OFFSHORE PRODUCTION OF GREEN HYDROGEN

JANUARY 2022

ABS

TABLE OF CONTENTS

OVERVIEW

The United Nations Framework Convention on Climate Change adopted the Paris Agreement in 2015 as the first-ever global climate agreement for its member States. The Paris Agreement's long-term temperature goal is to limit the rise of the mean global temperature no more than 2° C, preferably 1.5° C, above pre-industrial levels. For the maritime industry, the International Maritime Organization set ambitious targets for decarbonization of the global fleet; to reduce CO_2 emissions per transport work by at least 40 percent by 2030 and 70 percent by 2050, and to reduce Greenhouse Gas (GHG) emissions from shipping by at least 50 percent by 2050, compared to 2008. The scope of the Paris Agreement extends beyond just the maritime industry though, as it will affect the entire economies of signatory countries.

In their efforts to achieve these climate goals, many countries have set targets to limit or eliminate GHG emissions and other polluting emissions and transition toward carbon-neutral economies. The timeline and roadmap for this process vary by country, with most electing to pursue combinations of short-term, mid-term, and long-term targets designed to fit their immediate and future carbon reduction capabilities. As governments around the world implement new regulatory requirements to support these goals, companies must develop and implement new strategies and technologies to meet their regulatory obligations. One method companies are exploring to reduce their net GHG emissions is the use of alternative or renewable fuels with lower emission profiles than conventional fuels.

Recognizing the challenges that clients may be facing, ABS has developed and published a series of documents to reference available carbon reduction strategies, identify gaps for meeting regulatory goals, and inform the maritime industry on new developments regarding alternative fuels. The ABS *Advisory on Decarbonization Applications for Power Generation and Propulsion Systems* and the ABS *Sustainability Whitepaper Series on Alternative Fuels* were developed to advance industry understanding of what future fuels were available and how they could be incorporated into the global maritime fleet.

This whitepaper addresses the offshore production of green hydrogen, or hydrogen produced using renewable energy and water electrolysis. Specifically, it will explore the conditions driving the maritime and offshore industries toward the adoption of green hydrogen, the technologies that make green hydrogen production feasible, and how those technologies can be incorporated into an offshore facility.

GREEN HYDROGEN AS AN ALTERNATIVE FUEL

The term 'alternative fuels' refers to a broad spectrum of non-conventional energy carriers, such as ammonia, methanol, methane, or hydrogen. The increase in demand for alternative fuels as substitutes for conventional fuels can be attributed to the following primary drivers:

- Alternative fuels can help to bring companies in compliance with current statutory regulations, such as carbon emissions requirements.
- Alternative fuel technologies are undergoing rapid development as part of a long-term plan to meet the Paris Agreement's 2050 climate goals.
- Alternative fuels are more attractive to environmentally conscientious consumers looking for cleaner options that still meet their energy needs.

Direct comparisons between alternative fuels are difficult to make as they are subject to the varied requirements and objectives of the end user. Alternative fuels can have large differences in production techniques, use cases, and storage requirements. Additionally, alternative fuels differ in their technological readiness and maturity. For example, liquefied petroleum gas (LPG) or liquefied natural gas (LNG) fuels are much more widespread and better integrated into the global fuel network than alternative fuels like ammonia and hydrogen due to years of industry experience and historical policy drivers. Hydrogen and its derivatives are seen as viable long-term fuel solutions, but will require significant research and development to reach a comparable level of technological readiness to LPG and LNG.

Hydrogen is produced through chemical reactions that separate it from water or hydrocarbons. In industry, hydrogen is often referred to by different colors to indicate its origins:

- Brown hydrogen, produced via coal gasification or coal carbonization
- Grey hydrogen, produced in the steam reformation reaction using natural gas
- Blue hydrogen, produced in the same manner as grey hydrogen but the emissions are captured resulting in a net-zero carbon footprint from the reformation process
- Green hydrogen, produced from renewable energy sources powering the water electrolysis process with no carbon emissions.

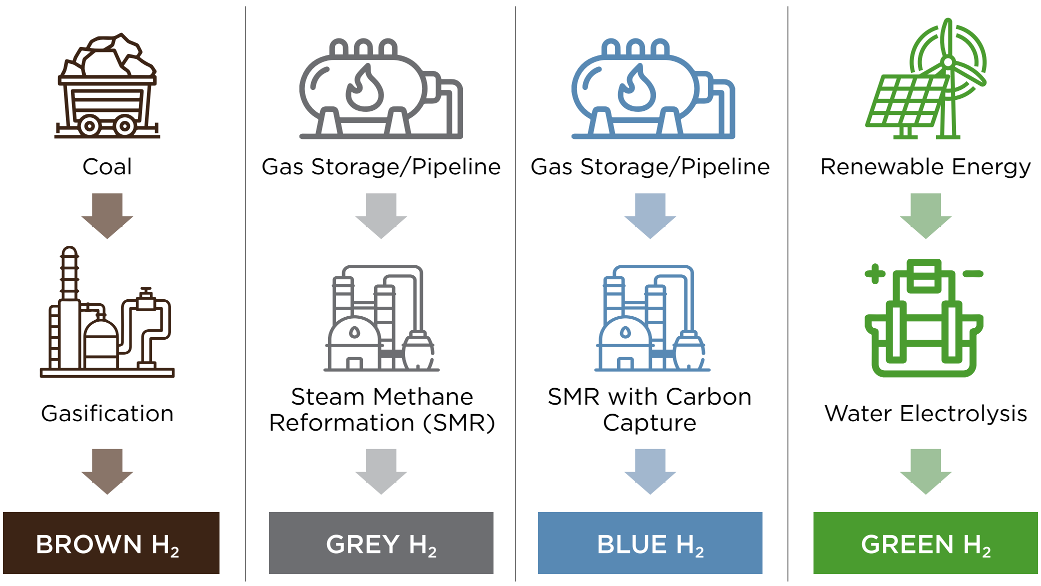


Figure 1. Different methods of hydrogen production

Brown, grey, and blue hydrogen production processes all create their hydrogen as a byproduct of burning fossil fuels. While these processes are possible in offshore environments, there are few compelling reasons to convert hydrocarbons into hydrogen in such an environment. None of these production methods require close proximity to renewable energy sources, and moving those production facilities offshore would only increase capital expenditures relative to comparable onshore projects. For further information on the production and potential use cases of brown, grey, and blue hydrogen fuels in marine applications, see the ABS Sustainability Whitepaper Publication *Hydrogen as Marine Fuel*.

Unlike brown, grey, and blue hydrogen, green hydrogen is produced by water electrolysis. Electrolysis is the process of passing a direct electric current through an electrolyte, inducing chemical reactions at the electrodes that result in decomposition, or breakdown, of reagents. In the electrolysis of water, water molecules are decomposed into their two elemental components – hydrogen and oxygen – with no additional emissions produced. The electrolysis process is performed by an electrolyzer system.

Green hydrogen production is powered entirely by renewable energy sources. As a result, green hydrogen development relies upon a continued shift toward renewable energy before it can be widely available on a commercial scale. The renewable energy source – in the case of offshore hydrogen production this is predominantly wind power with a small contribution from solar power – will be used to drive the water electrolysis reaction. The produced hydrogen can be exported via ship or pipeline, or can be stored for export at a later date.

RENEWABLE ENERGY LEADS THE DEVELOPMENT OF GREEN HYDROGEN MARKETS

The production of green hydrogen requires a renewable energy source to provide the input power into the electrolyzer system and any other equipment used in the process. In the case of offshore hydrogen production, the simplest source of renewable energy will come from offshore wind turbines. Other energy sources that may be used in offshore hydrogen production include tidal, wave, and solar energy harvesters. While tidal and wave harnessing technologies could potentially provide the requisite power for the electrolysis reaction, their share of the total offshore renewable power industry is currently orders of magnitude smaller than offshore wind, and they tend to be constructed in harbors or near shorelines. Offshore solar power is also less developed than wind, producing only one-tenth of the power of offshore wind power at facilities typically constructed on sheltered inland ponds and lakes as opposed to at sea.

In 2019, the global consumption of hydrogen fuel reached approximately 75 million tons. Of the 75 million tons of hydrogen, only 1.5 million tonnes were green hydrogen. A market analysis performed in April 2021 by the Energy Transitions Commission (ETC) indicated that the demand for hydrogen is expected to increase at a rate of seven to nine percent per year. This would lead to an estimated demand of between 500 and 800 million tons of hydrogen by the year 2050, which would fulfill between 15 and 20 percent of the global energy demand. To reach a production level of 500 million tons of hydrogen in the year 2050, there will need to be 3,000 to 6,000 GW of newly installed renewable energy sources devoted to hydrogen production.

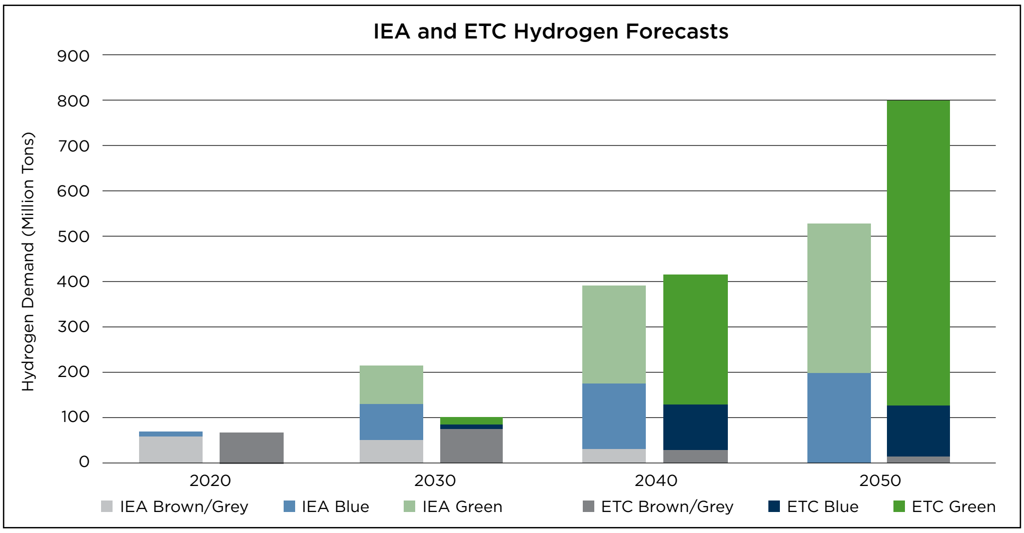


Figure 2. Low vs. High Demand Hydrogen Forecasts

In regions that are already heavily invested in developing renewable energy, hydrogen offers a reliable source of fuel during times where renewable energy alone can not meet grid demand. The production of green hydrogen is also a useful outlet for the energy generated during times when renewable power production exceeds the grid demand. In transportation and shipping, hydrogen fuel cells and hydrogen-based combustion engines can offer a reliable fuel source that reduces total emissions.

Reliable sources of renewable electricity for green hydrogen production can be found both onshore and offshore. Offshore green hydrogen production may be preferred over onshore green hydrogen production when certain conditions exist, such as:

- Unsuitable shore terrain or geography makes construction difficult and/or expensive
- Existing presence of permanent structures or communities
- Local government zoning restrictions targeting any industrial land usage, especially for large-scale facilities
- Possible regional unrest posing a greater security risk to shore-based facilities
- Existing offshore infrastructure suitable for hydrogen production and transport may be cheaper to adapt than constructing new onshore infrastructure

Due to green hydrogen's reliance on renewable energy sources, initial developments in offshore green hydrogen production will be localized to regions with existing or planned offshore renewable energy systems. The Global Wind Energy Council reported that the United Kingdom (29 percent), the People's Republic of China (28 percent), Germany (22 percent), the Netherlands (7 percent), and Belgium (6 percent) are responsible for 93 percent of the world's current offshore wind power production. China has led the world recently in newly installed offshore wind capacity – installing 50 percent of the world's new offshore wind power capacity in 2021 – and is expected to continue to do so as part of their overall renewable energy plans. Other regions are also beginning to develop offshore wind projects of their own, with countries like the U.S., Japan, and South Korea all expanding from onshore into offshore wind.

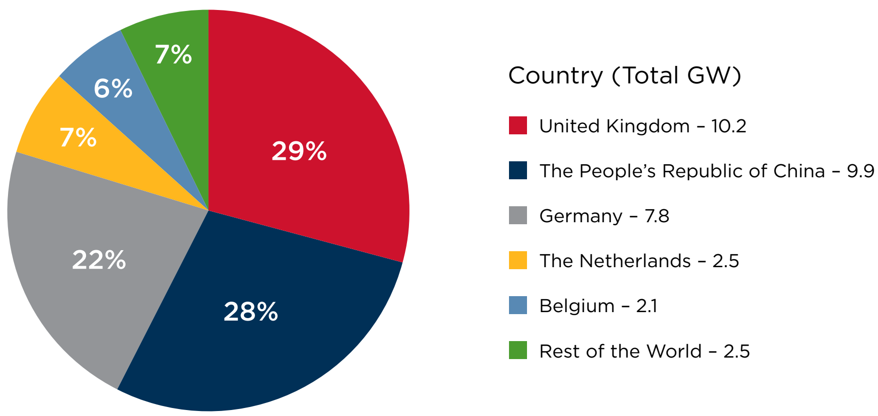


Figure 3. World's Current Offshore Wind Power Production

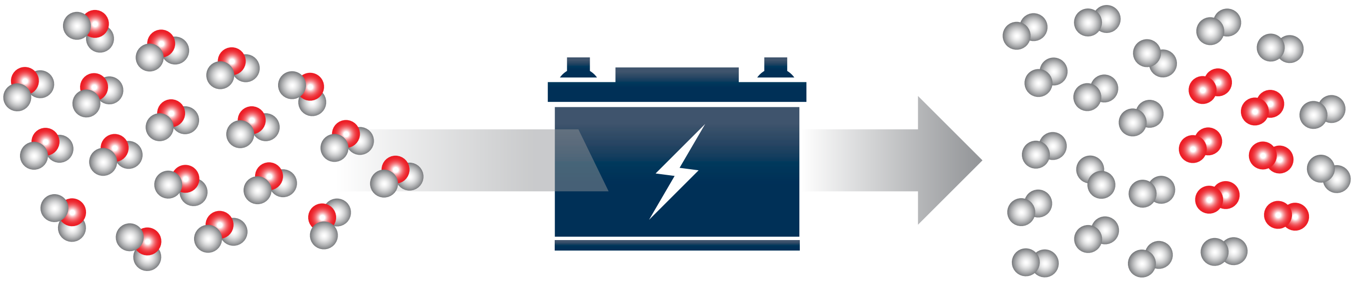
Northern Europe and China are two of the more likely regions for immediate development and installation of green hydrogen production facilities, due to the abundance of renewable offshore wind power, existing offshore infrastructure, and government policymaking that's favorable towards alternative fuels. Other countries like the United States, Saudi Arabia, and Australia are currently investigating and developing large onshore hydrogen production facilities and could potentially expand their scope to include offshore production facilities in coastal areas as well, but are limited by the lack of existing large-scale offshore renewable energy developments. While not an insurmountable challenge, it will take additional investment to develop offshore green hydrogen production facilities in these countries.

ELECTROLYZERS AND THE ELECTROLYSIS REACTION

The electrolyzer is the core of the green hydrogen production process. The design of the electrolyzer dictates the equipment's manufacturing cost, physical footprint, supporting equipment requirements, maintenance requirements, and the overall efficiency of hydrogen production. For these reasons, the selection of the electrolyzer design will dictate the design of the entire hydrogen production facility.

All electrolyzers are designed to facilitate the same base electrolysis reaction. As a result, there are several common features between all designs. There is an electrolyte to facilitate ion transfer between the two electrodes (i.e., the anode and cathode) where the chemical reactions occur. The electrodes and the electrolyte form the components of a circuit, where a direct current is supplied by a power source.

Hydroxide is oxidized at the anode, producing water and oxygen gas. At the cathode, water is reduced to produce hydroxide and hydrogen gas. The half-reactions are commonly balanced with a base, but in an acid-balanced reaction the hydrogen is still produced at the cathode and the oxygen is still produced at the anode.



$$H_2O \rightarrow H_2 + O_2$$

Water > Hydrogen + Oxygen

Figure 4. Water electrolysis produces hydrogen and oxygen.

Electrolyzers also have a membrane between the electrodes that permits different molecules to pass through depending on the system design. Other system variables that change between designs include operating temperatures and pressures, electrolyte selection, membrane material, and electrode arrangement.

All electrolyzer designs can be broken down into three distinct levels: the single cell (1st level); the stack (2nd level); and the total system (3rd level). A single cell is the core of the electrolyzer, where the electrochemical process takes place. A stack consists of multiple cells put together and any spacers, seals, or frames required for the connections. The third level is the total system, or the stack and all additional modules and equipment necessary for the hydrogen production process. This does not include any further gas compression, liquefaction, or storage. The total size of an electrolyzer system depends on the target hydrogen output and the design power input values. Some electrolyzer systems are as small as a refrigerator, while 10 MW or larger facilities can occupy spaces over 7,500 m^2 depending on the exact arrangement of machinery and piping.

Commercial electrolyzers in use today typically require an input power of at least 50 kWh (180 MJ) to produce 1 kg of pure hydrogen. For a single representative wind turbine with 8 MW capacity operating at a typical effectiveness of 35 percent powering a modern commercial electrolyzer, 490 metric tons of hydrogen could be produced every year. As of 2021, at least 69 offshore windfarms have a nameplate capacity of over 200 MW, and between them all have a total nameplate capacity of over 24,000 MW. At 35 percent effectiveness their gross annual energy production could be as high as 70 TWh. If the power generated by these large wind farms was leveraged entirely for hydrogen production, just over 1.4 million metric tons of hydrogen could be produced every year.

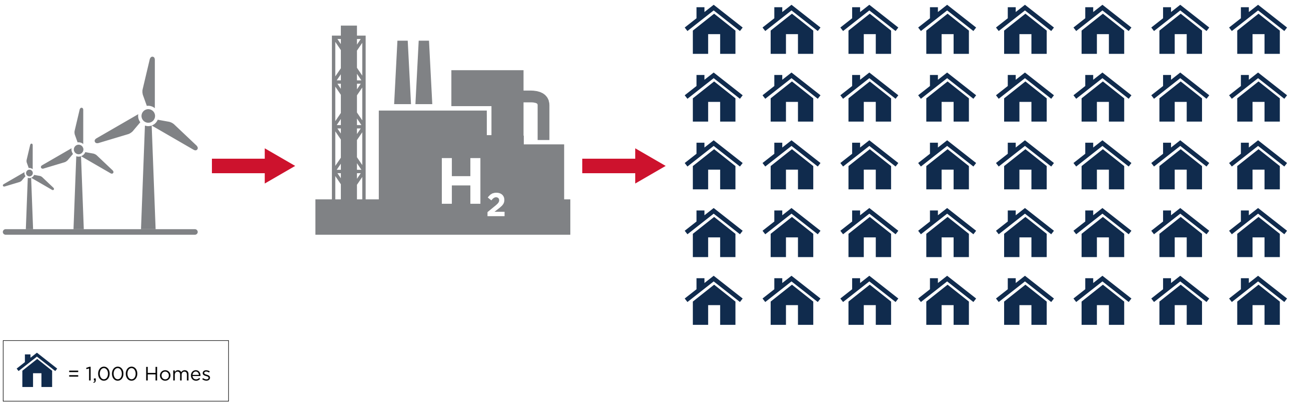


Figure 5. A single 1,000 MW windfarm could produce enough hydrogen to power 40,000 homes

ELECTROLYZER DESIGN COMPARISON

Currently there are three commercially viable designs of electrolyzers being considered for use in hydrogen production: proton exchange membrane (also known as polymer electrolyte membrane, or PEM) electrolyzers; alkaline electrolyzers; and solid oxide electrolyzers.

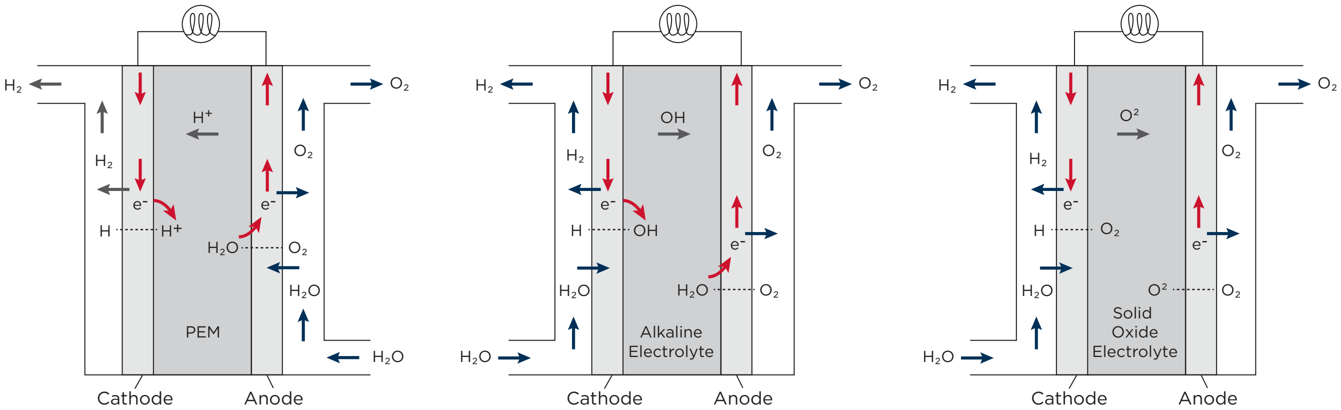


Figure 6. Common electrolyzer designs. (Left: PEM electrolyzer, Center: alkaline electrolyzer, Right: solid oxide electrolyzer)

Solid oxide electrolyzers operate using a solid ceramic membrane that requires operating temperatures upwards of 700° C to function. This elevated temperature can be efficiently achieved for hydrogen production processes where heat is already being produced, such as in nuclear reactors. When the energy comes from renewable sources operating at near ambient temperatures however, any additional heating of the water reduces the overall efficiency of the hydrogen production process. Solid oxide electrolyzers do not require any precious metals in their construction but do have lower longevity when compared to other electrolyzer designs.

Alkaline electrolyzers use a liquid alkaline solution of either potassium hydroxide (KOH) or sodium hydroxide (NaOH) to facilitate the electrolysis reaction. The working temperature for alkaline electrolyzers is between 60° C and 90° C, and the working pressure is between 1 bar and 30 bar. Alkaline electrolyzers can be either unipolar or bipolar in design. Unipolar designs, also known as monopolar or tank designs, have their electrodes suspended in parallel in alternating tanks separated by thin membranes that allow for the transfer of ions, but restrict the movement of the produced gases. Bipolar designs position the electrodes very close to each other, separated by a thin non-conductive membrane. Unipolar designs have the advantage of being cheaper and easier to build and maintain but are typically less efficient than bipolar designs. Alkaline electrolyzers operate best near their design loads, and they experience a drop in efficiency when operating under lower loads. Both of the designs for alkaline electrolyzers are more durable and contain fewer expensive rare earth metals than PEM and solid oxide electrolyzers.

PEM electrolyzers are similar to bipolar alkaline electrolyzers, but don't require an electrolytic solution to function. Instead, PEM electrolyzers have a thin, solid electrolyte membrane that permits hydrogen ions to pass through. PEM electrolyzers typically operate at higher current densities and higher pressures than their alkaline counterparts. The increased current density enables a more rapid system response to fluctuations in energy input, which can be a great benefit when working with intermittent renewable energy sources. They operate at temperatures between 50° C and 80° C, but at higher pressures than alkaline electrolyzers. Typical PEM electrolyzers are constructed using more rare earth metals than alkaline electrolyzers and require more precise construction techniques for their catalysts, which makes them more expensive to produce and maintain.

Each electrolyzer design has its own unique benefits and drawbacks, the selection of any particular design will influence the design of the complete facility and vice versa. They each require different pre-processing techniques for the supplied water, have different operating conditions, and have different maintenance requirements. In order to understand where each electrolyzer could be optimal, the complete hydrogen production facility must be examined.

Table 1. Comparison of common electrolyzer designs.

Name	**Alkaline Electrolyzer**	**PEM Electrolyzer**	**Solid Oxide Electrolyzer**
Electrolyte	Aqueous Alkaline Solution (KOH or NaOH)	Solid Polymer	Solid Oxide, Yttria-stabilized Zirconium Oxide
Current Density [A/m²]	2,000-4,000	10,000-20,000	3,500-5,500
Working Pressure [bar]	≤30	≤50	
Operating Temperature [°C]	60-90	50-80	500-850
Hydrogen Purity [%]	≥99.8	≥99.99	≥99.99
Export Component(s)	O_2 + lye, H_2 + lye	O_2 + Deionized Water, H_2 + Trace Deionized Water	O_2 + Deionized Water, H_2 + Trace Deionized Water
Input Component(s)	Deionized Water and Alkali Material	Deionized Water	Deionized Water (Steam)
Relative Volume	Large	Small	Small
Relative Manufacturing Cost	Low	Medium	High
Electrolyzer Lifetime	10 years	3-4 years	5-10 years

HYDROGEN PRODUCTION FACILITIES

Even though the offshore hydrogen industry doesn't have a long history, decades of offshore experience with both the oil and gas industry and the wind power industry provide many useful parallels to draw from. The challenges of adapting land-based hydrogen production facilities to offshore applications are numerous and vary in complexity. Some challenges associated with marinization are already well understood though, as the hydrocarbon and wind industries already addressed them when they began their own transitions from onshore to offshore applications:

- Large-scale hydrogen production facilities on land take up considerable space, and at the 100+MW scale they have a significant footprint. Finding the optimal size of a production facility to maximize limited space will be an important factor in initial planning and design of the facility, or when refitting an existing facility for hydrogen production.
- Environmental factors vary greatly depending on the region, and no two locations are the same. When designing the facility, typical and extreme wave and wind conditions at the site can drive decisions regarding the size, shape, and mooring arrangements when applicable.
- The proximity to renewable energy sources and any existing hydrogen infrastructure is also important to consider. For example, a facility close to a windfarm may reduce any power transmission losses and cable length but could require longer pipelines for exporting the hydrogen to shore.

In response to these and other challenges, there have been several proposed designs for offshore green hydrogen production facilities. These designs can be broadly categorized by the location of the electrolyzer and other associated core systems relative to the renewable energy source:

1. Directly incorporated into the structure of the renewable energy source (such as a wind turbine tower)
2. Not directly incorporated into the structure of the renewable energy source and located above water on a platform
3. Not directly incorporated into the structure of the renewable energy source and located on the seabed

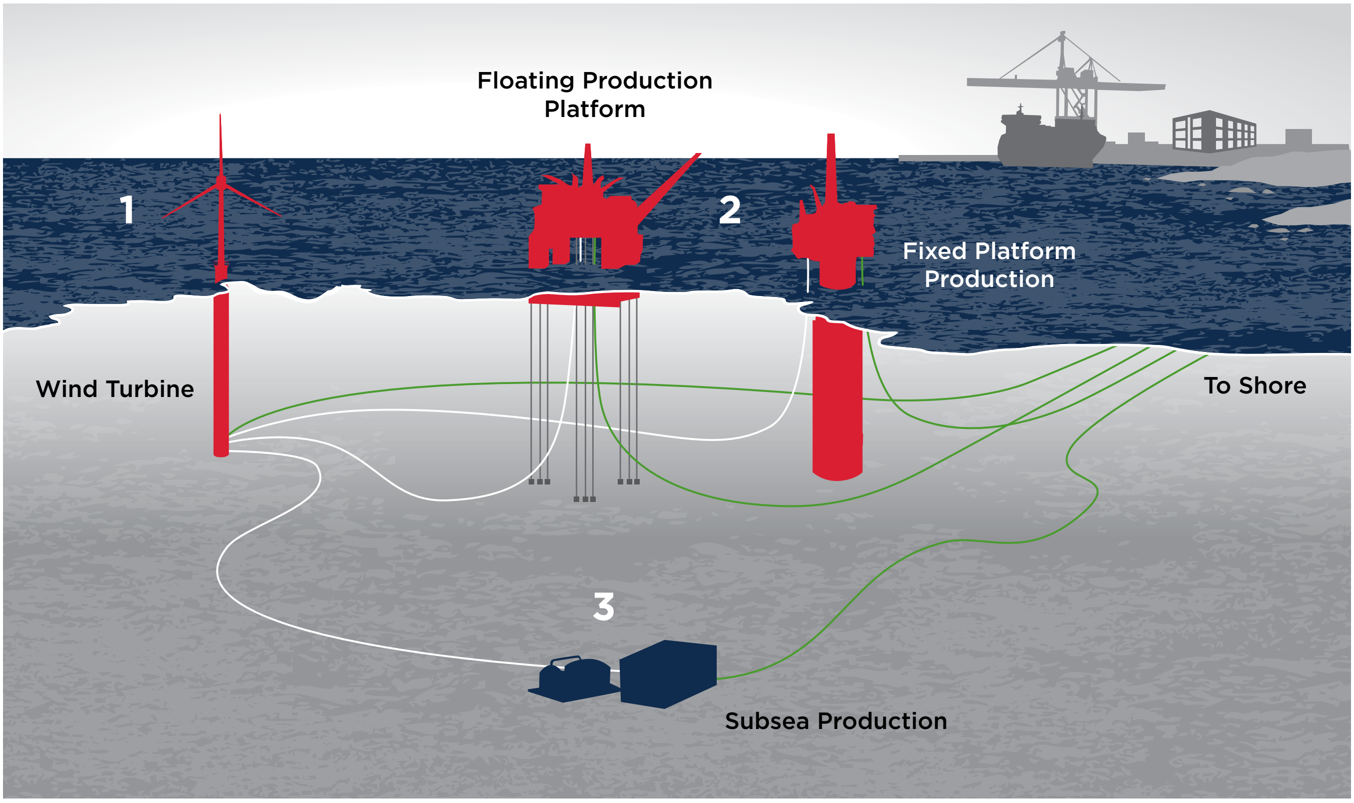


Figure 7. The design of an offshore green hydrogen production facility can take many forms. It can be incorporated into a wind turbine, constructed on a platform at the surface of the water, or located entirely at the seabed.

The first option has only been considered with respect to offshore wind farms and would have the electrolyzer directly integrated into the turbine structure. The electricity being produced is directed to the electrolyzer, seawater pumps, and any other equipment as necessary. The electrolyzer would then produce hydrogen and export it via delivery pipelines to a collection manifold located on either a platform or at the seabed, where the gas can be compressed to the desired pressure and exported to shore via a larger supply pipeline. This approach becomes more viable as the nominal power supplied by the wind turbines increases, since more powerful electrolyzers could be installed. Additional modifications may also be necessary for the wind turbine to accommodate the additional machinery on deck or within the structure. Existing wind farms will need to undergo extensive infrastructure modifications if this option is chosen, as pipelines would need to be laid and each turbine structure could require modifications.

The second option generally refers to the use of a floating or fixed platform with one centralized electrolyzer system. This design would require fewer changes to incorporate into existing renewable energy infrastructure. After incorporating the production platform into the system delivering power to shore, the platform is largely independent. The supplied power will be used to run the water supply pumps, electrolyzers, heat exchangers, compressors, and any other equipment as needed on the platform. As the hydrogen is produced it is compressed, and either immediately exported or undergoes additional compression and refrigeration for storage as either a gas or a liquid. It may be possible to retrofit existing offshore assets like platforms and pipelines to reduce the capital expenditure of a project.

The third option would place the entire centralized electrolyzer system on the seabed. This could be a viable alternative in areas where surface-based operations are not possible or desirable. This design reduces some of the power lost to pumping electrolyzer feed water in surface designs and negates most of the weather-related effects that surface designs may face, but does add complexity and additional construction costs to the project. Maintenance of any subsea system is more expensive to perform than a comparable surface system, so electrolyzers would need to be designed for longer maintenance intervals with more reliable catalysts and electrodes.

When considering the overall design of the production facility, there are some considerations that are generally applicable to any project. For example, green hydrogen relies on renewable energy sources to power the entire process. In the event that insufficient power is being supplied to the facility, the production system needs to be able to either safely shut down or operate at a reduced rate. For electrolyzer stacks, this could be done by taking some cells offline. Some hydrogen could be stored permanently onsite and used in conjunction with fuel cells as a backup power supply to ensure essential systems remain functioning until renewable power production returns to its normal rate.

Another factor to consider is how the facility will be crewed, if at all. While platform designs could dedicate some space to crew accommodations, subsea designs are only accessible to remotely operated vehicles or divers, depending upon the water depth. For decentralized designs, electrolyzers could be monitored and operated remotely from shore, or from a collection manifold if it's located on a platform. For additional information on autonomous and remote control system design, see the ABS *Guide for Autonomous and Remote Control Functions*.

As the demand for offshore production of green hydrogen grows, the ability to expand production capacity is also important. Choosing designs that are easily expandable could be more cost effective in the long run, especially in regions with large amounts of available renewable energy and forecasts for high hydrogen demand. Because hydrogen can also serve as a feedstock for producing other chemicals, like ammonia, designs might also consider additional systems for generating, storing, and exporting other chemicals in the future.

COMPONENTS OF A HYDROGEN PRODUCTION FACILITY

Although none of the proposed designs for offshore green hydrogen production have been built and operated at full scale, onshore hydrogen production facilities and other offshore industries can provide some insight into how such a facility might look and operate from a systems perspective. The following systems are all likely to be present in some capacity, regardless of the actual design of the facility.

POWER DELIVERY TO THE PRODUCTION FACILITY

One issue common to many windfarm installations is supplying electricity to shore. High voltage alternating current transmission systems have losses between one and five percent for wind farms located 50 to 100 kilometers offshore with nominal power between 500 and 1,000 MW. High voltage direct current lines have losses between two and four percent under the same circumstances and require conversion at each end of the line. Hydrogen, on the other hand, exhibits a loss of under one-tenth of a percent over the same distances through pipelines. Hydrogen pipelines can be a cheaper option than underwater electrical cables, because of their lower manufacturing cost and simpler infrastructure. This can make producing hydrogen closer to a wind farm more efficient than producing hydrogen far away. For existing renewable energy farms, the hydrogen production facility could be connected anywhere along the power transmission system.

The connection between the hydrogen production facility and the renewable power source will depend upon their respective locations. In the case of both floating and bottom-founded offshore facilities, power would be delivered using techniques comparable to those used for exporting it from wind farms. Floating facilities may add some complexity to the design, as the power umbilical would need to be incorporated into the mooring and riser system. In other cases, it may be possible to integrate the hydrogen generating facility into the wind turbine support structure or near the base of an offshore wind turbine installation. This could simplify the power delivery process, but could add significant challenges to the collection and export of produced hydrogen.

WATER PROCESSING SYSTEMS

For most electrolyzers, using unprocessed seawater is not advised. The presence of numerous other ions and particulates in seawater leads to the possibility of competing chemical reactions occurring with a wide range of products and unintended effects. The most problematic possible reaction is the chlorine electro-oxidation reaction, which occurs at the anode and is favored over the oxygen evolution reaction. This reaction produces a family of corrosive chlorine compounds such as chlorine gas and hypochlorite, all of which are environmental hazards and corrode the anode at a faster than normal rate.

Alkaline electrolyzers need an electrolyte solution to operate in, typically potassium hydroxide or sodium hydroxide, while PEM electrolyzers operate in pure deionized water. In the case of PEM electrolyzers, the water requires pre-treatment to remove any suspended particles before passing through reverse osmosis membranes which remove any dissolved salts or other impurities to deliver pure deionized water to the electrolyzer. Alkaline electrolyzers are generally more tolerant than PEM electrolyzers, and any particles involved in competing half-reactions can be managed with a water conditioning and treatment system. Because of the range of aqueous solutions suitable for use in alkaline electrolyzers, there is not a singular procedure for how water should be handled. For a higher level of control over quality of water being fed to an alkaline electrolyzer, the alkaline compound can be added to pure deionized water.

HYDROGEN STORAGE SYSTEMS

Once produced, hydrogen may be compressed or refrigerated for storage or offloading. In the event that hydrogen can't be received further downstream, having some capacity for storing hydrogen on-site is important to prevent a shutdown of the facility. Because hydrogen is a gas at ambient temperature and pressure, it can be volumetrically inefficient to store or transport at ambient conditions. In order to maximize the amount of hydrogen contained within a given volume, it can be compressed or (even liquefied below -234° C). High pressures between 350 and 700 bar, cryogenic environments below -234° C, or a combination of high pressure and low temperature may be required to reach higher hydrogen densities. It should be noted that hydrogen is typically handled as a gas when in a pipeline, at pressures between 30 and 150 bar. Solutions for hydrogen storage have been proposed at different temperatures and pressures, depending on the arrangement and design of the containment system.

Produced hydrogen can be stored using methods similar to natural gas, with some critical differences. Due to the small molecular size of hydrogen, equipment exposed to the gas is subject to a phenomenon known as hydrogen embrittlement whereby hydrogen can permeate into the walls of some metal alloy tanks over time. This can lead to general weakening of the structure along with crack formation and other forms of brittle failure in tank material. Hydrogen's small molecular size also makes it more prone to leakages, especially in links between pipeline sections and valves on pipes and tanks. Hydrogen oxidizing bacteria can also pose an issue for improperly stored hydrogen, as the bacteria naturally metabolize and reduce the purity of the stored hydrogen.

Hydrogen storage is currently done using either fabricated tanks or naturally occurring underground structures like salt domes. In geological storage methods, the hydrogen is pumped into an aquifer or salt cavern as a gas, similarly to natural gas industrial practices. However, underground hydrogen storage systems may be subject to leakage from aquifers at a higher rate than natural gas, therefore not all aquifers are suitable. Salt domes are preferred for geological storage, as they have low leakage rates, quick injection and recovery rates, and are easier to prepare than other geological formations.

In fabricated tanks, hydrogen is commonly stored as a liquid to increase stored density and reduce tank volume requirements. In a liquid state, hydrogen can be stored in metal tanks in a process similar to liquefied natural gas. The liquefaction process for hydrogen requires more energy to achieve lower cryogenic temperatures compared to LNG, which liquefies around -161° C (-258° F). This process is relatively standardized, with the gaseous hydrogen undergoing compression before being cooled via heat exchangers and liquid nitrogen in a series of refrigeration cycles. Liquid storage of hydrogen requires a high initial investment in the construction of the liquefaction plant and has a high operating cost in terms of energy expenditure to total hydrogen stored. A large risk with storing hydrogen as a liquid is the potential to lose storage capabilities if cryogenic temperatures are not maintained. To mitigate this risk, additional power reserves will need to be dedicated to the liquefaction system. Hydrogen stored under cryogenic conditions will require tanks designed with materials fitted for these extreme conditions, which also adds to the cost of storage and makes the system design more complex.

Download the ABS *Hydrogen and Marine Fuel* whitepaper from www.eagle.org.

For additional reading on the storage of hydrogen, the ABS *Sustainability Whitepaper Publication Hydrogen as Marine Fuel* covers this topic in greater detail.

HYDROGEN EXPORT SYSTEMS

The manner in which hydrogen will be exported from the production facility is dependent upon the design of the facility. In all scenarios, industry experience with oil and gas export systems will heavily influence the design of hydrogen export systems. In the case of a bottom-founded or a floating hydrogen production facility, the hydrogen could be exported by ships in a platform-to-ship arrangement or via pipelines on the seabed leading back to shore. For subsea hydrogen production, the export could be done to shore with subsea pipelines or to ships by means of a buoy with a riser connected to the subsea facility. In export systems that use a pipeline to deliver hydrogen to shore, there is potential for existing oil and gas infrastructure to be used. The commingling of hydrogen with natural gas has been proposed to take advantage of existing natural gas infrastructure, but is untested on large scales and there remain uncertainties regarding material requirements for such pipelines. If new pipelines are used, they would be constructed using materials compatible with hydrogen using existing industry practices for the pipelaying process.

HYDROGEN SAFETY SYSTEMS

Hydrogen has several critical physical characteristics that must be considered when designing a safe production facility. The most important characteristic is its large flammability range compared with other commonly handled fuels. While hydrogen may dissipate quickly in open, well-ventilated areas, confined spaces with little or no ventilation represent a significant fire hazard. Depending on the flammable mixture, the gas pressure, and the location of the leak, combustion may also occur. When hydrogen burns, it's invisible to the naked eye and burns quicker than most other compounds. To detect hydrogen leaks, hydrogen detectors and infrared cameras can be used. Leak detection strategies should also be implemented, along with proper ventilation. To extinguish a hydrogen fire, dry chemical extinguishers or carbon dioxide extinguishers are both effective. For additional information on fire safety practices for the handling of hydrogen, the ABS *Sustainability Whitepaper Publication Hydrogen as Marine Fuel* covers this topic in greater detail.

Because hydrogen is frequently held at extremely low temperatures, human contact with cryogenic materials and uninsulated pipes and tanks can lead to cold burns and skin damage. Hydrogen is non-toxic and lighter-than-air, but at high concentrations in confined spaces it acts as an asphyxiant. The flow of hydrogen through pipes can also cause a buildup of electrostatic charge, which can result in sparks when discharged and potentially cause ignition of hydrogen.

When hydrogen is being handled at cryogenic temperatures and high pressures, mechanisms for protecting systems from pressure buildup will also be necessary. This can be achieved through proper insulation of tanks and pipes and by installing pressure relief valves at appropriate areas in hydrogen-carrying systems. Additionally, a purging or inert gas system will be necessary to prevent the formation of flammable gas mixtures when tanks are being emptied. If the hydrogen is being handled at cryogenic temperatures, the gas selected for use in purging should not liquefy at temperatures below -234° C. The gas should also not contaminate or react with the hydrogen. Helium has traditionally been used for this purpose due to its suitable chemical properties, but sourcing enough helium may be difficult for long term use.

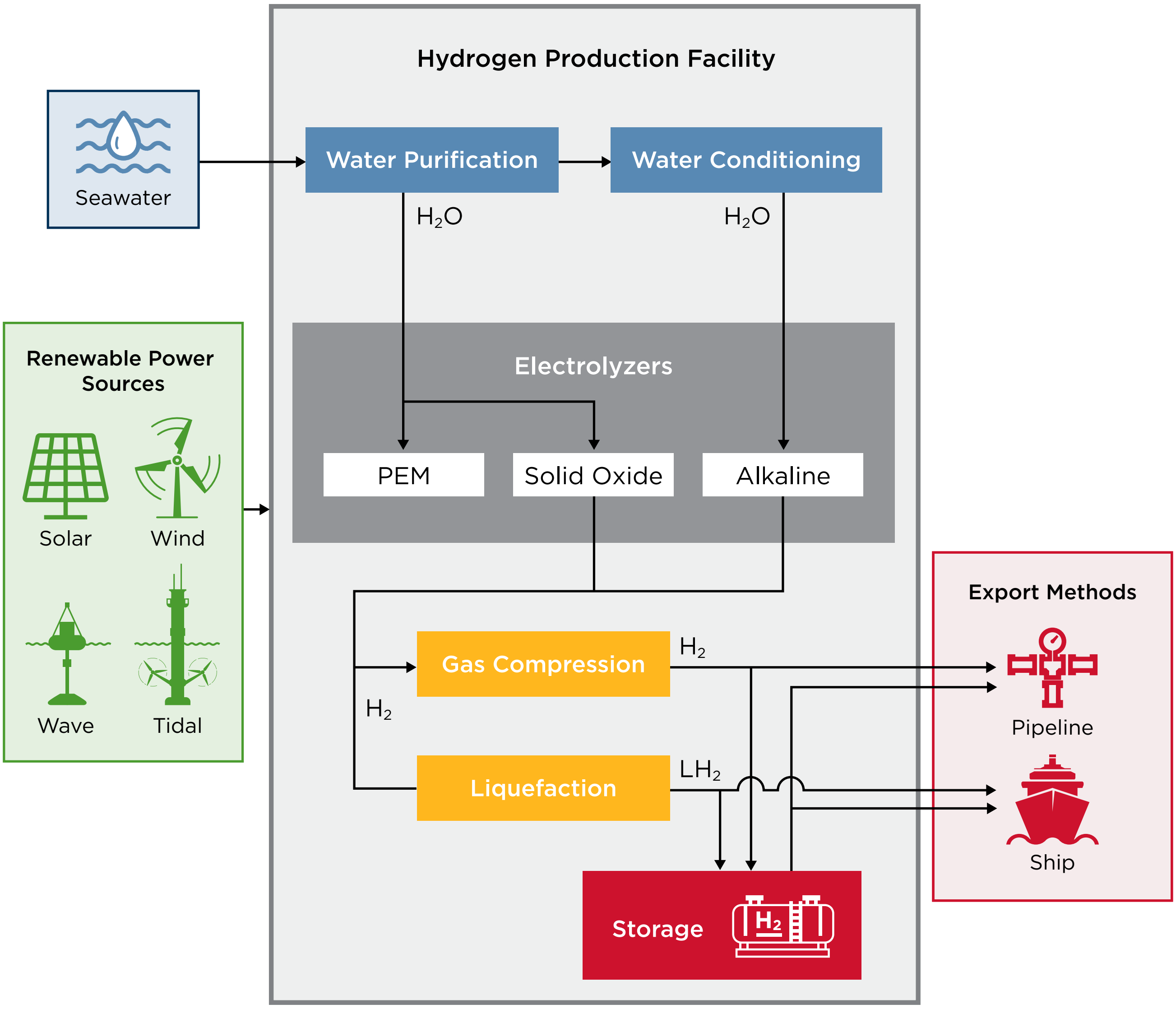


Figure 8. A diagram showing the different subsystems required for a green hydrogen production facility and how they interact with each other.

RISK ASSESSMENT

Many statutory regulations and certification schemes for hydrogen production facilities require risk assessments to verify that the system is appropriately safe and can exhibit at least an equivalent level of safety as conventional offshore oil & gas facilities. A risk-based approach justification of alternatives may be applicable either to the facility as a whole or to individual systems, subsystems, or components. As appropriate, attention should be given to remote hazards outside of the bounds of the system under consideration.

There are many tools that can be leveraged when performing a risk assessment. A risk assessment may include a Hazard Identification (HAZID) analysis to identify potential hazards that could negatively impact personnel, the environment, and property. A Hazard and Operability (HAZOP) study can also be conducted to evaluate hazards and identify root causes of hazards that may represent risks to personnel or equipment during the operation of a facility. A Failure Mode and Effects Analysis (FMEA) may also be used to identify and catalog potential failure modes of systems, and the causes and effects of those failures. The data collected from these studies plays a key role in determining whether current controls measures are adequate and if additional safeguards are necessary to mitigate risk.

See the ABS *Guidance Notes on Risk Assessment Applications for the Marine and Offshore Industries* for more information on risk assessment methods and standard recommended practice.

FINANCIAL DRIVERS OF GREEN HYDROGEN

The price of green hydrogen in April 2021 ranged between $3.00 and $6.55 per kg. This price makes green hydrogen comparatively expensive in the current market relative to hydrogen produced via blue or brown/grey processes, which cost between $1.30 and $2.90 per kg and $0.70 and $2.20 per kg respectively. The variation in cost for blue, brown, and grey hydrogen depends on a combination of current coal or natural gas prices at the production facility, as well as the costs of building and operating the production facility. Similar to how the availability of natural gas and coal impacts the price of blue, brown, and grey hydrogen, the availability of renewable energy sources has a large impact on the pricing of green hydrogen. As the technology and infrastructure develops, by 2030 green hydrogen is expected to drop in price to around $2.00 per kg in most regions with lows of $1.00 per kg in especially favorable regions. According to forecasts by the ETC, green hydrogen is expected to be cheaper than blue hydrogen in some areas by 2030 and most of the world in 2050.

One of the most expensive parts of green hydrogen production is the cost of the electrolyzer system. Reports from BloombergNEF (BNEF), the International Energy Agency (IEA), and International Renewable Energy Agency (IRENA) indicate that the average cost of alkaline electrolyzers in 2019 was $950 per kW, but predicted a drop to $625 per kW by 2030. For green hydrogen to be economically comparable to blue and brown/grey hydrogen, electrolyzer prices need to be reduced to closer to $125 per kW. This could be achieved through improvements in existing electrolyzer technologies, new electrolysis technologies being discovered, or an increase in the production rate of electrolyzer units to drop the unit price. Alkaline electrolyzers produced in China have already reached prices of $200 per kW, but both IRENA and BNEF have stated that the electrolyzers may not be able to compete with more expensive designs in terms of quality and reliability.

Another key factor in making green hydrogen economically viable is the introduction of financial incentives by governments. Governments can make green hydrogen cheaper by incentivizing production of green hydrogen, disincentivizing other methods of hydrogen production, or some combination of the two. One example of a financial incentive is a tax credit on new renewable energy developments. A tax credit for producing green hydrogen would decrease the net price to build and install the production facility. Many governments are also proposing low-carbon tax credits as a means of encouraging companies to reduce their GHG emissions below a certain threshold. This might drive traditionally high-carbon companies like those in the oil and gas industry to develop blue or green hydrogen divisions in their companies. As a complement to the incentives being offered by governments, carbon taxes encourage green hydrogen and other renewables by making hydrocarbons more expensive to use. A carbon tax is a tax levied on companies based on their total GHG emissions. As carbon taxes increase, businesses are starting to take greater steps to avoid operations that generate them. Companies can drive down their total GHG emissions by capturing their emissions, switching to renewable energy options, and by adopting cleaner technologies to power their operations.

ONGOING PILOT PROJECTS AND PLANNED DEVELOPMENTS

Offshore wind and wind/solar hybrid projects are the only renewable energy sources yet identified for integration into offshore hydrogen production facilities. Offshore wind is currently both the cheapest and most readily available source of offshore renewable energy and will continue to be so for the immediate future. As a result, the large offshore green hydrogen production projects proposed so far all integrate wind farms into their designs. 2020 saw 50 GW of green hydrogen projects announced.

The NortH2 Project (Equinor, Gasunie, Groningen Seaports, RWE and Shell Nederland, with backing from the Groningen provincial authority) off the Dutch coast has set a goal of four GW of green hydrogen from offshore wind by 2030 and over 10 GW by 2040. The project is considering three options for the electrolysis facility: located on either an existing or newly constructed platform; on either an existing or purpose-constructed island; or integrated into the wind turbine superstructure.

In Germany, the AquaVentus project (RWE, Shell, Siemens Gamesa, Vestas, and 75 other companies and institutions) is aiming for 10 GW of offshore wind energy being used to generate green hydrogen by 2035. By 2028, the project aims to have an offshore platform with an installed production capacity of 290 MW that pipes produced hydrogen back to shore in Heligoland.

Deep Purple (a consortium led by TechnipFMC) aims to design, build, and construct a pilot for its combined surface electrolysis and subsea hydrogen storage system by 2023.

There are also many other smaller projects at and below one GW that have been announced throughout both Europe and in Australia, Saudi Arabia, and China.

ABS has been engaged in various offshore hydrogen projects, including one with the goal of designing and constructing an offshore platform for green hydrogen production by 2025.

It is important to note that all of the offshore green hydrogen production projects are either early in the pilot phase or still in the conceptual phase of design. Onshore hydrogen production has outpaced offshore so far and is likely to lead the industry in the near future. As these initial offshore projects develop and more experience is gained in adapting green hydrogen technology to offshore operations, the industry will be better able to expand and establish a larger role in the hydrogen market as a whole. Adjusting and expanding quickly will be important for green hydrogen securing a share of the ever-increasing demand for hydrogen around the globe. The lessons learned from these projects will pave the way for the future of offshore production of green hydrogen.

ABS SERVICES

ABS can assist owners, operators, designers, and original equipment manufacturers as they consider the decisions and challenges associated with offshore production of green hydrogen. Services offered include:

- Risk assessments (such as HAZID, HAZOP, FMEA)
- Regulatory and statutory compliance
- New technology qualifications
- Techno-economic studies
- Greenhouse gas rating services
- Emissions certifications
- Remote Control and Autonomous functions development
- Cybersafety notations and assessments

APPENDIX I – REFERENCES

ABS PUBLICATIONS

ABS *Advisory on Decarbonization Applications for Power Generation and Propulsion Systems*

ABS *Sustainability Whitepaper: Hydrogen as Marine Fuel*

ABS *Guide for Autonomous and Remote Control Functions*

ABS *Guidance Notes on Risk Assessment Applications for the Marine and Offshore Industries*

REFERENCES

BloombergNEF. (2021). *New Energy Outlook 2021.*

Calado, G., and Castro, R. (2021). Hydrogen Production from Offshore Wind Parks: Current Situation and Future Perspectives. *Applied Sciences*, 11(12), 5561. https://doi.org/10.3390/app11125561

Christensen, A. (2020). *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe.*

Energy Transitions Commission. (2021). *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy.*

Global Wind Energy Council. (2021). *Global Wind Report 2021.*

Goldman Sachs. (2020). *Green Hydrogen: The Next Transformational Driver of the Utilities Industry.*

Guo, Y., Li, G., Zhou, J., and Liu, Y. (2019). Comparison between hydrogen production by alkaline water electrolysis and hydrogen production by PEM electrolysis. *IOP Conference Series: Earth And Environmental Science*, 371(4), 042022. https://doi.org/10.1088/1755-1315/371/4/042022

IEA (2019), *The Future of Hydrogen*, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen

IRENA (2018), *Hydrogen from renewable power: Technology outlook for the energy transition*, International Renewable Energy Agency, Abu Dhabi.

IRENA (2019), *Hydrogen: A renewable energy perspective*, International Renewable Energy Agency, Abu Dhabi.

IRENA (2020), *Green Hydrogen: A guide to policy making*, International Renewable Energy Agency, Abu Dhabi.

Siemens Gamesa. (2020). *Unlocking the Green Hydrogen Revolution.*

Sun, F., Qin, J., Wang, Z. et al. Energy-saving hydrogen production by chlorine-free hybrid seawater splitting coupling hydrazine degradation. *Nat Commun 12*, 4182 (2021). https://doi.org/10.1038/s41467-021-24529-3

APPENDIX II – ACRONYMS

ABS	American Bureau of Shipping
ETC	Energy Transitions Commission
FMEA	Failure Mode and Effects Analysis
GHG	Greenhouse Gas
GW	Gigawatt
GWEC	Global Wind Energy Council
HAZID	Hazard Identification
HAZOP	Hazard and Operability
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
KOH	Potassium Hydroxide
kWh	Kilowatt Hour
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MJ	Megajoule
MW	Megawatt
NaOH	Sodium Hydroxide
PEM	Proton Exchange Membrane, or Polymer Electrolyte Membrane
TWh	Terrawatt Hour
US	United States
USD	United States Dollar

CONTACT INFORMATION

GLOBAL SUSTAINABILITY CENTER
1701 City Plaza Dr.
Spring, Texas 77389, USA
Tel: +1-281-877-6000
Email: Sustainability@eagle.org

NORTH AMERICA REGION
1701 City Plaza Dr.
Spring, Texas 77389, USA
Tel: +1-281-877-6000
Email: ABS-Amer@eagle.org

SOUTH AMERICA REGION
Rua Acre, nº 15 - 11º floor, Centro
Rio de Janeiro 20081-000, Brazil
Tel: +55 21 2276-3535
Email: ABSRio@eagle.org

EUROPE REGION
111 Old Broad Street
London EC2N 1AP, UK
Tel: +44-20-7247-3255
Email: ABS-Eur@eagle.org

AFRICA AND MIDDLE EAST REGION
Al Joud Center, 1st floor, Suite # 111
Sheikh Zayed Road
P.O. Box 24860, Dubai, UAE
Tel: +971 4 330 6000
Email: ABSDubai@eagle.org

GREATER CHINA REGION
World Trade Tower, 29F, Room 2906
500 Guangdong Road, Huangpu District,
Shanghai, China 200000
Tel: +86 21 23270888
Email: ABSGreaterChina@eagle.org

NORTH PACIFIC REGION
11th Floor, Kyobo Life Insurance Bldg.
7, Chungjang-daero, Jung-Gu
Busan 48939, Republic of Korea
Tel: +82 51 460 4197
Email: ABSNorthPacific@eagle.org

SOUTH PACIFIC REGION
438 Alexandra Road
#08-00 Alexandra Point, Singapore 119958
Tel: +65 6276 8700
Email: ABS-Pac@eagle.org

ABS

TX 01/2 22008