

The Role of Nuclear Power in the Hydrogen Economy

Cost and Competitiveness



Nuclear Technology Development and Economics

The Role of Nuclear Power in the Hydrogen Economy: Cost and Competitiveness

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Foreword

There is growing interest among Nuclear Energy Agency (NEA) member countries in the role of hydrogen as a key component of future energy systems. In the near term, it is seen as a solution for the decarbonisation of different industrial processes and transport. In the longer term, it is expected to contribute to the flexibility of electricity grids with larger shares of variable renewables. However, hydrogen can contribute to net zero targets only if it is produced from low-carbon sources. In recent years, low temperature electrolysis, which requires inputs of water and electricity, has reached the required technical and economy maturity for large-scale production of low-carbon hydrogen.

Throughout this process, approximately 50 kWh of electricity is required to produce one kilogram of the gas. In other words, decarbonising the current hydrogen consumption worldwide of about 90 million tonnes would require 4 500 TWh of low-carbon electricity. In the future, the hydrogen demand is likely to increase by several order of magnitudes. This gives a sense of the challenge that lies ahead.

The Role of Nuclear Power in the Hydrogen Economy: Cost and Competitiveness is the first NEA publication on the role of nuclear power in the hydrogen economy. It provides an overview of the latest developments in the hydrogen economy and offers an in-depth analysis of nuclear competitiveness for hydrogen production and delivery. Building on the NEA's expertise and ground-breaking analyses in the system costs of electricity provision, this report investigates the system-level impacts of coupled electricity and hydrogen production. The combination of these complementary economic approaches sheds a new light on economics of the hydrogen economy and the role that nuclear technology can play in making it obtainable in the near future. The central conclusion from this study is that nuclear energy can produce low-carbon hydrogen at large scale and at competitive costs.

As the world faces profound and complex energy challenges, secure and affordable energy is needed more than ever. This report shows that nuclear power has a key role to play in the emerging energy paradigm that revolves around low-carbon electricity, heat and hydrogen.

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List of abbreviations and acronyms

BoP	Balance of plant
CCGT	Combined cycle gas turbines
CCS	Carbon capture and storage
CCUS	Carbon capture, use and storage
DOE	Department of Energy (United States)
GWe	Gigawatt electric
HTE	High-temperature electrolysis
HTGR	High-temperature gas reactors
HTR	High-temperature reactor
HTTR	High Temperature Engineering Test Reactor
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
JAEA	Japan Atomic Energy Agency
kWe	Kilowatt electric
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LCOHD	Levelised cost of hydrogen delivery
LTE	Low temperature electrolysis
LTO	Long-term operation
LWR	Light water reactor
MWh	Megawatt hour
NEA	Nuclear Energy Agency
NREL	National Renewable Energy Laboratory
NTE	Division of Nuclear Technology Development and Economics (NEA)
O&M	Operation and maintenance
PEM	Proton exchange membrane
PV	Photovoltaic
R&D	Research and development
SI	Sulphur-iodine
SOEC	Solid oxide electrolyser cell
VRE	Variable renewable energy

Executive summary

Growing momentum to use hydrogen to support ambitious decarbonisation efforts

The great majority of scenarios mapping out the road towards net zero emissions include a strong rise in the supply, demand and use of hydrogen by 2050. Although the potential contribution that hydrogen could make to decarbonising the energy sector, as an energy carrier or as a commodity, has been known for decades, the scale and ambition of current initiatives by both public and private actors have no precedent. For instance, the International Energy Agency (IEA) estimates in its 2021 report *Net-zero Pathways* that worldwide hydrogen consumption will rise from around 90 Mt in 2020, the vast majority of which is for industrial applications, to more than 500 Mt by 2050, with many new usages across the industrial, transport, power and heating sectors (IEA, 2021a). However, realising this long-term expansion in the hydrogen economy requires ambitious policy initiatives to support hydrogen deployment and to engage stakeholders in the short term. In this context, it is essential to identify the priorities and commit new resources to actions that, if taken today, will put the hydrogen economy on a path to fully contributing to reaching net zero targets.

The success of research, development and demonstration programmes, a strong and constant political commitment, and the ability of stakeholders to set and agree upon technical and regulatory frameworks over hydrogen handling and trading are key for future hydrogen deployments. Technology, policy and regulation barriers remain major challenges that explain in large part the differences between the high and low bound values for estimates of future market uptake. Beyond policy decisions, regional natural resource endowment is also a key driver on the technology landscape.

This new report by the OECD Nuclear Energy Agency (NEA) sheds light on the role and potential of nuclear power in the future hydrogen economy. It focuses in particular on the medium term, set as 2035, a time horizon identified as the turning point in global hydrogen strategies.

Typically, hydrogen strategies are characterised by three time horizons – 2025, 2035 and 2050. In the short term, priorities are to close the competitive gap between fossil fuel and water electrolysis and to decarbonise existing usages of hydrogen. In the medium term, electrolytic hydrogen production is expected to ramp up as new GWe hydrogen production capacity becomes available. Industrial applications continue to lead demand for hydrogen, although new usages in the transport sector enter the market. From 2035, the demand for hydrogen is expected to increase strongly due to its growing role in the industrial and transport sectors. Hydrogen markets will no longer be structured around limited areas of production and consumption, referred to as “hubs” or “valleys”; rather, hydrogen will become increasingly commoditised for use in industry or transport or as a flexible storage vector. By that time, given growingly stringent carbon constraints, low and high-temperature electrolysis using low-carbon electricity will dominate over the currently still widely used process of steam methane reforming.

The first chapter of this report provides an overview of the state of the current discussions about the role of hydrogen and hydrogen value chains in future decarbonised energy systems. Much about the future demand for hydrogen and its modes of production remain to be determined. Careful analysis and qualification of the assumptions and frameworks that shape different contributions is thus indispensable to develop a coherent view of the many scenarios for the hydrogen economy.

Chapter 2 provides a systematic analysis of the costs of different modes of hydrogen production and their value chains. Based on the NEA techno-economic hydrogen model, it provides both a plant-level analysis of the levelised cost of hydrogen production (LCOH) as well as a value chain analysis of the levelised cost of hydrogen delivery (LCOHD), taking into account

hydrogen storage, transport and distribution. A key point of focus here is, of course, on the potential role of nuclear energy in competition with other sources of electricity, both as a dedicated generator for large industrial installations and as a provider of low-carbon baseload power for the electricity grid.

Chapter 3 integrates key findings from Chapter 2 into an analysis of the system costs of the combined production of electricity and hydrogen. It assesses, in particular, the value that nuclear power can provide in low-carbon electricity systems through sector coupling with the hydrogen economy. Depending on different economy-wide carbon constraints and different levels of hydrogen production, this section highlights the different levels of contribution of nuclear energy for both electricity and hydrogen production along with an analysis at the level of overall electricity-hydrogen provision systems.

Together, the three chapters provide comprehensive insight into the determinants structuring the hydrogen economy and the key role that nuclear energy will play.

At the plant level, nuclear power is a competitive option to produce and deliver low-carbon hydrogen

The most pressing challenge of the hydrogen economy is to enable the decarbonisation of current hydrogen usages at a competitive price without impeding other decarbonisation objectives. Aiming to produce competitive hydrogen also requires considering the costs of hydrogen storage, transport and distribution as well as the total costs at the level of the power system.

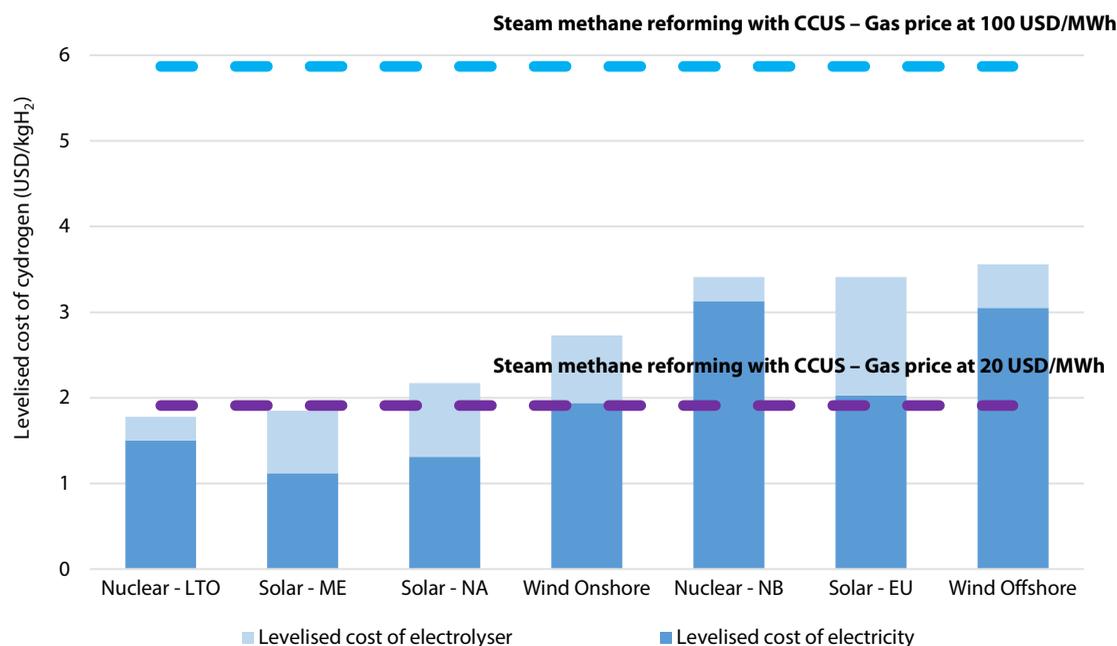
To reach global hydrogen roadmap goals, comprehensive low-carbon electricity sources are required. The IEA forecasts that by 2030 around 80 Mt of hydrogen will be produced annually through electrolysis. This represents a supplementary electricity demand of 4 050 TWh, or approximately 1.5 times the current European electricity demand. While variable renewables will represent the majority of future low-carbon sources, their deployment raises new challenges. To that extent, discriminating between different sources of production for low-carbon hydrogen – including via hydrogen support policies that apply a colour label based on the energy source – will add challenges to meeting climate goals.

Nuclear energy as a source of dispatchable and low-carbon electricity would make it possible to operate the electrolyser at high load factors without compromising hydrogen's carbon intensity. This analysis shows that nuclear is a competitive option to deliver hydrogen, particularly considering the competitiveness of the long-term operation of nuclear power plants and future opportunities offered by high-temperature electrolysis.

Ultimately, this analysis highlights that, when coupling the electrolyser to a specific source of electricity, electrolytic hydrogen production at large scale below USD 2.5 per kgH₂ will be hard to achieve in most places in the world by 2035. However, in a context of high volatility in the price of gas, the hydrogen cost of production from steam methane reforming, the incumbent technology, is also expected to increase significantly. Indeed, assuming a gas price of USD 100 per MWh, below the prices in certain regions of the world in Q2 2022, hydrogen production costs from steam methane reforming with carbon capture, utilisation and storage (CCUS) is estimated at USD 5.87 per kgH₂, or 65% more expensive than the least competitive option for electrolytic hydrogen in this analysis (e.g. wind offshore). In other words, the hydrogen market is likely to become increasingly fragmented, where regional resource endowment will largely determine the leading production technology and the final cost of hydrogen.

The business model of electrolysers, e.g. electrolysers coupled to a specific source of electricity or operated in baseload using electricity from the grid, is a key factor in the economic and the industrial feasibility of the hydrogen economy. In particular, while coupling the hydrogen production plant with a cheap electricity generation plant might optimise the production cost, assuming tax and levies on electricity prices are avoided, it fails to take into account value chain costs. This analysis shows that if the hydrogen production and consumption profiles do not match, it is likely to involve inefficient infrastructure design. In particular, in the short term, most of the demand will come from industry, which requires a steady flow of hydrogen and would be best served by a steady production of hydrogen.

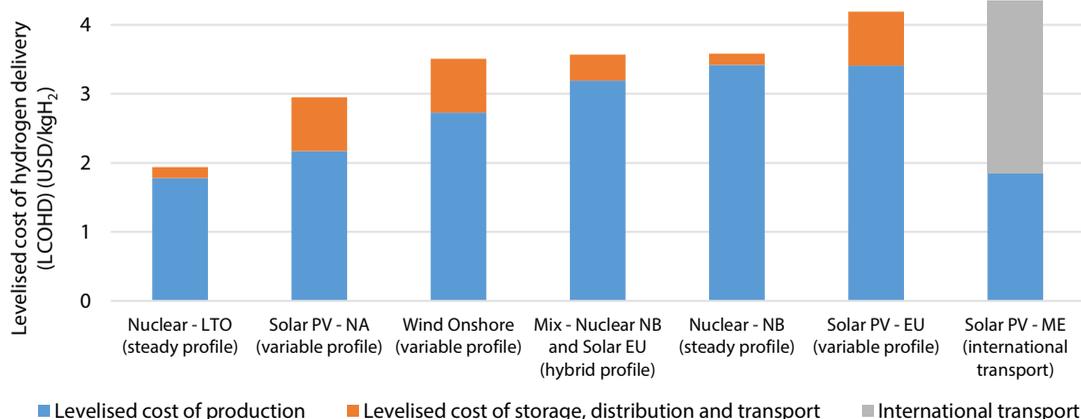
Figure ES1: **The levelised cost of hydrogen (LCOH) for different production options**



Note: LTO = Long-term operation; NA = North America; NB = New build; EU = European Union; ME = Middle East.

As a dispatchable and large-scale solution, nuclear power would enhance co-location synergies with large-scale industrial demand, minimising infrastructure costs for hydrogen storage, transport and distribution. This report estimates infrastructure costs for a nuclear-based value chain at around USD 0.16 per kgH₂ for a 500 MWe system that answers a continuous demand. For variable production in a similar configuration, value chain costs are estimated at around USD 0.77 per kgH₂. As a result, when value chain costs are added to hydrogen production costs for different options of electricity generation, nuclear stands out as a competitive solution. In fact, at a given electrolyser scale, the larger volume and continuous production of a nuclear-based hydrogen value chain allow for a cost-efficient deployment of all infrastructures.

Figure ES2: **The levelised cost of hydrogen delivery (LCOHD) for different electricity sources**



Note: LTO = Long-term operation; NA = North America; NB = New build; EU = European Union; ME = Middle East.

The analysis also highlights synergies between nuclear and renewable systems such as solar photovoltaic (PV). Indeed, leveraging nuclear steadiness and solar PV low-cost electricity, such mixed systems optimise both hydrogen cost of production and delivery.

The question of hydrogen cost competitiveness requires consideration of the full value chain. Such an approach would not only contribute to cost-efficient infrastructures, but would also enhance other potential synergies. For example, nuclear-hydrogen hubs could improve their economics using the clean heat produced by nuclear for other industrial processes nearby. Indeed, one key insight of this report is that quite frequently it is the total cost of the value chain that will determine the competitiveness of different business models for hydrogen production.

System level analyses verifies that nuclear energy provides a clear pathway to more affordable integrated energy systems

Coupling electricity and hydrogen production is a promising approach to promote the deep decarbonisation of sectors that are otherwise difficult to decarbonise – such as industry, transport and heating. While LCOH and LCOHD metrics are a good starting point to assess the relative competitiveness of nuclear-produced hydrogen compared with other alternatives, they do not provide a comprehensive overview. This is particularly the case in integrated systems with high shares of variable renewables (VRE). In such configurations, the competitiveness of nuclear power must be assessed also through integrated system cost modelling that takes into account the simultaneous interaction, cost and generation profile of each technology. While the technical detail of the hydrogen system is lower than in the plant-level approach, which considers in detail specific hydrogen value chains, the system analysis provides complementary insights.

LCOH and LCOHD cost figures are therefore complemented with a first system cost analysis in order to provide another perspective of the competitiveness of nuclear-produced hydrogen. The proposed system analysis considers as a reference system the case of a highly-interconnected country with a varying carbon constraint (25 MtCO₂ and 0 MtCO₂), share of nuclear power in the total installed capacity (*constrained nuclear case* and *unconstrained nuclear case*) and different exogenous hydrogen demand levels (0.5 MtH₂ and 1.5 MtH₂). In the *constrained nuclear case*, new nuclear build is not allowed, whereas in the *unconstrained nuclear case* nuclear power can expand to minimise system costs. By comparing the *constrained nuclear* and *unconstrained nuclear* cases, the value of nuclear power in an integrated power system can be demonstrated. Proton exchange membrane (PEM) electrolysis and existing steam methane reforming facilities are the only technologies considered in the modelling to meet exogenous hydrogen demands and can account for part of the hydrogen market depending on their relative cost and carbon constraints. For electrolyzers, the hydrogen demand is by default flexible, including, but not limited to, the periods where electrolyzers can absorb excess power generation. The role of hydrogen as an electricity storage vector is not taken into account. The core modelling assumptions are therefore representative of the hydrogen economy prospects by 2035.

As integrated energy systems move towards net zero and hydrogen demand grows, the role of nuclear power becomes increasingly important

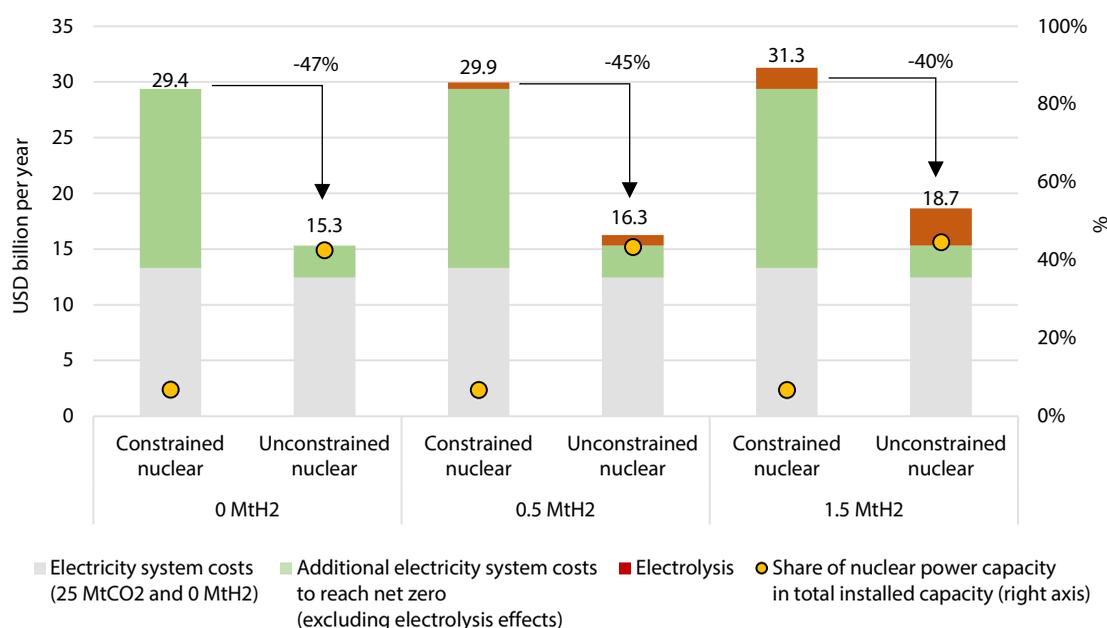
Under residual emissions corresponding to 25 MtCO₂, nuclear power lowers overall system costs. Compared to the constrained nuclear case, additional nuclear power capacity allows for system cost reductions of 7-11%. Given that this scenario allows for some residual carbon emissions from the combined power and hydrogen production, the cheapest option to produce hydrogen under these conditions remains carbon-emitting steam methane reforming, which is the least-cost option for the totality of hydrogen demand, even when it reaches 1.5 MtH₂ per year. Consequently, both electricity and hydrogen production systems remain decoupled; however, they still interact through the carbon constraint.

As integrated energy systems move towards net zero emissions, the role of nuclear power in lowering overall system costs becomes increasingly important. The system cost reductions enabled by nuclear new build increase from 7-11% to 40-50% as residual emissions are eliminated (Figure ES3). Displacing residual emissions is considerably more expensive if only variable renewables are used. Around 190 GW of variable renewables and batteries are thus

needed in the *constrained nuclear* case to meet the net zero carbon constraint, leading to a doubling of the system costs at the electricity grid level compared to scenarios with residual emissions. When nuclear new build is allowed to enter the system, only 30 GW of new nuclear power capacity is needed to displace the remaining emissions. The share of nuclear power that minimises the total costs of the combined power and hydrogen system is here around 40% of the total generation capacity. The resulting electricity mix combines the low plant-level costs of variable renewables with the dispatchability of nuclear power and thus makes it possible to meet a stringent carbon constraint and significant hydrogen production at the lowest cost.

In a net zero scenario, electrolysis is the only option available to produce hydrogen. The electricity and hydrogen production systems thus become fully coupled and a new set of interactions between them comes into play, affecting overall system costs. First, the whole system can take advantage of the assumed ability of electrolyzers to accommodate rapid load variations, especially in moments of excess variable renewable generation. This improves overall system flexibility and reduces the cost system gap at higher levels of hydrogen demand (Figures ES3). In parallel, electrolysis will also increase the need for baseload electricity, improving first the availability of existing nuclear units and then new nuclear units as hydrogen demand increases. At the systemic level, there is thus a trade-off between the additional flexibility that hydrogen production provides for variable generation from renewables and the need for a stable supply of hydrogen for industrial purposes and the increased utilisation rates of electrolyzers provided by nuclear baseload. Overall, the cost of electrolysis now represents up to 25% of the total system cost; most of the costs are to fully decarbonise the grid.

Figure ES3: **Total economic system costs at a net zero carbon constraint**



Note: Historical investments on existing capacity are not considered. The total economic system costs account for the physical costs (CapEx and OpEx) minus net export revenues. Balancing costs, connection costs and transmission and distribution costs are not considered. Discount rate = 5%.

The steady hydrogen production patterns associated with industrial applications further improve the competitiveness of nuclear power in integrated energy systems

By 2035, it is expected that a sizeable share of the low-carbon hydrogen produced will be devoted to decarbonising industrial applications. The technical constraints of industry require steady flows of hydrogen production, which can be supplied by electrolyzers connected to the

electricity grid and operating in baseload mode, especially if the hydrogen storage infrastructure faces deployment constraints. In such configurations, the case of nuclear power is further improved for two main reasons: first, the dispatchability of nuclear power matches well with the steady hydrogen production, leading to lower capacity additions and, second, systems with a higher share of nuclear power reduce reliance on the electrolyser's flexibility and are therefore less sensitive to hydrogen demand patterns.

Taking as a baseline a scenario with hydrogen demand of 1.5 MtH₂ at net zero carbon emissions, shifting from a flexible to a steady hydrogen demand (i.e. baseload operation for electrolysers) requires an additional 23 GW of variable renewables and batteries at an additional system cost of USD 4 billion per year, or 12% of the total system costs in relative terms. Since the flexibility of electrolysers is hampered by the steady production of hydrogen, the need for batteries, demand response, load shedding and variable renewable curtailment rapidly rises, contributing to this additional cost burden. With nuclear new build, only 4 GW suffice to meet more steady hydrogen demands at an additional system cost that is nine times lower, or USD 0.4 billion per year. These results underscore again the competitiveness of nuclear power to meet industrial hydrogen demands.

As indicated, the hydrogen economy can take many directions and assessing the cost and competitiveness of nuclear-produced hydrogen is not always a straightforward exercise. Due to increasingly stringent carbon constraints, it is, however, likely that PEM electrolysis will be the dominant means of satisfying industrial hydrogen demand by 2035. In this general context, electrolysers have the choice between two operational modes. They will either be coupled directly to a dedicated electricity generator or take their electricity from the grid, where it will be produced in various low-carbon configurations.

By combining plant-level (both production and delivery of hydrogen) and system-level economic approaches, this report provides a comprehensive picture of the cost and competitiveness of nuclear-produced hydrogen by 2035. It shows that nuclear power is a competitive option to produce and deliver hydrogen for industrial applications, both in the form of dedicated generation units for large installations and as an indispensable provider of low-carbon baseload power in decarbonised electricity systems. The scale and dispatchability of nuclear power thus contribute to the cost-efficient design and operation of hydrogen value chains as part of integrated low-carbon energy systems, which will be needed to provide the large amounts of hydrogen required to achieve the objective of net zero carbon emissions by 2050.

Key policy recommendations

1. **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 system costs in the longer term.
2. **Ensure that project assessments take into account the full value chain of hydrogen production and delivery.** Costs of hydrogen storage, transformation, transport and distribution can represent sizeable additional costs for hydrogen delivery. Taking into account the entire value chain requirements is essential to assess the project's overall business case and to design cost-efficient infrastructures.
3. **As an immediate first step: Demonstrate that large-scale, low-carbon water electrolysis is a viable alternative to today's carbon-intensive hydrogen production.** Ambitious demonstration initiatives are required to answer the economic, engineering and regulatory questions raised by large-scale electrolytic hydrogen production plants and value chains, whether based on renewable energies, current Generation-III light water reactors (LWR) or a combination of both.
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 water thermochemical cycles, possibly in conjunction with Generation IV reactor technologies, are promising low-carbon options that can reduce the primary energy requirements for hydrogen production.

1. The role of hydrogen in future low-carbon energy systems: An overview

1.1. An introduction to the hydrogen economy

The global hydrogen market is expected to surge from around 90 Mt in 2020 to more than 500 Mt by 2050 (IEA, 2021a). In 2020, hydrogen was largely consumed as a chemical input (i.e. feedstock or reagent) within the industrial sector for chemical manufacturing, oil refinement and, to a lesser extent, metal processing. However, the long-term decarbonisation goals of major economies give hydrogen an overarching role in low-carbon energy systems. For example, hydrogen governmental roadmaps in the United States, Canada and the European Union foresee key roles for hydrogen in the transport, power, building and industrial sectors by mid-century (DOE, 2020a; EC, 2020; NRCAn, 2020).

However, the future of hydrogen uptake remains highly uncertain. Deployment strategies face different challenges that must be urgently tackled. As a result, scenarios that consider no specific effort to encourage the deployment of hydrogen often describe moderate evolutions, mostly limited to existing market trends in the industry (DOE, 2020a; FCH JU, 2019). Worryingly, the International Energy Agency highlights in its 2021 *Global Hydrogen Review* that innovation of hydrogen-based technologies is already behind schedule to reach net zero goals (IEA, 2021b).

Hydrogen continues to benefit from a positive momentum worldwide. More than 20 countries or groups of countries boast national hydrogen roadmaps and several others are forming theirs (IEA, 2021a). In addition, the urgency to act against climate change and phase down fossil fuels appears likely to strengthen ambitions. For example, the European Union's hydrogen strategy was recently updated, raising its previous objective of producing 5.6 Mt of low-carbon hydrogen produced by 2030 to 10 Mt by the same year (EC, 2022a).

In this context, tracking discussions on hydrogen can be challenging. On one side, short-term challenges cast fundamental uncertainties over the future of hydrogen uptake. On the other side, public and private stakeholders continue to commit to increasingly ambitious hydrogen objectives and projects.

The concept of the hydrogen economy remains to a large extent theoretical. However, recent national roadmaps contributed to highlighting several key trends for the next ten years. In particular, a clearer picture has emerged of the technological landscape and markets. Furthermore, a growing number of stakeholders appear to be moving towards a similar market pattern, although its exact characteristics remain to be defined. The first chapter of this report presents these recent developments and discusses some of the most pressing challenges that remain. More precisely, it shows that while tackling the competitiveness gap between electrolytic and unabated hydrogen production is key, this is only one of various critical challenges that hydrogen systems will face in the near future. The report argues that the deployment of hydrogen projects on a large scale worldwide requires public and private stakeholders to consider the broader systems, whether those of the hydrogen value chain or the energy system.

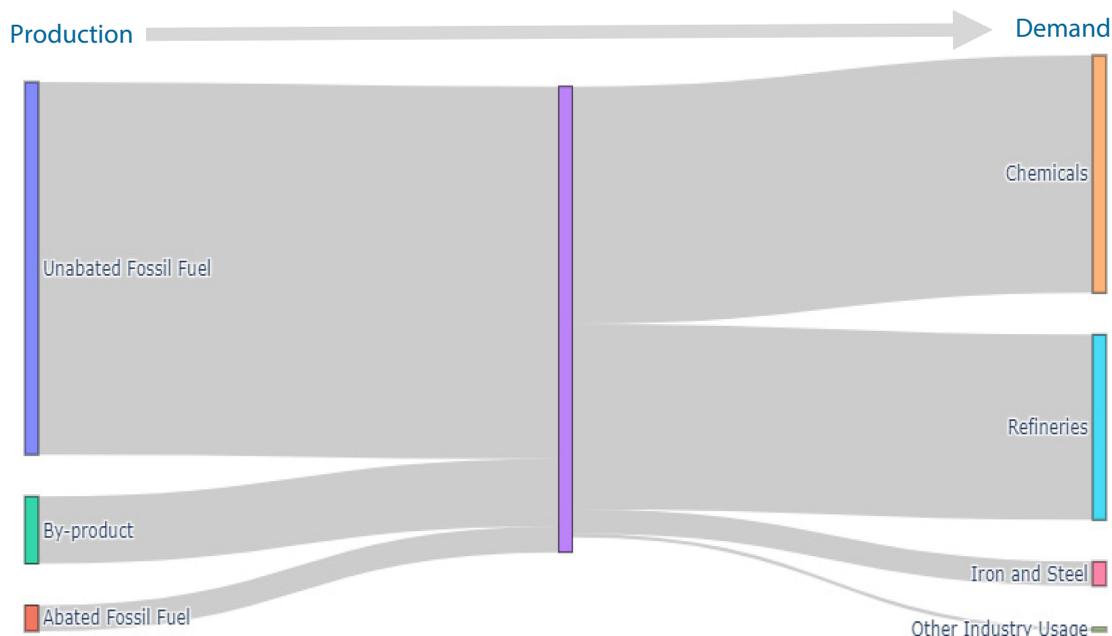
It is important to highlight that this section does not aim to be exhaustive but rather to present the most important elements that are expected to influence future hydrogen economies. For hydrogen production pathways, a complementary analysis is provided in Appendix 2.

1.1.1. Hydrogen production today: fossil fuel-based options vs. low-carbon water electrolysis

Hydrogen is not an energy source but an energy carrier. This means that it is not commonly found as is in nature; rather, it needs to be produced. Hydrogen bonds to other elements (e.g. oxygen, carbon, nitrogen) and is therefore commonly found in larger molecules like fossil fuels, biomass or water. In other words, producing hydrogen consists of extracting and collecting it from the above-mentioned larger molecules using an external source of energy.

Hydrogen production pathways are typically identified as either direct or indirect. The former designates hydrogen produced through dedicated methods, i.e. from hydrogen producing plants or merchant plants. As of 2021, this method represents around 80%, or 72 Mt, of global hydrogen production. Of this share, the vast majority uses a fossil fuel production pathway, largely unabated in terms of emissions. In indirect production pathways, the hydrogen is formed as a by-product of another industrial process. Indirect production pathways represent 20%, or 18 Mt, of global hydrogen production (Figure 1.1) (IEA, 2021b).

Figure 1.1: Hydrogen production and demand as of 2021



Source: NEA, with data from IEA (2021b).

Only direct hydrogen production is concerned by direct decarbonisation through non-polluting processes, while the indirect hydrogen production path is driven by other industrial dynamics. Indeed, most of the by-product hydrogen comes from naphtha refining and steam cracking, two polluting processes involved in gasoline production, plastic production or iron and steel processing (IEA, 2019a). In the short to medium term, using by-product hydrogen otherwise vented can represent a low-cost opportunity to stimulate the emerging market (NRCan, 2020). However, long-term decarbonisation requirements in the industry are expected to limit and reduce the relative importance of by-product hydrogen in total hydrogen production. This report focuses on direct and dedicated hydrogen production processes.

Regional resource endowment and political preferences are the key drivers for hydrogen technologies. Both of the most debated technologies, steam methane reforming and water electrolysis, have strengths and weaknesses. Ultimately, whether water electrolysis becomes the dominant solution globally seems tied to the feasibility and economics of steam methane reforming with carbon capture, utilisation and storage (CCUS), progress on hydrogen technologies and the possibility to produce enough clean electricity at a competitive price (FCH JU, 2019).

Steam methane reforming, which uses methane (CH₄) as a source of energy and hydrogen, enables large-scale hydrogen production, in the order of hundreds of tonnes of hydrogen per day (IAEA, 2018; NATF, 2020) at a very competitive price, between 0.5-1.70 USD/kg¹ (IEA, 2021b). Although this remains true in most regions of the world, it is important to highlight that the volatility in gas prices since 2021 has cast significant uncertainty on the future competitiveness of steam methane reforming.

Furthermore, it is a highly emitting process as it produces an average of 9 tonnes of CO₂ per tonne of hydrogen produced (IAEA, 2018; NATF, 2020). Carbon capture, utilisation and storage has proved to be efficient in reducing those emissions by 60-90% (IEAGHG, 2017). However, in practice, this comes with additional costs and operational challenges, starting with the infrastructure needed to transport and store captured CO₂, which might prevent such a solution from being deployed at scale or in certain regions.

On the other hand, water electrolysis, which uses electricity to split water molecules (H₂O) into oxygen and dihydrogen (H₂, thereafter hydrogen), is the cleanest way to produce hydrogen, provided it uses a decarbonised electricity source. In fact, water electrolysis surpasses steam methane reforming with CCUS on deep decarbonisation pathways (CCC, 2018; NATF, 2020). Further, it would enhance the penetration of variable renewables (VRE) (CCC, 2018; NATF, 2020). However, as of 2021 water electrolysis contributes only marginally to total hydrogen production (IEA, 2021b). This can be explained, at least partially, by the competitiveness gap with unabated and abated fossil fuel pathways in a context of low gas prices. Indeed, standard hydrogen costs of production from water electrolysis were estimated at USD 3-8 per kgH₂, approximately 2 to 4 times more than abated steam methane reforming (IEA, 2021b).

Box 1.1: Three electrolyser technologies compete for the market

Three different electrolyser technologies are most common: alkaline, proton exchange membrane (PEM) and solid oxide electrolyser cell (SOEC). Each has strengths and weaknesses based on the types of materials used and the electro-chemical reactions involved (see Appendix 2). The alkaline and PEM technologies are mature, with both at technology readiness level 9 (IEA, 2021c) although the latter is only starting to be deployed at scale (IEA, 2021b; HE, 2020). Systems of several MW are possible as shown by the largest alkaline and PEM electrolysers operating in Europe, in Rjukan, Norway, with a capacity of 9 MW, and in Linz, Austria, with a capacity of 6 MW. New systems of tens of MW or more are being deployed in Europe for both technologies (HE, 2020) and systems of several hundreds of MWe have been announced for the end of this decade.

An alkaline design based on common metals is currently the cheapest option. However, this technology is not optimised for dynamic operation, which would undermine system efficiency and hydrogen purity. On the contrary, PEM electrolysers have a short hot idle and cold start ramping time, which makes them match variable renewable power source requirements. However, PEM cells use expensive electrode catalysts (platinum, iridium) and membrane materials. They are more complex and suffer from shorter lifetimes than the alkaline technology.

The SOEC operates at much higher temperatures (of 650-1 000°C) than the other two technologies. It is therefore categorised as high-temperature electrolysis (HTE) (IEA, 2019a). It is the least developed technology but has been demonstrated at scale in laboratories, with an estimated technology readiness level of 7 (IEA, 2021c). Systems of hundreds of kW already exist, the largest deployed in Europe in Salzgitter, Germany, with capacity of 700 kW. The MULTIPLHY project in the European Union aims to install a 2.6 MW system. Leveraging the higher temperature operating mode, SOEC technology can reach electrical efficiencies greater than 95%. However, providing the required temperature and managing the associated material degradation remain key challenges (IAEA, 2018; IEA, 2019a).

Nuclear and solar power are two promising sources of clean heat being investigated for SOEC worldwide. In the United States, the “solid oxide electrolysis system (SOEC)” programme aims to provide nuclear-SOEC coupled plants of hundreds of MW by the end of the decade. In the European Union, the project PROMETEO, launched in 2021 and due to end in June 2024, aims to develop a pilot SOEC system of 25 kW coupled with a concentrating solar system.

1. Based on long-term average gas prices around USD 3 per MMBtu.

In this context, steam methane reforming with CCUS is likely to remain the leading option while water electrolysis penetrates the market in the short term (IOPG, 2021), with volatility in gas markets likely to accelerate its deployment. For water electrolysis to become dominant, technological costs must fall drastically and the production capacity of clean and cheap electricity increased significantly (FCH JU, 2019; IOPG, 2021; EC, 2022a).

The availability of cheap electricity or natural gas for hydrogen production will largely shape the technological landscape for hydrogen production. For steam methane reforming, the possibility of storing the CO₂, for example in geological caverns, and its political acceptability are also determining factors. The case of France, which benefits from a high share of nuclear electricity and has not considered steam methane reforming with CCUS in its national hydrogen strategy, highlights the decisive power of policy makers.

In the long term, other production pathways might emerge. Thermochemical water splitting, methane pyrolysis and biomass-based routes are the most touted. The first is another category of water-splitting techniques which principally uses heat as energy and provides promising opportunities for nuclear (see Box 1.2). Water is split into hydrogen and oxygen using chemical reagents which are recycled completely in the cyclic process. Further details are given on water thermochemical cycles in Appendix 2. Methane pyrolysis relies on the same principle but uses methane as a source of hydrogen instead of water. The third uses biomass as a source of hydrogen such as anaerobic digestion, gasification of biomass or fermentation. However, these technological pathways remain in early stages of development and are not expected to play a key role in the short to medium term.

Box 1.2: Nuclear power for water chemical cycles

Japan, China and Korea are leading the way in exploring opportunities to couple sulphur-iodine (SI) plants to high-temperature nuclear reactors. The Japan Atomic Energy Agency (JAEA) operates the 30 MW(t) gas-cooled High Temperature Engineering Test Reactor (HTTR), with an outlet temperature of 950°C that achieved first criticality in 1998 and successfully passed the 30% power loss of forced cooling test in 2010. On 3 June 2018, the Japanese Nuclear Regulatory Agency allowed the HTTR to resume its activities after a four-year safety review process. It passed again the 30% power loss of forced cooling test in 2021 and further safety demonstration tests are planned. Future research on the reactor concerns the core physics (xenon stability, decay heat measurement, burnup characteristics), the fuel behaviour (iodine, tritium) and component performances (heat exchanger, etc.) (Kunitomi, 2018).

In parallel, the JAEA has developed a bench-scale facility for hydrogen production using a continuous SI closed-cycle. In January 2019, it produced 30 litres of hydrogen per hour for 150 hours. A key future objective is to reach larger hydrogen production (100 L/h) for a longer time under stable conditions. The JAEA expects to conclude tests on the HTTR and for the development of basic technologies for the SI process in the next decade. Tests coupling the HTTR and SI systems are expected to be performed to enable the first operational HTGR-SI plants by 2040 (Kunitomi, 2018; Suppiah, 2020).

In China, the Institute of Nuclear and New Energy Technology (INET) has operated the HTR-10 since 1998, one of two high-temperature gas reactors (HTGRs) in operation, producing a power of 10 MWth and enabling outlet temperatures of 900°C. The next generation of HTGRs, the HTR-PM, with a thermal power of 250 MW, is being commissioned. INET selected the SI thermochemical cycle in 2005 as its leading technological pathway for coupling with the HTR-10, thus dropping research on high-temperature electrolysis. Since then, INET has developed and operated an SI pilot plant, enabling a production of 60 litres of hydrogen per hour. According to communicated R&D targets, coupling of the HTR-10 nuclear reactor and the SI thermochemical plant is expected between 2021 and 2025 (Suppiah, 2020).

Though less studied worldwide, other nuclear-hydrogen plant combinations are being investigated. Examples include the copper-chlorine cycle in Canada. This thermochemical cycle requires a maximum temperature of approximately 550°C which is to be provided by Canada's future nuclear technology (IAEA, 2018). The technology roadmap aims to demonstrate each step of the cycle process at laboratory scale and develop a pilot plant design by 2023 that enables production of up to 1 tonne H₂/day, and demonstrate the pilot plant by 2026.

1.1.2. Hydrogen as energy vector for economic sectors that are difficult to decarbonise

Hydrogen can be used in almost all sectors of the economy as a reagent, feedstock or energy vector (Figure 1.2). Today, the vast majority of the hydrogen produced is used in industrial cases for two principal applications, chemical production and oil refining, while most of the remaining share is used for metal processing (IEA, 2021b). In the future, hydrogen could contribute to decarbonising the industry further through new industrial applications (production of high-value chemicals [HVC], direct reduction of iron ore, etc.) provided it is low-carbon (see Box 1.3).

As a commodity, hydrogen can contribute to decarbonising the transport sector and produce synthetic fuels. In its pure form, hydrogen can be used in fuel cell electric vehicles, which have greater autonomy, higher power and faster recharge rates than battery electric options. As a feedstock for manufacturing synthetic fuels, hydrogen will become a key for the decarbonisation of heavy-duty transport (trucks, planes and ships) or the production of low-carbon industrial heat. Hydrogen could also be used to generate heat, either mixed with natural gas or purely in dedicated boilers. Burned as synthetic fuel, hydrogen could also contribute to the decarbonisation of high industrial heat generation (IEA, 2019a).

Box 1.3: Demand trends for industrial applications and synthetic fuels

The chemical, iron and steel sectors are expected to grow over the long term as a result of global economic and population growth (IEA, 2019a). Tied to global decarbonisation objectives, the future of the oil sector seems much more uncertain (IEA, 2019a). However, sectorial market perspectives are not enough to anticipate future demand for low-carbon hydrogen. Indeed, an important share of the hydrogen consumed within the industry is produced as a by-product of another process, most often relying mainly on fossil fuels (IEA, 2021b). As a result, although the total demand for hydrogen within industry might rise, this is of little help to assess future needs for low-carbon or merchant hydrogen. In this context, the literature highlights that to decarbonise industry, new processes that rely on merchant hydrogen need to be deployed (IEA, 2019a).

Within the chemical sector, demand for low-carbon hydrogen will likely rise as the needs for nitrogen-based fertilisers and methanol increase. Particularly promising, for example, is the deployment of methanol-to-olefins and methanol-to-aromatics technologies involved in the production of high-value chemicals (HVC) that are the precursors of many plastics, currently mostly derived from oil products and leading to the production of several million tonnes of by-product hydrogen per year (IEA, 2019a).

Within the iron and steel sector, the greatest opportunity for low-carbon hydrogen lies in the development of the direct reduction of iron-electric arc furnace (DRI-EAF) technology that uses merchant hydrogen. As of 2020, about 90% of primary steel is produced through the blast furnace-basic oxygen furnace (BF-BOF) route, which consumes a share of the by-product hydrogen it produces from coal (IEA, 2019a).

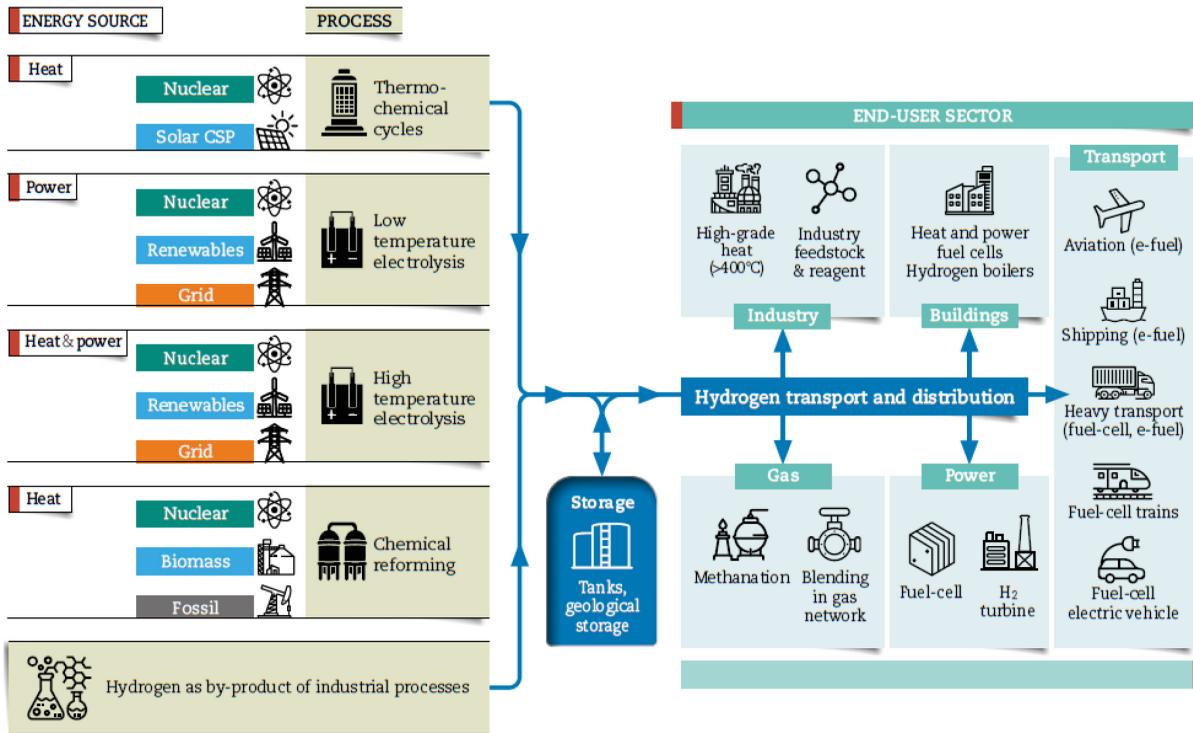
Around two-thirds of the demand for oil refinement is currently met with merchant or dedicated hydrogen, a share that is expected to remain stable in the future (IEA, 2019a). However, market perspectives are uncertain, on the one side pushed by regulations for lower sulphur content in oil products – hydrogen being used for desulphurisation – while on the other side potentially depressed by the context of the global energy transition. It is estimated that the need for hydrogen within the oil sector is likely to remain flat or decline in the coming decades.

In absolute terms, the literature assesses global hydrogen demand for industrial applications at around 100 Mt by 2030 and 150 Mt by mid-century (Agora, 2021). From this amount, the share of merchant hydrogen will largely be reliant on the deployment of new industrial processes, such as those mentioned above. Assuming that around 90% of industrial needs are met using dedicated hydrogen production, it seems reasonable to assume that demand from industry for merchant and dedicated hydrogen would be of at least 90 Mt by 2030.

Finally, synthetic fuel options are most likely to be medium- to long-term opportunities. For example, in its *Hydrogen Roadmap Europe*, Hydrogen Europe expects them to reach mass-market acceptability between 2035 and 2040, under an ambitious scenario (FCH JU, 2019). As a result, most of the demand in the transport sector by 2030 is expected to come from the heavy road sector, which at best represents several million tonnes of hydrogen (IEA, 2021a; IEA, 2021b). In the longer term, the literature estimates that hydrogen for the heavy road transport, planes and ship transport sectors could represent demand of 100-200 Mt per year.

Hydrogen is an efficient flexibility tool for the energy grid and would enable greater penetration of variable renewables. As VRE penetrates the grid, the need increases for flexibility, i.e. the ability to adapt to variations in electricity supply and demand, as well as long-term and large-scale energy storage (IEA, 2019b; NREL, 2020). Hydrogen produced from water electrolysis can contribute to answering both of these needs. In practice, during a drop-in supply, the electrolyzers can be easily disconnected to reduce the load on the grid. Conversely, during a surge in production, hydrogen can be stored at large scale and long term in salt caverns. The hydrogen can then be used either as a commodity or to produce electricity using a fuel cell when desired.

Figure 1.2: The hydrogen economy – energy sources, production processes and end-uses



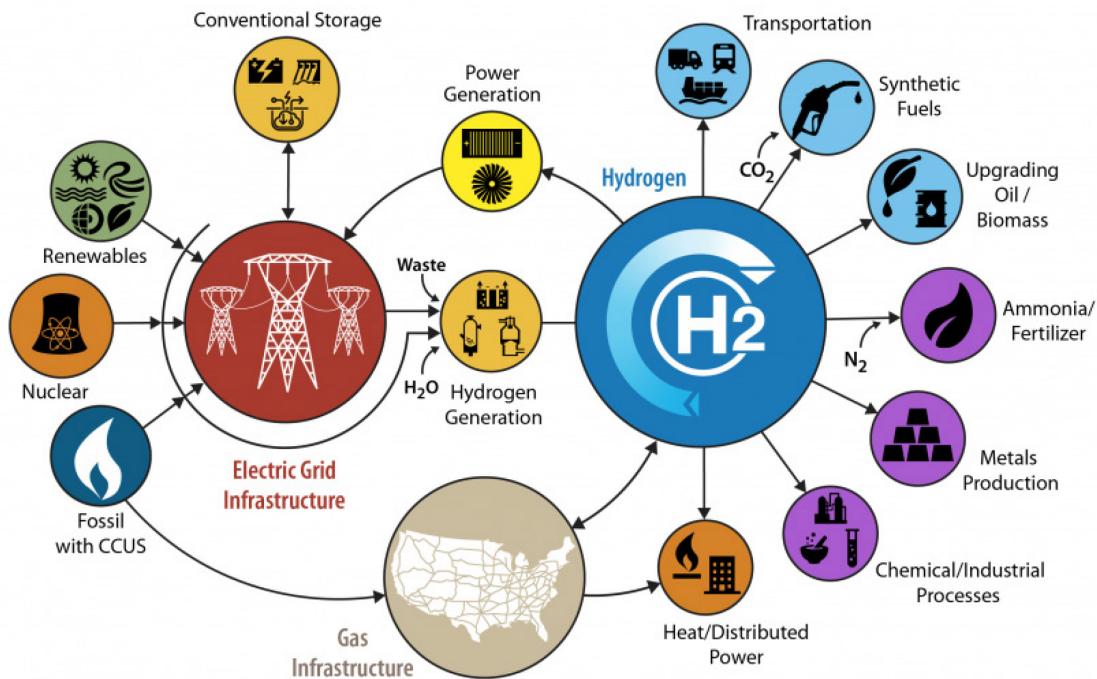
Source: NEA, 2022

A number of challenges have yet to be addressed before the hydrogen economy can become a reality. In particular, hydrogen value chains suffer from intrinsically lower efficiencies than alternatives such as direct electrification or biomass value chains (Hydrogen TCP, 2021; Agora, 2021). This particularly concerns certain applications within the transport and energy sectors. For example, fuel cell electric vehicles and combined heat and power fuel cells would use two to five times more electricity than, respectively, battery electric vehicles and electric heat pumps for an equivalent service (CCC, 2018; Agora, 2018). Furthermore, while the first units of hydrogen indeed enable greater penetration of VRE in the grid, this effect tends to plateau as the volume of hydrogen increases (Tsiropoulos et al., 2020). In other words, requirements for hydrogen as a flexibility tool are likely to remain limited in the future, even for systems with a high share of VRE. As a result, some scenarios anticipate that hydrogen will mostly be used in hard-to-electrify sectors, in particular for heavy-duty transport and industrial applications as well as flexibility applications (FCH JU, 2019; Agora, 2021).

1.2. Hydrogen deployment strategies

A large number of public institutional hydrogen roadmaps foresee final roles for hydrogen in the transport, power, building and industrial sectors (DOE, 2020a; EC, 2020). For example, The US Department of Energy's hydrogen strategy places hydrogen in the centre of its future decarbonised energy system. Called "H2@Scale" (Hydrogen at Scale, represented in Figure 1.3), it "provides an overarching vision for how hydrogen can enable energy pathways across applications and sectors in an increasingly interconnected energy system" (DOE, 2020a). For hydrogen produced from electrolysis, this overarching role in future low-carbon energy systems is also often referred to as the Power-to-Hydrogen, Hydrogen-to-X concept where X designates key categories of "high-value products and services" used in the economy, such as fuels (synthetic petrol, diesel, etc.), gas (synthetic methane, hydrogen-blending in natural gas), chemical (olefins, alcohols, etc.) (Hydrogen TCP, 2021).

Figure 1.3: **H2@Scale concept and the overarching role of hydrogen in future decarbonised energy systems**



Source: US DOE, 2022a.

1.2.1. Hydrogen production and consumption over different time horizons

Uncertainty over whether hydrogen uptake will be widespread or limited to hard-to-abate sectors is reflected through actual deployment strategies' time horizons. Typically, short-, medium- and long-term objectives refer to around 2025, 2035 and 2050, respectively. In the short term, set at around 2025, hydrogen demand is expected to remain stable and dominated by industry. Priorities are to close the competitiveness gap between fossil fuel and water electrolysis and to decarbonise existing usages (RTE, 2020). In other words, the industrial and economic feasibility of producing low-carbon hydrogen on a large scale must be demonstrated.

For example, leading initiatives on nuclear-produced hydrogen in the United Kingdom and in the United States are characterised by broad and intersecting objectives on economics, engineering, markets and licensing (EDF Energy, 2019; Bragg-Sitton and Boardman, 2020). 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-products 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.

Box 1.4: Focus on leading nuclear-hydrogen initiatives

Hydrogen to Heysham (H2H): This project directly connects a 1 MW alkaline electrolyser and a 1 MW PEM electrolyser to the gas-cooled reactor Heysham 2 (HYB) in the United Kingdom. In addition to testing and comparing the performance of both electrolyser technologies in real conditions, it aims to assess the benefits of using the oxygen produced from electrolysis for the reformation of CO₂ used in gas-cooled reactors (EDF Energy, 2019).

The Light Water Reactor Integrated Energy Systems Interface Technology Development & Demonstration programme, launched in the United States, aims to develop a hybrid system enabling diverse electrolyser technologies to be tested when coupled with a light water reactors (LWR). The project involves both modelling and field work as a first stage to enable nuclear-LTE hydrogen plants on the scale of 200-500 MWe to be commercially available by 2025 (DOE 2020b, Bragg-Sitton and Boardman 2020):

- Track I: Perform techno-economic assessments of hydrogen production using nuclear energy;
- Track II: Couple 1-3 MW PEM electrolyser 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 a 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 250 kW SOEC nuclear compatible system with ultra-high efficiency and at low cost. The laboratory aims to deliver a commercial 200 MW 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. Moreover, the programme tends to demonstrate that using heat augmentation techniques, such as resistive heating or chemical heat pumps, make it possible to employ current reactor technologies for HTE in a competitive manner (DOE, 2020b; DOE, 2020c).

In the medium term, set around 2035, electrolytic hydrogen production is expected to ramp up. Most of the deployed electrolyser systems' capacities are currently in the range of MW and kW for alkaline, PEM and SOEC technologies. They are the first steps of political and industrial visions that aim to make GW-scale hydrogen production plants commercially available by the end of the decade. The demand remains dominated by incumbent industrial stakeholders, although new applications, such as in the transport sectors or hydrogen-blending with natural gas, see steady growth (EC, 2020; HE, 2020; RTE, 2020).

This is the result of an acceleration in research and development objectives on hydrogen technologies across leading research agencies. For example, the European Hydrogen Roadmap expects mass market acceptability to be reached by 2030 for 14 out of 17 key hydrogen applications, excluding synthetic fuel manufacturing, pure hydrogen heating in buildings and low to medium industrial heating. By way of comparison, under the "business as usual" scenario, only 4 of the 17 applications (city buses, taxis, railways and vans) would have reached mass market acceptability by the end of this decade, with 3 of them in 2030 (FCH JU, 2019; HE, 2020).

Finally, from 2035 onwards, the demand for hydrogen is expected to surge, spearheaded by its roles in the industrial and transport sectors. The deployment of variable renewables at large scale increases national grids' need for hydrogen for flexibility management. Infrastructure to produce, transport and distribute low-carbon hydrogen is deployed on a large scale and hydrogen is traded on international markets.

1.2.2. **Towards centralised production plants closer to consumption hubs**

The deployment strategies described above lead energy planners and involved private stakeholders to converge on the short- to medium-term patterns for the hydrogen market. Industry, which is expected to dominate the hydrogen market over those time horizons, (FCH JU, 2020; BEIS, 2021), is characterised by large-scale and centralised demand. For this reason, current hydrogen markets are structured around delimited areas of production and consumption. For example, the hydrogen roadmap of the United States relies on the concept of regional clean hydrogen hubs, the idea being of “[c]o-locating large-scale clean hydrogen production with multiple end-uses [in order to] foster the development of low-cost hydrogen and the necessary supporting infrastructure [and] jumpstart the hydrogen economy in various market segments” (DOE, 2022b). In Europe, hydrogen deployment is focused on the concept of the Hydrogen Valley, defined as “a geographical area where clean hydrogen is produced and locally used by households, local transportation and industrial plants.” (EC, 2022b). Belgium, Germany and the Netherlands are leading the way (Agora, 2021). Other important clusters are expected in Eastern Europe and along the Mediterranean. In the United States, potential hubs could be deployed, among other locations, in the Great Plains and the Great Lakes regions, leveraging the vast amount of wind and nuclear energy, respectively (GPI, 2022).

The “Hub” or “Valley” 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. A leading project is the Freeport East Hydrogen Hub in the United Kingdom, where up to 1 GW 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 with nuclear energy (DOE, 2022b). There also interest in the role of small modular LWR and how they can contribute to hydrogen hubs. In particular, their flexibility and safety features could enhance the potential of co-location with large consumption points such as ports or large industrial facilities.

Although hydrogen valleys and hubs benefit from momentum, the definition of their exact characteristics and their feasibility within announced timelines remain unclear (see for example questions raised in DOE, 2022b). For example, a recent assessment described different types of valleys that are being deployed based on their scale and end-use sectors, such as “small-scale and mobility-focused”, “medium-scale and industry focused” or “international and export focused” (Weichenhain et al., 2021). As hydrogen production technologies improve, the demand for hydrogen might become more distributed as applications in the transport, power and heating sectors emerge (FCH JU, 2019).

1.2.3. **Maritime transport and long-distance hydrogen value chains**

Large ports, often connected to or near industrial hubs, are also identified as premium locations for hydrogen production plants in the short term (IEA, 2019a). Further, they open the possibility for hydrogen to be traded over long distances. However, the question of the delivery costs remains open. In general, delivery costs are influenced by four key parameters (IEA, 2019a; JRC, 2021): availability of infrastructures in exporting and importing countries, distance, means of transport, and the end-use sector.

Certain preliminary studies tend to show that long hydrogen chains can be competitive. For example, a case study from the IEA concluded that hydrogen produced in Australia and transformed into ammonia before being shipped to Japan could already find a market (Hydrogen TCP, 2021). That being said, deploying long and complex hydrogen value chains remains challenging. In particular, significant efforts should be made to streamline and co-ordinate stakeholders’ investments towards compatible visions (IOGP, 2021). This is for example part of Germany’s hydrogen strategy, which allocates around 20% of its federal investments to deploying bilateral approaches with identified exporting countries such as Australia, Chile and Namibia.

1.3. Outstanding challenges facing the hydrogen economy

The above description of hydrogen roadmaps and deployment strategies mentioned several uncertainties that can hamper their implementation and development speed. In particular, the different views on possible hydrogen uptake, i.e. widespread or limited to hard-to abate sectors, entail major differences for the long-term future of low-carbon hydrogen. Early use of hydrogen in the above-mentioned sectors would foster economies of scale, technological innovation and investments, in turn encouraging hydrogen-based solutions to spread (IEA, 2019a). Conversely, there is a risk that low-carbon hydrogen might miss its window of opportunity to establish itself in the global race towards decarbonisation, in which competitive alternatives exist (IOGP, 2021).

This challenge is well illustrated by the IEA, which singles out hydrogen-blending as a means to kick-start global hydrogen uptake (IEA, 2019a). In fact, in the IEA's net zero scenario, the demand for hydrogen blended in natural gas grids sees the greatest growth among all sectors between 2020 and 2030, from virtually none to 55 Mt (IEA, 2021a). There is not a consensus, however, on this view in the literature. Indeed, other studies consider that hydrogen demand for the sectors described above is likely to remain limited until at least 2030, primarily driven by pilot and demonstration projects (FCH JU, 2019).

1.3.1. Uncertainties over future hydrogen uptake

Hydrogen roadmaps are characterised by three types of uncertainties: policies, technologies and standards. The first highlights the fact that long-term deep decarbonisation strategies remain a highly divisive topic. In particular, the deployment of high shares of solar photovoltaic and wind generation systems in power grids has yet to be proved to be economically and politically feasible (NEA, 2019; IEA and RTE, 2021). In other words, the future of hydrogen is tied to uncertain policy frameworks that currently support the decarbonisation of energy systems.

The competitive gap between hydrogen-based technologies and alternatives such as direct electrification or fossil fuels with CCUS is a major difficulty that prevents widespread use of low-carbon hydrogen. In this context, leading research agencies have aggressively accelerated their research and development deadlines, as highlighted earlier in this chapter. Ultimately, the extent to which hydrogen will be deployed in the economy is tied to progress on key low-carbon hydrogen technologies. This requirement for rapid and significant technological progress also applies to end-use and value chain technologies such as hydrogen-powered vehicles or storage and transport options. What is more, it is key that the cost of electricity generation remains low, as it is the primary parameter that influences the production cost of hydrogen, as shown in Chapter 2 of the report.

Finally, hydrogen's future is tied to the ability of stakeholders to set and agree upon technical frameworks for hydrogen handling and trading. Hydrogen value chains are complex and involve many different transport, storage and transformation solutions. Beyond costs, shared sets of standards and regulations for those solutions have not yet been developed and implemented. The literature highlights how this could hamper some applications. For example, blending ratios for hydrogen in natural gas grids are not harmonised in Europe (Hydrogen TCP, 2021). The IEA expects in its net zero scenario that hydrogen-blending will represent around 25% of total demand by 2030, which illustrates the scale of uncertainty for future hydrogen markets (IEA, 2021a).

1.3.2. Toward a cost-efficient hydrogen economy

The French Transmission System Operator, Réseau de Transport d'Électricité, has analysed three modes of operation for electrolysers with the objective of producing 630 kt of hydrogen per year in 2035 (RTE, 2020):

- The “excess power mode”, where electrolysers only use excess power from the grid. Around 38 GW of electrolysers should be deployed as they operate 9% of the time on average.

- The “VRE coupled mode”, where electrolyzers are coupled to a solar photovoltaic plant. The capacity requirement falls to around 9 GW and electrolyzers run on average 38% of the time.
- The “baseload mode”, where electrolyzers are plugged into the grid and operated as a baseload. The capacity requirement falls farther to around 4 GW as a capacity factor of 93% is reached.

Each solution has its strengths and weaknesses. The “excess power mode” would leverage very cheap electricity but the low operating load factors offset this advantage. Additionally, installing the required electrolyser capacity would be a clear industrial challenge. The “VRE coupled mode” would benefit from low-carbon and cheap electricity as well as a high-enough load factor to produce competitive hydrogen. However, like the “excess power” mode, this might lead to substantive value chain costs from hydrogen storage, transformation, transport and distribution.

Indeed, managing variability in hydrogen production would involve inefficient infrastructure design in the likely case of a mostly unremitting industrial demand. Furthermore, business models under consideration might struggle to reach the necessary production volume required to amortise the high upfront costs from the deployment of value chain infrastructures. To answer this challenge, part of the literature explores the option of coupling a hydrogen production plant to a nuclear energy source, which is steady and large-scale. The question of the competitiveness of nuclear-based value chains is addressed in Chapter 2 of this report. The literature also showed how hydrogen production could contribute to improving the economics of nuclear in liberalised electricity markets (see Box 1.5).

Box 1.5: How hydrogen can improve the economics of nuclear power in liberalised electricity markets

The Idaho National Laboratory has examined the opportunity that hydrogen brings to the nuclear industry by diversifying its business model (INL, 2019). Indeed, existing reactors are typically operated either in a baseload mode, i.e. generating power all the time except during outage for refuelling or maintenance, or in a flexible mode, i.e. ramping generated power up and down to meet demand. These modes of operation draw the most out of nuclear power as they tend to maximise reactors’ load factor, a determining factor in nuclear economics. However, the ongoing transformation of electricity grids, characterised by a growing share of subsidised variable renewables and in certain regions cheap natural gas, makes both baseload and flexible modes of operation less sustainable (INL, 2019). This economic aspect played a significant role, for example, in the retirement of several US units in the last decade (Indian Point- 2 and 3, Three Mile Island-1, Duane Arnold-1, Oyster Creek, Pilgrim-1, etc.).

In this context, new modes of operation for nuclear reactors are being investigated and producing hydrogen is seen as a promising lever to enhance nuclear competitiveness. In particular, two business cases are commonly discussed in the literature: hybrid operations and power revenues optimisation (INL, 2019). In those operation modes, the nuclear reactor can generate electricity or hydrogen, depending on market signals. The idea is to produce hydrogen when electricity prices drop low and switch back to electricity whenever they rise up. Hybrid operations and power revenues optimisation differ in the end-usage of produced hydrogen. In the former, hydrogen is either to be used on-site for internal needs or sold to external industries. Under power revenues optimisation, hydrogen is stored and converted back into electricity through a fuel cell when prices are high enough.

It is essential to distinguish “commodity hydrogen,” used for example in industry or the transport sector, from hydrogen used as a flexibility tool for the energy system. Although synergies can be exploited, both roles answer different requirements as illustrated above. In this context, a growing share of the literature highlights the need for public and private stakeholders to consider both the supply and the demand requirements to ensure a cost-efficient deployment of hydrogen value chains (IEA, 2021b).

The “baseload mode” would reduce requirements for electrolyser capacities to a minimum and optimise hydrogen value chain infrastructures. However, part of the literature fears that this mode of operation as well as the “VRE coupled mode” would hamper the overall decarbonisation of the economy (HCC, 2021). Indeed, assuming an electrolyser efficiency of 60% (low heating value), producing 1 kg of hydrogen would require 55 kWh. Produced from unabated steam methane reforming, this would lead to emissions of around 9 kgCO₂. Assuming an average carbon intensity for the electrical grid of 230 gCO₂/kWh, i.e. the value for the European grid as of 2020 (EEA, 2022), producing 1 kg of hydrogen with taken hypotheses would lead to the emission of 12.65 kgCO₂. In other words, producing hydrogen using either low-carbon grid or dedicated low-carbon sources effectively contributes to lowering overall emissions for grid carbon intensities below 165 gCO₂/kWh.

To overcome this issue, the European Commission (EC) suggests applying the Principle of Additionality, which stipulates that all new demand for renewable electricity for hydrogen production must always be answered with additional renewable capacity (EUI, 2021). However, this strategy entails a clear investment challenge. Indeed, the EC anticipates that USD 340-492 billion would be required to deploy 40 GW of electrolysers, infrastructures and the necessary renewable generation capacity by 2030 (EC, 2020).

Additionally, part of the literature highlights that total investments in the power system are higher for market arrangements that limit the origin of electricity to VRE (IOGP, 2021; RTE, 2020; Aurora, 2021). For example, Aurora (2021) shows that total system spending would be 6-9% lower in the United Kingdom if renewables and nuclear support the energy transition. This leads some of the literature to support the use of nuclear power which, alongside variable renewables, has proved capable of enabling deep decarbonisation of the electricity grid (Appert and Geoffron, 2021).

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2. The competitiveness of nuclear-produced hydrogen

2.1. Understanding hydrogen production and delivery costs

Like the well-established concept of the levelised cost of electricity (LCOE), the levelised cost of hydrogen (LCOH) is a fundamental indicator for investors and policymakers to choose between options for hydrogen production. LCOH, just as LCOE, applies to the levelised cost at the level of the individual production unit. Also as is the case of LCOE, LCOH provides only a portion of the economic story and, applied alone, can lead to faulty conclusions. Any complete analysis of the economic costs of different hydrogen production options will quickly show that it needs to be expanded to take into account the costs of storage and transportation to provide meaningful information to decision makers.

The following analysis starts by discussing the competitiveness of common low-carbon hydrogen production pathways, i.e., steam methane reforming with carbon capture, utilisation and storage (CCUS), proton exchange membrane (PEM) electrolysis and solid oxide electrolysis using power (electricity and potentially heat) from renewables and nuclear.

In addition to costs of production, the costs of hydrogen storage, transformation, transport and distribution are increasingly discussed in the literature. To that extent, a “system-level approach” is promoted to ensure an efficient deployment of hydrogen value chains (JRC, 2021; IEA, 2021a). The final hydrogen cost, which takes into account production and the full value chain, could be referred to as the levelised cost of hydrogen delivery or LCOHD. Drawing from the latest literature on this aspect, the following analysis also considers the LCOHD for generic electrolyser business cases.

In order to assess hydrogen LCOH and LCOHD, a simplified Excel techno-economic model has been developed. The reader should note that assessing hydrogen cost of delivery remains a serious challenge as hydrogen value chains are complex and likely to be designed on a case-by-case basis. In this context, it is important to highlight the preliminary nature of given results and to insist on their dependence on chosen hypotheses.

2.1.1. Methodology and assumptions

The NEA hydrogen model, building on the US Department of Energy’s H2A approach, has been developed to assess LCOH and LCOHD for different sources of electricity (ANL, 2022). In particular, the competitiveness of low- and high-temperature electrolysis are calculated for amortised nuclear reactors (hereafter long-term operation) and new nuclear installations (new build). For the latter, both light water and high-temperature reactor technologies are considered. For LCOHD, all the scenarios consider a similar type of demand (e.g. continuous in time) and similar infrastructures (e.g. compressed storage, geological storage and hydrogen pipeline transport). A similar approach is applied to assess LCOH and LCOHD from different electricity sources such as the grid, solar photovoltaic and wind as well as from the alternative production pathway steam methane reforming.

The levelised cost of hydrogen (LCOH) represents the breakeven price of hydrogen limited to the production plant and given a determined cost of capital and rate of return, both coalesced within the actualisation rate. LCOH consists in the ratio of the sum of discounted hydrogen production costs and discounted hydrogen production volume over the hydrogen production plant’s entire assumed lifetime. Following the same logic, the LCOHD represents the breakeven hydrogen price for the entire value chain which includes hydrogen production as well as hydrogen storage and transport, also considering a given actualisation rate. Revenues that could emerge from selling by-products such as oxygen are not taken into account. LCOH and LCOHD are expressed in 2020 dollars per kilogram of hydrogen.

For example, for an infrastructure X (production plant, pipeline, compressed tank, etc.), the levelised cost would be calculated as follows:

$$LCOX = \frac{\sum_i^N ((CapEx_{X,i} + F_OpEx_{X,i} + V_OpEx_{X,i}) \times DF_i)}{\sum_i^N (Plant_prod_i \times DF_i)}$$

Where, i represents the year, N the analysis period, CapEx_i the total annual Capital Expenditures for year i, F_OpEx_i the total annual Fixed operation and maintenance expenditures for year i, V_OpEx_i the total annual Variable operation and maintenance expenditures for year i, Plant_prod_i the total annual plant production of hydrogen for year i and DF_i the discount factor for year i.

The discount factor for year i is calculated as follow:

$$DF_i = \frac{1}{(1 + r)^{i - Start_year}}$$

Where, r is the fixed discount rate and Start-year is the year the plant starts operating.

Levelised cost of hydrogen production and delivery are referred to as respectively LCOH and LCOHD. LCOHD is the sum of all different levelised costs along the full value chain. CapEx, F_OpEx and V_OpEx assumptions and perimeters are specified for each infrastructure type (production plant, pipeline, compressed tank, etc.) in the value chain hypotheses section.

This techno-economic analysis has a time horizon set at 2035. This near-future horizon allows the analysis to be based on pragmatic assumptions for technology performances. Tables 2.3, 2.4 and 2.5 show the key values used in this analysis for electrolysers, electricity generation technologies and steam methane reforming, respectively. Finally, sensitivity analyses are performed to compare, refine and discuss results.

In its base cases, the study assumes a uniform discount rate of 5% for all scenarios. In practice, the discount rate takes into account investment risk and uncertainty and is largely influenced by the regulatory framework or the market design. Although most of those parameters remain unknown for hydrogen projects, it is assumed that generalised government support, at least by 2035, will apply a downward pressure on discount rate values.

A uniform construction or refurbishment period of three years is considered for all assets (IEA GHG, 2017; Jacobs, 2018). Capital expenditures are equally split between construction and refurbishment and all assets other than electrolysers that reach the end of their lifetime during the period of analysis are considered replaced for 75% of their original cost. The process water price is set at USD 0.7 per m³ and for water electrolysis other revenues from oxygen sales or advanced services to the grid are not considered. The analysis is conducted over a 25-year lifetime.

Table 2.1: **Common economic parameters**

Parameter	value
Discount rate	5%
Construction/refurbishment period	3 years
Capital expenditure curve	33.3% per year over 3 years
Analysis period	25 years
Process water price	0.7 USD/m ³
Replacement capital costs (excluded electrolysers, % CapEx)	75%

Economic values used in this analysis are expressed in 2020 USD. Where necessary the following conversion factors were used:

Table 2.2: **Conversion factors**

Conversion factor	Value
EUR to USD	1.1
GBP to USD	1.3
Inflation factor	Value
2009-2020	1.21
2007-2020	1.25

2.2. The levelised cost of hydrogen (LCOH)

2.2.1. Model hypotheses

The techno-economic ExcelTM tool considers PEM and solid oxide electrolyser cell (SOEC) technologies for water electrolysis. Values for key techno-economic parameters often differ in the literature based on their scope, assumptions on R&D progress and assumptions on technology deployment. The following section details the assumptions taken in this analysis.

Proton exchange membrane electrolyser

A hydrogen production plant is typically made of an electrolyser connected to a mechanical part and an electrical part. The electrolyser uses electricity to split water molecules in dioxygen and hydrogen. The mechanical part (deioniser, tank, condenser, pump, etc.) prepares the water intake feeding the electrolyser and collects its by-product, e.g. a mix of O₂ and H₂O. The electrical part shapes the electrical current to match the electrolyser's technical requirements. It typically includes an AC transformer connected to an AC to DC rectifier. The mechanical and the electrical parts of the system are commonly referred to as balance of plant (BoP). The electrolysis hydrogen plant CapEx refers to the sum of stack and BoP capital costs.

This distinction matters as both elements contribute in roughly a similar manner to the total plant CapEx (Cihlar et al., 2021). Capital cost figures are commonly reported in terms of production capacity, either defined as the input capacity (USD per kWe) or the output capacity in terms of hydrogen produced (USD per kWh₂ or USD per kgH₂/d). As of 2020, total CapEx requirements (including BoP) for a hydrogen plant using PEM or SOEC technologies are in the range of USD 1 100-1 800 per kWe and USD 2 850-5 700 per kWe, respectively (IEA, 2019a; HE, 2020). In the following work, figures for CapEx, fixed OpEx and efficiency apply to a full and already installed hydrogen production plant, i.e. including balance of plant.

Additionally, the literature shows that more powerful electrolysers, larger hydrogen production plants and higher electrolyser manufacturing production rates would enable significant CapEx cost reductions (Hydrogen TCP, 2021; DOE, 2020). Larger plants enable economies on the BoP CapEx while the two other levers affect the stack CapEx. In the following analysis, the three levers are considered to impact system CapEx, leading to important costs reductions by 2035, for both PEM and SOEC technologies. CapEx values are assumed at USD 450 per kWe and USD 750 per kWe for PEM and SOEC, respectively.

Fixed operation and maintenance expenditures (fixed O&M) represent all recurrent costs related to staff, property, repair and maintenance that are not related to the electrolyser operation mode. They are expressed as a percentage of total capital costs.

Fixed O&M are largely influenced by stack longevity, typically defined as the total operating time before replacement (Cihlar et al., 2021). To assess the impact of stack longevity on hydrogen production costs, the literature introduces stack replacement costs (RepEx), also reported as a percentage of stack capital costs. Recent cost sensitivity assessments show that it has a limited impact on hydrogen production costs for low temperature electrolysis technologies, whether alkaline or PEM (DOE, 2020). The situation is different for high-temperature electrolysis, which suffers from much shorter stack longevity and for which fixed O&M and RepEx parameters have a significant influence on the final hydrogen production cost alongside electricity price and CapEx. However, this sensitivity is expected to sharply decline as progress is made on SOEC and stack longevity (DOE, 2016). In the following analysis, RepEx replacement is done at time:

$$T = \frac{Electrolyser_{life}}{(8\,760 \times Electrolyser_{Lf})}$$

Where, $Electrolyser_{life}$ is the lifetime of the electrolyser (hours) and $Electrolyser_{Lf}$ is the electrolyser load factor (%). RepEx are assumed to be 15% and 30% of capital costs for PEM and SOEC, respectively.

Variable operation and maintenance expenditures represent the sum of electricity and water consumption costs. Furthermore, the electrolyser efficiency is expressed as a percentage of the lower heating value of hydrogen (33.3 kWh/kg). For SOEC, electrical and thermal efficiencies are considered separately. Table 2.3 presents the assumptions for PEM and SOEC systems around 2035. A selected benchmark is provided in Appendix 4.

Table 2.3: **Assumptions for PEM and SOEC systems**

Parameter	Technology	Value
CapEx (USD/kW)	PEM	450
	SOEC	750
Efficiency (% LHV)	PEM	69
Energy consumption (kWh/kgH ₂)	SOEC	Electrical: 36 Thermal: 10
Fixed OpEx (% CapEx)	PEM	2
	SOEC	3.5
Lifetime	PEM	85 000
	SOEC	35 000
Output pressure (bar)	PEM	45
	SOEC	1
Water consumption (tap water)	PEM/SOEC	20
Stack replacement cost percentage (RepEx, % of installed capital costs)	PEM	15%
	SOEC	30%

Electricity generation sources

Reference values for specific technologies' LCOE, overnight construction costs and operation costs are derived from IEA/NEA (2020). For renewables' average load factors, values come from the IEA NZE 2030 scenario (IEA, 2021a). Values for wind onshore and offshore are averages of load factors given in NZE 2030, while different locations are distinguished for solar photovoltaic. For nuclear technologies' load factors, the value is derived from historical data of nuclear power plant operation in the United States (EIA, 2022).

Table 2.4: Assumptions for electricity price, power system load factors and size

Generation technology	Overnight construction costs (USD/kWe)	Operation costs (USD/MWh)	Average load factor (%)	LCOE (USD/MWh)
Solar photovoltaic (Middle East)	700	5.04	32	23
Solar photovoltaic (North America)	700	5.94	27	27
Solar photovoltaic (European Union)	700	9.41	17	42
Wind onshore	1 500	9.94	40	40
Wind offshore	2 500	19.13	49	63
Light water reactors (long-term operation)	550	23.02	90	32
Light water reactors (new build)	4 850	24.20	90	65
High-temperature reactor (high CapEx)	4 850	24.20	90	65
High-temperature reactor (low CapEx)	2 000	24.20	90	42
Grid	N/A	N/A	95	75
Grid (high gas prices)	N/A	N/A	95	150

Note: LCOE refers to grid electricity prices for the cases "grid" and "grid (high gas prices)". Overnight construction costs include contingency costs. Operation costs include fixed O&M, variable O&M, decommissioning and fuel costs.

Source: IEA/NEA (2020); EIRP (2017).

Steam methane reforming

The economic analysis considers an industrial-scale steam methane reforming plant equipped with carbon capture, utilisation and storage, so as to capture 90% of the CO₂ emissions.

Total capital costs refer to the costs of pre-reformer, reformer, high temperature shift, pressure swing reformer, carbon capture (using MEA-based chemical absorption technology), carbon compression and dehydration and other balance-of-plant costs. For a detailed description of the system, refer to IEA (2017) case 3.

Fixed operation and maintenance expenditures represent all recurrent costs related to staff, property, repair and maintenance that are not related to the steam methane reforming plant operation mode. They are expressed as a percentage of total capital expenditures. Variable operation and maintenance expenditures include natural gas, water and carbon management costs. Table 2.5 presents the key assumptions for the steam methane reforming plants, with or without CCUS, considered in the model.

Table 2.5: Steam methane reforming parameters used in LCOH calculations

Parameter	Steam methane reforming without CCUS	Steam methane reforming with CCUS
Plant size (tonneH ₂ /year)	153 300	153 300
Load factor (%)	95	95
CCUS CO ₂ capture rate (%)	0	90
Total capital costs (TCC) (USD ₂₀₂₀ /kWh ₂)	711	1 230
Fixed OpEx (% CapEx)	4.6%	3.5%
Efficiency (%)	77%	69%
Feedstock (natural gas) requirement (kgNG/kgH ₂)	3.39	3.74
CO ₂ emissions (kgCO ₂ /kgH ₂)	9.0	0.9
Water consumption (l/kgH ₂)	6.6	6.6

Note: Total capital costs include costs associated with CO₂ capture. For this analysis a linear regression of the different systems' TCC detailed in IEA (2017) is applied and leads to $TCC = 576.38 * CR (\%) + 711.13$, where CR is the plant's CO₂ capture rate. A similar approach was followed to converge on values for the plant's efficiency and feedstock requirement. It leads to the equations $plant\ efficiency = -0.0816 * CR (\%) + 0.7678$ and $feedstock\ requirement = 0.3935 * CR (\%) + 3.3875$ respectively. Variable O&M costs include costs associated with CO₂ storage and transport. A carbon tax is applied to residual emissions from the plant.

Natural gas and CO₂ costs

The CO₂ transport and storage costs are based on IEA (2021a) for the NZE 2030 scenario in Europe. The CO₂ cost is more conservative than IEA estimates and is assumed to increase slightly from the highest historical levels. The natural gas price and the natural gas high price are based on historical data and tend to reflect gas price volatility from 2021 onwards.

Table 2.6: Natural gas and CO₂ values used in LCOH calculations

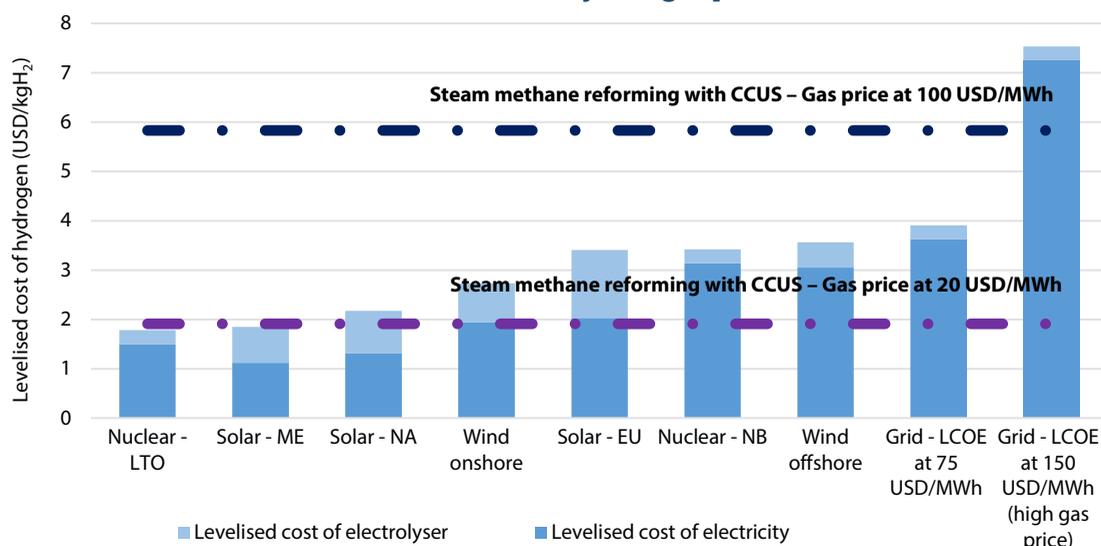
Parameter	Value
Natural gas price (USD ₂₀₂₀ /MWh)	20
Natural gas high price (USD ₂₀₂₀ /MWh)	100
CO ₂ cost (USD ₂₀₂₀ /tonne)	100
CO ₂ transport and storage cost (USD ₂₀₂₀ /tonne)	45

2.2.2. Results

Levelised costs of hydrogen for the different configurations are provided in Figure 2.1. The majority of water electrolysis cases yield a hydrogen production cost below or around USD 3.5 per kgH₂ by 2035. For all, the electricity generation cost clearly appears as the single most important factor influencing LCOH. This is particularly true for configurations with load factors greater than 35% where the electricity contribution to LCOH is between 75% and 95%, which is consistent with the literature (DOE, 2020; IEA, 2019a). Although secondary, the influence of the electrolyser CapEx on LCOH remains noticeable, in particular for systems with low load factor. For example, the costs of producing hydrogen from solar in the European Union and nuclear new builds are largely similar. This is largely due to nuclear’s higher load factor, which offsets its higher costs of electricity (around 50% higher than for solar in the European Union), with a better utilisation of electrolysers, leading to lower electrolyser costs.

In general, technologies that benefit from cheap electricity such as amortised nuclear (e.g. nuclear-LTO) and renewables in locations with high resource endowments (e.g. solar-ME and solar-NA) provide very competitive hydrogen, around USD 2 per kgH₂. On the contrary, electricity prices around and above USD 60 per MWh lead to LCOH above USD 3 per kgH₂, regardless of the system’s load factor.

Figure 2.1: Levelised cost of hydrogen (LCOH) for different sources of electricity and gas prices



Note: LTO = long-term operation; ME = Middle East; NA = North America; EU = European Union; NB = new build.

The competition between water electrolysis and abated steam methane reforming appears to be largely determined by the price of natural gas. Indeed, a breakdown of the cost of hydrogen production using steam methane reforming with CCUS shows feedstock accounts for 51% of total costs when the gas price is USD 20 per MWh, and rises as far as 84% with gas at USD 100 per MWh. The remaining cost is from capital investment.

Results show that hydrogen produced from water electrolysis remains more expensive than that produced from steam methane reforming in all but two cases, “nuclear – LTO” and “solar – ME”. For steam methane reforming with CCUS, the hydrogen production cost varies from USD 1.91 per kgH₂ to USD 5.83 per kgH₂ for gas prices of USD 20 per MWh and USD 100 per MWh, respectively.

Finally, as the grid electricity price is correlated to the gas price in liberalised markets, gas prices also influence LCOH in the “grid” cases, e.g., when the electrolyser is operated on a baseload mode. To represent this volatility, two grid electricity costs of USD 75 per MWh and USD 150 per MWh are considered. As a result, LCOH varies between USD 3.91 per kgH₂ and USD 7.53 per kgH₂, both grid cases being the two least competitive options.

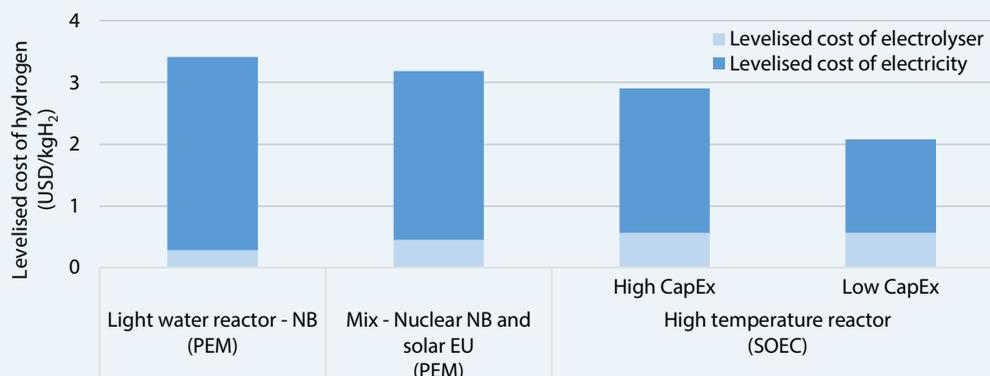
Box 2.1: Nuclear energy and high-temperature electrolysis perspectives

The previous analysis showed that the electricity generation cost is the single most important factor influencing LCOH. Therefore, improving the electrolysis hydrogen plant’s total electrical efficiency would substantially contribute to lower the feedstock expenditures. In general, the plant electrical efficiency takes into account electricity used by the electrolyser stacks as well as the balance of plant (BoP). The BoP’s electrical consumption usually represents a small share, roughly 10%, of the total electricity used (Cihlar et al., 2021; DOE, 2020). Therefore, improving the electrolyser’s stack electrical efficiency would influence the total plant electrical consumption the most and thereby influence the electrolysis hydrogen cost as well.

This is confirmed by the difference between the LCOH of a light water reactor – PEM system and that of a high-temperature reactor (HTR) – SOEC system: at USD 3.42 per kgH₂ and USD 2.91 per kgH₂, respectively. The reduced electricity consumption of high-temperature electrolysers clearly stands out as a promising competitive advantage, in spite of high capital costs and short lifetimes due to higher operating temperatures. The LCOH drops to USD 2.08 per kgH₂ for a HTR – SOEC system with nuclear overnight capital costs of USD 2 000 per kW_e, an ambitious but possible scenario for future nuclear systems (EIRP, 2017).

Finally, a system that mixes nuclear NB and solar-EU enables synergies between variable renewables and nuclear. In this configuration, the nuclear plant contributes to improving the system’s load factor while the solar system provides cheaper electricity, which further improves the overall plant economics. This configuration unveils possible synergies between nuclear and renewables and further work should be done to explore possible optimisations, also with high-temperature reactors and SOEC system.

Figure 2.2: Levelised cost of hydrogen for different nuclear configurations



Note: It is possible to operate a LWR-SOEC system, although the overall system efficiency would be slightly lower than with the HTR-SOEC configuration. PEM = proton exchange membrane; SOEC = solid oxide electrolyser cell; HTR = high-temperature reactor; Solar EU = Solar European Union; NB = New build.

2.3. Assessing the costs of delivery of nuclear-produced hydrogen

2.3.1. The concept of hydrogen delivery

The following analysis aims to clarify the impact that the production scale has on hydrogen delivery costs. There exists extensive literature surrounding hydrogen transport, storage and compression, highlighting the complexity of hydrogen value chains involving a large number of stakeholders and requiring case-by-case design (NREL, 2014; Nexant, 2008; Amos, 1999). To that extent, this assessment seeks to go beyond hydrogen production costs and acknowledges the short-term challenge of delivering electrolytic hydrogen at a competitive price. Indeed, required production, transport and storage infrastructures are capital-intensive and subject to economies of scale.

As illustrated in the previous analysis, the cost of electricity is the primary parameter influencing LCOH. In this context, co-locating the hydrogen production plant with the source of electricity to avoid taxes and levies, for example through a power purchase agreement, is a promising solution. However, locations that reach sufficiently high load factors and low electricity generation costs are limited in number. Furthermore, while locating the hydrogen production plant where electricity is cheapest optimises the production cost, it might lead to substantive value chain costs, e.g. costs emerging from hydrogen storage, transformation, transport and distribution. This is particularly true in the case of unremitting demand for hydrogen, for example for industrial uses.

Indeed, ensuring a continuity of supply under such “coupled” business models would require over-scaling value chain infrastructures. For example, a recent analysis estimated that in the context of industrial demand, storage between one to seven days of production would be necessary when coupling an electrolysis plant with variable renewables, in this case solar PV and wind respectively (IEA, 2021b). As discussed in Chapter 1, the same reasoning applies to the idea of limiting hydrogen production to moments where electricity is excessively produced on the grid (RTE, 2020).

Furthermore, the scale of the systems plays a decisive role and hydrogen transport cost surges as the volume transported decreases. For example, the cost of hydrogen transport through gas pipeline more than doubles between pipelines operating at 100% and 25% capacity, respectively (Guidehouse, 2021). In this context, announced projects tend to grow in scale, up to the gigawatt, although the current largest project is in the range of tens of MWe. As of 2021, the majority of announced projects is the range of hundreds of MWe (IEA, 2021b).

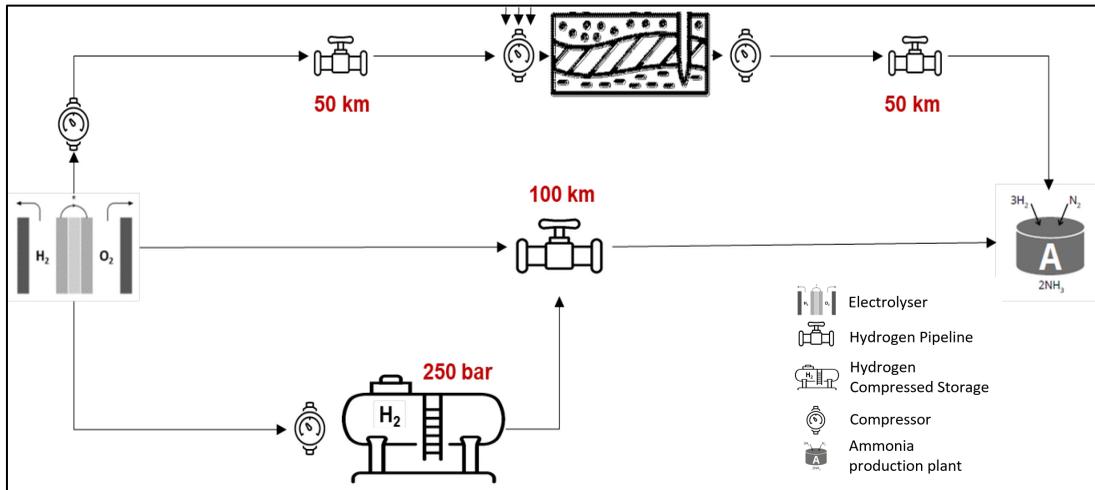
Solutions exist to reduce and optimise hydrogen value chain investment requirements. For example, natural gas pipelines can be refurbished for a fraction of new-built costs, salt mines and other geological formations offer cheap, large-scale storage, the demand side can improve its flexibility, and different electricity sources such as solar and wind can be coupled to reach greater steadiness. In any case, the above-mentioned challenges and solutions prove that there is no one-size-fits-all system for electrolytic hydrogen and that projects should be deployed on a case-by-case basis taking into account the full value chain. Ultimately, this analysis supports that a comprehensive approach considering the hydrogen costs of delivery should be promoted so as to ensure an optimised development of the hydrogen economy.

2.3.2. Scenario description

This following assessment draws on mainstream hydrogen deployment strategies based on the concept of hydrogen hubs or valleys presented in Chapter 1. It is based on a generic value chain infrastructure, in which total costs are assessed for different hydrogen production profiles (Figure 2.3). The analysis draws from this assessment to provide a comparison of LCOHD, i.e. costs of production plus storage, transport and distribution, between different electricity sources (Figure 2.2). However, in reality, it is important to keep in mind that hydrogen value chains are likely to be unique and designed on a case-by-case basis.

The generic value chain infrastructures used in this analysis include a hydrogen production plant of 500 MWe, directly coupled to its electricity source with a co-located compressed storage facility. The hydrogen production facility responds to continuous demand for hydrogen from an industrial plant situated at a distance of 100 km. A salt mine for seasonal storage is available 50 km away from the production plant. It is itself 50 km away from the industrial plant. The production plant is connected to the industrial facility and to the geological storage through distribution and transport pipelines, respectively. The salt mine is also connected to the industrial plant by a transport pipeline (Figure 2.3).

Figure 2.3: **Hydrogen value chain infrastructures**



The base case scenario considers that hydrogen is produced using a proton exchange membrane (PEM) electrolyser, which is transported and stored as a gas (no transformation). As the scenario is projected in the year 2035, the valley is considered at scale, which leads to consider a single hydrogen production plant of 500 MWe. Although the largest electrolysers today are around 20 MWe, this assumption is aligned with expected improvements in electrolyser stack sizes and manufacturing capacities (IRENA, 2020).

The idea of coupling large-scale electrolyser systems with a nuclear power plant draws from recent analyses such as the feasibility report for the Hydrogen to Heysham project and an assessment of non-electric applications for the Diablo Canyon nuclear power plant (EDF Energy R&D, 2019; Aborn et al., 2021). More generally, it is coherent with the strategy shared by different stakeholders to deploy a GW-scale nuclear-based hydrogen hub (DOE, 2022; EPRI, 2021). Far from being negligible, such installations would raise new regulatory challenges that remain to be solved. Those questions, however, are beyond the scope of this work.

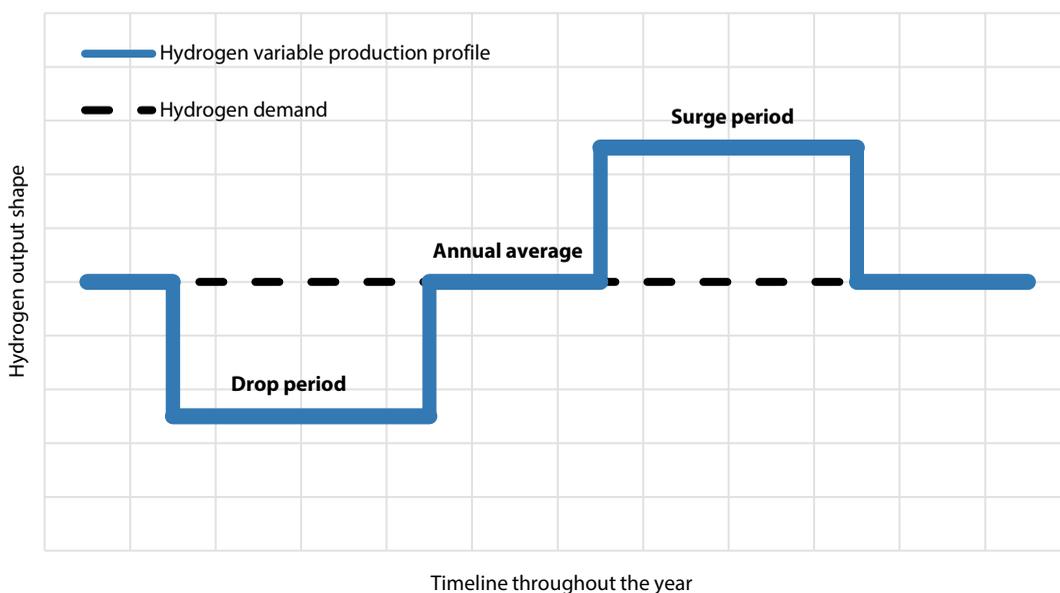
Gaseous hydrogen is transported through pipelines and stored in compressed tanks or a salt cavern. These solutions are the most mature today and likely to remain leading options until at least 2030 (Weichenhain et al., 2021). For gaseous pipeline distribution and transport, distances are typically in the order of 10 to 100 km. Also, different analyses will be considered depending on whether the pipeline is new or retrofitted. For hydrogen storage, both solutions (compressed tanks and salt cavern) are considered to manage variations in production output.

Hydrogen production profiles

Three generic electricity production profiles are considered: steady (100% nuclear), variable (100% variable) and hybrid (50% nuclear, 50% variable). The steady production profile is set at a 93% load factor throughout the year, a result given in the H2H feasibility report for a nuclear-based system (EDF Energy R&D, 2019).

The generic variable production profile is categorised by a lower annual average and two seasonal load factors, hereafter referred to as the drop and surge load factors. Concretely, the hydrogen production plant is estimated to operate for 3 months (91.25 days) at the drop load factor, 3 months at the surge load factor and 6 months (182.5 days) at the annual average. The average annual load factor for the variable production profile is set at 30%, the high load factor at 40% and the low load factor at 20% (Figure 2.4).

Figure 2.4: Variable production profile throughout the year



Finally, this analysis considers a hybrid profile based on a system gathering 250 MWe of steady production and 250 MWe of variable production. Daily production profiles are considered Boolean, with the electrolyzers operated at either 100% of its installed capacity or at 0%. Table 2.7 summarises the three generic scenario characteristics.

Table 2.7: Infrastructure pattern

Scenario	Production profile	Hydrogen transport and storage	Demand
Steady	93% average monthly load factor	Hydrogen transported through pipeline at 70 bar On-site compressed storage at 250 bar Geological storage 50 km from the production and consumption plants, i.e. halfway between the two	Continuous demand 100 km away from the point of production
Variable	30% annual average load factor 20%/40% seasonal (3 months) load factor		
Mix	250 MWe from steady production 250 MWe from variable production		

Infrastructure dimensioning

The Excel model is designed so as to ensure a continuous supply throughout the year. Three flows of hydrogen exit the electrolyser:

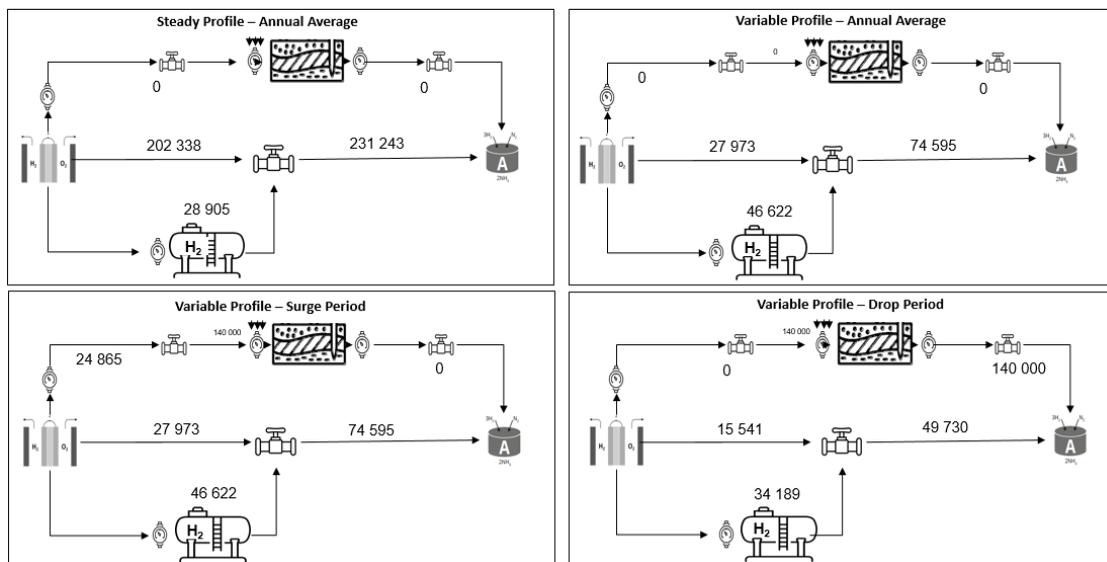
- the distribution flow that goes directly to the distribution pipeline towards the demand;

- the compressed storage flow that goes to the compressors and the compressed storage facility; and
- the transport flow that goes to geological storage through the compressors and the transport pipeline.

The compressed storage facility is emptied through the distribution pipeline as soon as the electrolyser production stops or does not match the annual average hydrogen flow. Based on this infrastructural pattern, the model determines the hourly hydrogen flow of each period of the year, thus ensuring a continuous supply. The different infrastructures are dimensioned based on the season that imposes the highest requirement.

It is important to highlight that as a consequence of hydrogen profiles' design, compressed storage goes through one charge-discharge cycle every day. In other words, its scale is limited to less than one day of production. Recent analyses showed that renewable-based production of hydrogen will require much greater storage volumes, between one and seven days of production for solar and wind sources, respectively, in cases where demand has limited flexibility (IEA, 2021b). However, such analyses do not consider the availability of geological storage, introducing a virtual “sink” and “well” for the daily production that exceeds or does not reach the annual average level. Figure 2.5 details the hydrogen flow for the different profiles of production throughout the year.

Figure 2.5: Average “seasonal” hydrogen flow for variable and steady production profiles

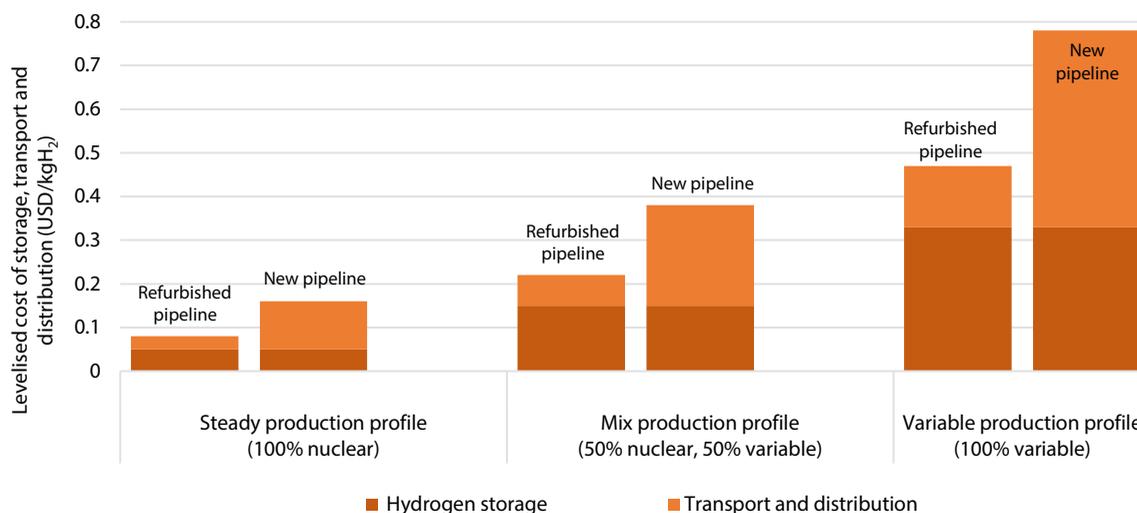


For variable costs, for both storage and transport, the required firm-up electricity is assumed to cost USD 75 MWh, purchased from the electricity grid.

2.3.3. Results

Figure 2.6 illustrates the added levelised cost from hydrogen transport, distribution and storage for the different production profiles, i.e. steady, hybrid and variable for the case of a 500 MWe electrolyser. Added costs range from USD 0.16 per kgH₂ to USD 0.78 per kgH₂, for steady and variable production profiles respectively.

Figure 2.6: **Levelised cost of storage, transport and distribution for different production profiles**



Considering the model's approximation, this range fits well within literature figures. For example, for hydrogen transport, the IEA estimates costs of USD 0.2-0.4 per kgH₂ for transport over 200 km using a 100 tH₂/d designed pipeline (IEA, 2021). In our scenarios, hydrogen daily outputs are between 74 595 kgH₂/d and 231 243 kgH₂/d for the variable and steady profiles, respectively. Associated costs of hydrogen distribution and transport over a total of 200 km with new pipelines (100 for distribution and two times 50 for geological storage) are USD 0.11-0.45 per kgH₂. Those values fall to USD 0.03-0.14 per kgH₂ for the steady and variable profiles, respectively, if using refurbished pipelines. This illustrates well the benefit of this approach, although cost assumptions remain largely uncertain.

For compression and on-site storage, Bruce et al. (2018) estimate a cost from USD 0.23 per kgH₂ to USD 0.3 per kgH₂ for systems of 150 and 350 bar, respectively. With the assumed hypotheses, levelised cost of compression and on-site storage at 250 bar are USD 0.06-0.32 per kgH₂. This analysis leads to a much lower bond value as only a small fraction of the total production requires compression for the steady production profile (most of it going directly to demand), while volumes of hydrogen produced are high.

The largest share of added delivery costs emerges from hydrogen distribution and transport. In particular, for all three production profiles, the single most important factor in delivery costs is hydrogen distribution. Indeed, the greater distance for distribution (100 km) than for transport to geological storage (50 km) offsets gains from the absence of compression. Also, the large volume of hydrogen transported from the geological storage to the demand sites largely amortises costs of transport.

Designed volumes of compressed storage vary between 11-71% of average daily production respectively, for steady and variable profiles. For the latter, the result seems coherent with estimates from the literature of around 1 day of average production for a similar production profile (e.g. solar photovoltaic) without geological storage (IEA, 2021b). The capital-intensive nature of compressed tanks largely explains the differences in costs between the three profiles. Indeed, geological storage represents around 10% of total storage costs for both the variable and hybrid profiles. Further details on the costs of geological storage are given in Box A3.1, Annex 3.

Sensitivity analyses

The system size and the pipeline lengths are the two most important factors influencing storage, transport and distributions costs.

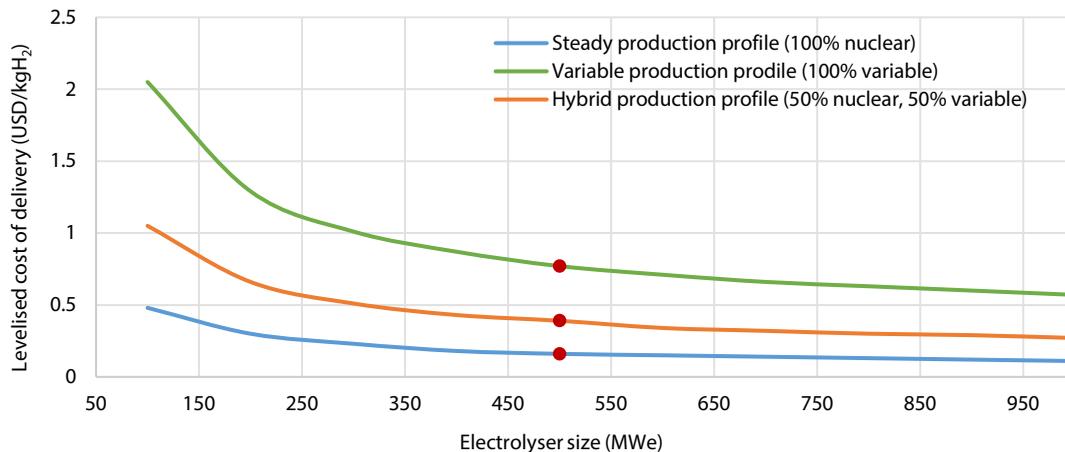
- Impact of the system size on storage, transport and distribution costs

Figure 2.7 illustrates the sensitivity of storage, transport and distribution costs to system sizes for the different production profiles. The base case scenario for a 500 MWe system is indicated by a red marker.

It illustrates how storage, transport and distribution costs increase sharply for small-scale systems as they surge to USD 2.05 per kgH₂ for a 100 MWe variable system. This can be explained by the capital-intensive nature of the infrastructures required, whether compressed tanks or pipelines. By design, for equivalent installed electrolyser capacity the steady configuration produces much larger volumes of hydrogen, leading on average to a four-fold decrease in costs compared to the variable profile.

Also, the costs decline is steeper for variable than it is for steady profiles as sizes increase but each profile ultimately plateaus. This is mostly due to the way capital expenditures for hydrogen pipelines are modelled, i.e. with incompressible costs. In other words, for small-scale increases, the marginal production of hydrogen offsets the rise in pipelines costs, leading to a visible decline.

Figure 2.7: **Levelised cost of hydrogen delivery (LCOHD) as a function of the electrolyser size for different production profiles**



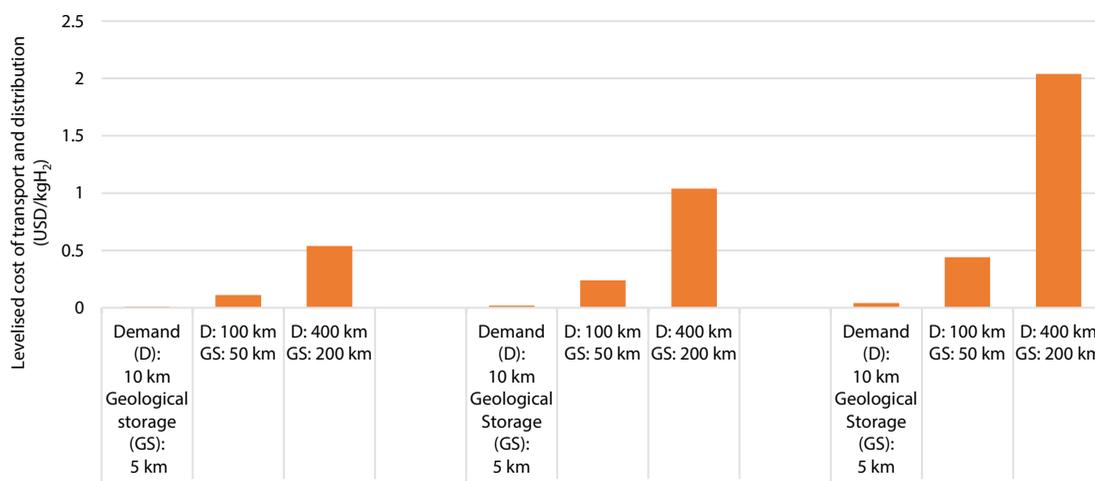
Furthermore, variable and hybrid profiles tend to have lower infrastructure utilisation rates than the steady one. Utilisation rate is defined as the ratio between modelled asset usage to maximum possible usage at designed values. By design, the utilisation rate of the transport pipeline used to carry hydrogen to geological storage is low for the variable and hybrid profiles as it is used exclusively during the surge period. A similar reasoning applies to compressor and storage assets. Conversely, thanks to on-site storage the distribution pipeline is optimised and benefits from very high utilisation rates for all profiles.

The above-mentioned reasons lead to the fact that a 1 000 MWe electrolyser following a variable profile reaches slightly higher storage, transport and distribution costs than a 100 MWe electrolyser following a steady profile, at around USD 0.5 per kgH₂, although the hydrogen output is three times higher for the former (149 189 kgH₂/d and 46 249 kgH₂/d respectively).

- Impact of distribution and transport distances

The different scenarios are also strongly sensitive to variations in distribution and transport pipeline lengths. Transport and distribution costs would reach as much as USD 2.04 per kgH₂ for a 500 MWe system with a variable profile supported by 200 km and 400 km of pipelines to the demand and geological storage sites, respectively. However, the possibility of using refurbished pipelines clearly changes the picture as it would lead to a 70% cost reduction for a similar case. Figure 2.8 illustrates the levelised cost of hydrogen distribution and transport for different combinations of pipeline lengths.

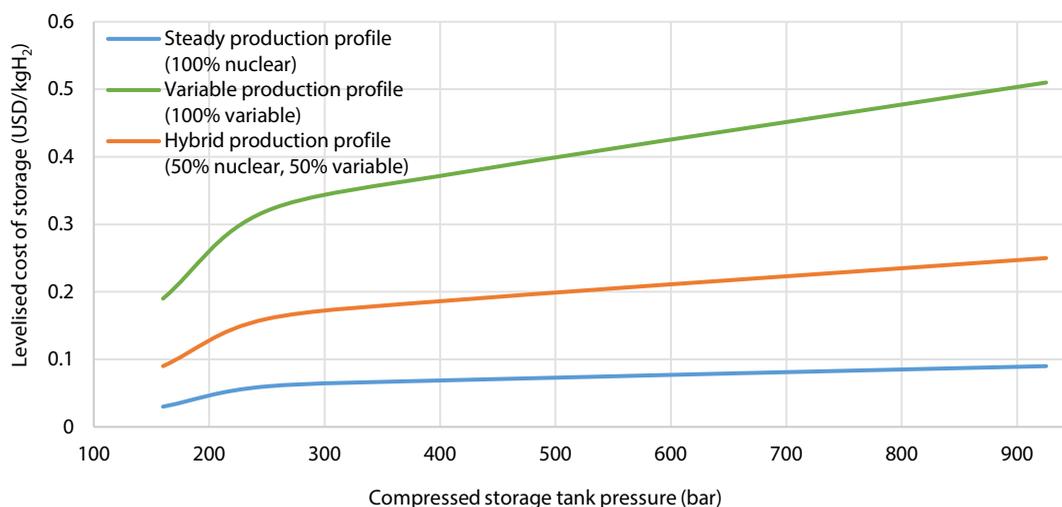
Figure 2.8: Levelised cost of hydrogen distribution and transport for different pipeline lengths



■ Impact of the storage pressure

Finally, Figure 2.9 illustrates the impact of different compressed storage pressures on the levelised cost of storage. For stationary compressed storage, the pressure is likely to be limited, although if hydrogen were to be transported with trucks, moderate pressures could be used. Ultimately, the best solution will have to take into account the required volume, period and safety concerns (Amos, 1998).

Figure 2.9: Levelised cost of hydrogen storage for different compressed tank pressures



2.3.4. Comparison of different sources under two sets of hypotheses

Drawing from the previous approach, Figure 2.10 illustrates the levelised cost of hydrogen delivery, i.e. costs of hydrogen production and value chain costs for three different scenarios with varying parameters for systems scale and pipeline lengths (Table 2.8):

- **Scenario 1: “Dense medium-scale hub”.** Value chain costs are calculated for a 500 MWe system, 100 km from the demand site and 50 km from a geological storage facility. The storage facility is itself 50 km from the demand site.

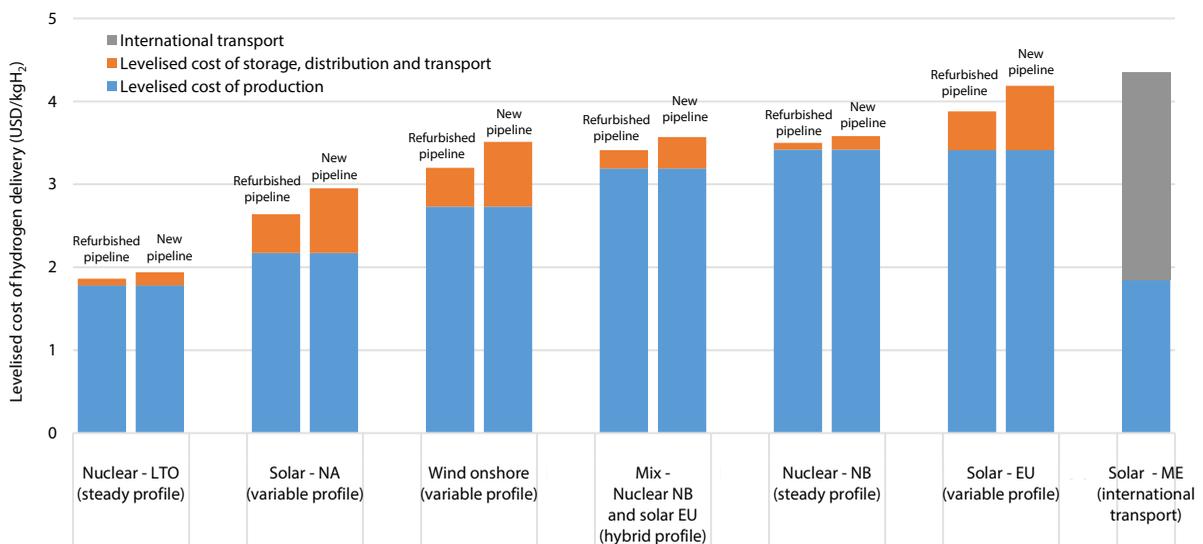
- **Scenario 2: “Dense large-scale hub”**. Value chain costs are calculated for a 1 000 MWe system, 100 km from the demand site and 50 km from a geological storage facility. The storage facility is itself 50 km from the demand site.
- **Scenario 3: “Expanded large-scale hub”**. Value chain costs are calculated for a 1 000 MWe system, 400 km from the demand site and 200 km from a geological storage facility. The storage facility is itself 200 km from the demand site.

Steady profile value chain costs are added to the levelised cost of production from nuclear (LTO, new build). Similarly, variable profile value chain costs are added to the levelised cost of production from solar PV and wind onshore. Finally, hybrid value chain costs are added to levelised cost of production of a system that mixes HTR-SOEC and solar EU, as described above. Finally, international transport of hydrogen is estimated at USD 2.5 per kgH₂ (WEC, 2021).

Table 2.8: **Scenario parameters**

Scenario 1 “Dense medium-scale hub ”	500 MWe system 100 km from distribution 50 km from geological storage
Scenario 2 “Dense large-scale hub”	1 000 MWe system 100 km from distribution 50 km from geological storage
Scenario 3 “Expanded large-scale hub”	1 000 MWe system 400 km from distribution 200 km from geological storage

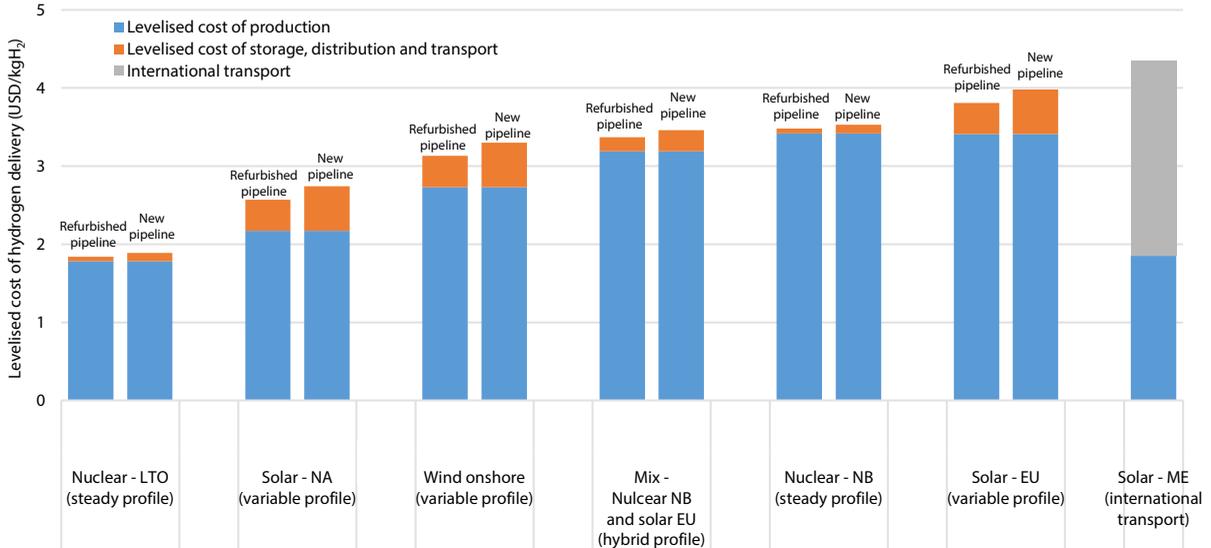
Figure 2.10: **“Dense medium-scale hub” levelised cost of hydrogen delivery for different electricity sources**



This analysis shows that the delivery of electrolytic hydrogen below USD 3 per kgH₂, at large scale, by 2035 is likely to be a serious challenge. Indeed, only “nuclear-LTO (steady profile)” breaks the USD 2 per kgH₂ threshold, although it is unlikely that existing reactors will be used *en masse* to produce hydrogen in the future. Similarly, the hydrogen produced in the Middle East at a very competitive price will have to be transported, which is likely to add significant delivery costs and largely deteriorate its competitiveness.

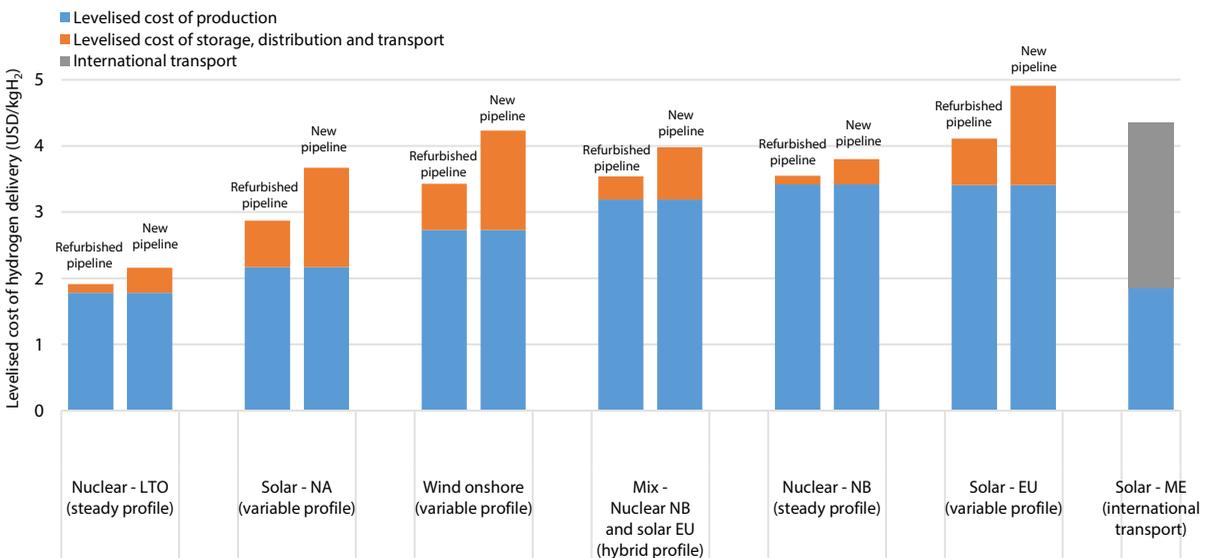
Figure 2.10 illustrates further the interest of mixed nuclear and renewables systems. In addition to yielding hydrogen production costs below USD 3 per kgH₂, infrastructures for hydrogen storage, transport and distribution are also optimised, making this option one of the most competitive.

Figure 2.11: “Dense large-scale hub” levelised cost of hydrogen delivery for different electricity sources



As can be expected, the “dense large-scale hub” configuration has a slightly more competitive LCOHD for all configurations, although gains from a doubling in size remain limited.

Figure 2.12: “Expanded large-scale hub” levelised cost of hydrogen delivery for different electricity sources



The “expanded large-scale hub” configuration highlights the decisive impact of pipeline lengths on the LCOHD. Although the hydrogen production plant is of 1 000 MWe, the benefits of the large scale are offset by the greater distances. This holds particularly true for the variable profile systems, which see their delivery costs rising faster than those of other production profiles.

2.4. Conclusion

This analysis showed that the costs of producing hydrogen are likely to represent the majority of costs of delivered hydrogen, but are not the only factor. It is argued that any comprehensive competitiveness assessment of hydrogen should take into consideration the entire value chain, which includes costs associated to hydrogen storage, transport and distribution.

This assessment confirms that the primary factor that influences the cost of hydrogen production is the cost of electricity. This explains the early interest in coupled systems, where the electrolyser uses electricity directly from a generation plant, avoiding taxes and levies from the electricity grid. This also explains the high sensitivity of the LCOH to the electrolyser’s efficiency. For example, in spite of a shorter lifetime, higher capital costs and replacement costs, solid oxide systems are likely to become a leading option to produce low-carbon hydrogen at competitive prices. This opens promising perspectives for nuclear power, from both LWRs and HTRs, as a source of cheap and abundant heat.

Based on the hypotheses, it is estimated that electrolysis hydrogen will cost globally around USD 3 per kgH₂ by 2035. This is a general figure and best-case scenario such as solar photovoltaic in the Middle East or nuclear long-term operation both yield hydrogen production below the USD 2 per kgH₂ threshold. Furthermore, this assessment anticipates that steam methane reforming retrofitted with CCUS is a competitive option, provided gas prices remain around USD 20 per MWh. Indeed, higher prices of gas will inevitably drive up the costs of hydrogen production, narrowing the competitiveness gap with electrolytic options in most places in the world.

On the costs of hydrogen storage, transport and distribution, this analysis considers steady demand, for example that of an industrial stakeholder. In this context, the report highlights the determining influence of the hydrogen production profile, whether “steady” or “variable”, the latter being approximated through load factors with a lower value and variations throughout the year. For the analyses, those profiles are schematically associated to different existing electricity generation technologies, i.e. nuclear and variable renewables (VRE), for the steady and variable profiles, respectively.

A clear conclusion from this analysis is that systems with steady production have hydrogen storage, transport and distribution costs that are up to four or five times lower than systems with variable production. In absolute values, this assessment estimates value chain costs of USD 0.16-0.78 per kgH₂. This represents 5-36% of the hydrogen production costs, depending on the electricity source being considered. However, the different sensitivity analyses on the system scale, pipeline lengths and compressed storage pressures show how those costs largely depend on the underlying assumptions. In fact, an ill-designed value chain could end up adding hydrogen storage, transport and distribution costs of well above USD 1 per kgH₂. Finally, it is clear that using retrofitted pipelines would contribute to lower hydrogen value chain costs and should be encouraged wherever possible. However, this assessment assumes a significant drop in costs for refurbished pipelines compared to new assets. This remains to be confirmed and might ultimately differ from one case to another.

A third production profile, labelled as “hybrid,” features two electricity sources of equal power, with a variable and a steady profile of production. This assessment illustrates how the steadiness of half of the electrical input helps to optimise the value chain efficiency. Conversely, the cheapest electricity source contributes to lower hydrogen production costs. These factors suggest complementarities between nuclear energy and variable renewables (solar PV in particular) that can yield competitive costs for the delivery of low-carbon hydrogen to industrial consumers.

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3. Hydrogen production and system costs

Plant-level economic analyses of hydrogen production with metrics such as the levelised cost of hydrogen (LCOH) are a good starting point to understand the relative competitiveness of different technology options. However, they do not provide the full picture. For this, the concept of the levelised cost of hydrogen delivery (LCOHD), widely explored in the previous chapter, becomes a relevant metric to consider, especially when assessing industrial applications with more stringent hydrogen demand requirements.

Most LCOH and LCOHD cases evaluated in the previous chapter assume that electricity generators are physically coupled to the electrolysers, without interaction with the electricity system (i.e. coupled operational mode of electrolysers). However, electrolysers can also be connected to the grid and operate in other modes (e.g. flexibly, using only excess electricity or baseload, as depicted in Chapter 1). Generators and electrolysers can thus interact through the grid, shaping one another, while adding and removing value to the system in different ways. The LCOH fails to capture the economic value of these interactions, especially in systems with high shares of variable renewables.

Using a highly interconnected country as a system of reference, the present chapter provides an illustrative system costs analysis to understand the role of nuclear power in coupled, low-carbon electricity and hydrogen production systems that have to meet different exogenous hydrogen demand levels. This analysis is not limited to the system costs; it offers some insights into the interactions between electricity and hydrogen production systems, including flexible and base operational modes for electrolysers connected to the grid, which are not explored in Chapter 2. By combining the system analysis with the plant-level, production and delivery costs, it is possible to get a more comprehensive picture of the competitiveness of nuclear-produced hydrogen in decarbonisation pathways.

3.1. Motivation and objectives

The installation of massive amounts of variable renewables, such as wind and solar, is leading the decarbonisation of modern economies while also opening new challenges.

By definition, the output of variable renewables is irregular and hard to predict. To accommodate their generation profile at a reasonable cost, it is necessary for the rest of the electricity system (both the generators and the grid) to adapt and become more flexible, while ensuring that capacity levels remain adequate to balance supply and demand at all times, even under extreme conditions. Such adaptations involve the need for large-scale electricity storage, more flexible supply, more interconnections and grid reinforcements, as well as demand response and sector coupling approaches. They all come at a cost for the system, to the point that pushing the deployment of variable renewables too far may not be desirable from an economic perspective. Further, the presence of low-carbon dispatchable capacity in the system (under the form of nuclear or hydropower, for instance) could limit these costs, increasing the value of the system.

This topic is the object of continued analysis by the NEA (2012 and 2019). These studies provide extensive quantitative evidence on increasing system costs associated with the installation of increasing shares of variable renewables¹, and how nuclear power keeps overall system costs in check by reducing the need for flexibility and grid reinforcement investments in the system, especially at high carbon constraints.² These costs cannot be captured by widely used plant-level measures such as the levelised cost of electricity (LCOE) (or LCOH for the case of hydrogen production), which underscores the need for systemic metrics to adequately assess the value of each technology in low-carbon electricity systems with high shares of renewables.

Reaching climate targets will also require the decarbonisation of other sectors such as transport, heating and industry. To do so, low-carbon electricity infrastructures can be coupled with such sectors (so-called sector coupling) by means of heat pumps and electric vehicles, for example. Low-carbon electricity and/or heat can also power electrolyzers to produce hydrogen to then decarbonise a variety of industrial and transport applications.

As depicted in Chapter 2, the coupling of and potential interactions between the electricity and hydrogen sectors can take different forms depending on the possible directions that the hydrogen economy may take. Large amounts of low-carbon hydrogen will be needed to decarbonise existing and emerging demand in the industrial and transport sectors. In the long run, hydrogen molecules could also be stored at large and transformed into electricity on demand. Such interactions remain relevant since they will ultimately determine the costs of coupled energy systems as well as the role that nuclear could play in limiting the associated system costs. At the same time, different hydrogen production approaches (e.g. various types of electrolysis, chemical reforming with carbon capture and storage [CCS], thermochemical processes) exist today and are being considered simultaneously. Which technologies will prevail will depend on many interlinked factors such as cost reductions, innovation breakthroughs, gas and carbon prices and policy decisions. Determining precisely the role that nuclear power may play in such constellations is not a straightforward exercise, but it is clear that more sophisticated modelling of the whole system, subsystems and associated interactions, rather than plant-level metrics, is required.

Some recent system modelling work concludes that nuclear power can improve the overall competitiveness of integrated electricity and hydrogen systems. According to Aurora (2021), co-locating a mix of nuclear power plants and variable renewables with electrolyzers contributes to a reduction in overall system spending of 6-9% by 2050. Nuclear-based electrolytic hydrogen can also complement fossil fuel-based hydrogen production in achieving the high baseload hydrogen demand for industry and transport applications projected by 2050, while limiting the reliance on fossil fuels. In terms of relative competitiveness of different hydrogen production alternatives, the IAEA concludes that for gas prices higher than USD 20/MMBtu, the optimal approach to producing hydrogen involves a combination of electrolysis powered by variable renewables and nuclear power plants and thermal processes that can eventually be supplied by advanced high-temperature nuclear reactors (Watson and Donovan, 2021).

Building on these results, the objective of this chapter is to assess the value that nuclear power can provide in low-carbon electricity systems at early stages of sector-coupling with the hydrogen economy. For that, an illustrative system cost analysis is proposed at the scale of a highly interconnected country that has to meet large-scale, exogenous hydrogen demand exclusively by means of domestic, low-carbon energy sources (i.e. without hydrogen imports). It is assumed that hydrogen is produced via proton exchange membrane (PEM) electrolyzers connected to the electricity grid in competition with existing steam methane reforming facilities. The analysis is therefore representative of short-term hydrogen economy prospects (i.e. before

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1. NEA (2012 and 2019) identifies three main sources of system costs induced by the penetration of variable renewables in an electricity mix: i) profile costs (due to the variability and intermittency of the generation), ii) balancing cost (associated with the uncertainty of the generation) and iii) connection, distribution and transmission costs (related to delivering electricity from distributed power sources to customers).
 2. In other words, system costs are, to a great extent, a function of the carbon constraints. The higher the carbon reduction ambition, the more variable renewables need to be deployed and, *ceteris paribus*, the more system costs will manifest.

2035) in which hydrogen is expected to develop first as a large-scale feedstock or commodity to decarbonise industry and transport applications. The systemic effects of the use of hydrogen for long-term electric storage, as well as hydrogen production with nuclear heat, are beyond the scope of this study. Delivery costs associated with hydrogen are not considered in this analysis, since they were largely covered in Chapter 2.

The analysis intends to be exploratory rather than exhaustive. Nevertheless, it provides preliminary quantitative evidence on i) the potential of nuclear power to reduce the overall economic costs of electricity systems coupled with large-scale hydrogen demands and on ii) the impact that hydrogen production can have on the behaviour of highly interconnected electricity systems, and *vice versa*. It is important to acknowledge that, as with any other modelling efforts, the results are subject to uncertainties and modelling limitations, and are reliant on the assumptions considered. In the real world, this translates into system costs that vary from one system to another, depending on their intrinsic characteristics (e.g. configuration of the electricity mix, technology costs or level of interconnections). The expansion of generation capacity is also exposed in practice to industrial risks and supply chain considerations that are not accounted for, or assessed, in the modelling.

Lastly, the proposed system cost analysis is complementary to the one presented in Chapter 2. The plant-level analysis, enriched with delivery cost considerations, remains a robust approach to evaluate specific business cases, while enabling rapid comparisons across options, especially if interactions with the electricity grid are limited (e.g. coupled mode). On the other hand, system analysis provides country- or regional-level cost figures for tightly coupled electricity and hydrogen systems, with all individual generators interacting simultaneously under specific systemic constraints, and opens the possibility to evaluate the impacts of other operational modes of electrolysers when connected to the grid.

3.2. System cost analysis

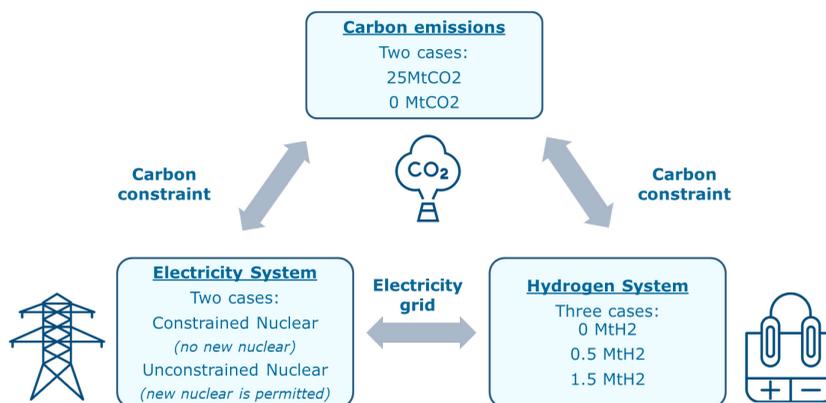
3.2.1. Main assumptions

This section provides an illustrative system costs analysis of coupled electricity and hydrogen production systems that have to meet different, exogenous hydrogen demand levels under stringent carbon constraints. The electricity and hydrogen systems interact with each other through the electricity grid under the same carbon constraint, as illustrated in the modelling approach in Figure 3.1.

The electricity system is modelled as a single bus representing the scale of a country. This bus can accommodate different types of generators (dispatchable and variable), storage facilities (e.g. batteries, pumped storage) as well as interconnectors with other countries. To evaluate the value of nuclear power in coupled electricity and hydrogen systems under stringent carbon constraints, two main cases are systematically evaluated:

- **Constrained nuclear case:** In this case, the assumed electricity system has a total peak demand of 83 GW and a nuclear power capacity constrained to 18 GW, corresponding to around 20% of the total initial (i.e. brownfield) installed capacity in the system. The remaining brownfield capacity is split between renewables (60%) and fossil fuels (20%) (see Appendix 1). All forms of capacity are allowed to expand if required by the model, except for hydropower facilities (i.e. reservoir, run of river and pumping stations) and nuclear power, both of them being artificially constrained. As a result, only variable renewables and lithium-ion batteries are built at high carbon constraints. This case is therefore the equivalent of an electricity system with high shares of variable renewables.
- **Unconstrained nuclear case (optimised):** This case considers the same initial assumptions as the *constrained nuclear* case, but nuclear power is no longer constrained and can thus expand to minimise system costs, if required by the model. This may result in a more balanced electricity mix with higher shares of nuclear power compared to the *constrained nuclear*. By comparing the *unconstrained nuclear* case with the *constrained nuclear* case, it is then possible to extract the economic value associated with new nuclear build.

Figure 3.1: Modelling scheme of integrated energy system



The hydrogen system considered in the analysis is assumed to meet hydrogen demand either with PEM electrolyzers and/or existing steam methane reforming facilities without CCS. Neither hydrogen imports nor electricity storage with hydrogen are considered in the modelling. The hydrogen demand levels considered are of 0.5 MtH₂ and 1.5 MtH₂. They have been selected according to projected hydrogen demand targets in industrialised countries by 2035, and are in line with the literature review presented in Chapter 1. A case without hydrogen production is modelled in order to evaluate the impact of electrolysis in the electricity system, by comparing cases with and without hydrogen demands.

Two carbon constraints are evaluated in the analysis: 25 MtCO₂ and 0 MtCO₂. The value of 25 MtCO₂ (residual carbon emissions) corresponds to a carbon footprint of approximately 50 gCO₂/kWh in the modelled system. This is consistent with the approach considered in NEA (2019) and, therefore, with Paris Agreement carbon emission reduction targets. The carbon constraint of 0 MtCO₂ (net zero) is proposed in line with recent, strengthened climate ambitions aiming at reaching net zero carbon emissions from electricity in advanced economies by 2035.³

Overall, the *constrained nuclear* and *unconstrained nuclear* cases in the electricity system are evaluated under three hydrogen demand levels (0 MtH₂, 0.5 MtH₂ and 1.5 MtH₂) and two different carbon constraints (25 MtCO₂ and 0 MtCO₂) which makes a total of 12 different cases. By default, flexible hydrogen demand⁴ is considered for all these cases. This means that electrolyzers can react, without any technical constraint, to market price fluctuations as long as the hydrogen production target is met at the end of the year. This includes, but is not limited to, moments of excess power in the electricity grid. In addition to electrolyzers, the present modelling exercise considers a full set of flexibility options including not only interconnectors but ion-lithium batteries, pumped storage, load-shedding and demand response as well as dispatchable electricity supply coming from combined cycle gas turbines (CCGT), hydropower and nuclear power plants. Moreover, two additional cases are explored in Section 3.2.5 to assess the impact of steady hydrogen demand on integrated energy systems. The whole set of assumptions and cases evaluated reflect the short-term hydrogen economy's prospects, in which hydrogen is expected to develop first as a large-scale feedstock or commodity to decarbonise industry and transport applications, playing a very limited role as an electricity storage vector.

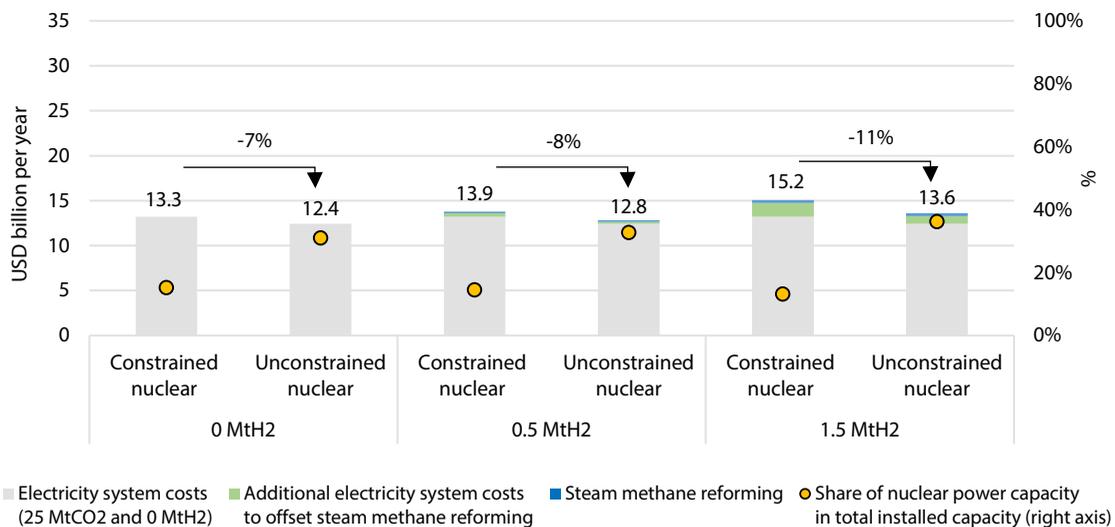
3. For instance, among the key milestones proposed in the IEA Net Zero by 2050 pathway, advanced economies should completely phase out unabated coal electricity production by 2030, reaching net zero emissions from electricity by 2035. Coal and oil electricity production should be abandoned globally by 2040, with significant decarbonisation efforts in the building, transport and industry sectors taking place in parallel in order to have a net zero global energy system by 2050 (IEA, 2021).
4. This is technically possible with PEM electrolyzers, which can accommodate load variations in a few seconds. As a result, electrolyzers can be an additional source of flexibility for the electricity system. This type of system flexibility, however, is different from the one provided by hydrogen as an electricity storage vector, and which is not considered in the present system modelling.

This system cost analysis is carried out with the NEA mixed-integer linear programming (MILP) model, POSY, that minimises the overall economic costs of the combined electricity and hydrogen system. Additional information about POSY and the input data considered in this modelling exercise is provided in Appendix 1. For each case and scenario evaluated, POSY optimises simultaneously the electricity generation and hydrogen production and derives a system configuration that minimises overall system cost. Regarding the system cost components, POSY only computes the profile cost of the system.⁵ Balancing costs, connection costs and transmission and distribution costs are not captured in the results.⁶ By convention, historical investment costs in existing (brownfield) capacity are considered fully amortised and thus do not affect outcomes. The economic system cost figures presented in this analysis correspond to the physical system costs (i.e. new investment, operation and fuel costs) minus net export revenues. This approach differs somehow from the one used in the NEA (2019), where only physical costs were taken into account and presented as the sum of profile, balancing and connection, transmission and distribution costs.

3.2.2. System costs with a carbon constraint of 25 MtCO₂ (residual carbon emissions)

In a system with residual carbon emissions, nuclear power lowers total system costs (Figure 3.2). Compared to the *constrained nuclear* case, and for a given hydrogen demand, total system costs are reduced by 7-11% when nuclear power is deployed. The share of nuclear power in the total installed capacity reaches around 30%. In the absence of new nuclear build, the capacity gap left by nuclear power is compensated with variable renewables (essentially onshore wind) and more CCGT plants, pushing the share of nuclear power in the total installed capacity down to 15%. As a result, capacity additions double in the *constrained nuclear* case and increase overall system costs. Total installed capacity remains 20-40% lower in the *unconstrained nuclear* case, in line with the trend of the economic system costs.

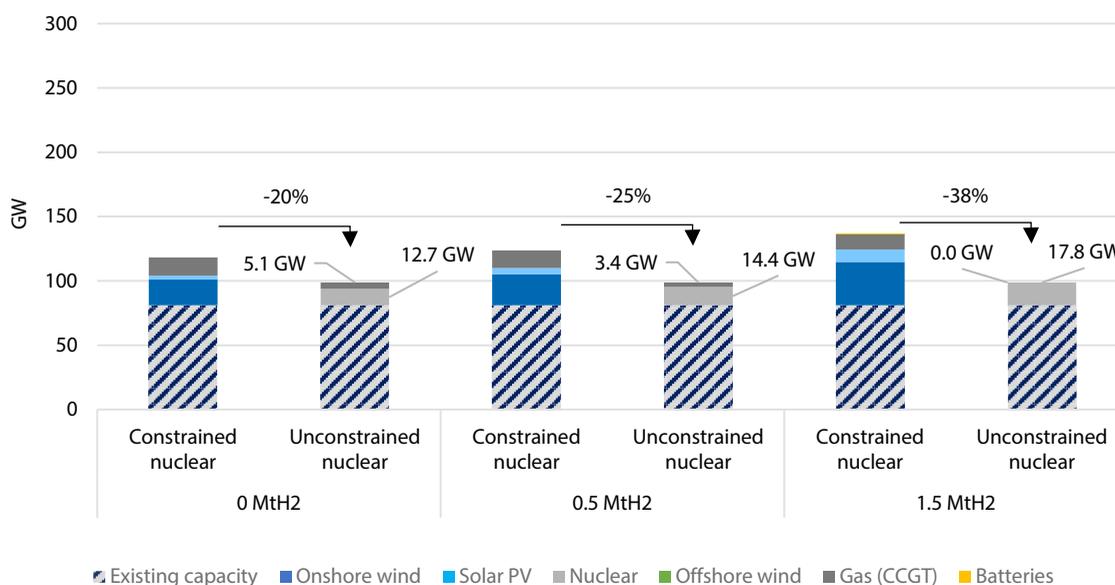
Figure 3.2: Total economic system costs with constrained and unconstrained nuclear capacity in function of different levels of hydrogen production under a 25 MtCO₂ carbon constraint



Note: Historical investments on existing capacity are not considered. The total economic system costs account for the physical costs (CapEx and OpEx) minus net export revenues. Balancing costs, connection costs and transmission and distribution costs are not considered. Discount rate = 5%.

- These costs arise from the variability of variable renewables that requires the deployment of more capacity in order to satisfy the demand at all times.
- Profile costs remain, by far, the higher system costs component (NEA, 2019).

Figure 3.3: Total installed capacity with constrained and unconstrained nuclear capacity as a function of different levels of hydrogen production under a 25 MtCO₂ carbon constraint



Under residual carbon emissions, steam methane reforming is the lowest cost option for producing hydrogen. Total hydrogen demand is thus satisfied with existing steam methane reforming facilities at a cost of USD 0.2-0.5 billion per year, i.e. 1-2% of the total system costs. This implies that only natural gas is used to produce hydrogen and, therefore, both the hydrogen and electricity production system remain decoupled. Nevertheless, both systems interact through the carbon constraint; the additional carbon emissions from steam methane reforming must be offset by further grid decarbonisation. In the case of *unconstrained nuclear*, the most efficient way to do so is via the expansion of nuclear power capacity. As the hydrogen demand increases, for every gigawatt of nuclear power added to system, the same amount of new CCGT capacity is avoided. This is possible due to the high capacity factors of nuclear power. On the other hand, more variable renewable capacity (especially onshore wind) is required to avoid the same amount of new CCGT capacity in the *constrained nuclear* case. This phenomenon drives most of the system costs and total installed capacity gaps between the cases of *constrained nuclear* and *unconstrained nuclear*, and its impact increases with the increase of hydrogen demand (Figure 3.3).

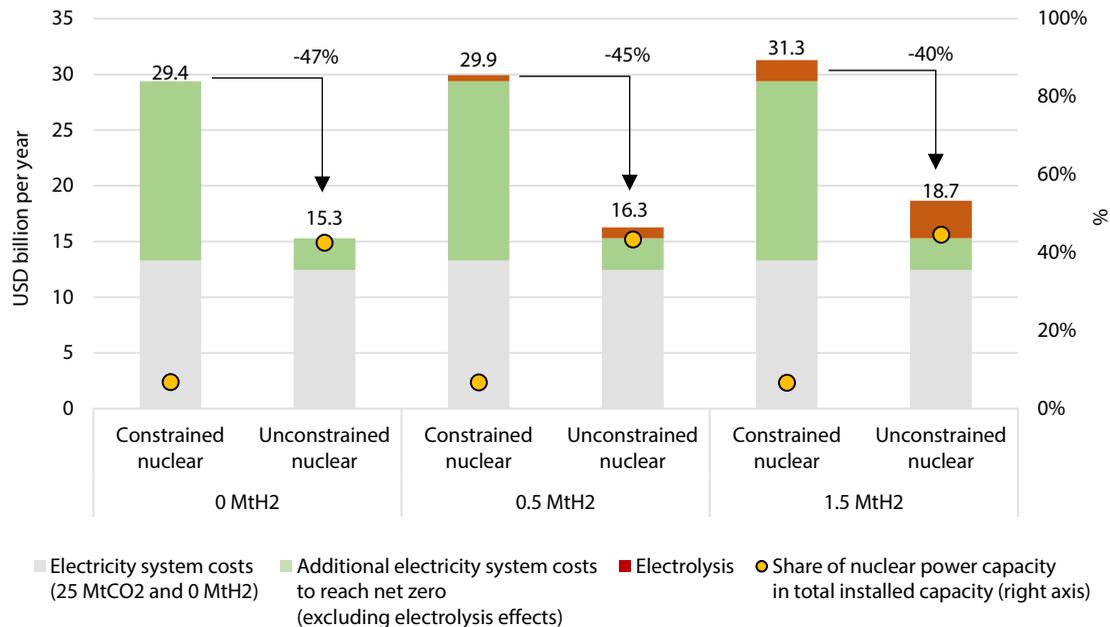
More detailed information about the system costs, installed capacities and generations for each of the scenarios analysed under a carbon constraint of 25 MtCO₂ can be found in Appendix 1.

3.2.3. System costs with a carbon constraint of 0 MtCO₂ (net zero emissions)

As electricity and hydrogen production systems move towards the goal of net zero carbon emissions, the role of nuclear power to lower total system costs becomes increasingly important (Figure 3.4). The system cost gap between the case of *constrained nuclear* and *unconstrained nuclear* increases by 7-11% under residual emissions, to around 40-50% under net zero conditions. The total installed capacity gap also increases significantly, reaching approximately 130-140% at net zero. In fact, as the carbon constraint gets closer to zero, displacing residual emissions becomes harder and harder, especially if only variable renewables are deployed. Meeting a net zero carbon constraint requires around 190 GW of additional variable renewables (mainly onshore wind and solar PV, but also offshore wind and batteries) in the *constrained nuclear* case, adding grid decarbonisation costs that lead to a doubling in electricity system costs compared to those observed at 25 MtCO₂. The share of nuclear power in the total installed capacity drops to 7%. However, with new nuclear build, the projections change notably. In the case of

unconstrained nuclear, around 30 GW of new nuclear suffice to displace residual emissions: six times less capacity additions than in the case of *constrained nuclear*. The share of nuclear power reaches 50% of the installed capacity. Overall, these results confirm that i) system costs are directly correlated with the carbon constraint and that ii) the deployment of nuclear power significantly reduces overall system costs with large-scale hydrogen demands under stringent carbon constraints.

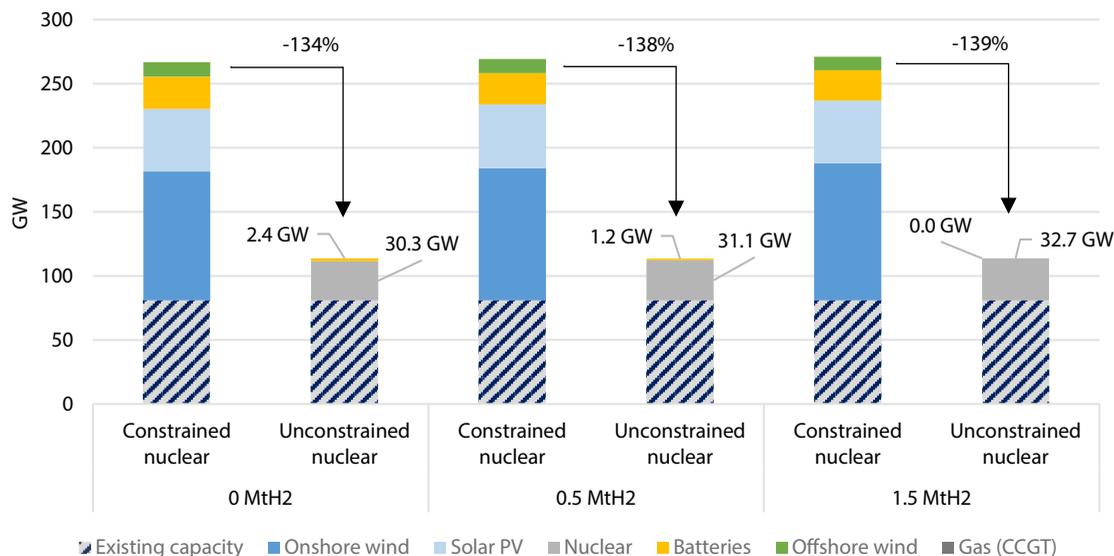
Figure 3.4: **Total economic system costs with constrained and unconstrained nuclear capacity as a function of different levels of hydrogen production under a 0 MtCO₂ carbon constraint**



Note: Historical investments in existing capacity are not considered. The total economic system costs account for the physical costs (CapEx and OpEx) minus net export revenues. Balancing costs, connection costs and transmission and distribution costs are not considered. Discount rate = 5%.

The net zero carbon constraint also forces the system to meet all the hydrogen demand solely through electrolysis. As observed in scenarios under residual carbon emissions, system costs tend to increase along with the increase of hydrogen demand levels; but in this case, the reason is the impact of electrolysis on the electricity system rather than the growing grid decarbonisation efforts which are needed to offset steam methane reforming emissions. As expected, the higher the hydrogen demand, the higher the costs of electrolysis, but also the lower the system cost gap between the *constrained nuclear* and *unconstrained nuclear* cases. This behaviour differs from the one observed at a 25 MtCO₂ carbon constraint and it can be explained, to some extent, by the system flexibility provided by electrolysers. Moreover, the additional system flexibility offered by electrolysers does not necessarily reduce the need of new capacity additions, in particular of new nuclear power units. This can be noticed in the capacity expansion trends of the case of *unconstrained nuclear* (Figure 3.5), in which increasing hydrogen demands are accommodated with deductions in battery capacity (no longer needed due to the presence of electrolysers) and up to 3 GW of new nuclear capacity. The amount of new capacity additions to support electrolytic hydrogen generation at net zero is, nevertheless, limited compared to the capacity expansion needed to decarbonise the grid.

Figure 3.5: Total installed capacity with constrained and unconstrained nuclear capacity as a function of different levels of hydrogen production under a 0 MtCO₂ carbon constraint



Overall, the system costs associated with electrolysis remain relatively low, and do not exceed 20% of the total costs of the system. Most of the system costs are, in fact, driven by the necessity to decarbonise the grid first. Once the grid is decarbonised, the adoption of electrolysis can be seen as low hanging fruit that requires low investments at the system level.

More detailed information about the system costs, installed capacity and generation for each of the different scenarios analysed at a net zero carbon constraint can be found in Appendix 1.

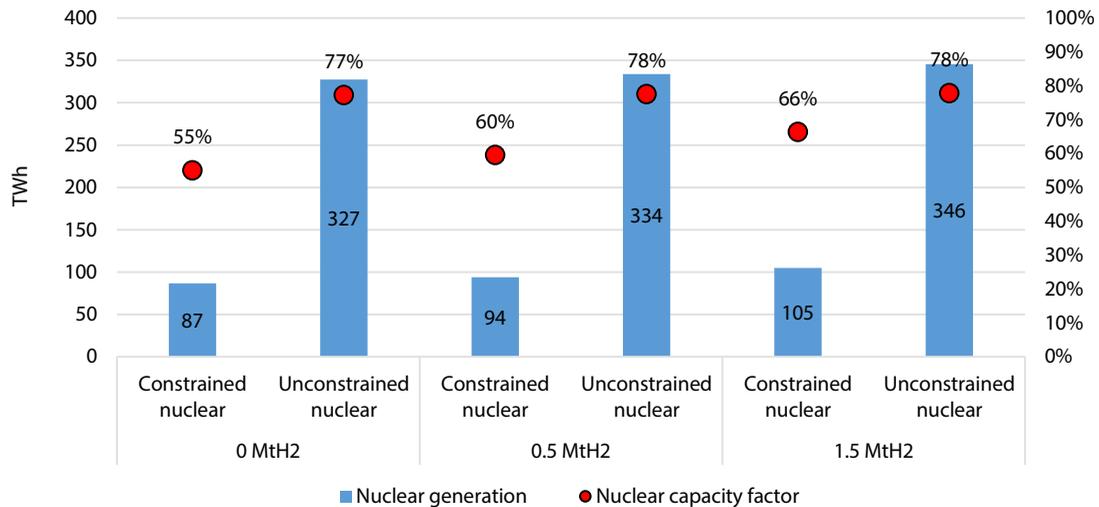
3.2.4. The impacts of electrolysis on interconnected electricity systems

The presence of electrolytic hydrogen production at net zero implies that both the electricity and hydrogen systems have become fully coupled. This means that the operation of the electrolyzers can have a direct impact on the electricity system costs and *vice versa*. Consequently, the costs induced by electrolysis in the electricity system are not limited to the installation and operation of electrolyzers and include additional electricity generation costs of existing and/or new capacity following the higher electricity demand, net export variations as well as system flexibility enhancements (i.e. reduced demand response and load shedding). In the next sections, the different systemic effects of electrolysis are analysed in further detail.

Increased electricity generation

The electricity demand induced by electrolysis will tend to increase the baseload needs of the system, improving the availability of the existing nuclear capacity. This effect is even more pronounced if nuclear load factors are initially low due to the presence of high shares of variable renewables in the system. In the *constrained nuclear* case (where the share of nuclear power in the total installed capacity is around 7%), hydrogen demand of 1.5 MtH₂ (representing an electricity consumption of approximately 70 TWh) boosts nuclear availability from 55% to 66% (Figure 3.6). In generation terms, this corresponds to an additional 10-20 TWh, sufficient to generate around 0.25-0.5 MtH₂ of hydrogen. This means that those regions with nuclear capacity that is underutilised due to specific system constraints could meet a sizeable share of the domestic hydrogen demand with nuclear power availability improvements, while increasing the overall economic performance of existing reactors. In the *constrained nuclear* case, the impact of electrolysis on nuclear power is fully accommodated with an increase in load factors whereas, in the *unconstrained nuclear* case, it is accommodated with a combination of improved availability (a 1% increase) and 1-3 GW of new nuclear capacity additions (Figure 3.5).

Figure 3.6: Nuclear generation and capacity factors with constrained and unconstrained nuclear capacity as a function of different levels of hydrogen production under a 0 MtCO₂ carbon constraint



Net export variations

Electrolysis can also affect the net export balance between neighbouring countries impacting overall system costs through changes in revenue. This behaviour is, to some extent, triggered by the economics of electrolyzers. In fact, beyond load factors of 35%, the economics of electrolyzers are dominated by the cost of electricity. Consequently, to minimise the costs of hydrogen production and of the whole system, electrolyzers will tend to operate when electricity prices are low. This is also when volumes of domestic electricity can be exported, competing with electrolysis needs if electricity prices are higher in neighbouring countries. Electrolyzers can also benefit from periods with excess electricity in the system. The operational mode of electrolyzers (e.g. power excess mode versus baseload mode) can also influence the net export balance and therefore overall system costs (RTE, 2020).

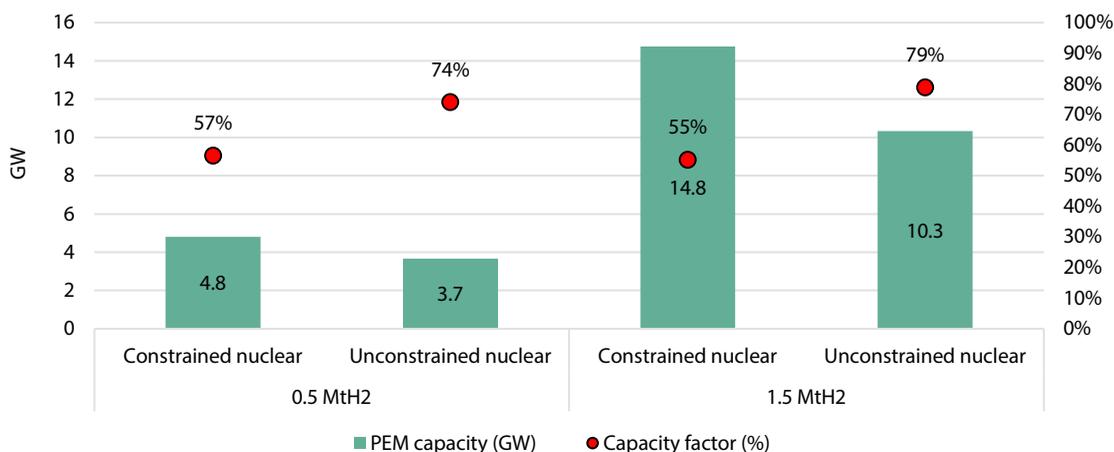
Optimal electrolyser capacity and utilisation

The optimal electrolyser capacity of the system will essentially hinge on three factors, which are, by order of higher impact (Figure 3.7):

- **Hydrogen demand size:** The higher the hydrogen demand in the system the higher the electrolyser capacity required. In this analysis, around 3-4 GW of electrolyzers are required to produce 0.5 MtH₂, corresponding to an electricity consumption of 24 TWh. A three-fold increase in hydrogen demand requires 10-14 GW of electrolyzers consuming 71 TWh.
- **Share of variable renewables:** For a given hydrogen demand, variations in the optimal electrolyser capacity and load factors can be observed. These variations are correlated with the share of variable renewables in the system. The higher the share of variable renewables (i.e. *constrained nuclear* case), the more the electrolyzers will tend to operate in a flexible manner driven by periods of excess of electricity which pushes their load factors down. This situation will necessarily require a higher installed electrolyser capacity to meet the same hydrogen production target across cases. Of course, the flexible operation of electrolyzers comes at a cost penalty. For load factors greater than 35%, the associated economic impact is, nevertheless, small.
- **Hydrogen demand patterns:** Forcing electrolyzers to produce hydrogen in a more continuous manner, for example, could also lead to higher load factors and a better utilisation of the installed electrolyser capacity. These aspects may be relevant when evaluating the impact of industrial hydrogen demand in the whole system.

These results illustrate how the optimal electrolyser capacity depends not only on the characteristics of the hydrogen demand, but also on the configuration of the electricity system (i.e. share of variable renewables) which, in turn, can determine how flexibly electrolysers may be used. Overall, the impact of the optimal electrolyser capacity and utilisation on the system costs will be low.

Figure 3.7: **Electrolyser capacity and load factors with constrained and unconstrained nuclear capacity as a function of different levels of hydrogen production under a 0 MtCO₂ carbon constraint**



Additional system flexibility

This analysis assumes that electrolysers satisfy a flexible hydrogen demand. Technically, this is possible with PEM electrolysers, since they can accommodate rapid load variations in a matter of seconds. As a result, electrolysers become a source of system flexibility in the same way as other options or technologies.

The first indication of the contribution of electrolysers to system flexibility lies in the deployed capacity and load factors (Figure 3.7). Systems with higher shares of variable renewables (i.e. *constrained nuclear* case) have higher installed capacity of electrolysers that are used more flexibly absorbing excess of variable renewable generation, and therefore operating with lower load factors. This effect increases with hydrogen demand and partly explains the limited capacity additions observed in the *constrained nuclear* case as hydrogen demand increases, since part of the hydrogen production will come from electricity generation that otherwise would be curtailed (Figure 3.5).

Electrolysers' flexibility also competes with batteries, demand response and load shedding services, replacing greater amounts of these flexibility options as hydrogen demand increases. For example, electrolysis completely offsets the need to deploy batteries in the *unconstrained nuclear* case at a hydrogen demand level of 1.5 MtH₂ (Figure 3.5). Battery capacity deductions are also observed in the *constrained nuclear* case as electrolysers penetrate the system. It is important to note that as systems become more reliant on the flexibility of electrolysers, they also become more sensitive to potential shifts in hydrogen demand which, ultimately, could generate a cost burden on the electricity system.

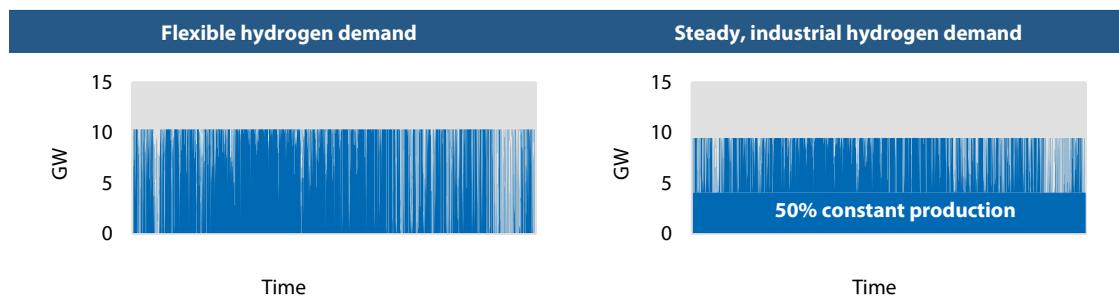
3.2.5. Flexible versus steady provision of hydrogen for industrial purposes

It is expected that most of the hydrogen production by 2035 will be devoted to decarbonise existing hydrogen demands as well as new industrial and transport applications. Industrial users have technical requirements that need steady hydrogen production flows. Two extreme configurations can be envisioned to ensure the steadiness of hydrogen production by 2035. The

first would be characterised by the presence of a well-developed and cost-effective hydrogen storage infrastructure. In this situation, electrolyzers will essentially operate in a flexible manner, taking advantage of periods of excess variable renewable electricity to produce hydrogen at a low cost. The hydrogen can then be stored and discharged as required by industrial users. The second configuration would consist of a less developed hydrogen storage infrastructure characterised by high storage costs. Such a configuration may force electrolyzers to operate in a steady manner, not only to meet industry requirements, but also to ensure competitive hydrogen production by increasing electrolyzers' load factor. RTE (2021) indicates that this configuration could dominate by 2035 in order to support the decarbonisation of existing industrial applications while limiting heavy investments in hydrogen transport and storage infrastructure by the industrial sector.

In coupled electricity and hydrogen production systems, different hydrogen demand patterns have specific constraints on the electricity system that can result in additional system costs. This can be the case, for instance, of centralised industrial hydrogen demands requiring more steady flows of hydrogen and a baseload operation of electrolyzers. The objective of this section is to evaluate the systemic impact of steady hydrogen demands, assuming that they require electrolyzers to operate in a more continuous manner due to lack of hydrogen storage infrastructures. The steady hydrogen demand pattern proposed for this analysis is described in Figure 3.8. The hydrogen production profile imposed to electrolyzers assumes that 50% of demand is met in baseload mode and the rest is satisfied in a flexible manner. A case with a hydrogen flexible demand of 1.5 MtH₂ at net zero is considered as a baseline for comparison in the present section.

Figure 3.8: **Flexible versus steady, industrial demand patterns**



A shift towards more steady hydrogen production flows has a direct impact on the total system costs that is due essentially to two main effects. First, baseload hydrogen production has to be supported with additional baseload electricity generation, which may require new capacity in the system. Second, the ability of electrolyzers to provide system flexibility changes significantly with the operation mode of electrolyzers indirectly impacting overall system costs. The impact of industrial hydrogen demand in coupled electricity and hydrogen production systems is summarised in Figure 3.9 and Figure 3.10.

In the *constrained nuclear* case, and taking hydrogen demand of 1.5 MtH₂ as a baseline, shifting from flexible demand to steady, industrial hydrogen demand leads to a cost increase of USD 4 billion per year. This represents a 12% system cost increase in relative terms. These additional costs are essentially driven by new capacity investments in the system. Around 17 GW of new variable renewable capacity, mainly wind, are needed to support steady hydrogen production. Additional 6 GW of batteries are also required to compensate for the loss of electrolyser flexibility under industrial demand patterns, increasing the total capacity additions of hydrogen to 23 GW.

When nuclear power is allowed to expand (i.e. *unconstrained nuclear* case), several system benefits can be unlocked. For hydrogen demand of 1.5 MtH₂, the shift to more steady hydrogen production patterns can now be accommodated with an additional 4 GW of nuclear power. This is the equivalent of 4.5 times less capacity additions than in the *constrained nuclear* case. Since the share of nuclear power in the total installed capacity is around 45%, the electricity system

is, in general, less demanding of flexibility services from electrolyzers. Therefore, the electricity system is less sensitive to hydrogen production patterns, limiting the total system cost increase to USD 0.4 billion per year, 9 times lower than in the *constrained nuclear* case.

Figure 3.9: Impact of supplying a steady hydrogen demand on the total economic system costs for a level of hydrogen production of 1.5 MtH₂ under a 0 MtCO₂ carbon constraint

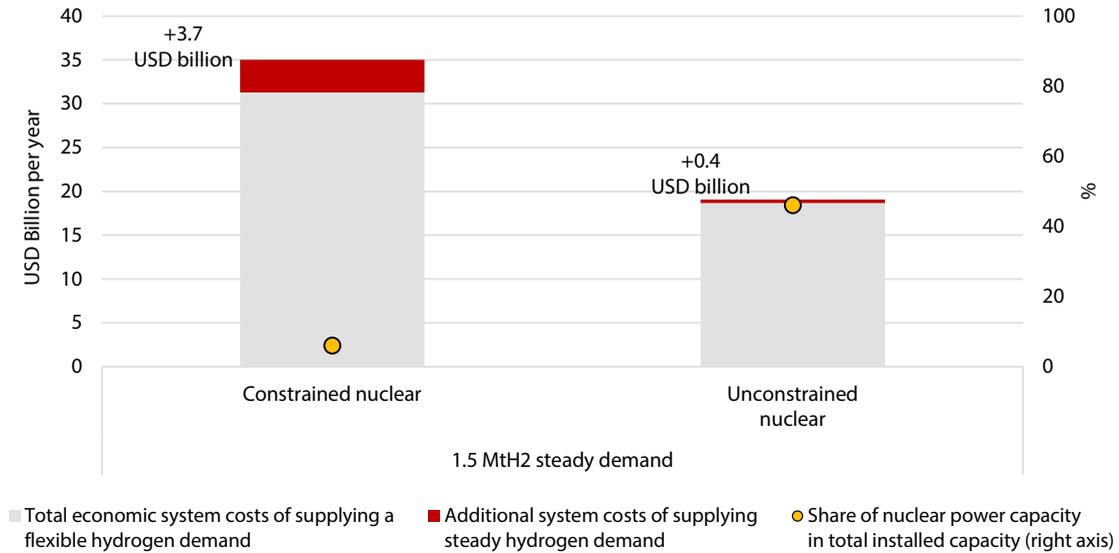
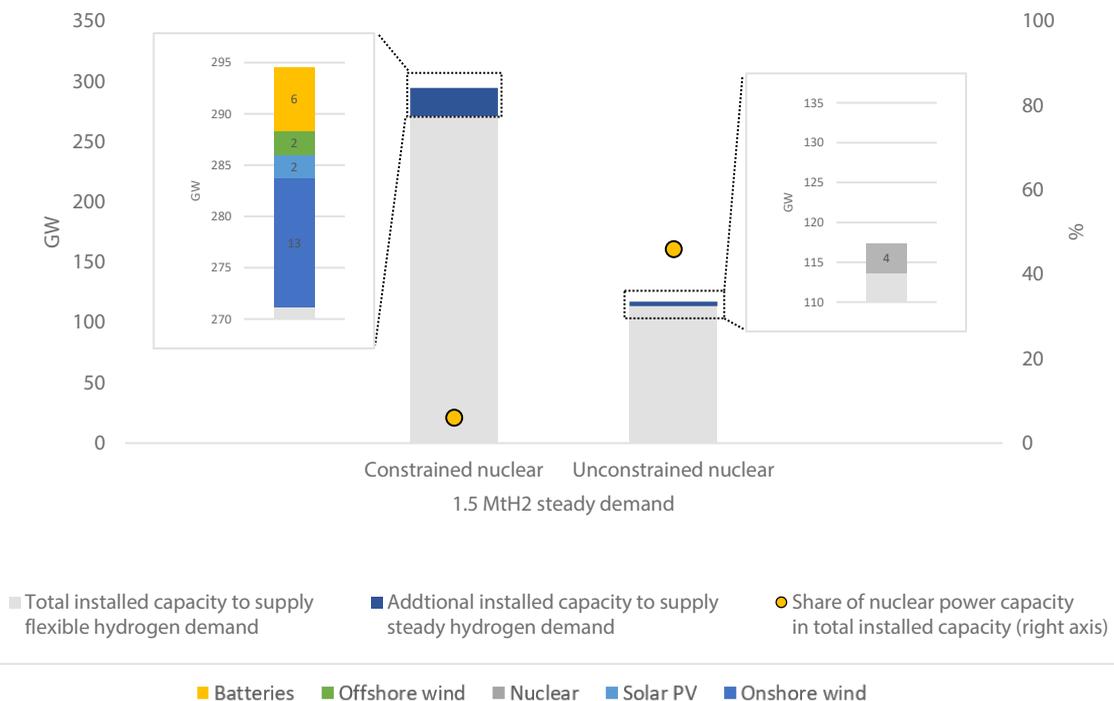


Figure 3.10: Impact of supplying steady hydrogen demand on the total installed capacity for a level of hydrogen production of 1.5 MtH₂ under a 0 MtCO₂ carbon constraint



These results demonstrate that the case of nuclear power is further improved when the system requires large amounts of baseload hydrogen at high carbon constraints, as long as the hydrogen storage infrastructure is not available and/or storage costs remain high. In such conditions, the following generic conclusions for integrated electricity and hydrogen production systems can be drawn:

- Systems with high shares of nuclear power (or high shares of low-carbon dispatchable capacity) are able to meet steady hydrogen demands in a more cost-efficient manner while limiting the need of system flexibility from electrolyzers.
- Conversely, systems with high shares of variable renewables will accommodate steady hydrogen production profiles at a higher cost penalty due to i) higher capacity additions in the absence of nuclear power and ii) the fact that such systems tend to be more reliant on electrolyser flexibility, being therefore more sensitive to changes in hydrogen demand patterns.

These conclusions are consistent with the results described in Chapter 2 suggesting that nuclear power contributes to the cost-efficient design and operation of hydrogen value chains for industrial applications.

3.3. Possible directions for future work

This report's analysis provides quantitative evidence about the value of nuclear power in coupled electricity and hydrogen production systems and the associated sector coupling interactions. Further potential work falls into three main categories:

- **Modelling hydrogen as an electricity storage vector:** Hydrogen molecules can be stored and transformed into electricity in fuel cells, in hydrogen turbines and in conventional turbines, either blended or after being transformed into synthetic methane. The model could account for such processes and be able to endogenously determine the optimal amount of hydrogen to be generated, stored and discharged into the grid on-demand as electricity to minimise system costs.
- **Enlarging the portfolio of hydrogen production technologies:** A variety of hydrogen production technologies exist and can contribute to supplying the significant amounts of hydrogen needed in net zero pathways. Fossil fuel-based chemical reforming with CCS will compete with different types of electrolysis technologies that can leverage the electricity from variable renewables and nuclear power to produce low-carbon hydrogen. Advances in thermochemical cycles and very high-temperature reactors could also unlock more efficient hydrogen production. Assessing the competition dynamics between all these technologies, the associated systemic effects and, in particular, the potential role of nuclear power requires more refined modelling work.
- **Assessing in more detail the interactions between electricity and hydrogen systems:** System costs of integrated power systems will depend on the interactions of the subsystems. In particular, future work on coupled electricity and hydrogen production systems would benefit from more refined interconnection modelling and the assessment of alternative hydrogen demand patterns according to specific industrial applications and/or system configurations.

3.4. Conclusions

Using the case of a highly interconnected country as a reference system, this chapter provides an illustrative system costs analysis to assess the value of nuclear power in coupled electricity and hydrogen production systems. Only two hydrogen production technologies are considered: PEM electrolysis and existing steam methane reforming facilities. Different carbon constraints (25 MtCO₂ and 0 MtCO₂), shares of nuclear power in the total installed capacity (*constrained nuclear* and *unconstrained nuclear* case) and exogenously-imposed hydrogen demands (0.5 MtH₂ and 1.5 MtH₂) are evaluated. The use of hydrogen to store electricity that can be reinjected into the grid on-demand is not taken into account. Nevertheless, the system flexibility that can be provided by electrolyzers is assessed. This approach is consistent with the short-term prospects

of the hydrogen economy that foresee, in the first stages of development, the utilisation of hydrogen as a chemical feedstock or commodity that needs to be produced at large scale to decarbonise existing hydrogen demand as well as industrial and transport applications.

This analysis is the last of three complementary economic approaches covered in this report that aim to provide a comprehensive perspective of the cost and competitiveness of nuclear-produced hydrogen. While the first two approaches (LCOH and LCOHD) focus on plant-level, industrial applications and their associated value chains with no (or little) interaction with the electricity grid (i.e. coupled mode), the present system analysis assesses the cost and value of coupling electricity and hydrogen production systems containing a variety of technologies interacting through the grid, including electrolyzers with different potential operational modes.

Although the analysis remains illustrative, it provides substantial insight into the role that nuclear power can play in enhancing the competitiveness of coupled electricity and hydrogen systems and identifies the main points that require further evaluation and will ultimately impact system costs significantly. The first one, consistent with the work carried out by the NEA (2012; 2019), is the carbon constraint. The second is the impact of electrolysis on electricity systems. The last one, linked to the previous point, is the role of hydrogen demand patterns (or different operational modes of electrolyzers), in particular those of industrial applications that are likely to emerge in the short term.

Based on the modelling assumptions detailed in Section 1.2 and Appendix 1, this report's system analysis finds that nuclear power reduces the overall economic system costs of coupled electricity and hydrogen production systems under stringent carbon constraints. At residual carbon emissions (corresponding to 25 MtCO₂), the optimal expansion of nuclear power enables system cost reductions of 7-11% compared to scenarios where nuclear capacity is constrained at relatively low levels. Existing steam methane reforming facilities remain the lowest cost option to produce hydrogen capturing all the market and represent 1-2% of the total system costs. However, the emissions from the chemical reforming processes must be offset by emission reductions in the electricity system. Even if the electricity and hydrogen production systems are not physically coupled under this configuration, they interact through the carbon constraint. The higher the hydrogen demand to be satisfied with steam methane reforming, the higher the grid decarbonisation costs and, hence, the higher the system cost gap between scenarios with and without new nuclear build.

As the integrated system moves towards net zero conditions, the role of nuclear power to lower overall system costs becomes increasingly important. The system cost gap increases from 7-11% to around 40-50%. Also, electrolysis becomes the only option to meet increasing hydrogen demands at very high carbon constraints. Under these conditions, displacing residual emissions is extremely hard and grid decarbonisation efforts capture most of the cost to reach net zero carbon emissions. If new nuclear build is not allowed, a six-fold increase of variable renewable capacity is required, leading to a doubling in electricity system costs compared to those observed under residual emissions. It is important to highlight that these results are obtained within an electricity system that leverages a full range of system flexibility options (e.g. interconnections, batteries) that tend to reduce the need of dispatchable generators such as nuclear power plants. In other words, higher cost reductions could be expected in the presence of nuclear power in systems with less flexibility options available. These results are consistent with the findings of the NEA (2012; 2019), Aurora (2021) and Watson and Donovan (2021), which illustrate the correlation of system costs with carbon constraint and encourage the contribution of nuclear power to reduce overall system costs in integrated energy systems.

With electrolyzers being exclusively deployed at net zero, both electricity and hydrogen production systems become fully coupled and a new set of interactions potentially impacting overall system costs enters into place. Electrolytic production of hydrogen induces additional costs and benefits that go beyond the installation and operation of electrolyzers. They include new generation costs necessary to satisfy the additional electrolysis demand, net exports variations, and system flexibility enhancements. Such interactions will also determine the optimal size of electrolyser capacity to be deployed and how it will be used. Overall, the costs of electrolysis are relatively low, representing up to 25% of the total system costs. Most of the system costs are incurred to decarbonise the grid and electrolysis can thus be seen as a low hanging fruit once the grid is decarbonised.

Taking a closer look at the impacts of electrolysis on electricity generation, the electricity demand induced by electrolysis will tend to increase the baseload range of the electricity load profile, enabling higher availability of nuclear power, improving the economic performance at both the plant and system levels. This effect is even more acute in systems with depressed nuclear load factors due to the presence of high shares of variable renewables. The electricity demand induced by electrolysis will also compete with electricity exports, especially if domestic electricity prices are low, potentially leading to a revenue loss that can drive system costs up.

Having a fully flexible hydrogen demand also has its benefits at the systemic level. The ability of PEM electrolyzers to load follow reduces the need of batteries, demand response and load shedding as well as variable renewables curtailment, especially at high penetration shares of variable renewables. The additional system flexibility offered by electrolyzers does not reduce, however, the need of new capacity additions, in particular of new nuclear power units. As hydrogen demand increases, load factors improve first, followed by new nuclear capacity additions and reductions in battery capacity. The system flexibility emerging from electrolyzers also narrows the system costs gap between scenarios with and without nuclear new build as hydrogen demand increases. This is a phenomenon that it is not observed under residual carbon emissions where steam methane reforming hydrogen production inhibits sector coupling. Of course, the flexible operation of electrolyzers comes at a cost penalty reflected in the lower load factors and higher installed capacities. However, the additional cost is almost negligible at the system level. Systems with high shares of variable renewable that rely heavily on electrolyser flexibility are also more exposed to the economic consequences of changes in hydrogen demand patterns.

In the short term, it is expected that large amounts of low-carbon hydrogen will be needed to decarbonise current hydrogen demands as well as industrial and transport applications. The technical requirements of the industry may impose more steady hydrogen production flows (or a baseload operational mode for electrolyzers) that can affect electricity system behaviour when coupled with hydrogen systems, especially if the hydrogen storage infrastructure is not available and the associated costs remain high. In such configurations, the case of nuclear power is further improved for two main reasons. First, the dispatchability of nuclear power matches well with steady hydrogen production patterns, leading to lower capacity additions. Second, higher shares of nuclear power reduce the reliance on electrolyzers as a source of system flexibility, and therefore the exposure to hydrogen demand shifts. Taking the case of hydrogen demand of 1.5 Mth₂ at net zero as a baseline, shifting from flexible to industrial, steady hydrogen demand patterns without nuclear new build requires 23 GW of new capacity, including variable renewables and batteries, at an additional cost of USD 4 billion per year. This represent 12% of the total system costs in relative terms. Since the flexibility of electrolyzers is hampered by the steady production of hydrogen, the need for batteries, demand response, load shedding and variable renewable curtailment rapidly rises, contributing to this additional cost burden. Conversely, if new nuclear capacity is built, only 4 GW suffice to accommodate steady production patterns at an additional cost that drops to USD 0.4 billion per year. The benefits unlocked by nuclear power are also significant in terms of the cost of hydrogen production. In the absence of new nuclear capacity additions, costs almost triple between a flexible and baseload hydrogen production, going from USD 1.3/kgH₂ to USD 3.8/kgH₂. With nuclear capacity additions, hydrogen production costs are contained at USD 2.5 kg/H₂ regardless of the type of hydrogen demand. These results remain aligned with those described in Chapter 2, showing the positive contribution of nuclear power in designing cost-efficient hydrogen value chains for industrial applications.

Lastly, it is necessary to recall that present modelling only considers hydrogen as a large, exogenous demand and not as an electricity storage vector, in line with the prospects of the hydrogen economy over the current decade. Nevertheless, a more comprehensive picture of the role of nuclear in a fully developed hydrogen economy may require system modelling that includes the use of hydrogen for electricity storage, a more refined interconnections modelling, as well as an enlarged portfolio of competing hydrogen production technologies (e.g. chemical reforming with CCS, high-temperature electrolysis), including hydrogen production with nuclear heat, among other technical considerations.

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4. Conclusions

Hydrogen produced by low-carbon sources such as nuclear energy and renewables is expected to make a key contribution in the transition towards an economy with net zero carbon emissions. It will have different roles over different time frames. In the short and medium term, until 2035, hydrogen will primarily remain an important chemical input for the production of vital commodities, for instance in the fertiliser industry. In the long run, the role of hydrogen will also be to serve as an energy vector for the storage and transport of energy as well as for the provision of energy end-use services in otherwise hard to decarbonise sectors such as transport and heating. However, beyond a general consensus about the importance of the future roles of low-carbon hydrogen, great uncertainties remain regarding their precise timing, scale and context. For all the scenarios, a key challenge is to answer the question: “What are the most cost-effective options for the production and delivery of low-carbon hydrogen?”

The analysis in Chapter 2 shows that the costs of electricity generation are decisive in determining the production costs of low-carbon hydrogen. However, it also illustrates that value chain costs, i.e. the costs of hydrogen storage, distribution and transport, are likely to represent a significant share of hydrogen delivery costs. This is particularly true for systems with low load factors and seasonal variations that meet an unremitting industrial demand over long distances.

Differences can be large. This assessment estimates that the costs of hydrogen production through electrolysis range between USD 1.78 and 7.54 per kgH₂ in 2035. The lowest costs are obtained with an electrolyser coupled to a best-case solar photovoltaic (i.e. solar Middle East) or nuclear long-term operation (LTO), while the highest costs come with an electrolyser powered with grid electricity in a context of high gas prices. On average, for both nuclear and renewables-based systems, hydrogen costs of production are estimated at USD 3-3.5 per kgH₂. This highlights the difficult competition with steam methane reforming retrofitted with carbon capture, use and storage (CCUS) at low gas prices (i.e. USD 20 per MWh), for which the levelised cost of hydrogen is estimated at USD 1.91 per kgH₂. However, the incumbent process depends largely on the price of gas and its LCOH surges to USD 5.83 per kgH₂ at gas prices of USD 100 per MWh. This assessment shows that regional resource endowment, i.e. the access to natural gas or electricity in large quantities at a competitive price, will play a key role in determining the future technological landscape for low-carbon hydrogen production.

A steady production profile makes it possible to minimise value chain costs in the case of continuous demand for hydrogen. Indeed, the previous analysis estimates the value chain costs for a nuclear-based system are between 7% and 14% of hydrogen delivery costs, depending on the pipeline lengths and considering new pipelines. Value chain costs for a renewables-based system (i.e. with a variable production profile) in a similar configuration, range between 25% and 56% of hydrogen delivery costs. In other words, nuclear stands out as the most competitive solution to deliver an unremitting flow of low-carbon hydrogen over large distances to industries, particularly in places where cheap variable sources are not available at the sufficient scale.

Other important results highlight the role of retrofitted pipelines that would largely contribute to lower hydrogen value chain costs and should be encouraged wherever possible. Additionally, hybrid systems with shares of steady and variable production appear to benefit from both sources' strengths, whether it be higher infrastructure efficiency or lower electricity costs.

Chapter 3 provides additional insights on the role of nuclear power in enhancing the competitiveness of coupled electricity and hydrogen systems, with electrolysers connected to the grid. In particular, it shows that system costs are 40% to 50% lower for a scenario that allows for the deployment of nuclear in a context of net zero emissions. This result is primarily determined by the system's carbon intensity as advantages offered by nuclear are estimated at

around 11% for systems under a constraint of 25 MtCO₂. Further, most of the hydrogen demand by 2035 will be devoted to decarbonise industrial applications. Industry requires steady flows of hydrogen that can be supplied by electrolysers operating in baseload mode, especially if the hydrogen storage infrastructure is not available and/or storage costs are high. This chapter also demonstrates that, in such system configurations, the use of nuclear power further minimises overall system costs.

The hydrogen economy can take many directions and assessing the cost and competitiveness of nuclear-produced hydrogen is not a straightforward exercise. Due to increasingly stringent carbon constraints, it is, however, likely that proton exchange membrane electrolysis will be the main means of satisfying industrial demand through 2035. In this general context, electrolysers have the choice between two operational modes. They will either be coupled directly to a dedicated electricity generator or take their electricity from the grid, where it will be produced in various low-carbon configurations.

By combining plant- and system-level economic approaches, this report provides a picture of the cost and competitiveness of nuclear-produced hydrogen by 2035. It shows that nuclear power is a competitive option to produce and deliver hydrogen for industrial applications, both in the form of dedicated generation units for large installations and as an indispensable provider of low-carbon baseload power in decarbonised electricity systems. The scale and the dispatchability of nuclear power contribute to the cost-efficient design and operation of both hydrogen value chains and integrated low-carbon energy systems, which will both be needed to provide the large amounts of hydrogen required to achieve the objective of net zero carbon emissions by 2050.

Appendix 1: System cost analysis assumptions and additional results

POSY overview

POSY is a tool developed by the Nuclear Energy Agency (NEA) to perform electricity system analysis. It performs capacity expansion and unit commitment computations in an hourly resolution using state-of-the-art linear optimisation (cost optimisation) and technical constraints (mixed-integer linear programming, or MILP). The model is based on the equations detailed in Morales-España et al. (2014; 2015), Gentile (2016) and Tejada (2019).

POSY considers a copper plate approximation in one single bus with interconnections being modelled through historical price series and net transfer capacities (i.e. interconnections) with neighbouring countries. Interconnection saturation mechanisms and congestion rents are taken into account. Perfect forecast of demand, weather conditions and net transfer capacity availability is also assumed.

In terms of system cost components, POSY solely computes the profile costs induced by the introduction of higher shares of variable renewables in the system. Balancing costs and connection, transmission and distribution costs are not computed by POSY.

Existing capacity

The existing capacity by technology considered initially in the modelled system is indicated in Table A1.1. As detailed in Section 3.2.1, hydropower (reservoir and run of river) and pumped capacity are fixed across cases. Nuclear power is only fixed in the *constrained nuclear* case. The rest of the technologies are allowed to expand in all cases.

Table A1.1: Brownfield capacity by case

Technology	<i>Constrained nuclear case</i> Capacity (GW)	<i>Unconstrained nuclear case</i> Capacity (GW)
Solar photovoltaic	10	10
Hydropower (reservoir)	6.5	6.5
Nuclear	18	18
Coal	3	3
Onshore wind	17	17
Offshore wind	0	0
Pumped storage	4.5	4.5
Hydropower (run of river)	10	10
Natural gas (combined cycle gas turbine)	12	12
Ion-lithium batteries	0	0

Source: Data derived from RTE (2022b).

Technology cost data

The main technology cost is summarised in Table A1.2.

Table A1.2: **Main technology costs data**

Technology	Lifetime	Load factor (%)	Overnight cost (USD/kWe)	Annualised investment costs (USD/MW/y)	Fuel cost (USD/MWh)	Annualised fixed O&M (USD/MW/y)	Variable O&M (USD/MWh)
Hydro reservoir	80	49%	3 319	169 358	0	44 142	0
Hydro pumped	80	15%	1 962	100 118	0	7 302	0
Hydro RoR	80	58%	4 399	224 467	0	32 496	0
Nuclear new build	60	81%	4 261	225 082	10	71 831	3
Gas (CCGT)	30	69%	808	52 589	23	31 917	5
Onshore wind	25	36%	1 508	107 011	0	32 854	0
Offshore wind	25	43%	2 510	178 061	0	73 415	0
Solar PV	25	25%	1 007	71 429	0	11 483	0
Coal	40	82%	2 373	138 319	10	57 189	10
Ion-Lithium batteries	15	N/A	832	80 157	0	37 000	0

Source: Data derived from IEA/NEA (2020), and Cole and Will Frazier (2020).

Note: Discount rate of 5%

The cost of load shedding corresponds to a value of lost load set a USD 10 000/MWh. The cost of demand response management is of USD 500/MWh.

Hydrogen cost data

The main hydrogen cost data is summarised in Table A1.3 and Table A1.4. This data is consistent with that detailed in Appendix 5. Only two technologies are considered in the system modelling: steam methane reforming without carbon capture and storage and proton exchange membrane (PEM) electrolysis.

Table A1.3: **PEM electrolysis cost data**

Variable O&M (USD/MWh)	Fixed O&M (USD/kWe)	Annualised fixed O&M (USD/MW/y)	Fuel cost (USD/MWh)	Overnight costs (USD/kWe)	Annualised investment costs (USD/MW/y)	Size (GW)	Lifetime	Hydrogen yield (tH ₂ /GWh)
0	22.5	2 913.9	Endogenous electricity price	450	58 277	0.2	10	21

Note: Discount rate of 5%.

Table A1.4: **Steam methane reforming cost data**

Fuel costs (USD/tgas)	CO ₂ emissions per tonne of H ₂ (tCO ₂ /tH ₂)	Fuel per tonne of H ₂ (tgas/tH ₂)
92	9	3.39

Note: As an approximation of the hydrogen production cost in existing steam methane reforming facilities, only fuel costs are considered.

Hourly profiles and other data

The system analysis requires additional input data related to the hourly profiles of demand, availability of renewables, natural intake for hydropower reservoirs, and interconnections (i.e. net transfer capacities and historical electricity prices series in neighbouring countries). The different sources consulted are summarised in Table A1.5.

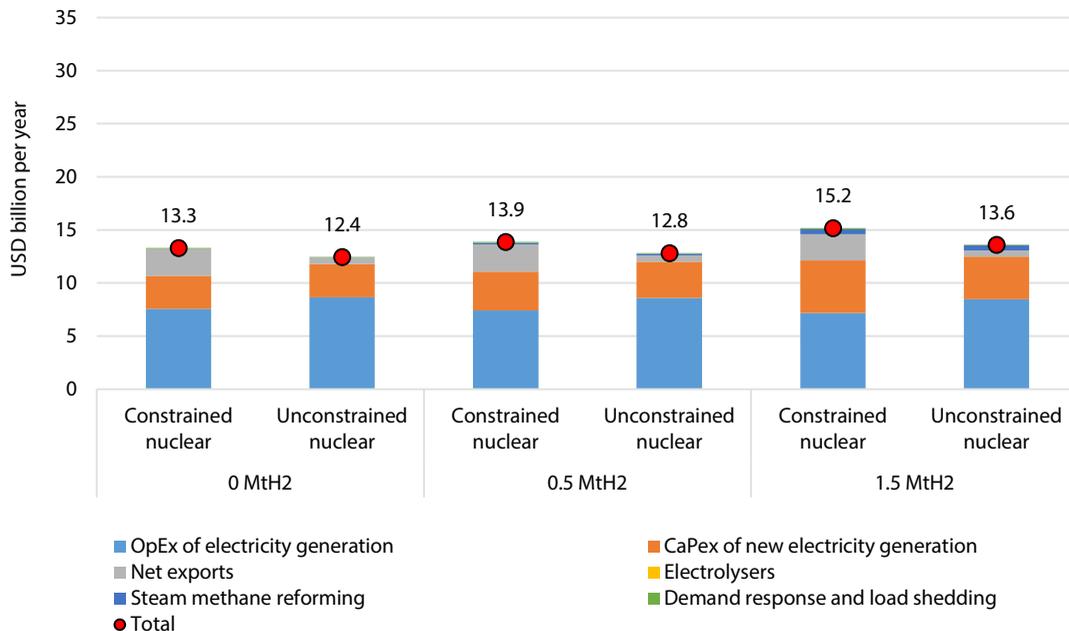
Table A1.5: **Additional input data sources**

Input data	Source	Comments
Demand	RTE (2022a)	Hourly profile with an average demand of 50 GW and a peak demand of 83 GW
Solar PV, onshore wind, hydropower run of river	RTE (2022a)	Hourly generation profile
Offshore wind	IRENA (2022), ENTSO-E (2022)	Hourly generation profile
Natural intake hydro reservoir	JASM (2022), OFEN (2022)	Hourly profile
Net transfer capacity	ENTSO-E (2022)	Net transfer capacities of 9.8 GW (imports) and 13.5 GW (exports) are considered. The capacity is assumed fully available throughout the year
Electricity prices	ENTSO-E (2022)	Hourly profile

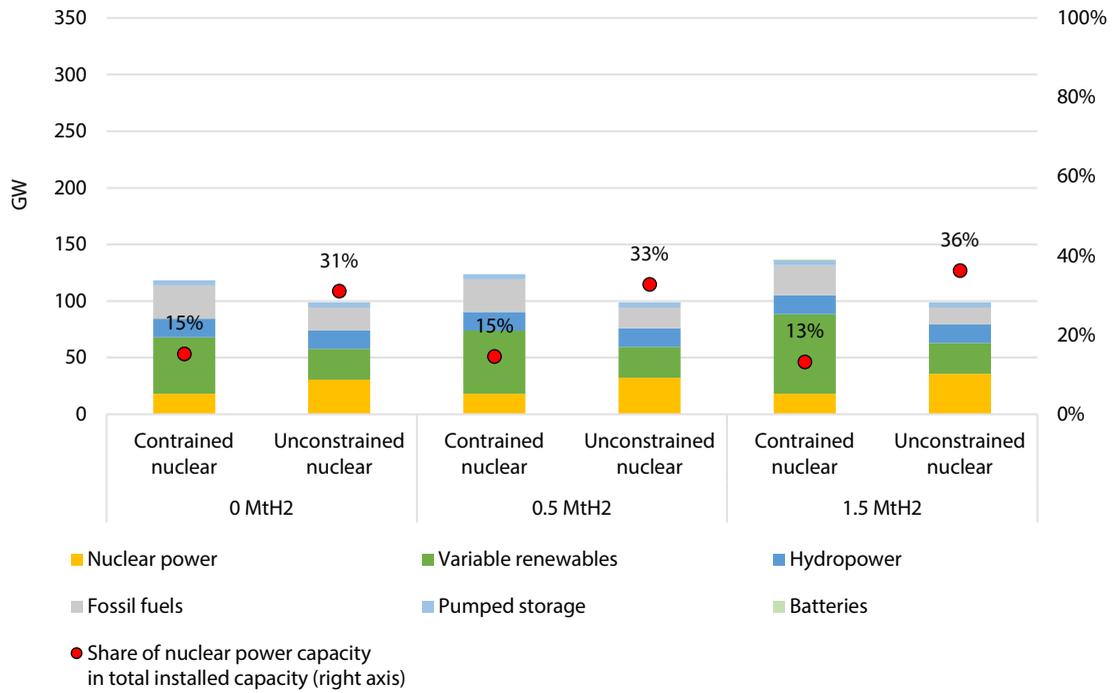
Additional results

Carbon constraint of 25 MtCO₂ (residual carbon emissions)

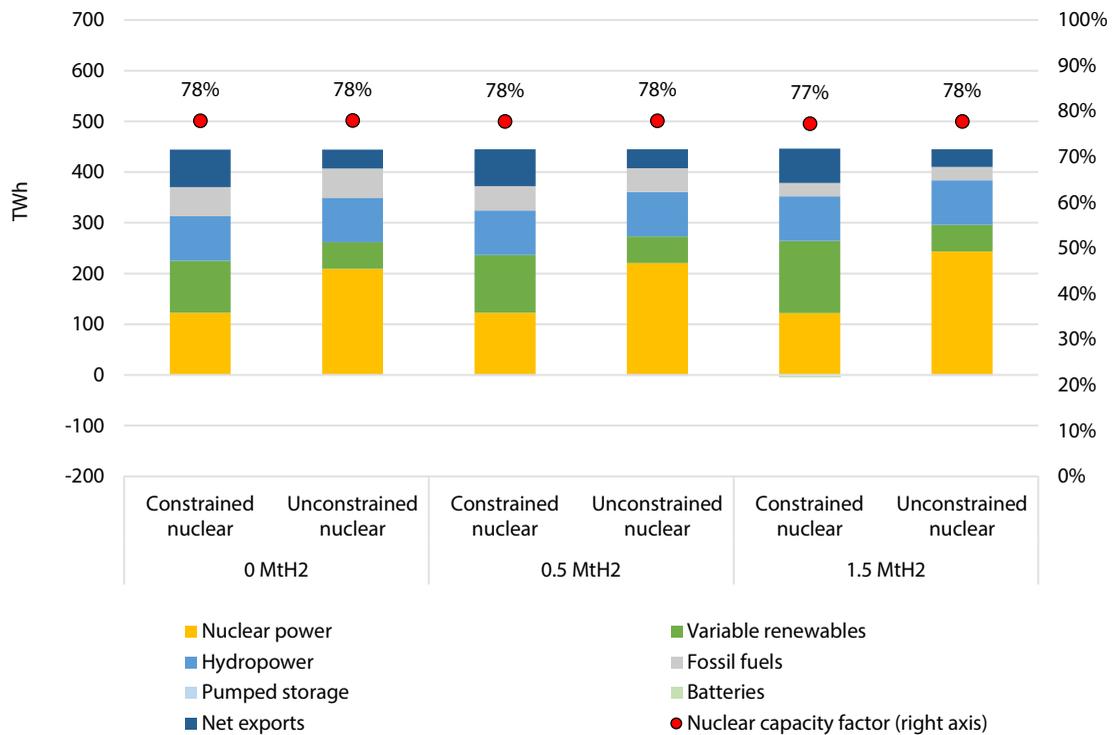
System costs



Capacity

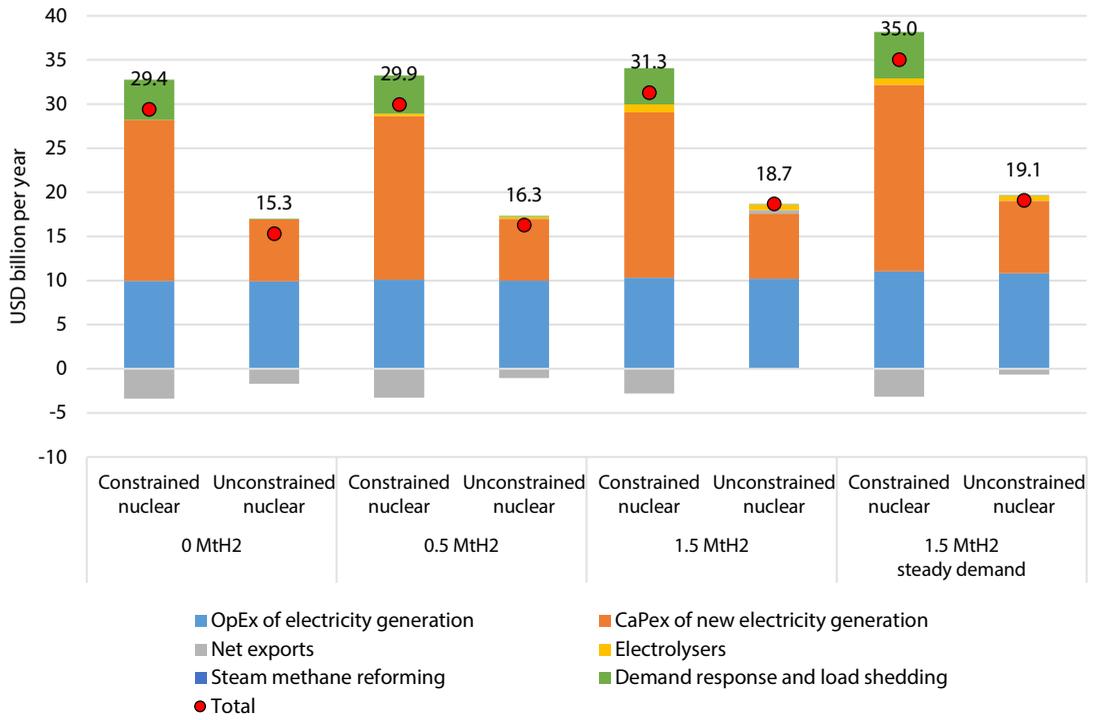


Generation

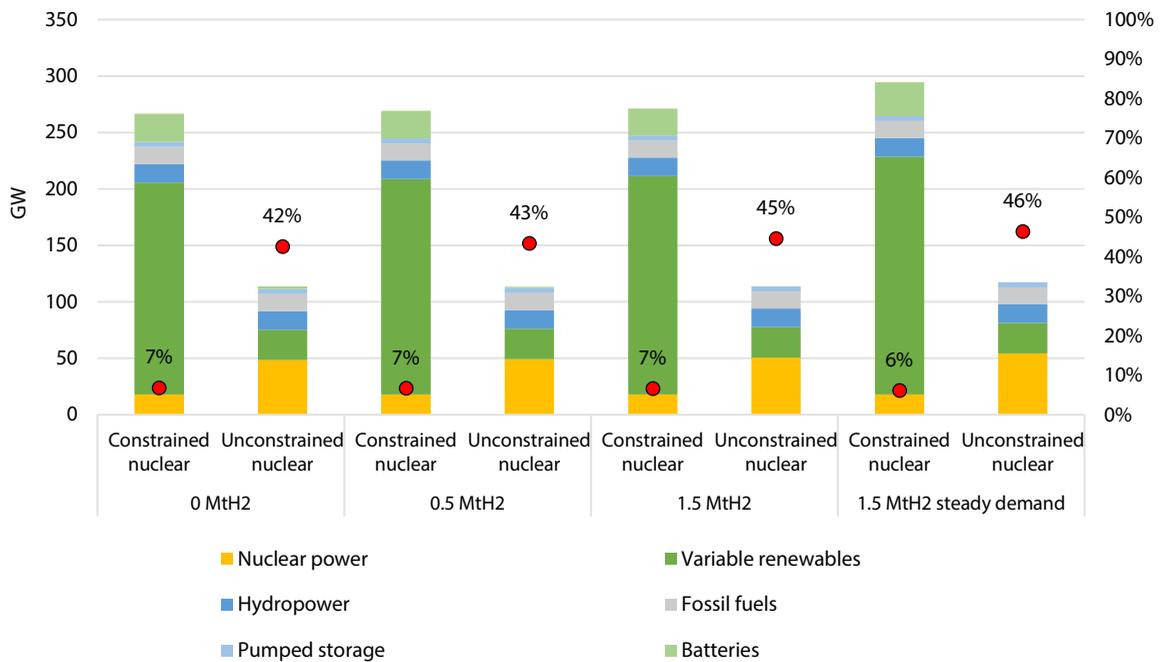


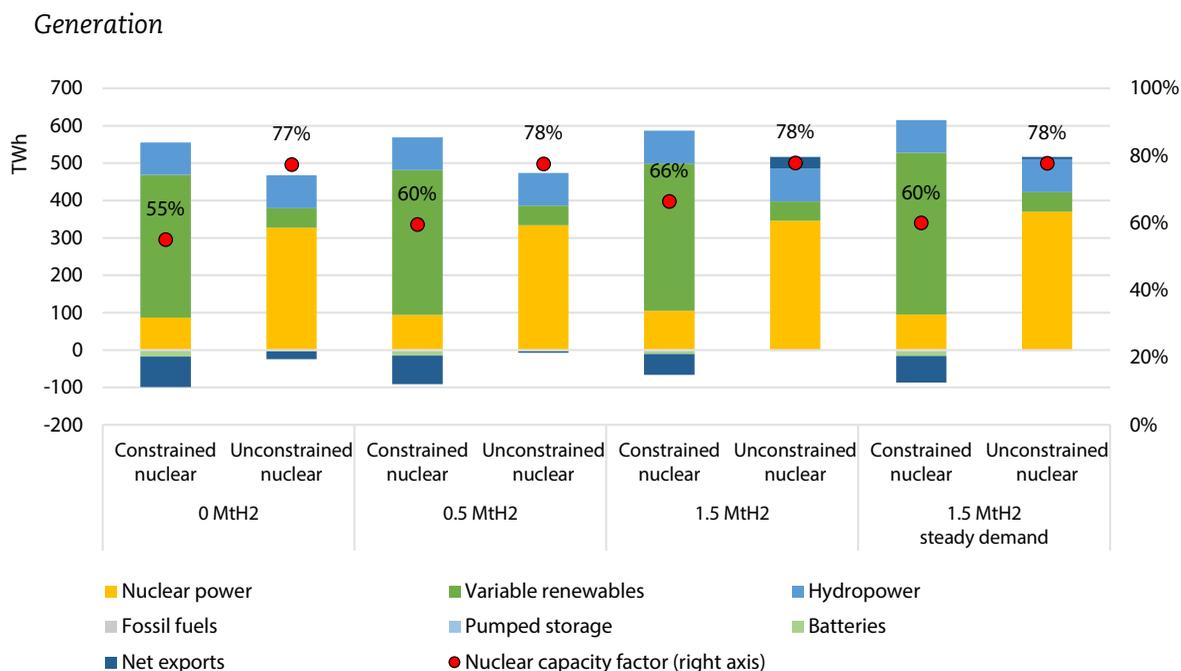
Carbon constraint of 0 MtCO₂ (Net Zero)

System costs



Capacity





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Appendix 2: Further details on hydrogen production pathways

As of 2019, approximately 99% of dedicated hydrogen production used fossil fuel-based methods, either methane chemical reforming or coal gasification. The former method is dominated by steam methane reforming, with more than 50 Mt of hydrogen produced in 2019 (IEA 2019).

Chemical reforming

Steam methane reforming involves the conversion of methane (CH₄) and steam into hydrogen (H₂) and carbon oxide (CO). It enables large-scale hydrogen production, to the order of hundreds of tonnes of hydrogen per day, at a very competitive price around USD 1 per kgH₂.¹ It is also a highly emitting process as it produces an average of 9 tonnes of CO₂ per tonne of hydrogen produced (IAEA, 2018; IEA, 2019; NATF, 2020).

Methane chemical reforming represents 76% of dedicated production, or 52 Mt (IEA, 2019). About 90% of this comes from steam methane reforming and the rest from two other chemical reforming paths of methane, partial oxidation (POR) and autothermal reforming (ATR) (IEAGHG, 2017).

Steam methane reforming

The simplified reactions read as follow (NATF, 2020):

- Steam methane reforming: $\text{CH}_4 + \text{H}_2\text{O} \rightarrow \text{CO} + 3\text{H}_2$ (840-920°C, 20-30 bar, nickel based catalyst)
- Methane partial oxidation: $\text{CH}_4 + 0.5\text{O}_2 \rightarrow \text{CO} + 2\text{H}_2$ (900-1 000°C, 20-60 bar, no catalyst)

To reach greater hydrogen purity, carbon oxide molecules are further treated through different reactions, such as the water-gas shift (WGS) reaction, where they react with water steam to produce H₂ and carbon dioxide.

- Water-gas shift: $\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$

Coal gasification

Coal gasification contributes approximately 23%, or 16 Mt, of global dedicated hydrogen production (IEA, 2019). This process consists in the production of a synthetic gas from coal and water. The simplified reaction reads as follow (NATF, 2020):

- Coal gasification: $\text{C} + \text{H}_2\text{O} \rightarrow \text{CO} + \text{H}_2$ (1 150-1 315°C)

Exhaust carbon oxide is further treated through processes similar to those of the methane chemical reforming method. However, this process reaches lower hydrogen purity than steam methane reforming and leads to greater CO₂ emissions, around 19 tonnes per tonne of hydrogen produced (IEA, 2019). As of 2019, it is mainly used in China where CHN China, the largest hydrogen producer in the world, operates 80 coal gasifiers that produce up to 8 MtH₂ per year (IEA, 2019a).

1. Based on long-term average gas prices around 3 USD/MMBtu.

With current technologies, coal with Carbon capture, use and storage (CCUS) enables emissions to reach 2 kgCO₂/kgH₂ while future technologies might slash this figure to 0.4 kgCO₂/kgH₂ (IEA, 2019). On the other hand, CCUS holds the same challenge as for steam methane reforming. In 2019, an important initiative² was launched by the Australian government in partnership with the Japanese company Kawasaki Heavy Industries to develop hydrogen production from lignite gasification with CCUS, where captured CO₂ would be stored in the lignite reservoir (NATF, 2020).

Although less discussed than CCUS, nuclear energy can also contribute to lower emission from steam methane reforming processes. In particular, high-temperature gas-cooled reactors (HTGRs) can be used to pre-heat methane, lowering emissions and reducing feedstock needs by up to 35% (IAEA, 2018). As of 2021, Russia and Japan were involved in research on coupling a HTGR to a methane chemical reforming hydrogen production plant (Suppiah, 2020).

Water electrolysis

Different electrolyser technologies ultimately refer to types of cells depending on the choice of electrodes (anode and cathode), catalyst and electrolyte:

- Electrodes enable the oxidation-reduction reactions and are commonly bipolar steel or carbon plates (NATF, 2020). The reduction reaction (a gain of electrons) occurs at the cathode, while the oxidation reaction (a loss of electrons) occurs at the anode;
- The electrolyte enables ions to move towards the cathode (which attracts positively charged particles called cations) or the anode (which negatively charged particles called anions).

Although not physically necessary, a catalyser is often added to enhance the chemical reactions occurring at the electrodes. Furthermore, it is important to note that fuel cells, used to generate electricity using hydrogen and oxygen, rely on the same physical process but in reversed mode. However, the nominal conditions of operation of electrolysers and fuel cells are most often different and not all electrolyser designs enable reverse mode operation.

In addition, with the potential large-scale deployment of electrolysers within our energy systems, the literature discusses other key performance indicators (KPI) such as (HE, 2020):

- Ramp time (s). Defined as the time required to reach nominal capacity in terms of hydrogen production rate whether “hot idled” when the system is already at operating temperature and pressure or “cold” when starting the device from scratch. This is a useful indicator to assess the potential uses of the electrolysers in dynamic mode (with frequent start-ups and varying power inputs) and their contributions to ancillary electric markets.
- Water consumption (l/kgH₂). Around nine litres of water are needed to produced one kg of hydrogen. This might be an issue in zones where fresh water is scarce (IEA, 2019).
- Use of critical raw material as catalyst (mg/W). Though the scale of each cell technology’s future deployment is unknown, electrolysers are expected to drive significant growth in demand for metals such as nickel and zirconium (IEA, 2021).
- Foot print (m²/W).

Alkaline electrolysis

In alkaline electrolysis, water is introduced at the cathode, where it is split into hydrogen (H₂) and hydroxide (HO⁻) ions that then move through the electrolyte towards the anode to form dioxygen (O₂). The oxidation-reduction reactions are as follows:

- At the cathode (reduction): $2\text{H}_2\text{O} + 2\text{e}^- \rightarrow 2\text{OH}^- + \text{H}_2$

2. The Hydrogen Energy Supply Chain Latrobe Valley project.

- At the anode (oxidation): $4\text{OH}^- \rightarrow \text{O}_2 + 2\text{H}_2\text{O} + 4\text{e}^-$

The aqueous electrolyte is commonly a potassium hydroxide (KOH) based solution. Nickel, which is a non-precious material, is mostly used as catalyst. Alkaline electrolyzers typically operate at low temperatures, around 60-80°C, and under a moderate range of possible pressure, of 1-30 bar. Though not physically impossible, current alkaline electrolyser designs do not enable reverse operation and therefore no market for alkaline fuel cells is currently being developed (NATF, 2020).

Proton exchange membrane

In a proton exchange membrane (PEM) electrolyser, water is introduced at the anode, where it is split into protons (H^+) and dioxygen (O_2). Hydrogen ions evolve through the electrolyte membrane towards the cathode to form dihydrogen (H_2). The oxidation-reduction reactions are respectively:

- At the anode: $2\text{H}_2\text{O} \rightarrow \text{O}_2 + 4\text{H}^+ + 4\text{e}^-$
- At the cathode: $4\text{H}^+ + 4\text{e}^- \rightarrow 2\text{H}_2$

The PEM electrolyte is a polymer conducting protons. The currently most used technology for PEM cells is the Nafion membrane, developed in 1960 by the American company DuPont, where a platinum-based catalyst is embedded into synthetic polymers to form a membrane electrode assembly (MEA). PEM electrolyzers typically operate at low temperatures, around 50-80°C and under moderate to high pressure of 30-80 bar. PEM electrolyzers are not reversible as the elements associated with the platinum used as catalyst are not compatible with a fuel cell mode of operation (NATF, 2020).

Solid oxide electrolysis

In solid oxide cells, steam water is introduced at the cathode, where it is split into hydrogen (H_2) and oxygen ions (O_2^-), which then evolve through the electrolyte towards the anode to form dioxygen (O_2). The oxidation-reduction reactions are respectively:

- At the cathode: $2\text{H}_2\text{O} + 4\text{e}^- \rightarrow \text{O}_2^- + 2\text{H}_2$
- At the anode: $2\text{O}_2^- \rightarrow \text{O}_2 + 4\text{e}^-$

A solid ceramic-based electrolyte and low-cost catalyst material such as nickel are commonly used (NATF, 2020). The critical difference with other technologies is that thermal energy replaces part of the need for electricity. In practice, solid oxide cells operate at much higher temperatures (of 650-1 000°C) and are therefore categorised as high temperature electrolysis (HTE) (IEA, 2019a). Possible pressure within the electrolyser is low and commonly reported to be around 1 bar. This technology also enables a reverse operating mode as a fuel cell (INL, 2019).

Thermochemical processes

Thermochemical cycles are another category of water-splitting techniques which principally use heat as energy. Water is mixed with reagents to produce hydrogen with other by-products through multiple reaction cycles (IAEA, 2018). There are thousands of possible thermochemical cycles, though most have been identified as unworkable because of low efficiencies or due to high temperatures (DOE, 2004).

Among the most promising discussed in the literature are the two sulphur-based cycles: Sulphur-Iodine (S-I) and Hybrid Sulphur (HyS), also known as the Westinghouse cycle, and the Copper-Chlorine Hybrid Cycle (Co-Cl) (DOE, 2004; IAEA, 2018).

The Sulphur-Iodine cycle (S-I) involves the production of sulphuric acid (H_2SO_4) and hydriodic acid (HI) before their separation into hydrogen and other by-products. The Hybrid Sulphur process (HyS), or “Westinghouse cycle”, involves two steps with first the decomposition of sulphuric acid (H_2SO_4) into sulphur dioxide, water and oxygen and second the decomposition

of sulphur dioxide (SO₂) into sulphuric acid and hydrogen. The Copper-Chlorine Hybrid Cycle (Co-Cl) exists in several options with three, four or five steps. It involves the decomposition of copper (Cu) and hydrogen chloride (HCl) into copper chloride (CuCl) and hydrogen. Further steps typically process the copper chloride to recycle it (IAEA, 2018).

Table A2.1: **Synthesis of chemical reactions for key thermochemical cycles**

Sulphur-Iodine cycle	$H_2O + SO_2 + I_2 \rightarrow H_2SO_4 + HI$ $2H_2SO_4 \rightarrow O_2 + 2SO_2 + 2H_2O$ $2HI \rightarrow H_2 + I_2$	(120°C) (900°C) (400°C)
Besides hydrogen and oxygen, all reaction products can be reused to start another cycle from the Bunsen reaction.		
Hybrid Sulphur process "Westinghouse cycle"	$H_2SO_4 \rightarrow SO_2 + H_2O + 0.5O_2$ $SO_2 + H_2O \rightarrow H_2SO_4 + H_2$	(850°C) (20-100°C)
Copper-Chlorine Hybrid Cycle (5 steps)	$2Cu + 2HCl \rightarrow 2CuCl + H_2$ $4CuCl \rightarrow 2CuCl_2 + 2Cu$ $2CuCl_{2(aq)} \rightarrow 2CuCl_{2(s)}$ $2CuCl_2 + H_2O \rightarrow CuO.CuCl_2 + 2HCl$ $CuO.CuCl_2 \rightarrow 2CuCl + 0.5O_2$	(430-475°C) (30-70°C) (<100°C) (400°C) (500°C)

Source: IAEA (2018).

The three processes depicted above differ greatly in terms of reagents involved and operating conditions. The S-I cycle only needs thermal energy but at very high levels, up to 900°C. Both other cycles are hybrids as they involve heat and electricity for the electrolysis of SO₂ and CuCl respectively in the Hybrid Sulphur and Copper-Chlorine cycles. This means those cycles require less thermal energy, reducing material maintenance (IAEA, 2018).

The processes have been demonstrated at the laboratory scale by many countries. Japan, Korea and China are leading the way on S-I cycles. The United States has historically pursued developments in the HyS cycle while Canada focuses on Cu-Cl cycles (IAEA, 2018). As of 2021, those processes remain at early stages of development but the literature acknowledges their potential, in particular with further progress on clean heat sources such as the next generation of nuclear reactors or advanced solar-based solutions (IEA, 2019).

Two other fields of research should be pursued in parallel to unlock thermochemical cycles' full potential. Regarding the hydrogen plant itself, there is a need for new construction and catalyst materials that enable steady operations in a harsh environment with extremely high temperatures and corrosive elements. Coupling systems need to see improvements in the efficiency and the robustness of thermal energy transfer between the energy source and the hydrogen plant.

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Appendix 3: Hypotheses and assumptions to compute the levelised cost of hydrogen delivery (LCOHD)

Hydrogen gaseous transport by pipeline

The model considers hydrogen transport through a pipeline, which is the preferred solution for short distance transport. Transportation costs are influenced by many different parameters such as the pipeline diameter, length, input and output pressure, flowrate and temperature. The developed model follows the US Department of Energy H2A's approach for key pipeline characteristics and costs assessment (ANL 2022):

Hydrogen pipeline is sized using the Panhandle B Equation:

$$d = 2.54 \times \exp^{0.2016 \times \left(\frac{\ln(Q) + 6.03}{0.51} + \ln \left(5.31 \times 10^{-3} \times \frac{\gamma^{0.961} \times L \times (T + 273) \times Z}{P_{in}^2 - P_{out}^2} \right) - 1.9916 \right)}$$

Where Q is the flow rate (kg/day), P_{in} is the inlet pressure of the pipeline (= 68 bar), P_{out} is the outlet pressure of the pipeline (= 48 bar), Z is the mean gas compressibility (= 1.04 at chosen inlet pressure and temperature), L is the pipeline length (km), T is the mean temperature (= 15°C), γ is the mean gas relative density (= 0.06897) and d the pipeline diameter (cm). It is assumed that distribution pipeline operates at the compressor output pressure (45 bar). However, following H2A hypotheses, this does not translate into a smaller diameter (ANL, 2022).

CapEx

Total pipeline capital expenditure sums up material, labour, miscellaneous and right-of-way costs and is calculated with the equation below:

$$\begin{aligned} & \text{Transport Pipeline CapEx} \left(\frac{\text{USD}_{2020}}{\text{km}} \right) \\ &= 8.27 \times 10^{-7} (63\,027 \times e^{0.0274 \times D} + 39.02 \times D^2 + 23\,955.94 \times D + 303\,657) \end{aligned}$$

Where, D is the pipeline diameter (cm).

Following H2A hypotheses, the equation is the same for a distribution pipeline, except when its diameter is greater than 20.32 cm. In this case, the distribution pipeline CapEx is calculated by the following equation:

$$\begin{aligned} & \text{Distribution Pipeline CapEx} \left(\frac{\text{USD}_{2020}}{\text{km}} \right) \\ &= 8.27 \times 10^{-7} (31\,513 \times e^{0.0274 \times D} + 39.02 \times D^2 + 23\,955.94 \times D + 303\,657) \end{aligned}$$

Fixed OpEx

Based on figures shared in Jacobs (2018), the fixed operation and maintenance cost is calculated as 5% of pipeline capital costs.

Variable OpEx

Hydrogen transport has no variable costs. No loss is taken into account.

Hydrogen storage

The model considers two complementary storage solutions, in pressurised tanks and in a geological facility to manage daily and seasonal variations in production. For pressurised tanks, pressures are commonly between 50 and 700 bar based primarily on the volume-to-store and the final application. Low pressures of between 150 and 300 bar are best for large-scale stationary applications (Tashie-Lewis and Nnabuife, 2021). Due to the large scale of the production plant, this analysis considers pressurised tanks at 250 bar. Further, storage pressure around 200 bar seems a realistic option for compressed tanks as it would reduce the need for further compression if the hydrogen were to be transported with a compressed trailer (ANL, 2022).

CapEx

Based on the DOE’s cost targets for stationary gaseous hydrogen tanks and considering an installation factor of 1.3, capital costs are estimated at 650 USD/kgH₂ (US EERE website).

Fixed OpEx

Based on figures shared in Jacobs (2018), fixed operation and maintenance costs are of 2% of capital costs for compressed storage.

Variable OpEx

Hydrogen storage has no variable costs. No loss from hydrogen storage, neither geological nor compressed, is taken into account.

For alternative scenarios with compressed storage at other pressures, tank CapEx values draw from the DOE’s long-term objectives. A 1.3 installation factor is considered. Installed compressed tanks at 160, 430 and 925 bar amount to 585 USD/kgH₂, 780 USD/kgH₂ and 975 USD/kgH₂ respectively (US EERE website).

Box A3.1: Assessing the costs of geological storage

The Excel model has been used to estimate the costs of geological storage, including hydrogen transport from the cavern to the demand site through a new 50 km pipeline.

It is assumed that the geological storage facility contributes to answering a demand for 153 300 kt of hydrogen per year, or roughly the amount of hydrogen consumed by a world-class ammonia production plant (IEA, 2021a). To remain consistent with the approach followed in the analysis, the entirety of this demand is assumingly met by one single type of source, although several plants would contribute to fill the cavern. Finally, all plants are considered synchronised, meaning that hydrogen is injected and withdrawn simultaneously.

Following the US DOE’s H2A approach, injection and output pressures are set at 125 and 70 bar, respectively. The cavern’s usable capacity is set at 85%, the minimum pressure at 25 bar, the temperature at 10°C and the lifetime at 30 years.

Also from the US DOE, the cavern total CapEx is given using the equation:

$$\text{Geological } C_{ppEx} (\$_{2020}) = 6\,830\,506 \times \left(\frac{C_{cap}}{19 \times 10^6} \right)^{0.7}$$

Where, C_{cap} is the cavern capacity (m³ of hydrogen).

Fixed OpEx

Based on figures shared in Jacobs (2018), fixed operation and maintenance costs are of 5% for geological storage.

Variable OpEx

Variable operation and maintenance costs come entirely from hydrogen compression. No loss is taken into account.

Finally, this approach leads to a geological storage levelised cost, along with transport to the demand site, of USD 0.07 per kg. Geological storage per se contributes 57% of that total, the rest being for hydrogen transport to the demand site, which confirms that it offers a cheap storage solution. Hydrogen transport to the demand site remains low, both due to the short distance considered (50 km) and the large volume transported throughout the year, which largely amortises pipeline costs. As a result, for lower cavern volumes both storage and transport costs increase rapidly. The assumption taken in this analysis should therefore be considered as a low bound value.

Hydrogen compression

Hydrogen compression costs are often excluded from techno-economic analyses because of the significant uncertainties surrounding the full value chain structure and pressure requirements (Jacobs, 2018). To include hydrogen compression costs, compressor power requirements are calculated using an idealised gas relationship. The model follows the relation given in H2A analyses:

$$P = Q \times \left(\frac{1}{24 \times 3600} \right) \times \frac{Z \times T \times R}{M_{H_2} \times \eta} \times \frac{N \times Y}{Y - 1} \times \left(\left(\frac{P_{out}}{P_{in}} \right)^{\frac{Y-1}{Y}} - 1 \right)$$

Where, Q is the flow rate (kg/day), P_{in} is the inlet pressure of the compressor, P_{out} is the outlet pressure of the compressor, Z is the compressibility factor (= 1.03198), N is number of compressor stages (= 2), T is the inlet temperature (= 283.15 K), Y is the ratio of specific heat (= 1.4), M_{H_2} is the molecular mass of dihydrogen (= 2.015 g.mol⁻¹) and η , the compressor efficiency ratio (= 84%).

P_{in} and P_{out} are determined by infrastructures (pipelines, storage) requirements. Following the US DOE's assumptions, the number of compressor stages is set at 2, each stage having a maximum pressure ration of 2.1 and the overall motor efficiency is assumed to be of 96%.

CapEx

Different compressor technologies are used for compressing hydrogen to pipeline pressure and storage requirements. As a result, different relations are given to compute installed compressor capital costs. The model follows H2A hypotheses and considers (USD₂₀₂₀):

$$\text{Transport pipeline compressor CapEx (USD}_{2020}) = 4\,905.5 \times \text{Comp}_{pw}^{0.8335}$$

$$\text{Storage compressor CapEx (USD}_{2020}) = 65\,858 \times \text{Comp}_{pw}^{0.4603}$$

Where, Comp_{pw} is the compressor power (kWe).

Fixed OpEx

In the literature, fixed operation and maintenance costs estimates range between 10% and 15% (Jacobs, 2018; IEA, 2021b). As a result, the model settles on the value of 12.5% of compressor capital cost.

Variable OpEx

Compressor variable operation expenses are based on the load factor, directly calculated by the tool. It is assumed that the electrolyser uses electricity from the grid. No constraint on compressor flexibility nor maximum flow rate is taken into account. No loss from hydrogen compression is taken into account.

By design, each point of compression is equipped with two compressors, ensuring partial continuity of supply in case one fails. Each compressor receives an equal flow of hydrogen. Finally, compressors are assumed to have a lifetime of 15 years.

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Appendix 4: Benchmark for water electrolysis techno-economic values

Table A4.1: Benchmark for water electrolysis techno-economic values

Parameter	Technology	Source	Time horizon	Scope*	Value	Value used in this report
CapEx (USD/kWe)	PEM	Jacobs (2018)	2035	System	393.25-936	450 USD/kWe
		HE (2020)	2030	System	550	
		IEA (2021)	2030	System	400-440	
		DOE (2020)	2035	System	263-446	
	SOEC	HE (2020)	2030	System	572	750 USD/kWe
		DOE (2016)	2025	System	530	
Efficiency (% LHV)	PEM	Jacobs (2018)	2035	System	845 – 1 950	69%
		HE (2020)	2030		66	
		IEA (2021)	2030	System	62-72	
		DOE (2020)	2035	System	69	
Energy consumption (kWh/kgH ₂)	SOEC	Jacobs (2018)	2035	System	Electrical: 34.5-37.6 kWh/kgH ₂ Thermal: 7.2-14.8 kWh/kgH ₂	Electrical: 36 kWh/kgH ₂ Thermal: 10 kWh/kgH ₂
		HE (2020)	2030	System	Electrical: 37 kWh/kg Thermal: 8.0 kWh/kg	
		DOE (2016)	2025	System	Electrical: 35.1 kWh/kg Thermal: 11.5 kWh/kg	
Fixed OpEx (% CapEx)	PEM	IEA (2021)	2030	System	1.5 – 3	2%
	SOEC	Aborn, J. et al. (2021)	2025-2035		3.5	3.5%
Lifetime	PEM	HE (2020)	2030		83 000	85 000 hours
		IEA (2021)	2030		50 000 – 95 000	
		DOE (2020)	2035		85 000	
	SOEC	HE (2020)	2030		20 000	35 000 hours
		DOE (2016)	2025	System	55 000	
Output pressure (bar)	PEM	HE (2020)	2030		30-80	45 bar
		DOE (2020)	2035	System	48	
	SOEC	HE (2020)	2030		1	1 bar
Water consumption (tap water, l/kgH ₂)	PEM	Jacobs (2018)	-	System	18-22	20 l/kgH ₂
		IRENA (2020)	-	-	18-24	
Plant life (years)	PEM	DOE (2020)	2035	-	20 - 40	25 years
		IEA (2021)	2030	-	25	
Stack replacement Cost percentage (% of installed capital costs)	PEM	DOE (2020)	2035	-	15%	15%
	SOEC	-	-	-	-	30%

* System scope applies to an installed entire hydrogen production plant (i.e including balance of plant). If nothing is specified the value only applies to the element considered.

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The Role of Nuclear Power in the Hydrogen Economy: Cost and Competitiveness

Hydrogen is expected to play important roles in decarbonised energy systems, as an energy source for otherwise hard-to-electrify sectors as well as a storage vector to enhance power system flexibility. However, hydrogen is not a primary energy resource and has to be produced using different chemical processes. Water electrolysis, which uses electricity to split water molecules to extract hydrogen, is expected to become a leading solution in this context. Electrolysis will, however, only be a feasible solution if the electricity used as feedstock comes from low-carbon sources. A significant number of countries are therefore considering a role for nuclear energy in their hydrogen strategies.

This report provides an assessment of the costs and competitiveness of nuclear-produced hydrogen across the hydrogen value chain and explores the impacts of hydrogen production on the overall costs of integrated electricity and energy systems. It shows, in particular, that nuclear energy can be a competitive source to produce and deliver low-carbon hydrogen for centralised industrial demand. The large scale and dispatchability of nuclear power can also improve the cost-efficiency of hydrogen transport and storage infrastructures, and reduce the overall costs of the energy system.