IEA Bioenergy
Technology Collaboration Programme

Status and perspectives of non-biogenic renewable gases

Synthesis Report of Work package 2 of the IEA Bioenergy Intertask project Renewable Gases: Deployment, markets and sustainable trade

March 2022

Status and perspectives of non-biogenic renewable gases

Synthesis Report of Work package 2 of the IEA Bioenergy Intertask project
Renewable Gases: Deployment, markets and sustainable trade

Authored by:

Fabio Bozzolo Lueckel, Mawini Chanika, Stefan Majer, Uwe Fritsche, Hans Werner Gress, Caoimhe Boyce, Rory Monaghan

The authors gratefully acknowledge the contributions of the following survey respondants, workshop participants, and study contributors:

Christiane Hennig, Amy Philbrook, Fabian Schipfer, Liisa Mällo, Glaucia Souza, Mäki Elina, Kees Kwant, Jennifer Hernandez, Adam Brown, David Styles, Andrea del Cura, Jon Hovland, Miguel Brandao, Mark Brown, Jasmijn Vrooland, Berend Vreugdenhil, Oshada Mendis,Olle Olsson, Peter-Paul Schouwenberg, Rebecca Heaton, Douke Jun, Christian Bang, Miguel Rodrigo Gonzalo, Tilman Schildhauer, Peter Coleman, Chenlin Li, David Wall, Jan Liebetrau, Patrick Lamers, Luc Pelkmans, Luiz Horta Nogueira, David Mahuma, Marina Holgado, Christian Bang.

IEA Bioenergy: Task 45

March 2022

Published by IEA Bioenergy

ISBN 979-12-80907-11-0

Executive Summary

Non-biogenic renewable gas (NBRG), encompassing hydrogen produced by electrolysis powered by renewable electricity and potential subsequent methanation with capture CO_2 are potentially important routes to decarbonisation energy and chemical feedstock use, especially in the hard-to-abate sectors. A growing number of countries have released national hydrogen strategies that seek to position hydrogen in their decarbonisation plans.

This report first identifies the most suitable technologies and concepts to produce NBRG. It then determines how different sources of electricity and CO_2 influence the economic feasibility and GHG abatement costs of NBRG. It achieves this using a survey and workshop for key stakeholders to focus attention on the core issues of production costs, technology commercial readiness, environmental sustainability aspects, and challenges presented by regulations. This leads to a review of the scientific, technical, policy and regulatory publications relevant for NBRG. Finally, the repot explores how regional characteristics impact the economic and environmental performance of these hydrogen pathways.

The findings of the survey, workshop, and review highlight that, while no countries have developed explicit NBRG strategies, a significant and growing number have developed hydrogen strategies, some of which, such as Germany, incorporate non-biogenic renewable methane, as defined in this study. National strategies can be defined as being focused on Imports (Japan, Germany, Netherlands) or exports (Australia, Canada); and green hydrogen (most European countries) or mixed green-blue hydrogen (UK, USA, Canada). Most strategies focused on green hydrogen have common themes including: an expectation that the first deployment of green hydrogen will be in industries that already consume fossil-derived hydrogen such as oil refining, and fertilizer and chemicals production; a focus on heavy duty transport such as buses and trucks; a focus on the co-benefits of hydrogen use including reduced GHG emissions, improved air quality, reduced reliance on fossil fuel imports. Japan's strategy foresees important roles for hydrogen in personal mobility, i.e., fuel cell electric vehicles. Some, notably, the UK, Germany, and the Netherlands, intend to repurpose the natural gas grid and associated infrastructure for large scale distribution and storage of hydrogen.

The analysis conducted in this report considers three regional case examples in the North Sea, Texas, and Brazil to illustrate how local factors such as renewable electricity resource, electricity grid GHG intensity, potential CO_2 source type, and other factors affect NBRG economic feasibility, measured by levelised delivered cost of gas, environmental sustainability, measured by GHG intensity of gas, and the cost of abating CO_2 emissions using NBRG. Some of the key findings of the analysis are summarized below.

The use of excess electricity as the sole power source for electrolysis is shown to be cost ineffective due to the low electrolyser capacity factors caused by the infrequency of excess electricity availability. On the other hand, the economic and environmental feasibility of using grid electricity to maintain high electrolyser capacity factor show strong dependences on regional factors including the price of grid electricity, its GHG intensity and the relative price of renewable electricity generation. In the North Sea, hydrogen produced from grid electricity has the lowest carbon abatement cost in 2030 (170 USD/tCO2), but by 2050 is overtaken by hydrogen produced by dedicated offshore wind (140 USD/tCO2). This is mostly due to the expected decrease in offshore wind electricity price and simultaneous increase in grid electricity price. In Texas, which possesses abundant wind and solar resources with high combined capacity factor, hydrogen produced from dedicated renewables achieves abatement costs of 180 USD/tCO2 in 2030 and 110 USD/tCO2 in 2050. Similar trends are seen in Brazil, with hydrogen produced from dedicated biomass electricity achieving abatement costs of 130 USD/tCO2 in 2030 and 100 USD/tCO2 in 2050. Expected ranges of levelized costs of delivered hydrogen by region and year are: 4-7 USD/kg in 2030 and 3-6 USD/kg in 2050 for the North Sea; 4-10 USD/kg in 2030 and 3-8 USD/kg in 2050 for Texas; and 3-6 USD/kg in 2030 and 3-4 USD/kg in 2050 for Brazil.

In all cases, methanation of hydrogen using captured CO_2 to renewable methane (RM) significantly increases abatement costs, but this must be balanced against the benefits of being able to use existing natural gas infrastructure and appliances. In the case of methanation using CO_2 from industrial sources, this high abatement cost is due to the GHG intensity of the CO_2, which is of fossil fuel origin. For methanation using CO_2 sourced from direct air carbon capture (DACC), the high capital and operating costs of DACC itself lead to high CO_2 prices and therefore to high abatement costs for RM. The lowest abatement costs for RM are seen for CO_2 captured from biomethane and bioethanol plants, which combine CO_2 of renewable origin with relatively low CO_2 capture price due to high CO_2 concentration in off-gases.

Other findings show that situating electrolysers close to the sources of renewable electricity is more cost effective that situating them close to hydrogen demand centres since it is cheaper to move energy via new hydrogen transmission pipelines than by new electricity transmission lines. Finally, the analysis shows that the lower ends of carbon abatement cost ranges are similar to carbon tax proposals in a number of countries, indicating the feasibility of NBRG in national decarbonisation strategies.

Index

Executive Summary 2
1 Introduction 7
1.1 Non-Biogenic Renewable Gases in decarbonisation 7
1.2 National strategies for NBRG 8
1.2.1 National hydrogen strategies – Hydrogen Production 8
1.2.2 National hydrogen strategies – Hydrogen Uses 9
1.2.3 Principle Issues regarding global hydrogen deployment 10
1.3 Report Structure and Objectives 10
2 Assessing the State of the Art 12
2.1 Survey and workshop 13
2.1.1 Survey results summary 13
2.1.2 Workshop results summary 14
2.2 Review of technologies 14
2.2.1 Renewable hydrogen from electrolysis 14
2.2.2 Renewable hydrogen from photocatalysis 16
2.2.3 Methanation in Renewable Methane production 16
2.2.4 Renewable hydrogen and methane end-use 18
2.3 Production costs 19
2.4 Commercial readiness 19
2.5 Aspects related to the sustainability assessment of NBRG 19
2.5.1 Aspects related to greenhouse gas accounting 20
2.5.2 Additional sustainability topics 22
2.6 Regulatory barriers 23
2.6.1 Certification 23
2.6.2 Additionality 23
3 NBRG in specific regional contexts 25
3.1 Introduction to case example approach 25
3.2 Description of case examples 27
3.2.1 North Sea 29
3.2.2 Texas 30
3.2.3 Brazil 31
3.3 Description of analysis methods 32
4 Results & discussion of regional case examples 33
4.1 North Sea 33
4.1.1 Levelised Cost of Delivered NBRG 33
4.1.2 GHG Intensity of NBRG 36

4.1.3 Carbon Abatement Cost 37
4.2 Texas 39
4.2.1 Levelised Cost of Delivered NBRG 39
4.2.2 GHG Intensity of NBRG 41
4.2.3 Carbon Abatement Cost 41
4.3 Brazil 43
4.3.1 Levelized Cost of Delivered NBRG 43
4.3.2 GHG Intensity of NBRG 45
4.3.3 Carbon Abatement Cost 46
5 Conclusions 47
6 References 49
7 Annexes 58
7.1 Analysis methods 58
7.1.1 Levelized cost 58
7.1.2 GHG intensity 62
7.1.3 Carbon abatement cost 62
7.2 North Sea Case Example inputs 63
7.2.1 North Sea case example evaluated scenarios 63
7.2.2 North Sea case example assumptions 64
7.3 Texas Case Example Inputs 67
7.3.1 Texas case example evaluated scenarios 67
7.3.2 Texas case example assumptions 68
7.4 Brazil Case Example Inputs 70
7.4.1 Brazil case example evaluated scenarios 71
7.4.2 Brazil case example assumptions 71
7.5 survey questions and responses 74
7.6 Renewable Methane projects 86

Abbreviations

AEM	Anion Exchange Membrane
BECCUS	Bioenergy with Carbon Capture Utilization and Storage
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilization and Storage
DACC	Direct Air Carbon Capture
EU	European Union
GHG	Green-House Gas
GO	Guarantee of Origin
IEA	International Energy Agency
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
LCOH	Levelized Cost of Hydrogen
LNG	Liquified Natural Gas
NBRG	Non-Biogenic Renewable Gases
NG	Natural Gas
OPEX	Operating Expense
PEM	Polymer Electrolyte Membrane
PtG	Power-to-Gas
PtL	Power-to-Liquids
PtX	Power-to-X
PV	Photovoltaic
R&D	Research and Development
RG	Renewable Gas
RM	Renewable Methane
SMR	Steam Methane Reforming
SOEC	Solid Oxid
TRL	Technology Readiness Level
UAE	United Arab Emirates
UK	United Kingdom
USA	United States of America
USD	United States Dollar
WP	Work Package

1 Introduction

This report presents the results of Work Package 2 (WP2) of the IEA Bioenergy Intertask Project "Renewable Gas – deployment, markets and sustainable trade". WP2 aims to provide perspectives on technological and economic development of non-biogenic renewable gases (NBRGs) and to identify and address questions regarding their sustainability. NBRG encompasses **hydrogen** produced from electrolysis powered by renewable electricity, or from direct water-splitting by sunlight, or **methane** produced by combining this hydrogen with carbon dioxide.

1.1 NON-BIOGENIC RENEWABLE GASES IN DECARBONISATION

Roughly two-thirds of the world's population live in countries that have committed to or announced net-zero greenhouse gas (GHG) emissions by 2050-2060. The EU *2050 Long Term Climate Strategy* aims to reach this by 2050, with a 2030 goal of 55% GHG emissions reduction (*European Parliament*, 2019). This, and other targets around the world, will be achieved primarily through energy efficiency improvements, direct electrification of mobility, space heating and cooling, and expansion of zero-carbon electricity generation. Efficiency and direct electrification, even when supplied by carbon-free sources, are unlikely to decarbonise the hard-to-abate sectors, including long-distance heavy-duty road, maritime and air transport, high-temperature industrial heat, and chemical feedstocks, or dispatchable power generation. Among approaches to decarbonise these hard-to-abate sectors, NBRGs, including hydrogen and methane, have been identified as having significant potential to scale sustainably to the levels required by 2050.

If this NBRG incorporates hydrogen produced by electrolysis powered by renewable energy (green hydrogen), it can enable sector integration, as envisioned by the EU's *Energy System Integration Strategy*, and enable indirect electrification of hard-to-abate sectors. Sector integration is key to decarbonising energy use beyond the electricity sector. The potential of NBRG to meet decarbonisation objectives has been recognised in the EU's *Hydrogen Strategy for a Climate Neutral Europe*, which envisions 40 GW of green hydrogen production in the EU by 2030, with a further 40 GW in neighbouring countries supplying the EU (European Commission, 2020). Combination of this hydrogen with CO_2 captured from an emission source or directly from the atmosphere in a methanation process creates methane, which can address the infrastructural challenges posed by pure hydrogen. Methane produced from CO_2 captured from the atmosphere or a biogenic process is renewable methane (RM).

Demand for hydrogen in 2020 was approximately 90 Mt, of which roughly 5% was produced by electrolysis. Of the electrolytic share, only a small portion was green hydrogen (IEA, 2021a). The largest green hydrogen production plant is the 10-MW REFHYNE project in Germany (REFHYNE.eu, n.d.). There is currently no commercial scale deployment of hydrogen from photocatalysis. For further information of photocatalytic hydrogen production, refer to Section 2.2.2.

NBRG is projected to be a key component of decarbonizing hard-to-abate sectors, including heavy industries like steel, polymer, chemical and cement production, long-distance heavy-duty transport such as heavy goods vehicles, ships and aircraft (IEA, 2021b). The IEA projects that global consumption of hydrogen could exceed 200 Mt in 2030 and 500 Mt by 2050, in a zero-emissions scenario.

1.2 NATIONAL STRATEGIES FOR NBRG

No country or region has an explicit strategy for NBRG, but many have developed, or are developing, hydrogen strategies. Hungary and Norway strategies focus on self-reliance; producing hydrogen only for internal use. Japan's strategy indicates only importing of hydrogen for national use whereas South Korea and Germany indicate a focus on hydrogen import with the emphasis on exporting of hydrogen technology. The Netherlands' approach is to import hydrogen to export thus serving as a hydrogen hub. Italy due to its central location in the mediteranean and proximity to Africa and the Middle east will position itself as a hydrogen hub as well. The planned estimated scale of hydrogen production for select countries is shown in figure 1 below. Countries that have large scale hydrogen production for export plans in their strategies and roadmaps are Australia, Canada, Chile, Portugal and Spain. The EU's hydrogen self reliance will be dependant on the member states' pledges.

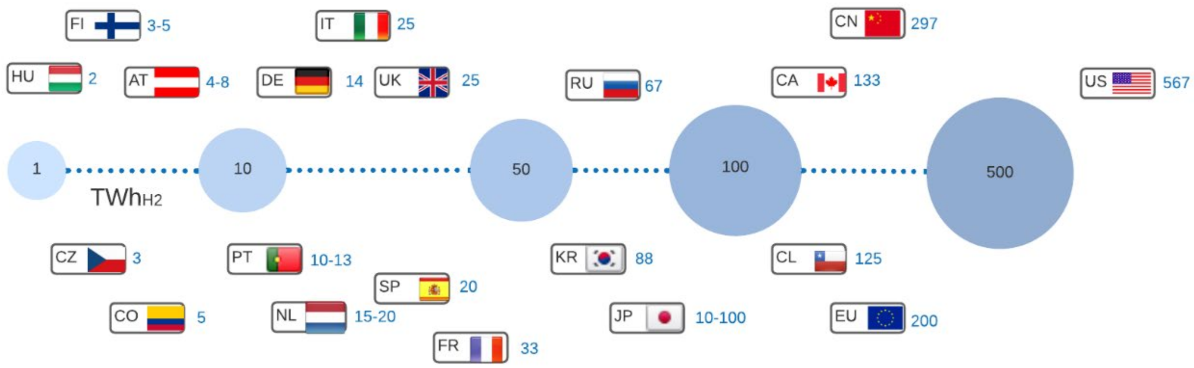


Figure 1: Countries' National Hydrogen Strategies/roadmaps targets in TWh_{H2} for the year 2030 (adapted from Fritsche et al., (2022)

1.2.1 National hydrogen strategies - Hydrogen Production

The production methods of hydrogen are mentioned in the strategies/roadmaps of the 18 countries and the European Union (EU) summarised in Table 1 adapted from International Energy Agency (2021a). Most strategies focus on zero- or low-carbon production, with green hydrogen, from water electrolysis powered by renewable electricity, and blue hydrogen, from natural gas reforming with CO_2 capture and storage, being the main technologies. Only Canada explicitly references biomass gasification as a route to hydrogen production.

Table 1: National Strategies - Production methods for hydrogen adapted from *International Energy Agency (2021a)*

	AU	CA	CO	CL	CZ	EU	FR	DE	HU	IT	JP	KR	NL	NO	PT	RU	SP	UK
RENEWABLE ELECTROLYSIS	✓	✗	✓	✓	✗	✓	✗	✓	✗	✓	✗	✗	✓	✓	✓	✗	✓	✗
OTHER ELECTROLYSIS	✗	✓	✗	✗	✓	✗	✓	✗	✓	✗	✓	✓	✗	✗	✗	✓	✗	✓
BIOMASS	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
FOSSIL FUEL (CCUS)	✗	✗	✗	✗	✗	✗	✗	✗	✓	✓	✓	✗	✗	✗	✗	✗	✗	✗
NATURAL GAS (CCUS)	✓	✓	✗	✗	✗	✓	✗	✗	✗	✗	✗	✓	✓	✓		✓	✗	✓
COAL (CCUS)	✓		✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗
OIL (CCUS)	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗	✗

1.2.2 National hydrogen strategies - Hydrogen Uses

Most of the strategies/roadmaps except for Russia show use of hydrogen in the transport sector. Other uses are industry (including chemicals and steel for some countries), electricity, refining and buildings. A few strategies have considered aviation and shipping, with only 2 strategies (Canada and Chile) mentioning the use of hydrogen in the mining sector. Figure 2 below shows details of hydrogen use by sector for various countries.

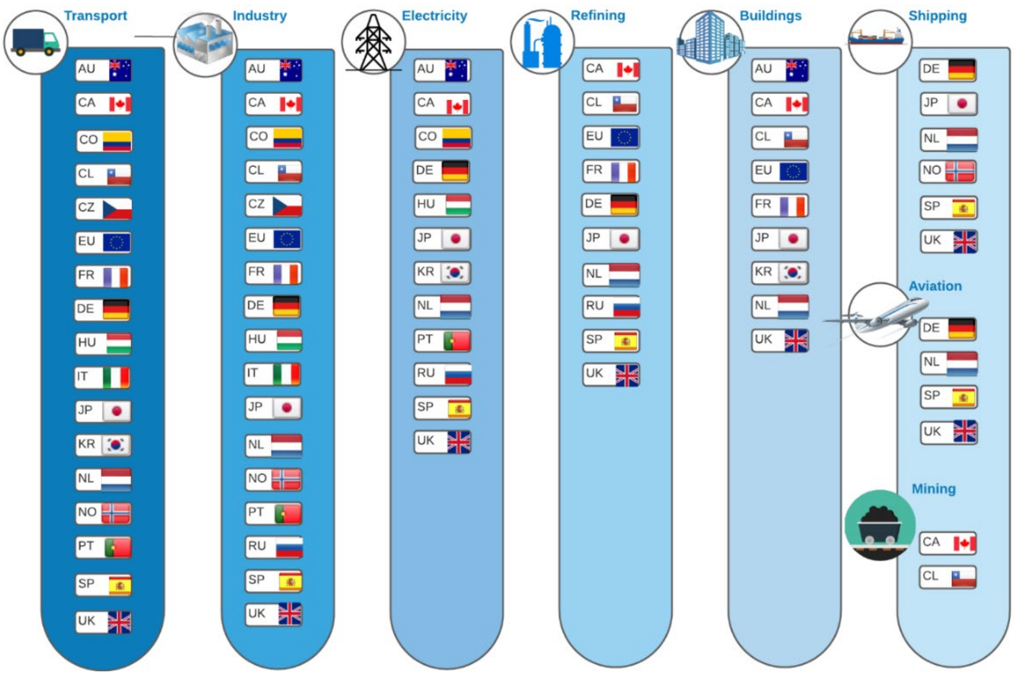


Figure 2: Proposed hydrogen uses adapted from *International Energy Agency (2021a)*

The other NBRG considered in this study, Renewable Methane (RM), is referenced in the strategy of Germany as an option for heating, but also highlights potential challenges of pursuing large scale RM production. Japan refers to 'power-to-methane' as a potentially relevant option to import energy and Italy mentions it as one of multiple renewable gases. However, despite the lack of RM mention in most of the strategies and roadmaps, ongoing projects in many countries show that large-scale RM production is worth investigating. Currently Germany, Italy, Belgium, Finland and the Czech Republic have large scale RM projects in the feasibility and concept stages. Refer to the IEA's Global Hydrogen Review 2021 for more details on national hydrogen strategies (https://www.iea.org/reports/global-hydrogen-review-2021).

1.2.3 Principle Issues regarding global hydrogen deployment

It is estimated that by 2030, about USD 50 billion of global investment and 65 GW of electrolyser capacity will be required to bridge the cost gap between grey and renewable hydrogen (equivalent to 6.58 MT of Hydrogen)[1] (World Energy Council, 2021). Apart from the large financial and technological push needed, there are a few other factors that would need to be addressed to stimulate global hydrogen market development. Many countries are forming bilateral hydrogen agreements and memoranda of understanding for hydrogen import/export. Other issues surrounding global hydrogen deployment are presented in Table 2 below.

1.3 REPORT STRUCTURE AND OBJECTIVES

In this report, the production of NBRG is be reviewed, assessing the state of the art of the available technologies, potential sustainability issues, and policy gaps for different national strategies. Case examples of NBRG deployment were developed to give better understanding of the projected levelized cost of NBRG, their greenhouse gas intensity, and the cost of carbon abatement. The objective of the report is to answer the following questions:

1. What are suitable technologies and concepts to produce NBRG?
2. How do different sources of electricity and CO_2 influence the economic feasibility and GHG abatement costs of these energy carriers?
3. How do regional characteristics impact the economic and environmental performance of these hydrogen pathways?

[1] Calculated assuming electrolyser capacity factor 55% and efficiency of 70%.

Table 2. Principle issues regarding hydrogen global deployment at scale

Issue	*Comments*
Global Hydrogen Standards	With the strategies indicating exponential growth in Hydrogen trade there is a need to hasten the development of global/international standards and certification to enable effective cross-border trade which would improve investor confidence (World Energy Council, 2021). Different countries' objectives will hinder or delay international standards development. Specific international standards on Carbon footprint, Safety, and Technological advancement are particularly important in the short term (IEA, 2021a). The *International Partnership for Hydrogen and Fuel Cells in the Economy* (IPHE) is currently developing a GHG quantification methodology for Europe that could potentially be used internationally. This is further discussed under the Certification section of this paper (Section 2.6.1). The American Institute of Chemical Engineers is developing a hydrogen safety standard (World Energy Council, 2021). Global Unified proof of origin - Currently, there are several hydrogen production methods. It will be important to have an agreed standard of presenting the source of the Hydrogen for cross-border trade. CertifHy has developed a "Guarantee of Origin (GO)" scheme for Europe (Barth et al., 2019).
Non-Binding Commitments	To achieve the collective global 2030 hydrogen milestones, action is required to fulfil the commitments made by each country.
Legal framework for Stimulating Demand	Action will be required by governments to stimulate individual countries' demand for hydrogen. A few countries including Portugal, Chile, South Korea, are reviewing and developing measures to allow greater participation of hydrogen in various parts of their energy mix.
Other Indirect Policy Issues	Electricity and gas grid fees and levies may affect Hydrogen entry into these sectors Energy taxation – must favour zero/low carbon gases over fossil fuels, and subsidies on fossil fuel must be phased out to further growth of hydrogen demand. In countries with existing carbon tax schemes, a higher carbon price would encourage the use of alternatives such as Hydrogen (World Energy Council, 2021). Spatial Planning – Need to include hydrogen infrastructure in local government planning

Source: own compilation

2 Assessing the State of the Art

Hydrogen and methane are two common compounds used in many industrial sectors around the world. They can be produced in different ways and the pathway selected for their production determines if they are considered renewable or not. For hydrogen, it will be renewable if it is produced from water by means of electrolysis driven by renewable electricity, or from biomass[2]. Hydrogen end uses include combustion or electrochemical conversion in a fuel cell, or conversion to a chemical product. In the case of non-biogenic methane, it can be generated by the Sabatier methanation reaction, which combines hydrogen and carbon dioxide. If the hydrogen is renewable and the carbon dioxide originates from a renewable, non-fossil source, for example, direct air capture (powered by renewables) or biogenic $CO_{2,}$ the resulting methane can also be considered renewable. The overall GHG balance of methane produced using renewable hydrogen and CO_2 from non-renewable sources is more difficult to determine. In that case, the climate impact of the CO_2, originating for example from power generation or industrial processes fueled by fossil energy carriers needs to be accounted for and considered in the GHG balance of the methane produced. Figure 3 shows a schematic of the process.

Different unit operations are required for producing non-biogenic renewable gases. The first one is the transformation of water into hydrogen by electrolysis (TRL 9) or photocatalysis (TRL 7)[3] (FSR, 2021). Once hydrogen is obtained, compression and a storage system may be required. Storage can take the form of high-pressure gas or cryogenic liquid tanks, buried pipes, salt caverns, or lined rock caverns. If methane is to be produced, carbon dioxide will need to be captured from the air or from a flue gas of a biogenic or non-biogenic source. Biogenic sources can include the burning of biomass, CO_2 from anaerobic digestion of biomass and the subsequent biogas upgrading, or fermentation off-gases, e.g., from bioethanol production. Non-biogenic sources of CO_2 include combustion of fossil fuels (coal, oil, or natural gas). The two gases H_2 and CO_2 can react in the methanation process, which is a catalytic reaction that forms methane and water. This stage is followed by water separation and may also include compression and storage if required.

---

[2] Renewable gases of non-biogenic are the focus of WP2. Biogenic gases are dealt with in WP1.
[3] The Technology Readiness Level (TRL) is a metric to describe the maturity of a technology, measured through 1 (lowest) to 9 (highest) (EU Horizon 2020, 2014).

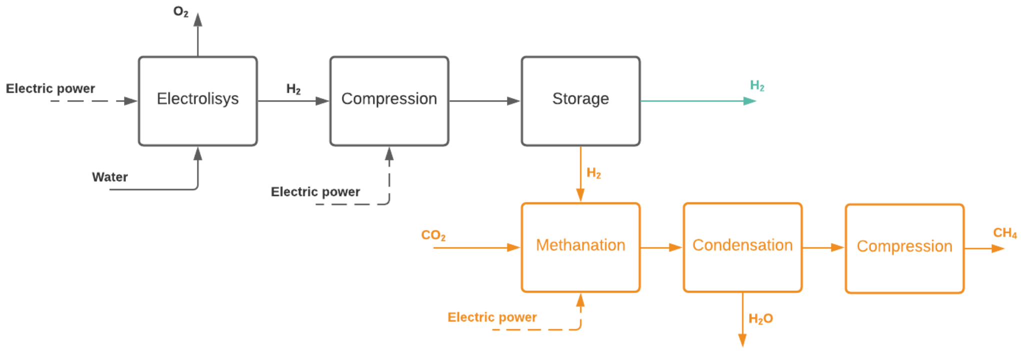


Figure 3. General production scheme of NBRG. Source: authors' own figure.

2.1 SURVEY AND WORKSHOP

The descriptions of technologies and processes above are summaries of the current state of the technology, but the supply chain of non-biogenic renewable gases involves many other topics besides production technology. To better identify the most relevant topics related to NBRG, a survey and a workshop were carried out to summarize the technological, environmental, social, and political issues that supply chains of this type entail. The respondents of these activities were mainly IEA partners involved in the study of NBRG technology.

2.1.1 Survey results summary

To help focus WP2, a survey on non-biogenic renewable gas technologies and sustainability was sent to members of IEA Bioenergy in late 2020 and early 2021. Respondents were asked to outline the role of NBRG technologies in their countries' energy and decarbonization strategies, represented by national hydrogen strategies. They were also asked for their opinions on (i) the market readiness of NBRG technologies, (ii) NBRG technology combinations of interest to their country/region, and (iii) potential sustainability challenges for NBRG deployment. 20 responses were received on behalf of 19 countries plus the European Union (EU). They were geographically distributed as follows: 2 from North America (Canada and USA), 1 from Latin America (Brazil), 1 from Africa (South Africa), 3 from Australasia (Australia, China, and Japan), and 12 from Europe (Austria, Denmark, Estonia, Finland, Germany, Ireland, Netherlands, Norway, Spain, Sweden, Switzerland, and the UK).

Eight countries (four in Europe) plus the EU have hydrogen strategies in place, with a further four (all in Europe) having such strategies under development. Most strategies emphasize green hydrogen (water electrolysis powered by renewable electricity). By and large, European countries' strategies are strongly oriented in this direction. Strategies in Australia, Canada, and USA, all major natural gas producers, reference steam methane reforming (SMR) as at least a transition hydrogen technology. These countries, as well as Denmark, Estonia, and Norway had a strong emphasis on hydrogen exports. Danish, German, and EU strategies reference power-to-X (PtX) using captured CO_2 for long-term decarbonization of hard-to-abate sectors. When asked for their opinion, respondents favour green hydrogen over blue to greater extents than national strategies. PtX also featured more in the opinions than the national strategies. Respondents proposed applications and combinations of NBRG technologies in renewable energy imports and exports, energy system integration (with heat and transport), use as feedstocks in heavy (steel and chemicals) industries, combination with CCUS and BECCUS for PtX.

The key environmental sustainability issues raised by respondents that are relevant for the assessment of hydrogen pathways are: the additionality and certification of renewable electricity for green hydrogen and the climate effects of CO_2 used for PtX production based on hydrogen. Freshwater availability, land-use concerns for greater renewable electricity requirements, and the global warming potential of hydrogen itself were also raised.

When asked about gaps in existing policy frameworks for RG, respondents stated that the key sustainability issues of additionality and certification are not yet represented in policy frameworks, even in those countries with hydrogen strategies. Finally, when asked to suggest exemplary, simplified NBRG cases for analysis, a small number of key themes emerged. These include the use of offshore wind in northwestern Europe, diverse combinations of renewables in the United States, integration with biofuels production in tropical regions including Brazil, and GHG impact of using CO_2 of both fossil and biogenic origin. These key themes were refined and developed into the case examples described in this report.

2.1.2 Workshop results summary

In the following sections, many issues suggested by the participants of the survey and workshop will be addressed, some of them, with more detail than others. Mainly, a summary of the technologies available for producing NBRG, greenhouse gas emissions associated with its production, other environmental problems like water availability, land use, renewable electricity requirements, and certification of the gas. Further, in this report, three case examples will be modelled and presented to better explain these issues in a real context based on a possible future where NBRG are an important part of the energy matrix. At the end of this chapter, a summary of the regulatory frameworks of different countries is presented with a special focus on the barriers to the implementation of NBRG supply chains.

2.2 REVIEW OF TECHNOLOGIES

2.2.1 Renewable hydrogen from electrolysis

One of the main points emphasised by the survey responses, the workshop, and the national strategies is the importance of hydrogen production by electrolysis using renewable energy. The two most commercialised electrolyser technologies that are projected to dominate the future of this hydrogen production route are alkaline and polymer electrolyte membrane (PEM).

Alkaline electrolysis, which was first developed more than 100 years ago, is now the most widely used technology for the production of hydrogen from water. This system uses a cathode and anode separated by an electrolyte (usually a solution of KOH or NaOH) and a diaphragm, wherein the cathode water is reduced, producing hydrogen and OH^- ions that travel through the diaphragm to react in the anode and form oxygen (Coutanceau et al., 2018; Keçebaş et al., 2019).

PEM electrolysis is a more recent technology, whose development has quickened during the last decades, projecting a decrease in its price in the next years that may make this technology cheaper than the alkaline systems (Tlili et al., 2020). It is based on the use of a solid membrane instead of an electrolyte, and water is decomposed in the anode, where the oxygen and protons are produced, the protons pass through the membrane and get reduced at the cathode (Coutanceau et al., 2018; Keçebaş et al., 2019). In Table 3, the main technical and economic characteristics of both electrolysis systems are shown. The predictions of future development of these technologies and their economic indicators vary according to the source. Table 4 presents projections of electrolyser specific capital expense (CAPEX) according to a range of sources.

Table 3. PEM and Alkaline electrolysis comparison.

	PEM	Alkaline	Source
Efficiency	56%-60%	63%-70%	(IEA, 2019)
Working pressure (bar)	30-80	1-30	(IEA, 2019b)
Working temperature (°C)	50-80	60-80	(IEA, 2019)
Current CAPEX (USD/kW)	1145-3664	916-1946	(Tlili et al., 2020)
Required purity of water	About 1 μS/cm	Below 5 μS/cm	(Guandalini et al., 2016)
Purity of hydrogen	99.99%	99.8%	(Y. Guo et al., 2019)
Starting-up time	Lower	Higher	(Y. Guo et al., 2019)
Other considerations	Longer lifetime	Shorter lifetime	(Y. Guo et al., 2019)

Source: own compilation

Table 4. CAPEX of PEM and Alkaline electrolysers according to different sources.

CAPEX (USD/kW)	PEM			Alkaline		
Source	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
(FCH, 2020)	1030	572	-	687	485	-
(IEA, 2021a)	1750	610	-	1000	500	-
(IEA, 2019)	1100-1800	650-1500	200-900	500-1400	400-850	200-700
(Bloomberg New Energy Finance, 2020)	-	-	-	-	135	98
(Tlili et al., 2020)	1145-3664	973-1889	343-800	916-1946	800-1145	458-800

Source: own compilation

As indicated in Table 4, it cannot be said with confidence which electrolyser technology is cheaper now and in the future. Hence, it is not easy to choose one value over another to make predictions of the cost of "green" hydrogen, because of the uncertainty in the CAPEX and OPEX of these systems.

Other technologies available for water electrolysis are Solid Oxide Electrolysis Cells (SOECs) and Anion Exchange Membranes (AEMs). These systems are not as developed as PEM or alkaline (SOECs TRL: 6-7, AEMs TRL: 4-5), but they have interesting characteristics that are worth mentioning. SOECs use steam as their feedstock steam instead of water, which passes through a ceramic membrane that works as an electrolyte. These electrolysers have high reported efficiencies of around 82% (IEA, 2021a). For AEMs, the key advantage is that they use transition metal catalysts instead of platinum, which is part of PEM electrolysers, giving them a potential price advantage in the future despite their currently lower TRL.

2.2.2 Renewable hydrogen from photocatalysis

Direct production of hydrogen from solar irradiation can also be performed. Photocatalysis systems use solar radiation to split water thanks to a semiconductor material that has two bands. The valence band oxidizes water and produces oxygen if its potential is higher than the oxidation potential of the water. The conduction band carries the reduction reaction of the water if its potential is lower than the reduction potential of the water. To avoid recombination of the electrons with the protons, a co-catalyst is generally used on the surface of the conduction band (Zhang et al., 2020).

This technology has a TRL of 7, which is lower than electrolysis (FSR, 2021), and has lower efficiencies compared to traditional photovoltaic generation and electrolysis of water, which has on the best cases reported an overall efficiency of 30%, versus 1% that photocatalytic systems present (Nishiyama et al., 2021). On the other side, it presents advantages like promising characteristics for scaling up, being potentially cheaper and simpler than other hydrogen production systems (Nishiyama et al., 2021). It is a system that may have a double purpose, it could remediate wastewater and produce hydrogen at the same time (Corredor et al., 2019).

Recently, research has been performed in the field of seawater photocatalysis, but it still needs to develop until it becomes a commercial alternative (Zhang et al., 2020). Nishiyama et al. (2021) have scaled a photocatalytic project up to 100 m^2. They conclude that better photocatalytic materials capable to utilize visible light are needed to improve the efficiency of the process, stating that efficiencies of 5% to 10% will make this system economically feasible.

2.2.3 Methanation in Renewable Methane production

Using hydrogen as a reductive source for producing methane has one major advantage that using hydrogen on its own does not have, which is that the existing natural gas infrastructure can be used. Methanation is the process of producing methane using carbon dioxide and hydrogen as feedstocks. The process can be driven by biological or chemical systems, but since the biological process is slower and less developed, this report is focused on the chemical route. The overall reaction of methanation is exothermic and shifts the equilibrium to the products at lower temperatures, hence the reactors need a heat removal system to work optimally (Ghaib et al., 2016). The following equation describes the main chemical reaction.

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \qquad \Delta H_R^{298K} = -165\frac{kJ}{mol} \tag{1}$$

At higher pressures, the process shows higher yields of conversion to methane. Further, the reaction can produce by-products that can be problematic for the system, such as carbon deposits that generate fouling, and higher hydrocarbons that lower the purity of the final product. The formation of by-products depends strongly on the catalyst. Different elements have been tested, showing that ruthenium has the best performance, but by being so expensive, iron and nickel have been shown to be attractive options. Nickel-based catalysts are the most widely used because of their low price, high selectivity to methane, and activity (Ghaib et al., 2016; Lee et al., 2021). The only drawbacks of nickel-based catalysts are their tendency to oxidize and to form toxic compounds like nickel carbonyl (Ghaib et al., 2016). The reactors tend to be fixed bed reactors, designed adiabatic or polytropic, where the first case shows better economic performances, but less flexibility on the feed flow. The theoretical process efficiency of conversion of hydrogen energy to the final product is 78% (Gorre et al., 2019), but from electricity to methane, the overall efficiency decreases to 41%-56% (Lee et al., 2021; Thema et al., 2019).

The origin of the carbon dioxide is an important parameter for the assessment of the GHG intensity of the methane. The carbon source can be classified as renewable or non-renewable, where the first group is composed of the biogenic carbon dioxide and direct air carbon capture, and the second group on the fossil sources like power plants or steel works (fuelled by fossil energy carriers), and the cement production flue gases. The origin of this carbon dioxide will also influence the cost of the carbon capture process. Concentrated sources require less expensive unit operations and hence less energy, implying lower costs and GHG process intensities. The use of renewable energies in the carbon capture process is crucial to ensure a low carbon footprint of the CO2 used as feedstock for methanation. Furthermore, if the carbon source is not renewable, it means that there are net emissions that need to be accounted for. Depending on the selected emission accounting scheme, the emissions might be allocated to the methane (as product of the methanation process) or the process which was the original source of the CO_2 (e.g., the power production process, cement production, etc.). In Baylin-Stern & Berghout (2021), some carbon sources prices are shown. Nevertheless, the price of carbon dioxide is generally significantly lower than the price of hydrogen. CO_2 is a by-product from biogas upgrading to biomethane. In order to use this product in other applications and markets, additional upgrading steps such as compression, and in some cases liquefaction, are necessary. According to Klepper and Thrän, (2019) capture and provision of CO_2 from biomethane plants is associated with additional costs that are below 20% of the investment costs of the biomethane facility.

Finally, some studies suggest that the production of Renewable Methane can be economically competitive in 2030 if the electricity prices are low enough (30 EUR/MWh), and if CAPEX and OPEX decrease in price due to the development of the technology (Gorre et al., 2019). Thus, the methanation field is expanding with several projects planning to be in operation by the end of this decade (Thema et al., 2019).

Table 5. Levelized cost of CO_2 capture by sector and initial CO_2 concentration, 2019

Source	Levelized Cost of Carbon Capture (USD/tonne)
Direct air capture	134-342
Power generation	50-100
Cement production	60-120
Iron and steel production	40-100
Hydrogen (SMR)	50-80
Ethylene Oxide	25-35
Bioethanol	25-35
Ammonia	25-35
Coal to chemicals	15-25
Natural gas processing	15-25

Source: Adapted from Baylin-Stern & Berghout (2021)

2.2.4 Renewable hydrogen and methane end-use

Currently, hydrogen is mainly used in the chemical industry and refineries as a reducing agent (IEA, 2021b). This means, that the first sector in which green hydrogen can help to abate carbon emissions is those industries. If this is done at scale, then injection of hydrogen into the natural gas grid could be facilitated (IEA, 2021a). In parallel, hydrogen can be used to store renewable electricity and reduce curtailment (IEA, 2021b). Long-distance heavy-duty transport, including trucking, shipping, and aviation, are hard-to-abate sectors with high operating costs that represent major opportunities for hydrogen. Supply of high-temperature heat and feedstock to industry represents a further route to market. There is also a potential role for hydrogen to supply heat to the built environment, although in this sector, hydrogen faces very stiff competition from other decarbonisation options, especially heat pumps.

The potential for the gas grid to transport large amounts of hydrogen and/or RM has led to calls to maintain existing gas infrastructure (World Energy Council, 2021). On the other hand, there are concerns that continued use and development of the gas grid will delay decarbonisation (Earthjustice, 2021). Without adopting either position, this report presents a short discussion on the transmission of methane using existing pipes in the case examples.

2.3 PRODUCTION COSTS

The levelized costs of production of renewable hydrogen and methane depend strongly on location and time factors. Due to the high dependency of the levelized cost on electricity price, production will vary with different conditions. Electricity is a significant portion of the cost of NBRG, accounting for 50-90% of the total production costs (IEA, 2021a). Research shows the differences between regions that have the potential for producing low-cost NBRG, like Australia, Chile, or Spain, which could produce hydrogen at lower than 2 USD/kg (Hydrogen Council, 2020; McKinsey & Company, 2020).

Projections for the future cost of methanation are not widespread, since this will depend directly on the hydrogen production costs. For example, Gorre et al. (2019), calculated the production cost of Renewable Methane in 2030 and 2050 for different scenarios at 20-200 EUR/MWh of methane. This illustrates that the production cost of NBRG is an open issue.

2.4 COMMERCIAL READINESS

The main electrolysis technologies of alkaline and PEM have TRLs of 9, meaning that they are commercially deployed. Other technologies, such as Solid Oxide Electrolyser Cells, have TRLs of 6-7. The power-to-gas process is also in a lower commercial readiness with a TRL of ~6. There are several projects for green hydrogen production around the world in different stages of development. For more information, refer to the Global Hydrogen Review 2021 (IEA, 2021a), which has a comprehensive summary of the main projects in different locations. Furthermore, for RM projects, Thema et al. (2019) presents a comprehensive review in which many initiatives are described for the production of either hydrogen or methane from electricity.

2.5 ASPECTS RELATED TO THE SUSTAINABILITY ASSESSMENT OF NBRG

Hydrogen is considered a promising energy carrier, potentially contributing the decarbonisation of the energy system since its oxidation does not emit any greenhouse gases. Thus, the use of hydrogen can help to reduce direct process emissions in different sectors of application. However, hydrogen is an energy carrier which can be produced from a wide range of resources and technologies. Both the production and supply of these resources as well as the hydrogen production technologies can be associated with potential impacts on sustainability (Falcone et al., 2021; Fredershausen et al., 2021).

Based on the results of the survey and workshop described in the Survey results summary section, we defined parameters and topics to be included in the discussion of potential sustainability issues for non-bio renewable gas pathways. These topics are presented in the following paragraphs. It should be noted that the focus on non-biogenic hydrogen pathways significantly reduces the number of potential topics and issues which could otherwise be related to the production of biogenic feedstock. This includes for example potential risks such as direct and indirect land-use change, deforestation, soil emissions, among others. Due the scope of this study, we will focus on a characterisation of those aspects that have been mentioned and prioritised in the survey answers and the workshop. Furthermore, the three cases which will be described in the subsequent chapters will include a quantitative assessment of costs as well as GHG emissions from H_2 production in different scenarios.

Additional information regarding the quantitative assessment of additional environmental impact categories for H_2 production and utilisation can be found for example in Valente, Iribarren and Dufour, 2016; Mehmeti *et al.*, 2018; Lotrič *et al.*, 2021a.

2.5.1 Aspects related to greenhouse gas accounting

The main motivation for the increasing demand for NBRG capacities is to replace GHG intensive, fossil-based energy carriers to limit the impact of global warming effects. Replacing fossil fuels with low carbon emissions fuels is one of the ways to abate GHG emissions. NBRG can contribute to this objective, however, the actual GHG mitigation effects depend on the GHG intensity of the inputs of the system. As for the production of NBRG, we identified the electricity used in the production processes and the carbon source for the methanation as the two main sources that are key for abating carbon emissions with NBRG.

2.5.1.1 Greenhouse gas intensity of the electricity source

The production of NBRG can be driven mainly by two types of systems, 100% renewable electricity (dedicated or curtailed), or connected to the electricity grid. For the latter case, the energy mix of the grid varies with place and time, which means that the carbon intensity of the electricity is not necessarily constant and difficult to predict. Of course, if the mix has more fossil fuel energy sources powering the grid, the GHG intensity of it will be greater compared to a grid with more renewable power connected to it. Nevertheless, renewable sources of energy also carry GHG emissions if a life-cycle assessment approach is followed, principally because of the construction of the electricity generation devices (wind turbines, solar panels, etc). In any case, the specific intensity is significantly less than fossil sources since non-biogenic renewable sources do not produce direct emissions. Besides, the various certification schemes have suggested certain limits or thresholds for GHG emissions associated to NBRG production to declare those gases “low carbon” products, for instance, CertifHy suggested a threshold value of 36.4 gCO_{2Eq}/MJ_{H2} as the limit for a low carbon hydrogen (Barth et al., 2019; CertifHy, 2014). Other work suggested a threshold of less of 3 $tonCO_2/tonH_2$, or in other cases between 35% and 75% of reduction of emissions using as a baseline hydrogen from SMR of natural gas (more details in (Fritsche et al., 2022)).

2.5.1.2 Climate effects of the carbon source

In the case of methane produced from carbon dioxide and hydrogen, the carbon dioxide used will carry emissions by itself as a potential direct emission after the burning of the produced methane, and due to the process of capture and purification. The direct emissions can be considered as net-zero if the carbon dioxide comes from a renewable source, which means that it was already in the atmosphere and was captured by biomass or by direct air carbon capture technology. The capture and purification emissions consider the GHG intensity of the energy requirements for running these operations. Depending on the GHG intensity of the energy used, these process emissions will add to the carbon dioxide to varying degrees. Different carbon sources have different energy requirements for capture and purification, which depend mainly on the concentration of carbon dioxide on the main source. In the following table, a summary of the energy requirements of carbon capture for different sources is available.

2.5.1.3 Greenhouse effect of NBRG emissions

In addition to the emissions from the production and the conversion of NBRGs, incomplete conversion processes (e.g., combustion) or leakage from infrastructure or slip in the conversion process might lead to direct emissions of NBRGs. Depending on the type of the NBRG, this can result in direct or indirect climate effects.

Table *6*. Different carbon sources' carbon capture energy requirements.

Carbon source	Energy required ($kJ/kgCO_2$)	References and notes
Direct air carbon capture	3500–9900	Value depends on the type of technology (Chatterjee & Huang, 2020)
Biomethanol upgrading	288–432	Assuming post-combustion carbon capture technologies (Jackson & Brodal, 2019)
Bioethanol production	432	(Moreira et al., 2016; Pace & Sheehan, 2021)
Natural gas power plant flue gas	288–432	Assuming post-combustion carbon capture technologies (Jackson & Brodal, 2019)
Cement plant	288–432	Assuming post-combustion carbon capture technologies (Jackson & Brodal, 2019)

Source: own compilation

Since methane is a potent greenhouse gas and methane emissions are a key contributor to climate change, aspects of direct emissions from methane slip or leakage are of high relevance for the development of future NBRG capacities and infrastructure. Furthermore, besides the identification and quantification of direct methane emissions, the selection of the time frame and the climate metrics can have a strong impact on assessment results. In general, methane has a much higher radiative forcing than CO_2, but is relatively short-lived. Thus, using climate metrices for Global Warming Potentials over a single 100-year time frame has been critically discussed in a number of publications. (Balcombe et al., 2018) presents a review of existing climate metrics for methane and the relevance of their selection in comparative assessments. Across all metrics, CO_2 equivalences for methane range from 4-199 $gCO_{2eq.}/gCH_4$, although most estimates fall between 20 and 80 $gCO_{2eq.}/gCH_4$.

Contrary to methane, hydrogen is not a direct greenhouse gas. Besides emissions related to the production of hydrogen as an energy carrier, a complete conversion of hydrogen to energy would result only in water vapour. However, incomplete hydrogen combustion as well as hydrogen emissions from distribution infrastructure and throughout the value chain can potentially cause climate impacts (Bond et al., 2011; Weger et al., 2021). In the atmosphere, hydrogen reacts and thus reduces the abundance of the hydroxyl radical, thus leading to a potential expansion of the atmospheric lifetimes of such as CH_4. Hydrogen is therefore considered an indirect greenhouse gas. (R. Derwent et al., 2006; R. G. Derwent et al., 2020; IPCC, 2007; Schultz et al., 2003). Furthermore, hydrogen emissions can influence O_3 concentrations, leading to additional potential impacts on air pollution and a potential contribution to the depletion of the O_3 layer in the stratosphere (Sand et al., 2020)

2.5.2 Additional sustainability topics

2.5.2.1 Water use

Electrolysis, even if it uses water as the main feedstock, is not an intensely water-consuming process. When it is compared to other hydrogen production processes, electrolysis consumes 9 kg of water per kg of hydrogen versus 13-18 kg of water per kg of "blue" hydrogen for Steam Methane Reforming with Carbon Capture (IEA, 2021a). Nevertheless, the availability of freshwater for electrolysis is a concern in several places that are rich in renewable sources but suffer from water scarcity or stress, such as Northwest Texas, the Atacama and Sahara Deserts, or Australia. In the regions that are near the sea, reverse osmosis seawater is a non-expensive option, because it affects by less than 1%, or increases only USD 0.01-0.02/kgH_2, the levelized cost of hydrogen (Gallardo et al., 2021; IEA, 2021a). For regions located inland, there are in some locations brackish water aquifers that can be extracted and desalinated, increasing the Levelized Cost of hydrogen only by 0.04 USD/kgH_2 (University Texas at Austin, 2021). Other projects are developing technology to use wastewater as a feedstock for electrolysis (Cater, 2021), or direct seawater electrolysis (IEA, 2021a), but there are not commercial yet.

2.5.2.2 Land use

The land footprint of NBRG production will depend on the electricity source and the electrolysis and methanation installation. The land use of the renewable electricity used for the NBRG production varies according to the source, wind being the least intensive in land-use terms with around 1 square meter per MWh delivered, followed by geothermal with 2.5, solar photovoltaic and hydropower with 10.15 for concentrated solar power, and 500 m^2/MWh for biomass (Fritsche et al., 2017). Tröndle (2020) has concluded that for meeting the electricity demand of Europe 97,000 km^2 need to be used if onshore wind and photovoltaic farms are considered, otherwise, if offshore wind farms are emplaced instead of onshore, and rooftop and utility-scale PV instead of large PV farms, the land use could be reduced in 50%, with only 5% more of total investment. Due to the land-use constraints of renewable power, NBRG produced by means of renewable electricity could use curtailment power to produce hydrogen and with it avoid building new facilities.

Nevertheless, the percentage of excess energy produced by renewable energy is between 8% and 10% of the total productive capacity (Abhyankar et al., 2021; Brinkman et al., 2021; IEA, 2021b), which means that the infrastructure for hydrogen production will have low capacity factors and it will increase the total value of the CAPEX. On the other hand, having dedicated renewable capacity will use more land (see below). The projections show that in a Net Zero Economy, hydrogen and its derivative fuels will use 10% of the total world's energy demand (IEA, 2021a). The report projects the demand for hydrogen may increase six-fold from 2020 to 2050 (530 Mt of H_2 annually). This means that, with an electrolysis efficiency of 70% and annual operating hours of 4,000 hours, around 6.3 TW of new renewable capacity worldwide will need to be installed. Using the values of power density shown above, for a PV solar plant the land requirements will be 265,000 km^2 and an onshore wind farm will need to have an equivalent surface of 25,200 km^2, areas greater than New Zealand for the PV case and the Munster region in Ireland for the onshore wind case. Nevertheless, if offshore wind becomes a major contributor in the energy supply side to meet the energy requirements, the land usage will be significantly lower.

Land use also depends on the transmission of the produced gas, which can be electricity or gas via pipelines. On this last point, pipelines have less footprint and land-use problems than high voltage transmission lines, mainly because of the higher density nature of gaseous energy carriers compared to electricity, and because pipelines can be buried underground (University Texas at Austin, 2021). The electrolyser footprint also varies with the type, with alkaline electrolysers double the size of PEM, at 0.095 m^2/kW_e and 0.048 m^2/kW_e respectively (IEA, 2019). Methanation installations do not have a large footprint compared to that of the primary renewable energy source.

2.5.2.3 Other issues

The use of non-renewable materials like different types of metals is also a sustainability concern for NBRG production. The use of platinum in PEM electrolysers makes the environmental impact of those systems greater than that for alkaline systems. Recycling of those metals decreases the impact of PEM electrolysers by approx. 39% in global warming potential, 66% in human toxicity potential, and 70% in its abiotic depletion potential (Lotrič et al., 2021). Further, RM production was evaluated by Blanco et al. (2020) who concluded that, in comparison with natural gas, RM had a lower environmental impact in the majority of the categories evaluated, only having a greater impact on metal depletion, water depletion, ionizing radiation, and terrestrial, marine and human toxicity. Many of the aforementioned categories' impacts were attributed to the electrolysis stage.

2.6 REGULATORY BARRIERS

2.6.1 Certification

Ensuring that NBRG are low in emissions is one of the key points of the production and trade of these goods. A standardized methodology that allows entities to certify low GHG emissions of NBRG (hydrogen or methane) is crucial for the development of the market because each country will have its own demands in terms of quality and GHG intensity. Some countries, such as Australia, the UK, and France as well as the EU, are working on certification schemes for hydrogen carbon footprint (Bermudez et al., 2020). Meanwhile, the IPHE launched a working paper with a methodology for determining the greenhouse gas emissions of hydrogen production. This methodology addresses different pathways of hydrogen production and establishes criteria for the GHG accounting for each of them (IPHE, 2021). The release of this working paper can draw a path for policymakers to adopt this type of methodology and establish a proper certification approach for renewable hydrogen. For RM, a methodology has yet to be developed, since it is not yet produced at scale. This will however be needed in the near future.

An important element of the certification for NBRGs is to establish coherent instruments that allow traceability of product information (e.g., the guarantee of origin of the electricity used, the origin and climate effects of CO_2) throughout the value chain elements. Especially for value chains that cover different industry or energy sectors, this coherent transfer of information can be challenging since it might include interfaces between different mass balancing methods (e.g., track and trace, book and claim, etc.).

2.6.2 Additionality

Achieving ambitious targets for renewable gases will require a significant amount of renewable electricity, which is also needed for the decarbonisation of several other industrial sectors. So, in order to avoid that the electricity demand for hydrogen becoming a drain on existing renewables in the energy system, the growing demand needs to be matched with new capacities of renewable electricity. (Fritsche et al., 2022) Thus, the EU framework for the support of renewable energy (EU Renewable Energy Directive) requires that, in order to be accounted as renewable, electricity used for the production of renewable energy carriers has to be “additional”. In that sense, Pototschnig, 2021 defines the concept of additionality as “the requirement that renewables-based electricity used in electrolysers for the production of renewable hydrogen is additional to the renewables-based electricity which is used to meet the renewable penetration target with respect to final electricity consumption”.

In practice, the proof of compliance with the additionality concept, which is an important factor for the GHG mitigation potential of the energy carrier and thus, the respective sustainability criterion of the RED, is verified by means of a certification process. (Fritsche et al., 2022) argues for the need of additonal delegated regulations under the RED II which shall provide stakeholders more clearance on how to understand which scenarios for electricity supply (direct connection to an installation producing renewable electricity, grid connection, etc.) can be considered additional and thus, be accounted as renewable electricity in the calculation of the GHG intensity of the Hydrogen produced from it.

Furthermore, Pototschnig, 2021 also argues that a rigid implementation of this concept increases the effort and costs for new projects. Especially in the early stages of NBRG deployment, this may serve as a barrier to market entry, especially when demand for NBRG in the energy and transport sectors is low.

3 NBRG in specific regional contexts

3.1 INTRODUCTION TO CASE EXAMPLE APPROACH

A wide range of technology combinations can be used to produce NBRG, which furthermore can be used to serve various demands as a feedstock or energy carrier. The technological, economic, and potential sustainability characteristics of these pathways are influenced by a number of key drivers, depending, amongst others, on the regional context of the specific supply chain elements.

To understand how the large-scale production of NBRG for local consumption depends on location, three case examples, which were informed by themes identified in the survey, were studied. These themes were: (1) the use of offshore wind in northwestern Europe, (2) diverse combinations of renewables in the United States, (3) integration with biofuels production in tropical regions, and (4) GHG impact of using CO_2 of both fossil and biogenic origin. The locations for the case examples were selected considering the availability of varied renewable electricity resources, availability of varied sources of CO_2, and the potential for internal consumption of NBRG. Case examples that would be heavily reliant on export-import of NBRG were excluded from consideration as international trade in renewable gases is covered in work package 3 of this Inter-Task project. The locations chosen for case examples are the North Sea in Europe, the State of Texas in the USA, and the state of Sao Paulo in Brazil. All the case examples were developed by following the same structure: statement of assumptions and scenarios, techno-econo-environmental modelling, and analysis of the results. For each scenario in each case example, the following techno-econo-environmental performance indicators, which are described in detail in the Annex in Section 7.1, were calculated:

1. **Levelised cost of delivered hydrogen (LCOH).** This is the rate of remuneration in USD/kg or USD/MWh at which an investor would precisely cover expenditures on a hydrogen project after paying debt and equity investors. It includes production, compression, storage, methanation (if applicable) and energy (electricity or NBRG) transmission. For hydrogen, it is calculated per kg and per MWh, while for RM, it is calculated per MWh.
2. **GHG intensity of hydrogen.** This includes the direct GHG intensity of electricity[4] used to power electrolysers, compressors, storage, and methanation (if applicable). For all NBRG, it is calculated per MWh.
3. **Cost of carbon abatement.** This is the cost of abating CO_2 using NBRG. It requires comparison of the delivered cost and GHG intensity of NBRG delivered in each scenario of each case example to those of a reference energy carrier. For hydrogen, the reference is blue hydrogen, while for RM, the reference is natural gas.

---

[4] This includes the operational GHG emissions of electricity generation but excludes the embodied GHG emissions of the electricity generation and transmission infrastructure. The latter is excluded as it requires assumptions about the existing and future energy infrastructure in the case examples that are beyond the scope of this study.

The topics and key characteristics addressed in the analysis include.

Costs of renewable gas production: At several points in recent decades, NBRG technologies have been the focus of intense interest from policymakers but have historically failed to make a significant impact on the world's energy system, primarily due to high costs, infrastructural challenges, and an overall lack of market readiness. In recent years, several drivers have potentially transformed the market landscape for NBRG, including (1) consistent worldwide reductions in renewable electricity prices, especially solar PV and wind, which heavily influence hydrogen production costs, (2) rapid growth in variable renewable electricity, again wind and solar PV, with a concomitant rise in excess and curtailed power, (3) rapid decreases in the costs of hydrogen technologies, especially electrolysers, driven by technological learning, R&D and scaled-up manufacturing, and (4) the shifting of the global policy debate from emissions reductions to net-zero targets in the 2050-2060 timeframe. The analysis explores how these trends will continue to impact NBRG production costs in the following case examples.

Market readiness level of renewable gas production: The decisive shift in national and global climate ambitions to focus on net-zero GHG emissions by 2050-2060 to limit warming to well below 2 °C is changing the commercial landscape for NBRG technologies. Electrification of elements of transportation and heating combined with near-zero or zero-emissions electricity sectors will drive demand for long-duration storage, including NBRG. Hard-to-abate sectors, which had previously not been considered feasible to decarbonize before 2050, are now seen as key mid-term markets for RG. Will these trends lead to the development of purpose-built hydrogen-generating wind and solar farms, or will NBRG production use excess electricity only? The analysis explores how these trends will continue to impact the market readiness level for RG production in the following case examples.

GHG intensity of the renewable gas produced: Global ambition to reduce GHG emissions is one of the main drivers for the increasing interest in NBRG. We will discuss the GHG emission intensity from the production of NBRG in the three case examples and describe the impact of the most influential factors, including GHG intensity of the electricity and CO_2 from fossil or biogenic sources.

GHG accounting of different CO_2 sources: In the case of CO_2 being used to produce renewable gas, the source of this CO_2 can impact the direct GHG emission reduction potential of the renewable gas product. Furthermore, coherent cross-sectoral accounting procedures are necessary to avoid double counting or underestimation of emissions.

Sustainability certification aspects of renewable gases: Supply chains for renewable gases can include elements and processes from different industrial sectors including energy production, agriculture, food production, and chemical production, which are affected by different regulations, policy frameworks, and demands. This imposes a number of potential challenges for the organization of robust certification activities for renewable gases, mainly regarding the transfer of information through the supply chain. This includes, for example, the transfer of information relating to guarantees of origin and proofs of sustainability, traceability, and mass balancing.

3.2 DESCRIPTION OF CASE EXAMPLES

As described above, three case examples of NBRG production and delivery to end-use sites were developed based on input from the expert survey and reviews of proposed NBRG projects worldwide. A North Sea case example enables study of offshore wind and multiple sources of biogenic and industrial CO_2. A Texas case example enables study of multiple forms of renewable electricity and CO_2 sources in the biofuels and petrochemicals industries. A Brazil case example enables study of multiple renewable sources, a grid with low GHG intensity, and CO_2 availability from biofuels production. The sections below give details of the fixed and variable elements of each case. All cases are selected so that NBRG is produced and used in the same country, or within the EU. We are therefore omitting international trade of NBRG, which, as stated above, is covered in WP3. The cases consider renewable electricity generation, water electrolysis, hydrogen storage, possible CO_2 capture and methanation, electricity/hydrogen/methane transmission and delivery to end-users. Three possible classifications of electricity source are considered in the analysis:

1. **Excess renewables:** In this classification, only renewable electricity that would otherwise be wasted or curtailed is used to power the electrolyser. The benefits of this source include: very low electricity price and GHG intensity, and ability to meet additionality requirements. Its major drawback is that the temporal irregularity of excess electricity means that electrolysers sized to capture high excess power flows will have very low capacity factors.
2. **Dedicated renewables:** In this classification, the sole purpose of a renewable energy generator is to supply hydrogen as opposed to electricity. The benefits of this source include: higher capacity factor than excess renewables, very low electricity GHG intensity, and ability to meet additionality requirements. Its major drawback is that the variability of renewable energy means that electrolysers may have moderate capacity factors. The price of electricity in this classification is solely dependent on the trajectory of renewable costs into the future.
3. **Grid electricity:** In this classification, the capacity of the electrolyser is maximised by connecting it directly to the electricity grid. The major benefit of this source is that electrolyser capacity factor can be maximised leading to highly effective use of capital. Its drawbacks include: GHG intensity that is fully dependent on the grid electricity mix, and inability to meet additionality requirements. The price of electricity in this classification is dependent on a number of factors relating to the evolution of electricity grids to zero carbon and the investments required to enable that.

The boundaries of the analysis take as inputs renewable electricity and water for electrolysis, and CO_2 for potential methanation. The outputs are in all cases NBRG in the form of hydrogen or methane. The end-use of NBRG is not considered in the analysis for the following reasons. Once produced, hydrogen and methane have known GHG emission factors and end-use GHG mitigation can be calculated by comparing these to the emissions factors of the fossil fuels they displace. Given the range of potential electricity and CO_2 sources, GHG emissions from RG production require consideration. Consideration of data availability is also given for all cases. The following table shows a summary of all three case examples.

Table 7. Case examples summary.

Case	North Sea	Texas	Brazil
Electricity source	Offshore wind farms in the North Sea (excess or dedicated electricity) Electricity grid for fulltime operation	Renewable mix (PV & onshore wind) from northwest Texas (excess or dedicated) Offshore wind in the Gulf of Mexico (excess or dedicated)	Renewable mix (PV & biomass) from the interior of Sao Paulo state Offshore wind in the Atlantic Ocean Electricity grid for fulltime operation
Electrolyser location & hydrogen transmission	At the offshore electricity source location (no electricity transmission, but with NBRG pipeline) At the onshore NBRG demand site (electricity transmission, but no NBRG pipeline)	At the inland/offshore electricity source location (no electricity transmission, but with NBRG pipeline) At the coastal NBRG demand site (electricity transmission, but no NBRG pipeline)	At the inland/offshore electricity source location (no electricity transmission, but with NBRG pipeline) At the coastal NBRG demand site (electricity transmission, but no NBRG pipeline)
CO_2 source for RM production	None (H_2 is the product) Biomethane upgrading Cement industry flue gas Direct air capture	None (H_2 is the product) Power plant flue gas Bioethanol production Direct air capture	None (H_2 is the product) Bioethanol production Steel industry flue gas Direct air capture
NBRG demand site	North Sea coastline in Germany	Petrochemicals hub near Houston	Heavy industry hub near Sao Paulo

Source: own compilation

3.2.1 North Sea

This case example considers the generation of NBRG via electrolysis powered mostly by offshore wind for use in north-western Germany as shown in Figure 4. 1 GW of electrolyser capacity was assumed for all scenarios. The independent variables selected for scenario development are shown below. Some of the 48 potential combinations of independent variables resulted in unrealistic scenarios, e.g., scenarios that use grid electricity offshore, or scenarios that bring industrial or agricultural CO_2 offshore for methanation. Therefore, only the 32 scenarios, shown in 7.2.1, which were deemed to be realistic were considered further.

- Year of construction (2030 or 2050),
- Source of electricity (grid, dedicated offshore wind power, or excess offshore wind power),
- Electrolyser location (onshore or offshore),
- Source of CO_2 (none, cement industry, direct air carbon capture, and biomethane upgrading).

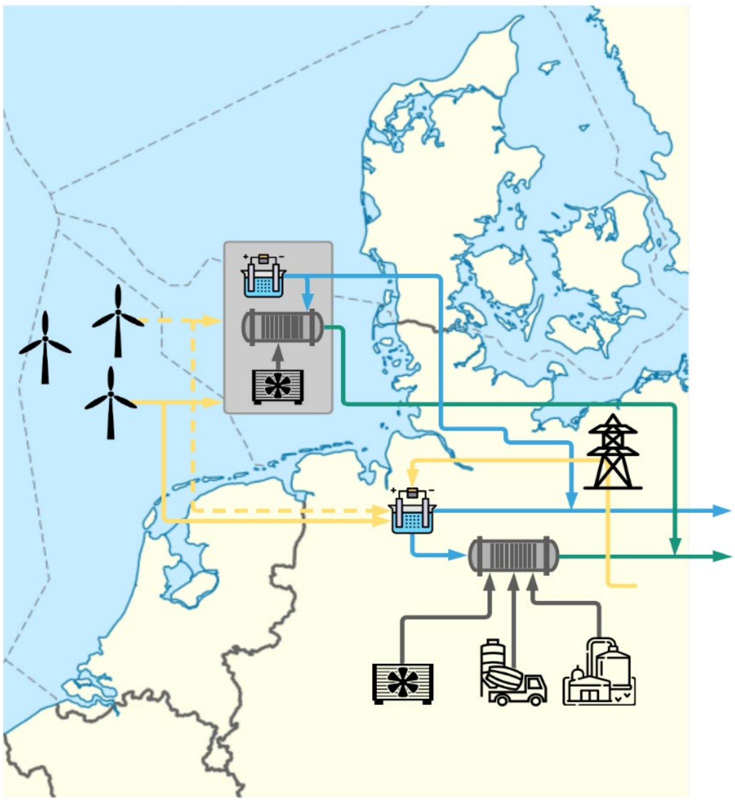


Figure 4. North Sea scenarios graphical description. Yellow lines show electricity transmission (solid for dedicated and dashed for excess). Blue, green and grey lines show H_2, CH_4 and CO_2 transmission, respectively.

For each scenario, the modelling considered different inputs (dependent variables) that vary depending on the independent variables. The most important dependent variables and the values used for the simulation of the scenarios are presented in the annexes. In addition, some assumptions were made considering the feedstocks for the process. The electricity generation was considered outside the boundaries, but not its transmission, which is influenced by electrolyser location. The power required to run the electrolyser and the methanation process was considered a utility with fixed annual average price and GHG gas intensity. The water supply required for the electrolysis was also considered as an input. For the offshore electrolyser cases, the price of desalinated water provided by reverse osmosis was used. For the onshore electrolyser cases, prices paid by industrial water consumers was used. A distance of 300 km between the offshore wind farm and the shore was considered. The type of electrolyser was considered according to the source of electricity. Alkaline electrolysis was assumed for dedicated and grid electricity scenarios, and PEM for the excess electricity scenarios. For all scenarios, the direct GHG emissions produced by the process and the feedstock used were counted. The accounting of the GHG intensity of CO_2 coming from the cement industry was evaluated separately using the four alternative schemes shown in Table 8. Finally, the GHG intensity of the electricity required for methanation, and compression was assumed to be the same as the GHG intensity of the electricity source used for the electrolysis in each scenario proposed.

Table 8. Four alternative schemes for the allocation of costs and GHG emissions for CO_2 between cement industry (producer of CO_2) and NBRG production (user of CO_2).

	Cement producer pays NBRG producer to "dispose" of CO_2	**NBRG producer pays cement producer for CO_2 feedstock**
NBRG producer liable for CO_2 GHG emissions	Intermediate, more realistic scenario	Worst case, less realistic scenario
Cement producer liable for CO_2 GHG emissions	Best case, less realistic scenario	Intermediate, more realistic scenario

Source: own compilation

3.2.2 Texas

For this case example, the state of Texas in the United States of America was selected as the location, where the final delivery point of the NBRG is around the Houston area, as shown in Figure 5. 1 GW of electrolyser capacity was assumed for all scenarios. The independent variables selected are shown below. For the same reasons as those stated for the North Sea, some of the 48 potential combinations of independent variables resulted in unrealistic scenarios. Therefore, only the 30 scenarios, shown in 7.3.1, which were deemed to be realistic were considered further.

- Year of construction (2030 or 2050),
- Source of electricity (Excess wind and solar energy from northwest Texas, dedicated wind and solar energy from northwest Texas, and dedicated offshore wind in the Gulf of Mexico),
- Electrolyser location (northwest Texas or Houston area),
- Source of CO_2 (None, DACC, bioethanol production, natural gas power plants).

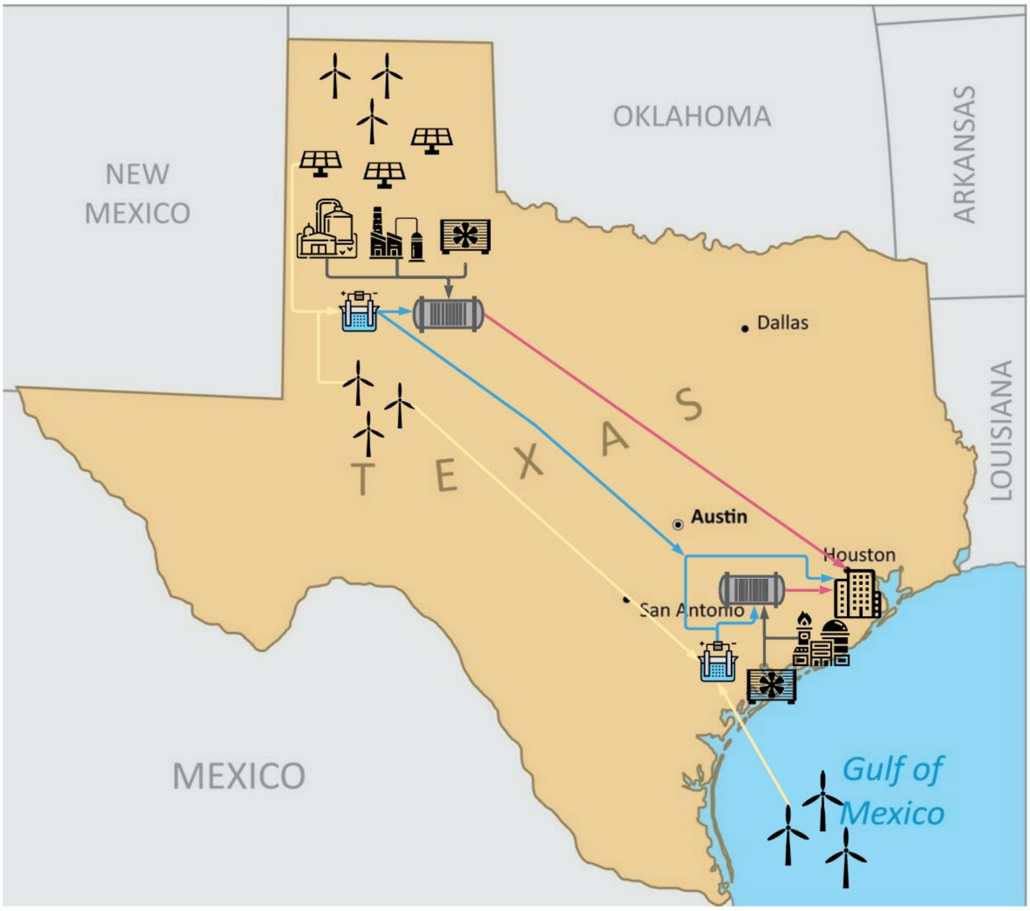


Figure 5. Texas scenarios graphical description. Yellow lines show electricity transmission. Blue, red and grey lines show H_2, CH_4 and CO_2 transmission, respectively.

The specific values of dependent variables used for the modelling are presented in Section 7.3.2. All system boundaries and output, and most inputs and assumptions, are the same as the North Sea case example, so only the differences are discussed here. The price of water for electrolysis was considered equal for both electrolyser locations, because in the northwest, brackish water is used, and in Houston, seawater is used. Both require desalination, which results in similar costs (University Texas at Austin, 2021). The distance between the different locations was considered as 850 km between Houston and the Northwest, and 250 km from the Offshore wind farm to Houston. In all cases, PEM electrolysers were used. The total CO_2 emissions will only consider that used in the methanation process, since all scenarios use only renewable energy that it does not produce any direct GHG emissions. The methanation process, the electrolysis, the compression, and all the energy-intense processes will work with renewable energy, with only the carbon capture process using grid electricity.

3.2.3 Brazil

For the Brazil case example, the state of Sao Paulo in the south of the country was selected as a location, where the final delivery point of the NBRG is the industrial hub at Santos on the coast near the city of Sao Paulo, as shown in Figure 6. 1 GW of electrolyser capacity was assumed for all scenarios. The independent variables selected as shown below. For the same reasons as those stated for the North Sea and Texas, some of the 36 potential combinations of independent variables resulted in unrealistic scenarios. Therefore, only the 18 scenarios, shown in Section 7.4.1, which were deemed to be realistic were considered further.

- Year of construction (2030 or 2050),
- Source of electricity (dedicated biomass power, dedicated PV from northwest of state, dedicated offshore wind off the coast),
- Electrolyser location (northwest of state, on the coast at Santos, offshore),
- Source of carbon dioxide (None, DACC, bioethanol plant, steel industry).

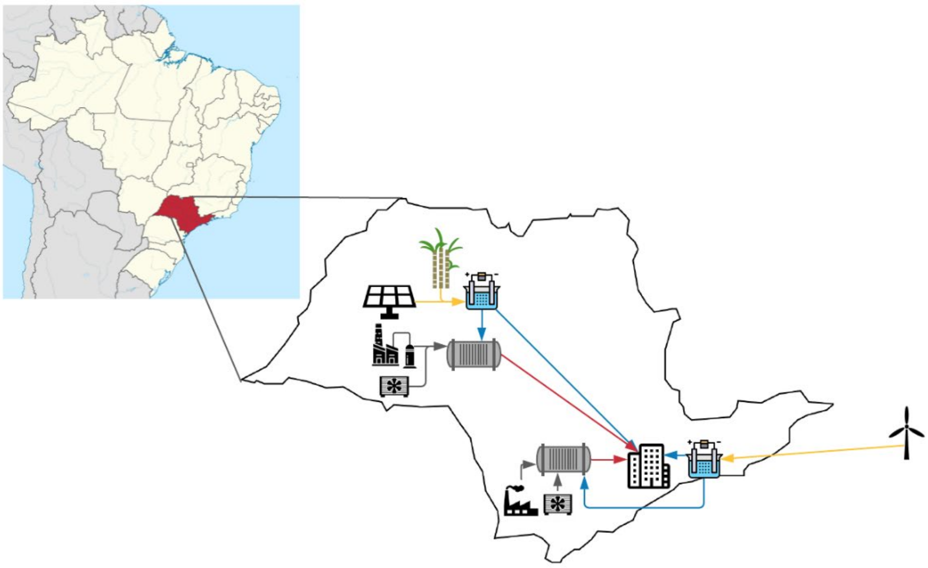


Figure 6. Brazil case example graphical description. Yellow lines show electricity transmission. Blue, red and grey lines show H_2, CH_4 and CO_2 transmission, respectively.

The specific values of dependent variables used for the modelling are presented in Section 7.4.2. All system boundaries and output, and most inputs and assumptions, are the same as the North Sea and Texas case examples, so only the differences are discussed here. The distance between the different locations was considered as 500 km between Santos and the northwest, and 500 km from the Offshore wind farm to Santos. In all cases, PEM electrolysers were used. The total CO_2 emissions will only consider that used in the methanation process, since all scenarios use only renewable energy that it does not produce any direct GHG emissions. The methanation process, the electrolysis, the compression, and all the energy-intense processes will work with renewable energy, with only the carbon capture process using grid electricity.

3.3 DESCRIPTION OF ANALYSIS METHODS

All case examples will be modelled to determine: **levelized cost** per kg and per MWh for hydrogen and per MWh for methane, **greenhouse gas intensity** per MWh delivered, and **carbon abatement cost** in USD/kgCO_{2e}. The detailed calculation of these indicators is explained in Section 7.1.

4 Results & discussion of regional case examples

4.1 North Sea

4.1.1 Levelised Cost of Delivered NBRG

Figure 7 presents the levelized costs of delivered hydrogen (method described in Section 7.1.1) for North Sea scenarios that produce hydrogen only. The 2030 scenarios are on the left and the 2050 scenarios are on the right. It is important to recall that hydrogen production is proposed to be powered by electricity from different sources with different prices and GHG intensities. Scenarios considered offshore or onshore electrolysis due to the differences between electricity and hydrogen transmission costs, as well as two different years, 2030 and 2050, which allows consideration of decreases in equipment costs over time. For each year, electrolyser electricity sources are, left to right, dedicated, excess, and grid. For each electricity source, offshore and onshore electrolyser locations are shown. Levelized costs components include H_2 production CAPEX and OPEX (shown individually), H_2 storage CAPEX and OPEX (shown combined), and H_2 (for offshore) or electricity (for onshore) transmission CAPEX and OPEX (shown combined).

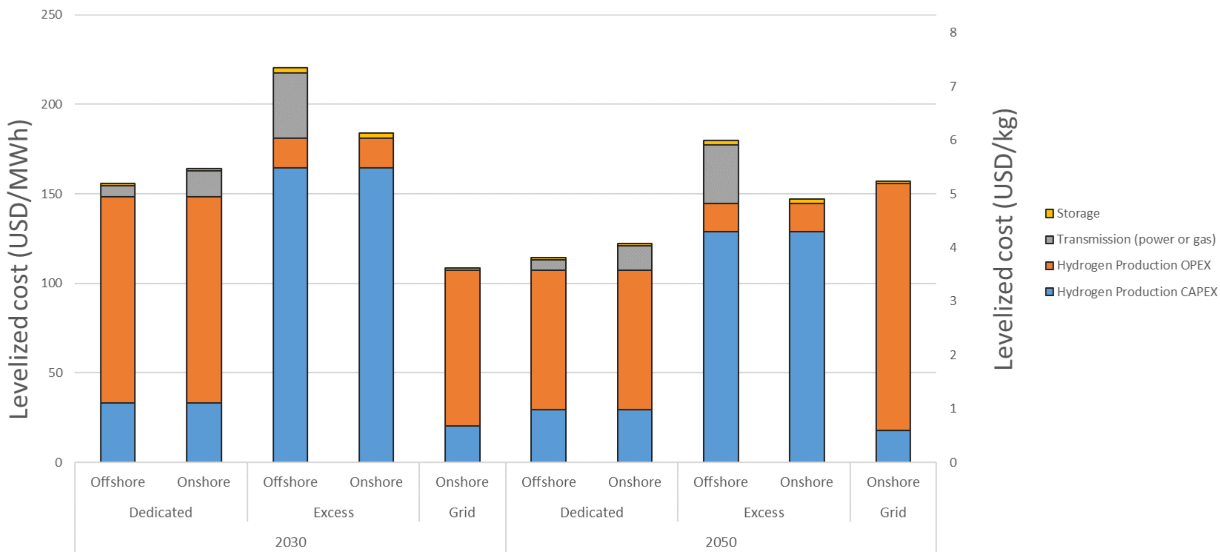


Figure 7. Delivered cost of hydrogen for scenarios in the North Sea case example.

The figure shows three key features: (1) using dedicated power is cheaper than using excess power, (2) the costs of dedicated and excess production decrease significantly from 2030 to 2050, and (3) grid-powered onshore electrolysis is the cheapest option in 2030, but not in 2050. These features are discussed in detail in the following paragraphs.

Dedicated power versus excess power operation. Hydrogen produced using dedicated offshore wind power is cheaper than that produced using excess offshore wind power. When using dedicated power, the electrolyser has a capacity factor of 55%, equal to that of the wind farm. In contrast, when using excess power only, the electrolyser has a capacity factor of 10%. Even though excess offshore wind power is assumed to have a price of 0 USD/MWh, the low operational hours of the electrolyser means that levelized costs of hydrogen are higher when that source of electricity is used exclusively. Considering production CAPEX and OPEX costs only, clear contrasts are observed between OPEX-dominated dedicated operation and CAPEX-dominated excess production.

Hydrogen produced using dedicated power is cheaper offshore than onshore as it is more cost-effective to transport hydrogen by pipeline than it is to transport electricity by transmission cable (University Texas at Austin, 2021). The opposite trend is seen for hydrogen produced using excess power. No transmission costs are calculated for hydrogen produced onshore using excess power only. This is because the transmission infrastructure, in this case, an electricity transmission line, would already have been built to connect the wind farm to the electricity grid, regardless of hydrogen production.

Dedicated and excess production costs in 2030 and 2050. The delivered cost of hydrogen produced using both dedicated and excess offshore wind electricity dropped by 26.6 and 18.3% respectively between 2030 and 2050. For dedicated production, the primary driver is the average price paid for electricity (explored in more detail in Figure 8 below), with a secondary contribution from electrolyser efficiency. The analysis presented in Figure 7 assumes offshore wind electricity prices of 76.3 USD/MWh in 2030 and 54.5 USD/MWh in 2050. Due to the uncertainty of these assumed values, their impact on delivered hydrogen costs is illustrated in Figure 8. This analysis uses offshore wind electricity prices of 54.5 to 98.1 USD/MWh in 2030 and 32.7 to 76.3 USD/MWh in 2050. Figure 8 shows delivered hydrogen costs for 2030 of 4.4 and 6.5 USD/kg, and for 2050 of 3 and 5 USD/kg. The calculated decrease in delivered hydrogen costs when excess power is used is driven primarily by decreasing electrolyser costs, which are projected to be 463 USD/kW in 2030 and 363 USD/kW in 2050 for PEM systems.

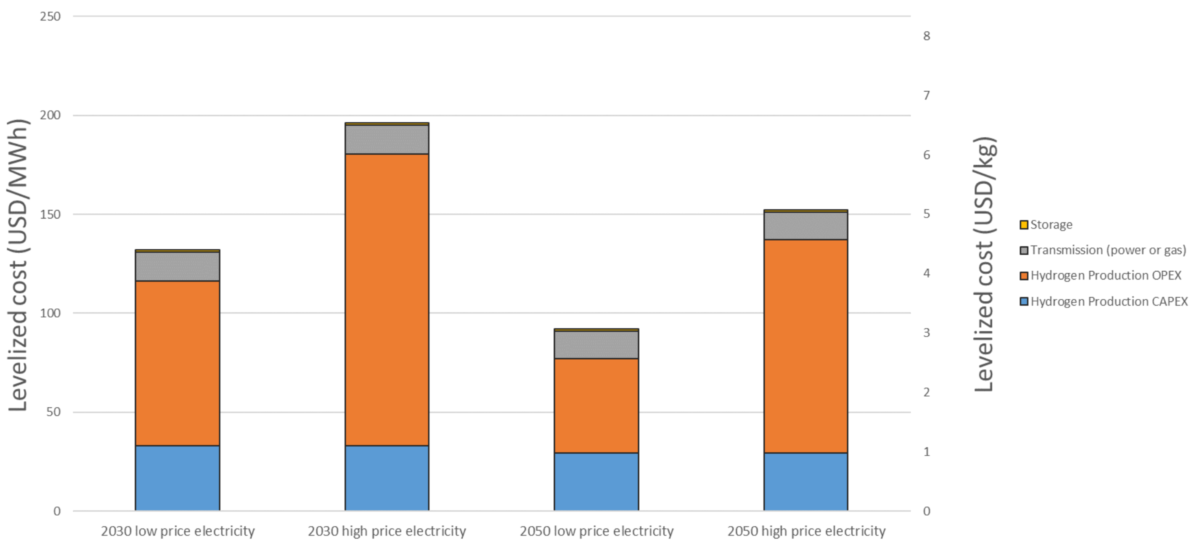


Figure 8. The impact of electricity price on the delivered cost of hydrogen produced offshore in 2030 and 2050.

Increasing cost of grid-powered hydrogen production. The only hydrogen scenarios that increase in cost between 2030 and 2050 are grid-powered production. Due to the high electrolyser capacity factor assumed in these scenarios, 90%, delivered hydrogen costs are dominated by electricity price. Due to ongoing efforts to decarbonise electricity generation by phasing out fossil fuels, setting increasing prices on CO_2 emissions, deploying renewables and nuclear power, this analysis assumes the wholesale price of electricity rises to 58 USD/MWh in 2030 and 98.6 USD/MWh in 2050 (Perez-Linkenheil, 2019). This has the direct effect of increasing the cost of delivered hydrogen.

The delivered costs, on a MWh basis for 2030, of non-biogenic renewable methane (RM or power-to-methane) produced onshore using H_2 from electrolysis and CO_2 from a variety of sources are shown in comparison to hydrogen in Figure 9. The studied CO_2 sources are: off-gases from a biogas to biomethane upgrader, flue gas from cement production, and direct air capture (DACC). On the right side of Figure 9, the hydrogen option is shown for comparison. The sole driver of cost differences between the RM options is the price of CO_2 from these sources. Recall that CO_2 is an input to the system and the price paid for it is assumed to cover the cost of capturing it. This same trend of RM costs is seen when any H_2 production scenario from Figure 7 is applied. While methanation increases the delivered cost of RM by 43.8 to 111.7 USD/MWh above that of hydrogen, it must be borne in mind that this RM can be used widely in unmodified natural gas infrastructure. The same cannot be said of hydrogen.

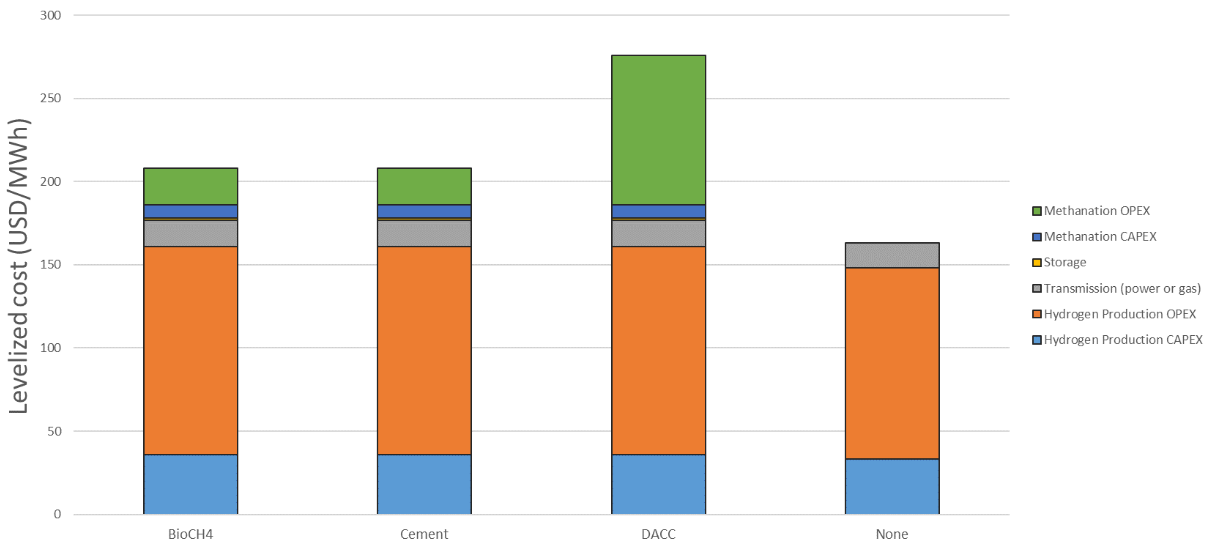


Figure 9. Delivered cost of renewable methane produced onshore using H_2 from electrolysis with dedicated electricity and CO_2 from a variety of sources in the North Sea case example for 2030.

Impact of discount rate most cost-effective scenarios. To explore the impact of discount rate on levelised cost, its value was varied +/-50% for one of the more cost-effective hydrogen scenarios. As shown in Table 9, the impact on levelised cost is roughly +/-5%, indicating discount rate is of secondary importance. This is explained by the fact that the most cost-effective scenarios involve dedicated renewable powered or grid-powered electrolysers. In these scenarios, OPEX, primarily electricity price, dominates. Discount rate has a bigger impact on scenarios in which the electrolyser is powered by excess renewables, but these are not cost effective.

Table 9. Effect of the discount rate over the LCOH in 2030 Dedicated onshore scenario for hydrogen production.

Discount rate	4%	6%	8%
LCOH (USD/MWh)	**156.2**	164.2	173.1
Percentage difference from baseline scenario	**-4.8%**	0%	5.4%

4.1.2 GHG Intensity of NBRG

The sole hydrogen-only North Sea scenario that produced direct GHG emissions (method described in Section 7.1.2) was the 2030 onshore grid scenario, with GHG intensity of 127 $kgCO_{2eq}/MWh$ since the European electricity grid will still have fossil fuels in the generating mix. This figure is lower than the lowest direct (combustion-related) GHG intensity of natural gas at 226 $kgCO_{2eq}/MWh$ (SEAI, 2021; Wernet et al., 2016). GHG intensities for 2030 dedicated onshore RM-producing scenarios are presented in Figure 10. The key feature of this figure is the high GHG intensity value for CO_2 sourced from the cement industry. The main assumption behind this value was that the NBRG producer is liable for GHG emissions of the CO_2 used and also pays the price of capturing it, as described in Table 8.

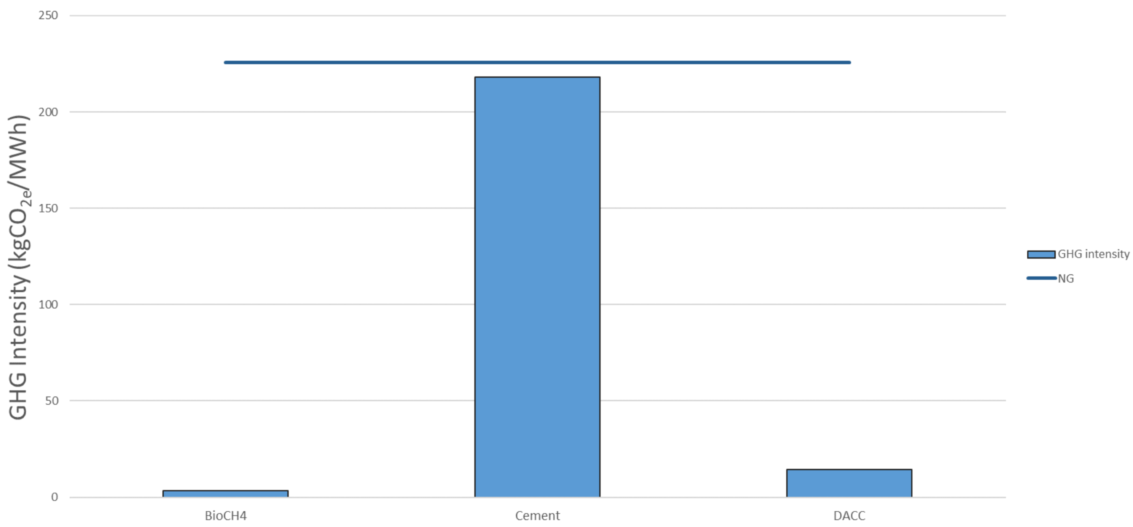


Figure 10. GHG intensity of renewable methane produced onshore using H_2 from electrolysis with dedicated electricity and CO_2 from a variety of sources in the North Sea case example for 2030.

The sensitivities of delivered RM levelized cost and GHG intensity to different schemes of allocating the emissions and costs of cement sourced CO_2 are explored in Figure 11. These different schemes are described in Table 8. The figure shows that the levelized costs are not very sensitive to the cost allocation scheme since the major cost components relate to hydrogen production. GHG intensity is, however, highly sensitive to the carbon accounting scheme used. The implications of this need careful consideration in the design of policy for NBRG.

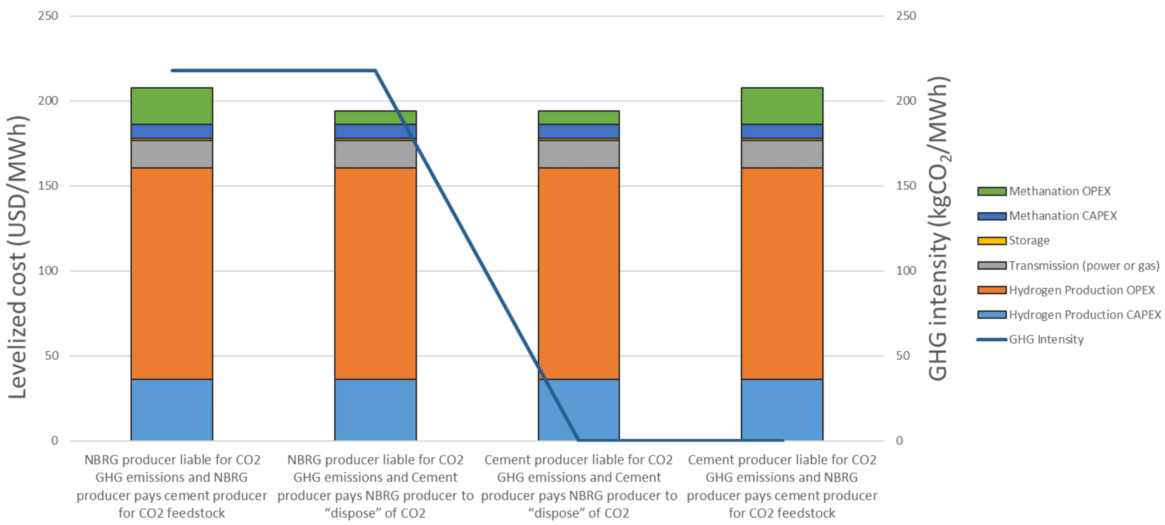


Figure 11. Levelized cost and GHG intensity of renewable methane and under different carbon accounting and cost charging schemes.

4.1.3 Carbon Abatement Cost

Figure 12 presents the carbon abatement costs of delivered hydrogen (method described in Section 7.1.3) for North Sea scenarios that produce hydrogen only. The 2030 scenarios are on the left and the 2050 scenarios are on the right. For each year, electrolyser electricity sources are, left to right, dedicated, excess, and grid. For each electricity source, offshore and onshore electrolyser locations are shown. The trends of levelized cost seen in Figure 7 are broadly present in Figure 12 since all scenarios except 2030 grid-powered electrolysis have no direct GHG emissions. The lowest carbon abatement cost, around 140 USD/tonneCO_{2eq}, are for the 2050 dedicated scenarios. These values are close to some countries' carbon tax values (World Bank, 2021). The highest carbon abatement costs are for the excess scenarios, where the high levelized cost makes these options uncompetitive for now.

Figure 13 presents the carbon abatement costs for 2030 dedicated onshore RM-producing scenarios, as well as that for hydrogen without methanation, shown by the "none" bar. The cement industry carbon source scenario is not shown because the carbon emissions are almost as high as the natural gas emissions making the carbon abatement cost too high, this is under the assumption that the NBRG producer takes responsibility for the GHG emissions of the CO_2 used and also the costs of capturing it. The trends observed here are replicated across the other RM scenarios. The carbon abatement costs for the RM options are high (above 700 USD/ton$CO2_{eq}$), meaning that these processes will struggle to be economically competitive.

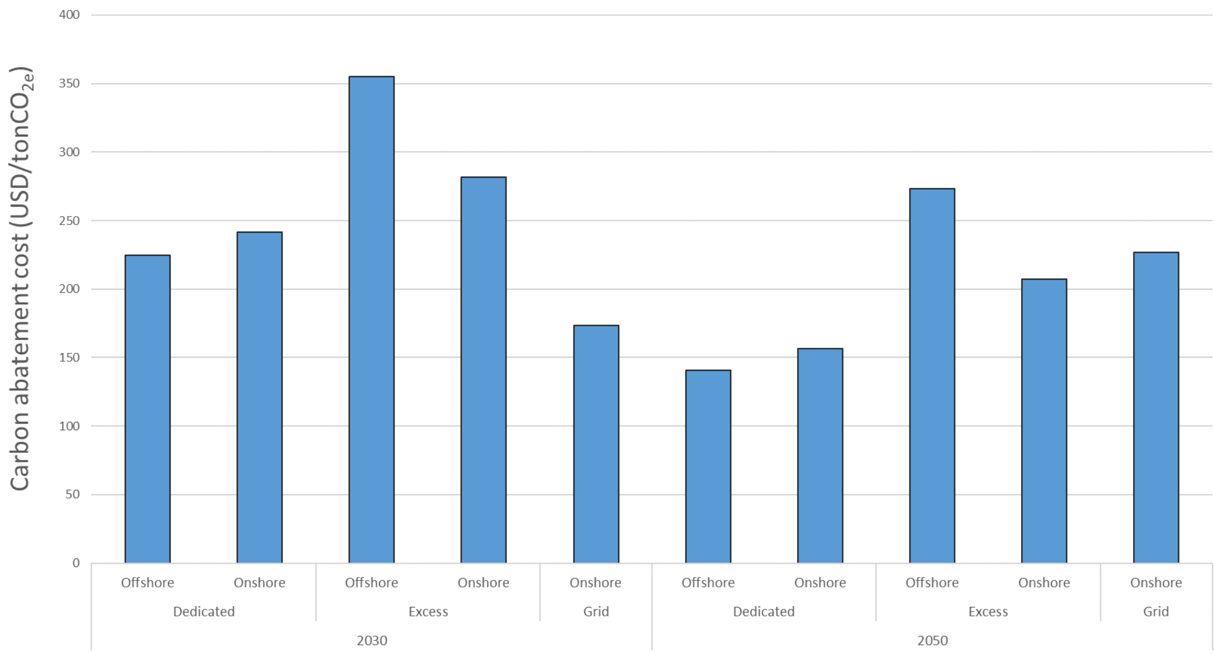


Figure 12. Carbon abatement cost of delivered hydrogen in North Sea case example scenarios.

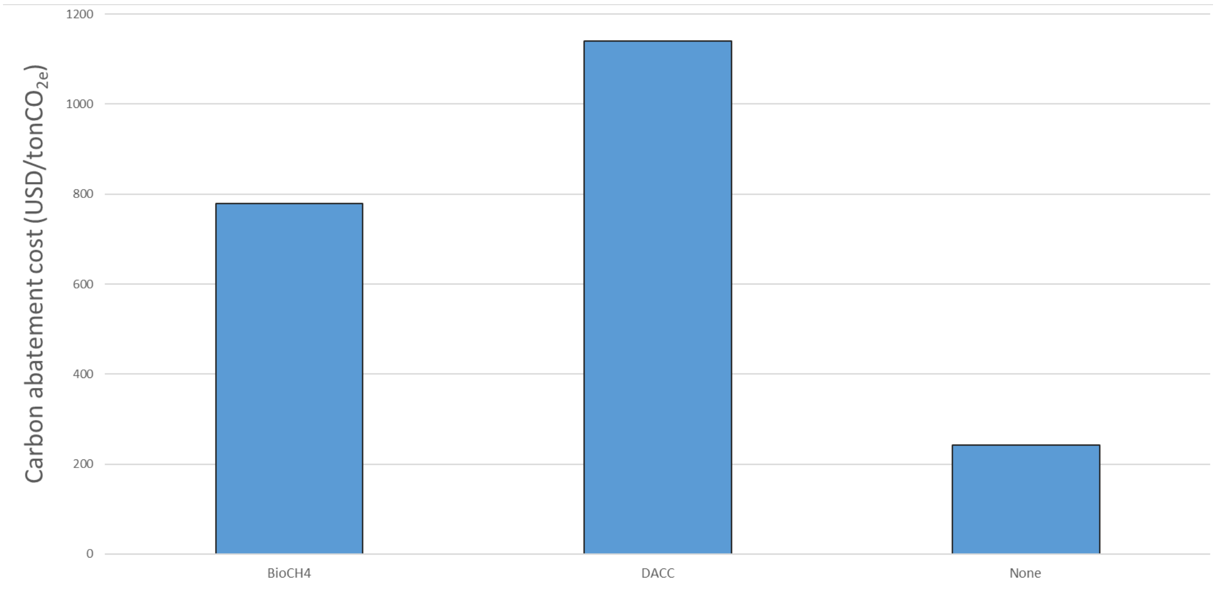


Figure 13. Carbon abatement cost of Renewable Methane produced onshore using H_2 from electrolysis and CO_2 from a variety of sources in the North Sea case example for 2030.

4.2 Texas

4.2.1 Levelised Cost of Delivered NBRG

Figure 14 shows the levelized costs of delivered hydrogen for Texas scenarios that produce hydrogen only. The 2030 scenarios are on the left and the 2050 scenarios are on the right. For each year, electrolyser electricity sources are, left to right, excess renewable mix energy (solar and wind) from the northwest, dedicated renewable mix energy from the northwest, and dedicated offshore wind. For each electricity source, various electrolyser locations are shown. Levelized costs components include H_2 production CAPEX and OPEX (shown individually), H_2 storage CAPEX and OPEX (shown combined), and H_2 (for offshore) or electricity (for onshore) transmission CAPEX and OPEX (shown combined).

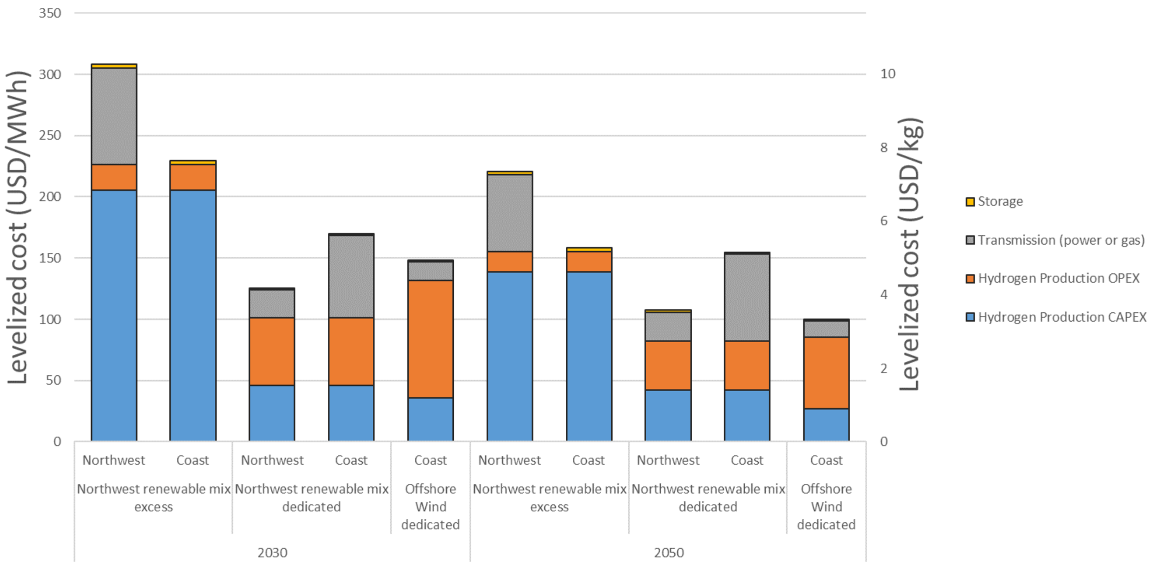


Figure 14. Delivered cost of hydrogen for scenarios in the Texas case example.

The figure shows three key features: (1) using dedicated power is generally cheaper than using excess power, (2) the costs decrease significantly from 2030 to 2050, and (3) dedicated renewable mix energy with electrolysis in the northwest is the cheapest option in 2030, but dedicated offshore wind is the cheapest in 2050. These features are discussed in detail in the following paragraphs.

Dedicated power produces cheaper hydrogen than excess power: Like in North Sea case example, the low capacity factors that excess power carries to the electrolyser make the CAPEX of hydrogen production much higher than if dedicated energy is used. Even if by using excess energy, transmission infrastructure can be dismissed by placing the electrolyser at the coast, it still has higher levelized costs. It is 26% cheaper to produce hydrogen with dedicated renewable power from the northwest at the coast by 2030.

Decrease in costs in 2050: The impact on levelized costs due to the expected decrease of prices of electrolysers and renewable electricity by 2050 is relevant in every scenario. For excess energy scenarios, only the CAPEX decrease has a large influence on the prices by 2050, with a decrease of 2.9 USD/kg in northwest electrolysis scenarios and 2.4 USD/kg in coastal electrolysis scenarios. For dedicated electricity scenarios, the change is less important, with a decrease of approximately 0.5 USD/kg. This is because of the less pronounced expected decrease of renewable electricity prices in Texas compared to the North Sea case example; 33 USD/MWh in 2030 versus 25 USD/MWh in 2050 (Abhyankar et al., 2021; Daprato, 2019; IEA, 2021b). On the dedicated wind scenarios side, the decrease in levelized costs is greater than in the dedicated renewable mix in northwest, due to a more pronounced decrease in offshore wind power expected for 2050 compared to 2030, from 60 USD/MWh to 40 USD/MWh.

Cheapest scenarios in 2030 and 2050: Since transmission of hydrogen in pipelines has a lower cost than power transmission, use of the dedicated renewable mix from the northwest with in-situ electrolysis is the most cost-effective way to deliver hydrogen in Texas in 2030. Nevertheless, because of the strong influence of electricity price, by 2050, the dedicated offshore wind scenario gives lower levelized costs than the northwest dedicated renewable mix scenario. Additionally, the transmission distance is considerably shorter for the offshore wind, which decreases investment cost. Finally, greater capacity factors in offshore wind scenarios (~47% compared to ~33% in dedicated northwest renewable mix scenarios), drives higher hydrogen production and with this, less CAPEX influence in the final levelized cost.

The delivered costs, on a MWh basis for 2030, of non-biogenic renewable methane (RM or power-to-methane) produced with the northwest renewable mix using H_2 from electrolysis at northwest or coast and CO_2 from a variety of sources are shown, as well as those for hydrogen without methanation, shown by the "none" bars, in Figure 15. The studied CO_2 sources are: ethanol production fermentation gas and direct air capture (DACC) for the northwest scenarios, and power plant flue gases and DACC for coastal scenarios. On the righthand side of each electrolyser location, the hydrogen-only option is shown for comparison. As in the previous case example, the sole driver of cost differences between the RM options is the price of CO_2 from these sources. The CO_2 is an input to the system and the price paid for it is assumed to cover the cost of capturing it. This same trend of RM costs is seen when any H_2 production scenario from Figure 14 is applied. The methanation stage adds between 32 and 113 USD/MWh to the levelized cost compared with pure hydrogen. Since methane can be used in existing natural gas infrastructure, for those systems that require transport of RM, existing pipelines could be utilized, decreasing the cost of the final product by 25 (USD/MWh). This could make RM production more competitive than hydrogen in the northwest regions of Texas.

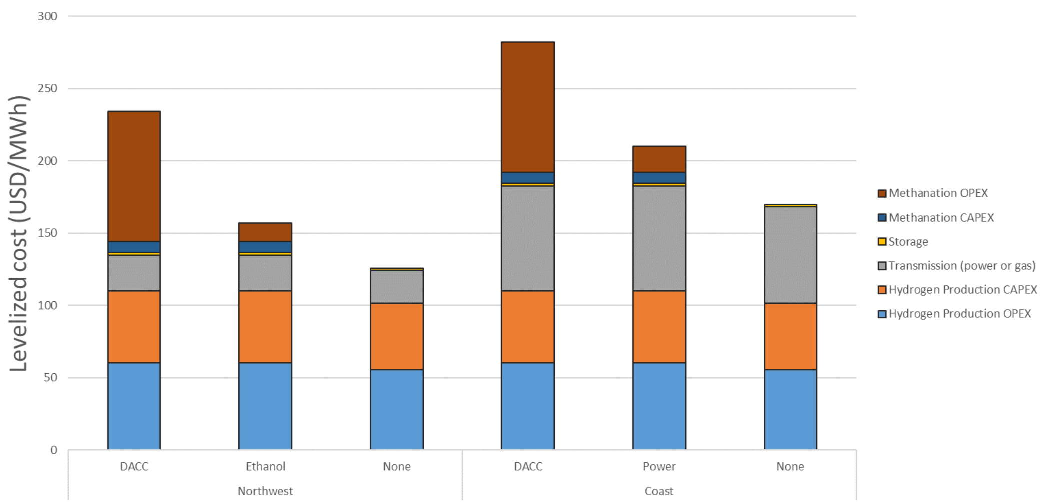


Figure 15. Delivered cost of renewable methane produced in northwest regions or in the coast using H_2 from electrolysis with dedicated northwest renewable mix power and CO_2 from a variety of sources in the Texas case example for 2030.

4.2.2 GHG Intensity of NBRG

As in the North Sea case example, no direct emissions were considered in the hydrogen scenarios, hence GHG intensities for 2030 northwest dedicated renewable mix scenarios are presented in Figure 16.

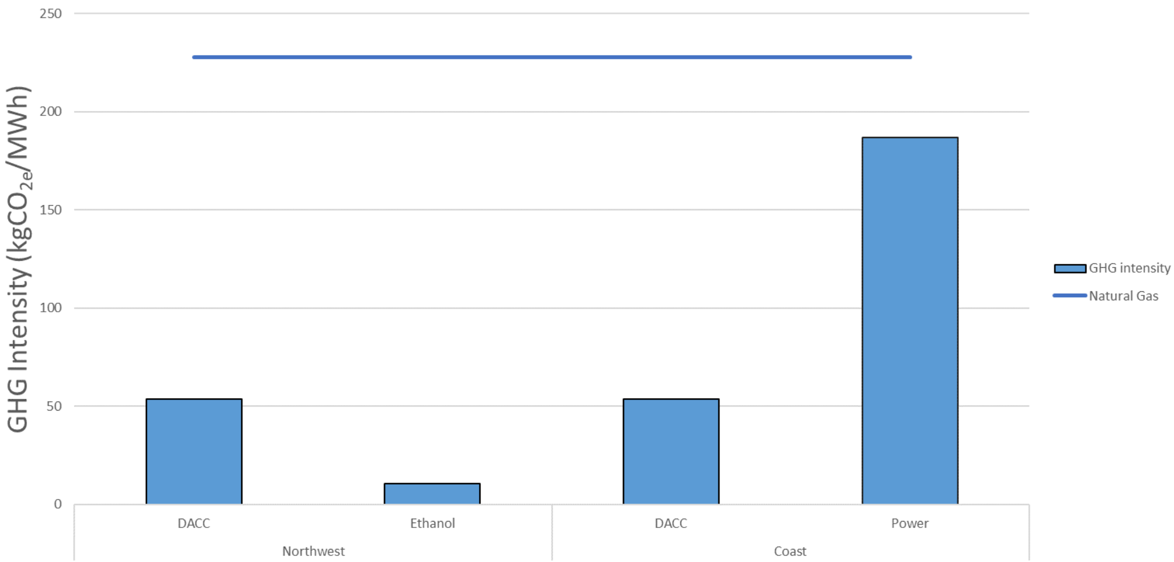


Figure 16. GHG intensity of renewable methane produced using H_2 from electrolysis with northwest dedicated renewable mix electricity and CO_2 from a variety of sources in the Texas case example for 2030.

Key features of the figure are (1) Ethanol fermentation gas carbon source is the least carbon-intensive option evaluated, (2) power plant flue gas carbon source options have the biggest carbon footprint but depend on the type of accounting.

Ethanol production gas is less carbon-intensive: the biogenic origin of the carbon dioxide that comes from ethanolic fermentation gives that source a lower GHG intensity. Among the other scenarios, according to Figure 15, it has the lowest production costs. Those advantages are because of the high purity that CO_2 has in fermentation off-gases (>95%), which makes the capturing process less energy-intensive (Pace & Sheehan, 2021).

Power plant flue gases have the highest carbon footprint: As in the cement scenarios in the North Sea case example, the GHG accounting for non-renewable carbon sources is crucial for analysing the environmental impact of NBRG production. If GHG intensity of carbon dioxide is attributed to the NBRG production, the carbon footprint of the RM will be greater than the natural gas, which makes the whole process non-feasible in environmental terms. Again, this topic will need to be considered carefully in NBRG policy development.

4.2.3 Carbon Abatement Cost

Figure 17 presents the carbon abatement cost in the different hydrogen-producing scenarios. Since no carbon emissions are considered for these scenarios, the trend follows the price behaviour shown in Figure 14.

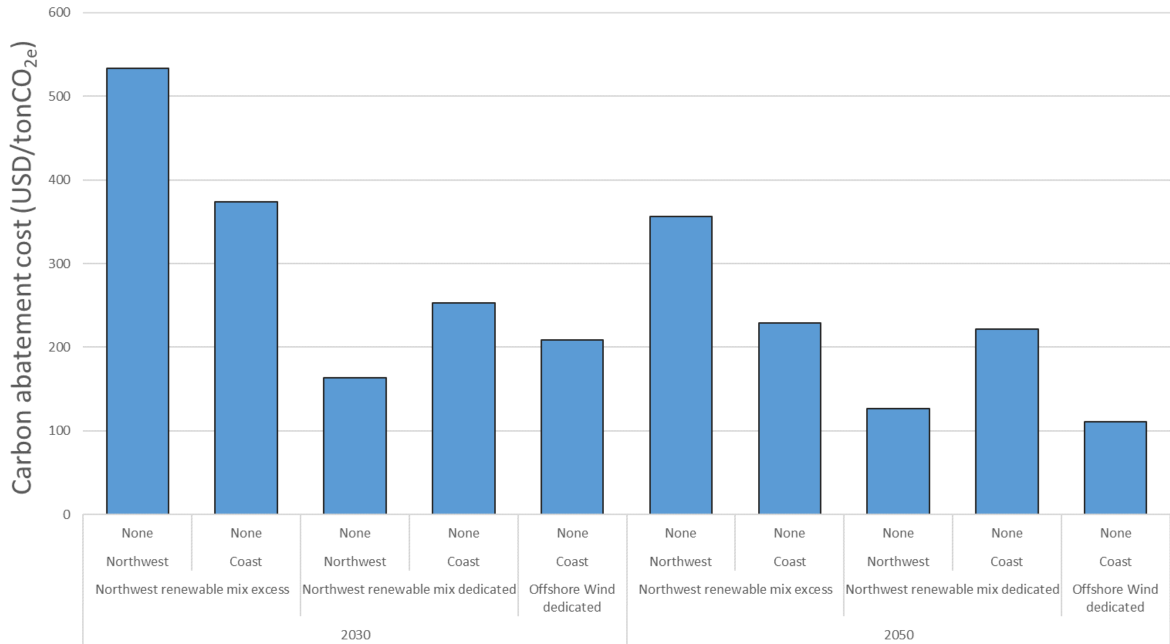


Figure 17. Carbon abatement cost of delivered hydrogen in Texas case example scenarios.

Low carbon abatement costs are reached by the cheapest scenarios like the northwest hydrogen production with dedicated northwest renewable mix and the coast production of hydrogen with dedicated offshore wind, both in 2050. These low values (126 and 111 USD/ton CO_{2eq}, respectively) may soon be comparable to carbon taxes imposed by some countries, for example Sweden and Switzerland (World Bank, 2021). Following that trend of carbon taxing, it is possible that renewable hydrogen might be economically feasible in Texas in the mid- or long-term.

In the case of RM, Figure 18 shows the carbon abatement cost in the dedicated northwest renewable mix scenarios by 2030. Power plant flue gases scenario is not shown due to the negative value that its carbon abatement cost takes. The values are 4.4 times higher than the hydrogen abatement cost in the ethanol scenario, which is the lowest among the RM scenarios. This trend is consistent in the other possible RM scenarios, making it unfeasible in economic terms to abate carbon with RM in Texas.

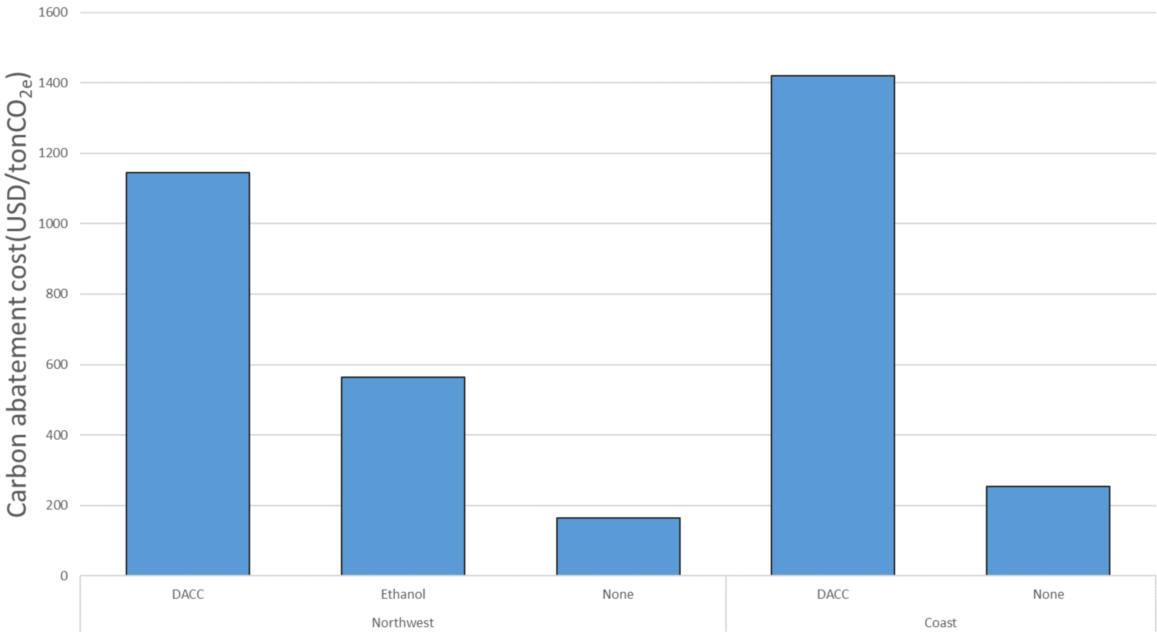


Figure 18. Carbon abatement cost of Renewable Methane produced in the Northwest or coast using H_2 from electrolysis driven by dedicated Northwest renewable mix power and CO_2 from a variety of sources in the Texas case example for 2030.

4.3 Brazil

4.3.1 Levelized Cost of Delivered NBRG

Figure 19 presents the levelized costs of delivered hydrogen for Brazil scenarios that produce hydrogen only. The 2030 scenarios are on the left and the 2050 scenarios are on the right. For each year, electrolyser electricity sources are, left to right, the electricity grid, dedicated solar, dedicated biomass, and dedicated offshore wind. For each electricity source like the previous case examples, electrolyser locations are shown. Levelized costs components include H_2 production CAPEX and OPEX (shown individually), H_2 storage CAPEX and OPEX (shown combined), and H2 (for offshore) or electricity (for onshore) transmission CAPEX and OPEX (shown combined).

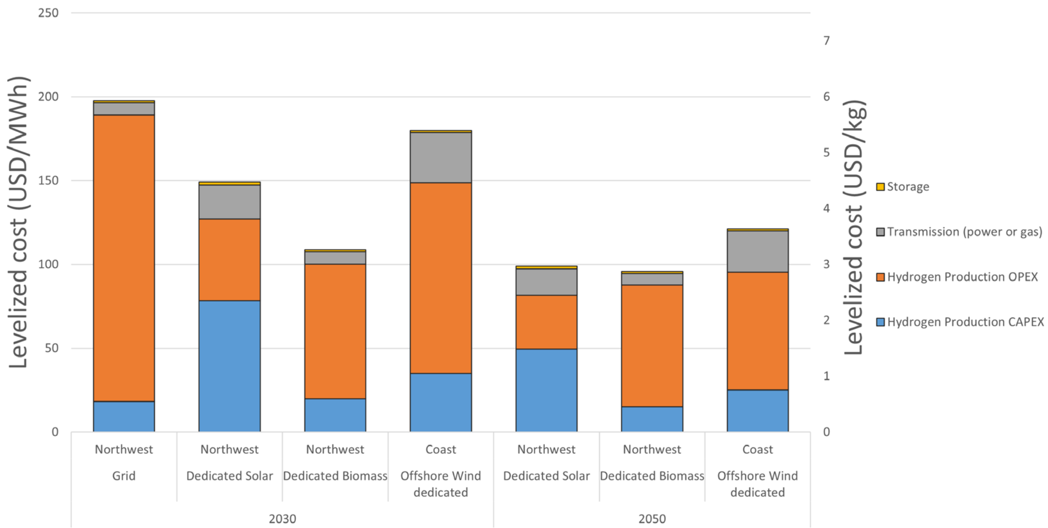


Figure 19: Delivered cost of hydrogen for scenarios in the Brazil case example.

The figure shows the following key features; (1) Dedicated sugarcane biomass source of electricity gives lowest delivered cost and (2) Effects of electricity price on Hydrogen OPEX for different dedicated scenarios

In the Brazil case example, four sources of electricity were used. A dedicated sugarcane biomass source of electricity proved to give the lowest of the delivered costs of hydrogen modelled, both in 2030 and 2050. Solar PV is a close second having the lowest electricity price and is predicted to decrease even further by 2050 (– International Renewable Energy Agency, 2019). Solar plants may never operate isolated with the low capacity factors, being much more likely to complement the existing biomass plants, equally renewable and with a very low GHG emission.

The delivered costs, on a MWh basis for 2030, of non-biogenic renewable methane (RM or power-to-methane) produced onshore using H_2 from electrolysis and CO_2 from a variety of sources are shown in Figure 20. The studied CO_2 sources are off-gases from ethanol production, off-gas from steelworks, and direct air capture (DACC). The figure shows that DACC is much more expensive implement than the capture of CO_2 that is currently vented from biofuel production plants, which is both biogenic and nearly pure. The sole driver of cost differences between the RM options is the price of CO_2 from these sources. Recall that CO_2 is an input to the system and the price paid for it is assumed to cover the cost of capturing it. This same trend of RM costs is seen when any H_2 production scenario from Figure 19 is applied. While methanation increases the delivered cost of RM by 30 -120 €/MWh above that of hydrogen, it must be borne in mind that this RM can be used widely in the existing Brazilian natural gas infrastructure. The same cannot be said of hydrogen, especially at high concentrations.

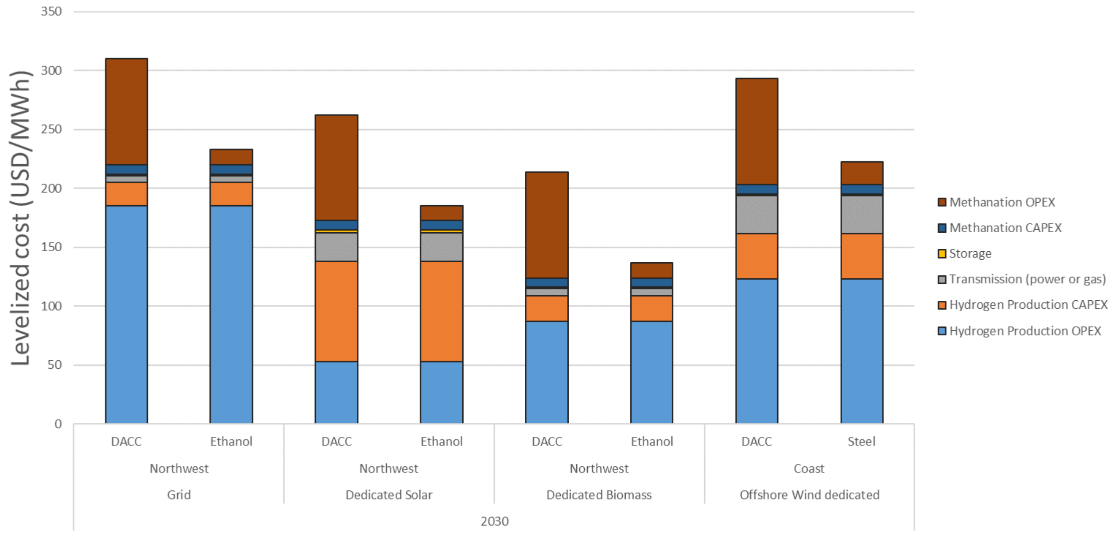


Figure 20: Delivered cost of renewable methane produced onshore using H_2 from electrolysis and CO_2 from a variety of sources in the Brazil case example for 2030.

4.3.2 GHG Intensity of NBRG

GHG intensities for 2030 dedicated RM-producing scenarios are presented in Figure 21. The key feature of this figure is the high GHG intensity value for CO_2 sourced from the steel industry. The main assumption behind this value was the use of the sustainable development scenario figure for off gases carbon intensity in 2030 of 0.8 t CO_2/t (International Energy Agency, 2020). The key feature of this figure is the difference between the low GHG intensities of DACC- and Ethanol-sourced CO_2 compared to that sourced from high intensity of steel off-gas.

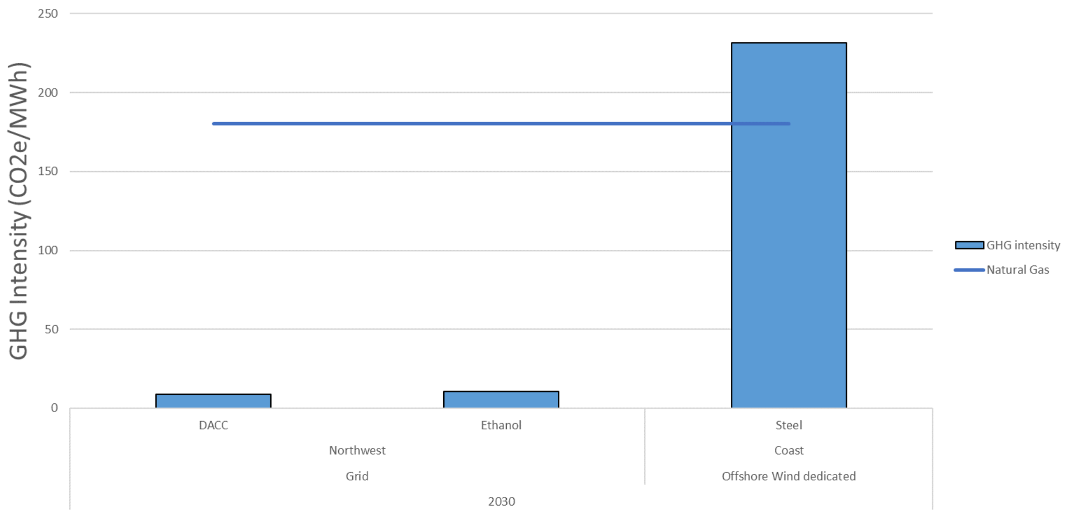


Figure 21: GHG intensity of renewable methane produced using H2 from electrolysis and CO_2 from a variety of sources in the Brazil case example for 2030.

DACC in this example assumes use of grid electricity. Brazil has one of the world's least carbon-intensive grids, at about 70 g CO_2/kWh (Climate Transparency, 2021). This value is expected to drop to under 50 g CO_2/kWh by 2030 and net zero by 2050. As indicated in the previous case examples, the GHG accounting for non-renewable carbon sources is crucial for analysing the environmental impact of NBRG production. Carbon capture in steelworks is considered to have a relatively low TRL of 5. There are existing commercial scale installations, such as Emirates Steel in the UAE, which uses the captured CO_2 for enhanced oil recovery applications (International Energy Agency, 2020). Some of the assumptions made are that larger proportions of scrap metal would be used as well as substitution of some proportion of coke with other fuels such as natural gas and hydrogen. It would be expected that equipment such as preheaters and boilers would be electrified in the years running up to 2050, which would enable a significant GHG intensity reduction.

4.3.3 Carbon Abatement Cost

Figure 22 presents the carbon abatement costs of delivered hydrogen for the Brazil scenarios that produce hydrogen only. The 2030 scenarios are on the left and the 2050 scenarios are on the right. For each year, electrolyser electricity sources are, left to right, grid, dedicated solar, biomass and offshore wind. For each electricity source, electrolyser locations are shown. The trends of levelized cost seen in Figure 19 are broadly present in carbon abatement costs.

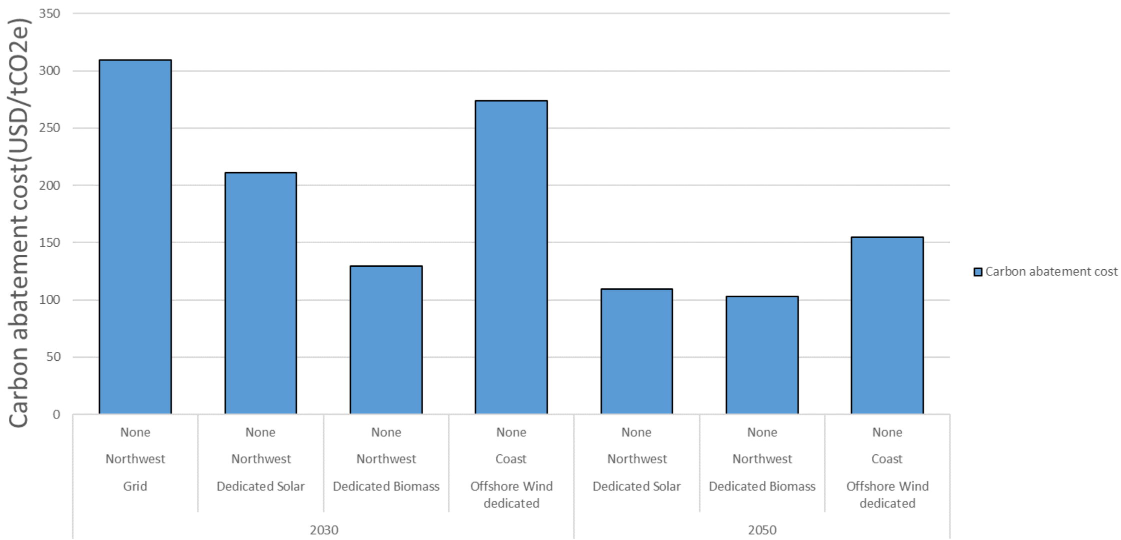


Figure 22: Carbon abatement cost of delivered hydrogen in Brazil case example

The lowest carbon abatement costs, between 100 and 150 USD/t CO_{2eq} for 2030 and 2050, are for the dedicated biomass scenarios. The greatest carbon abatement costs are for the 2030 grid scenarios, where the high levelized cost make these options uncompetitive for now.

In the case of RM, Figure 23 shows the carbon abatement cost in the various dedicated scenarios by 2030. The steelworks off-gases scenario is not shown due to its negative carbon abatement cost value, which results from its higher GHG intensity than natural gas. The values for carbon abatement cost in methanation scenarios are about four times higher than the lowest cost scenario hydrogen only scenario, which uses dedicated biomass and CO_2 from bioethanol production.

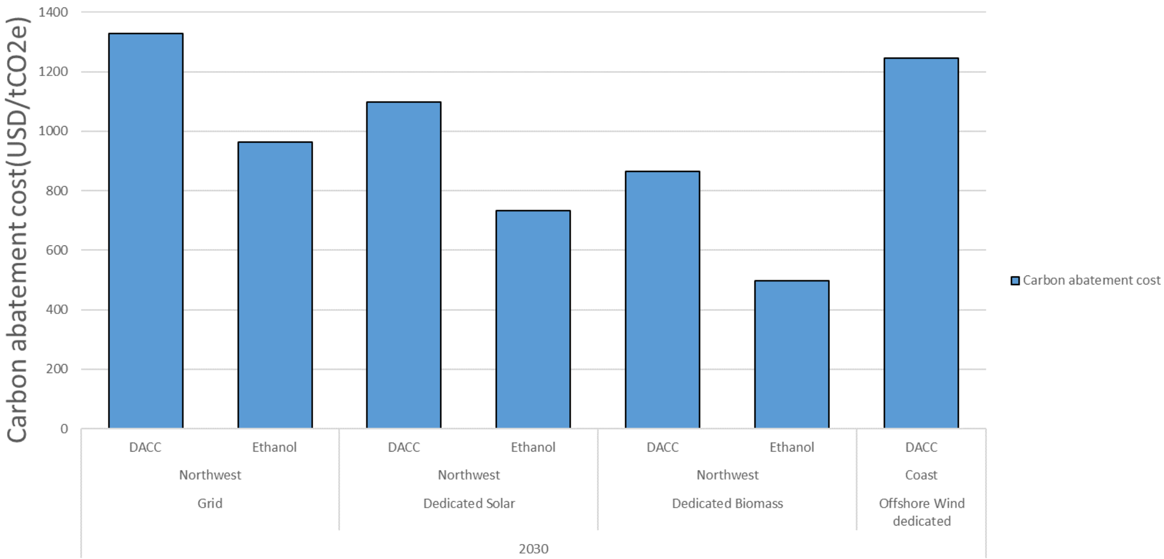


Figure 23: Carbon abatement cost of Renewable Methane produced in Northwest or coast using H_2 from electrolysis driven and CO_2 from various sources in the Brazil case example for 2030.

5 Conclusions

This report reviewed and explored the state of the art of non-biogenic renewable gas (NBRG) with respect to national policies, the costs and commercial readiness of key technologies, aspects related to sustainability, and regulatory issues. This was achieved through a stakeholder survey and workshop, literature review, and technoeconomic-environmental analysis of three regionally specific case examples of large-scale NBRG deployment.

The survey, workshop and reviews identified water electrolysers as the key NBRG technology due to its significant contribution to production costs. Among electrolyser types, both alkaline and proton exchange membrane (PEM) technologies are at high levels of commercial readiness, and both are also experiencing significant cost reductions due to technological advancements and the impacts of mass manufacturing driven by increasing demand. Alkaline electrolysers are currently cheaper per MW of installed capacity, but the steeper trajectory of PEM cost reductions implies cost parity at some point around 2030, with PEM becoming cheaper in the 2030-2050 timeframe.

The most important sustainability aspects were revealed to those related to the climate change impacts of the source of electricity for electrolysis, and the source of carbon dioxide for potential methanation. It follows from this that the most challenging regulatory issues that NBRG must overcome concern the GHG accounting for electricity and carbon dioxide. For electricity, the concept of additionality is intended to ensure that NBRG production does not hamper the decarbonisation of electricity end-uses. Rigorous enforcement of additionality in the early stages of NBRG deployment could however raise significant barriers to market entry. The relative merits of more or less rigorous enforcement of additionality on NBRG must be carefully weighed by policy-makers.

The report described three case examples for deployment of NBRG production in potentially important markets, the North Sea, the US state of Texas, and Brazil. Each case example established credible scenarios for NBRG deployment, which included variables such as electricity source (onshore or offshore wind, solar PV, biomass-generated electricity, or grid electricity, depending on local conditions), electrolyser operational mode (powered by excess renewable electricity only, powered by dedicated renewable electricity, or powered by the grid), electrolyser location (offshore, coastal, or inland), year of construction (2030 or 2050), end product (hydrogen or methane), and in the case of methanation, the source of CO_2 (cement plants, steel works, oil refineries, biomethane or bioethanol plants, or direct air capture, depending on local conditions). Case example scenarios were evaluated on the basis of levelised cost, the GHG intensity, and the carbon abatement cost of delivered NBRG. The key findings can be summarised as:

- Use of dedicated offshore wind in the North Sea and an onshore wind-solar mix in Texas results in high electrolyser capacity factors and delivered hydrogen costs of 4-6 USD/kg in 2030, which is highly dependent on the cost trajectory of wind. By 2050 in the North Sea and Texas, dedicated renewable hydrogen production is the cheapest option studied.
- For the Brazil case example, the lowest delivered cost hydrogen production route was for biomass-generated electricity, which has lower electricity price and decent capacity factors, resulting in a greater dependency on electrolyser cost reductions. By 2050, biomass-generated electricity hydrogen in this case study is the most competitive option.
- Use of excess electricity alone results in high levelized costs and abatement costs, despite having a very favourable GHG intensity.
- Renewable hydrogen GHG abatement costs in some scenarios are comparable to proposed carbon taxes in some countries.
- Renewable methane produced using CO_2 from DACC results in unfeasibly high levelised carbon abatement costs. Renewable methane produced using non-renewable carbon dioxide has greater GHG intensity than fossil natural gas, but this finding depends strongly on the method of GHG emissions accounting employed.
- Using existing natural gas pipelines could decrease the levelized cost of renewable methane, but it remains significantly more expensive than hydrogen for all scenarios and case examples studied.
- Situating electrolysers close to renewable electricity generation sites is desirable since it is more cost effective to transmit hydrogen in pipelines that it is to transmit electricity in high voltage cables.

6 References

– International Renewable Energy Agency, I. (2019) *FUTURE OF SOLAR PHOTOVOLTAIC Deployment, investment, technology, grid integration and socio-economic aspects A Global Energy Transformation paper About IRENA*. Available at: www.irena.org/publications.

Abhyankar, N. *et al.* (2021) *POWERING AMERICA'S CLEAN ECONOMY*. Available at https://www.ourenergypolicy.org/resources/2030-report-powering-americas-clean-economy-a-supplemental-analysis-to-the-2035-report/

Ahmadi, E. *et al.* (2020) "An Integrated Planning Framework for Sustainable Water and Energy Supply," *Sustainability 2020, Vol. 12, Page 4295*, 12(10), p. 4295. doi:10.3390/SU12104295.

Balcombe, P. *et al.* (2018) "Methane emissions: choosing the right climate metric and time horizon." doi:10.1039/c8em00414e.

Barth, F. *et al.* (2019) *Towards a Dual Hydrogen Certification System for Guarantees of Origin and for the Certification of Renewable Hydrogen in Transport and for Heating & Cooling Final Report of Phase 2 CertifHy 2-Final Report-Towards a Dual Hydrogen Certification System for G*. doi:10.2843/46282.

Baylin-Stern, A. and Berghout, N. (2021) "Is carbon capture too expensive? – Analysis - IEA," *International Energy Agency IEA* [Preprint]. Available at https://www.iea.org/commentaries/is-carbon-capture-too-expensive

Bermudez, J., Hasegawa, T. and Bennett, S. (2020) *Hydrogen – Analysis - IEA*, *Tracking report, iea.org*. Available at: https://www.iea.org/reports/hydrogen (Accessed: November 15, 2021).

Bhandari, R., Kumar, B. and Mayer, F. (2020) "Life cycle greenhouse gas emission from wind farms in reference to turbine sizes and capacity factors," *Journal of Cleaner Production*, 277, p. 123385. doi:10.1016/J.JCLEPRO.2020.123385.

Blanco, H. *et al.* (2020) "Life cycle assessment integration into energy system models: An application for Power-to-Methane in the EU," *Applied Energy*, 259. doi:10.1016/J.APENERGY.2019.114160.

Bloomberg New Energy Finance (2020) *Hydrogen Economy Outlook*. Available at https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

Bond, S.W., Alvarez, R. and Weilenmann, M. (2011) "Hydrogen emissions to the atmosphere from industry and transportation," *Transition to hydrogen: pathways toward clean transportation* [Preprint].

Brinkman, G. *et al.* (2021) "The North American Renewable Integration Study (NARIS): A Canadian Perspective." Available at https://www.nrel.gov/docs/fy21osti/79224.pdf

Caldera, U. and Breyer, C. (2020) "Strengthening the global water supply through a decarbonised global desalination sector and improved irrigation systems," *Energy*, 200, p. 117507. doi:10.1016/J.ENERGY.2020.117507.

Carlos Cosín (2019) *The evolution of rates in desalination (Part I)*, *Almar water solutions*.

Available at: https://smartwatermagazine.com/blogs/carlos-cosin/evolution-rates-desalination-part-i (Accessed: October 3, 2021).

Cater, H. (2021) *Incorporating used water into hydrogen production to develop a more sustainable energy source - Monash University*. Available at: https://www.monash.edu/news/articles/incorporating-used-water-into-hydrogen-production-to-develop-a-more-sustainable-energy-source (Accessed: November 15, 2021).

CertifHy (2014) "Developing a European Framework for the generation of guarantees of origin for green hydrogen Definition of Green Hydrogen." Available at: https://www.fch.europa.eu/sites/default/files/POSTER%20PANEL%2006-221116%20%28ID%202891260%29.pdf

Chardonnet, C. *et al*. (2017) "Study on Early Business Cases for H2 in Energy Storage and More Broadly Power To H2 Applications," *EU Commission*, (June), p. 228. Available at: https://www.fch.europa.eu/publications/study-early-business-cases-h2-energy-storage-and-more-broadly-power-h2-applications

Chatterjee, S. and Huang, K.-W. (2020) "Unrealistic energy and materials requirement for direct air capture in deep mitigation pathways," *Nature Communications 2020 11:1*, 11(1), pp. 1–3. doi:10.1038/s41467-020-17203-7.

Climate Transparency (2021) *BRAZIL: CLIMATE TRANSPARENCY REPORT: COMPARING G20 CLIMATE ACTION TOWARDS NET ZERO*. Climate Analytics. Available at: https://www.climate-transparency.org/g20-climate-performance/g20report2021

Corredor, J. *et al*. (2019) "Comprehensive review and future perspectives on the photocatalytic hydrogen production," *Journal of Chemical Technology and Biotechnology*, 94(10), pp. 3049–3063. doi:10.1002/JCTB.6123/FORMAT/PDF.

Coutanceau, C., Baranton, S. and Audichon, T. (2018) "Hydrogen Production From Water Electrolysis," *Hydrogen Electrochemical Production*, pp. 17–62. doi:10.1016/B978-0-12-811250-2.00003-0.

Cristina, C. *et al*. (2017) "The Brazilian Electricity Supply for 2030: A Projection Based on Economic, Environmental and Technical Criteria," *Environment and Natural Resources Research*, 7(4). doi:10.5539/enrr.v7n4p17.

Daprato, M. (2019) *Texas' Power Price Spike and Designing Markets for a Carbon-Free Grid | Greentech Media*, *Greentech Media*. Available at: https://www.greentechmedia.com/articles/read/texas-power-price-spike-and-designing-markets-for-a-carbon-free-grid (Accessed: November 20, 2021).

Derwent, R. *et al*. (2006) "Global environmental impacts of the hydrogen economy: Derwent, R. et al. International Journal of Nuclear Hydrogen Production and Application, 2006, 1, (1), 57–67," *Fuel and energy abstracts*, 47(6), p. 436. doi: 10.1504/IJNHPA.2006.009869

Derwent, R.G. *et al*. (2020) "Global modelling studies of hydrogen and its isotopomers using STOCHEM-CRI: Likely radiative forcing consequences of a future hydrogen economy," *International Journal of Hydrogen Energy*, 45(15), pp. 9211–9221. doi:10.1016/J.IJHYDENE.2020.01.125.

Earthjustice (2021) “RECLAIMING HYDROGEN FOR A RENEWABLE FUTURE.”. Available at: https://earthjustice.org/sites/default/files/files/hydrogen_earthjustice_2021.pdf

EEA (2021) *Greenhouse gas emission intensity of electricity generation - country level - 2018*. Available at: https://www.eea.europa.eu/data-and-maps/indicators/overview-of-the-electricity-production-3/assessment (Accessed: September 30, 2021).

EIA (2020) *The Annual Energy Outlook explores long-term energy trends in the United States*. Available at: https://www.eia.gov/outlooks/aeo/

EPA (2012) “Clean Power Plan: State at a Glance Texas,” 111(d), pp. 1–2. Available at: https://archive.epa.gov/epa/sites/production/files/2016-09/documents/texas.pdf

EPE. (2021). *Cardeno de precos da geracao*. Available at: www.mme.gov.br

EU Horizon 2020 (2014) *Technology readiness levels (TRL)*. Available at: https://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf

Eurelectric (2015) *Power statistics and trends: The five dimensions of the energy union, Eurelectric*. Available at: https://www.eurelectric.org/media/1992/power-statistics-and-trends-the-five-dimentions-of-the-energy-union-lr-2015-030-0641-01-e.pdf

European Commission (2020) “COMMITTEE AND THE COMMITTEE OF THE REGIONS A hydrogen strategy for a climate-neutral Europe.” Available at: https://www.eu2018.at/calendar-events/political-events/BMNT- (Accessed: February 8, 2022).

European Commission Eurostat (2014) “Electricity and natural gas price statistics,” *European Commission Eurostat*, (November 2014), pp. 1–12. Available at: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Natural_gas_price_statistics#Natural_gas_prices_for_non-household_consumers (Accessed: November 10, 2021)

European Parliament (2019) “European Parliament resolution of 15 January 2020 on the European Green Deal (2019/2956(RSP)).” Available at: https://www.europarl.europa.eu/doceo/document/TA-9-2020-0005_EN.html

Falcone, P.M., Hiete, M. and Sapio, A. (2021) “Hydrogen economy and sustainable development goals: Review and policy insights,” *Current Opinion in Green and Sustainable Chemistry*, 31, p. 100506. doi:10.1016/J.COGSC.2021.100506.

FCH (2020) *State-of-the-art and Future Targets (KPIs)*. Available at: https://www.fch.europa.eu/soa-and-targets (Accessed: September 30, 2021).

Fredershausen, S. *et al.* (2021) “Towards an Understanding of Hydrogen Supply Chains: A Structured Literature Review Regarding Sustainability Evaluation,” *Sustainability 2021, Vol. 13, Page 11652*, 13(21), p. 11652. doi:10.3390/SU132111652.

Fritsche, U.R. et al. (2017) “Energy and land use”. Working Paper for the UNCCD Global Land Outlook. Darmstadt etc. https://knowledge.unccd.int/publications/energy-and-land-usent

Fritsche, U.R. (2022) “Renewable Gas-Hydrogen in the grid”. Synthesis Report of the IEA

Bioenergy Task 41 Special Project. Darmstadt https://www.ieabioenergy.com/wp-content/uploads/2022/02/Renewable-Gases-H2-in-the-grid.pdf

FSR (2021) *Technology neutrality in hydrogen, opportunities and challenges: photocatalysis*. Available at: https://fsr.eui.eu/technology-neutrality-in-hydrogen-opportunities-and-challenges-photocatalysis/ (Accessed: November 25, 2021).

Gallardo, F.I. *et al.* (2021) "A Techno-Economic Analysis of solar hydrogen production by electrolysis in the north of Chile and the case of exportation from Atacama Desert to Japan," *International Journal of Hydrogen Energy*, 46(26), pp. 13709–13728. doi:10.1016/j.ijhydene.2020.07.050.

Gelder, van K. (2020) *Netherlands: drinking water price per company 2020 | Statista, Statista*. Available at: https://www.statista.com/statistics/597953/drinking-water-price-in-the-netherlands-by-company/ (Accessed: October 7, 2021).

Ghaib, K., Nitz, K. and Ben-Fares, F.Z. (2016) "Chemical methanation of CO2: A review," *ChemBioEng Reviews*, 3(6), pp. 266–275. doi:10.1002/CBEN.201600022/FORMAT/PDF.

Gorre, J., Ortloff, F. and van Leeuwen, C. (2019) "Production costs for synthetic methane in 2030 and 2050 of an optimized Power-to-Gas plant with intermediate hydrogen storage," *Applied Energy*, 253. doi:10.1016/j.apenergy.2019.113594.

Guandalini, G., Campanari, S. and Valenti, G. (2016) "Comparative assessment and safety issues in state-of-the-art hydrogen production technologies," *International Journal of Hydrogen Energy*, pp. 18901–18920. doi:10.1016/j.ijhydene.2016.08.015.

Guo, M., Song, W. and Buhain, J. (2015) "Bioenergy and biofuels: History, status, and perspective," *Renewable and Sustainable Energy Reviews* [Preprint]. doi:10.1016/j.rser.2014.10.013.

Guo, Y. *et al.* (2019) "Comparison between hydrogen production by alkaline water electrolysis and hydrogen production by PEM electrolysis," in *IOP Conference Series: Earth and Environmental Science*. doi:10.1088/1755-1315/371/4/042022.

Howarth, R.W. and Jacobson, M.Z. (2021) "How green is blue hydrogen?," *Energy Science and Engineering*, 9(10), pp. 1676–1687. doi:10.1002/ese3.956.

Hydrogen Council (2020) "Path to hydrogen competitiveness: a cost perspective," (January), p. 88. Available at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

IRENA (2019), Future of wind: Deployment, investment, technology, grid integration and socio-economic aspects (A Global Energy Transformation paper), International Renewable Energy Agency, Abu Dhabi. Available at: https://www.irena.org/-/media/files/irena/agency/publication/2019/oct/irena_future_of_wind_2019.pdf

IEA (2019) *The Future of Hydrogen, The Future of Hydrogen*. doi:10.1787/1e0514c4-en.

IEA (2020a) *Average CO2 emissions intensity of hourly electricity supply in India, 2018 and 2040 by scenario and average electricity demand in 2018 – Charts – Data & Statistics - IEA*. Available at: https://www.iea.org/data-and-statistics/charts/average-co2-emissions-intensity-of-hourly-electricity-supply-in-the-european-union-2018-and-2040-by-scenario-and-average-electricity-demand-in-2018 (Accessed: September 30, 2021).

IEA (2020b) "IEA G20 Hydrogen report: Revised Assumptions," *The Future of Hydrogen*, (December), pp. 1–14. Available at: https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

IEA (2021a) *Global Hydrogen Review 2021, Global Hydrogen Review 2021*. doi:10.1787/39351842-en.

IEA (2021b) *Net Zero by 2050: A Roadmap for the Global Energy Sector, International Energy Agency*. Available at: https://www.iea.org/reports/net-zero-by-2050

International Energy Agency (2020) *Iron and Steel Technology Roadmap Towards more sustainable steelmaking Part of the Energy Technology Perspectives series*. Available at: www.iea.org/t&c/.

IPCC (2007) *Climate change 2007 : the physical science basis : contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge ; New York: Cambridge University Press.

IPHE (2021) "Methodology for Determining the Greenhouse Gas Emissions Associated With the Production of Hydrogen." Available at: https://www.iphe.net/iphe-working-paper-methodology-doc-oct-2021

Irena (2019a) *FUTURE OF SOLAR PHOTOVOLTAIC Deployment, investment, technology, grid integration and socio-economic aspects A Global Energy Transformation paper About IRENA*. Available at: www.irena.org/publications.

Irena (2019b) *FUTURE OF WIND Deployment, investment, technology, grid integration and socio-economic aspects A Global Energy Transformation paper Citation About IRENA*. Available at: www.irena.org/publications.

IRENA (2020) *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5 C Climate Goal, /publications/2020/Dec/Green-hydrogen-cost-reduction*.

Jackson, S. and Brodal, E. (2019) "Optimization of the Energy Consumption of a Carbon Capture and Sequestration Related Carbon Dioxide Compression Processes," *Energies 2019, Vol. 12, Page 1603*, 12(9), p. 1603. doi:10.3390/EN12091603.

Keçebaş, A., Kayfeci, M. and Bayat, M. (2019) "Electrochemical hydrogen generation," *Solar Hydrogen Production: Processes, Systems and Technologies*, pp. 299–317. doi:10.1016/B978-0-12-814853-2.00009-6.

Klepper, G. and Thrän, D. (2019) "Biomasse im Spannungsfeld zwischen Energie-und Klimapolitik Potenziale-Technologien-Zielkonflikte." Available at: www.leopoldina.orgacatech-DeutscheAkademiederTechnikwissenschaften|www.acatech.de (Accessed: February 11, 2022).

Koivisto, M. *et al.* (2020) "North Sea region energy system towards 2050: Integrated offshore grid and sector coupling drive offshore wind power installations," *Wind Energy Science*, 5(4), pp. 1705–1712. doi:10.5194/WES-5-1705-2020.

Lee, W.J. *et al.* (2021) “Recent trend in thermal catalytic low temperature CO2 methanation: A critical review,” *Catalysis Today*, 368, pp. 2–19. doi:10.1016/J.CATTOD.2020.02.017.

Van Leeuwen, C. and Zauner, A. (2018) “Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimisation. D8.3,” *EU Horizon* [Preprint], (691797). Available at: https://www.storeandgo.info/fileadmin/downloads/deliverables_2019/20190801-STOREandGO-D8.3-RUG-Report_on_the_costs_involved_with_PtG_technologies_and_their_potentials_across_the_EU.pdf

Lotrič, A. *et al.* (2021a) “Life-cycle assessment of hydrogen technologies with the focus on EU critical raw materials and end-of-life strategies,” *International Journal of Hydrogen Energy*, 46(16), pp. 10143–10160. doi:10.1016/J.IJHYDENE.2020.06.190.

Lotrič, A. *et al.* (2021b) “Life-cycle assessment of hydrogen technologies with the focus on EU critical raw materials and end-of-life strategies,” *International Journal of Hydrogen Energy*, 46(16), pp. 10143–10160. doi:10.1016/J.IJHYDENE.2020.06.190.

Majer, S. *et al.* (2015) “D5.3 | Calculation of GHG emission caused by biomethane”. Available at: http://www.biosurf.eu/wordpress/wp-content/uploads/2015/07/BIOSURF-D5.3.pdf

McKinsey & Company (2020) *Perspective on Hydrogen; Lanzamiento de mesas técnicas*. Available at: https://energia.gob.cl/sites/default/files/clemens_muller-falcke_de_mckinseyco.pdf

Mehmeti, A. *et al.* (2018) “Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies,” *Environments 2018, Vol. 5, Page 24*, 5(2), p. 24. doi:10.3390/ENVIRONMENTS5020024.

Moreira, J.R. *et al.* (2016) “BECCS potential in Brazil: Achieving negative emissions in ethanol and electricity production based on sugar cane bagasse and other residues,” *Applied Energy*, 179, pp. 55–63. doi:10.1016/j.apenergy.2016.06.044.

National Infrastructure comission UK (no date) *Technical annex: Energy and fuel bills today and in 2050*. Available at: https://nic.org.uk/app/uploads/Technical-annex-energy-and-fuel-bills.pdf (Accessed: September 30, 2021).

Nishiyama, H. *et al.* (2021) “Photocatalytic solar hydrogen production from water on a 100-m 2 scale,” *Nature*, 598. doi:10.1038/s41586-021-03907-3.

Pace, G. and Sheehan, S.W. (2021) “Scaling CO2 Capture With Downstream Flow CO2 Conversion to Ethanol,” *Frontiers in Climate*, 3, p. 35. doi:10.3389/fclim.2021.656108.

Papadias, D.D. and Ahluwalia, R.K. (2021) “Bulk storage of hydrogen,” *International Journal of Hydrogen Energy*, 46(70), pp. 34527–34541. doi:10.1016/J.IJHYDENE.2021.08.028.

Perez-Linkenheil, C. (2019) *Update December 2019 – EU Energy Outlook 2050*. Available at: https://blog.energybrainpool.com/en/update-december-2019-eu-energy-outlook-2050/ (Accessed: September 30, 2021).

Plaza, M.G., Martínez, S. and Rubiera, F. (2020) “Co2 capture, use, and storage in the cement industry: State of the art and expectations,” *Energies*. doi:10.3390/en13215692.

Pototschnig, A. (2021) “POLICY BRIEF: Renewable hydrogen and the ‘additionality’ requirement: why making it more complex than is needed?”. Available at: https://cadmus.eui.eu/handle/1814/72459

Princeton University (2021) *Net Zero America Project*. Available at: https://netzeroamerica.princeton.edu/?explorer=year&state=texas&table=2030&limit=2000 (Accessed: November 20, 2021).

Ram, M. *et al.* (2018) “A comparative analysis of electricity generation costs from renewable, fossil fuel and nuclear sources in G20 countries for the period 2015-2030,” *Journal of Cleaner Production*, 199, pp. 687–704. doi:10.1016/J.JCLEPRO.2018.07.159.

REFHYNE.eu (no date) *REFHYNE – Clean Refinery Hydrogen for Europe*. Available at: https://refhyne.eu/ (Accessed: January 3, 2022).

Sand, M. *et al.* (2020) *Atmospheric Impacts of Hydrogen as an Energy Carrier, CICERO Report*. CICERO Center for International Climate and Environmental Research - Oslo. Available at: https://cicero.oslo.no/en/publications/internal/2913

Schiavo, M. and Pierre Georges (2020) *The Energy Transition : What It Means For European Power Prices And Producers*. Available at: https://www.spglobal.com/ratings/en/research/articles/210917-the-energy-transition-and-what-it-means-for-european-power-prices-and-producers-september-2021-update-12108381# (Accessed: November 8, 2021)

Schultz, M.G. *et al.* (2003) *Air pollution and climate-forcing impacts of a global hydrogen economy*. doi: 10.1126/science.1089527

SEAI (2021) *Conversion Factors | SEAI Statistics | SEAI*, *SEAI.ie*. Available at: https://www.seai.ie/data-and-insights/seai-statistics/conversion-factors/ (Accessed: November 20, 2021).

Silva, W.F. da *et al.* (2018) “Reverse osmosis desalination plants in Brazil: A cost analysis using three different energy sources,” *Sustainable Cities and Society*, 43, pp. 134–143. doi:10.1016/J.SCS.2018.08.030.

Singlitico, A., Østergaard, J. and Chatzivasileiadis, S. (2021) “Onshore, offshore or in-turbine electrolysis? Techno-economic overview of alternative integration designs for green hydrogen production into Offshore Wind Power Hubs.” Doi: 10.1016/j.rset.2021.100005

Terlouw, T. *et al.* (2021) “Life Cycle Assessment of Direct Air Carbon Capture and Storage with Low-Carbon Energy Sources,” *Environmental Science and Technology*, 55(16), pp. 11397–11411. doi:10.1021/acs.est.1c03263.

Thema, M., Bauer, F. and Sterner, M. (2019) “Power-to-Gas: Electrolysis and methanation status review,” *Renewable and Sustainable Energy Reviews*, 112, pp. 775–787. doi:10.1016/J.RSER.2019.06.030.

Thomson, C. and Harrison, G.P. (2015) “Life Cycle Costs and Carbon Emissions of Offshore Wind Power.” Available at: https://www.climatexchange.org.uk/media/1461/main_report_-_life_cycle_costs_and_carbon_emissions_of_offshore_wind_power.pdf

Tlili, O., de Rivaz, S. and Lucchese, P. (2020) *Task 38 Final Report*. Available at: https://www.ieahydrogen.org/es/

Tröndle, T. (2020) "Supply-side options to reduce land requirements of fully renewable electricity in Europe," *PLoS ONE*, 15(8 August). doi:10.1371/journal.pone.0236958.

Umweltbundesamt (2019) "Optionen für Biogas-Bestandsanlagen bis 2030 aus ökonomischer und energiewirtschaftlicher Sicht." Available at: https://www.umweltbundesamt.de/sites/default/files/medien/1410/publikationen/2020-01-30_texte_24-2020_biogas2030.pdf

University Texas at Austin (2021) *Renewable Electrolysis in Texas: Pipelines versus Power Lines*. Available at: https://sites.utexas.edu/h2/files/2021/08/H2-White-Paper_Hydrogen-Pipelines-versus-Power-Lines.pdf

US Department of Energy (2019) *Frequently Asked Questions (FAQs) - U.S. Energy Information Administration (EIA), Eia*. Available at: https://www.eia.gov/tools/faqs/faq.php?id=73&t=11 (Accessed: November 20, 2021).

U.S. Energy Information Administration (2021) *Annual Energy Outlook 2021*. Available at: https://www.eia.gov/outlooks/aeo/

Valente, A., Iribarren, D. and Dufour, J. (2016) "Life cycle assessment of hydrogen energy systems: a review of methodological choices," *The International Journal of Life Cycle Assessment 2016 22:3*, 22(3), pp. 346–363. doi:10.1007/S11367-016-1156-Z.

Voldsund, M. *et al.* (2019) "Comparison of Technologies for CO2 Capture from Cement Production—Part 1: Technical Evaluation," *Energies 2019, Vol. 12, Page 559*, 12(3), p. 559. doi:10.3390/EN12030559.

Wang, X. and Song, C. (2020) "Carbon Capture From Flue Gas and the Atmosphere: A Perspective," *Frontiers in Energy Research*. doi:10.3389/fenrg.2020.560849.

Weger, L.B., Leitão, J. and Lawrence, M.G. (2021) "Expected impacts on greenhouse gas and air pollutant emissions due to a possible transition towards a hydrogen economy in German road transport," *International Journal of Hydrogen Energy*, 46(7), pp. 5875–5890. doi:10.1016/J.IJHYDENE.2020.11.014.

Wernet, G., Bauer, C., Steubing, B., Reinhard, J., Moreno-Ruiz, E., & Weidema, B. (2016). The ecoinvent database version 3 (part I): overview and methodology. *International Journal of Life Cycle Assessment*, *21*(9), 1218–1230. https://doi.org/10.1007/S11367-016-1087-8

World Bank (2021) "State and Trends of Carbon Pricing 2021," *State and Trends of Carbon Pricing 2021* [Preprint]. doi:10.1596/978-1-4648-1728-1.

World Energy Council (2021) "National Hydrogen Strategies," pp. 1–20. Available at: https://www.worldenergy.org/assets/downloads/Working_Paper_-_National_Hydrogen_Strategies_-_September_2021.pdf

Zhang, J. *et al.* (2020) "Recent progress for hydrogen production by photocatalytic natural or simulated seawater splitting," *Nano Research*, pp. 2313–2322. doi:10.1007/s12274-020-2880-z.

7 Annexes

7.1 ANALYSIS METHODS

7.1.1 Levelized cost

The levelized cost of NBRG (LC_{NBRG}) was calculated as the sum of levelized costs of production (LC_P), storage (LC_S), transmission (LC_T) and methanation (LC_M)[5], as shown in equation 2, where all elements are in USD/kg_{H2} or USD/MWh.

$$LC_{NBRG} = LC_P + LC_S + LC_T + LC_M \tag{2}$$

For each levelized cost component, times for construction and operation of 3 and 20 years, respectively, were considered. A discount rate of 6% for calculating net present value was assumed.

7.1.1.1 Hydrogen production cost

Levelized cost of production was calculated using the following equation 3.

$$LC_P = \frac{\sum_{T=0}^{T=\tau_{constr}} \frac{\frac{C_{CAPEX,P}}{(\tau_{constr}+1)}}{(1+r)^T} + \sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{C_{OPEX,P}}{(1+r)^T}}{\sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{M_{NBRG}}{(1+r)^T}} \tag{3}$$

Where M_{NBRG} is the annual delivered energy or mass of NBRG (MWh or kg), $C_{CAPEX,P}$ and $C_{OPEX,P}$ are the capital expenditures and operation and maintenance expenditure, respectively, of the evaluated year in the hydrogen production stage (USD), T is the evaluated year, τ_{constr} and τ_{proj} are the construction time and the project lifetime, respectively, and r is the discount rate (%).

The capital expenditures were calculated by equation 4, using the costs of the electrolyser (C_E), compressor (C_{com}), energy management unit (C_{EM}), interconnection (C_{ICS}), engineering (C_{Eng}), and other costs (C_{other}).

$$C_{CAPEX,P} = C_E + C_{com} + C_{EM} + C_{ICS} + C_{Eng} + C_{other} \tag{4}$$

The cost of the electrolysis system is shown in the following annexes and depends on the case example in question. The cost of the compressor was obtained using the relations proposed by

[5] Only if RM, not hydrogen, was considered as the final product

Chardonnet et al. (2017). C_{EM}, C_{ICS}, and C_{Eng} were assumed at 10%, 20%, and 15%, respectively, of the sum of C_E and C_{com} (Chardonnet et al., 2017). For the other costs, equation 5, proposed by Chardonnet et al. (2017), was used, with IC meaning electrolysis installed capacity in MW.

$$C_{other} = 1.5652 \cdot (IC \cdot 1000)^{-0.154} \cdot (C_E + C_{com}) \cdot 1.16$$

5

The OPEX of the hydrogen production stage was calculated by adding the potential stack replacement of the electrolyser (C_{SR}), the compressor and storage system maintenance (C_{CM} and C_{SM}, respectively), the water expenditures (C_{water}), and the electricity costs ($C_{EL,P}$), as described in the next equation.

$$C_{OPEX,P} = C_{SR} + C_{CM} + C_{SM} + C_{water} + C_{EL,P}$$

6

The compressor and storage system maintenance costs were assumed as 2% of the CAPEX of the systems (C_{SR}), depended on the type of the electrolyser, as the following equations show (FCH, 2020).

$$C_{SR} = f \cdot (IC \cdot 1000)^{-0.305} \cdot (IC \cdot 1000) \cdot 1.16$$

7

Where f had a value of 349.8 or 266.52 for PEM or alkaline systems, respectively. By considering water consumption of 0.015 m^3/kg_{H2}, and the price of water established in the next annexes for each case example, it was possible to calculate the water expenditures by considering also the annual hydrogen production, which is described as following.

$$M_{NBRG,H} = IC \cdot cf \cdot 8760 \cdot \eta_{WE} \cdot \left(\frac{1000}{33.3}\right)$$

8

Where cf is the electrolyser capacity factor, depends on the electricity source considered in each scenario, and η_{WE} is the electrolyser efficiency described for each case in the following annexes. It is important is to that the value and units of $M_{NBRG,H}$ depend on the $\left(\frac{1000}{33.3}\right)$ factor, which, if it is applied the resulting value is in kg and if not, in MWh. When the final product considered was methane instead of hydrogen, the value of $M_{NBRG,M}$ was obtained on an energy basis (MWh/year) using the following equation.

$$M_{NBRG,M} = \frac{\eta_M \cdot 33.3 \cdot M_{NBRG,H}}{1000}$$

9

Where η_M is the methanation efficiency (%) and $M_{NBRG,H}$ the annual hydrogen production in kg.

7.1.1.2 Methanation cost

The levelised cost of methanation is calculated using the following equation.

$$LC_M = \frac{\sum_{T=0}^{T=\tau_{constr}} \frac{\frac{C_{CAPEX,M}}{(\tau_{constr}+1)}}{(1+r)^T} + \sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{C_{OPEX,M}}{(1+r)^T}}{\sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{M_{NBRG,M}}{(1+r)^T}}$$

10

The value of $C_{CAPEX,M}$ was obtained by multiplying the specific CAPEX cost of the methanation system ($c_{CAPEX,M}$ (USD/kW_{CH4})) by the installed methanation capacity, as the next equation describes.

$$C_{CAPEX,M} = M_{NBRG,M} \cdot c_{CAPEX,M} \cdot \frac{1000}{365 \cdot 24}$$

11

$C_{OPEX,M}$ was calculated by considering a specific value of methanation's OPEX ($c_{OPEX,M}$(USD/(year·kW_{CH4})) and the cost of carbon dioxide.

$$C_{OPEX,M} = c_{OPEX,M} \cdot M_{NBRG,M} \cdot \frac{1000}{365 \cdot 24} + c_{CO_2} \cdot M_{CO_2}$$

12

The specific cost of carbon dioxide (c_{CO_2} (USD/ton_{CO2})) depends on each scenario and case example, but the mass of carbon dioxide required per year (M_{CO_2} (ton_{CO2}/year)) was obtained using the stoichiometry of the reaction of methanation (equation 1) assuming 100% conversion.

$$M_{CO_2} = \frac{M_{NBRG,M}}{15.42} \cdot \frac{44.01}{16.04}$$

13

7.1.1.3 Hydrogen storage cost

The levelized cost of hydrogen storage was calculated using the following equation.

$$LC_S = \frac{\sum_{T=0}^{T=\tau_{constr}} \frac{\frac{C_{CAPEX,S}}{(\tau_{constr}+1)}}{(1+r)^T} + \sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{C_{OPEX,S}}{(1+r)^T}}{\sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{M_{NBRG}}{(1+r)^T}}$$

14

$C_{OPEX,S}$ value is 2% of the $C_{CAPEX,S}$ which is calculated by considering the specific cost of storage ($c_{CAPEX,S}$(USD/kg$_{H2}$)) and the total amount of NBRG that is required to be stored for an assumed period of 10 days is $M_{NBRG,H}$ in (kg/year).

$$C_{CAPEX,S} = c_{CAPEX,S} \cdot \frac{M_{NBRG,H} \cdot 10}{365}$$

15

The value of $c_{CAPEX,S}$ was obtained assuming storage in nearby salt caverns for all cases. This is a major assumption and relies on the development of this storage medium for hydrogen. Salt cavern storage cost can be modelled following the next equation (Papadias & Ahluwalia, 2021).

$$c_{CAPEX,S} = \exp\left(0.0858 \cdot \left(ln\left(\frac{M_{NBRG} \cdot 10}{365 \cdot 1000}\right)\right)^2 - 1.5492 \cdot ln\left(\frac{M_{NBRG} \cdot 10}{365 \cdot 1000}\right) + 9.8684)\right) - 6.3$$

16

7.1.1.4 Energy (electricity or NBRG) transmission cost

The levelised cost of transmission of electricity via high voltage cable or of NBRG by high-pressure pipeline was calculated as follows.

$$LC_T = \frac{\sum_{T=0}^{T=\tau_{constr}} \frac{\frac{C_{CAPEX,T}}{(\tau_{constr}+1)}}{(1+r)^T} + \sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{C_{OPEX,T}}{(1+r)^T}}{\sum_{T=\tau_{constr}}^{T=\tau_{proj}} \frac{M_{NBRG}}{(1+r)^T}}$$

17

In this case, the $C_{CAPEX,T}$ and $C_{OPEX,T}$ will depend on the type of transmission considered in each scenario. For those scenarios where electricity is required to be transmitted from the source to the electrolyser, the $C_{CAPEX,T}$ computation will depend on the specific cost of the transmission system (explained in detail in 7.2.2) and the distance between the production and delivery points. If the transmission is carried by NBRG in pipelines, and if those pipelines are made for hydrogen, the value of $C_{CAPEX,T}$ was obtained by multiplying the specific cost of the hydrogen pipelines by its total length (explained in detail in the next annex). The cost for methane pipelines $C_{CAPEX,T}$ was also calculated using the same approach. $C_{OPEX,T}$ value was assumed as a 2% of the $C_{CAPEX,T}$ per year, following the example of various sources (M. Guo et al., 2015; IEA, 2020b; Singlitico et al., 2021; van Leeuwen & Zauner, 2018). Finally, as in the previous elements, the value of M_{NBRG} depends on the final product delivered and the desired units (MWh/year or kg/year).

7.1.2 GHG intensity

The GHG intensity of the produced NBRG (GHG_{NBRG} in kg_{CO2eq}/MWh) was calculated using equation 18.

$$GHG_{NBRG} = \frac{EC \cdot GHG_E + M_{CO_2} \cdot GHG_{CO_2}}{M_{NBRG}} \tag{18}$$

Where EC is the electricity consumption per year (in MWh/year), GHG_E is the carbon intensity of the electricity used (in kg_{CO2eq}/MWh), M_{CO_2} is the carbon dioxide consumed by the methanation process during a year (in $tonne_{CO2}$/year), and GHG_{CO_2} is the carbon intensity of the carbon dioxide used according to its source (in $kg_{CO2eq}/tonne_{CO2}$). In this case, it is very important to state that M_{NBRG} has units of (MWh/year) and will depend on the final product delivered, either hydrogen or methane.

The values of the majority of the variables are defined in the following annexes of each case example, but the value of EC will depend on the considerations of each scenario.

$$EC = e_{comp} \cdot M_{NBRG,H} + cf \cdot 8760 \cdot IC + E_M \tag{19}$$

Where e_{comp} is the specific electricity consumption of the hydrogen compressor (MWh/kg_{H2}), $M_{NBRG,H}$ is the mass of hydrogen in kg_{H2}/year, and E_M is the electricity consumption of the methanation process.

The specific compressor electric consumption was assumed as $1 \cdot 10^{-3}$ MWh/kg_{H2} (Chardonnet et al., 2017). The electricity consumption of the methanation process was obtained from the following equation.

$$E_M = M_{NBRG,M} \cdot e_M \tag{20}$$

With $M_{NBRG,M}$ in units of MWh_{CH4}/year and e_M with a value of 0.013 MWh/MWh_{CH4} (IEA, 2020b).

7.1.3 Carbon abatement cost

The carbon abatement cost of NBRG (CAC_{NMRG}, in USD/kg_{CO2eq}) was calculated using equation 21

$$CAC_{NMRG} = \frac{LC_{NBRG} - LC_{NRG}}{GHG_{NRG} - GHG_{NBRG}} \qquad (21)$$

Where LC_{NRG} is the Levelized Cost of a reference non-renewable Gas (natural gas or blue hydrogen depending on the case, in USD/MWh$_{NRG}$). GHG_{NRG} is the greenhouse gas intensity of the reference non-renewable gas in kg$_{CO2eq}$/MWh. Further, since it is assumed that the renewable electricity used is considered coming from additional renewable capacity and that is not avoiding the replacement of fossil origin energy, there are no extra GHG emissions attributed to the NBRG production.

7.2 NORTH SEA CASE EXAMPLE INPUTS

7.2.1 North Sea case example evaluated scenarios

Year	Electricity source	Electrolyser location	CO_2 origin
2030	Dedicated	Offshore	DACC
2030	Dedicated	Offshore	None
2030	Dedicated	Onshore	BioCH4
2030	Dedicated	Onshore	Cement
2030	Dedicated	Onshore	DACC
2030	Dedicated	Onshore	None
2030	Excess	Offshore	DACC
2030	Excess	Offshore	None
2030	Excess	Onshore	BioCH4
2030	Excess	Onshore	Cement
2030	Excess	Onshore	DACC
2030	Excess	Onshore	None
2030	Grid	Onshore	BioCH4
2030	Grid	Onshore	Cement
2030	Grid	Onshore	DACC
2030	Grid	Onshore	None
2050	Dedicated	Offshore	DACC
2050	Dedicated	Offshore	None
2050	Dedicated	Onshore	BioCH4
2050	Dedicated	Onshore	Cement
2050	Dedicated	Onshore	DACC
2050	Dedicated	Onshore	None
2050	Excess	Offshore	DACC
2050	Excess	Offshore	None
2050	Excess	Onshore	BioCH4
2050	Excess	Onshore	Cement
2050	Excess	Onshore	DACC

Year	Electricity source	Electrolyser location	CO_2 origin
2050	Excess	Onshore	None
2050	Grid	Onshore	BioCH4
2050	Grid	Onshore	Cement
2050	Grid	Onshore	DACC
2050	Grid	Onshore	None

7.2.2 North Sea case example assumptions

Euros to dollar factor equal to 1.16 (Dollar/Euro)

Year	2030	2050	Source and notes
Efficiency Alkaline	0.69	0.74	(FCH, 2020; IRENA, 2020)
Capex alkaline electrolyser (€/kW)	471.8	423.3	(ICCT, 2020; IEA, 2019)
Efficiency PEM	0.67	0.74	(FCH, 2020; IRENA, 2020)
Capex PEM electrolyser (€/kW)	399.5	312.8	(ICCT, 2020; IEA, 2019)
GHG intensity (grid) (g_{CO2e}/kWh)	86.15	0	2050 value is assuming carbon neutrality in the electric grid (EEA, 2021; IEA, 2020a)
Methanation CAPEX (€/kW_{CH4})	649.65	482.96	(Gorre et al., 2019; IEA, 2020b)
Methanation OPEX (€/(kW_{CH4}·year))	65	48.3	Considering 10% of CAPEX. According to Gorre et al., the Fixed OPEX is 8% of the CAPEX. The variable OPEX will depend on the operation, but according to their results in a plant of 10 MW of electrolyser capacity in 2030, the total OPEX will be 7 EUR/MWh of methane produced which is 10% of the 2030 CAPEX. CO_2 cost is not included (Gorre et al., 2019; IEA, 2020b)
Methanation electric power consumption	0.013	0.013	(IEA, 2020b)
Methanation efficiency	0.78	0.78	Considering only the heating values of H_2 and CH_4 and the stoichiometry. Electricity and heat required are considered in the OPEX as expenses (Gorre et al., 2019; IEA, 2020b)

Electrolyser operation	Dedicated	Excess	Grid	Source and notes
Capacity factor or yearly run hours	55%	10%	90%	(Eurelectric, 2015; IRENA, 2019; Koivisto et al., 2020)
GHG intensity (gCO_{2eq}/kWh)	0	0	See table above	(Bhandari et al., 2020; IRENA, 2019; Thomson & Harrison, 2015) Only direct GHG emissions from electricity consumption are included in the analysis.
Electrolyser type	ALK	PEM	ALK	

Electricity price	Dedicated (€/MWh)	Dedicated low (€/MWh)	Dedicated high (€/MWh)	Excess	Grid (€/MWh)	Source and notes
2030	65.8	47	84.6	0	50	(IRENA, 2019; Schiavo & Pierre Georges, 2020)
2050	47	28.2	65.8	0	85	(IRENA, 2019; National Infrastructure comission UK, n.d.; Perez-Linkenheil, 2019)

Electrolyser location	Offshore	Onshore	Source and notes
Capex power grid (M€/km)	0	1.27	(Singlitico et al., 2021)
Capex H_2 pipe (M€/km)	1.04	0	(IEA, 2020b)
Capex CH_4 pipe (M€/km)	0.432	0	(van Leeuwen & Zauner, 2018)
Water price (€/m^3)	2.16	1.4	(Ahmadi et al., 2020; Caldera & Breyer, 2020; Carlos Cosín, 2019; Gelder, 2020; IEA, 2021a)
Length of pipeline (km)	300	0	(Singlitico et al., 2021)
Length of transmission line (km)	0	300	(Singlitico et al., 2021)

CO_2 origin	$BioCH_4$	Cement	DACC	None	Source and notes
CO_2 price (€/Ton)	73.1	73.1	430	0	Assuming post-combustion carbon capture technologies for BioCH4, Cement and Power (Chatterjee & Huang, 2020; Jackson & Brodal, 2019; Wang & Song, 2020)
CO2 GHG intensity 2030 (kgCO2e/kgCO2)	0.02	1.225	0.08	0	(Plaza et al., 2020; Terlouw et al., 2021; Voldsund et al.,

					2019)
CO2 GHG intensity 2050 (kgCO2e/kgCO2)	0	1	0	0	(Plaza et al., 2020; Terlouw et al., 2021; Voldsund et al., 2019) Assuming that the electric grid GHG intensity for 2050 will be 0.

Benchmark values	Lower value	Higher value	Source and notes
Blue Hydrogen LVC (EUR/MWh)	25.9	51.8	(IEA, 2021a)
Euro/dollar	0.862		
Natural gas price (EUR/MWh)	30	-	(European Commission Eurostat, 2014; Gorre et al., 2019)
Natural gas GHG intensity (kgCO2e/MWh)	180.5	225.8	(SEAI, 2021; Wernet et al., 2016)
Blue H2 GHG intensity (kgCO2e/MWh)	486	500.4	(Howarth & Jacobson, 2021)
Biomethane GHG intensity (kgCO2e/MWh)	54	-	(Majer et al., 2015)
Biomethane cost (EUR/MWh)	62	-	(Umweltbundesamt, 2019)

Pipeline model

$$H_2Pipeline_{capex} = 1.75 \cdot 10^6 \cdot (1.7 \cdot 10^{-6} \cdot D^2 + 0.574 \cdot 10^{-3} \cdot D + 0.314)$$

Where $H_2Pipeline_{capex}$ in €/km, D is the internal diameter of the pipeline in meters, and the diameter is calculated considering a density of 7.9 kg/m^3 and a linear velocity of 15 m/s (Singlitico et al., 2021).

HVDC transmission line model

$$HVDC_{capex} = \left(0.6 \cdot P + \frac{P}{P_{max}} \cdot 1.345\right) \cdot 1000000$$

Where $HVDC_{capex}$ in €/km, P is the power transmitted (assumed as 1 GW) and P_{max} equal to 2 (GW) (Singlitico et al., 2021).

Salt Cavern storage model

$$SC\left(\frac{€}{kg_{H_2}}\right) = exp\left(0.001798354 \cdot \left(ln(m)\right)^2 - 0.042016435 \cdot ln(m) + 6.43774627\right)$$

Where SC is the specific cost per kg of hydrogen stored and m is the mass of hydrogen that will be stored in tons (Papadias & Ahluwalia, 2021).

7.3 TEXAS CASE EXAMPLE INPUTS

7.3.1 Texas case example evaluated scenarios

Year	Electricity source	Electrolyser location	CO_2 origin
2030	Wind+solar northwest excess	Northwest	DACC
2030	Wind+solar northwest excess	Northwest	Ethanol
2030	Wind+solar northwest excess	Northwest	None
2030	Wind+solar northwest excess	Coast	DACC
2030	Wind+solar northwest excess	Coast	Power
2030	Wind+solar northwest excess	Coast	None
2030	Wind+solar northwest dedicated	Northwest	DACC
2030	Wind+solar northwest dedicated	Northwest	Ethanol
2030	Wind+solar northwest dedicated	Northwest	None
2030	Wind+solar northwest dedicated	Coast	DACC
2030	Wind+solar northwest dedicated	Coast	Ethanol
2030	Wind+solar northwest dedicated	Coast	None
2030	Offshore Wind dedicated	Coast	DACC
2030	Offshore Wind dedicated	Coast	Ethanol
2030	Offshore Wind dedicated	Coast	None
2050	Wind+solar northwest excess	Northwest	DACC
2050	Wind+solar northwest excess	Northwest	Ethanol
2050	Wind+solar northwest excess	Northwest	None
2050	Wind+solar northwest excess	Coast	DACC
2050	Wind+solar northwest excess	Coast	Ethanol
2050	Wind+solar northwest excess	Coast	None
2050	Wind+solar northwest dedicated	Northwest	DACC
2050	Wind+solar northwest dedicated	Northwest	Ethanol
2050	Wind+solar northwest dedicated	Northwest	None
2050	Wind+solar northwest dedicated	Coast	DACC
2050	Wind+solar northwest dedicated	Coast	Power
2050	Wind+solar northwest dedicated	Coast	None
2050	Offshore Wind dedicated	Coast	DACC
2050	Offshore Wind dedicated	Coast	Power
2050	Offshore Wind dedicated	Coast	None

7.3.2 Texas case example assumptions

Euros to dollar factor equal to 1.16 (Dollar/Euro)

Year	2030	2050	Source and notes
Efficiency Alkaline	0.69	0.74	(FCH, 2020; IRENA, 2020)
Capex alkaline electrolyser (€/kW)	471.8	423.3	(ICCT, 2020; IEA, 2019)
Efficiency PEM	0.67	0.74	(FCH, 2020; IRENA, 2020)
Capex PEM electrolyser (€/kW)	399.5	312.8	(ICCT, 2020; IEA, 2019)
GHG intensity (grid) (g_{CO2e}/kWh)	494	0	2050 value is assuming carbon neutrality in the electric grid (EPA, 2012)
Methanation CAPEX (€/kW_{CH4})	649.65	482.96	(Gorre et al., 2019; IEA, 2020b)
Methanation OPEX (€/(kW_{CH4}·year))	65	48.3	Considering 10% of CAPEX. According to Gorre et al., the Fixed OPEX is 8% of the CAPEX. The variable OPEX will depend of the operation, but according to their results in a plant of 10 MW of electrolyser capacity in 2030 the total OPEX will be 7 EUR/MWh of methane produced which is 10% of the 2030 CAPEX. CO_2 cost is not included (Gorre et al., 2019; IEA, 2020b)
Methanation electric power consumption	0.013	0.013	(IEA, 2020b)
Methanation efficiency	0.78	0.78	Considering only the heating values of H_2 and CH_4 and the stoichiometry. Electricity and heat required are considered in the OPEX as expenses (Gorre et al., 2019; IEA, 2020b)

Electrolyser operation	Wind+solar northwest excess	Wind+solar northwest dedicated	Offshore Wind dedicated	Source and notes
Capacity factor 2030	8%	36%	46%	(Abhyankar et al., 2021; IEA, 2021b)
Capacity factor 2050	9%	30%	48%	(Brinkman et al., 2021; IEA, 2021b)
GHG intensity (gCO_{2eq}/kWh)	0	0	0	
Electrolyser type	PEM	PEM	PEM	

* Capacity factor were calculated by taking the capacity factor of each type of energy source and multipliying it with its respective share percentage in the energetic mix (see table below).

Total capacity share	Wind	Solar	Source and notes
2030	65%	35%	(Princeton University, 2021)
2050	35%	65%	(EIA, 2020; U.S. Energy Information Administration, 2021)

Electricity price (€/MWh)	Wind+solar northwest excess	Wind+solar northwest dedicated	Offshore Wind dedicated	Source and notes
2030	0	28.5	51.7	(Abhyankar et al., 2021; Daprato, 2019)
2050	0	21.6	34.5	(IEA, 2021b)

Electrolyser location	Northwest	Coast	Source and notes
Capex power grid (M€/km)	0	1.27	(Singlitico et al., 2021)
Capex H_2 pipe (M€/km)	1.04	0	(IEA, 2020b)
Capex CH_4 pipe (M€/km)	0.432	0	(van Leeuwen & Zauner, 2018)
Water price (€/m^3)	0.911	0.911	(University Texas at Austin, 2021)
Length of pipeline (km)	850	0	250 in Offshore scenarios
Length of transmission line (km)	0	850	250 in Offshore scenarios

CO_2 origin	DACC	Power	Ethanol	None	Source and notes
CO_2 price (€/Ton)	73.1	73.1	25.86	0	Assuming post-combustion carbon capture technologies for power (Baylin-Stern & Berghout, 2021)
CO2 GHG intensity 2030 (kgCO2e/kgCO2)	0.3	1.049	0.06	0	Considering the carbon intensity of the grid in 2030 (see table above) (Jackson & Brodal, 2019; Pace & Sheehan, 2021; Terlouw et al., 2021)
CO2 GHG intensity 2050 (kgCO2e/kgCO2)	0	1	0	0	Assuming that the electric grid GHG intensity for 2050 will be 0.

Benchmark values	Lower value	Higher value	Source and notes
Blue Hydrogen LVC (€/MWh)	25.9	51.8	(IEA, 2021a)
Euro/dollar	0.862		

Natural gas price (€/MWh)	30	-	(European Commission Eurostat, 2014; Gorre et al., 2019)
Natural gas GHG intensity (kgCO2e/MWh)	180.5	227.7	(SEAI, 2021; Wernet et al., 2016)
Blue H2 GHG intensity (kgCO2e/MWh)	486	500.4	(Howarth & Jacobson, 2021)
Biomethane GHG intensity (kgCO2e/MWh)	54	-	(Majer et al., 2015)
Biomethane cost (€/MWh)	62	-	(Umweltbundesamt, 2019)

Pipeline model

$$H_2Pipeline_{capex} = \frac{4000000 \cdot D^2 + 598600 \cdot D + 329000}{Eur/Dollar}$$

Where $H_2Pipeline_{capex}$ in €/km, D is the internal diameter of the pipeline in meters, and Eur/Dollar in €/USD (IEA, 2020b). The diameter is calculated considering a density of 7.9 kg/m^3 and a linear velocity of 15 m/s.

HVDC transmission line model

$$HVDC_{capex} = \left(0.6 \cdot P + \frac{P}{P_{max}} \cdot 1.345\right) \cdot 1000000$$

Where $HVDC_{capex}$ in €/km, P is the power transmitted (assumed as 1 GW) and P_{max} equal to 2 (GW) (Singlitico et al., 2021).

Salt Cavern storage model

$$SC\left(\frac{€}{kg_{H_2}}\right) = exp\left(0.001798354 \cdot (ln(m))^2 - 0.042016435 \cdot ln(m) + 6.43774627\right)$$

Where SC is the specific cost per kg of hydrogen stored and m is the mass of hydrogen that will be stored in tons (Papadias & Ahluwalia, 2021).

7.4 BRAZIL CASE EXAMPLE INPUTS

7.4.1 Brazil case example evaluated scenarios

Year	Electricity source	Electrolyser location	CO_2 origin
2030	Grid	Northwest	DACC
2030	Grid	Northwest	Ethanol
2030	Grid	Northwest	None
2030	Dedicated Solar	Northwest	DACC
2030	Dedicated Solar	Northwest	Ethanol
2030	Dedicated Solar	Northwest	None
2030	Dedicated Biomass	Northwest	DACC
2030	Dedicated Biomass	Northwest	Ethanol
2030	Dedicated Biomass	Northwest	None
2030	Dedicated Offshore wind	Coast	DACC
2030	Dedicated Offshore wind	Coast	None
2030	Dedicated Offshore wind	Coast	Steel
2050	Dedicated Solar	Northwest	DACC
2050	Dedicated Solar	Northwest	Ethanol
2050	Dedicated Solar	Northwest	None
2050	Dedicated Biomass	Northwest	DACC
2050	Dedicated Biomass	Northwest	Ethanol
2050	Dedicated Biomass	Northwest	None
2050	Dedicated Offshore wind	Coast	DACC
2050	Dedicated Offshore wind	Coast	None
2050	Dedicated Offshore wind	Coast	Steel

7.4.2 Brazil case example assumptions

Euros to dollar factor equal to 1.16 (Dollar/Euro)

Year	2030	2050	Source and notes
Efficiency Alkaline	0.69	0.74	(FCH, 2020; IRENA, 2020)
Capex alkaline electrolyser (€/kW)	471.8	423.3	(ICCT, 2020; IEA, 2019)
Efficiency PEM	0.67	0.74	(FCH, 2020; IRENA, 2020)
Capex PEM electrolyser (€/kW)	399.5	312.8	(ICCT, 2020; IEA, 2019)
GHG intensity (grid) (g_{CO2e}/kWh)	50	0	2050 value is assuming carbon neutrality in the electric grid. 2030 value (Climate Transparency, 2021)
Methanation CAPEX (€/kW_{CH4})	649.65	482.96	(Gorre et al., 2019; IEA, 2020b)
Methanation OPEX (€/(kW_{CH4}·year))	65	48.3	Considering 10% of CAPEX. According to Gorre et al., the Fixed OPEX is 8% of the CAPEX. The variable OPEX will depend of

			the operation, but according to their results in a plant of 10 MW of electrolyser capacity in 2030 the total OPEX will be 7 EUR/MWh of methane produced which is 10% of the 2030 CAPEX. CO_2 cost is not included (Gorre et al., 2019; IEA, 2020b)
Methanation electric power consumption	0.013	0.013	(IEA, 2020b)
Methanation efficiency	0.78	0.78	Considering only the heating values of H_2 and CH_4 and the stoichiometry. Electricity and heat required are considered in the OPEX as expenses (Gorre et al., 2019; IEA, 2020b)

Electrolyser operation	**Grid**	**Solar northwest dedicated**	**Biomass northwest dedicated**	**Offshore Wind dedicated**	**Source and notes**
Capacity factor 2030	90%	30%	30%	60%	(EPE, 2021)
Capacity factor 2050		30%	30%	60%	(EPE, 2021)
GHG intensity (gCO_{2eq}/kWh)	50	0	0	0	
Electrolyser type	PEM	PEM	PEM	PEM	

Electricity price (€/MWh)	**Grid**	**Solar northwest dedicated**	**Biomass northwest dedicated**	**Offshore Wind dedicated**	**Source and notes**
2030	95.12	23	44	62	(Cristina et al., 2017; EPE, 2021; Irena, 2019b, 2019a)
2050	-	16.24	44	42	(EPE, 2021; Irena, 2019b, 2019a)

Electrolyser location	**Northwest**	**Coast**	**Source and notes**
Capex power grid (M€/km)	0	1.27	(Singlitico et al., 2021)
Capex H_2 pipe (M€/km)	1.04	0	(IEA, 2020b)
Capex CH_4 pipe (M€/km)	0.432	0	(van Leeuwen & Zauner, 2018)
Water price (€/m^3)	0.776	0.776	(Silva et al., 2018)
Length of pipeline (km)	500	0	500 in Offshore scenarios
Length of transmission line (km)	0	500	500 in Offshore scenarios

CO_2 origin	**DACC**	**Steel**	**Ethanol**	**None**	**Source and notes**

CO_2 price (€/Ton)	431	60.34	25.86	0	Assuming post-combustion carbon capture technologies for power (Baylin-Stern & Berghout, 2021)
CO2 GHG intensity 2030 (kgCO2e/kgCO2)	0.05	1.3	0.06	0	Considering the carbon intensity of the grid in 2030 (see table above) (Jackson & Brodal, 2019; Pace & Sheehan, 2021; Terlouw et al., 2021); (International Energy Agency, 2020) for Steel.
CO2 GHG intensity 2050 (kgCO2e/kgCO2)	0	0.8	0	0	Assuming that the electric grid GHG intensity for 2050 will be 0. (International Energy Agency, 2020) assuming 'sustainable development scenario' for direct and indirect Steel production off gas.

Benchmark values	**Lower value**	**Higher value**	**Source and notes**
Blue Hydrogen LVC (EUR/MWh)	25.9	51.8	(IEA, 2021a)
Euro/dollar	0.862		
Natural gas price (EUR/MWh)	30	-	(European Commission Eurostat, 2014; Gorre et al., 2019)
Natural gas GHG intensity (kgCO2e/MWh)	216.67	-	(Wernet et al., 2016)
Blue H2 GHG intensity (kgCO2e/MWh)	486	500.4	(Howarth & Jacobson, 2021)
Biomethane GHG intensity (kgCO2e/MWh)	54	-	(Majer et al., 2015)
Biomethane cost (EUR/MWh)	62	-	(Umweltbundesamt, 2019)

Pipeline model

$$H_2Pipeline_{capex} = \frac{4000000 \cdot D^2 + 598600 \cdot D + 329000}{Eur/Dollar}$$

Where $H_2Pipeline_{capex}$ in €/km, D is the internal diameter of the pipeline in meters, and Eur/Dollar in €/USD (IEA, 2020b). The diameter is calculated considering a density of 7.9 kg/m^3 and a linear velocity of 15 m/s.

HVDC transmission line model

$$HVDC_{capex} = \left(0.6 \cdot P + \frac{P}{P_{max}} \cdot 1.345\right) \cdot 1000000$$

Where $HVDC_{capex}$ in €/km, P is the power transmitted (assumed as 1 GW) and P_{max} equal to 2 (GW) (Singlitico et al., 2021).

Salt Cavern storage model

$$SC\left(\frac{€}{kg_{H_2}}\right) = exp\left(0.001798354 \cdot (ln(m))^2 - 0.042016435 \cdot ln(m) + 6.43774627\right)$$

Where SC is the specific cost per kg of hydrogen stored and m is the mass of hydrogen that will be stored in tons (Papadias & Ahluwalia, 2021).

7.5 SURVEY QUESTIONS AND RESPONSES

Experts surveyed

Twenty experts along five continents were surveyed, with a special concentration focus on the European region. The selection was done according to the contact network of the IEA. Public and private organization were the hosts of the consulted experts with a 75% belonging to the public sector.

In Figure 24 a cartographic representation of the surveyed location around the world is presented and in Figure 25 and Figure 26 the total of public and private institutions of which they belong are presented in a pie plot, and also the distribution of the heading of these organizations.

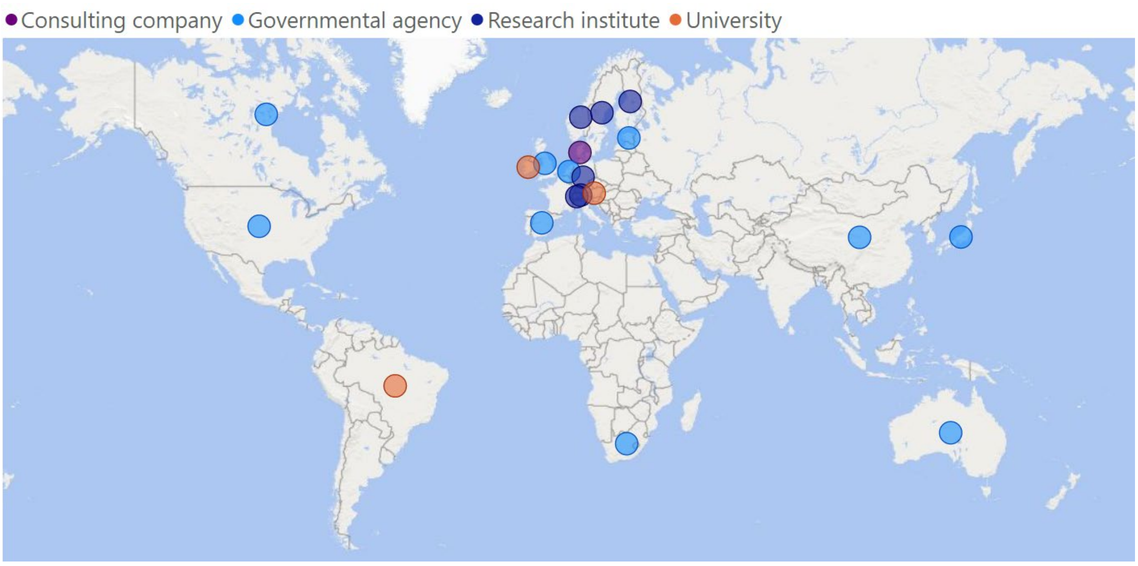


Figure 24. Surveyed expert's organization location and heading.

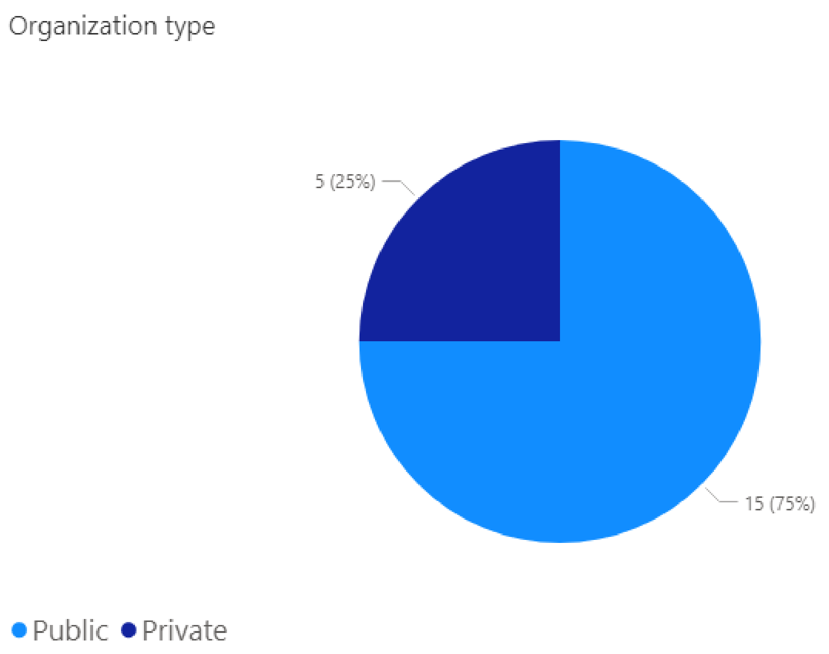


Figure 25. Surveyed expert's organization type distribution.

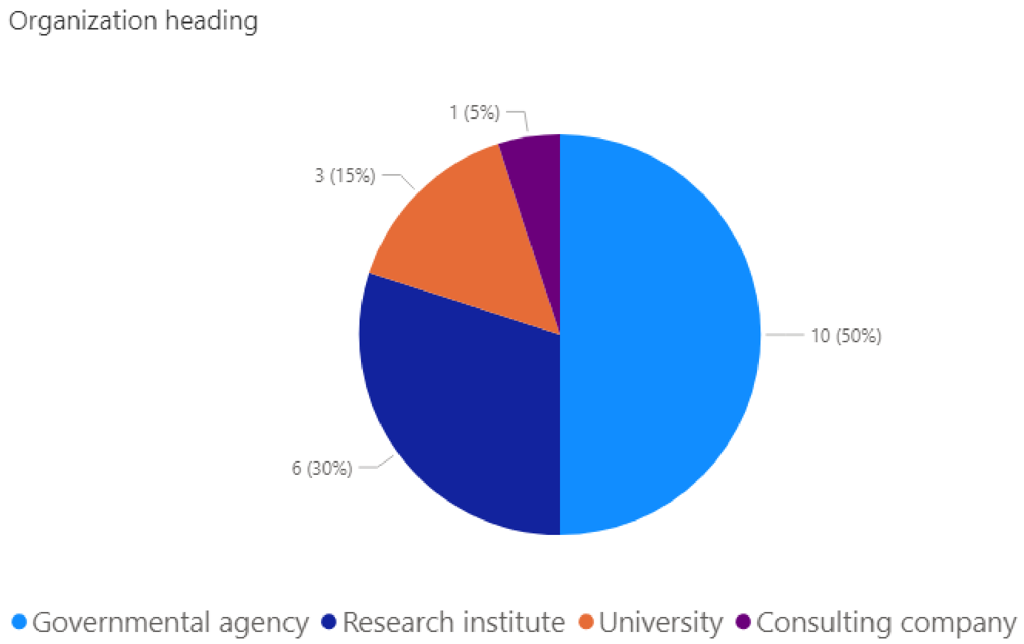


Figure 26. Surveyed expert's organization heading distribution.

Part 1: Identification of relevant technologies

In this section, the surveyed were asked to identify the state of the national/regional strategy (if there is) for any non-biogenic RG and after that some details about the scope of it and the technologies involved. Further, the opinion of the surveyed expert was asked according to the technologies and feedstocks that could be relevant for their country/region and if there are some promise relations between them.

Question: Does your country/region have strategies for non-biogenic renewable gas (RG)?

In this question, many responses were developed beyond the closed "yes" or "no" answer. In the following figures, the summary of the responses is shown, in one case locating the responses in each country and in the other highlighting the most repeated words.

Figure 27. Presence or absence of a national/regional renewable gas strategy.

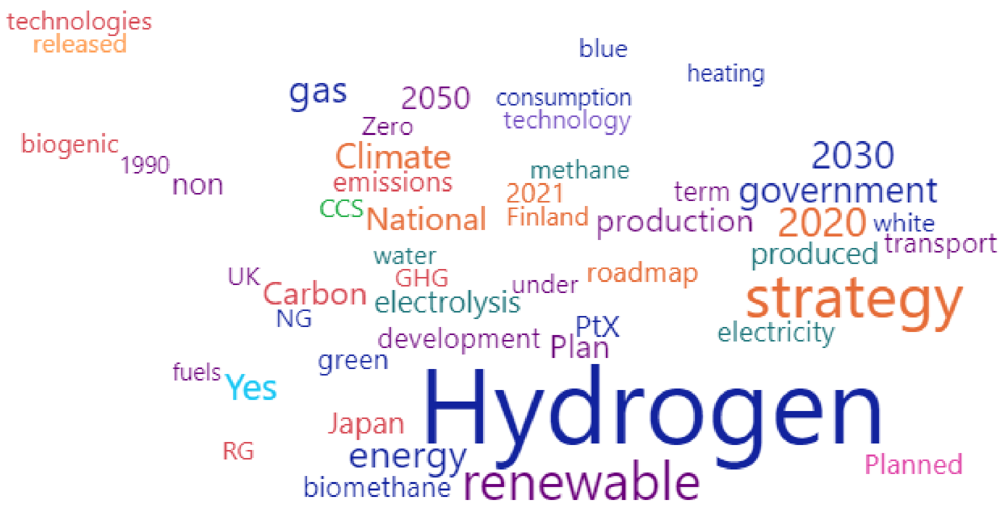


Figure 28. Most repeated word in question related to the presence or absence of a national/regional renewable gas strategy.

The trend along the world is clear, many European countries, and big countries rich in renewable energy potential have or are planning to implement a national strategy related to non-biogenic RG. On the other hand, less advanced countries in renewable gas implementation are still without any plans for a national strategy.

As it can be noticed the most repeated word among all responses (with a total number of 39 times) was Hydrogen. This molecule will be one of the central topics among all the survey responses. “Renewable” and “strategy” is the second most relevant words with 15 and 19 mentions. Interesting concepts are appearing such as PtX, CCS, blue (hydrogen), etc, concepts that will be repeated in the following questions and addressed after.

Question: If you answered “Yes” or “Planned” to Question 4, do these strategies focus on specific technologies and/or feedstocks?

As in the prior question, the results are presented in the same manner, in this case with focus on what the strategy says about feedstocks and/or technologies involved.

Figure 29. Presence of specific technologies and/or feedstocks in the national/regional renewable gases strategy.

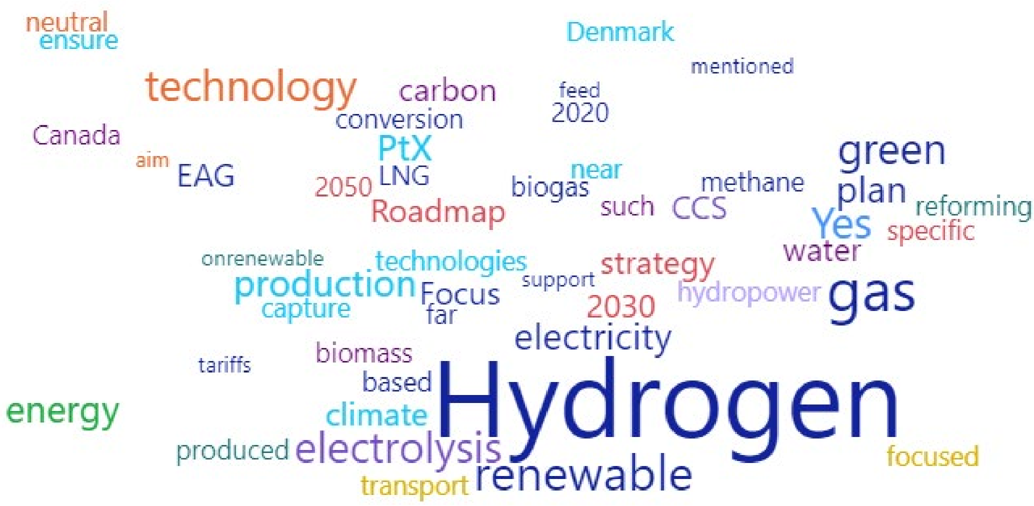


Figure 30. Most repeated words in answers referred to question of specific technologies and/or feedstocks in the national/regional renewable gases strategy.

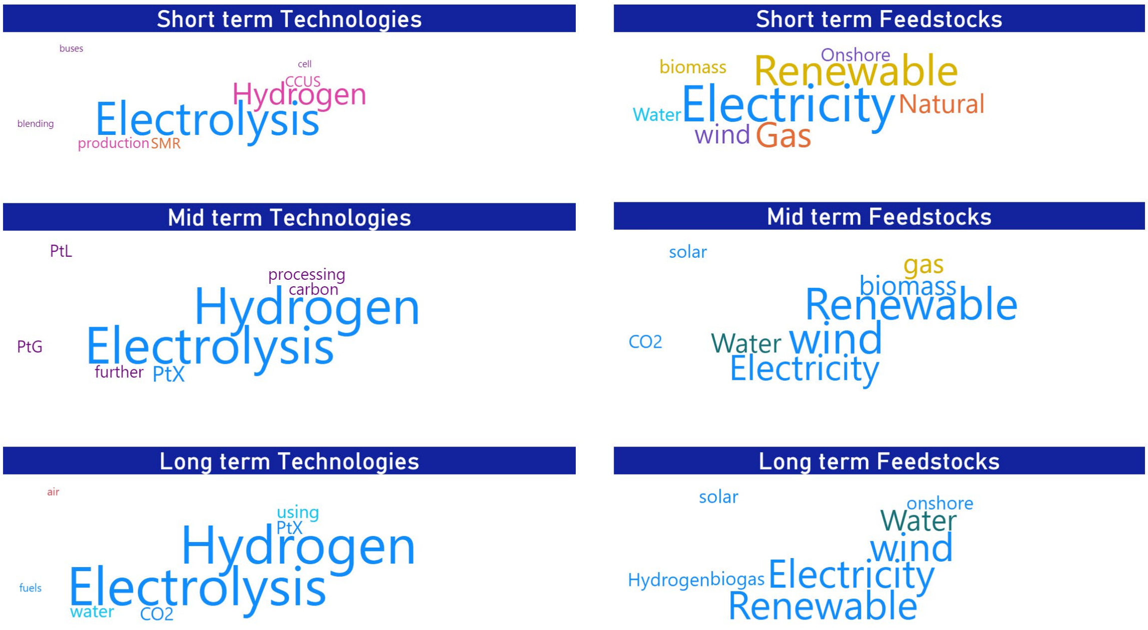
In this case, the majority of the countries that do focus on specific technologies and/or feedstocks are from the European region. This shows more detail on the origin and/or implementation of non-biogenic renewable gases technologies and feedstocks, possibly due to the experience that these countries have around renewable gases, for example with biogas.

Again, the most repeated word was Hydrogen (17 times), along with renewable and electrolysis (7 and 5 times respectively). This shows an interesting focus around the "green" production of this commodity. LNG, PtX, Methane, reforming, are words that appear and will be repeated and analyzed after too.

Question: If you answered “Yes” to Question 5, what are these specific technologies/feedstocksin the short (< 5 years), medium (5-20 years) and long terms (> 20 years)?

This question was answered in a table as shown in the following figure, with short answers in each box.

Table 10. Most repeated words related to the short-, mid- and long-term specific technologies and/or feedstocks mentioned in national/regional strategies.

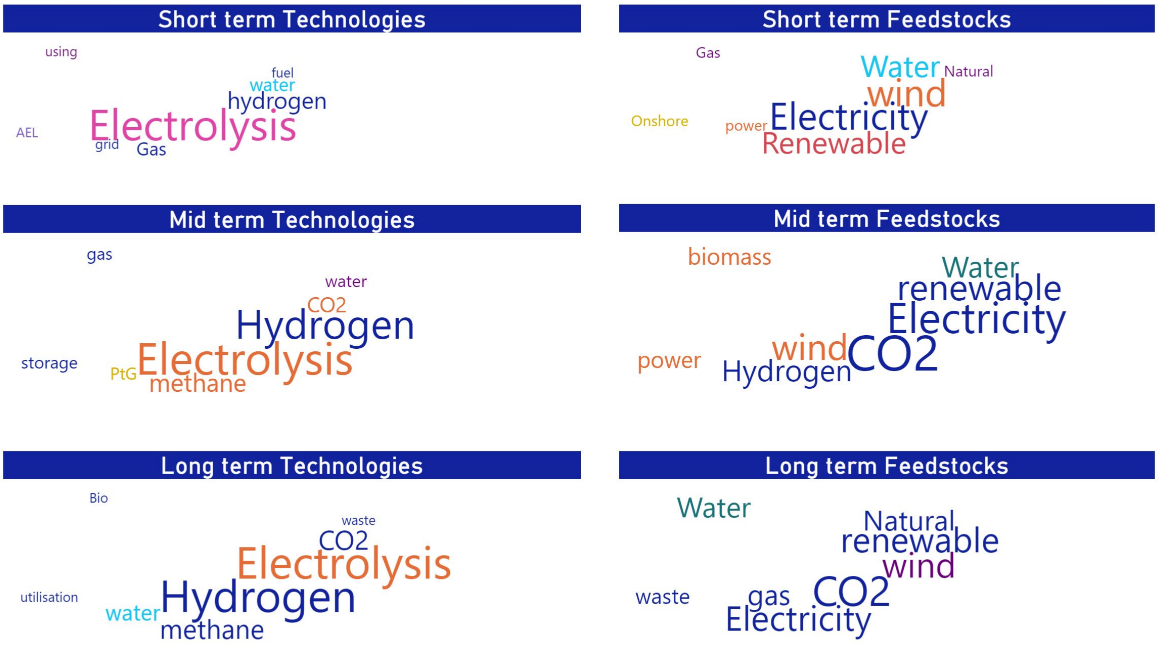


It is interesting to know how the trend evolves along the projected years for the different national/regional strategies, where electrolysis and hydrogen are the dominant technologies among the answers during the whole period. Some technologies such as CCUS, CCU, and SMR are only mentioned in the short term, mentioned by countries like Australia, USA, and Canada, big potential producers of renewable gases that see how the market will require an input of hydrogen but that the electrolyzed one is still on development, and looking for somehow supplying it to the consumers. The mentioned concepts disappear in the mid and long terms, appearing at the same time concepts as PtX, PtL, PtG, mentioned by countries like Germany, Denmark, and the European region, showing how the countries that potential will import this commodity are thinking on add-value to it utilizing transformation technologies. On the feedstocks field, the trend is similar, where renewable electricity for electrolysis takes major attention, and natural gas as a feedstock only is mentioned in the short term by countries like Australia, Canada, and USA, and in the mid and long term, CO_2 and Biogas for upgrading are in the focus of countries like Denmark.

Question: In your opinion, what are the most relevant non-biogenic RG technologies and feedstocks for your country/region?

In this part, the surveyed experts had their chance to respond about what they believed could be the most important technologies and feedstocks for their own country/region, adding, removing or replacing some ideas that could have appear on the national strategy.

Table 11. Most repeated words related to the short-, mid- and long-term technologies and/or feedstocks expected by the experts to be relevant for their countries/regions.



As in the previous question, hydrogen and electrolysis are a constant in the technology column, as well as renewable electricity and the sources as solar and wind power in the feedstocks. Methane from methanation in the mid and long term is of special interest for countries like Austria, Denmark, Germany, and UK, which, as mentioned before, probably want to increase the added value of hydrogen. Further, CO_2 appears strongly as an important feedstock for the same countries as before plus Ireland.

Question: Are there any combinations of technologies you listed in Question 7 that you think are particularly promising? If yes, please elaborate in less than 50 words.

In this section, some interesting matches for promising technologies were presented by the experts. These responses are summarized in the following table.

Table 12. Promising technologies combinations expected by the experts.

Australia	Wind and solar power to produce Hydrogen and export it
Austria	Urban energy production and demand profiles, urban Electrolysis with waste heat utilisation
Switzerland	SOE with heat integration with methanation or other exothermic processes.
Ireland	Sector integration for power, gas, salt caverns. Coupling electrolysis & hydrogen with data centre generators for peaking power.
China	Methane production from green hydrogen and BECCS
Canada	Methane cracking and photolysis for hydrogen production
USA	Improve efficiency in high-temperature electrolysis by integrating thermal and electric power from power plants. Solar and wind power could lower the prices of hydrogen.
Estonia	Hydrogen production with RE surplus
UK	Hydrogen practicalities and technology requirements under study
South Africa	GTL and CTL with CCUS, MSW and MWWT as gas source.
Brazil	Green hydrogen for industry (refinery and chemical industry)
Sweden	Green hydrogen for industry (iron reduction) and to balance power grids
Finland	Green hydrogen for chemical, refinery, steel industry, heavy duty transport, PtX and high value CCU, new chemicals and polymers
Japan	Cracking and reforming with PSA by using Liquid Natural Gas, Methanation / CCUS, green hydrogen
Norway	Blue hydrogen (Grey hydrogen and CCS)
Denmark	Biogas upgrading. CO2 captured for PtX. Hydrogen and CO2 captured to produce more Methane.
Europe	Ammonia, methanol and Liquid Organic Hydrogen as hydrogen carriers
Germany	Ammonia, methanol and Liquid Organic Hydrogen as hydrogen carriers

Question: If you answered "Yes" or "Planned" to Question 4, do these strategies focus on specific RG import or export opportunities? If so, please elaborate in less than 50 words.

This question aimed to identify how the national strategies were profiling the countries to the potential global trading market that will develop in the following years for non-biogenic RG. The role of each country in the global market according to the different strategies is summarized in the following figure.

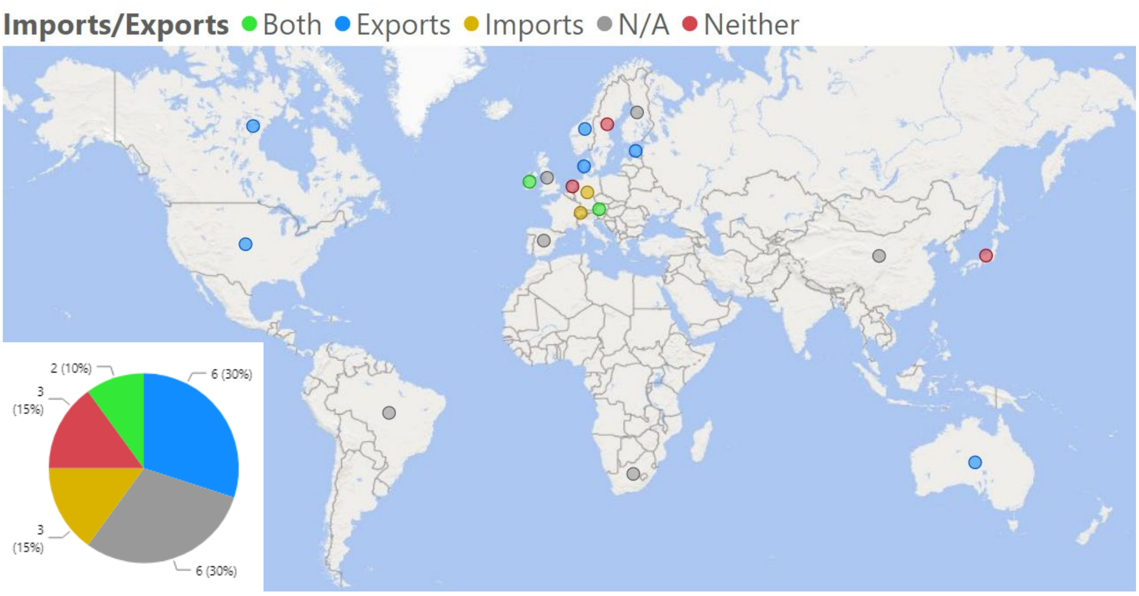


Figure 31. Export and/or import projections of renewable gases according to the national/regional strategies.

The rich in renewable resources countries such as Australia and Canada are mostly focused on exporting the excess of non-biogenic RG to the demanding markets, which according to this survey will be some of the European countries. Some other European states, also rich in renewable resources are rather thinking to trade or export gases, such as the Scandinavian countries or Ireland and Austria.

Part 2: Potential sustainability issues

In this part, the surveyed experts were asked about the most important issues that they identified on the technologies and feedstock supplies around non-biogenic RG, as well as the problems that they think their national strategies or legal framework have or could have.

Question: In your opinion, what are the most relevant issues and research questions related to environmental sustainability of RG?

On this first question, the experts shown which are, according to them, the most general issues related to environmental sustainability in RG matters, involving transport, resources use, pollution, carbon emissions, etc.

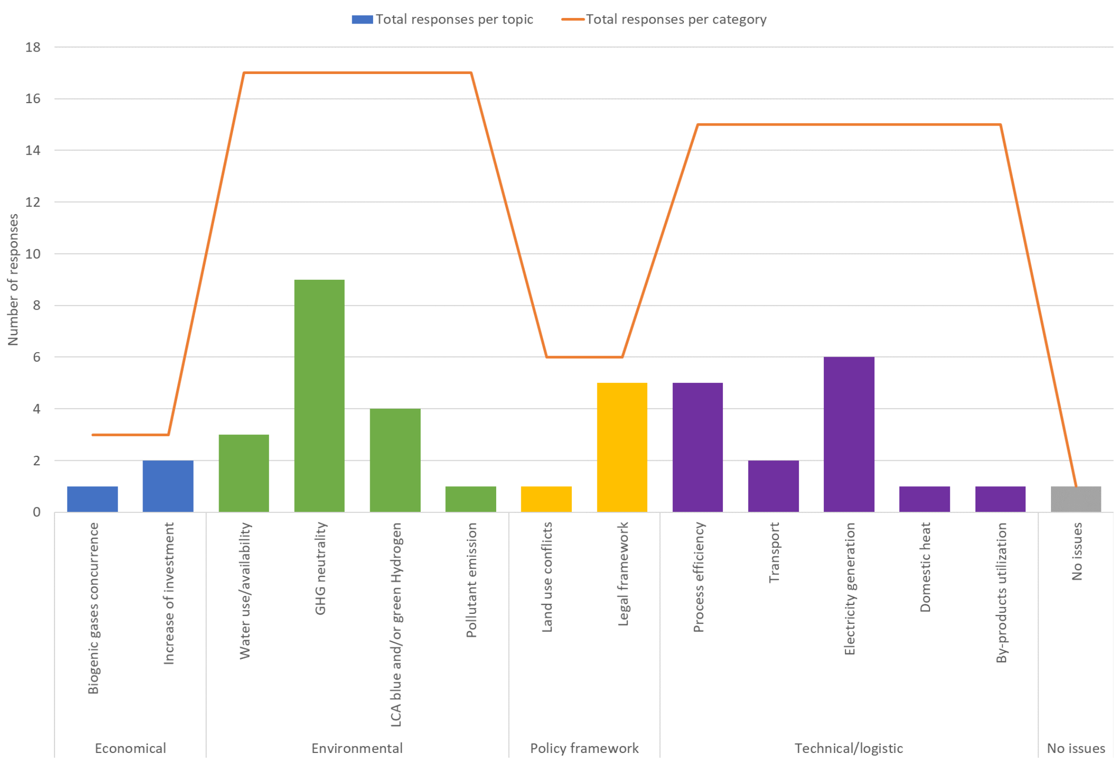


Figure 32. Categories and topics repeated by the surveyed experts related to the sustainability issues question.

GHG neutrality is the most repeated answer, followed by electricity generation, legal framework, and process efficiency. Of course, that every answer was focused on the country reality, but the topics were less always the same, and somehow many of them are related. For example, GHG neutrality can only be reached by having a highly efficient process, and by having a sustainable electricity generation within a strong legal framework. The context for each country will define the most relevant issues for each one that could or could not repeat in other places. For example, Australia as a dry country, mentioned water availability as an issue, meanwhile Canada also addressed this topic but with the focus on brackish water use. In any case, the solution for the issue could help for both cases, and having these opinions is useful to understand which are the most repeated ones and put more effort into those in the first place.

Question: In your opinion, are there gaps in the existing policy framework for RG, related to the following topics?

This question had two parts, the first one focused on policy/governance framework and the second on the coherence between sectors along RG production (Legal instruments, technologies available, etc).

a) The policy/governance framework, ensuring the sustainability of RG in your Country/Region?If yes, please elaborate in less than 50 words.

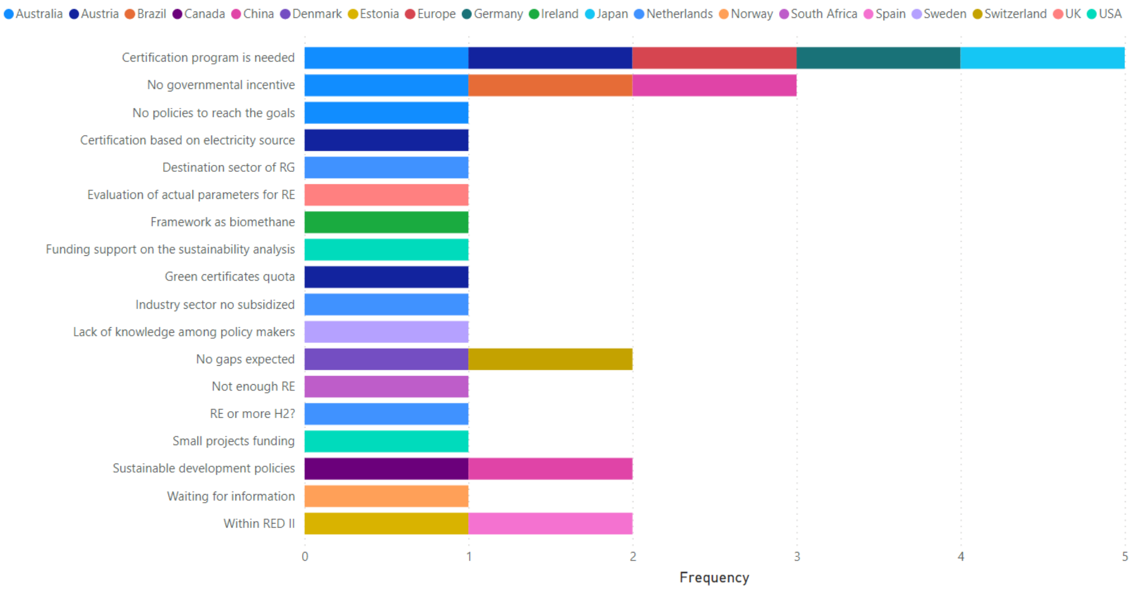


Figure 33. Principal policy/governance framework issues according to the surveyed experts.

Certification for RG is a big issue in the policy/governance framework, repeated by some potential RG producers and big potential consumers, as well as technology developer countries. Further, the governmental incentive is an issue in countries with big potential for RG production as Brazil, China, and Australia, and it is not a coincidence that China neither brazil have a non-biogenic RG strategy. More specifically, USA mentioned the lack of funds for small projects and sustainability analysis, the Netherlands talked about the lack of subsidies for the industry, and about the destination of RG and the dilemma between where to put the effort, into more renewable electricity or into producing hydrogen. This last issue will appear on the next part of the question with more frequency.

b) The coherence of sector specific instruments for the production of RG or the combinations of cross-sectoral technologies for RG production in your Region/Country? If yes, please elaborate in less than 50 words.

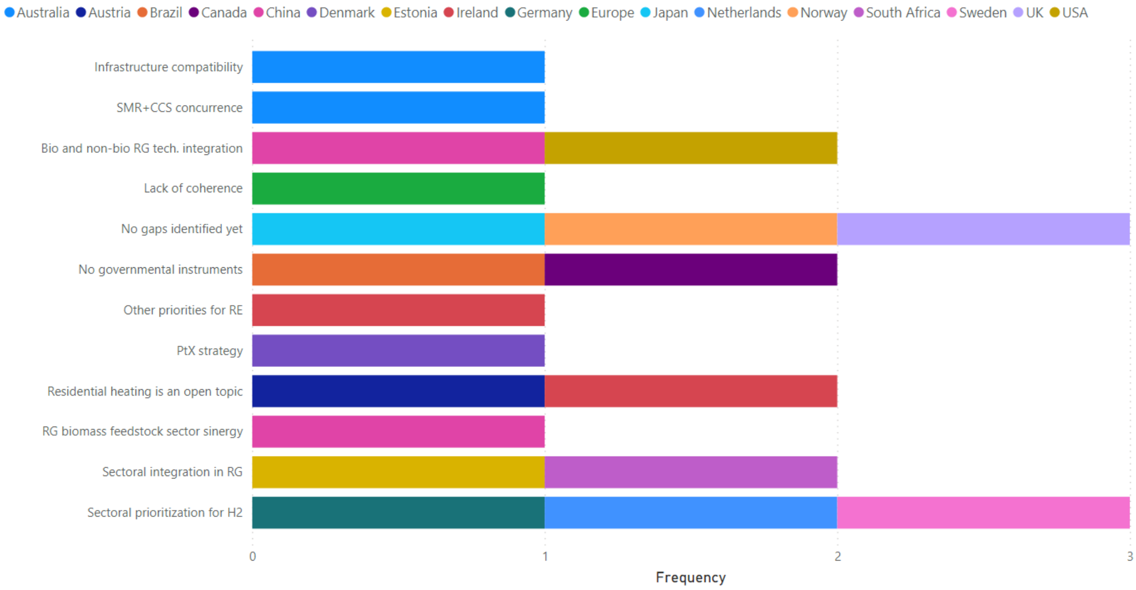


Figure 34. Principal sector or cross-sectoral specific instruments coherence issues according to the surveyed experts.

Besides the lack of gaps identified, the most repeated topic was the sectoral prioritization for hydrogen or RE once it is produced, between industry, domestic heating, transport, etc. This dilemma is presented in most of the answers in different countries. Other topics mentioned were the absence of governmental instruments, new technologies strategy as PtX are also mentioned as an issue in the future, projecting the actual problem of RG to the apparent, logical next step in the renewable industry development. Besides, the infrastructure compatibility and the competition with SMR+CCS hydrogen production (blue hydrogen) is also mentioned as an issue in some places.

Question: Are there specific combinations of technologies and regions, for which this WP should analyse potential sustainability issues related to RG in an exemplary, simplified case? If yes, please elaborate in less than 50 words

In this last question, the surveyed were asked to write down any interesting case of study related to RG that they could think that this work package should study in the near future.

Table 13. Possible study cases proposed by the surveyed experts.

Australia	Europe	Austria	Ireland	South Africa	Netherlands	UK	USA	Sweden	Germany	Brazil
Dry countries (like Australia) and water for electrolysis	Off-shore wind parks conditions to highest GHG reduction in H2 production	Electrolysis based on wind energy in Burgenland	RE export (interconnection) vs H2 export in Ireland	Potential for biogenic and non-biogenic RG generation, cost-benefit analysis in African context.	Hydrogen or electricity for: industry, heating and transport	Offshore wind to hydrogen	Geological diversity and available resources for RG production	Land use issue in Northern Sweden	"Excess-electricity" regions study	Chemicals and biofuels production using RE and RG in Brazilian context
		Hydrogen or synthetic Methane storage in large gas caverns for security of supply (lower Austria)	Most sustainable options for domestic heating			Gaseous fuels suitable to replace LPG and other gases in off-gas grid heating and cooking systems				
		Electrolysis based on pump storage in the Alps for storage-type conversion	Net positive/negative impact of data centres with/without hydrogen			Fossil or bio-CO2 to methane or other fuels				
		6MW PEM-electrolyser at Voestalpine steel industry in Linzin place								

7.6 RENEWABLE METHANE PROJECTS

Type of electricity (for electrolysis projects)	Project name	Country	Date online	Status	Electrolysis Technology	Technology Comments	If dedicated renewables, type of renewable	Product	Announced Size
Dedicated renewable	CRS4-Italgas Sardinia	Italy		Concept	Other Electrolysis	Unknown PtX	Unknown	CH_4	
Dedicated renewable	SLOP2G Project	Slovenia		Concept	Other Electrolysis	Unknown PtX	Unknown	CH_4	
Dedicated renewable	Northwest Natural Holding synthetic methane plant	United States		Concept	Other Electrolysis	Unknown PtX	Others/Various	CH_4	2-10MW
Dedicated renewable	PtG Switzerland	Switzerland	2022	Construction in Progress	PEM		Others/Various	CH_4	2.5MW
Dedicated renewable	APA Renewable Methane Demonstration Project	Australia	2023	DEMO	Other Electrolysis	Unknown PtX	Solar PV	CH_4	0.005MW
Other/Unknown	MethFuel	Germany		DEMO	PEM			CH_4	1MW
Other/unknown	AltHytude	France	2009	DEMO	ALK			CH_4	0.08MW
Other/Unknown	ElectroHgena	France	2016	DEMO	Other Electrolysis	Unknown PtX		CH_4	
Other/Unknown	Minerve, Nantes	France	2018	DEMO	SOEC			CH_4	0.12MW - 10m3 H2/h
Other/unknown	DemoSNG	Sweden	2015	DEMO	PEM			CH_4	28 m3/h
Other/unknown	Hitachi Zosen - PTTEP CO2 Conversion to Methane Project R&D)	Thailand	2012	DEMO	Other Electrolysis	Unknown PtX		CH_4	
Dedicated renewable	Wallonia e-methane project	Belgium	2025	Feasibility study	Other Electrolysis	Unknown PtX	Others/Various	CH_4	75MW
Dedicated renewable	Greening of Gas (GoG) - Net4Gas DEMO	Czech Republic	2023	Feasibility study	Other Electrolysis	Unknown PtX	Unknown	CH_4	50m3 CH4/h
Dedicated renewable	Element One (Element Eins), phase 1	Germany	2024	Feasibility study	ALK		Others/Various	CH_4	1.08 GWh H2/d
Dedicated renewable	Element One (Element Eins), phase 2	Germany	2028	Feasibility study	ALK		Others/Various	CH_4	1.8 GWh H2/d
Dedicated renewable	Pegasus	Italy	2024	Feasibility study	Other Electrolysis	Unknown PtX	Unknown	CH_4	23MW
Other/unknown	HySynGas	Germany		Feasibility study	PEM			CH_4	50MW
Dedicated renewable	Vantaa-Wartsila methanation	Finland	2025	FID	Other Electrolysis	Unknown PtX	Onshore wind	CH_4	20MW
Dedicated renewable	Underground Sun Storage	Austria	2018	Operational	ALK		Solar PV	CH_4	0.6MW
Dedicated renewable	PFI - Pirmasens-Winzeln	Germany	2019	Operational	Other Electrolysis	Unknown PtX	Others/Various	CH_4	2.5 MW
Grid (excess renewable)	Solothurn, STORE&GO	Switzerland	2019	Operational	PEM			CH_4	0.35 MW
Grid (excess renewable)	Falkenhagen STORE&GO	Germany	2018	Operational	PEM			CH_4	1 MW - 180 m^3 H_2/h

Type of electricity (for electrolysis projects)	Project name	Country	Date online	Status	Electrolysis Technology	Technology Comments	If dedicated renewables, type of renewable	Product	Announced Size
Grid (excess renewable)	Rostock, Exytron Demonstrationsanlage	Germany	2018	Operational	ALK			CH_4	4m3 H2/h
Grid (excess renewable)	ETOGAS, Solar Fuel Beta-plant AUDI, Werlte (Audi e-gas)	Germany	2013	Operational	ALK			CH_4	6 MW
Grid (excess renewable)	CO2RRECT-Niederaussem	Germany	2013	Operational	PEM			CH_4	50 m3 H2/h
Grid (excess renewable)	MicrobEnergy GmbH, Schwandorf	Germany	2013	Operational	PEM			CH_4	0.18 MW
Grid (excess renewable)	Troia, STORE&GO	Italy	2018	Operational	PEM			CH_4	0.2MW
Grid (excess renewable)	Tauron CO2-SNG	Poland	2019	Operational	Other Electrolysis	Unknown PtX		CH_4	18 m3/h
Other/unknown	Methanation at Eichhof	Germany	2018	Operational	PEM			CH_4	0.05 MW
Other/unknown	MicroPyros, Altenstant	Germany	2018	Operational	Other Electrolysis	Unknown PtX		CH_4	0.25 m3 H2/h
Other/unknown	MicroPyros, Staubing	Germany	2014	Operational	Other Electrolysis			CH_4	
Other/unknown	P2G-Biocat - Continued (Ref 508)	Denmark	2015	Operational	ALK			CH_4	0.5 MW - 100 m3H2/h
Other/unknown	CoSin: Synthetic Natural Gas from Sewage, Barcelona	Spain	2018	Operational	SOEC			CH_4	20m3 CH4/h
Other/unknown	Methane Synthesis test facility in Koshijihara Plant of INPEX's - Nagaoa	Japan	2019	Operational	Other Electrolysis	Unknown PtX		CH_4	16m3 H2/h
Other/unknown	SoCalGas-NREL	United States	2019	Operational	Other Electrolysis	Unknown PtX		CH_4	0.25 MW
Other/Unknown	Fenosa Canberra hydrogen demo project	Australia		Other/Unknown	Other Electrolysis	Unknown PtX		CH_4	

Extracted from https://www.iea.org/data-and-statistics/data-product/hydrogen-projects-database

IEA Bioenergy

Technology Collaboration Programme