NENE 2022
September 12-15
PORTOROŽ
SLOVENIA
31st International Conference Nuclear Energy for New Europe

Production of Hydrogen and Synthetic Methane with Nuclear Power Plants

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ABSTRACT

Paper presents currently available processes for hydrogen and synthetic methane production at nuclear power plants. In addition, an overview of possible new technologies for production with future nuclear power plants is given in the paper. A comparison of several fossil fuel free (carbon-free) hydrogen production technologies is presented. Paper also gives cost analysis of various hydrogen production installations based on current market availability, price estimations, efficiencies and overall capacity factor.

1 INTRODUCTION

Most, over 95 %, of the hydrogen currently produced worldwide is obtained from fossil fuels, either through steam methane reforming or coal gasification. If we want to exploit the potential of hydrogen as an energy vector for the decarbonization of the economy, it needs to be mass-produced in a sustainable way. But for this to happen, pure hydrogen must become cost-competitive comparing to conventional fuels. Currently, there are no plants on the market that would competitively produce and store hydrogen in sufficient quantities through electrolysis, so production and market for hydrogen still need to be developed. Today, most of the hydrogen produced is used by the industry for three principal applications: chemical production, oil refining and metal processing. The key advantage of hydrogen technologies is the possibility to decarbonize transport, industry, and some of the chemical processes.

Adding hydrogen to existing natural gas pipelines has major technical limitations. Due to failure of gas seals and other technical devices, as well as failures of gas turbines for the production of electricity, the proportion of hydrogen in the gas pipeline is in the best case limited to a maximum of 20 % or even less (in most countries existing standards limit hydrogen content in gas pipeline to below 10 %). Storing hydrogen (between 350 and 700 bars) is prone to leakage and technically quite demanding due to its high flammability and explosiveness. Due to these limitations, the storage of compressed hydrogen next to civil facilities is highly unlikely in the future.

2 NUCLEAR REACTOR TECHNOLOGIES FOR HYDROGEN PRODUCTION

In common clean energy development scenarios, conventional electrolysis of water is the main option available to produce hydrogen. Three different electrolysers technology are commonly considered. Alkaline (ALK), Proton Exchange Membrane (PEM) and Solid Oxide (SOE). Each have strengths and weaknesses based on the different types of materials used and the different electro-chemical reactions involved.

Any nuclear reactor can be the basis for hydrogen production. Several configurations of present commercial NPPs (II., III. and III.+ generation), based on mainly pressurized water reactor technology, are studied for hydrogen production. Most common processes are ALK and PEM electrolysis. ALK design based on common metals makes it the current cheapest option. However, this technology is not optimized for dynamic operation, which would undermine system efficiency and hydrogen purity. On the contrary, PEM electrolysers have their short hot idle and cold start ramping time that makes them match even variable renewable power sources requirements. However, PEM cells use expensive electrode catalysts (platinum, iridium) and membrane materials. They are more complex and suffer from shorter lifetime than the alkaline electrolysis alternative [1].

Future nuclear reactors (Generation IV) are expected to be further advanced in terms of performance, proliferation resistance and sustainability while maintaining very high nuclear safety. Of all six possible designs, two stand out from the point of view of hydrogen production, HTGR (high temperature gas-cooled reactor) including the next generation of the VHTR (very high temperature reactor) and GFR (gas-cooled fast reactor) designs. Typical features of this advanced reactors are cooling with helium and reaching the output temperature of the reactor coolant between 750-1.000 °C. Top candidate methods, considered presently by various countries, are High Temperature Electrolysis of Steam (HTSE) a.k.a. Solid Oxide Electrolysis (SOE), operating at temperatures between 650-1.000 °C and also Sulphur–Iodine thermochemical process. Assuming a plant availability of 90 % and an overall conversion efficiency of (aimed at) 50 %, the system would have a capacity of 27,4 t/d of hydrogen per 100 MW of nuclear thermal power [2].

2.1 Hydrogen production with current NPPs

In the last few years, first serious industrial projects for the construction of hydrogen production using electrolysis are already emerging next to existing NPPs in several countries.

2.1.1 PEM at Davis Besse, Ohio, USA

Energy Harbor, Xcel Energy, and APS are spearheading a multi-pronged project to develop and demonstrate nuclear-hydrogen hybrids and their commercial applications. The utilities will start pilot project to demonstrate hydrogen production using a 2 MW_e PEM technology electrolysis that will be integrated with Energy Harbor's 925 MW_e (2.817 MW_{th}) Davis-Besse Nuclear Power Station, a pressurized water reactor (PWR) in Ohio. USA. This NPP started with commercial operation in 1978 and has been issued a valid operating permit until April 2037 (the lifetime of the power plant has already been extended to 60 years). The location of hydrogen production is located approximately 400 m of the containment building. Davis-Besse presents a good location for the pilot because the plant's relative proximity to key markets is ideal for reducing transport distances. The nuclear plant is also within 250 km of major existing hydrogen consumers, such as oil refineries, steel manufacturers, syngas, and chemical plants. The location also has the right inputs for the necessary electricity and water. It will consume 2 MW_e of power at plant output, prior to the switchyard, and use the containerized PEM electrolyser and 2.400 gallons of water per day (at maximum operating capacity) to produce between 800 kilograms and 1.000 kilograms of hydrogen [3].

This first-of-its-kind project represents a significant improvement of long-term economic competitiveness of the PWR nuclear power plant industry. It will enable the production of additional market products such as hydrogen.

2.1.2 HTSE at Prairie Island Nuclear Generating Station, Minnesota, USA

Minneapolis-based Xcel Energy will work with Idaho National Laboratory to demonstrate a system that uses a nuclear plant's steam and electricity to split water. The resulting hydrogen will initially be used at the power plant, but it could eventually be sold to other industries. The new project is the first of its kind in pairing a commercial electricity generator with high-temperature steam electrolysis (HTSE) technology. HTSE technology is a natural fit at NPPs, where high-quality steam and electricity are both accessible. This project will demonstrate how hydrogen production facilities could be installed at operating NPPs. It offers a view of the energy structures of the future, which will integrate systems to maximize energy use, generator profitability and grid reliability all while minimizing carbon emissions. The project will demonstrate HTSE using heat and electricity from one of Xcel Energy's nuclear plants, likely the Prairie Island Nuclear Generating Station. Steam electrolysis can be a very efficient process in specific applications, and it relies on high temperature to split water and produce hydrogen [4].

2.1.3 Kola, Russia

The Kola NPP, VVER with four 411 MW_e reactors, owned by Rosatom in northwestern Russia has been named as the site for a hydrogen test. This pilot program will use nuclear energy to power hydrogen production. Throughout this process, the hydrogen production will be for small quantities but will be used to gain knowledge. The nuclear hydrogen test will use a calculated surplus of generated energy. It is expected to involve a very low cost, which is already associated with the operation of the complex. Producing the hydrogen in Kola is also viewed as appropriate due to the infrastructure and expertise availability. Though the 1 MW will be the starting point, the expectation is that over time, the complex will continue to grow. The expansion is expected to eventually reach 10 MW [5].

2.1.4 Barakah, UAE

The UAE has long been in the hydrogen market and Abu Dhabi authorities are considering the use of nuclear power for hydrogen production. Their NPP Barakah was built by South Korean companies, including Korea Hydro & Nuclear Power and has four APR-1400 PWR units. The first and second units are already in operation and the rest will be put into operation in the near future. The Emirates Nuclear Energy Corp. has been working with Électricité de France (EDF) since 2018 so that more hydrogen can be produced from nuclear power, and it can account for at least 25 percent of the global clean hydrogen market in 2030 [6][7].

2.1.5 PEM at Nine Mile Point, New York, USA

A containerised 1,25 MW PEM electrolyser is to be installed at Exelon Generation's Nine Mile Point NPP in New York as part of a hydrogen production demonstration project. Located in Scriba, New York State, Nine Mile Point consists of two boiling water reactors, the 620 MW_e Unit 1 and the 1.287 MW_e Unit 2. The unit will supply hydrogen for the plant's turbine cooling and chemistry control [8].

2.2 Hydrogen production with future NPPs

Hydrogen production using advanced nuclear reactors (Generation IV) will enable much higher efficiencies because of much higher coolant temperatures and production of larger quantities of hydrogen. Advanced reactors are not yet commercially available, however, there are many prototypes and demonstration projects in the world. Next, few pilot projects of high-temperature nuclear reactors alongside which experimental plants for hydrogen production are presented.

2.2.1 GTHTR300C (Gas Turbine High Temperature Reactor)

Planned concept for commercial nuclear hydrogen production in Japan is based on the GTHTR300C reactor to be connected to an S-I thermochemical water splitting process. The reactor design is a block type HTGR with a thermal power of 600 MW_{th} and a reactor outlet coolant temperature of 950 °C. The reactor uses nuclear fuel in ceramic form, it is moderated by graphite and cooled by helium.

The direct cycle gas turbine efficiently circulates the reactor coolant and generates electricity. This reactor is based on prototype reactor HTTR (High Temperature Test Reactor) with 30 MW_{th} which achieved first criticality in 1998 and was operating at full power in 2004. Hydrogen cogeneration is enabled by adding an intermediate heat exchanger (IHX) arranged in series between reactor and gas turbine as seen on Figure 1. In the IHX, a part of the thermal power, 168 MW_{th}, is transferred as 900 °C process heat to the hydrogen generation process. The remaining thermal power is used for electricity generation of 202 MW_e. The secondary loop, which includes safety design measures such as isolation valves, provides for physical and material separation between the nuclear plant and the conventional grade hydrogen plant. The conceptual flowsheet design reports a hydrogen production rate of 31.900 Nm3/h, corresponding to 50,2 % net efficiency, and by-product oxygen of 15.950 Nm3/h [2].

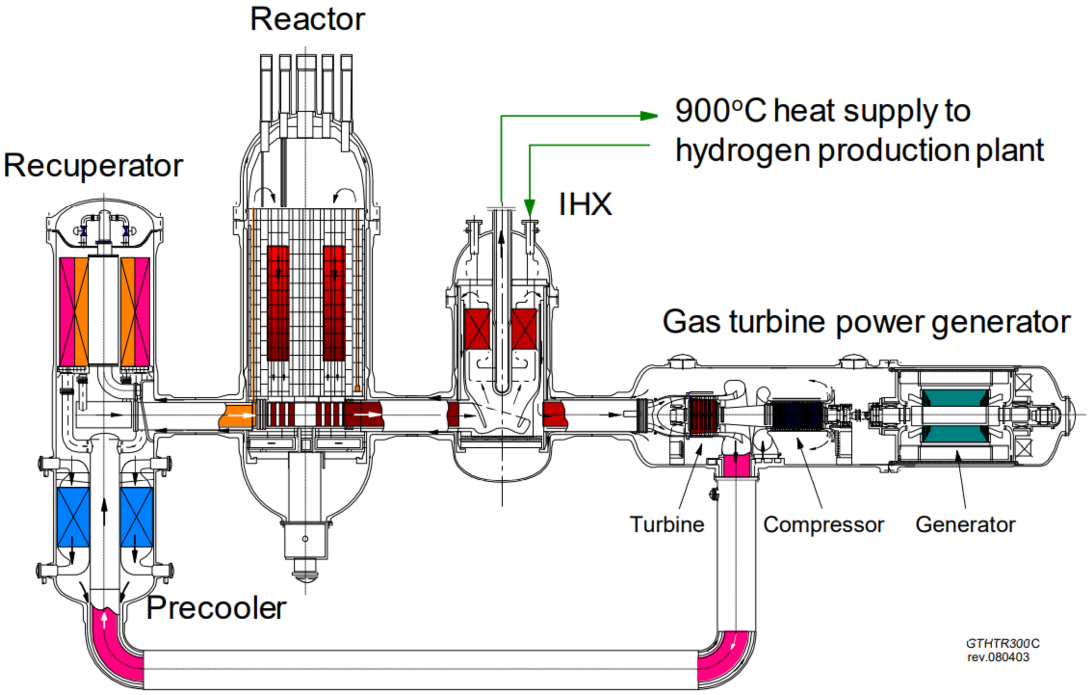


Figure 1: Japan`s commercial cogeneration reactor system GTHTR300C [2]

2.2.2 H_2 GT-MHR (Gas Turbine Modular Helium Reactor)

The GT-MHR design is a General Atomics development characterized by a helium cooled, graphite moderated, thermal neutron spectrum reactor with a prismatic and annular core directly coupled to a Brayton cycle power conversion system and with a filtered confinement. The design of this reactor is related to Japanese HTTR. The reactor core having a thermal power of 600 MW_{th} is designed for averaged coolant outlet temperatures of 850 °C working with an efficiency of about 48 % for electricity production. The design variants for cogeneration of process heat for non-electric applications including steam and hydrogen production have also been studied. The option for hydrogen production is referred to as H_2-MHR. In this process heat variant, the coolant outlet temperatures is raised in order to improve the efficiency and economics of hydrogen production, but still limited to 950 °C to avoid any potential adverse impacts on fuel performance and materials during normal operation. For the high temperature steam electrolysis (HTSE) based H_2-MHR, approximately 68 MW_{th} of heat is transferred through the intermediate heat exchanger (IHX) to generate superheated steam and the remaining heat is used to generate electricity. Helium at 924 °C temperature and 7,1 MPa pressure enters the thermochemical plant. For the S-I cycle based H_2-MHR, nearly all of the heat is transferred through the IHX to a secondary helium loop that supplies heat to the S–I process [2].

2.2.3 German HTR (High Temperature Gas-cooled Reactor) Modul

The baseline concept for a German modular HTR was the electricity producing 200 MW_{th} HTR-Modul pebble-bed reactor. This project is not active anymore, but it is relevant for future development of HTR reactors for hydrogen production. Pebble-bed reactor is technology which was developed in 1980 in Germany. It is characterized by a tall (9.43 meters) and slim (3.0 m diameter) cylindrical core to ensure - in combination with a low power density - that the release of fission products from the core would remain sufficiently low to cause no harm to people or environment even in postulated accidents. Consequently, a process heat variant of the HTR-Modul reactor has been developed, for which - in comparison to the electricity generating plant - several modifications were necessary. The principal cornerstones of the process heat version are a thermal power of 170 MW_{th} and a helium outlet temperature of 950 °C to deliver process heat for the steam methane reforming process (SMR). This project was not CO_2-neutral as it product hydrogen from methane. Without employing an IHX (which was deemed feasible and licensable at that time), the hot helium coolant is directly fed to the steam reformer which consumes 71 MW_{th}, and to the steam generator operated with 99 MW_{th} [2].

2.2.4 Chinese HTR-PM (High Temperature Gas-cooled Pebble-bed Reactor)

The HTR-PM is the world`s first modular commercial HTGR, which is being built in Shidao Bay, Northeastern China. The HTR-PM consists of twin pebble bed reactors of 250 MW_{th} each, 210 MW_e. The reactor outlet is 750 °C and 7 MPa. Each reactor is connected to its own steam generator with main steam conditions of 567 °C and 13,3 MPa. The steam from the steam generators is fed to a common steam turbine to produce a rated power output of 210 MW_e. According to the original concept, the plant is aimed at demonstrating the advantages and key benefits of design standardization that allows factory build and modular site construction. A precursor to the HTR-PM is the pebble bed high temperature gas cooled experimental reactor HTR-10 developed and built by INET, Tsinghua University. Sited on the outskirts of Beijing, this test reactor configured initially for power generation by steam turbine achieved full operation in 2003. To develop advanced application for the HTR-PM, the future plan for the HTR-10 includes replacement of gas turbine for power generation and connect to an HTSE or S-I cycle system for hydrogen production [2].

3 COMPARISON OF HYDROGEN AND SYNTHETIC METHANE PRODUCTION WITH NPPS AND OTHER TYPES OF POWER PLANTS

The conversion of electricity and heat into hydrogen and synthetic methane is a relatively new energy transformation that will increase the diversity of energy systems and open up an additional possibilities of decarbonization of energy sector. Considering only low-carbon possibilities for hydrogen production, a comparison according to the source of electricity can be made. Therefore, we can compare the production of hydrogen and synthetic methane with electricity (and heat) from NPPs and with electricity from variable renewables (VRE), more precisely hydro power plants, wind power plants and solar PV power plants. Other renewable energy sources (concentrated solar energy, biomass, geothermal, etc.) represent only a much smaller share.

3.1 Comparison of hydrogen production with NPPs and other types of power plants

Firstly, we can mention the possibility of also using process (waste) heat next to electricity from NPPs, whereas only electricity can be used from VRE power plants for hydrogen production. Secondly, the essential difference between the production of hydrogen via NPPs or VRE is in the constant availability and reliability of operation. Renewable power plants have very volatile production and low load factors, which means that for a large part of the time they stand still and do not produce electricity, or in other words, they produce much less electricity than expected from their nominal power. Therefore, water electrolysers that are connected to the VRE plant are much less utilized, as they stand without production for a large part of the day. Electrolysers connected to a NPP can operate at full power 24/7 and thus make full use of the device, which means that production costs are significantly lower. Thirdly, we can state the geographical advantage of using a NPP over VRE plants. NPPs are larger units and are usually located in relative proximity to energy consumption centres where gas pipeline networks already exist. Due to their size, larger PtG units can be built next to NPPs and thus take advantage of economies of scale, but since the power plants are close to gas pipelines, the cost of delivering gas to consumers is lower. The problem with distributed renewable energy sources is that we need several smaller units, which results in higher maintenance costs. In addition, VRE sources are usually located far from consumption centres (in deserts, on mountain tops, etc) and therefore achieve much higher costs for connection to the gas pipeline network.

3.2 Comparison of synthetic methane production with NPPs and other types of power plants

The conversion of electricity into gas (Power to Gas - PtG) is a new technology term that is most used to describe the production of hydrogen from electricity. Surpluses on the electrical network are converted into hydrogen by PtG electrolysis of water and, if necessary, into synthetic methane (SNG, which stands for Synthetic Natural Gas). SNG can be directly injected into the existing natural gas network without any limitations (not like hydrogen). A unit for the production of synthetic methane (PtSNG) consists of a unit for the production of hydrogen (by electrolysis) and reactors for methanation, where the hydrogen produced by electrolysis is converted into synthetic methane by adding carbon. The main advantages of using the electricity to synthetic methane (PtSNG) method over the mere conversion of electricity to hydrogen (PtG) are: use of the existing pipeline infrastructure for the transport and storage of methane, high energy density as shown on the Figure 2 (methane has > 1000 kWh/m3, and hydrogen 270 kWh/m3) and less stringent security restrictions and long-term and large-scale storage. The main disadvantages of PtSNG technology are relatively low efficiency and high investment management costs, mainly due to limited operating time due to low availability of RES. One of the technical challenges we have to face is the integrated operation of the electrolysers and methanation subsystems. To ensure adequate quality and constancy of synthetic methane, the dynamics of the electrolysis unit must be separated from the dynamics of the methanation unit. We can do this with a hydrogen storage system. Regarding the comparison of the use or utilization of PtSNG devices next to a renewable energy plant or a NPP, we can draw similar conclusions as for PtG devices. PtSNG plants next to NPPs will be able to operate 24/7 and, in addition to the reliability and continuity of production, can take advantage of the higher temperature due to waste heat. Therefore, production of synthetic methane at NPPs will be more competitive and cheaper than production at VRE plants. A detailed analysis of economic advantages is in the next chapter.

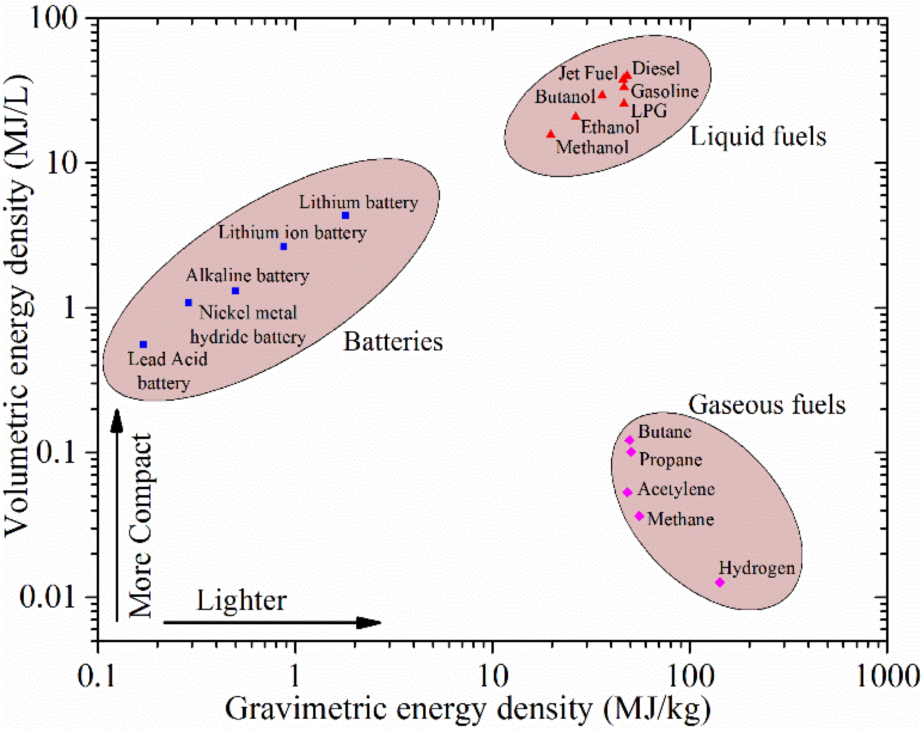


Figure 2: Comparison of gravimetric and volumetric energy densities of various energy storage materials and technologies [9]

4 HYDROGEN PRODUCTION COSTS OF DIFFERENT ENERGY TECHNOLOGIES (UK CASE)

Detailed analysis for hydrogen production costs has been made. Figure 3 shows solar PV at a CapEx of 1.095 $/kW with a maximum capacity factor (CF) of 27 %, implying a near-optimal location in a hot desert. Even with low-cost electrolysers (CapEx 500 $/kW) and a 64 % efficiency (low temperature electrolysis), the best achievable cost for hydrogen production from solar is 4,28 $/kg. If the quality of the location is lower (e.g., a country like Germany or the UK, where the capacity factor is 10-15 %), the production cost increases steeply.

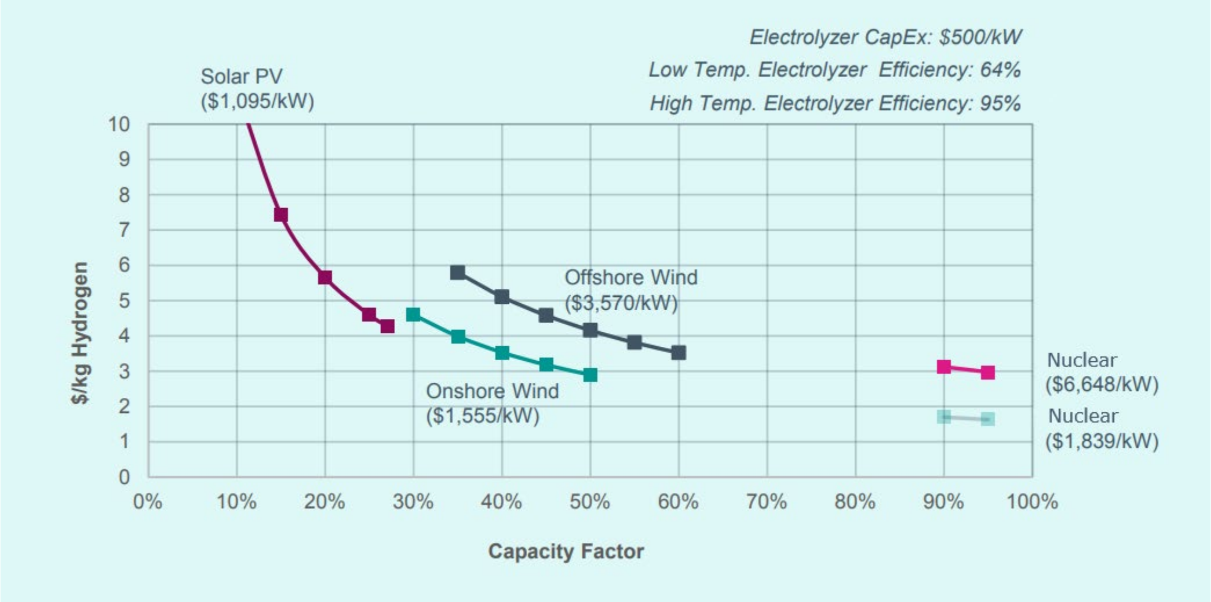


Figure 3: Current hydrogen production costs of different energy technologies

Figure 3 also adds onshore wind at an installed cost of 1.555 $/kW and capacity factor range of 30 % to 50 %. (This cost is also from the National Renewable Energy Laboratory, using the 2019 'mid'-case for utility-scale onshore wind.) The lowest achievable cost for onshore wind-derived hydrogen is just below 3 $/kg (also assuming a 64 % electrolyser efficiency). In less optimal conditions (lower CF of 35 % or less), cost climbs above 4 $/kg. Offshore wind achieves higher capacity factors but also has higher CapEx, so the lowest achievable cost is 3,50 $/kg for hydrogen.

Also, on Figure 3, we show nuclear-derived hydrogen, using two different 2019 capital costs for high temperature electrolysis. High-cost conventional new-build, such as in the EU or US, cannot produce hydrogen for less than 4 $/kg even with its higher capacity factor. Lower-cost new-build, such as in China or other Asian markets, can produce hydrogen closer to 2 $/kg, likely the cheapest near-term option from all the different technologies.

However, all these options are too expensive at current prices of natural gas (prices in 2018) to make a dent in global carbon emissions through hydrogen substitution. This is particularly the case in the UK context. Solar PV-generated hydrogen is a particularly poor choice economically in the UK due to very low capacity factors in a relatively high-latitude, cloudy country [10].

As shown in Figure 4 parts of the world are already delivering conventional heat sources cheaply enough to make hydrogen (based on high-temperature electrolysis with a depreciated pressurized water reactor whose CapEx has long ago been recouped) for close to 1 $/kg. Industrial capability in these countries, such as China and Korea, is advanced and experienced in scaling up chemical plants. Assuming that sufficient grid electricity would still be produced from other carbon-free sources, these countries could open up large export markets for hydrogen-based clean fuels in the near future from existing power plants. However, hydrogen from wind and solar remains at or above 3 $/kg at the current time.

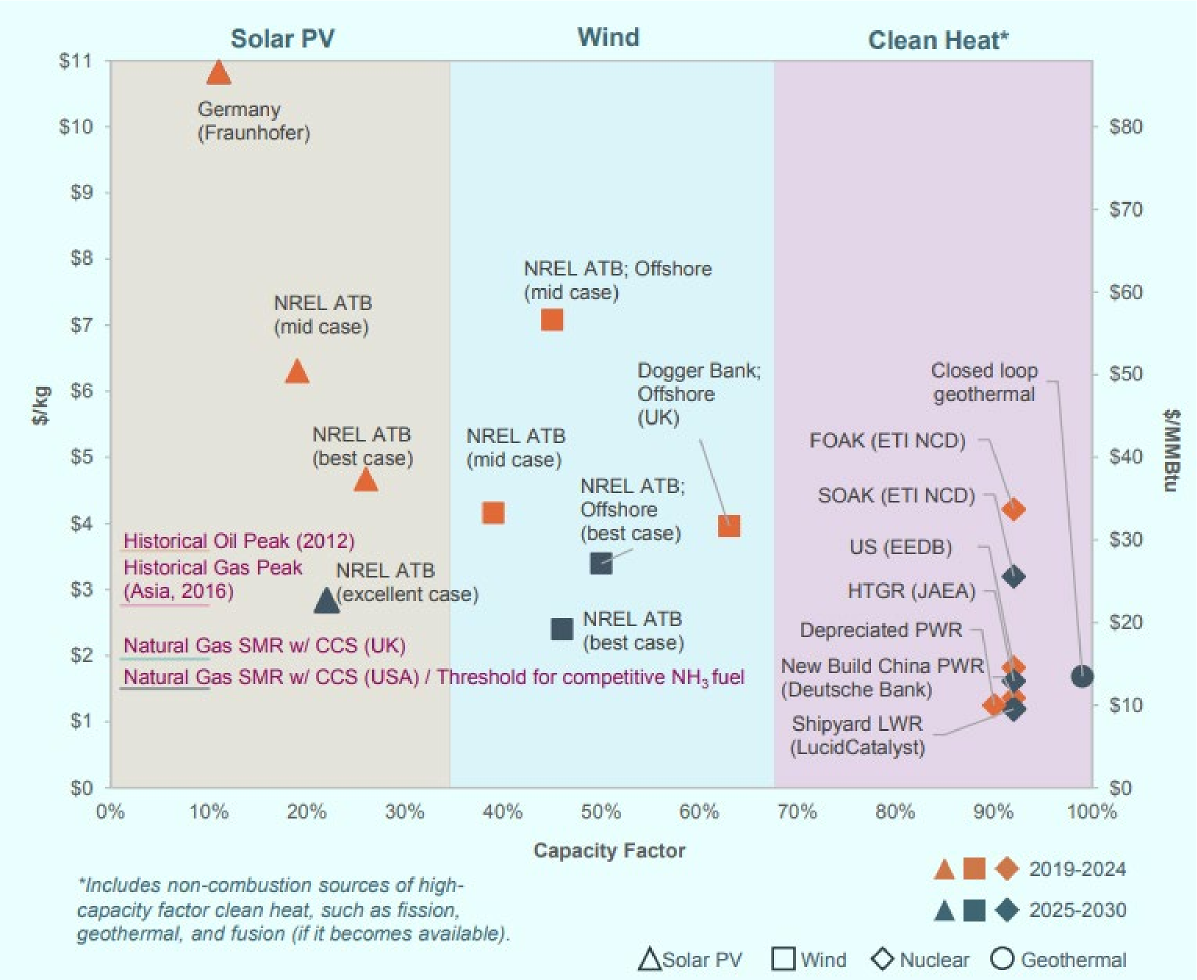


Figure 4: Cost of hydrogen production from different energy technologies in the real world now and in 2030

Looking forward to 2030 and using cost projections from the National Renewable Energy Laboratory, best-case wind and solar will be able to produce hydrogen at 2–3 $/kg in a decade, a significant improvement but still too expensive to compete with ‘grey’ hydrogen in the absence of a high price on emitted carbon and/or carbon capture and sequestration (CCS). Only nuclear-derived hydrogen is expected to be able to achieve close to price parity with fossil fuels, with best-case modular-built advanced modular reactors at or below 1 $/kg [10].

In United Kingdom, hydrogen has been identified as a promising alternative to electrification, when the latter is not easily available, because it burns without any carbon emissions and can be produced through well-known chemical processes. Their Ten Point Plan set an initial target of 5 GW of low-carbon hydrogen production capacity by 2030, enough to produce 42 TWh, 20 % of the 2050 target. Therefore, the growth rate to achieve 225 TWh of low-carbon hydrogen by 2050 will need to be significantly higher during 2030-50. Given this vast ambition, nuclear should be a key part of the green hydrogen mix. Nuclear offers a reliable option for hydrogen today, in electrolysis driven by clean, firm power, and promising options for hydrogen tomorrow, in steam electrolysis and thermochemical water splitting. The Nuclear Roadmap estimated that approximately 12-13 GW of dedicated nuclear capacity could produce 75 TWh per year of hydrogen by 2050 [11].

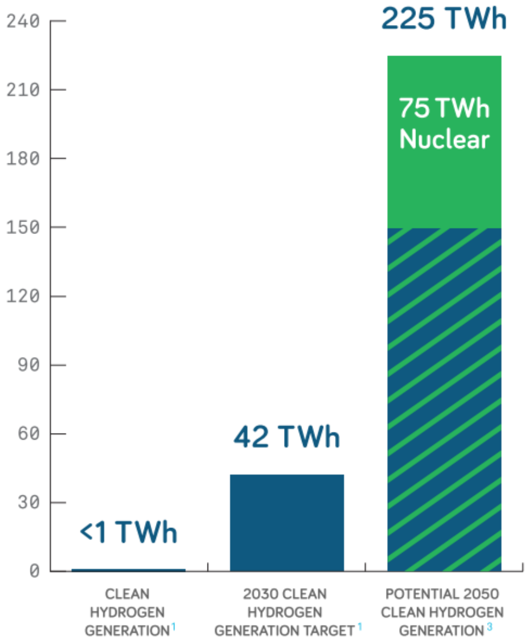


Figure 5: Clean hydrogen production today, in 2030 and in 2050

5 CONCLUSION

Hydrogen produced by electrolysis of water is currently more expensive than methods obtained from fossil fuels due to capital costs and dependence on electricity costs. Demonstration projects of electrolysis of water and steam in the scale of up to 10 MW are currently operating. Projects with power from 20 to more than 100 MW are being prepared. The current cost of hydrogen produced with these technologies varies between 2,6 € and 9,5 €/kg H_2. The main parameter when discussing the economics of hydrogen is the production costs per kilogram of hydrogen produced (€/kg H_2). The cost of hydrogen production using natural gas without carbon capture, use and storage (CCUS) varies between 0,85 €/kg H_2 and 1,45 €/kg H_2 in different regions (data for 2018), and with CCUS between 1,3 €/kg H_2 to 2,04 €/kg H_2. In the future, the cost of producing carbon-free hydrogen will need to drop by more than 50 % by 2030 if hydrogen is to become a viable alternative to conventional fossil fuels. In order to decarbonize various industrial processes, electrolysers will have to operate continuously at a good price with carbon-free electricity, since the resource availability factor (and the load on the electrolysis process) has the greatest impact on the final price of hydrogen. This can only be achieved with mainly nuclear power, supplemented to a lesser extent by VRE (wind and solar), to provide constant power for low-carbon hydrogen production.

Table 1 shows the impact of the price of electricity and the load factor of different technologies on the final cost of hydrogen. In all cases, the cost of producing hydrogen using nuclear power, which can continuously and reliably provide a source of heat and electricity for hydrogen production, is significantly lower than the cost of hydrogen made only with electricity from solar PV plants or wind. Carbon-free hydrogen production is thus the cheapest with nuclear energy, which is a consequence of the high availability of both the source and the electrolysis plant. Nuclear hydrogen is two to three times cheaper than hydrogen from VRE. The fact that carbon-free hydrogen will be the cheapest from NPPs (and large hydro power plants) is also noted by the French Parliamentary Commission. This commission found that hydrogen from NPPs can be up to four times cheaper than hydrogen from distributed renewable energy sources.

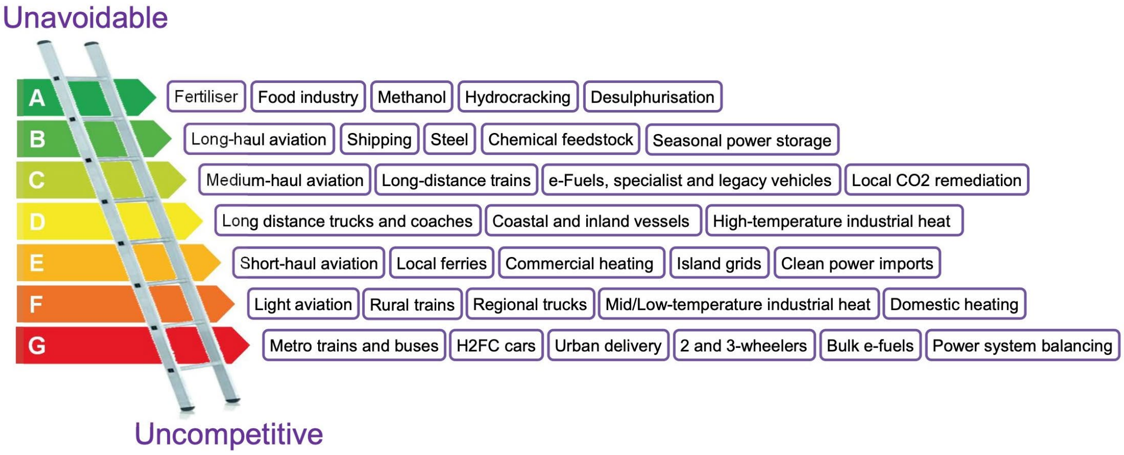
Table 1: Impact of electricity prices and load factor of different technologies on the final costs of H_2 [12]

	LCOE (€/MWh)	Load Factor	CAPEX/Production Cost	
			1000€/kw	500€/kw
Amortized nuclear (long term operation)	***32***	***90%***	***2.75€/kg***	***2.25€/kg***
New Nuclear	***80***	***90%***	***5.4€/kg***	***4.9€/kg***
PV	65	15%	8.5€/kg	6€/kg
Onshore Wind	74	23%	7€/kg	5.6€/kg
Market	40-50	90%	3-4€/kg	2.5-3.25€/kg

It is not yet known if hydrogen will ever be an important energy vector, because the infrastructure for massive hydrogen consumption must first be developed and built. Pure hydrogen has many limitations and disadvantages, especially when compared to methane and the liquid fuels it is supposed to replace.

Still, many initiatives are emerging, such as The Nuclear Hydrogen Initiative (NHI), which aim to raise awareness of the important role nuclear hydrogen can play in delivering “carbon-free, secure and affordable energy”. More than 40 organisations from around the world, including nuclear energy operators, reactors vendors, academia, and industry associations (such as IAEA, WNA, EPRI, Framatome, etc.), have joined forces to form the initiative to promote nuclear hydrogen as “a critical climate solution” [13].

It is highly likely that hydrogen will not be used in its pure form, but as a source to produce synthetic methane or even synthetic liquid fuels. In any case, regardless of the final use of hydrogen, hydrogen produced from facilities next to NPPs is cheaper than hydrogen from scattered VRE sources, and only hydrogen from NPPs can compete with fossil natural gas in the long term. Still, the use of hydrogen will not be equally competitive everywhere. The potential competitiveness of hydrogen for individual industries is shown in Figure 6.



A Fertiliser | Food industry | Methanol | Hydrocracking | Desulphurisation
B Long-haul aviation | Shipping | Steel | Chemical feedstock | Seasonal power storage
C Medium-haul aviation | Long-distance trains | e-Fuels, specialist and legacy vehicles | Local CO2 remediation
D Long distance trucks and coaches | Coastal and inland vessels | High-temperature industrial heat
E Short-haul aviation | Local ferries | Commercial heating | Island grids | Clean power imports
F Light aviation | Rural trains | Regional trucks | Mid/Low-temperature industrial heat | Domestic heating
G Metro trains and buses | H2FC cars | Urban delivery | 2 and 3-wheelers | Bulk e-fuels | Power system balancing

Figure 6: The Use Case Ladder [14]

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