Hydrogen Production from Offshore Wind

Subjects: Energy & Fuels
Contributor: Rui Castro

With the increase in renewable energy connected to the grid, new challenges arise due to its variable supply of power. Therefore, it is crucial to develop new methods of storing energy. Hydrogen can fulfil the role of energy storage and even act as an energy carrier, since it has a much higher energetic density than batteries and can be easily stored. Considering that the offshore wind sector is facing significant growth and technical advances, hydrogen has the potential to be combined with offshore wind energy to aid in overcoming disadvantages such as the high installation cost of electrical transmission systems and transmission losses. This paper aims to outline and discuss the main features of the integration of hydrogen solutions in offshore wind power and to offer a literature review of the current state of hydrogen production from offshore wind.

Keywords: green hydrogen ; offshore wind ; techno-economic analysis ; water electrolysis ; grid integration

1. Introduction

Hydrogen is a gas that can be easily produced using electrolysis and that has several potential applications, ranging from an energy source for transportation to being mixed into the natural gas grid, along with current applications in fuel refining and fertilizer production. Historically, hydrogen production is based on fossil fuels and emits a large amount of CO_2; however, in the last decades, significant advances have been made in electrolysis and renewable energy production, making possible the production of green hydrogen at a reasonable price point.

Furthermore, with governments pushing the reduction of carbon emissions and lowering the dependence on fossil fuels, the demand for green hydrogen has risen quickly and is expected to rise substantially in the coming years. With the help of incentives and policies, green hydrogen is undergoing significant investigation around the world, with the objective of producing hydrogen without carbon emissions that, with a small incentive, can compete with traditional hydrogen production methods.

Fuel cells are devices that use hydrogen to produce electricity, with the only by-products being water and heat. In recent years, fuel cells have also experienced significant advancements; they are starting to be used in commercial applications like passenger cars, trucks, buses, and grid-connected dispatchable power plants. One of the reasons electrical grids are still dependent on fossil fuels is due to their ability to regulate power production. Since typical renewable energy sources like wind and solar energy are intermittent, their power output can't be regulated (hydroelectric dams with reservoirs provide some flexibility but ultimately are dependent on rainfall upstream). Hydrogen can serve as an energy storage solution, where dispatchable fuel cells that run on green hydrogen can produce power when needed without any carbon emissions.

Wind power produces roughly 5% of the world's electricity [1], with most installations onshore. However, higher wind speeds and more consistent wind can be found offshore, which leads to higher energy production per turbine installed; the disadvantages are higher cost and technical challenges due to the rough sea conditions to which the equipment is subjected. One of the challenges is transporting the electricity back to shore, since traditional AC power cables have higher capacitance and thus higher losses than overhead lines, and more recent High Voltage Direct Current (HVDC) systems are expensive due to the converter stations necessary at each end of the transmission line. Considering that the transportation of gas in a pipeline suffers much smaller losses (<0.1%) [2][3] than electricity passing through an offshore cable, a case can be made for the production of hydrogen offshore, with pipelines to transport it to shore. From an economic perspective, the cost per unit length of an offshore pipeline is higher than an offshore cable. However, the pipeline's energy transmission capacity is greater than the cable, resulting in lower normalized pipeline capital costs compared to an equivalent offshore electrical cable to transmit the same energy [3].

Two system configurations can be found: the first consists of an offshore wind farm, offshore electrolyzer, and onshore hydrogen storage, while in the second system the electrolyzer is located onshore. A fuel cell can be added in both systems to provide electricity in high-demand periods and act as frequency control for the grid. For the first system, the electricity generated by the wind turbines travels a short distance to the electrolyzer platform, where hydrogen is produced, compressed, and transported to shore in a pipeline. On the other hand, for the second system, the electricity is transmitted to shore by a traditional cable, where a choice can be made: sell the electricity directly to the grid or produce hydrogen. This is known as a hybrid system, where the operator can control the amount of power being sold to the grid or fed into the electrolyzer, even being able to buy electricity from the grid to produce hydrogen during periods of extremely low electricity prices, which provides load flexibility to the grid operator as well. Since the source of the electricity powering the electrolyzer is wind farms, no carbon is emitted during the production of hydrogen.

2. Hydrogen Utilization

One of the properties of hydrogen that makes it so interesting is the wide array of utilization cases. Historically, hydrogen production was based on fossil fuels, so there wasn't an incentive to adopt hydrogen as an energy source since it had a carbon footprint. However, recent studies project significant cost reductions in electrolyzers in the coming years [4][5][6], with the possibility of green hydrogen becoming competitive with hydrogen produced from fossil fuels. Hydrogen electrolysis can also be a great way of reducing emissions, be it by working as energy storage to help when renewable resources are scarce or by reducing emissions caused by other polluting ways of producing hydrogen. The use cases for hydrogen can be divided into three main areas: generating electricity, Power to Gas (P2G), and hydrogen as the end product.

2.1. Generating Electricity

Hydrogen currently represents the best non-fossil fuel for some heavy vehicles that require large energy storage and fast recharge rates, such as long-haul trucks, buses, hybrid trains designed to operate on both electrified and non-electrified train tracks, and even for a common car, since refilling the hydrogen tank takes a few minutes and gives around 600 km of range [7]. This application is denominated as Power to Mobility (P2M).

For grid applications, the fast response time of some fuel cells makes them adequate as dispatchable power plants for peak demand or for frequency control. This application is denominated as Power to Power (P2P). Furthermore, some solid oxide systems can operate with high efficiencies in both electrolyzer and fuel cell modes; however, it should be noted this technology has not reached the commercial level yet [8][9].

The main fuel cell technologies are Polymer Electrolyte Membrane, also known as Proton Exchange Membrane (PEMFC), Alkaline (AFC), Phosphoric Acid (PAFC), Molten Carbonate (MCFC), and Solid Oxide (SOFC) [10]. The first two are considered low-temperature fuel cells, and the remaining are high-temperature fuel cells. As far as the efficiencies are concerned, they range from 40% (PAFC) to 60% (PEM, AFC, SOFC), with MCFC in between (50%).

Both AFC and PEMFC have quick start-up times; however, PEMFC presents greater power density, so it is the primary choice to equip hydrogen-based vehicles. Due to this emerging market, intensive research and development of PEMFC is being performed by car and bus manufacturers; consequently, cost reductions and increased durability are expected in the coming years.

Most stationary installations of fuel cells are at high operating temperature [11], with one example being the 50 MW Daesan Hydrogen-Fuel-Cell Power Generation that started operating in South Korea in 2020. The plant is composed of 114 PAFC fuel cells and will produce around 400,000 MWh of energy annually [12][13].

In the past few years, PAFC and MCFC have presented the highest growth rate, though this is expected to change due to several companies offering PEMFC in the order of >1 MW [11], some of them stackable modules.

2.2. Power to Gas

Hydrogen is a highly flammable gas, so it is possible to inject some hydrogen into the natural gas grid without significant modifications to the grid or the systems that use natural gas. This application is denominated as P2G. Some pilot projects already in operation blend up to 20% hydrogen in localized natural gas grids such as small communities or universities [14]. Several studies support the idea that a low concentration of hydrogen (up to 15–20%) in the natural gas grid does not significantly increase the risk associated with utilization of the gas [15][16].

Another approach is being studied at several locations, including Central do Ribatejo in Portugal by EDP [17], where a 1 MW electrolyzer produces hydrogen during ramp down periods and stores it at 300 bar (storage capacity of 400 kg, which is around 13 MWh). The project plans to study the injection of hydrogen in the natural gas grid and the co-combustion of hydrogen and natural gas in a regular gas turbine. This installation is part of an international project named FLEXnCONFU, which aims to integrate hydrogen and ammonia in the electrical grid [18].

2.3. Hydrogen as the End Product

Arguably the best industry to sell green hydrogen is the already existing industry for hydrogen, predominantly used in refineries and for ammonia production. The estimated demand in 2018 was above 80 million tons [6]. Since this industry is already in place, the source of hydrogen can simply be gradually replaced by green hydrogen, especially as the LCOH of green hydrogen continues to decrease.

While ammonia can be the end product, it can also act as a carrier of hydrogen in order to facilitate transport with an equivalent hydrogen density of 122.4 kg/m^3 at a temperature of around 25 °C and a pressure of 10 to 20 bar. When compared to liquid hydrogen, the density is roughly 75% higher, and it can be transported at ambient temperatures and low pressures. The main disadvantage is the increased cost and complexity of producing the ammonia and afterwards decomposing it to recoup the hydrogen [5].

3. State-of-the-Art Review

The annual production of hydrogen in the EU is roughly 9.75Mt; this is currently being produced using carbon-intensive methods, which would require 290 TWh of electricity if the hydrogen was produced solely from electrolysis, around 10% of current production in the EU. In 2020, G. Kakoulaki et al. [19] concluded that the EU has enough renewable energy resources spread throughout member countries to satisfy the hydrogen demand solely using green hydrogen, thus allowing for decarbonization of the sector.

Electrolyzers can play a role in adding flexibility to an electricity grid. A technical analysis was conducted by D. Gusain et al. [20] to study the use of electrolyzers as flexibility service providers. A model for large-scale PEMEL was developed, along with the simulation of different use cases, to assess frequency regulation, flexibility provision, and long-term impact analysis of a PEMEL connected to the CIGRE MV grid [21]. For the first use case, the electrolyzer's response was adequate, and even though the test had a 40 min duration, no cell degradation took place. For the second case, the electrolyzer was used to correct the difference between the expected power injection and the real power injected at a certain bus. The bus had a wind farm attached, so a forecast was made of the expected power produced throughout the day. The results showed the electrolyzer ensured that the real power was equal to the forecast power, which means an electrolyzer can be used to provide flexibility to the grid operator. In the final case, the electrolyzer was run at a constant current for a year; a drop in efficiency of 0.8% was calculated. Over a duration of five years, the efficiency drop increased to 3.5%. The impact derived from these efficiency drops must be taken into account in long-term strategies, so that the flexibility provided by the electrolyzer is always correctly assessed.[22]

The sizing of electrolyzers must weigh numerous factors, namely the power produced by the wind farm and if there is a grid connection to provide power to the electrolyzer during low wind periods. The main advantage of the grid connection is a more consistent hydrogen production rate, and the main disadvantage is not being able to guarantee 100% carbon-free hydrogen due to consuming power from the grid. José G. García Clúa et al. [23] state that the ratio between the wind turbine's nominal wind speed VN and the mean wind speed VM of the installation site and the shape coefficient of a Weibull probability function k are the main influences in sizing the nominal powers of the electrolyzer and the wind turbine. The paper concludes that for VN/VM lower than 1.67, the electrolyzer makes good use of the available turbine power; however, the wind potential of the site is not fully exploited. On the other hand, for VN/VM greater than 1.77, the opposite happens. The recommended operation point is VN/VM in the range of 1.67 to 1.77, since in this range a balance between making good use of the available turbine power and exploiting the wind potential of the location is struck.

A techno-economic analysis of grid-connected hydrogen production was performed by T. Nguyen et al. [24], in which several electricity pricing schemes and hydrogen storage solutions were analyzed. The pricing schemes considered were flat rates in five Canadian provinces and real-time pricing in Germany, California, and Ontario. The study concludes that a real-time pricing scheme yields lower LCOH, since the electrolyzer can reduce consumption during periods of high energy prices, and that including storage is a good alternative to increase flexibility, especially when underground storage can be implemented. A capacity factor ranging between 0.9 and 1 was found to be optimal, since this minimizes consumption during peak hours but ensures a high utilization of the CAPEX. The lowest LCOH obtained was 2.49–2.74 €/kg for AEL (2.26–3.01 €/kg for PEMEL) with underground storage in a real-time pricing scheme in Ontario; this is competitive with hydrogen produced using Steam Methane Reform (SMR) with carbon capture, which is around 2.51–3.45 €/kg.

A similar study on offshore hydrogen production with underground storage was developed by Van Nguyen Dinh et al. [25], where the CAPEX and OPEX used were consistent with the forecast for offshore wind power and electrolyzers in the year 2030. The results show that for a 101.3 MW wind farm 15 km off the coast of Arklow, Ireland, at a selling price of 5 €/kg, the Discounted Payback Period (DPB), considering storage for 2, 7, 21, and 45 days of average hydrogen production, is 7.8, 8.6, 11.1, and 16.2 years, respectively.

The wind potential in Patagonia is enormous, being anywhere from 4100 to 5200 full-load hours on average, which leads to an LCOE of electricity as low as 25.6 €/MWh. In 2018, Philipp-Matthias Heuser et al. [26] analyzed a link between Japan and Patagonia, where hydrogen is produced and liquefied in Patagonia and shipped to Japan. The analysis estimated that the LCOH is 2.16 €/kg at the output of the electrolyzer, with an increase of 0.57 €/kg after transport to the shipping port and a further 0.58 €/kg to liquefy the hydrogen and store it in liquid form, which brings the final LCOH to 3.31 €/kg. The cost of transport to Japan is 1.13 €/kg, so the cost of hydrogen upon arrival in Japan is 4.44 €/kg.

With the increasing presence of renewable energy in the grid, higher levels of curtailment in renewable power plants will take place. Considering this reasoning, a study was conducted to compare three scenarios using an offshore wind farm [27]: sell all electricity to the grid (scenario 1), convert all electricity to hydrogen (scenario 2), or a hybrid system where electricity is sold to the grid when prices are high and converted to hydrogen when curtailment occurs or electricity prices are low (scenario 3). A model was developed for a 504 MW wind farm located 14.5 km off the coast of Arklow, Ireland, and all three scenarios were simulated. The results obtained were an LCOE in scenario 1 of 38.1 €/MWh for 0% curtailment and 47.6 €/MWh for 20% curtailment, while the LCOH for scenario 2 was 3.77 €/kg. For scenario 3, if the hydrogen price was 4 €/kg, only at curtailment levels higher than 17% could adding hydrogen generation provide an equal or higher Net Present Value (NPV). If the hydrogen price was 4.25 €/kg, then the level of curtailment for which hydrogen generation becomes profitable is 10%.

Another article comparing the three scenarios described above was written by Pengfei Xiao et al. [28] in 2020, where the model was developed for a wind farm in Denmark. Here, the electricity price for the first and third scenarios varied from 80 €/MWh to 160 €/MWh, depending on the time of day, with the hydrogen price fixed at 6.27 €/kg in the scenarios where hydrogen was produced. The article concluded that the hybrid approach yields greater economic interest compared to the other scenarios, with most of the hydrogen being produced at night when the electricity price is lower.

A slightly different approach was taken by Peng Hou et al. [29], where a 72 MW offshore wind farm was considered for the production of hydrogen, with two possible operating scenarios. In the first scenario, all of the energy was converted to hydrogen in an electrolyzer, stored, and then converted back to electricity in a fuel cell to sell to the grid during peak hours. In the second scenario, the electricity generated by the wind turbines could be sold to the grid or fed into an electrolyzer, with the possibility of buying energy from the grid when prices are extremely low. The electricity prices considered were the electricity prices for Denmark in 2015. The study concluded that the first scenario was not economically viable due to the low round-trip efficiency of the electrolyzer and fuel cell. However, for the second scenario, considering a 50% capacity factor for the electrolyzer, the DPB was 24.4, 5.5, and 2.6 years and the nominal power of the electrolyzer was 5.5, 13.5, and 23.4 MW for a hydrogen price of 2, 5, and 9 €/kg, respectively.

A model to determine the most suitable electrolyzer technology and to compare solar and wind as the energy sources of a green hydrogen production system was developed by Christian Schnuelle et al. [30]. Several scenarios were included in the article, such as onshore and offshore wind as well as nominal powers of the electrolyzer of 40%, 60%, or 80% of the respective power plant's nominal power. All the renewable energy generation profiles considered were measured in northwest Germany in 2017. Considering a fixed electricity price, dependent on the installation chosen and typical annual load duration curves, the authors state that AEL proved the most economically viable option, mainly due to higher efficiencies and improved stack life, which reduces the investment in replacing stacks and the lower initial investment. The lowest LCOH achieved was 4.33 €/kg. Despite being more expensive, PEMEL offers an advantage regarding energy utilization, since it can operate at lower power and better harness the renewable resources available.

To compare the subject of this paper to other green hydrogen applications, two articles regarding hydrogen production using solar energy were analyzed. The first considers various locations in Morocco [31], with different types of Photovoltaic (PV) panel installations, from fixed to two-axis tracking, and a CSP installation. Even though fixed PV panels produced the lowest LCOH of 4.74 €/kg, a better balance was achieved using one-axis tracking, which produced 30% more hydrogen and a small LCOH increase to 4.88 €/kg.

The second article analyzed not only green hydrogen production using PV or CSP to harness the solar energy in the Atacama Desert, Chile, but also the existing technologies to transport hydrogen in a higher energy density—liquefied hydrogen and ammonia carrier [5]. The lowest LCOH in 2018, 1.82 €/kg, was obtained using PV, a power purchase agreement, and converting the electricity to hydrogen in an AEL. In 2025, LCOH reductions are expected to be around 20% to 34%, higher in PEMEL than AEL, to a minimum value of 1.39 €/kg. The cost of liquefying hydrogen (1.28 €/kg) is lower than the cost to convert to and from ammonia (total 2.04 €/kg), but due to the higher energy density and ease of transport, a case can be made for ammonia as a means of transporting hydrogen.

Both of the articles agree that despite CSP with thermal storage allowing for a much higher capacity factor, which reduces the nominal power of the electrolyzer, the reduction in CAPEX in the electrolyzer is smaller than the increase in CAPEX by using CSP instead of PV.

Regarding the applications of hydrogen, Rodica Loisel et al. [32] developed a model with an offshore wind farm off the coast of Saint Nazaire, France. The paper simulated the economic viability of each application individually, then combined the two applications (for example, P2P and P2G), and presented a final scenario where all applications considered were implemented. In all scenarios, the electrolyzer's nominal power was considerably lower than the wind farm nominal power; consequently, most of the energy produced was sold directly to the electricity grid at wholesale prices, with the remaining energy being reserved for secondary and tertiary reserves. The study concluded that the most economically viable approach was P2G, with a hydrogen price of 4.2 €/kg. However, even the most profitable approach presents a negative NPV. It should be noted that combining many applications led to a higher investment cost and ultimately reduced the project's profit.

Focusing on P2P, where fuel cells can play a role as long-term energy storage and fast-acting dispatchable power plants, a review of the main fuel cell technologies was conducted in 2018 [33]. After analyzing each technology, the authors concluded that since fuel cells do not have great electrical efficiencies (40% to 55%), the best way to harvest their potential is to utilize the heat generated, either for heating in the case of low-temperature fuel cells (PEMFC and AFC) or Combined Heat and Power (CHP) in the case of high-temperature fuel cells (AFC, MCFC, and SOFC). Integrating CHP yields an increase of 10% to 30% in efficiency. In addition, micro gas turbines can be used to provide further heat to the combined cycle, which might also lead to an increase in efficiency.

A challenge associated with a high percentage of renewable power in electricity grids is frequency containment, usually ensured by big synchronous generators in traditional power plants due to their high inertia. PEMFC presents high current density and fast response times; consequently, it might be an option to help maintain the grid frequency. To assess the role this technology can play in frequency containment, F.A. Alshehri et al. [34] developed a dynamic model to simulate PEMFC, validated that the model's response resembled the response shown in the existing literature, and compared the Frequency Containment Reserve (FCR) of PEMFC and synchronous generators. The scenarios consisted of a 50 MW disturbance for different system inertia with values 100%, 50%, and 25%, for both synchronous generators and PEMFC as FCR. For all scenarios, PEMFC provided the best nadir (lowest frequency recorded) and a faster rate of frequency stabilization, while the values representing Rate-of-Change-of-Frequency remained the same for both scenarios.

Continuing with the analysis for the viability of grid-connected fuel cells, an assessment was conducted in 2013 [35]. The authors of the assessment concluded that the start-up time of the fuel cell must be taken into account (around 10 min). Furthermore, the dynamic loading on the system severely influences the longevity of the fuel cells; a load ranging from 0–100% presented a much lower power output after 100 operating hours than a load ranging from 40–100% after 400 operating hours. As long as some requirements and the operating conditions mentioned above are respected, grid-connected fuel cells are viable.

In the past, green hydrogen production has not been able to compete with other methods of producing hydrogen due to the increased cost. However, costs are rapidly decreasing, and affordable green hydrogen can become a reality by the year 2030, as is pointed out in several articles analyzed in this section. Both solar and wind have the potential to be the renewable energy source used in the production of hydrogen, with researchers on all continents studying different approaches. With the prospect of clean hydrogen, innovative uses are also being studied, from P2G to grid-connected fuel cells and electrolyzers to aid in grid stability and energy storage. In order to transport large quantities of hydrogen, liquified hydrogen and ammonia carrier are technologies that are currently being developed and that show potential to further lower the cost of implementing green hydrogen solutions.

Table 1 contains a summary of the LCOH observed throughout the literature review. LCOH is calculated by adding all the expenses of the project (CAPEX and OPEX correctly adjusted according to the rate of return) and dividing by the amount of hydrogen produced by the electrolyzer in kg. The cost of hydrogen is influenced mainly by the electricity cost and the cost of the required infrastructure, which means AEL typically has a lower LCOH than PEMEL due to the lower cost. The same applies to the electricity source: the lower LCOH values are observed in locations with low electricity prices, such as the electricity grid in Ontario [24], solar PV in Chile [5], or onshore wind in Patagonia [26].

Table 1. Summary of LCOH.

Electricity Source	AEL (€/kg)	PEMEL (€/kg)
Grid	**2.49–2.74** [24]	**2.26–3.01** [24]
Solar PV	**2.04–5.00** [5][30]	**2.71–7.98** [5][30][31]
Solar CSP	**3.03** [5]	**3.79–8.5** [5][31]
Onshore Wind	**4.33** [30]	**2.73–6.61** [26][30]
Offshore Wind	**9.17** [30]	**3.77–11.75** [25][27][30][32]

The more economically viable electricity sources for producing green hydrogen are solar PV and onshore wind, mainly because the LCOE of these two energy sources is considerably lower than solar CSP and offshore wind. The LCOE is the factor that influences the LCOH the most [5][27]; therefore, technologies with the lowest LCOE are the best suited to being the electricity source in green hydrogen projects. More specifically, the lowest LCOH for solar PV was found in the Atacama Desert in Chile [5], and the lowest LCOH for onshore wind was found in Patagonia [26], two locations with abundant availability of their respective renewable resources.

References

1. Clúa, J.G.G.; Mantz, R.J.; de Battista, H. Optimal sizing of a grid-assisted wind-hydrogen system. Energy Convers. Ma nag. 2018, 166, 402–408.
2. Panfilov, M. 4—Underground and pipeline hydrogen storage. In Compendium of Hydrogen Energy, Woodhead Publishi ng Series in Energy; Gupta, R.B., Basile, A., Veziroglu, T.N., Eds.; Woodhead Publishing: Sawston, UK, 2016; pp. 91–1 15.
3. Miao, B.; Giordano, L.; Chan, S.H. Long-distance renewable hydrogen transmission via cables and pipelines. Int. J. Hy drogen Energy 2021, in press.
4. IRENA. Hydrogen from Renewable Power: Technology Outlook for the Energy Transition. 2018. Available online: (acce ssed on 7 April 2021).
5. Gallardo, F.I.; Ferrario, A.M.; Lamagna, M.; Bocci, E.; Garcia, D.A.; Baeza-Jeria, T.E. A techno-economic analysis of sol ar hydrogen production by electrolysis in the north of Chile and the case of exportation from Atacama desert to Japan. I nt. J. Hydrogen Energy 2021, 46, 13709–13728.
6. IRENA. Green Hydrogen Cost Reduction: Scaling Up Electrolyzers to Meet the 1.5 °C Climate Goal. 2020. Available on line: (accessed on 7 April 2021).
7. Toyota. 2021 Toyota Mirai. Available online: (accessed on 29 May 2021).
8. Buttler, A.; Spliethoff, H. Current status of water electrolysis for energy storage, grid balancing and sector coupling via p ower-to-gas and power-to-liquids: A review. Renew. Sustain. Energy Rev. 2018, 82, 2440–2454.
9. Wood, A.; He, H.; Joia, T.; Brown, C.C. Reversible solid oxide fuel cell development at versa power systems. ECS Tran s. 2015, 66, 23.
10. US. Department of Energy. Comparison of Fuel Cell Technologies. 2016. Available online: (accessed on 7 April 2021).
11. Weidner, E.; Ortiz Cebolla, R.; Davies, J. Global Deployment of Large Capacity Stationary Fuel Cells–Drivers of, and B arriers to, Stationary Fuel Cell Deployment; JRC115923; EUR 29693 EN; Publications Office of the European Union: L uxembourg, 2019; ISBN 978-92-76-00841-5.
12. Doosan starts installation of hydrogen-fueled 50 MW fuel cell power plant in South Korea. Fuel Cells Bull. 2018, 2018, 1.
13. Fuel Cells Works. Daesan Hydrogen Fuel Cell Power Plant Completed with Help of Doosan Fuel Cells. Available onlin e: (accessed on 26 April 2021).
14. HyDeploy. Available online: (accessed on 7 April 2021).

15. Melaina, M.W.; Antonia, O.; Penev, M. Blending hydrogen into natural gas pipeline networks: A review of key issues. Te ch. Rep. 2013.

16. Quarton, C.J.; Samsatli, S. Power-to-gas for injection into the gas grid: What can we learn from real-life projects, econo mic assessments and systems modelling? Renew. Sustain. Energy Rev. 2018, 98, 302–316.

17. EDP. FLEXnCONFU: Power-to-X to Increase the Flexibility of Thermal Plants. Available online: (accessed on 26 April 2 021).

18. FLEXnCONFU. Available online: (accessed on 29 May 2021).

19. Kakoulaki, G.; Kougias, I.; Taylor, N.; Dolci, F.; Moya, J.; Jager-Waldau, A. Green hydrogen in Europe—a regional asse ssment: Substituting existing production with electrolysis powered by renewables. Energy Convers. Manag. 2021, 228, 113649.

20. Gusain, D.; Cvetković, M.; Bentvelsen, R.; Palensky, P. Technical assessment of large-scale PEM electrolyzers as flexi bility service providers. In Proceedings of the 2020 IEEE 29th International Symposium on Industrial Electronics (ISIE), Delft, The Netherlands, 24 September 2020; pp. 1074–1078.

21. CIGRE. Available online: (accessed on 26 April 2021).

22. Clúa, J.G.G.; Mantz, R.J.; de Battista, H. Optimal sizing of a grid-assisted wind-hydrogen system. Energy Convers. Ma nag. 2018, 166, 402–408.

23. Nguyen, T.; Abdin, Z.; Holm, T.; Me´rida, W. Grid-connected hydrogen production via large-scale water electrolysis. Ene rgy Convers. Manag. 2019, 200, 112108.

24. Dinh, V.N.; Leahy, P.; McKeogh, E.; Murphy, J.; Cummins, V. Development of a viability assessment model for hydroge n production from dedicated offshore wind farms. Int. J. Hydrogen Energy 2020, in press.

25. Heuser, P.-M.; Ryberg, D.S.; Grube, T.; Robinius, M.; Stolten, D. Techno-economic analysis of a potential energy tradin g link between Patagonia and Japan based on CO2 free hydrogen. Int. J. Hydrogen Energy 2019, 44, 12733–12747.

26. McDonagh, S.; Ahmed, S.; Desmond, C.; Murphy, J.D. Hydrogen from offshore wind: Investor perspective on the profit ability of a hybrid system including for curtailment. Appl. Energy 2020, 265, 114732.

27. Xiao, P.; Hu, W.; Xu, X.; Liu, W.; Huang, Q.; Chen, Z. Optimal operation of a wind-electrolytic hydrogen storage system in the electricity/hydrogen markets. Int. J. Hydrogen Energy 2020, 45, 24412–24423.

28. Hou, P.; Enevoldsen, P.; Eichman, J.; Hu, W.; Jacobson, M.Z.; Chen, Z. Optimizing investments in coupled offshore win d -electrolytic hydrogen storage systems in Denmark. J. Power Sources 2017, 359, 186–197. Available online: (access ed on 26 April 2021).

29. Schnuelle, C.; Wassermann, T.; Fuhrlaender, D.; Zondervan, E. Dynamic hydrogen production from PV & wind direct el ectricity supply—modeling and techno-economic assessment. Int. J. Hydrogen Energy 2020, 45, 29938–29952.

30. Touili, S.; Merrouni, A.A.; El Hassouani, Y.; Amrani, A.i.; Rachidi, S. Analysis of the yield and production cost of large-sc ale electrolytic hydrogen from different solar technologies and under several Moroccan climate zones. Int. J. Hydrogen Energy 2020, 45, 26785–26799.

31. Loisel, R.; Baranger, L.; Chemouri, N.; Spinu, S.; Pardo, S. Economic evaluation of hybrid off-shore wind power and hy drogen storage system. Int. J. Hydrogen Energy 2015, 40, 6727–6739.

32. Guaitolini, S.V.M.; Yahyaoui, I.; Fardin, J.F.; Encarnac¸ao, L.F.; Tadeo, F. A review of fuel cell and energy cogeneration t echnologies. In Proceedings of the 2018 9th International Renewable Energy Congress (IREC), Hammamet, Tunisia, 2 0–22 March 2018; pp. 1–6.

33. Alshehri, F.; Torres, J.R.; Perilla, A.; Tuinema, B.; van der Meijden, M.; Palensky, P.; Gonzalez-Longatt, F. Generic mod el of PEM fuel cells and performance analysis in frequency containment period in systems with decreased inertia. In Pr oceedings of the 2019 IEEE 28th International Symposium on Industrial Electronics (ISIE), Vancouver, BC, Canada, 12 –14 June 2019; pp. 1810–1815.

34. Bernstein, P.A.; Heuer, M.; Wenske, M. Fuel cell system as a part of the smart grid. In Proceedings of the 2013 IEEE G renoble Conference, Grenoble, France, 16–20 June 2013; pp. 1–4.