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# Comparative analysis of electrolytic hydrogen production technologies with low-carbon (CCS-abated) hydrogen pathways.

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IEA Greenhouse Gas R&D Programme

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IEAGHG

# Report Overview:

# Comparative Analysis of Electrolytic Hydrogen Technologies with Low Carbon (CCS-abated) Hydrogen Pathways.

IEA/CON/22/293

## Introduction

The primary goal of this study, conducted by ERM is to evaluate various electrolytic hydrogen production pathways focusing on their technical, economic, and environmental aspects and to compare these with hydrogen production routes that involve fossil fuel with carbon capture and storage (CCS) abatement. Further, the objectives of the study include assessing the potential impact of global water resources through electrolysis in a net zero context, evaluating the potential impact of hydrogen consumption on water vapour emissions, and assessing the value of oxygen produced via electrolysis

## Key Messages

- Alkaline electrolysers (AEL), proton exchange membrane electrolysers (PEM), and solid oxide electrolysers (SOEC) technologies were modelled across three electricity connection scenarios (as follows) to produce a levelised cost of hydrogen (LCOH) in 2030 and 2050. The lifecycle assessment was conducted based on the aforementioned technologies, including anion exchange membrane electrolysers (AEM).

  - Scenario 1: The electrolyser was assumed to be connected to 100% grid electricity.
  - Scenario 2: A 50/50 combination of onshore wind and solar-generated electricity.
  - Scenario 3: It was assumed that wind energy that would otherwise be curtailed would be used by the electrolyser whenever the daily average electricity production from offshore wind exceeded the daily average electricity demand.
- Between 2030 and 2050, improvements in electrolyser performance, particularly in efficiency, and reductions in CAPEX unlocks cost reduction across the technologies and scenarios modelled.
- By 2050, dedicated renewables are the lowest cost option on a per kg $H_2$ basis, with LCOH ‹ 3€/kg across the technologies considered in this study. This is primarily due to the high utilisation factor of the electrolyser and the low cost of renewable energy.
  - The high utilisation factor is achieved through the balancing effect of combined onshore wind and solar generation capacities, which together provide a sufficiently consistent power output to support the electrolyser for nearly the entire year.
  - Additional cost reductions would be required to achieve the most ambitious hydrogen cost targets.
  - Increasing electricity costs increases the LCOH. The impact on LCOH is proportional to the change in cost, with the largest impact being felt under Scenario 1: Grid connected (Grid) where electricity costs are already large and a 50% increase in costs causes a larger total increase than under, for example, Scenario 2: Load following (RES).
- The Grid scenario can support 100% load factors, enabling consistently high-volume production of hydrogen. This positions the Grid scenario as the second lowest LCOH scenario in both 2030 and 2050, despite high electricity costs.
- The high LCOH in the Curtail scenario indicates that strategies relying solely on curtailed renewables for electrolysers are unlikely to result in cost-effective hydrogen production. This is primarily due to the low expected load factors and the resulting low hydrogen production volumes.
- In 2030, AEL electrolysers achieve the lowest LCOH due to their low relative CAPEX, good efficiency, and minimum load characteristics. By 2050, significant improvements in CAPEX across the technologies considered in this study make SOEC electrolysers the lowest cost option in all scenarios. Their high efficiency supports large volumes of hydrogen production, distributing costs effectively and maintaining a low LCOH despite the additional heating costs.

  - SOEC using renewable load following direct connection potentially achieves costs of €2.07/kg $H_2$ by 2050. Even at this LCOH, further cost reductions would be needed to meet the most ambitious hydrogen cost targets
- Increasing renewable energy generation capacity decreases the LCOH, with a particularly significant impact in 2030. This sensitivity applies specifically to renewable energy connected scenarios, such as load following (RES) and Curtailment (Curtail). Conversely, halving the generation capacity would result in an exponential increase in LCOH in the 2030 SOEC curtail scenario.
  - Where renewable energy supply causes reduced electrolyser load factor, increasing the electrolyser capacity (MW) increases the LCOH.
- The production pathway emissions for electrolyser technologies modelled (AEL, PEM and AEM) reach close to zero by 2050 because the only sources of emissions are from tap water, sodium hydroxide and hydrochloric acid (this analysis did not consider other environmental impacts, such as land use and the embodied emissions from the construction and manufacturing of materials).
  - The heat requirement for SOEC hydrogen production leads to the highest GHG emissions among the modelled electrolysis technologies if natural gas combustion is used to meet this demand. However, significant GHG emissions reductions can be achieved under natural gas decarbonisation scenarios.
- Stoichiometrically, 9 kg of water is required to generate 1kg of hydrogen. However, in practice total input can range from 20 - 60 kg $H_2O$/kg $H_2$ depending on the water source and balance of plant (BoP) configuration.
- In pursuing net-zero carbon emissions, it is crucial not to lose sight of the impact of other emissions, such as the emission of water vapour. At higher temperatures, the atmosphere can hold larger concentrations of water vapour. The warming associated with increased water vapour in the atmosphere is therefore part of a feedback loop between increased GHG emissions and global warming.
- The business case for $O_2$ valorisation is strongest where hydrogen costs are low and large volumes of oxygen can be produced. In cases where only small amounts of oxygen are produced, such as with small electrolysers or electrolysers with low load factors, the revenue generated on an LCOH basis may not be sufficient to justify the investment in the technologies and systems required to valorise and make electrolytic oxygen competitive.
- By 2050, electrolytic hydrogen is cost competitive with CCS-abated hydrogen production under load following (RES). For grid connected and wind curtailment scenarios, LCOH remains substantially higher than CCS-abated hydrogen production routes. Assumptions around electricity cost, electricity consumption and the volumes of hydrogen produced by each technology and scenario impact how competitive electrolytic hydrogen can be.

- By 2050, feedstock costs will constitute the bulk of the LCOH for both CCS-abated and electrolytic hydrogen, except in scenarios where electrolytic hydrogen is produced with very low load factors. Consequently, fossil fuel costs will primarily influence the cost of CCS-abated (blue) hydrogen production, while electricity costs will determine the cost of green hydrogen.

## Background

A gap exists in the literature with regards to in-depth understanding of the costs associated with electrolytic hydrogen production especially under varying production scenarios. While numerous studies quote figures for a production cost of the main electrolyser technologies, these often significantly undercut the costs observed in practical scenarios. This discrepancy can be attributed to the literature's oversight in including all the associated costs of electrolyser projects, such as those related to the electrolyser assets, BoP, design/engineering, site preparation, and installation. Gaining a comprehensive understanding of the varying costs of electrolytic hydrogen production is crucial for predicting the future adoption of these technologies. It also allows for a meaningful comparison with other low-carbon hydrogen production methods, such as CCS-abated options, as discussed in IEAGHG's recent publications "Low carbon hydrogen from natural gas - Global roadmap, 2022[1]" and "Blue hydrogen - Beyond the Plant Gate, 2022[2]".

## Scope

The Netherlands, a hub for hydrogen development and electrolyser deployment, was selected as a geographic reference to enable alignment with previous IEAGHG studies on blue hydrogen to facilitate comparison. Selecting a singular geography allowed an in-depth picture of both the emissions and costs involved in the hydrogen production process to be developed.

While variations in results may occur outside of Europe due to differences in local factors such as renewable electricity costs and water availability, the findings of the study remain largely applicable. The study focused on scenarios based on electricity sources, including grid-connected systems, a 50/50 mix of solar and wind, and curtailment. Therefore, the conclusions drawn are broadly relevant and can be adjusted to account for specific geographic conditions, making the study's results valid for regions outside of Europe as

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[1] 'IEAGHG, "'Low-Carbon hydrogen from NaturalGas: Global Roadmap" 2022-07, August 2022

[2] 'IEAGHG, "Blue Hydrogen: Beyond the Plant Gate", 2022-06, August 2022.

well. The scenarios considered provide a robust framework that can be adapted to different contexts while maintaining the core insights of the analysis.

A literature review was conducted to gain understanding of the landscape of electrolyser technologies. Technologies were evaluated based on a set of key performance indicators (Table 1), and the top four highest-scoring technologies were shortlisted for detailed focus in this study as follows:

- Alkaline electrolysers (AEL) - TRL: 9
- Proton exchange membrane electrolysers (PEM) - TRL: 9
- Solid oxide electrolyser cells (SOEC) - TRL: 7-8
- Anion exchange membrane (AEM) - TRL: 6

Each technology received a rating ranging from 1 (indicating low performance) to 3 (signifying high performance), based on its relative effectiveness compared to other technologies and its alignment with sector-specific requirements, such as achieving high purity, lower capital expenditure (CAPEX), and minimal maintenance needs.

The three electrolyser technologies modelled for techno-economic assessment (TEA) are based on a 300 MW hydrogen production facility. The defined boundaries for the modelled hydrogen production systems encompasses both the electrolyser and the compressor, aiming to produce hydrogen at a pressure of 200 bar.

The storage and distribution aspects of hydrogen are not included in the project's scope. This exclusion is due to the significant variability in these processes, which largely depend on the specific off-take connection and the amount of hydrogen generated, both of which can differ greatly depending on the electricity connection scenario.

To explore the impact of various types of electricity connections, three scenarios were modelled. These scenarios include:

i. Scenario 1; Grid connected: In this scenario, the electrolyser is linked exclusively to grid electricity. It is presumed that there is always enough electricity available for the electrolyser and compressor to operate at full capacity.

ii. Scenario 2; Load following (Renewable Energy Source): In the RES scenario, the electrolyser is powered by a mix of onshore wind and solar electricity. It is estimated that a combined total renewable energy capacity of 1 GW (comprising 500 MW from Photovoltaic (PV) and 500 MW from onshore wind) would be sufficient to meet the minimum load requirements of a 300 MW electrolyser.

iii. Scenario 3; Wind curtailment: Under this Scenario, wind energy that will otherwise be curtailed (i.e., not used) due to grid constraint or low demand is employed to produce hydrogen

Table 1: KPI scoring matrix for AEL, PEM, SOEC, and AEM electrolysers. Scoring is based on current technology performance. Please refer to Section 9.1 in the Appendix (Chapter 9) of the main report for the data informing the scoring criteria.

| Electrolyser Technology type | TRL | Current manufacturing capability | Future manufacturing capability | Efficiency | Operating range | System response to change in incoming power | System footprint | $H_2$ outlet pressure | $H_2$ outlet purity | Stack lifetime | CAPEX (system cost, factory gate) | Challenges | Advantages | Maintenance | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Weighting** | **2** | **3** | **2** | **3** | **2** | **2** | **1** | **1** | **1** | **2** | **3** | **2** | **1** | **1** | |
| **AEL** | 3 | 3 | 3 | 2 | 1 | 2 | 1 | 2 | 2 | 3 | 3 | 3 | 2 | 2 | **63** |
| **PEM** | 3 | 2 | 3 | 2 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | **63** |
| **SOEC** | 2 | 1 | 2 | 3 | 3 | 1 | 2 | 1 | 2 | 2 | 1 | 2 | 3 | 1 | **48** |
| **AEM** | 1 | 1 | 1 | 1 | 2 | 3 | 2 | 2 | 2 | 1 | 2 | 1 | 1 | 1[19] | **38** |

In the life cycle GHG assessment the system boundaries followed the cradle-to-gate approach, adhering to the guidelines set by the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) for calculating GHG emissions in hydrogen production. This boundary encompasses processes from raw material extraction through to the final production of compressed hydrogen.

# Findings

## Techno economic analysis

This task investigates the TEA of hydrogen production via electrolysis in the Netherlands for the years 2030 and 2050, focusing on AEL, PEM, and SOEC electrolysers, see table 2 below. The modelling includes the capital and operational expenses of these technologies, costs of feedstock and electricity, across three distinct electricity connection scenarios as outlined in the study's scope.

*Table 2: LCOH by technology & scenario for 2030 & 2050.*

| | | AEL | | | PEM | | | SOEC | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **First year of operation** | *Units* | **GRID** | **RES** | **CURTAIL** | **GRID** | **RES** | **CURTAIL** | **GRID** | **RES** | **CURTAIL** |
| **2030** | *€/kg* | 7.81 | 4.87 | 30.53 | 8.35 | 5.67 | 36.09 | 7.99 | 6.17 | 58.36 |
| **2050** | *€/kg* | 5.99 | 2.61 | 7.54 | 5.98 | 2.60 | 7.54 | 5.01 | 2.58 | 7.38 |

AEL, PEM, and SOEC technologies have been modelled to generate a LCOH by the year 2030 for the three scenarios considered in this study.

Scenario 1; Grid connected: The grid-connected scenario for hydrogen production offers the advantages of a stable and continuous power supply, essential for maximising electrolyser utilisation. However, this scenario also incurs higher electricity costs, which significantly impact the LCOH. For instance, the LCOH for grid connected AEL is 7.8 €/kg $H_2$, for PEM it is 8.3 €/kg $H_2$, and for SOEC it is 8.0 €/kg $H_2$. As the energy mix of the grid evolves towards a higher share of renewables, the cost and environmental footprint of grid-connected hydrogen production are expected to improve. Nonetheless, current grid-connected systems need to balance these costs against the benefits of reliability and flexibility in operations.

Scenario 2: Dedicated renewables (RES), emerges as the most cost-effective option in terms of LCOH (Figure 1). This scenario benefits from high electrolyser load factors achieved by combining onshore wind and photovoltaic (PV) power, which helps to mitigate the effects of seasonal fluctuations in electricity generation. Consequently, Scenario 2:

Load following (RES) production pathway is projected to attain a LCOH ranging from 4.9 to 6.2 €/kg by 2030, varying with the electrolyser technology used.

Scenario 3: Curtailment emerges as the costliest option in terms of LCOH, with costs exceeding 30 €/kg. Under the curtailment configuration modelled in this techno-economic assessment, this scenario is not viable in 2030. The extremely low load factors, created by limited electricity availability from curtailment and prohibitively high minimum electrolyser loads, coupled with significant electrolyser capital expenditures (CAPEX), result in an LCOH that is too high to be considered reasonable for competitively priced hydrogen. Curtailment may still offer a viable model for hydrogen production via electrolysis under ideal conditions. Such conditions include the availability of a consistently high-power supply from curtailed energy, such as in regions with high renewable energy penetration or employing market mechanisms that create scenarios where renewable energy is preferentially curtailed, for example, due to transmission constraints or to avoid negative pricing. This availability could increase the electrolyser's load factor and reduce costs, given that curtailed electricity is typically very low cost or virtually free. Therefore, when designing an electrolyser project that connects to a curtailed energy supply, it is crucial to ensure there is sufficient electricity available to operate the electrolyser for long enough periods to achieve a reasonable LCOH.

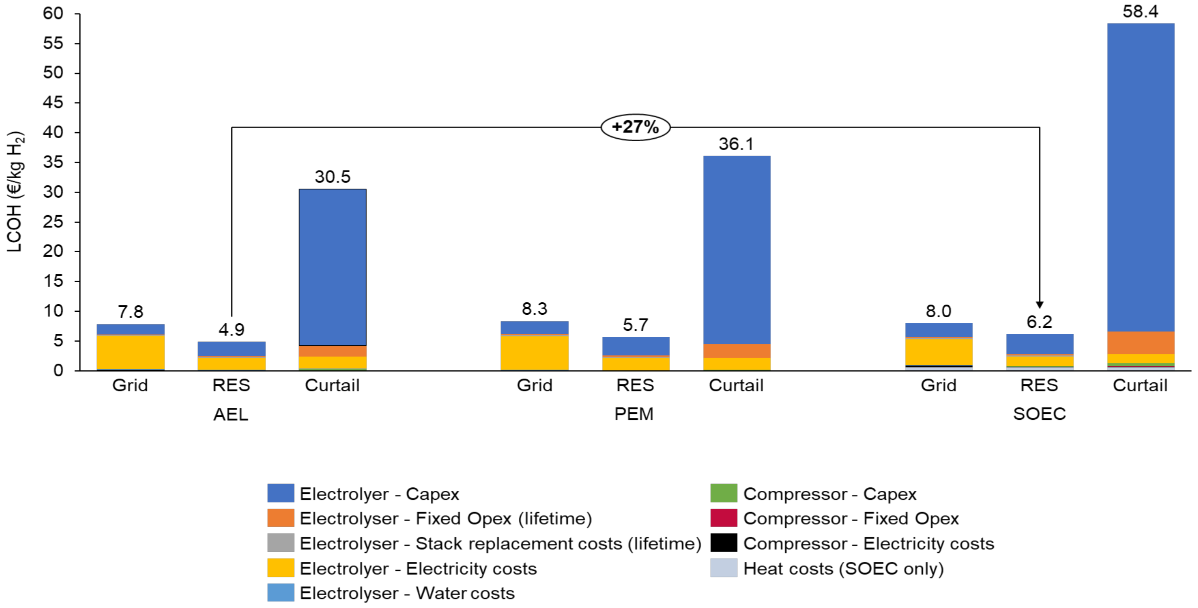

*Figure 1. LCOH across technologies and scenarios in 2030.*

The key takeaways from Figure 1 are that the RES scenario seems to be the most cost-effective for producing hydrogen across different electrolysis technologies, and the Curtailment scenario is the least cost-effective. The exact implications of this data would depend on the specific context in which these technologies are being considered, such as geographic location, availability of renewable resources, and the intended application of the hydrogen produced.

AEL is projected to be the most cost-effective technology across all scenarios by 2030, attributed to its comparatively low CAPEX costs. Although PEM technology requires lower minimum loads than AEL and has reduced compression needs due to its higher electrolyser output pressure, its higher CAPEX and consequently higher fixed operational expenditure (OPEX) result in a marginally higher LCOH compared to AEL in 2030. This cost differential is more pronounced when hydrogen production volumes are lower; there is approximately a 7% difference in LCOH between AEL and PEM in the Grid connected scenario, which expands to around an 18% difference under the Curtailment scenario.

By 2030, it is expected that SOEC technologies will achieve high operational efficiencies; however, their CAPEX will remain significantly high. Coupled with the additional expense of heat supply, this elevates the costs associated with SOEC above those for AEL and PEM technologies. In scenarios where the electrolyser load factor is low, such as Scenario 3: Curtailment, the substantial investment needed further escalates the LCOH.

It is important to acknowledge that SOEC technology is less advanced in its development compared to AEL and PEM electrolysers. By 2030, SOEC may still be in the process of scaling up to the projected 300 MW model and its high-efficiency claims are contingent on the availability of a heat source. Therefore, for a fair comparison, it is crucial to focus on the two more established technologies i.e., AEL and PEM.

## Cost implication of electrolyser technologies in 2050 scenarios

Between 2030 to 2050, advancements in electrolyser performance, especially in terms of efficiency, along with decreases in electrolyser costs, lead to a lower LCOH for all scenarios and technologies.

In Scenario 1: Grid connected, the LCOH remains elevated due to high electricity prices, despite reductions in other costs and increased hydrogen output from more efficient electrolysers. By 2050, electricity expenses account for over 80% of the costs in the grid connected scenario.

Scenario 2: Dedicated renewables continue to be the most cost-effective on a per kilogram hydrogen basis, with the LCOH falling below 3 €/kg for all technologies considered in this study. By 2050, projections suggest that SOEC with direct connection to renewable sources following demand could see costs as low as 2.07 €/kg $H_2$. However, even at this rate, more substantial cost reductions would be necessary to achieve the most challenging cost goals for hydrogen.

Under Scenario 3: Curtailment, despite the higher costs resulting from smaller production volumes, by 2050, the LCOH is projected to drop to approximately 75%, 79% and 87% for AEL, PEM and SOEC, respectively.

The RES scenario (A 50/50 combination of onshore wind and solar-generated electricity) consistently presents the lowest LCOH across all technologies (AEL, PEM, and SOEC). This suggests that integrating renewable energy into hydrogen production is the most cost-effective option among the scenarios presented as illustrated in Figure 2.

The key takeaways from Figure 3 are that by 2050, SOEC emerges as the most affordable technology across all scenarios. This underscores the potential of SOEC, given the assumptions of accelerated development progress (which is less concerning for the year 2050) and the availability of waste heat. By using a cheap heat source (waste heat), the cost of producing hydrogen (LCOH) drops by up to 20%. The biggest savings were in the SOEC connected to renewable energy sources.

By 2050, PEM and AEL technologies are projected to attain similarly low LCOH, resulting from their high efficiencies and ability to operate efficiently at low load factors, and low capital expenditures. Despite the slight cost variance between them (which could accumulate over the electrolyser's lifespan, affecting the long-term revenue capabilities of each technology), both are expected to achieve competitive LCOH levels especially under the RES scenario.

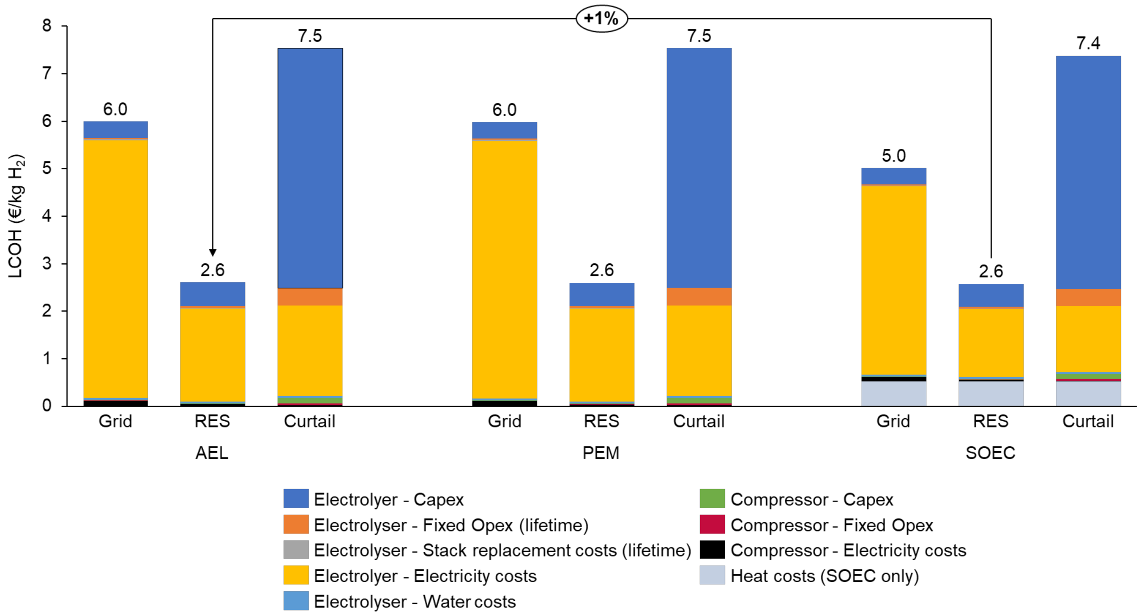

*Figure 2. LCOH in 2050 by scenario and electrolyser type.*

To summarise the cost findings in this task, as electricity costs rise, so does the LCOH, with the increase being proportional to the surge in electricity expenses. The most significant impact of this can be seen in grid-connected scenarios, where initial electricity costs are substantial. For instance, a 50% hike in electricity costs under such a scenario leads to a more pronounced rise in LCOH compared to a load-following scenario with renewable energy sources, where the initial costs are comparatively lower.

Boosting the capacity for renewable energy generation can lead to a substantial decrease in LCOH, especially in scenarios planned for 2030 that are reliant on renewable energy, such as load-following and curtailment scenarios. An example is the effect of halving the renewable energy generation capacity in a 2030 load-following scenario, which could skyrocket the LCOH by more than 4000% due to the already low load factor. This underscores the heightened sensitivity of such scenarios to both fixed cost variations and the reliability of electricity supply.

## Efficiency gains and cost dynamics in hydrogen production: Trends from 2030 to 2050

The trends from 2030 to 2050 suggest an industry moving towards more efficient and higher volume hydrogen production, especially in scenarios that leverage renewable energy sources. However, Figure 3 has illustrated that the cost components of the LCOH reveal that operational expenditures, particularly those related to electricity, remain significant contributors to the overall costs.

The decrease in the required minimum load percentage for operating electrolysers, particularly for SOEC and AEL, has led to enhanced hydrogen production volumes and a drop in the LCOH for Scenario 3: Curtailment. A lower minimum load facilitates a greater electrolyser load factor, as electrolysers can be activated and commence hydrogen production with a lower baseline input power. This allows for more operational days within a curtailment scenario. The combined effects of increased efficiency and a reduced minimum load have yielded an improvement of over 10% in hydrogen production volumes for Scenario 3: Curtailment when comparing AEL in 2030 with that in 2050.

The influence of these improvements is comparatively modest in Scenario 1: Grid connected and Scenario 2: Load following (RES) for all technologies, with AEL serving as an exemplar. In these scenarios, advancements from 2030 to 2050 facilitate an approximate 4% growth in hydrogen production volumes.

Large reductions in CAPEX unlock cost reductions by 2050. CAPEX reductions have the largest impact on a per kg $H_2$ basis in renewable energy connected scenarios where CAPEX forms a larger % contribution to the costs instead of electricity costs (which is proportional to the volumes of hydrogen produced).

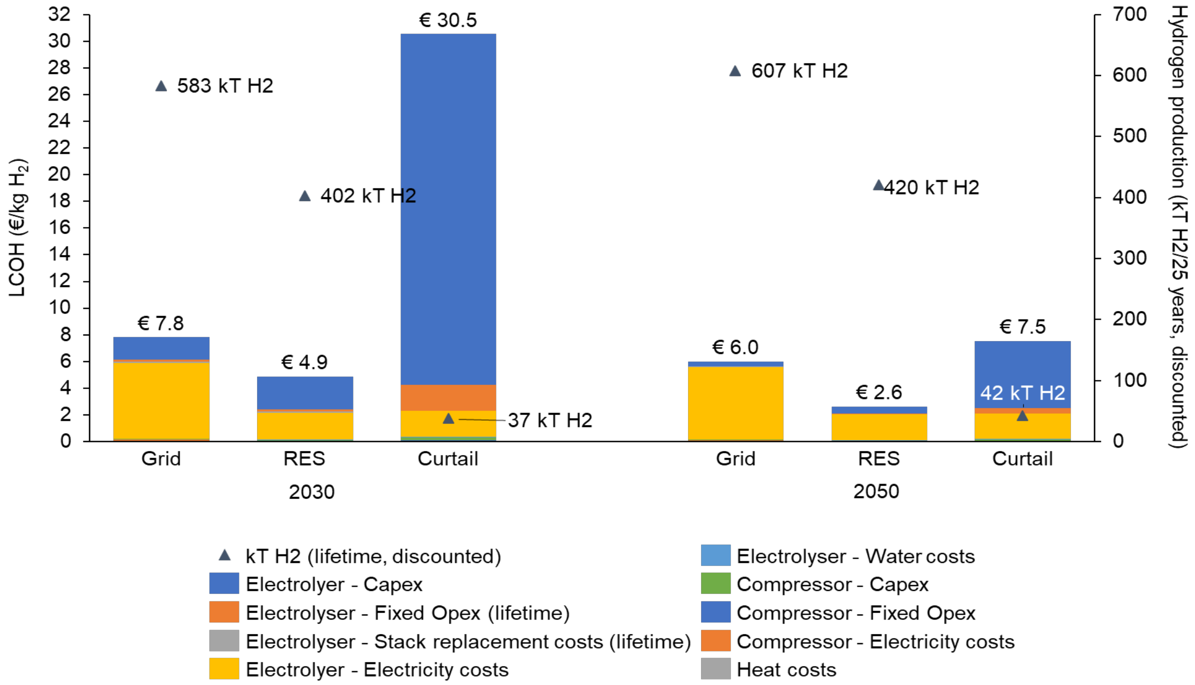

*Figure 3. Comparison between LCOH and lifetime volumes of hydrogen production (kT $H_2$) in 2030 and 2050 for an AEL across all scenarios.*

## Lifecycle assessment

In this study, cradle-to-gate system boundaries were employed in accordance with the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) GHG methodology for hydrogen production. This system boundary encompasses all process steps from the extraction of raw materials through to the production of compressed hydrogen.

As the electricity grid decarbonises by 2050, there is a substantial reduction in emissions related to the electrolytic hydrogen production methods. Unlike other electrolysis pathways, the SOEC electrolysis process necessitates an additional heat input. In this study, natural gas was assumed as the heat source for the SOEC pathway. Although this heat input allows for greater electrical efficiency in the SOEC process, the gas grid's slower pace of decarbonization, compared to the electricity grid, results in the SOEC pathway having the highest emissions (see Figure 4).

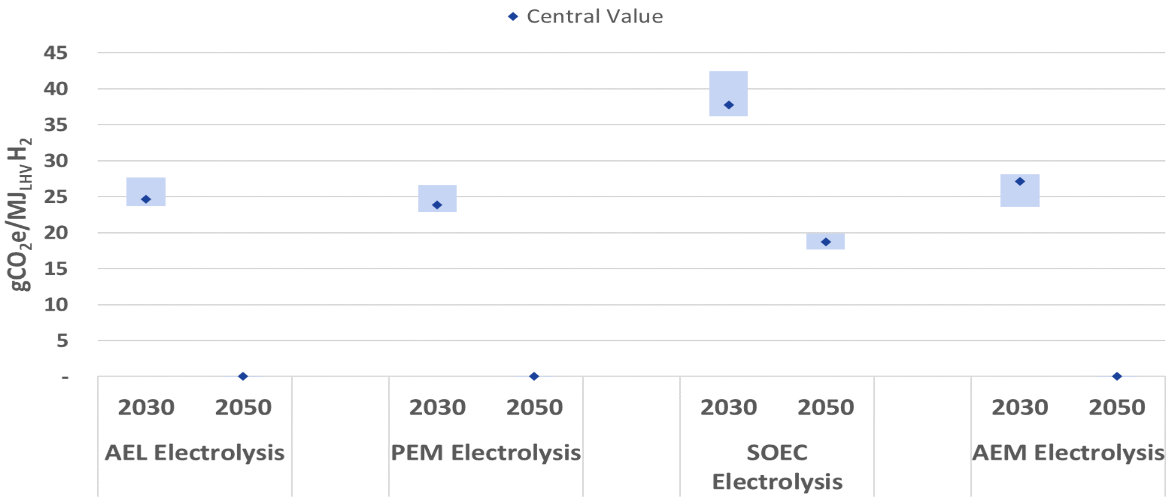

*Figure 4. Electrolytic hydrogen production emissions using grid electricity (scenario ranges, 2030 and 2050)*

By 2050, emissions from the production pathways of AEL, PEM, and AEM electrolyser technologies are anticipated to be nearly zero, with residual emissions stemming only from sources such as tap water, sodium hydroxide, and hydrochloric acid, (When the same analysis was conducted for 2050, the results showed no difference between using grid and renewable electricity because it was assumed that the Netherlands electricity grid decarbonises to run on 100% renewables by 2050).

The difference in results between the AEL, PEM and AEM electrolysis pathways can be attributed to the electrolyser efficiencies which are very similar for AEL and PEM (up to 0.6% difference in 2030 and up to 1.8% difference in 2050). The difference in efficiencies between the AEM electrolyser and the PEM and AEL electrolysers is bigger (up to 6.1% in 2030 and up to 4.1% in 2050) due to the lower efficiency of the AEM electrolyser compared to AEL and PEM.

## Impact of fugitive hydrogen emissions in electrolytic hydrogen production

A sensitivity analysis on varying the percentage of hydrogen losses from fugitive emissions during electrolytic production was conducted, with a GWP of 11 $gCO_2/g\ H_2$. The losses assumed for different cases were 0.11 $gH_2/MJ\ H_2$ for the Central case, 0.02 $gH_2/MJ\ H_2$ for the Best case, and 0.28 $gH_2/MJ\ H_2$ for the Worst case. This analysis demonstrated that fugitive hydrogen emissions from production can significantly impact total pathway emissions, adding between 0.2 - 9.1 gCO2e/MJ LHV $H_2$, depending on the assumed losses.

## Water requirements for electrolytic hydrogen production

Water is a crucial component in the production of electrolytic hydrogen, and there are concerns that if this process is scaled up without sustainable practices, it could exacerbate water stress issues. To produce 1 kg of hydrogen, stoichiometrically 9 kg of water is required, excluding additional demands such as cooling. The actual water needed can be much higher, between 20-60 kg per kg of hydrogen, depending on the source and system setup. Electrolysers need very pure water because any impurities can damage the cells and shorten their lifespan, increasing the cost of hydrogen due to more frequent maintenance and parts replacement. Proton Exchange Membrane (PEM) electrolysers, in particular, are highly sensitive to impurities that can affect the platinum cathode catalyst, while Alkaline Electrolysers (AEL) are vulnerable to anion and organic impurities. Despite the need for high-purity water, the costs of water treatment are relatively low in the overall context of the electrolyser plant, making up about 1% of the total hydrogen production cost.

In the context of an estimated global consumption of water in 2050 of 6,000 billion $m^3$/year, this hydrogen economy would account for 0.3% of the global water demand. This is based on an estimated global hydrogen demand in 2050 of 614 million tonnes/year and a water consumption of 31 kg $H_2O$/kg $H_2$.

Water vapor emitted at the earth's surface has a GWP (Global Warming Potential) of between -0.001 and +0.0005 $CO_2e$ over a 100-year timeframe. This small magnitude is due to several factors: additional water vapor cannot reach the upper atmosphere; water vapor has a short atmospheric lifetime (approximately 10 days) due to precipitation; and cloud cover reflects incoming solar radiation, mitigating warming effects. However, at higher temperatures, the atmosphere can hold larger concentrations of water vapor. The warming associated with increased water vapor in the atmosphere creates a feedback loop between increased GHG emissions and global warming.

## Electrolytic oxygen valorisation

The production of electrolytic hydrogen also results in the generation of 99.99% pure oxygen, which could serve as an extra source of income for hydrogen producers. Despite this potential, the oxygen market is primarily controlled by well-established companies using methods like pressure swing adsorption (PSA), or vacuum swing adsorption (VSA), and the demand for ultra-pure oxygen is relatively small. This demand is currently satisfied through long-standing agreements with major industrial gas companies. Using this high-grade oxygen in sectors that do not require such purity, like steel and glass manufacturing, offers little additional value.

Oxygen produced through electrolysis might offer certain benefits compared to other sources. For instance, industries like refineries, which require both oxygen and hydrogen, could find synergies that enhance the economic feasibility due to their large-scale demand for these gases. Additionally, electrolysers are capable of generating oxygen at the high pressures needed by refineries, which reduces the necessity for additional compression. If electrolysers are situated close to industrial users, this could also significantly cut down on distribution costs. However, it is worth noting that producing oxygen on-site using air separation units (ASU) also presents a compelling business argument, with a relatively short payback period of just 9 to 18 months.

There is growing interest in enhancing the economic viability of water electrolysis by utilising the oxygen it produces. An example is Shell's Holland hydrogen project, which involves a 200MW electrolyser scheduled to start operating in the latter half of the 2020s. This project aims to supply both waste heat and electrolytic oxygen to various industries. Additionally, Horizon Europe has initiated a call for projects focused on the "valorisation of by-product $O_2$ and/or heat from electrolysis."

## Quantifying valorisation

The financial impact of oxygen valorisation on electrolytic hydrogen production was assessed. Assuming an average oxygen price of €0.073 per kg and considering that 8 kg of oxygen is produced per kg of hydrogen, the value equates to €0.584 per kg of hydrogen. Given the variation in oxygen sales value and delivery costs, we assumed delivery costs at the lower end, about 40% of the oxygen's delivered value. This is likely an overestimate, but it helps in creating a rough estimate of the total costs involved in oxygen valorisation. After accounting for these costs, the net profit from oxygen valorisation is approximately €0.35 per kg of hydrogen. This estimate does not include factors like efficiency losses or storage costs, which could further influence the cost.

The benefit of oxygen valorisation as a percentage reduction in LCOH varies across different scenarios and technologies. The attractiveness of oxygen valorisation is higher in scenarios where hydrogen production costs are low and the market value of oxygen is high, leading to greater total revenues. However, in situations where only small amounts of oxygen are produced, like in smaller electrolysers or those with low load factors, the total revenue might not be sufficient to justify the investment in the necessary technologies and systems for making electrolytic oxygen competitive.

## Comparative analysis of electrolytic hydrogen production with CCS-abated hydrogen

The TEA and LCA findings of the electrolytic hydrogen production conducted in this study were compared with the findings of the CCS-abated hydrogen pathways in the 2022 IEAGHG studies, namely Blue Hydrogen: Beyond the Plant Gate, 2022 and Low Carbon Hydrogen from Natural Gas: Global Roadmap 2022. Hydrogen production technologies assessed in the earlier mentioned study include steam naphtha reforming (SNR), partial oxidation (POX), and hygienic earth energy (HEE), whereas the technologies considered for the latter study include steam methane reforming (SMR), autothermal reforming (ATR), electrified SMR (ESMR), and POX.

## TEA Comparison

CCS-abated hydrogen routes demonstrate generally lower and more stable costs compared to electrolytic routes, making them the cost-effective options available today. The estimates in Figure 5 provide a comparative analysis of the LCOH for production pathways discussed in this study as well as CCS-abated hydrogen technologies modelled from earlier IEAGHG reports. By 2050, it is anticipated that electrolyser technologies will have matured significantly and will have undergone large performance and cost improvements, unlocking reduced LCOH under electrolytic hydrogen production pathways. The findings from CCS-abated hydrogen, which were used in the comparative analysis with this study, have been considered for efficiency improvements up to 2050 as well, as discussed in the "Low-Carbon Hydrogen from Natural Gas: Global Roadmap," 2022-07, August 2022, and "Blue Hydrogen: Beyond the Plant Gate," 2022-06, August 2022.[1,2]

Electrolytic hydrogen costs are heavily influenced by the energy source and electrolyser technology. The renewable load following electrolytic hydrogen shows more competitive costs. The curtailment connected electrolytic hydrogen pathway was however observed to be notably expensive, reflecting inefficiencies and complexities tied to intermittent renewable energy sources.

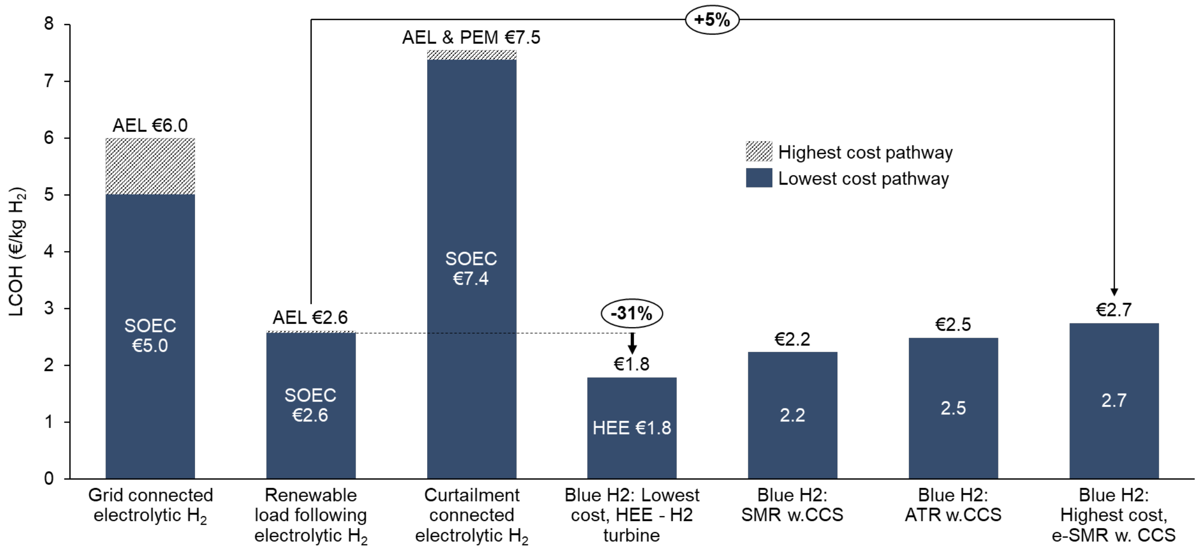

*Figure 5. LCOH by production pathway, 2050.*

It is imperative that electrolyser sizing be tailored to the use case, particularly where a low load factor is presented, such as in the curtailment scenario. If electrolysers are more appropriately sized, reductions in LCOH could be achieved under this scenario. If electricity costs were negated, this scenario could be low cost under the optimal conditions.

By 2050, feedstock costs will constitute the bulk of CCS-abated $H_2$ LCOH. The same is true for green electrolytic $H_2$ where electricity becomes the dominant cost on a per kg $H_2$ basis under scenarios with high electrolyser load factor. Therefore, fossil fuel and electricity costs will dictate the production cost of blue and green hydrogen respectively. Increasing the carbon price will also increase the blue hydrogen cost. If renewable electricity costs fall and fossil fuel costs climb, then post-2050 electrolytic hydrogen would present as a more attractive option than blue $H_2$ on an LCOH basis.

The comparative analysis highlights that blue hydrogen routes currently provide the most cost-effective hydrogen production methods. However, with technological advancements and the increased availability of low-cost renewable energy, electrolytic hydrogen is becoming increasingly viable. Decision-makers are encouraged to weigh current costs against future trends and consider the specific energy and environmental contexts of their projects when choosing between electrolytic and blue hydrogen.

Figure 6 reveals several critical insights into the GHG emissions of various hydrogen production pathways. Renewable energy-based electrolysers, specifically RES AEL and RES PEM, exhibit the lowest GHG emissions, approximately 0.1 g $CO_2$-eq / MJ $H_2$, due to their reliance on renewable energy sources. On the other hand, SMR and ATR pathways, when combined with CCS, show significant GHG emissions reductions of approximately 76% compared to their non-CCS counterparts.

Using CCS-abated SMR as an example, if the efficiency of capture is increased to ultra-high capture rates (95% or higher), and e.g., the process was re-configured to electric-SMR using decarbonised or renewable electricity, emissions would be on par with those from electrolytic hydrogen. This approach suggests that with increasing efficiency in capture rates, clean energy process modifications and the integration of renewable energy sources, even traditionally high-emission processes like SMR can potentially achieve comparable environmental benefits to those of electrolytic hydrogen production.

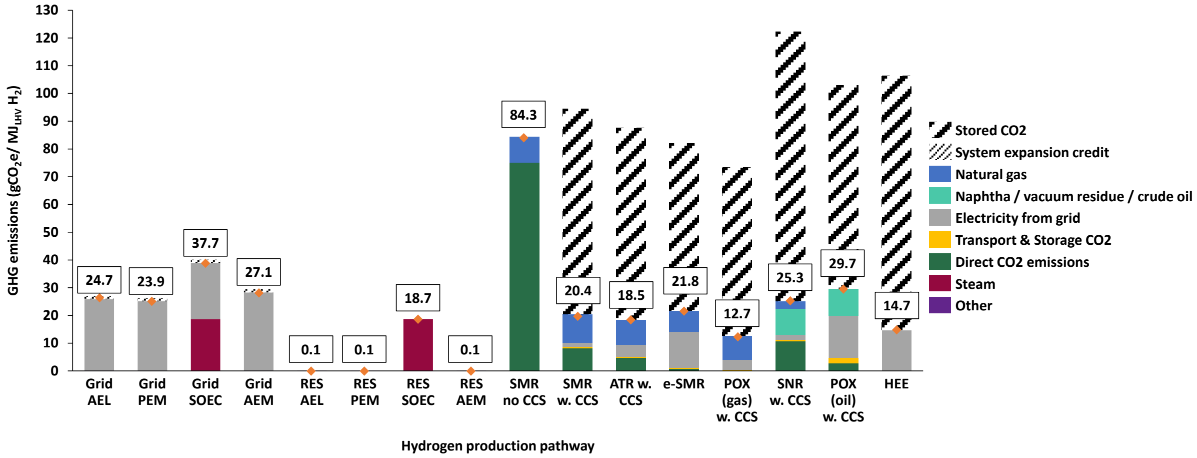

*Figure 6. Estimated hydrogen production emissions from electrolysis and CCS-abated pathways in 2030 (RES = electricity generated from renewable sources).*

Combining biomethane or renewable natural gas (RNG) with CCS-abated SMR presents a compelling pathway to producing low-carbon or even carbon-negative hydrogen. This approach leverages renewable energy sources and advanced carbon capture technologies to significantly reduce the environmental impact of hydrogen production. However, the availability and economic viability of biomethane can vary, and these factors need to be considered when planning large-scale hydrogen production projects.

# Expert review

The review of this study was conducted by seven experts who provided valuable feedback aimed at improving the clarity and depth of the analysis. Overall, the reviewers acknowledged the study's attention to detail and its comprehensive analysis of hydrogen production technologies under different energy scenarios.

Key areas of feedback included suggestions for refining the economic assumptions, particularly regarding the relationship between CAPEX and the scale of hydrogen production systems and moving away from the traditional "colour" classification of hydrogen in favour of emissions-based standards. The study responded by clarifying the assumptions used in the techno-economic analysis and adding text emphasising the need to transition towards emissions accounting and certification schemes for low-carbon hydrogen.

Reviewers also highlighted the importance of accurately measuring hydrogen leakage and its associated emissions. In response, the study included a reference to ongoing research in this area, acknowledging the need for further investigation. Additionally, the terminology around "low carbon" versus "clean" hydrogen was revised for clarity, based on feedback from the reviewers.

The report was updated to reflect the reviewers' comments and enhance its overall rigor, ensuring it offers a clearer and more accurate representation of the study's aims.

# Conclusions

## Technoeconomic analysis

- Given any set connection conditions (grid, renewable etc.), the electrolyser efficiency and minimum load determine which technology will have the lowest LCOH i.e., the technology which is able to make best use of the inputs and produce the largest quantity of hydrogen.
- Achieving a high load factor on the electrolyser is crucial for maintaining a low LCOH, especially when CAPEX is relatively high. For electrolytic hydrogen production connected to renewable sources, the electrolyser should be sized according to the available renewable generation capacity to maximize the load factor and hydrogen production volumes, thereby reducing the LCOH. This requires a careful balance of appropriately sizing both the generation capacity and the electrolyser to efficiently use energy for hydrogen generation, avoiding oversized electrolysers that increase LCOH and demand unnecessary CAPEX investment.
- It seems unlikely that relying solely on curtailed renewables for electrolyser operation will result in cost-effective hydrogen production, primarily due to the anticipated low load factors. However, if the installation costs (CAPEX) can be

significantly reduced, a broader array of cost-effective hydrogen production strategies could become viable.
- While PEM and AEL are expected to provide the lowest LCOH in 2030, SOEC shows significant promise for 2050. This potential is regardless of the heat source for SOEC but situating the electrolyser in areas with access to waste heat could lead to further substantial cost reductions.

As we move towards 2050 and CAPEX falls, electricity costs contribute a greater share of LCOH, thus increasing the importance of access to low-cost renewable energy.

## Lifecycle GHG analysis

- Although the SOEC electrolyser boasts higher electrical efficiency, its heat requirement leads to higher GHG emissions compared to other electrolysis methods if the heat is supplied through natural gas combustion.
- Considering fugitive hydrogen emissions from the production and distribution of electrolytic hydrogen can potentially increase total pathway emissions by over 10%, depending on hydrogen's GWP value.
- While enhancing technology efficiency, especially electrolyser efficiency, can reduce total pathway emissions, other factors such as grid decarbonisation, reducing fugitive hydrogen emissions, and adopting low-carbon transportation options can have a more substantial impact on emissions reduction.

## Comparison with CCS-abated hydrogen pathways

- By 2050, electrolytic hydrogen produced under renewable-connected, load-following scenarios could become cost-competitive with some CCS-abated hydrogen production pathways, resulting in a comparable LCOH. Significant advancements in electrolyser technologies are expected by then, leading to substantial improvements in performance and cost.
- By 2050, feedstock costs will account for the majority of the LCOH for both CCS-abated and electrolytic hydrogen, except in scenarios where electrolytic hydrogen is produced with very low load factors. Thus, fossil fuel costs will dictate CCS-abated hydrogen production costs, while electricity costs will determine green hydrogen costs.
- Electrolysis routes will achieve lower GHG emissions intensities than CCS-abated hydrogen routes if renewable electricity is used, or by 2050 as grid electricity fully decarbonises. The location of hydrogen production and decarbonisation of regional electricity grids can have a significant impact on the pathway emissions due to the electricity required.

## Recommendations

- Hydrogen leakage indirectly increases atmospheric GHG levels by altering the concentrations of methane, water vapor, and ozone through its interactions with hydroxyl radicals. Managing hydrogen leakage is important to ensure that the environmental benefits of hydrogen as a clean energy carrier are fully realised.
- To better account for hydrogen leakage, research is needed on accurate measurements of hydrogen emissions and the impacts of co-emissions. Recent publications have addressed this, but further consideration is required.
- The GWP of anthropogenically generated water vapor depends on emission location and altitude. More studies are needed, especially concerning water vapor produced at high altitudes from hydrogen-powered aviation.
- Electrolytic oxygen could be valorised as a by-product, though it is not commonly done in electrolysis projects. Future exploration of synergies might unlock new markets for electrolytic oxygen.
- This analysis did not consider other environmental impacts such as land use and embodied emissions from the construction and manufacturing of materials. Future work should examine additional impact categories to fully assess the environmental impacts of different hydrogen production routes.

# COMPARATIVE ANALYSIS OF ELECTROLYTIC HYDROGEN PRODUCTION TECHNOLOGIES WITH LOW CARBON (CCS-ABATED) HYDROGEN PATHWAYS

A report for

IEAGHG

# Comparative analysis of electrolytic hydrogen production technologies with low carbon (CCS-abated) hydrogen pathways

**ERM**

November 2024

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E4tech is an international consultancy focused on sustainable energy, with offices in the U.K. and Switzerland. Since 1997 E4tech has worked with companies, governments and investors wanting to understand the global opportunities and challenges of clean energy, building up a strong track record of providing strategic business and policy advice backed up by sound technical knowledge.

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To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts before its release.

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## Acronyms

| | |
|---|---|
| AEL | Alkaline electrolyser |
| AEM | Anion exchange membrane |
| AFC | Alkaline fuel cell |
| ASU | Air separation unit |
| ATR | Autothermal reforming |
| AWE | Alkaline water electrolysis |
| BoP | Balance of plant |
| CAPEX | Capital expenditure |
| CCS | Carbon capture and storage |
| $CO_2e$ | Carbon dioxide equivalents |
| e-SMR | Electrified steam methane reformer |
| GHG | Greenhouse gas |
| GWP | Global warming potential |
| GWP100 | Global warming potential, on a 100 year timeframe |
| HEE | Hygienic earth energy |
| HHV | Higher heating value |
| IPHE | International Partnership for Hydrogen and Fuel Cells |
| JRC | Joint Research Centre |
| KPI | Key performance indicators |
| LCA | Life cycle assessment |
| LCI | Life cycle inventory |
| LCOH | Levelised cost of hydrogen |
| LHV | Lower heating value |
| MAR | Managed aquifer recharge |
| MDEA | Methyldiethanolamine |
| MEA | Monoethanolamine |
| OPEX | Operating expenditure |
| PEM | Proton exchange membrane |
| PEMEL | Polymer electrolyte membrane electrolysis |
| PFSA | Perfluorosulfonic acid |
| POX | Partial oxidation |
| PSA | Pressure swing adsorption |
| PTL | Porous transport layer |
| PV | Photovoltaic |
| R&D | Research and development |
| R+CCS | Reformers with CCS |
| RES | Renewable energy source |
| SMR | Steam methane reformer |
| SNR | Steam naphtha reformer |
| SOEC | Solid oxide electrolyser cell |
| SOFC | Solid oxide fuel cell |
| TEA | Techno-economic analysis |
| TRL | Technology readiness level |
| VSA | Vacuum swing adsorption |
| WGS | Water gas shift |

# Definitions

| | |
|---|---|
| Blue water | Water stored on the surface and in groundwater bodies. *Note, in this report, water is used synonymously with blue water in the context of withdrawals.* |
| Consumption | Water which is consumed is used (i.e., consumed, evaporated, or incorporated into products) such that it is no longer available for immediate reuse or return to its original source. |
| Green water | Water which is stored in soil and plants. |
| Grey water | Grey water refers to wastewater generated from domestic activities (for example, water used for bathing, showering or utilities) which is not contaminated with faecal matter. |
| Groundwater | Groundwater is present below the earth's surface; for example, water present in porous rock layers called aquifers. |
| Water scarcity | Water scarcity occurs where there is a low availability of water per population member. |
| Water stress | Water stress occurs where the demand for water exceeds the availability of water of sufficient quality within a particular region or time period. |
| Withdrawal | The act of removing water from its source. Water which is removed may either be consumed or returned. |

# Executive Summary

Low-carbon hydrogen is increasingly recognised by public and private sector stakeholders around the world as a key constituent in meeting the Paris Agreement's climate goals. Electrolytic hydrogen production represents an increasingly viable generation pathway. The sector is accelerating pace with the first > 100 MW electrolysers[1, 2] now operational and multi-hundred MW projects under development with operation starting as early as the mid-to-late 2020s. Meanwhile, there are currently no operational blue hydrogen projects (2023).

The purpose of this study is to provide robust techno-economic and greenhouse gas (GHG) assessments of different electrolytic hydrogen production pathways for 2030 and 2050 in the Netherlands, to enable evaluation between different electrolytic options as well as comparison against other low-carbon hydrogen production technologies (e.g. CCS-abated (blue) hydrogen from natural gas). The Netherlands, a hub for hydrogen development and electrolyser deployment, was selected as a geographic reference to enable alignment with previous IEAGHG studies on blue hydrogen to facilitate comparison. Selecting a singular geography allowed an in-depth picture of both the emissions and costs involved in the hydrogen production process to be developed. Other key project objectives include assessing: the potential impact of electrolysis water consumption on water scarcity; the potential impact of hydrogen consumption on water vapour emissions; the value of oxygen generated and its potential industrial applications; hydrogen leakages during production and distribution.

## Roadmap of electrolytic hydrogen production

We conducted a detailed review and analysis of electrolyser technologies, both established and novel. Technologies were scored against a selection of key performance indicators (KPIs), and the four highest scoring technologies were shortlisted to be the focus of this study: alkaline electrolysers (AEL), proton exchange membrane electrolysers (PEM), solid oxide electrolysers (SOEC) and anion exchange membrane electrolysers (AEM).

Of the four commercial technologies analysed in detail:

- AEL and PEM electrolysers are currently the two most mature technologies.
- PEM electrolysers score more highly than AEL on most performance-based characteristics, with less mature technologies, SOEC and AEM, exhibiting potential performance gains over both PEM and AEL in the long run (if successful in reaching development targets by 2050).
- AEL score more highly than other technologies on most commercial characteristics linked to technology maturity (i.e. manufacturing capability, cost, lifetime).
- With ongoing development of PEM technology, production capacity is expected (based on published capacity announcements) to accelerate in the coming years, closing the gap between PEM and AEL production scales.
- PEM technologies face challenges due to high material demands (iridium) which could create blockages in the supply chain if the material demand per watt of electrolyser capacity is not reduced.
- SOEC and AEM technologies are at a much earlier stage of development and have very low deployed capacities.
- SOEC's small system footprint and high efficiency make it an attractive technology if the current issues with thermal cycling can be resolved.
- R&D is key to improving the lifetime and costs of SOEC and AEM technologies.

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[1] Hydrogen Insight 2023, World's largest green hydrogen project begins production in China.
[2] Recharge 2022, World's largest green hydrogen project, with 150MW electrolyser, brought on line in China.

- Each electrolyser technology has its advantages and disadvantages, and selection of a specific electrolyser type is often heavily dependent on use case and specifics of the site.

As part of the Roadmap, future cost reductions for electrolyser CAPEX were considered. Cost reductions resulting from electrolyser design and manufacturing improvements, combined with economies of scale, could unlock capital expenditures (CAPEXs) of <300 USD/kW for AEL, PEM, SOEC and AEM technologies by 2040/2050 (depending on the pace of development) amounting to a reduction of at least 80% in cost relative to today. However, in order to stabilise future electrolyser supply chains, reductions in critical material consumption and improvements in recycling rates are required.

## Techno-Economic Analysis (TEA) Comparison

The cost contributions in the TEA were broken down into CAPEX core components and operating expenditure (fixed and variable OPEX). A 300 MW electrolyser was considered for all scenarios, with an output pressure of 200 bar. The TEA considered three technologies (AEL, PEM & SOEC) across three electricity connection scenarios in both 2030 and 2050.

The three electricity connection scenarios considered were:

- **Grid:** The electrolyser was assumed to be connected to 100% grid electricity, assuming that sufficient electricity was available at all times to allow the electrolyser and compressor to operate at full load.
- **RES**: A 50/50 combination of onshore wind and solar generated electricity (renewable energy sources (RES)) was assumed as the power source for the electrolyser (and compressor), modelled to replicate the variation of each supply in the Netherlands. Where the available power did not meet the electrolyser minimum load requirements, the electrolyser would be ‘off’ and no hydrogen produced. Sufficient electricity for the electrolyser to be ‘on’ was available for most of the year (93-100% of days in a year, dependent on electrolyser technology).
- **Curtail**: Offshore wind generation capacity (modelled to replicate the variation of supply in the Netherlands) was compared to electricity demand, to establish the magnitude and frequency of curtailed electricity, referring to the supply of electricity in excess of demand. This was then assumed as the input power for the electrolyser, with the electrolyser only coming on when there was sufficient available power input. Under these conditions, there is only sufficient power to turn the electrolyser ‘on’ 11-24% of days in a year (dependent on electrolyser minimum load requirements).

Figures A and B show the levelised cost of hydrogen (LCOH) by scenario and electrolyser technology type in 2030 and 2050, respectively.

### Scenario comparison

- In both 2030 and 2050, the *RES* scenario produces the lowest LCOH, irrespective of electrolyser technology. This can be largely attributed high utilisation factor of the electrolyser and the low costs of renewable energy. High electrolyser utilisation can be met due to the balancing effect of the onshore wind and solar generation capacity which combined provides a sufficiently consistent power output to support the electrolyser for almost all days of the year.
- The *Grid* scenario can support 100% load factors (LFs), enabling consistently high-volume production of hydrogen. This positions Scenario 1 as the second lowest cost (LCOH) scenario in both 2030 and 2050, despite high electricity costs.
- The high LCOH associated with the *Curtail* scenario suggests it is unlikely that operating strategies for electrolysers based on using curtailed renewables only will lead to cost-effective hydrogen production, mainly due to low expected LFs and resulting low volumes of associated hydrogen production. If installed CAPEX can be reduced substantially, a wider range of operating strategies under which low-cost $H_2$ can be produced become feasible.

## Technology differentiation

- In 2030, AEL electrolysers result in the lowest LCOH as the low relative CAPEX is complemented by good efficiency and minimum load characteristics.
- By 2050, following vast improvements in CAPEX across all technologies, SOEC electrolysers present as the lowest cost option across all scenarios due their high efficiency, enabling large volumes of hydrogen production. This distributes costs which enables a low LCOH despite additional heating costs.

## Overarching Trends

- The biggest contributors to LCOH are:
    - **CAPEX** – dominated by the electrolyser CAPEX with minimal contribution from the compressor CAPEX.
    - **Electricity costs** – other variable OPEX contributes a much smaller amount to the LCOH.
    - **Fixed electrolyser OPEX under the curtailment scenario** – taken as a % of capex to capture operation and maintenance costs over the lifetime of the electrolyser.
- As CAPEX costs are set irrespective of electrolyser utilisation (i.e. based on the 300 MW electrolyser scale assumed), low electrolyser utilisation results in a high LCOH.
- As we move towards 2050 and CAPEX falls, electricity costs contribute a greater share of LCOH, thus increasing the importance of access to low-cost renewable energy.

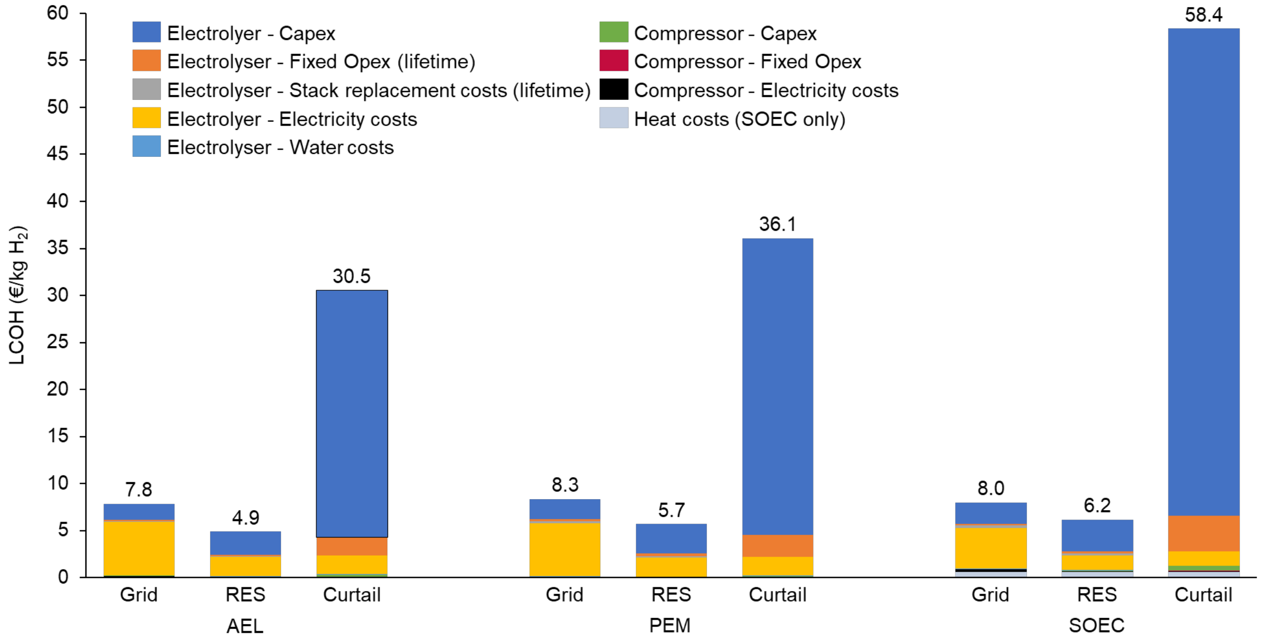

Figure A: LCOH across electrolyser technologies and scenarios in 2030.

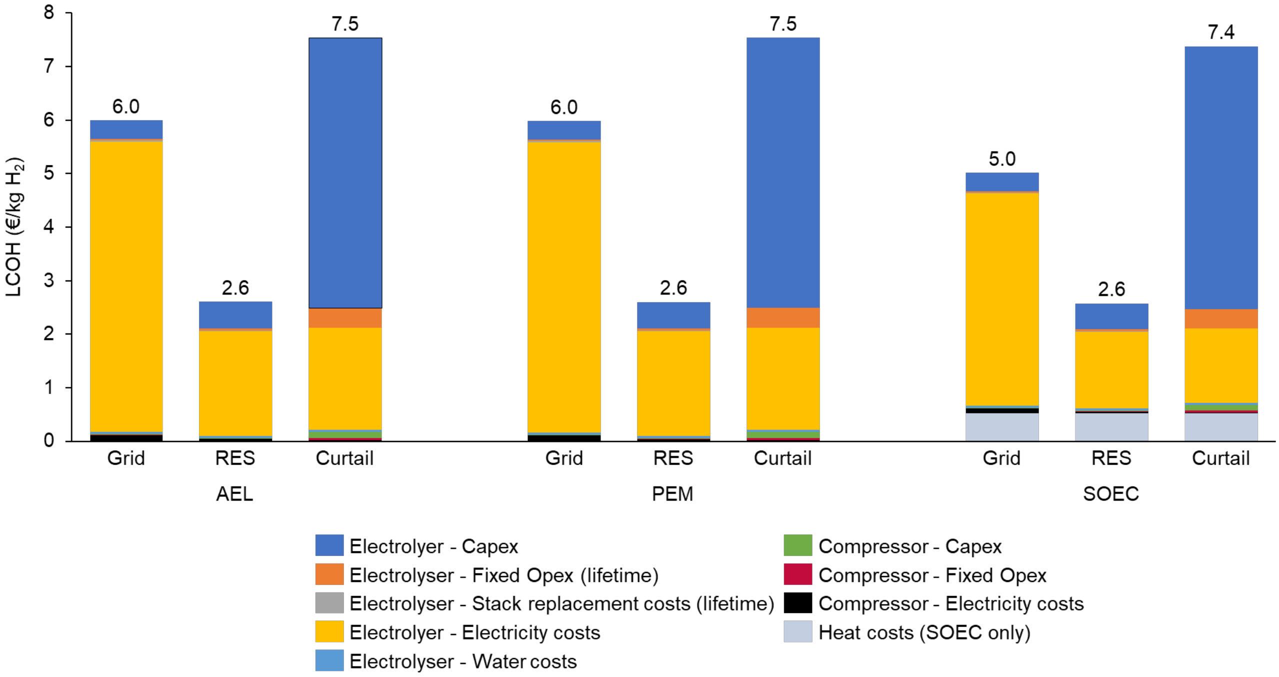

Figure B: LCOH across electrolyser technologies and scenarios in 2050.

## Blue hydrogen comparison

**Electrolytic hydrogen production could be cost competitive with blue hydrogen technologies (such as natural gas reforming with CCS[3]) by 2050, under load following RES connected conditions**. Figure C shows this comparison of LCOH by production pathway in 2050.

- By 2050, it is anticipated that electrolyser technologies will have matured significantly, undergoing large performance and cost improvements.
- **By 2050, electrolytic hydrogen is cost competitive with blue hydrogen production under *Scenario 2: Load following (RES).*** For grid connected and wind curtailment scenarios, LCOH remains substantially higher than the central cases for blue hydrogen production. Assumptions around electricity cost, electricity consumption and the volumes of hydrogen produced by each technology and scenario impact how competitive electrolytic hydrogen can be.
- **By 2050, feedstock costs constitute the bulk of blue LCOH** which is also the case for electrolytic hydrogen under scenarios with high electrolyser LFs. Fossil fuel and electricity costs will therefore dictate the production cost of blue and green hydrogen, respectively. Increasing the carbon price adds additional charges for emitted carbon for blue hydrogen production pathways (not 100% capture) and therefore also increases blue hydrogen LCOH.

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[3] Natural gas and grid electricity prices based on Blue Hydrogen: Beyond the Plant Gate assumptions for the Netherlands in 2030 and 2050 (~30 €/MWh for natural gas, ~ 100 €/MWh for grid electricity). The full breakdown of assumptions including renewable energy price assumptions can be found in the Appendix.

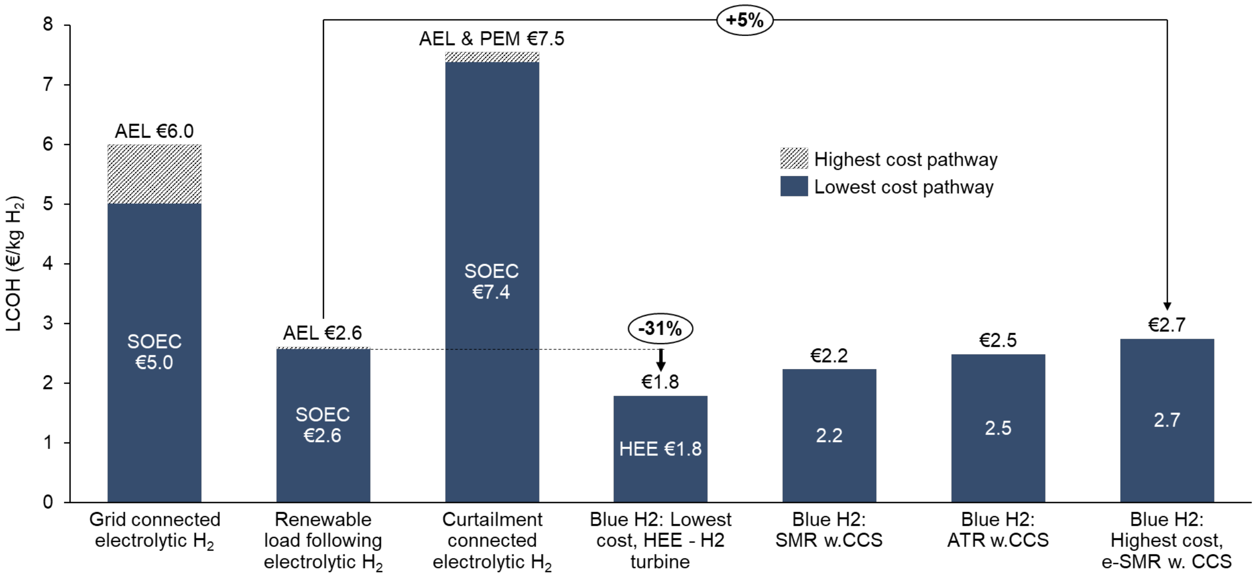

Figure C: LCOH by production pathway, 2050. IEAGHG studies only[4,5,6].

## Life Cycle Greenhouse Gas (GHG) Assessment Comparison

In addition to the TEA, a life GHG assessment was performed. The life cycle GHG assessment accounts for the source of electricity used for electrolytic hydrogen production to come from either the Netherland's grid or from renewable energy sources in the Netherlands. The figure below shows the significant drop in emissions when renewable electricity is used instead of grid electricity for electrolytic hydrogen production in 2030. The difference between the grid and renewable electricity highlights the significance of the emissions associated with the electricity input on the total pathway emissions.

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[4] IEAGHG 2022, Blue Hydrogen Beyond the Plant Gate.

[5] IEAGHG 2022, Low Carbon Hydrogen from Natural Gas: Global Roadmap.

[6] Lowest and highest cost technology by pathway. Central case results for blue hydrogen  presenting results for lowest and highest cost production pathways (HEE – H2 turbine and e-SMR with CCS) alongside the current most common production pathways combined with CCS (SMR & ATR). Due to the immaturity of HEE (hygenic earth energy) there is large uncertainty in the exact cost of this pathway.

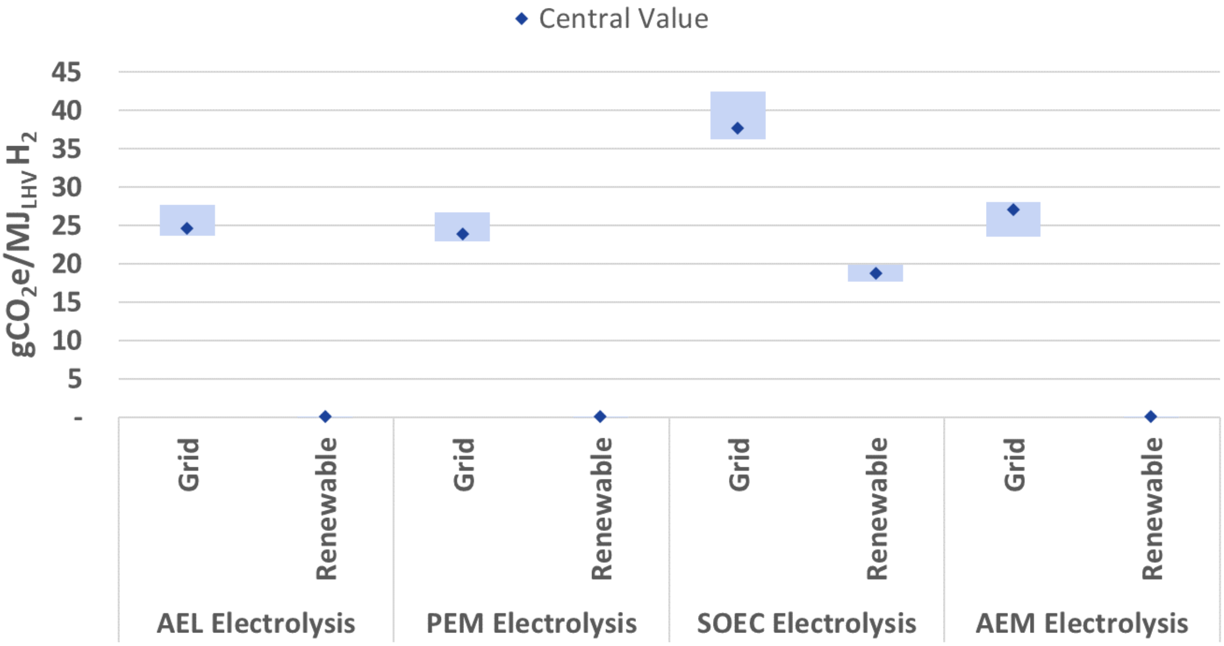

Figure D: Comparison of electrolytic hydrogen production emissions using grid or renewable electricity in 2030

When the same analysis was conducted for 2050, the results showed no difference between using grid and renewable electricity because it was assumed that the Netherlands electricity grid decarbonises to run on 100% renewables by 2050 based on published energy scenarios[7]. However, there will be factors that impact this trend and could result in a slower rate of decarbonisation of the Dutch grid than expected. For example, fewer windfarms or solar projects may be deployed or there may be increased reliance on natural gas.

Electrolytic hydrogen production using renewable electricity already has a significantly lower GHG emissions intensity than blue hydrogen production routes, and **electrolytic production using grid average electricity will become increasingly competitive as the grid decarbonises**. Figure E: shows the hydrogen production GHG emissions intensity calculated for grid electrolysis, renewable electrolysis, and blue hydrogen production pathways.

- **The heat requirement for SOEC hydrogen production results in this having the highest GHG emissions of the electrolysis production technologies modelled** if this heating demand is met via natural gas combustion.
- The use of **CCS in blue hydrogen production enables significant reductions in hydrogen production emissions**.

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[7] IEA 2020, The Netherlands. “100% of electricity to come from renewables by 2050”.

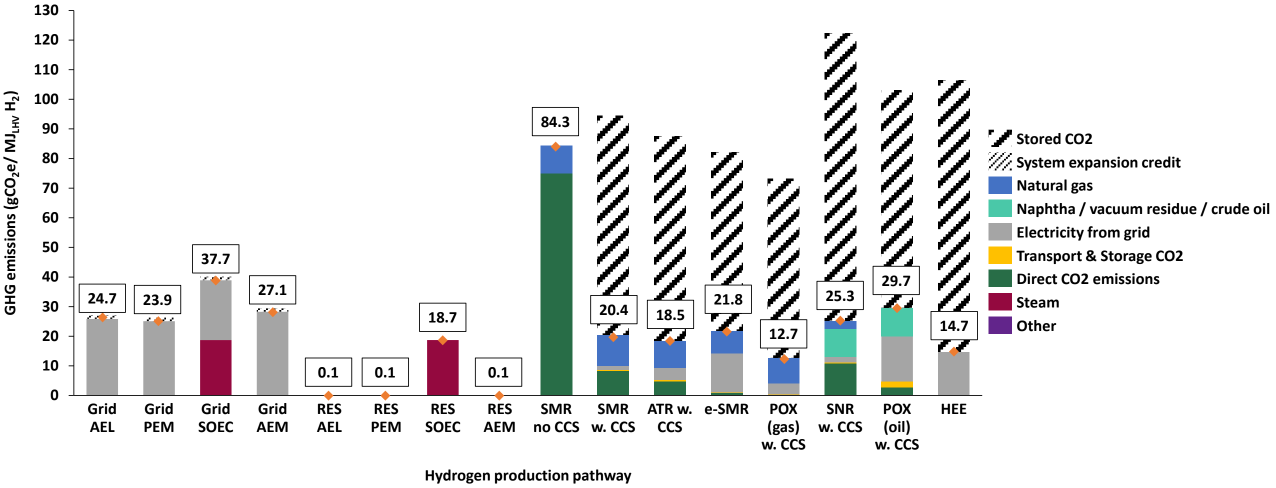

**Figure E: Estimated hydrogen production emissions from electrolysis and low-carbon (CCS-abated) pathways in 2030[8] (RES = electricity generated from renewable sources)**

The $CO_2$ capture rates applied to the blue hydrogen pathways varied between 90% and 98.6%. If these capture rates were increased to achieve **ultra-high capture rates (99%), an increase in electricity consumption would be required but overall, the total production emissions would reduce**. This sensitivity was performed in the IEAGHG blue hydrogen studies for SMRCCS and SNRCCS and showed that even increasing the electricity requirements by 10% leads to a significant reduction in the pathway emissions. This would allow for these blue hydrogen routes to outcompete grid electrolytic hydrogen production in 2030. However, as the electricity grid decarbonises, electrolysis routes would become more attractive from an emissions standpoint despite their greater LCOH. The **location of the hydrogen production would have a significant impact on the outcome of how these routes compare in terms of emissions** due to regional differences in the carbon intensity of the electricity grid.

## Combined grid electrolytic hydrogen production and distribution routes

Combining grid electrolytic hydrogen production with different distribution routes to supply hydrogen to end users leads to a range of GHG emission results being calculated for the total pathway emissions. Figure F shows the pathway GHG emissions for each production/distribution combination modelled. Note that in 2030, all electrolysis is assumed to use medium carbon-intensity grid average electricity, to illustrate a worst case. By 2050, the input electricity is fully decarbonised, and no distinction is made on emissions grounds between grid and renewable electricity.

- **Distribution to an end user, particularly over longer distances or involving transformation of gaseous hydrogen into other forms/carriers, can add significant GHG emissions on top of any electrolysis production emissions**. Distribution via compressed pipeline achieves significantly lower distribution emissions compared to other distribution routes modelled, as shown in the figure below.
- The **GHG intensity of input electricity and heat used in distribution steps is a key sensitivity** and therefore the rate of power grid & gas grid decarbonisation will greatly impact the potential to reduce GHG emissions for most routes.
- The methanol distribution pathway requires input $CO_2$ for conversion of hydrogen to methanol. The $CO_2$ may be sourced using $CO_2$ capture technologies that have different electricity and heat

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[8] 'Other' includes tap water, water treatment, and chemicals. This barely contributes to the total GHG emissions and therefore is not visible in the figure.

requirements. Depending on the $CO_2$ capture technology selected, the electricity and heat required for $CO_2$ capture can contribute a significant portion to the methanol distribution pathway.

- **Fugitive hydrogen emissions from electrolytic hydrogen production and distribution** could lead to total pathway emissions increasing by over 10% depending on the global warming potential (GWP) of hydrogen and the distribution pathway selected.

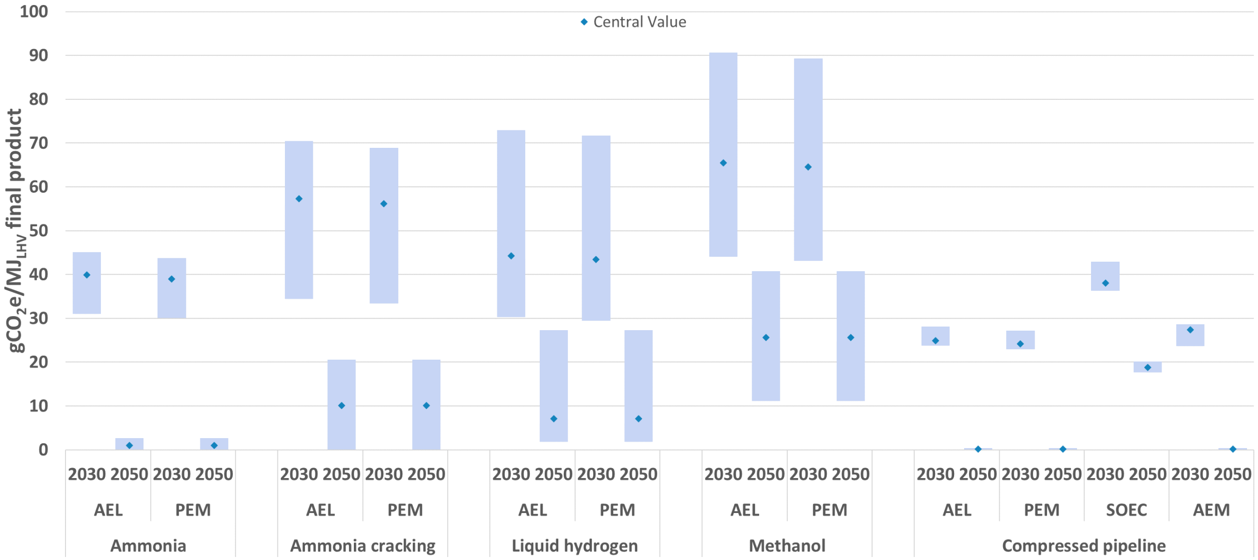

**Figure F: Combined grid electrolytic hydrogen production and distribution emissions (scenario ranges, 2030 and 2050)**

A breakdown of the emissions by process step is provided in the figure below for the combined electrolytic hydrogen production and distribution routes for the Central case in 2030. Grid electrolytic hydrogen production emissions contribute a significant portion of the total emissions for each pathway highlighting the impact that the rate of grid decarbonisation will have on the GHG emissions for these production and distribution pathways.

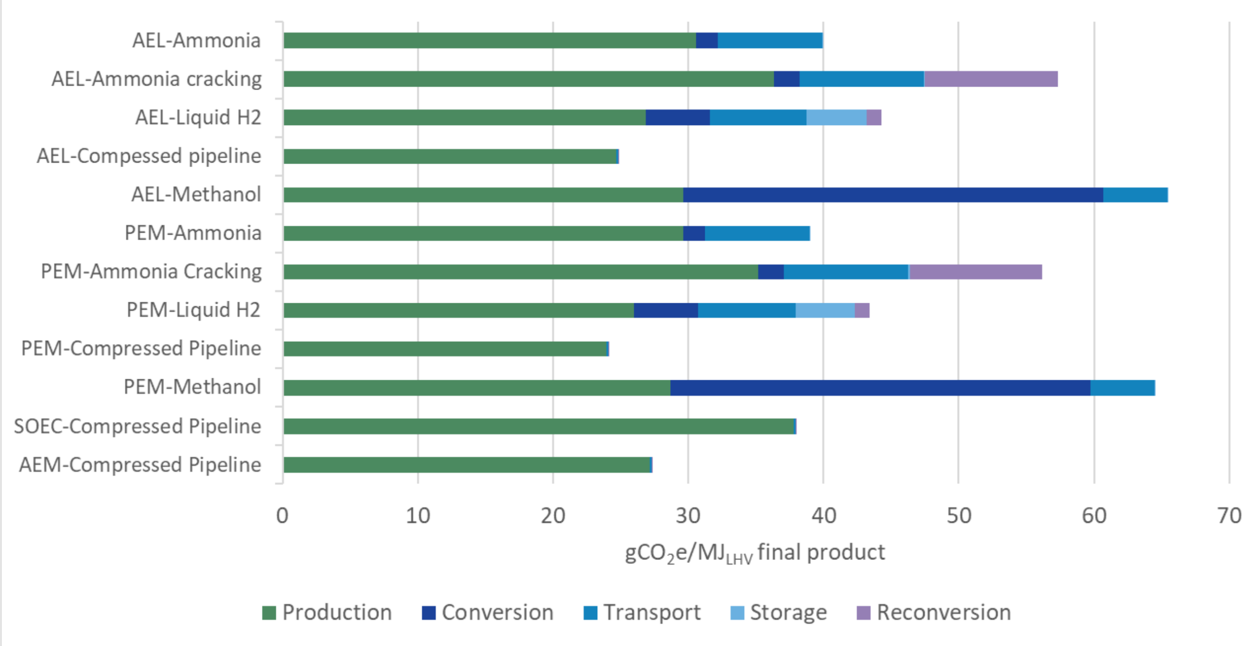

Figure G: Breakdown of combined grid electrolytic hydrogen production and distribution emissions by process step (central scenario, 2030)

## Water scarcity and water vapour

Due to electrolytic hydrogen's requirement for water, there are concerns that increased electrolyser uptake may contribute to water stress in some regions. Although the stoichiometric limit of water consumption for electrolysis is 9 kg($H_2O$)/kg($H_2$), the actual consumption may be significantly higher. To minimise stack degradation, electrolysers require high purity water meaning many times the volume of pure feedstock water (for example, 3.3 kg seawater/kg demineralised water, or >30 kg $H_2O$/kg $H_2$[9]) is required to produce demineralised water. Water losses in the stack, of approximately 1.5 kg($H_2O$)/kg($H_2$), and balance of plant (BoP) (for example, cooling) also increase the total plant water consumption.

When hydrogen is consumed in fuel cells or combusted, the product is water vapour. Although atmospheric water vapour contributes significantly to the greenhouse effect, anthropogenic near-surface emission of water vapor has a minimal warming effect. This is largely due to the short residency period of water vapour in the atmosphere of approximately ten days, as water is precipitated out of the atmosphere. When emitted at altitude from aircraft, from hydrogen combustion or utilisation in fuel cells, the global warming impact of water vapour increases, although the exact extent of this impact is uncertain (e.g., contrail lifetimes).

## Valorisation of oxygen

High purity oxygen is generated as a byproduct during electrolytic hydrogen production. Currently this oxygen is typically vented, and as part of this study, the valorisation of oxygen was explored. The sale of oxygen can in theory increase the revenue generated from the electrolytic hydrogen production process, effectively reducing the LCOH. However, there is not a significant gap in the market for electrolytic oxygen: the oxygen market is dominated by established players and the market for high purity oxygen, where electrolytic production has a competitive advantage, is limited. A significant proportion of the delivered cost of oxygen is storage,

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[9] In the case that 10.5 kg demineralised water is required for 1kg of hydrogen. This will be discussed in full in Section 5.2.1.

distribution and handling costs; this is especially true for high purity oxygen. This means that the valorisation of electrolytic oxygen may present a viable option when co-locating an electrolyser with an appropriate demand source to minimise costs associated with the distribution and handling. Appropriate demand sources include the medical sector which requires high purity oxygen and refineries which have demand for both hydrogen and oxygen which could be met with an on-site electrolyser[10][11]. However, given the cost and challenges of distributing, storing, and handling high-purity oxygen, and the relatively small market size, oxygen valorisation is unlikely to significantly reduce LCOH for most electrolytic hydrogen producers. As such, this route of revenue creation is often not pursued by current electrolysis projects.

## Recommendations

The successful deployment of hydrogen production technologies relies on factors such as technical feasibility, financial viability, integration with wider supply chains, and validated GHG emissions assessments. Findings from this report have been used to derive recommendations for research development and demonstration (RD&D), alongside policy and actions. The recommendations for RD&D highlight areas of study which require further development. This could result in improvement of both the environmental impact of electrolysis projects and the LCOH of hydrogen produced in the future. The policy asks and actions are focused on ways to improve the landscape for the deployment of electrolysis projects whilst ensuring an emissions reduction centred approach.

### Research, Development and Demonstration

- This study only considers the production of hydrogen at a hypothetical location, which for consistency purposes with other IEAGHG studies, was taken to be in the Netherlands. **Further work could consider hydrogen production in other locations** to understand the optimal location for deployment of hydrogen production technologies in terms of cost and emissions ranges.
- **Hydrogen leakage can occur across the hydrogen value chain.** Fugitive hydrogen indirectly increases the atmospheric concentrations of GHGs (methane, water vapour, ozone) due to reactions with hydroxyl radicals in the atmosphere. To improve accounting of hydrogen leakage, research into more accurate measurements of hydrogen emissions and the impacts of co-emissions is required[12].
- The **GWP of anthropogenically generated water vapour is influenced by factors including location and altitude of emissions**. More studies are required, including for considering water vapour generated at altitude from hydrogen powered aviation.
- **Electrolytic oxygen may be valorised as a by-product** however, this is not typically incorporated in electrolysis projects to date due to lack of demand. As synergies are further explored in the future, this may change and unlock markets for electrolytic oxygen.
- **Other environmental impacts** (e.g. land use, embodied emissions within construction/manufacturing of materials) were not considered in this analysis and will impact how different routes compare to one another. Further work could consider other relevant impact categories that influence the environmental impact of different hydrogen production routes.

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[10] G. Squadrito et. al, Oxygen from electrolysis for medical use: An economically Feasible Route, 2018.

[11] Safety concerns regarding on-site electrolysis for the medical sector may for a barrier to co-location, despite reporting from literature on the economic feasibility of this configuration.

[12] CICERO 2023, Global warming potential of hydrogen estimated.

- **Appropriate sizing of electrolysers to be coupled with renewable energy generation** is a growing field of study. Well-considered sizing, based on available renewable energy generation capacity, is needed in order to maximise electrolyser load factor and minimise LCOH. Where the intention is to use otherwise curtailed electricity for electrolysis, understanding of the patterns and quantity of available energy is key to correct electrolyser sizing.

## Policy and Actions

To enable the potential of electrolytic and other low-carbon hydrogen production to be realised, policy will be an important driver. Policymakers should consider policies that:

- Encourage **international collaboration** between those countries with low-cost hydrogen production and those with high demand for hydrogen.
- Encourage **harmonisation of a common global GHG methodology** or standard to facilitate international trade of hydrogen. The International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE)[13] are continuing efforts to develop a mutually agreed GHG methodology for hydrogen production and a global International Organization for Standardization (ISO) standard is expected in 2025[14].
- Advance the **deployment of renewables to accelerate decarbonisation** of regional electricity grids enabling electrolytic hydrogen production to become competitive with blue hydrogen production from both a life cycle GHG emissions and cost perspective.
- **Support low-carbon hydrogen production technologies** that achieve low GHG life cycle emissions and set an emissions threshold to identify those projects that may be eligible for support. This connects to the importance of continuing to develop emissions accounting and low-carbon hydrogen certification schemes. These will help to better define and deploy low-carbon hydrogen, and to transition away from the current "colour taxonomy" of grey, blue and green hydrogen which provides little insight into the true emissions intensity of the hydrogen produced.
- Provide funding for **research and development of electrolyser technologies** to achieve improvements in electrolyser performance and costs, enabling electrolytic hydrogen to become cost competitive with blue hydrogen.
- Plan for **scale up and standardisation of technologies to achieve cost reductions** which is already being encouraged by schemes such as the EU Innovation Fund[15], which supports the manufacture of decarbonisation technologies.
- **Support carbon pricing** to allow low-carbon production technologies to become more competitive compared to grey or blue hydrogen routes.

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[13] IPHE 2023, International Partnership for Hydrogen and Fuel Cells in the Economy.
[14] ISO 2022, ISO/TC 197/SC 1 Hydrogen at scale and horizontal energy systems.
[15] European Commission, Projects selected for grant preparation. Accessed on 09/11/23.

# Contents

# 1 Introduction

## 1.1 Context

**Low-carbon hydrogen is increasingly recognised as a key element in meeting the Paris Agreement's goal by public and private sector stakeholders around the world.** Specifically, many governments and other public sector bodies are committing to support the expanded use of *electrolytic* hydrogen and fuel cell technologies with, for example, the European Commission targeting 40 GW of electrolytic hydrogen production capacity by 2030, and the European Investment Bank suggesting that **€24-42 billion** will be required for electrolysers alone to meet this target.

**Electrolytic hydrogen represents a viable generation pathway with large-scale potential in the medium and long term, serving as a vector for achieving climate goals.** The resulting hydrogen can be used as an energy carrier and is capable of helping to decarbonise multiple sectors, including industry, power generation, and transport. In addition, electrolytic hydrogen can provide energy systems benefits due to its energy storage capabilities as well as the ability to modulate electrolyser operation as supply and demand fluctuates.

**There is a gap in the literature regarding accurate understanding of electrolytic hydrogen production costs.** Whilst there are several publications citing costs for electrolytic hydrogen production for each of the main electrolyser technologies (AEL, PEM and SOEC), the costs cited are typically much lower than those observed in real-world settings. This is likely due to the literature failing to account for all costs involved in electrolyser projects (those associated with the electrolyser, balance of plant (BoP), design / engineering, site preparation, installation, etc.). A robust understanding of different electrolytic hydrogen production costs is essential to understand future rollout of these technologies, and to enable comparison against other low-carbon (CCS-abated) forms of hydrogen production, as analysed in the IEAGHG's recent publications "Low carbon hydrogen from natural gas – Global roadmap" and "Blue hydrogen – Beyond the Plant Gate".

**The environmental and socio-economic implications of green hydrogen rollout have received little attention to date**. Understanding overall life cycle greenhouse gas emissions, as well as key opportunities and risks such as $O_2$ offtake to industrial users, hydrogen leakages, and impact on water availability in places of hydrogen production versus consumption are all critical to the large-scale rollout of, and successful planning for, large-scale electrolytic hydrogen production in a net-zero economy.

## 1.2 Objectives and Scope of Work

**The primary aim of this study is to assess the different electrolytic hydrogen production routes considering technical, economic, and emissions aspects**. Specific objectives include:

- To review and summarise existing electrolytic hydrogen production technologies, including their development status, scale of use, challenges, opportunities, technical description, and potential for expansion in line with demand, including both established (AEL, PEM, SOEC) and more innovative technologies, positioning these technologies relative to one another in terms of key techno-economic indicators.
- To conduct techno-economic and life cycle greenhouse gas assessments of different production configurations and provide comparative analysis against different electrolytic hydrogen pathways and other low-carbon (CCS-abated) hydrogen production routes.
- To conduct a literature review to determine the impact of water consumption for electrolytic hydrogen production in water scarce areas, and potential warming impact of increased water vapour in the atmosphere as a result of hydrogen consumption.

- To identify the conditions under which valorising emitted $O_2$ for use in industrial applications may be viable and the extent to which this benefits the hydrogen business case.
- To describe how hydrogen leakages during production and distribution occur in different hydrogen production pathways and quantify the associated environmental impact.
- To develop a series of policy recommendations to achieve competitiveness and scale of the routes examined.

## 1.3 Report Structure

The remainder of this report is structured into seven sections and associated Appendices:

- **Section 2** is focussed on a review of technical parameters for the three electrolytic hydrogen production technologies analysed in this report.
- **Section 3** describes the Techno Economic Analysis (TEA) methodology and presents the respective findings, including associated sensitivities.
- **Section 4** describes the Life Cycle Greenhouse Gas (GHG) Assessment methodology and presents the respective findings, including associated sensitivities.
- **Section 5** provides an overview of water scarcity and global warming potential in the context of hydrogen production and consumption.
- **Section 6** outlines the $O_2$ value chain and conditions for its valorisation as a by-product of electrolytic hydrogen production.
- **Section 7** assesses the findings from this study, and conducts a comparative analysis between different electrolyser technologies as well as against other low-carbon hydrogen production routes for 2030 and 2050
- **Section 8** outlines key conclusions from the project and provides recommendations for further sector development.
- **The Appendices** provide supporting information and assumptions for the analyses carried out in the study.

# 2 Roadmap of Electrolytic Hydrogen Production

The following section discusses the findings from a literature review and analysis based on key performance indicators (KPIs) of electrolyser technologies. This aims to present the current status of key electrolyser technologies, including developments and barriers including high costs and needed technological advances for example to increase the Technology Readiness Level (TRL). The focus of this section is on the four most mature technologies (alkaline electrolysers (AEL), proton exchange membrane (PEM) electrolysers, solid oxide electrolysers (SOEC) and anion exchange membrane (AEM) electrolysers), however other emerging technologies are also discussed.

## 2.1 Methodology and Aims

This section seeks to provide the reader with a comprehensive understanding of the main electrolyser technologies. Figure 1 (below) depicts the flow of activities conducted in this section.

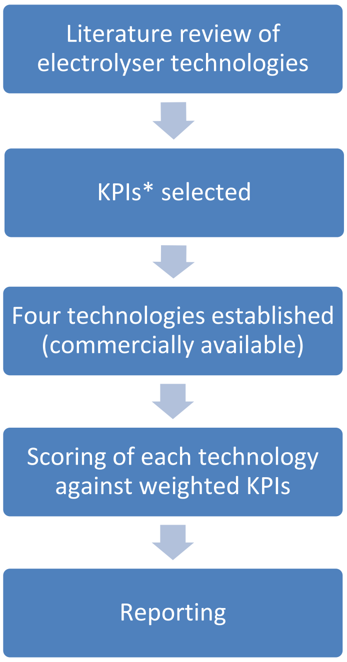

Figure 1. Section 2 research structure. *Key Performance Indicators.

A literature review was performed to understand the landscape of electrolyser technologies. This enabled 14 KPIs to be identified to quantify technology performance. Each KPI was weighted according to its impact on the viability of commercial rollout of the technology; capital expenditure (CAPEX) was weighted heavily, and system footprint was weighted lightly as an example of this system. The full list of KPIs and the reason for inclusion can be found below in Table 1. Through the literature review, four technologies were established as 'commercially available' and will be discussed in detail as part of this section, including in the KPI assessment. The four electrolyser technologies identified were:

- Alkaline electrolysers (AEL)
- Proton exchange membrane electrolysers (PEM)
- Solid oxide electrolysers (SOEC)
- Anion exchange membrane electrolysers (AEM)

In addition to these four main technologies, emerging electrolyser technologies were also considered and will be discussed briefly.

This section will highlight not only the specifics of each technology, but also how each technology might be differentiated from other electrolyser types. Through discussing the current manufacturing scale, benefits and challenges faced by the technology, alongside the research and development goals and focus points, a thorough picture of the current and potential future electrolyser market emerges.

Table 1. KPIs assessed.

| KPI | Reason for inclusion |
|---|---|
| TRL | Indicator of technology maturity. |
| Current & future manufacturing capability (MW) | Indicator of capability to manufacture electrolysers at scale to satisfy market. |
| Efficiency (kWh/kg) | Impacts cost and volumes of hydrogen produced per kWh of electricity input. |
| Operating range (%) | Indicator of the electrolyser's ability to accommodate variable power inputs. |
| System response to change in incoming power (minutes) | Indicator of the electrolyser's flexibility in handling variable power inputs. |
| System footprint ($m^2$/MW) | Suitability of electrolyser to constrained sites. |
| $H_2$ outlet pressure | Indicator of the scale (and cost) of additional compression systems. |
| $H_2$ outlet purity | Indicates whether additional purification may be required for specific end use case. |
| Stack lifetime | Indicator of costs associated with electrolyser stack replacement (stacks have shorter lifetimes than electrolysers so typically require replacement during the electrolyser lifetime). |
| CAPEX | Indicator of cost of hydrogen (and upfront cost). |
| Challenges (least) | Any challenges which are not represented by the other KPIs which may restrict market uptake of an electrolyser technology or impede development or manufacturing. |

## 2.2 Section structure

This section of the report starts with results from the KPI scoring and then discusses each technology in greater detail, laying out the findings from the literature review.

The performance characteristics of the four commercial electrolyser technologies discussed (AEL, PEM, SOEC, and AEM) were tabulated and scored across 14 KPIs. Each technology was awarded a score of 1 (low) to 3 (high) based on their performance relative to the other technologies and the requirements of the sector (e.g., high purity, low CAPEX, least frequent maintenance). Each performance characteristic was weighted to indicate the importance in overall commercial success of the technology. Qualitative categories (advantages, disadvantages, maintenance) were scored based on impact to performance with 3 indicating performance superior to competing technologies and 1 indicating performance significantly worse/inhibited compared to competing technologies. The scoring process was led by quantitative results from literature, and incorporated discussion and analysis of previous work by ERM in review of electrolyser technologies, manufacturers, and developments. The results of the literature review and wider analysis are presented in the following section. The KPI scoring approach aimed to highlight key areas for development of each technology along with its current suitability to different niches of demand for electrolysis.

The scale, maturity, production process, efficiency, benefits, and drawbacks of AEL, PEM, SOEC and AEM technologies are then presented in greater detail, followed by an overview of emerging technologies. Developments and cost reductions of AEL, PEM, SOEC and AEM technologies are then explored, whilst incorporating the context of material consumption and supply chain stressors.

## 2.3 Technology overview

### 2.3.1 Technology types

In recent years, the increase in demand for low-carbon hydrogen has led to increased focus on improving the electrolyser technology offering and achieving performance targets which would drive down the cost of electrolytic hydrogen. This includes improving electrolyser efficiency, increasing scale of production, increasing the scale of individual electrolyser deployments, and lowering purchase and operational costs.

There are currently four commercially available electrolyser types which are the focus of analysis and performance targets. AEL and PEM electrolysers are the two most mature technologies (TRL >9) and make up the bulk of electrolysers manufactured and deployed today. For both AEL and PEM, multi-100 MW capacity systems, and even some multi-GW electrolysers[16], have been announced (although are yet to be deployed at scales of >20 MW[17]) to be operational before 2030, alongside electrolyser gigafactories for scaled manufacture[18]. SOECs and AEMs are currently less mature (TRL 7-8 and TRL 6 respectively) but have also undergone substantial development over recent years. In particular, SOEC promise high efficiencies and low LCOH, where the technology can be scaled, and a suitable heat source is available for utilisation. This has captured the attention of major stakeholders in the electrolyser industry. Each technology will be presented in detail in Section 2.4.

Selection of the electrolyser type (and scale) is heavily dependent on the end use case, with each technology having different advantages and disadvantages. The following sections on the KPIs and technology deep-dive aim to represent as fully as possible the status and performance characteristics of current electrolyser technologies, combined with future development potential.

### 2.3.2 Key Performance Indicators - Results

Of the four commercial technologies analysed in detail, AEL and PEM electrolysers are the two most mature technologies. PEM electrolysers score more highly than AEL on most performance-based characteristics and AEL score more highly than other technologies on most commercial characteristics linked to technology maturity (manufacturing capability, cost, lifetime). SOEC electrolysers score more highly than AEL and PEM electrolysers on the efficiency KPI. With ongoing development of PEM

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[16] Thyssenkrupp, One of the largest green hydrogen projects in the world: thyssenkrupp signs contract to install over 2GW electrolysis plant for Air Products in NEOM. Accessed on 03/08/23.
[17] ENTSO-G, Hydrogen project visualisation platform. Accessed 31/07/23.
[18] Hydrogen Insight 2023. World's biggest hydrogen electrolyser factory will be a quarter the cost and size of a comparable PEM or alkaline plant.

technology, production capacity is expected (see Section 2.4.2) to accelerate in the coming years, closing the gap between PEM electrolyser and AEL production scale.

SOEC and AEM electrolyser technologies are at a much earlier stage of development and have low deployed capacities. SOEC's small system footprint and high efficiency make it an attractive technology if current issues with thermal cycling can be resolved. R&D is key to improving the lifetime and costs of SOEC and AEM technologies. The full KPI scoring matrix can be found below in Table 2, and the data informing this matrix can be found in the Appendix.

Each KPI was weighted with a multiplier (1-3) according to its impact on the viability of commercial rollout of the technology (for example CAPEX is a high impact KPI as has a large effect on commercial viability, whereas system footprint is a low impact as it is heavily use-case scenario dependent). Whilst somewhat subjective, the weightings ensured that the analysis accounted for the variation in significance between metrics from a commercial viability perspective. AEL, PEM, SOEC and AEM technologies were scored (on a scale of 1-3) according to their current known and reported performance against these KPIs (2023). Scores awarded were benchmarked against the general case of advancing electrolyser commercialisation. A poorly performing technology was scored with a 1, and a high performing technology was scored with a 3. All scores awarded are based on the technology's performance relative to other electrolyser technologies. Qualitative categories (advantages, disadvantages, maintenance) were scored based on impact to performance with 3 indicating performance superior to competing technologies and 1 indicating performance significantly worse/inhibited compared to competing technologies. The total "Technology" score is calculated by multiplying the technology's score by the KPI weighting.

**Table 2. KPI scoring matrix for AEL, PEM, SOEC and AEM electrolysers. Scoring is based on current technology performance, and data informing the scoring is presented in the Appendix.**

| Electrolyser Technology type | TRL | Current manufacturing capability | Future manufacturing capability | Efficiency | Operating range | System response to change in incoming power | System footprint | $H_2$ outlet pressure | $H_2$ outlet purity | Stack lifetime | CAPEX (system cost, factory gate) | Challenges | Advantages | Maintenance | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Weighting** | **2** | **3** | **2** | **3** | **2** | **2** | **1** | **1** | **1** | **2** | **3** | **2** | **1** | **1** | |
| **AEL** | 3 | 3 | 3 | 2 | 1 | 2 | 1 | 2 | 2 | 3 | 3 | 3 | 2 | 2 | **63** |
| **PEM** | 3 | 2 | 3 | 2 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | **63** |
| **SOEC** | 2 | 1 | 2 | 3 | 3 | 1 | 2 | 1 | 2 | 2 | 1 | 2 | 3 | 1 | **48** |
| **AEM** | 1 | 1 | 1 | 1 | 2 | 3 | 2 | 2 | 2 | 1 | 2 | 1 | 1 | 1[19] | **38** |

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[19] Current score of 1 awarded due to ongoing issues with membrane stability, however suppliers have been contacted to ascertain exact maintenance requirements.

Table 3. Highest scoring technology across KPIs. Data based on current electrolyser performance.

| KPI | Highest scoring technology/technologies |
|---|---|
| TRL | AEL & PEM |
| Current & future manufacturing capability (MW) | AEL |
| Efficiency (kWh/kg) | SOEC (small scale) |
| Operating range (%) | PEM & SOEC (<5% minimum load[20]) |
| System response to change in incoming power (minutes) | PEM & AEM (<20 minutes[21]) |
| System footprint ($m^2$/MW) | PEM & SOEC (c.73$m^2$/MW & c.74$m^2$/MW[22])[23, 24] |
| $H_2$ outlet pressure | PEM (30-70 bar[20]) |
| $H_2$ outlet purity | PEM (99.9999%[5]) |
| Stack lifetime | AEL (60,000-100,000) [20] |
| CAPEX | AEL (500 - 1000 USD/kWe)[20] |
| Challenges (least) | AEL (high maturity, low critical material consumption) |
| Advantages (most) | SOEC (if challenges can be overcome) |
| Maintenance (least) | AEL & PEM (limited (bi-)annual maintenance) |

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[20] IRENA 2022, Making the breakthrough: Green hydrogen policies and technology costs.
[21] ibid
[22] Source presents data in $m^2$/MW HHVm which has been converted to $m^2$/MW LHV for the purposes of comparison in this table.
[23] Element Energy 2018, Hydrogen supply chain evidence base (publishing.service.gov.uk).
[24] Topsoe 2020, SOEC high-temperature electrolysis factsheet.

## 2.4 Technology deep dive

### 2.4.1 Alkaline electrolysers (AEL)

#### Maturity and scale

AEL are the most established water electrolysis technology, having been operational as early as the 1920s to generate hydrogen for ammonia production[25]. AEL have a TRL of 9[26], indicating their high level of maturity, and have a large market uptake currently representing approximately two-thirds of all electrolyser deployments (estimated 404 MW deployed AEL capacity in 2022)[26].

As discussed, the system size of electrolysers has been increasing steadily. For AEL this increase in system size has been accompanied by increased stack size. Manufacturers including HydrogenPro, Asahi Kasei and Next Hydrogen are now targeting production of electrolyser stacks substantially larger than existing models, set to increase individual stack capacity up to 10 MW by the mid to late 2020s[27] (current stack size <1 with an increasing number of stacks >2 MW[28] including the 10 MW single stack Asahi Kasei electrolyser, deployed in Fukushima, Japan[29]).

#### $H_2$ production process and efficiency

To produce hydrogen, AEL use an electrolyte, typically a concentrated potassium hydroxide (KOH) solution, which transports hydroxide ($OH^-$) anions and produces hydrogen and oxygen at the cathode and anode respectively. The electrolyte is typically concentrated at 57 $mol^{-1}$. Alkaline electrolysis is performed at low temperatures, between 30 and 80 °C, however, operation at temperatures as low as 30 °C is uncommon and the typical temperature operating range lies between 70 – 90 °C[27]. AEL have achieved energy efficiencies between 50-78 kWh/kg $H_2$[20]) in commercial settings[30]. AEL stacks typically have lifetimes (2023) in the range of 60,000 – 80,000 hours[20, 31].

#### Costs

AEL have the lowest system costs of all current electrolyser technologies, with costs ranging between 500-1,500 USD/kWe[25,20,81] depending on the source and whether these costs refer to the electrolyser only, the full system or the system installed costs (the latter represents the highest end of cost ranges). The large-scale nature of AEL and increased manufacturing capabilities have enabled cost reductions associated with economies of scale. In addition to this, AEL are cheaper to build than some other electrolysers largely due to their increased maturity as a technology, easing the manufacturing processes when compared to its closest competitor, PEM electrolysers[32]. Low material costs for the electrodes and porous transport layers (PSL) of AEL, and the ability to substitute platinum, ruthenium, and iridium (see Proton Exchange Membranes (PEM), Drawbacks) catalysts (nickel for the electrodes doped with platinum or ruthenium (Pt or Ru) by some manufacturers) with other cheaper metals, contribute to reduced system costs for AEL.

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[25] nel 2022, Introduction to Alkaline Electrolysis.
[26] IEA 2023, Electrolysers - Energy System. Accessed on 21/07/23.
[27] ERM data from commercially available information 2022.
[28] Nel Hydrogen 2023, Atmospheric Alkaline Electrolyser. Accessed on 31/07/23.
[29] Asahi Kasei 2020, Asahi Kasei's electrolysis system starts world's largest-scale hydrogen supply operation at the Fukushima Hydrogen Energy Research Field in Namie. Accessed on 25/10/23.
[30] S.Kumar et al. 2019, Hydrogen production by PEM water electrolysis – A review.
[31] Hydrogen Tech World 2023, Electrolysis technologies and LCOH: current state and prospects for 2030.
[32] PEM electrolysers have a similar level of maturity, with manufacture at commercial scale.

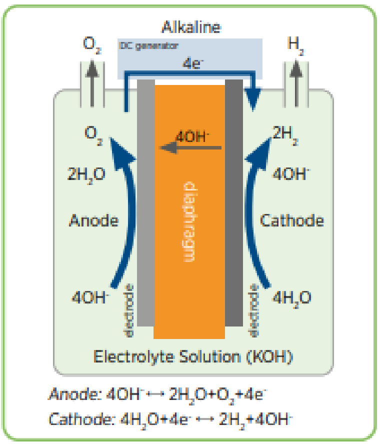

Figure 2. Diagram of Alkaline electrolyser operation, IRENA.

## Additional benefits

Key benefits of AEL are their high levels of maturity and low costs. This maturity comes hand in hand with strong performance characteristics across all categories, with good efficiencies and output pressures (30 bar, which is larger than for less mature SOEC technologies which have output pressure of ~10 bar).

## Drawbacks and performance targets

Historically, the key concern with AEL was their inability to support a low minimum load[20,33]. Flexibility is crucial to the efficient production of green hydrogen, as intermittent renewable energy sources (RES) (wind and solar) do not produce a constant power output. Recent developments in stack configuration and power electronics have begun to increase AEL flexibility (decreasing minimum load and start up time) and render them almost comparable to PEM technologies. To further improve AEL efficiency, AEL's limit for operating temperature needs to be increased, and thick diaphragms replaced. Redesigning the catalyst compositions to increase their surface area could also enhance the efficiency of AEL.

Previous electrolyser configurations used large, connected stacks, however, reconfiguring electrolysers to use multiple blocks of smaller stacks (i.e. five 1 MW blocks in a stack instead of a single 5 MW stack) enables increased flexibility of operation due to enabling parallel operation of individual stacks during times of decreased load. Whilst this is accompanied with more complex wiring needs, this represents a relatively small cost and complexity sacrifice for the operational flexibility gains. Varying the architecture of AEL enables them to be tailored to different end-use cases and different upstream renewable energy production scenarios. Through reconfiguring electrolyser stacks, AEL now have the ability to support minimum loads as low as 10%[34]

In addition to stack configuration, advances in power electronics including control systems and batteries have also contributed to increased flexibility of operation for AEL. Research and development activities continue to focus on closing the gap in performance between AEL and PEM operating under varying loads.

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[33] Hysata, Technology overview. Accessed on 25/7/23.
[34] ERM data based on commercially available information, (publicly available: Thyssenkrupp).

AEL also have lower current densities than competing PEM, meaning that the cells occupy more space and the electrolyser has a larger overall footprint[35]. To avoid mixing of the hydrogen and oxygen in the chamber, new technologies are under development which separate the production of each gas (See Section 5).

Currently AEL produce hydrogen at output pressure of ~30 bar. To make this comparable with other electrolysers (PEM) and reduce potential compression requirements, manufacturers have targets to increase this to 70 bar. AEL already have the longest stack lifetime of electrolyser technologies, but >100,000 hours lifetime is targeted by 2050. By 2050, a stack lifetime of 80,000 hours is targeted[20].

Advances in materials and manufacturing of AEL could reduce costs and demands for materials, for example, finding new electrode materials and improving production technologies could enable more efficient mass production of AEL[25]. Whilst AEL are the most developed technology and many advancements have already been made in its manufacture, there are still areas for improvement. Redesign could also benefit the material demand of AEL (e.g. redesign of the PSL to remove the need for precious metal coatings).

## 2.4.2 Proton exchange membrane electrolysers (PEM)

### Maturity and scale

PEM electrolysers are also established and commercially available technologies. In recent years, PEM electrolysers have reached scales of up to 20 MW[36] and >100 MW[20]. capacities deployed and announced, respectively with a few notable larger scale exceptions which are already operational[1,2]. PEM electrolysers are beginning to hold an increasing share of the electrolyser market[26], and have achieved TRL 9 (the same as AEL) [26]. PEM stacks typically have lifetimes (2023) in the range of 50,000 – 80,000 hours[20, 31].

### $H_2$ Production process and efficiency

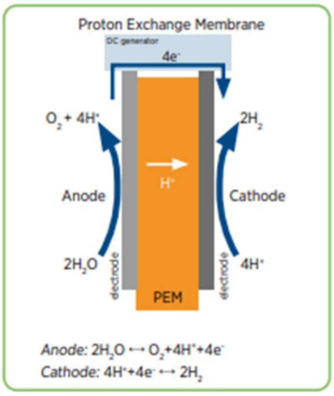

Figure 3. Diagram of PEM operation, IRENA.

PEM electrolysers use a stable perfluorosulfonic acid (PFSA) membrane which enables the electrolyser to operate at low temperatures between 20 to 80 °C[30], however, operation at temperatures as low as 20 °C is uncommon and the typical temperature operating range lies between 50 – 80 °C[27]. Commercially deployed

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[35] H. Lange et al. 2023, Technical evaluation of the flexibility of water electrolysis systems to increase energy flexibility: A review.

[36] Hydrogen Tech World 2021, World's largest PEM electrolyzer installed in Canada.

electrolysers have reached efficiencies of 50-83 kWh/kg $H_2$[37] (50 kWh/kg $H_2$ is >75% HHV, >65% LHV) but some literature reports efficiencies as high as 90% (HHV)[30]. Despite advances in AEL's ability to operate under partial loads, PEM electrolysers are still the frontrunners in this respect, with the operability at loads of 5 to 10%, with full operating load range between 5 to 120%[20, 38]. This enables large levels of flexibility for the electrolyser when connected to renewable energy sources. This flexibility is possible due to the non-porous separator membrane which enables rapid cycling, and fast system responses: a PEM can take 20 minutes from a cold start to full load operation (hydrogen generation), with some manufacturers quoting a 5 minute cold start-up time[39]. AEL also have relatively fast start up times of as low as 50 minutes, however PEM electrolysers demonstrate a substantial improvement. To demonstrate the full range, SOEC have a cold start up time of >600 minutes.

## Additional benefits

Depending on the hydrogen use case (for example use in fuel cells for mobility), PEM electrolysers have additional advantages. High purity outputs of 99.99% to 99.9999% enable direct use of hydrogen produced in a PEM electrolyser for fuel cell end use. In addition to this, the synergies in production of both PEM electrolysers and PEM fuel cells, have potential for companies to scale production of both in tandem and minimise production costs. The same synergy is possible for SOEC electrolysers and solid oxide fuel cells (SOFC). Alkaline fuel cells (AFC) are less commonly used and have susceptibility to $CO_2$ poisoning which inhibits performance and durability[40]. Without the presence of large-scale demand for AFC, there are no production synergies to benefit from. As such, companies such as Plug Power and Nel have been able to scale rapidly and connect to new hydrogen mobility markets (including fuel cell forklifts), supporting both upstream and downstream ends of the hydrogen value chain.

Other benefits of PEM electrolysers include the high-pressure hydrogen output and their small footprint (in part due to the high current density of the cells). PEM electrolysers are able produce hydrogen to pressures from 30-70 bar. This is a higher pressure range than can currently be achieved by both AEL and SOEC electrolysers. Whilst the advantage of high-pressure hydrogen output varies by use case, it has advantages where additional pressurisation is required, as reducing the step change between hydrogen output from the electrolyser and desired pressure, reduces the associated costs and the scale of compressor required. Whilst a small footprint can be beneficial where space is constrained, there are many instances where footprint is of little importance. As such, in this case the end-user may choose to select a lower cost AEL.

## Drawbacks

The key drawbacks of PEM electrolysers include the high costs and material requirements. The electrodes and catalysts require noble metals, including critical materials platinum and iridium, due to the acidic, corrosive environment of the electrolyser. These materials come at a high cost and are in limited supply[20]. As a result, both the catalysts and electrodes of PEM electrolysers are more expensive than their AEL counterparts which do not necessarily require these high-cost materials. Iridium is of particular concern regarding the security of supply, with potential to constrain the PEM electrolyser supply chain if changes are not made. The

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[37] Electrolyser efficiency is often measured in kWh/kg $H_2$. This is a measure of the energy input required to produced 1 kg of hydrogen output from the electrolyser. As such, the smaller the energy input required, the higher the percentage efficiency of an electrolyser. Therefore, a 50 kWh/kg $H_2$ efficiency gives a higher % efficiency than 85 kWh/kg $H_2$.

[38] The operating load range here refers to the electrical load range supplied to the electrolyser, where PEM electrolysers are capable of operating at an electrical load of up to 120% of the electrolyser nominal capacity, as cited by IRENA.

[39] Nel Hydrogen, M SERIES PEM Electrolyser. Accessed on 25/10/23.

[40] DOE, Types of Fuel Cells. Accessed on 31/07/23.

perfluorinated membranes and titanium current collectors also inflate the costs of PEM electrolysers, due to their complexity (increasing manufacturing costs).

### Performance targets

For PEM electrolysers, key improvements in their performance and costs can be met through improvements in the design of the electrolyser. Reducing the thickness, reducing the quantity of catalyst required and removing or substituting the expensive titanium PTL coating could all reduce costs. To reduce material demand, PEM could look to incorporate recombination catalysts into their design. By 2050, a stack lifetime of 100,000 – 120,000 hours is targeted[20].

## 2.4.3 Solid oxide electrolyser cells (SOEC)

### Maturity and scale

SOECs are currently in a pre-commercial stage (TRL 7-8) [26] . SOEC are now beginning to progress beyond the demonstration stage, however the largest SOEC are still at single digit MW scale and the total manufacturing capacity sits <5MW per annum[41]. However, SOEC are gaining increasing focus and investment from manufacturers. For example, Topsoe has now designed a 100 MW SOEC system, and in May 2023, began construction of an industrial scale SOEC manufacturing facility, targeting 500 MW capacity operational by 2025[42]. This would be the first of its kind for SOEC electrolysers. Other manufacturers, such as Sunfire and Bloom Energy, are also active in the SOEC market, with the advantage that current solid oxide fuel cell (SOFC) manufacturers would be able to adapt their production capabilities to produce SOEC.

### $H_2$ production process and efficiency

SOEC operate at high temperatures (800 – 1,000 °C) and can achieve high efficiencies of 40-55 kWh/kg $H_2$ due to their ability to utilise waste heat and exceed Carnot efficiency[43]. To contextualise this, an efficiency of 40 kWh/kg $H_2$ is equivalent to >80% (LHV) and >95% (HHV). This is only achievable with a high-quality heat source (700-850 °C, with ambitions to reduce this to 600 °C by 2050[44]), for example through capturing high-quality (>400 °C) waste heat available from industry (iron and steel)[44]. Commercially available SOEC have also achieved impressive turn down ratios of 10-100%, with future minimum loading anticipated to be ~3%[20,41], demonstrating potential to rival PEM electrolysers. Where SOEC have an advantage over PEM electrolysers is in their tolerance of impurities, as SOEC (and AEL) are less sensitive than PEM electrolysers, an issue which makes PEM electrolysers more susceptible to degradation and shortened lifetime.

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[41] ERM data from commercially available information.
[42] Topsoe 2023, Topsoe celebrates milestone in construction of world’s first industrial scale SOEC electrolyzer facility.
[43] The Carnot Efficiency is the maximum efficiency (ideal) which can be achieved for a heat engine cycle Engineering Toolbox. Carnot Efficiency. Accessed on 31/07/23.
[44] Abrar Inayat 2023, Current progress of process integration for waste heat recovery in steel and iron industries.

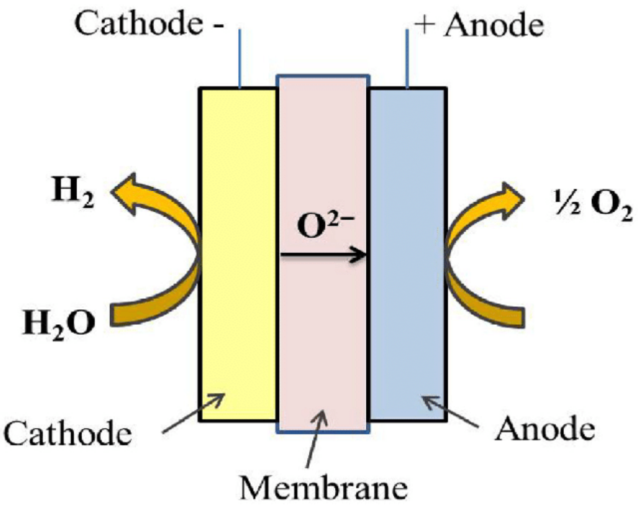

Figure 4. Diagram of SOEC operation[45]

## Costs

Whilst SOEC technology could offer the advantages outlined above, this technology is still at a lower level of development compared to AEL and PEM electrolysers and is high cost (>2,000 USD/kW)[20].

## Drawbacks

The high operating temperatures can create mechanical issues limiting the lifetime and durability of the SOEC. SOEC stacks typically have lifetimes (2023) in the range of 20,000 hours[20,31]. Improving this is a key development focus for SOEC. The high temperatures also create issues regarding lifetime, the mixing of gases and start up time. High operating temperatures create mechanical issues causing stack degradation which reduces efficiency and limits lifetime, with current SOEC stack lifetime typically <20,000 hours[20]. SOEC technologies have an increased risk of gases (oxygen and hydrogen) mixing due to the high temperatures, which can reduce the output purity of hydrogen.

In addition to this, because the electrolyser must be coupled with a heat source, the slow cold-start time is more than 100 times greater than that of PEM and AEL electrolysers, at ~600 minutes[20].

## Performance Targets

By 2050, SOEC costs are expected to reduce dramatically, by as much as 90%[20]. This would be a large step in making this technology competitive with AEL and SOEC. Research and development for SOEC is centred on making the electrolysers more robust in order to withstand the high temperature thermal cycling intrinsic to their design. Achieving improvements in this durability would allow for increased lifetime for SOEC, reducing replacement costs and making the long-term operation - needed to make electrolysis cost-effective - possible. By 2050, a stack lifetime of 80,000 hours is targeted[20].

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[45] Sampangi, Dr & Vurimindi, Himabindu 2019, Hydrogen production by PEM water electrolysis – A review.

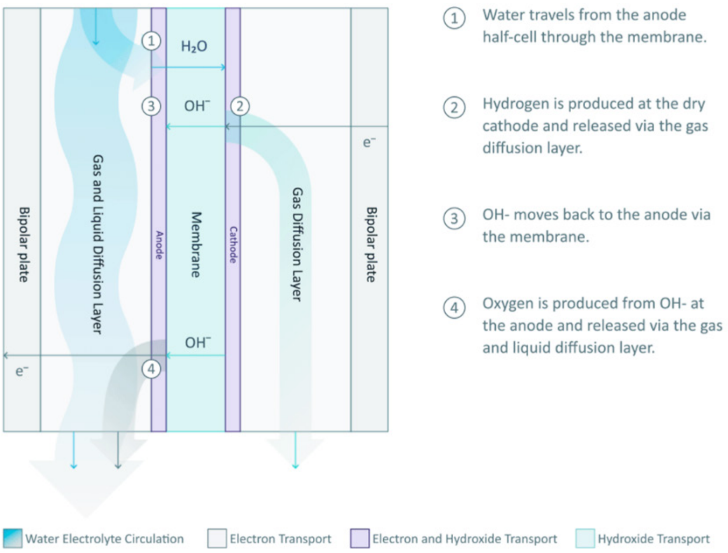
## 2.4.4 Anion exchange membrane electrolysers (AEM)

### Maturity and scale

AEMs are still in the early stages of development (TRL 6)[26], they currently suffer from high minimum loads (10-20%) and lower efficiencies than PEM and AEL technologies. Enapter is currently the main manufacturer[46]. AEM electrolysers are still operating at very small scale, with the Enapter electrolyser only ~0.003 MW, and their lifetime c.30,000 hrs[47], in part due to the sensitivity of the anion exchange membrane to carbon dioxide and overall system degradation. Other sources cite significantly lower AEM stack lifetimes of ~5,000 hours[20, 31].

### $H_2$ production process and efficiency

AEM electrolysers use lower concentration alkaline solutions than AEL reducing the likelihood of corrosion[48]. This allows AEM electrolysers to use low-cost, non-critical materials as catalysts, as with AEL. The diaphragms used in AEL are replaced by anion exchange membranes which reduce leakages and increase the overall efficiency of the electrolyser. Whilst high efficiencies are expected in the future, AEM electrolysers currently have lower efficiencies than AEL, PEM and SOEC electrolyser technologies.



① Water travels from the anode half-cell through the membrane.

② Hydrogen is produced at the dry cathode and released via the gas diffusion layer.

③ OH- moves back to the anode via the membrane.

④ Oxygen is produced from OH- at the anode and released via the gas and liquid diffusion layer.

Figure 5. Diagram of AEM operation[49].

### Costs

Due to the immaturity of AEM, there is little data available on current costs of AEM electrolysers. For their small-scale systems, Enapter quotes ~1,000 €/kW. This is yet to be reflected in wider literature estimates.

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[46] Enapter. AEM Electrolyser - Low-Cost Green Hydrogen. Accessed on 25/07/23.
[47] Given as c.30,000 hrs by ibid, and 35,000 hrs by Enapter[46]
[48] The Oxford Institute for Energy Studies 2022, Cost competitive green hydrogen: How to lower the cost of electrolysers?
[49] Enapter, Anion exchange membrane water electrolysis: How it works. Accessed on 25/10/23.

### Additional benefits

AEM have fast response times, and <20 minutes for start-up from cold. They have achieved low costs even at this early stage of development. This must be contextualised by the very small scale of current available technology.

### Drawbacks

As repeatedly discussed, AEM electrolysers are currently only available at very small scale. They also experience increased sensitivity to impurities due to the anion exchange membrane, which can reduce the lifetime of the electrolyser[48].

### Performance targets

Increasing the robustness of the membrane forms one of the primary development goals for AEM manufacturers. This is key to establishing reduced membrane sensitivity and increasing the lifetime of the electrolyser. By 2050, stack lifetime of 100,000 hours, equivalent to AEL and PEM targeted lifetime, is targeted[20,31].

## 2.4.5 Emerging electrolyser technologies

In addition to the four main commercially available technologies, further innovation has led to a range of emerging technologies which have been developed in order to address issues including cost, efficiency, material scarcity and durability[50]. One such example is Hysata's capillary technology, which is reported to offer efficiencies >80% (LHV) and a simplified BoP due to reduced cooling requirements[51]. Meanwhile H2Pro's electrolyser promises similar efficiencies through the sequential (de-coupled) production of oxygen and hydrogen to increase $H_2$ output.

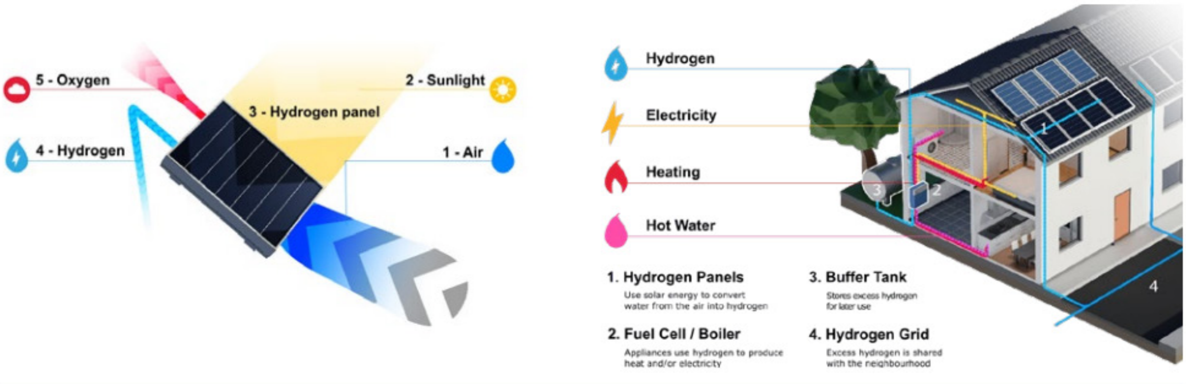

Figure 6. Photoelectrolysis as described by Solhyd[52]

There has also been a large focus on patent development for optimal operating conditions and incorporating non-noble metal electrocatalysts to mitigate growing concerns regarding material scarcity[50]. Stackability of cells is also a key focus of patent development, alongside durability[50]. This refers to the ability to scale the electrolyser total output by combining smaller stacks together. There is also currently a focus on

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[50] IRENA 2022, Patent Insight report. Innovation trends in electrolysers for hydrogen production.
[51] *Hysata, Technology overview.* Accessed on 25/7/23.
[52] The Solhyd project, Technology - the Solhyd project. Accessed 25/10/23.

photoelectrolysis, mostly at an academic rather than commercial level[50] with a few notable small actors such as SoHHytec[53] and Fusion Fuel[54]. Photoelectrolysis uses sunlight to produce hydrogen as in the figure below.

## 2.5 Supply chain development and constraints

### 2.5.1 Material consumption

The key factors underpinning the potential of each electrolyser technology are the materials and their availability. The critical components and the quantities required vary by electrolyser type and are due to differences in stack design. Compressors, water purification, dryers and electrical systems differ very little between the electrolyser types.

A PEM electrolyser stack is comprised of an anode, cathode, electrolyte, separator, PTL (anode and cathode), bipolar plates and finally frames and sealing[55]. To manufacture these components, materials including iridium, platinum, titanium, and gold are required. Critical materials across the manufacture of PEM electrolysers include copper, iridium, platinum, and titanium[56].

AELs are less critical material intensive than PEM electrolysers, however they still require copper, graphite, and nickel. As discussed in Section 2.4.1, they do not require platinum (Pt) group metal catalysts, though some manufactures use these as dopants for improved performance. Other mined materials required for AEL include aluminium, steel, and zirconium. A rough breakdown of material demand by technology type can be found in Figure 7.

The specific material composition of AEM and SOEC technologies varies more substantially due to the reduced level of development. SOECs typically require nickel, zirconium, lanthanum, and yttrium.

When considering global availability of materials, nickel and other non-critical materials have high production and extraction rates, with 300 million tonnes of nickel produced in 2022[57]. However, Pt group metals, particularly iridium, pose a much greater risk to the security of the electrolyser supply chain due to low quantities available (estimated 70,000 tonnes) mostly sited in South Africa (90%) and Zimbabwe. A lack of concrete projects in the future for platinum extraction, and the growing demand for iridium in particular, could have a drastic slowing effect on electrolyser production capacity, with the World Bank estimating that to sustain the growth in capacity, an 80% reduction in iridium per electrolyser by 2050 would be needed[56]. Whilst this is something manufacturers are working towards, it is not currently the reality of electrolyser design. The annual extraction of iridium (estimated at 7-7.5 tonnes/year) is estimated to only be sufficient for 10-12 GW of electrolyser production based on current designs[50]. Without effective redesign of PEM electrolysers and fuel cells (which also require iridium), iridium scarcity could place a constraint on the pace and scale of PEM electrolyser production and therefore the growth of the electrolyser market as a whole. It is worth noting that iridium can also be used in some instances in AEL technology, and as such this issue is not limited only to PEM electrolysers.

To ease the mining demand, increased circularity needs to be incorporated in electrolyser end-of-life. Current recycling rates (estimated in 2011 but without substantial change documented since this publication)[58] indicate rates of >50% for copper, titanium, platinum, palladium and nickel, but only 25-50% for iridium. AEL and PEM EL stacks have a lifetime of ~10 years (SOEC stacks currently have a lifetime of only 2-3 years)[55], creating a

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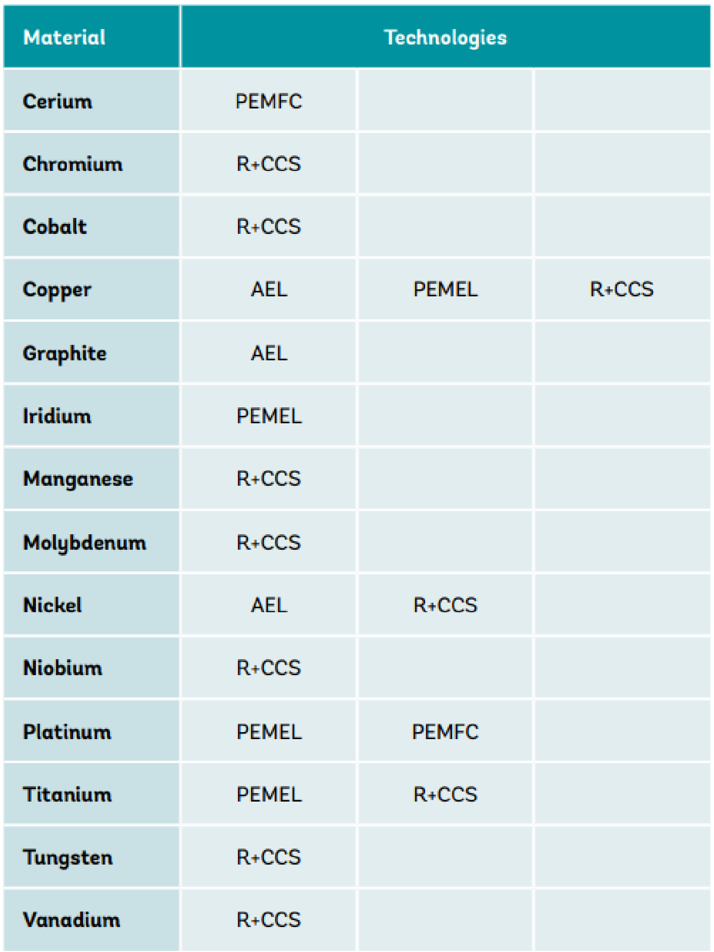
[53] SoHHytec, Solar Fuel, the smarter way. Accessed 25/10/23.
[54] Fusion-Fuel, Tech. Accessed on 25/10/23.
[55] Scottish Government 2022, Assessment of Electrolysers: Final Report.
[56] The World Bank 2022, Sufficiency, sustainability, and circularity of critical materials for clean hydrogen.
[57] Nickel Institute, About nickel. Accessed on 25/7/23 and referenced in Assessment of Electrolysers[55]
[58] T.E. Graedel et al. 2011, What Do We Know About Metal Recycling Rates?

lag in the availability of recycled materials, even in the case that improved processes enable a higher recovery rate for critical materials. As demand is expected to begin to spike in the 2030s, addressing the availability of necessary critical materials is a time pressured issue.

In addition to the material demand for electrolysers, the effectiveness of the supply chain is dependent on the material demands (and availability) for the renewable energy production processes (wind and solar). Key critical materials required for upstream renewable energy production technologies include aluminium, copper, nickel, and zinc[56].



| Material | Technologies | | |
|---|---|---|---|
| **Cerium** | PEMFC | | |
| **Chromium** | R+CCS | | |
| **Cobalt** | R+CCS | | |
| **Copper** | AEL | PEMEL | R+CCS |
| **Graphite** | AEL | | |
| **Iridium** | PEMEL | | |
| **Manganese** | R+CCS | | |
| **Molybdenum** | R+CCS | | |
| **Nickel** | AEL | R+CCS | |
| **Niobium** | R+CCS | | |
| **Platinum** | PEMEL | PEMFC | |
| **Titanium** | PEMEL | R+CCS | |
| **Tungsten** | R+CCS | | |
| **Vanadium** | R+CCS | | |

Figure 7. Critical material consumption by hydrogen production pathway, World Bank[56]. PEMEL = PEM; PEMFC = PEM fuel cell; R+CCS = SMR or SNR+CCS

### 2.5.2 Analysis of electrolyser manufacturing capacity and key stakeholders

Currently, China and Europe collectively manufacture ~2/3 of global electrolyser capacity[26]. In recent years, many European companies have merged with Chinese companies, making best use of manufacturing expertise. Companies which have undergone such mergers include John Cockerill (Cockerill Jingli), Cummins (Sinopec Group), Hydrogen Pro (THE), and NEL.

Across the market, producers are increasing the scale of their manufacturing capabilities and the scale of the electrolysers which they are producing. Electrolyser scale is increasing in tandem with demand for electrolysis, with PEM and AEL systems of several hundreds of MW stretching to GW scale under manufacture and planned for deployment by the mid-to-late 2020s. Announced manufacturing ambitions across key stakeholders indicate combined production capacities of >10 GW/year for PEM and >15 GW/year for AEL by 2030 (see

Figure 8). This comes with many electrolyser manufacturers announcing gigafactories, including ITM Power and McPhyEnergy SA. Genvia has also announced plans to begin construction of a gigafactory to produce their SOEC electrolysers by 2025.

There is also a trend for electrolyser manufacturers to couple with downstream offtake projects as the hydrogen economy is developing. This includes a variety of off-takers including the production of sustainable aviation fuel (SAF) and other mobility off-takers. In addition to this, Plug Power represents a broader trend of how fuel cell manufacturers can successfully expand their offering into electrolyser manufacturing. Plug Power was initially a dedicated manufacturer of PEM fuel cells and now also manufactures PEM electrolysers in connection with manufacturer Giner GLX and hydrogen merchant United Hydrogen Group Inc. (2020).

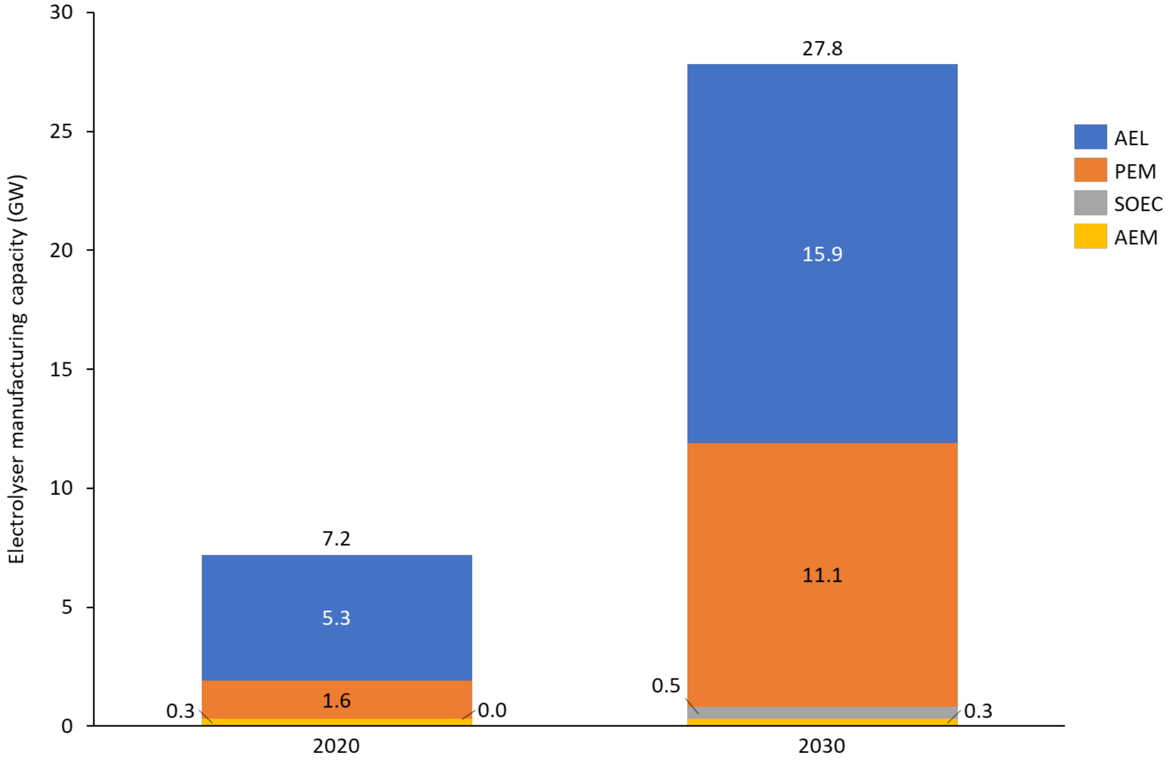


Figure 8. IEA data for 2020 manufacturing data, and ERM estimate for future manufacturing capacity based on announced manufacturing ambitions by key stakeholders.

## 2.6 Cost Reductions

One key area for improvement across all electrolyser technologies is the cost. As will be discussed in more detail as part of Section 2.6.1 below, the costs associated with an electrolyser constitute a significant fraction of the levelised cost of hydrogen (LCOH). As each technology has different material and manufacturing requirements (among the many other differences described), the approach to achieving lowered costs varies by technology.

### 2.6.1 Technology Specific Cost Reductions

In addition to the performance improvements discussed, key drivers for technology-specific cost reduction drivers are discussed in literature[20,48] where the ease and impact of achieving various improvements is discussed in detail. As an overview, some of the key drivers for technology specific cost reductions are:

- **AEL –** Increasing the current density of the electrolyser seeks to increase efficiency and reduce electrolyser footprint, decreasing material consumption and increasing hydrogen production. Reducing the diaphragm thickness can improve the stack efficiency, reduce electricity consumption (due to a reduction in the resistance for transporting OH-)[31], and reduce material costs (the diaphragm contributes ~57% of stack costs[31] and is typically comprised of zirconium (oxide) and polysulphone). These improvements must be balanced with sufficient diaphragm thickness to prevent gas permeation. Additional performance improvements can be made by increasing the electrode specific surface area through catalyst composition and electrode architecture redesign.
- **PEM –** Reducing the iridium and titanium usage due to high costs of these scarce materials (see *Technology Developments, Material consumption*).
- **SOEC –** Increasing the lifetime through reducing the impact on the electrolyser of thermal cycling.
- **AEM** – Increasing the stability of the polymer membrane, to maintain efficiency over the electrolyser lifetime, and to increase the lifetime of the electrolyser.

Across literature, estimates on the future cost reduction of electrolysers varies. To demonstrate this variation, current and future cost estimates of each of the four technologies reviewed can be seen in Figure 9.

### 2.6.2 Technology Neutral Cost Reductions

In addition to technology specific advancements, there are two key general technology-neutral improvements which can be made to minimise electrolyser system cost:

- **Achieving economies of scale**[20,31]**.** This can reduce power supply system costs and compression costs (due to compression favouring mechanical over electrochemical compression at larger scales). In addition, automation of manufacturing and assembly, which is viable at scale, reduces costs for example reducing the cost of electrodes. Through bulk purchase, material costs can also be reduced.
- **Improving system efficiency**[20,31]**.** The design of the system as a whole can enable better tailoring of the design to the end use case. This can reduce costs and improve the efficiency of the system. For example, reducing the number of rectifiers incorporated into the system to correctly account for the energy requirement of the electrolyser would increase system efficiency and reduce costs. Another method of improving system efficiency is through optimum siting. Siting electrolysers in proximity to demand can create savings in the delivery of hydrogen and reduce requirements for hydrogen distribution and storage. This can reduce the overall LCOH and may also allow for reduced electrolyser capacity due to reduced losses along the value chain, enabling reduced CAPEX.

Literature predicts relatively rapid reductions in costs across electrolyser technologies and their components[31]. Components including PTL, and bipolar plates in PEM and AEL are anticipated to experience cost reductions at a rate comparable to the system as a whole (18% learning rate). However, this shoud be contextualised by a recent stall in cost reductions, in part due to high inflation rates in recent months.

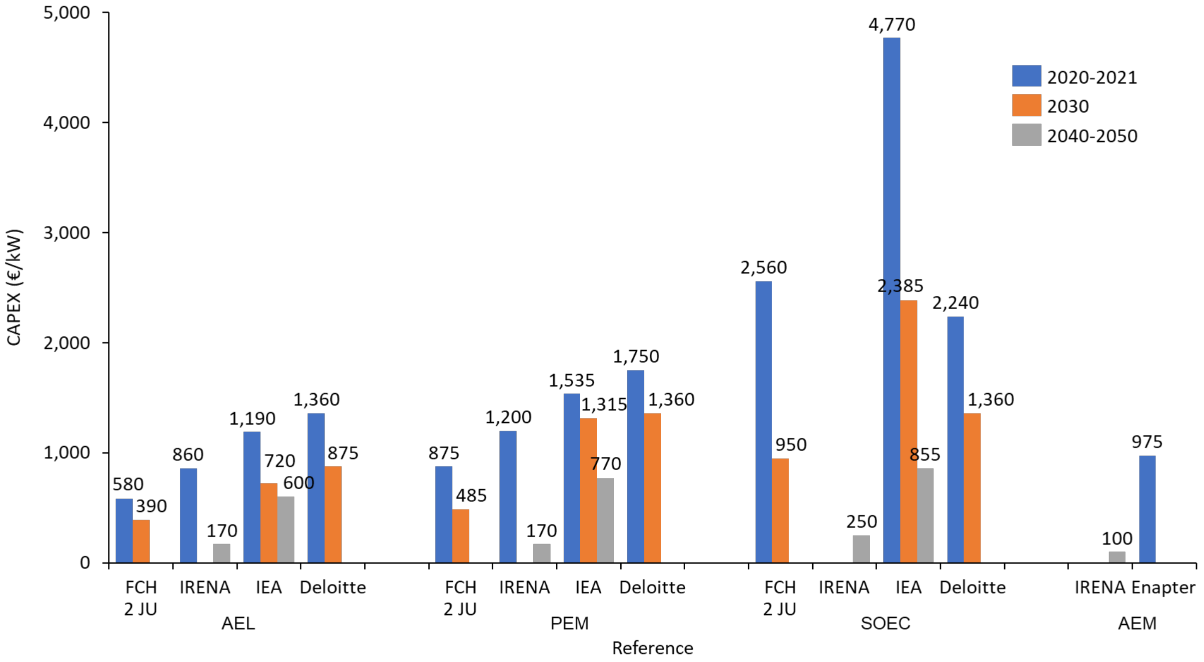


**Figure 9. Electrolyser CAPEX cost reductions as predicted by the FCH JU[59], IRENA[20], IEA[60], Deloitte[61] and Enapter[46, 47] (where ranges were given, the largest value was taken – the full breakdown is provided in the Appendices).**

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[59] Clean Hydrogen Partnership, Clean Hydrogen JU - SRIA Key Performance Indicators (KPIs) (Targets). Accessed on 25/7/23.

[60] IEA 2019, The Future of Hydrogen – Analysis.

[61] Deloitte 2021, Fuelling the future of mobility: hydrogen electrolysers.

# 3 Techno-Economic Analysis

This analysis explores hydrogen produced by electrolysis. For the full analysis, AEL, PEM, and SOEC electrolysers were modelled.

Each of these three technologies was modelled in the Netherlands, for deployment in 2030 and 2050. The modelling considers: technology capital and operational costs; feedstock and electricity; three electricity connection scenarios and their respective hydrogen production under each technology; and compression of hydrogen. The analysis results in a LCOH for each of the three most mature electrolysis technologies, and a sensitivity analysis.

A high-level analysis of AEMs was also performed (see Section 3.2.3 for further discussion); however, this technology was not integrated into the full model due to its commercial and technological immaturity.

## 3.1 Methodology and key sensitivities

### 3.1.1 TEA Methodology

This section outlines the modelling boundaries and key assumptions made for the techno-economic analysis (TEA). The full assumptions table can be found in the Appendices, Section 9.2. The primary output of this analysis is LCOH.

### Modelling boundaries and functional units

The boundaries applied to the hydrogen production systems modelled are shown below in Figure 10. At a high-level, the model incorporates the electrolyser and compressor to produce hydrogen at a pressure of 200 bar and minimum purity of 97%. These conditions were selected in order to align with the previous IEAGHG studies on blue hydrogen production[4,5]. The model also incorporates many nuances which are specific to the process of electrolytic hydrogen production:

- **Electricity input:** Whilst specific electricity input is out of scope, the model considers three electricity connection scenarios – generalised connections to the grid; dedicated renewables; and curtailed wind. These scenarios are discussed in detail in Section 3.1.4.
- **Electrolyser:** AEL, PEM and SOEC electrolysers were modelled based on estimated performance and cost characteristics in 2030 and 2050. Degradation based on hours of utilisation, and the resulting frequency of stack replacement, were incorporated into the model. The water source was assumed to be demineralised tap water. AEM electrolysers were included via qualitative analysis only (due to low relative TRL).
- **$H_2$ compressor:** As different volumes of $H_2$ are produced under different technologies and scenarios, the compressor was modelled to be dependent on the maximum hydrogen flow rate and the electrolyser output pressure for each technology.
- **$H_2$ output:** Compression to 200 bar was assumed. This was to align with previous IEAGHG studies on blue hydrogen production, and to produce hydrogen at a suitable pressure for large scale storage. Using the same functional unit allows for the comparison of different hydrogen production pathways. Whilst 97% minimum purity was specified, all electrolyser technologies modelled produce hydrogen >99.5% purity (PEM, SOEC & AEM >99.99%).

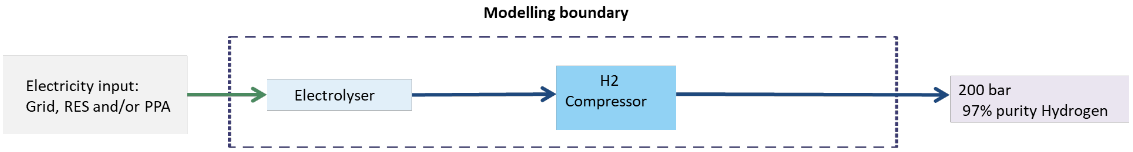

Figure 10. Techno-economic analysis modelling boundaries[62]

Storage and distribution of hydrogen is excluded from the scope of this project, as both are heavily contingent on the connecting offtake and the volume of hydrogen produced, which will vary significantly by electricity connection scenario. Hydrogen storage costs are dependent on the storage type and quantity of hydrogen stored; distribution costs are dependent on the distance and the method of transportation. Unless a specific use case is stated, an appropriate storage and transportation approach cannot be selected due to significant variation amongst end-use requirements, making the final LCOH value less meaningful. The Comparative Analysis (Section 7) will discuss a full range of cost components across previous IEAGHG studies on blue hydrogen and relevant literature, explicitly discussing differences in distribution and storage costs and methodology.

## Levelised cost of hydrogen (LCOH)

As in previous IEAGHG studies, the techno-economic model uses a cash flow to determine the LCOH, which is calculated across three technologies and three scenarios. It is assumed that there is zero net present revenue from the export of power to the grid, or other revenue generation pathways (oxygen valorisation will be discussed as part of Section 5). The below equation demonstrates how the LCOH is calculated, where LCOH is the total cost over the lifetime of the asset divided by the quantity of hydrogen produced. Discounted production and therefore LCOH is presented throughout this report.

$$LCOH = \frac{Net\ Present\ Expenditure}{Net\ Present\ H_2\ Production}$$

The following definitions apply:

- **Net Present Expenditure** is the sum of the discounted costs of electricity, water, capital, operations, compression over the asset's lifetime (25 years).
- **Net Present $H_2$ Production** is the sum of the discounted production of hydrogen over the asset's lifetime.

The model uses cost trajectories based on available literature at the time of writing, for inputs including:

- Cost of feedstock water and electricity
- Electrolyser CAPEX (discussed in Section 3.1.2)

The full assumptions, including description and sources can be found in the Appendices, Section 9.2, and where relevant, are discussed in greater detail in the following sections.

## Modelling parameters

To allow comparison with other IEAGHG studies, the below parameters were used.

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[62] The electricity input assumptions encompass costs for electricity production (in the case of renewable electricity inputs, this includes any required development costs e.g. installation, land etc. on a levelised basis), but do not include transmission costs (which are highly market-dependent).

- **Asset Lifetime** – A standard plant operating lifetime of 25 years was used across this analysis in order to align with IEAGHG blue hydrogen studies. This is 25 year lifetime[63] is also consistent with real electrolyser lifetime, with estimates for electrolyser lifetime varying from 20[48] to 40 years in literature[184, 64].
- **Discount factor** – A standard discount rate of 8% was used throughout the analysis.

To align with costs in Euros across all calculations, conversion rates of €1.17/£ and €1.11/USD, consistent with 2023 data[65], were applied. The Euro is down slightly against the dollar, and up against the pound, compared to 2020.

## Technology Readiness Level

As discussed as part of section 2, the four commercially available electrolyser types are at different stages of maturity, monitored by their technology readiness level (TRL). AEL and PEM electrolysers are now at the level of market uptake, TRL 9, with SOEC just a little behind (but advancing rapidly) at TRL 8. Meanwhile AEM electrolysers are lagging behind at TRL 6, between large prototype and demonstration level.

As such, while we consider it appropriate to assume the continued development and scaling of AEL, PEM and SOEC technologies into 2030 and 2050 to reach large-scale electrolyser deployment, the same is not necessarily appropriate for AEM at this stage. AEM electrolysers may well continue to develop and become competitive with other electrolyser technologies. However, the data currently available for AEM electrolyser performance is more abstracted from the system modelled in this analysis: to date, only very small scale AEM electrolysers (kW scale) are available, which are far from comparable with the 300 MW system modelled in this analysis. Thus, modelling AEM electrolysers on a cost basis would not necessarily represent accurate or reliable representation of the costs of AEM technologies on a LCOH basis in the future. On the other hand, there is still value in understanding the potential of this technology for low-carbon hydrogen production. Therefore, a qualitative discussion of an equivalent AEM electrolyser is included in Section 3.2.3 .

## Production Facility Capacity

All three electrolyser technologies modelled across the full TEA are based on a 300 MW hydrogen production facility (electrolyser efficiencies are in % LHV for the TEA and GHG assessment). This capacity is compatible with system sizes announced for operation into the late 2020's, 2030's, and beyond. This is demonstrated in the figure below which shows selected publicly announced electrolyser projects. This list is not exhaustive but can be used to indicate the scale up in electrolyser size expected. In addition to those included in the figure, a host of large-scale electrolysis projects have been selected for grant preparation by the Innovation Fund in recent months[66] alongside those selected in 2022[67]. This includes two 400 MW electrolyser in the Netherlands (H2Sines.Rdam and Holland Hydrogen), a 96 MW electrolyser in Sines. Larger systems across all technologies are likely to be announced in the coming years, following increased investment and interest in low-carbon hydrogen production.

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[63] Stack lifetime is also accounted for within the model, with stack replacement costs contributing to system costs based on the technology's lifetime and utilisation (i.e. after a given number of hours lifetime, the stack must be replaced, incurring CAPEX cost). Stack lifetime assumptions and cost assumptions can be found in the Appendix.

[64] NREL 2013, PEM Electrolysis H2A Production Case Study Documentation.

[65] European Central Bank 2023, Euro foreign exchange reference rates.

[66] European Commission 2023, Projects selected for grant preparation.

[67] European Commission 2022, LSC2 List of pre-selected projects.

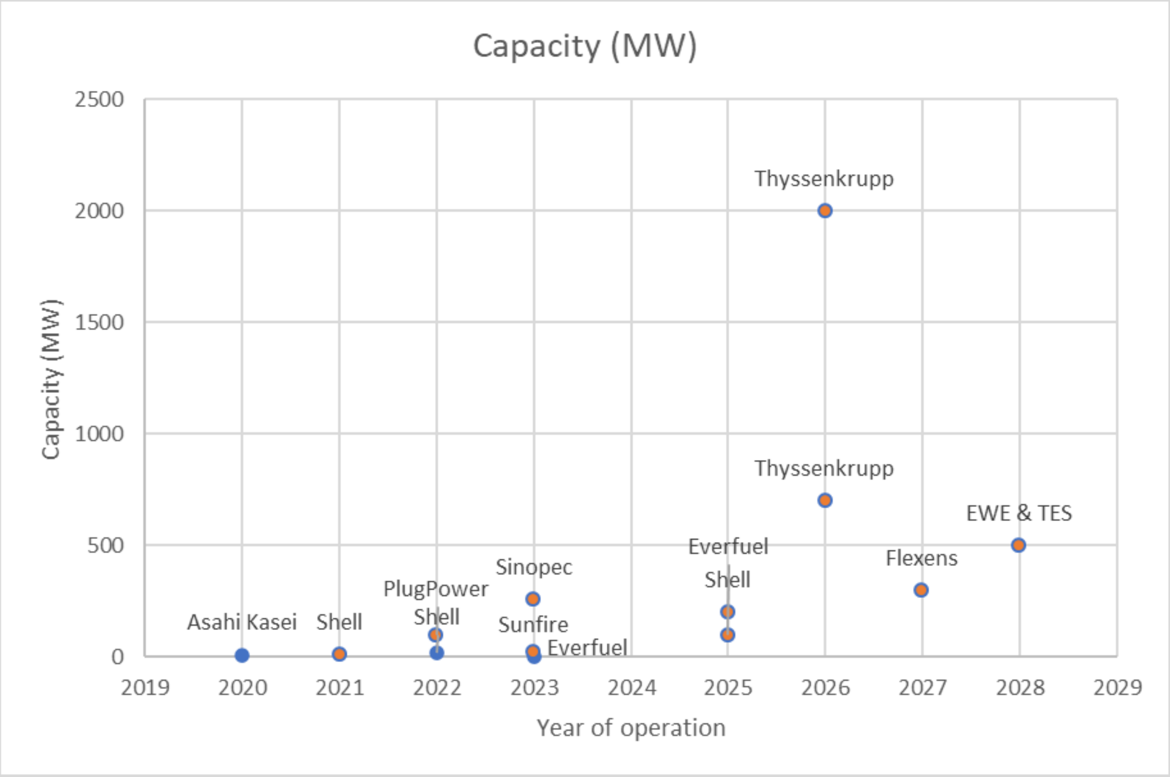

**Figure 11. Current and future electrolysers, by scale in MW and year of anticipated operation**[68,69,70,71,72,73,74, 75,76, 77, 78, 79, 80] **(AEL blue, PEM orange).**

### 3.1.2 CAPEX and Fixed OPEX

To fully account for the system costs, estimates for installed CAPEX were taken[81]. These were then contextualised with IRENA CAPEX estimates in 2020 and 2030[20] to isolate the installation costs and apply to all technologies. These estimates are supported by the cost ranges presented in literature, as discussed in Section 2. CAPEX estimates vary based on the system assumptions (e.g. installed or not installed cost). The

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[68] Energy Tech, Sunfire installs 2.6-MW Electrolyzer at Neste Refinery in Netherlands. Accessed on 01/08/23.

[69] Hydrogen Central, Shell Starts up Hydrogen Electrolyser in China with 20 MW Production Capacity. Accessed on 01/08/23.

[70] Energy Storage News, Hydrogen electrolysis using renewable energy begins at 10MW Fukushima plant. Accessed on 01/08/23.

[71] Shell Global, Shell to start building Europe’s largest renewable hydrogen plant. Accessed on 01/08/23.

[72] Shell Global, Shell starts up Europe’s largest PEM green hydrogen electrolyser. Accessed on 01/08/23.

[73] Energy monitor, Green hydrogen: TES and EWE to build 500MW electrolyser. Accessed on 01/08/23.

[74] Power Technology, Sinopec commits $470m to 300MW hydrogen electrolyser in China. Accessed on 01/08/23.

[75] Hydrogen Central, Åland-Based Firm Flexens has Announced Plans for a 300 Megawatt Hydrogen Plant in Kokkola. Accessed on 01/08/23.

[76] Offshore Energy 2023, Europe's largest electrolyser HySynergy sees its first hydrogen production.

[77] Hydrogen Central 2023, thyssenkrupp nucera Supplies the Electrolyzers for H2 Green Steel to Build One of the Largest Integrated Green Steel Plants in Europe.

[78] ReCharge News 2021, World's largest green hydrogen project – with 100MW electrolyser.

[79] thyssenkrupp 2021, One of the largest green hydrogen projects in the world: thyssenkrupp signs contract to install over 2GW electrolysis plant for Air Products in NEOM.

[80] Hydrogen Insight 2023, World's largest green hydrogen project begins production in China.

[81] Hydrohub Innovation Program 2020, Gigawatt green hydrogen plant State-of-the-art design and total installed capital costs.

purpose of the estimate (e.g. a target versus a prediction) also impacts the level of cost reduction anticipated between current and 2030 costs, and 2030 and 2050 costs. The general trends hold true irrespective of this, with the most and least expensive technologies clear, and large reductions in costs over time anticipated.

The IRENA CAPEX estimates referenced for the TEA are towards the lower end of the spectrum of costs found in the literature. In the medium term (to 2030), additional reductions in costs are anticipated to be smaller for large scale electrolysers (than for smaller, more widely manufactured smaller scale electrolysers)[82]. As technology develops, the cost reductions anticipated for smaller scale electrolysers would be expected to translate to long term (2050) cost reductions for electrolyser CAPEX, as presented in Section 2.6.

As fixed operating expenditure (OPEX) is directly proportional to CAPEX in this model (2%[83] of CAPEX), the CAPEX assumptions directly impact the fixed OPEX which accounts for operation and maintenance of the system.

**Table 4. Electrolyser installed CAPEX by technology & start of operation. *AEM costs based on Enapter 1,000 €/kW (comparable to typical AEL uninstalled CAPEX), aligned with installed cost for comparable AEL system. Full assumptions provided in the Appendix.**

| Parameter | *Units* | AEL | PEM | SOEC | AEM |
|---|---|---|---|---|---|
| **Electrolyser unit CAPEX, 2030** | *€/kW* | 1400 | 1800 | 2500 | 1400* |
| **Electrolyser unit CAPEX, 2050** | *€/kW* | 300 | 300 | 400 | 300 |

### 3.1.3 Electricity, water & heat costs – feedstock

Electricity and water costs were aligned with the IEAGHG's recent blue hydrogen studies[4,5]. This alignment was applicable to grid electricity only, as renewable energy connection scenarios were not considered as part of the blue hydrogen models.

**Grid electricity Prices**

As in previous IEAGHG studies on blue $H_2$[4,5], electricity costs were taken from forecasts provided up to 2030, and the European Union's electricity cost used to project costs out to 2050 using "EU Energy Outlook 2050"[84].

The trends to 2030 for electricity costs were wholesale electricity cost forecasts from 'Netherlands Climate and Energy Outlook 2020'[85]. Data for the Netherlands was provided by 'Denmark's Draft Integrated National Energy and Climate Plan'[86]. An additional charge to represent industrial electricity tax was applied, which was not applied to renewable energy costs. Electricity cost assumptions for 2030 and 2050 can be found in the Appendices, Section 9.3.3.

**Renewable electricity costs**

Forecasts for onshore wind, offshore wind and solar photovoltaic (PV) generated electricity were used for 2030 & 2050 estimates for renewable energy costs[87]. It was assumed that no grid charge would be applied for renewable energy costs. This is reviewed as a sensitivity in Section 3.3.

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[82] A. Reksten et al. 2022, Projecting the future cost of PEM and alkaline water electrolysers; a CAPEX model including electrolyser plant size and technology development.
[83] Lazard 2020, Lazards levelized cost of hydrogen.
[84] Energy Brain Blog 2019, EU Energy Outlook 2050 – How will Europe evolve over the next 30 years?
[85] Netherlands Environmental Assessment Agency 2020, Netherlands Climate and Energy Outlook 2020
[86] Energi-Forsynings-og Klimaministeriet 2018, Denmark's Draft Integrated National Energy and Climate Plan
[87] IEA 2021, Net Zero by 2050 - A Roadmap for the Global Energy Sector.

**Water costs**

Water is a feedstock in electrolytic hydrogen production. It was assumed that 20 kg $H_2O$/kg $H_2$ was required[23], at a cost of 0.0018 €/kg[88]. As is discussed in section 5, there is large variation in the water consumption from electrolysis (on a per kg $H_2$ basis). This context should be considered when reviewing the model estimates for water costing.

**Heat costs**

SOEC require a heat source of ~800 °C. Cost estimates for this heat source vary and will be explored as part of the sensitivity analysis. For the base case, it was assumed that the heat required for SOEC electrolysis was produced by a natural gas boiler. This is aligned between the TEA and GHG assessment. Natural gas costs were aligned with those used in the previous blue hydrogen studies[4,5] and averaged over the lifetime of the electrolyser. Varying these costs is also explored as a sensitivity. From this, steam generation costs were calculated on a per kg $H_2$ basis for 2030 and 2050 and added to the LCOH of SOEC. The full methodology and assumptions can be found in the Appendices, Section 9.3.4.

### 3.1.4 Scenario Design

To understand the implications of different electricity connection types, three scenarios were modelled. The scenarios are as follows:

#### Scenario 1: Grid connected (Grid)

In this scenario, the electrolyser is connected to 100% grid electricity, costed according to the year (operational period starting in either 2030 or 2050). It is assumed that sufficient electricity is available for the electrolyser and compressor to always operate at full load.

#### Scenario 2: Load following (RES)

Renewable energy data for the Netherlands was taken from ENTSO-E[89], and reduced to hourly and daily averages for handling purposes. Data was taken for both onshore wind and solar PV. The daily data was divided by the annual total energy production, to create a percentage of the total annual production on an hourly basis.

This percentage was then applied to the renewable energy site input into the model, with a 1 GW system comprised of 500 MW PV and 500 MW onshore wind assumed as the base case. This allowed seasonal and diurnal variation in electricity supply to be applied to the site, based on real electricity generation data.

To understand the impact of connecting to PV and onshore wind, the seasonal variation was modelled using ENTSO-E data (as discussed) which resulted in the outputs shown in Figure 12 and Figure 13. As depicted in Figure 13, seasonal variation in weather causes high solar power output and low wind (onshore & offshore) power output in the summer, with respect to the total annual production. In winter, the reverse is observed with low solar power output and high wind power output.

The *RES* scenario combines onshore wind and solar electricity to power the electrolyser. As observed in Figure 12, when combined, the inverted seasonal variation of the two production types minimises the days of low energy production. As a result, the total power output for a 1 GW total renewable energy capacity (500 MW PV, 500 MW onshore wind) is estimated to be capable of supporting the minimum load threshold of a 300 MW (AEL, 2030) electrolyser for most of the year. The available power is estimated to fall below the minimum load

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[88] NREL, H2A: Hydrogen Analysis Production Models. Accessed on 28/07/23

[89] ENTSO-E, Transparency Platform. Accessed on 28/07/23.

threshold of the electrolyser only briefly in January, November and December. As a result, 60-68%[90] of the maximum hydrogen production (at full load) could be achieved under Scenario 2: Load following (RES).

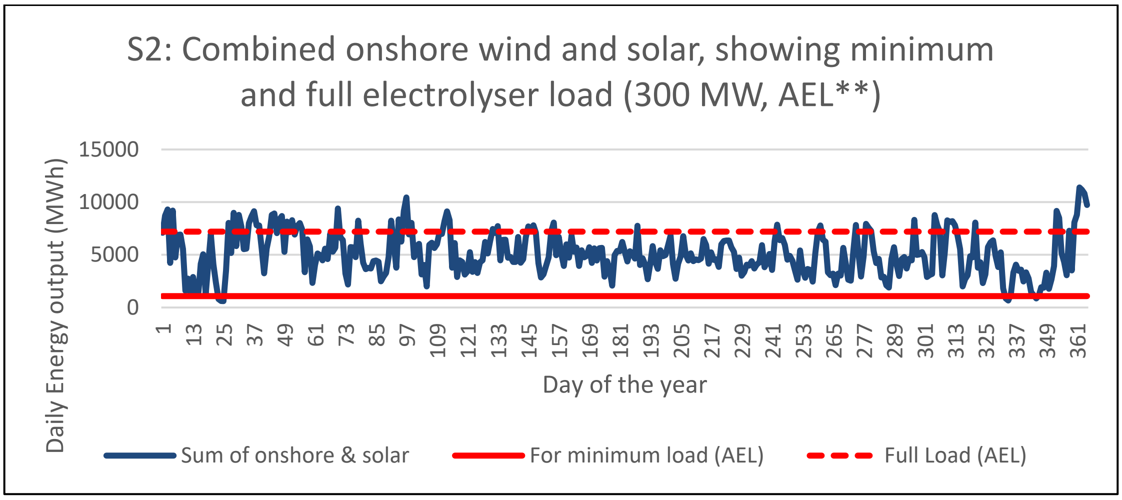

**Figure 12. Seasonal variation of combined onshore wind & PV generation, compared to minimum and full load of a 300 MW AEL electrolyser (2030 performance characteristics)[89].**

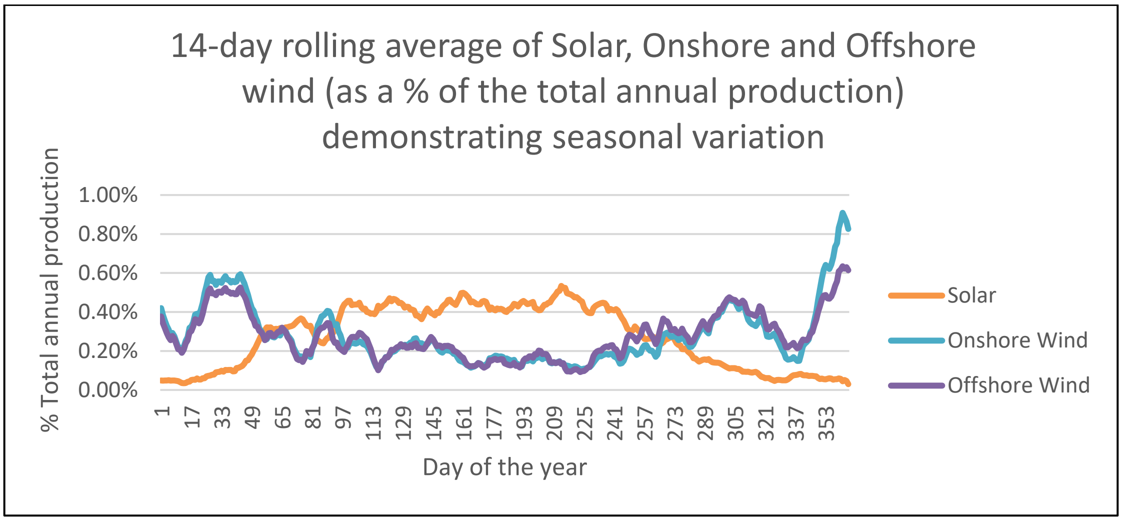

**Figure 13. 14-day rolling average of solar PV, onshore wind and offshore wind generation (% total annual production)[89].**

### Scenario 3: Wind curtailment (Curtail)

Curtailment refers to the intentional reduction in output power from renewable energy, for example in high wind speeds. Instead of making use of all the available energy from the wind, wind turbine blades may be angled parallel to the wind so as not to generate more power than the grid users' demand. Wherever possible,

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[90] Variation due to differences in sampling frequency and methodology (hourly vs daily average), with daily average used for the techno-economic analysis.

electricity grids seek to balance electricity generation with demand. Electrolytic $H_2$ production can provide a buffer to the grid by utilising electricity which would ordinarily be curtailed to produce hydrogen. This hydrogen can then be stored (at the scale of months via, for example, underground storage), or can supply other hydrogen demands from sectors such as industry and mobility. To model curtailed electricity, both supply and demand data is required.

*Scenario 3: Wind curtailment (Curtail)* also used ENTSO-E data from the Netherlands, this time for offshore wind generation. As in *Scenario 2: Load following (RES)*, data was reduced to daily averages. Electricity demand data from across the Netherlands (NL) was also reduced to daily averages. This electricity demand was then divided by the total NL production capacity reported in 2022[89] and multiplied out to a 1 GW system. From this, the differences between offshore wind electricity production and coupled electricity demand was estimated and used to calculate the average hourly and daily outputs of $H_2$ from curtailment.

Under *Scenario 3*, it was assumed that curtailment was possible wherever the daily average electricity production from offshore wind exceeded the daily average electricity demand (for 1 GW systems). Since the electrolyser can only operate when the minimum load is met, and the minimum load (MW) varies by technology and start of operation (2030/2050 technology), this means that more hydrogen can be produced from the same curtailment model using a PEM electrolyser than an AEL in 2030. This is because PEM electrolysers have a lower minimum load than AEL, reducing the power requirements for electrolyser start up.

As observed in Figure 14, there are many periods where demand (in a 1 GW system) exceeds electricity generation from offshore wind. In total, ~12.5% of the total annual energy production can be curtailed. The availability of this electricity is not consistent, but intermittent, corresponding to the energy supply. The highest frequency of curtailment occurs in the winter months due to the high generation capability of offshore wind during these periods. This result of 12.5% is in line with quoted values of 13% for curtailment in the Netherlands[91], implying that this model, whilst exhibiting limitations regarding the raw generation and demand data, is aligned with real curtailment scenarios.

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[91] TNO 2022, Profitability offshore wind in 2030 not self-evident.

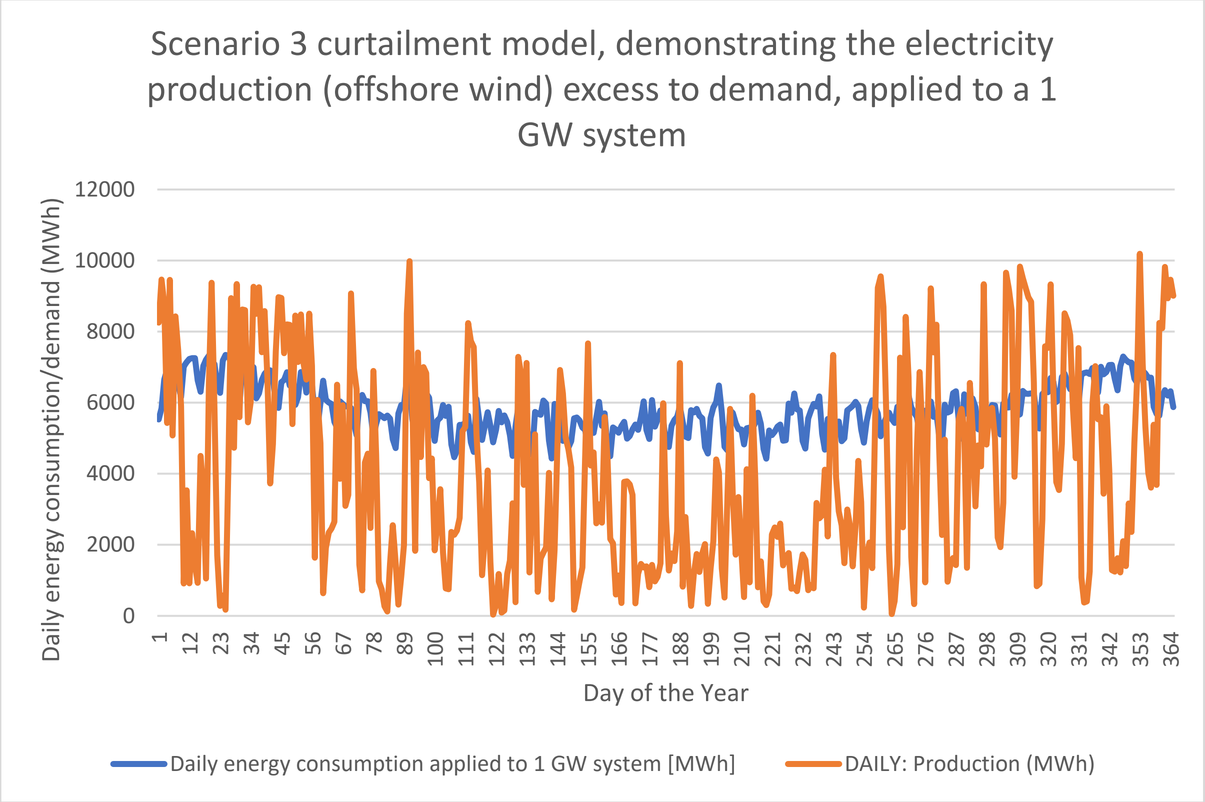

**Figure 14. Demonstration of *Scenario 3: Curtailment* model, with offshore wind generation (orange) and daily demand (blue) in MWh. Data used in the model taken from ENTSOE (2022 data)[89].**

### 3.1.5 Compressor lifetime

It is assumed that the compressor has a lifetime of 25 years. This is to align with the lifetime of the electrolyser, but also represents a reasonable estimate for compressor lifetime. Hydrogen compressor lifetimes are often quoted at 20 years. Centrifugal compressors, as modelled in this analysis (see Appendices, Section 9.3.3 on compressor design) are quoted at having increased lifetimes of 250,000 hours (~28 years)[92]. Where lifetime is given in years, this refers to continuous operation. As such, particularly in the instance of renewable connected scenarios, continuous operation of the compressor will not occur. Therefore, even where a compressor with a shorter lifetime (as low as 15 years[93]) is used, with a 60% LF approximately equivalent to the *Scenario 2* LF, the lifetime would be sufficient for the full 25-year period of operation. Compressors frequently remain operational far beyond this, even as long as 50 years[94].

The intermittent operation is not likely to have a large effect on the compressor lifetime (in terms of running hours), but it will reduce the compressor efficiency when operating away from the set-point. For electrolysers that are directly coupled to renewable generation, the required load profile of the associated compressor will be accordingly intermittent. The expected lifetime of compressors is not expected to be affected by operating

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[92] A World Of Energy, Hydrogen Compression. Accessed on 09/11/23.
[93] DOE, Technical Targets for Hydrogen Delivery. Accessed on 09/11/23.
[94] FS Elliott 2021, At a Glance Brochure.

with electrolysers coupled to renewable generation, but the efficiency of the compression process is likely to be lower[95].

When coupling electrolyser output to renewable generation the efficiency of the compression process is likely to be lower than for constant operation, particularly if the operating conditions are frequently varying. Compressors are most efficient running at a constant set point. Deviating significantly from the set point when ramping up and down across a wide operating envelope is likely to negatively influence the average compressor efficiency. Although variable loads on compressors can be met within their turndown range the overall efficiency of the compressor system can be reduced significantly during lower flow demands. This can be partly mitigated with compressors running in parallel, as the possibility of turning off individual compressors could allow other compressors to work closer to their set point.

Compressor failure can occur due to various factors, and most of these are unlikely to be more prominent for compressors operating with electrolysers that match the generation profile of renewables. Cycling of compressors will introduce variations in the stress state of moving parts. While this could introduce concerns about a potential fatigue failure mode, the high-cycle fatigue introduced by vibration, and unrelated to the cycling profile, has a stronger effect on the combined fatigue performance of compressors[96, 97]. Moreover, short cycling of compressors could lead to shortage of oil inside the compressor and the failure of bearings or other moving parts[98]. However, short cycling is related to short bursts of on and off cycles of just a couple of minutes, which is not expected to be the operational profile when matching the generation profile of renewables. Intermittent service could also affect lifetime when it is linked to long idle periods, as this could lead to hard starts, corrosion, or inadequate lubrication, but long idle periods of over a week are not expected to be part of the operational profile. Hence, the lifetime of compressors, in terms of compressor running hours, is not expected to be affected by operating with electrolysers coupled to renewable generation. In terms of years of mechanical lifetime, intermittent operation linked to renewable generation could actually lead to an increase in lifetime as the average number of running hours per year decreases. This is consistent with assumptions made by Jacobson et al. who model compressor lifetime as being inversely proportional to its load factor[99].

## 3.2 Results

### 3.2.1 2030 Results

AEL, PEM & SOEC technologies were modelled to produce a LCOH in 2030. The performance and cost characteristics can be found in the Appendix, Section 9.3.2. The results of this analysis are shown in Table 5 and Figure 14.

#### Scenario comparison

**The most expensive scenario on an LCOH basis is *Scenario 3: Curtailment (Curtail)*.** With costs >30 €/kg, this scenario is not a viable option in 2030 under the specific curtailment configuration modelled as part of this TEA. In 2030, extremely low electrolyser LFs, created by low available electricity from curtailment and prohibitively high minimum electrolyser loads, combined with high electrolyser CAPEX, inflates the LCOH beyond what would be reasonable for cost-competitive hydrogen. Curtailment could still offer a suitable model

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[95] Compressor electricity cost variation based on this has not been considered as part of the TEA, however, compressor electricity costs are already negligible compared to other LCOH components.
[96] Zhang, M et al. 2016, The fatigue of impellers and blades.
[97] Yakui, Z. 2018, Research on the Fatigue Performance of TC6 Compressor Blade under the CCF Effect.
[98] Abels, B and Kissock, K 2011, Optimizing Compressed Air Storage for Energy Efficiency.
[99] Jacobson, M. Z. 2023, Impacts of green hydrogen for steel, ammonia, and long-distance transport on the cost of meeting electricity, heat, cold, and hydrogen demand in 145 countries running on 100% wind-water-solar.

for electrolytic hydrogen production in ideal conditions. Discussion of the electrolyser sizing and the impact of renewable generation intermittency will be discussed in the Sensitivity analysis in Section 3.3 and further in Section 7.3.1. Electricity costs are comparable between *Scenario 2: Load following (RES)* and *Scenario 3: Curtailment (Curtail)*, due to low renewable electricity costs[100].

**The least expensive scenario on an LCOH basis is *Scenario 2: Dedicated renewables (RES)*.** High electrolyser LFs are enabled by combining onshore wind and PV, somewhat levelling off the impacts of seasonal variation in electricity generation capacity. In addition, electricity costs are lower than grid connected *Scenario 1*, as shown in Figure 15. This enables the *Scenario 2: Load following (RES)* production pathway to achieve LCOH between 4.87-5.67 €/kg by 2030, depending on the electrolyser technology.

**Under *Scenario 1: Grid connected (Grid)*, electricity costs dominate the LCOH.** This is due to the increased cost of grid electricity compared to renewables.

Table 5. LCOH by technology & scenario for 2030 & 2050.

| | | AEL | | | PEM | | | SOEC | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **First year of operation** | ***Units*** | **GRID** | **RES** | **CURTAIL** | **GRID** | **RES** | **CURTAIL** | **GRID** | **RES** | **CURTAIL** |
| **2030** | *€/kg* | 7.81 | 4.87 | 30.53 | 8.35 | 5.67 | 36.09 | 7.99 | 6.17 | 58.36 |
| **2050** | *€/kg* | 5.99 | 2.61 | 7.54 | 5.98 | 2.60 | 7.54 | 5.01 | 2.58 | 7.38 |

## Technology comparison

**AEL are the least expensive technology across all scenarios in 2030 due to low relative CAPEX cost.** In 2030, AEL has the lowest CAPEX cost. Despite lower minimum loads for PEM than AEL, and reduced compression requirements due to higher electrolyser output pressure[101], high CAPEX (and resulting fixed OPEX) leads to a slightly larger LCOH for PEM than AEL in 2030. This gap is increased where lower volumes of hydrogen are produced, as there is only a ~7% difference in LCOH between AEL and PEM in *Scenario 1: Grid connected*, but an ~18% difference in LCOH under *Scenario 3: Curtailment*.

In 2030, SOEC are anticipated to have high efficiencies, but will still have very high CAPEX. When combined with the cost for the heat supply, this pushes SOEC costs above AEL and PEM. Where electrolyser LF is low, as in *Scenario 3: Curtailment*, the high expenditure required increases the LCOH.

As discussed in Section 2, SOEC are less mature than AEL and PEM electrolysers. In 2030 SOEC may still be developing to reach the scale modelled (300 MW) and depends on a heat source to achieve the high efficiencies quoted. As such it is important to compare the two most mature technologies: AEL and PEM.

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[100] Full electricity pricing assumptions found in Appendices, Section 9.3.1.
[101] 70 bar for PEM; 30 bar for AEL.

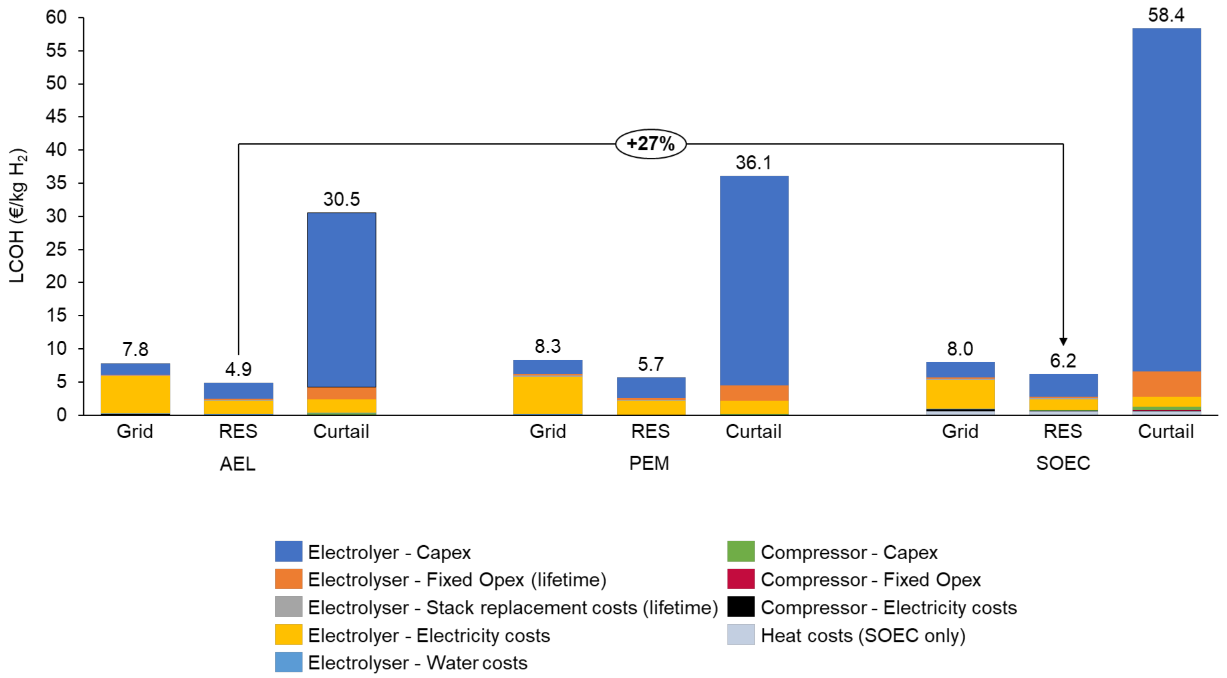

Figure 15. LCOH across technologies and scenarios in 2030.

## 3.2.2 2050 Results

### Scenario Comparison

**Between 2030 and 2050, improvements in electrolyser performance, particularly in efficiency, and reductions in electrolyser cost see a reduction in LCOH across all scenarios and technologies.**

***Scenario 2: Dedicated renewables* remains the lowest cost option on a per kg $H_2$ basis**, with LCOH <3 €/kg across all technologies. By 2050, this model estimates that SOEC with renewable load following direct connection could achieve costs of €2.07/kg $H_2$. Even at this LCOH, further cost reductions would be needed to meet the most ambitious hydrogen cost targets[102]. Whilst costs remain higher under Scenario 3: Curtailment than in other scenarios due to the low volumes of hydrogen produced, by 2050 costs are as low as ~€7/kg $H_2$.

**Under *Scenario 1: Grid connected*, the high electricity costs cause the LCOH to remain high** despite other costs having reduced and $H_2$ production volumes increasing due to improved electrolyser performance. Indeed, >80% of *Scenario 1: Grid connected* costs stem from electricity costs by 2050.

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[102] US DOE 2021, Hydrogen Shot. Target to reach $1/kg $H_2$ in one decade. $1 equivalent to €0.91.

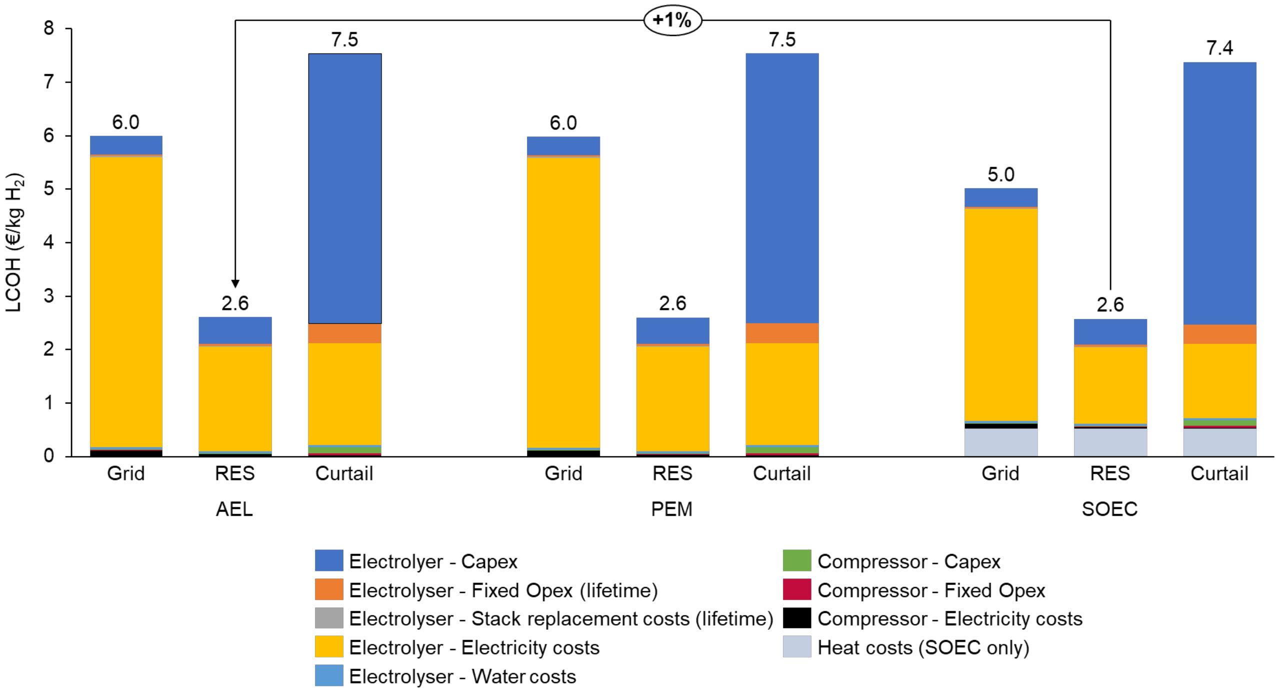

Figure 16. LCOH in 2050 by scenario and electrolyser type.

### Technology comparison

**SOEC are the lowest cost technology option across all scenarios by 2050, however, the difference in LCOH across technology types for the RES scenario is €0.03.** This highlights the promise of this technology, again with the caveat regarding pace of development (less of an issue for 2050) and availability of waste heat, whilst also highlighting the importance of low electricity costs and high electrolyser utilisation (as in the RES scenario).

**PEM and AEL reach almost equivalently low LCOH**, with high efficiencies, low minimum LFs, low CAPEX and overall, extremely closely comparable properties. Both technologies are able to achieve low LCOH by 2050 with marginal differences in cost (however, this would multiply out over the electrolyser lifetime so would amount to a difference in the revenue generation potential of either technology).

### 3.2.3 2030-2050 Trends

As discussed, between 2030 and 2050, an **increase in electrolyser efficiency** has a large impact on the LCOH across all scenarios, when combined with the **reduction in CAPEX** (and corresponding reduction in fixed OPEX).

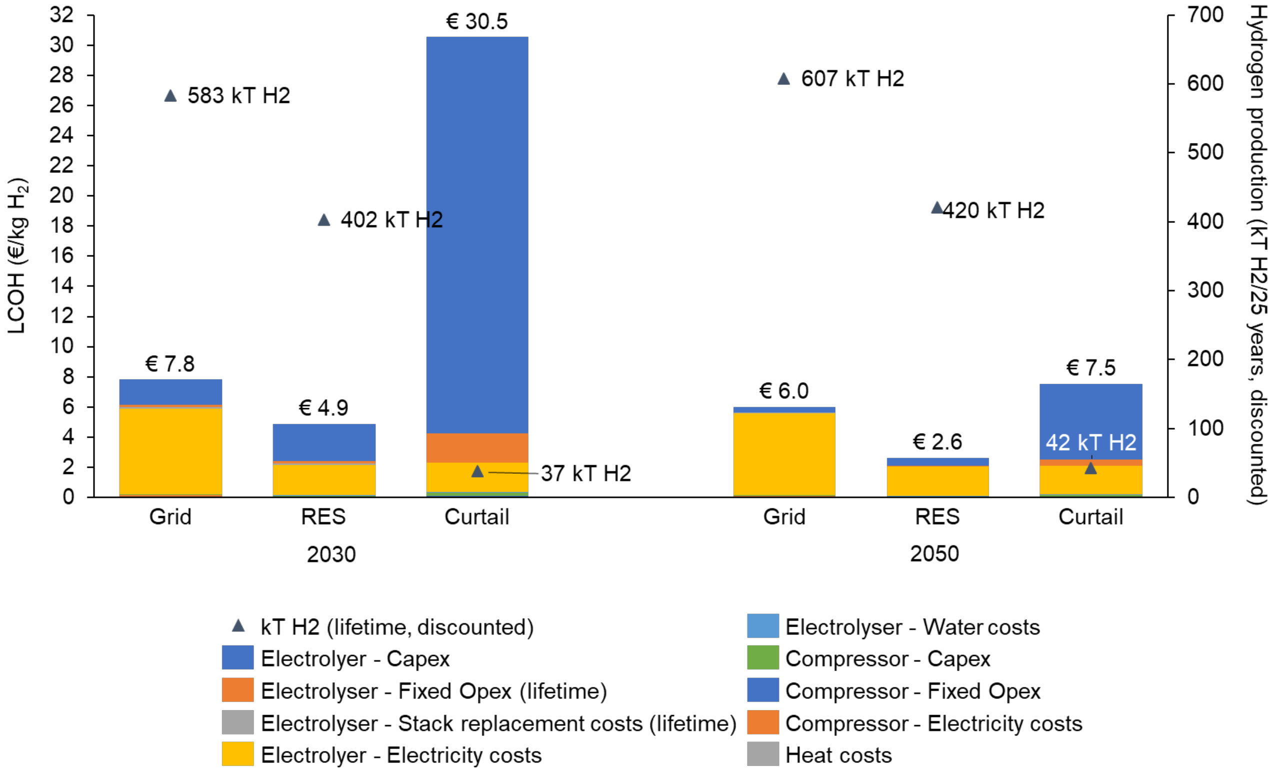

**Figure 17. Comparison between LCOH and lifetime volumes of hydrogen production (kT $H_2$) in 2030 and 2050 for an AEL across all scenarios[103].**

**Larger volumes of hydrogen are produced in 2050 than in 2030.** We can clearly see the impact of efficiency improvements and minimum load improvements through the increase in $H_2$ production and decrease in LCOH in Figure 17.

The reduction in the minimum load (%) needed to operate the electrolyser across SOEC and AEL also contributed to an increase in hydrogen production volumes and the reduction in LCOH under *Scenario 3: Curtailment.* Lower minimum load enables a higher electrolyser LF. This is because the electrolyser can turn on and produce hydrogen with a lower baseline input power, enabling operation for a larger number of days in the curtailment scenario. Higher efficiency and lower minimum load collectively enable an >10% improvement in the volumes of hydrogen produced under *Scenario 3: Curtailment* (AEL, 2050 compared to 2030).

The impact is less under *Scenario 1: Grid connected* & *Scenario 2: Load following (RES)* (across all technologies, using AEL as an example). Between 2030 and 2050, a ~5% increase in hydrogen production volumes is enabled by improved electrolyser performance.

**Large reductions in CAPEX unlock cost reductions by 2050.** CAPEX reductions have the largest impact on a per kg $H_2$ basis in renewable energy connected scenarios where CAPEX forms a larger % contribution to the costs instead of electricity costs (which is proportional to the volumes of hydrogen produced).

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[103] Note that the utilisation of the electrolyser limits that technologies hydrogen production. Therefore, less hydrogen is produced over the electrolyser lifetime from the "RES" and "Curtail" scenarios than under the "Grid" connected scenario.

### Performance of anion exchange membrane (AEM) electrolysers

As per the assumptions in the Appendices, Section 9.3.2, AEM electrolysers have relatively low efficiencies in both 2030 and 2050 (<70% LHV) and have low output pressures of 35 bar. In addition, AEM have short stack lifetimes of only 3 years due to the current instability issues. This would mean that stack replacement costs would be much higher, due to the increased frequency of replacement. Whilst CAPEX costs quoted are comparable to AEL and PEM systems in both 2030 and 2050, as quotes come solely from Enapter and are only applicable for very small-scale electrolysers currently, there is uncertainty about whether actual CAPEX would vary significantly from this. The low efficiencies would - counteracted by a low minimum load - limit hydrogen production slightly, and the poor stack lifetime would inflate stack replacement costs. If a 300 MW AEM system were to match the properties described by 2030 or 2050 it is reasonable to assume that LCOH would be larger than for AEL, PEM and SOEC technologies. This form of qualitative analysis can be used to better understand other emerging technologies and to contextualise performance characteristics of electrolysers.

## 3.3 Sensitivity analysis

This section discusses the sensitivities tested on the TEA. Figure 18 demonstrates the impact on LCOH of each sensitivity, and the impact on hydrogen production capacity of the scenario tested respectively. Full data tables summarising the results as LCOH in €/kg can be found in the Appendices, Section 9.4.2.

The results of the sensitivity analysis are summarised in Figure 18, with the below findings:

- **Increasing electricity costs increases the LCOH.** The impact on LCOH is proportional to the change in cost, with the largest impact being felt under *Scenario 1: Grid connected (Grid)* where electricity costs are already large and a 50% increase in costs causes a larger total increase than under, for example, *Scenario 2: Load following (RES).*
- **Increasing the electrolyser capacity (MW) causes no change to LCOH where LF is 100%**[104] i.e. under 2030 *Scenario 1: Grid connected (Grid)* SOEC. The reason that LCOH is immune to this change is because the electrolyser is operating at maximum utilisation under *Scenario 1: Grid connected (Grid)*. Since the amount of hydrogen that can be produced is dependent on the electrolyser capacity, and electrolyser CAPEX is calculated on a per kW basis where the electrolyser can operate at full capacity and fixed OPEX is already contributes less than 1 cent per kg $H_2$, varying the electrolyser capacity +/- 50% has no significant (in this case referring to >1 cent) impact on LCOH.
- **Where renewable energy supply causes reduced electrolyser LF, increasing the electrolyser capacity (MW) increases the LCOH.** This is caused due to the corresponding increase in minimum electrolyser load which comes with increased electrolyser size. This raises the threshold for the minimum power required for the electrolyser to operate and restricts the frequency that this can be met by renewable energy generation (in the modelled scenarios). However, the following is also true:
- **Increasing electrolyser capacity increases $H_2$ production where renewable energy supply allows.** There is a turning point signifying maximum revenue potential that can be found through varying electrolyser capacity. As discussed, when connected to intermittent renewable energy generation, increasing electrolyser capacity (MW) can simultaneously increase the LCOH and increase the volumes of $H_2$ produced. For maximum revenue generation, the ideal case is to minimise the LCOH and to maximise the hydrogen produced by the electrolyser. As such, the business case of a project cannot only be measured by the LCOH.

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[104] Note that the analysis is not based on a fixed scale of demand, so it is assumed that the load factor would remain at 100% if the electrolyser capacity were increased.

- **Increasing renewable energy generation capacity decreases the LCOH.** This has a particularly large impact in 2030 (this sensitivity only applies to renewable energy connected scenarios i.e. *Scenario 2: Load following (RES)* & *Scenario 3: Curtailment (Curtail)*). Not shown in the figure below due to the exceptionally large impact on LCOH is the impact of decreasing the coupled renewable energy generation site scale by 50% on the *Scenario 2: Load following (RES)* 2030 SOEC. This scenario already has extremely high LCOH due to extremely low electrolyser LF, and decreasing the generation capacity by 50% would lead to a >4,000% increase in the LCOH. The impact of designing electrolyser curtailment scenarios is discussed in greater detail as part of the Comparative Analysis in Section 7. However, it is evident that the low hydrogen production under *Scenario 3: Curtailment (Curtail)* increases the scenarios sensitivity to both variation in fixed costs and variation in the availability of electricity.

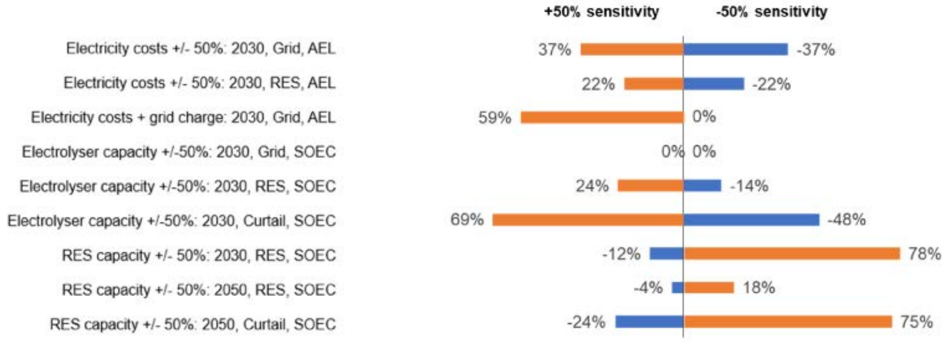

Figure 18. Percentage reduction/improvement in LCOH by sensitivity

A different compressor sizing methodology was also modelled. Under *Scenario 3: Curtailment (Curtail)*, the compressor is sized by the maximum flow rate of hydrogen output from the electrolyser. As the maximum flow rate occurs extremely infrequently in this scenario, it is of benefit to understand the impact of resizing the compressor according to a reduced flow rate. For an AEL under *Scenario 3: Curtailment (Curtail)* in 2030, the mode $H_2$ output in kg/hour (average, mean) is c.1 kg$H_2$/hour.

Sizing the compressor to this yields compressor rated power of 1.53 MW (53% reduction) and CAPEX = €1.12mn (61% reduction). However, the compressor CAPEX and OPEX comprise < 1% of the LCOH, meaning that this has little impact on the final cost on a per-kg$H_2$ basis. In future, as other associated costs reduce, there will be increased emphasis placed on optimising every stage of the system, however, under the 2030 & 2050 scenarios this would have little impact.

As discussed, SOEC require a heat source. The base case assumption was that this heat was produced by a steam boiler fed by natural gas. As natural gas costs vary widely, a large +/-50% sensitivity was tested. This demonstrated that the impact on LCOH was largest where the LCOH was already low (e.g. in *Scenario 2: Load following renewables (RES)*). This is due to heat costs being a fixed input on a per kg $H_2$ basis.

Use of waste heat instead of steam boiler fed SOEC was tested. Waste heat costs were assumed equivalent to steam costs from the IEAGHG blue hydrogen studies[4,5] (€0.0018/kg steam). Applying this vastly reduced cost, saw an up to 20% reduction in the LCOH. Again, as the cost of heat was fixed on a per kg $H_2$ basis, the largest impact was seen for the lowest cost scenario (SOEC, renewables connected (onshore and PV), 2050).

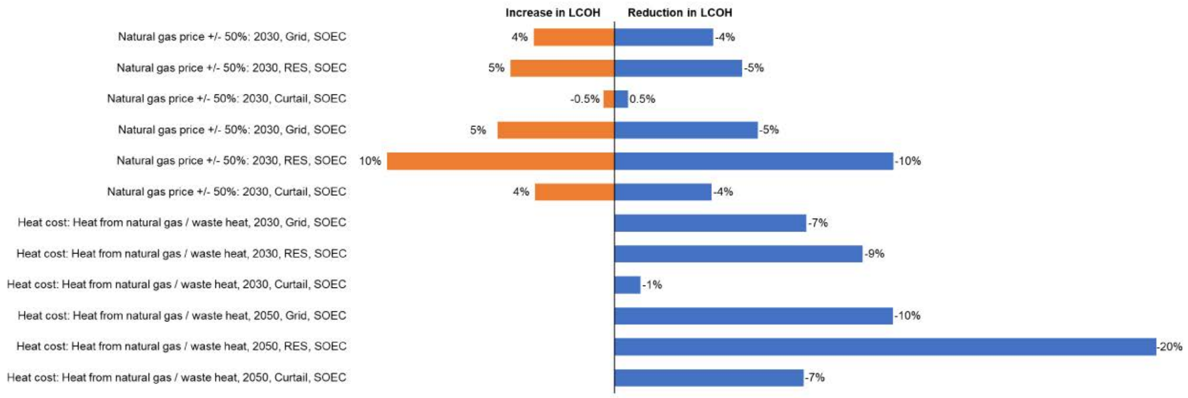

Figure 19. Percentage change in LCOH by heat source. SOEC, 2030 and 2050.

## 3.4 Limitations

Key limitations of the TEA have been discussed in the context of the fundamental assumptions made. It is important to note that the boundaries and system designed in this model are specific to this model only and will differ to other LCOH models across literature. The scenarios tested were designed specifically with this model in mind and do not reflect a view on which electrolytic hydrogen production pathways are better or worse. Application of electrolysis technologies is extremely dependent on the exact conditions of the project and this study should merely act as a tool to understand the components within LCOH and how these might be best manipulated to better design and understand future electrolysis projects.

One crucial addition to the limitations listed is this model's failure to include the start-up time of the electrolyser. As renewable electricity generation data was reduced to daily averages, it would have introduced a spurious level of accuracy to introduce the start-up time into the $H_2$ production and LCOH calculations for AEL and PEM technologies, which have start up times of 1 minute. This is also true for considering warm standby. However, it is important to note that for SOEC, start-up time is currently ~600 minutes. This reduces SOEC ability to respond quickly to sudden changes in electricity generation, which could form a barrier in some cases to connection with RES. The long start up time is connected to the high operating temperatures of SOEC and their demand of waste heat needed to boost the quality[105] of heat input which enables their high efficiency operation. It is important to note that this is cold start-up time, which is typically defined as the time taken for an electrolyser to go from -20 °C to nominal power[106]. Cold start up does not represent real operating conditions but is a marker of the flexibility of the electrolyser; electrolysers are able to operate in stand-by for short periods (hours). Hot idle ramp time is sometimes used as a more accurate representation of the suitability of an electrolyser to connect with intermittent renewable energy generation.

This analysis assumed that the electrolyser's operational profile is based on the availability of electricity, and it is assumed that this supply satisfies the electrolyser's minimum load requirements. However, it is important to recognise that when designing a bespoke project, individual stack configuration and operation will be an important consideration when aiming to ensure the maximum system cost efficiency. Under the scenarios modelled in this analysis only a very limited amount of additional hydrogen production would be unlocked by operating on a stack level rather than a system level and therefore has a negligible impact on the final LCOH. A larger impact is expected under the curtailment scenario due to the already low electrolyser utilisation. However, even a large increase in the number of days the electrolyser could be operational would not contribute sufficient volumes to reduce the LCOH to be comparable with the grid connected or load following scenarios modelled.

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[105] When referring to heat, the quality of a waste heat source refers to the temperature of the source.
[106] Davies, J et al. 2021, Historical Analysis of FCH 2 JU Electrolyser Projects.

# 4 Life Cycle Greenhouse Gas Assessment

This section presents the life cycle greenhouse gas (GHG) assessment methodology and results of the electrolytic hydrogen production pathways combined with downstream distribution chains.

The GHG assessment aims to assess and compare the GHG impacts of electrolytic hydrogen production in the Netherlands with different electrolyser types and downstream distribution routes. The focus of the GHG assessment is aligned with the TEA in terms of technological, geographical, and temporal scope, with the addition of the distribution pathways for the GHG assessment.

The life cycle GHG assessment has been carried out according to four stages as described in the International Organization for Standardization (ISO) norms 14040 and 14044:

1. Goal and scope definition
2. Life cycle inventory (LCI)
3. Life cycle impact assessment (LCIA)
4. Interpretation of results

The goal and scope of the study is described in Section 4.1, the LCI is detailed in Section 4.2 and the results of the impact assessment are discussed in Section 4.3, including sensitivity analysis.

## 4.1 Goal and Scope

The Goal and Scope is the first step in a life cycle assessment and defines the aims of the study which then inform the system boundary, functional unit, choice of methodology and data requirements.

### 4.1.1 Goal of the study

The goal of this study is to **assess the GHG impacts of different electrolytic hydrogen production technologies and distribution pathways for 2030 and 2050** to enable comparison between different technology and distribution options, as well as comparison of electrolytic hydrogen production against other low-carbon hydrogen production technologies. The comparative analysis of electrolytic hydrogen production with other low-carbon hydrogen production technologies is presented in Section 7.

### 4.1.2 Scope of the study

#### System boundary

In this study, cradle-to-gate system boundaries were used, in line with the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) GHG methodology for hydrogen production[107]. The system boundary includes all process steps from the extraction of the raw materials up to and including the production of compressed hydrogen, as shown in Figure 20. All processes are required to produce hydrogen at 200 bar and >97% purity. The emissions from construction and decommissioning of hydrogen production plants and supply chain infrastructure are excluded from the system boundary. See more detail on this in section on Limitation of the study.

A further analysis was carried out to assess the GHG impact of combining the electrolytic hydrogen production technologies with different downstream distribution chains. For this additional analysis, the system boundary was expanded to include the transportation of hydrogen from producer to consumer. This is represented by a

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[107] IPHE 2022, Methodology for Determining the Greenhouse Gas Emissions Associated with the Production of Hydrogen.

cradle-to-user system boundary shown in Figure 20. Consumption of hydrogen and end-of-life treatment of hydrogen is not included in this analysis.

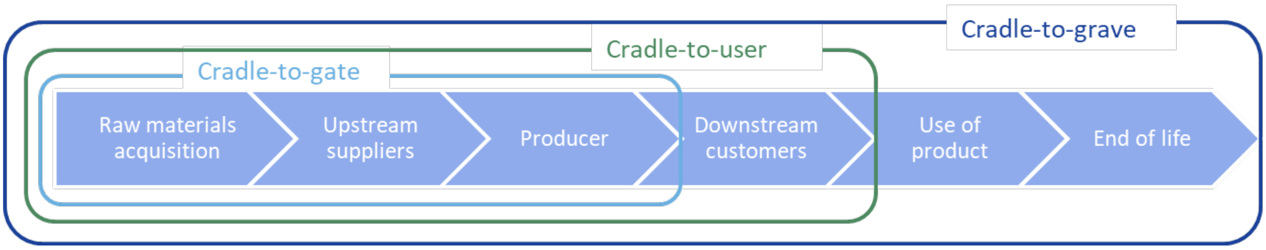

Figure 20. Illustrative example of system boundaries.

The supply chains and assumptions for each of the analysed technologies are given in the Appendices Section 9.4. Hydrogen is assumed to be produced in the Netherlands, assuming 2030 and 2050 Dutch grid emissions intensity, renewables profiles and representative transport distances.

### Functional unit

A functional unit serves as the basis upon which the analysis of each of the hydrogen production pathways is carried out. The functional unit in this study for electrolytic hydrogen production is defined as the production of 1 MJ lower heating value (LHV) of hydrogen compressed to 200 bar with a minimum purity of 97%. This is in line with the functional unit defined in the TEA and in previous IEAGHG blue hydrogen studies allowing for comparison across the different hydrogen production routes.

For the further analysis carried out to assess the GHG impact of electrolytic hydrogen production combined with different distribution pathways, the functional unit is defined as the production of 1 MJ final product where the final product may be ammonia, methanol, or gaseous hydrogen.

### Limitations of the study

There were some limitations of the study that should be noted:

- Emissions associated with construction, manufacturing and decommissioning of capital goods, business travel, employee commuting and upstream leased assets are excluded. This is in line with the IPHE methodology[107] and is justified by the relatively small contribution of these emissions to the total pathway emissions as well as the technological improvements and decarbonisation of upstream energy and material production expected to occur over time.
- The life cycle GHG emissions, also referred to as Global Warming Potential were assessed in this study but other environmental impacts (e.g. land use, and resource depletion) were considered out of scope, and as such, not evaluated in this project.
- Long-term impacts caused by elementary flows that occur over time frames of substantially more than 100 years are not included in this analysis. There is uncertainty in assessing impacts over such long timescales, therefore long-term impacts were excluded from this study.

### Life cycle inventory

**Background data** refers to indirect material and energy flows resulting from the production, consumption and end-of-life of all material and energy inputs used in hydrogen production. The main sources used in this study to collect background data include published industry reports, IEA reports, Joint Research Centre (JRC)-EUCAR-Concawe (JEC) datasets, EU implementing acts, and other literature.

**Foreground data** refers to the inputs and outputs directly associated with electrolytic hydrogen production and distribution pathways (e.g. source of energy, transport mode, technology used, yields etc.). Generally, foreground data is within the control of the plant operator which can be referred to as primary data sources. In this study, foreground data has been collected from secondary sources as opposed to primary sources such as electrolytic hydrogen producers. A range of literature sources has been used to provide the foreground data.

Further details on the foreground and background data are provided in the Appendix Section 9.4.

To account for the uncertainty in the data used to model the different hydrogen production and distribution pathways, three scenarios were modelled: Central case (Baseline impact), Best case (Low impact) and Worst case (High impact). Key parameters for which a range of values were used across the three scenarios included electrolyser efficiencies, sources of captured $CO_2$ used for methanol production, transport decarbonisation trajectories, and hydrogen global warming potential (GWP). Appendices Section 9.4 provides details on the data and assumptions used to model the scenarios for each pathway.

### LCIA

LCIA uses the LCI results to model the life cycle GHG impacts of produced hydrogen. The impact of climate change is evaluated using Global Warming Potential (GWP100) as the characterisation model. In line with the IPHE methodology[107], GWP values from the Intergovernmental Panel on Climate Change, Sixth Assessment Report (IPCC AR5) were used. No other impact categories were included in this life cycle assessment because this was out of scope of the study.

### Multifunctionality

Electrolysis produces oxygen and hydrogen. Oxygen can be sold as a useful product for other processes thereby meaning this is a multifunctional system. As such, the GHG impact of the electrolytic hydrogen production process needs to be assigned among the hydrogen main product and oxygen co-product.

Under the IPHE framework, the following order of approaches is taken to manage multifunctionality:

- Allocation based on energy content (frequently using LHVs)
- Allocation based on system expansion
- Allocation based on economic value

The oxygen co-product does not have an energy content therefore in this study, system expansion was used to account for multifunctionality. All GHG emissions of the process's inputs and outputs are attributed to hydrogen, but there are credits given for the avoided impacts of producing oxygen that is used outside the product system. To calculate the emissions allocated as a credit to the oxygen co-product, production of oxygen from a cryogenic air separation unit (ASU) using grid electricity was modelled. Further detail is provided in Appendix Section 9.4.8.

### Data Collection, Quality and Uncertainties

The data collection and selection for the GHG assessment is detailed in Appendices Section 9.4 which details the quality and uncertainty associated with the selected data.

The collected data is combined with background data values from literature listed in Appendices Section 9.4.9.

### Sensitivity analysis

The choices and assumptions selected for a life cycle GHG assessment in terms of the methodology and data used will impact the results. In this study, the following sensitivity analyses have been performed to assess the impacts of changing key parameters on the overall GHG emissions of the different electrolytic hydrogen production and distribution routes:

- Sensitivity 1: Changed the allocation method used to assign emissions to the oxygen co-product in the electrolytic hydrogen production pathways.
- Sensitivity 2: Applied different grid electricity decarbonisation scenarios projected to 2050.
- Sensitivity 3: Applied different natural gas grid decarbonisation scenarios projected to 2050.
- Sensitivity 4: Assumed an "all renewables" scenario in which power, heat and transport modes decarbonise by 2030.
- Sensitivity 5: Changed the storage times of ammonia, liquid hydrogen, and methanol in the distribution chains.
- Sensitivity 6: Changed the transport distances for all relevant distribution chains.
- Sensitivity 7: Included hydrogen leakage from electrolytic hydrogen production pathways and assessed the impact of three different hydrogen GWPs.
- Sensitivity 8: Changed the technology efficiencies of the pathways to choose either the Best or Worst case.

## 4.2 Life cycle Inventory (LCI)

The LCI includes all data for the material and energy inputs and outputs associated with the hydrogen production and distribution pathways. The Appendices Section 9.4 contains a summary of all the inventory data and assumptions used to model the GHG emissions from the hydrogen production and distribution pathways modelled in this study.

### Electrolytic hydrogen production and distribution chains analysed

The environmental impacts of the electrolyser technologies assessed in the TEA were analysed in the GHG assessment. Namely hydrogen production using AEL, PEM, SOEC, and AEM electrolysers. The electrolytic hydrogen production routes were combined with distribution options covering ammonia, methanol, gaseous and liquid hydrogen, as well as ammonia cracking back to gaseous hydrogen prior to use. The combinations that were modelled are listed in the table below.

Table 6: Combinations of electrolytic hydrogen production with distribution chains

| Electrolyser | Distribution chain | Supply chain steps | Final product |
|---|---|---|---|
| **AEL** | Conversion to ammonia | Ammonia conversion, truck, store, ship, store, truck | Ammonia |
| **PEM** | | | |
| **AEL** | Conversion to ammonia followed by cracking back to hydrogen | Ammonia conversion, truck, store, ship, store, crack, purify, compress, truck | Hydrogen (gaseous) |
| **PEM** | | | |
| **AEL** | Conversion to liquid hydrogen | Liquefy, truck, store, ship, store, truck, regasify | Hydrogen (gaseous) |
| **PEM** | | | |
| **AEL** | Conversion to methanol | Methanol conversion, truck, store, ship, store, truck | Methanol |
| **PEM** | | | |
| **AEL** | Compressed pipeline | Compress, pipe | Hydrogen (gaseous) |
| **PEM** | | | |
| **SOEC** | | | |
| **AEM** | | | |

Given the PEM and AEL electrolysers are more mature (TRL 9) compared to SOEC and AEM (TRL 7 and TRL 6, respectively) technologies, the combinations of the five distribution pathways with both PEM and AEL electrolytic hydrogen production were modelled, while only compressed pipeline was modelled for the SOEC and AEM electrolysers.

## 4.3 Life cycle GHG Assessment and interpretation of results

In this section the results of the life cycle GHG assessments and sensitivity analyses are presented. Section 4.3.1 analyses the carbon footprint results of the electrolytic hydrogen production life cycle GHG assessments. Section 4.3.2 presents the results from the distribution pathways and the different combinations that were modelled. Sensitivities are presented in Section 4.3.3.

### 4.3.1 Electrolytic hydrogen production

For the electrolyser technologies discussed in sections 2 and 3, the life cycle GHG emissions of electrolytic hydrogen production is analysed in the following section.

For the charts presented in the following section, the bars in the chart represent the range of impacts across the scenarios, where the bottom of the bar represents results from the Best case (Low impact) and the top bar represents results from the Worst case (High impact). The dark blue dot represents the results from the Central case (Baseline impact). The data and assumptions used to define the Best, Central and Worst cases are detailed in the relevant sections of the report, as well as in the Appendix.

In the figure below the GHG emissions for the electrolytic hydrogen pathways using grid electricity are presented for 2030 and 2050.

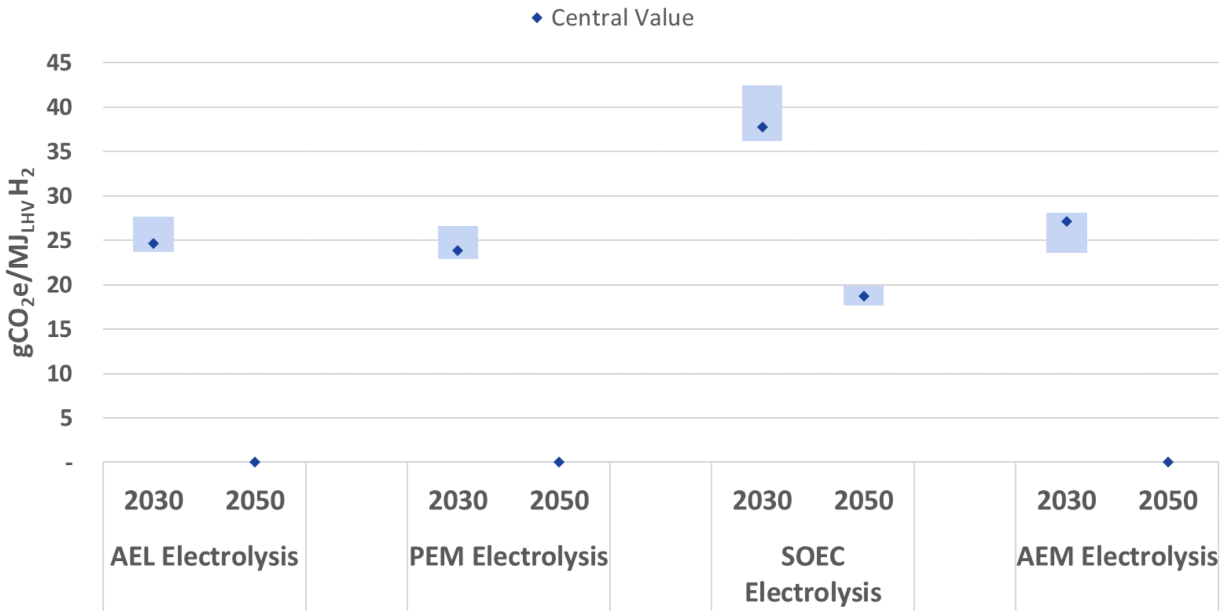

Figure 21. Electrolytic hydrogen production emissions using grid electricity (scenario ranges, 2030 and 2050)

As the electricity grid decarbonises to 2050, the emissions associated with the electrolytic hydrogen production pathways reduces significantly. The SOEC electrolysis pathway requires an input of heat, which is not required for the other electrolysis pathways. For this study, it was assumed that natural gas was used as the heat source. Whilst this heat input enables higher electrical efficiency to be achieved for the SOEC pathway, the slower decarbonisation of the gas grid compared to the power grid leads to the SOEC pathway achieving the highest emissions result in both 2030 and 2050.

The production pathway emissions for other electrolyser technologies (AEL, PEM and AEM) reach close to zero by 2050 because the only sources of emissions are from tap water, sodium hydroxide and hydrochloric acid. The difference in results between the AEL, PEM and AEM electrolysis pathways can be attributed to the electrolyser efficiencies which are very similar for AEL and PEM (up to 0.6% difference in 2030 and up to 1.8% difference in 2050). The difference in efficiencies between the AEM electrolyser and the PEM and AEL electrolysers is bigger (up to 6.1% in 2030 and up to 4.1% in 2050) due to the lower efficiency of the AEM electrolyser compared to AEL and PEM.

The differences between the Best and Worst cases are due to the ranges used for the electrolyser efficiencies (see Table 46 in Appendix Section 9.5.1). The chemical inputs (sodium hydroxide and hydrochloric acid) and tap water consumption were assumed to be the same across the electrolyser technologies and the scenarios. It was assumed there are no fugitive hydrogen emissions from leakage in the baseline. Sensitivities have been performed to understand the impact of fugitive hydrogen emissions on the total pathway emissions and further discussion on the uncertainties surrounding hydrogen leakage is provided in Section 7.4.2.

The system expansion credit allocated to the oxygen co-product was calculated as 1.2 $gCO_2e/MJ_{LHV}$ $H_2$ for 2030. The credit in 2050 is 0.0 $gCO_2e/MJ_{LHV}$ $H_2$ because it was assumed that the Netherlands power grid will operate on 100% renewables by 2050[7]. Despite the energy consumption of a cryogenic ASU being reasonably high (1.08 $MJ_{elec}$/kg oxygen), the oxygen produced per MJ hydrogen is low due to the hydrogen LHV (120 $MJ_{LHV}$/kg $H_2$).

The source of electricity for the electrolytic hydrogen production pathways may come from renewable sources rather than from the electricity grid. The emissions associated with the production of electrolytic hydrogen using renewable electricity would be significantly lower compared to hydrogen production that uses grid electricity. The figure below shows the difference in production emissions using grid electricity compared to renewable electricity.

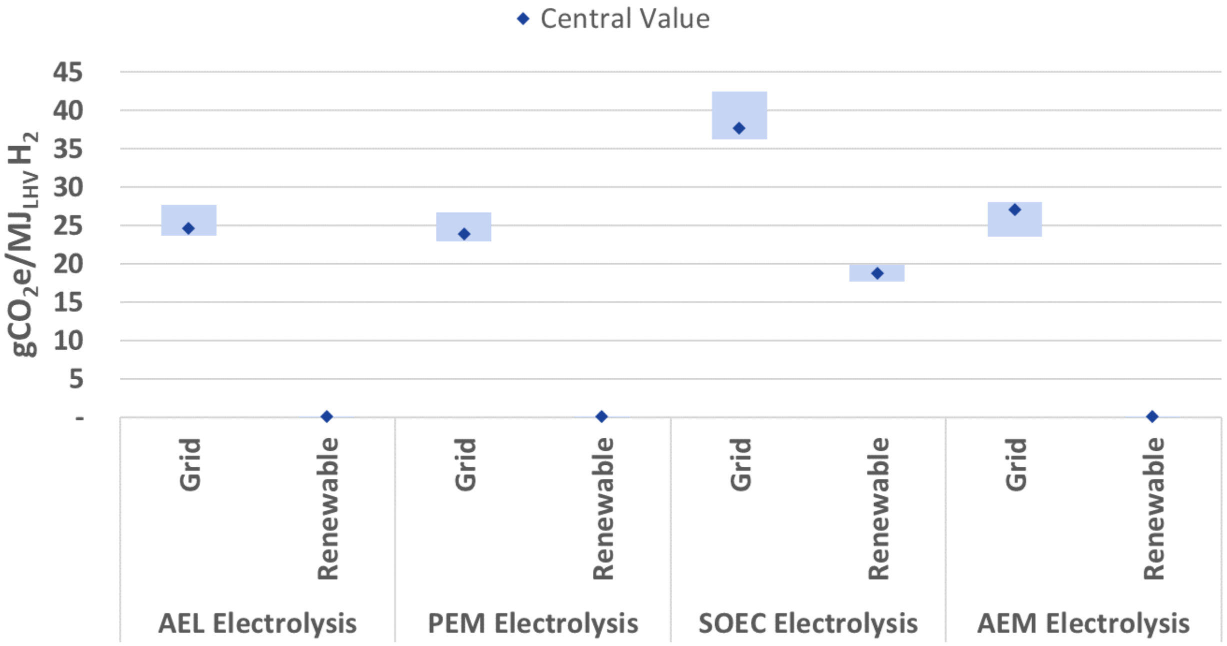

Figure 22. Comparison of electrolytic hydrogen production emissions using grid or renewable electricity (scenario ranges, 2030 and 2050)

The difference in the 2030 results highlights the impact of the emissions associated with the electricity input and decarbonisation of the electricity grid to achieve significant emissions reductions for electrolytic hydrogen production. In 2050, it was assumed the electricity grid decarbonises to run on 100% renewables therefore there is no difference observed between the sources of electricity. The assumption on the decarbonisation of the Netherlands electricity grid to 2050 is based on published energy scenarios but there will be factors that impact this trend and could result in a slower rate of decarbonisation of the Dutch grid than expected. For example, fewer windfarms or solar projects may be deployed or there may be increased reliance on natural gas. For the purposes of this study, as stated above, the Dutch grid was assumed to run on 100% renewables by 2050.

### 4.3.2 Distribution routes and combinations

Electrolytic hydrogen production pathways were combined with a selection of distribution pathways based on electrolyser TRL. Table 6 in Section 4.1.2 summarises the hydrogen production and distribution combinations that were modelled.

**Transport distances were assumed to be the same across the distribution pathways** either as 300 km via truck or 400 km via pipeline. For shipping of ammonia, liquid hydrogen, and methanol to a downstream user, it was assumed these products are shipped from Rotterdam, the Netherlands to Houston, USA (9,300 km). Despite the high hydrogen demand expected in the EU, to model shipping in the distribution chains, the USA was selected as the end user destination given this location is also expected to have increasing hydrogen demands[4]. In the near term, it is more likely that hydrogen produced in Europe will be used in Europe, and hydrogen will be exported from the USA to Europe. There are however no guarantees that this will be the case in the longer term and Europe could become a significant hydrogen exporter. We have performed sensitivities on the shipping and pipeline transport distances for these distribution chains to highlight the impact of transport distance on the pathway emissions.

**The storage time for these distribution pathways was assumed to be 20 days**, in line with the IEA G20 Hydrogen report[108]. A sensitivity was performed on the storage time to understand the impact on the final emissions result.

The methanol distribution pathway includes conversion of hydrogen to produce methanol which requires input of carbon dioxide. **Different sources of carbon dioxide were assumed for the scenarios modelled**. In the Central case the carbon dioxide was assumed to be sourced from industrial point source capture[109], geothermal sources[110] were assumed for the Best case, and direct air capture for the Worst case[48].

## Hydrogen distribution emissions

The GHG emissions calculated for the distribution pathways are presented in the figure below.

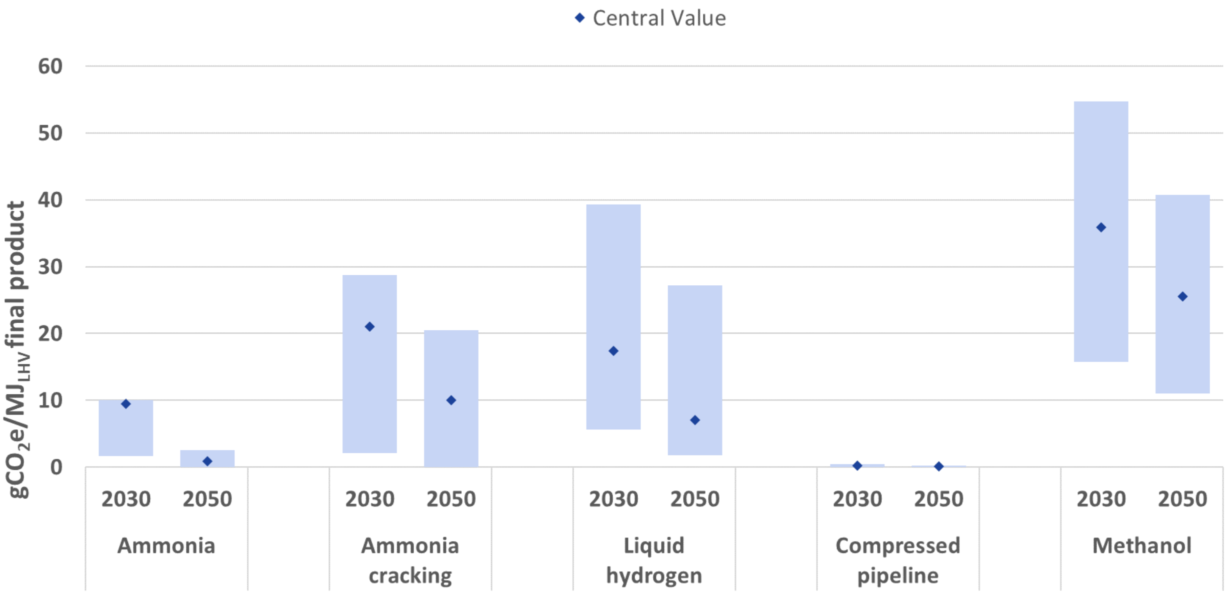

Figure 23. Hydrogen distribution emissions (scenario ranges, 2030 and 2050)

**All pathways show a significant reduction in emissions from 2030 to 2050 as the electricity grid and transport modes decarbonise**. But distribution emissions can be significant in the context of sector decarbonisation and regulatory fuel GHG intensity thresholds.

By 2050, it was assumed that shipping decarbonises to run on zero emission fuels based on the IMO strategy[111]. However, in 2030 shipping accounts for a significant portion of emissions in most chains and therefore should not be ignored. Ship capacity and fuel type are considered in the modelling of the distribution chains to account for differences in shipping ammonia vs liquid hydrogen[108]. Methanol shipping is assumed to be similar to ammonia shipping. The **assumptions around boil-off rate for shipping of the different products (ammonia, liquid hydrogen and methanol) can significantly impact the pathway emissions**. For the liquid hydrogen chain, a higher boil-off rate is assumed, which leads to the emission impact of the shipping step being more significant compared to other distribution pathways. The impact of shipping distance on the pathway emissions has been investigated as a sensitivity in the next section.

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[108] IEA 2020, IEA G20 Hydrogen report: Assumptions.
[109] JEC WTT v5 2020, Appendix 1 Pathways 5 Synfuels.xlsx
[110] CRI 2015, Power and CO2 emissions to methanol.
[111] IMO 2023, Revised GHG reduction strategy for global shipping adopted.

**Ammonia cracking adds significant emissions to the delivered ammonia pathways**. The best case assumed no external heat requirement for cracking, due to internal recycling of cracker and PSA off-gases, resulting in the range between the Best and Worst case. The Worst case assumes the cracker and PSA off-gases are sold externally resulting in natural gas input required to provide heat to the process.

**The electricity required for liquefaction is the main contributor to emissions from the liquid hydrogen distribution chain**, further highlighting the impact of decarbonisation of the power grid on the final emissions for these distribution pathways.

**Compressed pipeline has the lowest results for 2030 and 2050** due to only a small amount of electricity usage and compression and some hydrogen emissions from pipeline leakage.

**Methanol production is the largest single contributor to any distribution chain's emissions** due to its electricity and carbon dioxide inputs. The large range between the Best and Worst case for the methanol chain can be attributed to the different $CO_2$ capture scenarios that have been modelled. The high upper value is due to the high heat (steam) and electricity requirements for capturing $CO_2$ via direct air capture.

Methanol is the final product of the methanol distribution chain modelled in this study, therefore converting this to hydrogen would result in further emissions being generated from this pathway.

## Breakdown of hydrogen distribution chain emissions by process step

A breakdown of the emissions by process steps is presented for each distribution pathway in the figure below for the Central case in 2030.

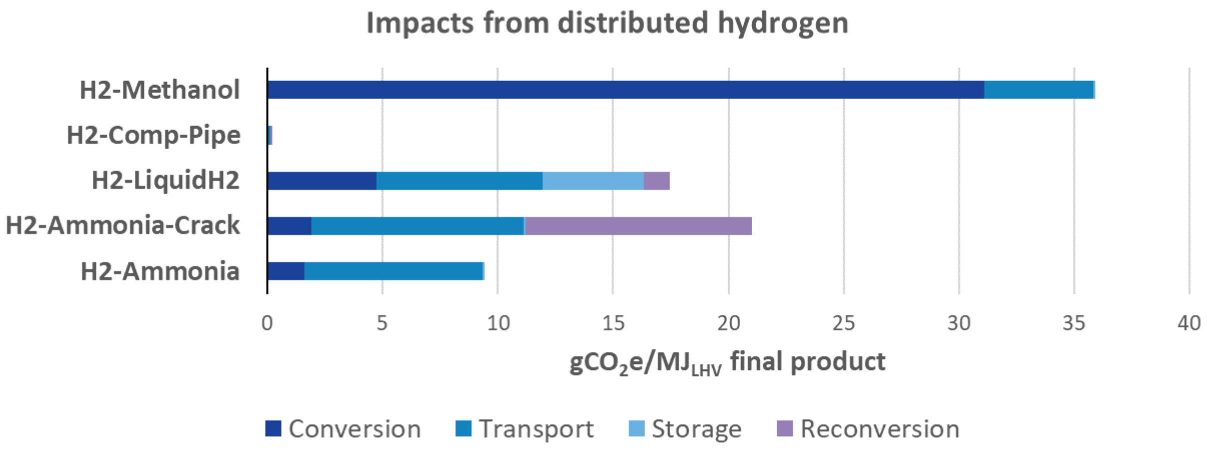

Figure 24. Breakdown of hydrogen distribution emissions by process step (central scenario, 2030)

The **conversion of hydrogen to methanol contributes a significant portion of the total emissions** for the methanol chain. The methanol production step accounts for ~86% of the total distribution pathway emissions.

The transportation steps in the liquid hydrogen and ammonia chains assume shipping from Rotterdam to the USA, therefore this contribution may be less significant if a more local end user is chosen. However, it is unlikely that shipping as a means for hydrogen distribution will be pursued for shorter distances given that shipping is only cost competitive for long distances[112].

For the ammonia cracking pathway, the efficiency and the heat requirement of the regasification step (i.e. reconversion) contributes 46% of the total emissions. The ammonia and ammonia cracking pathways have

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[112] Getting to Zero Coalition 2021, Hydrogen as a cargo.

slightly different emissions results for the conversion and transport process steps shown in the figure above because of the difference in the cumulative efficiency across the entire pathway. In addition to those steps in the ammonia distribution chain, the ammonia cracking chain includes cracking to hydrogen, purification, and compression. The efficiencies of these additional processes lead to different cumulative efficiencies for the two ammonia distribution pathways.

**Storage emissions are very small for the ammonia, methanol and compressed pipeline distribution chains.** Less than 1% of the total pathway emissions for these distribution routes is attributed to storage due to low electricity requirements, and modest losses. However, liquid hydrogen distribution has a much higher boil-off rate during storage, resulting in this process step contributing significantly more to the final pathway emissions compared to other distribution routes.

### Combination of grid electrolytic hydrogen production and distribution emissions

Combining electrolytic hydrogen production emissions with different distribution routes leads to a range of emission results being calculated for the total pathway emissions. The figure below presents the results from the hydrogen production and distribution combinations.

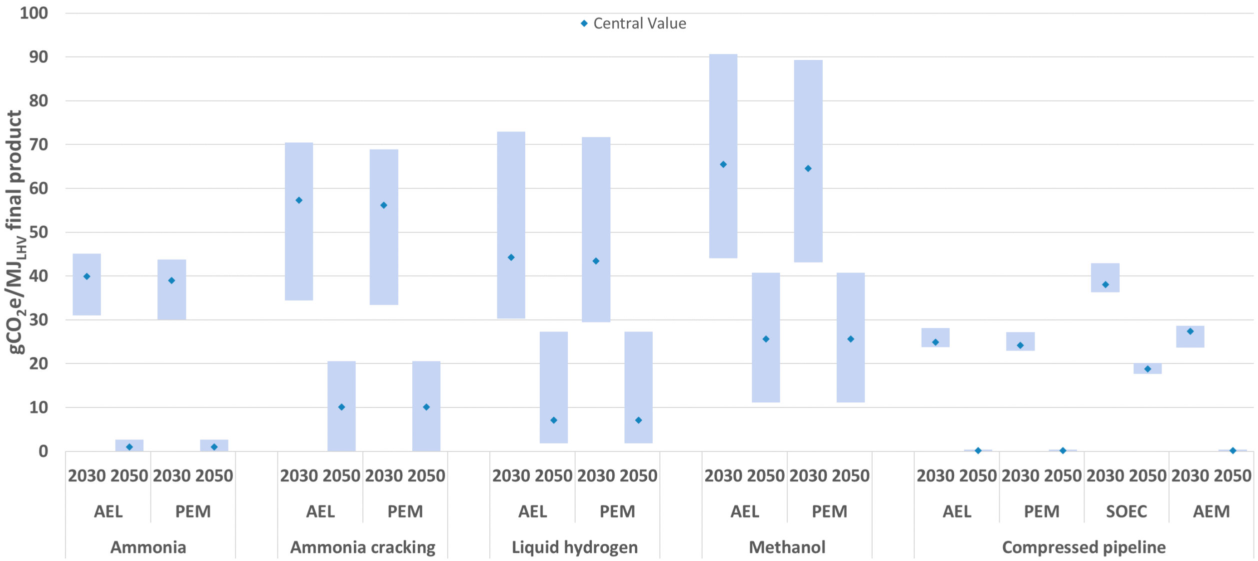

Figure 25. Combined grid electrolytic hydrogen production and distribution emissions (scenario ranges, 2030 and 2050)

The small differences between the AEL and PEM results for each distribution pathway is due to the difference in electrical efficiencies for these two electrolysers. **The wide ranges between the Best and Worst cases for the combined pathways are mainly due to differences in distribution chains, as well as some electrolyser efficiency variation**. The following assumptions contribute to the wide range of results:

- no external heating for ammonia cracking or regasification of liquid hydrogen in the Best case
- different captured $CO_2$ sources for the methanol chains
- zero carbon shipping/trucking in the Best case from 2030
- range of hydrogen GWP values impacting liquid hydrogen transport and storage

**The heat requirement for the SOEC electrolyser results in the combined SOEC compressed pipeline chain having the highest emissions** compared to the other electrolyser pipeline combinations. By 2050 in the Best case, pathway emissions are generally small across the multiple combined production and distribution routes due to decarbonisation of the electricity grid and transport, with the exception of methanol and SOEC chains due to heating requirements.

### Breakdown of combination of grid electrolytic hydrogen production and distribution emissions

A breakdown of the emissions by process step is provided for each of the combined electrolytic hydrogen production and distribution routes in the figure below for the Central case in 2030.

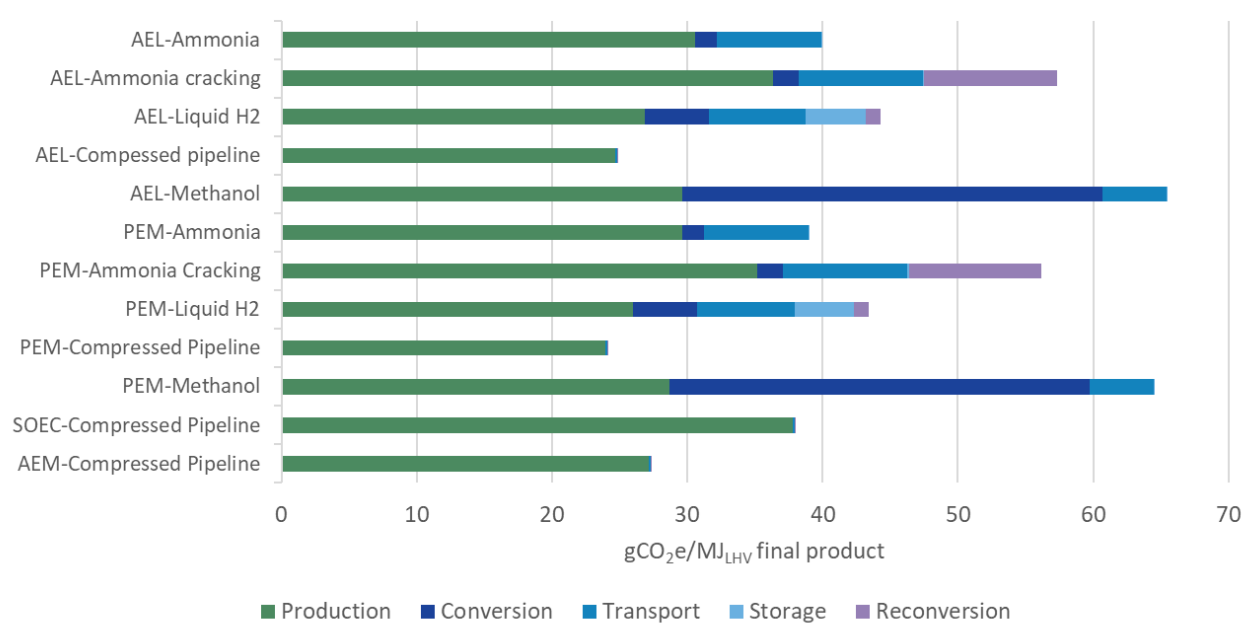

Figure 26. Breakdown of combined grid electrolytic hydrogen production and distribution emissions by process step (central scenario, 2030)

The emissions associated with grid electrolytic hydrogen production contribute a significant portion of the total emissions for each pathway when combined with distribution routes. For the **compressed pipeline pathways, more than 99% of the total pathway emissions are attributed to electrolytic hydrogen production**.

As stated earlier, the methanol conversion step contributes a large portion of the total emissions, accounting for ~48% of the total combined emissions for the PEM and AEL routes. Electrolytic hydrogen production contributes 44-45% to the total emissions for the combined electrolytic hydrogen production and methanol distribution pathways.

For the ammonia distribution pathways, ~76% of the total emissions are attributed to the hydrogen production step for both AEL and PEM electrolyser routes. For the distribution pathway which includes cracking of ammonia back to hydrogen, ~63% of the total emissions are associated with the electrolytic hydrogen production step for AEL and PEM electrolysers.

The **significance of the emissions associated with electrolytic hydrogen production using grid electricity** highlight the impact of grid decarbonisation on the total pathway GHG emissions of these combined production and distribution routes.

### 4.3.3 Sensitivity analysis

Sensitivities have been performed on the Central scenario (Baseline) for the combined electrolytic hydrogen and distribution pathways. A summary of the sensitivities performed are shown in the table below.

Table 7: Summary of sensitivities performed in the life cycle GHG assessment

| Sensitivity | Description | Baseline | Sensitivity |
|---|---|---|---|
| Allocation methodology | Changed the allocation method used to assign emissions to the oxygen co-product in the electrolytic $H_2$ production pathways. | System expansion credit is assigned to the oxygen co-product. | All GHG emissions are allocated to $H_2$. |
| All renewables | Assumed an "all renewables" scenario in which grid utilities and transport modes decarbonise by 2030. | Grid electricity and natural gas intensities, and transport modes decarbonise gradually. | 0 $gCO_2e$/unit for power, heating, shipping and trucking. |
| Fugitive $H_2$ emissions | Included $H_2$ leakage from electrolytic hydrogen production pathways and assessed impact of three different $H_2$ GWP. | GWP = 11 $gCO_2e/gH_2$<br>There are only fugitive $H_2$ emissions from the distribution chains in the baseline, and no fugitive $H_2$ emissions assumed from electrolytic $H_2$ production. | ~1% $H_2$ leakage from electrolysis step added, and:<br>(1) GWP = 6 $gCO_2e/gH_2$<br>(2) GWP = 11 $gCO_2e/gH_2$<br>(3) GWP = 16 $gCO_2e/gH_2$ |
| Transport distances | Changed the transport distances for all relevant distribution chains. | Shipping: Rotterdam to Texas city (9300 km)<br>Pipeline: Netherlands to UK (400 km) | Shipping from Rotterdam to:<br>(1) Australia (17,500 km)<br>(2) Dubai (11,400 km)<br>(3) UK (300 km)<br>Pipeline from Rotterdam to:<br>India (6500 km) |
| Storage time | Changed the storage times of ammonia, liquid $H_2$, and methanol in the distribution pathways. | 20 days of storage | (1) 1 day of storage<br>(2) 100 days of storage |
| Technology efficiencies | Changed the technologies efficiencies of the pathways to choose either the Best or Worst case. | Central case efficiencies | (1) Best case efficiencies<br>(2) Worst case efficiencies |

## Impacts of allocation method

A sensitivity has been performed on the allocation method used for the electrolytic hydrogen production pathways. A system expansion approach (following IPHE) has been used for the baseline and a sensitivity has been conducted with an LHV energy allocation approach (following EU RED, UK LCHS). The results from the sensitivity analysis are presented in the table below.

Table 8: Comparison of grid electrolytic hydrogen production emissions, $gCO_2e/MJ_{LHV}$ $H_2$, following different allocation methods (Central values, 2030 and 2050)

| Electrolyser pathway | System expansion | | Energy allocation | |
|---|---|---|---|---|
| | 2030 | 2050 | 2030 | 2050 |
| **AEL electrolysis** | 24.7 | 0.08 | 25.9 | 0.08 |
| **PEM electrolysis** | 23.9 | 0.08 | 25.1 | 0.08 |
| **SOEC electrolysis** | 37.8 | 18.7 | 38.9 | 18.7 |
| **AEM electrolysis** | 27.1 | 0.08 | 28.3 | 0.08 |

Following a system expansion approach, a credit is assigned to the oxygen co-product. This credit was based on oxygen production from an ASU and calculated as 1.2 $gCO_2e/MJ_{LHV}$ $H_2$ for 2030. This credit is subtracted from the total emissions from the electrolytic hydrogen production pathways. There is a nil credit applied in 2050 due to 100% renewables assumed for the 2050 Netherlands grid.

Following an LHV energy allocation approach, all the production emissions are allocated to the hydrogen because the oxygen co-product does not have an energy content.

The emissions intensities are therefore slightly higher in 2030 under an LHV energy allocation approach compared to following a system expansion approach because there is no longer a credit assigned to the oxygen co-product. There is no change in 2050 given the assumption that the Netherlands power grid runs on 100% renewables.

## Impacts of electricity decarbonisation scenarios

The impact of different electricity decarbonisation scenarios was investigated. Scenarios published by PBL and Aurora were used for this sensitivity.

- Aurora Central Scenario[113]: includes current planned pipelines for renewables and buildout of gas plants, alongside limited growth of electricity demand
- Aurora Net Zero aligned Scenario[114]: includes increased electrification and hydrogen as well as more renewables and phase out of thermal plants
- PBL Netherlands Environmental Agency Scenario[115]: 70% electricity production is renewable by 2030 and emission-free by 2050

The results from this sensitivity are presented in the figures below for 2030 and 2050.

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[113] Aurora 2021, Decarbonising the Dutch power sector.

[114] Aurora 2021, $CO_2$-free flexibility options for the Dutch power system.

[115] PBL 2022, Decarbonisation options for the Dutch onshore gas and oil industry.

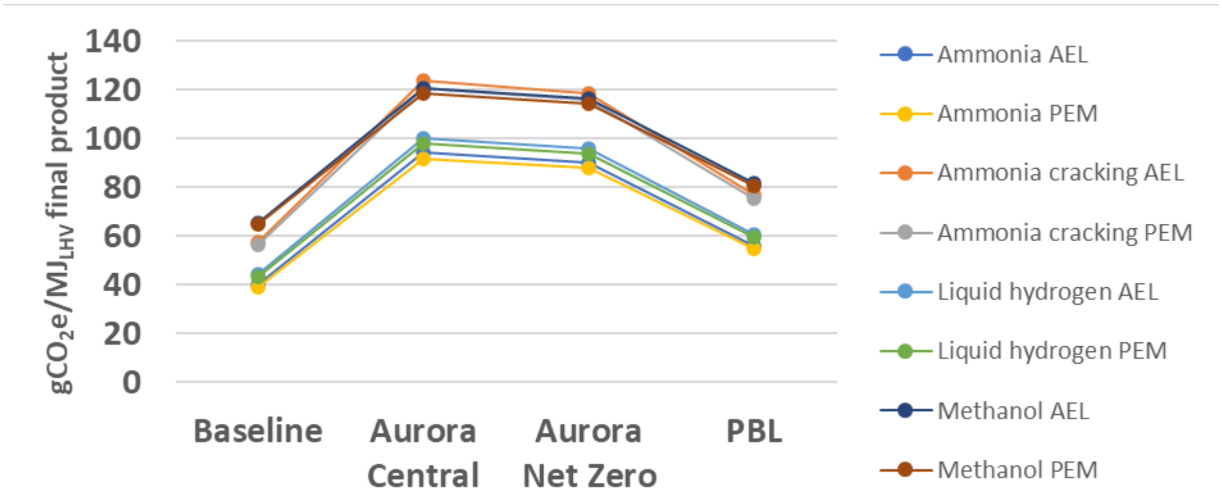

**Figure 27. Comparison of hydrogen production and distribution pathway emissions, gCO$_2$e/MJ$_{LHV}$ $H_2$ for different electricity decarbonisation scenarios (Central values, 2030)**

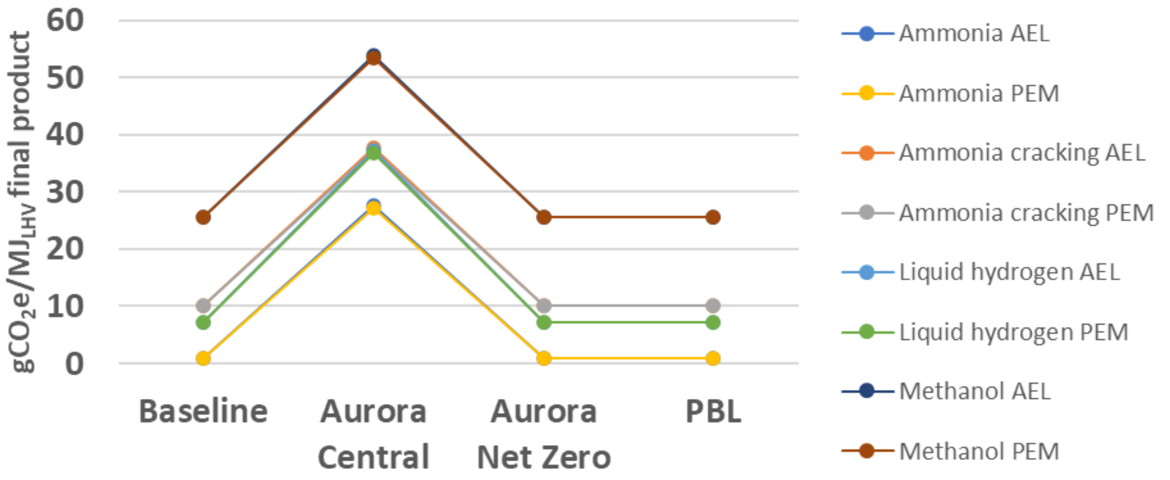

**Figure 28. Comparison of hydrogen production and distribution pathway emissions, gCO$_2$e/MJ$_{LHV}$ $H_2$ for different electricity decarbonisation scenarios (Central values, 2050)**

In the baseline, Aurora Net Zero and PBL scenarios, the Netherlands electricity grid was assumed to reach 100% renewables by 2050[7]. The Aurora Central scenario does not assume a grid carbon intensity of zero emissions has been reached by 2050 but does see a drop in emissions between 2030 and 2050 by ~70%.

The Aurora scenarios assume the highest grid intensities in 2030, almost double the grid carbon intensity of the PBL scenario. The different electricity decarbonisation scenarios in 2030, achieve a range of emissions results highlighting the impact of the electricity grid intensity on the hydrogen production and distribution emissions.

By 2050, the electricity grid is assumed to decarbonise to run on 100% renewables meaning there is no difference between using an AEL or a PEM electrolyser on the hydrogen production emissions. This is shown by the single overlapping lines for each distribution chain shown in the 2050 figure above.

## Impacts of natural gas decarbonisation scenarios

A sensitivity was performed on natural gas decarbonisation scenarios. In one scenario, it was assumed the upstream carbon intensity of natural gas reaches net zero by 2050[116] therefore only combustion emissions are accounted for in 2050. In the second scenario, fuel switching to biomethane was assumed therefore only upstream emissions were accounted for because biogenic combustion emissions are zero[117].

The same emission factor for natural gas was assumed in 2030 as the baseline therefore only the 2050 sensitivity results are presented below.

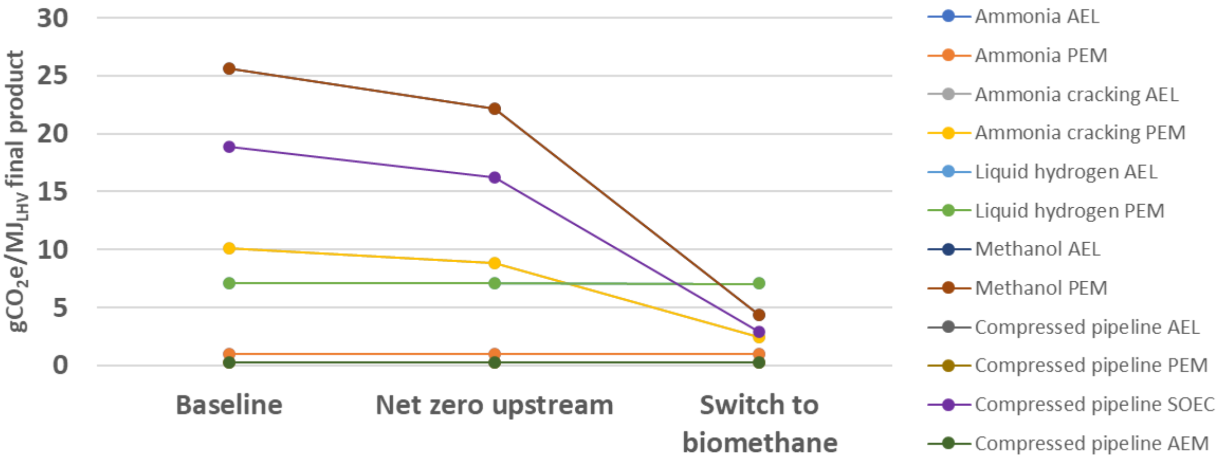

Figure 29. Comparison of hydrogen production and distribution pathway emissions for different natural gas decarbonisation scenarios (Central values, 2050)

The electricity grid is assumed to run on 100% renewables by 2050 therefore the production emissions using a PEM, AEL or AEM electrolyser are the same. Under the pipeline distribution pathway, the SOEC electrolyser production route which includes input of natural gas sees a reduction in GHG emissions as the gas network is decarbonised, while the other electrolyser routes using pipeline distribution remained the same. The compressed pipeline distribution chain has no natural gas input so all electrolyser routes that have no heat requirement (AEL, PEM, AEM) do not show any difference between sensitivities.

The gas input for the regasification step in the liquid hydrogen chain is very small (0.0012 MJ gas/MJ $LH_2$, accounting for <0.1 $gCO_2e/MJ_{LHV}$ $H_2$) therefore no difference was observed in the results between the different natural gas decarbonisation pathways. The heat requirement for cracking of ammonia to hydrogen and for $CO_2$ capture in the methanol production step leads to the significant drop in results between the baseline and the natural gas decarbonisation pathways for these two distribution chains.

The ammonia distribution chain does not require gas input therefore there is no difference in the emissions result across the different natural gas decarbonisation scenarios.

## Impacts of “all renewables” scenario by 2030

In the baseline, the electricity grid and transport modes (shipping and trucking) decarbonise over time. A sensitivity was performed for an “all renewables” scenario whereby the input power, heat and transport modes are all assumed to run on zero carbon sources by 2030.

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[116] IEA 2021, Net Zero by 2050 A Roadmap for the Global Energy Sector.
[117] JEC WTT v5 2020, Appendix 1_Pathways 2_CBM.xlsx.

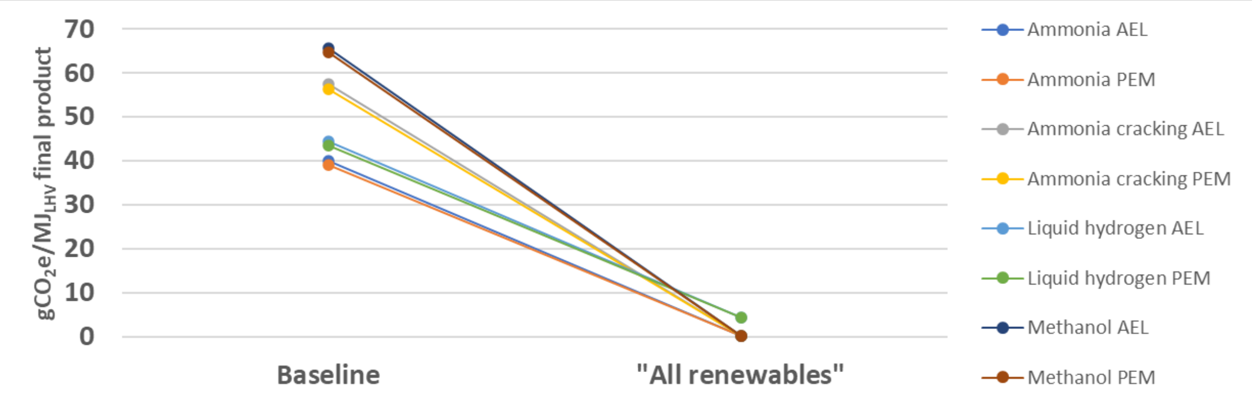

Figure 30. Comparison of hydrogen production and distribution pathway emissions for an "all renewables" scenario (Central values, 2030)

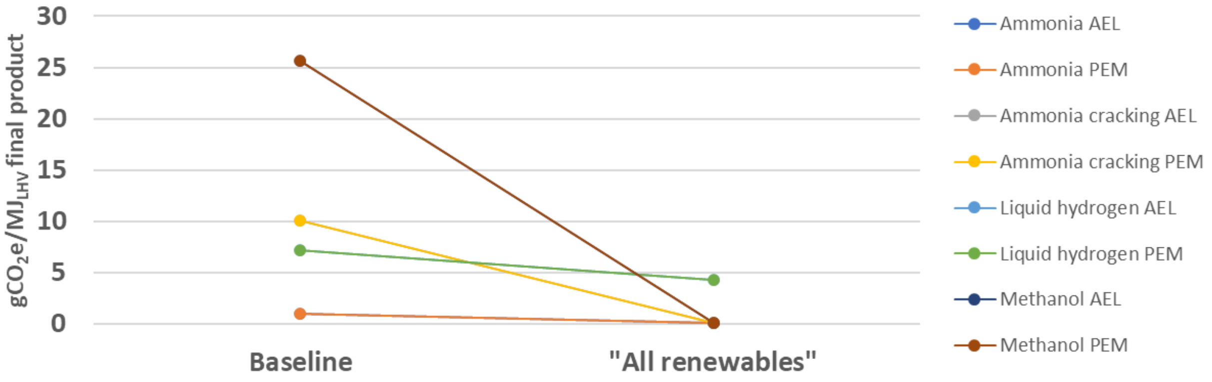

Figure 31. Comparison of hydrogen production and distribution pathway emissions for an "all renewables" scenario (Central values, 2050)

The results for 2030 and 2050 are the same in the "all renewables" scenario because it is assumed utilities and transportation have already decarbonised in 2030. After applying the sensitivity, there are no emissions from use of utilities (electricity/heat) and transport, therefore all emissions are due to the use of chemicals and water, as well as any fugitive hydrogen emissions from the distribution chains.

The fugitive hydrogen emissions from storage and transport of liquid hydrogen leads to this pathway having higher emissions compared with other pathways under this sensitivity.

As was the case for the sensitivity comparing different electricity decarbonisation scenarios, there are only single lines for each distribution chain in the 2050 figure above, as the grid is assumed to fully decarbonise by 2050 therefore there is no difference in hydrogen production emissions between using AEL or PEM electrolysers (i.e. the electrical efficiency of the electrolyser does not impact the production emissions).

## Impacts of storage time

In the baseline, it was assumed ammonia, liquid hydrogen and methanol are stored for 20 days[108]. A sensitivity was performed to understand the impact of the storage time on the total pathway emissions. The results from this sensitivity are presented below.

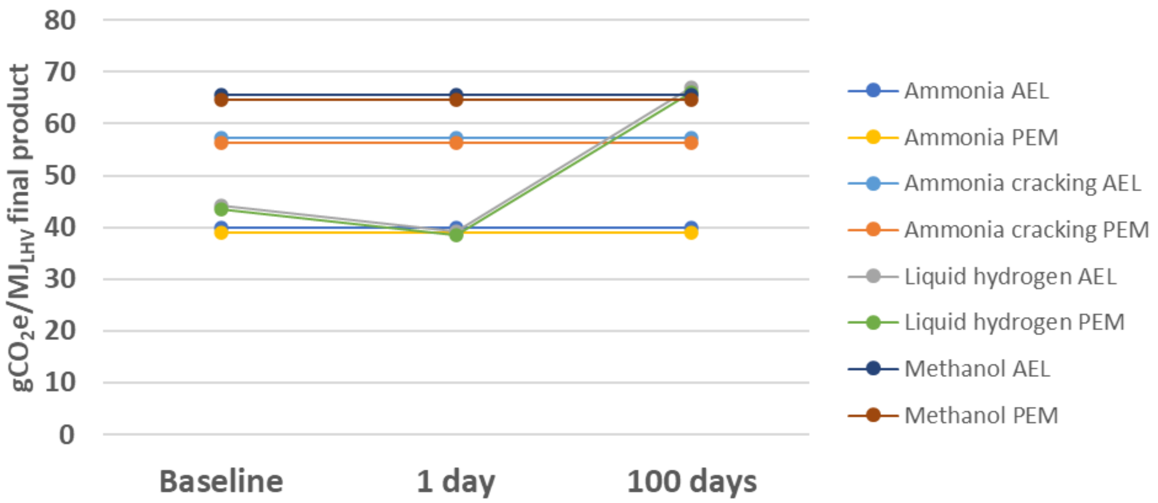

**Figure 32. Comparison of hydrogen production and distribution pathway emissions for different storage time scenarios (Central values, 2030)**

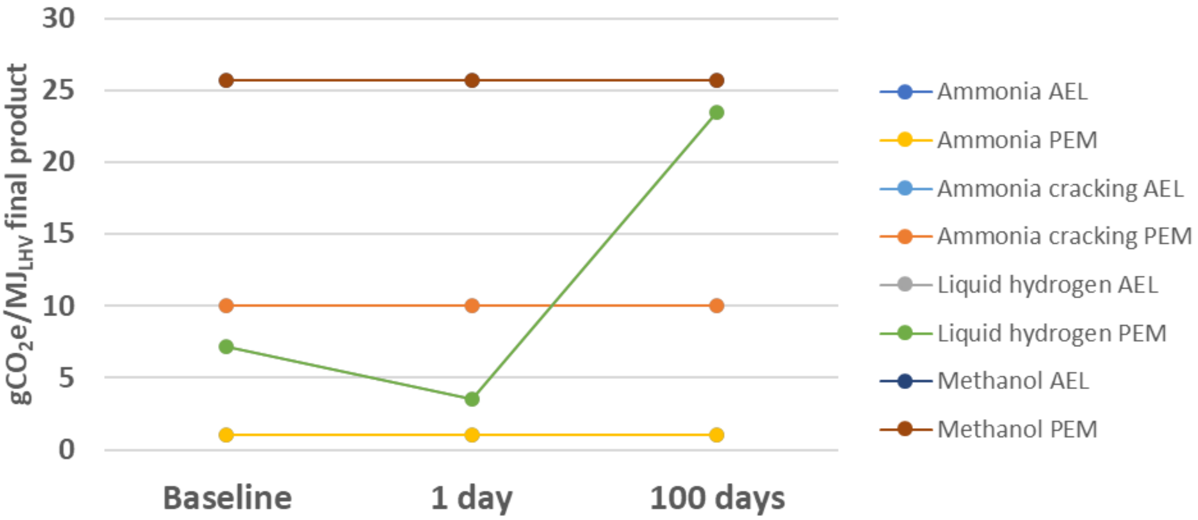

**Figure 33. Comparison of hydrogen production and distribution pathway emissions for different storage time scenarios (Central values, 2050)**

Adjusting the storage time to 100 days does not impact the results for the ammonia and methanol pathways because it was assumed there is no boil-off/efficiency losses during storage in the Central case for these distribution chains. The liquid hydrogen pathways show an increase of ~50% in the final emissions in 2030 when the storage time is increased from 20 days to 100 days. A boil-off rate of 0.1% is assumed in the Central case leading to fugitive hydrogen emissions contributing a significant portion to the total emissions.

There is no difference between the AEL and PEM electrolyser results for each distribution pathway in 2050 because the electricity grid is assumed to run on 100% renewables by 2050 therefore the AEL or PEM hydrogen production emissions are the same.

The distribution chains modelled do not include above ground gaseous hydrogen storage, but this would likely show some boil-off over time (less than liquid hydrogen storage).

## Impacts of transport distance

The impact of varying the transport distances for shipping and pipeline were analysed in this sensitivity.

In the baseline, it was assumed the final products from each pathway are shipped from Rotterdam to end users in the USA (9,300 km). This distance is in the range of shipping from Brazil, Gabon or Qatar to the Netherlands (8,600 – 11,800 km) which were locations investigated in the IEAGHG 2022 report[4]. The figures below show the impact of the shipping distance on the total pathway emissions.

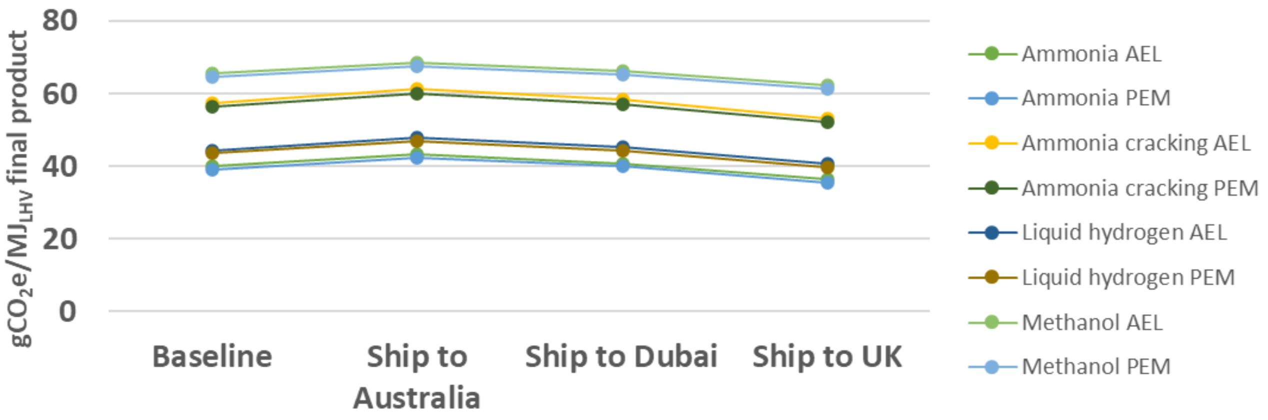

Figure 34. Comparison of hydrogen production and distribution pathway emissions using different shipping distances (Central values, 2030)

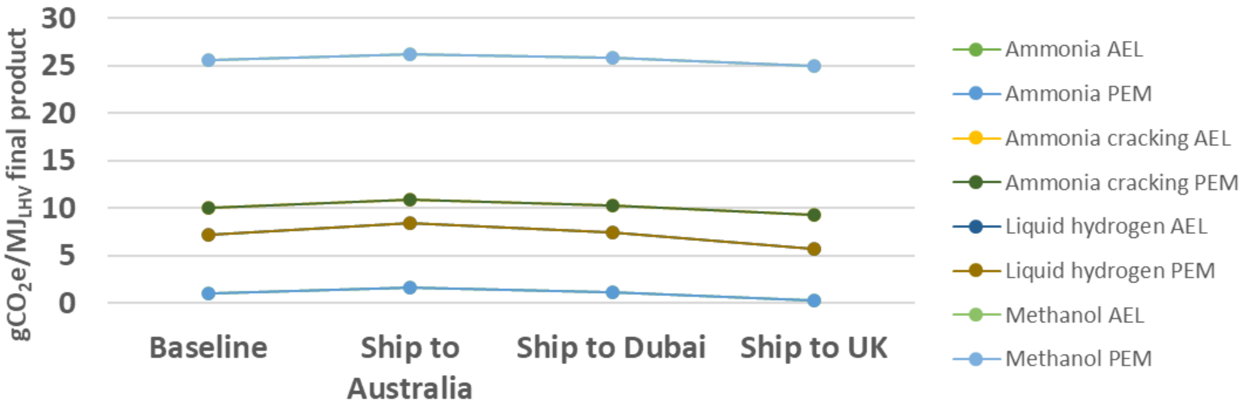

Figure 35. Comparison of hydrogen production and distribution pathway emissions using different shipping distances (Central values, 2050)

In 2030, the impact of longer shipping distance leads to higher fossil marine oil consumption, and higher overall pathway emissions.

By 2050, the substantial decarbonisation of shipping (following the IEA Net Zero by 2050[7] trajectory) means the distance sensitivity has a smaller absolute impact than in 2030. This is because there is only some residual use of fossil fuels in shipping. The remaining differences are larger for liquid hydrogen chains, due to the longer shipping distance resulting in higher liquid hydrogen boil-off.

Across the liquid hydrogen distribution chain, boil-off rates of 0.1-0.4%/day, 0.3-0.6%/day and 0.03-0.3%/day were assumed for shipping, transport and storage steps, respectively[108]. LNG carriers typically have a boil-off rate in the range of 0.1-0.15%/day[118] [119] [120]. To address these losses, effective storage systems will be required which will be costly[121], reflecting the challenges of liquid hydrogen distribution.

In the baseline for pipeline distribution pathways, it was assumed compressed hydrogen is piped from the Netherlands to the UK (400 km). The figures below show the impact of the pipeline distance on the total pathway emissions.

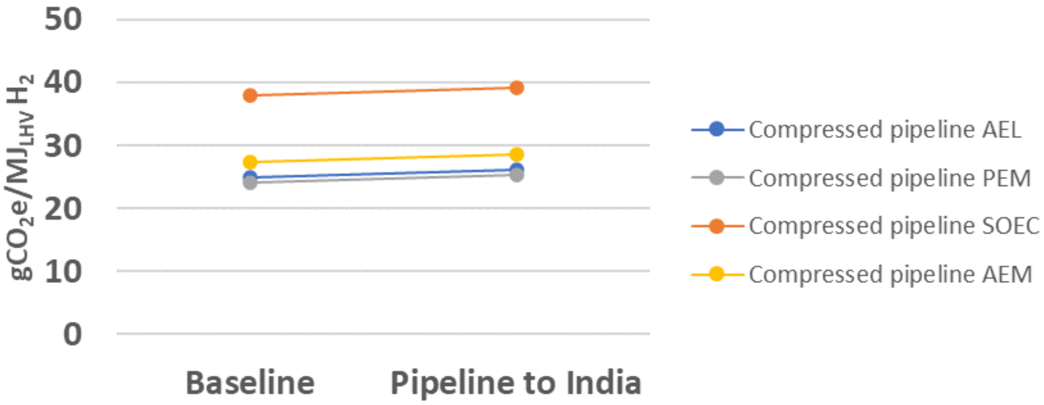

Figure 36. Comparison of hydrogen production and distribution pathway emissions using different pipeline distances (Central values, 2030).

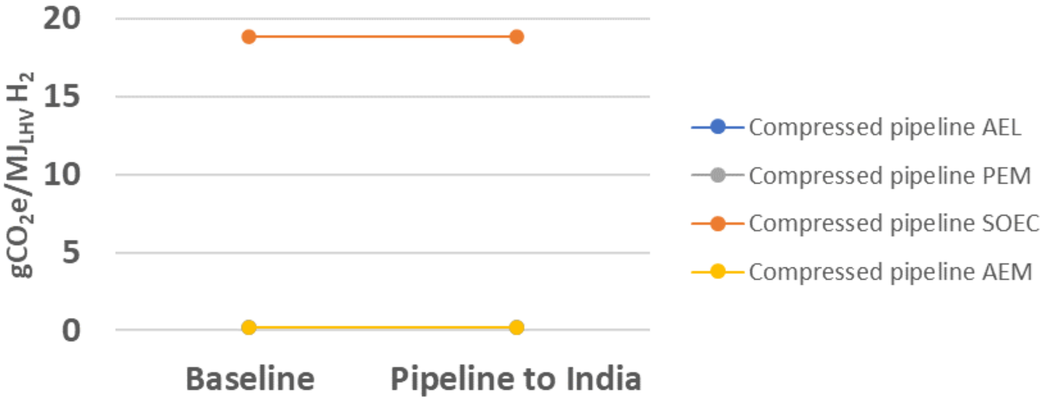

Figure 37. Comparison of hydrogen production and distribution pathway emissions using different pipeline distances (Central values, 2050).

The compressed pipeline distribution pathways only have a small electricity requirement and some fugitive hydrogen emissions therefore most of the total pathway in 2030 can be attributed to electrolytic hydrogen production.

In this sensitivity, increasing to 6,500 km of pipeline transport only shows a modest increase in emissions, due to a limited increase in power consumption and fugitive hydrogen emissions with the extra distance.

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[118] Wärtsilä 2023, Boil-off rate (BOR).
[119] DNV 2020, GIE database Liquid Renewable Energy.
[120] Aziz 2021, Liquid Hydrogen A Review on Liquefaction, Storage, Transportation, and Safety, page 19.
[121] Wärtsilä 2015, Creating Optimal LNG Storage Solutions.

By 2050, it is assumed the electricity grid (along the whole length of the pipeline) runs off 100% renewables therefore the total emissions for the AEL, PEM and AEM compressed pipeline pathways are close to zero. The heat requirement for the SOEC electrolyser results in this pathway having significantly higher emissions compared to the other electrolyser routes, particularly noticeable in 2050 when the grid is fully renewable.

## Hydrogen GWP

In the baseline it was assumed there are no fugitive hydrogen emissions from electrolytic hydrogen production, but fugitive hydrogen emissions are included in the distribution chains which assume a GWP of 11 $gCO_2e/g$ $H_2$ in the Central case. A sensitivity was performed on the GWP of hydrogen assuming electrolytic hydrogen production losses of 1% resulting from hydrogen/oxygen crossover, hydrogen purge and drying.[122] The percentage hydrogen losses from the distribution chains were kept the same as the baseline, but the GWP of hydrogen was varied. Three hydrogen GWP values were applied to account for uncertainties as noted in literature[123] and the results are presented in the charts below. The GWP sensitivities are compared to the baseline which assumes no fugitive hydrogen emissions from electrolytic hydrogen production.

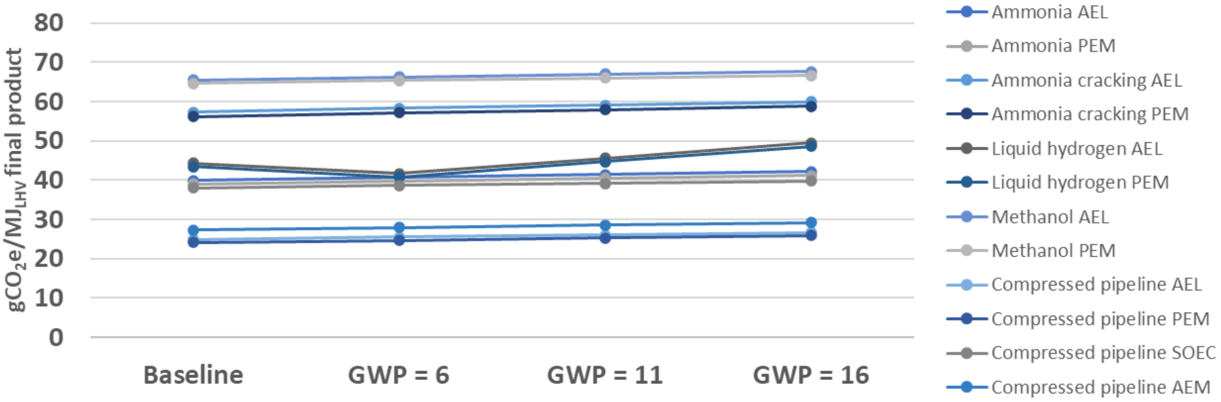

Figure 38. Comparison of hydrogen production and distribution pathway emissions using different hydrogen GWPs (Central values, 2030)

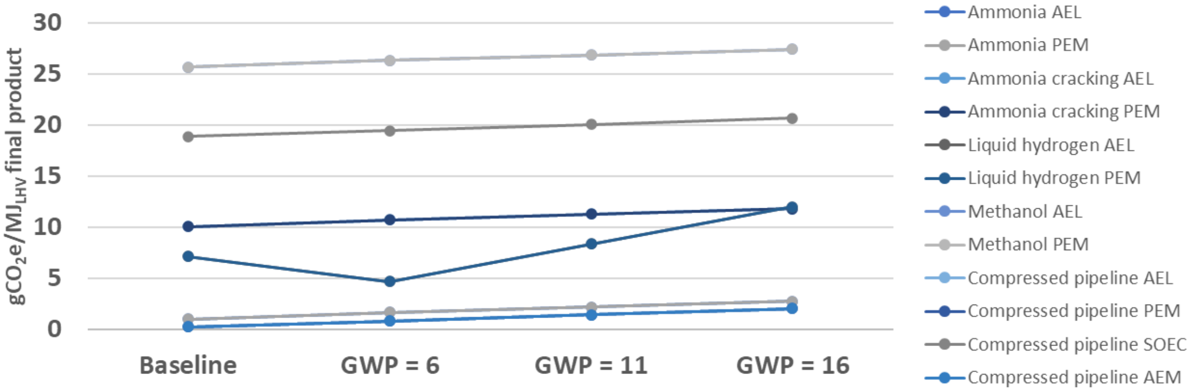

Figure 39. Comparison of hydrogen production and distribution pathway emissions using different hydrogen GWPs (Central values, 2050)

When a GWP of 6 $gCO_2e/g$ $H_2$ was used, there was a reduction in the total emissions for the liquid hydrogen distribution pathways compared to the baseline. In the baseline Central scenario, a GWP of 11 $gCO_2e/g$ $H_2$ is

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[122] US DOE 2021, H2NEW: Hydrogen (H2) from Next-generation Electrolyzers of Water Overview. Page 18 Calculated % losses using PEM electrolyser 2030 efficiency (50 kWh elec/kg $H_2$).
[123] BEIS 2022, Atmospheric implications of increased hydrogen use.

used and applied to the fugitive emissions from shipping, trucking and storage of liquid hydrogen. Despite now including fugitive emissions from electrolytic hydrogen production in the sensitivity, the lower hydrogen GWP used for the distribution chain in the first sensitivity (GWP = 6 $gCO_2e/g\ H_2$) results in overall lower emissions for the liquid hydrogen pathway.

Another sensitivity was performed on the fugitive hydrogen emissions to understand the impact of varying the percentage of hydrogen losses from fugitive hydrogen emissions in electrolytic hydrogen production. In the previous sensitivity, hydrogen losses of 1% were assumed and different GWPs of hydrogen were applied. For this sensitivity, a GWP of 11 $gCO_2/g\ H_2$ was assumed and the percentage of fugitive hydrogen emissions from losses during electrolytic hydrogen production was varied. The results of this sensitivity analyses are presented in the figures below.

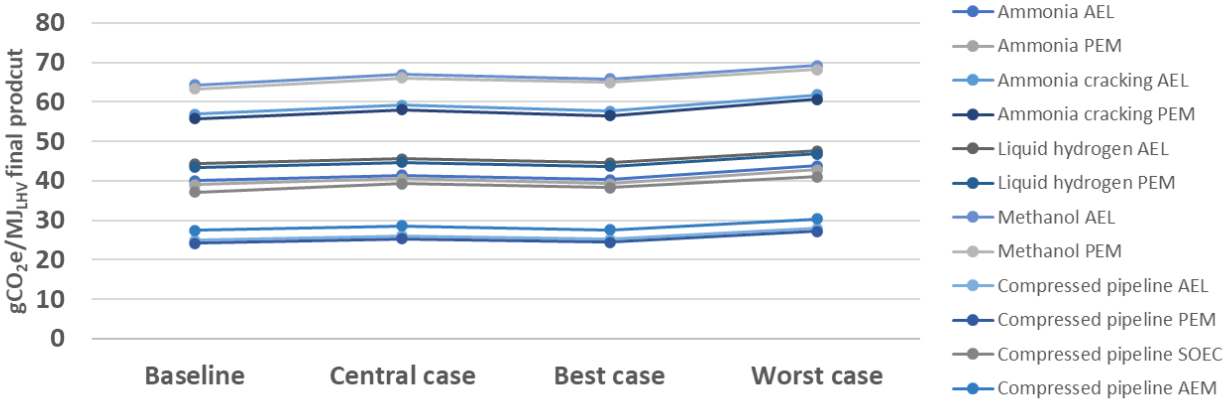

Figure 40. Comparison of hydrogen production and distribution pathway emissions assuming different fugitive hydrogen emissions from electrolytic hydrogen production (Central values, 2030)

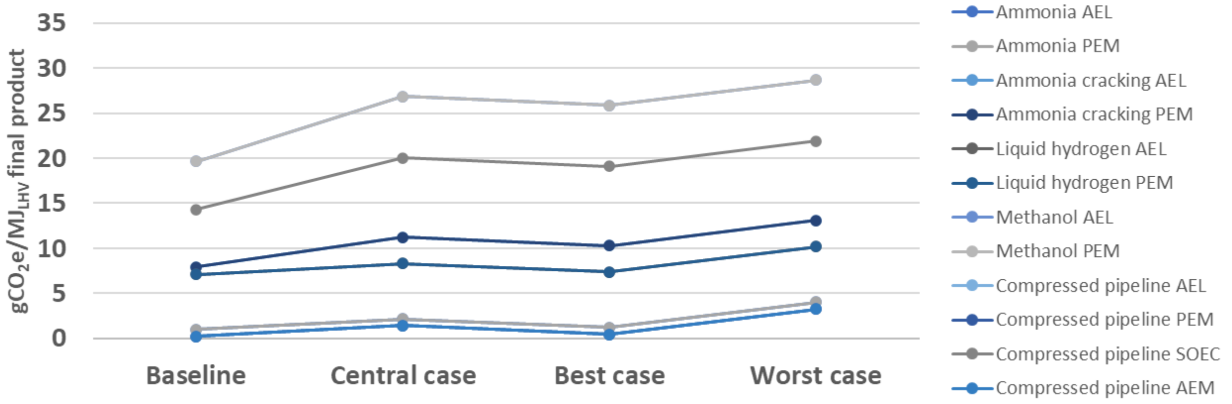

Figure 41. Comparison of hydrogen production and distribution pathway emissions assuming different fugitive hydrogen emissions from electrolytic hydrogen production (Central values, 2050)

The hydrogen losses assumed for the different cases were:

- Central case: 0.11 $gH_2$/MJ $H_2$[124]
- Best case: 0.02 $gH_2$/MJ $H_2$[125]
- Worst case: 0.28 $gH_2$/MJ $H_2$[61]

The sensitivity shows that fugitive hydrogen emissions, from electrolytic hydrogen production, can be significant. Compared to the baseline, hydrogen losses can add between 0.2-9.1 $gCO_2e/MJ_{LHV}$ $H_2$ to the total pathway emissions, depending on the losses assumed.

### Technology efficiencies

In the baseline, Central case efficiencies were used. The Best/Worst case efficiencies have been modelled in this sensitivity, including assumptions on hydrogen losses. Efficiencies related to the following steps were adjusted from their Central values:

- Electrolyser efficiencies as shown in Table 46 (in Appendix Section 9.5.1)
- Ammonia cracking (99-99.5%) and purification (85-91%)
- Methanol production (2030: 77-83%, 2050: 83% across all scenarios leading to no change in 2050 results between baseline and sensitivities)

The results from this sensitivity analysis are presented in the figures below.

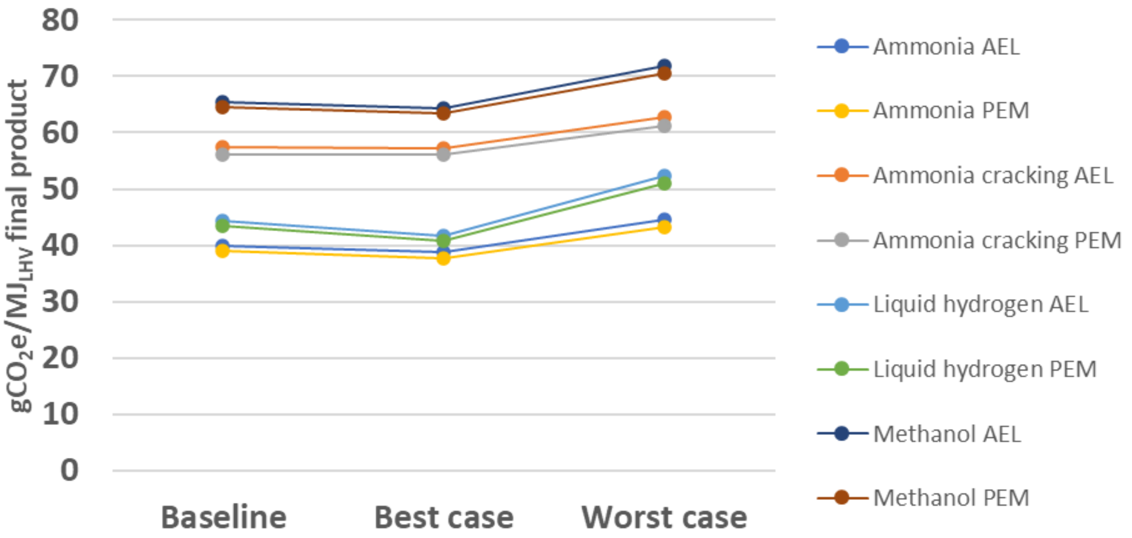

Figure 42. Comparison of hydrogen production and distribution pathway emissions from electrolytic hydrogen production assuming Best/Worst case technology efficiencies (Central values, 2030)

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[124] US DOE 2021, H2NEW: Hydrogen (H2) from Next-generation Electrolyzers of Water Overview. Hydrogen losses from H2/O2 crossover, H2 purge (LPHS) and O2 removal. Calculated percentage losses using PEM electrolyser 2030 efficiency (50 kWh/kg $H_2$)

[125] Frazer-Nash 2022, Fugitive Hydrogen Emissions in a Future Hydrogen Economy. Hydrogen losses with full recombination of hydrogen from purging and crossover venting (Best case – 0.24%). Hydrogen losses with venting and purging (Worst case – 3.32%).

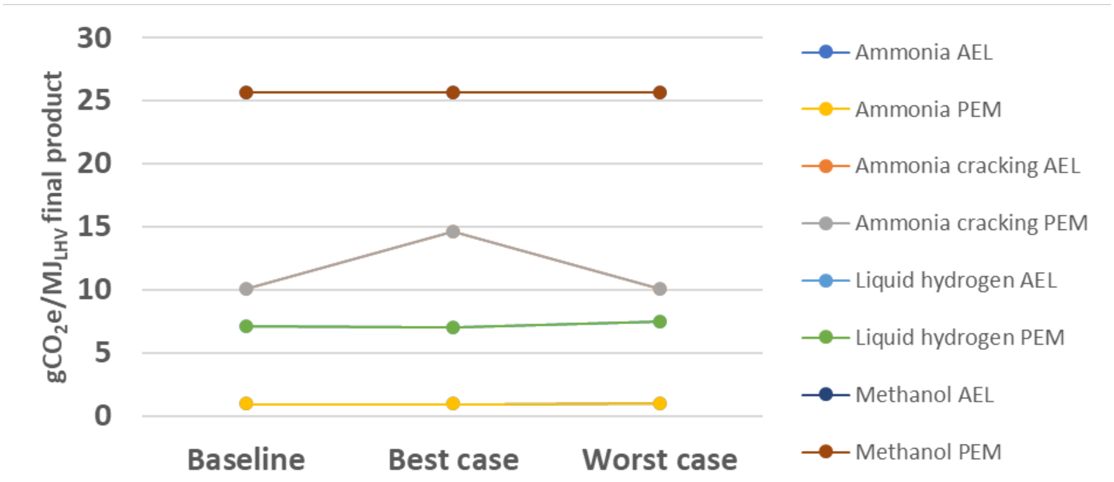

**Figure 43. Comparison of hydrogen production and distribution pathway emissions from electrolytic hydrogen production assuming Best/Worst case technology efficiencies (Central values, 2050)**

The largest sensitivity between the Best and Worst cases was found for the electrolytic efficiency, as this step contributes to a large portion of the total pathway emissions for these routes.

For the ammonia cracking pathway, taking the Best case efficiency results in higher total pathway emissions compared to the baseline. This is because the increased efficiency of the purification step leads to less co-product gas being produced and recycled back to the cracker, and therefore more natural gas input is needed to meet the heat requirement for the cracker. This results in higher emissions compared to the Baseline where more co-product gas is made (and less natural gas is consumed).

# 5 Water scarcity and water vapour’s global warming potential in a net zero scenario

## 5.1 Context

**Water scarcity is a global concern, only 0.5% of the world’s fresh water is available and usable[126] and 50% of the population experience severe water scarcity for some parts of the year**. Currently, approximately 4,000 billion[127] cubic metres of fresh water are withdrawn annually with agriculture accounting for approximately 70% of freshwater withdrawals[128]. Agriculture is also responsible for the bulk of water consumption, due to evaporation from land surfaces during irrigation and transpiration from plants[129]. Industry and primary power generation also contribute significantly to withdrawals, accounting for 12% and 10% respectively[128].

**Water stress is determined by both the demand and availability of acceptable quality water and is expected to increase in the twenty-first century[126].** Water demand is increasing globally. Withdrawal of blue water has increased by approximately 1% annually since the 1980s to meet demand in developing countries[129]. Additionally, the global population is estimated to increase by as much as two billion by 2050[130] which will inevitably raise the demand for drinking water as well as water for agriculture and industry.

**This increasing demand coincides with a decrease in the availability of freshwater; groundwater supplies are being systematically diminished by a rate of extraction at 1-2% per year globally**, outpacing the rate at which these supplies are being naturally replenished (recharge rates). The impact of recharge rates being outpaced is uncertain, but it may have a delayed impact with negative effects occurring hundreds of years from now[131]. The recharge rate is being outpaced is caused by (among other factors): inadequate water management practices, such as excessive extraction of groundwater for irrigation in arid regions; as well as the impact of rising sea levels which leads to salt intrusion into freshwater sources, heightening coastal flooding, and loss of freshwater ecosystems which act to purify and recharge groundwater sources. Beyond limiting water abstraction to equal natural recharge rates, novel groundwater recharge techniques are available to help manage water reserves sustainably. An example recharge technique is managed aquifer recharge (MAR)[132]. MAR involves injecting treated water into aquifers during period of low demand and extracting during periods of high demand. This is an effective buffer against fluctuations in water demand, drought and climate change.

**Even non-consumptive water withdrawal can have detrimental environmental impacts.** For example, the power sector accounts for approximately 10% of the water withdrawn annually but only 3% of water consumed (driven by the cooling requirements of thermal power plants)[129]. Although much of the withdrawn water is returned, it can be thermally polluted and damage the aquatic ecosystems of rivers and lakes it is returned to. These negative impacts can however be mitigated by appropriate wastewater treatments.

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[126] United States Bureau of Reclamation, Worldwide Water Supply. Accessed on 09/11/23.
[127] Our World in Data 2015, Water Use and Stress.
[128] IEA 2016, Special Report: Water-Energy Nexus.
[129] Ibid.
[130] United Nations, Population. Accessed on 09/11/23.
[131] Gleeson, T & Richter, B 2017, How much groundwater can we pump and protect environmental flows through time? Presumptive standards for conjunctive management of aquifers and rivers.
[132] Iowa State University 2021, Potential Adoption of Managed Aquifer Recharge Systems in the Corn Belt Region.

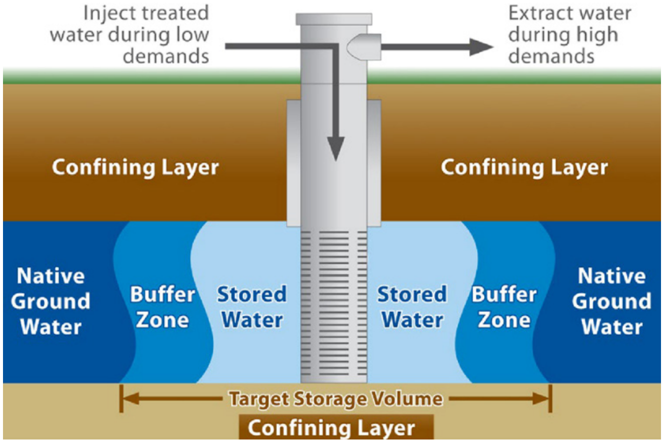

Figure 44. Managed aquifer recharge system (MAR)

## 5.2 Electrolytic hydrogen production's water consumption

### 5.2.1 Background: water requirements for electrolytic hydrogen production

Given the essential role of water as a feedstock in electrolytic hydrogen production, there are concerns that large scale electrolytic hydrogen production without appropriate, sustainable management may further increase water stress.

**An electrolyser splits water into oxygen and hydrogen using electricity:** $2H_2O \rightarrow 2H_2 + O_2$. Stoichiometrically, 9 kg of water is required to generate 1kg of hydrogen. However, in practice the demineralised water consumption of an electrolyser once stack losses are accounted for is typically quoted as approximately 10.5 kg ($H_2O$) / kg ($H_2$). Note this does not include BoP water demands such as cooling. As demineralised water must be produced from purifying feedstock water, the total input can range from 20-60 kg($H_2O$)/kg($H_2$) depending on the water source and BoP configuration. A high-level process flow of the water consumption from electrolysis and water production *via* hydrogen utilisation is shown schematically in the figure below.

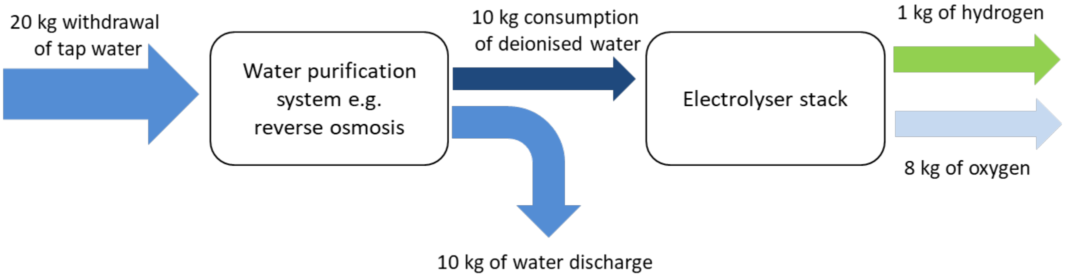

Figure 45. Demonstrative water flow diagram for electrolytic hydrogen production

Electrolysers require high purity water as impurities accelerate cell degradation, leading to a shorter electrolyser stack lifetime, which increases the LCOH through stack replacement and maintenance costs. Although all electrolyser technologies are sensitive to impurities in the water feedstock supply, PEM electrolysers are more sensitive than AEL electrolysers. PEM electrolysers are sensitive to metal deposition on the platinum cathode catalyst due to cation exchange for $H^+$, which deactivates the catalyst[133]. AEL are not as sensitive to cation impurities because anions, predominantly $OH^-$, are the main charge carriers. However, AEL are sensitive to anion and organic impurities[134].

Despite the demand for high purity water for electrolysers[135], the cost of water treatment (both CAPEX and OPEX) is typically low compared to the electrolyser plant as a whole, representing as little as 1% of the cost of hydrogen[136].

### 5.2.2 Water purification pathways

Water treatment facilities and electrolysers are typically co-located as transporting de-ionised water at scale is challenging. De-ionised water transported through pipelines is liable to pick up impurities from the pipelines, meaning further purification would be required on-site. Therefore, feedstock water is transported in its untreated form with purification systems typically co-located at the site of an electrolyser. Equally, storing large volumes of demineralised water is challenging and typically avoided; it is easier to store feedstock water to be converted to demineralised water with limited demineralised water buffer storage, for 1-2 days of water demand.

The initial water source determines both the ratio of feedstock water to electrolyser-ready, de-ionised water (as highlighted in the figure below) and the required treatment process. Groundwater requires treatment to remove chemicals including iron, manganese, and ammonium.

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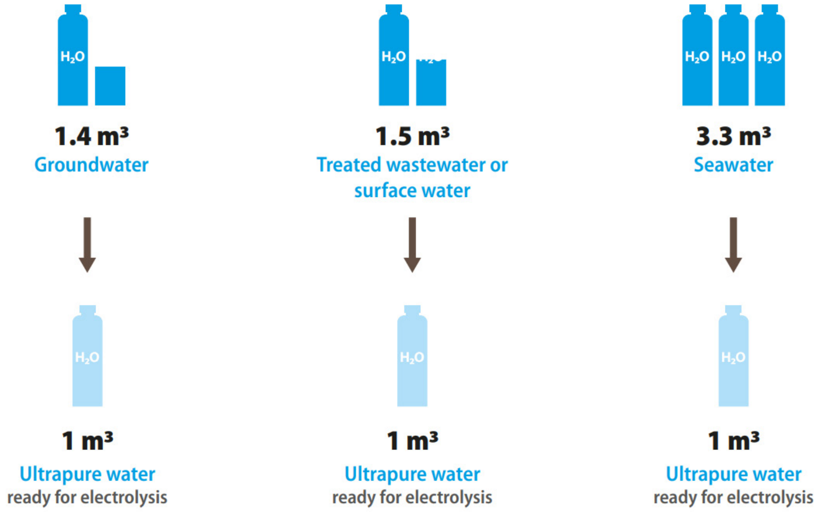
[133] Grace A. Lindquist, Qiucheng Xu, Sebastian Z. Oener, Shannon W. Boettcher 2020, Membrane Electrolyzers for Impure-Water Splitting.

[134] Becker. H et. al. 2022, Impact of impurities on water electrolysis: a review.

[135] Water treatment systems purify the water up to the American Society for Testing and Materials Type 2 (standard) for which water must have a resistivity of ≥1 MΩ cm at 25 C and TOC (total organic carbons) of <50 ppb. ASTM Type II Water

[136] Dokhani, S. 2023, Techno-economic assessment of hydrogen production from seawater.



© Silhorko-Eurowater

Figure 46. Estimates from Silhorko-Eurowater on feedstock requirements by source for the production of ultrapure water suitable for use in electrolysis[137]

**Recycling or reusing wastewater offers benefits,** from households reducing water and sewage costs to industrial wastewater management optimising resource-use efficiency and ground water replenishment at times of water surplus. Co-locating industrial wastewater treatment facilities and electrolysers can minimise water transmission costs and minimise water withdrawn by an electrolyser.

**Saline water can also be used as a feedstock.** Desalination, typically achieved using reverse osmosis, can produce water suitable for electrolysis[138]. This is a well-established technology with over 21,000 desalination plants globally[139]. It is also a low cost, low energy process; accounting for less than 1% of the total cost of hydrogen, desalination requires 0.003 kWh/kg($H_2O$)[139] which equates to approximately 0.1 kWh/kg($H_2$) and is negligible in the context of electrolysis requiring approximately 49 kWh/kg($H_2$)[140]. If an electrolyser's desalination plant is oversized, potable water can be produced in freshwater-scarce regions. Additionally, minerals such as sodium, chlorine, potassium, and magnesium may be extracted from the effluent to provide an additional revenue source. Desalination must be managed appropriately as effluent discharged with high mineral concentrations can create hypoxic conditions and damage aquatic ecosystems. As it must be diluted and oxygenated, synergies may arise with electrolytic oxygen being used to treat the effluent.

Upstream electricity generation and electrolyser BoP also impact life cycle water demands. Cooling water may be required in the electrolyser plant, with approximately 12.5 kg($H_2O$)/kg($H_2$) required depending on the plant configuration. As the electrolyser stack degrades, efficiency losses to increased heating of the stack increase cooling load.

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[137] Eurowater, Water treatment for green hydrogen. Accessed on 09/11/23.
[138] Beswick, R et. al. 2021, Does the green hydrogen economy have a water problem?
[139] Eyl-Mazzega, M & Cassignol, E 2022, The Geopolitics of Seawater Desalination.
[140] Clean Hydrogen Partnership 2024, Electrolyser targets.

### 5.2.3 Impact of upstream power production on water demand

**Large scale electrolytic hydrogen production will not be distributed evenly across the globe.** Green hydrogen will be most viable where there is co-location of low-cost renewable energy (PV or wind) and large demand or export opportunities. However, low-cost renewable solar energy is often located in water scarce regions[141,142], a potential issue for electrolytic hydrogen production. Although research to date on the impact of electrolytic hydrogen production on worsening droughts in water scarce regions is sparse, desalination and sustainable water abstraction processes are key tools to preventing worsening water stress in arid regions.

Electrolysers are commonly supplied with power from solar or wind assets, both of which have minimal water requirements. Other electricity sources have significantly higher water requirements with biomass generation having the highest water consumption, followed by fossil fuel and nuclear sources. Water consumption of various power generation method is shown in Table 9.

As part of this discussion, it is important to contextualise electrolytic water consumption within the large water consumption of incumbent fossil fuel energy generation. Where electrolytic hydrogen production is displacing these fossil fuels, and is coupled with renewable electricity generation, it has potential to reduce water consumption from power generation, as highlighted in the table below.

Table 9. Summary of water consumption of different power generation methods.

| Power generation method[143] | Water consumption /L.MWh$^{-1}$ |
|---|---|
| Biomass | 85,100 |
| Oil | 3,220 |
| Nuclear | 2,290 |
| Coal | 2,220 |
| Electrolytic hydrogen production[144] | 924 |
| Natural gas | 598 |
| PV | 330 |
| Wind | 43 |

### 5.2.4 Projections of water demand for electrolytic hydrogen production

**The literature available on water demand from large scale electrolytic hydrogen uptake is limited and does not form a reliable basis for analysis.** However, one paper considered the following thought experiment: a renewable hydrogen future consuming 2.3 Gt $H_2$ per year, assuming stoichiometric water consumption of 9 kg($H_2O$)/kg($H_2$) and renewable power generation, and concluded 0.0001.5% of the Earth's available freshwater would be required[138]. ERM modified the assumptions to an estimated global hydrogen demand in 2050 of 614 megatonnes/year[145] and a water consumption of 31 kg($H_2O$)/kg($H_2$). In the context of an estimated global consumption of water in 2050 of 6,000 billion m$^3$/year, this hydrogen economy would account for 0.3%[146] of the global water demand[147].

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[141] Green Hydrogen Projects will Stay Dry Without a Parallel Desalination Market to Provide Fresh Water, Rystad Energy
[142] For a map of water scarcity, see for example WWF Water Risk Filter - Maps
[143] Jin, Y et. al. 2019, Water use of electricity technologies: A global meta-analysis.
[144] Assuming raw water feedstock, a non-air cooled system and wind as electricity source, as in previous ERM study ERM 2022, HICP Water Study.
[145] S&P Global 2022, Global hydrogen demand seen at 614 million mt/year by 2050: IRENA. Accessed on 09/11/23.
[146] Using data from ERM's study on water consumption by hydrogen production pathway. Using results from the low case (17 kg($H_2O$)/kg($H_2$)) would account for 0.17% global water demand, and the high case (47kg($H_2O$)/kg($H_2$)) would account for 0.48%.
[147] Boretti, A. & Rosa, L. 2019, Reassessing the projections of the World Water Development Report.

Additional thought experiments were conducted to test the impact on water withdrawal of an extremely ambitious hydrogen uptake scenario[148]. In this analysis, it was assumed that hydrogen would displace the entirety of the existing energy supply. The water demand to do so was then compared to existing water withdrawals in each country. The countries where electrolysis would constitute the largest % of current water withdrawals are presented in Figure 47. It is important to note that whilst indicative of water withdrawals (and power consumption) in a region, this does not account for population/country size or imports of hydrogen. This study also assumes that hydrogen use is far more prolific than estimated under even the most hydrogen-leaning Net Zero scenarios. However, even within this context, this analysis concludes that in most cases, countries would not struggle to support the water demand for electrolysis. Further work is needed in this field to perform more robust studies on the impact of water consumption by electrolysis. In many cases, this is done as part of bespoke studies for specific electrolysis projects instead of at a global level.

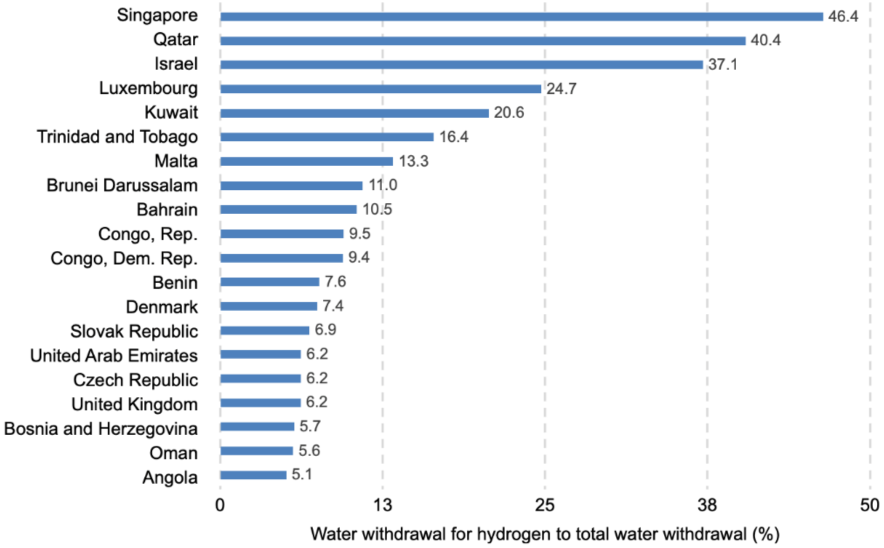

Figure 47. Water withdrawal for $H_2$ production as a % of total water withdrawal in a region, to support the full energy requirement of the country[148].

## 5.3 Impact of water vapour produced from hydrogen consumption

### 5.3.1 Background: Global warming potential of water vapour

In pursuing Net-Zero carbon emissions, it is crucial not to lose sight of the impact of other emissions, such as the emission of water vapour. The GWP of a gas is a measure of its ability to trap radiation emitted from the Earth. Assessing the GWP of a gas is challenging: altering the concentration of one gas in the atmosphere can impact the composition of other gases in the atmosphere; the geographical location and altitude at which gases are emitted effects both their lifetime in the atmosphere and impact on wider atmospheric chemistry; and in the case of water vapour, both the absorption of longer wave radiation from the Earth by water vapour and reflection of incoming radiation by clouds needs to be considered. The GWP of a gas is typically considered on a 20-to-100-year timeframe and is measured relative to carbon dioxide with a unit of $CO_2e$.

**Water vapour emitted on the earth's surface has a GWP of between -0.001 and +0.0005 $CO_2e$ based on a 100-year lifetime[149].** The small magnitude of water's GWP is due to several factors including: additional water vapour cannot reach the upper atmosphere; the short lifetime of water vapour in the atmosphere

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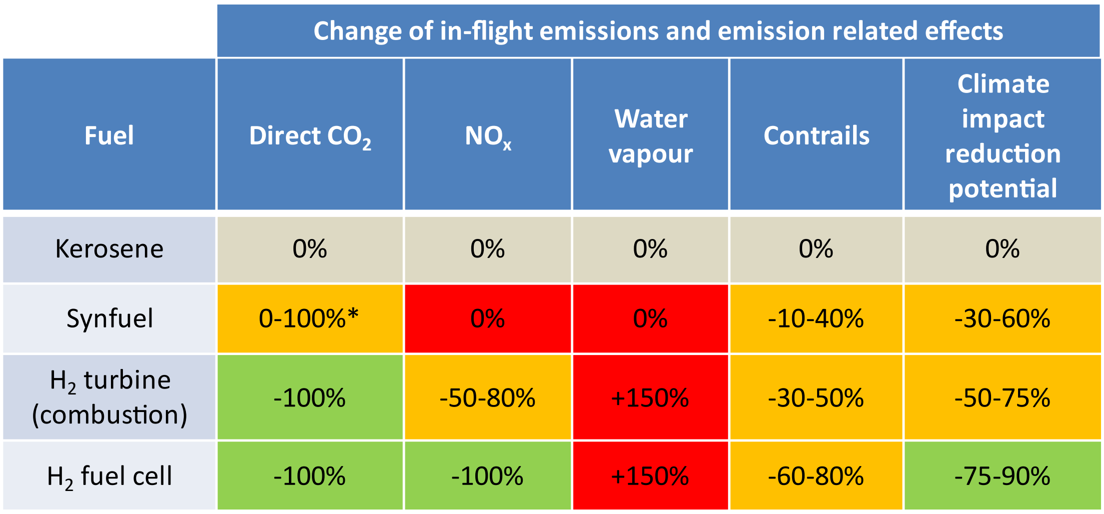
[148] World Economic Forum 2022, Will moving to a hydrogen economy affect water security?
[149] Sherwood, S. et. al. 2018, The global warming potential of near-surface emitted water vapour.

(approximately 10 days) due to precipitation; and cloud cover acts to reflect incoming solar radiation, mitigating warming effects from water vapour. However, at higher temperatures, the atmosphere can hold larger concentrations of water vapour. The warming associated with increased water vapour in the atmosphere is therefore part of a feedback loop between increased GHG emissions and global warming. Nevertheless, given the very low GWP of water vapour emitted at the earth's surface, and the very small amounts of water vapour emissions associated with electrolytic hydrogen production (compared to irrigation, for example), the impact is still negligible.

### 5.3.2 Case study: Hydrogen for aviation

When water vapour is emitted at altitudes >30,000 ft, the GWP increases. This is a typical cruising altitude for commercial flights. Contrails are produced by aircraft and are comprised of condensed water and ice (and soot in the case of fossil fuels). Although contrails are larger when produced by aircraft with hydrogen drivetrains than those produced from kerosene (the incumbent technology), they contain less ice which reduces their residency, and therefor GWP[150]. This is further reduced due to the high purity of water in contrails from hydrogen aircraft. Figure 48 shows that the use of hydrogen fuel cell technologies for aircraft could have a ~75-90% reduction of the climate impact of aviation.



| | Change of in-flight emissions and emission related effects | | | | |
|---|---|---|---|---|---|
| Fuel | Direct $CO_2$ | $NO_x$ | Water vapour | Contrails | Climate impact reduction potential |
| Kerosene | 0% | 0% | 0% | 0% | 0% |
| Synfuel | 0-100%* | 0% | 0% | -10-40% | -30-60% |
| $H_2$ turbine (combustion) | -100% | -50-80% | +150% | -30-50% | -50-75% |
| $H_2$ fuel cell | -100% | -100% | +150% | -60-80% | -75-90% |

**Figure 48.** ***Comparison of impact of hydrogen and synfuels to kerosene-powered aircraft[150, 151]. In this table, kerosene is defined as the baseline and the impact switching to an alternative fuel is shown relative to kerosene[152]; 0% indicates no change and -100% indicates complete elimination of an emission. *Dependent on the source of $CO_2$, it is -100% reduction if $CO_2$ is captured from air or from biogenic sources.***

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[150] Clean Sky 2 JU 2020, Hydrogen-powered aviation.

[151] Barcellona, S. 2022, Techno-economic review of hydrogen powered aircraft.

[152] The source data specifies ranges, to accommodate the variation in emissions reduction across a range of aircraft. The types of aircraft included in the study are commuter aircraft, regional aircraft, short-range aircraft, medium range aircraft and long-range aircraft. Climate impact reduction potential accounts for the emissions (various) reductions of a hydrogen powered aircraft as specified, when compared to a reference case of a kerosene fuelled equivalent aircraft.

# 6 Identification of conditions for valorisation of $O_2$

## 6.1 Context

**High purity oxygen is produced as a by-product of the electrolytic hydrogen production process**, and it offers an additional potential revenue stream to hydrogen producers. However, the current oxygen market is dominated by established players, largely producing oxygen with air separation adsorption units, pressure swing adsorption (PSA) or vacuum swing adsorption (VSA), and the market for ultra-pure oxygen is limited. This report will explore conditions which allow electrolytic oxygen to be valorised.

## 6.2 Oxygen value chain

The oxygen value chain is comprised of production, distribution, compression and storage, and an end user. This section of the report provides a brief overview of each stage of the value chain, and how electrolytic oxygen may fit into the current market.

### 6.2.1 Oxygen production

**Cryogenic separation** is the main oxygen capture technology in commercial use today. It exploits the incremental boiling points of air's constituent gases and can produce oxygen up to 99.8% purity for as little as 0.04 €/kg[153]. Further cost reductions may be achieved by exploiting the low temperatures of LNG regasification sites, analogous to exploiting industrial waste heat. Cryogenic production is ill-suited to being coupled to renewables due to its slow start up time. **PSA** is another common low-cost oxygen production method which exploits differences in the tendency to adsorb. However, the purity of oxygen produced, 92-95%, limits its application to industrial use cases. **VSA** is the other oxygen production technology which is deployed at scale. This method operates at atmospheric pressure, reducing power consumption by up to 50% compared to PSA[154], but also produces low purity oxygen suited to industrial applications such as steel manufacturing. There are novel oxygen production routes at varying stages of technology readiness, including **membrane separation and chemical looping**, which may also compete with electrolytic oxygen production in the market. Table 10 (below) summarises incumbent oxygen production technologies.

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[153] Gas Technology Institute 2018, Emerging and existing oxygen production technology scan and evaluation.

[154] Chem Europe, Vacuum swing adsorption. Accessed on 09/11/23.

**Table 10. Summary of oxygen production and capture methodologies. Sources referenced throughout text.**

| Name | Extent of use / technology readiness | Typical output oxygen purity | Output scale suitability | Production cost information |
|---|---|---|---|---|
| Cryogenic separation / air separation units | Established – main commercial technology in use by output | 99.8% | > 1000 tpd (tonne per day) | 0.04 €/kg |
| PSA | Established – commonly used for smaller scale facilities requiring onsite production | 92-95% | 100-300 tpd | Cheaper than cryogenic at small scale, become more expensive at larger scale. Costs reductions achieved through improvements in the zeolite |
| VSA | Established | 90-93% | 1-150 tpd | Cheaper than PSA |
| Membrane separation | Deployed with limited use | 99% | 10-25 tpd | 0.05-0.07 €/kg |
| Water electrolysis | Novel | 99.99% | Capped by electrolyser size | 2.92-5.84 €/kg |
| Cyclic auto thermal recovery | Pilot plant | Unknown | Unknown – pilot has 10 tpd output | Unknown |
| Vortex air separation | Novel | <80% | Unknown | Unknown |
| MOLTOX | Old but not used commercially | 95% | Unknown | Historically reported to have a 5-20% cost reduction versus cryogenic separation[155] |
| Chemical looping | Novel – multiple methodologies under research | Varied | Expected similar to PSA | Unknown |
| Advanced cryogenic air separation | Novel, not practically proven | Unknown as not tested practically | Unknown | Expected less than cryogenic separation due to reduced electricity consumption |
| Oxygen separation in a vortex tube with applied magnetic field | Novel, not being actively pursued at present | 42.1% | Unknown | Unknown |

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[155] Erickson, D C 1983, Oxygen production by the Moltox process. Final report.

Oxygen is a by-product of electrolytic hydrogen production; the process is illustrated in Figure 49[156]. A purity of 99.99%[157] is achieved, making it suitable for medical and other high grade use cases. However, applications requiring ultrapure oxygen have relatively low demand which is currently met through long-term partnerships with industrial gas incumbents157. The additional benefit from using ultrapure electrolytic oxygen in applications where this is not required, such as steel plants and glass manufacturing, is negligible. Relative to its purity, electrolytic oxygen has low production costs and is competitive with more traditional production methods. Oxygen production for medical use is estimated to become cost effective when the retail price is between 2.5 – 5 £/kg (3-6 €/kg)[10]. From the TEA conducted in Section 3, this price range is achievable (depending on connection type) by 2050.

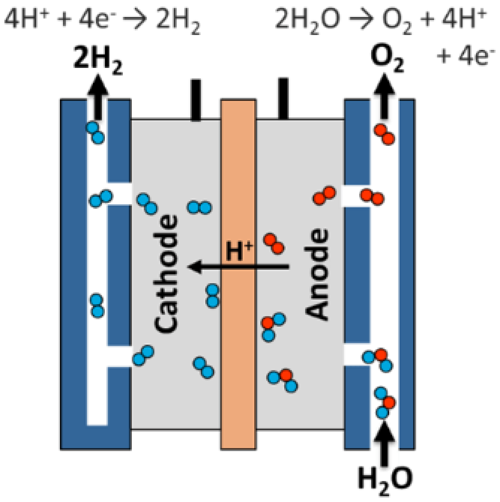

Figure 49. Oxygen production from a polymer electrolyte membrane electrolyser.

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[156] DOE Office of Energy Efficiency & Renewable Energy, Hydrogen Production: Electrolysis. Accessed on 09/11/23. 2
[157] E4Tech for Tatkraft 2020, UK e-methanol/hydrogen market analysis.

### 6.2.2 Oxygen distribution and storage

#### Distribution

**Oxygen is delivered either as a compressed gas or in liquid form.** Gaseous oxygen is mostly delivered by pipelines, typically over short distances within industrial sites; the total cost of an oxygen pipeline is typically 0.98-2.45 €M/km[158]. Electrolytic oxygen could be distributed via existing pipeline networks; however, this would introduce impurities to ultrapure electrolytic oxygen, negating a key benefit. To meet small scale demand, gaseous oxygen cylinders can be employed. Liquid oxygen can be used to deliver bulk or mini-bulk and can also be stored to contain deliveries or create a buffer in the case of onsite production[159]. Oxygen delivery is very expensive and represents around 40-50% of the delivered cost of oxygen. Onsite production minimising distribution and handling costs would be the most feasible deployment of electrolytic oxygen. However, this would have to compete with onsite production from an ASU which has a strong business case, with a payback period of only 9-18 months[158].

#### Safety considerations

Oxygen is a dangerous substance as its oxidising properties means it accelerates fire. It is therefore regulated by the European agreement concerning the international carriage of dangerous goods by road (ADR). This contributes to high costs and logistical difficulties of road transport. Oxygen pipeline transport removes the logistical challenge of transporting a dangerous substance by road.

| Technology | Oxygen state | Typical scale | Use case description |
|---|---|---|---|
| **Pipeline** | Compressed gas | Industrial – 5-2000 tonnes / day | • Used either to connect on-site production with a consumption point, or to connect a neighbouring industrial facility producing the $O_2$ |
| **Bulk** | Liquid | 250 – 500 kg / day | • A vacuum insulated storage tank is installed at the customer site, and filled by a road tanker either at regular intervals or by the order |
| **Mini-bulk** | Liquid | 50 – 250 kg / day | • As for bulk, except when consumption is smaller, and refilling tends to be more ad hoc<br>• Typical of hospitals / laboratories |
| **Cylinder** | Compressed gas | Low – less than 50 kg / day | • Customer either collects themselves or arranges delivery, typically for miscellaneous uses<br>• Around 600 outlets in the UK |

Figure 50. Oxygen distribution summary.

#### Storage

On-site buffer storage would be required if an electrolyser was coupled to renewables with a variable power output supplying oxygen to a user with constant demand; oxygen is typically stored as a liquid as it is cheaper and occupies a smaller footprint than compressed gas storage.

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[158] Gas Technology Institute 2018, Emerging and existing oxygen production technology scan and evaluation. 8

[159] Berenschot 2019, Oxygen synergy for hydrogen production.

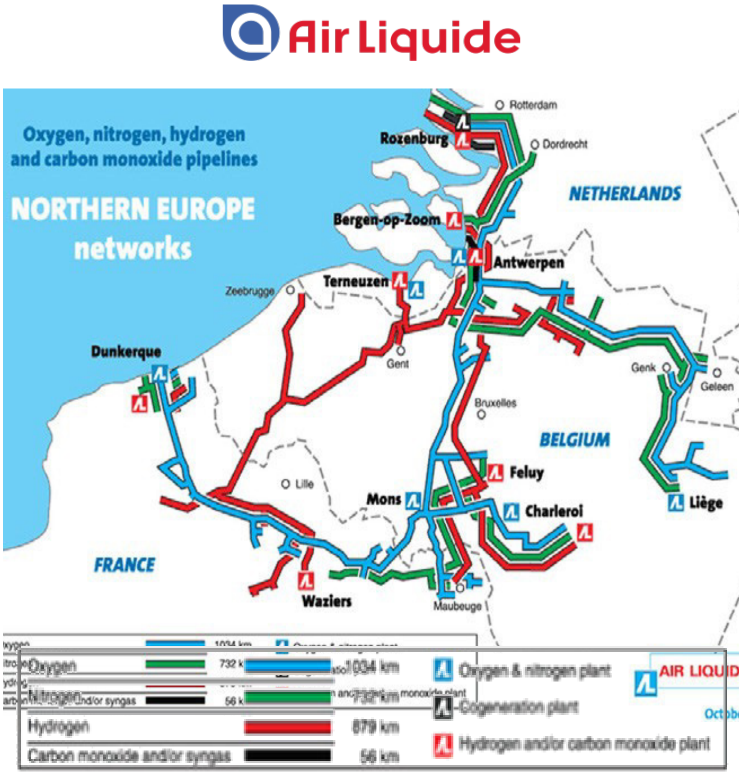

Figure 51. Air Liquide's existing European gas pipeline network[160].

Liquid oxygen can be used to deliver bulk or mini-bulk and can also be stored to contain deliveries or create a buffer in the case of onsite production[159] (see Figure 50). Onsite buffer storage would be required if an electrolyser was coupled to renewables with a variable power output supplying oxygen to a user with constant demand; oxygen is typically stored as a liquid as it is cheaper and occupies a smaller footprint than compressed gas storage.

### 6.2.3 Oxygen compression

The outlet pressure of oxygen produced via electrolysers is similar to the hydrogen outlet pressure and is dependent on the electrolyser technology employed; AEL have an output range of up to 30 bar and PEM electrolysers have an output of 30-70 bar. As different use cases require different pressures, a compressor may be required (e.g., industrial users require up to 65 bar[10]). Oxygen compressors are a well-established technology: many large manufacturers sell oxygen compressors which are suitable and safe for handling large volumes of oxygen.

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[160] Emerging and existing oxygen production technology scan and evaluation, Gas technology institute, April 2018

## 6.3 Use cases for oxygen

Currently, oxygen is used by multiple end users, including healthcare, metal manufacturing and in the chemical industry. The global oxygen market is forecast to increase from $34.8 billion USD in 2022 to $39.3 billion USD in 2023 driven by increased demand from the healthcare[161].

Although there is geographical variation, a large proportion of oxygen is consumed by the steel and metals sector, with the total ranging from c.40-65%, depending on source and country. The chemical sector also represents a large demand, and accounts for 7-20% of oxygen consumed. Globally, the healthcare sector is estimated to consume roughly 10%, however this varies significantly by country. These distributions are shown in Figure 52.

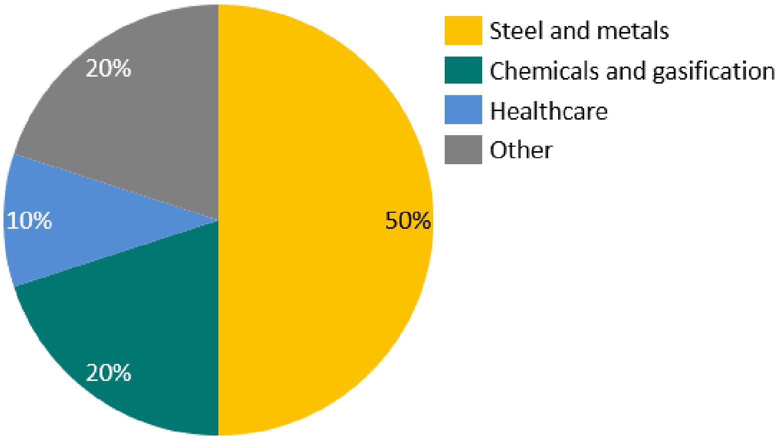

Figure 52. Breakdown of global oxygen consumption by sector[162].

### 6.3.1 Electrolytic oxygen valorisation

Electrolytic oxygen may have some advantages over other oxygen sources. For example, synergies between oxygen and hydrogen users may improve the business case as industries such as refineries have demand for both gases and represent an end user with large scale demand. Further, electrolysers can produce high pressure oxygen, as required by refineries, minimising the need for compression. If an electrolyser can be co-located with industrial demand sources, the significant distribution costs are minimised. However, oxygen from an onsite ASU also has a strong business case, with a payback period of only 9-18 months[163].

As highlighted, a key distinction of electrolytic oxygen is its high purity, which makes it well-suited to the medical sector where it is largely used in ventilators. Onsite oxygen production for healthcare would remove the need for expensive distribution by road and would allow for increased flexibility. Studies have shown that this is a cost competitive route to source oxygen for healthcare[10] and the incumbent supply option (expensive bulk road tankers) may be displaced by onsite electrolytic oxygen production coupled with low-cost renewables such as PV[10,164]. However, applications requiring ultrapure oxygen have relatively low demand, which is currently met through long-term partnerships with industrial gas incumbents[157].

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[161] The Business Research Company, Oxygen Market Size, Trends and Global Forecast To 2032. Accessed 09/11/23.
[162] Cioli, M. et. al. 2021, Decarbonisation options for the Dutch industrial gases production.
[163] Kornbluh 2019, High volume oxygen.
[164] Gasworld 2020, Understanding medical oxygen.

Oxygen valorisation is gaining attention to improve the business case of water electrolysis. For example, Shell’s Holland Hydrogen, a 200MW electrolyser planned to enter into operations in the second half of the 2020s, is looking to deliver both waste heat and electrolytic oxygen to industry[165]. Horizon Europe opened a call for the “Valorisation of by-product $O_2$ and/or heat from electrolysis.” This had a value of €195mn and was open to electrolyser projects at a scale of more than 15 MW[166].

The opportunities for electrolytic oxygen to be deployed are summarised in Table 11. This is colour coded to highlight the most promising use cases.

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[165] Shell 2023, Shell Holland Hydrogen 1.

[166] Ministere de L'ensignement Superieur et de la Recherche 2023, Valorisation of by-product O2 and/or heat from electrolysis.

Table 11. Summary of oxygen demand by sector, highlighting the potential deployment of electrolytic oxygen.

| Sector | Opportunities | Challenges | Typical Scale of $O_2$ consumption | Suitability to electrolytic oxygen |
|---|---|---|---|---|
| Refining | • Consumers of both oxygen and hydrogen in large volumes<br>• Existing distribution infrastructure | • Demand from refining anticipated to stabilise between 2030 & 2040[167]<br>• Decarbonising impact on a carbon producing industry limited in the long term | 180 k tonnes/annum | Strong business case, particularly for refineries in industrial clusters which can export any excess oxygen |
| Healthcare | • Requires high purity $O_2$ as produced via electrolysis<br>• Demand is predicted to continue to grow (fastest growing in Asian-Pacific market)[168] | • Disaggregated demand<br>• Low demand (comparative to refining)<br>• Licence required to supply medical $O_2$ | 200 tonnes/annum for one hospital with 200-250 beds[169] | For large hospitals there is a strong business case |
| Steel | • Large volumes of $O_2$ required<br>• Where hydrogen direct reduction (HDR)[3] is used, both hydrogen and oxygen demand could be supplied by electrolysis | • Large existing supply delivered by incumbent players or through on-site production<br>• Little advantage to using ultrapure $O_2$ | Up to 200 k tonnes/annum | While hydrogen direct reduction (HDR) may have a business case for future sites, performance improvements from using ultrapure $O_2$ may not be sufficient to incentivise electrolytic $O_2$ |

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[167] McKinsey 2022, Refining in the energy transition through 2040.
[168] Mordor 2023, Oxygen Market Size & Share Analysis.
[169] By country number of beds per 1000 people ranges between 0.5 – 8 globally, meaning the potential demand varies by population and the set-up of the country's healthcare system

| | | | | |
|---|---|---|---|---|
| Chemical Manufacture | • Many markets, with potential to grow in proportion to the biofuel market | • Market is fragmented i.e. not concentrated in one area<br>• Unclear as to benefits of high purity $O_2$ | Large variation in scale, potentially as high as 500 k tonnes/anum | Large scale demand could be seen from biofuel production facilities<br>Benefit of ultrapure $O_2$ unclear |
| Pulp/paper | • High volumes of $O_2$ required | • Low purity requirements, meaning that the additional cost of electrolytic $O_2$ is not counteracted by efficiency gains<br>• Larger plants have existing on-site production | 20 k tonnes | 20 k tonnes<br>Weaker business case |
| Mining | • Remote location could make on-site electricity generation powered electrolyser viable | • Minimal gain from using high purity oxygen<br>• Oxygen already provided by on-site ASUs at low cost | 90k tonne / annum / large mine | Weaker business case |
| Glass | • Large volume required | • Stable or decreasing demand | 1000-2000 t / annum | Weaker business case |
| Water treatment/aquaculture | • Potential synergies with use of other hydrogen fuelled technologies along the value chain (e.g. vessels, use case dependent) | • Low volume required<br>• Existing players offer end-to-end solutions for water purification, including oxygen equipment supply | 120 tonnes / annum | Weaker business case |

🟩 Good potential 🟨 Some potential 🟧 Low potential

### 6.3.2 Quantifying valorisation

#### Impact on techno-economic results from Section 3

Currently, literature on the impact valorisation of oxygen may have on LCOH is limited, with few available studies. However, one study considered hydrogen production from both electrolysis and autothermal reforming (ATR) (a process requiring oxygen) to investigate if there was a use case for electrolytic oxygen in this scenario. It found that capturing electrolytic oxygen allowed the incumbent ASU to be downsized and resulted in a 0.02-0.07 €/kg $H_2$ reduction in LCOH[170].

To test the impact of $O_2$ valorisation on the economics of electrolytic hydrogen production, we incorporated it into our TEA results from Section 3. If an average price of $O_2$ of 0.073 €/kg $O_2$ is considered[170], this equates to a value of 0.584 €/kg $H_2$ (8 kg $O_2$/kg $H_2$ produced). As $O_2$ sales value varies by use case, as do delivery costs, if we assume the lower end of delivery costs estimates equivalent to 40% of the value of the delivered $O_2$[170]. This is likely an over-estimate, but since little data is available for other costs associated with oxygen by end use case this will be used to form a high-level estimate of total costs involved in valorising oxygen. This results in a remaining net profit per for $O_2$ valorised of ~0.35 €/kg $H_2$. This margin does not include efficiency losses, storage costs and other factors which may drive the LCOH down but acts merely as a tool to best understand scenarios which are attractive for $O_2$ valorisation.

We can then consider the impact of this as a percentage reduction to total LCOH across each scenario and technology. As the value of $O_2$ is set independent of other LCOH cost components i.e. the revenue generated per kg of $H_2$ is the same regardless of the scenario, the business case for $O_2$ valorisation is best where hydrogen costs are low and high volumes of oxygen can be produced (generating larger total revenues). Where only small amounts of oxygen are produced, as would be the case from small electrolysers or electrolysers with low LFs, despite generating significant revenue on an LCOH basis, the total revenue generated may not reach the threshold to justify investment in the technologies and systems required to valorise and make competitive electrolytic oxygen.

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[170] The case considered most similar to ERM's TEA assumed a new 250 MW electrolyser, coupled with dedicated offshore wind, with oxygen was liquefied following production and an electricity cost of 44 €/MWh. This resulted in a 0.07 €/kg reduction.

# 7 Comparative Analysis of Electrolytic Hydrogen Production with CCS Abated Hydrogen

## 7.1 Studies for comparison

To better demonstrate the implications of the results of the TEA and life cycle GHG assessment conducted as part of this study, a comparison against other low-carbon $H_2$ production methodologies was undertaken. The literature search focused on specific and detailed comparison of academic and industry results against previous IEAGHG studies on blue hydrogen. This comparison enables the results from this analysis to be contextualised through understanding the implications of different assumptions, model boundaries, and scenarios for hydrogen production pathways. This analysis was performed by comparing quantitative outputs from this study, the available literature and the previous IEAGHG studies. Differences and limitations across studies were examined and are discussed in the following sections.

### 7.1.1 Introduction to 'Blue Hydrogen: Beyond the Plant Gate' Study

The IEAGHG's 'Blue Hydrogen: Beyond the Plant Gate' study[4] aimed to compare the deployment of blue hydrogen production from oil and oil-based feedstocks with current technologies that are based on natural gas. The oil-based hydrogen production technologies that were analysed in the study were Steam Naphtha Reforming (SNR), Partial Oxidation (POX), and Hygienic Earth Energy (HEE).

**SNR** – Steam naphtha reforming converts naphtha into hydrogen via reforming using the same configuration as conventional Steam Methane Reforming (SMR) which is a common route to produce hydrogen from natural gas. There has been growing interest in the replacement of natural gas with an oil-based feedstock such as naphtha in recent years [171]. There are currently no SNR facilities that operate with CCS, but this could be integrated into the production process.

The naphtha feed is produced from crude oil distillation. A pre-treatment stage is used to remove impurities from the naphtha feedstock which is then fed through a pre-heater and pre-reformer alongside a recycled hydrogen stream. The energy required for the pre-reformer depends on how heavy the oil-based feedstock is. Heavier hydrocarbons are converted to methane, hydrogen, and carbon oxides. Methane is reacted with steam in the presence of a catalyst to produce hydrogen and carbon oxides (mainly carbon monoxide). The reaction is endothermic meaning that heat must be supplied for the reaction to proceed. The carbon monoxide and steam are combined to produce carbon dioxide and hydrogen via the water-gas shift reaction. PSA is used to remove carbon dioxide and other impurities from the gas stream to produce pure hydrogen.

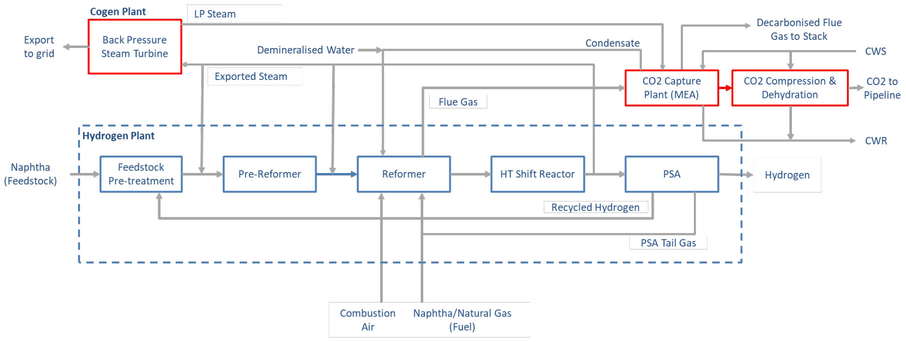

Figure 53. SNR process flow (adapted)[172].

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[171] El-Shafie et al 2019, Hydrogen Production Technologies Overview

[172] IEAGHG 2017, Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS

**POX** – Partial oxidation involves gasification of both liquid and gaseous feedstocks at very high temperatures (1,300-1,500 °C) in the presence of oxygen and steam. POX was traditionally used in refineries to produce syngas from heavy hydrocarbon feedstocks[173]. There is no catalyst requirement for the POX process and a wide range of feedstocks can be processed without requiring pre-treatment. The oxygen supplied to the process is usually produced via an ASU. Oxygen with a purity of >99% is typically used to enhance process efficiency, hence it is a significant energy requirement of the process. The process is exothermic therefore there is no additional heat input required and compared to SMR, the POX process occurs at higher pressure and temperature which can reduce downstream compression requirements.

The syngas exiting the POX reactor is fed through the water-gas shift reactor to convert carbon monoxide into hydrogen. The hydrogen is purified using a methanation step to achieve purities of 95-97%. For higher purities, a PSA can be used to achieve hydrogen purities of 99.999%.

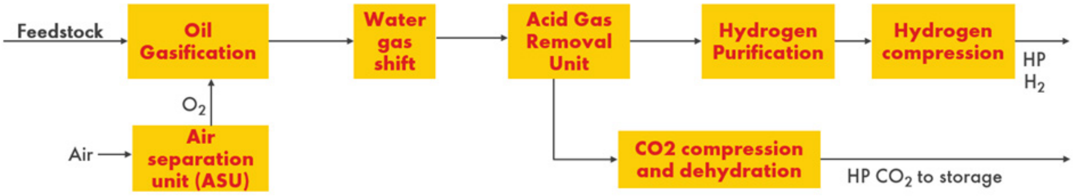

Figure 54. Shell Gasification Process (SGP) blue hydrogen production process[174].

**HEE** – Hygienic Earth Energy is a process patented by Proton Technologies[175] in which high purity oxygen is injected deep into hydrocarbon reservoirs whilst pure hydrogen is harvested through a selective membrane. The patented “Ox-injection” and “Hygeneration” wells inject oxygen and extract hydrogen, respectively. This technology is currently at TRL 4-6 and has been tested with success in laboratories and in the field.

The oxygen injected into the reservoirs is produced from an ASU. The production of oxygen via an ASU is the most energy intensive step of the process. A portion of the hydrogen extracted from the process can be used to run a hydrogen generator producing electricity to power the ASU. Palladium membranes are inserted at the top of the reservoir and only extract pure hydrogen gas leaving all carbon dioxide emissions stored underground. The “Hygeneration” well that extracts hydrogen can also be used to process other valuable produces such as oil, syngas, steam, and thermal energy. Dual extraction has been tested for extraction of hydrogen and oil.

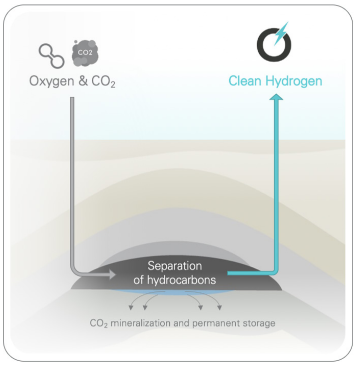

Figure 55. HEE hydrogen production process.

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[173] Linde 2007, Industrial Hydrogen Production & Technology
[174] Shell 2020, Affordable blue hydrogen production with the Shell Blue Hydrogen Process
[175] Patent 2017, In-Situ Process to Produce Hydrogen from Underground Hydrocarbon Reservoirs

### 7.1.2 Introduction to 'Low Carbon Hydrogen from Natural Gas: Global Roadmap' study

The IEAGHG's 'Low Carbon Hydrogen from Natural Gas: Global Roadmap' study sought to assess the deployment of hydrogen production technologies in comparison to incumbent SMR. The study was set in the Netherlands and aimed to establish the differences in various emerging hydrogen production technologies in terms of technology development, the LCOH and life cycle assessment. The technologies considered for this study, alongside the baseline SMR, were: SMR with carbon capture and storage (CCS), electrified SMR (e-SMR), ATR and POX.

**Steam methane reforming (SMR)** – Steam methane reforming uses small chain hydrocarbons such as natural gas or naphtha as feedstock. SMR plants are typically large scale (35-700 MW) and currently produce ~50% of the world's hydrogen[176]. During high temperature (750-900 °C) combustion of natural gas around the reformer combustion tubes, steam is mixed with the feedstock, producing a mix of hydrogen carbon dioxide and carbon monoxide. This mixture, referred to as Syngas[177], is fed through the Water Gas Shift (WGS) reactor in which catalytic reactions between carbon monoxide (CO) and steam ($H_2O$) enable additional hydrogen production as CO is converted to $CO_2$ and steam is converted to $H_2$. A PSA cleans and purifies the hydrogen produced.

**Electrified SMR (e-SMR)** - Electrified steam methane reforming follows the same hydrogen production process as described for SMR, however the reformers are electrically heated. This decreases the emissions intensity of hydrogen produced using this method (where electricity is not produced from fossil fuel sources).

**Gasification and Partial Oxidation (POX)** – Gasification refers to solids and partial oxidation to liquids and gases. Coal gasification is performed using a similar methodology to POX, which is described in detail in the context of *Introduction to $H_2$ Beyond Plant Gate.*

**Autothermal Reforming (ATR)** – ATR combines SMR and POX technologies to increase the hydrogen yield. The process is similar to SMR and POX, with the reaction vessel being followed by WGS reactor and a PSA to purify and clean the $H_2$ produced. Steam and catalysts are used to increase $H_2$ yield from the SMR process and oxygen is used to deliver the energy for POX[5].

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[176] Kalamaras and Efstathiou 2013, Hydrogen Production Technologies: Current State and Future Developments.

[177] Syngas blend for SMR pre-WGS includes c. 52% $H_2$, c. 12% CO, 5% $CO_2$, 29% $H_2O$ and 2% $CH_4$ on a mole basis , IEAGHG 2017, Techno – Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS.

**Carbon capture and storage** – Each of the technologies analysed under this project were assessed with and without CCS. The two of the main types of carbon capture system are post-combustion and pre-combustion. For the process of each carbon capture method, refer to Figure 56[178]. The goal of these technologies is to separate and remove carbon dioxide either from the flue gas (post-combustion) or the syngas (pre-combustion).

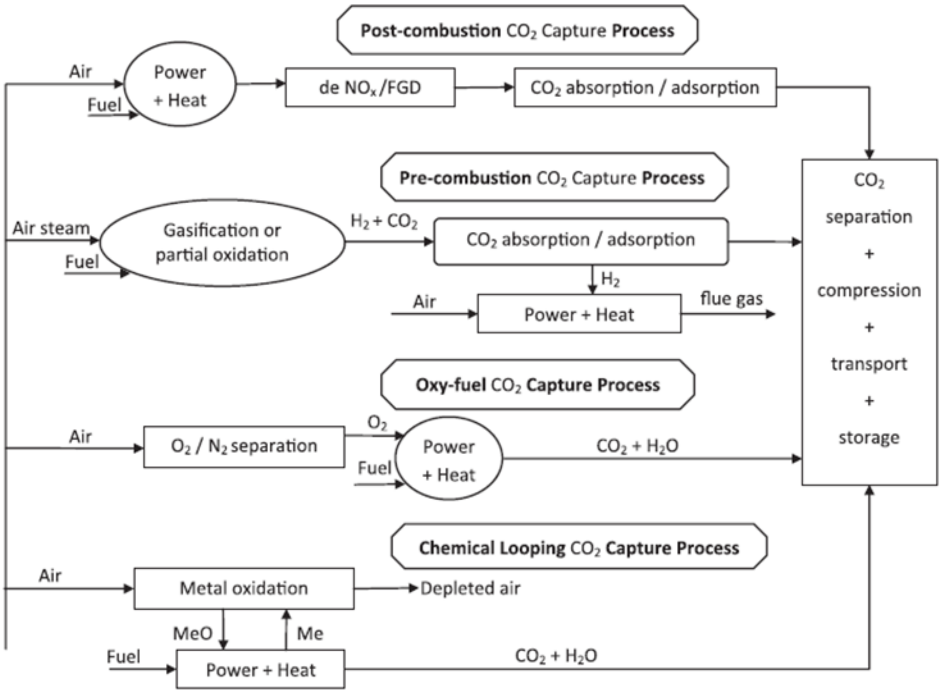

Figure 56. $CO_2$ capture technologies.

Alternatively, in oxyfuel combustion capture, nitrogen is removed from the air, resulting in the burning of the hydrocarbon in high purity oxygen (95-97%) which results in flue gas which primarily consists of $H_2O$ and $CO_2$[179]. As the presence of nitrogen in the flue gas is a key challenge for $CO_2$ separation and removal, this eases the process of purifying the $CO_2$ stream for compression, transportation, and storage. Oxyfuel combustion capture is currently only deployed at smaller scales (~30 MW) and requires large quantities of oxygen which can increase costs of this method. A full overview of CCS methods is provided in Table 12.

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[178] Leung et al 2014, An overview of current status of carbon dioxide capture and storage technologies.

[179] IEAGHG 2019, Further Assessment of Emerging CO2 Capture Technologies for the Power Sector and their Potential to Reduce Costs.

Table 12. Overview of $CO_2$ separation technologies for different capture methods as presented in the Blue Hydrogen Roadmap[4,5].

| Capture Option | Separation Technology | Method |
|---|---|---|
| **Post-combustion** | Absorption by chemical solvents | • Amine-based solvent e.g. monoethanolamine (MEA)<br>• Alkaline solvents |
| | Adsorption by solid sorbents | • Amine based solid sorbents |
| | Membrane separation | • Polymeric membranes e.g. polymeric gas permeation membranes |
| | Cryogenic separation | • Cryogenic separation |
| | Hot Potassium Carbonate | • Chemical Absorption |
| | Pressure/Vacuum swing adsorption | • Zeolites<br>• Activated carbon |
| **Pre-combustion** | Absorption by physical solvents | • Selexol, rectisol |
| | Absorption by chemical solvents | • Amine-based solvent e.g. Methyl Diethanol amine (MDEA) |
| | Hot Potassium Carbonate | • Chemical Absorption |
| | Adsorption by porous organic frameworks | • Porous organic framework membranes |
| **Oxyfuel Combustion** | Separation of $O_2$ from air | • Oxyfuel process<br>• Chemical looping combustion<br>• Chemical looping reforming |

For the purpose of thorough comparison, we widened our research to include additional hydrogen production pathways including:

- Coal gasification with CCS
- Biomass-based hydrogen production
- Biomass gasification with CCS
- Biomethane reforming with CCS

The following section seeks to provide a brief overview of these technologies.

**Coal gasification with CCS** – Coal gasification is widely used to convert coal to synthesis gas in the presence of oxygen and steam at high temperature. The raw syngas is cooled and treated to remove impurities then fed through the water-gas shift reactor to result in mainly hydrogen carbon dioxide in the product stream. There are different types of gasifiers (fixed bed, fluidised bed, entrained flow) that influence the properties of the syngas produced. In some gasifiers, heat produced from the combustion of coal is used to provide heat for the gasification reactions[107]. Generally, coal gasification is used in applications for the synthesis of chemicals such as ammonia and methanol, rather than to produce pure hydrogen.

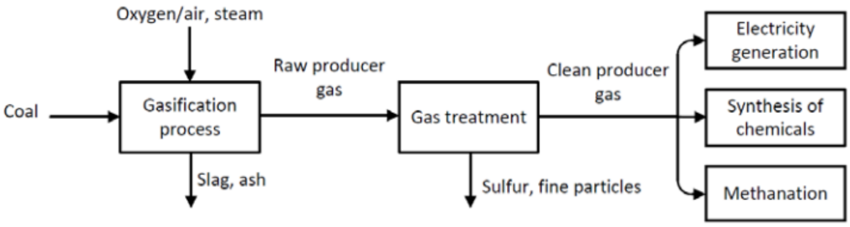

Figure 57. Process flow diagram for coal gasification[180]

**Biomass-based hydrogen production** – Hydrogen produced via biomass gasification and biogas reforming are two widely used routes. Biomass feedstocks can include wet organic wastes, forestry residues, dedicated energy crops, and non-food crops. Waste biomass sources are the focus of current guidance for these pathways. Storage of biogenic carbon dioxide from the gasification and reforming routes can result in overall negative carbon emissions for these hydrogen production pathways.

**Biomass gasification with CCS** – Similar to coal gasification and POX detailed above, biomass gasification is a thermochemical process converting feedstock into product gas. Depending on the gasifier used, the product gas may be fed directly to the water-gas shift reactor, or the product gas may first need to be fed through an SMR then the water-gas shift reactor. Catalysts are required if the product gas is fed directly to the shift reactor.

**Biomethane reforming with CCS** – Biomethane can replace natural gas in a reforming unit to produce hydrogen. The biomethane is obtained from upgrading biogas derived from biomass sources fed through an anaerobic digestor. Similar to SMR, the reformer product gas is fed through the water-gas shift reactor to yield hydrogen and carbon dioxide, followed by a purification step to produce pure hydrogen.

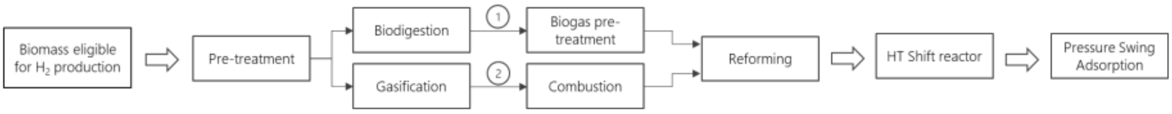

Figure 58. Process flow diagram for hydrogen production from biomass sources

Where relevant, we also incorporate other analyses of electrolytic hydrogen production, to contextualise the results and assumptions presented in this report.

## 7.2 Overview of methodological differences between studies

For effective comparison of different $H_2$ production pathways, it is crucial to understand the differences between assumptions across models, and the implications of these assumptions on the results of each study. Direct comparison and discussion of results will follow; however, Table 13 provides a high level overview of key assumptions and differences between this study and previous IEAGHG studies on blue hydrogen[4,5]. This is also intended to bring to the reader's awareness of the nuances in assumptions between different $H_2$ production pathways.

Additionally, CAPEX range estimates are provided to contextualise the upfront costs of each technology (Table 14). It is important to note that the electrolytic sector is accelerating pace with the first > 100 MW electrolysers now operational and multi-hundred MW projects under development with operation starting as early as the

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[180] IEA Bioenergy 2018, Hydrogen from biomass gasification.

mid-to-late 2020s. Meanwhile, there are currently very few operational blue hydrogen projects (2024), the majority of which have capture rates that are too low for the hydrogen to be considered low carbon.

Please refer to the relevant sections (TEA & life cycle GHG assessment) for the full list of assumptions made to model electrolytic $H_2$ production, and the relevant report for equivalent assumptions for blue $H_2$ production.

**Table 13: Summary of methodology assumptions used for the IEAGHG blue hydrogen studies[4,5], the impact of each assumption on the results and the relevance to the TEA and/or the life cycle GHG assessment**

| Assumption (e.g. system boundary) | Relevant pathway (i.e. production route) | Impact/effect on results (brief description) | Relevant section (TEA/GHG assessment/both) |
|---|---|---|---|
| **Functional unit:** 1 kg $H_2$ compressed to 200 bar with minimum purity 97% | All oil and gas $H_2$ production routes | Allows for comparison against other $H_2$ routes. Will need to convert to MJ basis. Note small differences in final purity (97-99.999%) but unlikely to have significant impact on results. | Both |
| **System boundary (GHG assessment):** extraction of raw materials up to and including production of compressed $H_2$ (cradle-to-gate). Capital goods of foreground system not included (equipment/ infrastructure in $H_2$ production facility). Capital goods included in background processes (construction of pipelines and ships for $CO_2$ transport/storage) | All oil and gas $H_2$ production routes | Allows for comparison against other $H_2$ routes | GHG assessment |
| **System boundary (TEA):** three production gateways were considered. Gateway 1 assumes production, purification and compression only, Gateway 2 incorporates $CO_2$ transportation & storage and Gateway 3 incorporates $H_2$ distribution and storage. | All oil and gas $H_2$ production routes | Allows for comparison with Gateways 1 & 2. Direct quantitative comparison with Gateway 3 not appropriate due to variation in $H_2$ produced under electrolytic $H_2$ scenarios (not present in oil & gas models) | TEA |

| | | | |
|---|---|---|---|
| **Electricity production:** average grid mix (per country) | All oil and gas $H_2$ production routes | Different average mix has significant implications on results given contribution of electricity to these production pathways. | GHG assessment |
| **Time horizon (GHG assessment):** modelled for 2020. Sensitivity for 2030. | All oil and gas $H_2$ production routes | Need to compare same years. Comparison with 2030 sensitivity estimates can be compared. | GHG assessment |
| **Time horizon (TEA):** modelled for 2020 and 2050. | All oil and gas $H_2$ production routes | Need to compare same years. Comparison can be contrasted between 2020 & 2030 with discussion of the differences created due to time horizon. 2050 estimates can be compared. | TEA |
| **Geography:** different countries | All oil $H_2$ production routes | Electrolytic routes are modelled in the Netherlands so not appropriate to compare against production routes in different countries. | Both |
| **Geography:** the Netherlands | All gas $H_2$ production routes | Allows for comparison against electrolytic $H_2$ routes. | Both |
| **Multifunctionality:** no co-products are produced from these routes | All oil and gas $H_2$ production routes | No impact given no co-products are assumed for the blue hydrogen routes. | GHG assessment |
| **LCIA methodology:** GWP IPCC 2013 GWP 100a V1.03 | All oil and gas $H_2$ production routes | Different methodology but both use IPCC GWP values. | GHG assessment |
| **Compressor sizing:** Compressor sized according to energy input entered into model as a set kWh/kg $H_2$, as specific to the technology | All oil and gas $H_2$ production routes | Different methodology, but comparable as compressors also sized according to technology (electrolyser, electrolyser performance in given year). Additional level of complexity in $H_2$ model due to flow rate of $H_2$ varying by scenarios modelled. | TEA (&GHG assessment) |
| **Asset lifetime:** 25 years | All oil and gas $H_2$ production routes | Same across all studies. | TEA |
| **Discount factor:** 8% | All oil and gas $H_2$ | Same across all studies. | TEA |

| | | | |
|---|---|---|---|
| | production routes | | |
| **Water costs:** | All oil and gas $H_2$ production routes | Costs of water for blue $H_2$ production pathways does not account for the cost of demineralisation which is required as additional to prevent damage to the electrolyser stacks. | TEA |
| **Construction year:** 1 year construction period | All oil and gas $H_2$ production routes | Construction period not accounted for electrolyser. Current electrolyser construction period ~18-24 months[181]. Whilst not directly accounted for, many comparable studies on electrolytic $H_2$ production assume a larger lifetime of 30 years (incorporating 3 years of construction). This construction period may also vary by technology, site and first year of operation as this may reduce as more experience is gained in large scale electrolyser deployment. As such the exclusion of a construction period for the electrolyser can be counterbalanced by the reduced lifetime assumption. | TEA |
| **Learning rates:** Learning rates were assumed 5% across all technologies | All oil and gas $H_2$ production routes | Estimates for reduction from CAPEX were taken from literature. Learning rates vary by electrolyser technology due to the large span in TRL. CAPEX reductions into 2050 are estimates based on literature and account for installation costs. | TEA |

**Table 14: CAPEX comparison for blue and electrolytic production technologies. Ranges given for 2021 and 2022 data.**

| Technology | CAPEX range (2021/22) |
|---|---|
| **AEL** | c.500 – 1,000 (uninstalled) (€/kWe) |
| **PEM** | c.700 – 1,400 (uninstalled) (€/kWe) |
| **SOEC** | >2,000 (uninstalled) (€/kWe) |
| **AEM** | c.1,000 (uninstalled) (€/kWe) |
| **SMR** | 570 (€/kW LHV $H_2$) |

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[181] Hydrogen Fuel Cell Partnership 2017, Hydrogen Station Update Webinar - Questions & Answers.

| | |
|---|---|
| **SMR w. CCS** | 993 - 1,070 (€/kW LHV $H_2$) |
| **ATR w. CCS** | 965 – 968 (€/kW LHV $H_2$) |
| **e-SMR** | 646 – 707 (€/kW LHV $H_2$) |
| **POX (gas) w. CCS** | 807 – 965 (€/kW LHV $H_2$) |
| **POX (oil) w. CCS** | 965 – 1,111 (€/kW LHV $H_2$) |
| **SNR w. CCS** | 993 – 1,070 (€/kW LHV $H_2$) |
| **HEE** | 597 – 697 (€/kW LHV $H_2$) |

## 7.3 Comparison and discussion of results

### 7.3.1 Comparison of techno-economic analyses

The following section compares techno-economic analyses conducted in IEAGHG's two blue hydrogen studies and further external assessments in order to present a balanced comparative assessment of the LCOH according to different production pathways. Across the different blue hydrogen studies, a few key takeaways can be made. As technologies improve, costs for blue $H_2$ production reduces over time. Blue hydrogen, produced from all pathways, is currently (using 2020 estimates) cheaper on a per kg $H_2$ basis than electrolytic hydrogen production (regardless of electrolyser technology), with grey hydrogen currently the cheapest option. Over time, as carbon taxes increase and electrolysis technologies improve, this gap in LCOH between blue and electrolytic $H_2$ production reduces, enabling electrolytic $H_2$ production to become increasingly competitive in cases where the electricity connection is supportive (e.g. low cost renewable electricity/zero cost in the case of curtailed energy, with sufficient capacity factor).

Under previous IEAGHG studies on the production of $H_2$ via blue hydrogen production pathways (Section 7), 2020 and 2050 were taken as the years of reference[182]. Therefore, to compare results between blue and electrolytic hydrogen production pathways, we consider the following:

- **Blue $H_2$ production pathways in 2020 were comparatively analysed** using data from IEAGHG studies and relevant literature.
- **Comparison of electrolytic $H_2$ production LCOH in 2020 & 2030**, to analyse a range of LCOH results and cost components of electrolytic hydrogen, to better understand the impact of different assumptions and system boundaries.
- **Comparison of LCOH in 2050 for blue and electrolytic hydrogen,** from IEAGHG blue $H_2$ studies and this study. This includes comparison of cost components and system boundaries.

Throughout the following section, Gateways 1 & 2 from previous IEAGHG studies will be used for cross-comparison against the LCOH outputs from this study, as these account for the LCOH with and without CCS. Each of the gateways modelled as part of the two previous IEAGHG studies on blue $H_2$ production[4,5] are outlined in Figure 59. The central case is used for comparison within the graphs presented, however, the variation and sensitivities are included in the discussion where directly relevant. All IEAGHG study results are set in the Netherlands and assume pipeline distribution of $CO_2$ and central storage costs. Please refer to Low-

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[182] Nominal values for costs are given throughout. It is important to note that assumptions made in the TEA were based on nominal cost estimates from reports in 2020-2022 and as such are in approximate alignment with previous IEAGHG studies, and the literature reviewed in this section.

Carbon Hydrogen from Natural Gas: Global Roadmap[5] and Blue Hydrogen: Beyond the Plant Gate[4] for the full results from these studies.

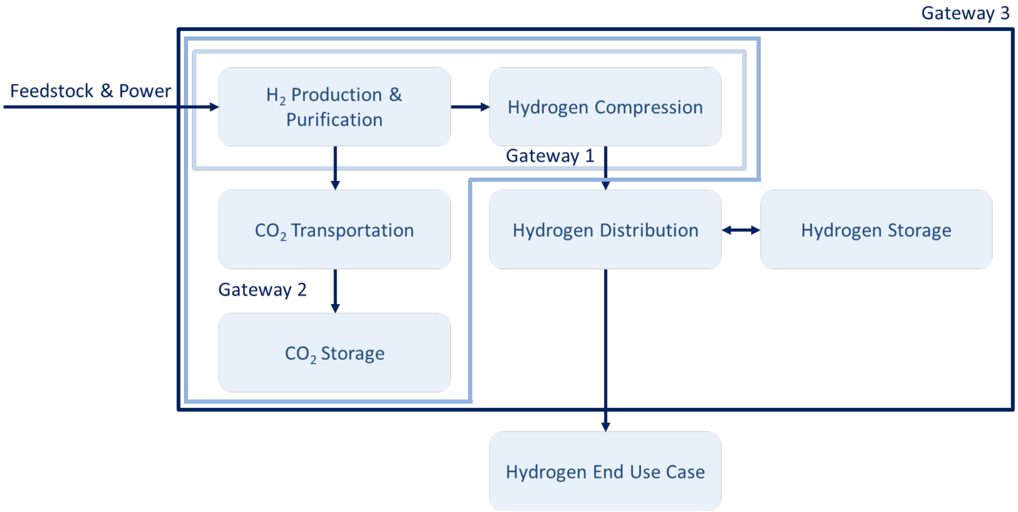

**Figure 59. Cost and emission gateways for blue hydrogen production modelling (IEAGHG)[4,5]**

Gateway 3, incorporating $H_2$ storage and distribution, will be used as a discussion tool regarding the storage and distribution of $H_2$, however, as this is rarely modelled in literature regarding electrolytic $H_2$ production (and has been excluded from the scope of this study), a quantitative analysis will only be performed in the final comparison. It is also important to note, that whilst in-scope under previous IEAGHG studies, $H_2$ storage and distribution was modelled to cater to specific $H_2$ production volumes and specific end use cases; a set volume of 79 tonnes per day of $H_2$ was to be produced irrespective of $H_2$ production pathway, short distance pipeline distribution was assumed and offtake was assumed to users in Rotterdam. Through constraining these assumptions, the Blue Hydrogen Roadmap study was able to apply the hydrogen distribution and storage costs as a flat fee of €0.05/kg $H_2$, with a variation of +/- 10% applied in the sensitivity analysis. Due to the variation in volumes of $H_2$ produced by technology and scenario in Section 3 of this study, such assumptions would not transfer smoothly. $H_2$ storage costs are dependent on storage type and the amount stored. The distribution costs will depend on the distance and the way that the hydrogen is being transported. Unless a specific use case for $H_2$ is stated, then the correct storage and transportation approach cannot be selected which would make the final LCOH value less meaningful. This report instead focuses on the specific scenarios (Grid, RES, Curtail) presented in Section 3.1.4 to model the cost of generating and compressing the hydrogen so that is ready for storage and/or distribution. However, the discussion of distribution and storage methodologies presented in previous IEAGHG studies holds true and relevant for both this study and further discussion and analysis of $H_2$ storage and distribution in future. Please refer to section 3.1.1 for the full discussion of the system boundaries selected for the TEA.

## Blue $H_2$ production: Contextualising 2020 estimates in literature and IEAGHG studies

In addition to the previous IEAGHG studies on CCS-abated (blue) hydrogen production, additional studies were selected for analysis[183] [184]. Each study builds on different assumptions and systems, reflected by the variation in LCOH shown in Figure 60. It is notable that there has been little research conducted on the LCOH

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[183] Global CCS Institute 2021, Blue Hydrogen.

[184] GOV.UK 2021, Hydrogen production costs 2021.

produced by less common CCS-abated (blue) hydrogen production pathways, with SMR + CCS being the most studied technology followed by coal gasification with CCS.

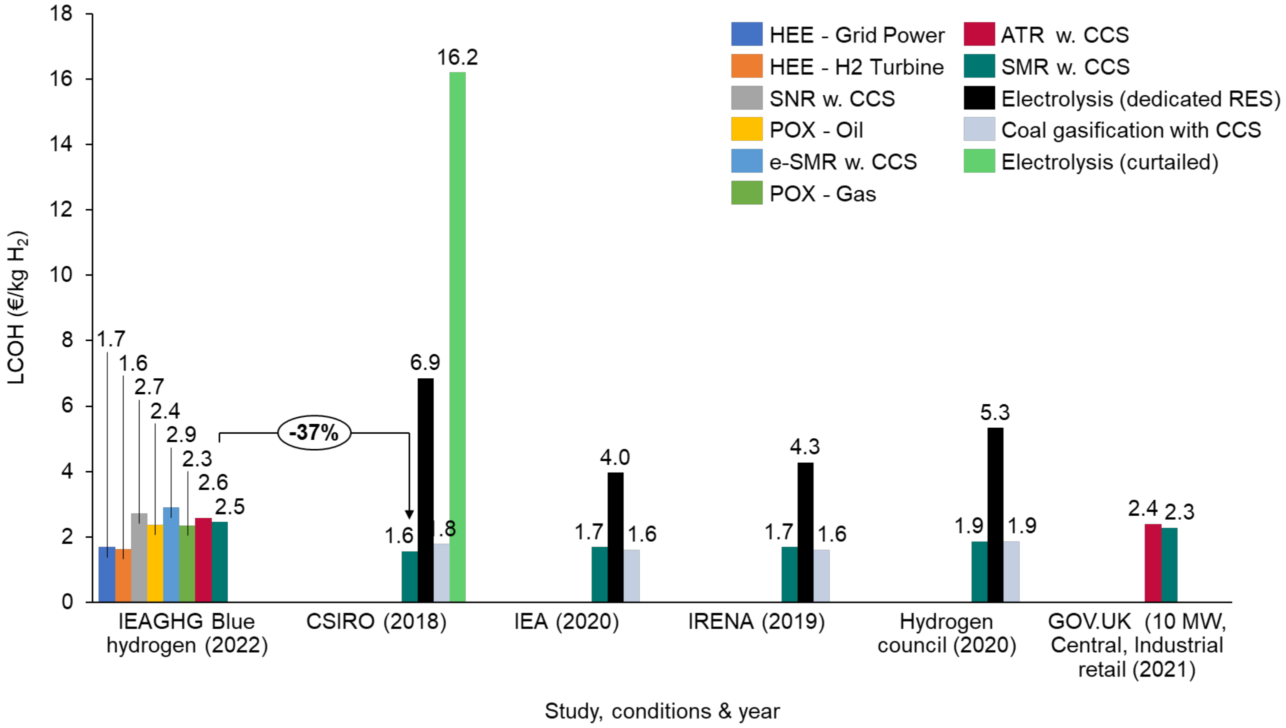

Figure 60. Comparison of hydrogen production pathways assessed in previous IEAGHG studies and literature (2020). The largest LCOH estimate across each technology is presented in the data labels.

**Results of previous IEAGHG studies (2020) -** Across SNR, POX, e-SMR, ATR and SMR, the introduction of CCS increases the LCOH by ~€0.40-€0.60/kg $H_2$ (for the central case). HEE is the lowest cost blue hydrogen production pathway and e-SMR (with or without CCS) is the highest cost on a per kg $H_2$ basis. When compared to the 'base case' of SMR with no CCS, HEE is less expensive for both grid power and hydrogen turbine technologies. All other blue hydrogen production technologies are more expensive on an LCOH basis than the base case grey hydrogen production via SMR, with the variation on LCOH of blue hydrogen pathways demonstrated in Figure 60. Under Gateway 1 (where costs of $CO_2$ storage and transport are not included), SNR, POX, and ATR are all similar costs, with <5% difference (+/-), compared to the base case SMR. Gas POX is the lowest cost non-oil option at €2.35/kg$H_2$ and e-SMR the highest cost of €2.83/kg $H_2$. There is large overlap between the sensitivity bands across all blue $H_2$ pathways for LCOH.

**Results of other LCOH studies** – As discussed, the breadth of technologies presented as part of the previous IEAGHG studies was not well reflected in literature, with SMR and coal gasification being the most commonly researched. This is representative of the current $H_2$ production methodologies and could be considered as indicative of the potential for retrofitting current $H_2$ production facilities with CCS. Literature indicates that SMR and ATR (with CCS) are similarly low cost $H_2$ production pathways.

Literature on the LCOH from bio-pathways (biomass gasification & biomass reforming) is extremely limited. A 2017 study presented the LCOE of bio-hydrogen produced as ~€2.70/kg $H_2$, including CCS[185]. Cost reductions

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[185] Progressive Energy 2017, Bio-hydrogen: Production of hydrogen by gasification of waste.

were predicted to occur due to scaling of the sector (i.e., reductions for the n^th^-of-a-kind plant). This estimate would align costs of biomass production pathways with other blue hydrogen production pathways (albeit at the higher end of cost estimates).

Where ranges and sensitivities were present in these studies, the median or central case was selected. IEAGHG estimates align best with the upper estimates provided in these studies. This can in part be attributed to the inclusion of compression and water costs. However, as discussed in each study, the variation in carbon pricing assumed has a sizeable impact on the LCOH[183,184]. Carbon pricing can only be estimated based on forecasting and varies significantly by geography; a key discrepancy across the studies reviewed as part of this analysis.

## Electrolytic hydrogen production scenarios, 2020 & 2030

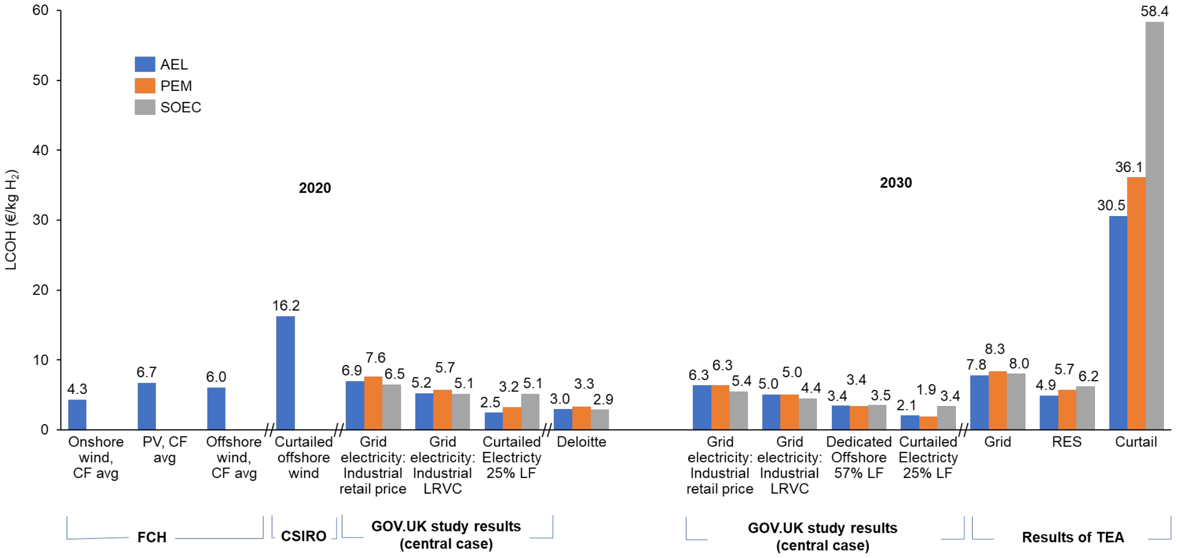

Figure 61. Comparison of electrolytic hydrogen production LCOH in literature. 2020, 2030.

## Selection of studies

The studies presented in this section were selected based on the availability of information regarding the electrolyser technology type and the connection scenarios, as these factors greatly impact LCOH. The studies analysed include the previously referenced GOV.UK hydrogen study (2021)[184], a study on electrolytic hydrogen production by Deloitte[61] (with thorough analysis of different electrolyser technologies) and a study conducted for the FCH Observatory[186] analysing hydrogen production cost by energy connection type and location. Results are presented in Figure 61.

## Results of comparison

There are several key trends which can be observed across the literature which reinforce the results presented in this report. Firstly, LCOH is observed to decrease over time across all technologies. This is demonstrative of improvements anticipated in electrolyser performance and cost. This can be seen from 2020 to 2030 and again from 2030 to 2050, with the most significant improvements observed across the least mature technologies (i.e. SOEC experience the largest improvement in LCOH over time). It can also be seen that in 2020 and 2030, PEM electrolysers are the most expensive electrolytic $H_2$ production technology on an LCOH

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[186] FCH Observatory 2022, Levelised Cost of Hydrogen.

basis. As discussed in the TEA Results section, PEM electrolysers have high CAPEX and low efficiency compared to other competing technologies, contributing to this high relative LCOH.

As was found in this report, AEL are the lowest cost technology on an LCOH basis when connected to high LF RES. By 2050, the LCOH benefits from the high efficiencies of SOEC technology which more than counteracts the large CAPEX (also compression costs and OPEX). However, in 2030, worsened under low electrolyser LF conditions i.e. under curtailment scenarios, electrolysis using SOEC is the most costly $H_2$ production method; the high system costs remain, without the high volumes of hydrogen production to spread the total costs and reduce the LCOH to be comparable with AEL and PEM LCOH. As discussed as part of Section 2, SOEC are still at a substantially lower TRL than AEL and PEM electrolysers and are currently manufactured at smaller capacities. Therefore, to reach the low LCOH estimates presented across literature, technology manufacturers must succeed in developing the SOEC offering to compete with more mature technologies. This is also true for AEMs, although a full discussion can be found in Section 2.

Table 15. Comparison of assumptions made for TEA of electrolytic hydrogen production, 2030 deployment

| Assumption | IEAGHG Electrolytic hydrogen (this study) 2023 | GOV.UK[184] 2021 | FCH 2022 |
|---|---|---|---|
| **Electrolyser scale (MW)** | 300 | 10 | N/A |
| **CAPEX (€/kW)** | 1400 AEL, 1800 PEM, 2500 SOEC (by electrolyser type, 2030. Includes estimates for installation costs) | ~500-2000 (by electrolyser type, 2030) | 600 (AEL only) |
| **Fixed OPEX (% CAPEX)** | 2 | £/kW HHV/year basis, by technology type | 4% |
| **Location** | Netherlands | UK | Netherlands |
| **Degradation of electrolyser** | 0.1% per 1000 hrs[187] | Stack replaced but reduced hydrogen production from degradation not accounted for. | 0.12% per 1000 hours |
| **HHV/LHV** | LHV | HHV | Unclear |
| **Compression of hydrogen** | 200 bar system output | Not included | Not included |
| **System lifetime** | 25 years | 30 years | 30 years |

As shown in Table 15, assumptions differ vastly across techno-economic models. The full cost component breakdown was provided by the GOV.UK study, therefore this was used as a reference point to test the impact of different cost components further, to better understand discrepancies between the models. The cost component breakdown can be seen in the figure below.

## Aligning with literature assumptions

To test the impact of varying the assumptions made in this study, Table 16 shows this study before and after aligning with the assumptions from the GOV.UK study[184]. This was tested on AEL in 2030. Across all scenarios, the electrolyser size was reduced to 10 MW, the CAPEX reduced to 600 €/kW, and water and compression costs removed. For Scenario 3, it was also assumed that electricity costs were zero, as in the

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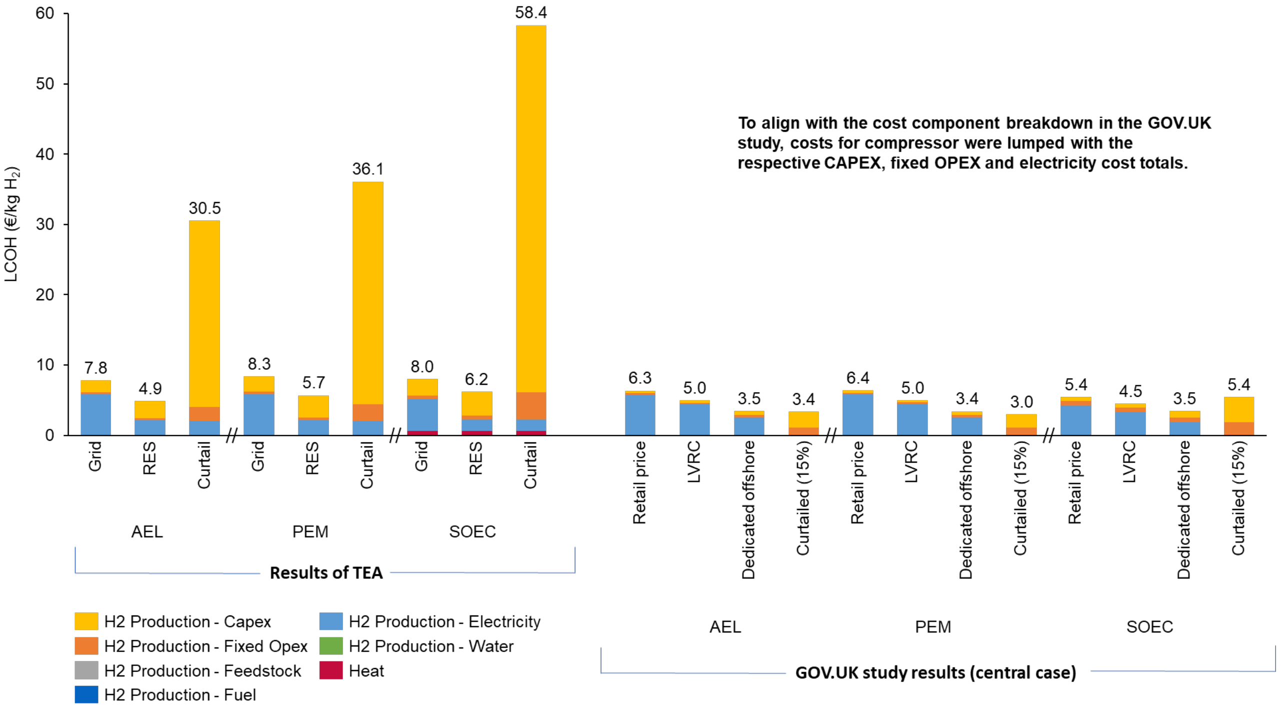
[187] Degradation of the electrolyser is given to only one significant figure as exact degradation rates vary by electrolyser operating conditions and technology type. Therefore, the degradation rate is an estimate and further granularity would produce spurious accuracy.

curtailment model of GOV.UK. This assumption relies on the fact that curtailed electricity would otherwise be discarded and can therefore be assumed to be zero cost.



To align with the cost component breakdown in the GOV.UK study, costs for compressor were lumped with the respective CAPEX, fixed OPEX and electricity cost totals.

**Figure 62. LCOH comparison of electrolytic hydrogen production under various electricity connection scenarios, as modelled in Section 3: TEA and in the GOV.UK 2021 study.**

Through adjusting the CAPEX, electrolyser scale, and costs of water and compression, a drastic reduction in the LCOH under Scenario 3: Curtailment is observed. Reducing the electrolyser scale has the largest impact on the LCOH, followed closely by the reduction in CAPEX. As the intermittency of RES, caused by seasonal and diurnal variation in solar and wind, creates intermittency in the operation of a coupled electrolyser, this reduces the electrolyser LF and increases the LCOH. Where the capacity factor[188] is low, the LCOH can become larger than what is reasonable for the business case of the electrolyser. This is observed in the *Scenario 3: Curtailment* in 2030 in the results of the TEA.

**Table 16. Comparison of electrolytic LCOH through changing key assumptions**

| | LCOH (€/kg $H_2$) | | |
|---|---|---|---|
| | GOV.UK | IEAGHG electrolytic hydrogen | Adjusted - IEAGHG electrolytic hydrogen |
| **Direct grid connection** | 6.33 | 7.81 | 6.54 |
| **Dedicated RES** | 3.44 | 4.87 | 2.91 |
| **Curtailed wind** | 2.08 | 30.53 | 3.20 |

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[188] Capacity factor refers to the power generated by a given generation source, compared to the total possible power generation of that source (given as a %). Load factor refers to the power input to a technology compared to the full rated power (MW) of that technology. This is also given as a %.

Reducing the size of the electrolyser reduces the minimum load. This means that for the same amount (MWh) of electrical energy curtailed, the electrolyser is operational for a larger percentage of the year. As electrolyser CAPEX is large, the larger the volumes of hydrogen produced, the more the cost can be diluted on a per kg $H_2$ basis. Hydrogen production and CAPEX are proportional to electrolyser scale, but hydrogen production is also proportional to the electrolyser LF. Therefore, a higher LF increases the ratio of hydrogen production to CAPEX, thus lowering the overall LCOH.

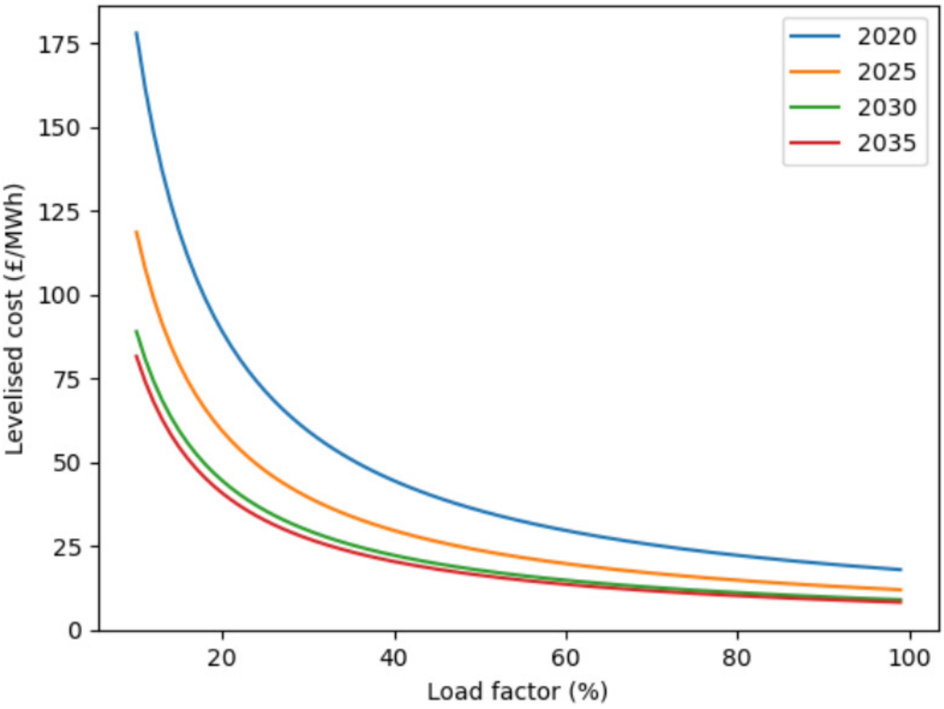

**Figure 63. Relationship between LF and levelised cost of energy (LCOE) by year of operation, figure from ClimateXchange[189] therefore accounting for costs in £/MWh. Figure demonstrative of inverse relationship between electrolyser LF and LCOE.**

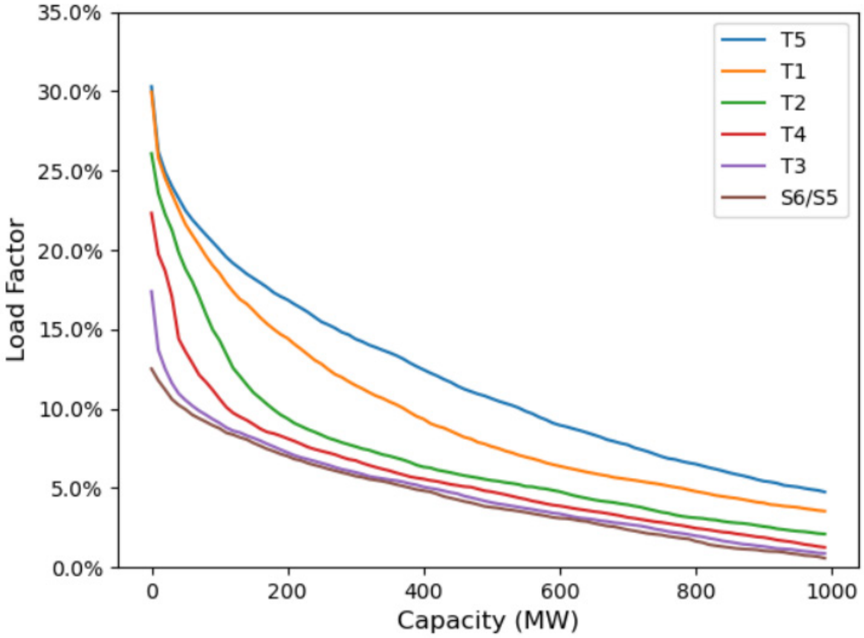

**Figure 64. Relationship between electrolyser capacity and LF for different sites in Scotland, ClimateXchange[189].**

To further demonstrate the impact of LF and electrolyser scale, the impact of varying LF on LCOH from a Scottish LCOH study[189] is analysed. In Figure 64, T1-5 and S6/S5 refer to zones (areas) where data was collected as part of this study. The figure above demonstrates the impact of electrolyser LF on LCOH; for low LFs (<10%), a small increase in LF yields a large reduction in the LCOH. Using this model as an example, an increase in LF from ~10% to ~20% yields a >35% reduction in LCOH. This effect is amplified as electrolyser LF decreases with electrolyser size for a given RES source i.e., the bigger the electrolyser, the more electricity required to satisfy a given % of its full load capacity (a 300 MW electrolyser full load is 300 MW). This effect is shown in Figure 64. This translates to inflated LCOH as large equipment comes at a large cost: a 300 MW electrolyser is more expensive than a 10 MW electrolyser in unit cost, and if you are not utilising it to its full capacity then this cost is not compensated by increased $H_2$ production.

Whilst important for understanding the potential to achieve low LCOH from curtailment scenarios, a large electrolyser was selected for our model to understand to potential of scale. Testing the same electrolyser across different scenarios clearly demonstrates the importance of designing your electrolyser based on the specific conditions under which it will operate. As discussed in Section 3.1.2, a larger CAPEX was assumed than across many studies due to the decision to include installation costs. This is an important inclusion, as installation costs are still very high, and inclusion has a significant impact on LCOH, which increases with decreasing electrolyser LF.

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[189] ClimateXchange 2022, The potential for hydrogen to reduce curtailment of renewable energy in Scotland.

## Looking ahead to technological maturity in 2050: Comparison of LCOH of blue and electrolytic hydrogen

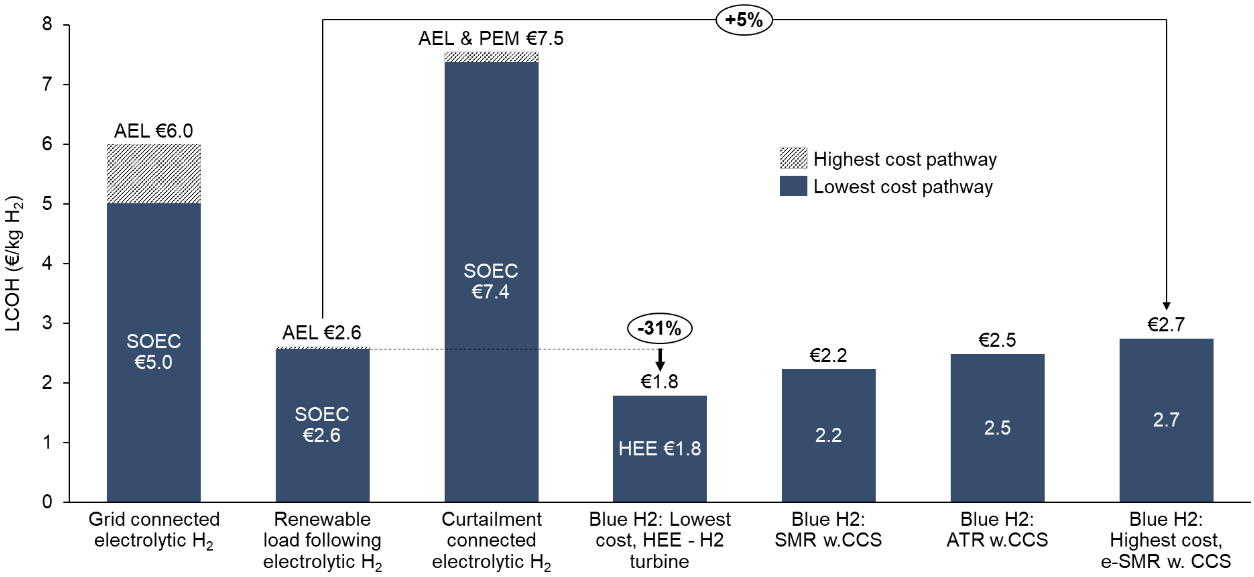

**Figure 65. Upper and lower range of LCOH by production pathway, 2050. IEAGHG studies only[190].**

We will compare our 2050 results from this report's TEA with the 2050 outputs from the two previous IEAGHG blue hydrogen studies. By 2050 it is anticipated that electrolyser technologies will have matured significantly and will have undergone large performance and cost improvements, unlocking reduced LCOH under electrolytic hydrogen production pathways. Blue and electrolytic $H_2$ production LCOH estimates are shown in the figure above. Under the central case for blue $H_2$ production via the more expensive pathways (e-SMR), we see potential for electrolytic hydrogen to become comparable in cost with by 2050. This is dependent on the conditions modelled, specifically assumptions regarding electricity cost, electricity consumption and the volumes of $H_2$ produced by each technology and scenario.

As established, electrolyser sizing should be tailored to the use case, in particular where a low LF is presented (curtailment scenario). If electrolysers are more appropriately sized, reductions in LCOH could be made under *Scenario 3: Curtailment*. If electricity costs were zero, or even negative to incentivise electricity consumption during periods of high renewable electricity surplus, this scenario could be very low cost under the right conditions. Electrolyser operators could benefit from revenues from these 'negative costs' during surplus hours, partially offsetting the high electrolyser CAPEX costs.

By 2050, feedstock costs constitute the bulk of blue $H_2$ LCOH. The same is, in essence, true for green electrolytic $H_2$ where electricity becomes the dominant cost on a per kg $H_2$ basis under scenarios with high electrolyser LFs. Therefore, fossil fuel and electricity costs will dictate the production cost of blue and green hydrogen respectively. Increasing the carbon price will also increase the blue hydrogen cost. If renewable electricity costs fall and fossil fuel costs climb, then post-2050 electrolytic hydrogen would present as a more attractive option than blue $H_2$ on an LCOH basis.

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[190] Lowest and highest cost technology by pathway. Central case results for blue hydrogen presenting results for lowest and highest cost production pathways (HEE – H2 turbine and e-SMR with CCS) alongside the current most common production pathways combined with CCS (SMR & ATR). Due to the immaturity of HEE (hygenic earth energy) there is large uncertainty in the exact cost of this pathway.

### 7.3.2 Comparison of Life Cycle GHG Assessments

The next section of the report compares the life cycle GHG emissions of hydrogen production via different pathways. The life cycle assessments conducted as part of the IEA blue hydrogen studies were used as well as literature studies to compare the electrolytic hydrogen production emissions modelled in Section 4 of this study, with CCS-abated routes using natural gas, oil-based, biomass and coal feedstocks.

The methodology used to model the life cycle emissions of hydrogen production can vary greatly between literature sources. To enable a robust comparative analysis between different hydrogen production routes, the methodologies followed should align as closely as possible. Key assumptions for alignment include the system boundary, co-product allocation approach, functional unit of hydrogen (i.e. energy/mass, purity and pressure), geography and time horizon (time period of analysis).

For each hydrogen production pathway, the methodology assumptions are listed for the various literature sources reviewed, followed by a breakdown of the emissions results, and a comparative analysis of hydrogen production via the different pathways including the results from Section 4.

#### Blue hydrogen production pathways

The assumptions detailed in the IEAGHG blue hydrogen studies are summarised in Table 13, highlighting the differences in the methodological assumptions made between the IEAGHG blue hydrogen studies and this electrolytic hydrogen study.

The results from the IEAGHG blue hydrogen studies were used to compare the GHG impact of hydrogen production with $CO_2$ capture from gas and oil-based feedstocks against electrolytic hydrogen production. The results from the blue hydrogen studies for 2030 are summarised in Table 17 and Table 18. Results are presented for SMR, with and without CCS, alongside those for ATR, e-SMR, POX, SNR and HEE.

The scope of the oil-based blue hydrogen study did not model every pathway in the Netherlands. Hydrogen production in Algeria, Brazil, Gabon, Kuwait, R. Congo and Saudi Arabia was modelled for the oil-based POX route and hydrogen production in E. Guinea, Iran, Nigeria, and Venezuela was modelled for the HEE route. For both these routes an average of these countries was taken and is provided in Table 18 below. All these hydrogen production pathways utilise electricity and for some (e.g. e-SMR) the emissions associated with imported electricity contribute significantly to the final emissions result. The grid intensity used to model the hydrogen production emissions in different countries may be significantly different to the Netherlands and will therefore have a substantial impact on the final emissions result. For the POX and HEE routes modelled in the IEAGHG blue hydrogen studies, the 2030 grid intensities used for the countries mentioned above ranged between 38.9 $gCO_2e/MJ$ elec to 247.2 $gCO_2e/MJ$ elec, significantly higher than the 2030 Netherlands grid factor used in this study to model electrolytic hydrogen production (16.7 $gCO_2e/MJ$ elec). To allow for a more accurate comparison, further studies should align around a common set of GHG intensity inputs (e.g. for the Netherlands).

**Table 17: Hydrogen production emissions in $gCO_2e/MJ_{LHV}$ $H_2$ for IEAGHG natural gas-based blue hydrogen routes (using grid electricity)**

| SMR (no CCS) | SMR + CCS | ATR + CCS | e-SMR+ CCS | POX + CCS |
|---|---|---|---|---|
| 84.4 | 20.4 | 18.5 | 21.8 | 12.7 |

**Table 18: Hydrogen production emissions in $gCO_2e/MJ_{LHV}$ $H_2$ for IEAGHG oil-based blue hydrogen routes (using grid electricity)**

| SNR + CCS | POX + CCS | HEE |
|---|---|---|
| 28.7 | 33.1 | 18.6 |

Using an oil-based feedstock compared to natural gas in the POX hydrogen production pathway can result in almost twice as many emissions being produced. The oil-based POX pathway assumed a $CO_2$ capture rate of 96% and refinery vacuum residue as the feedstock whereas the gas-based POX pathway assumed there are no direct $CO_2$ emissions and natural gas as the feedstock. The power and water requirements for the oil-based POX pathway are also higher compared to the gas-based POX pathway.

A breakdown of the GHG emissions allocated to the system inputs and outputs for the gas-based blue hydrogen production pathways is provided in Figure 66. Implementing CCS results in a significant reduction in the emissions associated with hydrogen production, as shown by the difference between grey hydrogen (SMR without CCS) and the blue routes. Despite the lower natural gas input and lower direct $CO_2$ emissions for the e-SMR hydrogen production pathway, the additional electricity requirement results in this pathway producing higher emissions in 2030 compared to natural gas SMR+CCS when both are using grid electricity. Due to the reliance of e-SMR on electricity, the hydrogen emissions intensity is highly sensitive to grid intensity, so e-SMR should achieve significantly lower GHG emissions than standard SMR+CCS by 2050 or if renewable power is used. However, it was noted in the IEAGHG blue hydrogen study that e-SMR is at a low TRL and has poor data availability compared to the other gas-based blue hydrogen routes. The 'Other' category labelled in the figure below includes negligible tap water and wastewater treatment emissions.

The higher natural gas input and lower $CO_2$ capture rate for SMR+CCS compared to ATR+CCS (90% vs 94%), results in a higher GHG intensity for SMR+CCS hydrogen in 2030. The electricity requirement for ATR+CCS is greater compared to SMR+CCS to run the ATR plant, for hydrogen compression and to run the ASU for oxygen production. In future years, as the grid decarbonises, or if renewable power is sourced, the difference in emissions between these two reforming routes could become even more significant.

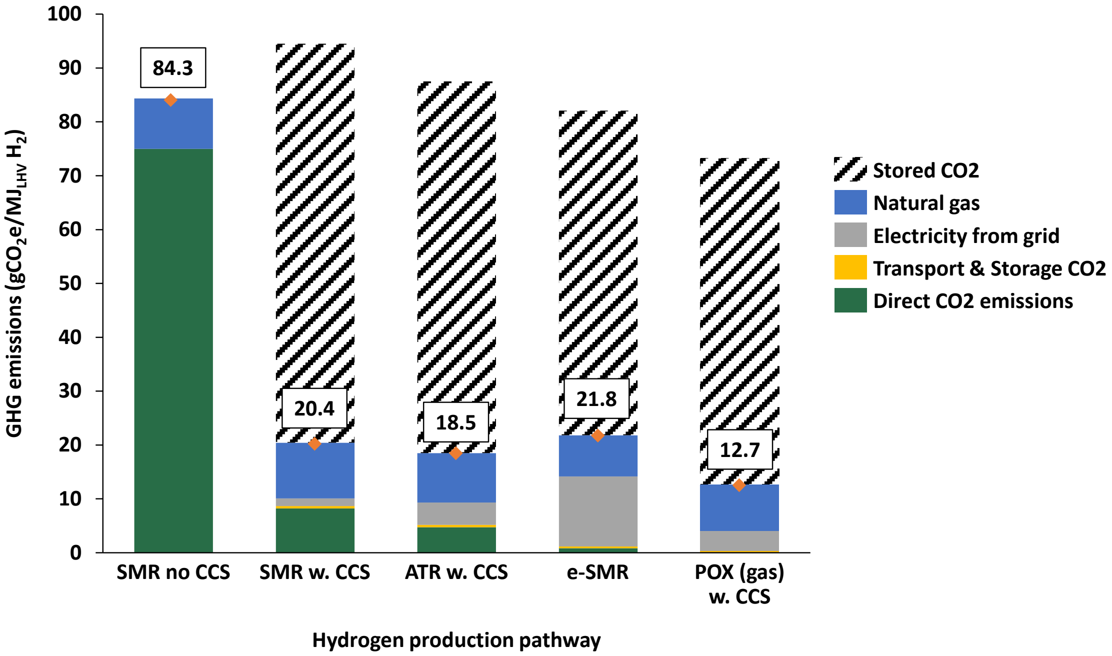

Figure 66. Breakdown of the emission sources from the natural gas-based blue hydrogen production pathways and SMR without CCS benchmark in 2030. Source: IEAGHG Blue hydrogen roadmap

For the oil-based blue hydrogen pathways, a breakdown of the system inputs and outputs for each route modelled is modelled in Figure 67 and covers a range of countries. The location of hydrogen production can have a significant impact on the emissions associated with electricity due to the dependence on the GHG intensity of the regional grid. This is highlighted by the variation in electricity contribution (grey bars in the figure below). For the SNR+CCS pathway, there is less variation between countries due to this route having a lower electricity requirement compared to the POX and HEE routes.

Based on the assumption that no process emissions are released in the HEE pathway because the process takes place underground, this technology achieves the lowest emissions amongst the oil-based hydrogen production routes. However, this technology has the lowest maturity meaning there is a high level of uncertainty in these results. In the IEAGHG Blue hydrogen beyond plant gate study, a scenario was considered where the electricity for the HEE pathways is not imported from the grid but is instead generated onsite using the hydrogen produced from the process. This same onsite hydrogen-to-power concept could be employed for other hydrogen production pathways, but would lead to significant yield reductions, which would increase other components of the resulting hydrogen intensity.

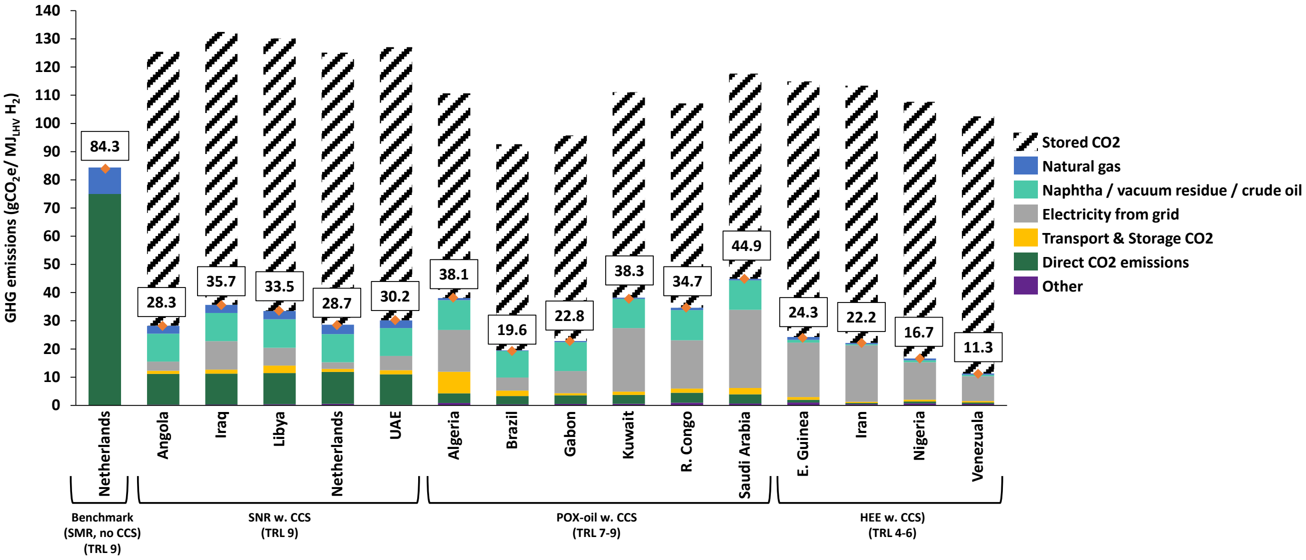

**Figure 67: Breakdown of the emission sources from the oil and oil-based blue hydrogen production pathways and SMR without CCS benchmark in 2030. Source: IEAGHG Blue hydrogen beyond plant gate**

Conclusions that can be drawn from this analysis:

- CCS can substantially reduce blue hydrogen production emissions, and very high capture rates are feasible for some pathways.
- The location of hydrogen production and decarbonisation of regional electricity grids or sourcing of renewable electricity can have a significant impact on the pathway emissions due to electricity requirements.
- Oil-based blue hydrogen routes generally have a higher GHG intensity compared to gas-based routes due to the higher carbon-to-hydrogen ratio of oil-based feedstocks.

## Biomass gasification CCS

There are different feedstocks that can be fed to a gasifier to produce hydrogen. Literature sources reviewed for this pathway indicate the choice of biomass/waste feedstock can greatly impact the final emissions intensity of the production route. Table 19 summarises the methodology assumptions used to model this gasification pathway in the literature studies identified.

Table 19: Summary of methodology assumptions used in literature studies to model hydrogen production via biomass gasification

| Assumption (e.g. system boundary) | Progressive Energy[185] | Mehmeti et al[191] | Hydrogen Council[192] | BEIS[193] | Comparison: Electrolytic hydrogen study |
|---|---|---|---|---|---|
| **Functional unit** | 1 MWh $H_2$ | 1 kg $H_2$ | 1 kg $H_2$ | 1 MJ $H_2$ (LHV) compressed to 30 bar with minimum purity 99.9% | 1 MJ $H_2$ (LHV) compressed to 200 bar with minimum purity 99.9% |
| **System boundary** | Municipal waste transport, refuse-derived fuel (RDF) production, $H_2$ production, and $CO_2$ capture. Compression excluded. | Cradle-to-grave. Purification, upgrading and delivery of $H_2$ excluded. | Well-to-supply including energy production, $H_2$ production. | Cradle-to-gate up to the point of $H_2$ production. | Cradle-to-user including downstream transport, storage and distribution. |
| **Geography** | UK | Not country specific | Australia and China | UK | Netherlands |
| **Time horizon** | 2020 | 2018 | 2030 & 2050 | 2020, 2030, 2040 & 2050 | 2030 & 2050 |
| **LCIA methodology** | Not specified | ReCiPe 2016 | Not specified | LCHS | IPHE v2 |
| **GWP values** | Not specified | IPCC AR5 | IPCC AR5 | IPCC AR5 without feedback | IPCC AR5, without feedback |
| **Multifunctionality** | Not specified | None (all burden assigned to main product $H_2$) | Not specified | Energy allocation | System expansion |
| **Feedstock** | Waste | Energy crops | Wood chips | Forestry residues | Grid electricity |

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[191] Mehmeti et al 2018, Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies.
[192] Hydrogen Council 2021, Hydrogen decarbonization pathways: A life-cycle assessment.
[193] BEIS 2021, Options for a UK low carbon hydrogen standard.

For some of the literature sources, compression and purification of hydrogen is excluded from the system boundary and furthermore none of the sources are specific to the Netherlands. This means the conclusions that can be drawn from comparing the results from literature for hydrogen production via biomass gasification with the results from section 4 electrolytic hydrogen production will be somewhat limited.

The emissions from hydrogen production via biomass gasification are summarised in Table 20 for the different literature sources. Gasification of waste can achieve the lowest emissions for hydrogen production while gasification of energy crops is expected to result in the highest emissions. Energy crops involve upstream emissions from cultivation (e.g. fertiliser use), harvesting, collection, any pre-processing and transportation to the plant whereas forestry residues will have emissions from collection, chipping, and transportation. Depending on the methodology used, waste biomass feedstocks may have zero emissions at the point of collection or the avoided emissions from the counterfactual fate of the waste feedstock may be considered.

Biomass gasification routes that include $CO_2$ capture result in negative emissions intensity hydrogen being achieved. Sequestered biogenic $CO_2$ is assigned a GWP of -1 $gCO_2e/gCO_2$ because the feedstock has effectively removed this $CO_2$ from the atmosphere and therefore geological sequestration results in a net negative effect.

Table 20: Hydrogen production emissions in $gCO_2e/MJ_{LHV}$ $H_2$ for biomass gasification pathways modelled in literature

| **Progressive Energy[185]**<br>**[modelled for 2020 using waste feedstock]** | **Mehmeti et al[191]**<br>**[modelled for 2018 using energy crops]** | **Hydrogen Council[192]**<br>**[modelled for 2030&2050 using wood chips]** | **BEIS[193]**<br>**[modelled for 2020, 2030, 2040 & 2050 using forestry residues]** |
|---|---|---|---|
| 12.8 (without CCS)<br>-89.4 (with CCS) | 22.3 (without CCS) | 2030: 14.2 (without CCS)<br>2050: 12.5 (without CCS) | 2030: -168.4 (with CCS)<br>2050: -165.6 (with CCS) |

The total production emissions from biomass gasification with CCS calculated in the BEIS study are slightly less negative in 2050 compared to 2030, due to assumed improvements in the gasification process efficiency by 2050.

A breakdown of the emissions from waste gasification is presented in the figure below based on the data provided in Progressive Energy 2017 report. The main source of emissions for hydrogen production via waste gasification is from imported electricity accounting for ~50% of the total pathway emissions. Refuse-derived fuel (RDF) production includes electricity, diesel, and sulphuric acid inputs to convert municipal waste to RDF which can then be fed to the gasifier.

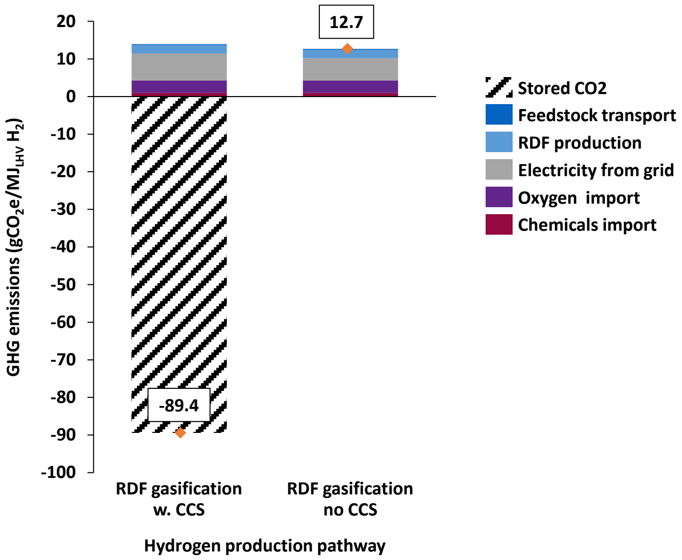

Figure 68: Breakdown of the emission sources from biomass waste gasification with and without CCS (data from Progressive Energy 2017[185])

## Biomethane reforming CCS

The literature sources used to estimate the emissions from hydrogen production via biomethane reforming is summarised in Table 21. Similar to the biomass gasification routes, different feedstocks have been used to model this pathway in literature and these have been highlighted in the table.

Table 21: Summary of methodology assumptions used in literature studies to model hydrogen production via biomethane reforming

| Assumption (e.g. system boundary) | Royal Society of Chemistry[194] | Mehmeti et al[191] | Hydrogen Council[192] | BEIS[193] | Comparison: Electrolytic hydrogen study |
|---|---|---|---|---|---|
| **Functional unit** | 1 MJ $H_2$ (LHV) compressed to 200 bar with purity 99.97% from SMR and 99.9% from ATR | 1 kg $H_2$ | 1 kg $H_2$ | 1 MJ $H_2$ (LHV) compressed to 30 bar with minimum purity 99.9% | 1 MJ $H_2$ (LHV) compressed to 200 bar with minimum purity 99.9% |
| **System boundary** | Cradle-to-gate excluding biogenic waste collection, anaerobic digestion. | Cradle-to-grave. Purification, upgrading and delivery of $H_2$ excluded. | Well-to-supply including energy production, $H_2$ production. | Cradle-to-gate up to the point of $H_2$ production. | Cradle-to-user including downstream transport, storage and distribution. |
| **Geography** | UK | Not country specific | Australia and China | UK | Netherlands |
| **Time horizon** | 2020 | 2018 | 2030 & 2050 | 2020, 2030, 2040 & 2050 | 2030 & 2050 |
| **LCIA methodology** | EF v2 | ReCiPe 2016 | Not specified | LCHS | IPHE v2 |
| **GWP values** | IPCC 2013 | IPCC AR5 | IPCC AR5 | IPCC AR5 without feedback | IPCC AR5, without feedback |
| **Multifunctionality** | None (all burden assigned to main product $H_2$) | None (all burden assigned to main product $H_2$) | Not specified | Energy allocation | System expansion |
| **Feedstock** | Waste | Energy crops | Wood chips | Forestry residues | Grid electricity |

The study by the Royal Society of Chemistry (RSC)[31] models hydrogen production with the same functional unit as that used in Section 4 of this study. However, a robust comparison is still constrained by the differences in location and year, as well as system boundary and allocation methodology (multi-functionality).

The results from the literature sources reviewed for hydrogen production via biomethane reforming are presented in Table 22. The hydrogen production emissions reported in literature vary between 3.3-116.8 $gCO_2e/MJ_{LHV}$ $H_2$ for biomethane reforming without CCS. The feedstock type (energy crops or waste), anaerobic digestor design and whether a feedstock counterfactual is considered will greatly impact the potential emissions from this hydrogen production route. Implementing CCS with these routes leads to sequestration of biogenic carbon resulting in the final GHG emissions for this hydrogen production pathway achieving negative emissions, provided low emission feedstocks are selected.

Table 22: Hydrogen production emissions in $gCO_2e/MJ_{LHV}$ $H_2$ for biomethane reforming modelled in literature

| Royal Society of Chemistry[194]<br>[modelled for ATR 2020 using waste feedstock] | Mehmeti et al[191] [modelled for SMR 2018 using energy crops] | Hydrogen Council[192] [modelled for SMR 2030 & 2050 using energy crops or waste feedstock] | BEIS[193]<br>[modelled for ATR 2030 & 2050 using waste feedstock] |
|---|---|---|---|
| -125.0 (with CCS) | Wheat: 116.8 (without CCS)<br>Corn: 76.6 (without CCS) | Energy crops, 2030: 27.5 (without CCS)<br>Energy crops, 2050: 23.3 (without CCS)<br>Waste, 2030: 8.3 (without CCS)<br>Waste, 2050: 3.3 (without CCS) | 2030: -63.3 (with CCS)<br>2050: -67.1 (with CCS) |

Emissions associated with feedstock supply, feedstock transportation, imported electricity for biogas production and upgrading, for the ATR plant and for hydrogen compression and purification, contribute to the total pathway emissions for bio-based ATR hydrogen production.

## Coal gasification CCS

For the coal gasification with CCS pathway, a number of literature sources were reviewed, and the methodology assumptions are summarised below in Table 23.

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[194] Royal Society of Chemistry 2020, Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis.

Table 23: Summary of methodology assumptions used in literature studies to model hydrogen production via coal gasification with CCS

| Assumption (e.g. system boundary) | JEC WTT v5[195] | Mehmeti et al[191] | Hydrogen Council[192] | Comparison: Electrolytic $H_2$ study |
|---|---|---|---|---|
| **Functional unit** | 1 MJ $H_2$ (LHV) compressed to 880 bar | 1 kg $H_2$ | 1 kg $H_2$ | 1 MJ $H_2$ (LHV) compressed to 200 bar with minimum purity 99.9% |
| **System boundary** | Well-to-tank including coal production & conditioning, $H_2$ production, compression & dispensing at retail site. | Cradle-to-grave. Purification, upgrading and delivery of $H_2$ are excluded. | Well-to-supply including energy production, $H_2$ production. | Cradle-to-user including downstream transport, storage and distribution. |
| **Geography** | EU-mix | Not country specific | Australia and China | Netherlands |
| **Time horizon** | 2017-2025+ | 2018 | 2030 and 2050 | 2030 and 2050 |
| **LCIA methodology** | ILCD | ReCiPe 2016 | Not specified | IPHE v2 |
| **GWP values** | IPCC AR4 | IPCC AR5 | IPCC AR5 | IPCC AR5, without feedback |
| **Multifunctionality** | System expansion | None (all burden assigned to main product $H_2$) | Not specified | System expansion |

Given that the JEC WTT v5[195] models this pathway using an EU-mix and the multi-functionality (allocation) approach is comparable to this electrolytic hydrogen study, the results from this literature source will be relatively robust when comparing with the electrolytic hydrogen results from section 4. The largest disparity is the JEC study goes as far as vehicle refuelling, involving significant compression, well beyond the pressure assumed in this study.

The final emissions for hydrogen production via coal gasification with CCS are summarised in Table 24. The JEC result for the EU-mix is between the 2030 range reported in the Hydrogen Council study.

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[195] JEC 2020, JEC Well-to-Tank report v5.

Table 24: Hydrogen production emissions in $gCO_2e/MJ_{LHV}$ $H_2$ for coal gasification with CCS in literature

| JEC WTT v5[195]<br>[modelled for 2017-2025+] | Mehmeti et al[191]<br>[modelled for 2018] | Hydrogen Council[192]<br>[modelled for 2030&2050] |
|---|---|---|
| 53.3 | 34.0 | 2030: 29.2 (Australia), 76.7 (China)<br>2050: 25.8 (Australia), 59.2 (China) |

A breakdown of the sources of emissions for hydrogen production via coal gasification with CCS is provided below. The main source of emissions is from the gasification process because coal has a high carbon content resulting in significant process $CO_2$ emissions released during this conversion process. The inputs to the gasification process will include air/steam/oxygen to partially oxidise the coal, chemicals, catalyst, water and possibly some natural gas[196]. A capture rate of 97% is assumed resulting in the total emissions from this process being ~53 $gCO_2e/MJ_{LHV}$ $H_2$.

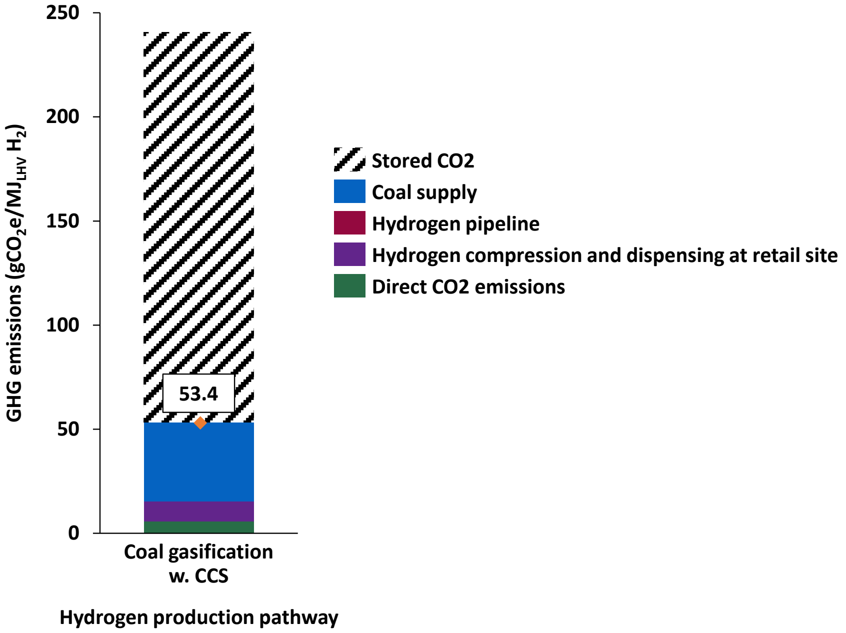

Figure 69: Breakdown of the emission sources from coal gasification with CCS (data from JEC WTT v5[195])

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[196] IEA 2008, Co-production of hydrogen and electricity by coal gasification with $CO_2$ capture – updated economic analysis.

## Comparison of electrolytic hydrogen production with other hydrogen production pathways

In the following section, the results from the IEAGHG blue hydrogen studies and the literature studies, reviewed earlier in this section, are compared against electrolytic hydrogen production from Section 4. The figure below provides a summary of the hydrogen production emissions from the different routes.

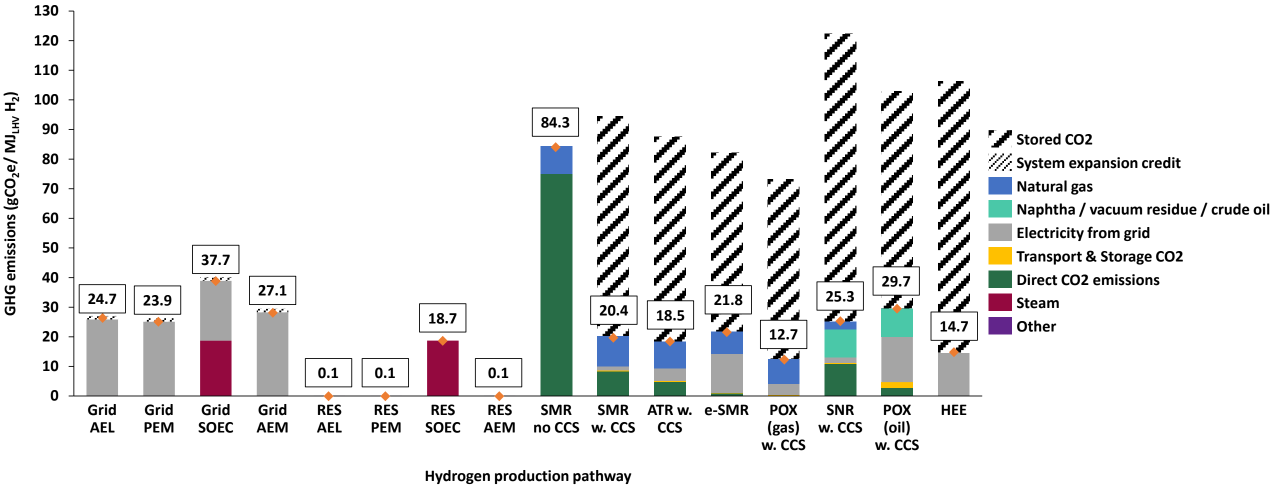


Figure 70: Estimated hydrogen production emissions from electrolysis and low-carbon (CCS-abated) pathways in 2030[8] (RES = electricity generated from renewable sources).

The results presented in the figure above compare the electrolytic hydrogen production emissions using either grid electricity or renewable electricity with the blue hydrogen production pathways modelled in the IEAGHG studies. The results from the biomass and coal CCS-abated pathways have not been included because different data sources have been used which vary in terms of the methodological assumptions (e.g. year of production, location, and approach followed). 2030 values were modelled for the electrolytic and blue hydrogen routes presented in the above figure. For hydrogen production routes discussed earlier in this section that were modelled for 2020 (coal gasification CCS, biomass waste gasification CCS and biomethane reforming CCS), a reduction in the emissions would be expected if these were modelled for 2030 based on decarbonisation of the grid and improvements in technology efficiencies.

Bio-based hydrogen production routes with CCS achieve negative emissions due to capturing biogenic carbon being given a credit. For the bio-based routes that were modelled for 2020, total pathway emissions intensities may become less negative over time with process efficiency improvements.

Only the electrolytic, gas-based blue hydrogen, and SNR pathways are modelled for hydrogen production in the Netherlands. An average of the different location data provided in the IEAGHG oil-based blue hydrogen studies was taken for the POX and HEE routes. The coal gasification route[195] uses an average EU-mix which will be similar to the Netherlands grid average, compared to the waste[185]/forestry residue[193] biomass gasification and waste-derived biomethane reforming[194] routes which use UK-specific data.

The electrolytic pathways assume compression of hydrogen to 200 bar which is in line with the IEAGHG blue hydrogen studies as well as the waste ATR route[193]. Compression to 30 bar was modelled for hydrogen production via biomass gasification using forestry residues[181] while the coal gasification route[195] included compression of hydrogen to 80 MPa (880 bar). A slight reduction of ~1 $gCO_2e/MJ_{LHV}$ $H_2$ for hydrogen production via coal gasification is anticipated if the hydrogen is compressed to 200 bar rather than 880 bar, but this not enough for the coal gasification route to achieve emissions comparable to even the grid electrolysis routes. SOEC electrolytic hydrogen production achieves the highest emissions results due to the heat requirement.

The hydrogen purity is slightly higher for the electrolytic hydrogen production pathways compared to the blue routes, but all electrolytic hydrogen produced is above 97% purity and therefore the difference in purity is unlikely to significantly impact the final emissions result.

Grid electrolysis routes in 2030 all achieve lower emissions compared to coal gasification with CCS and SMR without CCS. The use of CCS with natural gas SMR, ATR and e-SMR results in lower emissions (between 18.5-21.8 $gCO_2e/MJ_{LHV}$ $H_2$) compared to the 2030 grid electrolytic hydrogen production routes. If renewable electricity is used instead of grid electricity, or the analysis is conducted in 2050, the electrolysis routes will become significantly lower emitting than these blue hydrogen routes.

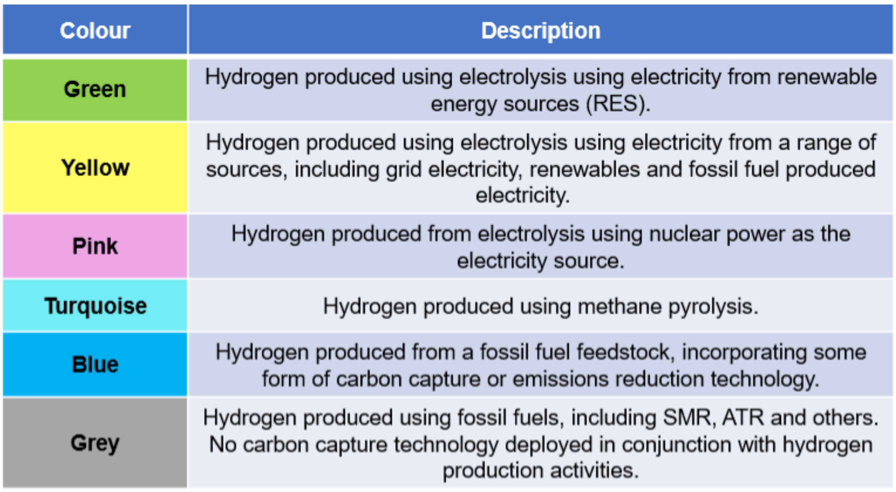
Out of all the blue hydrogen routes, POX using natural gas as the feedstock achieves the lowest emissions while POX that uses an oil-based feedstock (vacuum residue) results in the highest emissions. The choice of feedstock has significant implications for both the blue and bio-based pathway emissions results.

When evaluating the life cycle impact of hydrogen production pathways, it is important to not only consider the GHG emissions, but also consider other environmental impacts such as human toxicity, acidification, eutrophication, land use, and water consumption. Using a different impact category lens can greatly impact how one hydrogen production route ranks against another. For example, bio-based hydrogen production routes can achieve negative GHG emissions but utilisation of biomass as feedstock can have a significantly larger impact on land use compared to other routes. The hydrogen production pathways are likely to achieve quite different outcomes when different environmental impact categories are considered.

The 2030 data from the blue hydrogen production pathways modelled in the IEAGHG studies[4,5] was used to allow for a meaningful comparison with the electrolytic hydrogen production results. This 2030 data did not include the ultra-high capture rates (99%), which was a separate sensitivity performed in the blue $H_2$ studies, for 2020 data only.

## Hydrogen colour taxonomy

There is no formal definition to differentiate hydrogen production technologies by emissions intensity. Colours are typically used for the different hydrogen production technologies, however these are not well-defined country-by-country nor universally agreed across industry and academia.



| Colour | Description |
|---|---|
| Green | Hydrogen produced using electrolysis using electricity from renewable energy sources (RES). |
| Yellow | Hydrogen produced using electrolysis using electricity from a range of sources, including grid electricity, renewables and fossil fuel produced electricity. |
| Pink | Hydrogen produced from electrolysis using nuclear power as the electricity source. |
| Turquoise | Hydrogen produced using methane pyrolysis. |
| Blue | Hydrogen produced from a fossil fuel feedstock, incorporating some form of carbon capture or emissions reduction technology. |
| Grey | Hydrogen produced using fossil fuels, including SMR, ATR and others. No carbon capture technology deployed in conjunction with hydrogen production activities. |

Figure 71: Colour coding of hydrogen by production pathway[197] [198] [199]

The technologies that have been analysed in this study and the colour associated with the hydrogen produced via each technology are summarised in the table below. Note there are no strict requirements for a certain capture rate to be achieved for hydrogen produced via a technology using fossil fuels or biomass with CCS to be considered blue. There are some organisations working to better define hydrogen production technologies including Hydrogen Europe[200], CertifHy[201], UK DESNZ[193], European Union[202].

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[197] Bianco, E. and H. Blanco. 2020, Green Hydrogen Supply: A Guide to Policy Making.

[198] Abad, A.V. and P.E. Dodds. 2020, Green hydrogen characterisation initiatives: Definitions, standards, guarantees of origin, and challenges. Energy Policy. 138: p. 111300.

[199] Giovannini, S. 2020, 50 shades of (grey and blue and green) hydrogen.

[200] Hydrogen Europe 2020, The EU Hydrogen Strategy: Hydrogen Europe's Top 10 Key Recommendations.

[201] CertifHy 2019, CertifJy – The First European Guarantee of Origin for Green & Low Carbon Hydrogen.

[202] Euroactive 2020, Renewable or 'low-carbon'? EU countries face off over hydrogen.

Table 25: Hydrogen production emissions and colour of hydrogen produced via the technologies analysed in this study

| Technology | Colour | $gCO_2e/MJ_{LHV}$ $H_2$ |
|---|---|---|
| **Electrolysis using renewable electricity** | Green | 0.1-18.7 (2030/2050) |
| **Electrolysis using grid electricity** | Yellow | 23.9-37.8 (2030)<br>0.1-18.7 (2050) |
| **SMR (no CCS)** | Grey | 84.4 (2030) |
| **SMR + CCS** | Blue | 20.4 (2030) |
| **ATR + CCS** | Blue | 18.5 (2030) |
| **e-SMR + CCS** | Blue | 21.8 (2030) |
| **POX + CCS** | Blue | 12.7 (2030) |
| **SNR + CCS** | Blue | 28.7 (2030) |
| **POX + CCS** | Blue | 33.1 (2030) |
| **HEE** | Blue | 18.6 (2030) |
| **Biomass gasification + CCS** | NA | -89.4 (2020, waste feedstock)<br>-168.4 (2030, forestry residues)<br>-165.6 (2050, forestry residues) |
| **Biomethane reforming + CCS** | NA | -125.0 (2020, waste feedstock)<br>-63.3 (2030, waste feedstock)<br>-67.1 (waste feedstock) |
| **Coal gasification + CCS** | NA | 53.3 (2017-2025+) |

## 7.4 Limitations and uncertainties

### 7.4.1 Additional limitations

#### $O_2$ valorisation

In addition to the TEA results, as shown as part of Section 5, additional revenue may be generated from $O_2$ valorisation. Despite high potential earnings when considering the sale of by-product $O_2$ in isolation, when factoring in the high costs of distribution and storage, $O_2$ valorisation is currently not typically incorporated in electrolysis projects to date. As synergies are further explored in the future, this may change and unlock markets for by-product $O_2$.

#### $H_2O$ GWP

As discussed in Section 5, water vapour emitted at point of use of electrolytic $H_2$ (combustion or utilisation in fuel cells) also has a GWP. Whilst this is incredibly small in comparison to other GHGs, more work should be done in future years to best understand the factors and impact of water vapour emissions from hydrogen utilisation under all use case conditions (e.g. emission at altitude).

### 7.4.2 Persisting limitations in the study of the environmental impact of $H_2$

The environmental impact of hydrogen leakage during the production, distribution, and transport of hydrogen from electrolytic and low-carbon routes has not been considered in the IEAGHG Blue Hydrogen studies. Given that hydrogen is an indirect GHG and the small size of hydrogen molecules means it is vulnerable to leakage hydrogen emissions should be considered when modelling the environmental impact of hydrogen production value chains.

When hydrogen is released into the atmosphere, a large proportion will be removed by soils (hydrogen soil sink) and the remainder will react with hydroxyl radicals. The latter leads to the atmospheric concentrations of GHGs (e.g. methane, water vapour, ozone) increasing. The warming potential of hydrogen is relatively short-lived compared to other GHGs, and therefore has been underestimated from methods that consider a long-term framework. Studies have shown that the potency of hydrogen's GWP can be at least 3 times greater compared to $CO_2$ depending on the time horizon considered[203].

An increase in the atmospheric concentration of hydrogen can:

- Decrease the concentration of hydroxyl radicals in the troposphere, meaning there is less hydroxyl radicals available to react with methane leading to increases in the atmospheric lifetime of methane
- Increase tropospheric ozone via a chain of reactions
- Decreases in upper stratospheric ozone mixing ratios
- Increases in water vapour in the atmosphere, particularly in the stratosphere
- Increase radiative forcing due to increases in tropospheric ozone, water vapour and methane

These impacts will counter the climate benefits of switching to low-carbon hydrogen.

There is uncertainty around the hydrogen soil sink, radiative forcing scaling factors and the absolute global warming potential (AGWP) for $CO_2$. For a 100 year time horizon, UK BEIS calculated a hydrogen GWP of 11 ± 5 $gCO_2e/gH_2$[204]. Compared to previous publications, this GWP is more than twice as large, due to the stratospheric effects not being considered in previous studies.

# 8 Conclusions and Recommendations

## 8.1 Electrolytic hydrogen production

### Techno-economic analysis

Our TEA highlighted several key conclusions, including:

- **The relative importance of CAPEX, fixed OPEX, and variable OPEX (mainly electricity costs) on LCOH.**
  - Electrolyser CAPEX represents a significant cost component of the LCOH, with high CAPEX needing to be justified by (and spread over) large volumes of hydrogen production in order to minimise LCOH. CAPEX is largest for least mature technologies.
  - Accessing low-cost electricity for a high number of hours per year is critical to minimising LCOH, explaining the high LCOH in *Scenario 3: Wind curtailment* irrespective of year or technology.
- **The importance of achieving a high LF on the electrolyser (especially while CAPEX is relatively high) to achieve a low LCOH.**

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[203] Ocko and Hamburg 2022, Climate consequences of hydrogen emissions.
[204] BEIS 2022, Atmospheric implications of increased hydrogen use.

  - For electrolytic (renewable connected) hydrogen production, the electrolyser should be sized according to the renewable generation capacity available in order to maximise the electrolyser LF and volumes of hydrogen and reduce the LCOH. This is a careful balance of identifying appropriately sized generation capacity and sizing the electrolyser to be able to capture as much of this energy for hydrogen generation as possible. If the electrolyser is oversized, this increases the LCOH and demands unnecessary CAPEX investment.
- **As we move towards 2050 and CAPEX falls, electricity costs contribute a greater share of LCOH, thus increasing the importance of access to low-cost renewable energy.**
- **It appears unlikely that operating strategies for electrolysers based on using curtailed renewables only will lead to cost-effective hydrogen production**, mainly due to the low LFs expected. If installed CAPEX can be reduced substantially, a wider range of operating strategies under which low-cost $H_2$ can be produced become feasible.
- **Given any set connection conditions (grid, renewable etc.), the electrolyser efficiency and minimum load determine which technology will have the lowest LCOH** i.e. the technology which is able to make best use of the inputs and produce the largest quantity of hydrogen.
  - Whilst electrolyser cost is an important component of LCOH, high CAPEX can be counterbalanced by high volumes of $H_2$ produced, if the electrolyser performance is good enough.
  - The more variable the quantity of electricity generated over time, the larger the impact the minimum load will have on the LCOH.
- **Whilst PEM and AEL provide the lowest LCOH in 2030, SOEC offer significant promise in the 2050 timeframe**. This is irrespective of the heat source of the SOEC, however siting the electrolyser in areas with access to waste heat would unlock further substantial cost reductions.

**PEM and AEL are competitive with each other in both the 2030 and 2050 timeframe**, reaching almost equivalently low LCOH, with high efficiencies, low minimum load factors, low CAPEX and overall, closely comparable properties.

### Life cycle GHG assessment

The key conclusions from the life cycle GHG assessment included the following:

- Despite the higher electrical efficiency of the SOEC electrolyser, the input heat requirement results in **higher GHG emissions from the SOEC** pathway compared to other electrolysis routes if this heating demand is met via natural gas combustion.
- Distribution to an end user, particularly over longer distances or involving transformation of gaseous hydrogen into other forms, can add significant GHG emissions on top of any electrolysis production emissions and therefore **appropriate end users** should be considered.
- Compressed pipeline distribution achieves the lowest GHG emissions by a significant margin compared to other distribution chains due to only requiring a small amount of electricity usage for compression and some hydrogen emissions from transmission leakage.
- The GHG intensity of input electricity and heat used in distribution steps is a key sensitivity and therefore the rate of power grid & gas grid decarbonisation will greatly impact the potential to reduce GHG emissions for most routes.
- Accounting for **fugitive hydrogen emissions** from electrolytic hydrogen production and distribution can potentially lead to total pathway emissions increasing by over 10% depending on the GWP value of hydrogen.
- Total combined pathway emissions are highly dependent on the **choice of certain parameters** such as the heating source for ammonia cracking, the source of the captured $CO_2$ for methanol catalysis or the GWP value of hydrogen attributed to the fugitive hydrogen emissions from liquid hydrogen transport and storage.
- Ammonia cracker off-gases could be used to provide the required process heat, instead of input natural gas, but will involve a trade-off in the processing step efficiency. The optimal balance of heating fuels to minimise overall combined pathway emissions therefore depends on the process input intensities and upstream supply chain emissions.
- Improvements in technology efficiency, in particular electrolyser efficiency, can achieve lower total pathway emissions but there are **other factors that can have a more significant impact** on emissions reduction such as grid decarbonisation, reduction of fugitive hydrogen emissions, and low-carbon transportation options.

## 8.2 Comparison with blue hydrogen routes

- **Electrolytic hydrogen produced under renewable connected, load following scenarios, can become cost competitive with some blue hydrogen production pathways by 2050**, resulting in LCOH comparable with blue hydrogen. By 2050, it is anticipated that electrolyser technologies will have matured significantly, undergoing large performance and cost improvements.
- **By 2050, feedstock costs constitute the bulk of blue and electrolytic LCOH,** except for electrolytic hydrogen produced under scenarios with very low electrolyser load factors. Fossil fuel and electricity costs will therefore dictate the production cost of blue and green hydrogen, respectively. Increasing the carbon price will also increase the blue hydrogen costs.

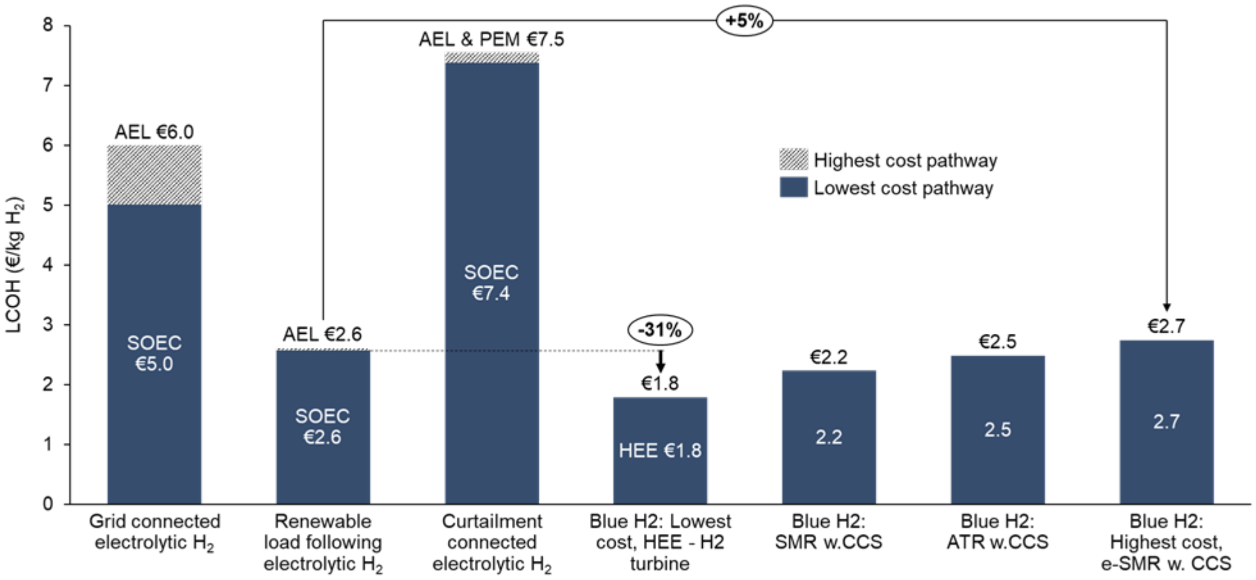

Figure 72: Upper and lower, range of LCOH by production pathway, 2050. IEAGHG studies only[205].

- **The use of CCS in blue hydrogen production enables significant reductions in hydrogen production emissions.** In the case of biomass-based hydrogen, capturing biogenic $CO_2$ can lead to negative emissions, although this is highly dependent on the feedstock used. Blue production routes are also somewhat sensitive to the feedstock used, with oil based blue routes generally having higher emissions than natural gas blue routes.
- **Electrolysis routes will achieve lower GHG emissions intensities than blue hydrogen routes if renewable electricity is used, or by 2050 as grid electricity fully decarbonises**. The location of hydrogen production and decarbonisation of regional electricity grids can have a significant impact on the pathway emissions due to electricity requirements.

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[205] Lowest and highest cost technology by pathway. Central case results for blue hydrogen presenting results for lowest and highest cost production pathways (HEE – H2 turbine and e-SMR with CCS) alongside the current most common production pathways combined with CCS (SMR & ATR). Due to the immaturity of HEE (hygenic earth energy) there is large uncertainty in the exact cost of this pathway.

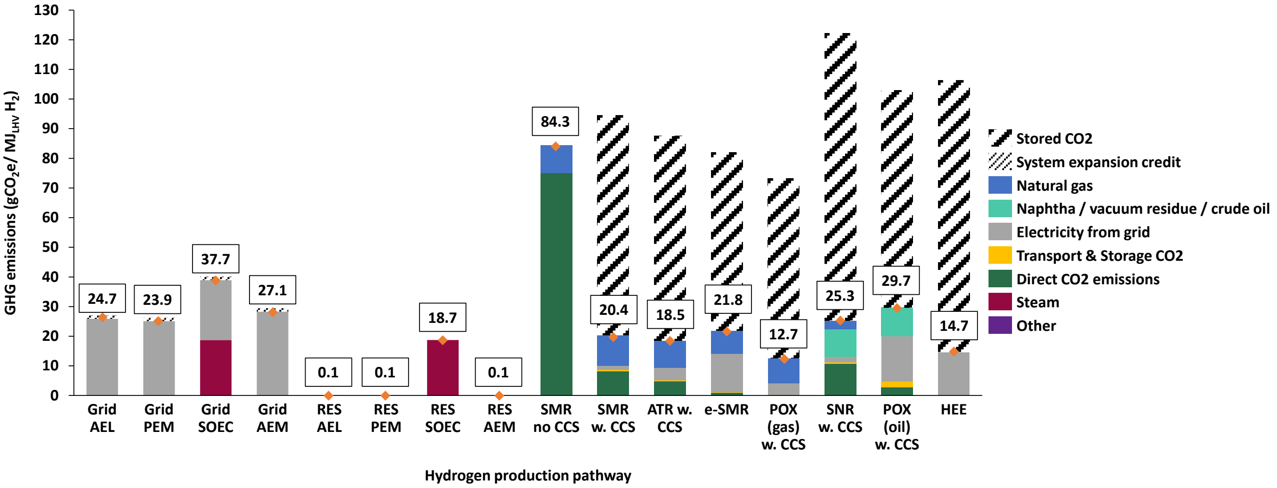

Figure 73: Estimated hydrogen production emissions from electrolysis and low-carbon (CCS-abated) pathways in 2030[8] (RES = electricity generated from renewable sources).

## 8.3 Recommendations

The successful deployment of hydrogen production technologies relies on factors such as technical feasibility, financial viability, integration with wider supply chains, and validated GHG emissions assessments. Recommendations to increase the deployment of electrolytic hydrogen production are provided below.

### Research, Development and Demonstration

- **Further work could consider hydrogen production in other locations** to understand the optimal sites for deployment of hydrogen production technologies in terms of cost and emissions ranges. This study only considers the production of hydrogen at a hypothetical location, which for consistency purposes with other IEAGHG studies, was taken to be in the Netherlands. The viability of electrolytic hydrogen will be location specific.
- **Hydrogen leakage can occur across the hydrogen value chain.** Fugitive hydrogen indirectly increases the atmospheric concentrations of GHGs (methane, water vapour, ozone) due to reactions with hydroxyl radicals in the atmosphere. To improve accounting of hydrogen leakage, research into more accurate measurements of hydrogen emissions and the impacts of co-emissions is required. The latter has received some attention in a recent publication[206] but is due greater consideration.
- **The GWP of anthropogenically generated water vapour is influenced by factors including location and altitude of emissions**. More studies are required, including for considering water vapour generated at altitude from hydrogen powered aviation.
- **Electrolytic oxygen may be valorised as a by-product** however, this is not typically incorporated in electrolysis projects to date. As synergies are further explored in the future, this may change and unlock markets for electrolytic oxygen.
- **Other environmental impacts** (e.g. land use, embodied emissions within construction/manufacturing of materials) were not considered in this analysis and will impact how different routes compare to one another. Further work could consider other relevant impact categories that influence the environmental impact of different hydrogen production routes.

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[206] Sand, M. 2023, A multi-model assessment of Global Warming Potential of hydrogen.

## Policy and Actions

To enable the potential of electrolytic and other low-carbon hydrogen production to be realised, policy will be an important driver. Policymakers should consider policies that:

- Encourage **international collaboration** between those countries with low-cost hydrogen production and those with high demand for hydrogen.
- Encourage **harmonisation of a common global GHG methodology** or standard to facilitate international trade of hydrogen. The IPHE[207] are continuing efforts to develop a mutually agreed GHG methodology for hydrogen production and a global International Organization for Standardization (ISO) standard is expected in 2025[208].
- Advance the **deployment of renewables to accelerate decarbonisation** of regional electricity grids to enable grid-powered electrolytic hydrogen production to become competitive with blue hydrogen production from life cycle GHG emissions and cost perspectives.
- **Support low-carbon hydrogen production technologies** that achieve low life cycle GHG emissions and set an emissions threshold to identify those projects that may be eligible for support.
- Provide funding for **research and development of electrolyser technologies** to achieve improvements in electrolyser performance and costs, enabling electrolytic hydrogen to become cost competitive with blue hydrogen.
- Plan for **scale up and standardisation of technologies to achieve cost reductions.** This is already being encouraged by schemes such as the EU Innovation Fund[209] which support manufacturing of decarbonisation technologies.
- **Support carbon pricing** to allow electrolytic hydrogen production technologies to become more competitive compared to grey and blue hydrogen routes. The successful deployment of hydrogen production technologies relies on factors such as technical feasibility, financial viability, integration with wider supply chains, and valid emissions assessments.

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[207] IPHE 2023, International Partnership for Hydrogen and Fuel Cells in the Economy.
[208] ISO 2022, ISO/TC 197/SC 1 Hydrogen at scale and horizontal energy systems.
[209] European Commission, Projects selected for grant preparation. Accessed on 09/11/23.

# 9 Appendix

## 9.1 Data and assumptions for the roadmap of electrolytic hydrogen production

Table 26. Qualitative data used in KPI scoring.

| Technology | Additional challenges | Additional advantages | Maintenance requirements |
|---|---|---|---|
| **AEL** | Not yet comparable to PEM operating range. Potential for hydrogen and oxygen mixing. | Mature technology with low-cost catalysts and large system sizes available. Electrolyser tolerant of impurities. | Annual preventative, KOH pump replacement after 3 years, replacement of KOH electrolyte after 4-5 years, stack refurbishment/replacement after 10 years[27] |
| **PEM** | High costs, material requirements Complexity in manufacturing titanium current collectors. Can be sensitive to impurities. | Mature technology with high durability. Synergies in manufacturing with PEM fuel cells. High current density. Rapid cycling and fast system responses due to non-porous separator membrane. | Half-year maintenance, stack refurbishment/replacement after 10 years[27] |
| **SOEC** | High cost, low level of development. High operating temperatures create mechanical issues and increase start-up time, meaning coupling with renewable energy production is more difficult. High temperatures create low durability and lifetime and increase the risk of gases diffusing through the materials in the cell, reducing $H_2$ purity. | High efficiencies due to high temperature operation and utilisation of waste heat recovery. Low minimum loading comparable to PEMs. Less sensitive to impurities (e.g. than PEM) | Increased maintenance frequency required due to current high potential for mechanical failures from thermal cycling. |
| **AEM** | Very small scales. Sensitivity of membrane reducing lifetime of electrolysers. High minimum loads (10-20%). Early stage of development. | Non-critical materials suitable as catalysts, reducing costs. Membrane reduces gas leakages ($H_2$). | Very low stack lifetime necessitating stack replacement after as little as two full years of operation. |

Table 27. Quantitative data used in KPI scoring.

| Technology | TRL | Current manufacturing capability (GW/year) | Future manufacturing capability (est. GW/year (2030)) | Efficiency (kWh/kg of $H_2$) | Operating range (minimum load %) | System response to change in incoming power (minutes) | System footprint | $H_2$ outlet pressure (bar) | H2 outlet purity (%) | Stack lifetime (hours) | CAPEX (system cost, factory gate (uninstalled), USD/kWe) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **AEL** | 9[26] | ~5.3 GW[26] | ~15 [27] | 50-78[20] | 15-40[48] | < 50[20] | 136 $m^2$/MW[23] | 1-30[20] | 99.5 - 99.99998[48] | 60,000-100,000[20] | 500-1000[20] |
| **PEM** | 9 [26] | ~1.6 GW (1/5 of total) [26] | ~11 [27] | 50-83[20] | 5-10[27] | <20 minutes[20] | c.73 $m^2$/MW[23] | 30-70[20] | 99.9 - 99.9999[48] | 50,000-80,000[20] | 700-1400[20] |
| **SOEC** | 7 [26] | Single digit (~5) MW[27] | ~500[24, 27] | 40-55[20] | >3[48] | > 600[20] | c.84 $m^2$/MW[24] from 8,400 $m^2$ for 100 MW | 1-10[20] | c.99.99[48] | <20,000[20] OR 50,000-90,000[48] | >2000[20] |
| **AEM** | 6 [26] | 300 MW from single manufacturer[46] | No production capacity announcements for 2030[46] | 57-69[20] | 10-20[48] | <20[20] | c.102 $m^2$/MW[46] | <35[20] | c.99.99[48] | 5,000[20], OR c.30,000[48] | c.1000[27] |

Table 28. Electrolyser CAPEX cost reduction estimates. USD ($).

| Electrolyser technology | Source | Electrolyser CAPEX ($*/kW) | | |
|---|---|---|---|---|
| | | 2020-2021 | 2030 | 2040-2050 |
| **AEL** | FCH 2 JU[59] | 580 | 390 | - |
| | IRENA[20] | 430-860 | - | <170 by 2050 |
| | IEA[60] | 430-1,190 | 340-720 | 170-600 long term |
| | Deloitte[61] | 730-1,360 | 390-875 | |
| **PEM** | FCH 2 JU | 875 | 485 | - |
| | IRENA | 600-1,200 | - | <170 by 2050 |
| | IEA | 940-1,535 | 570-1,315 | 170-770 long term |
| | Deloitte | 780-1,750 | 585-1,360 | - |
| **SOEC** | FCH 2 JU | 2,560 | 950 | - |
| | IRENA | - | - | <250 by 2050 |
| | IEA | 2,385-4,770 | 680-2,385 | 430-855 long term |
| | Deloitte | 780-2,240 | 485-1,360 | - |
| **AEM** | IRENA | - | - | <100 by 2050 |
| | Enapter | 975 | - | - |

## 9.3 Data and Assumptions used in the TEA

### 9.3.1 General assumptions

Table 29. TEA general assumptions.

| Assumption | Value | Unit | Source |
|---|---|---|---|
| Plant scale | 300 | MW (LHV) | As in proposal |
| Asset lifetime | 25 | Years | As in proposal |
| System output pressure (of $H_2$) | 200 | bar g | As in proposal and IEAGHG blue hydrogen studies |
| Minimum output $H_2$ purity | 97 | % | As in proposal and IEAGHG blue hydrogen studies |
| Discount factor | 8 | % | As standard (and in previous study) |
| Total site RES capacity | 1 | GW | Rough sizing of RES to complement electrolysers of multiple 100 MW scales |
| Unit tap water demand (indiscriminate by electrolyser type) | 20 | kg/kg $H_2$ | Hydrogen supply chain evidence base[23] |
| Unit water costs | 0.002 | €/kg $H_2$ | Lazard[83] |
| Compressor efficiency | 62% | % | Combining electrical, mechanical, isentropic efficiencies and $H_2$ losses, as reported by Hyjack[210] among other sources |
| Grid electricity cost (2030) | 103.17 | €/MWh | As in previous Element – IEAGHG study on Blue $H_2$[4,5,84,85] |
| Grid electricity cost (2050) | 107.82 | €/MWh | As in previous Element – IEAGHG study on Blue $H_2$[4,5,84,85] |
| Onshore wind generated electricity cost (2030) | 45 | €/MWh | [87] |
| Offshore wind generated electricity cost (2030) | 40 | €/MWh | [87] |
| Solar electricity cost (2030) | 35 | €/MWh | [87] |
| Onshore wind generated electricity cost (2050) | 40 | €/MWh | [87, 211] |

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[210] Hyjack. Compressor sizing. Accessed on 01/08/23.

[211] IEA 2021, Net Zero by 2050 - A Roadmap for the Global Energy Sector.

| | | | |
|---|---|---|---|
| Offshore wind generated electricity cost (2050) | 25 | €/MWh | 87 |
| Solar electricity cost (2050) | 25 | €/MWh | 87 |

### 9.3.2 Electrolyser assumptions

Table 30. TEA assumptions for AEL.

| Electrolyser | Value (2030) | Value (2050) | Unit |
|---|---|---|---|
| **Electrolyser efficiency (LHV) system** | 50[212] | 48[20] | kWh/kg $H_2$ |
| **Electrolyser efficiency (LHV)** | 67%[212] | 69% | % |
| **Electrolyser minimum load** | 15%[20] | 5[20] | % |
| **Electrolyser unit capex (installed)** | 1400[81] | EST.300[20,81] | €/kW |
| **Stack lifetime** | 9[20] | 11[20] | Years |
| **Stack replacement cost (% CAPEX)** | 20% (ranges between 5-40% in literature) | 20% | % |
| **Stack replacement cost** | 280 | 60 | €/kW |
| **Electrolyser O&M costs** | 1.5%[83] | 1.5%[83] | % CAPEX |
| **Electrolyser output pressure** | 30[20] | 70[20] | bar |

Table 31. TEA assumptions for PEM.

| Electrolyser | Value (2030) | Value (2050) | Unit |
|---|---|---|---|
| **Electrolyser efficiency (LHV) system** | 50[212] | 48[20] | kWh/kg $H_2$ |
| **Electrolyser efficiency (LHV)** | 67%[212] | 69% | % |
| **Electrolyser minimum load** | 5%[20] | 5[20] | % |

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[212] Hydrogen Tech World 2022, Electrolysis technologies and lcoh current state and prospects for 2030.

| | | | |
|---|---|---|---|
| **Electrolyser unit capex (installed)** | 1800[81] | EST.300[20,81] | €/kW |
| **Stack lifetime** | 7[20] | 11[20] | Years |
| **Stack replacement cost (% CAPEX)** | 20% (ranges between 5-40% in literature) | 20% | % |
| **Stack replacement cost** | 360 | 60 | €/kW |
| **Electrolyser O&M costs** | 1.5%[83] | 1.5%[83] | % CAPEX |
| **Electrolyser output pressure** | 70[20] | 70[20] | bar |

Table 32. TEA assumptions SOEC.

| Electrolyser | Value (2030) | Value (2050) | Unit |
|---|---|---|---|
| **Electrolyser efficiency (LHV) system** | 38[212] | 35[20] | kWh/kg $H_2$ |
| **Electrolyser efficiency (LHV)** | 88%[212] | 95% | % |
| **Electrolyser minimum load** | 30%[20] | 5%[20] | % |
| **Electrolyser unit capex (installed)** | 2500[20,81] | EST.400[20,81] | €/kW |
| **Stack lifetime** | 6[20] | 9[20] | Years |
| **Stack replacement cost (% CAPEX)** | 20% (ranges between 5-40% in literature) | 20% | % |
| **Stack replacement cost** | 500 | 80 | €/kW |
| **Electrolyser O&M costs** | 1.5%[83] | 1.5%[83] | % CAPEX |
| **Electrolyser output pressure** | 10[20] | 70[20] | bar |

Table 33. TEA assumptions AEM.

| Electrolyser | Value (2030) | Value (2050) | Unit |
|---|---|---|---|
| **Electrolyser efficiency (LHV) system** | 55[212] | 48[213] | kWh/kg $H_2$ |
| **Electrolyser efficiency (LHV)** | 61%[212] | 69% | % |
| **Electrolyser minimum load** | 5%[20] | 5%[20] | % |
| **Electrolyser unit capex (not installed)** | 1000 (quoted by Enapter for small scale system) | EST.300[20,81] | €/kW |
| **Stack lifetime** | 3[20] | 11[20] | Years |
| **Stack replacement cost (% CAPEX)** | 20% (ranges between 5-40% in literature) | 20% | % |
| **Stack replacement cost** | 200 | 60 | €/kW |
| **Electrolyser O&M costs** | 1.5%[83] | 1.5%[83] | % CAPEX |
| **Electrolyser output pressure** | 35[20] | 70[20] | bar |

### 9.3.3 Compressor design

In the techno-economic analysis, the compressor was sized based on the flow rate of hydrogen produced for a given technology and scenario. Compressor sizing is aligned between the life cycle GHG assessment and TEA.

The starting pressure was set by the electrolyser output pressure. The final pressure was set to 200 bar g. The temperature was set to 20°C. The number of compressor stages was set to accommodate the step in pressurisation required. A diaphragm compressor was modelled.

Table 34: Parameters used for compressor sizing

| Mechanical efficiency ($\eta_{mech}$) | Electrical Efficiency ($\eta_{elec}$) | Leaks | Isentropic efficiency($\eta_{isen}$) (diaphragm compressor) | Compressor stages (N) |
|---|---|---|---|---|
| **79%** | 95% | 3% | 85% | Dependent on compression ratio (system output pressure: electrolyser output pressure) |

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[213] Aligned with central case life cycle GHG assessment.

The below equation[214] was used to calculate the rated power of the compressor required, assuming $C_p/C_v$= 1.41[215] and the compressibility factor of $H_2$ to be 1.27 (2 d.p.)[216].

$$P_{multi\ stage} = N\left(\frac{k}{k-1}\right)\left(\frac{Z}{\eta_{isen}}\right)T_{suc}(q_M)R\left[\left(\frac{P_{disc}}{P_{suc}}\right)^{\left(\frac{k-1}{Nk}\right)} - 1\right]$$

$$P_{rated} = P_{multi-stage} \times \frac{(1 + Leaks)}{\eta_{mech}\eta_{elec}}$$

Compressor costing (CAPEX and OPEX) was calculated using the same methodology as presented in the IEAGHG Blue $H_2$ production model applied in previous studies[4,5]. Compressor sizing was aligned between the TEA and life cycle GHG assessment, with system efficiency (~62%) tested across multiple methodologies to confirm the accuracy of compressor sizing calculations.

### 9.3.4 Heat generation cost (SOEC only)

The operating conditions presented in Table 35 were assumed.

Table 35. SOEC operating conditions.

| Technology | Oxide Ion Transport Solid-Oxide Electrolysis |
|---|---|
| **2023 Operating Temperature** | 700 – 800 °C[20] |
| **2023 Operating Pressure** | 1 bar[20] |
| **2050 Operating Temperature** | 600 °C[20] |
| **2050 Operating Pressure** | 20bar[20] |

The water requirements for the steam boiler were estimated using the assumptions in Table 36. It was assumed that losses and inefficiencies not accounted for upstream in the process would account for 10% losses each.

Table 36. Steam boiler requirements.

| Property | Value |
|---|---|
| **Stoichiometric water demand (kg $H_2O$/kg $H_2$)** | 9 |
| **Boiler inefficiency (%)** | 10 |
| **Steam losses between the boiler and electrolyser (%)** | 10 |
| **Steam boiler requirements (kg $H_2O$/kg $H_2$)** | 10.89 |

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[214] Khan. M et al., 2021, The Techno-Economics of Hydrogen Compression.
[215] Bhattacharjee. S., Properties of Various Ideal Gases (at 300 K). Accessed on 01/08/23.
[216] Department for Energy Security & Net Zero 2023, UK Low Carbon Hydrogen Standard, Version 2, April 2023: data table annex.

Gas costs were assumed consistent with previous IEAGHG studies on blue hydrogen. Gas costs between 2030-2055 and 2050-2075 were respectively averaged to form an average gas cost in €/MWh. This was converted to a cost in €/kg steam through the following equation:

$$Fuel\ cost\ \left({}^{€}/_{kg}\ steam\right) = Gas\ price\ \times \left(\frac{Steam\ enthalpy - Feedwater\ enthalpy}{Boiler\ efficiency}\right)$$

The fuel cost was calculated based on the gas cost and operating conditions of the SOEC in 2030 and 2050, as in. Table 37. From this the final steam cost was calculated by applying an adjustment of +30% to account for other associated costs (raw water supply, water feed treatment, feed pumping power, air fan, boiler blowdown, ash disposal, emissions control and material and labour)[217]. This was then multiplied to account for the heat demand of 8 kWh/kg $H_2$. This led to the final cost of steam as in

Table 37. Fuel cost (€/kg steam)

| | Units | 2030 | 2050 |
|---|---|---|---|
| **Gas cost** | *€ / MWh* | 29.99 | 30.67 |
| **Steam enthalpy** | kJ/kg | 4159.7[218] | 3705.5 |
| **Steam enthalpy** | kWh/kg | 1.15 | 1.03 |
| **Feedwater enthalpy** | kJ/kg | 54.66219 | 54.66 |
| **Feedwater enthalpy** | kWh/kg | 0.015 | 0.015 |
| **Boiler efficiency** | % | 85%[220] | 85% |
| **Fuel cost** | €/kg steam | 0.040 | 0.037 |

Table 38. Total cost of heat (steam).

| Cost | Units | 2030 | 2050 |
|---|---|---|---|
| **Steam generation costs** | *€ / kg* | 0.05 | 0.05 |
| **Steam value (€/kg $H_2$)** | *€ / kg* | 0.57 | 0.52 |

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[217] DOE 2003, How to Calculate the True Cost of Steam.
[218] Thermopedia 2011, STEAM TABLES.
[219] ThermExcel, Physical characteristics of water. Accessed on 03/08/23.
[220] IEA 2010, Industrial Combustion Boilers.

## 9.4 TEA Results

### 9.4.1 Results of primary analysis

Table 39. Lifetime hydrogen production by scenario and technology. Discounted and undiscounted.

| | | 2030 | | | | | | | | | 2050 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | AEL | | | PEM | | | SOEC | | | AEL | | | PEM | | | SOEC | | |
| | | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 |
| **Undiscounted** | *kt* | 1,260 | 870 | 81 | 1,260 | 872 | 87 | 1,657 | 1,126 | 73 | 1,312 | 908 | 90 | 1,312 | 908 | 90 | 1,800 | 1,246 | 124 |
| **Discounted** | *kt* | 583 | 402 | 37 | 583 | 403 | 41 | 767 | 521 | 34 | 607 | 420 | 42 | 607 | 420 | 42 | 832 | 576 | 57 |

Table 40. Discounted LCOH by technology and scenario.

| | | 2030 | | | | | | | | | 2050 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | AEL | | | PEM | | | SOEC | | | AEL | | | PEM | | | SOEC | | |
| **LCOH** | | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 | S1 | S2 | S3 |
| **Electrolyer - Capex** | *€ / kg* | 1.69 | 2.44 | 26.27 | 2.17 | 3.14 | 31.56 | 2.29 | 3.37 | 51.76 | 0.35 | 0.50 | 5.05 | 0.35 | 0.50 | 5.05 | 0.34 | 0.49 | 4.91 |
| **Electrolyser - Fixed OPEX (lifetime)** | *€ / kg* | 0.12 | 0.18 | 1.94 | 0.16 | 0.23 | 2.33 | 0.17 | 0.25 | 3.82 | 0.03 | 0.04 | 0.37 | 0.03 | 0.04 | 0.37 | 0.02 | 0.04 | 0.36 |
| **Electrolyser - Stack replacement costs (lifetime)** | *€ / kg* | 0.11 | 0.07 | 0.00 | 0.21 | 0.17 | 0.00 | 0.28 | 0.22 | 0.00 | 0.02 | 0.01 | 0.00 | 0.02 | 0.01 | 0.00 | 0.02 | 0.02 | 0.00 |
| **Electrolyser - Electricity costs** | *€ / kg* | 5.66 | 2.03 | 1.99 | 5.66 | 2.03 | 1.99 | 4.30 | 1.55 | 1.51 | 5.43 | 1.95 | 1.91 | 5.43 | 1.95 | 1.91 | 3.96 | 1.42 | 1.39 |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Electrolyser - Water costs** | *€/ kg* | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| **Compressor - Capex** | *€/ kg* | 0.02 | 0.03 | 0.21 | 0.01 | 0.02 | 0.12 | 0.03 | 0.05 | 0.47 | 0.01 | 0.02 | 0.12 | 0.01 | 0.02 | 0.12 | 0.01 | 0.02 | 0.11 |
| **Compressor - Fixed OPEX** | *€/ kg* | 0.01 | 0.01 | 0.05 | 0.00 | 0.00 | 0.03 | 0.01 | 0.01 | 0.11 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.03 |
| **Compressor - Electricity costs** | *€/ kg* | 0.16 | 0.06 | 0.04 | 0.10 | 0.04 | 0.02 | 0.29 | 0.12 | 0.08 | 0.12 | 0.04 | 0.03 | 0.11 | 0.04 | 0.02 | 0.10 | 0.04 | 0.02 |
| **Heat cost (SOEC only)** | *€/ kg* | | | | | | | 0.57 | 0.57 | 0.57 | | | | | | | 0.52 | 0.52 | 0.52 |
| **TOTAL** | *€/ kg* | 7.81 | 4.87 | 30.53 | 8.35 | 5.67 | 36.09 | 7.99 | 6.17 | 58.36 | 5.99 | 2.61 | 7.54 | 5.98 | 2.60 | 7.54 | 5.01 | 2.58 | 7.38 |

### 9.4.2 Results of sensitivity analysis

Table 41. Sensitivity analysis – LCOH of AEL produced $H_2$ in 2030 with varying electricity cost.

| Scenario | LCOH (€/kg) – base case | LCOH (€/kg) – +50% electricity costs | LCOH (€/kg) - -50% electricity costs |
|---|---|---|---|
| **Grid connected** | 7.81 | 10.72 | 4.9 |
| **RES load following** | 4.87 | 5.92 | 3.82 |

Table 42. Sensitivity analysis – LCOH of AEL produced $H_2$ in 2030 with the introduction of a grid charge to electricity cost. 2030, AEL, S2.

| Scenario | LCOH (€/kg) – base case | LCOH (€/kg) – with grid charge |
|---|---|---|
| **RES load following** | 4.87 | 7.74 |

Table 43. Sensitivity analysis - LCOH of AEL produced $H_2$ in 2030 with varying electrolyser capacity (base case (BC), +/-50%).

| Scenario | BC 300 MW (LCOH) | +50% 450 MW (LCOH) | -50% 150 MW (LCOH) | BC (kTH₂/ year) | +50% (kTH₂/ year) | -50% (kTH₂/ year) |
|---|---|---|---|---|---|---|
| **S1: GRID** | 7.81 | 7.81 | 7.81 | 53 | 79 | 26 |
| **S2: RES** | 4.87 | 6.03 | 4.21 | 36 | 38 | 25 |
| **S3: Curtail** | 30.53 | 51.59 | 15.78 | 3.4 | 2.9 | 3.5 |

Table 44. Sensitivity analysis - LCOH of SOEC produced $H_2$ in under S2& S3 with varying RES capacity (base case (BC), +/-50%).

| Scenario | BC 1 GW (LCOH) | +50% 1.5GW (LCOH) | -50% 0.5GW (LCOH) | BC 1 GW (kTH₂/year) | +50% 1.5GW (kTH₂/year) | -50% 0.5GW (kTH₂/year) |
|---|---|---|---|---|---|---|
| **RES 2030** | 6.17 | 5.43 | 10.99 | 47 | 60 | 20 |
| **RES 2050** | 2.58 | 2.47 | 3.04 | 52 | 65 | 27 |
| **Curtail 2030** | 58.36 | 30.32 | 2,891.19 | 2.3 | 4.7 | 0.45 |
| **Curtail 2050** | 7.38 | 5.60 | 12.91 | 5.2 | 7.8 | 2.5 |

Table 45. Cost of heat sensitivity. SOEC, 2030 and 2050.

| | | BC | Gas cost +50% | Gas cost -50% | Waste heat |
|---|---|---|---|---|---|
| **2030** | Grid | 7.99 | 8.27 | 7.70 | 7.43 |
| | RES | 6.17 | 6.45 | 5.89 | 5.61 |
| | Curtail | 58.36 | 58.64 | 58.07 | 57.80 |
| **2050** | Grid | 5.01 | 5.27 | 4.75 | 4.51 |
| | RES | 2.58 | 2.83 | 2.316725 | 2.07 |
| | Curtail | 7.38 | 7.64 | 7.12 | 6.88 |

## 9.5 Data and Assumptions used in the life cycle GHG assessment

### 9.5.1 Electrolytic hydrogen production

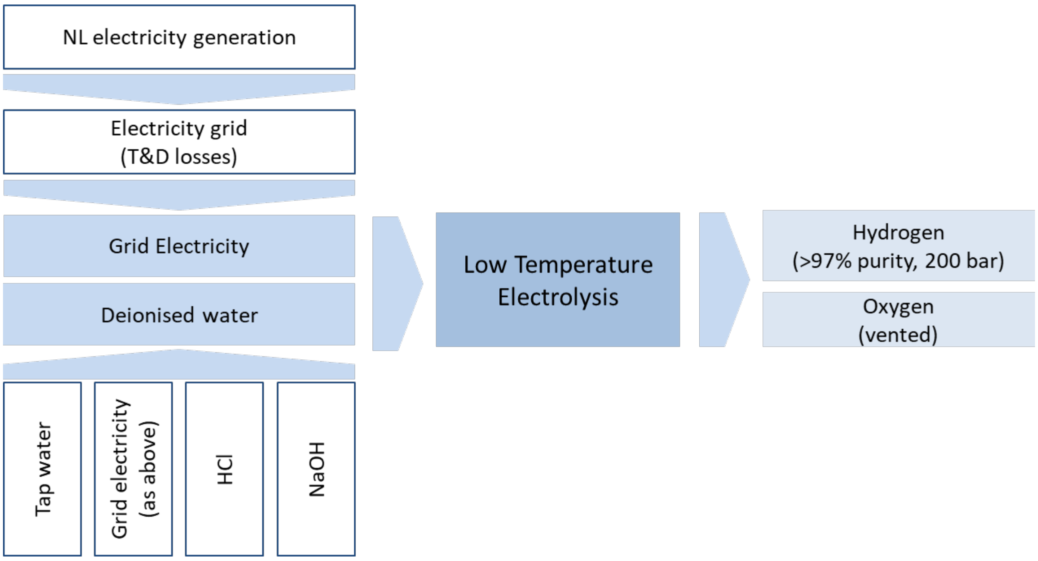

Figure 74: Process flow diagram of electrolytic hydrogen production

A range of electrolyser efficiencies have been used to provide a Best, Worst and Central case for each electrolysis pathway. The 2030 and 2050 efficiencies used in the model and relevant data sources are referenced in the table below.

### Table 46: Electrolyser electrical efficiencies (LHV) used in the TEA and life cycle GHG modelling

| Electrolyser type | Efficiencies in 2030 | Hydrogen production in 2030 (MJ $H_2$/MJ elec) | Efficiencies in 2050 | Hydrogen production in 2050 (MJ $H_2$/MJ elec) |
|---|---|---|---|---|
| **AEL** | 60[221]-69[20]%<br>(central: 67%[31]) | 1.44-1.68<br>(central: 1.50) | 63[23]-74%[,23]<br>(central: 69%[23]) | 1.35-1.59<br>(central: 1.44) |
| **PEM** | 60[20]-69%[23]<br>(central: 67%[31]) | 1.44-1.67<br>(central: 1.50) | 65-74%[23]<br>(central: 69%) | 1.35-1.55<br>(central: 1.44) |
| **SOEC** | 74-90%[20, 221]<br>(central: 88%[31]) | 1.11-1.35<br>(central: 1.14) | 90-98%[23]<br>(central: 95%) | 1.02-1.11<br>(central: 1.05) |
| **AEM** | 58-69%[20, 221]<br>(central: 61%[31]) | 1.44-1.71<br>(central:1.65) | 61-74%[20,31]<br>(central: 69%[31]) | 1.35-1.65<br>(central: 1.44) |

### Table 47: Process data for electrolytic hydrogen production common to all electrolyser technologies modelled (the same values were assumed across Best/Central/Worst case in 2030 and 2050)

| Variable | Units | Value |
|---|---|---|
| **Inputs** | | |
| Tap Water | $m^3/kgH_2$ | 0.00017[222] |
| Sodium hydroxide | $kg/kgH_2$ | 0.00002[222] |
| Hydrochloric acid | $kgHCl/kgH_2$ | 0.00004[222] |
| **Energy** | | |
| Electrical requirement to deionise | MJ elec/MJ $H_2$ | 0.00027[222] |
| **Emissions** | | |
| Fugitive hydrogen | $gH_2$/MJ $H_2$ | No fugitive hydrogen emissions assumed in baseline |
| **Products** | | |
| Hydrogen | MJ $H_2$/MJ $H_2$ | 1.00 |
| Oxygen | $gO_2$/MJ $H_2$ | 66.13[223] |
| **Process** | | |
| Purity of Hydrogen | % | >97% |
| Hydrogen Export Pressure | bar | 200.00 |

### Table 48: Process data for electrolytic hydrogen production with an AEL electrolyser

| Variable | Units | Central Case | Best Case | Worst Case |
|---|---|---|---|---|

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[221] Clean Hydrogen Partnership 2022, Renewable hydrogen production.

[222] Ecoinvent 2007, Life Cycle Inventories of Chemicals Data v2.0. Table 93.2.

[223] Calculated based on molar masses and water input

| | | | | |
|---|---|---|---|---|
| Electrical requirement for electrolyser - 2030[224] | MJ elec/MJ $H_2$ | 1.50 | 1.44 | 1.68 |
| Electrical requirement for electrolyser – 2050 | | 1.44 | 1.35 | 1.59 |
| Electrical requirement for hydrogen compression – 2030 | MJ elec/MJ $H_2$ | 0.046 | | |
| Electrical requirement for hydrogen compression – 2050 | MJ elec/MJ $H_2$ | 0.026 | | |

**Table 49: Process data for electrolytic hydrogen production with a PEM electrolyser**

| Variable | Units | Central Case | Best Case | Worst Case |
|---|---|---|---|---|
| Electrical requirement for electrolyser – 2030 | MJ elec/MJ $H_2$ | 1.50 | 1.44 | 1.67 |
| Electrical requirement for electrolyser - 2050 | MJ elec/MJ $H_2$ | 1.44 | 1.35 | 1.55 |
| Electrical requirement for hydrogen compression – 2030 | MJ elec/MJ $H_2$ | 0.026 | | |
| Electrical requirement for hydrogen compression – 2050 | MJ elec/MJ $H_2$ | 0.026 | | |

**Table 50: Process data for electrolytic hydrogen production with a SOEC electrolyser**

| Variable | Units | Central Case | Best Case | Worst Case |
|---|---|---|---|---|
| Electrical requirement for electrolyser – 2030 | MJ elec/MJ $H_2$ | 1.14 | 1.11 | 1.35 |
| Electrical requirement for electrolyser – 2050 | MJ elec/MJ $H_2$ | 1.05 | 1.02 | 1.11 |
| Heat Requirement – 2030 / 2050 | MJ heat/MJ $H_2$ | 0.24[221] | | |
| Electrical requirement for hydrogen compression – 2030 | MJ elec/MJ $H_2$ | 0.073 | | |
| Electrical requirement for hydrogen compression – 2050 | MJ elec/MJ $H_2$ | 0.026 | | |

**Table 51: Process data for electrolytic hydrogen production with an AEM electrolyser**

| Variable | Units | Central Case | Best Case | Worst Case |
|---|---|---|---|---|
| Electrical requirement for electrolyser – 2030 | MJ elec/MJ $H_2$ | 1.65 | 1.44 | 1.71 |
| Electrical requirement for electrolyser – 2050 | MJ elec/MJ $H_2$ | 1.44 | 1.35 | 1.65 |
| Electrical requirement for hydrogen compression – 2030 | MJ elec/MJ $H_2$ | 0.042 | | |
| Electrical requirement for hydrogen compression – 2050 | MJ elec/MJ $H_2$ | 0.028 | | |

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[224] Electrical requirements for each electrolyser have been calculated from the electrical efficiencies listed for each electrolyser in Table 46.

### 9.5.2 Ammonia distribution

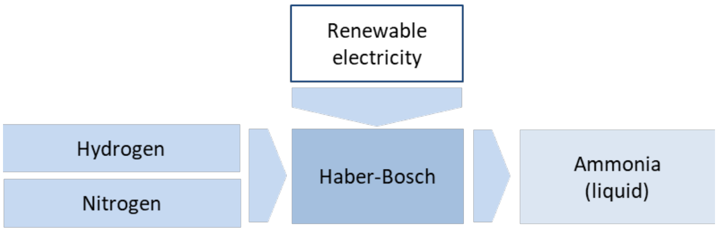

Figure 75: Process flow diagram of ammonia distribution

Table 52: Process data for ammonia distribution

| Process step | Units | |
|---|---|---|
| **Ammonia production** | | |
| Electricity requirement | GJ elec/tonne ammonia | 1.80[225] |
| Ammonia LHV | MJ/kg | 18.6[225] |
| Step efficiency | % | 80.7%[225] |
| **Trucking** | | |
| Distance from production plant to storage / Distance from second storage to end user | km | 300[226] |
| Trucking ammonia tanker adjustment factor | Tonne tank+cargo/tonne cargo | 1.90[227] |
| Step efficiency | % | 100%[228] |
| **Storage (1)** | | |
| Electricity requirement | kWh elec/kg ammonia | 0.005[227] |
| Boil-off | %/day | 0%[227]<br>0.03%[229] (Worst case only) |
| Storage days | days | 20[227] |
| Step efficiency | % | 100% |

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[225] IEA 2021, Ammonia Technology Roadmap Process requires 36 GJ elec/tonne ammonia produced with efficiency of 64%.

[226] JEC WTT v5 2020, Appendix 1 Pathways 8 H2.xlsx Assumed transport distance of trucking ammonia would be the same as trucking liquid hydrogen.

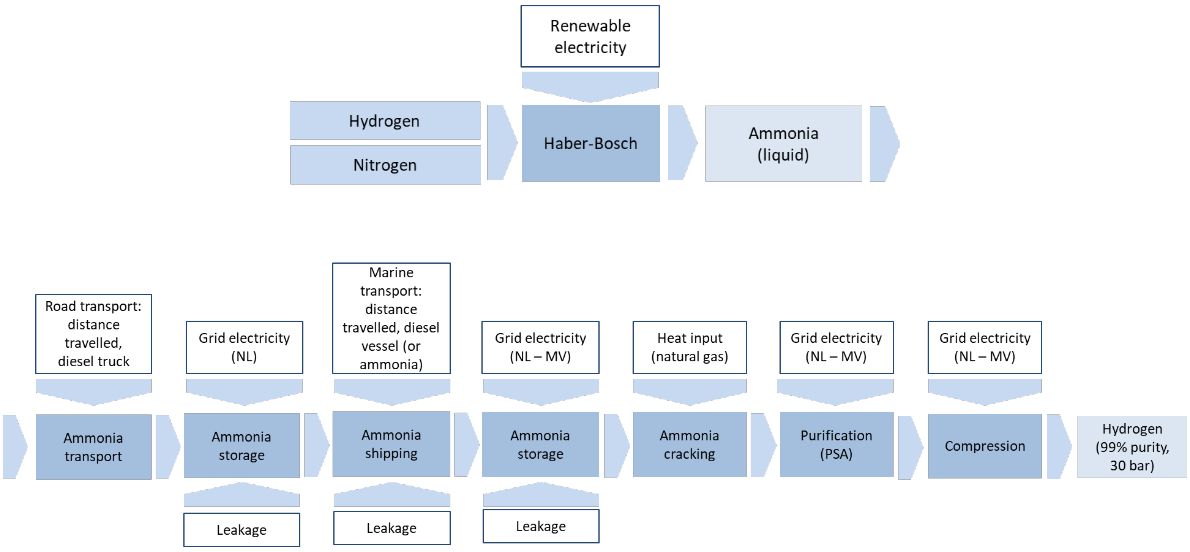
[227] IEA 2020, IEA G20 Hydrogen report: Assumptions States 2.6 tonnes of hydrogen capacity per truck (14.7 tonnes of ammonia using molar mass of ammonia). Not a full 26 tonne cargo liquid tanker as stated in JEC WTT v5 2020, Appendix 1 Pathways 5 Synfuels.xlsx. Given the road transport emission factor is based on this JEC dataset, ammonia trucking has been adjusted upwards to reflect the smaller cargo.

[228] No loss in transport is assumed

[229] DNV 2020, GIE database Liquid Renewable Energy

| | | |
|---|---|---|
| | | 99% (Worst case only)[230] |
| **Shipping** | | |
| Distance from the Netherlands to the USA | km | 9,300[231] |
| Boil-off | %/day | 0%[227]<br>0.08%[229] (Worst case only) |
| Flash rate | % | 0[227] |
| Ship speed | km/hr | 30[227] |
| Step efficiency | % | 100%<br>99% (Worst case only)[230] |
| **Storage (2)** | | |
| Electricity requirement | kWh/kg ammonia | 0.020[227] |
| Boil-off rate | %/day | 0%[227]<br>0.03%[229] (Worst case only) |
| Storage days | days | 20[227] |
| Step efficiency | % | 100%<br>99% (Worst case only) [230] |

## 9.5.3 Ammonia with cracking back to hydrogen



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[230] Calculated from above losses
[231] Sea-Distances 2023, Port of Departure to Port of Arrival

Figure 76: Process flow diagram of ammonia distribution with cracking back to hydrogen

The input data used to model ammonia production and distribution is provided in Table 52. The additional inputs for ammonia cracking to produce gaseous hydrogen is provided in the table below.

Table 53: Process data for ammonia distribution with cracking back to hydrogen

| Process step | Units | Value |
|---|---|---|
| **Ammonia cracking** | | |
| Heat requirement | kWh heat/kg pure $H_2$ | 9.70[227]<br>0 (Best case only)[232] |
| Heating efficiency | % | 90%[233] |
| Step efficiency | % | 99%[227]<br>99.5% (Best case only)[232] |
| **Hydrogen purification** | | |
| Electricity requirement | kWh elec/kg$H_2$ | 1.50[227]<br>0.05 for Best case only[232] |
| Step efficiency | % | 85%[227]<br>91% (Best case only)[232] |
| **Hydrogen compression** | | |
| Electricity requirement | kWh elec/kg$H_2$ | 0.34[234] |
| Step efficiency | % | 100%[235] |
| **Products** | | |
| Hydrogen | MJ/MJ $H_2$ | 1.00 |
| Residual cracker gases | MJ/MJ $H_2$ | 0.01[236]<br>0.005 (Best case only) |
| PSA off gases | MJ/MJ $H_2$ | 0.18<br>0.10 (Best case only) |

In the Central and Best cases, the cracker and PSA off gases are assumed to be consumed in process heating and therefore are not exported as a coproduct. In the Worst case, it is assumed that the mixed/impure gases would be used locally by other nearby plants (e.g. for heating) therefore the gases are considered as an exported co-product stream.

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[232] H21 North of England 2018, Figure 3.37 and Table 3.22. Assume all internal heating is provided by PSA off gases and there are no co-products.

[233] JEC WTT v5 2020, Appendix 1 Pathways 7 Heat and Power.xlsx

[234] BEIS 2021, UK Low Carbon Hydrogen Standard. Assumed that 0.1 bar residue off-gases from PSA are used onsite within the ammonia cracking process, and do not need compression. Assume output pressure of 17 bar from H21 North of England 2018 and compressed to 30 bar.

[235] No loss in final compression assumed

[236] Residual cracker gases and PSA off gases are calculated from the PSA step efficiency

### 9.5.4 Liquid hydrogen

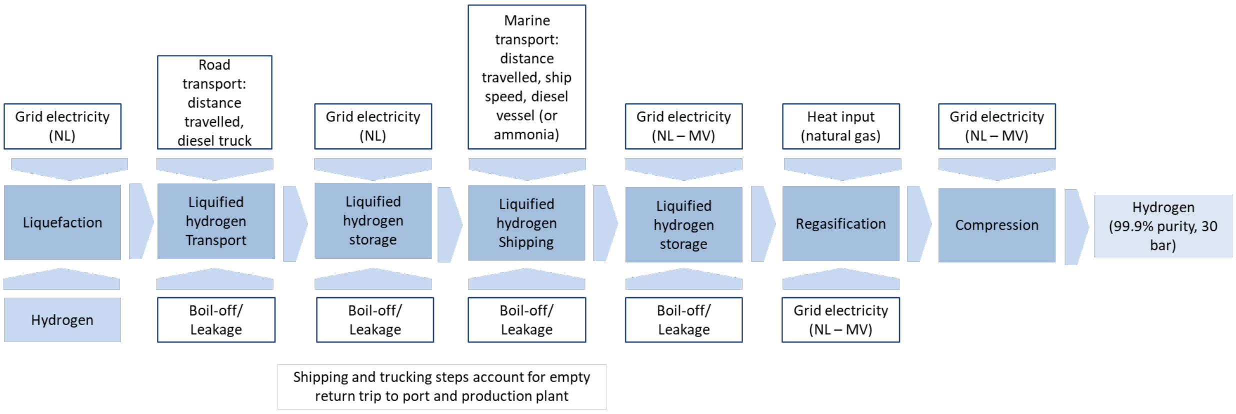

Figure 77: Process flow diagram of liquid hydrogen distribution

Table 54: Process data for liquid hydrogen (LH$_2$) distribution

| Variable | Units | Value |
|---|---|---|
| **Liquify** | | |
| Electricity requirement – 2030 | kWh elec/tonne LH$_2$ | 8.70 (Central case)[225]<br>6.10 (Best case)<br>11.31 (Worst case) |
| Electricity requirement – 2050 | kWh elec/tonne LH$_2$ | 6.10<br>7.93 (Worst case only) |
| Liquid hydrogen LHV | MJ/kg | 120[225] |
| Step efficiency | % | 100%[237] |
| **Transport** | | |
| Distance from production plant to storage / Distance from second storage to end user | km | 300[238] |
| Trucking liquid hydrogen tanker adjustment factor | tonne tank+cargo/tonne cargo | 7.86[238] |
| Boil-off rate | %/day | 0.45% (Central case)[239]<br>0.3% (Best case)<br>0.6% (Worst case) |
| Trucking time | days | 0.25[240] |
| Step efficiency | % | 99.89% (Central case)[230]<br>99.93% (Best case) |

---

[237] No boil off assumed in IEA 2020, IEA G20 Hydrogen report: Assumptions
[238] JEC WTT v5 2020, Appendix 1 Pathways 8 H2.xlsx
[239] Aziz 2021 Liquid Hydrogen A Review on Liquefaction, Storage, Transportation, and Safety, page 19
[240] Assume 50 km/hr average truck speed

| | | |
|---|---|---|
| | | 99.85% (Worst case) |
| **Storage** | | |
| Electricity requirement | kWh elec/kg $LH_2$ | 0.61[108] |
| Boil-off rate | %/day | 0.1% (Central case)[227]<br>0.03% (Best case)[229]<br>0.3% (Worst case)[229] |
| Flash rate | % | 0.1%[227] |
| Storage time | days | 20[227] |
| Step efficiency | % | 97.9% (Central case)[230]<br>99.3% (Best case)<br>93.9% (Worst case) |
| **Shipping** | | |
| Distance from the Netherlands to the USA | km | 9,300[241] |
| Boil-off rate | %/day | 0.2% (Central case) [227]<br>0.1% (Best case)[229]<br>0.4% (Worst case)[229] |
| Flash rate | % | 1.3[227] |
| Ship speed | km/hr | 30[227] |
| Use of boil-off $H_2$ for propulsion | %/day | 0.08%[227] |
| Step efficiency | % | 96.1% (Central case)[230]<br>97.4% (Best case)<br>93.5% (Worst case) |
| **Storage (2)** | | |
| Electricity requirement | kWh elec/kg $LH_2$ | 0.20[227] |
| Boil-off rate | %/day | 0.1% (Central case) [227]<br>0.03% (Best case)[229]<br>0.3% (Worst case)[229] |
| Flash rate | % | 0.1%[227] |
| Step efficiency | % | 97.9% (Central case)[230]<br>99.3% (Best case)<br>93.9% (Worst case) |
| **Regasification** | | |
| Electricity requirement | kWh elec/kg $H_2$ | 0.02 (Central case)[242]<br>0 (Best case) [227]<br>0.03 (Worst case)[242] |
| Natural gas requirement | kWh elec/kg $H_2$ | 0.041 (Central case)[242] |

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[241] Sea-Distances 2023, Port of Departure to Port of Arrival.

[242] Øyvind Sekkesæter 2020, Evaluation of Concepts and Systems for Marine Transportation of Hydrogen. Page 94.

| | | |
|---|---|---|
| | | 0 (Best case)[227]<br>0.14 (Worst case)[242] |
| Hydrogen compression | | |
| Electricity requirement | kWh/kg $H_2$ | 2.01[243]<br>0[244] (Best case only) |
| Step efficiency | % | 100%[227] |

### 9.5.5 Compressed pipeline

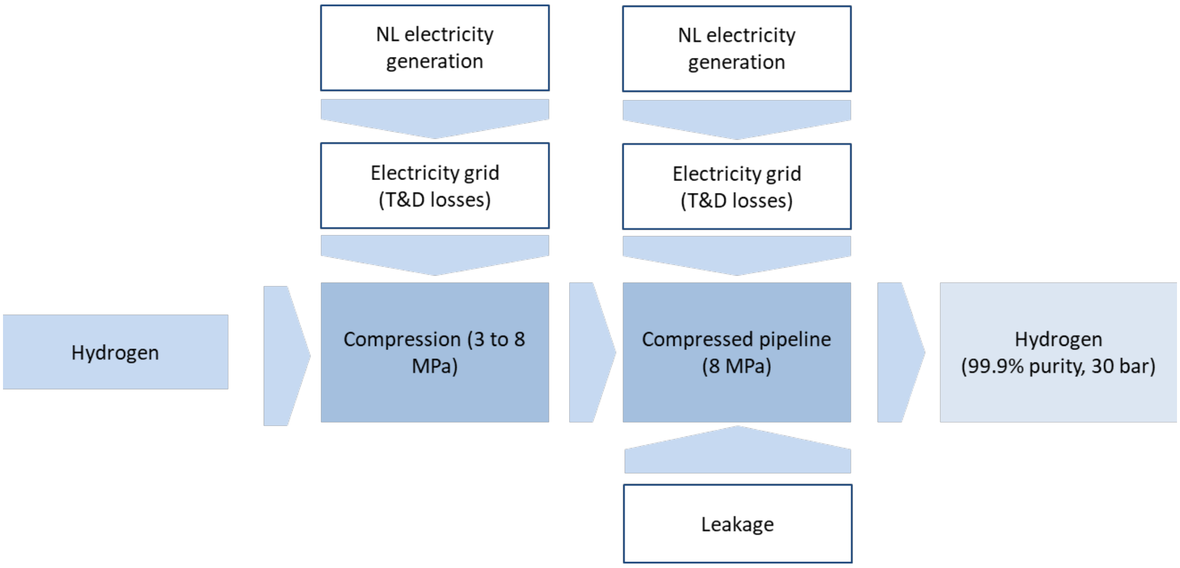

Figure 78: Process flow diagram of compressed hydrogen distribution

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[243] Element Energy 2021, Low Carbon Hydrogen Well-to-Tank Pathways Study – Full Report. Assume compression from 1 bar to 30 bar is required. Assume isentropic compression with 92% driver efficiency.

[244] Hinkley, J. T. 2021, Energies, A New Zealand Perspective on Hydrogen as an Export Commodity: Timing of Market Development and an Energy Assessment of Hydrogen Carriers. It is possible that a cold engine/Brayton cycle at high efficiency (up to 72%) could generate the required electricity from the LH2 regasification step. This generation could be up to a theoretical maximum of 2.8 kWh elec/kg $H_2$ hence in the Best case we assume this is sufficient to fully meet the compression needs.

Table 55: Process data for compressed hydrogen distribution

| Process step | Units | Value |
|---|---|---|
| **Compression** | | |
| Electricity requirement | MW elec/MW $H_2$.km | 0.000011[245] (Central case)<br>0.000002[244] (Best case)<br>0.000026[243] (Worst case) |
| Pipeline distance | km | 400[246] |
| Step efficiency | % | 100%[247] |
| **Pipeline** | | |
| Hydrogen losses | g/MJ $H_2$ | 0.013 (Central case)[248]<br>0.0083 (Best case)<br>0.017 (Worst case) |
| Step efficiency | % | 99.85% (Central case)[249]<br>99.90% (Best case)<br>99.80% (Worst case) |

### 9.5.6 Methanol

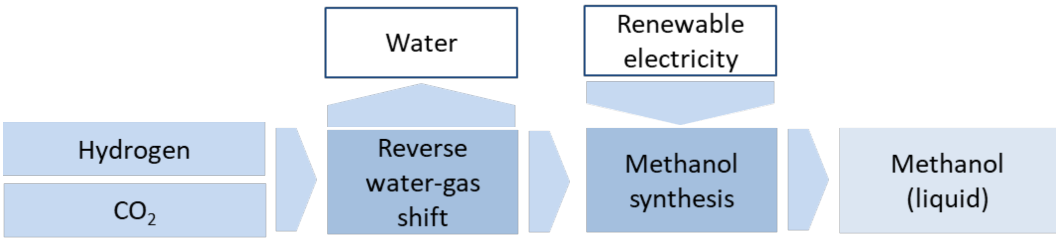

Figure 79: Process flow diagram of methanol distribution

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[245] European Hydrogen Backbone 2021, Analysing future demand, supply, and transport of hydrogen. Page 107, Table 35, Appendix C. Central case: 36 inch pipeline, 50 bar, at 75% capacity, Best case: 20 inch pipeline, 50 bar, at 25% capacity, Worst case: 48 inch pipeline, 80 bar, at 100% capacity

[246] FreeMapTools Netherlands to UK

[247] No loss in compression assumed

[248] National Grid data reports transmission level leakage is 0.1-0.2%

[249] Element Energy 2021, Low Carbon Hydrogen Well-To-Tank Pathways Study – Full Report Page 96 fugitive losses 0.1-0.2%

Table 56: Process data for methanol distribution

| Process step | Units | Value |
|---|---|---|
| **Methanol production** | | |
| Electricity requirement | GJ elec/tonne methanol | 3.60[250] |
| Carbon dioxide capture – 2030 | kg $CO_2$/MJ methanol | 0.089 (Central case)[251]<br>0.083 (Best case)<br>0.094 (Worst case) |
| Carbon dioxide capture – 2050 | kg $CO_2$/MJ methanol | 0.079 (Central case)<br>0.073 (Best case)<br>0.083 (Worst case) |
| Methanol LHV | MJ/kg | 19.9[252] |
| Step efficiency | % | 77% (Central case)[251]<br>83% (Best case)<br>71% (Worst case) |
| **Transport** | | |
| Distance from production plant to storage / Distance from second storage to end user | km | 300[238] |
| Trucking ammonia tanker adjustment factor | tonne tank+cargo/tonne cargo | 1.36[253] |
| Step efficiency | % | 100%[254] |
| **Storage** | | |
| Electricity requirement | kWh elec/kg methanol | 0.005[253] |
| Boil-off | %/day | 0%[255] |
| Storage days | days | 20[253] |
| Step efficiency | % | 100%[230] |
| **Shipping** | | |
| Distance from the Netherlands to the USA | km | 9,300[231] |
| Boil-off | % $H_2$ losses | 0%[255] |
| Ship speed | km/hr | 30[253] |
| Step efficiency | % | 100%[230] |
| **Storage** | | |

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[250] IRENA 2021, Innovation Outlook: Renewable Methanol Most electricity is for the electrolyser (~9-10 MWh/tonne methanol of the 10-11 MWh/tonne methanol input is used in the electrolysis step)

[251] Brynolf et al. 2018, Supplementary Material for "Electro fuels for the transport sector: a review of production costs"

[252] The Engineering Toolbox, Fuels – Higher and Lower Calorific Values

[253] IEA 2020, IEA G20 Hydrogen report: Assumptions States 2.6 tonnes of hydrogen capacity per truck (20.7 tonnes of methanol using molar mass of methanol). Not a full 26 tonne cargo liquid tanker as stated in JEC WTT v5 2020, Appendix 1_Pathways 5_Synfuels.xlsx. Given the road transport emission factor is based on this JEC dataset, methanol trucking has been adjusted upwards to reflect the smaller cargo. Assume same as ammonia storage at export terminal.

[254] No loss in transport is assumed

[255] DNV 2020, GIE database Liquid Renewable Energy No boil-off because it is liquid at ambient conditions

| | | |
|---|---|---|
| Electricity requirement | kWh elec/kg methanol | 0.025[253] |
| Boil-off | %/day | 0%[255] |
| Storage days | days | 20[253] |
| Step efficiency | % | 100%[230] |

### 9.5.7 Carbon footprint of natural gas and electricity production

The grid intensities of the utilities used in this study are given in the table below. The carbon intensity of the natural gas grid is assumed to be constant to 2050 while the electricity grid is expected to decarbonise. Sensitivities have been performed applying different decarbonisation scenarios to test the impact of the carbon intensity of the electricity and natural gas grids. Results are presented in Section 4.3.3.

**Table 57: Grid carbon intensity of utilities for the Dutch grid**

| Variable | Year | Units | GHG intensity |
|---|---|---|---|
| Natural gas grid | 2030 | $gCO_2e$/MJ natural gas | 66.0[256] |
| | 2050 | | Same as 2030 |
| Grid electricity | 2030 | $gCO_2e$/MJ elec | 16.7[115] |
| | 2050 | | 0[7] |

### 9.5.8 System expansion credit calculation

To calculate the system expansion credit for producing oxygen from electrolytic hydrogen production, the following inputs were used. The credit for oxygen production is modelled for an ASU to estimate the carbon intensity of this co-product. The electricity grid factors in Table 57 have been used to calculate emissions for 2030 and 2050. The carbon intensity in $gCO_2e$/MJ elec is multiplied by the electricity required in MJ elec/kg oxygen and the amount of oxygen output from electrolytic hydrogen production in kg $O_2/MJ_{LHV}$ $H_2$. This credit is then subtracted from the hydrogen production emissions for this pathway with 100% allocation to hydrogen.

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[256] European Commission 2022, Commission Implementing Regulation (EU) 2022/996, Standard values of emissions factors, Annex IX.

Table 58: Calculation of system expansion credit

| Variable | Units | GHG intensity |
|---|---|---|
| Electricity requirement for oxygen produced via an ASU | MJ elec/kg $O_2$ | 1.08[257] |
| Oxygen produced via electrolytic hydrogen production | g $O_2$/$MJ_{LHV}$ $H_2$ | 66.1[258] |
| Grid electricity | g$CO_2$e/MJ elec | See table above |
| System expansion credit (calculated from above rows) | g$CO_2$e/$MJ_{LHV}$ $H_2$ | 1.19 [2030]<br>0 [2050] |

## 9.5.9 Background process and data used in the life cycle GHG study

The background data used for to model the GHG emissions is listed in the following sections.

Table 59: Background data sources for the GHG impacts of inputs and outputs used

| Variable | Baseline impact | Low impact | High impact |
|---|---|---|---|
| Tap water | DESNZ (2023)[259] | Same as baseline | Same as baseline |
| NaOH | JRC (2017)[260] | Same as baseline | Biograce v4[261] |
| HCl | JEC (2017) | Same as baseline | Biograce v4 |
| Diesel (supply and use) | BEIS (2020)[262] | JRC (2017) | Biograce v4 |
| Carbon dioxide capture | JEC (2020)[263] – industrial flue gas | JEC (2020) - DAC | CRI (2015)[264] |
| Emission of Hydrogen | BEIS (2018)[265] - central | BEIS (2018) - low | BEIS (2018) - high |
| Emission of Oxygen | No GHG impacts associated with oxygen emission to air | | |
| Emission of ammonia | OzonAction[266] | Same as baseline | Same as baseline |

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[257] Variny et al 2021, Cutting Oxygen Production-Related Greenhouse Gas Emissions by Improved Compression Heat Management in a Cryogenic Air Separation Unit.

[258] Calculated based on molar masses and water input

[259] DESNZ 2023, Greenhouse gas reporting: conversion factors 2023.

[260] JRC 2017, Default values for biofuels.

[261] Biograce, Biograce standard values – version 4 - Public.

[262] BEIS 2020, Greenhouse gas reporting: conversion factors 2020.

[263] JEC WTT v5 2020, Appendix 1_Pathways 5_Synfuels.xlsx.

[264] CRI 2015, Power and $CO_2$ emissions to methanol.

[265] BEIS 2018, Atmospheric implications of increased hydrogen use.

[266] OzonAction, Global Warming Potential (GWP) of Refrigerants: Why are Particular Values Used?

The road transport decarbonisation scenarios described in the UK LCHS were applied[193].

**Table 60: Road transport and shipping decarbonisation scenarios**

| Variable | Baseline impact | Low impact | High impact |
|---|---|---|---|
| Road transport | Diesel emission factor, methane emissions, and nitrous oxide emissions from JEC (2020)[263]. Assume 2030: 12% biofuel blend (energy basis)<br>2050: $H_2$ HGV assumed, 5 $gCO_2e/MJ$ dispensed $H_2$. Hydrogen emission factor from GREET (2020) | Assume current biofuel blend in ICE vehicle – 2030<br>Assume renewable electricity used in an electric HGV - 2050 | Assume 12% biofuel blend (energy basis) – 2030<br>$H_2$ HGV assumed, 15 $gCO_2e/MJ$ dispensed $H_2$ – 2050 |
| Ammonia sea transport | Heavy fuel oil (HFO) emissions intensity[267], fuel use and ship capacity[268] used to calculate emissions assuming a decarbonisation trajectory in line with IEA (2021)[269] | Assume all vessels involved in global trade of hydrogen are running on zero carbon $H_2$/ammonia by 2030 | Same values used for HFO intensity, fuel use and ship capacity as Baseline impact. Assume IMO current goal of 70% reduction in global shipping emissions intensity is met by 2050 and 40% by 2030 relative to 2008 baseline[270] |
| Liquid hydrogen sea transport | HFO intensity, fuel use and ship capacity taken from same sources as ammonia sea transport. Assume 50% of vessels are running on zero carbon $H_2$ (boil-off) or otherwise using dual engines – 2030[271]<br>Assume all $LH_2$ vessels run on 100% zero carbon $H_2$ (from the boil-off) – 2050 | Assume all $LH_2$ vessels run on 100% zero carbon $H_2$/ammonia (from the boil-off) by 2030 | Same values used for HFO intensity, fuel use and ship capacity as Baseline impact. Assume IMO current goal of 70% reduction in global shipping emissions intensity is met by 2050 and 40% by 2030 relative to 2008 baseline[270] |
| Methanol sea transport | Assume same scenarios as ammonia shipping | | |

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[267] JRC 2017, Solid and gaseous bioenergy pathways: input values and GHG emissions.
[268] IEA 2020, IEA G20 Hydrogen report: Assumptions.
[269] IEA 2021, Net Zero by 2050 A Roadmap for the Global Energy Sector. Figure 2.35.
[270] ICCT 2020, Limiting engine power to reduce $CO_2$ emissions from existing ships.
[271] IEA 2020, IEA G20 Hydrogen report: assumptions. Assume LH2 boil-off onboard will be used to (partially) power the vessel, hence fuel use is reduced

### 9.5.10 Hydrogen production and distribution cumulative efficiencies

| Electrolyser | Hydrogen distribution pathway | Cumulative efficiency (2030) | Cumulative efficiency (2050) |
|---|---|---|---|
| AEL | Ammonia | 53.8% | 56.1% |
| PEM | Ammonia | 53.8% | 56.1% |
| AEL | Ammonia cracking | 45.3% | 47.2% |
| PEM | Ammonia cracking | 45.3% | 47.2% |
| AEL | Liquid hydrogen | 61.3% | 63.8% |
| PEM | Liquid hydrogen | 61.3% | 63.8% |
| AEL | Methanol | 55.6% | 57.9% |
| PEM | Methanol | 55.6% | 57.9% |
| AEL | Compressed pipeline | 66.6% | 69.3% |
| PEM | Compressed pipeline | 66.6% | 69.3% |
| SOEC | Compressed pipeline | 87.6% | 95.1% |
| AEM | Compressed pipeline | 60.5% | 69.3% |

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