International Energy Research

Hydrogen in the Irish Energy Transition

Opportunities and Challenges

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Disclaimer

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Executive Summary

In December 2022 the Irish Government launched Climate Action Plan 2023, which sets out ambitious targets for decarbonisation across the energy, transport, heating and agriculture sectors. The Climate Action Plan has been prepared under the Climate Action and Low Carbon Development (Amendment) Act 2021, which committed Ireland to a legally binding target of net-zero greenhouse gas emissions no later than 2050, and a reduction of 51% by 2030.

The Climate Action Plan sets out indicative ranges of emissions reductions for each sector of the economy, to be achieved by final year of 2026-2030 (with respect to 2018 baseline).

- Electricity: 75%
- Transport: 50%
- Built environment (residential): 40%
- Built environment (commercial): 45%
- Industry: 35%
- •Agriculture: 25% reduction
- Other (F-gases, waste & petroleum refining): 50%

Achieving these targets, cost effectively, safely and reliably, will be challenging and are likely to require changes in how society operates and the introduction of new technologies which today are considered uneconomic.

For example, in order to achieve a target of 80% renewable electricity will require at least a trebling in installed capacity of our wind fleet with offshore wind a key component of this expansion. Wind at this level will produce more than enough electrical energy to power the equivalent of every home in the country however utilising the energy that is produced at the correct time will be challenging. To achieve this, we will need to make the best use of all available resources connected to the energy system and it will be essential to be able to move in time or location, energy consumption or generation to balance supply and demand. Storing energy in the form of hydrogen produced by renewable electricity is seen by many as a key enabler of these targets. However, the use of hydrogen goes beyond its use as storage or a replacement for fossil fuel-based power plant. It also has been shown to have potential to decarbonise other difficult to decarbonise industries such as heat, transport (particularly heavy goods vehicles) and industrial processes.

The large-scale use of hydrogen in an energy system to enable the decarbonisation of a country's energy system has not been attempted or achieved anywhere in the world. Challenges exist with respect to the cost effective and safe production, storage, transportation, and consumption of hydrogen but many of these are being currently addressed by the market and with innovative technology. Therefore, the state-of-the-art is in constant advancement from multiple areas of the hydrogen eco-system.

This paper summarises the research conducted at the International Energy Research Centre to seek the evidence and information on options for addressing these barriers and opportunities that hydrogen presents to enable Ireland's decarbonisation targets and potentially establish Ireland as a world leader in this technology. The paper delivers empirical-evidence based suggestions for policy considerations in hydrogen to the Department of Environment, Climate and Communications. The research project gathered information from the stakeholders of hydrogen in Ireland through a call for evidence which contributed to:

- Support the development of hydrogen policy in Ireland;
- Collect evidence on the challenges and opportunities associated with the production of low carbon hydrogen in Ireland;
- Collect evidence on the challenges and opportunities associated with the distribution and delivery of low carbon hydrogen in Ireland and;
- Collect evidence on the challenges and opportunities associated with the consumption of low carbon hydrogen in Ireland.
- Provide feedback on a first draft of this paper.

This paper is organised in the following sections:

Key recommendations from this report are the following:

- Continue to monitor and evaluate the use of green hydrogen in road transportation.
- Develop a framework to support for the development of dedicated renewable energy sources for green hydrogen production.
- Develop a framework to support the development of green hydrogen production using curtailed renewable energy.
- Introduce financial instruments and incentives to support the development of green hydrogen production in Ireland.
- Demonstrate use of hydrogen as flexibility provider to perform power system balancing.
- Evaluate the blending of hydrogen into the existing Irish gas network.
- Evaluate the conversion of portions of the Irish gas network to pure hydrogen.
- Determine whether low carbon hydrogen obtained using carbon capture and storage technologies applicable to geological basins and structures may be a practical pathway for Ireland.
- Robustly evaluate feasibility of large-scale hydrogen storage in salt caverns.
- Establish an appropriate greenhouse gas emissions standard for low carbon hydrogen that meets multiple relevant criteria.
- Demonstrate storage and conversion technologies such as Power-to-Gas and Gas-to-Power conversion in microgrids.
- Evaluate the production of low carbon ammonia using green hydrogen in Ireland.
- Evaluate the costs of electrifying or using green hydrogen to decarbonise elements of the rail system.

1. Introduction

1.1 Overview

The Intergovernmental Panel on Climate Change (IPCC) recommends a reduction in energy demand, decarbonisation of electricity and other fuels, greater levels of electrification and complementary carbon dioxide (CO_2) removal activities, to limit global warming to 1.5 °C and achieve net zero carbon dioxide emissions by the year 2050. To achieve these targets, in a manner that is both cost effective and ensures that the security and reliability we enjoy today is maintained, is a fundamental challenge to the operation of our societies. How economies will realise this transition to a nett zero society is unclear, with a number of new technologies and concepts potentially providing solutions to accelerate and reduce the costs associated with achieving these targets.

Hydrogen is seen as one potentially game changing technology of the net zero economy, because it is a clean, reliable, and sustainable energy vector. The key value proposition of hydrogen is that it is an energy-rich and environmentally friendly substance that enables low carbon transport and/or the storage of energy. This also facilitates the consumption of energy remote in time and/or space from a primary production site. Furthermore, it can also be used as fuel in transportation applications.

The incorporation of hydrogen production and storage into energy systems has been shown to be feasible even though more expensive than battery bank approaches for energy storage over shorter timescales [1]. However, for inter-seasonal or longer-term storage, research indicates that hydrogen in suitable geological formations will be feasible [2], in contrast to grid-connected battery storage solutions which are expected to be limited to shorter-term applications [3-4].

Furthermore, hydrogen could play a significant role in decarbonizing the iron, steel, and transport sectors in all the EU countries plus Switzerland, Norway, and Iceland, thereby helping to fulfil tight carbon constraints.

Green hydrogen, which is hydrogen derived completely from renewable energy and water using electrolysers, can be used for electricity generation using a fuel cell, a technology that can efficiently convert hydrogen to electricity with by-products being water and heat. Moreover, hydrogen can be used as a substitute of natural gas to be combusted in gas turbines, heaters, boilers, or other energy devices for electricity generation [5]. These capabilities also mean that green hydrogen could be a key enabler for renewables in the electricity sector and move towards the '100% renewables' scenarios.

Despite its higher production costs, green hydrogen is still appealing because the potential scalability of the carbon capture and storage technologies however this scalability has not been fully demonstrated yet.

1.2 Research Overview

The report has been commissioned to identity the opportunities and challenges associated with the development of a hydrogen economy to support decarbonisation is proposed under the EPICA (Energy Policy Insights for Climate Action) project at IERC.

This research supporting the development of this report followed the following approach for bringing an evidence-based policy recommendations:

- Extensive review of academic publications as well as policy/strategy papers of different countries along with policy guidelines published by EU Commission as well as other international organizations such as IEA, IRENA, World Energy Council etc.
- Call for evidence and review of draft report

The following section of introduces the types of hydrogen and their key differences, the standards that are emerging with respect to low carbon hydrogen and an overview of the potential paths for hydrogen integration and the development of the hydrogen economy. Section 3 presents an analysis of current EU Policy and national policy initiatives with respect to hydrogen.

Section 4 describes the key opportunities that have been identified for hydrogen in future decarbonised energy system scenarios. This is followed by an overview of how the future relationships between the various stakeholders across the sector are likely to emerge in Section 5.

Section 6 focusses on the required technologies for Innovation and scaling to enable the cost-effective deployment of hydrogen across the most appropriate areas of the energy system. Finally, recommendations on the development of an enabling framework for hydrogen in Ireland in terms of research and innovation, legislative framework, cost competitiveness, capacity building, stakeholder buy-in, opportunities to be prioritized, shot-term, medium-term and long-term actions required etc. are presented in Section 7.

The call for evidence aimed at clarifying the current and potential hydrogen utilisation in Ireland for the transportation, industry, and domestic heating sectors was held in January 2022. It also provided some insights on how the stakeholders perceive the benefits of hydrogen consumption with respect to other alternative fuels and energy carriers.

2. Background and potential

2.1 Hydrogen Definitions

Hydrogen is often defined in terms of colours and there are a number of different definitions to these. For the avoidance of confusion, in this work, we are using definitions for four different varieties of hydrogen, obtained using different production processes [6]. They are:

- grey
- blue
- turquoise
- green
- pink
- produced using biomass gasification

Grey hydrogen is obtained by a steam reforming chemical process using fossil fuels such as coal or natural gas. The production of grey hydrogen produces approximately ten tonnes of CO_2 waste per tonne of hydrogen produced [7]. Currently, the cost of grey hydrogen is about 1.5 €/kg [8]. However, in 2021/22 limited gas supplies may cause an increase of the European prices determining higher production costs for the grey hydrogen [9].

The European Commission has a target of replacing the 8 Mt grey hydrogen demand currently consumed in EU as feedstock by 2030 with green hydrogen. This would require around 400 TWh. of renewable electric power per annum [10].

Blue hydrogen is produced by natural gas steam reforming, a process that involves the separation of natural gas into hydrogen and CO_2. In this case, the CO_2 produced can be capture and stored, potentially avoiding CO_2 emissions. The European Commission considers CO_2 capture and storage as priority breakthrough technology in its Green Deal [8]. Blue hydrogen finds support within the oil and gas industry because its production can utilise their existing facilities [8]. However, the economist Dr James Richardson observed that there is a hidden cost associated with the residual emissions of CO_2 to be considered when deciding to produce blue hydrogen, because the CO_2 generated in the production process cannot be fully stored. In the UK, the Government is supporting a mix of blue and green hydrogen. The cost of blue hydrogen is 2-3 €/kg [8]. Similarly, to grey hydrogen, the cost of blue hydrogen is affected by the price variations of the natural gas and might increase in 2021/22. Hydrogen produced from the gasification of biomass is also considered grey hydrogen with emissions from this process are generally lower than other types of grey hydrogen, but this is dependent on the type of biomass and the carbon capture and storage technologies used.

Turquoise hydrogen is produced by means of the methane pyrolysis, breaking down natural gas into hydrogen and solid carbon. In thiws case there is no CO_2 production at all, and the by-product produced is only solid carbon. Turquoise hydrogen technology is currently still at the development stage.

Green hydrogen is obtained by the electrolysis of water using only electricity from renewable energy. In this case, the production process in fully green because there is no CO_2 produced, neither in the electricity generation through renewable sources nor in the electrolysis of water to obtain the hydrogen. The cost of green hydrogen is 3.5-6 €/kg [8]. By 2030, the cost of solar hydrogen is expected to reduce to 0.7–1.8€/kg due to forecast reductions in the costs of PV generation and water electrolysis [11].

Pink hydrogen is obtained from electrolysis using nuclear power. It is sometimes also referred to as purple hydrogen or red hydrogen. In addition to electrolysis, some production processes may use the very high temperatures generated by nuclear reactors e.g., to produce steam to make electrolysis or fossil gas-based steam methane reforming more efficient. Heat can also be used in thermochemical process to produce zero-carbon hydrogen. Although these production processes may be characterised by zero-carbon or low-carbon emissions, the utilisation of nuclear power produces wastes that are a biological hazard nearly for ever. The price of pink hydrogen can be estimated in 2.3 - 2.5 €/kg [12].

Hydrogen produced from biomass gasification has not been given a colour. The process for hydrogen's production is gasification without combustion and uses heat, steam, and oxygen for the conversion of biomass to hydrogen and other products. Although the chemical reactions of biomass gasification and water shift emit CO_2, the net CO_2 emissions of this production method can be quite low, because the growth of biomass removes CO_2 from the atmosphere. Moreover, the process can be coupled with carbon capture, utilization, and storage [13]. Most recent price estimation we are aware of is 4.7 - 6 €/kg [14].

Type of Hydrogen	Production process	Advantages	Disadvantages	Cost Weighting
Grey	**Steam Reforming** **stage1:** high temperature (700–1100 °C) endothermic reaction: $CH_4 + H_2O \rightarrow CO + 3\ H_2$ **stage2:** low temperature (360 °C) exothermic reaction: $CO + H_2O \rightarrow CO_2 + H_2$	Production process is well established and cheap compared to other types of hydrogen	10 kg CO_2/kg Ten tonnes of CO_2 are generated as waste per tonne of hydrogen produced	1.5 €/kg
Blue	**Steam Reforming** with capture and storage of the produced CO_2 or carbon capture and conversion	Low carbon emissions when compared to Grey, cheaper than Green	Residual emissions of CO_2 and fugitive methane are present	2-3 €/kg
Turquoise	**Methane Pyrolysis** the natural gas is broken down into hydrogen and graphite or carbon granules	The production process is carbon free (no CO_2 production at all)	Turquoise technology is at development stage	-
Green	**Electrolysis of water** $2H_2O$ + electricity + heat $\rightarrow$ $2H_2 + O_2$ Electricity and heat needed for the chemical reaction to happen are generated from renewable sources.	The production process is carbon free (no CO_2 production at all)	Production requires a renewable plant, solar or wind. Costs are currently higher than Blue	3.5-6 €/kg
Pink	Electrolysis powered by nuclear energy or thermochemical process using the very high temperatures from nuclear reactors.	CO_2 free production process but producing radioactive toxic waste in the long term	Non-circular and unsustainable production pathway; nuclear wastes are dumped in the oceans, where they remain a potential biological hazard for an extremely long time	2.3-2.5 €/kg
From biomass gasification (no colour)	**Biomass gasification** $C_6H_{12}O_6 + O_2 + H_2O \rightarrow CO + CO_2 + H_2$ + other species Water shift reaction $CO + H_2O \rightarrow CO_2 + H_2$ + heat	Low net carbon emissions, offsetting the CO_2 released from producing hydrogen with its consumption from plants' growth process	High capital cost of equipment High biomass feedstock costs	4.7-6 €/kg

Table 1: *Comparison of the different types of hydrogen*

2.2 Production Approaches for Low Carbon Hydrogen

The production of blue hydrogen involves the presence of fugitive methane, which is not captured and stored. An emission rate of methane from natural gas of 3.5%, can be assumed, the CO_2 equivalent emissions are therefore between 18%-25% less than for grey hydrogen [15]. The actual amount of CO_2 captured when producing blue hydrogen depends on whether the capture applies only to the steam methane reforming (SMR) process of natural gas or also to the flue gases for the energy that drives the SMR process. However, studies have established that the carbon footprint associated with the production of blue hydrogen is more than 20% greater than directly burning either natural gas or coal, because of both the uncaptured carbon dioxide and the large emissions of unburned methane emissions (also known as "fugitive methane") [16].

A new emerging concept enabling scaling-up of Carbon Capture and Storage (CCS) from blue hydrogen and thus reducing the associated costs through economies of scale is called Carbon Clusters Linked to Storage (CCLS). CCLS will allow to pool together large volumes of CO_2 emissions from industrial processes such as refineries, petrochemical plants and metal (steel, aluminium) processing sites and to transport the CO_2 to geological storage sites (depleted oil and gas reservoirs or saline aquifers). The usage of existing pipelines connecting the point of CO_2 emission with the point of storage will enable to save up to 75% of costs compared to the case of a new pipeline construction or usage of a ship [17].

Another possibility, related to the production of reduced carbon blue hydrogen involves transforming the CO_2 emitted into other chemical products according to the carbon dioxide reduction reaction $xCO_2 + yH^+ + ne^- \rightarrow C_XH_YO_Z + H_2O$, to determine which chemical is more useful to produce, market research is required to determine which hydrocarbon products e.g. methanol, ethanol or ethylene are best economically [18].

Production technologies suitable for green hydrogen include not only renewable electrolysis, but also SMR of bio-methane and thermochemical conversion of biomass. The CERTIFHY body proposed an EU wide guarantee of origin policy that aims at increasing the utilisation of renewable energy sources and reducing the GHG emissions [19]. Green hydrogen produces CO_2 emissions at least 60% lower than the baseline SMR carbon intensity that is 36.4 $gCO_2e/MJ\ H_2$ for the past 12 months. The production process can be any renewable pathway meeting the threshold. This definition has also been adopted in the international standard CEN/CENELEC CLS JCT 6 WG1/WG2. Finally, TÜV SÜD is following a similar approach to qualify green hydrogen in Germany, requiring CO_2 emissions 35–75% lower than the SMR baseline depending on the production process, which can be either renewable electrolysis or bio-methane SMR or glycerine pyroreforming [20].

2.3 Green Hydrogen Production Standards

It should be noted that that there are a number of definitions for green hydrogen presented in literature, many of which are different to the one presented here. Currently, there are initiatives underway to standardise a definition for green hydrogen worldwide, from various regulation bodies.

Other definitions focus more on GHG emissions reductions rather than the production pathway. The use of renewable pathways to produce green hydrogen is recommended because it results in zero carbon emissions.

The French association for hydrogen and fuel cells requires that green hydrogen is produced using 100% renewables from any renewable pathway, such as electrolysis powered by renewable electricity or bio-methane. In the UK there was a consultation process regarding a green hydrogen standard that was taking a technology neutral approach with the goal of reducing CO_2 emissions. This approach was eventually abandoned and did not result in an official standard.

2.4 Potential of the Hydrogen Economy

The concept of the "hydrogen economy" was conceived several decades ago, and only in recent years has the hydrogen value chain begun to demonstrate its commercial value for applications that go beyond the chemical industry as economies change to reflect technology development and the value of sustainability and decarbonisation in our societies.

The key drivers in this change are the increasing pressure to decarbonise economies across the globe, the dramatic fall in the cost of solar and wind electricity generation technologies as well as the progressive improvements of both hydrogen technologies and supporting infrastructure. The active interest shown by countries like Japan, South Korea, China and Germany in supporting the growth of the demand for hydrogen and in creating a supply chain, has also helped to reduce the cost of the whole hydrogen value chain, making it globally an appealing resource for the decarbonisation of society [21].

While hydrogen has significant potential to enable the decarbonisation of society, due to current costs and a lack of a supply chain, policymaker have been slow to incentivise or support green hydrogen projects and infrastructure. Instead, policy makers have rightly focussed on the application of proven and low costs technologies and concepts to reduce energy demand and recycle or remanufacture products and to electrify sectors such as transport and heat which will be decarbonised further as the generation fleet is decarbonised through higher penetrations of renewable energy on the system.

Green hydrogen could be conveniently produced using excess renewable generation capacity which is not used to supply demand. This will become increasingly viable as the installed capacity of renewable generation increases further resulting in larger and more frequency mismatches between available generation and demand. At the point when the production of green hydrogen becomes very cost effective and supply chains exist to decarbonise a number of sectors of the economy the use of dedicated plants for green hydrogen production may become viable and appropriate. This approach is represented graphically in Figure 1 [22].

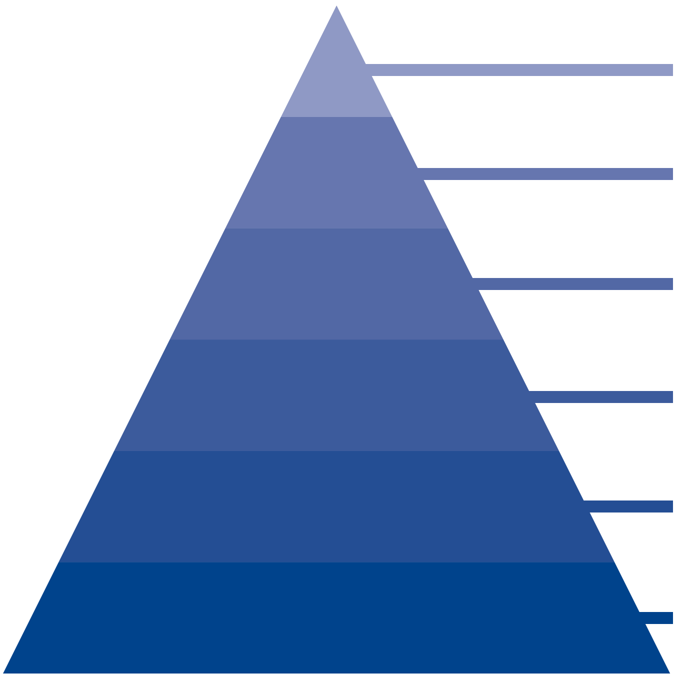

Figure 1: *Clean energy system triangle [22]*

2.4.1 Hydrogen in domestic heating

The UK heat sector has a number of parallels with the Irish heat sector both in term of stock, climate and primary heat sources. Heating in the UK contributes to about one third of their emissions and it is estimated that there are 25 million of homes requiring a low carbon solution.

Mixing green hydrogen with natural gas to supply conventional gas combustion boilers for domestic heating systems is a potential approach to reducing CO_2 emissions from gas heated homes in Ireland [23]. The flame temperature of hydrogen is 2,045 °C in air, whereas the flame temperature of methane in air is 1,957 °C [24].

Hydrogen could be used in domestic heating systems either as a pure fuel or blended with natural gas. Blending hydrogen into the existing natural gas infrastructure with concentrations as high as 20%, presents several advantages related to energy storage, system resiliency, and emissions reductions. However, the long-term impact of hydrogen on materials and equipment needs to be assessed and question marks over the use of green hydrogen in this way to reduce emissions [25,26].

Materials can be tested for the hydrogen embrittlement susceptibility according to the standard ISO 11114-4 and the technical report ISO/TR 15916:2004 Basic considerations for the safety of hydrogen systems provides some information with respect to the sensitivity to hydrogen embrittlement of metallic and non-metallic materials [27].

If the hydrogen blending percentage is high or pure hydrogen is going to be used, then there is a need for some component re-design of domestic gas-fired boilers. Furthermore, to maintain the same thermal load the fuel flow with hydrogen blending must be increased up to more than 3 times and this affects designs of fuel/air mixer and gas valve [28]. Furthermore, if the hydrogen is used as a direct fuel, the combustion velocity is significantly increased with respect to that of natural gas, so that specialised burners are needed [23]. Hydrogen-fuelled boilers have been already manufactured by industry. The specific adaptations of the gas distribution network's components required for hydrogen blending, such as compressors, gas turbines used to drive compressors, valves and underground storages will be discussed in section 6.2.3.

2.4.2 Hydrogen in industry

Green hydrogen has a number of potential applications in industry. It can be used to produce oxy-hydrogen flames and for the reduction of metals from their ores. Oxy-hydrogen flames are obtained from the exothermic reaction of hydrogen with oxygen and can be used for welding or cutting non-ferrous metals [29]. Pure hydrogen can also be used in a shaft furnace to reduce iron ore thereby reducing emissions from iron and steel production significantly [30]. Furthermore, hydrogen reduction is a reliable method to produce metal precipitating powders from water solutions of metal compounds [31].

Other applications of hydrogen are found in industries such as the chemical industry and oil refineries, glass industry and electronics industry. In the chemical industry, hydrogen is used to make ammonia for agricultural fertilizer (the Haber process) [32]. It is also commonly used to produce methanol, which can be converted into other chemicals or used as an energy carrier or fuel [33]. In oil-refining, hydrogen is used to remove sulphur from fuels [34].

In the food industry, hydrogen is used to hydrogenate liquid oils to form solid or semi-solid fats, which can be mixed with other fats to prepare fat spreads similar to butter [35]. In the glass industry, hydrogen is used as a protective atmosphere for making flat glass sheets. A continuous ribbon of glass moves out of the melting furnace at a temperature higher than 1000˚C within a controlled atmosphere of nitrogen and hydrogen [36]. Moreover, combustion of hydrogen can be used to supply part of the energy required for the glass melting process allowing a partial decarbonisation of the manufacturing process [37].

Finally, in the electronics industry semiconductors are grown or processed under hydrogen-rich ambientes during the manufacture of silicon chips. Interactions between hydrogen and semiconductors' dopants were studied in [38].

2.4.3 Hydrogen in road transport

Hydrogen is also expected to play a role in decarbonisation of road transport. In Ireland, road transport is responsible for the vast majority of the CO_2 emissions from the transport sector. This represents about 94% of the all transport sector emissions, corresponding to 9.7 Mt CO_2 equivalent in 2020 [39]. Road transport is also responsible for the production of a significant number of other pollutants emitted from the tailpipe, that are harmful to human health.

Road transport is currently highly dependent on oil-derived fuels and therefore particularly sensitive to oil price variations and supply changes. For example, if 80% of road vehicles could be fuelled by green hydrogen by 2050 the CO_2 emissions would be 50% lower than under the business-as-usual (BAU) scenario.

Compared to battery powered electric vehicles, hydrogen fuelled vehicles can be refuelled in minutes, whereas charging a large truck-sized battery requires a much longer time (up to several hours, depending on the specific battery or charging technology). Logistics of heavy duty/goods vehicles may benefit from hydrogen fuel cell technology because of its zero emissions, high specific energy and power density in comparison with battery electric heavy-duty vehicles with current battery technologies, and comparable ranges to diesel trucks [40].

The efficiency of fuel cells in converting hydrogen to electricity can reach 50%, whereas that of an internal combustion engine is in the order of 20%, therefore emission reduction could be more than doubled if they were used as a replacement of traditional engines [41].

However, there are a number of challenges to the widespread adoption of hydrogen fuelled vehicles. The volumetric energy density is lower than gasoline, thus requiring a bulkier hydrogen tank than equivalent petrol or diesel tank to achieve the same range. Highly resistant and cost-effective hydrogen fuel tanks can be manufactured, which may be guaranteed to last for the whole lifetime of the vehicle [42]. However, with the current technology the volume of the tanks is unsatisfactory with respect to the desired utilisation of the vehicles [43].

Building infrastructure for hydrogen production, transmission and refuelling is a much riskier and more expensive task than building a recharging infrastructure for battery powered electric vehicles, because of hydrogen's explosive properties and the costs associate with storing hydrogen. In particular, systems handling liquid hydrogen pose even higher risks than those based on compressed hydrogen showing dense gas behaviour and significantly longer hazard distances than for releases from compressed hydrogen systems [44].

It is anticipated that to enable the development of adequate, and sustainable business models to be established, as the market for hydrogen fuelled vehicles develops, will require cost-sharing between government and industry with forecasts indicating that this will be required for the delivery of the first thousand hydrogen stations [45]. In Ireland, Mercury Renewables will invest €200 million by 2025 to build a wind farm at Firlough (northeast Co. Mayo), which will generate the electrical power to supply 45,000 homes and a plant that will convert electricity into hydrogen. The current plan has envisaged that this hydrogen will be used by fuel heavy vehicles [46].

2.4.4 Hydrogen in aviation

In the aviation sector, liquid hydrogen is being considered as a cleaner alternative to kerosene because it produces lower GHG emissions and can be produced from renewable energy.

A CO_2 neutral fuel which was considered in the past as a good alternative to kerosene is synthetic kerosene. It can be produced from biomass, and it has about the same energy content of kerosene. The advantage of synthetic kerosene is that it would require minimal changes to the aircraft and fuel systems in comparison with hydrogen. However, hydrogen has become an even more attractive option because it can be produced from water using any energy source, whereas renewable kerosene would require large amounts of biomass [47]. Moreover, the high-energy content and improved combustion kinetics of liquid hydrogen have the potential to extend engine life and reduce aircraft maintenance costs. On the other hand, because of hydrogen's low ignition energy and high flame velocity there could be the risk of producing traces of unburnt hydrogen during combustion, that can cause metal embrittlement. Finally, there is still some uncertainty on the operating cost of aircraft fuelled by liquid hydrogen because the costs of the fuel depend on the production and storage method and therefore also eventually influenced by specific governmental policies.

3. EU Policy and national policy initiatives on Hydrogen

3.1 Overview

The objective of the EU's policies on hydrogen is to foster the good operation of the hydrogen market by incentivizing both supply and demand. The policy will have to bridge the cost gap between conventional solutions and renewable and low-carbon hydrogen, through appropriate state aid rules. Furthermore, policies and incentives will need to be developed to form a comprehensive support scheme to bridge the gap between market requirements, sustainability and climate requirements, and hydrogen technology development [48].

The policies are designed to increase the EU's support and will stimulate investments when a sustained expansion of the hydrogen market will take place over a brief period. The EU's goal is to establish an open and competitive EU hydrogen market by 2030, removing the obstacles to cross-border trade and enabling a truly efficient allocation of hydrogen supply among the sectors.

The EU also regulates several other aspects that may have influence on hydrogen's technology diffusion in its Member States and hydrogen EU policy. In fact, the EU has set well defined targets regarding energy efficiency and/or the share of renewable energy in electricity production. It also manages the emission trading scheme and has a central role in the management of European markets for gas and electricity. It also sets minimum levels for energy taxation and subsidises energy technologies through its regional funds and research projects. Finally, the EU has developed a policy called Trans-European Networks for Energy (TEN-E), which is focused on linking the energy infrastructure of EU countries [49].

3.2 The position of the European Parliament and the strategy

The EU Parliament acknowledged that the blue hydrogen has a transition role, even though some members of the Parliament recommend focusing exclusively on green hydrogen. More generally, the importance of carbon capture and storage technologies is recognized on the basis that these technologies can contribute to make heavy industry more sustainable and climate neutral. Moreover, the EU Parliament recommends that the Commission discloses its legal classification of various types of hydrogen and that a regulatory framework is established such that hydrogen certification, labelling, origin guarantees, and tradability can be readily achieved. The EU Parliament also recognises the prominent role of hydrogen in the decarbonisation of the transportation sector and the related necessity of an adequate refuelling infrastructure [50].

The EU strategy determines short-term vs long-term objectives for hydrogen introduction. Two stages are foreseen, namely objectives to be achieved from 2020 to 2024 and from 2025 to 2030 [51].

1. The EU strategic objective from 2020 up to 2024 is to install at least 6 GW of renewable hydrogen electrolysers in the EU and the production of up to 1 million tonnes of renewable hydrogen (produced using mainly wind and solar energy).

2. In the second stage, from 2025 to 2030, electrolysis with a capacity of 100 MW next to existing industrial demand centres such as: larger refineries, steel plants, and chemical plants will be rolled out. They would ideally be powered directly from local renewable electricity sources. Furthermore, hydrogen refuelling stations will be used to support hydrogen fuel-cell buses and, at a later stage, trucks. Electrolysers will thus also be used to locally supply an increasing number of hydrogen refuelling stations.

The EU strategic objective from 2025 to 2030 is to make hydrogen an intrinsic part of an integrated energy system with the goal to install at least 40 GW of renewable hydrogen electrolysers by 2030 and the production of up to 10 million tonnes of renewable hydrogen. Renewable hydrogen will be used to balance the power system with a high penetration of renewables, by transforming electricity into hydrogen when renewable electricity is abundant and cheap and by transforming back hydrogen into electricity when there is a shortage of electrical power from renewables. Hydrogen's use for daily or seasonal storage to provide a load balancing function will contribute to improve the supply system's security in the medium term.

3.3 Trans-European Networks for Energy (TEN-E)

The TEN-E policy identified nine priority corridors and three priority thematic areas. The goal of the policy is to help EU countries close to priority corridors to collaborate for the development of projects of common interest (PCIs) related to the priority thematic areas (smart grid deployment, electricity highways, cross-border carbon dioxide network), for a better interconnection of energy networks, and to provide funding for new energy infrastructure. The electricity corridors are:

- North Sea's offshore grid
- North-South electricity interconnections in western Europe
- North-South electricity interconnections in central-eastern and south-eastern Europe
- Baltic Energy Market Interconnection Plan in electricity.
- The gas corridors are:
    - North-South gas interconnections in western Europe
    - North-South gas interconnections in central eastern and south-eastern Europe
    - Southern Gas Corridor
    - Baltic Energy Market Interconnection Plan in gas.

The oil corridor is the Oil Supply Connections in central eastern Europe.

The Commission has proposed a revision of the TEN-E policy aiming at modernising and upgrading the policy to better reflect the Green Deal objectives and the infrastructure needs to support the development of the clean energy system of the future. Natural gas and oil infrastructures will no longer be eligible for PCI status under the revised version of the TEN-E policy. Hydrogen infrastructures will be among the categories supporting smart electricity grids and low carbon energy solutions.

The European Council invited the Commission in March 2022 to promulgate a policy to eliminate the dependency of Europe on Russian energy imports as soon as possible and to promote the energy transition. Russia's war against Ukraine has caused high energy prices and energy security issues. The EU is overdependent on imports of gas, oil and coal from Russia and the Russian energy supplies are becoming unreliable. Also, payments for Russia's fossil fuels are contributing to sustain its war. The policy, titled REPowerEU plan, also covers aspects related to energy savings, diversification of energy imports, smart investment in European interconnection and infrastructure needs, measures that will allow the Member States to be prepared for a severe supply disruption.

The interventions on the European gas infrastructure determined by REPowerEU to thoroughly compensate the elimination of the Russian gas imports to fulfil the demand in Central and Eastern Europe and in the northern Germany, consist in a combination of demand reduction, an adequate increase of domestic production of biogas, biomethane and hydrogen, and some limited expansions of the existing gas infrastructure. Moreover, the Southern gas corridor will be reinforced [52].

3.4 National Energy & Climate plan 2021-2030

The policy for hydrogen's part in the decarbonisation of the Irish economy in Ireland is discussed in the National Energy & Climate plan 2021-2030 [53]. The policymaker believes that decarbonisation of the Irish energy system requires to consider coupling between the electricity, heating/cooling, and transport sectors. The document states the belief that green hydrogen may play a prominent role in sectors such as heavy vehicles and maritime traffic, which cannot be fully decarbonised used other means. There is a realistic potential to produce green hydrogen at the scale with a competitive market price, using large scale offshore renewable energy. Furthermore, the plan states that blue hydrogen can only be acceptable in case a full capture and storage of the produced carbon can be demonstrated. In addition, grey hydrogen is likely to be considered not good enough to support the transition of the country to a fully decarbonised energy system. Finally, the cooperation with other European countries is required to develop the market rules, the safety standards and the cross-border infrastructure required for the development of the hydrogen economy.

3.5 National Level Policy, Strategy and Initiatives in Europe

At national level, energy policy has a significant influence on technological diversity, self-sufficiency, and the security of electricity power generation of a country. From a comparative analysis of six EU countries published hydrogen strategies (from Portugal, Spain, France, Germany, Netherlands and Norway), it appears that they differ in scale, sophistication, and ambition level. In the longer term the EU will have to prevent regulatory and competition policy issues, because national hydrogen strategies have the potential to create national or regional hydrogen energy markets, that could easily damage the EU wide hydrogen market and lead some of the countries to a dominant position [54].

In countries with high levels of renewable generation, such as Denmark, the policy targets are determining or are likely to determine whether the country will export electricity or hydrogen. In other countries where the main policy target is self-sufficiency, such as Germany, the installed hydrogen capacity should be increased to meet the target. However, there are countries like Bosnia-Herzegovina, which are highly dependent on energy imports where self-sufficiency would be a target difficult to achieve and are therefore likely to require energy imports in either electrical or hydrogen form in the future [55].

In Spain, green hydrogen seems destined not to play a significant role in the power system's future development. It is envisaged that electricity production from renewables that exceed its exogenous demand will be exported to other countries via electrical infrastructure. The Spanish strategy is to start with electrification and then use renewables to produce hydrogen only for limited use and for power system balancing.

Portugal plans to decrease its dependency on energy imports from 78% to less than 20% through an increasing utilization of renewable energy.

France's power generation is currently dominated by its nuclear fleet therefore diversification of generation technologies is one of the main policy's targets.

Italy has the potential to become a hub for the hydrogen trade because of its central location in the Mediterranean situated between potential major exporters in Africa and the Middle East and the consumers in northern Europe. Italian hydrogen strategy will require €10bn of investments between 2020 and 2030 to facilitate the development of a hydrogen-based economy. The goal in Italy is the installation of 5 GW of electrolysis capacity by 2030 and the development of a regulatory framework supporting the green hydrogen production. First experiments regarding the blending of hydrogen in a gas network were conducted in 2019 and they were successful in increasing the percentage of hydrogen by volume to 10% [56].

In the UK, the Government's Hydrogen Strategy plans to attract up to £4bn of private investment by 2030 in blue and green hydrogen generation, storage and usage and create 9,000 jobs [57]. Large pilot projects underway demonstrate the commitment of the Government in supporting technological developments needed to deploy cost effective hydrogen solutions. The ambition of the UK government is detailed in strategic plans to scale-up hydrogen production and consumption domestically and supply from 20% to 35% of the whole nation's energy consumption using hydrogen by 2050, whereas the global average hydrogen utilisation has been forecasted at only 10% by Bloomberg Intelligence.

The construction of a new £12.7m hydrogen transmission network research facility started in 2021, with £9.07m of funding provided by Ofgem's Network Innovation Competition and with the remaining amount coming from the other project partners [58]. The facility will be making use of several decommissioned assets and will be representative of a hydrogen transmission network. The goal of the trial project is to test hydrogen blending up to 100% at transmission pressures. The testing of the facility is due to commence in 2022.

Another large project running in the UK is HyDeploy [59]. The project will demonstrate the injection of up to 20% volume of hydrogen into Keele University's existing natural gas network, feeding about 100 homes and 30 faculty buildings. It is anticipated that this injection can be achieved without requiring any modifications to the existing gas appliances in the homes and faculty buildings.

3.6 Energy policy and the gas industry

The European Green Deal commits Europe to become the world's first climate neutral continent by 2050. Net-zero is likely to require a full fossil fuel usage elimination. The gas industry is supporting this vision by reducing greenhouse gas emissions across the sector, especially those due to methane emissions. A typical case is the evacuation of the natural gas from a pipeline to the atmosphere which is called blow-down phenomenon, that brings the pipeline from high pressure to atmospheric pressure. This is currently done keeping in operation the downstream compressors, after the upstream valve has been closed to isolate the section [60].

Hydrogen is an opportunity for the gas industry to move to a near zero-carbon alternative. In fact, assuming a leakage rate of 1%, hydrogen has a climate impact of 0.6% of the current fossil fuel system. Even increasing the leakage rate up to 10%, the climate impact would be only 6% of that of the existing fossil fuel based system [61].

A 55% emission reduction target in Europe for 2030 is likely to be very difficult to achieve in the context of current renovation rates and the rate of decarbonisation of electricity. Therefore, a policy which can effectively incentivize the decarbonisation of the gas for heating sector can provide additional levers to decarbonise the economy. The EU Strategy on Energy System Integration, adopted by the European Commission in July 2020, will promote the adoption of renewable and low-carbon fuels such as hydrogen, for all those end-use applications where direct heating or electrification do not work. The revision of the REDII directive is one of the opportunities for the European Commission to drive such integration [62].

3.7 Carbon Capture Utilisation and Storage

Carbon Capture and Storage (CCS) is a way of reducing carbon emissions, which could be key to helping to tackle global warming. It's a three-step process, involving: capturing the carbon dioxide produced by power generation or industrial activity, such as steel or cement making; transporting it; and then storing it deep underground. A related concept is Carbon Capture Utilisation (CCU). In this concept instead of storing carbon, it is intended to be re-used in industrial processes by converting it into, for example, plastics, concrete or biofuel. Collectively these two concepts are known as Carbon Capture Utilisation and Storage (CCUS) [63].

The Irish Government will continue to monitor the technological development of carbon capture and storage (CCS) systems as stated in the National Energy & Climate plan 2021-2030 [64]. The development of CCS has an important bearing on the development of hydrogen systems in Ireland as they are both an enabler of the production of blue hydrogen and also a potential mechanism to retain conventional fossil fuel plant part of any low carbon emitting future energy system.

In 2019 a steering group was formed to evaluate the technical feasibility of CCS in Ireland and to develop a relevant policy. Two approaches can be used to capture CO_2, namely the pre-combustion and post-combustion capture. With the former approach the carbon can be removed before burning the fuel, whereas with the latter the CO_2 is recovered from the flue gas. There is a major issue with the CO_2 recovery from the flue gas, which is due to the flue gas being at near atmospheric pressure, and the CO_2 concentration low. The low partial pressure of CO_2 determines a small driving force for the adsorption/absorption processes [65]. The use of pure oxygen instead of than air in combustion (known as oxyfuel combustion) has a high potential to facilitate CO_2 separation and capture and to reduce costs. The CO_2 separation using oxyfuel combustion requires three major components: an air separation unit for oxygen production, an oxy-combustion boiler and a CO_2 purification and compression unit [66]. Finally, it is remarked that CO_2 can be captured directly from methane reformation instead of the flue gas [67].

There are several sites in Ireland which are suitable for geological storage of CO_2; most important ones are the Kinsale Head depleted gas field in the North Celtic Sea Basin, the Portpatrick Basin in the North Channel and the Clare Basin off the west coast.

The Kinsale depleting gas field offers potentially a large storage capacity (330 Mt), which could provide a storage solution for Moneypoint and Cork for up to 50 years. The Kinsale gas field is considered overall a low-risk site, but additional risks apply when considering CO_2 storage, such as those ones related to containment and leakage. Leakage risk through existing production wells can be mitigated through application of cement barriers. It can be noticed that hydrogen has a higher mobility and permeability than CO_2 (and natural gas) and therefore shows an even faster diffusion through the rock matrix with respect to CO_2 [68]. For this reason, a storage site could be better suitable for carbon storage than hydrogen storage.

The Portpatrick saline aquifer has 37 Mt of effective storage capacity in closed geological structures and up to 2200 Mt of further theoretical storage capacity to be proven up. The 37Mt could be used for Kilroot storage needs for 10 years, which could be extended to 58 years if the 10% of the theoretical storage capacity were available.

Even less explored than Portpatrick is the Clare Basin, since the available geological data do not allow the quantification of the theoretical onshore or offshore storage capacity yet [69]. A Memorandum of Understanding has been recently established between Ervia and Equinor (Norway) and this agreement has received letters of support for a PCI application from various stakeholders: the Dutch Ministry, Athos (Netherlands), Gasunie (Netherlands), Sapling (Scotland), Northern Lights (Norway), UKCCS Research Group, Bellona (Norway) and Port Talbot (Wales). After successfully receiving the PCI status the project applied in Q2 2020 for Connecting Europe Facility (CEF) funding.

The CCS demonstration project has been successfully granted funding under the European Horizon 2020 scheme to develop and assess a carbon capture plant on Ireland's only oil refinery in Whitegate, Cork harbour. The refinery produces 75000 barrels of oil per day, which cover around 40% of the country's fuel demand, while emitting 321,932 tonnes of CO_2 (2018 data [70]). The refineries contribute about 4% of global CO_2 emissions and are the third sector for CO_2 emission among stationary producers, after power and cement. Refineries will exploit carbon capture technologies to make CO_2 available for either storage (CCS) or use (CCU), allowing to lower the cost of meeting the targets defined in the Paris Agreement by about 40% [71]. The goal of the project is to increase the CO_2 capture from multiple sources in operating refineries, such that 90% CO_2 capture is achieved, and costs are lowered by 30%. Additional funding to allow a study concerning the CO_2 storage potential in the Kinsale Gas Field (and in another potential European location) will be likely attracted by the H2020 Geological Storage Pilot. However, it is remarked that a CCU technology is compatible with the Paris Agreement only if the CO_2 capture and conversion process has low GHG emissions, replaces a more GHG-intensive process and preferably enables a permanent storage of CO_2 [72].

A public consultation regarding CCS has been held with the participation of ESB, Ervia and the Department [73]. ESB has proposed to re-establish the Government's Interdepartmental Committee on CCS to review the technology from the perspective of Ireland's low carbon energy future needs. Ervia recommended to ensure that any abandoned wells are plugged such that the reservoir would be suitable for future utilisation as a CO_2 storage or that the need for additional works in relation to the same utilisation is timely determined. The Departments technical advisor agrees that the future CCS potential can only be assessed after carrying out a review of previously plugged wells.

3.8 Discussion

In Europe, policies have tended to support blue hydrogen more than green hydrogen, with the objective being the initial creation of a hydrogen market and that green hydrogen from renewables would come to dominate at some unspecified point in the future [74]. As discussed in section 2.1, blue hydrogen has a more negative impact on the environment and climate in comparison with green hydrogen.

If the energy strategy is to prioritise renewable sources of hydrogen, rather than develop a hydrogen system, then there may be needs to be policy decision of not incentivizing the investments in blue hydrogen technology. Green hydrogen already appears to offer a partial solution to the intermittency of renewable generation.

Business cases in various sectors should primarily consider the costs and the added benefits associated with hydrogen production, storage and transmission, and secondarily the efficiencies of the required conversion processes.

Green hydrogen technology has the potential to enable the installation of renewable generators in locations where wind speed and/or solar irradiation are more conducive to energy production, to convert the energy into hydrogen and to transport it to locations where renewables are unavailable.

Bulk energy transportation using hydrogen is made more attractive by the higher capacity of a gas pipeline (15-20 GW) when compared to electricity cables (1–4 GW) and its lower costs, that can be almost 10 times cheaper to build. The cost difference between cable and pipeline transmission is increasing with the distance increment for both the onshore and offshore cases and is likely to be a significantly cheaper solution than an offshore cable when the distance to cover is greater than 1,000 km [75]. Therefore, even considering reduced conversion efficiencies, the entire process involving green hydrogen could still be profitable than installing electrically connected renewable power generators in locations where their yield would be low.

4. Opportunities for Green Hydrogen in Ireland

4.1 Existing hydrogen demand opportunities

The International Energy Agency published a report that analyses the current state of play for hydrogen and offers guidance for future developments [76]. The report includes data regarding global hydrogen consumption until 2018 showing millions-of-tons steadily increasing demand with super-linear growth. When this data is used for demand forecasting, it can be predicted a total demand covering refining, ammonia and other existing applications of hydrogen of nearly 200 Mt in 2053 (Fig.2).

Ireland is also following this growth pattern being very active in both import and export of hydrogen with other EU countries. Ireland is importing hydrogen from UK, Algeria, France, Belgium and the Netherlands (Fig. 3a) and is exporting it to UK, Germany, Saudi Arabia, Spain and Belgium (Fig. 3b). Ireland was the worldwide 52nd exporter of hydrogen in 2019 with 5.35 M$ exported. In the same year, Ireland was the 40th importer of hydrogen with 23.7 M$ imported.

From 2018 to 2019 it was observed a fast growth of hydrogen export markets in Saudi Arabia (413 k$), Spain (36.2 k$), and Brazil (33.8 k$) [77]. It should be noted that the current market of hydrogen in Ireland does not include energy-related applications.

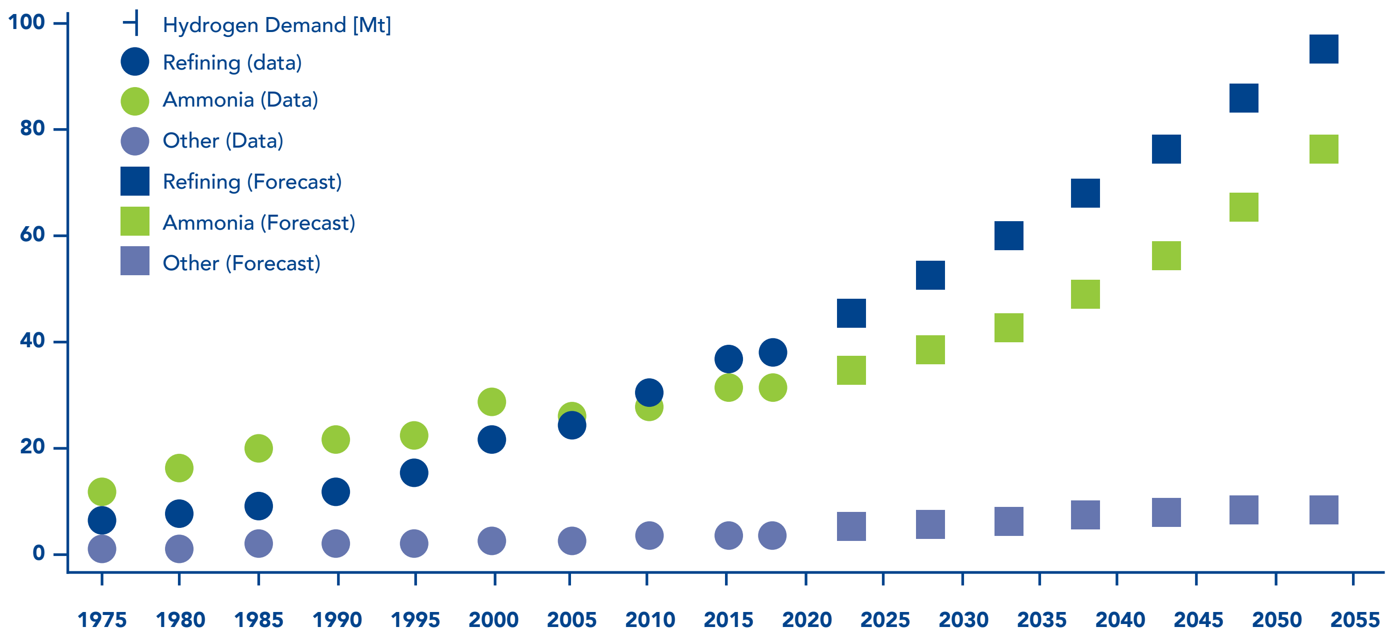

Figure 2: *Global hydrogen consumption for refining, ammonia production other existing industrial uses*

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In addition to existing opportunities in the industry, there are new opportunities for green hydrogen driven by the necessity to decarbonise all sectors of the economy.

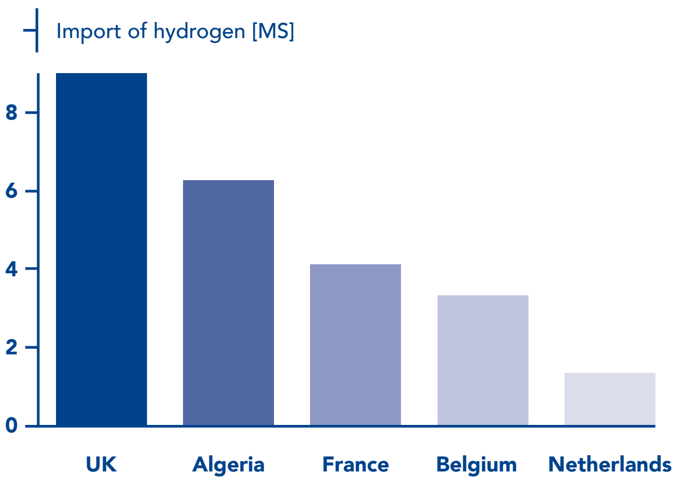

Figure 3a: *Ireland import of hydrogen from other countries*

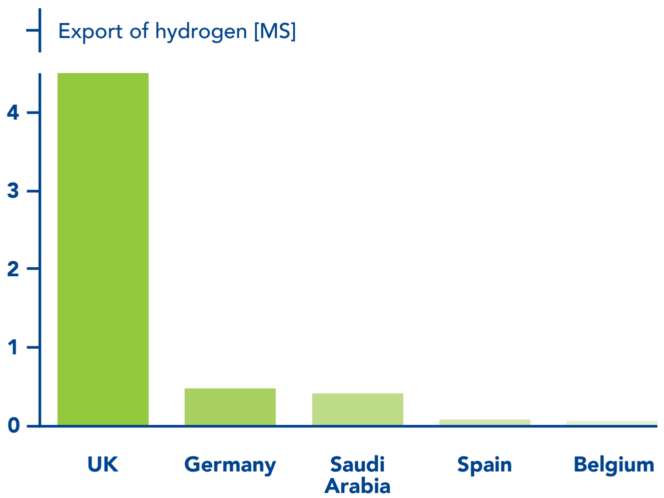

Figure 3b: *Ireland export of hydrogen to other countries*

4.2 Hydrogen in the electrical power system

The Transmission System Operator (TSO) envisages that many existing peat, heavy oil and coal plants will close over time and will be replaced by gas fired generation, which currently already plays a fundamental role to meet adequacy needs of the country. The Government considers its policy of prohibiting the exploration for and extraction of coal, lignite and oil shale as fundamental to achieve the implementation of a circular economy and has included it as part of Circular Economy Bill 2021 [78].

In response to these and other changes, to support economic development and energy security the development of lower carbon gas-fired generation is a priority set out by the Government's policy on security of electricity supply and the need of delivering about 2 GW of such generation by 2030 is recognized in the National Development Plan 2021-2030 and the Climate Action Plan 2021 [79]. As these fossil fuel-based units are still likely to be significant GHG emitters it will be important to look for ways to decarbonise their operation and reduce their importance to the electrical power system in the long-term. CCS technologies could be helpful in the decarbonisation of the gas-fired generation fleet as they will be gradually refurbished and the decisions of large investments in new technologies will likely consider also the goal of achieving deep decarbonisation [80].

There is also an opportunity to retrofit existing gas-fired generation to use hydrogen, the installation of hydrogen turbines and use them as backup systems for intermittent renewable sources and also the use of fuel cells to generate electricity [81]. Fuel cells have the potential to have the highest efficiency in terms of conversion of hydrogen to electrical energy but are currently very expensive at this scale (e.g. in comparison with battery storage) [82]. In this context, a study found that CCGT (Closed Cycle Gas Turbine) technology in conjunction with the HVDC cables for electricity transport have been evaluated to be the most cost-effective pathway for hydrogen electricity reconversion, followed by the Solid Oxide Fuel Cell (SOFC) technology for net zero carbon scenarios for German in 2050 [83].

Green hydrogen could also help to integrate elevated levels of variable generation on the electricity system by creating a variable electricity demand that utilises the renewable sources not used to supply other loads to produce green hydrogen, which can be stored in the local gas grid and used for decarbonising domestic heating, transport, and industry sectors. In fact, curtailment of renewable generation can be alleviated using congestion management methods which exploit flexibility options alternative [84], such as an optimized operation of controllable generation units and green hydrogen production.

Fig. 4 shows the integration of green hydrogen production in the electric grid using electricity that would otherwise be curtailed, to supply electrolysers. The produced hydrogen can be stored and distributed to the various consumers when demand occurs. In power systems dominated by variable renewable generation supplying both firm and flexible electricity loads green hydrogen production can act as a new flexible load that can effectively contribute to a better utilisation of the generation assets. When excess generation capacity is available during most of the hours of a day, the flexible loads (especially the small ones) can operate at high-capacity factors.

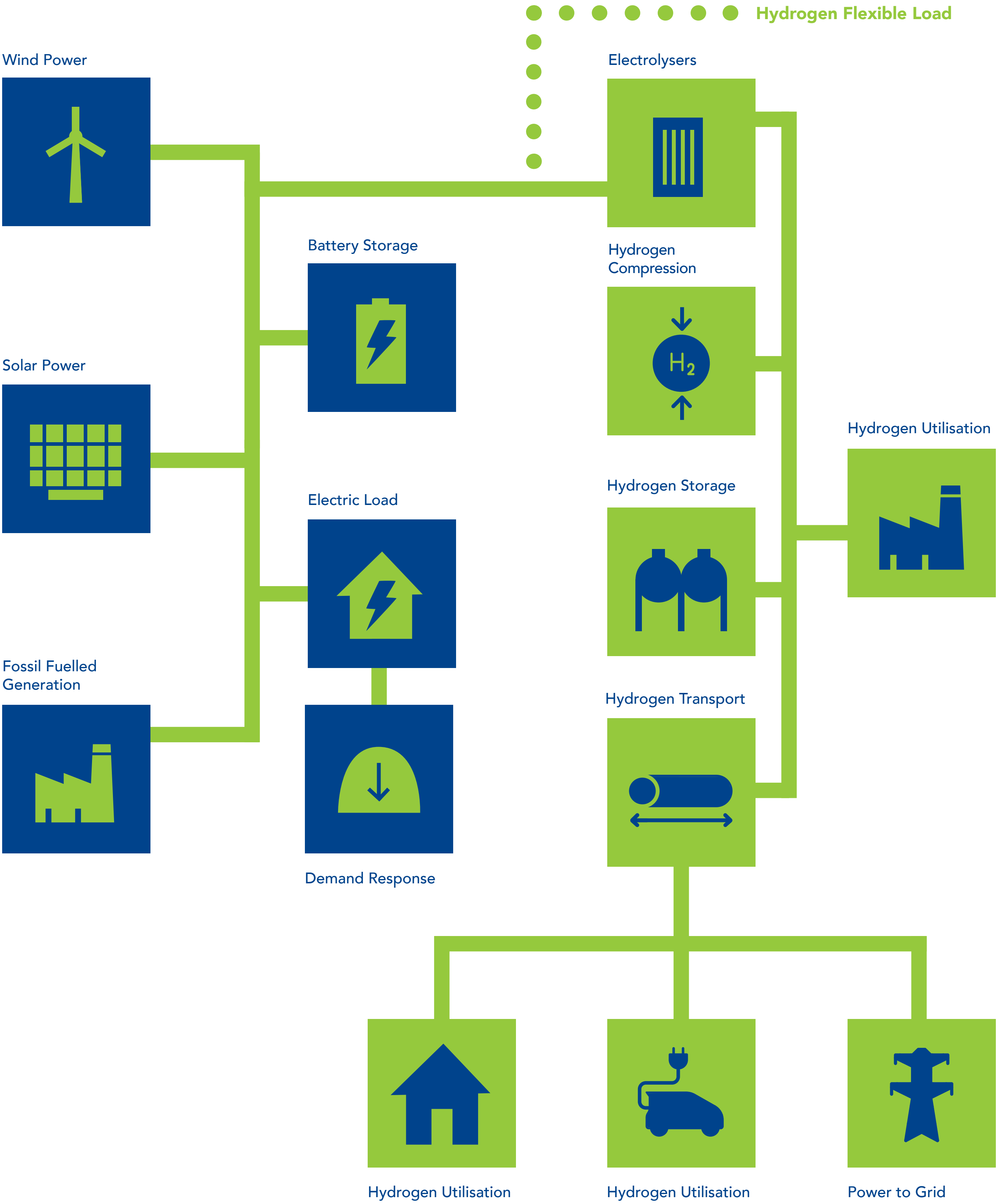

Figure 4: *Hydrogen production integrated in the electrical grid as a flexible load*

Flexible loads such as electrolysers for hydrogen production could contribute to reduce the average cost of electricity by allowing a better exploitation of the generation capacity which was installed for the supply of firm loads. In fact, the electricity that is used to supply the electrolysers would be lost if not used for hydrogen production; on the other hand, the produced hydrogen can be stored and converted back to electricity when needed. In many system configurations, the variable renewable electricity assets supplying firm loads at current energy costs could supply about 25% or more additional flexible load with 10% or less capacity expansion, reducing at the same time average electricity costs by 10%-20% [85]. The electrolysers used for hydrogen production can be seen as an additional flexible load that could be added to the combination of load-following generators, energy storage, expansion of grid transmission, and other flexible loads to effectively fill the gaps existing between non-dispatchable generation and inflexible demand [85, 86].

The design of an energy system, including hydrogen production using potentially curtailed renewable power, has some challenges however. For example, if power curtailment occurs only for short periods of time, the electrolysers would work at low-capacity factors when only absorbing the spikes of excess power potentially reducing operational efficiency and reducing revenues under existing business models. An approach to mitigate this risk is additional storage to better manage excess generation, resulting in higher equipment costs or new business models that provide appropriate financial recognition for this demand side flexibility and the production of low carbon hydrogen when electrolysing when the entire power system is being powered by high levels of renewables.

Finally, the electricity output of waste-to-energy plants may be used to produce green hydrogen, especially the amount that would be otherwise curtailed because of low demand or high renewable generation (as these plants continue to incinerate waste even when their electricity output is curtailed).

4.2.1 Analysis of potential hydrogen production on today Irish electrical power system

The results of analysis of the potential performance of electrolyser plants of various capacities with respect to the potential daily green hydrogen production using curtailed power under current Irish electrical system scenarios are shown in Fig. 5.

Figure 5: *Potential hydrogen production using curtailed wind power in 2020 (EirGrid data)*

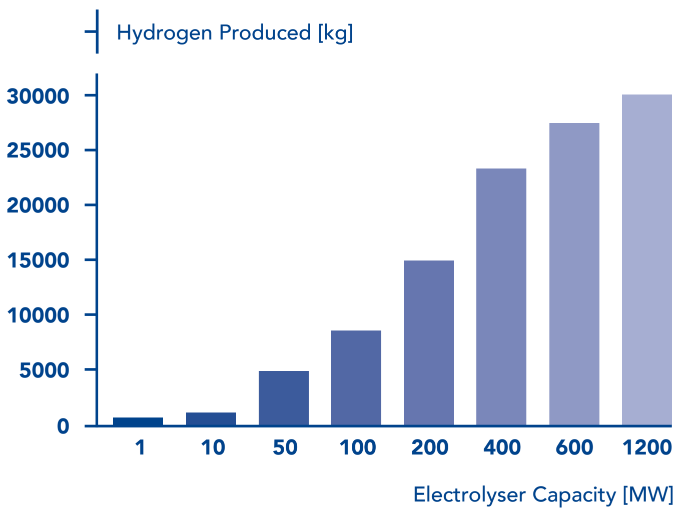

Figure 5a: *Average daily hydrogen production*

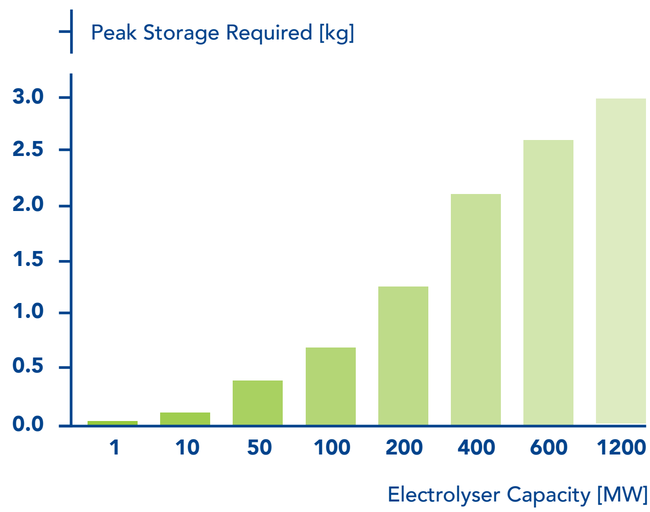

Figure 5b: *Hydrogen storage capacity required*

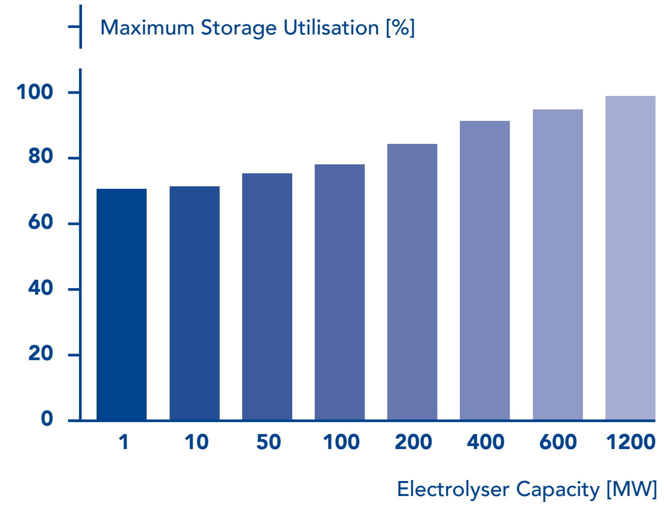

Figure 5c: *Maximum daily utilisation of hydrogen storage*

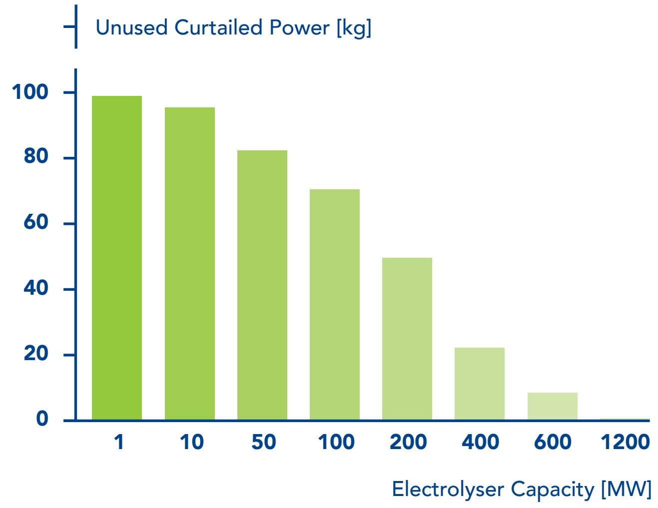

Figure 5d: *Percentage of unused curtailed power*

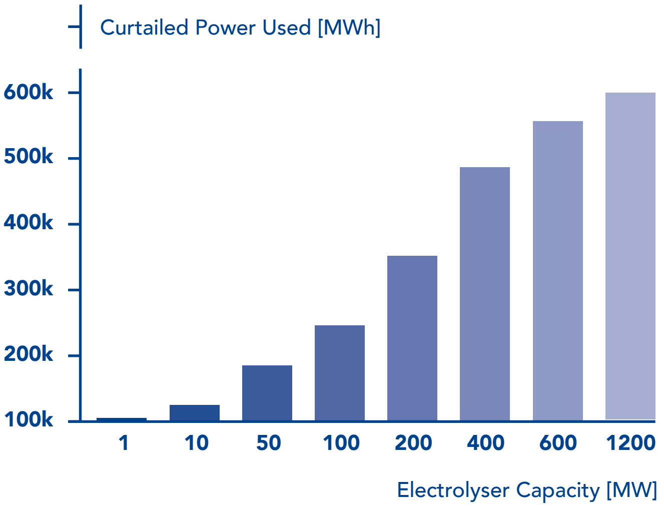

Figure 5e: *Curtailed energy used by the electrolysor*

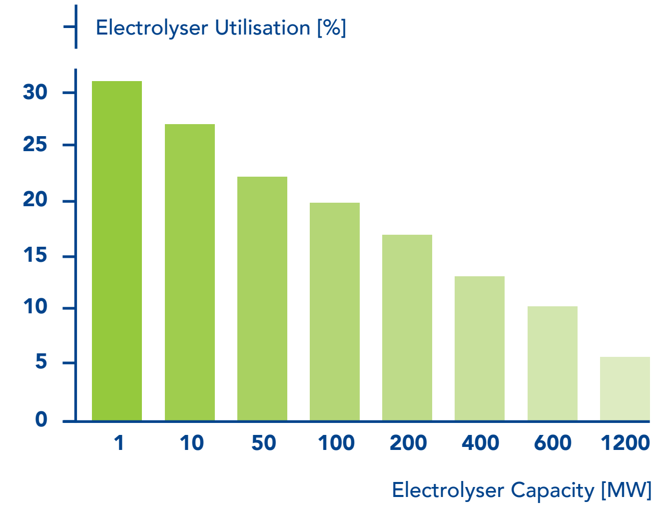

Figure 5f: *Utilisation factors of electrolysers of various capacities*

Fig 5a shows that the amount of hydrogen produced increases with the installed capacity of the electrolysers. In order to operate the system exploiting a high amount of curtailed energy, the electrolysers must be coupled with a storage system. The peak size of the storage grows with the size of the chosen electrolyser capacity as shown in Fig. 5b. However, larger electrolysers capacities lead to a better exploitation of available storage capacity as well, with a maximum storage daily utilisation which grows with the size of the installed electrolyser capacity (Fig. 5c). Also, the unused curtailed power decreases when the system size increases (Fig. 5d, 5e). Finally, in Fig. 5f it is shown that utilisation factors of electrolysers decrease when the system capacity increases. There is clearly a trade-off between electrolysers and hydrogen storage implementation costs and the benefits associated with a higher hydrogen production using more curtailed power from renewables. The size of the hydrogen production plant should be determined considering the desired payback time of the investment.

4.2.2 Role of other renewable gases

The roll-out of renewable gas, such as a mixture of bio-methane and hydrogen might reduce the reliance on CCS and contribute at the same time decarbonisation of the heat and transport sectors. Bio-methane is expected to play a role in the decarbonisation of the heat sector in the short term because it is interchangeable with natural gas, whereas hydrogen is not. Moreover, while the blending of 20% of H_2 by volume in the natural gas is considered tolerable for most appliances, it can be foreseen that 30% of the appliances may not cope well with this quantity of hydrogen [87].

4.3 Hydrogen in the transportation sector

The transport sector is the second highest contributor to greenhouse gases emissions in Ireland, the largest in the energy sector. For this reason, the green hydrogen produced by electrolysers powered by renewable energy, can play a key role to achieve zero emissions when used as fuel for heavy goods vehicles and in combination with battery EVs for cars and lighter commercial vehicles.

Hydrogen Mobility Ireland, a member association, was formed in 2019 by a group of companies that want to develop hydrogen fuel cell transport in Ireland working with stakeholders from North and South of the Island of Ireland. The group organised and demonstrated a hydrogen powered bus on various routes in Dublin, supported by CIÉ, Bus Éireann, Dublin Bus, Dublin City University (DCU) and Dublin Airport and were performed in November and December 2020 [88]. The bus was the H_2. City Gold bus manufactured by the Portuguese company CaetanoBus. The bus was fuelled using hydrogen produced in Dublin by BOC Gases Ireland by means of grid-connected electrolysers [89].

The hydrogen for fuel cell vehicles can be generated by electrolysers located at an existing wind farm using either curtailed or available wind power and by on-site photovoltaic (PV) arrays. Studies have shown that hybridizing PV, electrical energy storage (EES) system or with a hydrogen system is more cost effective than a more conventional hybrid PV and EES system configuration even if the cost of the battery bank decreases [90]. The sizing of the electrolyser, PV array and battery can be optimised to minimise the levelized cost of hydrogen. With current technology, the green hydrogen cost at the refuelling station from a distributed hydrogen supply chain may range from 5 to 10 €/kg. It is forecast that cost parity between diesel and H_2-fuelled buses could be achieved by 2030 in Dublin [91]. On the other hand, some concerns exist among the various stakeholders about the fact that wind farms are located far away from most urban centres where H_2 demand for transport is arising. If large volumes of H_2 would be daily transported through rural roads using diesel trucks, the associated risks and high carbon footprint may not encounter the full endorsement of the local communities.

A comprehensive study in the UK considering whole system thinking evaluating the options with respect to the use of electrification or hydrogen for UK freight was presented in [92]. This research was motivated the Chief Scientific Advisor at the Department for Transport London (DfT) to commission this work to inform DfT policy and provide a system-wide analysis on both electric and hydrogen energy systems. The study found that a hydrogen pathway requires more unknowns to be further researched and higher barriers to be overcome than an electric system, in part due to a decade lag in government investments into the hydrogen energy system compared to electrical system components. The study also found that the main barriers for a hydrogen system are economically producing low-carbon hydrogen and that without a clear distinctive path forward on how hydrogen will be produced at national level, downstream infrastructure is at risk and thus the final cost of a hydrogen based HGV system cannot be determined.

In California, a Low Carbon Fuel Standard was introduced in 2009, with the objective of improving air quality and reducing CO_2 emissions of the fuel mix of 10% by 2020. When used for fuel cell electric vehicles, green hydrogen produces at least 30% lower GHG emissions and 50% lower NOx emissions than new gasoline vehicles (over the entire vehicle life cycle, from the energy and materials used to produce the fuel to the direct tailpipe emissions).

Hydrogen could also have interesting application to maritime transport in Ireland. An interesting project is going to be undertaken in the Valentia Island in County Kerry, where there is a plan to use hydrogen to propel the Island's ferry service. A second application considered is the energy supply of the power public lighting [93].

4.4 Blending hydrogen in the gas network

Blending of hydrogen in natural gas will allow the use of the existing natural gas infrastructure consisting in 14,617 km of pipelines. Gas Networks Ireland has set a target of a net zero gas network to be in place by 2050 by introducing hydrogen and other renewable gases into the national gas network [94].

The gradual transformation of the natural gas network into a carbon neutral could result in a reduction of at least 18.7 Mt per annum of CO_2 emissions which corresponds to the 31% of the current Ireland's emissions according to Gas Networks Ireland. A 2050 energy mix scenario foresees about 100,000 households out of 1 million supplied by hydrogen, while the remaining 900,000 would be supplied by Bio-methane. Other possible scenarios are 100% Bio-methane supply and electrification [95]. Ervia assumes that in the 10% hydrogen scenario, the production of hydrogen which will be blended in the gas network in 2050 will determine CO_2 emissions, and that the emitted CO_2 will be stored (with additional costs). Therefore, both blue hydrogen and CCS processes appear to be part of the foreseen Irish pathway toward the decarbonisation of the domestic heating sector.

However, concerns exist regarding the safety related to the higher probability of ignition of the mix of hydrogen-natural gas in comparison with natural gas (which increases the risk of incidents) should also be considered [96]. The UK's pathway towards decarbonisation of the domestic heating sector is also likely to impact on policy making in this space. Furthermore, research from Germany's Fraunhofer Institute states that they believe that "initiatives by gas distributors and governments to add up to 20% green hydrogen to gas grids would be expensive, wasteful, technically complex to achieve and would reduce carbon emissions by a far lower amount than other uses of that H_2". Instead they believe that other uses such an in fertilisers, steel, shipping and aviation would avoid lock-in risks, generate greater GHG [greenhouse gas] savings for the investments made and avoid added costs being put on all gas consumers.

4.5 New developments

Pilot projects currently planned in Ireland aim at demonstrating and validating technologies for green hydrogen production, transmission and storage and will involve large operators in electricity and gas as well as high-tech start-up companies.

ESB Generation and Trading, the generation business of ESB Group, has planned to introduce green hydrogen production and storage in the multi-billion Euro programme Green Atlantic at Moneypoint in County Clare by the end of the decade. The Moneypoint power station is the largest electricity generation station in Ireland with an installed capacity of 915 MW. It is a coal-fired power station and has been the single largest emitter of greenhouse gases in the country. It was commissioned between 1985–87 and it is located on the River Shannon near Kilrush. Green Atlantic is a relatively short-term project which will specifically target the demonstration of hydrogen usage with power generation, heavy good vehicles and multiple manufacturing industries including pharmaceuticals, electronics and cement.

Another short to medium term project is the partnership between ESB and dCarbonX, which will support the development of green hydrogen storage and subsea offshore energy storage technologies in Ireland. dCarbonX Ltd is a geo-energy company based in London and Dublin developing subsurface hydrogen storage, carbon sequestration and geothermal baseload assets to enable the Energy Transition. This partnership will also support the creation of a new 'Green Hydrogen Valley' in the Poolbeg peninsula in Dublin.

Many of the existing refining and chemicals production facilities around the world using hydrogen are concentrated in coastal industrial zones, including the North Sea in Europe, the Gulf Coast in North America and south-eastern part of China. These zones and more in general many of the industrial ports could become centres for scaling up the use of green hydrogen. In Ireland, the plan is to build one of the largest green hydrogen facilities of its kind in the world, a 50 MW plant near Aghada, close to lower Cork Harbour. The Worley company is going to enter the concept design phase for the plant which will produce green hydrogen by electrolysis using renewable energy. This facility will have capacity to supply more than 20 tonnes of green hydrogen per day to the local commercial market and to remove 63,000 tonnes of carbon emissions annually [97]. The cost of construction and connection to the electricity grid is expected to be about 120 million euro [98].

Green electric power generation will also be supported by Ireland's Climate Action Plan through the promotion of all PCI projects under the EU TEN-E policy. In November 2020 Ireland has secured a 360MW hydro-electricity project as one of the EU Projects of Common Interest (PCI) approved by the European Commission. The project will be realised by the Silvermines Hydro in county Tipperary and will enable to supply green electricity to 200,000 homes by means of a pumped hydro storage technology [99].

4.6 Vision for hydrogen production, transportation and usage in Ireland

The vision for short- medium- and long-term opportunities for hydrogen production, transportation and usage in Ireland should originate from availability of renewables and potential to deploy additional renewable plants, and from the industries that are established in the country.

At European level, there is still a debate on whether low carbon production processes would be still appealing for hydrogen production, in other words the question is whether the blue hydrogen (produced capturing and storing the carbon dioxide emitted in the natural gas steam reforming process) may represent a cheaper alternative to the green hydrogen in the short- to medium- term (since the long-term policy should value only a fully green production based on renewables). Blue hydrogen has been produced for decades and would be the lowest cost low-carbon choice in the majority of locations [100]. The association Wind Energy Ireland reports that the current production cost of green hydrogen is estimated to be 2-3 times that of blue hydrogen [101]. However, blue hydrogen (as well as green) demands an appropriate policy to incentivise investments at the rate which is required to achieve the climate mitigation targets [102].

Given the abundance and the potential of renewables in Ireland it would be appropriate that green hydrogen production and use should be prioritised. However, in the medium-term blue hydrogen could be used to stimulate the demand and develop all the end-user services, until more green hydrogen facilities are developed. However, the longer-term vision for green hydrogen and the drop of electrolysis technology prices thanks to economies-of-scale [103] is likely to discourage investments in blue hydrogen in Ireland.

The specific costs of electrolysis stacks are expected to drop within 10 years because of the technological progress for both alkaline and PEM types of stacks, from about 200 €/kW to less than 90 €/kW for alkaline stacks and from 380 €/kW to about 220 €/kW for the PEM stacks [104]. In another study, PEM electrolysers are set to fall by 35% and 50% respectively by 2025, with solid oxide electrolysers seeing the "most dramatic [price reductions] in the next six to eight years" [105].

The emerging auto-thermal reforming (ATR) process is more efficient when used in conjunction with carbon capture with respect to steam methane reforming (SMR), losing only the 2% of efficiency (compared to the 18% of the SMR) when adding CCS. Moreover, it has been shown in [106] that, for the ATR process, a much lower price on carbon per tonne CO_2 would be sufficient to incentivize the use of a carbon capture and liquefaction system, whereas the addition of the same system to a SMR plant could not be incentivized even at much higher prices per tonne CO_2. Therefore, the payback time of such ATR plants should be carefully evaluated before concluding that they are feasible on the Irish hydrogen market due to too high implementation costs. Furthermore, as the world adjusts to high commodity prices while demand bounces back from Covid-19 lows and unstable political conditions in gas producing areas of the world, the economics and the security of blue, grey and brown hydrogen have become far less favourable than they were a year ago [107].

Long-term opportunities of implementing a green hydrogen economy are related to the large-scale deployment of wind and solar energy [108]. The target determined by the EU Renewable Energy Directive in Ireland was to achieve the 16% share of renewable energy in gross final consumption by 2020. Wind power contributed for 52% towards such target [109]. The deployment of 11GW - 16GW of onshore wind and 30GW of offshore wind is envisaged by 2050. Ireland has the potential to produce electricity from wind exceeding the domestic demand by 2030. In 2050 the electricity produced from wind is expected to be more than 2.5 times higher than the domestic demand [110]. On the other hand, the utilisation of wind power in 2018 was only 16% of the electrical demand. These considerations about the potential of implementing more wind power plants suggest that wind-hydrogen systems will become a very appealing technology in Ireland. Particularly, the concept of available wind power exceeding the regional or scheduled demand and the excess energy used to electrolyse water and to use the produced hydrogen as a fuel in transportation or heat for industry to generate again electricity using fuel cells or suitable gas turbines [111].

There appears to be a large potential for green hydrogen production in Ireland assuming that more than 20% of the electrical energy demand will come from green hydrogen production in 2050 for Europe in the Low Emissions Scenario (and about 10% globally) [112]. This would be potentially a similar scenario for Ireland in comparison with the UK.

4.7 National Policy Development

National strategy and policies with respect to hydrogen will have a significant impact in the development of the hydrogen economy in Ireland. To maximise the potential impact of green hydrogen in the energy system, policy and strategy need to consider adjacent energy vectors and systems which in future scenarios will be more heavily coupled. Examples of this inter-sector and inter energy vector coupling include the:

- Electricity systems
- Transport (particularly heavy goods vehicles and trains) [112]
- Industrial decarbonisation
- Domestic and commercial heat
- Agriculture

Furthermore, the national strategy and a policy should address:

- the targets and/or other long-term policy signals;
- likely technological and commercial advances;
- support needed for demand creation;
- mitigation of the investment risks;
- flexibility to deal with technological and market place changes;
- promotion of R&D activities, demonstration projects and knowledge sharing;
- harmonisation of standards, and removal of barriers [101].

5. System thinking and mapping on hydrogen

5.1 Primary hydrogen stakeholders and their behaviour

The main stakeholders of a generic hydrogen value chain are:

- the government
- hydrogen producers
- hydrogen consumers

In addition to these stakeholders, the production of green hydrogen requires engagement with significantly more stakeholders [113, 114, 115].

The main role of the government in decarbonisation is to implement a strategy that reduces GHG emissions in the economy. Government policy, incentives, regulations and legislation are the key levers of government to implement any strategy.

In order to incentivise the production of low or zero carbon hydrogen to decarbonise the economy by means of a financial incentive to hydrogen producers, government needs to gather taxes from appropriate actors within the economy. The government also sustains a cost proportional to the health impact of energy and fuel production and utilisation. This cost could be reduced when low or zero carbon hydrogen is used as a replacement for natural gas and fossil fuels, as the greatly reduced environmental impact of green hydrogen as the potential to improve our environment and thus improve health outcomes particularly when used as a replacement fuel in road transport, power generation and industrial processes. Government's goal therefore should be to minimise the cost per unit of GHG emissions reduction considering the incentives paid to hydrogen's or indeed any other renewable energy producers and the potential financial savings and other benefits to from other parts of the economy [116].

- Green hydrogen producers invest in electrolysis equipment and in the renewable production infrastructure and typically operate the installed system. They receive a revenue that is the sum of revenue from selling the green hydrogen product to the consumer and the incentives received from the government. The green hydrogen producers contribute to the reduction of GHG emissions by producing green hydrogen and at the same time pay a tax to the government which is proportional to their profit. Ideally, the green hydrogen producers want to maximise their profit by investing in the production infrastructure and selling the product to the consumers. The production of green hydrogen will be unique to each jurisdiction due to the availability of renewable energy production in each country. For example, in Ireland wind based green hydrogen production is likely to be the most cost-effective.
- Green hydrogen consumers are willing to contribute to the reduction of GHG emissions by replacing for example the natural gas used for building heating with hydrogen, and the fossil fuels used to currently power road vehicles. In doing so, each hydrogen's consumer wants to minimize the additional costs associated with hydrogen's utilization with respect to conventional natural gas and fossil fuels. These additional costs are affected by the required development of infrastructure including charging/refuelling infrastructure, the purchase of hydrogen instead of conventional gases or fuels and taxes or levies applies by government.

Intervention could take the form of capital grant offered to companies which produce green hydrogen and address the current high capital costs associated with this nascent industry. When green hydrogen is produced using wind power, a combination of feed-in-tariff and capital grant is most promising solution to achieve cost-effectiveness and profitability for both wind energy producers and government [117]. In the long-term an EU Directive should determine a minimum taxation of hydrogen while entrepreneurs and SMEs in hydrogen and fuel cell sector get better access to capital incentives and financing schemes possibly using a European trust fund [118]. These incentivises could be revised to reflect the changing economics associated with the equipment associated with hydrogen production for example electrolysers whose costs are anticipated to change as we move through the next decade (incentives that decrease over time [119]). This could enable producers to enter the market leading to increased competition resulting in in economies of scale and increased efficiency in production. From a consumer point of view government could introduce penalties to incentivise green hydrogen consumption for example in the transportation sector penalising through an appropriate taxation the manufacturers or importers of vehicles using diesel or gasoline fuels, with respect to zero-emissions electric vehicles using batteries or hydrogen fuel-cells. In UK, a government's decision could ban from 2040 onwards the sale of all new non-electric vehicles. This could be obtained by means of a tax on every non-electric vehicle sold [120].

It is clear that each actor within the sector will try either to minimise its costs or maximise its profit. In order to incentivise the utilisation of hydrogen, the government will have necessarily to increase the related taxes. Furthermore, the location of producers and consumers and their co-location will be important as the challenges and costs of transportation and storage are not trivial and incentives and penalties may need to correctly incentivise the appropriate development of infrastructure. Finally, the promotion of scientific research related to hydrogen could help to obtain more efficient production processes and approaches, that will eventually determine a lower cost of hydrogen for the consumers.

5.2 Interactions between society stakeholders

The success of any hydrogen economy will depend on its socio-political, market and community acceptance. The different stakeholders bring diverse perspectives thanks to their knowledge and expertise, which can influence decisions and eventually policies applicable to hydrogen [121].

Socio-political acceptance of hydrogen is significantly impacted by public sector stakeholders and policymakers. These actors have traditionally perceived hydrogen as an environmentally friendly substance with potential safety implications that has the potential to replace fossil fuels in a number of scenarios. Furthermore, the industrial use of hydrogen has resulted in an expansion of business activities and the creation of new jobs in some countries. These factors have a positive influence on the stakeholders of the public sector.

For residents living in a community or neighbourhood, the local authorities, local agencies, or organisations are the stakeholders that determine the community acceptance of hydrogen. These stakeholders are influenced by safety, aesthetical factors, environmental impact, distributive benefits, and shared costs. They can have a direct influence on the discussion, planning and execution of a hydrogen project.

Consumers, suppliers, investors, firms, and other market players are the stakeholders that are and will determine the market acceptance of hydrogen. These stakeholders are typically positively influenced by technology demonstration projects showing safe, sustainable and cost-effective hydrogen solutions. Firms and investors drive the hydrogen technology commercialisation and influence the policymakers in developing favourable policies to their endeavours. The 109 companies forming the Hydrogen Council represent over USD 6.8 trillion in the market of hydrogen, with more than 6.5 million employees [122].

Stakeholders agree on the factors that determine the success of hydrogen industry and therefore can work together to develop them: availability of infrastructures, engagement with local communities, development of regional skills and capabilities, benefits distributed to the community and safe utilisation of hydrogen by the community [123].

Governmental intervention through incentives at the early stage of the hydrogen economy development is likely to support the development of pilot projects which address the concerns and support the positive attitudes associated with green hydrogen. More hydrogen pilots would also allow the project developers to make hydrogen more socially acceptable and well received from the local communities by means of effective marketing campaigns. That way, investors and firms would be more stimulated to make the technology commercially viable. Further incentives could support the subsequent hydrogen industrialisation and enable economies of scale to reduce customer costs.

Hydrogen stakeholders could contribute to the development of a hydrogen economy showing commitment towards the environment and the reduction of harmful emissions, and their preference of green solutions for the energy consumption and transportation needs when they are made sufficiently accessible and affordable to be used. Stakeholders such as policymakers, industry players, and investors realise that the transition towards the hydrogen economy will not happen spontaneously and are keen to undertake combined and coordinated efforts to overcome the existing barriers related to the legal and policy framework, the environmental impact, available infrastructures, safety, and societal factors [124-125].

Policymakers and industry representatives may work together to define long-term pathways for decarbonisation in all the sectors by defining targets for end applications, such as targets for emission of vehicles or targets for the decarbonisation of domestic heating, and to determine the necessary infrastructure for energy generation and distribution. Industry stakeholders should work closely with policymakers to develop a strong national market and establish the hydrogen value chains across the EU [126]. They can also cooperate with other industries located in other markets, such as those in the Asian countries to foster technology development and mitigate risks. Moreover, policymakers should also work with gas companies setting targets for renewable products used in the gas grid or regulatory measures such as feed-in tariffs and incentives for green hydrogen utilisation. Moreover, regulations applicable to hydrogen blending into the natural gas grids should be harmonized across different EU countries, whereas hydrogen blending should be promoted through tax exemptions.

5.3 Interactions between key adjacent industries influencing the hydrogen success

5.3.1 Electricity Industry

Policymakers, transmission system operators (TSOs) and industry should collaborate to establish power balancing markets, where the existing spinning reserves provided by gas turbines are replaced by carbon neutral alternatives, such as flexible green hydrogen production. The development of a fully decentralized power-to-gas market in Europe through stakeholders' cooperation will determine lower production costs, while establishing more stable prices in the sector, adequate capabilities (including storage) to manage seasonal power imbalances and a reduced need to curtail or constrain renewable generation. At the same time stakeholders should explore technical feasibility and opportunities for seasonal and long-term storage, because hydrogen storage comes with a lower impact and cost per kWh stored than pumped hydro, batteries, or compressed air storages.

5.3.2 Transport Sector

Policymakers and regulators should work with industries of the transport sector to develop the transport sector through coordinated actions promoting a harmonic development of regulations, refuelling infrastructure and vehicles. Relevant regulations include incentives, the public procurement of FCEV buses, fleet regulations applicable to truck, coach, and taxi operators, as well as nonmonetary incentives for FCEV drivers. Sector's regulations incentivise industry investments in product development such as trucks, buses, vans, and larger passenger vehicles, as well as in their maintenance. If the regulatory stakeholder envisages that with the FCEV number growing the investments in hydrogen refuelling stations will be more profitable and appealing, they should set as a priority the support to product development; on the other hand, if the regulatory stakeholders see the lack of an adequate refuelling infrastructure as an obstacle to the expansion of the FCEV market, they should provide a direct support for the infrastructure development [127].

5.3.3 Industrial sector

In the industrial sector, policymakers and industry players should work together to promote the transition from grey to green hydrogen across all the major uses of hydrogen, respectively creating new regulations (such as an import tax for hydrogen imported from UK and Europe) and implementing the technology for green hydrogen production. Regulations needed by industry should ensure that low carbon targets are applied to chemical processes using hydrogen in industry and that the carbon-free hydrogen production contributes towards renewable targets. Furthermore, stakeholders should develop a standard related to green hydrogen to guarantee that it meets some essential criteria related to requirements for hydrogen production to label it as "green" (such as a limit on the life-cycle carbon emissions [128]), the boundaries associated to hydrogen production and utilisation and transportation routes; the chain of custody; the applicable emission intensity thresholds; and the eligibility of production pathways and technologies. Currently, a comprehensive standard does not exist yet, and green hydrogen is sometimes generically associated with production using low carbon energy sources and/or with low environmental impact [129].

Development of more hydrogen and fuel cell applications, as well as plans for their scale up require joint work of industry and policy stakeholders. Such applications include hydrogen utilisation in trains, shipping, and cogeneration in the residential and commercial sectors. Policymakers are expected to establish policies for replacing diesel trains with hydrogen fuelled ones and to set decarbonisation targets for ports, rivers, and lakes (target for ocean shipping is set by the International Maritime Organization). Also, policies for energy efficiency in buildings should consider the use of the blended hydrogen and its benefits with respect to natural gas.

5.4 Cross-sectoral engagement

All the stakeholders should engage with activities that foster end-users' awareness, information, education, training, addressing thoroughly their safety concerns and knowledge gaps about technology and legal framework. In order to gain end-users' hydrogen acceptance, they also need to contribute to regulations, codes and standards for safety, such as the European CEN/CENELEC/TC 6 standard [130].

The call for evidence provided further insights about stakeholders' knowledge and expectations of hydrogen utilisation in different application sectors. The knowledge produced by the call for evidence was used to further improve the understanding of stakeholders' expected behaviour and of how they can work together, balancing the different interests, to develop a hydrogen economy in Ireland.

6. Innovation, scaling and cost-effectiveness

6.1 Hydrogen technologies for innovation

6.1.1 The evolution of green hydrogen production technologies based on electrolysis

Electrolysis is commercially a well-established technology that was initially developed for oxygen generation in closed environments, such as crewed space missions and submarines. Most of the electrolyser product development has focused on scale and assembly. Fuel cells prototype development deeply requires material optimisation, because it is believed that an enormous potential for cost and performance improvements can be seen from current lab and subscale experiments.

The scaling pathways of hydrogen production, storage and utilisation of key technologies can be predicted by analysing the evolution of prototypes towards commercial products as well as the scale up of the already available commercial products. A distinction between different proposed technologies must be made because they have not reached the same level of maturity and marketability readiness level [131]. Figure 6 shows the differences between the major technologies for hydrogen production through electrolysis.

Alkaline Electrolysis

Older electrolysis technologies operate at low temperature and use as the electrolyte in water, the concentrated potassium hydroxide (KOH) or other alkaline electrolysers. These systems have been built up to the multi-megawatt size, are very cost-effective and are still in use for a range of applications in some large-scale industrial markets. However, they need to operate at balanced pressure and require either mechanical compression of the generated hydrogen or generation of oxygen at elevated pressure. For this reason, electrolysis systems based on potassium hydroxide present additional safety risks related to the high pressure of gases. Furthermore, these systems use a corrosive electrolyte as the circulating fluid and work with lower operating current densities with respect to most recent systems using a solid electrolyte.

Exchange Membrane Electrolysis

Most recent solid-state-electrolyte-based systems use membranes instead of potassium hydroxide as electrolyte, such as the proton exchange membranes (PEM). These systems can generate electrochemically compressed hydrogen while maintaining the oxygen loop at ambient pressure and can operate at higher current densities than the KOH systems, typically in the range 1.5–2 A/cm^2 instead of less than 0.5 A/cm^2.

The electrolysis systems based on PEM have been available since 2004 with the 40-kW size, whereas 1 and 2 MW systems were released in 2014. Today 20-40 MW systems are being built and by 2030, it is foreseen that 100 MW will be the standard.

New prototypes are being developed using the Anion exchange membrane (AEM) instead of the PEM. AEM technology is currently less mature than PEM but has potentially some advantages related to the fact that the membrane conducts hydroxide ions rather than protons. This determines a higher pH locally and enables to use a significantly broader range of cell materials and catalyst. The AEM systems have the advantages of both liquid KOH systems and membrane systems: low-cost materials, noncorrosive electrolyte, and low-pressure operation. Since existing stack platforms and balance of plant systems available for PEM technology can be leveraged by AEM, it is foreseen that AEM will mature quickly when suitable materials will be available and that commercial low temperature membrane systems will be a mix of PEM and AEM.

Solid Oxide Electrolysis

Solid oxide electrolysis cells (SOEC) use an oxide or ceramic material as the electrolyte. These systems operate at much higher temperatures typically 600–1000 °C vs the 50–100 °C of the PEM technology in fuel cell mode, and typically 700–1000 °C vs the 20–100 °C of the PEM in electrolyser mode.

The higher operating temperature enables a broader fuel flexibility for the fuel cell version and higher efficiency for both the fuel cell and electrolysis operation due to low activation polarisation at the catalyst. The efficiency range is of 60-70%, instead of 40-50% of the PEM technology when operating in fuel cell mode, and 81-86% vs 62-82% when operating in electrolyser mode.

Furthermore, non-precious catalysts can be used in the cell which is a drawback of other technologies. When operating in fuel cell mode, the cell generates high quality heat that makes it suitable for combined heat power applications. When operating in electrolyser mode, it can heat can be used as power supply, which has traditionally been cheaper than electricity. The manufacture of a SOEC requires higher quality materials and sealing, however this technology has nowadays reached a good level of maturity. There are few commercial SOEC systems now available and are beginning to find favour in stationary applications.

Preconditions to the scale-up these systems and conditions that would support market growth, would be to leverage the knowledge of existing commercial fuel cell systems using similar materials with respect to SOEC technology, to further develop the SOEC technology. On the other hand, there are differences with the fuel cell and electrolysis requirements as well as with the balance of plant, which do not share the piping and instrumentation layouts and electrical and controls definition used by the low temperature membrane-based electrolysers. Overall, it can be optimistically hypothesized that these systems will have a growth like that of low-temperature systems at best.

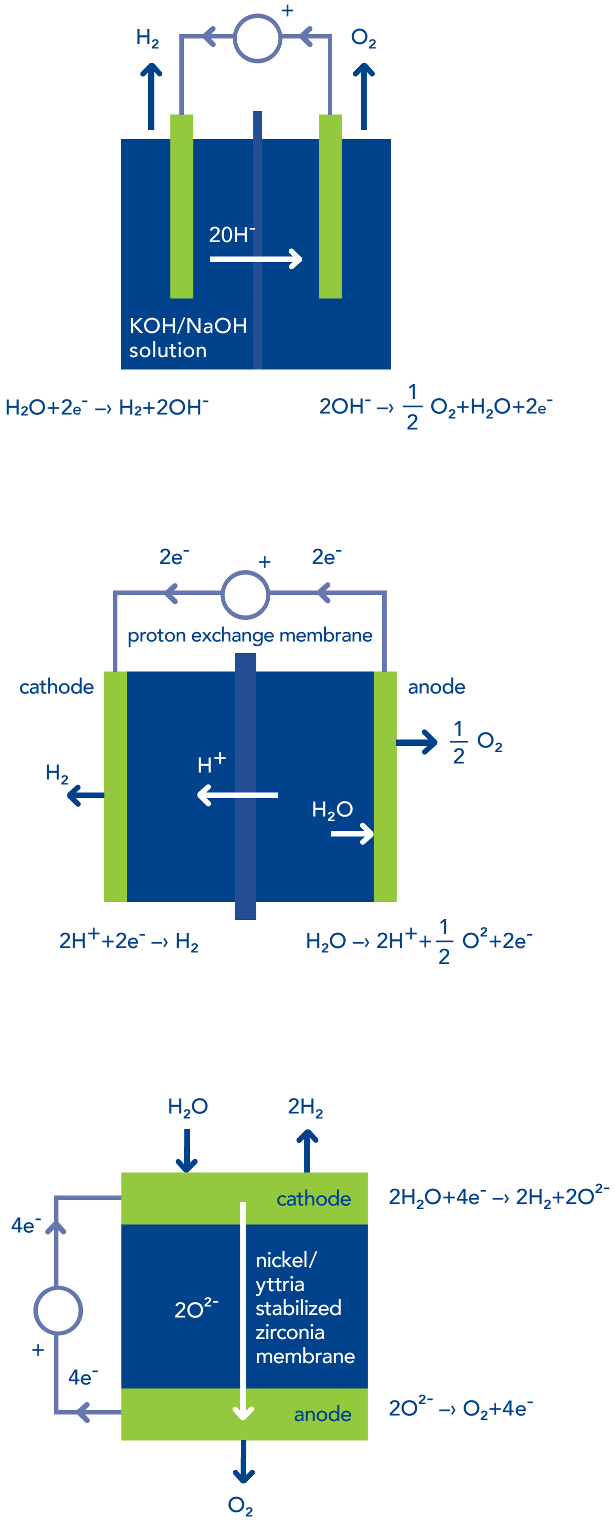

Figure 6: *Electrolysis technologies for hydrogen production*

Alkaline Electrolysis Cell

- Introduced by Troostwijk and Diemann in 1789
- Operates at lower temperatures such as 30–80 °C
- Electrolyte is aqueous solution (KOH/NaOH) with concentration of ~20% to 30%

PEM Electrolysis Cell

- idealized by Grubb in the early 1950s and developed in 1966 by General Electric Co.
- compact design
- high current density (> 2 A cm^2),
- high efficiency (~80%)
- fast response
- operates under lower temperatures (20–80 °C)
- produced ultrapure hydrogen and oxygen as a by-product
- Low current densities (< 400 mA/cm^2), low operating pressure (~ 3.2MPa) and low energy efficiency (up to 73% for commercial units)

Solid Oxide Electrolysis Cell

- Introduced by Donitz and Erdle in the 1980s
- operates at high pressure and high temperatures 500–850 °C
- utilises the water in the form of steam
- some issues related to lack of stability and degradation
- Efficiency > 90%
- Not a commercial product yet

6.1.2 Novel technologies for green hydrogen production using solar energy

Green hydrogen production technologies relying on solar energy to directly produce green hydrogen are:

- photo-electrochemical
- solar thermochemical

Photo-electrochemical

A photo-electrochemical cell combines the functions of a traditional photovoltaic solar cell with an electrolysis cell. This type of cell includes a semi-conductor electrode (the photo-anode) that absorbs light and enables to split electrochemically water.

The main drawback of this technology is that the photo electrode requires quite a large energy from the solar flux to win the energy band gap and provide the electrical potential required for water splitting, and the electrode surfaces must enable both the absorption of solar light and to catalyse the hydrogen and oxygen chemical reactions.

Developed prototypes with size of less than 100 cm^2 demonstrated that these devices operate at a low current density, in the order of 10 mA/cm^2. The scale up of the photochemical technology is therefore difficult, also considering that no balance of plant has been developed yet at any scale. An optimistic prediction is to achieve 100 kW scale in 10 years and 5 MW scale in 20 years.

Solar-thermochemical

A solar thermochemical hydrogen plant uses concentrated solar power to heat a receiver and thermally split water at high temperature (about 2000 °C). Solar radiation can be concentrated via heliostat mirrors.

Some prototypes of these systems have been developed, but there are currently no commercialization pathways. The preconditions to scale the innovation brought by solar thermochemical hydrogen is to continue the experimentation and improve the understanding of system configuration, standard tests, operating conditions. Solar thermochemical hydrogen technology is considered even less mature than photo-electrochemical, in lag of some years in terms of development.

Nuclear-thermochemical

A nuclear-thermochemical cycle for hydrogen production is a process comprising a series of thermally driven chemical reactions where water is split into hydrogen and oxygen using heat recovered from a nuclear power plant. An example of such a process is illustrated in Fig. 6. The intermediate chemical compounds which are generated in the cycle and support the water splitting, are regenerated and remain completely in the system.

Discussion

In order to evaluate the effectiveness of using solar energy for green hydrogen production, one needs to determine the area of photo-voltaic (PV) panels required to supply the considered demand. This issue is particularly important for the transportation sector, because ideally one wants to generate the hydrogen needed by a refuelling station in a close location such that the costly transportation of hydrogen from remote locations is avoided.

The costs of transportation of hydrogen depend on the storage modes, namely compressed gaseous hydrogen (CGH_2), liquid hydrogen (LH_2) and liquid organic hydrogen carriers (LOHC). In [132] the transportation costs considered were 2.69 €/kgH_2 for compressed gaseous hydrogen, 0.73 €/kgH2 for liquid hydrogen, and 0.99 €/kgH_2 for LOHCs.

Comparing the energy content of hydrogen with that of conventional fuels, it can be estimated that a single refuelling station would require 1000 kg of hydrogen per day, when considering an efficiency of 65% for the electrolysis process and the lower heating value of hydrogen, this quantity corresponds to 51 kWh of electric energy. Considering that 10 m^2 of PV panels with 10% efficiency can deliver approximatively 1kWp and that a PV can produce energy for 5 hours/day we obtain that the operation of a refuelling station of hydrogen would require 102,000 m^2 of PV to be independent on a hydrogen distribution network [133].

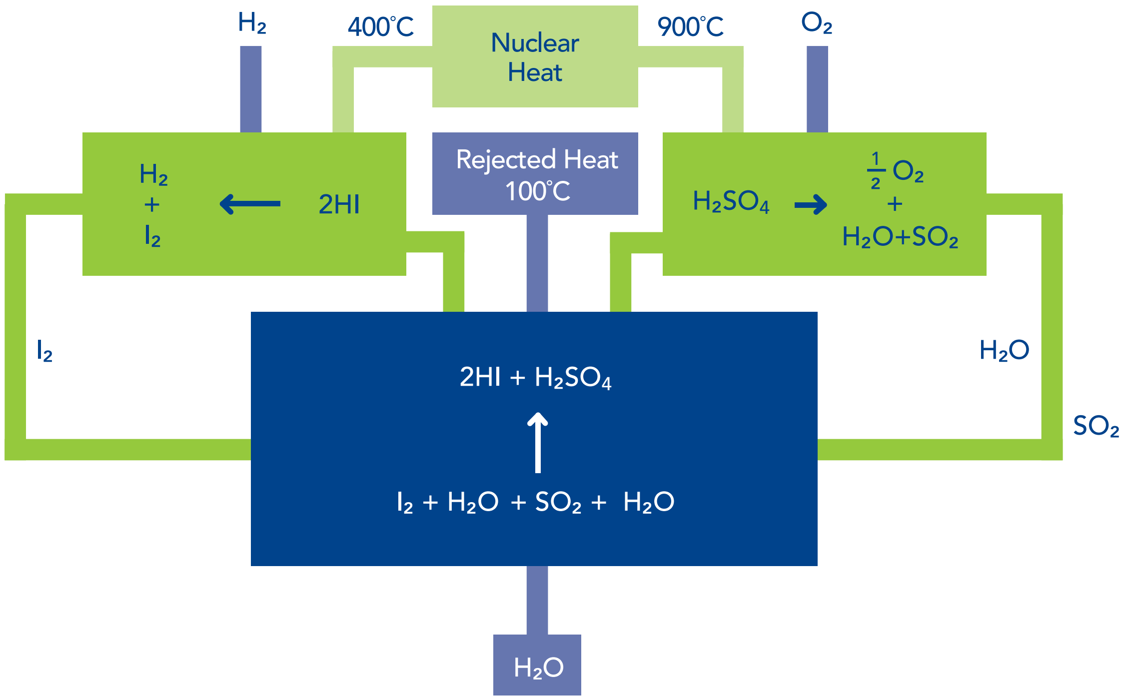

Figure 7: *Thermochemical process for hydrogen production using nuclear power*

6.1.3 Research on carbon capture and conversion (CCC)

When analysing the development of adjacent hydrogen technologies, it is worth to mentioning the fact that carbon capture enables not only its storage, but also the conversion into chemical products. In fact, the CO_2 storage using the earth as a huge reservoir may have long-term ecological and environmental impacts which are currently not well-understood yet. Moreover, current adsorbents materials technology shows some limitations. Even though various adsorbents have been developed to capture and store CO_2, their high regeneration temperatures and/or limited CO_2 adsorption capacities still limit the development of such technologies.

An alternative strategy is CO_2 capture and conversion (CCC), that involves capture and subsequent conversion of CO_2 into high valuable chemicals and fuels. CO_2 can be converted into urea, formic acid, salicylic acid, organic carbonates like acyclic carbonate, cyclic carbonates such as ethylene carbonate, polycarbonates, and fine chemicals like the biotin [134].

It is worth to notice that various processes named CCC or CCU or CCS are classified as Carbon Dioxide Removal (CDR) when they remove physically the CO_2 from the atmosphere, store it out of the atmosphere in a manner which is intended to be permanent, and the amount of CO_2 removed from atmosphere and stored is greater than the amount of CO_2 equivalent emitted [135]. Metal–organic framework (MOF)-based materials are emerging as new promising adsorbents and catalysts for CO_2 capture and conversion showing excellent capabilities for selective CO_2 capture in the presence of N_2, CH_4, and H_2O and other gases. Among the various products that can be obtained by converting CO_2, there are intermediate products used to produce engineering plastics, electrolyte solvents for lithium-ion batteries, polar aprotic solvents, degreasers, and fuel additives [136]. Another promising CO_2 adsorbent material is the graphite [137].

To conclude this brief discussion about CCC technologies, it can be said that their development could support the development of a hydrogen economy and simultaneously support CO_2 emissions reduction.

6.2 Infrastructure development and scaling pathways for the hydrogen economy

6.2.1 Hydrogen consumption pathways

The Hydrogen Council, the largest industry-led hydrogen association launched in January 2017 at the World Economic Forum, has set goals and pathways to scale-up hydrogen economy by 2030 and by 2050 in five areas:

- Transportation
- Industrial energy
- Building heat and power
- Industry feedstock
- Energy systems [132].

Transportation

The use of hydrogen as a replacement fuel in transportation could result in 20 million barrels of oil replaced per day and 3.2 Gt CO_2 abated per year [138]. To enable this fuel cell technology must move to large-scale production. The scaling-up of fuel cells from prototypes to commercial products requires that a sufficient capital return and a net positive life cycle assessment are achieved. An analysis of the current technologies reveals that the current manufacturing cost of fuel cells is higher than the cost of internal combustion engines, whereas their operating costs can be much lower than those of competing technologies (e.g., IC engines or boilers) because of a higher thermal efficiency of fuel cells. On the negative side, low reliability of fuel cells results in high repair and maintenance costs and may determine a cost increase up to 60% as well as a reduction of availability. In fact, even a small uneven distribution of the flow can cause an operational misalignment of cells and stacks, which may compromise the reliability of the FC and determine the need of a frequent repair or maintenance interventions [139].

Road Transport

In the transportation sector, one of the main innovations brought by hydrogen are the Fuel Cells Electrical Vehicles (FCEVs) which should emerge as a complementary technology for Battery Electric Vehicles (BEV) to achieve deep decarbonisation of the transportation sector.

FCEVs have typically longer ranges and faster refuelling time in comparison with BEV. Fuel cells technology is becoming commercially available in medium-sized/large cars, buses, trucks, vans, trains, and forklifts. However, FCEVs are forecast to make a relatively slow impact on the automotive market because they are more expensive, may have lower reliability than other types of vehicles and are perceived as a market entrant technology by many people [140]. It is anticipated that the first success for FCEVs will appear in niche markets, prove their added value to potential clients, reduce their costs, and eventually move into the larger markets [132].

FCEVs are envisaged to have a commercialisation pathway from 2020 to 2050 prioritising in a first phase the light duty vehicles, followed by freight vehicles and cars. FCEVs will be improved leading to more cost-effective solutions and their market share consolidation [141].

In some forecasts between 10 and 15 million passenger and 500,000 trucks powered by hydrogen will be on road across the glove [132]. In these forecasts, 1 in 12 cars in Germany, Japan, South Korea, and California will be fuelled by hydrogen. These figures will be significantly increased in 2050, with up to 400 million passenger vehicles, 15 million buses and 5 million trucks powered by hydrogen [132]

Rail Transport

Trains and passenger ships powered by hydrogen also have considerable potential to enable decarbonisation. In 2050, some sources anticipate that 20% of diesel trains will be replaced by hydrogen powered trains [132].

Industrial Energy

Hydrogen is currently the frontrunner to provide the decarbonised heat required by industrial processes and is seen as the most realistic alternative to post-combustion CCS [132]. In 2030, 4 Mt of additional hydrogen will be used in industry globally, which correspond to 166.67 TWh of energy. It is foreseen that one in ten steel and chemical plants in Europe, North America, and Japan will be using hydrogen in 2030 [140]. In 2050, 12% of global industry energy demand will be met using hydrogen, corresponding to 4444.44 TWh of energy. Hydrogen usage will determine the abatement of about 1 Gt CO_2 per year [132].

Building heat and power

Hydrogen could also be used to decarbonise building heat and power in regions with existing natural gas networks. In some forecasts, 6.5 million households will be heated with blended in concentrations of up to 20% with natural gas or pure hydrogen using about 3.5 Mt and 138.89 TWh of hydrogen by 2030. Moreover, it is forecasted that in 2030 fuel cell combined heat and power units will be used by 10% of users connected to the hydrogen natural gas network. In 2050, according to the forecasts hydrogen will supply the 8% of global building energy demand of heat and power, corresponding to 3055.56 TWh of energy. The amount of CO_2 abated per year will be about 700 Mt [132]. Furthermore, the commercialisation of fuel-cell co-generation units for buildings will begin in 2030 and in 2050 the co-generation units will cover 5% of the residential demand and 1.5% of the services demand [142].

Industry feedstock

Hydrogen is currently used in industry as feedstock in refining, fertilizer, and chemical production processes. The commercialisation pathway of hydrogen's use in industry will begin in 2030 and in 2050 8-11% of crude oil steel production and the 15% of chemical and petrochemical industry will come from hydrogen. By 2050, hydrogen could also be used for iron smelting [132]. Usage of green hydrogen as industry feedstock may significantly contribute to the decarbonisation of the sector.

Switching from grey hydrogen to green hydrogen in existing industrial applications (large-scale chemical synthesis processes) has the potential to remove every year 1.6 Gt of CO_2 that would be produced by global industry in a business-as-usual scenario by 2050 [143]. Forecasts, indicate that steel plants will use about 100,000 t of hydrogen in hydrogen reduction for zero-carbon iron making in 2030. In 2050, about 200 Mt of crude steel (10% of the global production) will be produced using hydrogen, leading to 190 Mt CO_2 savings per year [132]. Furthermore, in 2030 about 2.5 Mt hydrogen will be used to produce between 10 Mt and 15 Mt of methanol and derivatives, including olefins and aromatics [132]. The quantity of methanol and ethanol derivatives produced using hydrogen will be increased up to 30% in 2050 enabling a reduction of 360 Mt of CO_2 per year [140]. Chemical and refining industries will begin the demonstration of green hydrogen use by 2030 and should fully decarbonise their feedstock by 2050, eventually saving 440 Mt of CO_2 per year [132].

Energy Systems

Hydrogen enables cost-effective long-term storage in underground salt caverns. By 2030, 250 to 300 TWh of excess solar and wind power will be converted into hydrogen and 200 TWh will be stored [132]. The excess solar and wind power converted to hydrogen will increase to 500 TWh in 2050, which correspond to 416.67 TWh of hydrogen energy, whereas the storage will be 3,000 TWh of hydrogen in 2050. The power plants will produce from 100 to 200 TWh of dispatchable power using green hydrogen by 2030, whereas the predicted production in 2050 is 1,500 TWh from 2500 TWh green hydrogen. It is estimated that ships will transport 100 kt of hydrogen per year overseas in 2030 and 55 Mt in 2050 [132].

To achieve these ambitious targets will require investment of $ 2.5 trillion for hydrogen and fuel cell equipment and the require the creation 30 million jobs worldwide.

6.2.2 Hydrogen production pathways

Innovation in all aspects of hydrogen production is necessary to address the challenges posed by climate change in a clean, efficient, effective, reliable and affordable way. In [143] the key elements and dimensions of innovation in hydrogen production were defined as source, system, service, scope, staff, scale-up, safety, scheme, sector, solution, stakeholder, standardisation, subsidy, stimulation, structure, strategy, support, and sustainability. These dimensions ensure that the innovative system are developed to support the overall objectives of improving efficiency, cost-effectiveness, resources use, design and analysis, energy security, environment [144]. When considering these multiple criteria this study identified that the best performing sources for hydrogen production are geothermal and biomass, followed by hydro and solar. Coal, nuclear and natural gas are the sources that overall perform the worst [143].

Pathways in hydrogen production have previously been evaluated under the objectives of: cost minimization, emissions reduction, system size decrease, improvement of reliability and durability, improvements of service, training, and maintenance programs, improvements on safety, standardisation and certification, increased efficiency, better quality of produced hydrogen [139]. Lowest emissions are achieved by photonic hydrogen production systems whereas thermochemical has the highest emissions. Thermochemical processes have the lowest costs, whereas photo-electrochemical systems have the highest. Thermolysis has the highest efficiency, whereas photocatalysis has the lowest efficiency. When multiple criteria are considered, thermo-chemical systems are the best performing, followed by photo-fermentation and artificial photosynthesis. The lowest performances are achieved by photo-electrochemical systems, followed by photocatalysis and thermolysis.

Achieving optimal transitions to hydrogen energy systems depend on the success of hydrogen service sectors. The potential of the different pathways to support an increasing demand of hydrogen are shown in Table 2 [145]. Note that the preferred production pathway supported by the EU policy is the electrolysis powered by renewable electricity. Green hydrogen's cost was on average $6.00 (€5.09) per kilogram in 2020, whereas the predicted cost for 2030 is $2.50 (€2.12) per kilogram, thanks to high European wind capacity factors [146].

The waste pathway towards hydrogen which uses thermochemical and biochemical processes to produce hydrogen from wastes is also important to note. Waste can produce hydrogen yields up to 33.6 mol/kg and hydrogen concentrations of 82%. Biochemical methods based on fermentation techniques can produce hydrogen up to 418.6 mL/g [142]. A waste-to-hydrogen project has been planned in the island of Martinique to power buildings and municipal buses. Two companies, a global supplier of renewable hydrogen systems (Ways2H), and a Caribbean ecological and energy solutions provider (Valecom) have engaged into the transformation of 9,000 tons of waste per year into clean hydrogen [147].

Hydrogen production pathway	Production process	Advantages	Disadvantages	Predicted Impact
Thermal-chemical Pathway (grey/blue)	Natural gas steam methane reforming (SMR) with carbon capture and sequestration (CCS), coal gasification CCS, and biomass gasification CCS	Can achieve low carbon emissions at a low production cost when CCS is available	If CCS is not available i n the in the near- or mid-term then CO_2 emissions reduction will not be achieved	High impact on demand fulfilment because the production process is well established
Electrolysis powered by renewable electricity	Onshore/offshore wind, ground-mounted or rooftop solar PV and hydropower used to supply power to an electrolyser	Potential to achieve zero carbon emissions	Production costs high. Intermittency and variability of renewable energy sources and integration challenges with the electricity grid and energy systems at large scale	High because of no carbon emissions and abundance of renewables
Solar photo-electrochemical (PEC) pathway	A photo-electrolytic cell is a device using the light incident on a photosensitizer, semiconductor (photocatalytic) or aqueous metal immersed in an electrolytic solution to directly produce electrolysis of water	Potential to achieve zero carbon emissions.	Technology not mature yet and/or production costs high	Low
High-temperature electrolysis powered by nuclear or solar energy	Reverse reaction of the solid oxide fuel cell (SOFC) technology, using higher temperature (800–1000°C) to split water and consumes lower electricity	Potential to achieve zero or near-zero carbon emissions. Advanced nuclear reactors are ideal to produce cheap and clean hydrogen on a large scale	Technology not mature yet and/or production costs high. No significant progress in the R&D and deployment of nuclear reactors in more than 20 years. Solar energy requires areas with abundant land resources and good solar irradiance	Low to medium
Thermal water splitting powered by nuclear or solar energy (thermolysis)	Sunlight is concentrated onto a reactor tower using a field of mirror "heliostats,". High-temperature heat (500°–2,000°C) drives a series of chemical reactions that produce hydrogen. The chemicals used in the process are reused within each cycle, such that only water is consumed and hydrogen and oxygen produced	Potential to achieve zero or near-zero carbon emissions. Advanced nuclear reactors are ideal to produce cheap and clean hydrogen on a large scale	Technology not mature yet and/or production costs high. No significant progress in the R&D and deployment of nuclear reactors in more than 20 years. Solar energy requires areas with abundant land resources and good solar irradiance and costs are high	Low, because more research is needed for robust reactor design and improve process efficiency and durability of materials

Hydrogen production pathway	Production process	Advantages	Disadvantages	Predicted Impact
Biological pathway	Microorganisms such as green microalgae or cyanobacteria use sunlight to split water into oxygen and hydrogen ions (also known as photo-biological method). Hydrogen ions are recombined with electrons and released as hydrogen gas Artificial photosynthesis is a production process replicating the natural process of photosynthesis, that converts sunlight, water and carbon dioxide into carbohydrates and oxygen. This has been recently used to split water into hydrogen and oxygen using an artificial compound called Nafion Photo-fermentation is the conversion of organic substrate to biohydrogen using fermentation produced by photosynthetic bacteria	Zero carbon emissions produced	Still in the early scientific research and laboratory testing stage. Low rates of hydrogen can be produced. Water splitting using the photobiological method also produces oxygen that quickly inhibits reaction for hydrogen production Photo-fermentation is limited to the difficulty of maintaining a constant temperature for the bacteria in the bioreactor	Very low
Waste pathway	Thermochemical (gasification and pyrolysis) and biochemical (fermentation and photolysis) processes applied to wastes	Positive environmental impact, carbon cutting potential, and low Global Warming Potential, reduction of waste to landfill or incineration, alternative to fossil fuels	High costs of production and operations, inconsistent feedstock, low efficiencies, inadequate management and logistics, and lack of policy support	Low to medium

Table 2: *Comparison of the different pathways for hydrogen production*

6.2.3 Hydrogen transportation pathways

Any pathway for scaling-up of hydrogen consumption will require the development of an appropriate infrastructure for hydrogen transportation and distribution. Hydrogen can be transported in variety of different ways including

- gas pipelines
- marine terminals
- shipping
- truck loading
- rail transportation [144].

However, within these mechanisms there can be considerable differences in the mechanisms used to load, store and unload hydrogen.

Liquefied Transport Approach

Currently, liquefied natural gas (LNG) is transported using LNG tankers from the production zones. Gas unloading is performed using specially designed pipelines supporting low temperatures (-160°C) and cryogenic tanks for storage. Subsequently, LNG can be converted back to gas in facilities called LNG terminals. Similarly, hydrogen can be liquefied but a much lower temperature (−253°C) and stored in thermally insulated containers. Liquification of hydrogen comes with the benefit of reducing the storage volume, because the density increases by a factor of around 800. Existing LNG terminals could be adapted to enable hydrogen transportation and be multipurpose [148], [149].

Alternatively, hydrogen can be embedded in liquid organic hydrogen carriers to reduce the need for very low temperatures and pressurised tanks for storage and transport. Hydrogen can be transported and stored in liquid form are by combining it with CO_2 to produce methanol, and in the form of ammonia by combining it with nitrogen. In the latter case the liquefaction point is at around −30°C, a much higher temperature than the liquefication temperature of the pure hydrogen. Hydrogen can also be transported in gaseous form mixed with other gases in pressurised containers or transported and stored within the existing gas infrastructure when combined with CO_2 to produce methane gas.

The best delivery option for hydrogen depends on the distance to cover; if that is below 1,500 km the cheapest transport means is a gas pipeline, whereas above 1,500km a more cost-effective solution may be the shipping of hydrogen as ammonia or by using a liquid organic hydrogen carrier (LOHC). Moreover, for small or very small station sizes hydrogen's delivery (either as compressed gas or liquid) by means of trucks may be the most cost-effective solution. In [150] it was found that the compressed gas truck delivery is the preferred solution for very small station sizes of 500 kg/day or less, whereas liquid hydrogen truck delivery is most suitable for small station sizes, low market development levels, and low densities of population. Hydrogen transport using LOHC requires first a hydrogenation process, i.e. the hydrogen loading into the LOHC molecule to form a liquid (at ambient temperature) showing comparable properties as crude oil-based liquids (e.g. diesel, gasoline), and eventually (after the transportation) the de-hydrogenation process, which involves the unloading of hydrogen from the embedding liquid. Dehydrogenation requires elevated temperatures, which determine the consumption of a significant part of the transported energy (as much as 28% of it, corresponding to 11kWh/kg). For this reason, it is advantageous to locate LOCH preparation in places where there is availability of waste heat sources. Although more research on LOHC is necessary to obtain low-temperature de-hydrogenation combined with high storage densities and fast reaction kinetics, some promising LOHC candidates have already been identified. They are the dibenzyltoluene for energy-transport and energy-storage (good availability, non-toxic, easy to handle, energy demand is high though) and N-ethylcarbazole for mobility applications (particularly good process design and gas flow, but storage characteristics are less good). Moreover, other potentially good candidates are toluene for the transport sector (very good storage densities, moderate toxicity, and reasonable low price), and methanol for all three applications (excellent energy storage capability, low energy demand to release hydrogen from the loaded LOHC), but a compromise between de-hydrogenation temperature and gas flow must be achieved with further R&D work [151]. The costs of hydrogen transport are estimated to be between 0.11 and 0.21 €/kgH_2/1,000km when using a newly built transport infrastructure.

The blending of hydrogen into the existing gas pipelines poses several technological challenges related to measurements, energy conversion, process gas chromatographs, and gas metering. Furthermore, compressor stations used to compensate the pressure losses due to the friction of the transported gas along the pipeline are optimised only for the molar weight of a particular type of gas (natural gas). Manufactures of compressors determine the effect of hydrogen blending into existing gas pipelines. It is likely that a low hydrogen share (e.g., below 10%) only requires minor changes of existing compressors, whereas a share of more than 40% may determine the equipment replacement. In addition, some gas network operators consider 20% the upper bound to avoid the adaptation of the downstream users. To carry 100% hydrogen may be a better solution than blending more than 20% hydrogen in the natural gas [152]. Other system components such as gas turbines used to drive compressors, valves and connected underground storages might require modifications to work fine with hydrogen. The choice of a compression system for hydrogen is still an open research problem, which is currently being studied for values of pipeline length, operating pressure, and hydrogen flow-rates. It can be observed that for a given pipeline length and operating pressure, the number of compressor stages and/or the number of compressors required grows when the desired hydrogen flow rate increases, thereby allowing to effectively remove the heat generated in the compression process in each of the stages [153].

Regarding the blending of hydrogen in the existing infrastructure, it can be observed that the injection of 5%–15% of hydrogen by volume would not cause significant issues. Some issues must be addressed for hydrogen fractions in the range of 15%–50%. More than 50% hydrogen blending are likely to generate multiple issues related to inadequate pipeline materials, safety, and required modifications of end-use equipment [154]. In the case of a pipeline conversion into a dedicated hydrogen pipeline, the estimated conversion costs are between 0.2 and 0.6 million € per km, which approximatively corresponds to 10–35% of the costs required to build a new hydrogen pipeline [155].

The conversion process of an existing gas pipeline involves the assessment of the technical conditions of the pipeline, its cleaning, the integrity inspection of the existing pipelines and fittings, the installation of new compressors, turbines or motors for hydrogen compression, the achievement of proper tightness and sealing of system, the replacement of measuring equipment such as gas chromatographs [152].

If the pipeline to convert has already some fractures, the dynamical stress caused by internal pressure fluctuations may lead to an even faster crack growth when the pipeline is operated with hydrogen, because of hydrogen embrittlement phenomenon, that determines a loss of load bearing capability of the metal caused by its hydrogen absorption. Titanium and aluminium are valid alloys that can be used to prevent hydrogen embrittlement [156]. Also polymers are not affected by the embrittlement phenomenon [157]. Furthermore, the cracking effects apply mostly to cases where hydrogen is injected at high concentrations into existing pipelines. Different types of steel react in different ways to hydrogen; therefore, the negative effects should be assessed on a case-by-case basis. Some carbon steel pipelines transporting pure hydrogen have been tested and kept in operation for many years. Other metallic pipes, including ductile iron, cast and wrought iron, copper pipes show no hydrogen damage under the general operating conditions in natural gas distribution systems. Similarly, it can be verified that there are no aging effects related to hydrogen on polyethylene (PE) or polyvinylchloride (PVC) pipe materials [158]. Finally, it has been observed that replacing valves may be beneficial.

6.3 Skill development and training opportunities

The opportunities of training and skill development related to hydrogen are wide in Europe as well as in Ireland, ranging from academic degrees to more focused courses of short duration. The national association Hydrogen Ireland reports on its website multiple opportunities to develop skills related to hydrogen technology. The Dublin City University (DCU) has made available since 2020-21 undergraduate degrees and a Masters with updated modules on advanced sustainable energy systems that now include sustainable hydrogen among the topics. The company Energy CoOps Ireland and the Valentia Islands project want to support the DCU Masters offering field trips, guest speakers, shared research work and project supervision. The representative association for the Irish wind industry Wind Energy Ireland (WEI) is offering an introductive training to renewable energy developers, energy companies, transport companies and fleet owners to teach the hydrogen role in the energy transition, the technologies related to hydrogen storage and its use as an energy vector and fuel. The project HySkills is developing a modular training course on green hydrogen safety skills and a method for course accreditation to the benefit of future hydrogen workers. The project is also going to train vocational education teachers to ensure that they have the technical knowledge and the pedagogical skills to effectively teach in vocational courses about green hydrogen. The national engineering association Engineers Ireland is offering seminars on hydrogen and energy system decarbonisation. The green institute in Ireland is also offering a short training covering the supply chain aspects, the production methods, the storage and the challenges in hydrogen distribution.

6.4 Financing of hydrogen projects

In recent years, several projects in heavy industry have been successfully financed especially in the sectors of the heavy transport, mining and industrial production using green bonds and loans.

Bonds and loans offer both loans to borrowers and charge an interest for that. The borrower can borrow funds from the lender either by getting a loan or purchasing a bond and pays periodic interests over the period of the bond or loan term. When the bond or loan matures, the borrower repays the total principal amount plus any other interest payments due. With loans, the bank and other financial institutions are the lenders, whereas individuals or corporations are the borrowers. With bonds, the general public is the lender, whereas corporations and governments are borrowers [159].

Bonds are issued to large corporations or governmental entities and can be traded such that the lender can obtain their funds before reaching the maturity. A loan can be issued to anybody who can repay it. There is no market where to trade loans, however recently banks have been allowed to sell off a loan to other financial institutions.

The financing of green hydrogen pilot projects will require cataloguing and allocating of risks in a manner that is already familiar to project financiers, but it will also require the development of new tools, for example to classify hydrogen as a new asset as opposed to already existing assets [160].

It is foreseen that banks, financial institutions and project financers will be initially more confident in delivering bankable offtake schemes for those projects which are closer to the existing use of hydrogen, related to the production of ammonia for fertilizer and the refinement of gasoline and diesel fuel from crude oil. After these sectors, projects supporting hydrogen based vehicles utilising fuel cells to power diverse types of vehicles are envisaged as the next sectors to find financial confidence and attract attention.

Project financing decisions are significantly influenced by stable and long-term purchase agreements in place, the adoption of a reliable technology and the presence of an effective regulatory framework. Financial institutions typically assess the expected revenues which are needed to repay a green loan.

As the economics of green hydrogen change as the industry scales the cost differential between it and conventional hydrogen produced from fossil sources will reduce, which will ensure that commercial lenders are more incentivised in financing new development projects [161]. The International Renewable Energy Agency (IEA) and the World Economic Forum has recently set out 38 measures to cut the cost of green hydrogen in Europe and to promote an international market [162]. Financial institutions are also aware of the emerging use cases related to electricity generation, balancing of renewables fluctuations, new use cases for the de-carbonisation of industrial processes, industrial, residential, and commercial heating. They will assess market and offtake risks on a case-by-case basis, prioritising the support of those technologies which are considered more consolidated or present a lower development risk.

In some hydrogen sectors financial institutions have determined that the probability of sufficiently high revenues is high so that a long-term offtake commitment is not necessary. Hydrogen storage is one sector that is an exception though, since hydrogen storage projects can be seen as more attractive for investors in the long-term. This is due to storage being associated with generation assets that have the potential to produce a predictable long-term revenue stream based on applicable energy prices, which will effectively support a loan repayment. Moreover, as the costs for generating renewable energy are decrease this has the impact of making downstream on the costs of green hydrogen lower, and this will have a positive impact on storage costs as well [163]. In order to be successful in obtaining a loan, the project developers should prove that the expected cash-flow is enough stable to reduce the risk of not being able to return the project debt.

Bankability requirements are likely to be satisfied when a project demonstrates that either “green” or “blue” hydrogen will be used to replace an already existing supply of “grey” hydrogen for which there is a long-term, stable demand, and that the required infrastructure for production and/or distribution is available. Investors may very positively evaluate agreements with industrial customers, where hydrogen demand has already existed for a long-time. Additional sales arrangements with other sectors such as transport may further increase their trust and willingness to consider acceptable the project offtake risks [164].

6.5 Organisational aspects related to the development of a hydrogen economy

The development of the sustainable energy sector requires to synthesize multiple knowledge and data sources. Inter-organisational R&D collaborations are a valuable source of scientific and technical knowledge, whereas an integrated organisational approach based on the formation of alliances and the integration of sources is the most suitable to strengthen the connections between hydrogen knowledge-sharing networks and policymakers.

The cooperation of lower-level actors enables a multidisciplinary approach where the involvement of academic institutions and local energy companies enables the collection, organisation and processing of the information required to carry out the research activities on hydrogen. The connection between academic and industrial partners can be facilitated by a central entity acting as a system builder, because the actions of multiple and diverse actors involved in R&D and implementation projects often show misalignment with each other.

Successful R&D work balances exploitative and explorative actions in a way that determines technology maturation and demonstration of use cases of interest. System builders perform both exploitative and explorative work when connecting academic and industrial partners; universities and research centres usually contribute more to exploration, while energy companies contribute more to exploitation.

The actual contribution to either exploitation or exploration in the Power-to-X sector by university or industry will depend on the knowledge and capability to develop new solution which can be readily deployed to the market. Universities and other Research Performing Organisations (RPOs) have focused on new solutions which can improve process efficiency and are thus relatable to exploitation activities performed by commercial companies.

In contrast, industrial companies have been very active in researching and implementing new solution for carbon capture and are therefore active in exploration as well as exploitation activities in this area. Both exploitative and explorative knowledge transfer between universities and industry representatives is required to increase the pace of growth of the hydrogen economy [165].The different actors bring their different capabilities, roles, and motivations into a dynamic and adaptive system called "innovation ecosystem", a collaborative environment where to develop and drive the innovation process towards its success.

6.5.1 Universities and RPOs

In Ireland the NexSys (Next Generation Energy Systems) programme is performing a mix of basic research combined with industry informed applied research on a Net Zero Carbon Energy System by 2050 [166, 167]. Multiple Irish universities and research institutions as well as multiple industry partners are participating in the program, coordinated by the UCD Energy Institute.

The HyLIGHT programme (Leading Ireland's Green Hydrogen Transition) is involving 25 industry partners collaborating with the leading Irish universities and stakeholders to facilitate the delivery of hydrogen to heat, transport, electricity and industry sectors, considering safety and cost-related aspects for energy consumers and industry [168]. HyLIGHT will end in June 2024.

6.5.2 Industry associations

Hydrogen associations are prominent players, that may perform tasks of primary importance for the development of the hydrogen economy.

The Hydrogen Ireland association[1] promotes the adoption of hydrogen and fuel cells as key assets of the future low carbon energy system on the island of Ireland and has provided detailed feedback to this report by answering the questionnaire provided by the call for evidence.

Hydrogen Europe Research (HER) is an international non–profit association active in the sectors of hydrogen and fuel cell which groups together 91 universities as well as Research & Technology Organisations (RTO) from 26 European countries and beyond. The association participates in the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), along with Hydrogen Europe (which focuses on industry applications), the European Clean Hydrogen Alliance (ECHA) and the European Commission. These public-private partnerships support Research, Technological development, and Demonstration (RTD) activities in fuel cell and hydrogen technologies across Europe. The three pillars of the JU are Hydrogen production, Hydrogen storage, transport and distribution, hydrogen end-uses. More recently HER has joined the Institutionalised European Partnership (IEP) entitled Clean Hydrogen Joint Undertaking, that will run from 2021 to 2027. HER members take part in the different Technical Committees and roadmaps to discuss annual strategic priorities as well as to draft the topics for future Calls for proposals.

1 https://hydrogenireland.org/

6.6 Hydrogen markets

The primary energy commodities globally traded are oil and natural gas, which enjoy regulations, infrastructure, trading platforms, multiple suppliers and customers. Over time, the markets of hydrogen and hydrogen derivatives are likely to emerge with a similar structure.

The main market for hydrogen is related to grey hydrogen usage in industry as a chemical product, with refineries and ammonia production plants consuming 80% if global hydrogen production. It is anticipated that this market for hydrogen will expand further over the coming decades.

Global hydrogen production was 61 Mt per year in 2015, with the 96% of production being derived fromfossil sources with natural or refinery gas reforming, chemical processing, or coal gasification, representing 48%, 30% and 18% respectively of total production [169].

The global natural gas production used for hydrogen is 6% whereas 2% of global coal production is used for hydrogen production annually. Production of about 70 Mt of grey hydrogen per annum results in atmospheric emissions of about 830 Mt of carbon dioxide [170]. The global hydrogen production from electrolysis was only the 4% in 2015. Therefore, it can be seen that the production of hydrogen for existing industrial uses is already a very significant GHG producers with the potential expansion of the use of green hydrogen presenting a large opportunity for global decarbonisation. In most jurisdictions, under current market and policy arrangements, green or blue hydrogen will enter this market as soon as their selling price equals the price of grey hydrogen. The success of green hydrogen in the industrial sector produced via electrolysis with respect to the well-established SMR is related to the following factors:

- The cost of energy from renewable sources for electricity production
- The wholesale cost of natural gas
- Carbon tax

Hydrogen production cost using electrolysis could be achieved at a cost lower than 2$/kg of hydrogen, if the cost of renewable energy decreases further on the proviso that load factors are sufficiently profitable [171].

The development of other markets is likely to be more dependent on the energy-related policies that may foster or delay hydrogen's large-scale deployment. Multi-regional assessment of hydrogen market penetration has shown different energy contexts and challenges arising under different circumstances. A thoroughly developed market should include multiple options for procurement, pricing and volume control means using set tariffs and auctions, as well as quotas and incentives to determine demand creation and market balancing [172, 173].

Responses to the call for evidence believe that it is critical to ensure that the green hydrogen market should quickly scale in order to increase the volumes in the market to support lowering the cost of hydrogen until green hydrogen production costs will match fossil fuels plus carbon prices. A potential road map for the development of hydrogen markets is presented in the following sections and is segmented into three phases [174]:

- Kick-start phase
- Ramp-up phase
- Growth phase

6.6.1 Kick Start Phase of the Hydrogen Market Development

Stakeholders stated their belief that a kick-start phase will be required which will run from 2021 to 2025 and will enable to increase the hydrogen production up to 1 million ton of clean hydrogen per annum using at least 6 GW of electrolyser capacity [175].

The kick-start phase should be driven either by a set production tariff mechanism or auctions, or a combination of the two. The auctions are procurement schemes that use competitive tendering to determine the tariff, whereas a set production tariff is a scheme that guarantees the potential producers would receive a fixed tariff, which may be indexed to compensate for inflation.

Auctions may also be used to trade the emissions that green hydrogen could avoid with respect to grey hydrogen. With this scheme, producers would receive a premium as set by the auctions for each tonne of CO_2 avoided, which is added to the revenues from selling hydrogen.

In the Netherlands, green hydrogen is subsidised up to USD 300/tCO_2 (about USD 3/kgH_2) using the national auctions scheme for CO_2 reduction. Moreover, if taxes and levies are applied to grey hydrogen, and adequate support is provided for green hydrogen, the cost-gap between the two is reduced and the purchase of green hydrogen is incentivised. Carbon taxes on the GHG emissions associated with grey or blue hydrogen production could be used for example. As for the blue hydrogen, even if most of the CO_2 emitted would be stored when producing it, regulations regarding who would sustain the responsibility for the CO_2 and the cost of storage does not exist yet [176]. Using these mechanisms, it is believed that the cost of grey hydrogen can be increased of 20-40% [175, 177]. Grey hydrogen is already subject to the carbon tax in France, which was introduced in 2020 and will be further increased through 2030 [178].

6.6.2 Ramp-up Phase of the Hydrogen Market Development

The kick-start phase will be followed by a ramp-up phase, running from 2025 to 2035 and should result in achieve commercial competitiveness of green hydrogen through large scale storage and infrastructure, as well as appropriate regulatory measures to stimulate supply and demand. The regulatory support required for the ramp-up phase includes investment support, tariffs, auctions and tenders, guarantees of origin, quotas, tax relief. Also, legislation and regulatory obstacles should be removed by this stage. One example is the Renewable Energy Directive, which limited the use of renewable electricity for hydrogen production and therefore is being revised.

In July 2021 the European Commission published a proposal to revise the Directive which fosters the utilisation of renewable hydrogen in those sectors considered hard to decarbonise such as the transport and industry sectors and provides an extension to the certification and traceability rules applicable to renewable fuels in all sectors [179]. Under this proposal EU Member states will have to ensure that 50% of the industry's hydrogen demand is supplied by green hydrogen (the Directive refers to a renewable fuel of non-biological origin) while imposing tight limitations to the definition of "green" hydrogen. The prescription of using at least 50% of green hydrogen will apply to all the industry sectors including iron and steel, aluminium, chemicals, fertilizer (including ammonia) and cement [180].

6.6.3 Growth Phase of the Hydrogen Market Development

After that hydrogen has reached commercial competitiveness with the ramp-up phase, there will be a market growth phase from 2035 to 2050, characterized by price determined by demand and supply equilibrium and support mechanisms different on those of the ramp-up phase, such as those required to avoid monopoly [181]. The hydrogen infrastructure will be expanded with a large part of the natural gas pipelines converted in hydrogen pipelines and a better integration of the whole European hydrogen system [182].

Another measure that could foster the hydrogen market growth are the Guarantees of Origin (GOs) certificates. If this measure were applied to the hydrogen sector under the current regulatory framework, hydrogen producers could connect an electrolyser to the electricity grid, to purchase energy from the local electricity mix including electricity produced using non-renewable fuels; they could then purchase GOs to sell their hydrogen as "green" to their clients. There is a risk that the internal market for hydrogen would get distorted because the two types of hydrogen, respectively produced using electricity from additional renewable electricity capacity and produced using exclusively the local electricity and labelled "green" using cheap GOs, would be both traded as green hydrogen. However, this risk should be considered within the context of decarbonising the entire energy system rather than ensuring that the hydrogen system is as "green" or carbon free as possible.

In the mobility sector the creation of a hydrogen market is a likely possibility, and it may present an opportunity to raise appropriate tax revenue in for some countries in the medium to long-term. Appropriate political decisions are needed to trigger investments such that uncertainties and the risk perception can be managed. The development of the mobility market is more favourable in countries where the competitor (such as the gasoline) is penalized by high taxes and there is a clear roadmap for hydrogen including support schemes. With regards to hydrogen-based fuels, it is likely that in some countries they will not be able to enter the market segment profitably, because of limitations in the regulatory framework in providing ground for the classification of such fuels as advanced ones. Finally, the injection of hydrogen into natural gas networks exhibits very low market entry costs, which can be as low as 2.3$/kg and are hard to achieve [183].

6.7 Regulatory framework and changes

In the context of climate change and geo-political changes across the globe, EU countries are committing, to varying degrees, to the development of a hydrogen economy. In spite of these commitments there are still barriers that are hampering of hydrogen in industry, chief among these are direct fiscal benefits [184].

In 2018 Backer McKenzie conducted a survey revealing that 77% of respondents from the industry considered the legal and regulatory frameworks related to hydrogen inadequate [175]. In many cases, these barriers are still in place today and should be removed by policymakers to enable the development of a hydrogen economy.

6.7.1 Lack of origin guarantees

The lack of origin guarantees for hydrogen makes impossible a distinction between types of hydrogen based on greenhouse gas emissions associated to its production process.

6.7.2 Unclear power-to-hydrogen legal status

"Power-to-hydrogen" plants or storage systems have an unclear legal status, and this can prevent appropriate economic rewards.

6.7.3 Safety regulations

Safety regulations are in many cases deemed unclear or incomplete.

6.7.4 Funding rules

Funding rules are considered inconsistent or limited. There is the fear that government might discriminate against some technologies because of superficial or incomplete information [175].

6.7.5 Additionality and the EU Renewable Energy Directive II (REDII)

The EU Renewable Energy Directive II (REDII) is perhaps the regulation that is generating most of the uncertainties and doubts related to green hydrogen production from renewables. In order to comply with the directive, a hydrogen producer needs to prove that electricity used to supply their electrolysers is produced exclusively from renewable sources, either using on-site electricity renewable production or grid purchase. In the latter case, the utilisation of the renewable electricity can be claimed only once.

In relation to green hydrogen production, the European Commission is also working on a methodology to formalise the concept of additionality. Additionality means new renewable power generation is built for new hydrogen projects. The delegated act allows for a phase-in period of stricter rules until 2026, from which time only new unsubsidized wind and solar farms can be used to make green hydrogen. This means that the renewable electricity generation used to supply the electrolysers to produce green hydrogen is additional to the renewable electricity generators is used to meet the target of final electricity consumption from renewables. The objective there would be to ensure that the renewable electricity generation used to supply electrolysers should come entirely from renewables power plants of recent construction, which would otherwise not have been installed to produce renewable electricity to decarbonisation the electricity system.

The association Hydrogen Europe has expressed some concerns regarding the practical implementation of the additionality principle. Although beyond the scope of the REDII, the lack of regulatory clarity could have a negative impact on the deployment of renewable hydrogen even hindering the targets set by the EU Hydrogen strategy and the long-term EU climate goals.

One of the main concerns is that, if the additionally principle is strictly enforced, electrolyser project developers would have a very low incentive to build until new electricity capacity is not made available yet. Moreover, the lead time for investments into some renewable electricity generation assets may be longer than the time needed to build an electrolyser (respectively up to 7 years and less than 2 years) [185].

Fulfilment of Additionality

Two important indicators can be used to assess the fulfilment of the requirement of additionality:

- Direct consumption by the electrolysers or the renewable electricity generated to produce hydrogen.
- Temporal and geographical correlations between renewable electricity generation.

Temporal correlation means that electricity generated using renewable power plants equals the electricity used to produce hydrogen in the considered time interval. Geographical correlation means that that electricity generated using renewable power plants, matches the electricity used to produce hydrogen within a certain geographical proximity based on the electrical network topology.

The current regulatory framework is not satisfactory regarding the definition of the time interval to be used for evaluating the temporal correlation and the way to be used to define geographical proximity.

If the time interval used to evaluate time correlation is very short, then electricity production from renewables and consumption from the electrolysers will need to occur nearly simultaneously with the advantage of guaranteeing that the consumption of the electrolysers is fully supplied at any time instant by the additional renewables. The big disadvantage of this choice is that it would either pose a limitation on the utilisation factor of the electrolysers, increasing costs, or require greater capacity of renewables-based electricity generation to allow the electrolysers to operate at their optimal utilisation rates also increasing costs.

Conversely, a long correlation interval would allow to operate the electrolysers at higher utilisation factors, that way avoiding the need for installing a much larger capacity of renewable generation using renewables. The disadvantage of choosing a large time interval to evaluate correlation, is that electrolysers could potentially be supplied with electricity for a greater proportion of time by a generation mix of non-renewable technologies, which may include also a significant fraction of fossil fuelled power plants. However, it should be noted as the electrical system moves to higher penetration levels of renewable generation this is likely to become less of an issue.

Even more challenging is to define detailed requirements for geographical correlation. There is currently no legislation, which defines this requirement. The existence of a physical link between the renewable power plant and electrolysers, would immediately prove the full geographical correlation. However, this exacting requirement may unnecessarily increase costs as a commercial arrangement, utilising existing power system infrastructure to electrically link the electrolyser to the renewable generation would, if correctly formulated, would provide similar carbon reduction benefits [186, 187].

Other issues

The current definitions associated with additionality do not appear to provide incentives to develop electrolysers system to enable the provision of grid balancing and flexibility services. Furthermore, the additionality criteria appears to hinder the use of curtailed renewable electricity generation to produce hydrogen. This is hugely significant in the Irish context as the target for renewable electricity generation (80% by 2030) will require significant over installation of renewable generation, which will entail significant periods where renewable generators will be curtailed. Therefore, efforts to hinder the use of curtailed renewable electricity generation are likely to increase costs of overall energy system (electricity + hydrogen) decarbonisation.

6.7.6 Authorisation

The authorisation process for hydrogen production is long and costly, therefore small-scale, localised production is significantly hindered by the existing legal and administrative barriers. A similar comment also applies to the hydrogen refuelling stations.

6.7.7 Future Developments

It should be noted, that a number of new hydrogen technologies have emerged as early as 2020, while a developed hydrogen economy is not expected to begin to emerge until 2030. Other technologies will emerge later, before 2050, such as cost-effective fuel cells cars and some technologies used in industry for iron smelting. In [188] the inclusion of hydrogen technologies and systems in energy system models was considered still difficult due to the uncertainty and complexity associated with the hydrogen value chain.

The European Commission has a plan to deploy green hydrogen technologies at large scale between 2030 and 2050, reaching all the sectors where other alternatives might not be feasible or have higher costs. To reach this goal, regulatory changes and updates will be evaluated, including a revised state aid framework, new incentives in the Emission Trading Scheme, introduction of quotas for green hydrogen to drive demand, a certification scheme for hydrogen technologies, facilitation of access to energy infrastructure, such that the supply and the demand can be better connected to each other [189].

Regulatory changes will also be implemented through the EU Green Deal Recovery package, which will aim at offering a stable revenue to the users of green hydrogen [183]. The recovery package will provide the adoption of a contract for difference (CFD) system for carbon for green hydrogen projects which will be used to reduce the financial risk associated with these investments.

A CFD is an agreement between two parties whereby one party agrees to pay the other party the difference between the market price of a commodity at a point in time and the strike price which was agreed when the CFD was signed [190 - 191]. Green hydrogen users bid the strike price at which they can reduce carbon emissions by a ton with their project, still obtaining a return. If the carbon market price goes above that strike price, they would pay back the difference to EU. If the carbon price fell below that level, the EU would pay the difference [183]. Furthermore, the draft of Green Deal Recovery package also supports efforts to reduce costs of electrolysers.

The call for evidence provided more information about the possible developments of the Irish regulatory framework and gathered stakeholders' inputs for a national policy (section 1) as well as information on several technical aspects related to hydrogen production (section 2), transportation and distribution (section 3), consumption (section 4), which have highlighted current gaps in the regulatory framework and clarify the needs for updates to it.

7. Hydrogen Competing Technologies for decarbonisation of society

7.1 Fuel cells electric vehicles and battery electric vehicles

The two main technologies currently available to supply power to all-electric vehicles are the fuel cells and electro-chemical batteries. Fuel cells convert the hydrogen stored in the vehicle into electrical energy, whereas batteries store electrical energy drawn from the electrical grid. Both technologies can be zero carbon fuels, because hydrogen and electricity can be produced using low- or zero-carbon sources including renewables, nuclear energy or fossil fuels with carbon capture and storage (CCS).

In some respects, these approaches to decarbonisation of the transport sector are complimentary, in other respects they are competing technologies. Although the amount of energy required to manufacture a compressed hydrogen storage cylinder is lower than the energy required to work the materials storing energy in a battery such as electrode paste, electrolyte, and separator (per unit of stored energy), lithium-ion batteries are energetically more efficient when considering jointly the overall system operation and its manufacture. This is due to their higher overall energy efficiency (which is 0.83 versus around 0.30 for a fuel cell based system) [192].

Fuel cells electric vehicles (FCEV) are lighter than battery electric vehicles (BEV) for a given range since the compressed hydrogen powering a fuel cell can supply five times more energy per unit mass than NiMH batteries used in most fossil fuelled based hybrid electric vehicles (HEVs) and twice that of more advanced Lithium-ion batteries used in battery electric vehicles (BEVs) [193]. The weight of both FCEVs and BEVs are related to the range capability of the vehicles. However, the weight of an FCEV grows more slowly than a BEV. For example, a BEV, with current battery technology, with a 320 km range is typically 30% heavier than a FCEV with a comparable range, whereas a 480 km BEV is more than 70% heavier than a comparable FCEV [194].

A comparison of different battery technologies against fuel cell technology is presented in Fig 2.

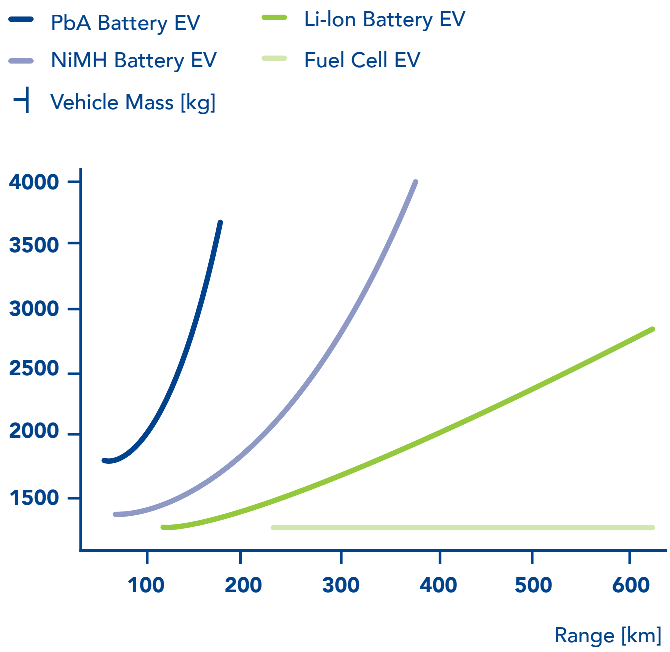

Figure 8: *Mass of an electric vehicle as a function of the range and of the battery or fuel cell technology [195]*

For existing battery technologies the mass of the vehicle is highly correlated with vehicle range. Lithium-ion batteries achieve the best performance and are by far the most common battery technology type used in BEVs. In contrast, the mass of a FCEV is almost independent on its range.

Several studies have determined that BEV are 1.25–3.9-times more energy efficient than FCEV when considering the overall transmission, distribution, and conversion of chemical/electro-electrical energy in to motive power from the primary source of energy e.g. the renewable generator also known as the wheel-to-wheel efficiency [195]. The factors that impact on efficiency are the site of hydrogen production (whether transport is required or not) and the primary energy source used.

Regarding the refuelling time, the performances of 140 FCEVs were monitored by the National Renewable Energy Laboratory (NREL) for several years, and it was found that the average refuelling time time was 3.3 min, which is typically far lower than charging batteries for an all-electric vehicle [196].

FCEVs are seen by many as a more appealing alternative to BEV if the production costs of green hydrogen rapidly decrease due to the similarity in the experience with the existing fossil fuel based solutions. In the future, it is anticipated that a diverse mix of battery and fuel-cell vehicles are likely to co-exist since Lithium-ion batteries also have the excellent technical features for some specific electric mobility applications and because the hydrogen refuelling infrastructure is more complex to deploy than charging stations for BEV [196]. However, considerable challenges remain with some authors maintaining that the developments in charging and battery technology is making the advantages of hydrogen irrelevant for transport [197]. In the UK, work commissioned by Chief Scientific Advisor at the UK's Department for Transport (DfT) inform DfT policy, produced a semi-quantitative study [198] of energy and transport system analysis for UK road freight focused on a comparison between electrification and hydrogen for road freight. The report concluded that considering the whole system challenges hydrogen requires more research into a number of areas and comparatively higher barriers to be overcome than an electricity based system.

7.2 Hydrogen boilers and heat pumps for domestic heating

Electric heat pumps are the main competing technology of hydrogen for decarbonisation of domestic heating. [199] They are a zero-carbon emission system if their electrical supply is generated using renewables.

The UK is continuing to increase the number of installations with a target of 600,000 new heat pumps installations per annum in 2028. Heat pumps, depending on the Coefficient of Performance (COP) of the installation, can provide two to three times the electrical input energy in thermal heating capability to the house. However, the running costs are currently not necessarily lower than gas fired boilers as electricity is typically significantly more expensive per kWh than natural gas. In existing homes featuring natural gas or oil fired boilers installing heat pumps can be expensive as the fabric of the existing houses may need to be significantly upgraded to make a heat pump installation practical as the heat output from these devices is low grade (low temperature. Furthermore, peak heat and thus electricity demands from heat pumps are typically coincident with electrical system peaks (winter peak during cold spells) in climates such as Ireland's thus increasing the requirements on the electrical power system, both transmission and distribution, during these periods.

Hydrogen based residential heat systems have a number of potential advantages to provide low carbon heating systems [200]:

- Hydrogen based boilers produce higher-grade heat than what is possible from heat pumps potentially enabling houses with lower building energy ratings to decarbonise without substantial building fabric upgrades. On the other hand, heat pumps produce heat at a temperature of around 35°C, often requiring the replacement of the traditional radiators with relatively small surface area with larger radiators or a network of under floor heating, in order to effectively distribute. Moreover, heat pumps require homes to be significantly better insulated as the rate of heat loss in a poorly insulated home makes it impractical to use a heat pump to provide enough heat input into the house thus necessitating the use of more conventional 70°C heating systems [201]
- Hydrogen can potentially be transported using the same infrastructure as natural gas today
- As hydrogen is not provided via the electrical power system the issues associated with peak heating load coinciding with peak electrical power system load are largely avoided.

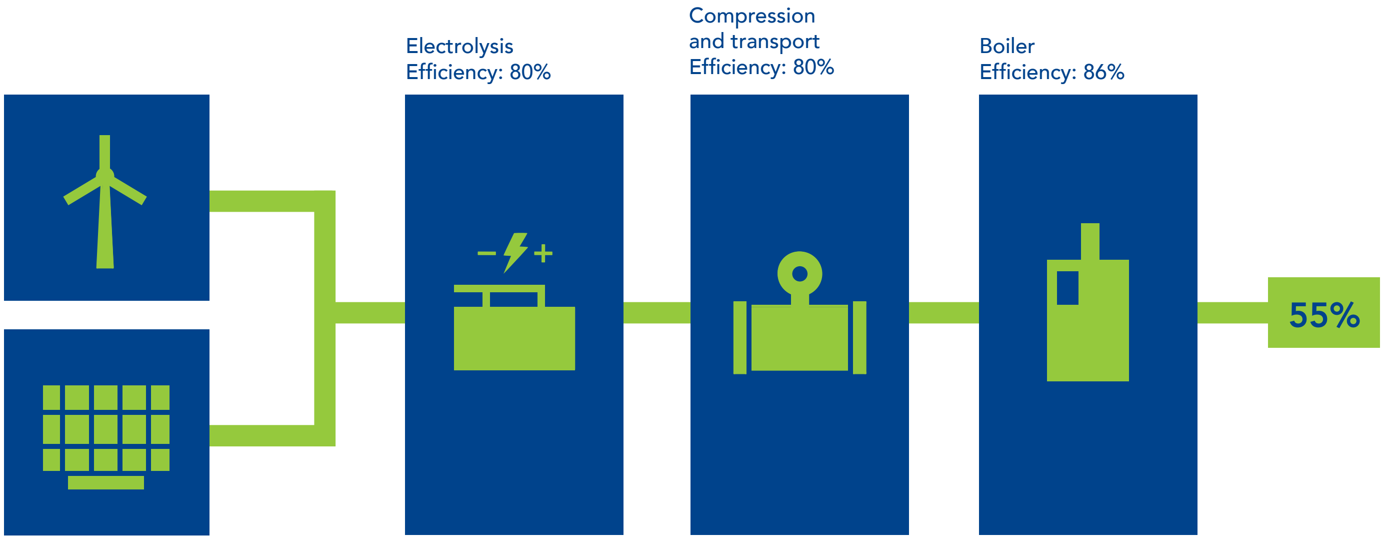

Figure 9: *Efficiency of a green hydrogen boiler based domestic heating system*

However, the efficiency of a green hydrogen based domestic heating systems considering the entire supply chain from production of green hydrogen to the provision of heat in a home is poor in comparison with what can be achieved with a heat pump-based system. This is illustrated in (Figure 3) which illustrates the efficiencies of the supply chain associated with a green hydrogen based residential heating. The system consists of renewable electrical energy generation, electrolysis, the compression, storage and transport and then a boiler that converts hydrogen into heat energy. The overall efficiency of this system has been estimated to be 55%.

In contrast the efficiency of a heat pump based residential heat system can be estimated and expressed as 250% or higher (Fig.4) when considering the input electricity and thermal output of the heat pump.

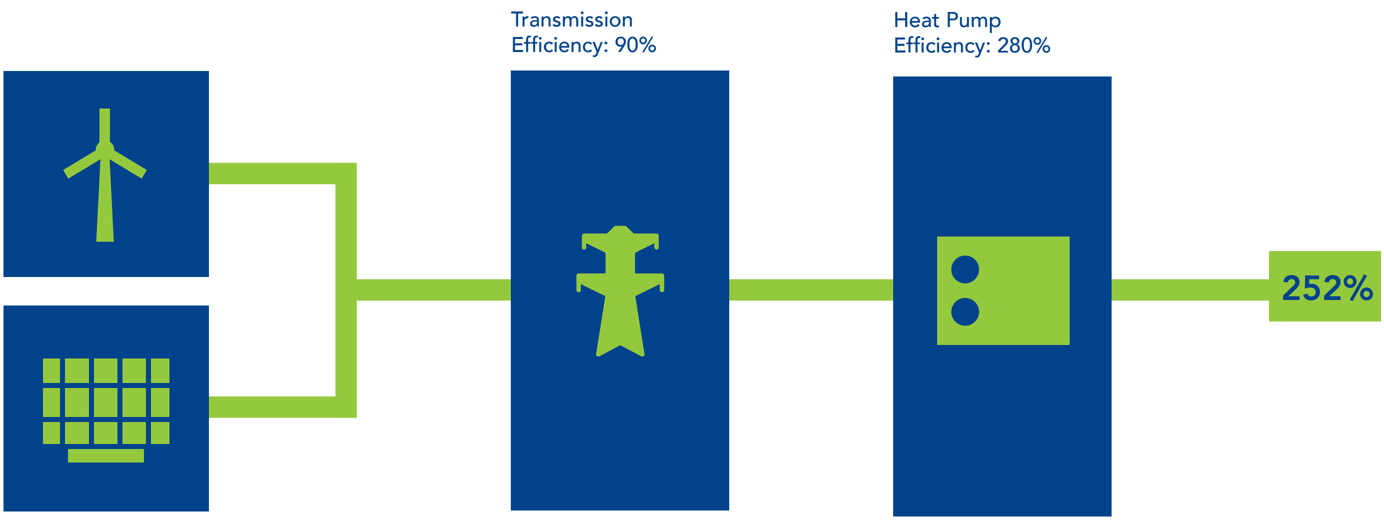

Figure 10: *Efficiency of a heat pump system supplied by renewable energy*

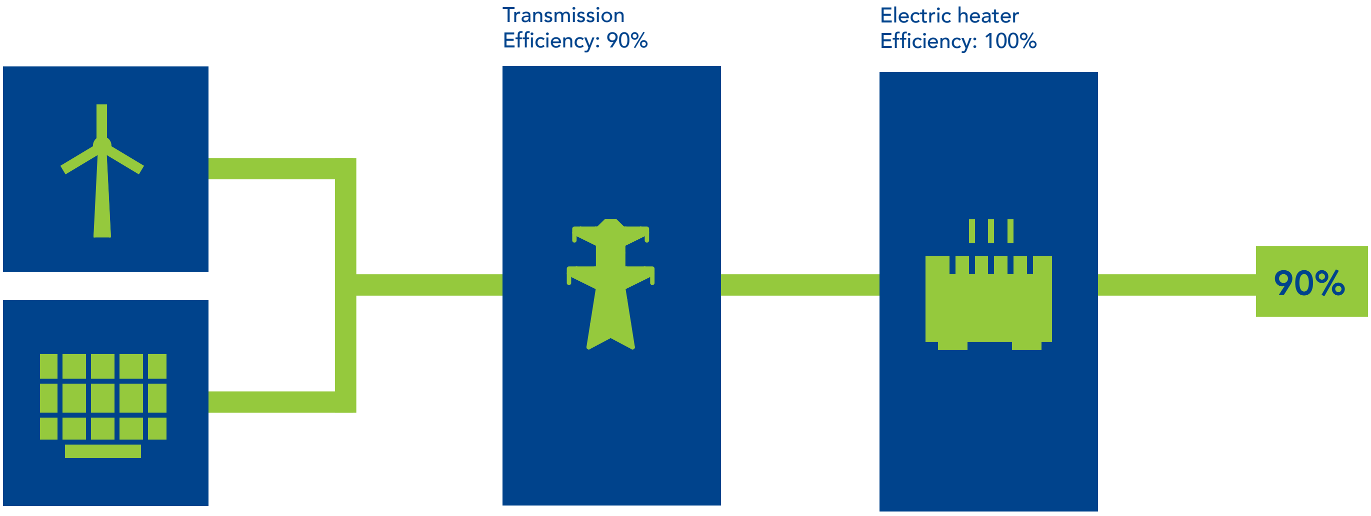

Figure 11: *Efficiency of an electric heating system supplied by renewable energy*

It should be noted that that the effective efficiency of a green hydrogen boiler based residential heat system is 4 to 6 times lower than a heat pump based system in utilising renewable electricity to generate heat in homes.

Another renewables based residential heat option is direct electric heating using electric power from renewables (Fig. 5) which is also an option where heat pumps may not be an appropriate option for example in existing apartments. These systems could potentially be coupled with thermal storage to provide flexibility and enable the use of electricity during off-peak or maybe high renewable energy production periods [202].

A further option, consisting of a combination of heat pump and hydrogen boiler technology, uses a heat pump as the main heat supply unit and the hydrogen boiler the auxiliary one to be used in the coldest days. This system alleviates some of the potential pressure put on the distribution system during peak days by utilising hydrogen to provide additional capacity and also enables the utilisation of the high effective efficiency of heat pumps. These systems are likely to be capital intensive and also are very complex.

A hydrogen transmission network could be used as energy carrier to transport energy as an alternative to the traditional electrical grid. This is depicted in Fig. 6.

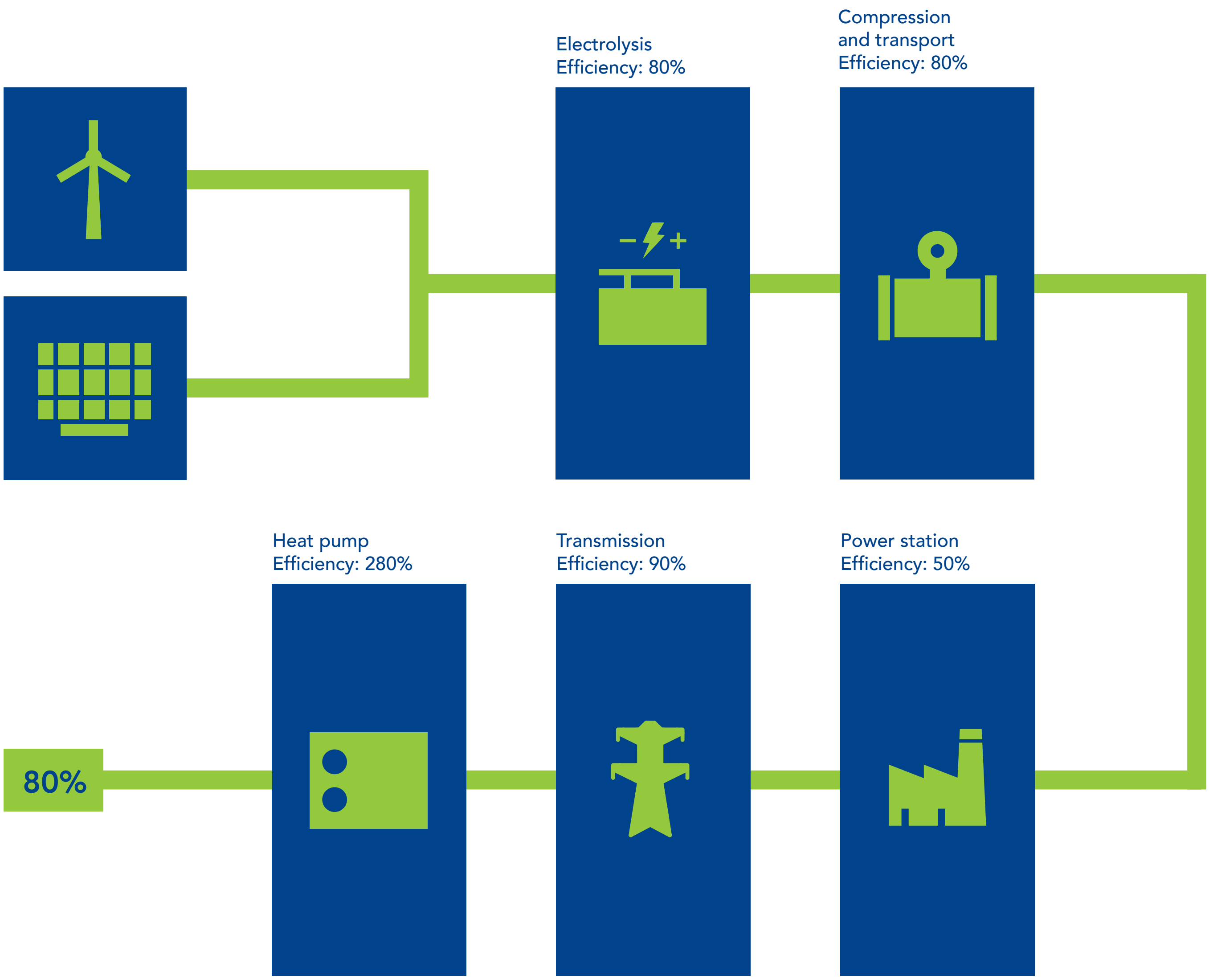

Figure 12: *Efficiency of a heat pump system supplied through a hydrogen power station using green hydrogen*

In this case the total efficiency of the system including a heat pump drops to 80% because of the efficiency losses of electrolysis, hydrogen transmission and distribution system and the power station efficiency compared to the case where only the electric network as illustrated in Fig. 4. However, the possibility of using either hydrogen or electricity to transport energy adds flexibility to the entire system and the mix of different technologies has the potential to enhance the security of supply.

A variation on this model would see hydrogen almost completely the electrical distribution system by a hydrogen connection and a home fuel cell which can produce electricity and heat. In this model, hydrogen, solar and wind energy could be used to supply the residential load and an electric vehicle charge point, while an energy management algorithm determines the economic load sharing between the supply sources, the efficient and safe operation of the fuel cell, and the reduction of fuel consumption with a negligible effect on the user comfort level [203].

A thorough comparison of low carbon residential heating options should take into consideration life cycle costs including the environmental costs.

- Heat pumps produce emissions of sulphur oxide compounds (SOx) even higher than natural gas fired boilers [204].
- The manufacturing impact of a heat pump is higher than the manufacturing impact of a gas boiler. More energy is required with respect to a gas boiler, to transform raw materials into components (compressor, external and internal fans, batteries, damping, connections, etc), to assembly components and eventually to dismantle and recycle metals, refrigerant, and oil [204]. This also applies to the new hydrogen fuelled boilers, because they require a manufacturing process rather similar to natural gas fired boilers.
- Heat pumps will have lower operational costs than hydrogen boilers, capital costs and environmental costs are higher in the investment stage [205]. This is likely to change as the electricity grid moves to 100% renewable production, and manufacturing innovations will simplify the heat pumps manufacturing process.
- Environmental emissions of heat pumps should consider the direct refrigerant emission which occur throughout the whole equipment lifetime due to the non-hermetic sealing of the system, the end-of-life disposal losses and the failure losses (which rarely occur) [206]. Some refrigerants used in heat pumps have high global warming potentials (GWP), such as the R245fa and the R134a. Recently alternatives with lower GWP to these two refrigerants have been found, they are respectively R1234ze(Z) and R1234ze(E) [207- 208].
- While there are a number of pilot programmes which have evaluated the potential of hydrogen based residential heating systems the technology is not mature, in contrast to heat pumps, the real world costs are unknown, green hydrogen is still very expensive and the health and safety implications of the large-scale deployment of this technology in domestic settings are not yet known.

In the UK, policymakers are anticipating that that the market will support a mix of heat pumps and decarbonised gas-fired heating replacing the current fossil fuel methane. The UK strategy has set the 2026 as the year for taking a decision about utilization of hydrogen in heating after the neighbourhood level trials in 2023 and the village level trials in 2025 are evaluated [209].

7.3 Competing technologies for large-scale energy storage

Increasing diffusion of renewable power plants, which are not controllable energy sources are determining a more important weight given to energy storage in the future power system. Energy storage technologies are a way to circumvent the fact that renewable energy production does not follow the desired consumption pattern and enables to reshape the consumption pattern to harvest more renewable energy. Different technologies are emerging, being placed side by side with the already well-established ones. Among the novel energy storage means that will be competitors of hydrogen storage, there are: pumped hydro energy storage, gravity-based energy storage, liquid air energy storage, compressed air energy storage, flow batteries energy storage [210].

7.3.1 Pumped Hydro Energy Storage (PHES)

Pumped Hydro Energy Storage (PHES) is based on moving water between low and high reservoirs, from which the water descends to generate electric power, when there is demand and pumps water back up to the higher reservoir when there is a surfeit of generation typically. The main advantages of pumped hydro have been the relatively low cost of the storage and the potential for large capacity compared to even largest batteries currently available on the market. In the US, pumped hydro still provides about 95 percent of grid storage. The Electric Power Research Institute (EPRI) reported that pumped hydro covers around 127 GW bulk energy storage, more than 99% of worldwide capacity [211]. The main challenge to pumped hydro is the difficulty in finding and developing suitable new sites for pumped-hydro storage.

New projects focussing on isolated reservoirs, that preserve existing river ecosystems will find permissions more straightforward however, development time and costs will be high. In contrast, projects utilising existing river systems are likely to face lower costs but with significantly more challenging circumstances with respect to planning and damage to ecosystems.

Pumped hydro energy storage has an efficiency variable between 70% and 80% with capability of reaching the 87%. Most common pumped-hydro plants for energy storage have a size in the range of 1000 - 1500 MW, however the largest plants are in the range 2000 – 3000 MW with individual turbines sizes of 300 – 400 MW [212].

An innovative evolution of PHES is the Gravity-Based Energy Storage (GBES) which uses gravitational potential energy to store energy, similarly to PHES. The storage system includes a container filled with water, a large piston, and a return pipe [213]. The water flow from the container into and out of the return pipe is controlled by a valve. When energy is stored into the system, the water is pumped such that it flows through the return pipe causing the piston to move upward and store energy. When energy is released, the downward motion of the piston forces the water to flow through a turbine driving a generator to produce energy. The efficiency of this GBES system is more than 80% and it can be used to generate significant amounts of power in the MW range.

A variant of GBES has been proposed by the start-up company Energy Vault. Instead of using a piston whose position changes because of the water flow, they designed a prototype that is using a six-armed robotic crane to stack monoliths into a tower to store energy and drop them down again when energy release is needed.

PHES are likely to be a significant part of the additional energy storage requirements of future power systems however their growth is likely to be challenged by a lack of cost-effective sites, ecological and environmental concerns and huge costs for GW level facilities

7.3.2 Compressed Air Energy Storage (CAES)

Compressed Air Energy Storage (CAES) is another promising means to deal with load levelling and following, power balancing and peak shaving, which is cost effective if employed at large scales. Air can be compressed and pumped into a suitable natural underground formation (such as salt domes or caverns) and released when electric power is needed. Alternatively, the compressed air can be stored in above ground in pressurised steel tanks, although with significantly higher costs. Excess electricity can be converted into compressed air. When used at large scale, CAES is much more cost effective than batteries and is particularly suitable for a long duration energy market required for global electrical grid decarbonisation, having a life of more than 50 years.

A Canadian company called Hydrostor [214] has built caves or used existing ones and uses water to maintain pressure to store energy by means of compressed air using mature technologies available from industry [215].

For CAES to be cost effective underground formations for storage are likely to be required. Several candidate methods for using underground formations for CAES including salt caverns CAES storage and are relatively common in Ireland [216]. Round-trip efficiency of CAES is less than some other technologies such as PHES but likely to be higher than hydrogen. As salt caverns are likely location for CAES it should be noted that this could be in competition with hydrogen which offers similar round-trip efficiencies but much higher energy densities [217].

7.3.3 Liquid Air Energy Storage (LAES)

An alternative to CAES is the Liquid Air Energy Storage (LAES) that is currently considered a good candidate for bulk storage of electrical energy, especially in the UK. Liquid air has a higher energy density than compressed air and can be more compactly stored. It only needs a well-insulated container to be stored, which can be installed almost anywhere. A pressurised vessel is not needed to store liquid air.

LAES is currently developed by the start-up company Highview Power, which has adopted above-ground tanks as well as other equipment form established industries for compression and power generation. Air cooled down to -196°C becomes liquid and can be stored in insulated vessels at low pressure. Re-gasification happens at ambient temperature and determines a rapid expansion in volume (700-fold), such that air can directly be used to drive a turbine and generate electricity without the need of combustion. The technology has been demonstrated in large-scale plants.

LAES systems have advantages over PHES and CAES systems in that they are less geographically limited in terms of their location. System efficiencies typically tend to be lower than these other two technologies however system efficiencies can be improved by co-locating the systems with other systems such as Liquefied Natural Gas (LNG) regasification processes. This is due to the poor efficiency of the liquefaction stage of the system. However, baseline studies indicate that an efficiency of 60% is possible [218].

7.3.4 Hybrid energy storage systems (CAES and LAES)

A hybrid energy storage system combining CAES and LAES has been proposed to benefit from the distinctive characteristics of CAES and LAES. In fact, the CAES has a higher roundtrip efficiency than LAES, whereas LAES has a lower cost per unit of energy storage capacity than CAES. This way, the low frequency power fluctuations which apply to substantial amounts of energy stored determine the conversion between compressed and liquid air and vice-versa, whereas higher frequency fluctuations determine only variations of smaller quantities of energy stored in the CAES system [219].

7.3.5 Redox Flow Batteries (RFBs)

Redox Flow Batteries (RFBs) are considered a promising technology for stationary long-duration and large-scale storage in terms of cost, reliability, and safety [211]. They comprise cathode and anode chambers, membranes, and flowable electrolytes. Electrochemical reactions convert energy and store it by holding the electrolytes active species in external containers. In an all-vanadium redox flow battery, the reactions taking place respectively at positive and negative electrodes when the flow battery is discharging are the reduction of VO_2^+ ion at the cathode electrode and the oxidation of V^{2+} at the anode electrode [220]:

Positive electrode: $VO_2 + 2H^+ + e^- \rightarrow VO^{2+} + H_2O$

Negative electrode: $V^{2+} \rightarrow V^{3+} + e^-$

The H^+ ion diffuses through the membrane from the negative electrode chamber to the positive electrode chamber, whereas electrons flow through the external circuit connected to the battery. When the flow battery is charging the cathode/anode electrodes and the reactions are reversed, such that VO_2^+ ion oxidates while V^{2+} reduces.

RFBs have not captured significant market share yet the primary reason being the dominance of lithium-based battery technologies. In comparison with lithium-based battery energy storage systems RFBs have typically higher capital costs and the promise of scalability in terms of the energy capacity does not seem to be realised with current designs. However, it is anticipated that they will suffer from lower degradation than lithium-based batteries and are likely to have longer lifecycles improving the economic case for this technology [221].

Furthermore, a reduction in the construction and operation costs of RFBs can be achieved by improving the cell and stack design, as well as the battery system management. The energy density of RFBs is determined by the volume of the electrolytes, concentration of active species, the cell voltage, and the number of stacks. A higher energy density can be obtained by adopting new active redox couples with higher concentration and higher cell voltage. Moreover, the power generation capability depends on the reaction kinetics behaviour of redox-active systems and can be increased enabling faster kinetics as well as increasing the size of electrodes.

The ESS company has raised $30 million funds for new demonstration projects due to their interest in testing an iron flow chemistry not utilising more expensive and rare-earth minerals like vanadium and lithium. This new chemistry enables 20 years or more battery life as opposed to 7-10 of conventional chemistries before needing augmentation [214]. To overcome the issue of high material cost,

Invinity Energy Systems (previously known as Avalon Battery) company has developed an agreement for renting vanadium from mining companies, which are seeking a new market for their product. They have produced 160 flow batteries by factory turnkey mass-producing, which are competitive with lithium-ion batteries on life cycle for high-throughput applications. Current products have a rated power ranging from 78 kW to 10 MW and a nominal energy storage ranging from 220 kWh to 40 MWh. The battery discharge duration is from 2 to 12 hours. The lifetime is 25 years with unlimited cycle life [222].

In hydrogen production, the RFBs can be used as a buffer between renewable resources and electrolysers, such that the electrolyser can operate at a constant load. The goal is to drive the electrolysis using mainly energy harvested from renewable resources, rather than fossil fuel or nuclear resources, to produce green hydrogen [223].

7.3.6 A hybrid energy storage system using compressed air and hydrogen

A hybrid energy storage system using compressed air and hydrogen as the energy carrier was proposed in [224]. Despite its moderate efficiency (almost 40%), the compressed air hybrid energy storage (CAHES) system has some characteristics that may determine investment decisions. The system is highly flexible because of the load modulation capabilities of individual subsystems are combined. Especially the load of the hydrogen production sub-system can be varied within a wide range, such that it can be adapted to the surplus of electricity production.

The CAHES system can also comprise a subsystem producing methane gas from the reaction between hydrogen and CO_2 and this production can be supplemented with gas from the gas network adding flexibility to the entire system operation. The hydrogen produced by means of the electrolysis process can be used for other purposes. The CAHES system does not emit any harmful substances. The required capacities of compressed air tanks may be several times smaller than large scale CAES with the same energy storage capacity. This means that suitable mine excavations such as corridors and mine shafts, or even above-ground reservoirs can be used. Therefore, the CAHES system can be installed an area without salt deposits or aquifers while keeping a high storage potential. Moreover, the technology used for hydrogen storage in geological formations (large amounts of storage) is similar to that which is used with the natural gas. However, the storage cost of hydrogen is significantly higher than the natural gas because the energy density of hydrogen is much lower than that of natural gas (about one third). To make the storage process more efficient, hydrogen is compressed up to 20 MPa [225].

7.3.7 Hybrid battery/hydrogen storage system

A hybrid battery/hydrogen storage system has been proposed in [226]. The considered hydrogen storage technology includes a hydrogen tank, electrolyser and fuel cell and has been significantly improved in recent years also achieving a tangible cost reduction. When the hydrogen storage system cost will become the 47% of the current costs assumed in [226], hydrogen storage will have the same costs of the battery system. If the hydrogen storage components cost will keep decreasing, a combined system is more cost effective than each of the two alone systems. A fuel cell working in cogeneration mode contributes to the reduction of the total cost of hydrogen storage in high load conditions, considering that the average thermal efficiencies are 46% for SOFC and 57% for PEMFC (whereas average round-trip electrical efficiencies are 37% for the SOFC systems and 32% for the PEMFC systems) [227].

7.3.8 Demand Side Response (DSR)

Demand Management is a set of programs that help customers to shift their demand of electricity to off peak periods and to reduce their energy consumption. Demand response is a particular DSM which determines voluntary changes of end-consumers' usual consumption patterns in response to price signals. According to Article 2(20) of Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity 'demand response' is defined as 'the change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised markets.

Demand Response or Demand Side Response (DSR) programmes and incentives can potentially reduce the peak demand for the 20-50 hours of highest demand throughout the year or the maximum demand in a 24-hour period. This allows increased utilisation of base load generation plants which are cheaper than peaking power plants, reduced alternative energy storage requirements [221] and, where locally and coherently applied can improve the utilisation of network assets [222]. Energy efficiency is promoted by means of energy conservation programs that encourage customers to reduce energy usage and replace old appliances with more energy efficient models – to save money [223].

Several energy storage technologies have been used to support DSR activites in both residential and commercial contexts. These include battery energy storage technologies such as:

- Li-ion or Na-Ion
- Lead-acid
- Redox Flow Batteries (RFBs)

Or other technologies described earlier such as PHES, CAES and LAES. Although all these technologies are suitable for the purpose of DSR and have specific advantages and disadvantages [224].

Furthermore, thorough DSR adoption determines a different mix of PV and wind minimising the amount of backup energy required to ensure reliability of power system [225]. At European level, without DSR the optimal mix of renewables with respect to backup energy is 19% PV and 81% wind, whereas with full DSR utilisation, studies indicate that the optimal mix becomes 36% PV and 64% wind which represents a significant reduction in the required installed capacity of these technologies required to enable decarbonisation. PV typically has more synergies with DSR because it has a deterministic diurnal cycle and is aligned with the availability of DSR, which is aligned with customer demand usage, than wind power [226].

DSR located within the commercial sector is already commonplace in Ireland with over 540MW installed in Ireland as of 2021 [227]. This is in the form of Demand Side Units. A DSU consists of one or more individual demand sites that can be dispatched as if it were a generator. An individual demand site is typically a medium to large industrial premises. A DSU Aggregator may contract with the individual demand sites (IDS) and aggregate them together to operate as a single DSU [228].

A limitation of the current programme is that IDSs must register with the TSO Eirgrid and can only do so if they are metered by the MRSO (Meter Responsible System Operator) ESB Networks using quarter hourly (QH) metering. These meters record electricity consumption over a 15 minute period every day. QH metering is not available for customers with an annual consumption less than 300,000 kWh per annum [229].

DSR in Ireland participates in the wholesale energy market, the capacity market and also provides almost all of the flexibility/frequency services that are available under Eirgrid's DS3 programme [230].

7.3.9 Electric Vehicles, Energy Storage and DSR for the power system

Projections for the Irish vehicle fleet in 2050 comprises 60% electric vehicles (EV) and 18% H2 Fuel Cells vehicles (FCEV) in Ireland [231]. Plug-in electric vehicles (PEV), such as battery electric vehicles (EVs) and plug-in hybrids (PHEV) along with the stationary energy storage units have considerable potential to reduce the need for dedicated stationary grid storage [224].

PEVs participation in DSR could be categorised as follows:

- Charging based on a time-of-use or dynamic tariffs
- Smart charging controlled by an aggregator potentially through virtual power plant networks
- Distributed control providing services based on global (frequency) or local (voltage magnitude) parameters

Virtual power plants are a network of decentralized, medium-scale power generating units such as wind farms, solar plants, combined-heat-power generation units, as well as flexible loads and storage systems such as those provided by PEV.

Vehicle-to-grid (V2G) enables the participation of customer in the operation of the power system, by allowing energy to be exported from the PEVs and the power system to enable more active participation in DSRs by exporting electrical energy to the grid as well as controlling their charging rate. V2G storage enables PEVs to charge and discharge electricity generated from renewable energy sources to contribute to smoothing out power fluctuations [232].

The business case for V2G and the provision of other energy and flexibility services originates from the realisation that PEVs are driven for far less time than they could be on charge and thus their storage capability is not fully exploited. This capability can be exploited potentially to reduce import from the electricity grid and power devices within the home or even to export excess power to the grid to provide system services [233]. The former service is called vehicle-to-home, whereas the second is the vehicle-to-grid (V2G).

The energy can be sold to the grid at the regular selling price for the considered electricity market plus an additional compensation for providing an up-regulation ancillary service. Moreover, the PEV may offer a down-regulation ancillary service where it acts as an energy consumer. When the down-regulation service is provided to the grid, the PEV's owner pays the electricity tariff discounted by the down-regulation compensation [234].

Battery capacities of current EVs range from 17.6 kWh for a small Smart EQ ForTwo with a range of 58 miles, up to 100 kWh in a Tesla Model S and Model X with a range of more than 500km [235]. Considering an average capacity of 60 kWh/vehicle, 1.7 million of EVs in 2050 and a utilization factor of 70%, the storage capacity available to the grid for ancillary services would be about 70 GWh [230], enough to fully integrate all the wind energy output under a 40% RES-E scenario (which applies already in 2020 [236]) and 80% RES-E by 2030.

It is critical that the primary use of the PEV is still considered in any operational scenario. That is the PEV must be available as required to provide the primary function of the PEV, which is transportation, when the PEV owner requires it. The use of the PEV in this manner will require significant engagement and new propositions to entice PEV owners to engage with the electrical power system in this way.

7.4 Conclusions

Significant advancements across the energy, heating and transportation sector in technologies that can enable the decarbonisation of these sectors is making the evaluation of the most appropriate technologies to support in terms of policies challenging.

In terms of transport, the use of hydrogen for domestic vehicle use appears to be receiving comparatively less support than battery based electric vehicles (EVs). Concerns have been raised about the capability of the existing electrical infrastructure to support the large-scale deployment of EVs across the country [237]. However, the impact of EVs on the electrical distribution system due to the diversity of use cases for the vehicles should be manageable particularly if charging occurs at home. It is estimated in Ireland that more than 80% of charging will occur at home [238].

8. Recommendations on the development of an enabling framework for hydrogen in Ireland

Please see below for some recommendations regarding the development of a hydrogen policy to promote the use of hydrogen and its benefits [239].

Recommendation 1: Continue to monitor and evaluate the use of green hydrogen in non-domestic transport applications.

Demonstration of green hydrogen in road transportation has already started with fuel-cells buses in Dublin. Existing road vehicles include cars (Toyota and Hyundai), buses (Wrightbus, a manufacturer based in Ballymena, CaetanoBus), vans (Renault and LDV), trucks (Hyundai, Nikola), Refuse Collection Vehicles (FAUN). Numbers of these vehicles are very low. Ireland should follow the example of other countries which are already progressing in evaluating the use of green hydrogen in road transportation.

These demonstrations should be extended to prove the reliability and feasibility of the large-scale adoption of the technology and its benefits such that the technology will be considered mature for adoption as the costs of green hydrogen approach that of gasoline. The focus of the demonstrators should be on Heavy Goods Vehicles (HGVs) and buses rather than personal vehicles and smaller good vehicles such as vans.

Recommendation 2: Develop a framework to support for the development of dedicated renewable energy sources for green hydrogen production.

Green hydrogen is the preferred type of hydrogen because does not emit any carbon. By 2030 it is forecast that Ireland would be using only 2% of its total renewable energy production potential, therefore there is large room for building-up additional facilities to produce green hydrogen from renewables and supply part of the demand in a cost-effective manner.

An example of this is the project in for the first green hydrogen plant in County Mayo, which has recently received approval. The plant will make use of 1,500 Thermal/Electric panels, a technology delivering seven times more kWhr output per m^2 than solar PV [240].

Recommendation 3: Develop a framework to support the development of green hydrogen production using curtailed renewable energy.

There are also opportunities to use part of the excess electricity produced by existing renewable power plants, typically wind, to supply power to electrolysers which should be exploited to fulfil part of the green hydrogen demand. As the penetration of renewables increases in Ireland (up to 7GW offshore by 2030) curtailment levels will increase. Therefore, there will be increasingly significant periods where the generation is unused. Renewable energy developers will therefore need strong signals to be encouraged to find other revenue streams for this energy. Furthermore, the electricity market should be developed to support this objective.

Recommendation 4: Introduce financial instruments and incentives to support the development of green hydrogen production in Ireland.

In the long-term, green hydrogen or hydrogen produced from other zero carbon energy sources are the only technology compatible with net zero objectives.

The cost of green hydrogen is forecast to continuously decrease due to anticipated development and adoption of more cost effective electrolyser technologies and economies of scale. This approach is unlikely to result in significant infrastructure investment in the short-term and is likely to make achieve Climate Action Plan targets for 2030 and beyond more challenging and costly. Therefore, the development of green hydrogen production capability should be incentivised. This can be achieved by:

- Quotas - This is already under consideration by the European Commission.
- Auctions - The advantage of using auctions is that they create competition between producers, which may lead to lower prices for consumers. Auctions allow the allocation of support at a level that can be timely updated and competitively determined. They allow non-discriminatory volume control of the support they provide. The success of auctions depends on the competition levels in an auction, and how the available technology addresses the specific needs of the market [241]. Opportunities for specific sectors should be identified. Industry, heat users, cement factories, data-centres etc. They could participate directly in green hydrogen production projects through, to make the technology mix of renewable energy projects broader including electrolysers, and to increase system security and sustainability while ensuring that cost effective solution can be implemented, as recommended by the Renewable Electricity Support Scheme RESS2.

Recommendation 5: Demonstrate use of hydrogen as flexibility provider to perform power system balancing.

Scale experiments and laboratory demonstrations should be carried out to evaluate the practical challenges of the use of hydrogen storage as a low carbon storage technology, that is complimentary to batteries and other shorter term storage solutions, to support the balancing fluctuations in system load and renewable production on electrical power system.

The operation of small size electrolysers and fuel cells can be first demonstrated and evaluated in relatively small power systems, such as microgrids or laboratory settings. Electrolysers for hydrogen production can be seen as a flexible load that can help TSOs manage the variability of renewables and to maintain the system stability and security. If hydrogen sites are made bi-directional, either through gas turbines or fuel cells, they could participate in the capacity marker and system services markets such as Eirgrid's DS3 program "Delivering a Secure, Sustainable Electricity System" or of a successor of it.

Recommendation 6: Evaluate the blending of hydrogen into the existing Irish gas network.

Blending higher proportions, from 20% to 50% of hydrogen, in the existing gas network should be evaluated. Currently it is not clear whether the Irish gas network, which is almost fully made of polyethylene, would allow to blend 50% hydrogen in volume into natural gas and operate the network ensuring its safety and reliability, therefore it is recommended first to set-up a feasibility investigation, performing experiments aiming at demonstrating 10% and 20% hydrogen blending as already done in other countries. Any evaluation should consider:

- The practical reduction in carbon carried by the system
- The impact on downstream appliances

Recommendation 7: Evaluate the conversion of portions of the Irish gas network to pure hydrogen.

An evaluation of the costs, safety and benefits of upgrading portions of the existing distribution network to a pure hydrogen network should also be evaluated. Low-cost green hydrogen boilers are now arriving and residential levels fuel cells which are potentially more suited to deliver energy to existing buildings with simpler upgrades. A revision of the applicable legislation may be required to achieve this objective.

Recommendation 8: Determine whether low carbon hydrogen obtained using carbon capture and storage technologies applicable to geological basins and structures may be a practical pathway for Ireland.

The production of low carbon hydrogen (blue hydrogen) is considered a viable opportunity by the European Commission and in several European countries. The reforming of natural gas into hydrogen with CCS to produce blue hydrogen has been presented as a very competitive process in some technical publications and hydrogen's strategies of some countries give a prominent role to it.

Ireland has commenced research and demonstration activities on CCS at Whitegate oil refinery in the Cork harbour. It is recommended to continue with reduced scale demonstration of CCS technologies and to investigate their applicability to hydrogen production, because they could be a cost-effective alternative to the green hydrogen in the medium term. In the UK the H2Teesside project aims to produce 1GW of CCUS-enabled blue hydrogen from 2027. The project will capture and send for storage up to 2 million tonnes of carbon dioxide (CO_2) per year, equivalent to capturing the emissions from the heating of one million UK households [242].

In Ireland further geological and engineering studies are needed to determine actual CO_2 storage capacities of onshore and offshore geological basins and structures. The island of Ireland has a theoretical capacity for CO_2 storage in natural structures of 93,115 Mt. A thorough geological assessment based on deep geological data, is needed for each basin or structure to determine the exact amount of theoretical and effective capacities. More geological data should be obtained drilling exploration wells from the existing platforms and the data should be used to conduct reservoir simulations to investigate the effect of CO_2 injection on the structure stress and to identify possible leakage points.

Significant government investment into pilot projects should be avoided until successful pilots are carried out in other jurisdictions. The costs of carbon capture technologies are currently considered prohibitive and until this changes, investment should be limited.

Recommendation 9: Robustly evaluate feasibility of large-scale hydrogen storage in salt caverns.

In the North of Ireland there are a few underground salt layers which could be used to build hydrogen storage facilities. Seven salt caverns located at Islandmagee in County Antrim (Northern Ireland) will be used to store up to 500 million cubic metres of gas in the salt beds 1,500 metres below Larne Lough [243]. These caverns could also be used to store hydrogen. Feasibility of hydrogen storage in salt caverns is required to prove that hydrogen can be used in the future as a flexibility resource to balance the fluctuations of renewables, given the 2030 scenario where the expected installed capacity of intermittent renewable sources will be three times higher than the forecasted average load.

In the US salt caverns have been used for decades to store hydrogen in the Gulf Coast. Large companies such as Mitsubishi Power and Siemens are looking for partnerships to convert large natural gas reserves in giant underground salt caverns into hydrogen storage sites in both the eastern and western part of the country. The evaluation should consider alternative uses for these sites for technologies such as CAES.

If appropriate support for the development of large scale hydrogen production and storage and to identify opportunities for using salt caverns and aquifers for hydrogen storage.

Recommendation 10: Establish an appropriate greenhouse gas emissions standard for low carbon hydrogen that meets multiple relevant criteria.

Low carbon hydrogen , obtained through well-understood chemical processes, is currently cheaper to obtain than green hydrogen obtained from the electrolysis process. Without any prejudice for the path towards a full utilisation of electrolysers powered by renewables for green hydrogen production, there are possible advantages of other technology pathways to produce green hydrogen.

Following the UK example, it is recommended to establish a GHG emission standard meeting relevant criteria such as: neutral with respect to technology, accessible, cost-effective, user-friendly, transparent, compatible with other schemes in the energy sector and with other countries' standards, ambitious, accurate, robust, including penalties for fraud, predictable [244].

The standard should be not so stringent that it results in excessive costs for production but needs to sufficiently stringent that non-renewables based production is incentivised. A graded approach with long-term trajectory to a very high standard could be used. It should also be noted that increases in the price of carbon is likely to make non-renewables based hydrogen production less competitive over time. This should also be considered in the context of electrical power system that is anticipated to be increasingly decarbonised (80% by 2030).

Recommendation 11: Demonstrate storage and conversion technologies such as Power-to-Gas and Gas-to-Power conversion in microgrids.

Irish microgrid demonstrator sites, laboratories and facilities such as those available in Cork [245] or Sligo [246] or Galway [247] could be used to demonstrate a "Power-to-Power" storage and conversion system based on hydrogen, comprising an electrolyser converting electricity into hydrogen (Power-to-Gas), and a fuel cell system converting the hydrogen stored back to electricity (Gas-to-Power). The different configurations of storage in microgrids, battery-based, hydrogen-based and hybrid combination of battery-hydrogen-based should be evaluated and compared against each other to identify the one enabling the highest exploitation of renewable generation and eventually the most cost-effective solution for the Irish market.

Recommendation 12: Evaluate the production of low carbon ammonia using green hydrogen in Ireland

Ammonia is potentially an attractive fuel and energy carrier due to its characteristics of being a low carbon substance, carrying high energy density, and to be relatively convenient for transportation and storage. Recent low-carbon routes for ammonia production, use hydrogen produced from renewables such as wind, solar photovoltaic or biomass gasification electrolysis [248]. It is recommended to evaluate these pathways to determine the ones which are most effective in Ireland. Furthermore, ammonia is a key component of fertilisers for agriculture and production of these products in Ireland may present a number of advantages as currently this is imported and the costs of production are heavily linked to the production of grey hydrogen.

Recommendation 13: Evaluate the costs of electrifying or using green hydrogen to decarbonise elements of the rail system.

In Germany, 14 Hydrogen-fuelled trains manufactured by Alstom ("Coradia iLints") began to be used in permanent operation since March 2022 on a regional line between Buxtehude, near Hamburg, and the coastal town of Cuxhaven. The development of these trains began in 2016 by adapting a diesel train design. They use an electric drive system powered by a hydrogen fuel-cell. Moreover, batteries are installed on-board to recover electricity from braking. Alstom's trains have a range of 1000 km at a maximum speed of 140 km/h and can carry up to 150 seated and 150 standing passengers [249]. Operational performance of these trains are reported to be satisfactory and have potential for use in areas of Ireland's rail system. The capital and operational costs of these trains, demonstrating their use in Ireland, should be evaluated in the context of electrifying of existing train lines.

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