cavern (reservoir) temperature	45	n/a	100
Storage	Number of caverns (DGFs) required	2	20	1

4.1.4.3 Economical parameters

Cost analysis for offshore hydrogen storage is still uncertain and varies on a case-by-case basis. Key cost factors include cushion gas injection, surface facilities such as compressors and gas cleaning units, well drilling and completion, and construction and leaching process (only for caverns). These factors need to be carefully considered for an accurate assessment.

Shell conducted a more detailed study on offshore cavern development, with results included in the Hubs Design Report (Section 2.4.3). In that study, using a deep salt cavern and raising the minimum pressure to 52% (compared to the typical 24–30% for onshore) increased the unit CAPEX from about €30/kg for onshore to €200/kg for offshore. More information can be found in the report.

4.1.4.4 HSE parameters

HSE considerations are crucial for underground hydrogen storage, especially in offshore settings. Below are some key HSE aspects to take into account:

- **Storage and well integrity:** For offshore storage, ensuring storage and well integrity is crucial to prevent hydrogen from migrating through faults, fractures, caprock and borehole, which could lead to unintentional release. Well integrity testing and continuous monitoring are necessary to manage this risk.
- **Hydrogen leak:** Detecting hydrogen leaks is challenging because it is odourless, colourless, and has a low molecular weight, which means it can easily disperse and escape.
- **GHG emissions:** While hydrogen does not produce CO_2 when combusted, indirect emissions could arise from associated processes, e.g. energy requirements for compression and gas cleaning.
- **Brine disposal (only caverns):** Managing brine extracted from offshore salt caverns presents environmental and logistical challenges. Direct discharge into the ocean requires careful control, as high salinity can harm marine ecosystems; thus, dilution with seawater or use of diffusers to spread the brine more broadly is often necessary. An alternative is reinjecting brine into adjacent geological formations, though this needs additional infrastructure. Each of these strategies requires careful considerations to minimize ecological impact while maintaining operational efficiency.

4.2 Electricity

4.2.1 Introduction

Electricity (battery) storage is a crucial solution for balancing supply and demand on the power grid. This technology includes a range of storage durations, from milliseconds to daily (short-term storage). Lithium-ion (Li-ion) batteries, lead-acid, sodium-sulfur (NaS), and flow batteries will play important roles depending on the specific application and scale. Battery storage enhances grid stability, supports the integration of renewable energy, and provides backup power solutions for various needs.

By co-locating battery storage to an offshore wind park the intermittency of wind production can be reduced. This reduces the stress on the farm-to-shore electrical connection and can therefore reduce the related costs for this infrastructure.

4.2.2 Current State of Art

The four types of batteries covered in the fact sheets are:

- **Sodium-Sulfur Battery**: This battery features liquid sulfur at the positive electrode and liquid sodium at the negative electrode. The oxidation of sodium creates Na+ ions, generating an electric current.
- **Li-ion Battery**: These batteries use lithium or a lithium compound as the anode and are widely used in consumer electronics. The biggest large-scale energy storage facility using lithium-ion batteries currently has a capacity of 750 MW.
- **Lead-Acid Battery**: This is the oldest rechargeable battery technology used in household and commercial applications. It employs a positive lead-dioxide electrode and a negative metallic lead electrode, with an electrolyte made of sulfuric acid.

- **Flow Battery:** Known in its most common form as the Vanadium Redox Battery, this type operates based on the redox reaction of ionic forms of vanadium. Energy is stored externally in tanks, where the charged liquid can be used as needed.

In terms of TRL, Lead-acid batteries, being the oldest technology, have the highest TRL of 8. Flow batteries, an innovative technology with room for future improvement, have the lowest TRL of 5. Lithium-ion batteries have a TRL of approximately 7, while sodium-sulfur (NaS) batteries are at around 6.

4.2.3 Future Lookout

The key to advancing battery storage for offshore applications in the future is space availability. Unlike non-battery technologies, batteries generally need to be located above ground and water, requiring placement on platforms or islands. This creates significant challenges for implementing large-scale utility battery storage facilities. Although batteries offer relatively high energy density, utility-scale systems still require a large surface area; for example, a 3,000 MWh lithium-ion battery system would need approximately 150,000 m². Finding or building this required surface area could be a major challenge for deploying large-scale battery energy storage systems (BESS) offshore. Additionally, the batteries must be resistant to the marine environment, capable of withstanding severe weather, and protected against saltwater corrosion.

The current TRL for various batteries is not low. However, for technologies like flow batteries, future advancements towards higher TRLs will focus primarily on innovations to improve energy efficiency, while for other battery types, the emphasis will be more on optimizing performance and scaling-up these technologies for larger applications.

4.2.4 Fact sheets (scope, values)

Key technical parameters in the factsheets include:

- Lifetime: The expected operational duration or lifespan of the system.
- Cycling Capacity: The number of charge-discharge cycles a system can undergo.
- Efficiency: The effectiveness with which a system converts input energy into useful output energy.
- Specific Energy: The amount of energy stored per unit mass.
- Energy Density: The amount of energy stored per unit area.
- Energy Volume Density: The amount of energy stored per unit volume.

The numbers in the factsheets for electricity storage do not specify timeframes for 2030, 2040, or 2050. Instead, they provide low, mid and high values for each parameter, with the certainty of these numbers based on available literature.

4.2.4.1 Technical parameters

The NaS battery, along with Li-ion and lead-acid batteries, are well-established technologies with global applications. NaS is the most mature high-temperature battery, operating within a temperature range of 300 to 350°C. While the lifetime for batteries is relatively shorter compared to UHS technologies, averaging around 12 years, their efficiency remains relatively high, at over 80%. The energy density is quite high, combined with a relatively low cost (see

Table 4). Despite its strong technical performance, it does come with some challenges, particularly related to maintenance and safety.

Table 4 Technical parameters for Sodium Sulphur (NaS) Battery

Parameter	Unit	Low	Mid	High	Quality certainty
Energy carrier (in/out)			Electricity		
Lifetime	Years	10.0	12.5	15.7	High
Capacity	MWh	0.1		400.0	Medium
Capacity	MW	0.1		34.0	Medium
Discharge duration		1 hr		2 days	Medium
Response time			msec		Medium
Cycling capacity	x1000	2.6	2.5	4.0	High
Efficiency	%	77.9	84.5	86.7	High
Depreciation rate	-	-	-	-	-
Specific energy	Wh/kg	126.4	150.0	210.5	High
Energy density	kWh/m2	140.0	140.0	140.0	Low
Energy Volume Density	kWh/m3	150.0	225.0	300.0	Low

Table 5 shows the technical parameters for Li-ion batteries. They have one of the highest energy densities, giving them an advantage over other battery types. They offer the highest efficiency and an operational life of around 14 years. However, the costs are significantly high, partly due to the need for an expensive overcharge protection circuit. Despite its widespread use in consumer devices, further development and testing are required to scale up this technology for larger applications in future projects.

Table 5 Technical parameters for Lithium ion (Li-ion) battery

Parameter		Low	Mid	High	Quality certainty
Energy carrier (in/out)			Electricity		
Lifetime	Years	8.8	14.5	14.8	High
Capacity	MWh			75.0	Medium
Capacity	MW			100.0	Medium
Discharge duration		5 mins		2hrs	Medium
Response time		msec		sec	Medium
Cycling capacity	x1000	1.4	2.3	5.1	High
Efficiency	%	84.7	93.5	95.0	High
Depreciation rate	-	-	-	-	
Specific energy	Wh/kg	100.5	150.0	380.9	High
Energy density	kWh/m2	194.0	194.0	194.0	Low
Energy Volume Density	kWh/m3	94.0	297.0	500.0	Low

Lead-acid batteries are the oldest and most commonly used type of battery which leads to relatively low costs and a high TRL. However, despite their maturity, these batteries have low energy density and a short lifetime, which are critical factors for offshore applications. While this technology has been in use for a long time, it may not be the best choice for large-scale energy storage, especially in offshore environments. Table 6 summarizes the technical parameters for lead-acid batteries.

Table 6 Technical parameters for Lead Acid battery

Parameter		Low	Mid	High	Quality certainty
Energy carrier (in/out)			Electricity		
Lifetime	Years	6.3	8.5	12.8	High
Capacity	MWh	0.0		4.0	Medium
Capacity	MW	0.0	10.0	40.0	Medium
Discharge duration		30s		30min	Medium
Response time		msec		sec	Medium
Cycling capacity	x1000	1.0	1.5	1.9	High
Depreciation rate	-	-	-	-	
Efficiency	%	71.2	80.0	84.2	High
Specific energy	Wh/kg	33.6	40.0	75.0	High
Energy density	kWh/m2	17.0	17.0	17.0	Low
Energy Volume Density	kWh/m3	25.0	57.5	90.0	Low

The Vanadium Redox flow battery is an innovative technology that operates differently from most other batteries. It uses liquid electrolytes, allowing energy to be stored in large tanks rather than within the batteries themselves. As a result, estimating its energy density is difficult, as it depends on the dimensions of the storage containers. Its energy density is roughly comparable to that of lithium-ion batteries. This technology could offer a relatively low cost per kW and a long lifespan. Although its efficiency is currently the lowest among battery technologies, there is potential for improvement due to the technology's novelty (see Table 7).

Table 7 Technical parameters for Flow Battery

Parameter	Unit	Low	Mid	High	Quality certainty
Energy carrier (in/out)			Electricity		
Lifetime	Years	17.5	17.5	17.5	Low
Size	MWh			400.0	Low
Size	MW	20.0		100.0	Low
Charging rate			Hours		Low
Response time			<sec		Low
Cycling capacity	x1000	10.0	10.0	10.0	Low
Efficiency	%	72.5	72.5	77.5	Low
Depreciation rate	%/yr	-	-	-	
Specific energy	Wh/kg	30.0	40.0	50.0	Low
Energy density	kWh/m2		25.0		Low
Energy Volume Density	kWh/m3	10.0	21.5	33.0	Low

4.2.4.2 Economical parameters

There is a wide range of cost estimates for each type of battery, resulting in significant uncertainty in cost predictions. Table 8 displays the capital costs per kW or kWh, which can be used interchangeably. OPEX typically accounts for 1%-2% of CAPEX. The sources for these cost estimates are provided in the factsheets. The capital cost per kW as per kWh can be used interchangeably.

Table 8 Economic parameters of different types of electricity storage

Battery type	Parameter	Unit	Low	Mid	High	Quality certainty
NaS Battery	Capital cost per kW	€/kW	857.5	1431.5	2465.5	Medium
	Capital cost per kWh	€/kWh	368.8	475.0	557.5	High
	OPEX	€/kW/yr	8.6		49.3	Low
	Decommissioning cost	€/MW	-	-	-	-
Li-ion battery	Capital cost per kW	€/kW	1113.7	1654.5	3189.5	Medium
	Capital cost per kWh	€/kWh	696.2	900.0	1957.4	High
	OPEX	€/kW/yr	11.1		63.8	Low
	Decommissioning cost	€/MW		39.0		Low
Lead Acid battery	Capital cost per kW	€/kW	488.3	521.0	1049.3	Medium
	Capital cost per kWh	€/kWh	226.9	400.0	451.3	High
	OPEX	€/kW/yr	4.9		21.0	Low
	Decommissioning cost		-	-	-	
Flow Battery	Capital cost per kW	€/kW	1113.7	1654.5	3189.5	Low
	Capital cost per kWh	€/kWh	696.2	900.0	1957.4	Low
	OPEX	€/kW/yr	11.1		63.8	Low
	Decommissioning cost	€/MW		416.0		Low

4.2.4.3 HSE parameters

Battery safety is a concern in offshore environments, where evacuation options for personnel are limited, and emergency response times can be slower. To address these risks, a highly reliable safety system is essential for the use of battery storage on offshore platforms. Each battery chemistry presents unique safety considerations, which are detailed in Table 9.

Table 9 HSE parameters of different types of electricity storage

Battery chemistry	Safety concerns
NaS	Operation at high temperature (350^{o}C). Sodium burns when in contact with air or moisture.
Li-ion	Damage to the electrolyte can cause a short circuit which could lead to a thermal runaway.
Lead-Acid	Includes the toxic cadmium
Flow	A relatively unknown technology (it is suggested that these batteries are resilient to short circuits, making them relatively safe during operation)

4.3 CO_2 Storage

4.3.1 Introduction

CO_2 storage plays a crucial role in the EU's efforts toward emissions reduction, particularly for North Sea countries. These countries have a high concentration of industries that must transition to carbon neutrality Furthermore, the region has significant offshore storage potential in depleted gas reservoirs and aquifers, complemented by established infrastructure such as pipelines and platforms. This section focuses on describing main design parameters of CO_2 storage offshore in depleted gas reservoirs (not aquifers).

4.3.2 Current State of Art

CO_2 storage in saline aquifers has been ongoing in Europe for a long time, with the Sleipner project in Norway offshore operating since 1996. This has provided extensive experience, particularly in Norway. Additionally, the Northern Lights project, another aquifer CO_2 storage initiative becomes operational in 2025. Given this experience, the TRL for saline aquifer storage is estimated at 8-9. However, due to limited historical data from other aquifer sites, further studies are needed to fully evaluate their long-term storage potential.

For depleted gas fields, several pilot projects have been conducted, but large-scale operational experience is not yet operational. The Porthos project, expected to start in 2026, will be the first full-scale CO_2 injection into depleted gas fields (P18 blocks of the Dutch offshore) in Europe. Porthos aims to store 2.5 million tons of CO_2 per year for 15 years. Given the absence of long-term operational data, the TRL for depleted gas field storage is currently around 7-8. However, with the start of Porthos and more large-scale projects in the coming years, this TRL is expected to increase before 2030.

4.3.3 Future Lookout

CO_2 storage in depleted gas fields is expected to expand significantly in the future as part of efforts to reduce CO_2 emissions in Europe. With the development of ongoing and upcoming CCS projects, Europe has set an ambitious target of 500 Mtpa of CO_2 storage by 2050. Additionally, as oil and gas reservoirs decline in production, they will offer substantial storage capacity. This also presents an opportunity to repurpose existing oil and gas infrastructure, including platforms, pipelines, and wells, for CO_2 storage. However, CO_2 injection into depleted fields comes with challenges, particularly concerning well integrity, thermodynamic behavior of CO_2 in the well and reservoir (e.g., Joule-Thomson effect, thermal fracturing near the wellbore, hydrate formation, and salt precipitation). To address these uncertainties, various engineering solutions have been developed to improve the safety and efficiency of CO_2 storage in these reservoirs.

Beyond technological advancements, other factors require attention to enable widespread CO_2 storage across Europe. These include regulations, industry standards, and societal acceptance of CCS. Additionally, since CO_2 is captured from various sources across different countries, two critical aspects—the flexibility of CCS infrastructure and cross-border collaboration—must be thoroughly investigated to ensure the success of future CCS operations.

4.3.4 Fact sheets (scope, values)

This section presents the factsheets on CO_2 storage in depleted gas fields. The information provided is primarily based on gas reservoirs located in the K, L, Q, and P blocks of the Dutch offshore, as shown in Figure 19. The low, mid, and high values in the factsheets specifically refer to these reservoirs and do not represent the entire North Sea. In general, the data is reflective of the Porthos and Aramis projects.

The parameters are not linked to specific years such as 2030, 2040, or 2050; instead, they are reported as low, mid, or high estimates. The factsheets provide basic data on these gas fields, but to keep them concise, detailed reservoir data is not included. A more in-depth analysis would be required for each specific reservoir, as such detailed information cannot be generalized in the factsheets.

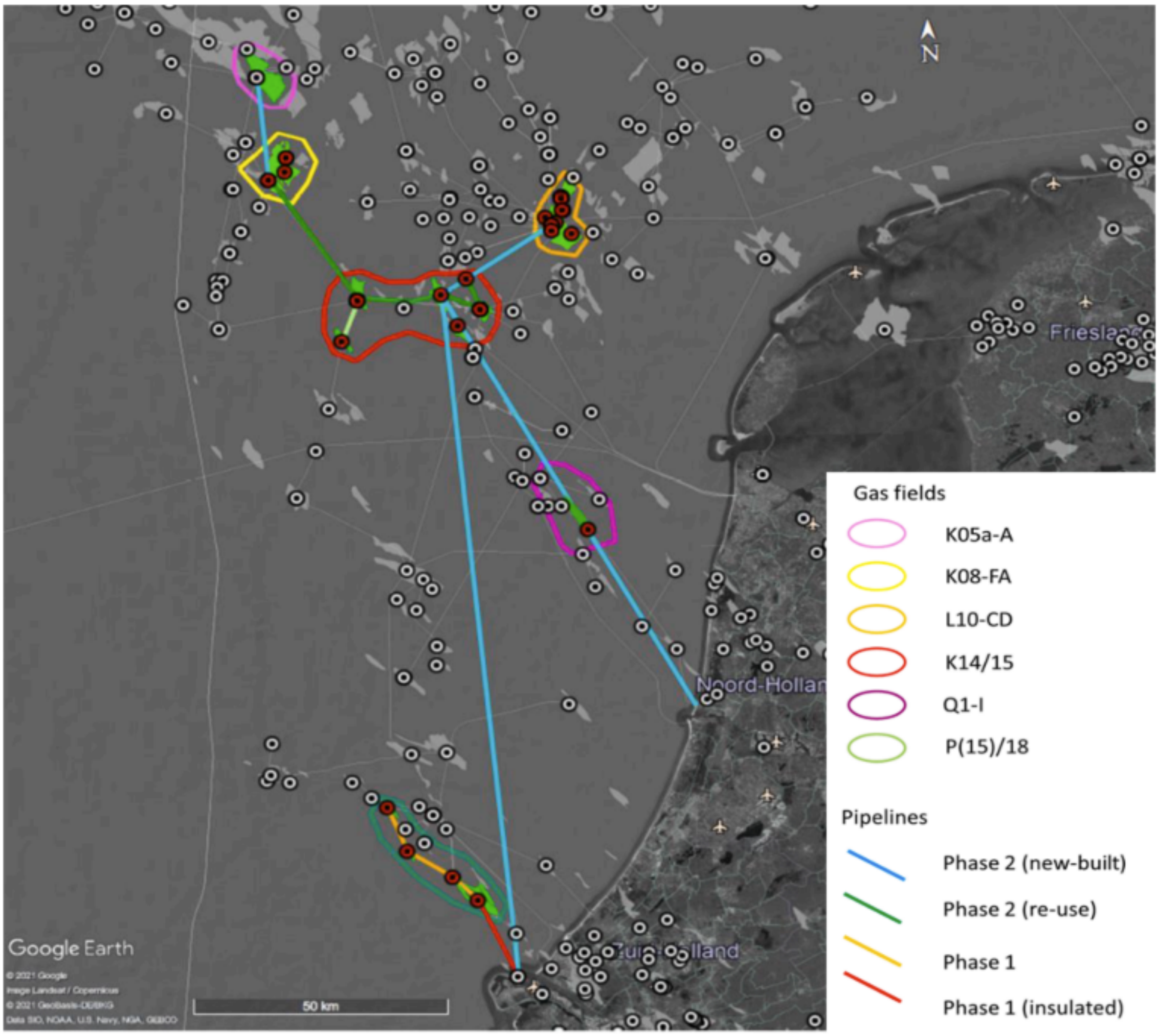


Figure 19 Location of depleted gas fields in the Dutch offshore used in this study for the factsheets[58].

4.3.4.1 Scope boundaries

The scope of the factsheet is limited to subsurface CO_2 storage, focusing on four blocks in the Dutch offshore. It mainly addresses the storage aspect, providing key technical inputs for underground storage, such as injection rate, storage capacity, initial reservoir pressure and temperature, reservoir depth, transmissivity, number of wells, abandonment pressure, and other relevant parameters.

4.3.4.2 Technical parameters

Table 10 shows the technical parameters for a depleted gas field included in the factsheets. These data provide the main design parameters for CO_2 storage.

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[58] Large-scale CO2 transport and storage infrastructure development and cost estimation in the Netherlands offshore - ScienceDirect

Table 10 Technical parameters for CO2 storage in depleted gas fields

Parameter	Low	Mid	High	Certainty
Location of Storage blocks in the Dutch offshore [km]		K, L, Q and P blocks		High
Storage formations		Cretaceous, Triassic(Buntsandstein), Permian(Rotliegend)		High
Injection CO_2 rate per well [Mtpa]	0.5	1	1.5-3	Mid
Individual fields storage rate [Mtpa]	1	2-5	10	Mid
Total combined storage rate in the Dutch offshore [Mtpa]	3	10	27	Low
Individual fields storage capacity [Mt]	8	10-50	>130	Mid
Reservoir depth [m]	2,400	3,000	4,000	High
Reservoir temperature [°C]	80	100	130	High
Initial reservoir pressure [bar]	240	300	400	High
Transmissivity, Kh [md.m]	2,000	5,000	>10,000	Mid
Abandonment pressure, bar	10	50	>90	High
Number of wells per field	1	3	>5	High
Age of existing platform [years]	<5	20-25	50	Mid

4.3.4.3 Economical parameters

Table 11 presents the economic parameters for a depleted gas field included in the factsheets. The data includes CAPEX for platforms, wells, and pipelines, considering both new installations and the reuse of existing infrastructure. It also provides estimates for decommissioning costs, including platform removal and well abandonment expenses, as well as the annual OPEX for wells and platforms.

In the final rows of the table, the unit technical cost is shown for offshore pipelines, storage, and compression units, as well as the total unit technical cost for the entire system.

Table 11 Economical parameters for CO2 storage in depleted gas fields

Parameter	Low	Mid	High	Certainty
CAPEX - platform (re-use) [MEUR]	10	12.5	15	Mid
CAPEX - platform (new) [MEUR]	20	22.0	25	Low
CAPEX - wells (re-use) [MEUR]		3.0		Mid
CAPEX - wells (new) [MEUR]		24.0		Low
CAPEX - new pipeline (per length per diameter)	0.05	0.3	1	Mid
CAPEX - existing pipeline (per length per diameter)	0.005	0.025	0.1	Mid
Decommissioning platform[MEUR]		10.0		Mid
Plug and abandon well[MEUR]		5.0		Mid
Annual OPEX - platform [MEUR]		2.5		High
Annual OPEX - well[MEUR]		0.4		High
Unit technical cost [(CAPEX+OPEX)/Storage Capacity)] - Compression unit [EUR/ton]		3.0		Mid
Unit technical cost [(CAPEX+OPEX)/Storage Capacity)] - Offshore pipeline [EUR/ton]	0.2	0.8	1.4	Mid
Unit technical cost [(CAPEX+OPEX)/Storage Capacity)] – Storage [EUR/ton]	2	4.3	7.3	Mid
Unit technical cost [(CAPEX+OPEX)/Storage Capacity)] - Total (transport + compression + storage) [EUR/ton]	5.2	8.1	11.7	Mid

4.4 Disruptive innovations

There is a wide array of energy storage technologies available, each with its own unique benefits and challenges. Therefore, no single technology can meet all energy storage needs and a diverse mix of solutions is required. Using a combination of storage technologies can enhance the grid's reliability and efficiency. Future research should explore how different storage solutions can work together effectively, especially considering various geographic and environmental factors.

One of the proposed storage method is Ocean Battery. The Ocean Grazer's Ocean Battery is an innovative underwater energy storage system that uses ocean pressure instead of gravitational energy. Similar to a pumped hydro storage (PHS) system, it operates by utilizing water pressure to store and release energy but is specifically designed for underwater deployment.

The Ocean Battery consists of a concrete reservoir buried in the seabed, which stores water at low pressure. When renewable energy sources like offshore wind turbines produce excess power, this energy is used to pump water into a flexible bladder on the seafloor. Later, when energy is needed, the pressure of the surrounding seawater forces the water back into the reservoir, driving turbines to generate electricity and supply it to the grid.

Note that from current options like battery storage, hydrogen storage, and compressed air energy storage to emerging systems like the Ocean Battery, ongoing advancements are continuously expanding the possibilities and effectiveness of energy storage solutions.

4.4.1 POWBOX – H – Subsea 7

A versatile hydrogen/energy storage concepts supporting the development of the renewable and low-carbon hydrogen economy. PowBox-H offers a simple and robust hydrogen storage capacity at seabed.

- Flexible storage system that can be scaled up to suit specific decarbonation needs
- Subsea storage of 15T of gaseous hydrogen at up to 350 bars
- Water depth from 30 – 1500m
- Storage capacity pf each unit >500 MWh. Several units can be connected to build up a larger capacity of several GWh.
- Floating structure towed to site and submerged into position at seabed in a controlled manner.

4.4.2 Hydro – Pneumatic Liquid Piston Technology

Disclaimer – All of these information's are taken from the company website. Fact and data checking has not been done by TNO

Storing energy at sea - FLASC BV[59] is a company based in Malta, Spain and Delft, NL. FLASC solutions is the **first utility scale energy storage solution** tailored for co-location with offshore wind farms. With their proprietary **Hydro Pneumatic Energy Storage (HPES)** technology designed specifically for offshore: safe, reliable and cost-effective.

- **Pneumatic Pre-Charging** - Minimizes fatigue and increases energy density resulting in a Levelized Cost of Storage competitive with onshore systems
- **Ocean as a Natural Heatsink -** Enable an isothermal process with 70-75% round trip efficiency without complex thermal storage or heat exchangers.

Key Technical Advantages of this technology:

- No seawater inside the system
- Significantly increased energy density
- Use of efficient positive-displacement pumps
- **Charging mode**: A motor and hydraulic pump drive a reciprocating liquid piston array to compress air into a pre-charged container
- **Discharging mode**: The stored air expands through the liquid pistons which drive the hydraulic system in reverse to produce electricity

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[59] Technology – FLASC

5 Offshore energy transport

Offshore energy production is becoming a critical part of the energy transition. The denvelopment of offshore wind farms and other marine renewable energy sources is rapidly growing, driven by the clean energy demand of the globe. However, a key challenge remains: efficiently and reliably transporting this energy from offshore production sites to shore.

This section of the report delves into the transport mechanisms required to deliver offshore produced energy (ie., electricity and hydrogen) to shore, with a particular focus on the current state of art, future outlook and factsheet description. Offshore energy transport encompasses the following topics:

- Electricity transmission
- Hydrogen transport
- Compression required for hydrogen transport

5.1 Electricity

5.1.1 Introduction

The Dutch government has set a target of at least **4.5 GW of operational offshore wind capacity by 2023**, with plans to increase this to **around 11 GW by 2030 and 70 GW of offshore wind by 2050**. This expansion in offshore wind capacity is expected to result in a proportional increase in electricity generation. The electricity produced offshore can be transported to shore either directly as electrical power or converted into other energy carriers, such as **hydrogen**. This section of the report will focus on the transportation of electricity from offshore wind turbines to the shore, examining the various methods and associated considerations.

5.1.2 Current State of Art

Most offshore transmission systems installed thus far are P2P connections based on HVAC cables, connected to the onshore High Voltage Substations (HVS). The another futuristic alternative is High Voltage Direct Current (HVDC) cables. Within the Dutch North Sea, network operator TenneT is responsible for connecting the new offshore wind farms to the national high voltage network and for the distribution of electricity generated by wind. As mentioned previously, the electricity generated from offshore wind farms are transported to land via power cables and/or used to produce hydrogen (which is transported vie dedicated pipelines). Currently, 2 government programmes are investigating the routes and locations for landings from sea to land:

- Landing in Eemshaven (PAWOZ – Eemshaven)
- This program investigates the option to connect the offshore wind farms planned for the Ten noorden van de Waddeneilanden and Doordewind Wind Farm Zones to the high-voltage grid or hydrogen network in Eemshaven in 2032.
- Options to connect future offshore wind farms to the high-voltage grid or hydrogen network in Eemshaven.
- New landing locations (VAWOZ)

- This program is investigating promising cable routes and connection locations to shore to connect the 29 GW planned between 2031 and 2040.
- The program is investigating approximately 15 locations in the following regions: Noord Holland, Zuid Holland, Zeeland, Noord Brabant and Limburg regions.

An undersea high-voltage connection is needed to transport the offshore produced electricity to shore. TenneT has planned to establish 8 standard alternating current (AC) connections, each with a capacity of 700 MW, up to and including 2026. After 2027, the wind farms will be built further away from the coast in the Ijmuiden Ver wind energy region from 2027. Given the larger capacity and to limit the loss of energy during transport, TenneT is carrying out the connections as a Direct Current (DC) connections.

Project planning from TenneT:

- 2024 – 700 MW Hollandse Kust (west) Alpha (AC)
- 2025 - 700 MW Hollandse Kust (west) beta (AC)
- 2026 – 700MW Ten Noorden van de Waddeneilanden (AC)
- 2027 – 2 GW IJmuiden Ver Alpha (DC)
- 2029 – 2 GW IJmuiden Ver Beta (DC)

High Voltage Alternating Current (HVAC): The electricity produced by the offshore wind turbines is collected on the offshore substation via 66KV cables. At the offshore platform the voltage level is stepped-up and transported to shore via offshore transmission cables, where it is connected to the public grid through a HV substation. Therefore the offshore network frequency follows the European grid frequency that is controlled around 50 Hz.

HVAC Substations: HVAC substations are applied both offshore and onshore for power collection, voltage transformation and protection. Due to the offshore environment and the size restrictions Gas Insulated Switchgear (GIS) is applied, while for onshore mostly it is Air-Insulated Switchgear (AIS). Due to environmental restrictions the use of SF6 gas as insulation medium needs to be abandoned, which requires novel type of GIS equipment for voltages above 150kV.

5.1.3 Future Lookout

HVDC systems are playing and are expected to play an increasingly significant role in energy transmission due to their technical and economical superiority over HVAC systems for long distance transmission.

Bulk energy transmission/interconnection is feasible using both HVAC and HVDC links. Historically, HVAC has been the main transmission technology benefiting from the early development of AC transformers that allowed for high voltage AC transmission for longer distances and lower losses. However, the consequent development of mercury arc valves and their widespread adoption by 1930s gradually paved the way for DC to re-enter the transmission market as they also allowed for energy to be transmitted at higher DC voltages.

The use of HVDC transmission over long distances provides several technical advantages when compared to HVAC. DC transmission losses/ costs are significantly lower than HVAC due to the absence of transmission line capacitive/reactive charging effects. DC transmission can thus be used efficiently for very long transmission distances that exceed 3000 km as of 2018, compared to 1049 km for point-to point HVAC. It also requires fewer cables/conductors and utilizes the full lines transmission capacity up to their thermal limits. This reduces the required cross-sectional area for DC cables and consequently the transmission cost[60].

For instance, TenneT is building two transformer platforms in the Ijmuiden Ver wind energy area that convert the AC from offshore wind energy into DC. Figure 20 shows the 2 GW program promoted by TenneT.

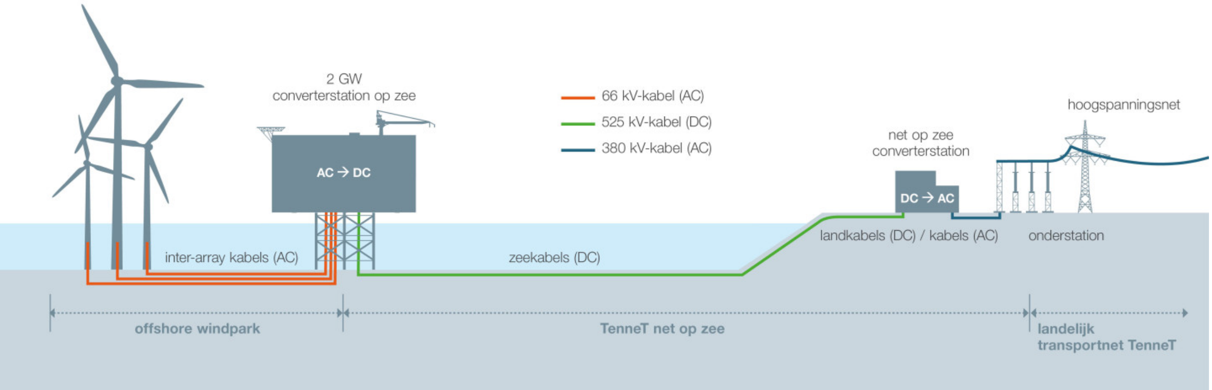

Figure 20: HVDC system with convertor stations at sea and on land - Source TenneT

North Sea Wind Power Hub (NSWPH) came up with a key concept of electrical connections. The hub and spoke concept (Figure 21) is a future outlook on how the electrical connections might develop in the future. The evolution started from near shore radial AC connections to far offshore DC connection. The hub and spoke concept is assumed to be another step in this evolution adding interconnection and potential electricity conversion[61].

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60 [HVDC Transmission Technology Review, Market Trends and Future Outlook]
61 [Key concepts | North Sea Wind Power Hub]

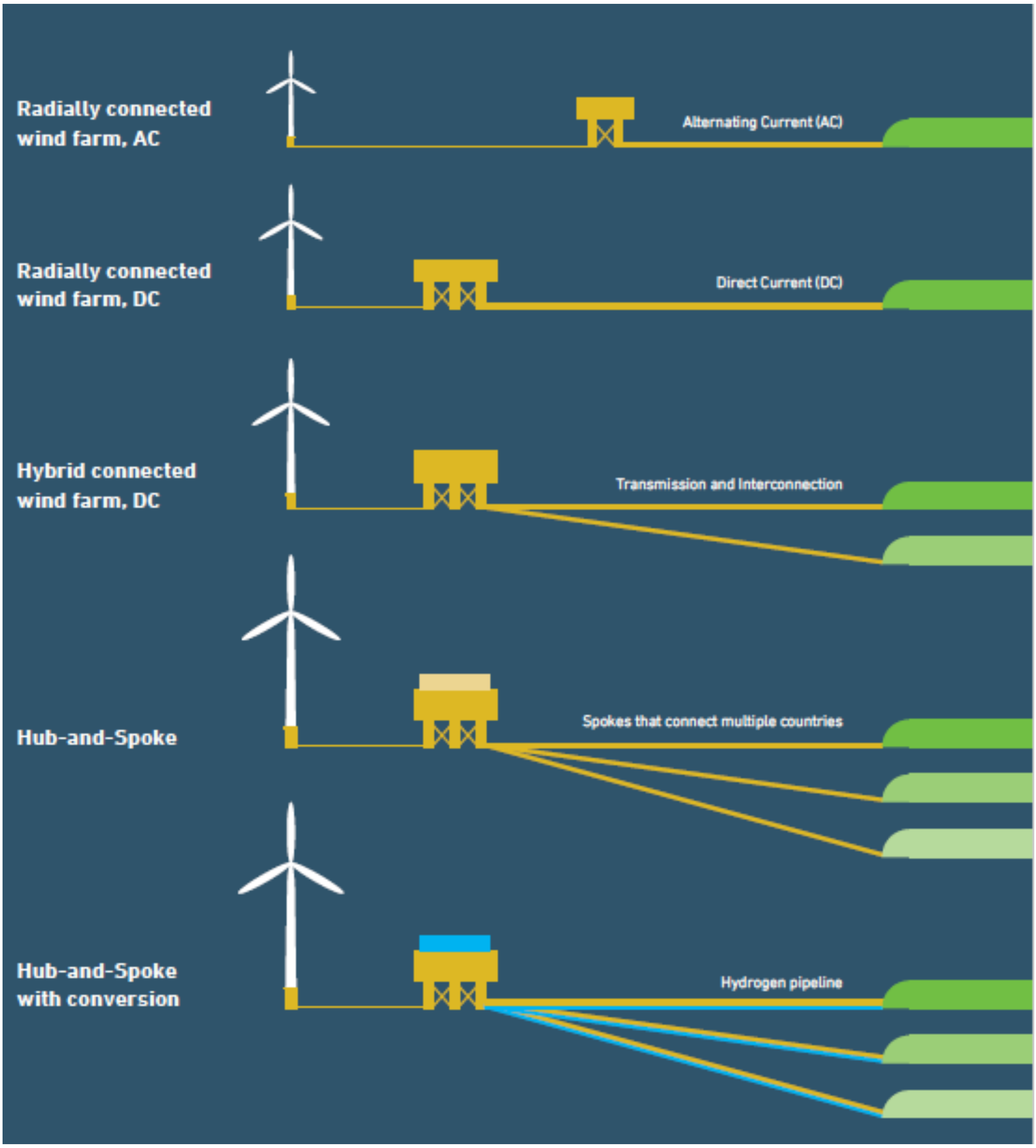


Figure 21: Hub & Spoke concept (Source - NSWPH)

5.1.4 Fact sheets (scope, values)

5.1.4.1 Scope boundaries

The information and data's provided in this section is taken from the North Sea Wind power hub programme dataset[62]. The scope of the described dataset includes only offshore transmission infrastructure.

- **Connections to individual windfarms**: Always assumed DC as this allows for hybrid/meshed connection

[62] ETM Library | North Sea Wind Power Hub programme (NSWPH)

- **Connection aggregated sites**: DC for distances from 80 km and above, AC for distances below 80 km

The table below provides details on the connection type for each wind farm, the voltage step-ups performed by the high-voltage substations, and the location of these windfarms.

Table 12 Existing wind farms within Netherlands

Wind farm	Capacity	Distance to shore	Type of connection	Location
Princess Amalia Wind farm	120 MW	23 km off the coast	22kV à 150 kVAC (OHVS)	Ijmuiden
Luchterduinen wind farm	129 MW	23 km off the coast	33kV à 150 kVAC (OHVS)	Zaandvoort
Gemini wind farm	600 MW	60 km off the coast	33kV à OHVS (230 V) à LHVS (380 kV)	Wadden Island
Borssele I & II	752 MW	24 km off the coast	66 kV à 220 kV (OHVS)	Zeeland
Borssele III & IV	730 MW		66 kV à 220 kV Borssele Beta (OHVS)	
Hollandse Kust Zuid	1520 MW	18 – 36 km off the coast	66 kV into 220 kV(OHVS) à 380 kV(LHVS)	The Hague & Zandvoort
Hollandse Kust Noord	759 MW	23 km off the coast		Ijmuiden

5.1.4.2 Economical parameters

Table 13 Economical parameters of transportation

Parameters	Units	2025	2030	2040	2050
Platforms & substations					
AC platform	M€/MW	0,161	0,158	0,153	0,149
DC Platform	M€/MW	0,268	0,264	0,256	0,249
AC Substation	M€/MW	0,032	0,032	0,031	0,030
DC Substation	M€/MW	0,268	0,264	0,256	0,249
Topsides DC Adjustment	M€/MW	0,048	0,047	0,046	0,045
Transmission lines					
AC Offshore (submarine)	K€/km/MW	7,065	6,961	6,752	6,564
DC Offshore (submarine)	K€/km/MW	2,141	2,109	2,046	1,989

Alongside these data's, the OPEX is expected to be around 1,5% of CAPEX and the contingency factor is around 5%.

5.2 Hydrogen Transportation

5.2.1 Introduction

In the future, it is expected that hydrogen will be produced offshore, given the huge increase in offshore wind production capacities. In the previous section, it was discussed abut transporting electricity via electric cables. But studies have shown that transporting the generated energy in the form of molecules (ie., P2X) via dedicated pipelines would be more cost effective option than using electricity cables and converting electricity to hydrogen onshore (Hugo Groenemans et al., 2022). In this section, we are going to dive deeper into transporting hydrogen via pipelines and this transport could be achieved by developing new hydrogen – dedicated infrastructure or re-using existing natural gas pipelines.

5.2.2 Current State of Art

When discussing hydrogen transportation from offshore, there are two primary options: transporting it either as pure hydrogen or as a blend with natural gas.

Transporting as pure hydrogen:

HyNetwork Services (part of GTS) will be available in the coming years. The hydrogen backbone will connect industries, hydrogen storage facilities and the production sites. **It is expected that the network will primarily consist of retrofitted existing natural gas pipelines** (Top, 2022). It's also expected that the backbone will not transport pure hydrogen (100%) due to possible contamination during the transmission. As a result, GTS conducted a public consultation in 2020 to address hydrogen quality specifications and it led to deciding a reasonably pure hydrogen (around 98%) will be transported to the market via the backbone. Figure 22 represents the future hydrogen backbone envisioned by Gasunie. A large part of the below figure will consist of existing natural gas pipelines.

The development of an offshore hydrogen network is still at an earlier phase, and the routing will depend heavily on the availability and usability of existing pipelines, as well as the overall developments in the offshore energy sector. Gasunie is performing several studies under HyONE[63] to identify possible routes depending on specific scenarios.

[63] Our offshore activities › Gasunie

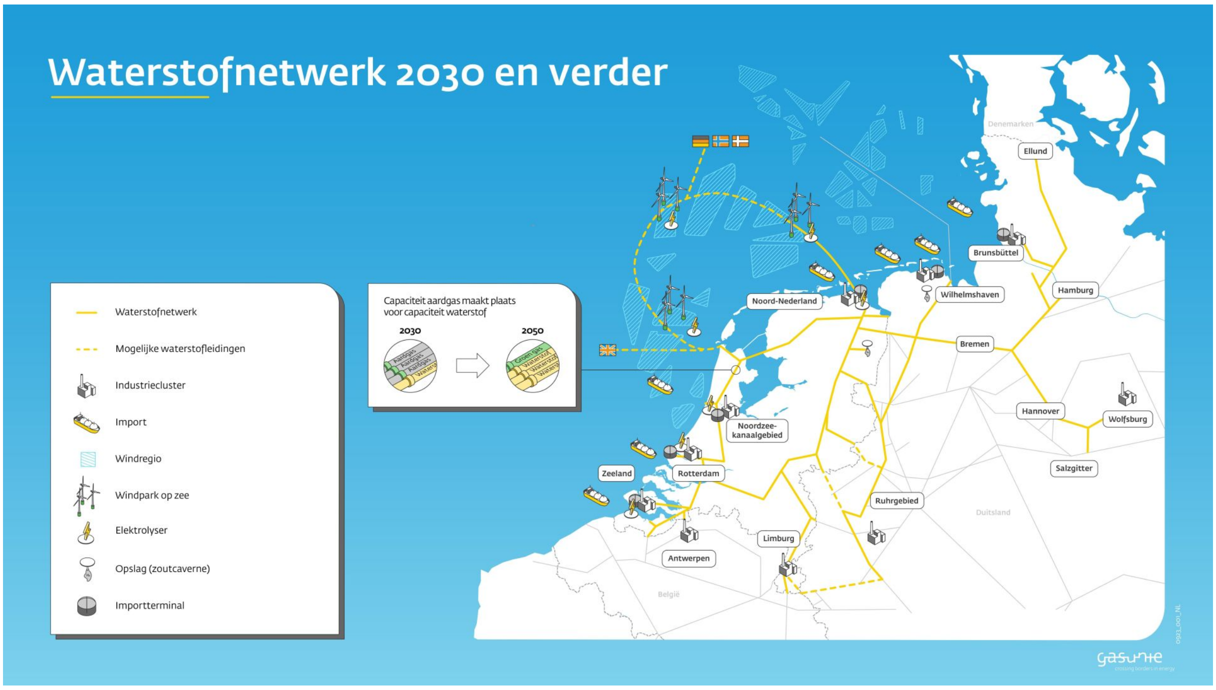


Figure 22: Gasunie's hydrogen networking in the Netherlands[64]

Component	Symbol	Unit	Minimum	Maximum
Hydrogen	H_2	mole %	98	
Total sum of hydrocarbons including methane	C_xH_y	mole %		1.5
Total sum of inerts (nitrogen, argon and helium)	N_2, Ar, He	mole %		2.0
Oxygen	O_2	ppm		10
Carbon dioxide	CO_2	ppm		20
Carbon monoxide	CO	ppm		20
Total sulphur including H_2S	S	ppm		5
Formic acid	CH_3OOH	ppm		10
Formaldehyde	CH_2O	ppm		10
Ammonia	NH_3	ppm		10
Halogenated compounds		ppm		0.05
Water dewpoint	H_2O	°C @ 70 bara		-8

Figure 23: Indicative quality specifications hydrogen backbone

[64] Hydrogen network Netherlands | Hynetwork

Key points to note with re-purposing existing pipelines:

- Eliminating unwanted components and creating a safe environment by performing nitrogen purging
- Inspecting the pipeline for potential fractures
- Operating the Natural gas pipelines at a reduced pressure for hydrogen transport

Blending with Natural Gas:

Until the hydrogen backbone becomes available, hydrogen can be transported by blending it into the existing natural gas pipeline network. This approach offers a cost-effective and technically feasible solution for the long-distance transport of hydrogen, leveraging current infrastructure while minimizing the need for new investments. Once hydrogen is blended, there are 2 options: either directly sell the blend of H2/NG to a consumer or to de-blend the hydrogen from the natural gas stream.

As seen, blending & de-blending of hydrogen would play a crucial role if hydrogen is transported by blending with Natural gas.

- Hydrogen blending is the process of injecting (pure) hydrogen to a pipeline that mostly carries natural gas. Once hydrogen is blended and transported to the shore, there are two options as mentioned above. If hydrogen needs to be stripped out of natural gas, it has to be separated (i.e.., de blended). An internal TNO study was conducted to understand the impact of hydrogen blend with NG, and some conclusions were achieved.
- When the hydrogen content in NG is low (less than 20 vol%), it has no significant effect on the Wobbe index of the blend. Higher hydrogen content decreases the Wobbe index, when very high (>80%) hydrogen increase the Wobbe index of the mixture.
    1. Literature survey says that low hydrogen content (<5%) have negligible impact on most materials and equipment on natural gas transport networks.
- Hydrogen blended NG would require re-evaluation of the ATEX hazardous zone classification, which may have an impact on the operating permit of end users.
- Hydrogen blending would have a significant impact on the cost of the hydrogen-NG blend. As example, hydrogen blend with 5% hydrogen could increase the cost of the energy between 10% and 40% with respect to normal NG.

De-blending is simply gas separation and it’s a mature & well established technology. There are different technologies available, but the most relevant technologies for hydrogen de-blending are Pressure Swing Adsorption (PSA), Cryogenic Distillation and Membrane separation.

- All the 3 technologies are mature from a technological perspective, and they are commercially used for the separation of gases including hydrogen.
- The costs of hydrogen blending depends strongly on the hydrogen blend % and the input/output pressure.
- In case of low hydrogen blends (<5%), de-blending could cost between 10-14 €/kg for around 2 bar outlet, and between13-13€/kg for 20 bar outlet.

5.2.3 Future Lookout

The current outlook suggests that for smaller-scale pilot projects, hydrogen will be blended into existing natural gas pipelines and transported to shore. For instance, PosHYdon is a 1MW pilot offshore hydrogen production project, located approximately 13 kilometers off the cost of The Hague. The hydrogen produced in the platform will be mixed with the natural gas and transported via the existing natural gas pipeline to the coast. Approximate production is expected to be around a maximum of 400 kilograms per day. There has been no clear information provided regarding the use of hydrogen and whether it will be de-blended upon reaching the shore. The specifics of how hydrogen will be separated from natural gas, if required, remain uncertain at this stage.

Repurposing existing natural gas pipelines for hydrogen transport offers a cost-effective solution. In the future, it is expected that the NGT pipelines, proposed for repurposing, will play a key role in facilitating the transportation of offshore-produced hydrogen to the Dutch shore. Once the hydrogen reaches the shore, it will be injected into the HyNetwork, also known as the hydrogen backbone, for distribution to various industrial regions and storage facilities across the country. HyNetwork, a division of GTS, is developing a national hydrogen network in the Netherlands. GTS has stated that this network will provide all industrial regions with access to hydrogen infrastructure, with the goal of having it fully operational by 2030.

5.2.4 Fact sheets (scope, values)

Translation from state of art to fact sheets.

5.2.4.1 Scope boundaries

North Sea Wind Power Hub programme (NSWPH)[65] is a consortium of Energinet, Gasunie and TenneT to realize climate goals. For this particular parameter, the factsheet[66] provided by the consortium will be referenced, as it offers a solid estimation of the current and future economic outlook when discussing offshore hydrogen transport.

5.2.4.2 Technical parameters

- The general observed cost split is 1/3rd for installation and 2/3rd for equipment's
- 10% cost decrease per 10 years (between 2030 to 2050) is assumed for the installation cost

5.2.4.3 Economical parameters

While discussing offshore hydrogen transport to shore, there are two main approaches:

1. Offshore compression of hydrogen
2. Onshore compression of hydrogen

Currently, the industry lacks established standards on which approach is optimal. As a result, both cases are considered in the factsheet, with a further sub-classification of whether new compressors are used or existing ones are repurposed. The key parameters that are on the

[65] North Sea Wind Power Hub
[66] ETM Library | North Sea Wind Power Hub programme (NSWPH) (energytransitionmodel.com)

focus of economical parameters are CAPEX (of infrastructure & compressor) & OPEX (including both). Table 14 provides an overview of the economical parameters described in the factsheet. **No transmission losses are assumed.**

Table 14 Economical parameters of offshore hydrogen transport

Elements	Parameters	2025	2030	2040	2050
	CAPEX Infrastructure (€/MWth_LHV/km)	449	443	430	418
H2 pipes including offshore compression (new)	CAPEX Compression (€/MWth_LHV/km)	224	220	214	208
	OPEX (incl., pumping) (€/MWth_LHV/km/year)	11	11	11	11
	CAPEX Infrastructure (€/MWth_LHV/km)	455	448	428	416
H2 pipes including onshore compression (new)	CAPEX Compression (€/MWth_LHV/km)	61	60	58	56
	OPEX (incl., pumping) (€/MWth_LHV/km/year)	6	6	6	6
	CAPEX Infrastructure (€/MWth_LHV/km)	99	96	93	91
H2 pipes including onshore compression (repurposed)	CAPEX Compression (€/MWth_LHV/km)	49	48	46	45
	OPEX (incl., pumping) (€/MWth_LHV/km/year)	2	2	2	2

5.3 Compression

5.3.1 Introduction

State of the Art commercial PEM water electrolyzer system can operate at hydrogen outlet pressure of 30-40 bars. HyNetwork services, in later stages, will increase its network at around 40–60 barg. The design pressure of HyNetwork is expected to be 66,0 barg[67]. To increase the outlet pressure of the produced hydrogen from 30 to a minimum of 50 bar, compression is necessary. This indicates that compression will be a crucial component of the future hydrogen value chain.

5.3.2 Current State of Art

Compressors are well matured and commercially available technology[68]. Over the past century several types of compressors have been developed. Two types of compressors can be identified:

- Mechanical Compressors
  - Positive Displacement – like Reciprocation & Rotary
  - Dynamic – Like Centrifugal & Axial
- Non Mechanical compressors – like electrochemical compressors

The selection of compressors will depend on the specific application requirements. Typically, in hydrogen applications, compressors are used for (Leonard van lier et al., 2022):

- Injection into the transport grid – Discharge pressure around 30 to 80 bar
- Storage – Discharge pressure around 300 bara
- Fuelling stations – Around 350 bar to 900 bar
- End-use applications, which can have a large variety of end pressures.

In the current state of the art, positive displacement compressors have been used for hydrogen compression for a significant period, making this technology well-established and mature. Out of the different types of positive displacement compressors, reciprocating compressors are a most traditional member, with a long track record for hydrogen (Leonard van lier et al., 2022). In the upcoming discussion about the factsheet, it's assumed that a reciprocating compressor would be used for offshore operations, as the operating window for hydrogen transport fits well with this compressor technology. Alternative types that are also used for hydrogen compression, such as screw compressors, typically are not implemented at discharge pressures above 30 bar.

Figure 24 shows an schematic representation of how a reciprocating compressor works. Reciprocating compressors are capable of producing higher pressure up to 400 bar in multi stage processes and depends on the end use. In case of transporting hydrogen via pipeline the expected discharge pressure could be around 30 – 80 bars (Rik van Rossum et al., 2022). Depending on the hydrogen purity requirements, the choice between using lubricated or non-lubricated reciprocating compressors must be made. For application where high purity

[67] Specifications › Hynetwork
[68] EFRC Hydrogen Compression White Paper

hydrogen is required (ie., fuel cells), non-lubricating reciprocating compressors must be used. The absence of lubrication may introduce extra wear to the system.

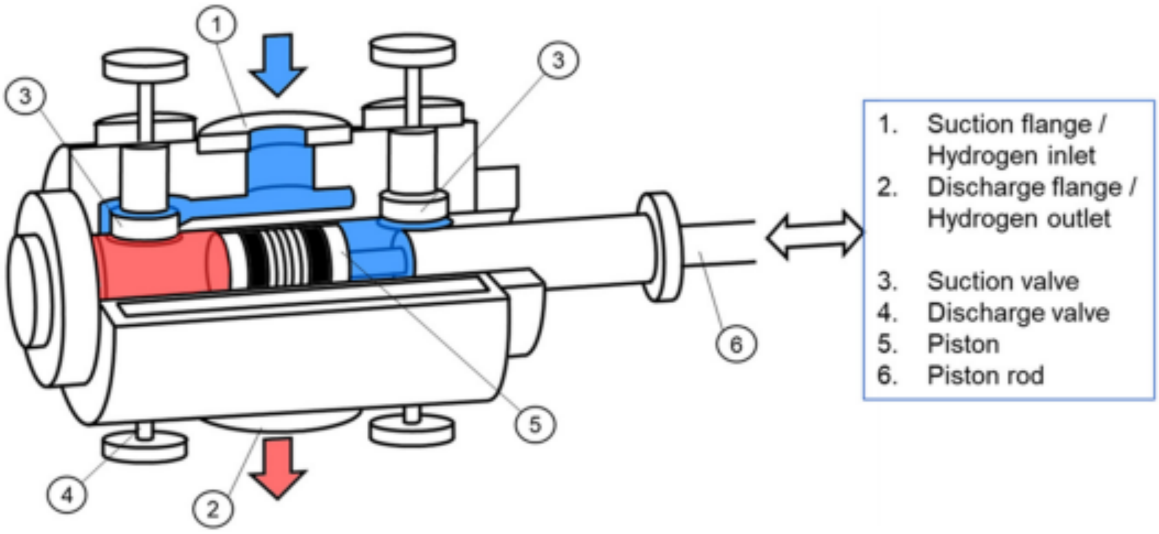


Figure 24: Schematic representation of recip compressors (Leonard van lier et al., 2022)

Reciprocating compressors are preferred over centrifugal compressors due to their technological maturity and superior performance in managing surge and choke phenomena, making them more reliable for hydrogen compression applications.

5.3.3 Future Lookout

As mentioned, mechanical compressors are currently the standard for hydrogen applications due to their technological maturity. However, in the future, there may be potential to use non-mechanical or hybrid compressors, as these technologies are expected to mature and offer new possibilities for hydrogen compression (Leonard van lier et al., 2022).

- **Non-**Mechanical **compression**: Hydrogen can be compressed in non-mechanical ways by including different principles like electrochemistry, adsorption etc., Compared to conventional compressors, key advantages of non-mechanical compressors are the absence of moving parts (no vibration, less wear o material, no use of lubricants etc.,) and higher hydrogen purity (up to 99.999 %). There are 3 categories of non-mechanical compressors:
- **Metal Hydrides** - The working principle is a thermally driven chemisorption process with reversible adsorption-desorption kinetics. These compressors are commercially available for pressures up to 200 bar, while higher outlet pressures are still under development (G Sdanghi et al., 2019) TRL of this technology compressor is around 6.
- **Electrochemical** – These types of compressors are based on the same principle as that of a PEM fuel cells. Main advantages of this technology is the low energy requirements, since they ensure isothermal compression. These compressors are commercially available for pressure up to 1000 barg, but efficiency decreases as pressure increases. TRL of this technology is around 7.
- **Adsorption/Desorption** - The working principle behind this class of non-conventional compressors is thermally driven bonding of hydrogen onto microporous materials, similar

to metal hydride compressor. TRL of this technology is around 3 (very early stage) and number of technical challenges has to be addressed in the future.

- **Hybrid Compressors** - Future hybrid compression solutions shall be explored. This could be combination of various conventional compression techniques, such as boosting with a screw compressor and the higher pressure stage with a reciprocating compressor, or a reciprocating compressor boosting a high-pressure diaphragm compressor. Also hybrid solutions with non-mechanical compression may be economically viable, for instance by using metal hydride/electrochemical compressor as pre-compressor stage, upstream of a reciprocating compressor.

5.3.4 Fact sheets (scope, values)

The previous paragraphs, explored the role of compressors, their necessity in hydrogen applications, the current state of the art, and the future potential of the technology. With this information and further detailed analysis, the NSE team has developed a factsheet outlining key performance indicators (KPIs) and their expected capacities. The following section provides a detailed explanation of the figures presented in the factsheet.

5.3.4.1 Scope boundaries

The study boundary/assumptions of this factsheet on compression systems are provided below:

1. Proton Exchange Membrane (PEM) Electrolyser of installed capacity 100 MW

- Discharge pressure of the PEM electrolyser is **around 30 bar**
- **Reciprocating compression** is assumed due to their technology maturity and industrial preference
- Compressor outlet pressure **is around 100 bar** (only to transport to grids) and not for storage/end users
- Pure hydrogen (>95%) is considered
- A 100MW PEM electrolyser would produce **around 1,5 – 1,8 tonnes of H2/hr**
- The compressor system is located next to the electrolyser system (i.e.., not in a separate platform)
- For the calculation of the CAPEX & OPEX, no platform costs are included

5.3.4.2 Technical parameters

There are different KPI's that were considered for this technical parameters. Technical parameter refer to the specific, measurable characteristics and criteria that define the performance, capabilities and limitation of the compressor technology. All the values provided below are for 2030 and come with a high level of confidence. These values have been gathered from various sources, including company brochures, research papers, and other relevant publications. For a 100MW PEM electrolyser, a compressor of around 4 MW would be required to compress the hydrogen throughput [69]. For the compressor throughput, it usually depends on the capacity of the electrolyser input. Table 15 provides an overview of the technical parameters described in the factsheet.

[69] Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal (irena.org)

Table 15: Technical parameters of a recip compressor

Parameter (unit)	Low	Mid	High	Quality
Reference capacity (MW)	3,5	3,8	4,2	High
Isentropic efficiency (%)	80	85	90	High
Specific power consumption (kWh/KgH2)		1,9		High
Compressor throughput (t/hr)		1,6		High
Discharge pressure (bar)		100		High
Discharge outlet pressure (deg C)	115	120	125	High

5.3.4.3 Economical parameters

The key KPIs included in the economic parameters were CAPEX, OPEX, and the lifetime of a reciprocating compressor. While the CAPEX is based on a 100 MW reciprocating compressor, the OPEX value will depend on the overall system. Calculating OPEX is challenging, as it varies depending on each specific system and how the compressor is operated. It's also challenging to calculate the lifetime of a compressor as it'll depend on the level of maintenance. Table 16 provides an overview of the economical parameters described in the factsheet.

Table 16: Economical parameters of compressor

Parameters (unit)	Low	Mid	High	Quality
CAPEX (€/kW		1789		High
OPEX (% of CAPEX)		5		Low
Lifetime (years)		15		High

5.3.4.4 HSE parameters

Offshore platforms have limited space, and the physical footprint of a compressor is crucial to consider. A compact footprint is required to facilitate safe access of maintenance and operation. Table 17 presents the NSE parameters that were taken into consideration.

Table 17: HSE parameters of a compressor

Parameters (unit)	Low	Mid	High	Quality
Footprint (m^2)		110		Medium

Appendix A: Factsheets

A.1 Factsheet 1 – Offshore Wind Energy

Link to the share → WP 1 - Tech Innovations Final version factsheets

A.2 Factsheet 2 – Offshore Solar

Link to the share → WP 1 - Tech Innovations Final version factsheets

A.3 Factsheet 3 – Green Hydrogen

Link to the share → WP 1 - Tech Innovations Final version factsheets

A.4 Factsheet 4 – Blue Hydrogen

Link to the share → WP 1 - Tech Innovations Final version factsheets

A.5 Factsheet 5 – Separation Technology

Link to the share → WP 1 - Tech Innovations Final version factsheets

A.6 Factsheet 7 – Battery Storage

Link to the share → WP 1 - Tech Innovations Final version factsheets

A.7 Factsheet 8 – CO2 storage

Link to the share → WP 1 - Tech Innovations Final version factsheets

A.8 Factsheet 9 - Compressors

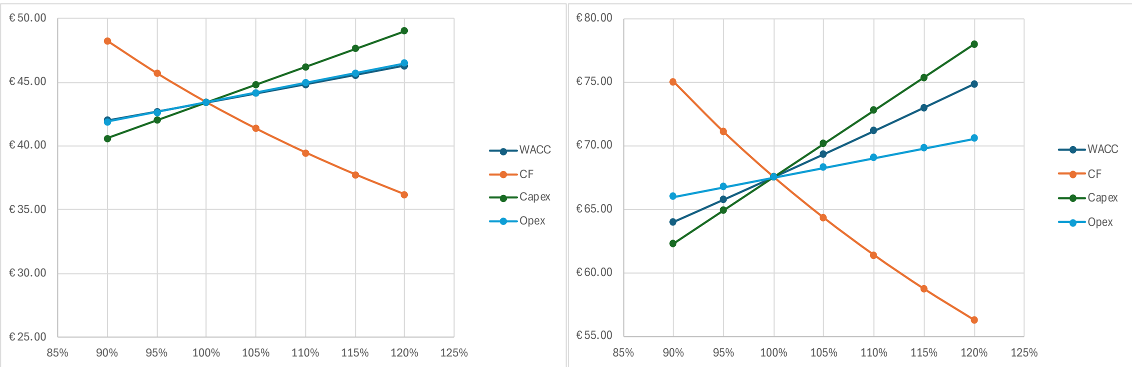
Link to the share → WP 1 - Tech Innovations Final version factsheets

Appendix B: Deep dive: wind farm power density

The (offshore) wind sector is going through a more difficult time to assure a viable business case, mostly resulting from economic reasons. Another reasons for a changing business case is the lower energy yield, usually expressed in the capacity factor or also number of Full Load Hours (FLH). The energy yield reduces due to two reasons:

- increase in the number of wind farms, resulting to substantial more (cluster) wake effects, i.e. wake effects due to wind farms upstream. Even though the upstream wind farm might be quite far away it appears to have a substantial effect on the FLH.
- The higher wind farm power density results in substantial lower FLH, resulting in (much) higher levelized cost of energy (LCOE).

Below two graphs, spider diagrams, are shown, on the left for the pre 2020 situation and right for the 2024 situation. The graphs show the LCOE for the assumed center values for CAPEX, OPEX, WACC and the Capacity Factor (CF).



The values for pre 2020 and 2024/25 used are shown in table below and the LCOE calculation is performed using the equation $LCoE = \frac{\frac{Capex}{a}a+Opex}{AEP}$ in which the annuity is $a = \frac{1-(1+r)^{-n}}{r}$, with the parameters shown in the table below.

The yield (AEP) equals the CF * 365*24 and r is the interest rate equal to the WACC. The economic lifetime (n) is assumed to be 25 years.

Scenario		< 2020	2024/25
CF	[%]	52	45
WACC (r)	[%]	5%	8%
CAPEX	[€/MW]	1800000	2200000
OPEX	[€/MW/yr]	70000	60000
Yield	[MWh]	4555.2	3942
annuity	[years]	14.09	11.65
LCOE	[€/MWh]	43.40	67.50

The yield or CF clearly has the highest sensitivity on the LCOE and this sensitivity is even stronger in the 2024/25 situation. Uncertainty about potential curtailment due to grid constraints or lacking demand will increase the LCOE even more.

How to increase the Yield?

The yield is mainly determined by the wind conditions, the rotor area and the wake losses, internally and externally. The wind conditions are external, i.e. given, except with respect to the cluster wake losses that is determined by location choices. The rotor area, per installed MW, is also indicated as Rotor Power Density (RPD) in Watts/m2, usually has values between 300 and 400 W/m2. Lower RPD will result in higher yield per installed MW and thus higher number of FLH. Wake losses are determined by amongst others:

- Wind Farm Power Density (WFPD),
- spacing between turbines, usually given in rotor diameters.
- lay out of the wind farm

All these criteria are strongly related and determined by the area given. Lower WFPD usually results in lower internal wake losses. Wind Farm power density is strongly related to the average spacing between turbines. Spacing can be varied within the wind farm, e.g. in North Sea situations where much more wind is coming from the Southwest increasing the spacing in the prevalent wind directions and reducing the spacing in the direction with relatively less wind results in lower wake losses. Some examples of capacity factors for the IJmuiden Ver Alpha site, 200 km2 installed with 134 wind turbines with a rotor diameter of 236m with 3 different generators, a 12, 15 and/or 20 MW generator. Results resulting in different RPD's and different WFPD's. Two additional scenarios with 25% plus or 25% less wind turbines.

Scenario		1	2	3	4	5
Description		**Baseline**	**Increased RPD**	**Decreased RPD**	**Reduced WFP**	**Increased WFP**
Nominal power WT	[MW]	15	20	12	12	20
Rotor diameter	[m]	236	236	236	236	236
Rotor Power Density	[W/m^2]	343	457	274	274	457
Hub Height	[m]	143	143	143	143	143
# turbines	[-]	134	134	134	100	167
WF Power	[MW]	2.01	2.68	1.608	1.2	3.34
WF Power Density	[MW/km2]	10.6	13.4	8	6	16.7
Annuel E prod	[GWh]	9053.1	10581.1	7914.1	6158.1	12468.7
Capacity factor	[%]	51.4	45.0	56.1	58.5	42.6
Wake Losses	[%]	14.86	17.34	13.21	9.51	21.85

The scenario's 1-3 show the effect of different RPD's where the increase in rotor power density from 274 – 457 W/m2 lead to a capacity reduction from 56% to 45%, while at the same time varying the WFPD between 8 and 13.4 MW/km2. The increase WFPD, at a rotor power density of 457 W/m2, 13.4 to 16.7 MW/km2 decreases the CF of 45.0% to 42.6% and a decrease in WFPD, at a RPD of 274 W/m2, increase the capacity factor of 56.1 to 58.5%. A reduction in nominal power of the wind farm of 20% leads to a reduced yield of 13% while an increased WF power of 133% leads to just 17% more yield.

From scenario 4 and 5 compared to scenario 3 and 2, shows that assuming a high wind farm power density and increasing that with 25% will lead to a power increase of 18% while assuming a low WFPD and decreasing that even more with 25% will lead to a reduction in yield of nearly 22%.

Appendix C: Energy Islands

C.1 Executive summary of work by van Oord

Within the NSE program, a Techno-economic assessment of offshore hydrogen production in the Dutch North Sea was performed by M.J. Bakker[70]. He performed a Comparative analysis of offshore hydrogen and electrical infrastructure with green hydrogen import using standardized breakdown and open-source cost model. This study addresses the need for a transparent, standardized techno-economic method to compare various offshore wind supply chains by developing an open-source model with automated configuration generation. Applying this model to the hub North case study explicitly demonstrates its proof of concept and the feasibility of integrating energy islands for the NSE programme, ensuring this concept is not overlooked. By utilizing the model, industry players can input their latest cost and efficiency values, resulting in more accurate calculations. This could enhance the recognition of its proof of concept, further leading to industry-wide efforts into collaborative design methods to overcome the challenges of the competitive hydrogen and wind market.

C.2 Cost increments of The Princess Elisabeth Island

The Princess Elisabeth Island is considered as the world's first artificial energy island. It is located off the Belgian coast in the North Sea. The island will serve as an electricity hub that will bundle together the cables leading to wind farms in Belgium's second offshore wind zone, helping to bring the electricity they generate back to shore. It will also act as an intermediate landing point for interconnectors that link Belgium to other European countries. Our teams have adopted a nature-inclusive design approach for the island: it has been designed in such a way that it will foster biodiversity and help marine life to flourish around it.[71]

Conclusion of energy islands made in NSE 4 are considered to be still applicable for NSE 5 (within the given timespan). There have been several notifications on significant cost increments for the total costs of the islands. KPMG has made an independent cost analysis of Elia's technical choices (including the island) and confirmed that the costs of the island are in line with the market and are the right choices. The large cost overrun is linked to a very overheated market for direct current components (HVDC).[72]

[70] FinalVersion_MSc_thesis_MaartenBakker_2024.pdf
[71] Princess Elisabeth Island
[72] KPMG's cost analysis of the energy island confirms unprecedented market prices for HVDC and states that Elia's technical choices are in line with the market

Appendix D: Breakout Session – Sprint 3

During the 3rd Sprint of NSE5, WP 1 technical Innovation hosted 2 breakout session with around 25 participants per session. The discussions were based on under-appreciated technical innovations that could play a key role in the future energy systems and also on the changes that needs to be implemented today to have a resilient energy system in the future. Below is a brief overview of the discussion and key pointers:

Various **under-appreciated and emerging technologies** were highlighted during the discussions, but here the focus is on with a focus on those that were repeatedly mentioned. These included ocean energy sources such as tidal, wave, and hydropower, along with their storage solutions. There was also a strong emphasis on further integrating AI and digitalization into offshore energy systems. Innovations like direct seawater electrolysis, enhanced storage technologies (including batteries, heat storage, and by-product integration), and the circularity and recyclability of materials used in energy infrastructure were also discussed. Additionally, attention was drawn to the advancement of power electronics, particularly HVDC cables for international connections and inter-array systems operating at 66kV–132kV. The importance of research into data sharing and cybersecurity was also underscored.

On the topic of production strategy and spatial planning, discussions revolved around reusing existing infrastructure—such as upgrading older turbines in the OWEZ wind farm from 3MW to 7MW—exploring alternative production and storage methods, and designing integrated approaches that combine technologies. A call was made for research into aligning energy systems more closely with demand-driven scenarios rather than solely supply-focused models.

Broader conversations about the future of energy transition stressed the importance of international collaboration. This includes learning from other countries, increasing the involvement of knowledge institutes and academia, and aligning with existing research consortia to enable better data sharing and avoid duplication of efforts. A multidimensional perspective was encouraged—going beyond technical aspects to include environmental sustainability, circularity, infrastructure resilience, and societal impact. Nature-inclusive designs, recyclability, and data security were considered crucial. Moreover, the role of government was deemed essential in steering innovation, through measures such as embedding promising technologies into tender procedures, subsidizing R&D projects, and setting clear policies and regulations. Lastly, the need for a coherent Europe-wide renewable energy strategy was emphasized, underpinned by joint investment decisions and a unified direction for the continent's energy future.

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