Project Frame of Reference

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Abbreviations and acronyms

Acronym	Description
AEL	Alkaline Electrolysis
AGR	Advanced Gas-cooled Reactors
BWR	Boiling Water Reactor
CANDU	CANada Deuterium Uranium reactors
CAPEX	Capital Expenditure
CCUS	Carbon Capture Utilization and Storage
COMAH	Control of Major Accident Hazard
DOE	Department of Energy
EFTA	European Free Trade Association
EU	European Union
ETC	Energy Transitions Commission
FOAK	First-of-a-Kind
Gen IV	Generation IV
GFR	Gas cooled Fast Reactor
GHG	Green House Gases
HAZID	Hazard Identification
HEEP	Hydrogen Economic Evaluation Programme
HPP	Hydrogen Production Plant
HTE	High Temperature Electrolysis
HTGR	High Temperature Gas Reactors
HTR	High Temperature Reactor
HTSE	High Temperature Steam Electrolysis
HV	Hydrogen Valley
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LFR	Lead-cooled Fast Reactor
LHV	Lower Heating Value
LOHC	Liquid organic hydrogen carriers
LTE	Low Temperature Electrolysis
LTO	Long-Term Operation
LWR	Light Water Reactor
MIT	Massachusetts Institute of Technology
MSR	Molten Salt Reactor
NG	Natural Gas
NOAK	Nth-of-a-kind
NPP	Nuclear Power Plant
NZE	Net Zero Emissions

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Acronym	Description
PEM	Proton Exchange Membrane
PEMEL	Proton Exchange Membrane Electrolyzer
PWR	Pressurized Water Reactor
R&D	Research and development
SCWR	Super Critical Water-cooled Reactor
SFR	Sodium-cooled Fast Reactor
SMR	Small Modular Reactor
SOEC	Solid Oxide Electrolysis Cell
UK	United Kingdom
USA	United States of America
USD	Unites States Dollar
VHTR	Very High Temperature Reactor
VRE	Variable Renewable Electricity sources
WEO	World Energy Outlook
WP	Work Package

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Summary

This document establishes the frame of reference for the Nuclear-Powered Hydrogen Cogeneration (NPHyCo) project.

In the first section of the document (Section 2), an assessment, based on a literature review, has been performed to identify in-process and already performed projects as well as research successes regarding nuclear-powered hydrogen production. In Annex 11.1, two lists have been included, one for projects and initiatives of hydrogen production using existing Nuclear Power Plants (NPPs) and another one for Research and Development (R&D) activities focused on hydrogen production with advanced reactors and Small Modular Reactors (SMRs). There have also been identified several gaps and fields that need further analysis, and this is where the NPHyCo project shall provide added value within the research of nuclear-powered hydrogen cogeneration.

In the following section (Section 4), arguments based on technical, economic and social factors have been gathered in order to justify the need and benefits of nuclear-powered generated hydrogen. The arguments identified are:

- Nuclear is the low-carbon technology with the lowest Levelized Cost of Energy (LCOE), and the values for Levelized Cost of Hydrogen (LCOH) in the upcoming years tend to decrease
- Nuclear-powered hydrogen generates very low life-cycle emissions
- NPPs can provide nearly constant power source compared to renewable intermittency. This implies an increase in the capacity factor of the electrolyzers and the possibility of running the electrolyzer at high full load hours and paying for the additional electricity, what seems the cost-efficient option.
- There is a great versatility of nuclear-assisted hydrogen production methods
- Nuclear- powered hydrogen is crucial to reach carbon neutrality by 2050
- The coupling of an NPP and a Hydrogen Production Plant (HPP) could provide flexibility services that can benefit both the nuclear facility and the grid infrastructures.

The main conclusion obtained from this section is that the perfect timing for investigating nuclear-powered hydrogen production is now.

In Section 5, qualitative and quantitative information on the available technologies to produce hydrogen has been compiled. There are 4 possible pathways for nuclear-powered hydrogen cogeneration, namely low-temperature water electrolysis (LTE), high-temperature electrolysis (HTE), thermochemical water splitting and fossil fuels reforming.

Hydrocarbon reforming technologies extract hydrogen from hydrocarbon fuel by employing high temperatures. Reforming fossil fuels is associated with significant Green Houses Gases (GHG) emissions, although they can be reduced with a carbon capture, utilization, and storage (CCUS).

The thermochemical process is a method that uses thermal energy to split water into hydrogen and oxygen. It requires high temperatures that cannot be satisfied by low-temperature reactors such as Light Water Reactors (LWR). Thermochemical cycles are still in an early developmental phase. The cycles analyzed in this report are the Sulphur-iodine cycle, hybrid Sulphur cycle and copper chlorine cycle.

Steam electrolysis is a promising pathway for hydrogen production by nuclear electricity and heat. High-temperature electrolysis enables reaching higher electrical efficiencies than LTE. The integration

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of HTE with an NPP is more challenging than LTE. HTE is a less developed technology than LTE. HTE can be achieved through solid oxide electrolyzers cells (SOEC).

Water electrolysis is a method of producing hydrogen directly from water. The decomposition of water is driven by electrical energy. The LTE hydrogen plant is suitable for coupling with nuclear power plants in several interface degrees. There are two commercially available LTE technologies and in par with large-scale central hydrogen generation (scalable to 50-100MW), namely Alkaline Electrolysis (AEL) and Proton Exchange Membrane (PEM) electrolysis.

In Section 6, the suitability and advantageous factors of the different nuclear power reactors for being coupled with a hydrogen production plant have been analyzed. The study is divided into two main parts: the currently available reactors and the Generation IV advanced reactor designs.

As of February 2023, 180 NPPs were in operation in Europe, and 8 nuclear power reactors were under construction. These reactors are mainly categorized as Pressurized Water Reactors (PWR) and Boling Water Reactors (BWR), although there are two other types operating in UK and Romania (CANDU and AGR). The coupling between a hydrogen production facility and the NPP could significantly increase the system's flexibility by producing hydrogen during low-demanding periods. However, power plants in operation were not designed to be coupled with a hydrogen production facility, and consequently, several challenges are expected. LTE is one of the most suitable hydrogen production technologies for this kind of reactors. HTSE could result in a more challenging coupling with significantly reduced hydrogen production costs.

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New generations of nuclear power plants are being developed to address the challenges and limitations of current nuclear reactor technologies. These reactors operate at higher temperatures, and the coupling with an HPP would be planned during the design phase. Gen IV reactors are expected to be more flexible compared to the currently available technologies, and their higher temperatures raise the possibilities of process heat applications. Gen IV reactors are in active research worldwide, and their commercial deployment is expected in the following decades.

After hydrogen is produced at the nuclear power plant, it must be distributed and/or transported for further processing or to the end user. In Section 7.1., the different possibilities for hydrogen storage have been analyzed. These possibilities are compressed gaseous hydrogen, liquid hydrogen, metal hydrides, liquid organic hydrogen carriers (LOHC), green ammonia, and methanol. Regarding the transport of hydrogen, the following options have been considered: pipelines, pipelines for compressed gaseous hydrogen, road, rail and sea. All these variants must be evaluated in more detail when the scenarios have been established because they are highly dependent on the specific situation of a given location and the respective industrial surroundings and existing transport connections.

An important external boundary condition is the H_2 market, that is, the consumers that are willing to buy and/or use the hydrogen and the conditions and characteristics of the demanded H_2. In Section 7.2, a market analysis has been performed, and it is concluded that the biggest share of hydrogen demand comes from refineries and the ammonia industry. The biggest hydrogen consumption in European Union (EU) takes place in Germany (20%), the Netherlands (15%), Poland (9%) and Spain (7%).In terms of final foreseen use (2050), chemicals and transport will be the leading sectors.

The wholesale energy price is one of the external conditions more relevant at the time of determining the technical and economic feasibility of the project. In Section 7.3, this topic is evaluated. In 2020, the highest grid electricity hydrogen production costs were in Germany, Cyprus and Malta (8-10€/kg H_2) and the lowest production costs were in the Scandinavian countries: Finland (3€/kg H_2), Norway

(3,8 €/kgH_2) and Denmark (4,1 €/kgH_2). The main reason for these differences in H_2 prices between countries is the electricity prices.

In Section 8.1, an applicable regulation overview has been included. In the Licensing Roadmap, the current regulations concerning nuclear and hydrogen facilities in Europe will be analyzed. The level of conflict between different regulations in an integrated facility shall also be evaluated, as well as the proposal of potential solutions for the issues identified for each integration scenarios.

Another external requirement for the feasibility of the NPHyCo project is the support of the European Commission by classifying the nuclear-powered hydrogen production as an activity sustainable and aligned with climate targets. Section 8.2 details the current situation about the taxonomy and the economic and social consequences that this classification implies.

NPHyCo relates two fields of high public awareness and potential tension. Hydrogen generation plants in combination with nuclear power might not be perceived positively by the public because two potentially dangerous plants are being combined. In Section 8.3, information about current public opinion on this topic is included. One of the objectives of the NPHyCo project is to communicate and inform the public about the potential and safety concerns of producing nuclear-powered hydrogen in order to prevent objections due to a lack of information.

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1 Introduction

The purpose of the **Deliverable 1.1** is to establish a frame of reference for the project and to complete a detailed description of the Nuclear-Powered Hydrogen Cogeneration (NPHyCo) project research foundation by gathering:

- Arguments based on technical, economical, and social factors that support the need and benefits of nuclear-powered hydrogen generation.
- Qualitative and quantitative information on the available technologies to produce hydrogen with nuclear energy. Review of the nuclear plant technologies currently operating in Europe as well as new reactors to compare the suitability and advantageous factors when coupling them with hydrogen production.
- Assessment of external requirements introduced by other stakeholders that the consortium members have compiled. These requirements may come from new standards and guidelines, potential hydrogen customers, the public, EU authorities, end users' groups and other projects in the Horizon or Euratom projects. Previous gaps and research successes identified in the field will also be identified.

The main objective of this document is to produce a report that will benefit European nuclear plants, policymakers and the public to make informed decisions on the matter of nuclear-produced hydrogen.

The Deliverable 1.1, Project Frame of Reference, has been developed during Task 1.1 of WP1 that corresponds to Conceptualization.

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2 Background

Interest in hydrogen production using nuclear energy is growing internationally due to the potential to deliver electricity and heat for hydrogen synthesis in a sustainable, constant, low carbon and cost-effective manner. This is reflected in an increasing number of demonstration projects and international partnerships to analyze the feasibility and business opportunities of hydrogen production.

These projects are often motivated by the need to improve the economics of the existing fleet, especially in electricity markets with low or sometimes negative prices, by producing an additional high-value product.

Research and development activities are also focused on advanced reactors and SMRs- including high-temperature gas reactors (HTGRs)- for non-electric applications and hydrogen production using high-temperature steam electrolysis (HTSE) or thermochemical processes [1].

There are many international, national and company projects focused on hydrogen from nuclear generation (see Annex 11.1). One of the most relevant projects considering an existent NPP is Hydrogen2Heysam Project in the UK. The first phase of the project demonstrated the technical feasibility and great potential of coupling low-temperature electrolyzers (PEM and AEL) with the electricity from an NPP. This configuration of hydrogen production is also being deployed at three nuclear power plants in the United States (Davis-Besse NPP, Palo Verde NPP and Nine Mile Point NPP) via government-funded project (H2@Scale initiative from the Department of Energy (DOE)). Besides, in the USA, there is also another demonstration project in Prairie Island NPP where a high-temperature electrolyzer (SOEC) is going to be coupled to the nuclear facility. In Canada, Russia and Sweden, other

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nuclear hydrogen projects are also underway. This clearly highlights the international trend of interest in this field [2].

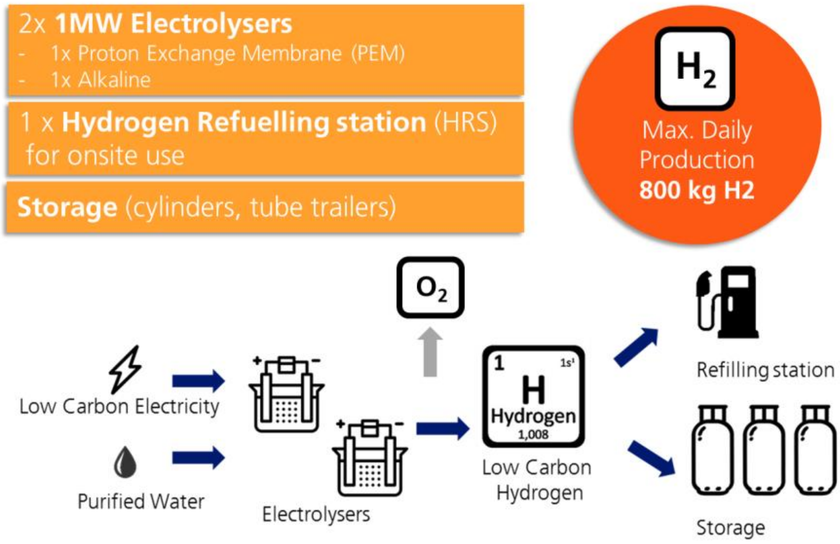

Figure 1 Hydrogen2Heysam (H2H) project basic components and features [3]

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All these leading initiatives on nuclear-produced hydrogen are characterized by broad and intersecting objectives in economics, engineering, markets, and licensing. Typically, operational performances of electrolyzers and coupled systems remain to be tested at scale under real conditions. Furthermore, the market and economic cases for hydrogen or other electrolysis by-product need to be specified. In parallel, other production and end-use solutions have to be brought to technological maturity, and international standards along the entire hydrogen value chain have to be developed [4].

Installing an electrolyzer which is connected directly to a nuclear power plant is technically possible [2] and economically competitive if the LCOH is below USD 2,5 per kgH_2, but it will be hard to achieve this value in most places in the world by 2035 [4]. Besides, there are important safety/regulatory considerations, as well as legal and competition aspects which require stakeholder consensus.

Industry, which is expected to dominate the hydrogen market over those time horizons, is characterized by large-scale and centralized demand. For this reason, current hydrogen markets are structured around delimited areas of production and consumption. In Europe, hydrogen deployment is focused on the concept of Hydrogen Valley (HV), defined as “a geographical area where clean hydrogen is produced and locally used by households, local transportation and industrial plants”. Belgium, Germany and the Netherlands are leading the way. Other important HVs are expected in Eastern Europe and along the Mediterranean [4].

The HV approaches strongly align with large-scale and concentrated energy sources such as nuclear. Several initiatives have already begun investigating the benefits of linking large-scale nuclear and hydrogen hubs, like the Hungarian Central-Danube Hydrogen Valley. A leading project is the Freeport East Hydrogen Hub in the UK, where up to 1GW of electrolyzers would use Sizewell’s nuclear electricity to supply the entire ecosystem. Similarly, the United States plans to deploy at least one hydrogen hub powered by nuclear energy. There is also interest in the role of small modular LWRs and how they contribute to hydrogen hubs. In particular, their flexibility and safety features could enhance the potential co-location with large consumption points such as ports or large industrial facilities [4]. As hydrogen production technologies improve, the demand for hydrogen might become more distributed as applications in the transport, power and heating sector emerge.

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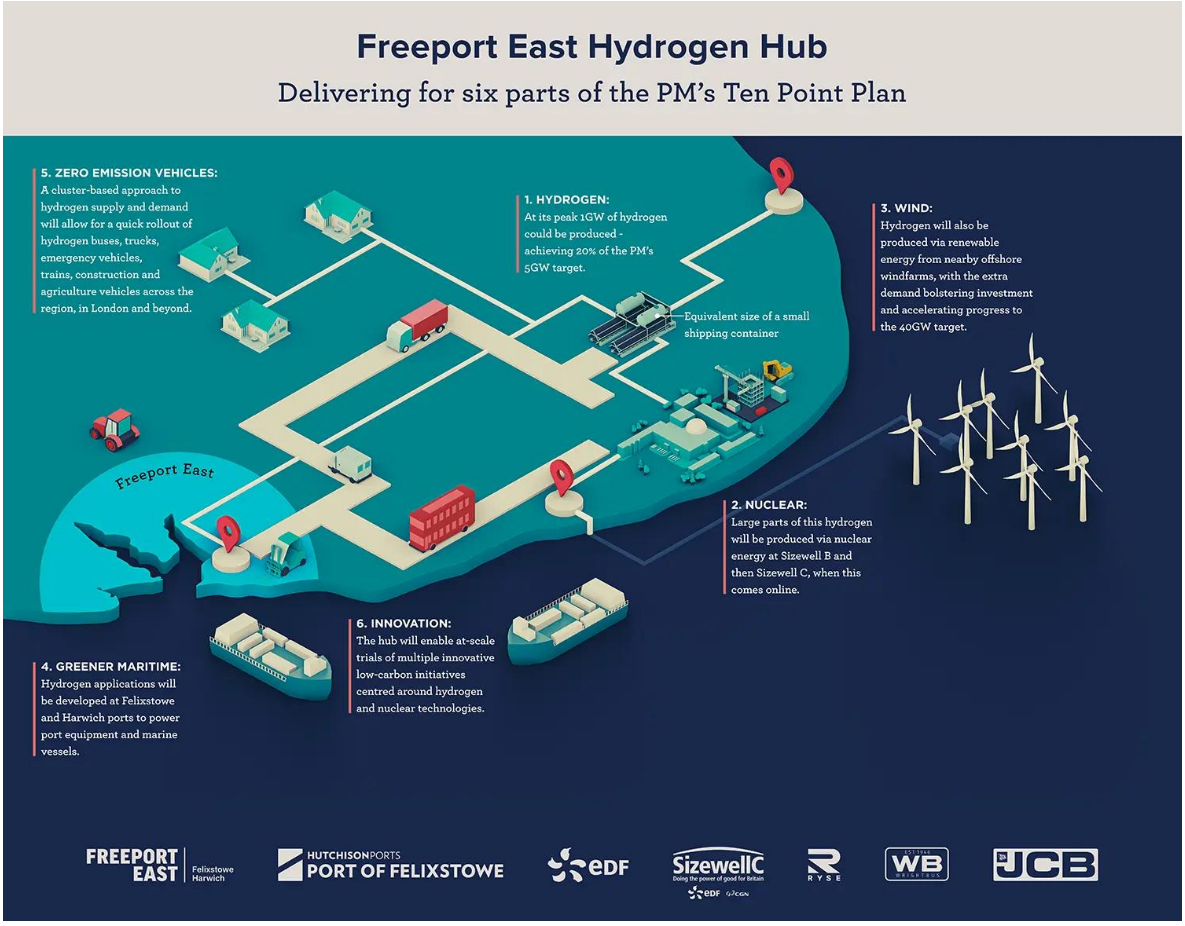

Figure 2 Freeport East Hydrogen Hub

The International Atomic Energy Agency (IAEA) has tried in recent years to incorporate and promote hydrogen as a meaningful co-product of NPPs. The most recent effort is the development of a Hydrogen Economic Evaluation Programme (HEEP), which can be used to analyze the economics of large-scale hydrogen production plants. Nevertheless, such analysis has been mainly generic or conceptual designs for small to medium-sized H_2 plants up to a few MW. The potential cost savings and technical advantages of integrating and intertwining e.g., auxiliaries or staff on an operating NPP site, have not been explored for specific use cases, leaving a large unknown in these investigations.

Another research field has been the review of relevant nuclear safety and industrial regulatory requirements. Generic HAZID studies, COMAH regulations and theoretic safety concepts have been explored, just to name a few. The consensus being, that non-nuclear accidents must not compromise the safety of the nuclear power plant and vice versa [5]. However, modifying or tapping into available structures within operating NPPs for integrating a H_2 production plant has not been assessed.

The interest and scale of coupling nuclear technologies with hydrogen production can be seen across many stakeholders and regions. However, there are several fields that need additional research to bring forward the opportunities that nuclear technologies can offer to help grow the hydrogen economy within Europe. By analyzing the projects already performed or in progress, the following topics have been considered which need a deeper assessment:

- Analysis of economic values of hydrogen as the Levelized Cost of Hydrogen (LCOH) within the EU from various forms of energy including existing nuclear reactors, small modular reactors, and advanced nuclear technologies such as Generation IV reactors [2]. It is essential to

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demonstrate that large-scale, low-carbon water electrolysis is a viable alternative to today's carbon-intensive hydrogen production.

- Analysis and integration of the complete value chain of hydrogen production. It must be ensured that project assessments consider the full value chain of hydrogen production and delivery (storage, transformation, transport, and distribution) to design cost-efficient infrastructures [4].
- Over the medium term: accelerate research and development (R&D) efforts on less mature options that can improve hydrogen production efficiency. Methane pyrolysis or thermochemical cycles, possibly in conjunction with Gen IV reactor technologies, are promising low-carbon options that can reduce the primary energy requirements for hydrogen production [4].
- Develop policy frameworks to enable the broad-based production of low-carbon hydrogen. Reference net zero pathways underline the importance of rapidly scaling up the production of low-carbon hydrogen. Restricting energy sources to produce low-carbon hydrogen will limit deployment in the short term and lead to additional systems cost in the longer term [4].

In the following points, it is shown that NPHyCo objectives are completely aligned with the scenarios that need further analysis [6]:

- Demonstrate that nuclear H_2 cogeneration is technically and economically feasible and attractive compared to other equivalent H_2 production types. Several KPIs shall be defined to test its competitiveness because most papers and tools available for assessing nuclear-produced hydrogen do not incorporate the recent up-to-date market and technology.
- Identify suitable pilot project locations. A universal decision matrix for the European NPPs will be developed to support the choice of location and hydrogen technology for future possible investments/ projects by giving an overview on the most important criteria. If successful, the project has the potential to initiate a market-roll-out for the NPHyCo concept to several NPPs, for the case study plant types and locations and beyond that.
- Assess the technical feasibility and the added value of H_2 production based on existing plants. According to our knowledge, a techno-economic analysis for the coupling of VVER type NPP with a hydrogen production plant has not been done before. The available published literature in many parts refers to high-temperature reactor designs coupled to HTSE and/or explicates on general methods and technologies.
- Identify the critical licensing issues that are to be foreseen for the integration of an operating NPP with a H_2 production plant and definition of the optimal process for solving the critical issues to minimize the licensing effort and timeline.

3 Hypothesis, assumptions and pre-requisites

By the time this report was performed, the following hypothesis and assumptions regarding the development of the NPHyCo project were considered:

- NPHyCo project focuses on low-carbon hydrogen production. Those H_2 production pathways that imply CO_2 emission to the atmosphere will not be considered within the scope of this project. Besides, it is assumed that nuclear energy and nuclear-powered hydrogen are considered as environmentally sustainable activities in the energy taxonomy.
- Technologies with higher readiness level and commercially availability at the time of performing the scenarios selection will be prioritized because the project objective is to prepare the

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realization of nuclear hydrogen generation projects in the short term (pilot plant launch between 2025 and 2030 and relevant size >30MW). The project is not going to consider additional costs for H_2 technology development.

- It is assumed that nuclear hydrogen cogeneration should be cost-competitive at some point when already existing facilities of an NPP can be coupled with an HPP. However, this assumption will be proved by the feasibility analysis to be performed in this project. The cogeneration concept assumes the possibility of sharing some supplies from the NPP with the H_2 production plant. Demineralized water, refrigeration system, chilled water, pressurized air, nitrogen supply, wastewater or electricity are some of the systems whose possibility of being integrated within the two facilities will be analyzed.
- Preliminary economic analysis shows that costs associated with electricity and/or heat consumption are one of the most relevant variables to take into consideration in the economic balance.
- Preliminary economic analysis also shows that the second most relevant concept is the CAPEX and OPEX and the degradation associated with the equipment belonging to the hydrogen value chain. These values can be established based on current information, but the scale effect as well as the price evolution in the upcoming years will respond to a less precise estimation.
- A central element to evaluate the economic viability of a hydrogen generation plant is the cost of electricity consumption. The same plant can obtain different economic returns depending on the production strategy it uses. The best results are obtained if hydrogen is produced when electricity is cheapest at night or midday, and all the electricity produced at the nuclear power plant is sold to electricity markets when electricity is most expensive. The evolution of the prices in the electricity markets will be influenced by the future penetration of renewables (for example: Photovoltaic generation in Spain has gone from being irrelevant to covering around 25% of the demand in the central hours of the day in February 2023, and the expectations are that its impact will be even greater in summer and in the coming years). The photovoltaic impact will go in the direction of lowering electricity prices in the central hours of the day and, therefore, will cause a greater slope between midday and early evening. It is what some authors call the "duck curve". If these low prices in the central hours of the day materialize, it will significantly affect the profitability of the nuclear power plant and help to make hybridization with hydrogen generation economically attractive for the nuclear power plant. For these reasons, the NPHyCO project will have to make some hypotheses about the impact of future photovoltaic penetration. The same problem, but from a daily to a seasonal scale, can occur with respect to wind (and even hydro) increased generation. It may then happen that the economic viability of the NPP+HPP hybrid plant depends on its operation only in certain seasons and/or only during the central hours of the day, and this operating mode may evolve during the life of the installation.
- It is assumed that existing NPPs are willing to collaborate with the NPHyCo project. The coupling of an NPP with an HPP is considered as an additional flexibility source which will allow the NPP to maintain the nominal load and support the management of grid flexibility. NPPs are originally designated to base load operation, and the plants and the national grids would benefit from a coupled H_2 plant as this would allow to avoid load follow mode but produce hydrogen instead from idle capacity. This is especially interesting for plants of VVER type as they were originally not designed to be operated in load-following mode or only at a limited range. In the EU, especially the Czech locations in Temelin and Dukovany, the Slovakian units in Bohunice and Mochovce or the Hungarian location in Paks might be favourable locations. Preliminary discussions within the consortium partners have also shown possible interest from NPP locations outside the EU, e.g. in Ukraine and USA.

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- The H_2 generation could take place on-site at the nuclear power plant premises or off-site, but close to the nuclear power plant site as proximity leads to economic or technological advantages. The produced hydrogen itself can be either used by nearby existing large industrial areas, transported to other national customers, or exported. The transportation and delivery of the hydrogen produced by the nuclear power plant may probably be based on a set of infrastructures (hydro pipelines) that will be shared with other generation systems and that will be considered in this analysis.

4 Need and benefits

The aim of this section is to analyze from several perspectives the reasons to support the need for nuclear-powered generated hydrogen and the benefits reported by its production. The arguments will take into consideration the applicable regulatory context, and they will be based on technical, economic, and social factors.

Context

Hydrogen is experiencing a renewed and rapidly growing attention in Europe and around the world. Hydrogen can be used as a feedstock, a fuel or an energy carrier and storage, and has many possible applications across industry, transport, power and building sectors.

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According to IEA [7], hydrogen production today is primarily based on fossil fuel technologies. Around 60% of it is produced in "dedicated" hydrogen production facilities, meaning that hydrogen is their primary product. Most hydrogen is currently produced near to its end use. Overall, less than 0,7% of current hydrogen production is from renewables or from fossil fuel plants equipped with Carbon Capture and Use/Storage (CCUS).

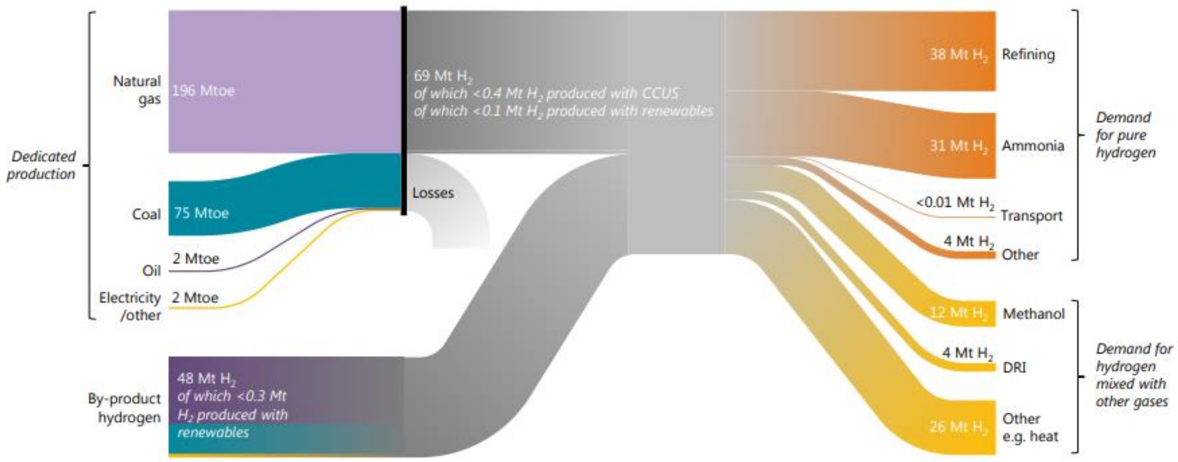

Figure 3 Today's hydrogen value chains (2018) [7]

The demand for pure hydrogen has increased more than threefold since the 1970s to reach around 75 million tons of hydrogen per year today. The demand from oil refining, ammonia production, and other applications that require hydrogen in processes has also increased significantly since 1975 [8]. Demand for hydrogen is expected to increase significantly in the next 30 years as the transition towards a net zero economy advances. The Energy Transitions Commission (ETC) estimates that 500 to 800Mt/year will be needed in 2050 [1].

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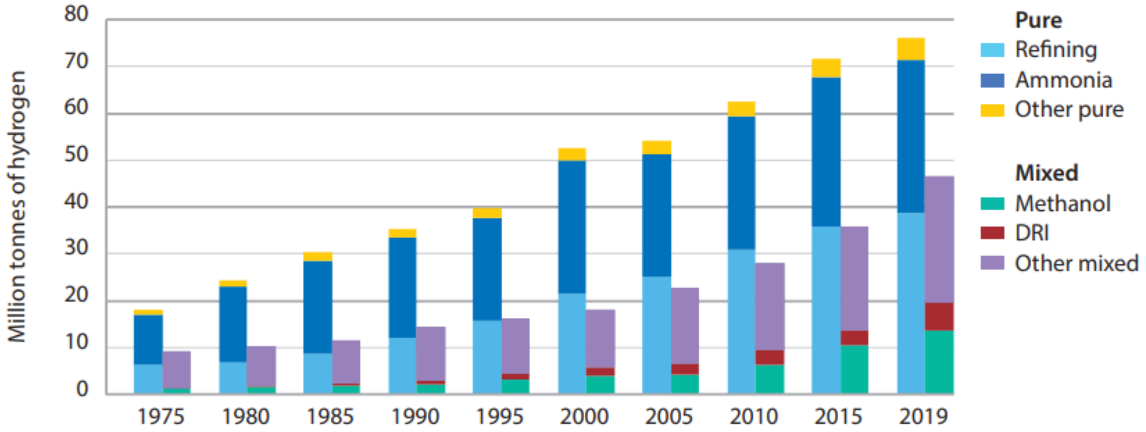

Figure 4 Evolution of global annual demand of hydrogen (pure and mixed) since 1975 [8]

Apart from the targets to be accomplished, the global energy crisis following Russia's invasion of Ukraine has bolstered energy security concerns about the supply of conventional fuels such as oil and gas, providing further impetus to the need and policy support for clean energy technologies.

<u>Nuclear is the low-carbon technology with the lowest LCOE, and the values for LCOH in the upcoming years tend to decrease , but LCOH will be very much dependent of the electricity price.</u>

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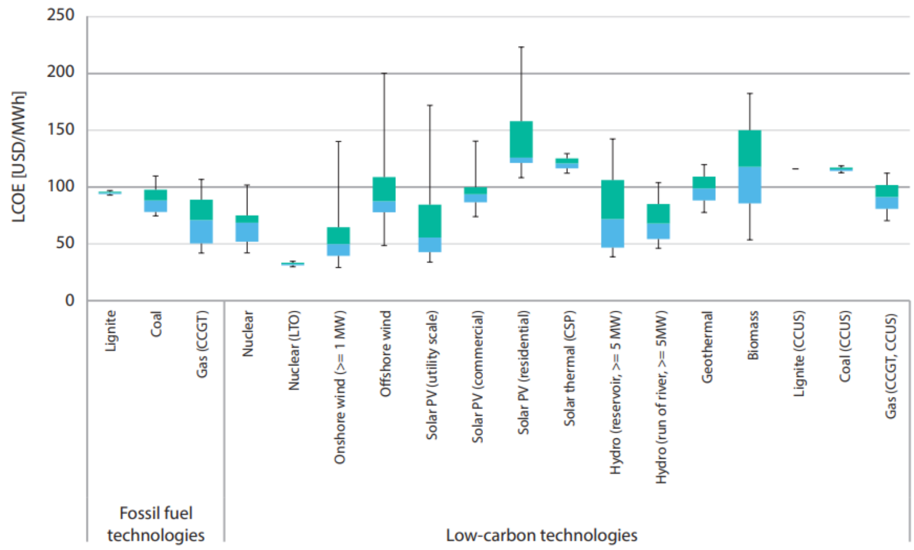
According to an IEA report issued in 2020 [8], nuclear remains the dispatchable low-carbon technology with the lowest expected costs in 2025. Electricity produced from nuclear long-term operation (LTO) by lifetime extension is highly competitive and remains not only the least cost option for low-carbon generation- when compared to building new power plants- but for all power generation across the board.



Note: Values at 7% discount rate. Box plots indicate maximum, median and minimum values. The boxes indicate the central 50% of values, i.e. the second and the third quartile.

Figure 5 LCOE by technology (2020) [8]

Making use of the existing facilities and infrastructure, significantly reduces costs compared to building new greenfield plants. Even at lower utilization rates, a potential scenario for nuclear units in systems with high shares of variable renewables, costs are below those of new investments in other low-carbon technologies. Hydroelectric plants could be similarly attractive for such LTO investments, but they are highly dependent on the natural endowments of individual countries.

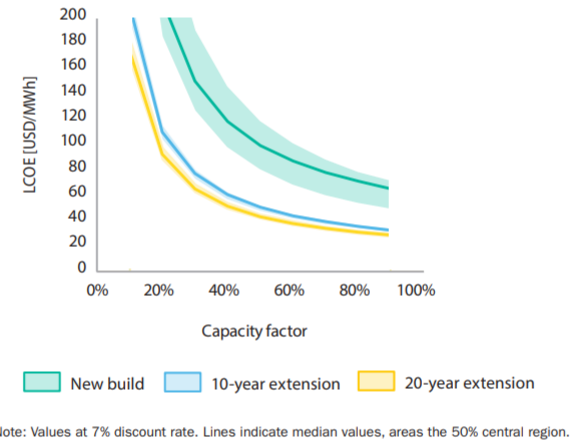


Figure 6 Costs for nuclear new build and lifetime extension of existing plants [8]

The LCOE values indicate that from an economic perspective, the hydrogen production from an NPP with operation extension could be in an advantageous situation. Regarding other nth-of-a-kind (NOAK) nuclear projects (plants to be completed by 2025 or thereafter), the expected costs are also decreasing. However, recognizing the importance of going beyond the LCOE and to enable more robust cross-technology comparisons in evolving power systems, it would be advisable to analyze the price of producing hydrogen from nuclear generation considering ancillary services and/or additional flexibility to be provided with the new configuration.

As shown in Figure 7, in 2021, the cost of low-emission hydrogen production was more expensive than the fossil fuels without the CCUS route. The average cost comparisons are: USD 1,0-2,5/kg H_2 from unabated gas natural; USD 1,5-3,0/kg H_2 from natural gas with CCUS; USD 4,0-9,0/kg H_2 for production via electrolysis with renewable electricity; and USD 3,5-7/kg H_2 from nuclear generation.

Russia's invasion of Ukraine in early 2022 has amplified energy security concerns, with physical supply constraints for natural gas in Europe and a surge in the natural gas process over recent months, following a price surge in the second half of 2021, as demand recovered from the Covid-19 pandemic. This has changed the economics of producing hydrogen from natural gas, for both with and without CCUS. Hydrogen production costs from unabated natural gas at USD 4,8-7,8 /kg H_2 are up to three-times the levels in 2021. Costs for hydrogen from natural gas with CCUS are in the range of USD 5,3-8,6/kg H_2, of which USD 4,1-7,4/kg H_2 alone is due to natural gas costs.

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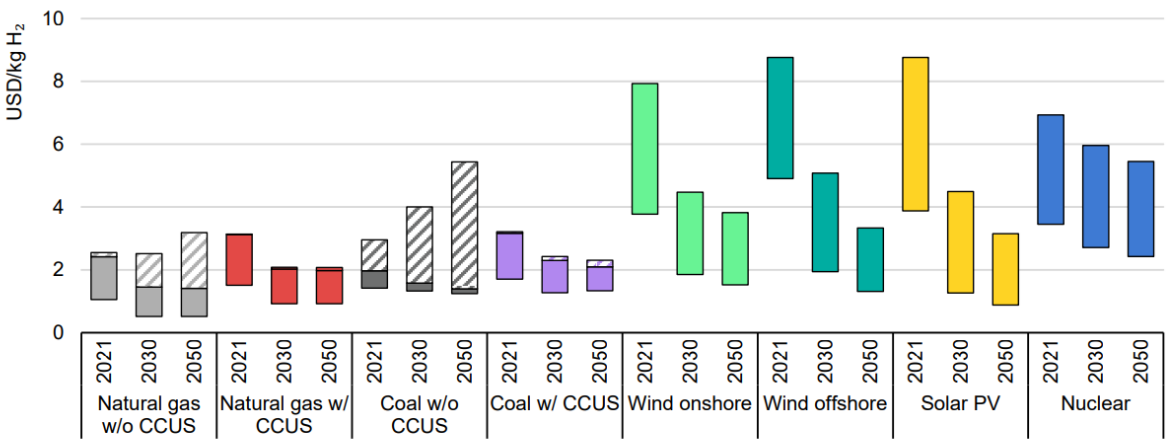

Figure 7 Levelized cost of hydrogen production by technology in 2021 and in the Net Zero Emissions by 2050 Scenario, 2030 and 2050 [9]

According to S&P Global Rating [10], the costs for producing hydrogen from renewables must decrease by more than 50% to USD 2-2,5/kg H_2 to become a feasible alternative to conventional fossil fuels. This situation could be reached with solar and wind production costs around USD 20-30/MWh and a 30-50% reduction in the electrolyzer's prize. The LCOE of renewable energies represents around 60% of green hydrogen production costs, and a decrease of about USD 10/MWh in the energy price would reduce the hydrogen costs by around USD 0,4-0,5/ kg H_2. A price drop of USD 250/kW in the electrolyzer CAPEX would reduce the green hydrogen production by around USD 0,3-0,4/kg H_2. Finally, if the capacity factor increases from a 40% to a 50%, the hydrogen production costs will also decrease by around USD 0,2-0,3/ kg H_2.

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It is pending to deeply evaluate the technical and economic feasibility of nuclear hydrogen production, but if the capacity factors are increased from 50% to 90%, the hydrogen production costs could be reduced in around USD 1/kgH_2. In order to achieve hydrogen production costs of about USD 2-2,5/Kg H_2, the LCOE needs to be in the range of USD 35-45/MWh, much lower than projections for new nuclear power plants in many regions of the world. However, such costs can be achieved with lifetime extensions of existing reactors and may enable existing plants to diversify their revenues [1]. Hence, the nuclear-assisted hydrogen production costs are promising.

Very low life-cycle emissions

Electrolysis can achieve very low emissions if powered with renewable energy or nuclear power. Nuclear power comes in at 0,6kg CO_{2eq}/kg H_2, one of the lowest Green House Gases (GHG) emissions, but it is also important to note in this context that it leads to 0,115g of radioactive waste per kg of hydrogen [11]. This value was calculated for the current technologies, but Gen. IV reactors aim to reduce nuclear waste by higher burn-up, transmutation and a closed nuclear fuel cycle.

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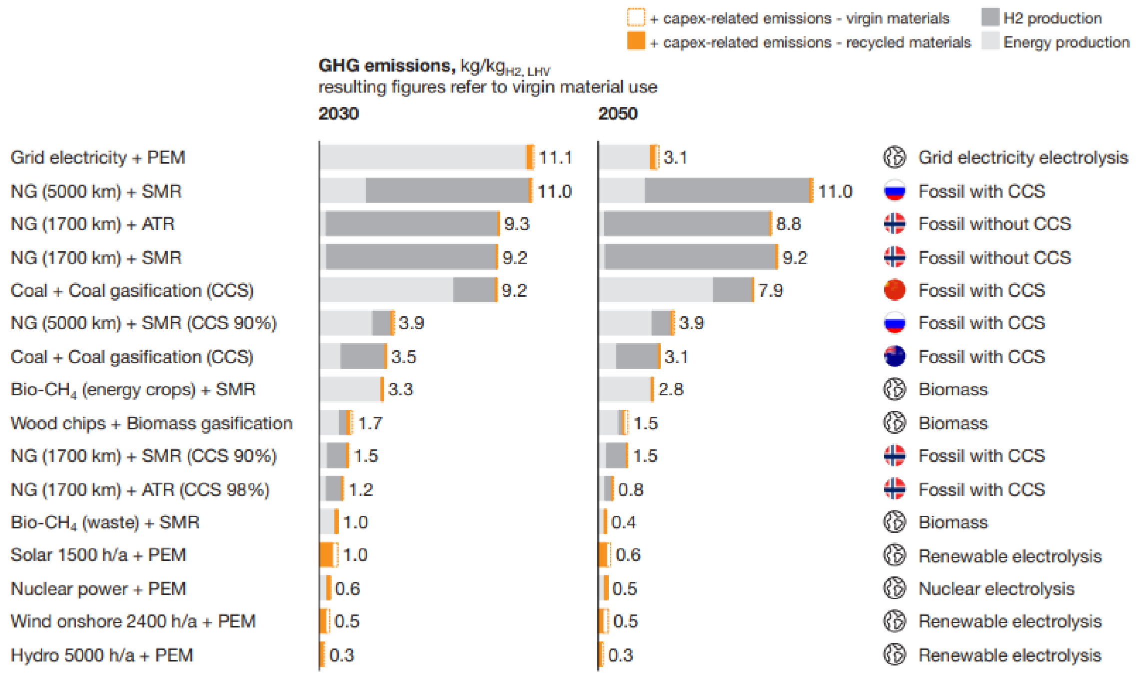

Figure 8 Carbon-equivalent emissions by hydrogen production pathways, 2030 and 2050 [11]

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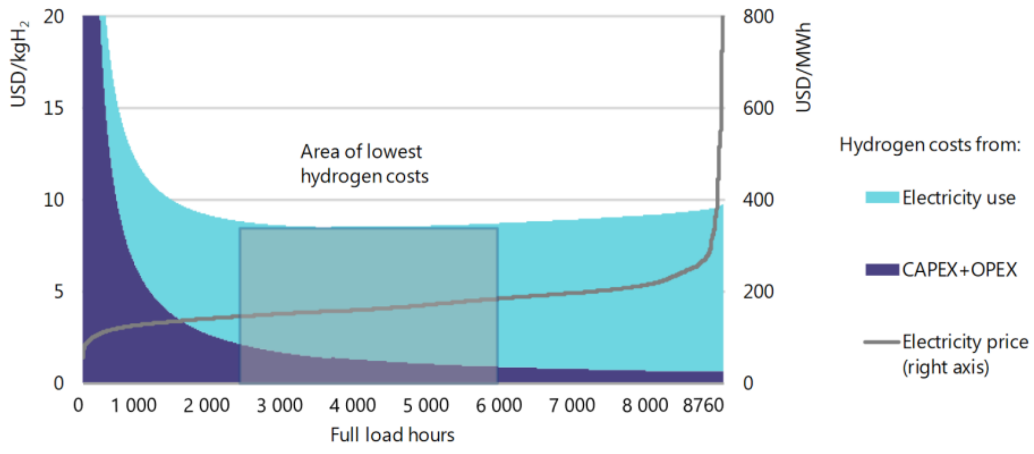
Electrolyzer competitive operational advantages

The IEA states that *"As electrolyzer operating hours increase, the impact of CAPEX costs on the levelized cost of hydrogen declines and the impact of electricity costs rises. Low-cost electricity available at a level to ensure the electrolyzer can operate at relatively high full load hours is therefore essential to produce low-cost hydrogen"* [7].

As it is shown in Figure 9, the CAPEX share will decrease with an increase in the capacity factor of the electrolyzer, confirming that an optimal functioning time could be somewhere between 3000h-6000h. In electricity systems with an increasing share of variable renewables, surplus electricity may be available at a low cost. Producing hydrogen through electrolysis and storing the hydrogen for later use could be one way to take advantage of this surplus electricity, but if surplus electricity is only available on an occasional basis, it is unlikely to make sense to rely on it to keep costs down. Running the electrolyzer at high full load hours and paying for the additional electricity can be cheaper than just relying on surplus electricity with low full load hours.



Notes: CAPEX = USD 800/kW$_e$; efficiency (LHV) = 64%; discount rate = 8%.
Source: IEA analysis based on Japanese electricity spot prices in 2018, JEPX (2019), *Intraday Market Trading Results 2018*.

Figure 9 Hydrogen costs from electrolysis using grid electricity [7]

Dedicated electricity generation from renewables or nuclear power could become a low-cost supply option for hydrogen, but in case of renewables, a location where the resources are excellent may be assured and the constant supply is not guaranteed.

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<u>Nuclear-assisted hydrogen production versatility</u>

Nuclear power plants can produce hydrogen through a variety of ways by taking advantage of their constant supply of thermal energy and electricity. There are four main pathways:

1. Water electrolysis- only using nuclear electricity
2. Steam electrolysis- using nuclear heat and nuclear electricity
3. Thermochemical processes- using nuclear heat and a small amount of nuclear electricity
4. Reforming fossil fuels- using nuclear heat.

According to IEA [7], there is a lot of interest in the scope for integrating heat into hydrogen production and how best to source heat requirements. Nuclear power plants are an option for the provision of heat for hydrogen production. Depending on local conditions, using steam from nuclear power could be cheaper than using steam from natural gas, as well as reducing the carbon intensity of the hydrogen produced. It could also provide a useful revenue stream for NPP. Electricity and heat (produced at temperature levels of around 300°C by NPP) could also be used to provide electricity and steam for SOEC electrolysis.

Small Modular Reactors (SMR) could also have a role to play in SOEC electrolysis in the future. Six small modular reactors with a combined capacity of 300MW$_e$ could, for example, meet the annual hydrogen demand of a mid-sized ammonia plant.

In the longer term, advanced nuclear reactors, such as the two industrial prototype high-temperature pebble-bed reactors currently in operation in China, could also become the heat source for thermochemical water splitting, with some reactor designs having coolant outlet temperatures of 800-1000°C.

Besides, high-temperature electrolysis systems could advantageously comply with HTGRs. HTGRs Gen IV have an outlet temperature of around 850°C and are suitable as heat sources for SOECs. In the high operating temperature range (800-1000°C), approximately two-thirds of the energy required for the electrolysis reaction must be supplied as electricity, and one-third may be supplied as heat. Hence, the high-temperature heat produced by such a nuclear plant could be employed in a high-temperature water electrolyzer to produce hydrogen and increase the energy efficiency of the HTGRs (which is close to 30%), maximizing a formal electrical efficiency of SOECs [13].

These are some examples of hydrogen production applications from nuclear heat and electricity, but there are many more. As it can be concluded, the nuclear-assisted hydrogen production is a vast and diverse field to be explored.

Nuclear-powered hydrogen is crucial to reach carbon neutrality by 2050

Hydrogen does not emit CO_2 and causes almost no air pollution when used. Hydrogen and its derivatives should play an important role in the decarbonization of those sectors where emissions are hard to abate, and alternative solutions are either unavailable or difficult to implement. All this makes hydrogen essential to support the EU's commitment to reach carbon neutrality by 2050 and for the global effort to implement the Paris Agreement while working towards zero pollution.

A comprehensive analysis conducted at MIT in 2018 concluded that although a number of low or zero-carbon technologies can be advantageously employed in various combinations, nuclear is virtually essential as a contributing low-carbon technology. This growing role of nuclear power to meet decarbonization objectives is also confirmed by the Intergovernmental Panel on Climate Change (IPCC, 2018) [8].

Nuclear energy complements and supports the rapid growth of renewables in bringing emissions from the electricity sector worldwide down to net zero by 2040. Nuclear power contributes to the low emissions electricity supply and, as a dispatchable generating source, enhances the security, adequacy and flexibility of electrical grid. Global nuclear power capacity almost doubles from 413GW at the start of 2022 to 812GW in 2050 in the NZE. This represents a major acceleration compared with the last three decades, when capacity increased by about 15%, or about 60% [14].

According to IEA Report [14], a Low Nuclear Case has been analyzed considering that the nuclear capacity declines from 413GW at the start of 2022 to 310GW in 2050. This is about 500GW less than in the NZE (see Figure 10).

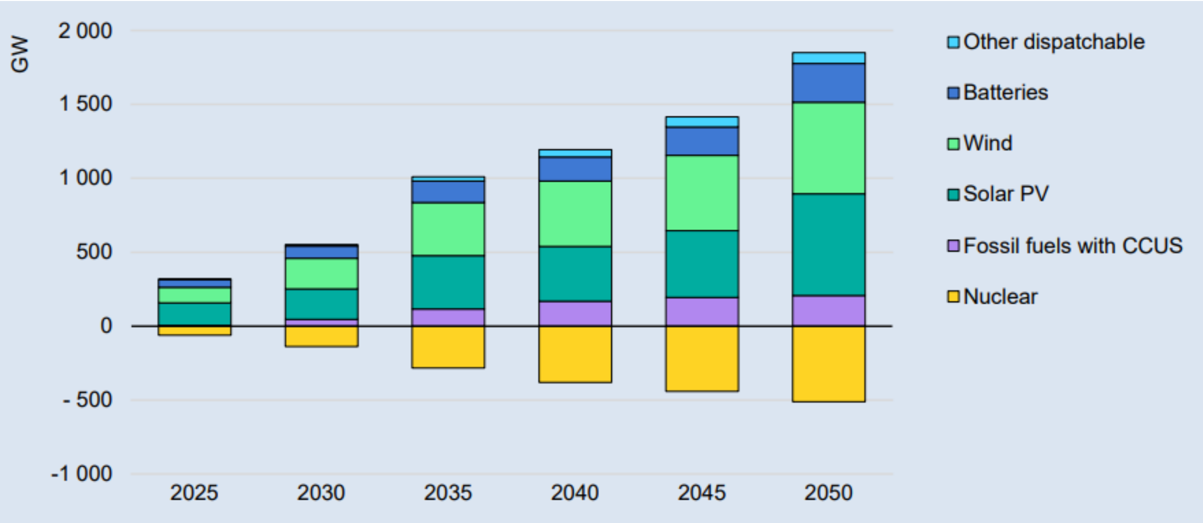

Figure 10 Change in global power capacity in the Low Nuclear Case relative to the Net Zero Emissions by 2050 Scenario [14]

AL: N ECCN: N

In addition, there are three main implications of integrating more renewables into the electricity system:

- Higher overall costs: cumulative investment increases by over USD 500 billion and consumer electricity bills by almost USD 600 billion over the period to 2050. This includes the additional investment costs for power technologies, the cost of grid expansion to support additional renewables and additional fuel costs for coal and natural gas.

- Additional strain on clean energy supply chains: for every 1 GW reduction in nuclear capacity in the Low Nuclear Case, an additional 3,5GW of capacity from other sources is needed, with a greater call on critical minerals for both power generation technologies and grid infrastructure.

- Higher exposure to natural gas and coal market prices: coal and gas prices would be more important for consumer electricity bills, removing a degree of the shelter offered in the NZE.

Nuclear energy is well-placed to support the forecasted hydrogen economy. The existing reactors are an ideal option for large-scale centralized H_2 production. They operate at very high annual capacity factors, enabling a high utilization of the electrolyzer and the production of steady and adjustable streams of low-carbon hydrogen. This means that less hydrogen storage is required to smooth out daily, monthly, and seasonal fluctuations in the supply of hydrogen. A stable, reliable flow of hydrogen is important to industrial users in particular for making optimal use of their production facilities [14]. Besides, there is a wide range of applications where nuclear heat and electricity may play a key role in the decarbonization strategy.

SMRs could also play a role in complementing variable renewables and other low-emission generating technologies to achieve net zero goals by supplying electricity to the grid, producing heat and hydrogen, and desalinating water.

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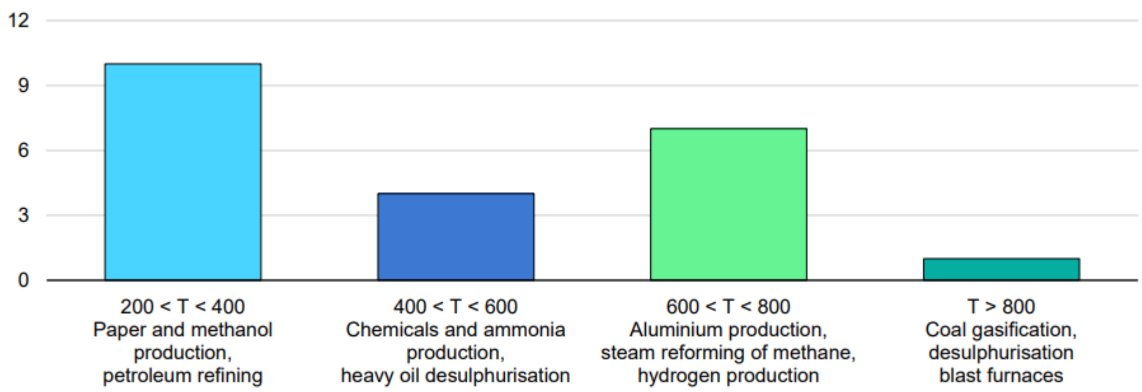

Figure 11 Number of leasing SMRs projects globally by temperature range and targeted used [14]

<u>Nuclear power plant operation vs grid flexibility</u>

Electricity system flexibility- the ability of the system to manage the variability and uncertainty of demand and supply reliably and cost-effectively- is becoming increasingly central to electricity security as the share of variable renewables in generation grows. Flexibility over different timeframes, from minute-to-minute, hour-to-hour and season-to-season, is needed to ensure instantaneous stability of the power system and long-term security of supply. Hour-to-hour flexibility needs in electricity systems worldwide will quadruple on average from 2020 to 2050 in the NZE. The growing share of generation linked to weather conditions means that other generators are called upon to change their output more often and by larger amounts. Changes in the pattern of electricity demand, which varies more within the day as a result of the increasing electrification of road transport, heating in buildings, industrial processes and the expansion of electrolytic hydrogen, also drive-up flexibility needs [14].

Nuclear power continues to contribute to power system flexibility in the NZE. In advanced economies, its share of hour-to-hour flexibility will rise from around 2% today to 5% in 2050. In France, flexibility has been incorporated into reactor designs to allow some plants to ramp up and down their output quickly at short notice so as to operate in a load-following mode to align electricity supply and demand. However, innovation has the potential to make nuclear power more flexible. Advanced technologies, including SMRs, could open up the possibility for nuclear reactors to vary their output of electricity more readily, possibly switching to produce heat or hydrogen alongside electricity. Efforts are being made to inform policymakers and planners about the potential cost benefits of making nuclear power more flexible [14].

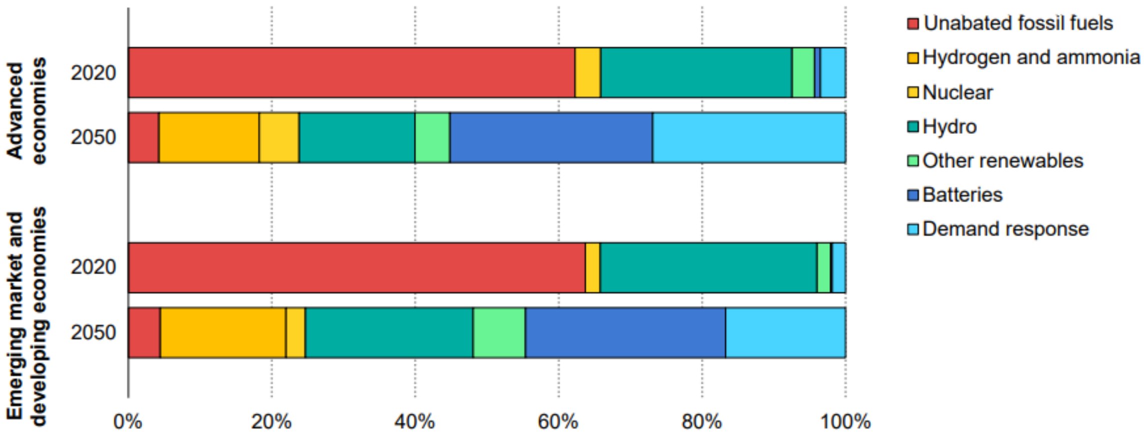

Figure 12 Hour-to-hour power system flexibility by source and regional grouping in the Net Zero Emissions by 2050 Scenario [14]

In existing NPPs, the excess of electricity (in particular, that generated in off-peak hours) could be used for hydrogen production, storage and then re-electrification (electrochemical combustion in a fuel cell (FC)) on demand. Thus, a so-called hydrogen cycle or hydrogen battery could be used for load shifting of nuclear power plants, thereby eliminating the inefficient non-baseload operation; this, in turn could maintain nuclear generation costs at a level that conforms to nominal load.

The effective application of water electrolyzers will include their integration with nuclear power plants, which improve the plant maneuverability. At night off-peak hours, low priced energy of a nuclear power plant could be utilized for water electrolysis, with further accumulation of electrolytic grade gases in the storage system. In the hours of peak electrical load, accumulated gases could be used for electricity production (using FCs or gas turbines) in order to make up for shortfall of the electric power [13].

In the NZE, the fast-growing shares of variable solar PV and wind in the global electricity mix, as well as the progressive electrification of energy end uses, erodes the capacity factors of baseload power generating plants, including nuclear plants, as renewables increasingly drive nuclear power down the merit order. They also increase the need for system flexibility [14].

Flexible hydrogen production could provide a means of exploiting underutilized capacity. In the NZE, the average capacity factor of the global fleet of nuclear power plants falls from 84% in 2030 to 76%

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in 2040 and 77% in 2050, while total installed capacity increases from 512GW in 2030 to 730GW in 2040 and 812GW in 2050. Raising the capacity factor of the global nuclear fleet to 90% and using the additional electricity for electrolysis would theoretically allow for the production of additional low-carbon hydrogen, reaching 6Mt (4% of total low-carbon hydrogen production) in 2030, 19Mt (5,5%) in 2040 and 20Mt (3,9%) in 2050. More hydrogen could be produced using the global fleet of nuclear reactors, but this would mean reducing low-emission electricity output [14].

Due to the expected renewable power's growth worldwide, traditional baseload energy sources, like nuclear energy, will need to operate more flexibly over different timeframes. By operating steadily at full power, while modulating output between electricity and non-electric products, nuclear power plants can achieve high load factors while providing flexibility services at very low cost and respond to market demands for each product (electricity, heat, hydrogen), thus maximizing revenues.

Summary: the perfect timing for investigating nuclear-powered hydrogen is now

According to an IEA Report [8], in the medium term, low-carbon hydrogen offers a solution for reducing emissions of the industrial sector by replacing the hydrogen today produced from fossil fuels and used in oil refineries, fertilizer plants or other industries (chemicals, aeronautics, etc.). It also creates opportunities to reduce emissions in the transport sector (for heavy transport and trains, as a replacement for oil) or gas networks.

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In the long term, developing the production and storage of low-carbon hydrogen can offer an additional system flexibility solution, particularly interesting in view of scenarios with a significant share of renewable energies in the power mix.
Therefore, it is necessary to assess in the coming years the technical and economic feasibility of the different paths of nuclear hydrogen production to be ready to produce significant volumes of low-carbon hydrogen.
Hydrogen is omnipresent but not readily available. If hydrogen is to play a major role in a future energy economy, the whole spectrum of primary energies for its production must be considered.
In many countries, large hydrogen development programs are underway, although nuclear production of hydrogen is a virtually untapped potential. Whereas around 26 countries adopted national hydrogen development strategies or announced their intention to do so, only five countries have projects on nuclear hydrogen production, and even they are in their early stages [15].

5 Assessment of available technologies for nuclear power H_2 generation

Hydrogen can be produced using a variety of energy sources, feedstocks, and technologies. The most common hydrogen production processes are based on adding energy in the form of electricity or heat to water or hydrocarbons. Although other routes such as biological processes (photolysis, dark and photo fermentation), biomass gasification or radiolysis of water have been proposed [16][17], this study focuses on the most viable options for hydrogen generation in terms of coupling with a nuclear power plant.

Figure 13 illustrates 4 possible pathways for nuclear-powered hydrogen cogeneration, namely low-temperature water electrolysis, high-temperature steam electrolysis, thermochemical water splitting and fossil fuel reforming. All these technologies need electricity and/or heat as a driving energy form. Both electricity and heat can be supplied by an NPP without releasing direct GHG emissions. Coupling hydrogen production via these technologies with NPP can also benefit from utilizing already existing infrastructure.

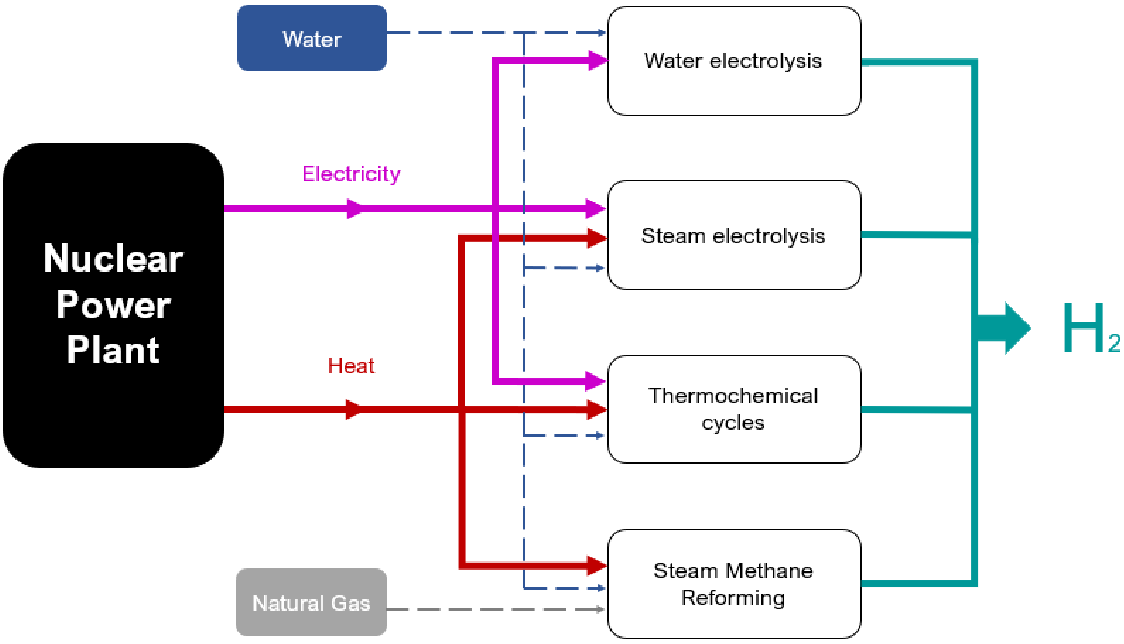

Figure 13 Pathways for hydrogen production from nuclear energy

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Figure 13 mentions two hydrogen production technologies based on the electrolysis of water. Water electrolysis (also called low-temperature electrolysis) uses electricity to decompose liquid water into hydrogen and oxygen. Steam electrolysis (also called high-temperature electrolysis) is an analogous process that operates at higher temperatures and requires a heat supply to convert water to high-temperature steam prior to electrolysis. The next possible pathway for nuclear-powered hydrogen generation is thermochemical water splitting. This technology utilizes high-temperature heat to drive a series of chemical reactions to split water. In the case of hybrid thermochemical cycles, an additional minor electricity supply is required. Finally, hydrogen can also be produced by reforming of fossil fuels using nuclear heat.

The following sections provide an assessment of the above-mentioned technologies for nuclear-powered hydrogen generation.

5.1 Water electrolysis

Electrolysis is a method of producing hydrogen directly from water that has been used for over 100 years. Water electrolysis involves an electrochemical process that splits water molecules into their constituent parts – hydrogen and oxygen. The decomposition of water is driven by electrical energy. The working principle is based on passing an electrical current between two electrodes immersed in an electrolyte. As a result, high purity gaseous hydrogen and oxygen are produced [17].

Electrolysis has many attributes that make it suitable for coupling with nuclear power plants. A hydrogen generation plant based on low-temperature electrolysis (LTE) utilizes demineralized water as a feedstock and electricity as an energy source. There are other auxiliary inputs to the plant, such as cooling water, nitrogen, and instrumentation air supply. All these interfaces can potentially be shared with a nuclear power plant. The outputs of LTE hydrogen production plant (HPP) are hydrogen, oxygen, heat (absorbed by cooling water) and wastewater. Nuclear powered LTE process does not emit CO_2.

Due to electricity being the only driving energy form needed for LTE, any nuclear reactor type is suitable for coupling with low-temperature electrolyzers. Hydrogen plants based on LTE may therefore be powered by existing nuclear power plants as well as new, advanced nuclear reactors. The power supply for LTE process is realized via electric transmission only. The absence of heat input makes LTE the simplest hydrogen production method to integrate at NPP´s site. Unlike high-temperature electrolysis, thermochemical cycles and steam reforming processes, water electrolysis does not require interventions into turbine island or connection of NPP and HPP via steam piping. LTE technology also offers the possibility of partial off-site integration, where the hydrogen production plant is located outside of NPP´s perimeter and connected to the NPP by power lines. This partial off-site integration scenario reduces safety concerns, helps to overcome regulatory limitations and minimizes the need for intervention into NPP´s existing infrastructure.

There are two commercially available LTE technologies, namely Alkaline Electrolysis and Proton Exchange Membrane (PEM) electrolysis. These technologies are introduced below.

5.1.1 Alkaline electrolysis

Alkaline water electrolysis is the most developed electrolysis technology. Alkaline electrolyzers (AEL) have been commercially produced since the 1890s [17]. The first multi-MW plants became operational in the 1920s.

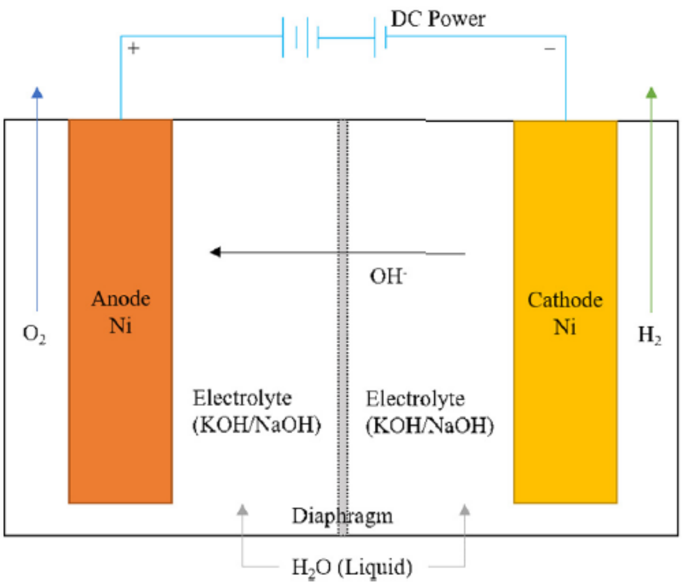

Figure 14 A schematic diagram of an alkaline electrolysis cell [16]

An alkaline electrolysis cell consists of two metallic electrodes, that are submerged in a liquid electrolyte, typically an aqueous solution of KOH or NaOH. Gaseous hydrogen is produced at the cathode, whereas oxygen emerges at the anode. The electrodes, as well as the product gases, are physically separated by a porous ion-conducting diaphragm. The material of electrodes is conventionally based on nickel. Pure nickel, nickel-based metals or nickel-coated steels are commonly used. Platinum can be used as a catalyst, but platinum-free designs that do not contain noble metals exist. [16][17][18][19][20]

Alkaline electrolysis typically operates between 60 and 80 °C. Working pressure ranges from atmospheric to 30 bar. Electrical efficiency of alkaline electrolyzers reaches 63-70 % (based on LHV) [7]. Due to stack degradation, electrical efficiency degrades over time. The efficiency loss of AEL is estimated at around 0,12 % per 1000 operating hours, but it strongly varies depending on the mode

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of operation and other factors [21]. Commercial alkaline electrolyzers have the longest operating lifetime among all electrolyzer technologies, ranging between 60.000 and 90.000 hours [7].

As previously stated, alkaline electrolysis is a mature and currently available technology for commercial-scale applications [7]. Nowadays, numerous multi-MW hydrogen production plants based on AEL are operational. According to Hydrogen Project Database by International Energy Agency [22], the largest green hydrogen project using alkaline electrolyzers up to the present is Ningxia Solar Hydrogen Project (Phase 2) with a 150 MW_{el} electrolyzer system. Bigger hydrogen plants employing alkaline electrolyzers are already under construction [22]. This deployment status corresponds to the technology readiness level of 9, with 9 being the highest on the scale [16][20].

Alkaline electrolysis is the only hydrogen generation method that was ever coupled with a nuclear power plant. A 0,6-MW_{el} hydrogen plant has been producing hydrogen using nuclear power at Oskarshamn nuclear plant in Sweden since 1992 [22].

Alkaline electrolyzers have lower capital costs compared to other electrolyzer technologies due to higher maturity, higher deployment level and use of low-cost materials for electrodes [7].

Despite being used for over a century, there remains potential for improving AEL. The R & D activities are focused on the optimization of materials, especially for electrodes and catalysts, cell design and pressurized operation. Cost reductions are being realized through increasing current density and enhancing efficiency. [18]

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5.1.2 PEM electrolysis

Proton exchange membrane (PEM), also known as polymer electrolyte membrane, water electrolysis is a type of low-temperature electrolysis that was first introduced in the 1960s [17].

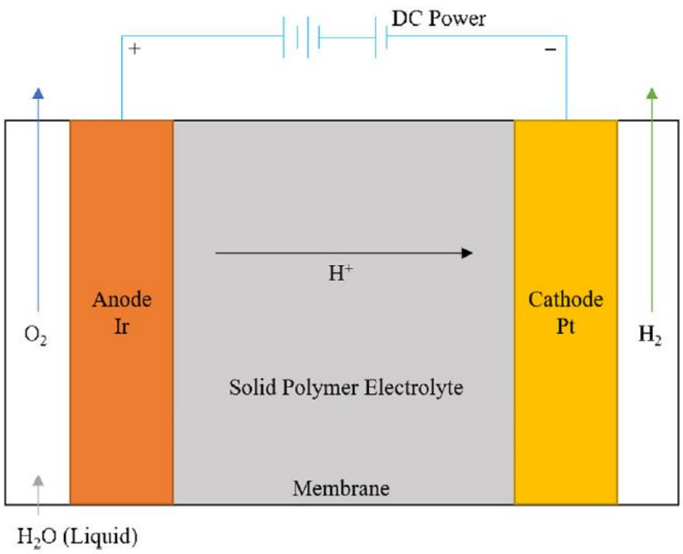

Figure 15 A schematic diagram of a PEM electrolysis cell [16]

PEM electrolysis cell is based on a solid polymer electrolyte, as opposed to a liquid electrolyte used in alkaline electrolysis cells. The electrodes are separated by a proton exchange membrane, typically a perfluorosulfonic acid membrane, that serves as an electrolyte, allowing the transport of ions between electrodes, and separates product gases at the same time. To withstand the highly acidic environment of PEM, noble catalysts like platinum or iridium are typically used for electrodes that come to direct contact with the membrane [16][18][20].

PEM electrolysis operates between 50 and 80 °C. Both LTE technologies yield high-purity gas, but the purity of hydrogen produced by PEM electrolysis is higher [16]. PEM electrolyzers (PEMELs) have slightly lower efficiency than alkaline electrolyzers, i.e. around 56-60 % (based on LHV) [7]. Due to stack degradation, electrical efficiency degrades over time. The efficiency loss of PEMELs is estimated at around 0,19 % per 1000 operating hours, but it strongly varies depending on the mode of operation and other factors [21]. One of the advantages of PEM electrolysis technology is the production of highly compressed hydrogen. The working pressure of PEMEL typically ranges from 30 to 80 bar [7]. This technology also offers flexible operation with a wide operating range, quick response, and short start-up times [18]. These characteristics make PEM electrolyzers more suitable for fluctuating demand than AELs. Another attractive attribute of PEMEL is its smaller plant footprint (space requirements) than that of an alkaline electrolyzer. On the downside, the lifetime of commercial PEM electrolyzers is somewhat shorter compared to alkaline electrolyzers. They provide between 30.000 and 90.000 operating hours. [7]

PEM electrolysis is a proven technology, although less widely deployed than alkaline electrolysis. It is available for commercial applications on multi-MW scale [18]. According to Hydrogen Project Database by International Energy Agency [22], the largest green hydrogen production projects using PEM electrolyzers are Puertollano Green Hydrogen Plant in Spain and Air Liquide's Bécancour Plant in Canada, both operating 20-MW_{el} PEM electrolyzers. Scaling up of PEM electrolysis hydrogen plants is expected in the near future. One example of this trend is a project called REFHYNE, which aims to build a 100MW_{el} PEM electrolyzer at a refinery site in Germany [23]. This deployment status corresponds to a technology readiness level between 7-8 [20].

Although the coupling of hydrogen production by PEM technology to a nuclear power plant has not yet been demonstrated, it is experiencing growing attention as several pilot projects have been announced. Three NPPs located in the US (Davis-Besse NPP, Palo Verde NPP and Nine Mile Point NPP) are expected to start producing hydrogen via PEM electrolysis within the next few years (see Annex 11.1) [22].

PEM electrolyzers currently have higher capital costs than alkaline technology due to expensive electrode and membrane materials and lower deployment level [16][7].

The developmental activities are focused especially on bringing down costs by replacing noble catalysts and optimizing polymer membrane materials. Technology improvements are expected to increase the lifetime of PEMEL and the operating pressure of the system as well. [18]

5.2 Steam electrolysis

Steam electrolysis is a promising pathway for hydrogen production by nuclear electricity and heat. Unlike LTE, which operates near ambient temperature, high-temperature electrolysis (HTE) employs higher temperatures (650 – 1000 °C) to split water. In the HTE process, the first step is the conversion of water to high-temperature steam by consuming heat. Steam is subsequently supplied to an electrolysis cell where it is dissociated to hydrogen and oxygen by using electricity.

HTE enables reaching higher electrical efficiencies than LTE, because part of the energy required for the decomposition of water is supplied in the form of heat. Furthermore, electrolysis reaction consumes less energy at higher temperatures. This results in specific electricity consumption decrease by approximately one-third compared to LTE [12][18]. The heat input also improves economic viability since thermal energy is generally cheaper than electricity. These characteristics make steam electrolysis an attractive candidate for coupling with NPPs.

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A hydrogen generation plant based on HTE utilizes demineralized water as a feedstock and requires electricity and heat as energy sources. Another auxiliary input is sweep gas (usually air), that flows produced oxygen out of the system. All these interfaces can potentially be shared with a nuclear power plant. The outputs of a HTE hydrogen production plant are hydrogen, oxygen, and wastewater. Heat recovered from exhaust gases is used to preheat the input media. Nuclear powered HTE process produces low-carbon hydrogen.

Medium- and high-temperature nuclear reactors are more suitable for coupling with HTE due to the requirement of high-temperature steam input. Nonetheless, the use of lower temperatures is also possible. A preliminary analysis undertaken by EDF [24] indicates that supplying HTE process with low-temperature heat (c. 150- 200°C) from pressurized water reactors is technically feasible and provides benefits over water electrolysis.

The integration of HTE based hydrogen plant to NPP´s site is more complex compared to LTE technology because the HTE process requires both heat and a power source. In addition to power lines, a heat connection between HPP and NPP via steam pipes is necessary. This makes potential partial off-site integration of an HTE hydrogen plant more complicated in comparison to LTE. Furthermore, an increase in the distance between the H_2 plant and NPP leads to a higher amount of heat loss. Another barrier to implementation is the low technology readiness level of HTE. This advanced electrolysis method is still in a developmental phase and has not yet been deployed at a commercial scale [7].

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High-temperature electrolysis can be achieved through solid oxide electrolyzer cells (SOEC). This technology is described in the following section.

5.2.1 SOEC

High-temperature steam electrolysis via solid oxide electrolyzer cells is the least mature electrolysis technology presented. SOEC is an emerging technology potentially offering high-efficiency operation, but it has yet to be demonstrated at a multi-MW scale.

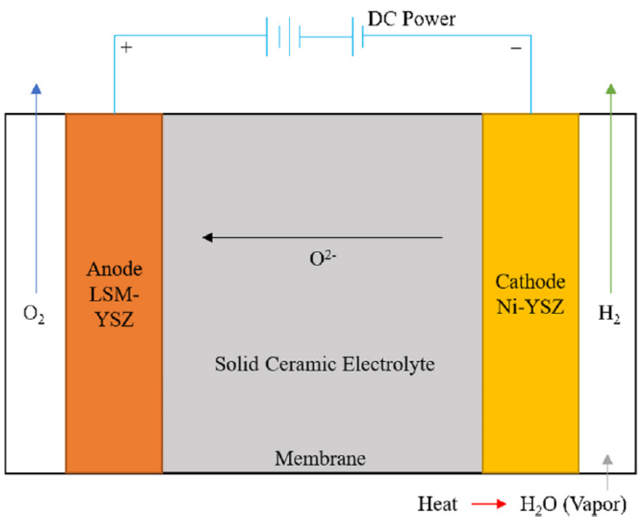

Figure 16 A schematic diagram of a Solid Oxide Electrolysis Cell [16]

Solid oxide electrolyzer cells operate in reverse mode to a solid oxide fuel cell (SOFC). The electrolyzer cell is based on a solid ceramic membrane, typically yttria-stabilized zirconia (YSZ) [12][18]. This oxygen-conducting ceramic material serves as an electrolyte and separates the electrodes as well as the product gases. Among the most commonly used materials for cathode and anode are Nickel-

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zirconia (Ni-YSZ) cermet and strontium-doped lanthanum manganite (LSM), possibly in combination with YSZ, respectively [16][18].

To perform steam electrolysis, SOECs operate at high temperatures between 700 and 1000 °C. As a consequence, cold start times are much longer (typically 12 hours) compared to LTE technologies (1 hour for AEL, 30 seconds for PEMEL) [21]. Solid oxide electrolyzer cells work at atmospheric pressure. Since part of the required energy input is supplied in the form of heat, SOECs achieve the highest electrical efficiency of all the above-mentioned electrolyzer types. It ranges between 74-81 % (based on LHV) [7]. Due to stack degradation, electrical efficiency degrades over time. The efficiency loss of SOECs is estimated at around 2 % per 1000 operating hours, but it strongly varies depending on the mode of operation and other factors [21]. The operating lifetime of current systems is estimated between 10.000 and 30.000 hours [7]. SOECs produce pure hydrogen, although the purity is lower compared to LTE methods [16].

Unlike AEL or PEMEL, SOEC technology offers a unique possibility to be operated in reverse mode as a fuel cell. With the ability to convert electricity to hydrogen and hydrogen back to electricity, SOECs could provide balancing services to the grid. SOEC electrolyzers can also perform co-electrolysis of steam and carbon dioxide. This process produces syngas which can be converted into a range of synthetic fuels.

Solid oxide electrolyzer cells are currently in developmental phase. As the SOEC technology still needs to be demonstrated at a multi-MW level, it has not yet been widely commercialized. According to Hydrogen Project Database by International Energy Agency [22], the largest green hydrogen project using SOEC electrolyzers is Hydrogen Lab Leuna (phase 1) with a 1 MW_{el} SOEC system. Bigger high-temperature electrolyzer systems are already under construction. For example, the MULTIPLHY project [25] aims to demonstrate green hydrogen production via HTE at a multi-MW level. The SOEC system with the nominal power input of 2,6 MW_{el} is expected to become operational by the end of 2024. This deployment status corresponds to the technology readiness level between 5 and 7 [20].

ECCN: N

AL: N

Initiatives are currently underway to demonstrate nuclear-powered HTE. Prairie Island NPP (USA) is to pilot hydrogen production using steam and electricity from nuclear reactors. The SOEC electrolyzer system is scheduled to become operational in 2024 [26].

Since SOEC technology has not yet been widely deployed and commercialized, it is characterized by the highest costs of all electrolyzer technologies (AEL, PEMEL) [7].

The developmental efforts are focused on an industrial scale-up. To achieve this, capital cost reductions and an increase in SOEC´s lifetime are needed. Research is focused on optimizing the materials of solid electrolytes and electrodes. Other activities are devoted to issues concerning high-temperature operation or improvements in manufacturing technology, e.g., thin electrolyte film production. [18][20]

5.3 Thermochemical processes

Thermochemical processes present another method of producing hydrogen directly from water. Unlike water electrolysis, which uses electricity, this method employs only thermal energy to split water into hydrogen and oxygen. Direct thermal decomposition of pure water requires temperatures around 2000 °C for partial dissociation and over 4000 °C for complete dissociation. These temperatures are extremely high to be supplied by most heat sources and create various engineering challenges, especially in terms of material design. By incorporating multiple-step reactions, the required temperature can be reduced. Thermochemical cycles accomplish water decomposition by

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using heat and a set of chemical reactions at temperatures below 1000 °C. This thermal water-splitting process works in a closed loop, that consumes only water, while all the other chemical compounds are fully recycled and reused each cycle. The thermal efficiency of thermochemical cycles is projected in the range of 25-55 % [17]. As heat is generally less expensive than electricity, hydrogen production costs are expected to be reduced compared to electrolysis [12]. The disadvantages of this water-splitting concept include long response times, large plant footprint, lower purity of produced hydrogen and the use of hazardous chemicals [16].

In addition to pure thermochemical cycles driven solely by thermal energy, hybrid thermochemical processes that incorporate electrochemical reactions have been developed. In hybrid cycles, electricity is supplied to one step of the reaction chain, while heat remains the major energy input.

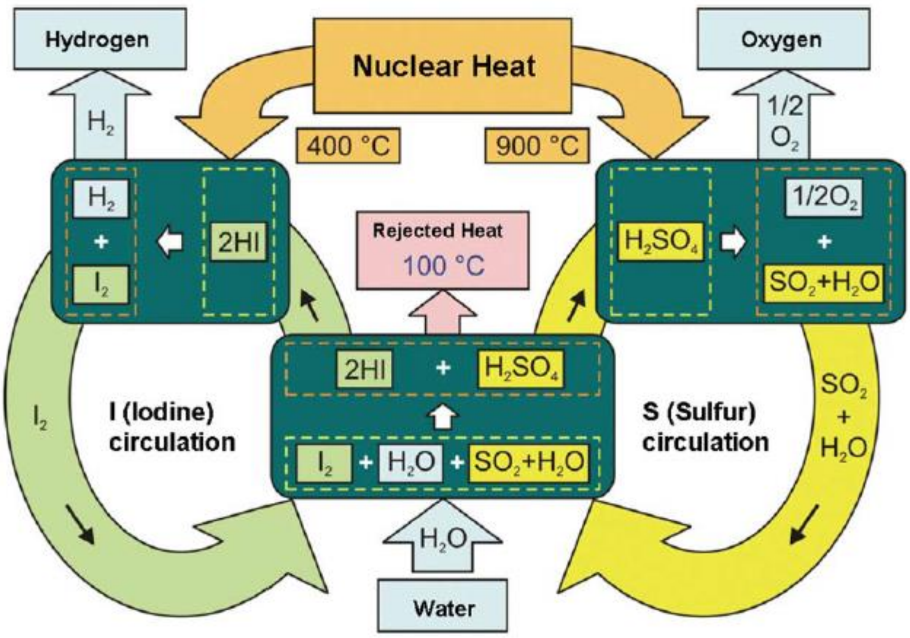

Figure 17 A schematic diagram of the Sulphur-Iodine thermochemical cycle [12]

A hydrogen generation plant based on thermochemical water-splitting utilizes demineralized water as a feedstock and heat as a major energy source. In the case of hybrid thermochemical cycles, electricity is used on top of that as a minor energy input. All these interfaces can potentially be shared with NPP. Nuclear-powered thermochemical processes offer CO_2 emission-free hydrogen generation.

Low-temperature reactors, like LWR, are unable to satisfy the high-temperature (600 – 1 000 °C) heat input demand without an additional heat source. To meet the thermal energy requirements, advanced medium- or high-temperature nuclear reactors are necessary. The integration of a hydrogen plant based on thermochemical cycles to an NPP´s site is more challenging compared to electrolysis technologies, as the process requires heat as a major energy source. Consequently, a heat connection via steam pipes between HPP and NPP is required. This contributes to the complexity of potential partial off-site integration of the hydrogen plant. In addition, the longer the distance between the H_2 plant and NPP, the greater the heat loss.

The low technology readiness level, which ranges between 3 to 4 [16], poses another obstacle to implementation. Thermochemical cycles are still in an early stage of development. The feasibility of the most developed thermochemical cycles was demonstrated only at a laboratory scale [27]. Further R & D activities are needed to scale up. The main challenges that prevent this technology from

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commercialization are the complexity of multiple steps chemical cycles and material problems related to the high-temperature operation and exposure to certain chemicals [27].

Research on thermochemical cycles began in the 1960s. Since then, over 100 possible thermochemical cycles have been identified [16]. Here, we focus on the most feasible candidates in terms of coupling with nuclear power plants according to a number of sources [5][16][28]. The cycles of interest to nuclear technology operate at suitable temperature levels, that match the heat capability of nuclear reactors. The thermochemical cycles being considered are Sulphur-Iodine cycle, hybrid Sulphur cycle and Copper Chlorine cycle.

5.3.1 Sulphur-Iodine cycle

Sulphur-Iodine (S-I) cycle is considered the most promising thermochemical cycle [16]. Thermal decomposition of water in the S-I cycle is accomplished in 3 main process steps, and the highest required temperature is ca. 900 °C. This temperature level is attainable from technical as well as economic perspective [28]. The S-I cycle can theoretically reach a thermal efficiency of 51 %, which makes this concept one of the most effective thermochemical cycles [12]. Some conceptual studies reported efficiency at this level, but further developmental activities are needed to validate these numbers on bigger scale units [27][28].

The concept of the S-I cycle was proven by laboratory-scale experiments and has the highest level of development among thermochemical cycles [16][27]. The major issues, that prevent the S-I cycle from commercial deployment, are high-temperature operation and corrosivity of used chemical substances [27].

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5.3.2 Hybrid Sulphur cycle

Another hydrogen generation concept being investigated for coupling with NPP is a modification of the Sulphur-Iodine cycle, a so-called Hybrid Sulphur (HyS) cycle. This cycle involves only two reaction steps, which minimizes the number of chemicals and makes the plant less complex. The high-temperature step performing the decomposition of sulphuric acid is followed by low-temperature electrolytic step. The maximum required temperature of heat addition is around 900 °C [12]. This method can potentially reach efficiencies higher than 40 % [27].

HyS cycle is among the most developed hybrid thermochemical water-splitting technologies, but still far from commercial deployment. It is currently studied at a laboratory scale [27]. The research activities are focused on developing SO_2 electrolysis cells, as the degradation of the cell and material selection for electrodes and catalysts remain a challenge.

5.3.3 Copper-chlorine hybrid cycle

Copper-chlorine (Cu-Cl) hybrid cycle is an alternative thermochemical process that operates at moderate temperatures. Lower operating temperatures (ca. 500 °C) have many advantages, including reduced material and maintenance costs or a higher number of possible heat sources [16]. Opposed to other thermochemical cycles, whose temperature requirements can only be satisfied by high-temperature nuclear reactors, the Cu-Cl hybrid cycle can be coupled with medium-temperature reactors as well. This process has different configurations employing 3, 4 or 5 steps. The efficiency of Cu-Cl hybrid thermochemical cycle is estimated to reach approximately 40 %. The electric demand corresponds to 39 % of the total energy input [12][28].

Although being a promising candidate for nuclear hydrogen production, Cu-Cl hybrid thermochemical cycles are less mature than other processes mentioned above. The viability of all Cu-Cl hybrid cycle

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steps was demonstrated at a laboratory scale [12][16]. Research activities are currently focused mainly on improving the materials for electrolysis cells. [27]

5.4 Reforming fossil fuels

A major part of current hydrogen production is based on the reforming of fossil fuels. This method extracts hydrogen from a hydrocarbon fuel, mostly natural gas or coal, by employing high temperatures. Hydrocarbon reforming technologies are mature and widely commercially available. The most widespread technologies include steam methane reforming and partial oxidation (POX). Steam reforming is used for the decomposition of light hydrocarbons, such as natural gas, while POX produces hydrogen from coal or heavy fuel oil.

In these processes, hydrocarbons react with steam (steam methane reforming) or oxygen (POX) to produce syngas, a mixture of H_2 and CO. In the following step, CO reacts with water to produce more H_2 and CO_2. The thermal energy required for these reactions to occur is supplemented by partial combustion of the feedstock. Reforming of fossil fuels is therefore associated with significant GHG emissions. Although carbon emissions can be reduced by CCUS technologies, less than 1 % of current hydrogen production comes from plants equipped with carbon capture system [7].

Natural gas is currently the primary feedstock for global hydrogen production, followed by coal [7]. By providing thermal energy for reforming reactions with nuclear power, fossil fuel consumption can be reduced. According to a Technical study by Idaho National Laboratory, integration of nuclear heat into the steam methane reforming process can decrease natural gas consumption by 15 % and reduce CO_2 emissions by the same percentage (if carbon capture is not considered) [29].

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The issues associated with coupling this technology to a nuclear power plant are similar to those of thermochemical cycles. The high-temperature (700 – 1 000 °C) heat input cannot be satisfied by low-temperature reactors (if no extra heat source is desirable). Advanced medium or high-temperature nuclear reactors are suitable energy sources to fulfill the heat demands. Implementing steam methane reforming or POX hydrogen production technology to an NPP´s site is more difficult in contrast to LTE, mainly due to the requirement of heat as a main energy source, which necessitates heat connection via steam pipes between HPP and NPP. This adds to the complexity of potential partial off-site integration, as longer distance between a heat source and a hydrogen production facility is related to greater heat loss.

Nuclear-assisted steam reforming has not yet been deployed at a commercial NPP, but the concept was demonstrated in pilot plants in Germany and Japan [12]. Although nuclear-powered fossil fuel reforming is not GHG emission-free, it is considered an important near-term option for the energy transition due to attractive features such as high thermal efficiencies (around 70 % for POX and 80 % for steam methane reforming based on LHV) and high level of maturity and commercialization [12]. According to IEA´s report [7], fossil fuel reforming is expected to remain the most cost-competitive hydrogen production pathway until 2030.

5.4.1 Summary and comparison

The previous sections explored possible pathways for nuclear-powered hydrogen generation. The main advantages and disadvantages of each technology are presented in Figure 18. As a result of the examination, only water and steam electrolysis technologies will be considered for further analysis. The hydrogen generation process via reforming of fossil fuels releases CO2 emissions and therefore does not fall under the concept of the NPHyCo study that focuses on low-carbon hydrogen cogeneration. Thermochemical cycles are excluded from further investigation due to low maturity,

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resulting in a lack of relevant operational data from large-scale units. Thermochemical water-splitting technologies are in an early developmental stage and are not likely to become widely commercially available within the next ten years.

Water Electrolysis	Steam Electrolysis	Thermochemical cycles	Steam Methane Reforming
CO_2 emissions-free process, when powered by nuclear energy			➢ Mature ➢ Commercially available ➢ Economically efficient nowadays
➢ Mature technology ➢ Commercially available ➢ High purity hydrogen ➢ Modular ➢ Flexible operation ➢ Can be powered by all nuclear reactor types	➢ Higher efficiency than LTE ➢ Potentially lower hydrogen production costs than LTE ➢ Modular ➢ SOECs can operate in reverse mode to produce electricity from hydrogen	➢ Potential for bulky hydrogen production at low cost ➢ High thermal efficiency possible	
➢ Higher hydrogen production costs than SMR	➢ Not commercial ➢ In developmental phase (TRL 5-7) ➢ Higher CAPEX than LTE ➢ Slow response time	➢ Not commercial ➢ In early developmental phase (TRL 3-4) ➢ Much developmental activites still needed ➢ High capital costs ➢ Need for medium- or high-temperature nuclear reactors ➢ Slow response time	Produces CO_2 emissions ➢ Requires fossil fuel supply ➢ Lower purity of hydrogen ➢ Subjected to Natural Gas prices ➢ Need for medium- or high-temperature nuclear reactors ➢ Slow response time

Figure 18 Advantages and disadvantages of choosing hydrogen generation technologies coupled to NPP

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As stated above, the technical and economic feasibility assessment conducted in the remainder of the NPHyCo research project will be primarily concerned with nuclear-powered hydrogen production facilities based on electrolysis. Low-temperature electrolyzers, represented by alkaline and PEM technology, as well as high-temperature electrolyzers, represented by SOEC technology, will be considered. A comparison of key parameters of electrolysis technologies is provided in Table 1. Since the performance characteristics vary among different producers and depend on operating mode, a representative range is given in some cases.

Parameter	Unit	Water electrolysis		Steam electrolysis
		Alkaline	PEM	SOEC
Electrical efficiency (LHV)	%	63-70	56-60	74-81
Operating temperature	°C	60-80	50-80	650-1 000
Operating pressure	bar	1-30	30-80	1
Lifetime/ Operating hours	Thous. hrs	60-90	30-90	10-30
Efficiency degradation rate	%/1000 hrs	0,12	0,19	1,9
Cold start up time	sec	3 600	30	12 (hrs)
Footprint/Space requirements	m^2 /MW	100	50	150
Technology readiness level	scale 1-9	9	7-8	5-7

Table 1 Overview of key parameters of electrolyzers technologies. Data sources: [7][21][20]

As the table indicates, alkaline electrolyzers are the most mature and most durable hydrogen generation systems nowadays. PEM electrolyzers, on the other hand, provide several benefits over AELs, such as flexible operation and the ability to produce highly compressed hydrogen. PEMELs are also the most compact in size. It is expected that these advantages will result in a gradual shift from alkaline to PEM electrolysis technology during the next 10 years, especially due to PEM systems being

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more suitable for operation with renewable energy sources [18]. High-temperature electrolysis via SOECs is a promising technology, but it has not yet been commercialized. The major advantage of this hydrogen generation method is its high electrical efficiency. The key challenge to be overcome before an industrial scale-up of SOEC is the low stack lifetime caused by degradation of materials under high operating temperatures.

6 Assessment of nuclear power reactor suitability and advantageous factors

Nuclear power has long been recognized as a reliable and efficient source of electricity, and it has the potential to play a significant role in hydrogen production. In recent years with the growing share of renewable energy sources, there has been growing interest in using nuclear power for hydrogen cogeneration, which involves the simultaneous production of electricity and hydrogen using nuclear energy.

In the following sections, the assessment of the existing nuclear power plants and the potential advanced reactor designs for nuclear-powered hydrogen production is performed. This will include an overview of the different types of nuclear power plants and their specific characteristics and an introduction to the current state of research and development in this area.

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6.1 Assessment of existing NPP

The share of nuclear energy in the global electricity market has been slowly decreasing over the last two decades. Installed nuclear power capacity has not changed considerably in recent years, except for Asia, where 70 new reactors have been brought online since 2005 [30]. Nuclear energy has the potential to play a more significant role in reducing carbon emissions; however, there are several challenges with current technologies which prevent large-scale extension. These include risks associated with the operation of nuclear power plants, environmental concerns, financial and regulatory obstacles, unresolved issues surrounding nuclear waste disposal, potential risks of nuclear weapons proliferation, and negative public perception [31].

6.1.1 Generation of nuclear power plants

Nuclear reactors are categorized into generations: I, II, III, III+, and IV. These generations are defined based on the key features and characteristics of the reactor designs, and they indicate the main differences between the various types of reactors [32]. Figure # illustrates the development of nuclear power plant generations in time.

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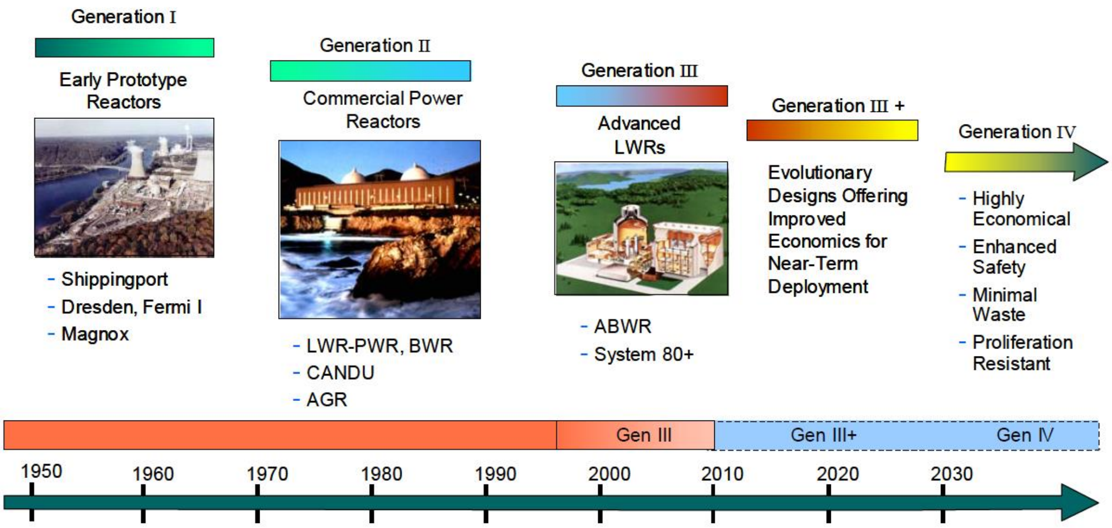

Figure 19 Generation of Nuclear Power Plants [43]

The first generation of nuclear reactors were early prototypes developed in the 1950s and 1960s to demonstrate the feasibility of nuclear power generation. These reactors typically operated at low power levels and are now shut down.

The second generation refers to a group of commercial nuclear reactors designed to be economical, reliable, utilize active safety features, and have an operational lifetime of 40 years. They began operation in the late 1960s and make up most of the world's pressurized and boiling water reactors. In many cases, these reactors are at the end of their original operational lifetime and receive permits from regulators to continue operations. Typical examples of Generation II reactors are the Pressurized Water Reactors (PWR/VVER), CANada Deuterium Uranium reactors (CANDU), Boiling Water Reactors (BWR), and Advanced Gas-cooled Reactors (AGR).

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Generation III nuclear reactors are an evolution of Generation II reactors, incorporating advanced design improvements in fuel technology, thermal efficiency, standardization, modular construction, and employ passive safety systems. They are aimed for safer operation and have longer operational life, typically 60 years or more. Relatively few Generation III reactors have been built with the first entering operation in 1996. Generation III+ designs are the next evolutionary step, which are commercially available today. These reactors offer significant improvements in many areas like safety and are expected the achieve higher fuel burnup. Main examples of Generation III+ designs are: VVER-1200, ACR-1000, AP1000, EPR, ESBWR and APR-1400.

Generation IV reactors are six advanced nuclear reactor concepts under development and will be introduced in more detail in Section Chapter6.2

6.1.2 Nuclear power plants currently in operation

As of February 2023, 180 nuclear power plants were in operation in Europe, with a total electrical capacity of 152 GW, and eight power reactors were under construction. As mentioned in the previous sections, several types of nuclear power plants have been deployed in the last decades; however, in Europe, power reactors in operation are generally categorized as Pressurized Water Reactors (PWR) and Boiling Water Reactors (BWR). (There are Advanced Gas-cooled Reactors (AGR) operating in the UK and 2 CANDU reactors in Romania.) [33], [34]

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6.1.2.1 Pressurized Water Reactors

The PWR utilize Uranium dioxide (UO_2) fuel with lightly enriched uranium (around ~4% ^{235}U). The fuel pellets are placed in zircaloy tubes and submerged in light water, which serves as the moderator and coolant. The reactor operates around 155 bar of pressure at which water boils at 344 °C. The water is heated from 275 to 315 °C in the primary circuit and always stays liquid. The heat exchanger transfers nuclear heat from the primary circuit to the secondary circuit, where the generated steam usually has a temperature of 275 °C at 60 bar. The generated steam is fed to the turbines to generate electricity, then passes through the condenser, where it cools down, condenses to a liquid form, and is pumped back into the steam generator. [35],[36]

6.1.2.2 Boiling Water Reactors

There are many similarities between the BWR and PWR designs as they use similar uranium fuel and water as both moderator and coolant; however, it differs from the PWR as there is no distinct primary and secondary circuit. The subcooled water is preheated, and saturated steam is generated in the primary circuit. The reactor is designed to have a stable boiling process in the reactor core. The typical pressure in a BWR is usually around 75 bar, where water boils at 285 °C. The steam is then directed to the turbines, cooled in a condenser, converted to liquid water, and returned to the reactor core. [35],[36]

6.1.3 Flexibilities of current Nuclear Power Plants

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In the last decade, the energy sector is undergoing a major transformation due to the rising share of Variable Renewable Electricity sources (VRE). Today, flexibility is a key characteristic of modern power plants and is defined as the ability to handle supply and demand variability in a reliable and cost-effective way. [37]

Nuclear Power Plants are characterized by high capital cost and low variable cost and are most economical when operated at the maximum rated capacities rather than in load-following operation. Nevertheless, Nuclear Power Plants are capable of flexible operation, which includes adjusting their power output over time and offering frequency regulation and operating reserves. For example, operators in France and Germany have extensive experience with flexible operation as they operate in load-following mode with large daily power variations and participate in frequency control [38], [39], [40]. European Utilities Requirements (EUR) covers a wider range of design requirements for efficient and safe operation, including plant layout, materials, systems, and safety assessment methods. The EUR also requires modern reactors to have significant manoeuvrability, especially to be able to operate in load-following mode. [41]

The coupling between a hydrogen production facility and the Nuclear Power Plant could significantly increase the system's flexibility by producing hydrogen during low-demanding periods. This would allow for maintaining the reactor's nominal power, resulting in high fuel burnup and lower maintenance costs and a more cost-efficient operation. However, power plants in operation were not designed to be coupled with a hydrogen production facility; consequently, several challenges can be expected regarding regulatory barriers, safety, and other technical subjects. With the existing Nuclear Power Plants, Low-Temperature Electrolysis is one of the most promising hydrogen production technologies, as the electric transmission is sufficient to be the only connection between the two facilities. (Auxiliary resources can still be an option to be shared to reduce cost, but it is not a necessity.) In this way, the hydrogen plant could be sited more freely, even outside of the safety zone of the power plant, which could help to overcome regulatory or safety limitations [36]. In an INL report issued in 2019 [42], a techno-economic analysis is done for the viability of retrofitting existing PWRs with High-Temperature Steam Electrolysis (HTSE). Such a system would require a deeper integration, as heat needed to be transferred to the hydrogen production plant, resulting in a more challenging coupling with significantly reduced hydrogen production costs.

6.2 Assessment of new advanced reactors

New generations of nuclear power plants are being developed to address the challenges and limitations of current nuclear reactor technologies. These reactors are designed to be more efficient, expand the current nuclear fuel reserves, and to have increased safety requirements than existing nuclear power plants. In many cases, higher operation temperatures are planned with improved efficiency and with the direct utilization of the process heat for various applications, including water desalination, providing industrial steam, or hydrogen production. The coupling is planned during the design phase and will be realized as a closely connected system with the reactor and a thermochemical water-splitting process or a high-temperature steam electrolyzer.

The close coupling, the increased safety requirements, the limited experience with the new technologies, and the high operating temperatures present extensive logistical, regulatory and development challenges. Therefore, there is significant international interest in developing advanced nuclear reactors to address these many challenges.

6.2.1 Generation IV International Forum and its development

The Generation IV International Forum (GIF) is an international organization that was established in 2000 to promote the development and deployment of advanced nuclear reactor technologies, also known as Generation IV (Gen IV) reactors [43], [44]. In 2002, GIF selected six concepts as Generation IV technologies aiming for safer, sustainable, more economical, and proliferation-resistant nuclear reactors:

- Very-High-Temperature Reactor (VHTR);
- Gas-cooled Fast Reactor (GFR);
- SuperCritical-Water-cooled Reactor (SCWR);
- Lead-cooled Fast Reactor (LFR);
- Molten Salt Reactor (MSR);
- Sodium-cooled Fast Reactor (SFR).

Each of these reactor types has its specific characteristics and operational requirements, resulting in a different possible integration with a hydrogen production facility.

6.2.1.1 Very-High-Temperature Reactor

Very High-Temperature Reactor or VHTR is a graphite-moderated, helium-cooled reactor with a thermal neutron spectrum, which can supply nuclear heat and electricity over a range of core outlet temperatures between 700 and 950 °C, with the possibility of reaching 1 000 °C in the future. The high-temperature capabilities allow for more efficient energy conversion and electricity generation and are considered for hydrogen production through steam reforming or the S-I process [45]. The VHTR is derived from the previous experiences of High-Temperature Gas-cooled Reactor (HTGR) plants, such as Dragon, Peach Bottom, AVR, THTR, and Fort St Vrain, and is being further developed in concepts like the GT-MHR and Pebble Bed Modular Reactor (PBMR) [44] Ongoing projects like the High Temperature Engineering Test Reactor (HTTR) [46] in Japan and the HTR-10 in China will provide support for the development of this reactor technology.

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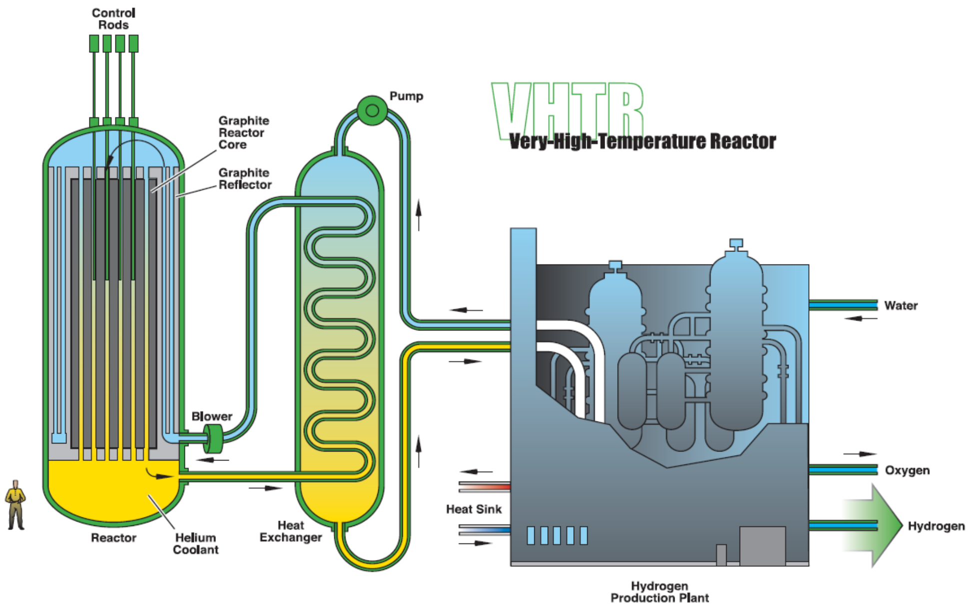

Figure 20 The Very-High Temperature Reactor concept [43]

In 2022, the Japan Atomic Energy Agency (JAEA), and Mitsubishi Heavy Industries, Ltd. (MHI) began the Hydrogen Production Demonstration Project Utilizing Very High-Temperature program to produce hydrogen using the High-Temperature Engineering Test Reactor (HTTR). The goal of this program is to demonstrate the feasibility of using high-temperature heat from a HTTR, through an intermediate heat exchanger, for thermochemical hydrogen production (S-I cycle).[47]

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Prototype pebble bed reactor HTR-10, with 10 MW_{th} power, was constructed and operated in full power condition at Tsinghua University in China in 2003. Two HTR-PM reactors, scaled-up versions of the HTR-10 with 250 MW_{th} power, were installed and achieved first criticality in 2021 and full power in December 2022 [48],[34]. Furthermore, a successful laboratory-scale demonstration of the Sulfur-Iodine process was performed, at the Institute of Nuclear and New Energy Technology (INET) at the Tsinghua University of China. The INET plans to proceed to a pilot-scale stage to couple the HTR-10 to a hydrogen production plant.[49]

6.2.1.2 Gas-cooled Fast Reactor

The GFR system is a high-temperature helium-cooled fast-neutron-spectrum reactor [50], designed to have a high breeding ratio and to minimalize nuclear waste through transmutation. The reference design concept has 2400 MW_{th} power with an inlet coolant temperature of 480 °C and an outlet temperature of 850 °C. The reactor core has high flux levels, which translates to high power densities, and is cooled by helium as it has chemical compatibility with structural materials, and its negligible absorption allows a harder neutron spectrum.

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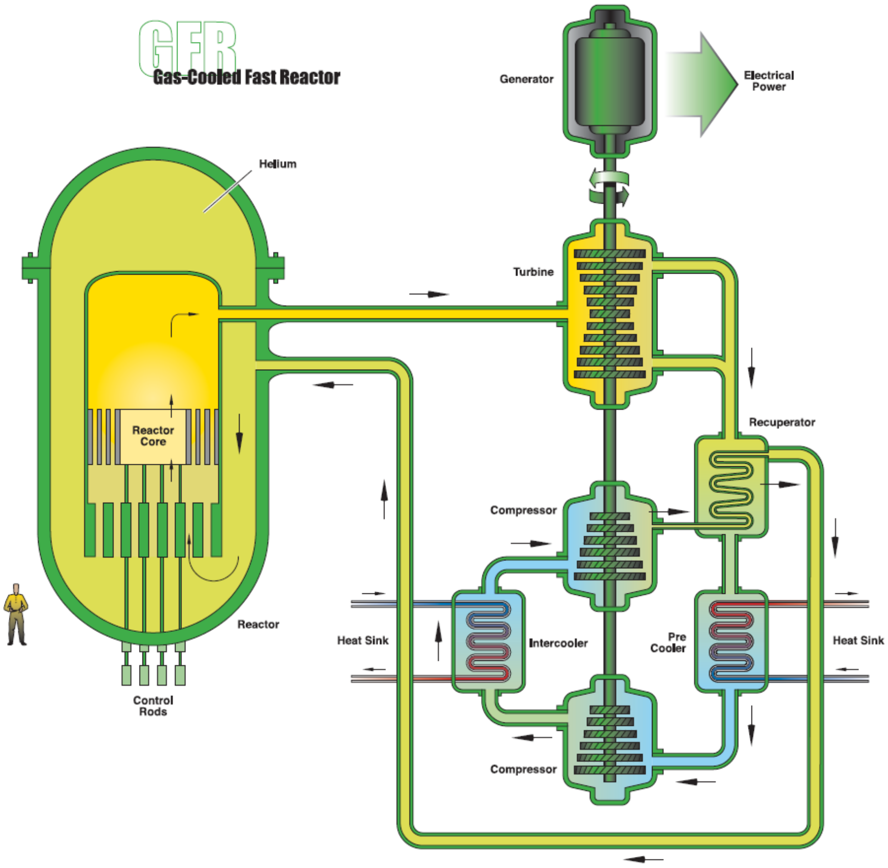

Figure 21 The Gas-cooled Fast Reactor concept [43]

As no GFR reactor has ever been built, the ALLEGRO is designed to be the first demonstrator of this technology. Initially, the ALLEGRO reactor was developed by the French Alternative Energies and Atomic Energy Commission (CEA) until 2009, then the V4G4 Centre of Excellence, which is a consortium of four countries (the Czech Republic, Hungary, Poland and the Slovak Republic), continued the preparation. It will be an experimental reactor with around 80 MW_{th} power to test the viability of the specific GFR technologies. [51],[52]

The GFR concept has many aspects similar to the VHTR, as both reactors use helium as a coolant and aim for high outlet temperatures to maximize thermal efficiency. The high temperatures would allow coupling the reactor with a hydrogen production facility through an intermediate heat exchanger (IHX).

6.2.1.3 Lead-cooled Fast Reactor

A Lead-cooled fast reactor (LFR) is an advanced nuclear reactor that uses liquid lead or lead-bismuth eutectic (LBE) as a coolant. The high thermal conductivity and high boiling point of lead allow the LFR to operate at higher temperatures (~600 °C), resulting in improved electricity generation efficiency. Furthermore, LFRs have the potential to close the nuclear fuel cycle, which also makes them an attractive option for long-term, sustainable nuclear energy generation.[53]

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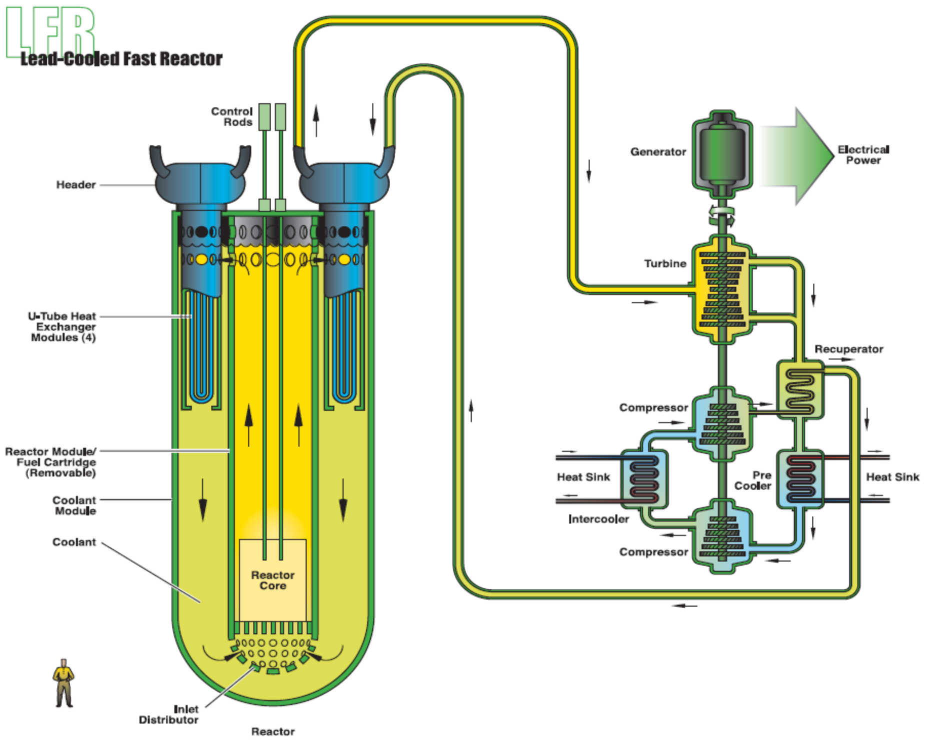

Figure 22 The Lead-cooled Fast Reactor concept [43]

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The early development of LFR technology was primarily performed by Soviet and Russian scientists and industries throughout the 1950s to design and construct nuclear reactors for submarine propulsion. Since then, a series of nuclear-powered submarines and land-based prototypes have been constructed and operated, resulting in around 80 reactor years of operation experience from these facilities. However, the LFR technology is still in the early stage of development, and there are several challenges associated with material compatibility with the lead coolant, corrosion of the structural materials, prevention of coolant freezing and LFR-specific modelling methodologies. [54]

Several projects are currently conducted in support of the LFR technology: MYRRHA in Belgium, BREST in the Russian Federation, URANUS in Korea, CLEAR in China and ALFRED in Europe [54]. Wang et al, (2015) investigate in [55] the preliminary conceptual design and the feasibility of the coupling of the China LEAd-based Reactor (CLEAR) concept with Solid Oxide Electrolysis Cells (SOEC) for hydrogen production.

6.2.1.4 Molten Salt Reactor

A molten salt reactor (MSR) is a type of nuclear reactor in which fissile material is dissolved in the molten fluoride salt, or the primary coolant is a liquid salt mixture. Early MSR development was performed in the United States between 1950 and 1976; since then, international interest has been raised with the active participation of the European Union, France, Japan, Russia, USA, China and India. Current development and needs in MSR technology are well summarized in [56] and [57]

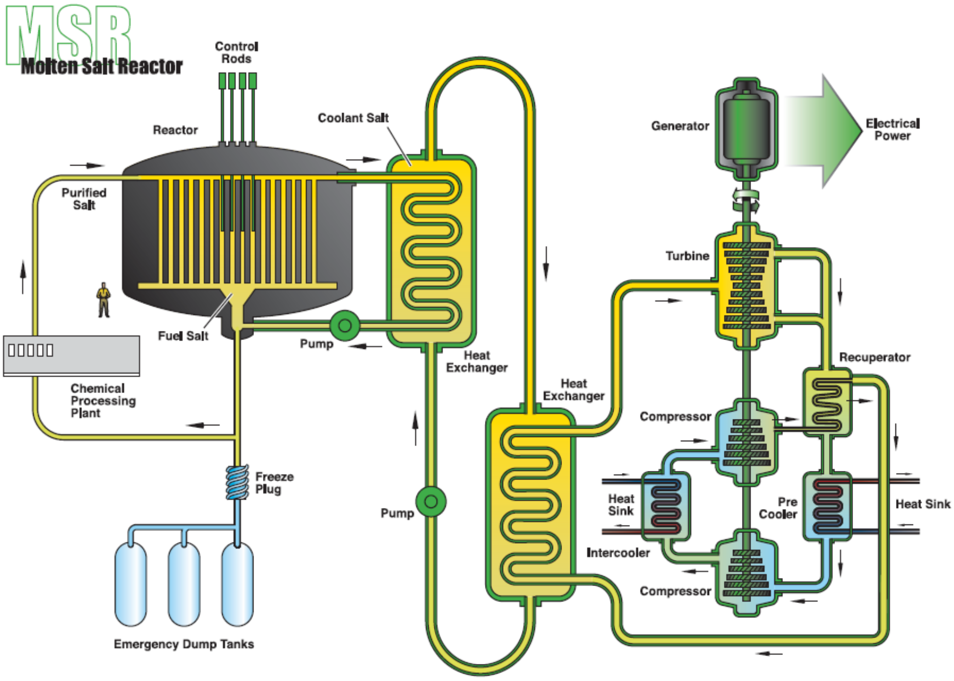

Figure 23 The Molten Salt Reactor concept [43]

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The salts used in MSR technology are typically mixtures of lithium and beryllium or thorium, and uranium fluorides have high melting points and are stable at high temperatures, which allows for higher operating temperatures (~700 °C) with more efficient electricity generation. In China, Thorium Molten Salt Reactor Nuclear Energy System (TMSR) project aims for thorium-based nuclear energy utilization with hydrogen cogeneration [58]. Forsberg et al. (2003) introduce in [59] the molten-salt-cooled Advanced High-Temperature Reactor (AHTR) concept to provide very high-temperature heat to enable efficient hydrogen and electricity production.

6.2.1.5 Sodium-cooled Fast Reactor

A sodium-cooled fast reactor (SFR) uses liquid sodium as a coolant, which allows high-power density operation. Sodium is an attractive coolant as it has very advantageous thermo-physical properties like high boiling point, heat capacity, and thermal conductivity. The coolant is a chemical reactivity metal; therefore, an oxygen-free sealed coolant system is necessary to prevent corrosion and ensure safe operation.

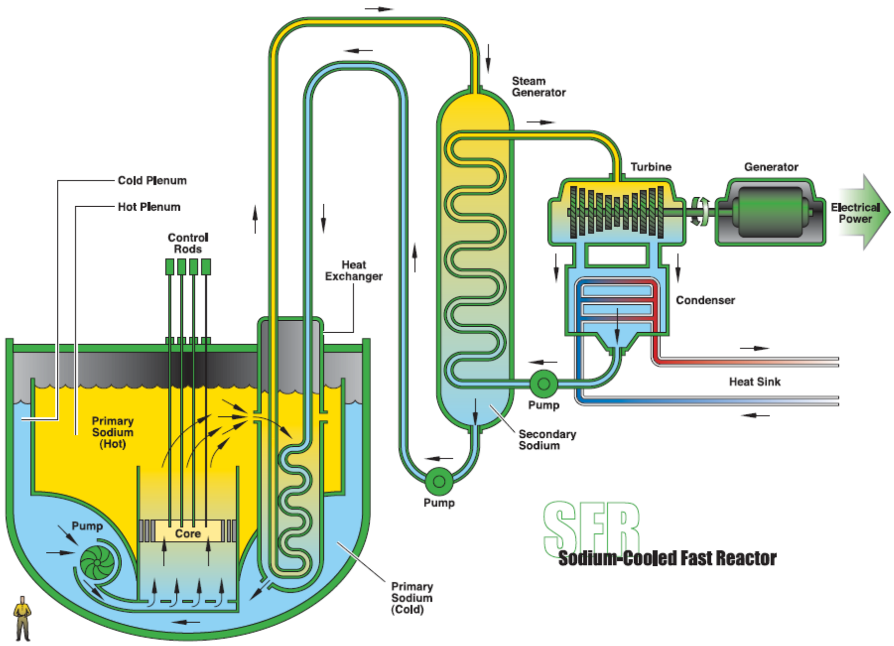

Figure 24 The Sodium-cooled Fast reactor concept [43]

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Much of the basic technology for the SFR has been established in designs, constructions, tests, and operations of demonstration and prototype reactors such as PFR (UK), Phénix (France), BN-350 (Kazakhstan), Super Phéenix (France), BN-600 (Russia), Monju (Japan). Furthermore, several countries have ongoing research programs in safety, fuel, materials and economics [60]

Various plant size options are under consideration ranging from small modular reactors from 50 to 300 MW to larger plants up to 1500 MW_{el} power. The relatively low expected outlet temperatures compared to other advanced reactors, 500-550 °C, currently limits the possibilities of hydrogen cogeneration [61]; however, Marques, et al. (2018) investigate in [61] the coupling with a Na-O-H thermochemical water splitting cycle.

6.2.1.6 Supercritical-Water-cooled Reactor

Supercritical water-cooled reactors (SCWR) use water beyond the thermodynamic critical point as coolant, which aims for higher efficiencies (45%), compared to the existing commercial light water reactors (33%). The SCWR is the only direct upgraded version of the traditional water-cooled reactor among the six proposed reactor concepts [62],[63].

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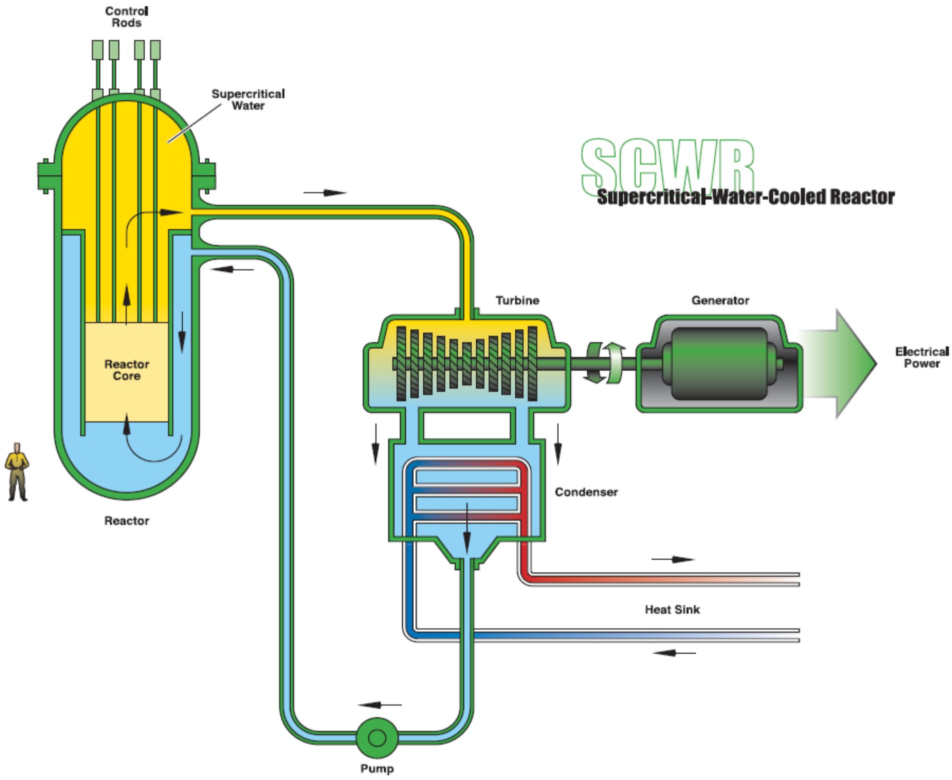

Figure 25 The Supercritical-Water- cooled Reactor concept [43]

The designs are categorized into two groups: pressure-vessel and pressure-tube type reactors. Several countries have ongoing research programs on SCWR, include: Canada, Japan (Super LWR and Super FR), China (CSR1000 and SCWR-M), Europe (HPLWR), Russia (VVER-SCP), and Korea (SCWR-R). The neutron spectrum, the reactor power, the inlet, and outlet temperatures heavily depend on the exact design [63]. Atomic Energy of Canada Ltd. identified the copper–chlorine cycle as the most promising thermochemical hydrogen production option for the Canadian SCWR reactor concept, as it has relatively low temperature needs. [64]

6.2.2 The flexibility of the Gen IV reactors

Generation IV reactors are expected to be more flexible compared to the currently available technologies. A position paper, Ref. [65], was created to investigate the effect of the increasing share of renewable energy sources on the deployment of Gen IV reactors. This paper well summarizes the different kinds of flexibility potentials and development needs of the introduced six advanced reactor concepts. Developers are considering flexible operation during the design phase to reduce thermal fluctuations and optimize operating conditions. The fast neutron spectra will decrease the effect of xenon poisoning, which could increase the load-following capabilities of the power plant. Furthermore, Gen IV systems are more suitable for cogeneration as higher outlet temperatures are expected. The increased temperatures raise the possibilities of process heat applications, and it could also result in high efficiencies with new thermochemical hydrogen production technologies.

6.3 Conclusion

With the increasing share of Variable Renewable Electricity sources in the energy market, the need for flexible operation of Nuclear Power Plants dramatically increases. Hydrogen production can potentially increase the power plant's flexibility by producing hydrogen in low-demanding periods and maintaining the reactor's nominal power. These rapidly changing needs drive international interest

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and research programs to explore the potential possibilities for coupled systems. For commissioned Light Water Reactors, Low-Temperature Electrolysis is a promising option for coupling, as it provides considerable freedom in the exact implementation. The viability of coupling PWRs with High-Temperature Steam Electrolysis is also widely studied; however, it appears to be a more challenging task.

The Generation IV reactors are in active research worldwide to provide the remaining development needs for commercial deployment, which is expected in the following decades. These reactors will have a significant increase in efficiency compared to currently available designs by reaching higher outlet temperatures (in the range of 500–1,000 °C). In order to increase the flexibility of the advanced reactors, process heat application and cogeneration are widely studied in the international research community. Research programs worldwide investigate the possible coupling between hydrogen production plants and the new generation of nuclear power plants. Close coupling with a High-Temperature Electrolysis or a thermochemical cycle could result in high efficiencies in hydrogen production [66]. However, these technologies are in or before the demonstration phase.

Technology		Coolant	Planned electric power	Neutron spectrum	Coolant inlet temperature	Coolant outlet temperature
Pressurized Water Reactor	**PWR**	Water	~ 1100 MWe	Thermal	390 °C	350 °C
Boiling Water Reactor	**BWR**	Water	~ 1300 MWe	Thermal	215 °C	285 °C
Very-High-Temperature Reactor	**VHTR**	Helium	250 -300 MWe	Thermal	640 °C	1000 °C
Gas-cooled Fast Reactor	**GFR**	Helium	1200 MWe	Fast	490 °C	850 °C
SuperCritical-Water-cooled Reactor	**SCWR**	Supercritical water	300 - 1700 MWe	Fast/Thermal	280 °C	550 °C
Lead-cooled Fast Reactor	**LFR**	Lead eutectic	100 -1200 MWe	Fast	350 °C	550 - 800 °C
Molten Salt Reactor	**MSR**	Molten salt mixture	190 - 1000 MWe	Fast	560 °C	700 - 800 °C
Sodium-cooled Fast Reactor	**SFR**	Sodium	50 - 1500 MWe	Fast	400 °C	550 °C

Table 2 Comparison of the different reactor technologies. (Exact parameters are design dependent.) [43][44][52][53][57][60][63]

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7 Assessment of external boundary conditions

Apart from the NPP and the hydrogen production plant, other external boundary conditions may impact the technical and economic feasibility of the nuclear-assisted hydrogen production. Once the hydrogen is produced, may be stored, transformed or distributed to the end user, and this could imply high and additional costs depending on the final use and the location where the hydrogen is going to be consumed. The characteristics of the produced H_2 are also relevant at the time of performing the analysis. The energy price is another variable that needs to be taken into consideration because has a

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big impact in the H_2 production costs. Finally, an evaluation about possible financial assistance regarding the singularity of the project to be performed, is included.

7.1 H_2 storage, distribution and transport assessment

After the hydrogen is produced at the nuclear power plant, it must be transported for further processing or to the end user. Here, various factors such as the costs and, above all, the safe storage and transport of the hydrogen must be taken into account.

There is no single best method for delivering hydrogen between the different transportation scenarios. The cost-effective approach for providing low-carbon hydrogen depends on several factors, including the distance of transportation, the quantity of hydrogen needed, the end use of the hydrogen, and the availability of existing infrastructure.

To describe this topic completely, the following chapters will first present the different ways of storing hydrogen and then the transportation of the stored hydrogen.

7.1.1 Storage of hydrogen as a transport medium

This chapter discusses the different types of hydrogen storage for transportation. The respective advantages and disadvantages are also briefly discussed. Figure 26 shows the main potential possibilities.

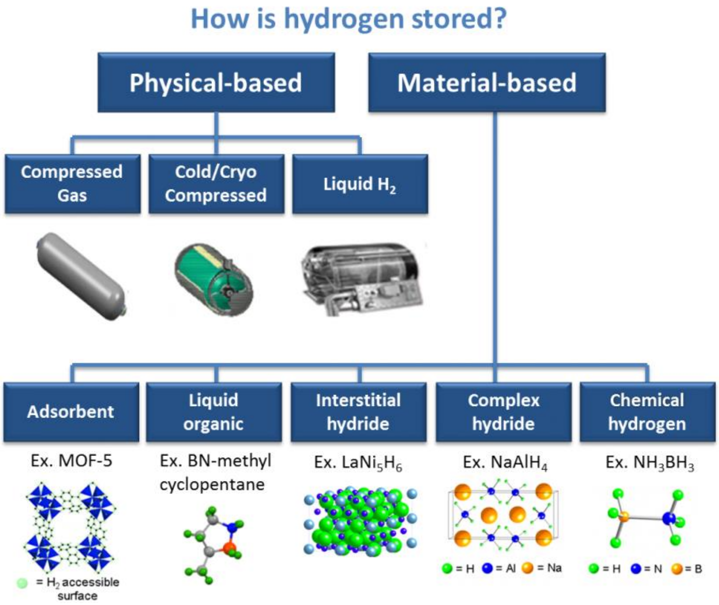

Figure 26 Possibilities for hydrogen storage [83]

7.1.1.1 Compressed gaseous hydrogen

The most common methodfor storing and transporting hydrogen is as a compressed gas. This involves compressing hydrogen gas to high pressures, typically around 350 bar (5000 psi) or 700 bar (10 000 psi) and storing it in high-pressure tanks. Even pressures up to 1000 bar are possible. These tanks can be made of various materials, such as carbon fibre composites or metal alloys, and are designed to withstand high pressures and temperatures.

The high pressure of the gas requires strong, expensive, and heavy tanks and high compression and cooling costs. The disadvantage of this transport medium is the low energy density (compared to liquid

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hydrogen), despite the high pressure. This transport option is, therefore, primarily suitable for smaller volumes with shorter transport distances as e.g. in the supply of gas stations [67].

Another option is to transport/store the hydrogen at relatively low pressures (30 to 200 bar) in existing natural gas pipelines [68] or to blend it in the natural gas in those pipelines up to a certain percentage [69]. This process is discussed in more detail in chapter 7.1.2.2

7.1.1.2 Liquid hydrogen

Another method for storing hydrogen is as a liquid. This involves cooling of the hydrogen gas to cryogenic temperatures (-253°C or -423°F) in specially designed insulated tanks. These tanks are typically made of stainless steel or aluminium and are heavily insulated to maintain the extremely low temperature. Liquid hydrogen is much denser than gaseous hydrogen, allowing for more hydrogen to be stored in a smaller space. This method is mainly used for aerospace applications, such as rocket propulsion, because of its high energy density.

However, it is very expensive to liquefy hydrogen and maintain it at these low temperatures. Also, the transport of liquid hydrogen requires special insulated containers. [70] [71]

7.1.1.3 Metal hydrides

A third method of storing hydrogen is in solid form, such as in metal hydrides. Metal hydrides are materials that can absorb and store hydrogen in their crystal structure. This allows hydrogen to be stored at ambient temperatures and pressures, making it a potentially safer and more convenient option for consumer and transportation applications. Additionally, metal hydrides are less expensive than the high-pressure tanks or cryogenic tanks.

The biggest drawback of this option is the comparatively heavy weight. Also, this technology is still in development and not yet commercially available [72].

7.1.1.4 Liquid organic hydrogen carriers

Liquid organic hydrogen carriers (LOHC) are chemical compounds that can be hydrogenated and dehydrogenated in a reversible manner and are easily transported. During the hydrogenation process, the liquid compound chemically binds with hydrogen, allowing it to be transported at atmospheric pressure, similar to other oil-like substances. Once it reaches its destination, the hydrogen is released via an endothermic dehydrogenation process, and the dehydrogenated LOHC can be transported back to the hydrogen source for reuse. The process parameters for LOHCs depend on the specific organic compound that is used, but typically, temperatures between 100-200°C and pressures of around 20-30 bar are suitable for the hydrogenation process. The dehydrogenation process can occur at a higher temperature of around 250-350°C and lower pressures. The catalysts used for these processes are typically transition metal catalysts such as palladium, platinum, and nickel.

There are various organic carrier substances available, with toluene, dibenzyl toluene, and benzyl toluene (known as heat transfer fluids) being the most commonly used.

Benzyl toluene is an easily storable, transportable, and manageable substance that is safe to use. It has good viscosity properties, making it similar to diesel, which allows for the utilization of existing infrastructure like trucks, trailers, vessels, and storage containers. Furthermore, hydrogenated LOHCs, including benzyl toluene, do not experience hydrogen losses, enabling long storage periods and the storage of large volumes. Compared to ammonia and liquefied hydrogen, the LOHC hydrogenation process is more adaptable to accommodate fluctuating hydrogen H_2 supplies from intermittent renewable sources.

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The dehydrogenation process of LOHC necessitates very high temperatures, causing energy expenses to increase. To transport hydrogen on a large scale, large quantities of LOHC liquid are required. This is causing significant additional capital expenditures. And expansion of production capacities for LOHC liquid is necessary. The production of the carrier creates an additional CO_2 footprint, depending on the number of cycles the LOHC can undertake. Although demonstration projects worldwide indicate promising results, the long-term sustainability of LOHC is yet to be determined. [73] [74]

7.1.1.5 Ammonia

Ammonia (NH_3) is typically made from natural gas and primarily used as a chemical feedstock, particularly for fertilizer production. However, it can also be utilized as a means of clean hydrogen storage. To produce the storage medium, hydrogen is reacted with nitrogen, derived from air via an air separation unit, to create liquid ammonia. This process is similar to the conventional Haber-Bosch production method. The ammonia is then transported in refrigerated tanks and broken down into nitrogen and hydrogen through an endothermic cracking process upon arrival. The resulting gas mixture is purified, nitrogen is removed, and then released back into the atmosphere. Since ammonia is commonly used as a chemical feedstock, the infrastructure for storing, transporting, and handling it is already well-established. Additionally, because it is a globally traded commodity, there are already existing standards in place.

However, ammonia is a hazardous liquid, and it can have negative impacts on human health, soil, air and water quality. When it comes to production, incorporating an intermittent supply of H_2 from renewable sources into Haber-Bosch plants is not a simple task. The process itself is energy-intensive, requiring high temperatures and pressures. Furthermore, the ammonia cracking process is still in its early stages of technological development, and has high energy requirements, as well as necessitating additional purification steps to make the hydrogen usable. [71] [73]

7.1.1.6 Methanol

Another transport medium for hydrogen is methanol, which has numerous applications. Methanol has advantages over ammonia. It is available in liquid form at atmospheric pressure and has a much lower toxicity. It can be transported almost without problems - even in pipelines. The synthesis of methanol is a proven process and can be used with green hydrogen. Methanol has a drawback as a potential transport option for hydrogen, which is both highly flammable and toxic. However, the advantage of using methanol is that existing infrastructure and prior knowledge can be utilized to transport and store it. Similar to ammonia, methanol can also be utilized as a fuel in fuel cells, as a chemical, and as a means of storing hydrogen [75].

The impact of the main possibilities of hydrogen storage on the needed storage volume is shown in Picture 21.

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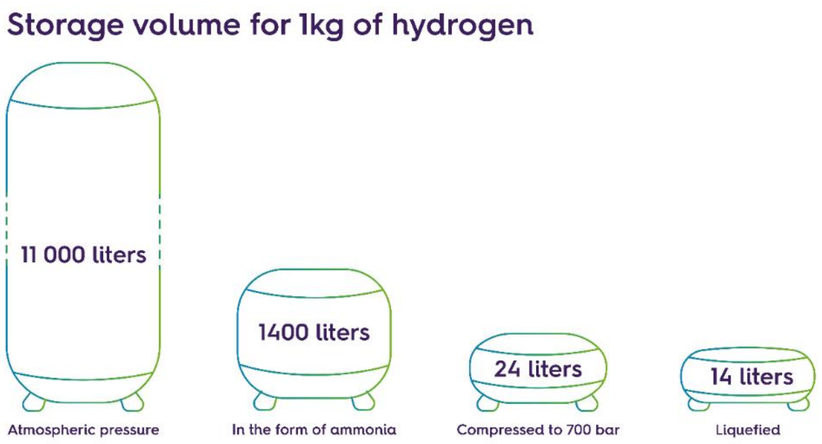

Figure 27 Comparison of storage volume of hydrogen [82]

7.1.2 Transport of hydrogen

In this chapter, the different types of hydrogen transport are discussed. Special attention is given to the transport of hydrogen in pipelines since it does not have to be specially stored/bonded to reach the end user after production.

7.1.2.1 Pipelines

Pipelines can be used for the following and above-mentioned transport media: compressed gaseous Hydrogen (CGH2), Ammonia, LOHC and Methanol. It can transport different amounts of hydrogen over different distances, including large quantities of hydrogen over long distances at the regional or national level, as well as smaller amounts of hydrogen over shorter distances.

Major advantages of pipelines as a means of transport are, on the one hand, that most existing pipelines of the industry can be used and, on the other hand, that the construction of a new pipeline is only a one-time investment with low incidental costs [76].

7.1.2.2 Pipelines for compressed gaseous hydrogen

Hydrogen transport in pipelines is an emerging technology that is being explored as a way to transport hydrogen from production sites to end-users such as industrial facilities or hydrogen fueling stations. Gas networks have two main advantages. Firstly, they can transport significantly greater amounts of energy than other modes of transport. For instance, a large pipeline with a diameter of one meter and a pressure of 80 to 100 bar can carry roughly 24 GW, which is eight times more than a high-voltage line. The second advantage is that the storage capacity in the electrical system is usually about 30 minutes, whereas the German natural gas network has ample storage reserves that can bridge a gap of up to three months.

For this purpose, hydrogen can be blended into the natural gas network at a rate of 5 to 10% (up to 20% are currently tested in R&D projects). In addition, researchers at the Fraunhofer-Gesellschaft have developed a technology that allows hydrogen and natural gas to be separated cost-effectively and efficiently. The membrane technology thus makes it possible to transport the two substances together through the nationwide natural gas network and separate them at their destination. This is a major step forward for the transport and distribution of hydrogen as an energy carrier.

For the transport of pure hydrogen through pipelines, it has to be said it is similar in many ways to the transport of natural gas, but there are some important differences to consider. One of the most

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significant differences is that hydrogen is a smaller molecule than natural gas, which can cause it to leak more easily through small gaps in pipelines or other equipment.

To mitigate the risk of leaks, hydrogen pipelines are typically made of materials that are compatible with hydrogen, such as high-strength steel, or lined with materials that prevent embrittlement or other degradation. Additionally, pipelines may be equipped with sensors and other monitoring equipment to detect leaks and other potential safety hazards.

Another important consideration in hydrogen transport is the fact that hydrogen can cause certain materials to become brittle over time. This means that pipelines and other equipment that are designed to handle hydrogen must be carefully selected and maintained to ensure their long-term durability and safety.

Overall, hydrogen transport in pipelines is a promising technology that has the potential to play a significant role in the transition to a low-carbon energy system. However, there are still many technical and logistical challenges to be addressed in order to ensure the safe and efficient transport of hydrogen on a large scale. [77] [78] [79] [80] [81]

7.1.2.3 Road

In case that there are no respective pipelines to connect to in reasonable vicinity transportation of hydrogen can be achieved through road transport, using either gas, liquid, or a carrier. This mode of transportation is best suited for smaller amounts of hydrogen that need to be transported over shorter distances. [76] In this case the production unit needs to provide a fuelling station for the respective containers.

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7.1.2.4 Rail

Similar to road transportation hydrogen can be transported via rail as well. The transport containers and a fuelling station would be similar. This mode of transportation is well-suited for transporting smaller amounts of hydrogen over medium distances. [76]. Whether rail is to be preferred to road is depending on the logistic connections of the off-takers e.g. rail connection are quite common in chemical industry.

7.1.2.5 Sea

When transporting hydrogen over long distances and in very large volumes e.g. export of hydrogen in large scale to other countries that are not connected to a pipeline grid sea transport is another option. Again the hydrogen needs to be compressed, liquefied or stored in a carrier for that. [76]

7.1.3 Conclusion

The best choice for transportation is highly depending on the amount of hydrogen, the location of production, the location of the main off-taker and the available infrastructure. In the frame of NPHyCo with medium scale production in the vicinity of european nuclear power plants and direct use with rather close off-takers direct transportation of compressed gaseous hydrogen via pipelines seems to make the most economic sense. For all other media and transport options, it is necessary to install equipment at the production site and at the consumer site that converts the hydrogen or loads/deloads the respective transport medium with hydrogen. This results in high investment and also energy costs. In addition, the hydrogen must always be stored for a certain time at the production site to allow liquefaction/conversion and to cover transportation pauses.

If pipelines are already available at the hydrogen production site and these pipelines lead to the end user, this is the preferred way of transporting hydrogen.

However, if this is not the case, the other variants must be evaluated again in more detail with respect to the specific situation of a given location and the respective given industrial surroundings and existing transport connections.

7.2 H_2 consumers/ selling (markets, commitments, etc.)

According to Clean Hydrogen Report information [84], the total hydrogen production capacity in Europe was equal to 11,5Mt per year at the end of 2020.

The conventional production methods of reforming, partial oxidation, gasification, by-product production from refining operations, and by-product production from ethylene and styrene represent 95,7% of total capacity. By-product electrolysis (i.e., capacity from chlorine and sodium chlorate production) accounts for 3,7%. Reforming with carbon capture contributes 0,5% of total hydrogen production capacity. Power-to-hydrogen accounted for only 0,1% of total hydrogen production capacity in 2020.

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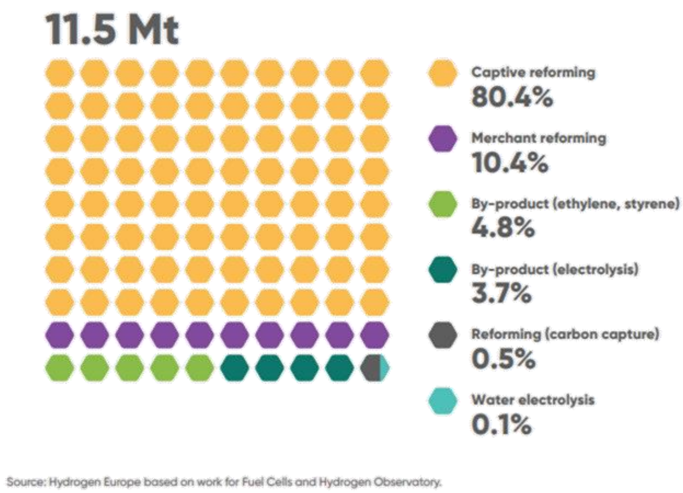
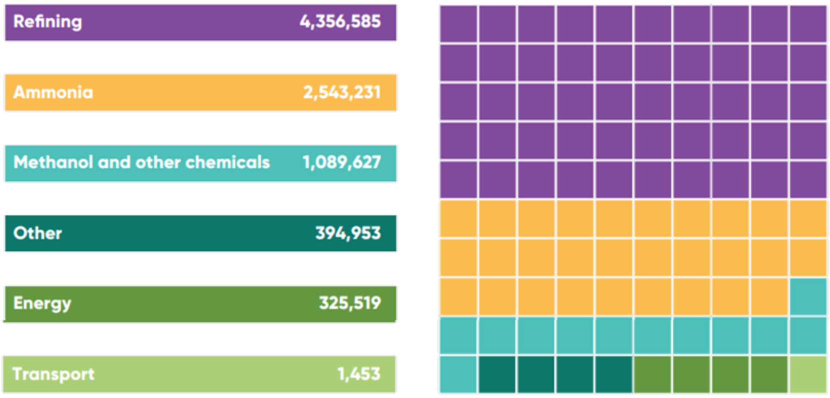


Figure 28 Hydrogen generation capacity by the production process in 2020 [84]

Germany, Netherlands, Poland, Italy, and France have the largest hydrogen production capacity. These five countries account for 55% of the total hydrogen production capacity of the EU, European Free Trade Association (EFTA), and the UK.

Regarding hydrogen demand, in 2020, it was estimated at 8,7 Mt. The biggest share of hydrogen demand comes from refineries, which were responsible for 50% of total hydrogen use (~4,4 Mt), followed by the ammonia industry with 29% (~2,5 Mt). Together, these two sectors consumed 79% of the total hydrogen consumption in the EU, EFTA, and the UK.



Source: Hydrogen Europe based on work for Fuel Cells and Hydrogen Observatory.

Figure 29 Total hydrogen demand in 2020 by application (t) [84]

Total hydrogen consumption in the EU, EFTA, and the UK represents only 8,7% of global hydrogen demand in 2020 [85].

More than half of the total EU, EFTA, and UK hydrogen consumption takes place in just four countries: Germany (20%), the Netherlands (15%), Poland (9%), and Spain (7%).

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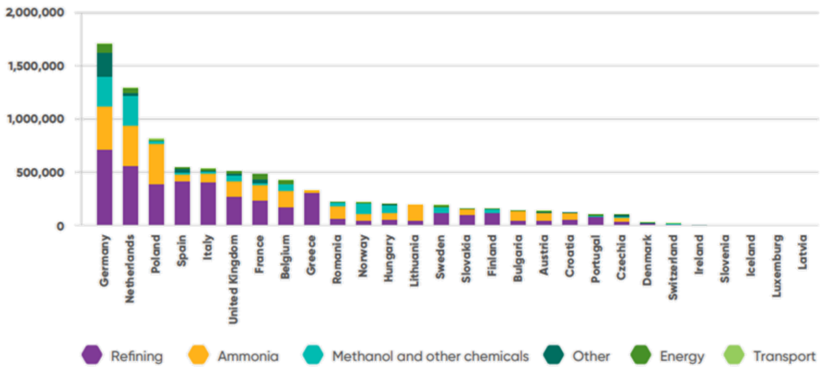

Figure 30 Total demand for hydrogen in 2020 by country (t/y H2) [84] [86]

The REPowerEU plan introduced by the Commission sets a target of 20Mt of renewable hydrogen use by 2030, a 3-fold increase when compared with the Fit for 55 proposal[1]. Refining and ammonia are still predicted to take a big share of the hydrogen demand, but other uses are now also considered, as depicted in the chart below.

[1] Fit for 55 refers to the EU's target of reducing net greenhouse gas emissions by at least 55% by 2030 . The proposed package aims to bring EU legislation in line with the 2030 goal. The Fit for 55 package is a set of proposals to revise and update EU legislation and to put in place new initiatives with the aim of ensuring that EU policies are into line with the climate goals agreed by the Council and the European Parliament. [Ref. https://www.consilium.europa.eu/it/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/].

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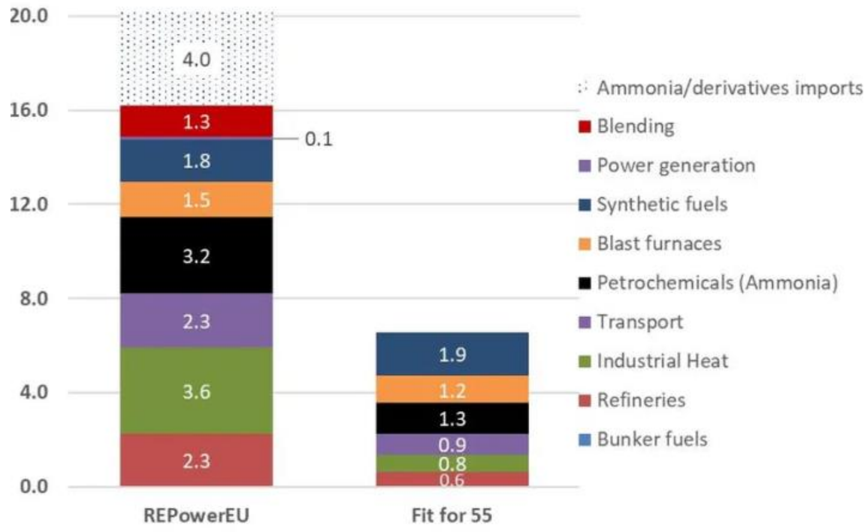

Figure 31 Hydrogen use by sector in 2030 (Mt H2) [84]

From all this information, the following conclusions may be drawn:

- The current hydrogen production is mainly fossil based and will need to be decarbonized
- On top of the current production, the European Union is raising the targets, doubling the hydrogen consumption and the additional production should also be decarbonized.
- It must be emphasized that even if the targets are expected to be reached only relying primarily on renewables, the low-carbon hydrogen production which can be significantly done also using nuclear electricity(see more in Section 8.2)

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In terms of final foreseen use, hydrogen demand in end-use sectors is expected to grow by almost five times by 2050 [85]. Although there is a wide range of users for this demand, chemicals and transport will be the leading sectors. Ammonia and methanol demand could grow three to four times, driven by growth in developing economies and in their use as fuels, which is currently negligible. For transport, uses as pure hydrogen to complement electricity arise in the road and rail transport sectors: use of ammonia for international shipping and synthetic fuels for international aviation are among the largest uses. For steel, demand remains uncertain given that the leading decarbonizing technologies (direct reduced iron with hydrogen and carbon capture and storage) are still to be proven and rolled out at large scale. Ammonia is mostly expected to cover long-distance trade. For ammonia, the global demand grows from 183 Mt/year today to almost 560 Mt/year by 2050, mainly driven by the use of ammonia as fuel for international shipping and growth in developing economies for use as an industrial feedstock. Additionally, 130 Mt/year of ammonia is needed as a hydrogen carrier (i.e. to be reconverted to hydrogen). Almost 80% of the ammonia supply is expected to be green ammonia. About two thirds of the green ammonia supply (400 Mt/year) is globally traded, while the rest is used for domestic demand (see Figure 32). This means more ammonia is traded to be ultimately used as feedstock or fuel rather than as a hydrogen carrier. This reflects the large impact that ammonia cracking has (nearly doubling the transport cost) and the importance of decreasing the costs associated with cracking.

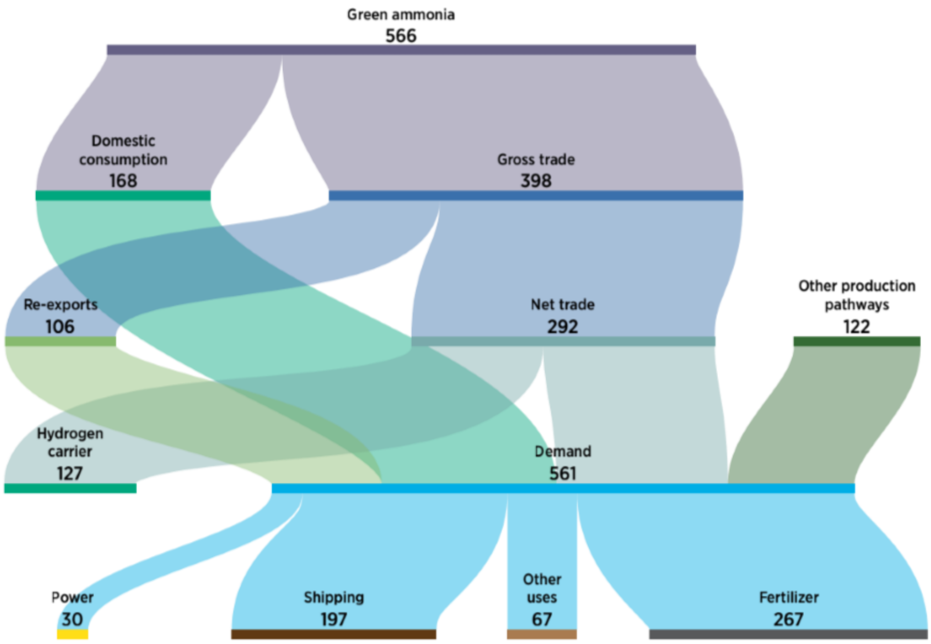

Figure 32 Global energy balance for ammonia in an optimistic technology scenario [85]

Finally, in terms of estimated trade volumes of hydrogen and derivatives, Figure 33 reflects the cost optimal global hydrogen trade flows in 2050, based on a hydrogen demand of about 50 EJ/year (about 420 MtH_2/year). This excludes the share of hydrogen used for power generation, which is expected to be mostly from domestic production, and the share used to provide seasonal storage for renewable power and to ensure system adequacy during periods of continued low renewable generation. Notable exceptions are Japan and the Republic of Korea, which are very constrained in land availability and will potentially import hydrogen (derivatives) for power generationFigureFigure 33 also considers optimistic assumptions for the techno-economic performance of all the technologies, representing a future where innovation and international collaboration have been successful in tackling the barriers that hinder technology from reaching its full potential

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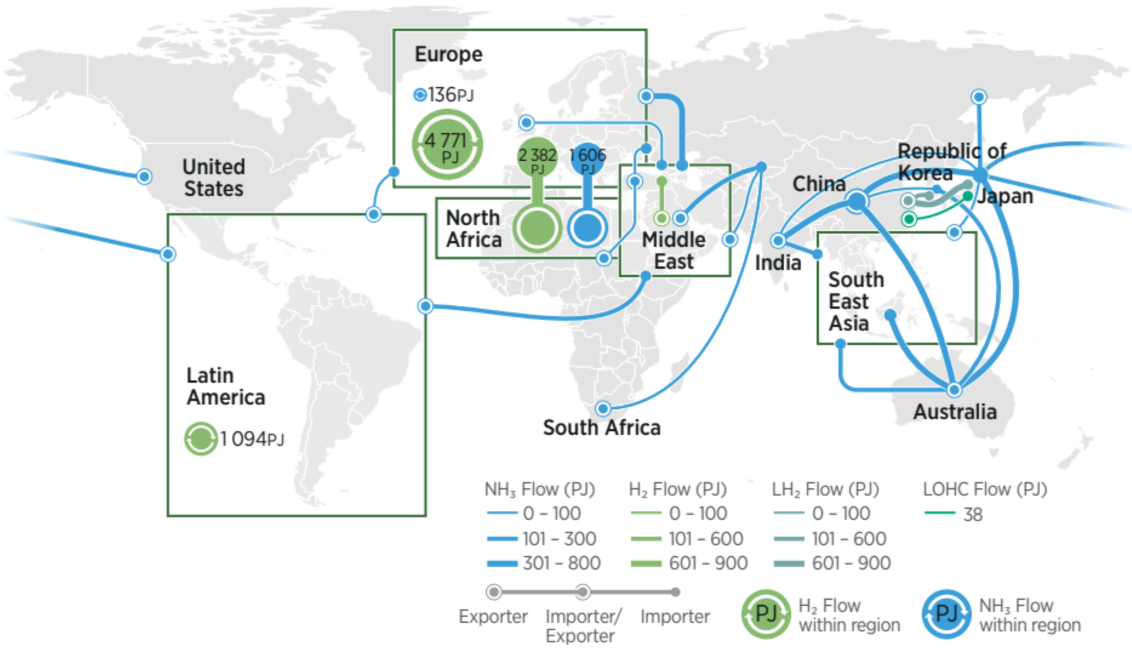

Figure 33 Global hydrogen trade map under optimistic technology assumptions in 2050 [86]

7.3 Energy market price

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The hydrogen production costs using grid electricity [87] [88] in the EU (together with Norway) in 2021 have been estimated in the range of 3,0-9,7 €/kg (compared to 1,8-7,7 in 2020), with the average for all countries being 5,3 €/kg and a median of 5,1 €/kg. As was the case in 2020, the highest grid electricity hydrogen production costs are in Germany, Cyprus, and Malta, estimated at around 8 - 10 €/kg. On the other end of the spectrum are the Scandinavian countries: Finland (3,0 €/kg), Norway (3,8 €/kg) and Denmark (4,1 €/kg)

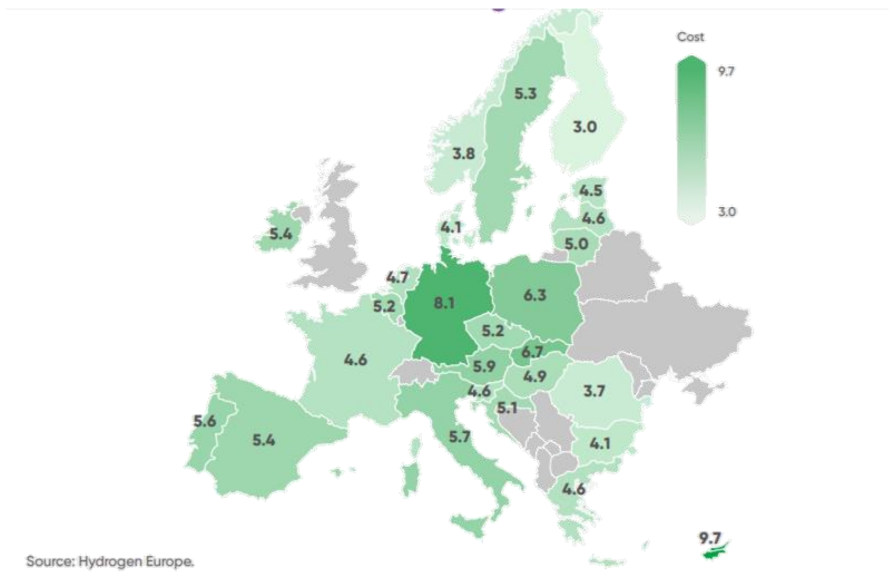

Figure 34 Map of grid-connected electrolysis hydrogen production costs in the EU in 2021 (€/kg) [84]

Apart from reasons related to domestic policy choices, the most important reason for the difference among the Countries is the difference between wholesale electricity prices, which contributes the most to most countries' final cost of hydrogen. High wholesale electricity prices explain to a large extent the high hydrogen cost in Cyprus and Malta, where the electricity prices are among the highest in Europe. The described calculations assumed that the electrolyzer would run, on average, around 4 000 hours per year in off-peak hours, when the wholesale electricity prices are lowest (see methodology note for more details). This is close to optimum for most EU countries. If one increased the number of operating hours, the impact of CAPEX on final hydrogen production costs would decrease. Reversely, limiting the operational time to a few hours daily could reduce the average electricity price. In this case, however, as lower amounts of hydrogen would be produced, the impact of CAPEX on the final cost would increase – again offsetting any gains from lower electricity prices.

Figure 35 shows calculated hydrogen generation costs in the EU, based on wholesale electricity prices and network costs and fees for 2021.

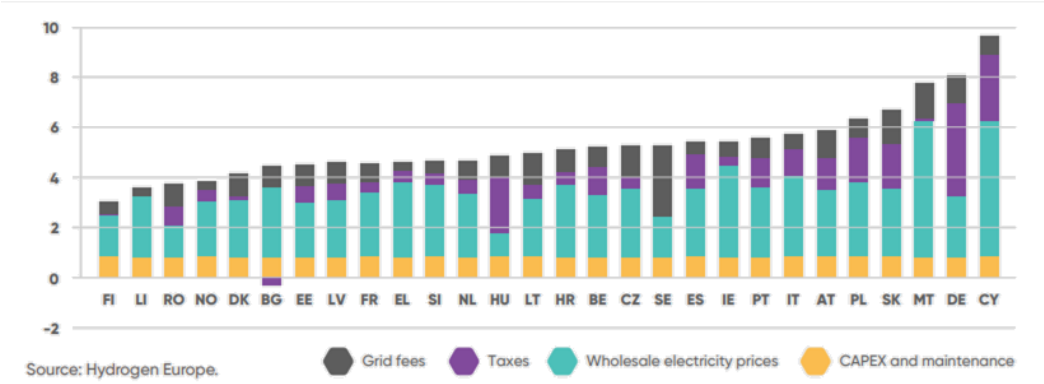

Figure 35 Grid-connected electrolysis hydrogen production costs in the EU in 2021 (€/kg) [84]

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The described calculations assumed that the electrolyzer would run, on average, around 4,000 hours per year in off-peak hours, when the wholesale electricity prices are lowest (see methodology note for more details). This is close to the optimum for most EU countries. If one increased the number of operating hours, the impact of CAPEX on final hydrogen production costs would decrease.

Methodology note [86]

The general approach to estimate the levelized cost of hydrogen (LCOH) is based on a standard discounted cash flow model and the following formula:

$$\frac{I_0 + \sum_{t=1}^{n} \frac{I_t + E_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H_t}{(1+r)^t}}$$

Where,

I0 - Investment expenditure in year 0;

It - Investment expenditure in year t (stack replacement costs);

Et - Electricity consumed in year t including generation costs (wholesale price or RES LCOE + capacity factor), grid costs and taxes when applicable;

Mt -Other operational expenditures in year t;

Ht – Hydrogen production in year t;

r - Discount rate; n - Lifetime of the system in years.

The electrolysis system cost assumptions were based mainly on the latest information for current state-of the- art alkaline electrolysis, provided by the Strategic Research and Innovation Agenda of the Clean Hydrogen Joint Undertaking.

For hydrogen produced exclusively from renewable energy, the levelized cost of that electricity was calculated individually for each member state for three technologies: PV, onshore wind, and offshore wind (excluding the landlocked EU Member States). No network costs, taxes and fees were considered for this scenario, and the capacity factor of the electrolyzer was assumed to be equal to that of the renewable energy source to which it is connected to. Capacity factors for various renewable energy technologies and the EU Member States were taken from the JRC EMHIRES and ENTSPRESSO databases. Data on current renewable energy costs were taken from the most recent IRENA Renewable Power Generation Costs report (from July 2022).

For grid-connected electrolysis, the capacity factor of the electrolyzer was assumed to be 4,000 hours, with the running hour set to fall in time with the lowest wholesale electricity prices (based on data from the ENTSO-e's transparency portal). Network costs, taxes and fees were included in this scenario (based on Eurostat data on electricity prices for non-household consumers in the consumption range from 20 000 MWh to 69 999 MWh per year).

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Item	Unit	Value	Source
CAPEX (Alkaline)	EUR/kW	600	[CHE SRIA 2021]
Economic lifetime	years	30	Own assumption
Energy consumption	kWh/kgH2	50.00	[CHE SRIA 2021]
Stack degradation[30]	per 1000 hrs	0.12%	[CHE SRIA 2021]
Other OPEX[31]	% CAPEX	4.00%	[CHE SRIA 2021]
Costs of capital	%	5.0% in real terms	[IRENA 2022]

Table 3 Assumptions for estimation of hydrogen production costs [84]

Item	Unit	PV	Wind Onshore	Wind Offshore	Source
Economic lifetime	years	25	25	25	[IRENA 2022]
CAPEX	EUR/kW	697	1,425	2,346	[IRENA 2022]
O&M	EUR/kW/year	15	31	64	[IRENA 2022]

Table 4 Renewable energy generation cost assumptions [84]

7.4 Fees, financial assistance

On 18 May 2022, the Commission presented the REPowerEU Plan. The Plan responds to the energy market disruptions caused by the Russian invasion of Ukraine and seeks to rapidly reduce the EU's dependence on Russian fossil fuels. The Commission has devoted an entire section of the REPowerEU to hydrogen, setting an indicative, non-binding target of 10 million tons of domestic hydrogen production and 10 million tons of imported renewable hydrogen by 2030. Moreover, in September 2022, President of the European Commission Ursula Von der Leyen announced the creation of a new European Hydrogen bank, which role will be to "help guarantee the supply of Hydrogen" and construct a "future hydrogen market". This public bank will be able to invest 3 billion € using money from the Innovation Fund and aims to contribute to fill the investment gap faced by the industry. Finally, in the context of the REPowerEU efforts, the Electrolyzer Partnership was launched in September 2022. The Partnership is a dedicated platform under the European Clean Hydrogen Alliance, which brings together electrolyzer manufacturers and suppliers of components and materials.

The European Commission estimates that a total of 86-126 billion € will need to be invested in key hydrogen infrastructures to achieve the EU's ambition of producing 20 million tons of hydrogen by 2030, as outlined in the RePowerEU Communication. Table 5 summarizes the investment required for different types of hydrogen infrastructure.

EU-internal pipelines	EUR 28 - 38 billion
Storage	EUR 6 - 11 billion
Electrolysers	EUR 50 - 75 billion
Upscaling of manufacturing capacities	EUR 2 billion

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Table 5 Capital needed for hydrogen infrastructure [84]

Several EU funding programmes offer support for hydrogen applications. They differ in their objectives and beneficiaries in the financing type and the technology readiness level they support.

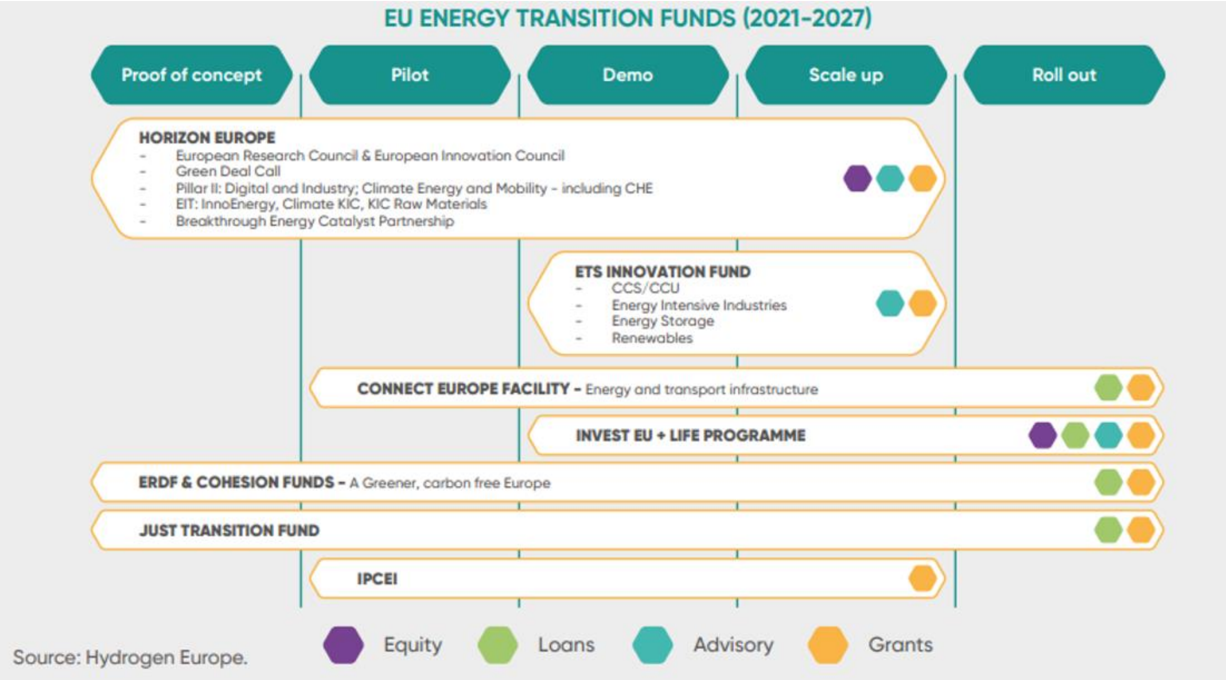

Figure 36 Mapping of the EU Funding Programs supporting hydrogen applications (Hydrogen Europe, 2022 [84]

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In addition, the Commission has planned to unlock up to EUR 300 billion by 2030 to implement the RePowerEU energy objectives, most of which will be allocated through existing EU funding programmes.

As stated in [89], many governments are now adopting hydrogen strategies – setting out the intention for how low-carbon hydrogen will be deployed across their economy. These are important steps giving some clarity to investors as to what the future legislation of and support for hydrogen in different jurisdictions may be. Japan has been an early mover in the hydrogen market, having formulated its “Basic Hydrogen Strategy” in 2017 and built on this since. Other jurisdictions such as such as the US, there is also a combined push amongst the private sector to develop coherent thinking on hydrogen deployment, with the Road Map to a US Hydrogen Economy being developed by a coalition of US energy sector players. Furthermore, a number of countries are gearing themselves up to be the top global green hydrogen exporters aiming to beat the competition on price (e.g. Chile) or through geographic positioning (e.g. United Arab Emirates which based on its hydrogen strategy aims to hold a fourth of the global hydrogen market by 2030.) Germany is one of the few jurisdictions to have passed dedicated legislation by updating its Energy Act to provide for regulation of hydrogen networks, although aspects such as the capture and storage of emissions associated with blue hydrogen production are not covered at all. In addition to Germany, France is taking steps to entrench hydrogen into national law, amongst other things defining “renewable hydrogen”, “low-carbon hydrogen” and “carbon-based hydrogen” in legislation. In the UK, the government is developing dedicated hydrogen “business models” aimed at reducing these risks through revenue support for producers of eligible hydrogen via the “contracts for difference” regime, familiar to renewable generators in that jurisdiction. Revenue support for initial projects is likely to play an important role in getting them off the ground.

Large scale demonstration projects are already underway in some jurisdictions aiming to demonstrate applications ranging from urban transport to gas grid injection. Looking forward the ambition will be to move from demonstrators to full-size projects producing low-carbon hydrogen at commercial scales.

In order to facilitate commercialization of low-carbon hydrogen production and supply, the development of standards of good practice and market-standard documents will be essential. Jurisdictions which are already developing a regulatory framework to facilitate hydrogen production may be quicker to develop these standards than others. Importantly, given the ambition of many countries to export a portion of the hydrogen produced, these standards may also need to be internationally recognized. One element of this will be developing internationally recognized standards for certifying hydrogen as low-carbon.

The scale up of low-carbon hydrogen will likely also see the development of hydrogen “hubs” – where infrastructure for hydrogen transport and storage is shared by a number of players, and production may be co-located with end users e.g. industrial users, to decarbonize their own production. This is the start of what looks to be a global hydrogen market with production and consumption on a cross-border scale seen in other fuels and commodities. For example, in April 2021, Australia’s Prime Minister pledged AUD$275,5 million to accelerate the development of hydrogen hubs, 3 as well as to implement a clean certification scheme. If built, the Asian Renewable Energy Hub in Western Australia will produce about 1.8 mtpa of green hydrogen for use both on the continent and possibly by neighboring countries of Japan and South Korea. Japan has also signed memorandums of understanding with New Zealand, Argentina and the Netherlands for cooperation with a view to developing hydrogen technology and international supply chains.

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8 External conceptualization requirements

8.1 Applicable regulation (standards and guidelines)

One crucial aspect to consider within the NPHyCo project is the regulatory framework applicable to the cogeneration of nuclear hydrogen. In fact, one work package of the project is entirely dedicated to this dimension: WP4, Licensing Roadmap.

As there is no specific regulation for the cogeneration of nuclear hydrogen, the Licensing Roadmap will identify the current regulations concerning nuclear and hydrogen facilities in Europe, focusing on licensing process of the two types of facilities and specific limitations regarding the proximity or integration between them.

The level of conflict between the different regulations in an integrated facility will also have to be analyzed, as well as the proposal of potential solutions for the issues identified for each integration case.

One of the main aspects that is considered in the regulations is the safety of the installations: how the safety concept is developed in the regulations of the nuclear power plants and in the regulations of the hydrogen production plants should be taken into account.

In the European Union, the most relevant regulation for nuclear power plants is the 2009/71/EURATOM directive and its amendment, the 2014/87/EURATOM directive. This directive establishes a community framework for the nuclear safety of nuclear installations.

For hydrogen production plants, the 2012/18/EU ‘Seveso Directive’ is relevant, which is the non-nuclear equivalent to the nuclear Directive 2009/71/EURATOM.

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Additionally, the Directive 2010/75/EU on industrial emissions and the ATEX Directives (1999/92/EG on explosion protection are applicable.

In addition to the safety concept, several aspects must be taken into consideration, including the environmental impact, external hazards and risks, operation and emergency provisions and response organization.

Furthermore, the analysis should include several European countries. At the moment of writing this document, it is planned to study the regulations of Ukraine, Germany, the Netherlands, Spain, Romania and France.

The analysis should include the permitting process, describing the necessary steps, documents and parties involved in the process. On the other hand, the contents of the legislative document must be studied to define, among others, which topics need to be addressed.

8.2 EU authorities' position

Hydrogen as a tool to decarbonize the EU industry has been mentioned since the publication of the European Green Deal back in 2019, the flagship initiative of the current European Commission.

In 2020, the EU Hydrogen Strategy [15] was published, proposing to rely on 2 main hydrogen categories depending on the sources of energy used to produce it:

- 'Clean hydrogen' refers to renewable hydrogen (hydrogen produced through the electrolysis of water (in an electrolyzer, powered by electricity), and with the electricity stemming from renewable sources.
- 'Low-carbon hydrogen' encompasses fossil-based hydrogen with carbon capture and electricity-based hydrogen, with significantly reduced full life-cycle greenhouse gas emissions compared to existing hydrogen production.

But when talking about the targets, only the clean hydrogen strategy has been proposed.

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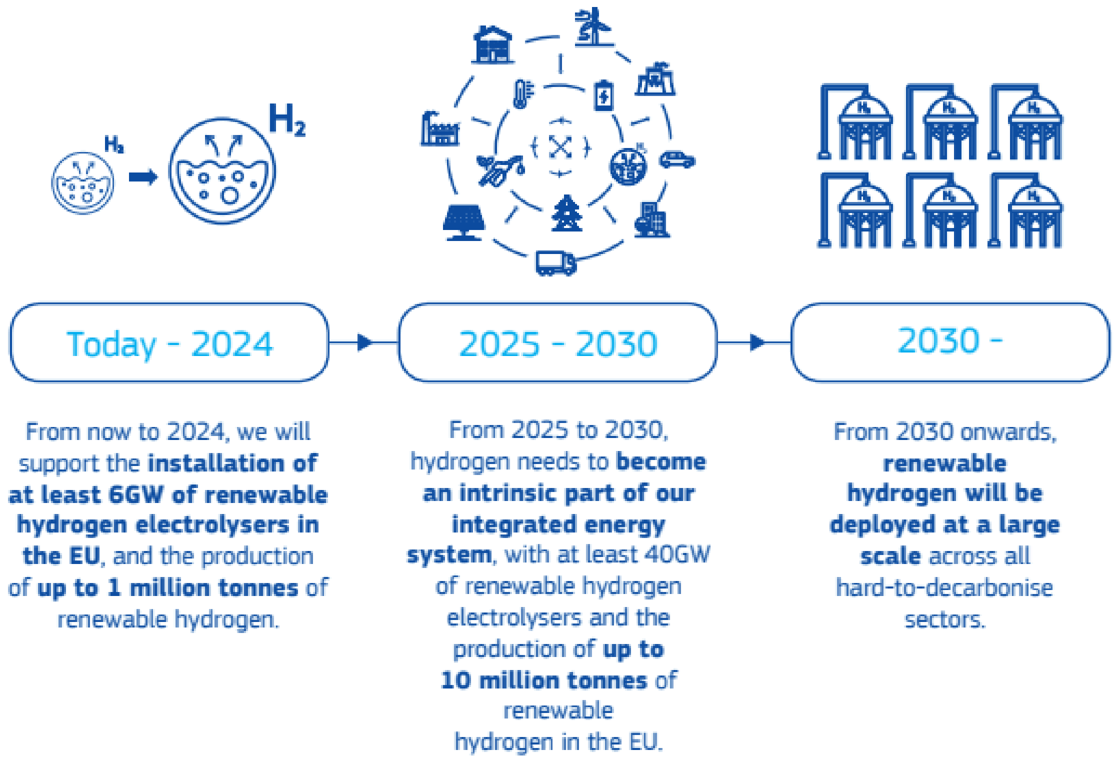

Figure 37 The path towards a European hydrogen eco-system step by step (A Hydrogen Strategy for a climate-neutral Europe [15])

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In 2022, the REPowerEU [90] Plan was published, with the main scope to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition. The Plan is proposing to go even further with the above-mentioned targets by setting a so-called Hydrogen Accelerator that will ensure the 10 million tons of domestic renewable hydrogen production and will add 10 million tons of renewable hydrogen imports by 2030.

The usage of the overall annual amount of 20 million tons of renewable hydrogen is presented in fig.3

But the only renewable or, as per definition, clean hydrogen needed rules to be set out and, in this respect, the European Commission proposed 2 delegated acts under the Renewable Energy Directive with details:

- 1st delegated act defines when hydrogen, hydrogen-based fuels or other energy carriers can be considered as a renewable fuel of non-biological origin (RFNBO)
- 2nd delegated act sets the methodology to calculate GHG emissions savings from RFNBOs and recycled carbon fuels.

For the low-carbon hydrogen category, a clear definition and targets are missing for the moment, the so-called Gas package [91] is expected to provide more details, including a dedicated delegated act to be published by the end of 2024.

Standards and taxonomies classify activities that are sustainable and aligned with climate targets, and those which are not, providing clear direction for energy investment and the basis for incentives, standards, and regulations. Taxonomies, such as the EU taxonomy, can help to ensure capital flows into clean energy projects and technologies, and away from unabated or emissions—intense fossil fuels. Such taxonomies, standards and certifications that hydrogen projects and products comply with can significantly de-risk investment. The flip side is that before taxonomies are agreed and finalized,

there is uncertainty and risk. Companies are unlikely to invest in CCUS hydrogen production, for example, until there is clarity on whether this will be eligible for "low-carbon" investment [12].
Certification of hydrogen could play a major role in this regard, directing capital to low-carbon projects, and giving both producers and consumers the confidence- and data- that a switch to hydrogen will support their decarbonization efforts.
This project will assume the hypothesis that nuclear energy will be considered as an environmentally sustainable activity in the energy taxonomy.

8.3 Public opinion

Currently, there is very little information about public opinion regarding low-carbon hydrogen, especially hydrogen produced from electricity with significantly reduced full life-cycle greenhouse gas emissions (mainly nuclear) compared to existing hydrogen.

But when we are talking about public opinion, two aspects should be mentioned:

- There is a need to inform both the general public and other stakeholders about the potential of nuclear for producing hydrogen either through electrolysis or through thermochemical water splitting using high-temperature heat from advanced nuclear reactors to be deployed
- Public opinion on nuclear, in general, would have an impact on hydrogen production using nuclear produced electricity. Over the last couple of years, polls done in some Member States like Czech Republic [92]. Poland [93], Belgium [94] or Finland [95] show a significant increase in support for nuclear and consequently, this can also be considered as a support for low-carbon hydrogen.

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9 Conclusions

The growing interest in hydrogen production using nuclear energy is reflected in an increasing number of demonstration projects and international partnerships to analyze the feasibility and business opportunities. USA, UK, Russia, Sweden and Canada are the countries where the first pilot projects are being deployed on-site. There are also many R&D projects focused on advanced reactors and SMRs. In the European Union, several hydrogen cogeneration related fields that need further analysis have been detected, and NPHyCo is completely aligned with these requirements.

Hydrogen is emerging as a key player in the transition towards carbon neutrality. The nuclear-powered hydrogen cogeneration is one of the paths that can play a critical role in supporting the forecasted hydrogen economy, and it is concluded that the perfect timing for investigating it is now. Forecasted reduction of LCOH, low life-cycle emissions, hydrogen production versatility, large-scale centralized H_2 production or grid flexibility are some of the benefits that nuclear hydrogen cogeneration can provide.

The fast-growing share of VRE in the global electricity mix shall imply a bigger necessity for flexible operation among traditional base-load energy sources such as NPPs. Hydrogen production can potentially increase the flexibility of the plant to ensure instantaneous stability of the power system and the security of supply. There is international interest in exploring the range of possibilities that coupled systems could provide. LWRs with LTE are a promising option for coupling, and the viability of combining PWRs with HTSE is also widely studied, although it appears to be a more challenging task.

The Generation IV reactors are in active research so as to reach commercial deployment in the following decades. The flexibility of advanced reactors and the possibility of coupling them with HTE or a thermochemical cycle is widely studied as it could result in high efficiencies for H_2 production. However, these technologies are in or before the demonstration phase.

As a result of the H_2 generation technologies assessment, it has been concluded that only water and steam electrolysis will be considered for further analysis within the scope of this project. Hydrogen cogeneration via reforming of fossil fuels releases CO_2 emissions and NPHyCo is focused on low-carbon hydrogen cogeneration. Thermochemical water-splitting technologies are in an early development stage and are not likely to become widely commercially available within the next ten years.

Within water and steam electrolysis, alkaline electrolyzers are the most mature and most durable hydrogen generation systems nowadays. PEM electrolyzers, on the other hand, provide more flexibility than AELs, and they produce highly compressed hydrogen. It is expected certain evolution of these technologies within the next ten years. HTE via SOECs is a promising technology, it presents higher efficiencies, but it has not been commercialized yet.

Transportation, storage and final uses shall be considered as part of the value chain of hydrogen production. Direct transportation of compressed gaseous hydrogen via pipelines from the production site to the end user is the most economical option. However, if this is not the case, additional equipment shall be installed on the production site or in the consumer site so as to convert the hydrogen to the most convenient state. This implies high investment and additional energy costs that need to be evaluated.

The largest consumers of hydrogen in the EU at the moment are Germany (20%), the Netherlands (15%), Poland (9%) and Spain (7%), and the sectors where hydrogen is mainly consumed are the refineries (50%) and the ammonia industry (29%). Energy and transport represent 3,73% and 0,016%, respectively, of total EU H_2 consumption. During the assessment, it has been also identified that the wholesale market energy price is one of the parameters that has greater influence on the viability of coupling NPP and hydrogen production, and it will be crucial to determine a competitive LCOH for the end users identified.

Standards and taxonomies classify activities that are sustainable and aligned with climate targets, and those which are not, providing clear direction for energy investment and the basis for incentives, standards and regulations. Certification of nuclear-powered hydrogen as clean hydrogen is still under discussion in the EU, being its final classification determinant for the feasibility of NPP and H_2 production coupling.

Finally, there is not much information about the public opinion regarding hydrogen production from nuclear power, but over the last couple of years, polls done in some Member States show a significant increase in support for nuclear, so it is expected a similar perception for nuclear-powered hydrogen. However, it is important to inform about the potential of NPPs and H_2 production coupling and this is part of the mission of the NPHyCo project.

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11 Annexes

11.1 Annex 1- Nuclear hydrogen production projects overview

These two charts have been built taking into consideration IEA projects database, the EU CORDIS database and other references detailed in each of the projects and initiatives below.

Table 6 Projects and initiatives of hydrogen production using existing NPPs

 USA	The US Departments of Energy's hydrogen strategy places hydrogen in the centre of its future decarbonized energy system. Called "H2@Scale" it "provides and overarching vision for how hydrogen can enable energy pathways across applications and sector in an increasingly interconnected energy system" [14]. The **Light Water Reactor Integrated Energy Systems Interface Technology Development and demonstration programme**, launched in the USA, aims to develop a hybrid system enabling diverse technologies to be tested when coupled with a light water reactor (LWR). The project involves both modelling and field work as a first stage to enable nuclear-LTE hydrogen plants on the scale of 200-500Mwe to be commercially available by 2025 [14]: • Track I: Perform techno-economic assessment of hydrogen production using nuclear energy. • Track II: Couple 1-3MW PEM electrolyzer demonstration plant at the Davis-Besse nuclear Power Station in Ohio. Assessment of the opportunities of providing produced hydrogen to local public transportation fleets and iron and steel making industries • Track III: Install and operate a high-temperature steam electrolysis (HTSE) system at the Idaho National Laboratory • Track IV: Develop the initial design and feasibility assessment for retrofitting one plant in order to integrate a reversible hydrogen electrolysis system and hydrogen storage infrastructures. The **Solid Oxide Electrolysis System (SOEC) programme** launched in the United States. In the short term, its objectives are to demonstrate and validate a 250kW SOEC nuclear compatible system with ultra-high efficiency and low cost. The laboratory aims to deliver a commercial 200MW SOEC system before 2026. Compared to other electrolysis technologies, the Idaho National Laboratory is confident that SOEC's cost targets can be achieved in the near term without major materials and manufacturing R&D. Besides, the DOE are teaming up with utilities to support four hydrogen demonstration projects at nuclear power plants. The four projects include [11]: • **Nine Mile Point Nuclear Power Station (Oswego, NY).** Exelon is supporting the construction and installation of 1MW PEM electrolyzer to produce $430kgH_2$/day to meet the boiling water reactor's turbine cooling and chemistry control needs. • **Davis-Besse Nuclear Power Station (Oak Harbor, OH).** Energy Harbor is working to demonstrate the technical feasibility and economic benefits of clean hydrogen production, which could facilitate future opportunities for large-scale commercialization. • **Prairie Island Nuclear Generating Plant (Red Wing, MN).** Bloom Energy and Xcel Energy are working on a FOAK project to demonstrate high-temperature electrolysis (240kWe and $90kgH_2$/day) at the Prairie Island NPP. The data collected from this demonstration will be used to scale up this process. • **Palo Verde Generating Station (Tonopah, AZ).** Hydrogen from Palo Verde may be used as energy storage for use in reverse operable. Experience from this pilot project will offer valuable insights into methods for flexible transitions between electricity and hydrogen generation in solar-dominated electricity markets- and demonstrate

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	how hydrogen may be used as energy storage to provide electricity during operating periods when solar is not available. DOE is continuing to support the development and maturation of clean hydrogen production, including funding for 6 to 10 regional clean hydrogen hubs across the USA. At least one of the hubs will be focused on clean hydrogen production using nuclear energy.
 UK	The UK's strategy around hydrogen production considers carbon intensity as the primary factor in market development, aiming to be low carbon. According to the **Ten Point Plan for a Green Industrial Revolution** issued in November 2020 by the UK Government, it is expected to produce 270TWh of low-carbon H_2 by 2050, of which 1/3 would be produced from the 12-13GW of installed nuclear energy by this year. **Hydrogen to Heysam (H2H):** This project directly connects 1MW alkaline electrolyzer and a 1MW PEM electrolyzer to the gas-cooled reactor Heysam 2 in the UK. In addition to testing and comparing the performance of both electrolyzer technologies in real conditions, it aims to assess the benefits of using the oxygen produced from electrolysis for the reformation of CO_2 used in gas-cooled reactors [14]. EDF confirmed the technical feasibility of low-carbon hydrogen production at the Heysam NPP, but the project has not advanced to the demonstration phase [11]. **Freeport East Hydrogen Hub and Sizewell C project** [14], [11]: The Freeport East Hydrogen Hub will be developed with partners EDF, operators of Sizewell B and developers of Sizewell C NPPs and Ryse Hydrogen who are building the UK's first hydrogen production and distribution network. EDF is considering large-scale hydrogen production powered by its UK nuclear plants, starting with a MW demonstration electrolyzer supplying H_2 to decarbonize construction at the Sizewell project.
 Sweden	**Ringhals NPP:** Vattenfall has been producing hydrogen (0,8MWe LTE) at Ringhals NPP since 1997. Hydrogen was used to cool generators. It was also injected into the feedwater to prevent corrosion. The NPP was decommissioned in January 2021 [11]. **Oskarshamn NPP:** OKG has long operated a facility at the Oskarshamn site, which uses electricity from the NPP to produce hydrogen through electrolysis of water (0,7MWe ALK). During power operation, this hydrogen was added to the reactor coolant of the plant's three boiling water reactors in order to reduce the risk of stress corrosion cracking of the reactor piping by reducing the amount of free oxygen in the coolant. Initially, they produced small volumes of hydrogen but now the surplus could be sold to customers on a commercial basis. **HYBRIT:** Vattenfall, together with a steel producer (SSAB) and mining company (LKAB), has launched an initiative to decarbonize steel production using low-carbon electricity and hydrogen, with plans to produce 1 million tons of fossil-free steel per year [11]. By September 2022, a rock cavern storage facility (FOAK in the world) for storing fossil-free hydrogen was completed.
 Russia	**Kola NPP:** By December 2022, Kola NPP produce hydrogen at the new electrolysis unit for the first time (1MWe LTE). The hydrogen was used to cool down the turbine generators. The Kola NPP become the pilot site for hydrogen production in Russia. A project to create a bench test complex for the production of hydrogen is planned for 2025.
 Canada	**Bruce Nuclear Generating Station:** The utility Bruce Power is exploring the technical feasibility and business case for nuclear hydrogen production at the Bruce Nuclear Generating Station to support achieving net zero emissions on site by 2027. The feasibility study is expected to be completed by early 2023 [11].

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Table 7 R&D activities focused on hydrogen production with advanced reactors and SMRs

 USA	**Hydrogen facility at modular NuScale plant:** NuScale and Shell Global solutions, along with other industry partners, will develop an assess a concept for an economically optimized Integrated Energy System (IES) that produce hydrogen using electricity and process heat from a NuScale Voygr plant. NuScale will use a control room simulator to show how the reactor would work with the IES, as well as include models for the SOEC system for hydrogen production, and the RSOFC for electricity production. An evaluation by Idaho National Laboratory shows NuScale 250MWth SMR could economically produce almost 50T H_2/day, avoiding 168kt CO_2 per year compared to H_2 from natural gas. **Next Generation Nuclear Plant (NGNP):** The mission of the NGNP project is to develop, license, build and operate a prototype of a modular high-temperature gas-cooled reactor (HTGR) plant that would generate high-temperature process to be used in hydrogen production and other energy-intensive industries while generating electric power at the same time. NGNP pre-licensing interactions began in 2006 and were suspended in 2013 after DOE decided in 2011 not to proceed into the detailed design and license application phases of the NGNP project.
 UK	**HTGR Demonstration Programme (Department of Business, Energy, and Industrial Strategy-BEIS):** The Government of the UK has identified HTGR as the most promising candidate for the use of nuclear energy for the decarbonization. The UK plans to promote the Advanced Modular Reactor Research, Development and Demonstration (AMR RD&D) programme leading to the demonstration of HTGR by the early 2030s. The Japan Atomic Energy Agency (JAEA), having a co-operative relationship with the UK National Nuclear Laboratory (NNL) in the field of HTGR technologies, applied for the AMR RD&D programme as a member of NNL team consisting of NNL, JAEA and UK companies. On September 2022, BEIS announced that NNL team had been selected as the project entity to implement the AMR RD&D programme [11].
 Russia	**HTGR commissioning- Rosatom**: Rosatom plans to commission and HTGR to produce hydrogen via the adiabatic conversion of methane with utilization of carbon dioxide by 2030 [11]. The stages of the programme for development of hydrogen technologies in Russia are: • 2020-2024: R&D. Design of the reference unit and key elements of nuclear island, methane steam conversion, hydrogen storage and transport, CO_2 utilization, marketing of key elements of hydrogen generation. • 2024-2030: construction and commissioning of HTGRs for hydrogen production, establishing infrastructure for hydrogen economy. • 2030 and beyond: large-scale environmentally friendly hydrogen production and further infrastructure development for hydrogen economy. Thermochemical hydrogen production from water is also envisaged in Russia [11].
 China	**China National Nuclear Corporation (CNNC) HTGR P2G demo**: the demonstration of the High-Temperature Reactor prototype module, with a design temperature of 750ºC, reached its first criticality in November 2021 and started power generation by the end of that year. HTGRs is considered one of the preferred solutions for large-scale hydrogen production by China. It is expected that before 2030, China will perform a helium turbine generation cycle for HTGRs and the engineering application of nuclear hydrogen production utilizing HTGRs. **CNNC 600MW HTGR P2G for steel**: CNNC has teamed with Tsinghua and Baosteel to develop a HTGR based on hydrogen production for the iron and steel producer. A pilot project of 100Nl/h H_2 production capacity has passed the experiment. The firm is now eyeing on embark

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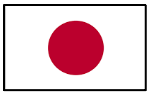
	P2G in its future 600MW HTGR project, which would have 50.000Nm^3/h H_2 production capacity. Upon that pilot project, CNNC would continue working with Baosteel for using nuclear power to generate hydrogen.
 Japan	**Thermochemical water splitting iodine-sulphur High-Temperature Test Reactor (HTTR)**: JAEA has studied iodine-sulphur process, a thermochemical cycle to produce hydrogen by water splitting. Hydrogen production was demonstrated at the High-Temperature Test Reactor (HTTR) using the iodine-sulphur thermochemical process in 2019. In 2022, JAEA began designing hydrogen production equipment that will use the near-1000ºC high temperature of the HTTR [11].
 Poland	**Poland and Japan to develop HTGR reactor**: The Polish National Centre for Nuclear Research (NCBJ) initiated a project to develop the HTGR reactor in cooperation with Japan. NCBJ began to work on conceptual design of a HGTR research reactor in 2021. The new agreement between NCBJ and JAEA supplements and earlier agreement by providing for R&D cooperation on the research reactor, which would be built in Poland at the NCBJ [11].
 European Union	**GEMINI 4.0 (Horizon Europe):** International agreement between American and European Research organizations and industry to work with their respective governments to carry out the design and regulatory requirements for the development of the first commercial High-Temperature Gas-cooled Reactor (HTGR). (Started in June 2022) **EUROPAIRS- End User Requirements for Process heat Applications with Innovative Reactors for Sustainable energy supply (Euratom):** The objective of EUROPAIRS is to identify boundary conditions for the viability of nuclear cogeneration systems connected to conventional processes and to initiate the partnership of nuclear organizations and end-user industries. (Sept 2009- May 2011) **ARCHER- Advanced high temperature Reactors for Cogeneration of Heat and Electricity R&D (Euratom)**: The aim of ARCHER project is to get further knowledge relative to the technology of very high-temperature reactors (V-HTR) and, in particular, to demonstrate the safety of the concept. It also aims to contribute to demonstrate the feasibility of the cogeneration of electricity and heat by a nuclear reactor. ARCHER is continuing the work of the RAPHAEL project. (Feb 2011- Jan 2015)

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