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Evaluating technology options to mitigate greenhouse gas emissions

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Low-Carbon Hydrogen from Natural Gas: Global Roadmap

IEA GREENHOUSE GAS R&D PROGRAMME

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This report describes work undertaken by Element Energy and CE Delft on behalf of IEAGHG . The principal researchers were:

- Silvian Baltac
- Matt Wilson
- Conor O'Sullivan
- Cor Leguijt
- Mart Beeftink
- Isabel Nieuwenhuijse
- Antonia Mattos
- Diederik Jaspers
- Chris Jongsma

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The IEAGHG managers for this report were Keith Burnard, Mónica García and Abdul'Aziz A. Aliyu.
The expert reviewers for this report were:

- Philip Cohen (BEIS)
- Guido Collodi (Wood)
- Paul Feron (CSIRO)
- Andrea Fontanella (Ergo)
- Uwe Remme (IEA)

The report should be cited in literature as follows: 'IEAGHG, "'Low-Carbon hydrogen from Natural Gas: Global Roadmap" 2022-07, August 2022'.

Further information or copies of the report can be obtained by contacting IEAGHG at:
IEAGHG, Pure Offices, Cheltenham Office Park
Hatherley Lane, Cheltenham,
GLOS., GL51 6SH, UK
Tel: +44 (0)1242 802911
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

LOW-CARBON HYDROGEN FROM NATURAL GAS: GLOBAL ROADMAP

IEAGHG NOTE TO READERS

Hydrogen is a versatile fuel that can be produced from all sources of energy (coal, oil, natural gas, biomass, renewables and nuclear) via a broad spectrum of technology processes (reforming, gasification, pyrolysis, electrolysis, and many others).

Depending on the source (or feedstock) and production process, many organisations colloquially refer to the hydrogen produced using a colour-based taxonomy. This approach, while often used, can potentially lead to misperception as there is no universally-recognised naming convention. For example, the following are the set of definitions offered by the UK's National Grid:[1]

- Green hydrogen: Hydrogen made by using clean electricity from surplus renewable energy sources (RESs), such as solar or wind power, to electrolyse water.
- Blue hydrogen: Hydrogen produced from fossil fuels, where the carbon dioxide by-product is removed at source using carbon capture and storage (CCS) technologies.
- Grey hydrogen: Hydrogen created from natural gas, or methane, but without capturing the greenhouse gases generated in the process.
- Black and brown hydrogen: These terms refer to hydrogen produced from bituminous coal (black) and lignite (brown), again without capturing the greenhouse gases generated in the process.
- Pink hydrogen. Pink hydrogen is generated through electrolysis powered by nuclear energy. Nuclear-produced hydrogen may also be referred to as purple or red hydrogen.
- Turquoise hydrogen. Turquoise hydrogen is made using a process called methane pyrolysis to produce hydrogen and solid carbon.
- Yellow hydrogen. Yellow hydrogen refers to hydrogen produced via electrolysis using solar power.
- White hydrogen. White hydrogen refers to naturally occurring geological hydrogen found in underground deposits and created through fracking.

While there may be broad agreement of these terms, it is important to recognise that precise definitions can vary over time, can vary between organisations and even between countries and though the definitions may not differ markedly, it takes only a small divergence for environmental impacts and cost estimates to vary significantly. Given all these production routes, it is important to note that, with the exception of biomass-based hydrogen production, no hydrogen production technology (including electrolysis with renewables) offers net-zero emissions over its life cycle. Recognising that the availability of sustainable biomass is likely to be limited, adding CCS to biomass gasification, for example, can lead to net negative GHG emissions.

The myriad of colours used, the lack of a globally agreed (ISO) convention and the potential for definition shift have all led to some of the energy world's influential organisations, the International Energy Agency, the US Department of Energy, and the IEA's Hydrogen TCP, not using the colour taxonomy in favour of a technology agnostic approach. The technology-based modus operandi essentially characterises the hydrogen produced based on its source and production pathway, for

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[1] National Grid. The hydrogen colour spectrum. 2022

example, hydrogen from natural gas (rather than grey hydrogen) and low-carbon (or low-emissions) hydrogen from natural gas (rather than blue hydrogen). It is important to appreciate, however, that the carbon intensity of production can differ even if the same technology is employed based on upstream emissions, feedstock type, geography, process and/or operational configuration, electricity mix, and even the LCA methods and assumptions employed.

Moving forward, IEAGHG plans to adopt the technology agnostic approach. However, it is recognised that many organisations globally will continue to use the colour-based taxonomy in their written and/or oral outputs. For this reason, IEAGHG will also refer to the colour spectrum, but in parentheses or footnotes, where clarification is required or confusion to be avoided.

As this study was undertaken prior to the current decision, readers will note that, in the body of this report, the hydrogen produced from natural gas (with the CO_2 abated using CCS)-is referred to as blue hydrogen. In a nod to the future, however, the title has been changed from its original "*Blue Hydrogen: Global Roadmap*" to "*Low-Carbon Hydrogen from Natural Gas: Global Roadmap*".

LOW-CARBON HYDROGEN FROM NATURAL GAS: GLOBAL ROADMAP

The primary objective of this study is to conduct a techno-economic and environmental assessment of the production of natural gas-based hydrogen with accompanying carbon capture and storage (CCS) technology. Further, the purpose of this study is to enrich knowledge and compare the deployment of steam methane reforming (SMR), electrified SMR (E-SMR), autothermal reforming (ATR), and partial oxidation (POX) with CCS in the Netherlands. The findings of this study will be of interest to policy makers, industrial emitters, as well as technology developers.

KEY MESSAGES

- The life cycle assessment (LCA) for the natural gas-based blue (CCS-abated) hydrogen production technologies reveals that a reduction of the carbon footprint ranging between 43-76% can be achieved in the Netherlands in 2020 for all the investigated technologies. This reduction is set against the reference grey (without CCS) hydrogen with a carbon footprint of 10.13 kg CO_2 eq./kg H_2.
- The carbon footprints of blue hydrogen produced using SMR (2.78 kg CO_2 eq./kg H_2), ATR + GHR (3.23 kg CO_2 eq./kg H_2) are comparable to that of POX, with POX (2.43 kg CO_2eq./kg H_2) achieving the lowest carbon footprint. In contrast, blue hydrogen produced using ESMR has the highest carbon footprint (5.74 kg CO_2 eq./kg H_2). This is primarily because of the significant utilisation of the carbon intensity of electricity in the Netherlands (480 gCO_2/kWh in 2020).
- Direct CO_2 emissions (reaction emissions and emissions related to combustion of natural gas), natural gas production and transport as well as grid electricity, were found to be important contributory factors in the carbon footprint of the blue hydrogen production pathways. The most influential factor on the carbon footprint of hydrogen produced via SMR + CCS was the natural gas production and transport. The largest contributing factor of the carbon footprint for ATR + gas heated reformer (GHR) + CCS, ESMR + CCS and POX, in this study, was the source of electricity utilised to run these thermochemical processes.
- The carbon capture rate has a significant impact on the carbon footprint of the blue hydrogen production technology. The overall carbon footprint of hydrogen produced with the SMR technology is reduced by 8% when the carbon capture efficiency is increased from 90% to 99%, this is despite the increase of electricity usage increase by 10%.
- An increase of the carbon footprint of natural gas by 171% and 29% were observed for natural gas imported to the Netherlands from Russia and Algeria respectively.
- The projected reduction in carbon footprint for different technologies varied significantly from 12% for SMR + CCS to 54% for ESMR + CCS by 2030.
- All the four investigated technologies were observed to be most sensitive to feedstock/fuel costs and the price of CO_2 T&S. SMR was also found to be highly sensitive to increasing carbon prices because this technology exhibits the lowest CO_2 capture efficiency amongst the studied technologies. In contrast, ATR, POX and ESMR are observed to be largely sensitive to electricity costs.
- POX is the most cost-effective process for avoiding CO_2 emissions, whereas ESMR is the highest cost in Netherlands in 2020. SMR and ATR both have a cost of CO_2 abatement of about €110/tCO_2, which is about 28% higher than POX and between 9% to 25% lower than ESMR (with grid and renewable electricity respectively).
- By 2050, the investigated blue hydrogen production technologies have between 17% to 31% lower LCOH against the reference case. In this case scenario, significant reduction of the cost of CO_2 T&S for all technologies is realised as CCS projects are de-risked. Significant learnings are gained from numerous deployment projects and economies of scale are achieved.

BACKGROUND OF STUDY

Since the first Hydrogen Energy Ministerial (HEM) meeting in Japan in 2018, impetus to develop the hydrogen economy in all its ramifications has intensified. In 2020 104 MT of both pure and syngas (hydrogen and carbon monoxide) were produced. Escalation of production capacity is required to deliver the ambitious climate goals in line with the Paris Agreement. In light of the shift towards creating a hydrogen economy, the IEAGHG has undertaken two parallel studies on hydrogen production pathways. These include 'Blue Hydrogen – Beyond the Plant Gate', which delivers hydrogen production pathways using oil and oil-based feedstock, and this report which focusses on natural gas-based blue hydrogen production. Further, these studies build on the IEAGHG published study on 'Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS' in 2017.

There are a range of hydrogen production technologies at different stages of commercial maturity. This study focuses on the blue hydrogen technologies which use natural gas as a feedstock. The well established SMR which was commissioned in 1936 in Billingham, England[1] is still one of the well-established hydrogen production routes to date, (accounting for almost 67% of the global hydrogen demand in 2020). However, there is a knowledge gap in the literature regarding newer and emerging technologies. The costs and environmental benefits of newer blue hydrogen production technologies, as well as their adaptability to use CCS, has not been fully examined to date. Thus, a study of four production pathways (i.e., SMR, e-SMR, ATR + GHR, and POX) has been undertaken, whilst employing established LCA and TEA methodologies aligned with literature to date. Further, to identify key enabling drivers and develop a series of policy recommendations to achieve competitiveness and scale of the routes examined.

IEAGHG commissioned Element Energy and CE Delft to address the knowledge gaps in the techno-economic and environmental aspects of the specified thermochemical processes. The Netherlands, which is an active European country in the CCS, was selected as a reference location for the study.

SCOPE OF STUDY

This study examined the techno-economic and environmental perspectives of SMR (TRL 9) + CCS, ATR (TRL 7 - 9) + GHR + CCS, ESMR (TRL 4) + CCS and POX (TRL 9) against a benchmark conventional SMR in the Netherlands (with no associated CCS).

All the designated thermochemical processes are based on a 300MW (79 ktonnes/year) hydrogen production facility assuming a 100% load factor. All cases have similar scale and boundary conditions so that techno-economic and life cycle assessments are comparable. This analysis also provides commentary on the supply of blue hydrogen from natural gas in 2050.

In this study, cradle-to-gate system boundaries are employed, in line with the LCA methodology for hydrogen production proposed by Valente et al., 2017, as shown in Figure 1.[2] The cradle-to-gate system boundaries include all process steps from the extraction of the raw materials up to, and including, the production of compressed hydrogen. This means that all processes that are required to produce (200 bar, >97% purity) hydrogen, plus transportation and storage of the captured CO_2, are included (e.g., production of required fuel, feedstock, and electricity).

[1] Johnson Matthey Technology Review. Eighty Years of Steam Reforming. Volume 60, Issue 4, October 2016.

[2] Valente et al. Harmonised life-cycle global warming impact of renewable hydrogen. 2017

The hydrogen production scenarios are modelled against 2020. Additionally, a sensitivity analysis evaluated the effects of deploying these technologies in 2030 by modelling the expected electricity mix (and related carbon footprint) for 2030. The LCA results for other environmental impact categories are provided to show possible environmental trade-offs between carbon footprint and other impact categories. As earlier mentioned case studies are based on a location in the Netherlands. The composition of natural gas sourced from countries is reflected in the analyses.

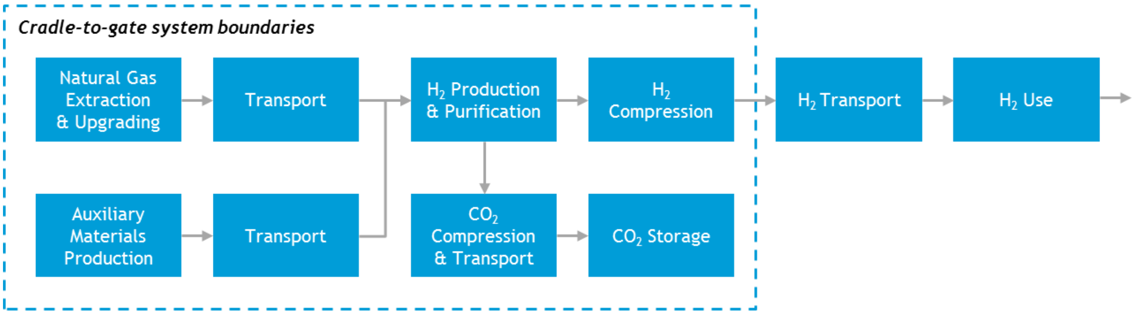

Figure 1. Cradle-to-gate system boundaries of hydrogen production from natural gas

Three boundaries for the techno-economic analysis (TEA) considered in this study (Figure 1) is as follows:

- **Gateway 1** only accounts for the hydrogen production facility and hydrogen compression.
- **Gateway 2** accounts for the hydrogen production, compression, and the CO_2 T&S facility.
- **Gateway 3** accounts for the entire value for produced hydrogen chain up to the point of end use.

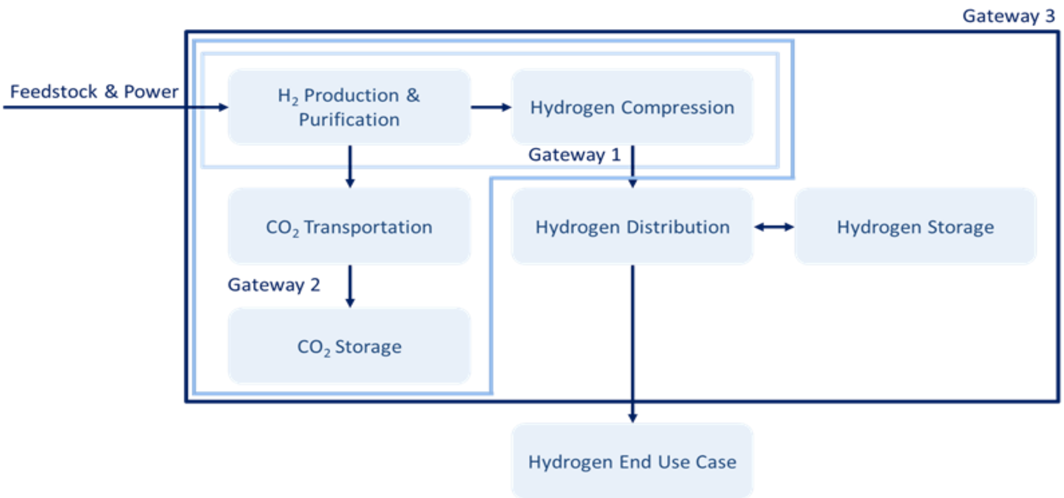

Figure 2. Model cost and emissions gateways

FINDINGS OF STUDY

Life cycle assessment

The carbon footprint of hydrogen produced via SMR + CCS, ATR + GHR + CCS, ESMR + CCS and POX signifies 73%, 68%, 43% and 76% reduction against the carbon footprint of the benchmark SMR at 10.13 kg CO_2 eq./kg H_2. Natural gas production and transportation accounts for the highest contribution to the carbon footprint in the SMR + CCS case. However, direct CO_2 emissions also sizeably accounts for the carbon footprint when the CO_2 capture efficacy is modelled at 90%. For ATR

+ GHR + CCS, ESMR + CCS and POX, electricity usage for various process endeavours account for the largest contributing factor to the carbon footprint. For ATR, ESMR and POX, this includes electricity required to operate the plants and hydrogen compression. Further, oxygen production via an air separation unt (ASU) in the case of ATR and POX adds to the electricity usage.

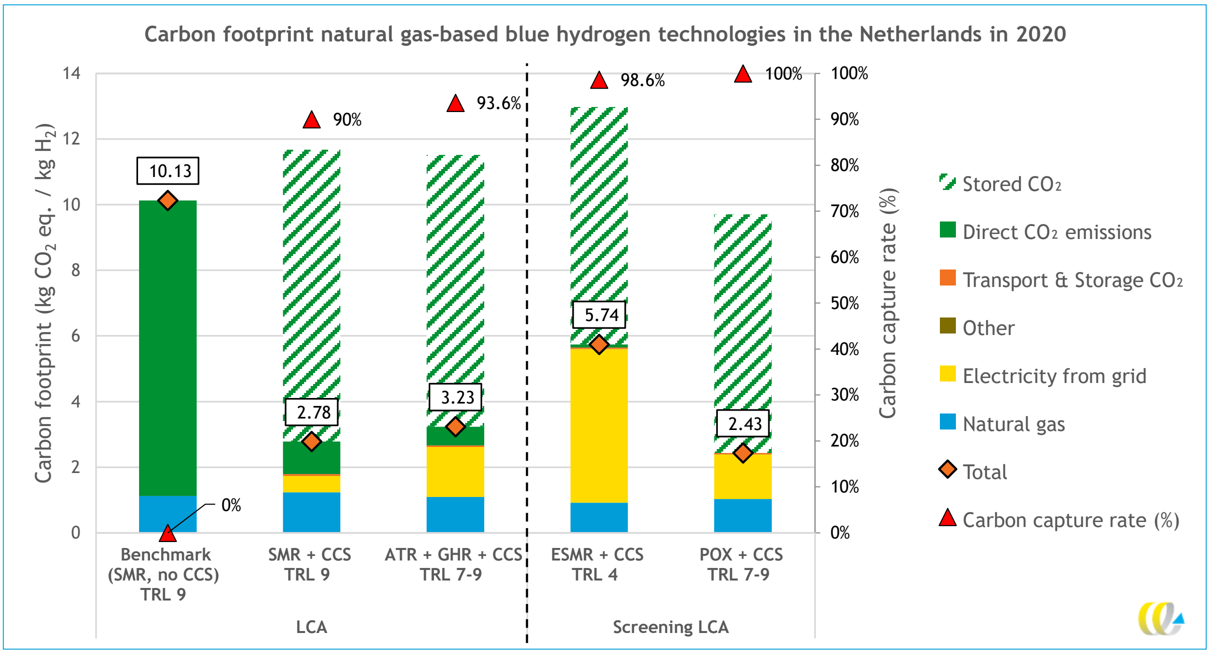

Figure 3. Contribution analysis of the carbon footprint of four natural gas-based blue hydrogen production scenarios and the grey hydrogen benchmark

The following sensitivity analysis have been undertaken in this study to assess the effects of changing key parameters on the overall carbon footprint of the investigated technologies:

- Sensitivity Analysis 1: For all technologies (including the benchmark), the electricity mix has been adjusted to estimated electricity mix in the Netherlands in 2030.
- Sensitivity Analysis 2: The carbon capture rate of SMR + CCS is increased from 90% to 99%.
- Sensitivity Analysis 3: All the natural gas used is imported from:
  - Scenario 1: Algeria.
  - Scenario 2: Russia.

For Sensitivity Analysis 1, the degree of the carbon footprint of electricity was observed to have a significant impact on the total carbon footprint of blue hydrogen production. The carbon footprints of the investigated technologies were reduced from 12% to 54% when the carbon footprint of the Dutch electricity supply was reduced by 67% in 2030 (Figure 4). ESMR, which is largely reliant on electricity, gained the largest absolute reduction in carbon footprint. The results of this sensitivity analysis reveal that having a sustainable electricity source is critical in the production of blue hydrogen.

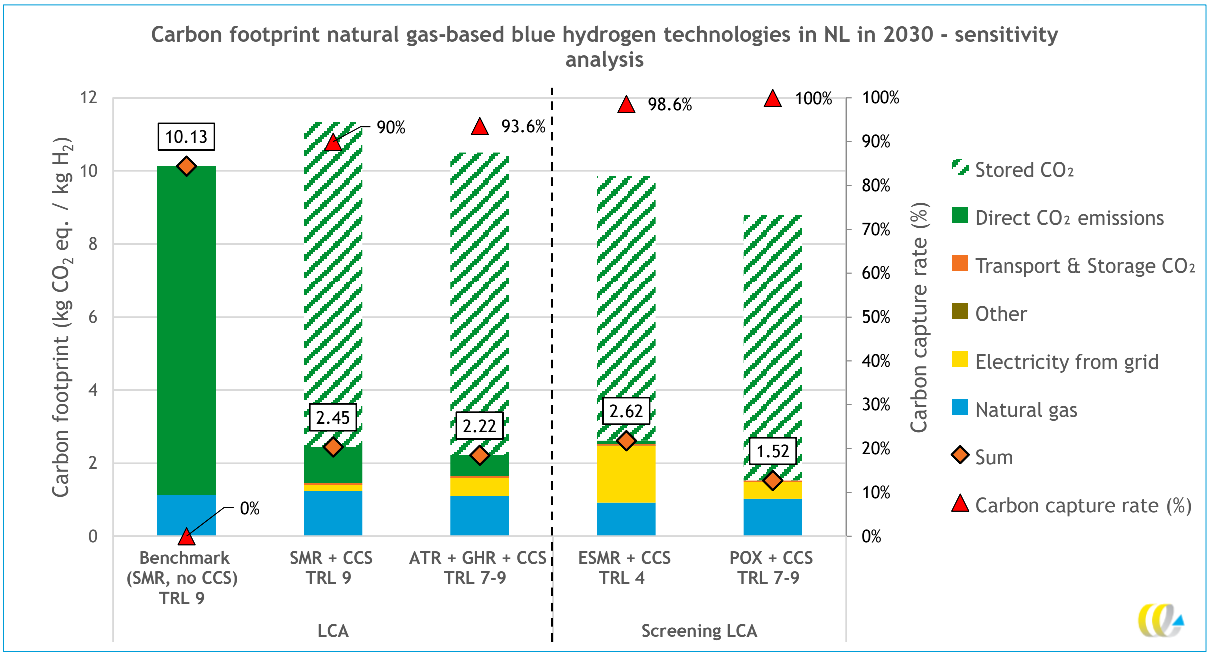

Figure 4. Sensitivity Analysis 1 – Modelled life cycle emissions of blue hydrogen technologies based on the projected carbon intensity of Dutch electricity supply in 2030.

The carbon capture rate was established to have a pronounced impact on the carbon footprint of the blue hydrogen production technology (SMR + CSS) in Sensitivity Analysis 2. The overall carbon footprint of hydrogen produced with the SMR technology was decreased by 8% when the carbon capture rate was increased from 90-99% (based on the modelled increase in electricity usage of 10%). This reduction is due to negligible direct CO_2 emissions by 2030. This sensitivity analysis was undertaken for SMR + CCS.

Changes in the carbon capture rate are possible for each blue hydrogen production technology. Consequently, changing the carbon capture rate has a significant effect on the overall carbon footprint and is pertinent for all blue hydrogen technologies.

Sensitivity Analysis 3 demonstrates that the origin of natural gas has a substantial impact on the carbon footprint of these blue hydrogen technologies. The carbon footprint of all hydrogen production technologies (including the benchmark) increases when only imported natural gas from either Algeria or Russia is used. This effect is largest for Russian natural gas with an associated 171% increase in the carbon footprint of natural gas. In contrast, a 29% increase in the carbon footprint of natural gas was gained when imported from Algeria. The results show that, for the Netherlands, a larger imported share of natural gas leads to increased carbon footprints. This effect is intensified via methane leakages in the course of natural gas transportation.

Techno-economic analysis

All the blue hydrogen production technologies using SMR, ATR, POX, ESMR (grid) and ESMR (renewables) were found to be 21.4%, 21.9%, 10.2% 32.6% and 29.8% higher than the reference grey hydrogen production case (SMR without CCS) as presented in Figure 5. The significant CO_2 T&S costs that result from the CCS projects in the early stages of development, along with the low carbon price in the Netherlands in 2020, intensified the LCOH. For ATR, POX, and especially ESMR, the electricity costs for hydrogen production were found to be substantially higher than the SMR reference case. The LCOH of blue hydrogen production technologies analysed in this study are relatively similar although there is greater variation between the individual cost components. Central costs range from €2.37 /kgH_2 (POX) to €2.85 /kgH_2 (ESMR) with significant overlap between the sensitivity bands.

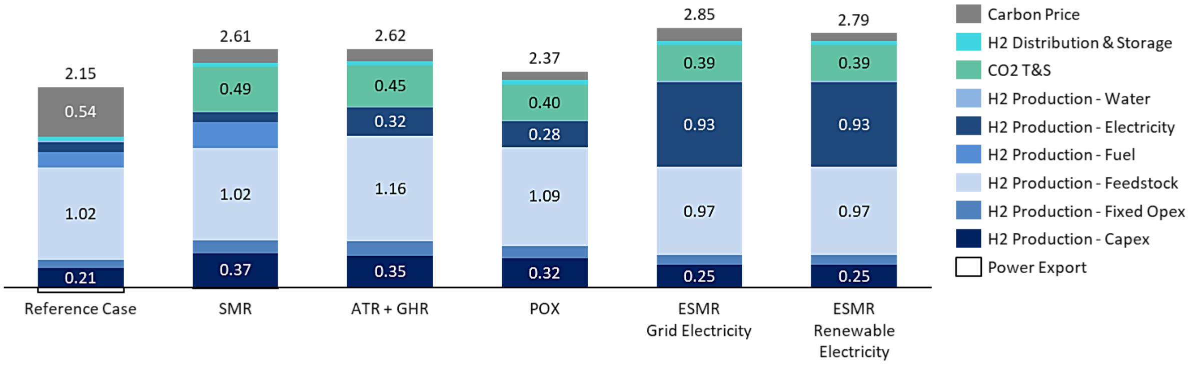

Figure 5. LCOH for natural gas-based blue hydrogen production in the Netherlands against SMR without CCS reference case in 2020 (€/kgH_2)

All the blue hydrogen production technologies were most sensitive to feedstock/fuel costs in 2020. As SMR was modelled with a 90% capture rate, OPEX was especially sensitive to increasing carbon prices. ATR and POX OPEX were also found to be very sensitive to electricity cost owing to oxygen production by ASU. Whereas ESMR OPEX sensitivity to electricity cost is because of high reliance of electricity to operate the plant.

However, the situation in 2050 changes (assuming a 5% learning rate) as demonstrated in Figure 6. The reference case SMR without CCS is considerably impacted by the higher carbon prices (as are the technologies with lower capture rates). The cost of CO_2 T&S is significantly reduced for all technologies as CCS projects are de-risked and significant learnings are acquired from several deployment projects and as economies of scale are realised. However, natural gas and electricity costs remain impactful. The LCOH of blue hydrogen production technologies analysed in 2050 remains relatively similar although variation between the individual cost components remains evident. This suggests that there will be a variety of business cases that favour different technology options based on varying scenarios (e.g., feedstock & electricity prices, hydrogen production scale and carbon prices).

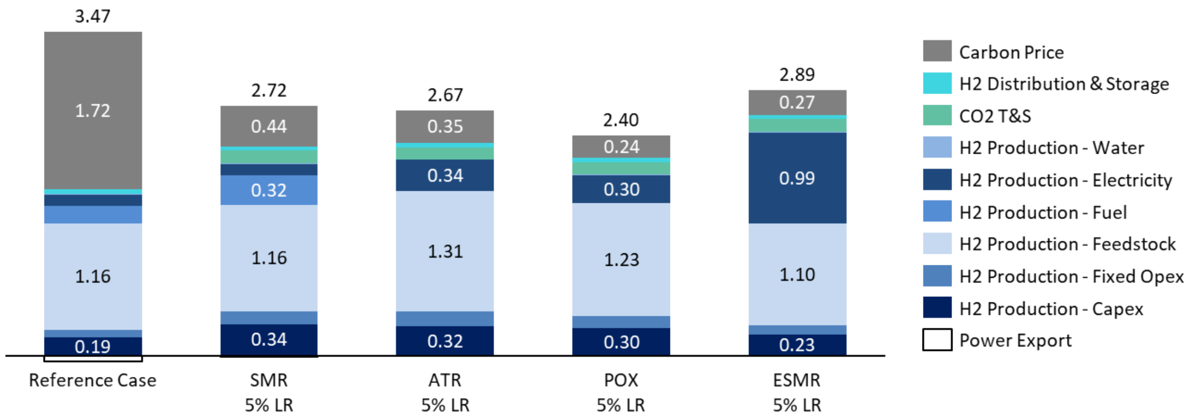

Figure 6. LCOH for natural gas-based blue hydrogen production in the Netherlands against SMR without CCS reference case in 2050 (€/kgH_2)

Lifetime emissions analysis

ESMR from the grid electricity supply in the Netherlands has the highest lifetime emissions amongst the investigated blue hydrogen pathways in 2020. However, if renewable electricity is utilised the lifetime emissions are reduced by approximately 46%. A renewable energy electricity supply for ESMR delivers the lowest lifetime emissions of all analysed production processes. As the electricity grid is likely to be significantly decarbonised by 2050, the ESMR process has the potential to significantly reduce the lifetime emissions of natural gas-based hydrogen production in the future. POX was also found to have the second lowest value in lifetime emissions amongst the investigated technologies. This unique feature is attributed to a 100% capture efficiency and therefore no direct emissions. The feedstock emissions were observed to be the recurring variable which all thermochemical processes are significantly exposed to.

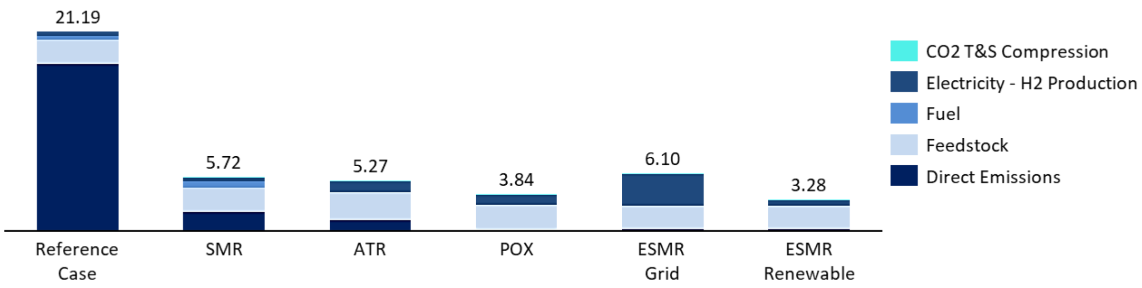

Figure 7. Lifetime emissions for each blue hydrogen production process in 2020 ($MtCO_2$)

EXPERT REVIEW COMMENTS

Five expert reviewers from the industry and research organisations took part in the expert review process of this study. Several comments attracted minor responses and/or amendments. Some of the substantive review comments are as follows:

The reviewers remarked that the technical discussions across the spectrum of the study scope were considered brilliant. The report was also well structured, detailed, and clear. However, greater discussion was needed on the improvement potential of the technologies by 2050 in terms of CAPEX and OPEX cost reductions, as well as efficiency improvements. Qualitative discussion in the technology sections is therefore valuable. This feedback was incorporated into the report.

Environmental impacts other than global warming potential was remarked to be included in the study. LCAs are included in the report to take account of these broader impacts. Considering electricity is one of the main influences on the overall environmental impact, the specific contribution of electricity consumption for hydrogen production was observed to be identified for CO_2 capture and separately for CO_2 T&S. The costs for CO_2 T&S are accordingly treated independently from capture in the report. Another reviewer stated that the performance on POX in both cost and capture rate, are based on a single study form University of Florida. This study was subjected to a thorough review of the technical information presented in the report.

The ATR, with GHR and without GHR, are used relatively flexibly throughout and should been treated as two distinct processes according to another reviewer. All technical terminology has been clearly explained in the report. A reviewer remarked that Hydrogen should not have been classed as used in DRI, it is mainly natural gas and whilst hydrogen acts as a reductant in that process so does carbon monoxide. Hydrogen has great potential across industry; however, its use in industry is not fully developed yet, and much innovation is still required. This observation is widely recognised and not unique to this review. An observation to compare renewable energy-based hydrogen production and other methods (as the analysis goes out to 2050) has been included in the report.

Renouncing the colour taxonomy for hydrogen used in this study was advised. Instead, a codification based on carbon intensity of hydrogen production technologies was recommended. Kindly refer to the 'IEAGHG note to readers'.

CONCLUSIONS

- This study has established that, in the short term, all the natural gas based blue hydrogen production technologies analysed are likely to be costlier than the established grey hydrogen production without CCS in the Netherlands. However, as carbon pricing increases (to make grey hydrogen production become an unattractive economic option), CCS integration will be crucial for reducing the cost of natural gas-based hydrogen production.
- The development of policy instruments is imperative to establish demand via incentivizing decarbonization through low carbon hydrogen pathways. Such a policy should stimulate hydrogen production through the development of infrastructure and cost reduction via economies of scale.
- In the longer term, the decreasing cost of renewable electricity is likely to make green hydrogen production increasingly competitive and cheaper than blue hydrogen production. This is especially attractive for regions such as North Africa and Southern Europe (which lie within the high level of solar irradiation) where low cost, carbon free electricity generation from solar power can be produced. Blue hydrogen produced in the Netherlands will likely face impending competition from hydrogen sourced in the renewable energy rich regions. This competition will also come from oil and oil-based blue hydrogen. Provided there is a significant reduction in the cost of hydrogen distribution over long distances, importing low-cost hydrogen may become economically favourable compared with local production in regions such as the Netherlands. At present, large-scale transport of hydrogen over long distances faces many technical challenges and is not operational due to the high costs associated with the process.
- CO_2 T&S faces a considerable cost component for all blue hydrogen production technologies. T&S cost accounts for between 14-19% of the LCOH for technologies investigated in 2020. Cost reduction in this area will be crucial to ensure cost competitiveness with established grey hydrogen production. The development of shared CCS infrastructure, in industrial clusters or with other large-scale emitters such as gas fired power stations with CCS, enables the advantages to be gained from economies of scale.
- Sensitivity analysis undertaken in this study has shown that the origin of natural gas, and the carbon footprint associated with it, can vary significantly. Consequently, the origin of the natural gas can have a big influence on the carbon footprint of blue hydrogen technologies. The carbon footprint of all the investigated hydrogen production technologies (including the benchmark) was found to increase when only imported natural gas from either Algeria or Russia is used. This effect is largest for Russian natural gas. The results show that an increase in the carbon footprint for the imported natural gas used in the Netherlands is largely caused by methane leakages.
- In general, the prospect of blue hydrogen in a viable low carbon hydrogen economy can only be attained if a combination of key barriers is addressed. These include economies of scale, technical advances, infrastructure investment, bulk storage, transport and distribution, safety consideration, risk mitigation measures and corresponding supply and demand. Development of blue hydrogen requires the right political, industrial, and academic symbiosis.

Comparative-based conclusions with parallel study (oil-based blue hydrogen)

- For all the investigated blue hydrogen production scenarios from this study (natural-gas based) and the parallel study (oil-based), all have significantly lower carbon footprints compared with the benchmark (SMR without CCS). More than 90% of the CO_2 destined for anthropogenic discharge is captured and stored. The blue hydrogen production technologies, with a TRL of 7-9, have a carbon footprint reduction of between 47%-77% compared to the benchmark.
- The carbon footprint of SMR (with CCS) was found to be 19% lower than steam naphtha reforming (SNR) with CCS) in Netherlands. This is because oil-based hydrogen production has a higher carbon-to-hydrogen ratio than the natural-gas based hydrogen production pathway. Hydrogen production routes that use oil as a feedstock instead of natural gas, generally have a higher carbon footprint. Compared to the benchmark, however, this difference in carbon footprint is relatively small (73% reduction for SMR + CSS and 66% reduction for SNR + CCS).
- ESMR (natural gas-based) and HEE (oil-based) have the highest potential for carbon footprint reduction in the future. This is attributed to the reduction of the carbon footprint of electricity production. Further, as the electricity grid is likely to be significantly decarbonised by 2050, both ESMR and HEE stand to significantly reduce the lifetime emissions of natural gas-based and oil-based hydrogen production in the future. These technologies, however, also have the lowest TRL and, accordingly, exhibit the greatest uncertainties in terms of attaining technology goals.

Comparative-based conclusions with alkaline electrolysis production route

- Renewable electricity produced from wind and solar in the Netherlands in 2020 has a carbon footprint of 0.0329 kg CO2 eq./kWh, whereas that of the Dutch electricity mix is 0.479 kg CO_2 eq./kWh. This translates to a carbon footprint of 1.723 and 25.06 kg CO_2 eq./kg H_2, respectively. These results underscore the importance of employing renewables for hydrogen production via electrolysis. This production route has the potential to curtail the carbon footprint of hydrogen production compared to the SMR benchmark by 80-90%.

RECOMMENDATIONS

Production of natural gas-based blue hydrogen with a minimum CO_2 capture efficiency of 90% has yet to be demonstrated at scale. The successful deployment of these technologies relies on a multiplicity of factors highlighted in the preceding sections. Addressing the cocktail of the challenges identified in this study will represent the opening stages towards long-term, commercially viable blue hydrogen production.

- The cost of CO_2 T&S has been established as a key cost component in blue hydrogen production. Therefore, incorporating blue hydrogen production technologies within CCS cluster strategies, to take advantage of associated scales of deployment, will support blue hydrogen cost reduction.
- Further work is required to appraise the various natural gas-based blue hydrogen technologies by region. The cost ranges for all the investigated technologies in this study have shown that there are potentially competitive options.
- Critical knowledge gaps to facilitate the deployment of emerging technologies, for example ESMR, is needed via demonstration projects to address the techno-economic uncertainties and increase the TRL. This will ensure that these technologies are better understood and incorporated into national and international hydrogen strategies, facilitating greater international collaboration.

- Leveraging experience gained from ongoing projects such as Acorn which demonstrates ways existing infrastructure can be reused for CO_2 T&S. This dimension can be linked to local hydrogen demand scenarios and cost reductions in the value chain for hydrogen distribution.
- Comparative analysis of the investigated natural gas and oil-based hydrogen production technologies against electrolytic hydrogen from renewables is critical. This significant conclusion stems from the projection of the robust role that renewables will play in the global energy sector by 2050 and beyond.

Low-Carbon Hydrogen from Natural Gas: Global Roadmap

A report for

Element Energy & CE Delft

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Element Energy Limited, Suite 1, Bishop Bateman Court, Thompson's Lane, Cambridge, CB5 8AQ, Tel: +44 (0)1223 852499

Authors

This report was authored by the project lead, Element Energy

Element Energy is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. The team of over 80 specialists provides consultancy services across a wide range of sectors, including the built environment, carbon capture and storage, industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon transport. Element Energy provides insights on both technical and strategic issues, believing that the technical and engineering understanding of the real-world challenges support the strategic work.

Study Authors (Element Energy):

Silvian Baltac	Principal Consultant
Matt Wilson	Senior Consultant
Conor O'Sullivan	Consultant

CE Delft led the Life Cycle Assessment in this report.

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LCA Authors (CE Delft)

Cor Leguijt	Manager - Energy & Fuels division
Mart Beeftink	Researcher/consultant, LCA-specialist
Isabel Nieuwenhuijse	Researcher/consultant, LCA-specialist

Supporting Authors: Antonia Mattos (Element Energy), Diederik Jaspers, Chris Jongsma (CE Delft).

For comments or queries please contact: ccusindustry@element-energy.co.uk

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The IEAGHG managers for this report were: Keith Burnard, Monica Garcia and Abdul'Aziz A. Aliyu.

Report Contributors included:

- Air Products
- Haldor Topsoe
- Johnson Matthey
- Shell

The expert reviewers for this report were:

- Philip Cohen (BEIS)

- Guido Collodi (Wood)
- Paul Feron (CSIRO)
- Andrea Fontanella (Ergo)
- Uwe Remme (IEA)

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This study was developed in parallel with '**Blue Hydrogen: Beyond the Plant Gate**", which studies the production of blue hydrogen from oil and oil-based products. Many readers may find it useful to read the studies together to provide complementary information and perspectives.

Executive Summary

Hydrogen is increasingly recognised by public and private sector stakeholders around the world as a key element in meeting the Paris Agreement's goal. To ensure decarbonisation, hydrogen (H_2) must be produced in a low carbon way. Hydrogen derived from fossil fuels with carbon capture and storage (CCS), referred to as blue hydrogen, represents a viable large-scale production pathway , serving as a vector for achieving climate goals.

Traditionally, the main hydrogen production technology has been steam methane reforming (SMR) without CCS. SMR has been the subject of most blue hydrogen assessment studies to date, including IEAGHG's 2017 techno-economic studies. However, new hydrogen production technologies are emerging and are considered for deployment by recent project developers. These include ESMR (electrified SMR), autothermal reforming (ATR), and partial oxidation (POX). All can use natural gas as their feedstock.

The purpose of this study is to enrich knowledge and compare the deployment of SMR, e-SMR, ATR, and POX with CCS in the Netherlands, one of the countries in Europe most active in the natural gas, hydrogen, and CCS space. The findings of this study will be of interest to policy makers, industrial emitters exploring fuel switching opportunities, and technology developers.

Current Hydrogen Market

There are a range of hydrogen production technologies at different stages of commercial maturity. This study focuses on the blue hydrogen technologies which use natural gas as a feedstock. However, green hydrogen (from electrolysis) and other blue hydrogen technologies which use oil and oil-based products as feedstock could also be competitive. This will depend on respective technoeconomics, i.e. technology maturity and access to low-cost feedstock, and government policy, i.e. the European Union has set a target of 40GW installed electrolyser capacity by 2030.

In the near-to-medium term, however, blue hydrogen could provide the majority of the world's low carbon hydrogen due to the more mature production processes and the ability to deploy these facilities at large scale in industrial clusters with CCS. This also satisfies industrial demand which is responsible for nearly 100% of current demand. The primary blue hydrogen production pathways which use natural gas are described below.

Steam Reforming

Steam reforming production accepts small-chain hydrocarbons in the range of natural gas to naphtha. These plants are typically sized between 35 & 700MW (10,000 & 235,000 Nm^3/h) and are responsible for nearly 50% of the world's hydrogen demand[1]. In this process, the hydrocarbon feedstock is mixed with steam in a reformer at temperatures of 750-950°C. These high temperatures are generated by combusting natural gas around the reaction tubes. This produces a mix of hydrogen, carbon dioxide and carbon monoxide known as Syngas[2]. The syngas stream is then fed through the Water Gas Shift (WGS) reactor where catalytic reactions between carbon monoxide and steam facilitate the additional production hydrogen. The hydrogen stream is subsequently purified and cleaned in a pressure swing adsorber (PSA).

A variation on this configuration is to use electrically heated reformers, eSMR. This significantly reduces emissions directly produced from the facility.

Gasification and Partial Oxidation

Gasification (for solids) and partial oxidation (POX – for liquids and gases) is widely deployed at a global scale for hydrogen production and is particularly prevalent in countries where coal is both more widely available and at lower cost than natural gas. This is commonly the case in East Asia. The process involves converting

[1] Kalamaras and Efstathiou 2013, Hydrogen Production Technologies: Current State and Future Developments
[2] Syngas blend for SMR pre-WGS includes c. 52% H2, c. 12% CO, 5% CO2, 29% H2O and 2% CH4 on a mole basis , IEAGHG 2017, Techno – Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS

feedstock material such as natural gas, but also coal and heavy oil fractions, at very high temperatures (1300 - 1500 °C) in the presence of oxygen and steam to produce syngas. In a similar manner to the steam methane reforming (SMR) process, the syngas stream is then fed through the WGS reactor where catalytic reactions between carbon monoxide (CO) and steam facilitate the production of additional hydrogen. The hydrogen stream is subsequently purified and cleaned in a PSA.

Autothermal Reforming Configurations

Autothermal reforming (ATR) combines SMR and POX by using steam and catalysts to increase hydrogen yield (from SMR) and using oxygen to deliver the energy for reaction (POX). The process stream is similar to POX and SMR, with the reaction vessel leading to a WGS reactor before the hydrogen is purified and cleaned in a PSA. A gas heated reformer (GHR) can be added to the process to pre-heat and partially reform the natural gas feedstock prior to entering the primary ATR reformer. The integration of the GHR is typically referred to as the low carbon hydrogen (LCH) configuration, a technology that is getting particular attention in the UK in H21 North of England, Zero Carbon Humber and HyNet projects.

Global Hydrogen Production and Demand

The hydrogen production market (including both dedicated and by-product production) is currently dominated by SMR and coal gasification without CCS. Due to the co-location of production with end use, the distribution of global hydrogen production follows hydrogen demand. Nominally industrial clusters. The breakdown of production by region and technology is shown in Figure 1. This includes both pure hydrogen and hydrogen used as part of a mixture of gases known as syngas.

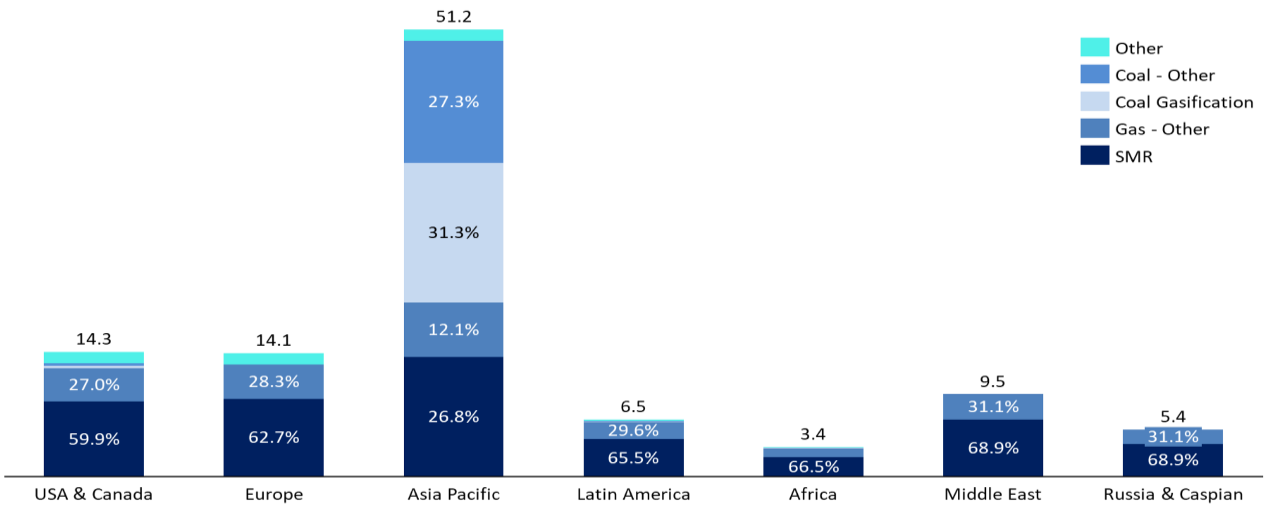

Figure 1: Hydrogen demand by region and production type in 2020 (MtH_2/year)

Nearly all of this hydrogen (including syngas) is destined for industrial processes. This includes methanol and ammonia production, hydrotreatment and hydrocracking in refineries. The use of hydrogen for direct reduction of iron (DRI) and for providing industrial grade heat is currently in development; there is significant potential demand in this sector. Hydrogen for transport, heat and power all show promise, but their uptake is uncertain and currently represent <1% of global demand. This breakdown is shown in Figure 2.

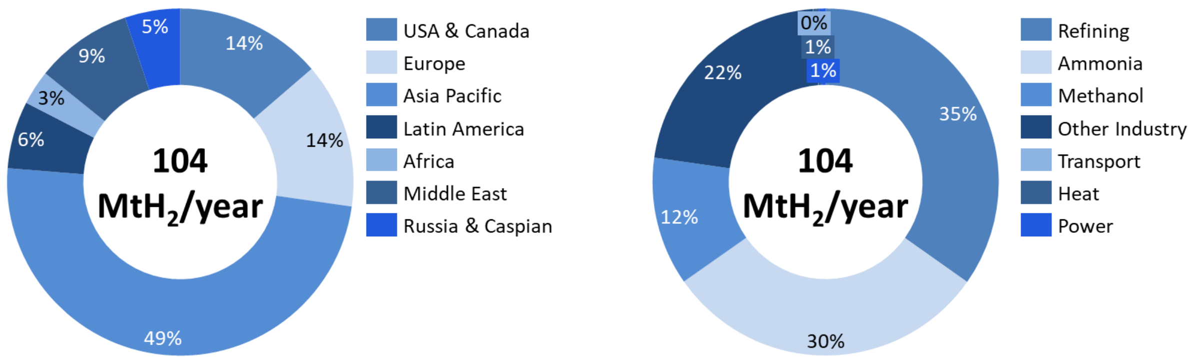

Figure 2: Global hydrogen demand by region (left) and end use case (right) in 2020 (MtH_2/year)

TEA Comparison

The reference case, for both the TEA and LCA is the Base Case from IEAGHG's SMR study[3]. For the 'central case' scenarios in 2020, all blue hydrogen production technologies have a higher cost than the reference grey hydrogen production case via SMR without CCS as shown in Figure 3. This is primarily due to the significant CO_2 T&S costs that arise from CCS projects in the early stages of development alongside the low carbon price in the Netherlands in 2020 (€13.50/tCO_2). Central costs range from €2.35 /kgH_2 (POX) to €2.83 /kgH_2 (ESMR) with significant overlap between the sensitivity bands.

In 2050 the reference case SMR without CCS is significantly impacted by the higher carbon prices in the Netherlands (Min: €35/tCO_2, Central: €100/tCO_2 and Max: €227/tCO_2) and the analysed blue hydrogen production technologies have a 17% to 31% lower levelised cost of hydrogen (LCOH). The LCOH of blue hydrogen production technologies analysed in 2050 remains relatively similar although variation between the individual cost components remains. Central costs range from €2.40 /kgH_2 (POX) to €2.89 /kgH_2 (ESMR) with significant overlap between the uncertainty bands.

However, all four blue hydrogen production technologies show significant overlap in their LCOH range. This suggests that, in different scenarios (i.e. feedstock & electricity prices, H_2 production scale and carbon prices) there will be a variety of business cases that favour different technology options.

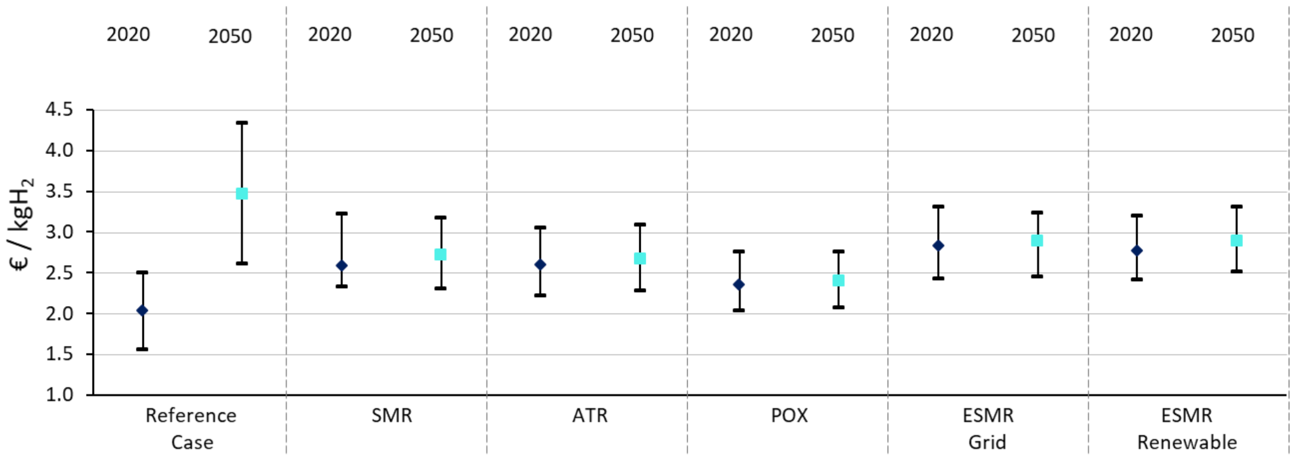

Figure 3: Range of LCOH for blue hydrogen production technologies compared to the reference case (without CCS) in 2020 (diamonds) and 2050 (squares) in the Netherlands with a carbon price (€/kgH_2)
CO_2 Price in the Netherlands in 2020 - €13.5/tCO_2 and 2050 - €100.4/tCO_2

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

LCA Comparison

The LCA for the blue hydrogen natural gas-based production technologies shows that the carbon footprint for all analysed technologies is significantly lower than the reference grey hydrogen production case without CCS. A reduction of the carbon footprint ranging between 43-76% can be achieved in 2020s as shown in Figure 4.

- **SMR (without CCS) (TRL 9) (Benchmark).** Generated CO_2 emissions account for the largest share of the carbon footprint of grey hydrogen production. These emissions are mostly related to burning of natural gas as a fuel to heat the process and to the process emissions caused by the reaction which takes place.
- **SMR with CCS (TRL 9)** can achieve a 73% reduction compared to the carbon footprint of the benchmark. Natural gas (production and transport) accounts for the largest contribution to the carbon footprint. As the carbon capture rate of SMR + CCS is modelled to be 90% (and consequently not all CO_2 is captured and stored), the direct CO_2 emissions still account for a large share of the carbon footprint. These include both reaction emissions and emissions related to combustion of natural gas to heat the process.

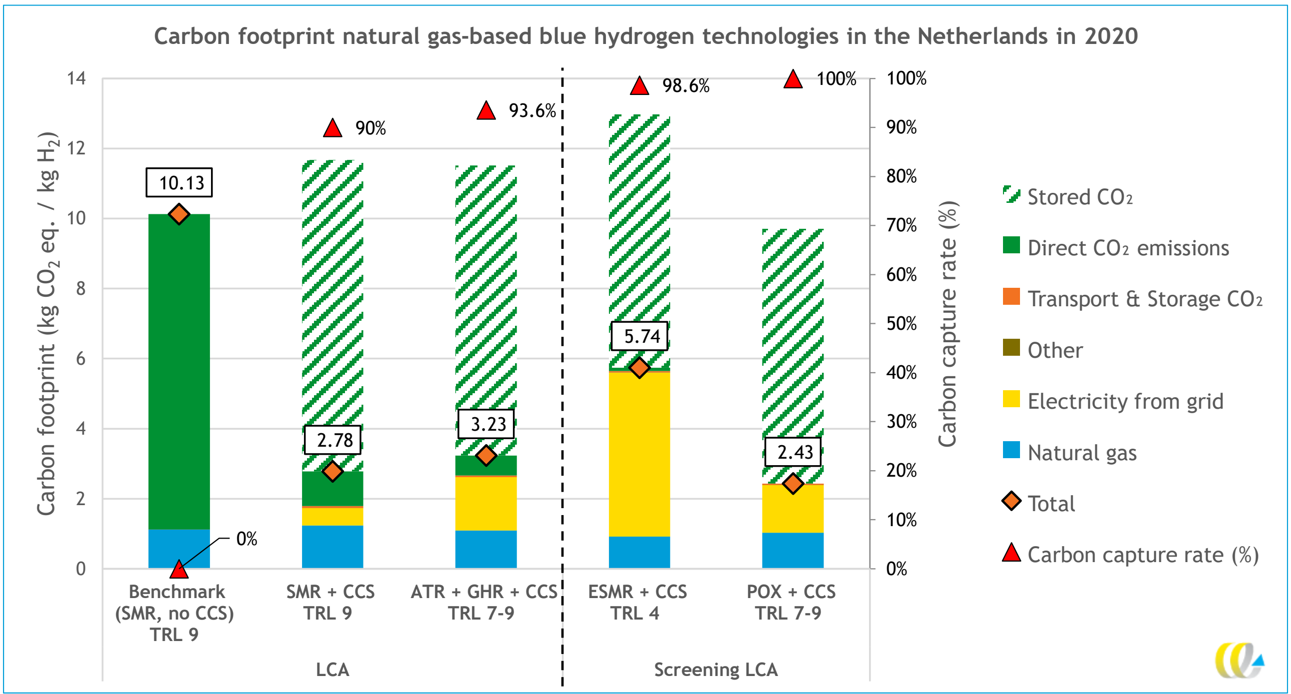

Figure 4: Contribution analysis of the carbon footprint of four natural gas-based blue hydrogen production scenarios and the grey hydrogen benchmark.[4]

- **ATR with GHR + CCS (TRL 7-9)** can achieve a 68% reduction compared to the carbon footprint of the benchmark. Electricity use accounts for the largest contribution to the carbon footprint. This includes electricity needed to run the ATR plant and H_2 compression. Additionally, it includes O_2 production using an ASU. Natural gas (production and transport) has the second largest contribution to the carbon footprint. As the carbon capture rate of ATR with GHR + CCS is modelled to be 94% (and consequently not all CO_2 is captured and stored), the direct CO_2 emissions still account for a share of the carbon footprint. These include both reaction emissions and emissions related to combustion of natural gas to heat the process.
- **ESMR + CCS (TRL 4)** can achieve a 43% reduction compared to the carbon footprint of the benchmark. Electricity use accounts for the largest contribution to the carbon footprint. This includes electricity needed to run the ESMR plant and for H_2 compression. The reason for the high contribution of electricity (and relatively low contribution of natural gas) is that in an ESMR plant, heat is generated using electricity instead of natural gas. As a result, the carbon footprint of hydrogen produced in an ESMR unit strongly

[4] 'Other' includes tap water and water treatment. 'Electricity' includes electricity used for H_2 production and compression, as well as electricity generation and O_2 production (ATR with GHR, POX).

depends on the carbon footprint of the electricity production. In the base analysis of this study, the current (2020) average Dutch electricity mix is used. As the carbon capture rate of ESMR + CCS is modelled to be 98.6%, the direct CO_2 emissions have a minor contribution to the carbon footprint. This is a realistic carbon capture rate, as carbon capture from an ESMR unit can be done at an earlier stage in the process and with a higher purity, making it comparatively easy to reach a high capture rate.

- **POX + CCS (TRL 7-9)** can achieve a 76% reduction compared to the carbon footprint of the benchmark. Electricity use accounts for the largest contribution to the carbon footprint. This includes electricity needed to run the POX plant and H_2 compression. Additionally, it includes O_2 production using an ASU. Natural gas (production and transport) has the second largest contribution to the carbon footprint. As the carbon capture rate of POX + CCS is modelled to be 100%, the direct CO_2 emissions have no contribution to the carbon footprint.
- The carbon footprint of the electricity production is a significant contributor to the total carbon footprint of all technologies. This shows that, besides using **CCS** and having a **high carbon capture rate**, a **sustainable electricity source** is important when producing blue hydrogen. As the carbon footprint of electricity production of the Netherlands will likely decrease between 2020 and 2030 (as a result of increased renewable electricity sources), the carbon footprint of the natural gas-based blue hydrogen technologies will also reduce. This especially has a high impact on ESMR as it uses the largest amount of electricity. Further reductions of the carbon footprints can be achieved by reducing the carbon intensity of the supply of feedstock, i.e. access to biogas from sustainable sources.

The carbon footprint results of SMR with CCS and ATR with GHR and CCS, closely match analysis performed by the UK Government's 'Consultation on a UK Low Carbon Hydrogen Standard'[5].

Current Market

Blue hydrogen production technologies will have to compete with established grey hydrogen production technologies in the near-term as well as developing green hydrogen production from renewable sources in the future. SMR without CCS is currently the dominant production technology globally and is expected to remain lower cost in the short to mid-term until carbon prices increase. This, of course, is not the only pressure on transition to low carbon alternatives as direct competition with green production is increasingly common. Blue hydrogen production is predicted to remain cheaper than green hydrogen production in the near term.

This study shows that in the short term, all of the natural gas based blue hydrogen production technologies analysed are likely to be higher cost than established grey hydrogen production without CCS in the Netherlands. However, as carbon pricing increases, CCS integration will be crucial for reducing the cost of natural gas-based hydrogen production. Policy support is therefore required to increase the uptake of blue hydrogen and bridge the time period gap, until carbon price increases result in grey hydrogen production being an unattractive economic option.

The CO_2 T&S "fee" is a significant costs component for all blue hydrogen production technologies in this study accounting for 14-19% of the LCOH for the analysed technologies in 2020. Therefore, reducing costs in this area will be crucial to ensuring cost competitiveness with established grey hydrogen production. The development of shared CCS infrastructure in industrial clusters or with other large-scale emitters such as gas fired power stations with CCS enables the advantage of economies of scale to ensure CO_2 T&S costs are reduced. In the long term, blue hydrogen production will be lower cost than grey due to higher carbon prices.

Future Markets

In the longer term, the falling cost of renewable electricity is likely to make green hydrogen production increasingly competitive and lower cost than blue hydrogen production in cases where low-cost electricity is available. For example, North Africa and Southern Europe are expected to have high capacities of low-cost solar electricity that could be utilised for green hydrogen production via electrolysers. Hydrogen production from natural gas with CCS in the Netherlands is expected to face significant competition from global hydrogen

[5] UK Government 2021, Consultation on a UK Low Carbon Hydrogen Standard

imports from regions where low-cost hydrogen production is available. This not only includes the import of green hydrogen, but also blue hydrogen production from oil and oil-based feedstocks. If the cost of hydrogen distribution over long distances can be reduced sufficiently, importing low-cost hydrogen may be more economical than local production in regions such as the Netherlands. However, the large-scale transport of hydrogen over long distances currently faces many technical challenges and is not operational due to the high costs associated with the process.

Recommendations

Production of blue hydrogen with a minimum CO_2 capture rate of 90% via technologies that use natural gas has not yet been demonstrated at scale. The successful deployment of these technologies relies on a multiplicity of factors such as: proving technical and financial viability, validating CO_2 footprint and assessing integration with the wider regional supply chains. **Government grants**, **risk mitigation measures** and **private industry funding** are essential to drive blue hydrogen demonstration projects forward. This is the first stage towards long-term, unsubsidised blue hydrogen production.

Research, Development and Demonstration

- **Including blue hydrogen production technologies in CCS cluster plans** to take advantage of scales of deployment. This will reduce CO_2 T&S costs.
- **Further work is needed to explore optimal technology type by region.** This study explored four blue hydrogen production technologies. These technologies are not limited to deployment in the Netherlands and cost ranges show that all analysed technologies can be competitive options. Blue hydrogen producers should conduct further feasibility and FEED studies to optimise technology deployment choices.
- **Additional technology development, including demonstration projects, to prove the technologies in the field and raise awareness.** This includes resolving data gaps and uncertainties e.g. ESMR was at TRL 4 at the start of the study (end of 2020, technology developer is hoping to increase TRL to 7/8 through a pilot installed in 2021), and process data is therefore less reliable. This will ensure that these technologies are understood and included in national and international hydrogen strategies, facilitating international collaboration.
- **Further evidence gathering around relative economies of hydrogen transportation**. Comparing hydrogen distribution methods at different scales, distances, operating parameters and archetypes.
- **Exploring local hydrogen demand scenarios and reducing costs in the value chain for lower cost hydrogen distribution**. This includes leveraging learnings and investments from ongoing projects such as Acorn which are demonstrating ways to reuse existing infrastructure for CO_2 T&S.
- **Exploring synergies between transporting CO_2 and hydrogen**. Opportunities to utilise the same port infrastructure and ships for shipping of hydrogen and CO_2.

Policy and Actions

- Governments should only support blue hydrogen technologies with sufficiently low carbon footprints as calculated from life cycle assessments. This includes sufficient high carbon capture rates (preferably >90%), use of electricity with low carbon content, and a strong focus on the reduction of methane leakages involved with extraction, transportation and consumption.
- Including blue hydrogen production technologies in CCS cluster plans to take advantage of scales of deployment. This will reduce CO_2 T&S costs.
- Support for carbon pricing to outcompete conventional production of “grey” and “brown” hydrogen production technologies.
- Business model development for blue hydrogen production is required to make low carbon hydrogen competitive with that produced from high carbon alternatives.
- International collaboration between global regions with low-cost hydrogen production and those with emerging hydrogen demand. In the short to medium term, materialising these connections may require

international trade of hydrogen to areas with more developed hydrogen strategies and with proven end-uses for hydrogen.

- Development of new grey hydrogen production facilities should be discouraged unless they have accompanying CCS retrofit strategies.
- CCS retrofits to existing grey hydrogen production facilities should be encouraged where hydrogen plants are expected to remain operational for many years.

Acronyms and Abbreviations

ATR	Auto Thermal Reforming	LH_2	Liquefied Hydrogen
ASU	Air Separation Unit	LHV	Lower Heating Value
CAPEX	Capital Expenditure	LOHC	Liquid Organic Hydrogen Carriers
CCS	Carbon Capture and Storage	LPG	Liquid Petroleum Gas
CO	Carbon Monoxide	MEA	Mono-ethanol Amine
CO_2	Carbon Dioxide	M	Millions
DRI	Direct Reduction of Iron	MOFs	Metal Organic Frameworks
EOR	Enhanced Oil Recovery	N/A	Not Applicable
ESMR	Electric Steam Methane Reforming	NH_3	Ammonia
EU	European Union	OPEX	Operational Expenditure
FCEVs	Fuel Cell Electric Vehicles	POX	Partial Oxidation
FEED	Front End Engineering Design	PSA	Pressure Swing Adsorption
GH_2	Gaseous Hydrogen	SGP	Shell Gasification Process
GHG	Greenhouse Gas	SMR	Steam Methane Reforming
GHR	Gas Heated Reformer	SNR	Steam Naphtha Reforming
H_2	Hydrogen	T&S	Transport and Storage
HEE	Hygienic Earth Energy	TEA	Techno Economic Assessments
HHV	High Heating Value	TRL	Technology Readiness Level[6]
HRS	Hydrogen Refuelling Station	UK	United Kingdom
LCA	Life Cycle Assessment	USA	Unites States of America
LCOH	Levelised Cost of Hydrogen	USD	United States Dollar

[6] TRL levels defined in appendix – Section 7.1

Contents

1 Introduction

1.1 Context

Hydrogen is increasingly recognised by public and private sector stakeholders around the world as a key element in meeting the Paris Agreement's goal. To ensure decarbonisation, hydrogen must be produced in a clean way. Hydrogen derived from fossil fuels with carbon capture and storage (CCS), called blue hydrogen, represents a viable generation pathway with large-scale, serving as a vector for achieving climate goals. The resulting hydrogen can be used as an energy carrier, similar to natural gas, and is capable of decarbonising multiple sectors, including industry, heating, power generation, and transport. In addition, CCS will play a complementary role in decarbonisation, ensuring that process emissions associated with hydrogen production are safely stored underground. Many governments and other public sector bodies are beginning to commit support to expand the use of hydrogen and fuel cell technologies, with some seeing a pivotal role for blue hydrogen in the energy transition.

Traditionally, the main hydrogen production technology has been steam methane reforming (SMR) without CCS. SMR has been the subject of most blue hydrogen assessment studies to date, including IEAGHG's 2017 techno-economic studies. However, new hydrogen production technologies are emerging and are considered for deployment by recent project developers. These include ESMR (electrified SMR), autothermal reforming with a gas heated reformer (ATR + GHR), and partial oxidation (POX). All use natural gas as their feedstock.

However, there is a gap in the literature regarding newer technologies. The costs and environmental benefits of newer blue hydrogen production technologies, as well as their adaptability to use CCS has not been fully examined to date. A comparative study examining all four production pathways (SMR, e-SMR, ATR + GHR, and POX) must be undertaken, using a clear methodology aligned with literature to date, including IEAGHG's publications, to allow a streamlined comparison. The purpose of this study is to enrich knowledge and compare the deployment of SMR, e-SMR, ATR, and POX with CCS in the Netherlands, one of the countries in Europe most active in the natural gas, hydrogen, and CCS space.

1.2 Objectives and Scope of Work

The primary objective of this study is to provide a roadmap for hydrogen production routes and assess the production of hydrogen from natural gas with CCS. This includes considering technical, economic, and emissions aspects. The analysis concentrates on the following five objectives:

- To consider the existing technologies for the production of hydrogen, their development status, scale of usage, and potential for expansion in line with demand, as well as the with the CCS value chain.
- To assess the main technologies used to produce hydrogen from natural gas, including SMR, ATR (including with GHR), and POX as well as emerging technologies such as ESMR.
- To conduct a techno-economic and environmental assessment of different production configurations in the Netherlands.
- To conduct the analysis independently and impartially, without dismissing or promoting certain production options.
- To compare the production pathways with other literature sources, identify key enabling drivers and develop a series of policy recommendations to achieve competitiveness and scale of the routes examined.

This study has run in parallel to a similar report on production of hydrogen from oil and oil-based products. The methodologies for these two reports and associated analyses are similar and so comparisons are made where appropriate.

1.3 Report Structure

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

- **Section 2** explores available literature on the hydrogen production pathways and demand sectors (including transport, heat, power and industry) deployed to date. This also includes understanding these production processes and the different types of carbon dioxide (CO_2) capture.
- **Section 3** is focussed on a review of technical parameters for the four blue hydrogen production technologies analysed in this report.
- **Section 4** describes the Techno Economic Assessment (TEA) methodology and presents the respective findings, including associated sensitivities.
- **Section 5** describes the Life Cycle Assessment (LCA) methodology and presents the respective findings, including associated sensitivities.
- **Section 6** assesses the findings from this study, determines the strengths and weaknesses of these production pathways and provides recommendations for further sector development.
- **The Appendices** provide supporting information and assumptions for the analyses carried out in this study.

2 Assessment of Current Global Blue Hydrogen Production

2.1 Overview

Today, the majority of the world's hydrogen is derived from fossil fuels without carbon capture. It is consequentially denoted as grey hydrogen and is associated with a high carbon footprint. This hydrogen is largely confined to industrial applications such as ammonia and methanol production and various refinery chemical processes.

However, promising low carbon production technologies are coming to market. These include blue hydrogen technologies, which incorporate CCS, and green hydrogen technologies, such as electrolysis. Carbon capture technologies significantly reduce CO_2 emissions from targeted process streams via a combination of different capture practices. Investment in the blue hydrogen sector is continuing to increase due to the sector's significant potential to contribute to decarbonisation. The market is expected to grow from 104 MtH_2/yr in 2020 to more than 570MtH_2/yr by 2050 in a supportive policy environment[7]. This arises from increased demand from transport, power, heat and other industrial processes currently using natural gas and coal.

This section reflects on the current status of the hydrogen market, including: the different hydrogen production technologies and their respective installed production capacity; segmentation of hydrogen demand; types of CO_2 capture systems; the status of hydrogen storage and strategies for flexible hydrogen production.

2.2 Hydrogen Production Pathways

Today, hydrogen is largely derived from natural gas and coal in large-scale industrial processes. However, there are a variety of emerging production technologies which accept a range of different feedstocks. The production capacities of these technologies span several orders of magnitude, making them suitable for a variety of end use cases. In 2020, between 104 (Element Energy analysis) and 140Mt[7, 8] of both pure hydrogen and syngas was produced. This production is dominated (>96%) by production from natural gas, coal and as a by-product from processes such as catalytic naphtha reforming.

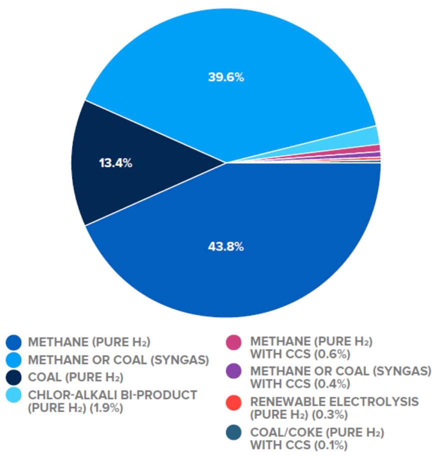

Figure 5: Global shares of H_2 production by feedstock in 2020[9]

Carbon capture is not commonplace for almost all hydrogen production facilities. The carbon intensity of the hydrogen is therefore high. This type of hydrogen is termed grey hydrogen. Increasingly, there is a greater focus on lower carbon alternatives such as:

- **Blue Hydrogen -** Hydrogen derived from fossil fuels with carbon capture.
- **Green Hydrogen -** Hydrogen derived from renewable electricity via processes such as electrolysis.

[7] IEAGHG: Beyond the Plant Gate, Element Energy, 2021
[8] Government of Canada, Hydrogen Strategy for Canada 2021
[9] Global CCS Institute, Global Status of CCS 2020

A more detailed discussion on the colours of hydrogen, based on production technology and carbon intensity is given in Section 3.1. This section provides an overview of strategically significant technologies and their respective technology readiness levels (TRLs), production costs and global distribution.

2.2.1 Production Pathways

There are a number of different options for producing hydrogen, as shown in Table 1. This shows that there are a range of technologies that have reached commercial maturity, whilst there are also a number of technologies currently in development for future hydrogen production. The most popular options, as previously discussed, use fossil fuels without carbon capture. The blue hydrogen variations of these are discussed below.

Other options which don't rely on fossil fuels include electrolysis, the chlor-alkali process and nuclear assisted production. The chlor-alkali process produces hydrogen as a by-product and nuclear assisted production remains limited in its deployment. However, electrolysis is expected to be the main competitor to blue hydrogen.

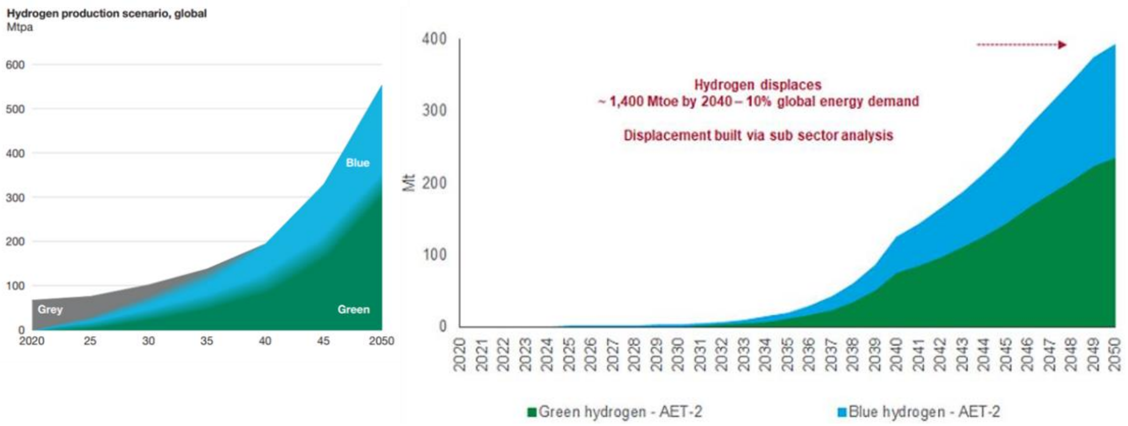

Figure 6: Global hydrogen demand forecasts from the Hydrogen Council[10] (*Left*) and Wood Mackenzie[11] (*Right*).

This momentum for green hydrogen produced via electrolysis means it is a direct competitor to blue hydrogen in the long-term, with high demand regions such as the European Union (EU) setting targets of 40GW of installed electrolyser capacity by 2030[12]. Some reports have suggested that by 2050 the global mix of hydrogen production could be a blend of approximately 40% blue to 60% green hydrogen production, as shown in Figure 6. However, there is significant uncertainty around the future mix of hydrogen production; this will be influenced by technoeconomics as well as regional and international policy.

However, in the near-to-medium term, blue hydrogen may provide the majority of the world's low carbon hydrogen due to the more mature production processes. Another advantage is the option of deploying these facilities at large scale in industrial clusters with CCS, satisfying industrial demand which is responsible for nearly 100% of current demand, as discussed in Section 2.3.

[10] Hydrogen Council 2021, Hydrogen Decarbonization Pathways: Potential Supply Scenarios
[11] Wood Mackenzie 2020, Green Hydrogen: A Pillar of Decarbonisation?
[12] renews 2020, EU unveils 40GW green hydrogen vision

Table 1: Selection of hydrogen production technologies, including their feedstock, TRL and technology description

Technology	Feedstock	TRL	Description
Steam Reforming	Natural Gas / Light Oils (i.e. Naphtha)	9	The most established H_2 production technology, the feedstock and steam react in a reactor to produce syngas. The water gas shift (WGS) reactions and purification via pressure swing adsorption (PSA) produces a pure stream of H_2.
Partial Oxidation	Natural Gas / Oil	7 – 9	Non-catalytic process whereby the feedstock is gasified in the presence of oxygen to produce H_2.
Autothermal Reforming Configurations	Natural Gas	7 – 9	Syngas is produced from natural gas, steam and O_2 (O_2 replaces natural gas as the driver of the reaction). This is followed by WGS & PSA. A variants on the ATR is the Low Carbon Hydrogen (LCH) technology which includes a gas heated reformer (GHR).
Electrified steam reforming	Natural Gas / Light Oils (i.e. Naphtha)	4	Variation on the traditional SMR process that replaces natural gas fuelled combustion with electrically heated reformers. Potential for significant emissions reductions when deployed with renewable electricity.
Gasification	Coal / Biomass / Waste	4 - 9	Thermochemical conversion of feedstock into syngas in air, oxygen and / or steam. Low efficiency but WGS reaction facilitates the production of additional hydrogen.
Pyrolysis	Natural Gas / Oil / Coal / Biomass	4 – 9	Thermochemical decomposition of hydrocarbons at medium to high temperatures in an inert atmosphere. This is focussed on biomass production.
Reservoir Production	Natural Gas / Oil	4	Injection of oxygen into reservoirs initiates in-situ combustion which splits hydrocarbons into their basic elements. A selective membrane extracts H_2 from these reservoirs.[13]
Electrolysis	Water & Electricity	6 – 9	Electricity is used to split water into O_2 and H_2. Where renewable electricity is used this is zero-carbon. Variants include polymer-electrolyte membrane, alkaline and solid oxide.
Chlor-Alkali	Brine (Sodium Chloride) & Electricity	9	H_2 is a by-product of the electrolytic decomposition of salt in which chlorine and sodium hydroxide are produced.
Nuclear Assisted Production	Various	3 - 6	Nuclear energy can provide steam or electricity for a) powering other production technologies and / or b) thermal hydrogen production such as thermolysis.

[13] Hydrogen production via Underground Coal Gasification is an alternative reservoir production method however is not considered in this study.

Blue hydrogen production technologies use carbon capture to remove CO_2 from process streams. This CO_2 is either stored in underground reservoirs or used in other processes. In this way, conventional hydrogen production processes with a high carbon intensity are significantly decarbonised. There are three production routes which are expected to be competitive in the blue hydrogen space. These technologies are discussed in detail in Section 3 and largely follow the same process configuration, as shown in Figure 7.

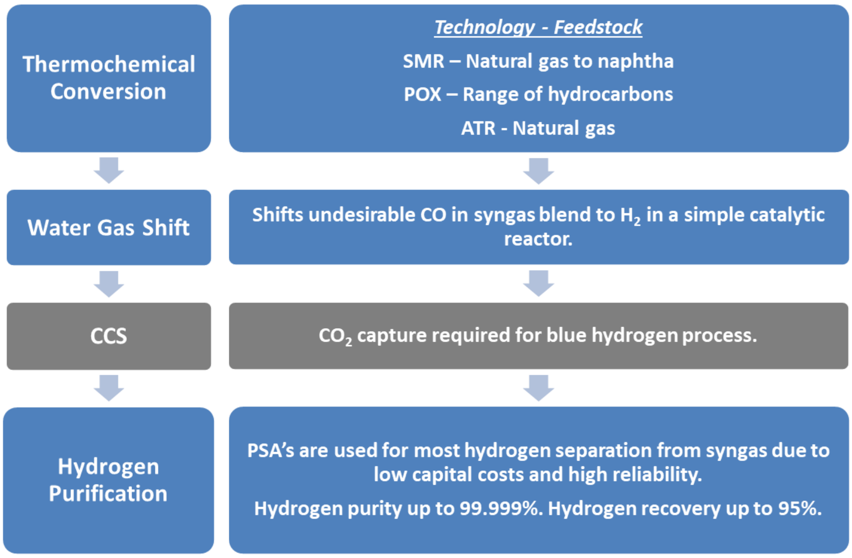

Figure 7: Typical blue hydrogen production pathway

Steam Reforming

Steam reforming production accepts small-chain hydrocarbons in the range of natural gas to naphtha. These plants are typically sized between 35 & 700MW (10,000 & 235,000 Nm^3/h) and are responsible for nearly 50% of the world's hydrogen demand[1]. In this process, the hydrocarbon feedstock is mixed with steam in a reformer at temperatures of 750-950°C. This produces a mix of hydrogen, carbon dioxide and carbon monoxide known as Syngas[14]. The syngas stream is then fed through the Water Gas Shift (WGS) reactor where catalytic reactions between carbon monoxide and steam facilitate the additional production hydrogen.

A variation on this configuration is to use electrically heated reformers. This significantly reduces emissions directly produced from the facility.

Gasification and Partial Oxidation

Gasification (for solids) and partial oxidation (POX – for liquids and gases) is widely deployed at a global scale for hydrogen production and is particularly prevalent in countries where coal is both more widely available and at lower cost than natural gas. This is commonly the case in East Asia. The process involves gasifying feedstock material such as natural gas, but also coal and heavy oil fractions, at very high temperatures (1300 - 1500 °C) in the presence of oxygen and steam to produce syngas. In a similar manner to the steam methane reforming (SMR) process, the syngas stream is then fed through the WGS reactor where catalytic reactions between carbon monoxide (CO) and steam facilitate the production of additional hydrogen.

Autothermal Reforming

Autothermal reforming (ATR) combines SMR and POX by using steam and catalysts to increase hydrogen yield (from SMR) and using oxygen to deliver the energy for reaction (POX). The process stream is similar to POX and SMR, with the reaction vessel leading to a WGS reactor before the hydrogen is purified and cleaned in a pressure swing adsorber. A gas heated reformer (GHR) can be added to the process to pre-heat and partially reform the natural gas feedstock prior to entering the primary ATR reformer. The integration of the

[14] 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

GHR is typically referred to as the low carbon hydrogen (LCH) configuration, a technology that is getting particular attention in the UK in H21 North of England, Zero Carbon Humber and HyNet projects.

2.2.2 Production Costs

The lowest cost pathway for producing hydrogen is by separating the molecule as a by-product from processes such as catalytic naphtha reforming. Where dedicated hydrogen is needed, SMR is conventionally deployed as it is often the lowest cost production pathway. This is shown in Figure 8, for a breakdown of technologies by levelized cost of hydrogen (LCOH), mainly in Canada.

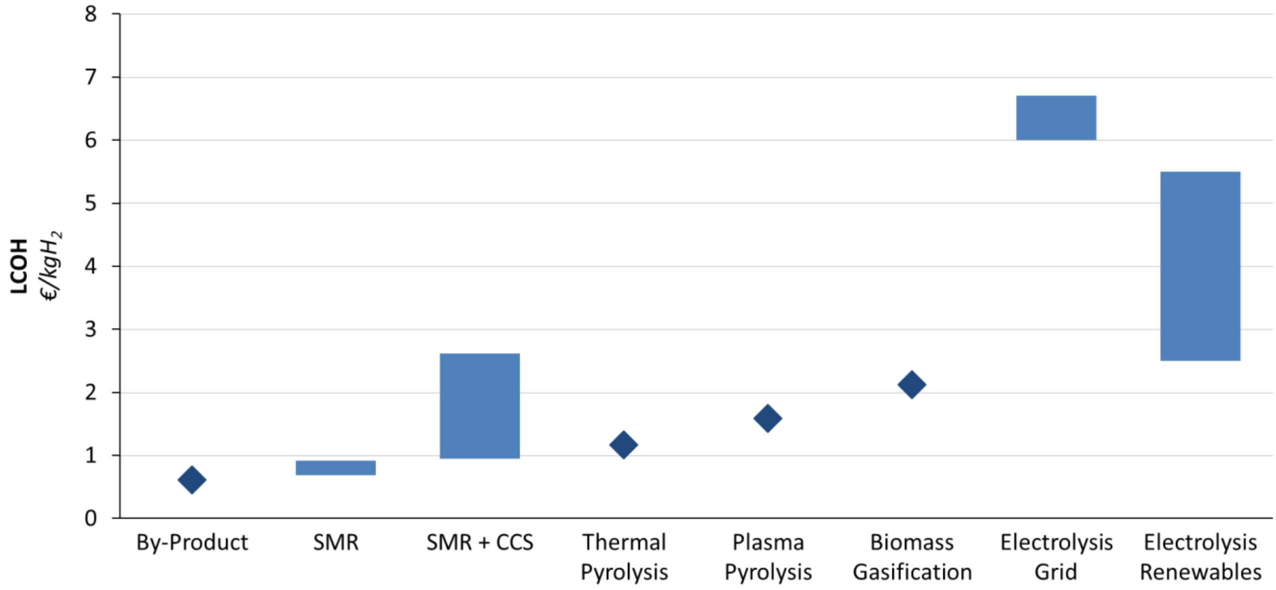

Figure 8: Comparison of Hydrogen Production Pathway Costs in 2020 (US$/kg$H_2$) [8, 15, 16, 17, 18]

A breakdown of LCOH by region for different technologies is also displayed in Figure 9. This shows that both blue and green production technologies remain more expensive options without a) further technology cost reductions and b) a supportive policy environment. Government willingness to address these issues warrants the ongoing international investment in these production options. However, technology choices are expected to vary by country and region due to varying availability and costs of fossil fuels and electricity as well as different policy environments.

[15] IEA 2019, The Future of Hydrogen
[16] ZEN and the art of Clean Energy Solutions 2019, British Columbia Hydrogen Study
[17] BEIS, 2021, Hydrogen Production Costs; Used for Grid Electrolysis
[18] European Commission, 2020, A Hydrogen Strategy for a Climate-Neutral Europe; Used for the Renewable Electrolysis

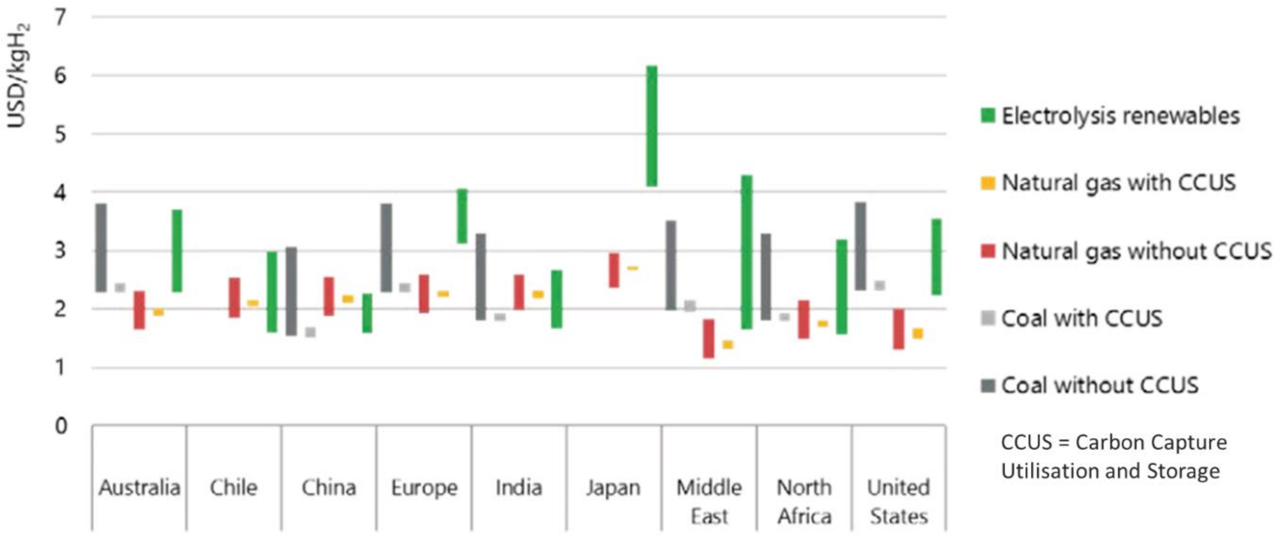

Figure 9: Comparison of Hydrogen Production Costs by region – bars represent near term (2030) and long-term (2050) cost opportunities[15]

Current Production Capacity

Due to the co-location of production with end use, the distribution of global hydrogen production follows hydrogen demand. Hydrogen demand analysis by region for 2020 is shown in Figure 10. The breakdown of hydrogen production technologies by region is based on the following:

- 96.8%[8,9] of production currently uses natural gas and coal as feedstocks. Methane is responsible for 45.9%, coal is responsible for 15.7%, various mixes of methane and coal in for the production of syngas are responsible for 36.3% and other production technologies are responsible for 2.1%.
- Using the IEA's "The Future of Hydrogen" breakdown of feedstocks to produce hydrogen for ammonia and methanol production by region as a general trend for all end use cases.
- That all gas-based production is based on SMR and all coal-based production is based on coal gasification for ammonia and methanol production. Other production technologies which use these feedstocks are unclassified and are therefore listed as other. These include catalytic naphtha reforming, steam cracking and propane dehydrogenation.

The hydrogen breakdown by region and production type in 2020 is shown in Figure 11.

Over the past ten-years, hydrogen production has increased by approximately 30%. However, blue hydrogen production still only constitutes a small portion of global capacity, with <1% of fossil fuel based hydrogen production having any form of CCS. This is expected to increase through time as countries increase their focus on decarbonisation via hydrogen.

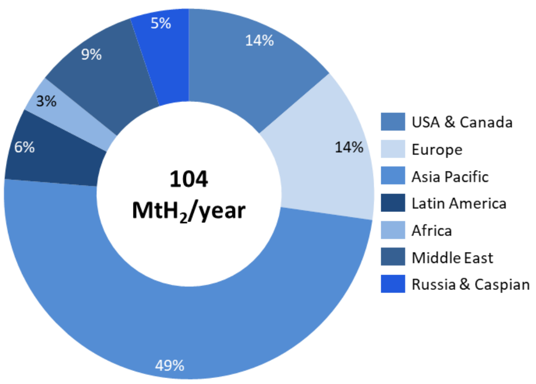

Figure 10: Current hydrogen production by region (%)

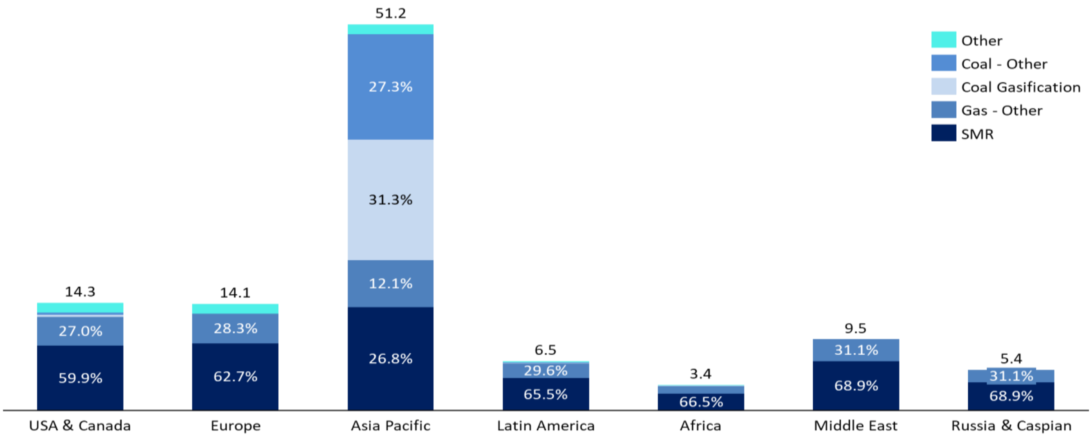

Figure 11: Hydrogen demand by region and production type in 2020 (MtH_2/year)

2.3 Global Hydrogen Demand

Hydrogen demand in 2020 is dominated by industry. In industry, either pure hydrogen or a mixture of gases, also containing hydrogen, such as synthesis gas are used as shown in Figure 12. The main applications include:

Pure hydrogen:

- **Refining –** Hydrogenation of crude oil to reduce sulphur content and reduce unsaturated hydrocarbons.
- **Ammonia Production –** Produced by combining hydrogen and nitrogen gas mainly for fertiliser usage, precursor in chemical industry, and solvent.

Mixed gases

- **Methanol Production –** Usually uses syngas (a mixture of hydrogen and carbon monoxide), which is passed over a catalyst.
- **Direct Reduction of Iron (DRI) –** Removal of oxygen from iron ore or other iron bearing materials in the solid state in the blast furnace. The reducing agents are carbon monoxide and hydrogen, coming from reformed natural gas, syngas or coal. This is largely in demonstration but is expected to grow rapidly.

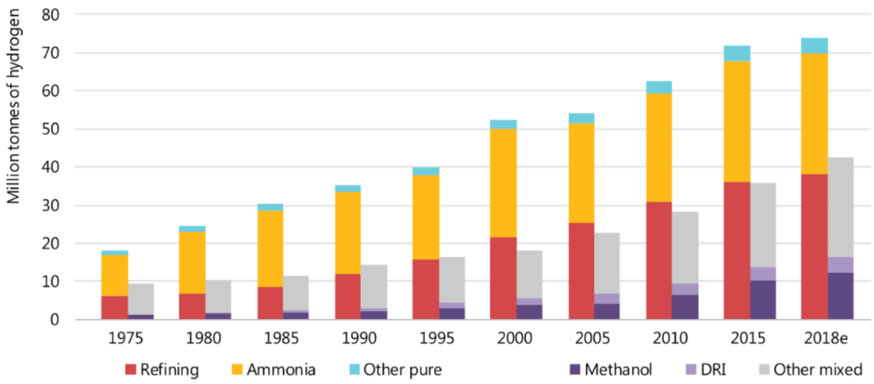

Figure 12: Global annual demand for hydrogen since 1975[15]

2.3.1 Ammonia & Methanol Production

Large quantities of dedicated hydrogen are required as feedstock to produce both ammonia and methanol. Fossil fuels have traditionally been used in the chemical sector as a source of carbon and hydrogen required in both production techniques. Natural gas currently accounts for 65% of the feedstock for hydrogen in ammonia and methanol production.

Regional Production

The choice of production technology is very reliant on the price of feedstock. This leads to the regional variation shown in Figure 13. Natural gas is low cost and widely available, helping to make it the most common feedstock for hydrogen production in ammonia and methanol production. Oil is rarely used in these processes, whilst most of the hydrogen derived from coal is in China.

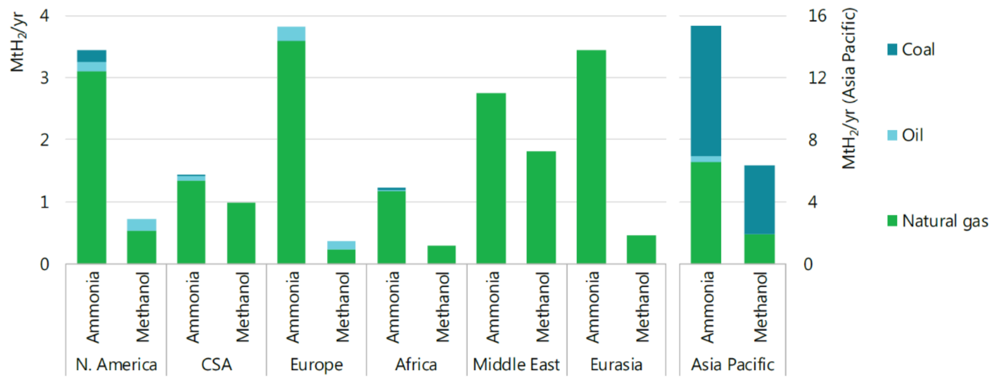

Figure 13: Hydrogen demand for ammonia and methanol production by region in 2018[15]

2.3.2 Refining

Approximately two-thirds of hydrogen demand for oil refineries is produced in dedicated on-site facilities. The majority of onsite hydrogen production uses natural gas as feedstock; however, the use of heavier feedstocks is focused on China and India where natural gas is costly to import. The USA, Europe and China account for approximately half of total hydrogen consumption in oil refineries.

Hydrogen in refineries is primarily used for:

- **Hydrotreatment –** the removal of impurities, primarily sulphur (desulphurisation)
- **Hydrocracking –** a process of upgrading heavy hydrocarbon feedstocks (heavy residual oils) into more valuable oil-based products

Hydrogen production as a by-product from onsite processes comes primarily from catalytic naphtha reforming. Hydrogen is consumed in the upgrading of oil sands to remove sulphur from raw bitumen to produce synthetic crude oil. Some hydrogen consumed or produced by refineries cannot be recovered economically and is burned as fuel compromising of a mixture of waste gases.

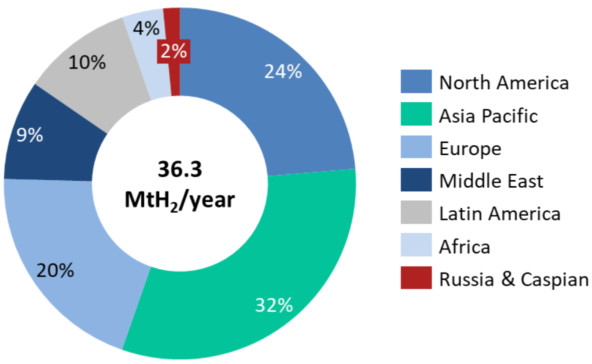

Figure 14: Estimated hydrogen demand in refining by region in 2019

2.3.3 Other Industry

Hydrogen can be used in many other industrial sectors, denoted here as "Other Industry".

Chemical Sector

Ammonia and methanol account for the majority of hydrogen demand in the chemical industry, however approximately 3 MtH_2/yr come from other processes within the chemical sector. This includes demand for the production of ethylene, propylene, benzene, toluene and mixed xylenes. The majority of this hydrogen is supplied as a by-product of other chemical processes within the same industrial clusters.

Industrial Heat Demand

Industrial process heat accounts for almost 45% of total industrial energy consumption as shown in Figure 15. Heat is used in industrial processes such as drying, melting, cracking and reforming. High temperature process heat is often described as a hard to decarbonise sector as the temperature requirements result in significant technical and economic challenges for electrification. Natural gas, coal and oil-based fuels are currently used to supply the majority of this process heat however hydrogen could also be used as an alternative fuel in many of these processes.

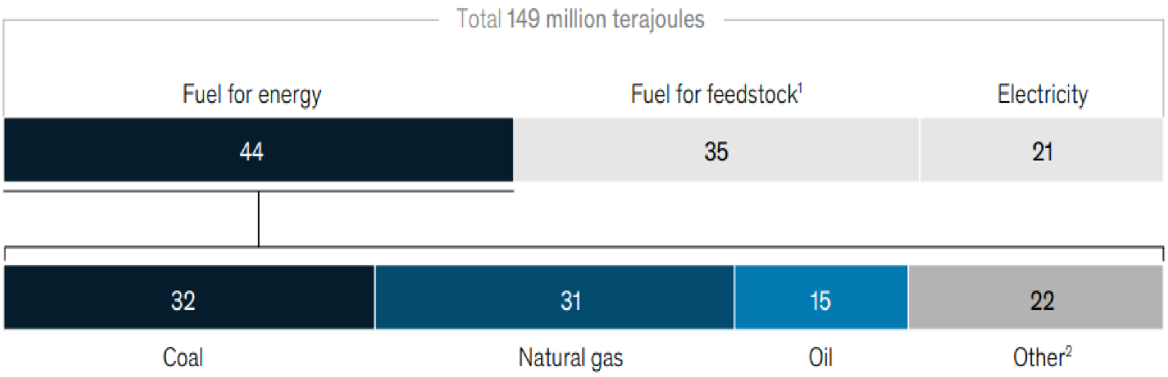

Figure 15: Share of total estimated industrial energy consumption, 2017[19]

Sectors requiring process heat include the production of non-ferrous metals (that don't contain iron e.g. Aluminium), Cement, Glass, Paper and Printing, Food & Drinks

Direct Reduction of Iron (DRI)

7% of primary steel production derives from DRI, a process where oxygen is removed iron ore or other iron bearing materials in the solid state in the blast furnace. The reducing agents are carbon monoxide and hydrogen, coming from reformed natural gas, syngas or coal. Annual global DRI production required 4.3 MtH_2/yr in 2018 as shown in Figure 16. From 2016 to 2018, world DRI production has increased by 38%[20]. The Middle East, North Africa, Latin America and Asia Pacific are the largest regional proponents of this production pathway.

[19] McKinsey & Company 2020, Plugging in: What electrification can do for industry
[20] Midrex 2019, World DRI Production Exceeds 100M Tons

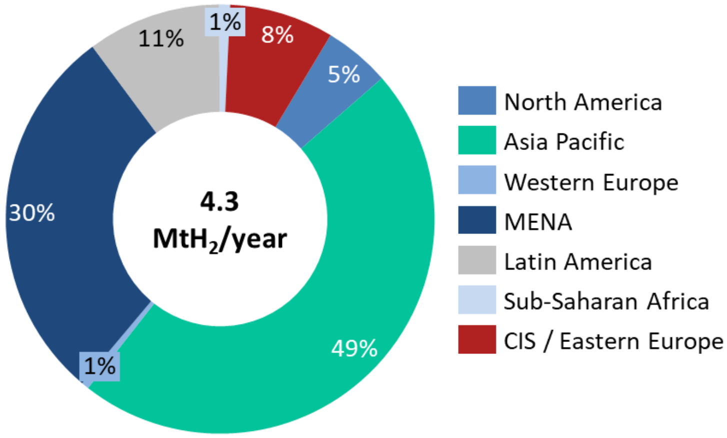

Figure 16: Estimated hydrogen demand for Direct Reduced Iron (DRI) in 2018

2.3.4 Transport

Hydrogen demand in the transport sector is currently very small; equivalent to less than 0.1MtH$_2$/yr. This largely comes from fleets of fuel cell electric vehicles (FCEVs) in Asia Pacific, US & Canada as well as bus deployments in Europe. Hydrogen purities >99.99% are required for FCEVs. Therefore, either pressure swing adsorbers (PSAs) in blue hydrogen production or electrolysers are required to meet the anticipated growing demand in the sector from 2030.

Hype – Paris

The world's first fleet of hydrogen FCEV taxis was developed by Hype, a French company operating in Paris. The fleet currently includes over 100 FCEVs and has recently announced plans to replace 600 diesel vehicles with the hydrogen fuelled Toyota Mirai[21]. To supply this growing fleet, new hydrogen refuelling stations will be developed throughout Paris with a target of 20 operational sites by 2024. Paris aims for all taxis to be FCEVs for the Paris 2024 Olympic games.

Figure 17: Hype – hydrogen taxi in Paris[22]

California

At the end of 2020 there were over 8,900 FCEVs used in the USA, with the vast majority found in California. California currently has 43 operational hydrogen refueling stations with a further 44 stations in development[23].

2.3.5 Power

Power currently forms less than 1% (0.67 MtH$_2$/yr) of global hydrogen demand, largely from Asia Pacific.

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[21] Air Liquide 2021, Hydrogen mobility pioneer, Hype, is entering a new phase with HysetCo's acquisition of major taxi firm Slota
[22] Fuel Cell Works 2021, Hype, a Pioneer in Hydrogen Mobility, Takes a New step with the Acquisition by HysetCO of Slota, a Major Taxi Player
[23] California Fuel Cell Partnership 2021, FCEV Sales, FCEB, & Hydrogen Station Data

Hydrogen can be used to produce electrical power using two processes:

- **Hydrogen gas turbines –** many natural gas fired turbines can already run safely with small blends of hydrogen. However, large scale power turbines are currently in development that will run on 100% hydrogen.
- **Hydrogen fuel cells –** fuel cells provide a more efficient method for converting hydrogen into electricity, particularly if the heat produced in the chemical reaction is captured. However, unlike gas turbines which can accept lower purity hydrogen, fuel cells require hydrogen with very low levels of certain impurities such as carbon monoxide and sulphur. Overall hydrogen purity is typically >99.99mol%.

Global hydrogen demand is predicted to grow as countries relying on natural gas fired power generation look to blend hydrogen into fuel streams to achieve emission reductions. The use of stationary hydrogen fuel cells is also predicted to grow, particularly to meet heat and power demands in cities. Growth in demand for hydrogen powered buildings (via fuel cell combined heat and power units) is predicted to come initially from East Asia with China and South Korea already in the process of developing hydrogen fuelled cities.

Power Generation in South Korea

South Korea is prioritising large scale stationary fuel cells for power generation. A target of 15GW capacity by 2040 has been set, of which 2.1GW is to be applied in buildings[24]. Work has started on the development of the world's largest hydrogen fuel cell power plant. Located in the South Chungcheong Province. The plant will have a 50MW capacity[25]. The plant will use by-product hydrogen produced from petrochemical manufacturing.

Figure 18: Fuel cell power plant concept in South Korea[25]

2.3.6 Heat

Domestic heat forms less than 1% (0.56 MtH_2/yr) of global hydrogen demand, largely from Asia Pacific[26]. Global hydrogen demand for heat could grow rapidly as countries with national gas grids look to decarbonise whilst continuing to utilise existing infrastructure. Demand could increase significantly in parts of Europe, North America and Asia Pacific in areas where hydrogen is more economic than electrification. In rural areas, electrically powered heat pumps are likely to provide the majority of low carbon domestic heat, however in densely populated cities, the space requirements for heat pump technologies are likely to be more challenging to accommodate and the potential to repurpose existing gas infrastructure may provide a more optimal solution. Domestic gas boilers and cooking appliances capable of running on a hydrogen-natural gas blend are currently in development with many appliances already safety certified. For countries without an existing natural gas infrastructure, stationary fuel cells may provide a suitable solution for providing low carbon heat.

HyDeploy

HyDeploy[27] is the first project in the UK to inject hydrogen into a natural gas network. In November 2019, permission was granted to start live tests of blended hydrogen and natural gas on part of the private gas

[24] Ifri 2020, South Korea's Hydrogen Strategy and Industrial Perspectives
[25] Fuel Cell Works 2019, South Korea: Work Begins on World's Largest Hydrogen Fuel Cell Power Plant
[26] Small scale hydrogen demand in heating likely includes the use of hydrogen as Town Gas in Asia Pacific.
[27] HyDeploy 2021

network at Keele University campus. The demonstration concluded in spring 2021 proving that blending up to 20% volumes of hydrogen is safe whilst also resulting in carbon emissions of approximately 6.1%[28]. The next stage of the HyDeploy project will blend 20% volumes of hydrogen into a public network in Winlaton in the North-East of England.

HyNet

HyNet will expand on the initial demonstration at Keele University and aim to supply a 20% hydrogen blend to over 2 million customers in the North-West of England[29]. Development of this project is expected to commence from 2023 with the hydrogen production facility expected to be operational by 2025

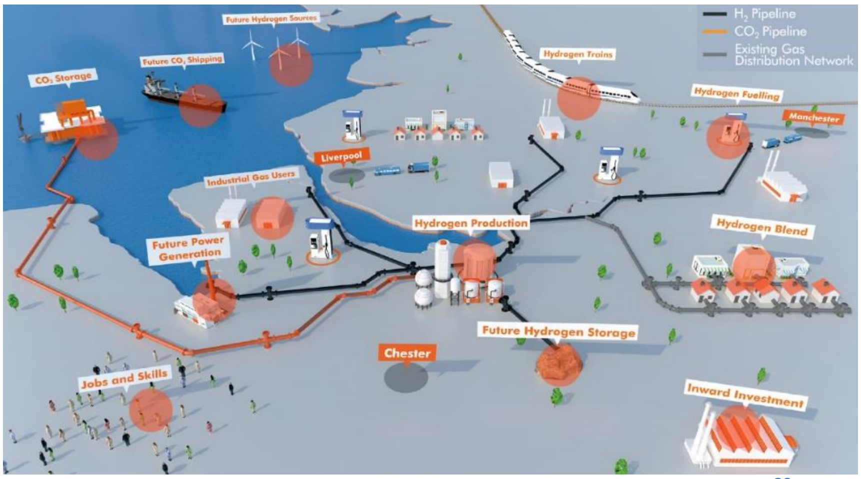

Figure 19: HyNet – North West England project concept[29]

2.3.7 Summary of Current Hydrogen Demand

The demand analysis performed in this study estimates that hydrogen demand in 2020 is 104 MtH_2/year as shown in Figure 20. This is slightly less than the IEA's value of 115 MtH_2/year. Almost half of global hydrogen demand is in the Asia Pacific region with approximately 99% of demand coming from the industrial sector.

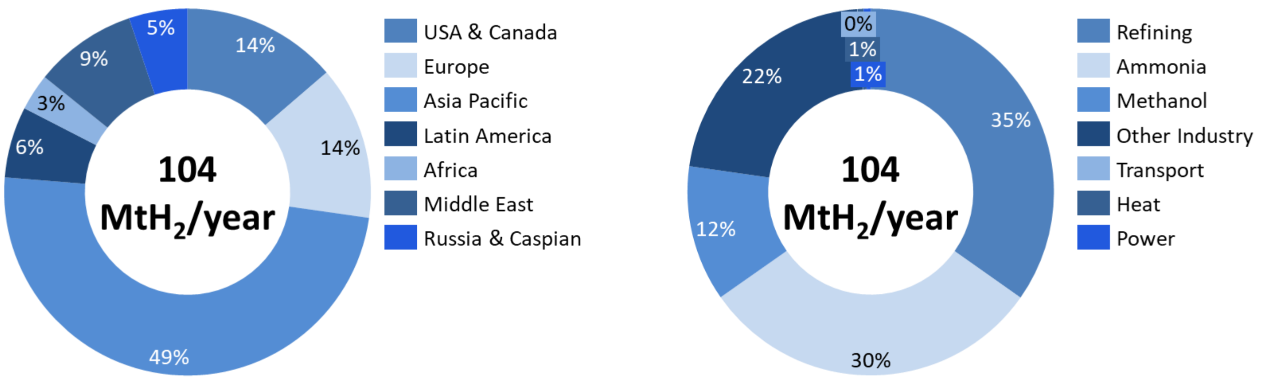

Figure 20: Global hydrogen demand by region (left) and end use case (right) in 2020 (MtH_2/year)

2.3.8 Hydrogen Import and Export

Hydrogen is widely used in industrial applications with sources of production and consumption nearly always co-located. As a result, there is very little import or export of hydrogen globally beyond the movement of some liquid and compressed hydrogen to fulfil demand during site downtime within regions themselves. It is expected that this will remain the case in the near future with the development of "hydrogen valleys" across the world as

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[28] Volumetric energy density of hydrogen is approximately a third of natural gas. Hydrogen = 3.30 kWh/m_3 (LHV), Natural Gas = 10.85 kWh/m_3 (LHV)
[29] HyNet 2021

shown in Figure 21. These areas co-locate hydrogen production technologies with regions of high demand to improve economics and scale of deployment.

Figure 21: Hydrogen valleys emerging around the globe[30]

However, the long-term future of hydrogen import and export looks promising. Work is ongoing in Europe and Asia Pacific, recognising those regions and countries which are expected to export or import hydrogen. For example:

- **Western Europe -** demand for hydrogen is expected to be significant enough to warrant import infrastructure. This could come in the form of blue hydrogen from Russia and Norway as well as green hydrogen from Spain and Ukraine. Hydrogen imports via pipelines and ships are both being considered although costs remain uncertain.
- **Australia, Japan and South Korea -** have signed MOUs and letters of intent regarding the import and export of hydrogen and hydrogen technologies[31].

2.4 Carbon Capture Systems

Carbon capture facilities have grown in capacity and number over the past few years, driven largely by national and global net zero targets. The Intergovernmental Panel on Climate Change (IPCC) identified four scenarios limiting global temperature rise to 1.5°C, three of which require significant use of CCS[9]. Carbon capture technology deployment is therefore expected to play a significant role in reducing emissions from large scale industrial emitters in traditionally hard to abate sectors, including the production of hydrogen.

Hydrogen production from fossil fuels without CCS accounts for approximately 830 $MtCO_2$/year[15]. These emissions are a function of the hydrogen production technology and the feedstock. For example, hydrogen production from natural gas, oil and coal produces approximately 10 tCO_2/tH_2, 12 tCO_2/tH_2 and 19 tCO_2/tH_2, respectively.

A complete CCS system includes a portfolio of technologies incorporating different processes for CO_2 capture, separation, transport and storage. An overview of the capture and separation technologies currently available is presented in the following section. This outlines the suitability of the technology to the hydrogen production pathways considered in this study.

[30] Fuel Cells and Hydrogen Joint Undertaking 2021, Mission Innovation Hydrogen Valleys Platform
[31] Fuel Cell Works 2019, South Korea and Australia Sign a Letter of Intent for Hydrogen Cooperation

2.4.1 Overview of Capture Technologies

CO_2 capture systems are commercially available but costly. They account for approximately 70-80% of the total cost of a CCS system which includes capture, transport and storage of CO_2[32]. Significant research and development activities are underway in order to reduce the cost of these CO_2 capture systems. The three main capture systems are post-combustion, pre-combustion and oxyfuel combustion. These processes are outlined in Figure 22.

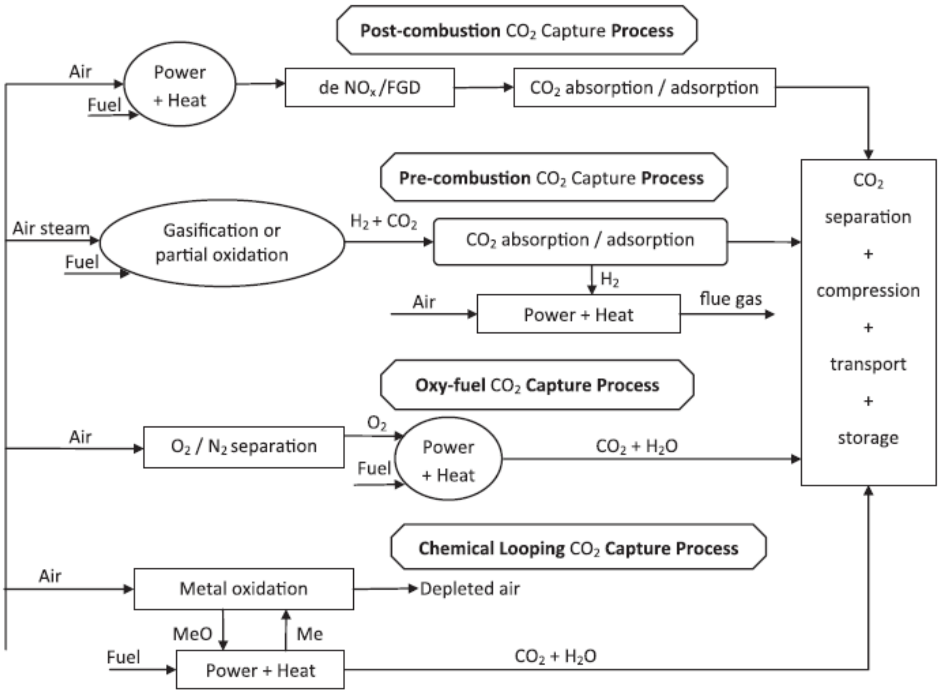

Figure 22: CO_2 capture technologies[32]

Post-Combustion Capture

Post combustion CO_2 capture is the most mature CCS capture technology[33] and involves removing CO_2 from the flue gas once combustion has taken place. Typically, this is the preferred technology option for retrofitting to existing industrial emitters. However, it is only suitable for hydrogen production technologies that require combustion as part of the process. Examples include SMR where combustion of natural gas takes place around the reactor tubes, leading to significant flue gas emissions.

The major challenge for post combustion CO_2 capture technologies is the low partial pressure of CO_2 in the flue gas stream. This leads to a large parasitic load (increased energy requirement to run the CCS system). Flue gas CO_2 levels can be as low as 4% for natural gas fired combustion[32], resulting in a significant energy requirement to achieve high capture rates above 90%. In the power sector, it was estimated that post combustion CO_2 capture would increase the cost of electricity production by between 14 - 44% for natural gas fired production[34]. Higher capture rates for natural gas based blue hydrogen can result in greater cost impacts.

Pre-Combustion Capture

Pre combustion CO_2 capture involves removing CO_2 from the syngas stream. For fossil fuel-based hydrogen production, this involves capturing CO_2 downstream of the reforming or oxidation process. The raw syngas is typically a mixture of CO, CO_2, H_2, CH_4, N_2 and H_2O, with traces of other contaminants present depending on the fuel source used[33]. Typically, the raw syngas is then cleaned to remove impurities and subsequently

[32] Leung et al 2014, An overview of current status of carbon dioxide capture and storage technologies
[33] IEAGHG 2019, Further Assessment of Emerging CO2 Capture Technologies for the Power Sector and their Potential to Reduce Costs
[34] Assuming median cost of 71 US$/MWh for unabated gas CCGT. Gas CCGT with CCS range determined from lower and upper quartiles, IEA 2020, Projected Costs of Generating Electricity 2020

processed through a shift reactor to generate a stream of H_2 and CO_2. The CO_2 concentration in the syngas stream is typically 25-40 vol% at pressures of 20-50 bar[35]. Adsorption and physical absorption are typically used for pre-combustion CO_2 capture and are inherently more efficient than equivalent post-combustion flue gas capture when the partial pressure of CO_2 is high. Higher pressure capture can also lead to reduced plant size requirements. When deployed in hydrogen production facilities that don't require heat input into the process via combustion (e.g. POX and ATR configurations) this can therefore result in lower capital costs.

Oxyfuel Combustion Capture

Oxyfuel combustion involves the removal of nitrogen from the air prior to combustion. Hydrocarbon fuel is then burned in high purity oxygen (typically 95-97%), resulting in a flue gas consisting of primarily H_2O and CO_2[35]. This reduces the quantity of nitrogen in the flue gas and subsequently reduces the challenge of removing the relatively low concentration CO_2 from the large amounts of nitrogen found in post-combustion flue gas. Particulates and impurities in the flue gas are removed via conventional electrostatic precipitator and flue gas desulphurisation methods, resulting in the remaining gas containing a high concentration CO_2 stream (80-98% depending on the fuel used). This purified CO_2 stream can then be compressed, transported and stored.

Although technically feasible, oxyfuel combustion capture requires large quantities of oxygen produced by an energy intensive air separation unit (ASU) for operation[32]. The high energy intensity of the process can therefore result in high CO_2 capture costs. This technology is also yet to be developed at scale with deployments currently limited to smaller capacity projects (approximately 30MW). There are some projects, such as HyNet and Acorn, that will use an air separation unit. This means that oxygen instead of air is injected into the reformer, leading to oxy-fired reformers at the 300MW+ scale. There is currently on-going research on reducing the energy intensity of the oxyfuel process as this is typically found to be a limiting factor in comparison to other capture technologies. In a similar manner to post-combustion CO_2 capture, this technology is only applicable to SMR based hydrogen production.

2.4.2 Overview of CO_2 Separation Technologies

CO_2 captured from the hydrogen production process requires isolating from the flue gas or syngas stream prior to transportation and storage. This section outlines the primary technologies available for CO_2 separation. Separation technologies suited to each of the CO_2 capture processes are outlined in Table 2.

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

Table 2: Overview of CO_2 separation technologies for different capture methods[33, 36, 37]

Capture Option	Separation Technology	Method
Post-combustion	Absorption by chemical solvents	• Amine-based solvent e.g. monoethanolamine (MEA) • 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 • 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 • Chemical looping combustion • Chemical looping reforming

Absorption

Absorption is the most mature method of CO_2 separation and can utilise both physical (solid) absorption and chemical absorption. The majority of commercial CCS systems currently available utilise the chemical absorption process[38]. Absorption using chemical solvents can capture CO_2 even at low partial pressures. This separation method is therefore the preferred option for post-combustion capture systems where CO_2 partial pressure is low. Ideal chemical solvents for CO_2 capture should possess high absorption capacity, high CO_2 reactivity, low regeneration cost requirements, low solvent cost, thermal stability and low solvent degradation[38]. Monoethanolamine (MEA), diethanolamine (DEA) and Methyldiethanolamine (MDEA) are used commercially with MEA and MDEA capable of achieving capture rates of greater than 90%[32]. Amine degradation is one of the key challenges that has limited the wide scale deployment of this technology for CCS systems, as this can result in solvent loss and equipment corrosion.

Absorption is a cyclic process with the solvents requiring regeneration. This is achieved by increasing the temperature and / or reducing the pressure to break the solvent-CO_2 bond. CO_2 removal via physical absorption is dependent on the CO_2 solubility within the solvents. The solvent solubility is increased with high partial pressures and low temperatures of the feed gas. Absorption by physical solvents is suited to pre-combustion capture where the increased partial pressure of CO_2 in the syngas results in increased solubility. For pre-combustion capture, physical solvents such as selexol and rectisol are used. MEA is the preferred chemical solvent for both pre- and post-combustion capture.

[36] Raza et al 2019, Significant aspects of carbon capture and storage – A review
[37] Concawe 2021, Technology scouting—carbon capture: from today's to novel technologies
[38] Badiei et al 2012, Overview of Carbon Dioxide Separation Technology

Adsorption

Adsorption CO_2 separation involves the capture of CO_2 on a solid surface known as the adsorbent. An ideal adsorbent will possess a large specific surface area, high CO_2 selectivity and high regeneration ability[36]. The process is currently applicable at industrial scale for post-combustion processes[38], with typical sorbents including molecular sieves, activated carbon, zeolites and calcium oxides. The adsorption process is a promising technology for CCS systems as it typically has lower energy requirements and lower capital costs in comparison to the absorption process.

Adsorption is a cyclic process and the adsorbent therefore requires regeneration to recover the captured CO_2 for transport and storage. As the process is exothermic, this can be achieved using a Temperature Swing Adsorption (TSA) where the temperature is increased to release the CO_2, or a Pressure Swing Adsorption (PSA) where the pressure is reduced to atmospheric pressure to desorb the CO_2. In pre-combustion hydrogen production processes, the use of adsorbents is also being investigated to increase hydrogen yields.

Membrane Separation

Membrane CO_2 separation utilises permeable or semi-permeable materials that allow the selective transport of CO_2 from gaseous streams. Membrane separation technologies have great potential for both pre- and post-combustion CO_2 capture using inorganic membranes (carbon, zeolite, ceramic or metallic) and organic (polymeric) membranes[38]. The membrane material is the predominant factor impacting the membrane cost and performance for CO_2 separation systems. The ideal membrane for CO_2 separation will have high permeability (high flux allows a specific gas through the membrane), chemical stability and selectivity (the ability to only let one gas pass through the membrane e.g. CO_2, whilst blocking others) as well as mechanical stability at high temperatures.

Membrane separation technologies are most suitable for high CO_2 concentration applications (partial pressure >20%) and are therefore most suitable for application on syngas and oxyfuel combustion flue gas streams. Membrane operation is simple and compact in comparison to the cyclic absorption and adsorption processes and is also suitable for modular scale up in CCS systems. This ability for modular scale up could prove advantageous for membrane technology deployment in future systems as CCS has traditionally only been economical at large scale. However, the ability for membrane materials to operate in demanding high temperature environments has traditionally limited further deployment.

CO_2 Capture Cost Drivers

Key parameters influencing the technical and economic operation of CO_2 capture and separation systems are outlined below[39]:

- **Flue gas / Syngas flow rate –** this determines the size of the absorber/adsorber required with larger absorbers contributing significantly to the overall cost of a CCS system.
- **CO_2 content –** with the flue gas often at atmospheric pressure, the partial pressure of CO_2 will be low making it hard to recover. Syngas is typically at higher pressures where the partial pressure of CO_2 is higher, making it less energy intensive to recover.
- **CO_2 removal rate –** high recovery rates will require increased energy requirements, taller absorption/adsorption columns and therefore increased costs.
- **Solvent flow rate –** for post combustion systems, this will determine the size of the majority of the system equipment. The solvent flow rate is fixed by the flue gas flow rate, flue gas CO_2 content and required capture rate.
- **Energy requirement –** this is the sum of the thermal and electrical energy required for the absorption/adsorption regeneration cycle. This also includes compression and pumping requirements prior to CO_2 transportation and storage.

[39] IPCC 2005, Carbon Dioxide Capture and Storage

2.4.3 CCS Economics

The economics of CCS plants are typically stated in terms of CO_2 avoidance costs. This is the CO_2 tax at which the product (hydrogen) cost is the same for:

- A fossil fuel plant without CCS but paying CO_2 tax.
- The same fossil fuel plant that includes the added costs and efficiency losses of adding CCS whilst avoiding the majority of the CO_2 tax.

The CO_2 tax must therefore be higher than the cost of CO_2 avoidance to justify the higher risks, increased capital and lower overall efficiency of deploying CCS to increase uptake[40].

The cost of CO_2 capture (€/tCO_2) for hydrogen production is calculated based on CO_2 captured per unit net product produced and is shown by equation below[35]:

$$CO_2\ Capture\ Cost = \frac{LCOH_{Capture} - LCOH_{Ref}}{CO_2\ Captured}$$

Where $LCOH_{Capture}$ is the LCOH of the technology with CCS (€/MW), $LCOH_{Ref}$ is the LCOH of the technology without CCS (€/MW) and CO_2 captured (tCO_2).

The cost of CO_2 avoidance (€/tCO_2) for hydrogen production is calculated based on CO_2 reduction per unit net product produced and is shown by the equation below[35]:

$$CO_2\ Avoidance\ Cost = \frac{LCOH_{Capture} - LCOH_{Ref}}{\left(\frac{CO_2\ emissions}{Hydrogen\ Production}\right)_{Ref} - \left(\frac{CO_2\ emissions}{Hydrogen\ Production}\right)_{Capture}}$$

Where the reference plant provides the CO_2 emissions (tCO_2/MW) for the plant without CCS, whereas the capture plant provides the CO_2 emissions (tCO_2/MW) for the plant with integrated CCS.

The ultimate goal of CCS is to reduce CO_2 emissions to the atmosphere rather than capture the greatest amount of CO_2. For this reason, CO_2 avoidance cost is the preferred metric for measuring CCS costs. CO_2 avoidance costs are typically compared against a base case without capture as shown by the equations above. However, fuel switching scenarios can also be considered for hydrogen production technologies. Significant quantities of CO_2 emissions can be abated by electrifying system processes. For example, a natural gas fired reformer in an SMR plant can be replaced by an electrically heated reformer supplied with renewable electricity.

2.4.4 Current CCS Hydrogen Production

There are currently four SMR hydrogen production facilities with integrated CCS worldwide, accounting for approximately 800,000 tonnes of low carbon hydrogen per year[9]. The Air Products' Port Arthur, Texas hydrogen production facility was the first commercial scale SMR facility to integrate CCS and became operational in 2013. The facility incorporates vacuum swing adsorption which captures CO_2 downstream of the systems water gas shift reactor, capturing approximately 1 MtCO_2 per year[41]. The captured CO_2 is transported via pipeline for enhanced oil recovery (EOR) at the nearby West Hastings oil field.

Gasification facilities with integrated CCS utilising coal, coke and asphaltene feedstocks are also operating commercially. Currently, there are three facilities operational producing approximately 600,000 tonnes of low carbon hydrogen per year. The world's largest clean hydrogen facility is the Great Plains Synfuel plant located in North Dakota which produces approximately 1,300 tonnes of hydrogen per day from lignite (brown coal) feedstock[9]. The facility has been producing hydrogen since 1988, with CCS capabilities added to the facility in 2000. Approximately 3 MtCO_2 per year is transported via a 330km pipeline to oil fields in Saskatchewan, Canada[42].

[40] Simbeek and Beecy 2011, The CCS Paradox: The Much Higher CO2 Avoidance Costs of Existing versus New Fossil Fuel Power Plants
[41] IEAGHG 2018, The CCS Project at Air Products' Port Arthur Hydrogen Production Facility
[42] ZeroCO2, Great Plains Synfuels Plant

Projects such as the Port Arthur and Great Plains Synfuel demonstrate that low carbon hydrogen production with CCS at large scale is both technically and economically feasible today. Initially, further CCS deployment is expected to be developed with the aim of maximising the economic benefits that can be achieved from EOR. However, a number of blue hydrogen production projects are currently under development and expected to become operational in the next few years where CO_2 is not used for EOR, such as Acorn hydrogen production in the UK. Currently, less than 0.7% of hydrogen production is estimated to come from renewable or low carbon (including CCS) sources. However, CCS deployment may scale significantly in the future due to increased technology maturity and as blue hydrogen also scales.

Box 1 CCS Case Study – H2H Saltend UK

H2H Saltend aims to deploy low carbon hydrogen production technology at scale in the Humber region of the UK. The project will produce hydrogen from natural gas via an ATR with carbon capture used to capture at least 95% of the associated CO_2. The project is led by Norway's Equinor and is set to be the largest plant of its kind in the world at 600 MW.

Potential end users for the hydrogen include Triton power (switching to at least 30% in the short term and 100% hydrogen in the long term via its upgraded Mitsubishi turbines), SSE Clean Power Hub, Drax, British Steel and Saltend Chemicals Park. The CO_2 by product will be stored permanently offshore at the Southern North Sea Endurance storage site. The potential of H2H Saltend to produce low carbon marine fuels to be used by the port will also be evaluated (e.g. the production of synthetic fuels).

The Zero Carbon Humber project plan aims for a wider hydrogen and CO_2 infrastructure across the cluster that will be developed from 2024-2035 as shown in Figure 23 in the stages outlined below[43]:

1. Expansion of hydrogen production capacity at Saltend (fuel switch at Triton to 100% hydrogen).
2. Transmission of hydrogen produced at Saltend will provide the option for decarbonisation at SSE Keadby Clean Power Hub.
3. Expansion of hydrogen production and transmission system further west towards Drax and Ferrybridge power plants
4. Hydrogen available to support decarbonisation of British Steel, one of only two primary steel works in the UK.
5. Development of green hydrogen production at Saltend Chemicals Park through electrolysis.
6. Potential to develop hydrogen storage at Aldbrough.

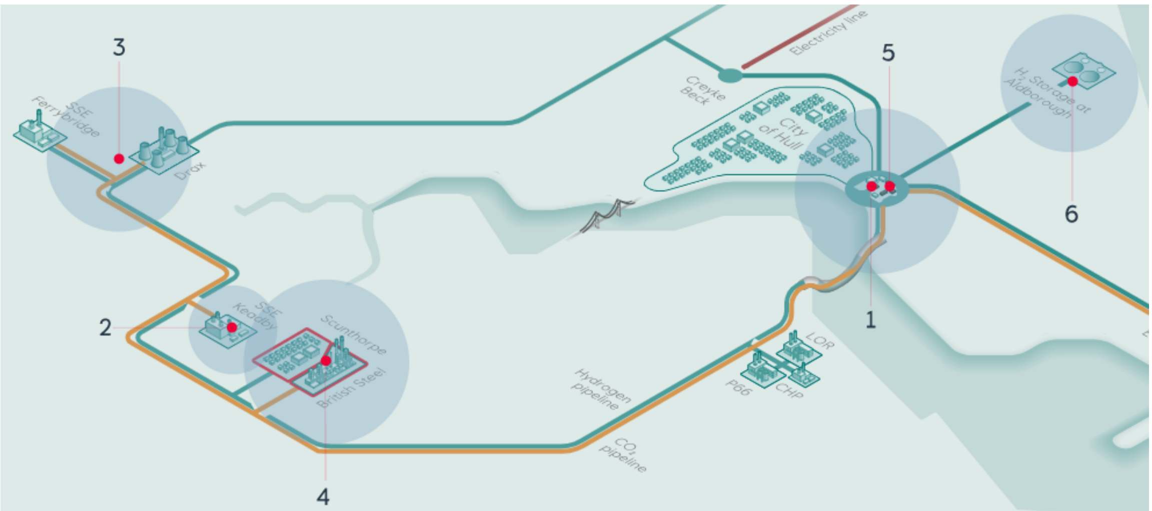

Figure 23: Planned expansion of hydrogen and CO_2 infrastructure in the UK Humber cluster from 2024 to 2035[43]

2.4.5 Hydrogen Storage

It is important to consider different hydrogen storage options and strategies since hydrogen gas has a low volumetric energy density at atmospheric conditions and a low boiling point. Fortunately, hydrogen is a versatile energy vector. This means that suppliers, distributors and end users can store hydrogen in different ways between the point of production and end use. This section considers gaseous hydrogen (GH_2), liquefied hydrogen (LH_2), liquid organic hydrogen carriers (LOHCs) and molecular carriers such as ammonia (NH_3) as shown in Figure 24. These different technologies possess advantages and drawbacks depending on scale, storage longevity, local geology / geography and use case. Hydrogen storage largely falls into two categories:

[43] Equinor 2021, H2H Saltend

- **Centralised Storage -** Large scale storage for inter-seasonal purposes. Demand is low in the summer and high in the winter to match heating requirements. Salt caverns, depleted oil and gas fields, aquifers and rock caverns are expected to provide the majority of this storage.
- **Distributed Storage -** Found closer to the point of end use and distribution to meet short-term local demand. Storage of this type includes liquid hydrogen, pressurised tanks and compressed cylinders, atmospheric tanks and metal hydrides.

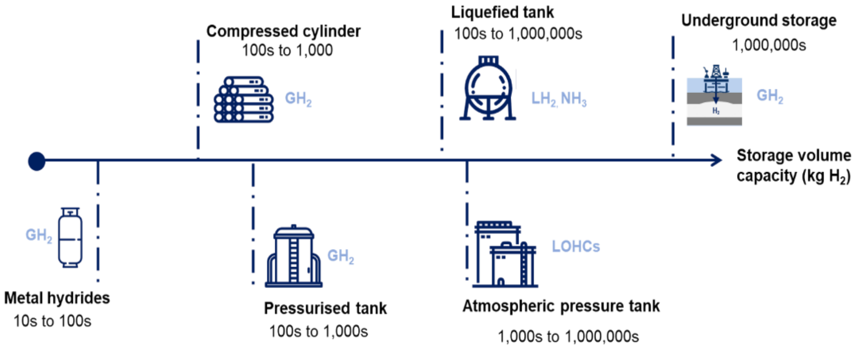

Figure 24: Hydrogen storage options by capacity

Underground Storage

Underground storage systems include salt caverns, depleted oil and gas fields, aquifers and rock caverns[44, 45]. These systems are orders of magnitude larger than any other storage technology considered in this study, with capacities of the order of terawatt hours (TWh) of H_2. As a result, these systems are particularly suited to inter-seasonal energy demand. However, salt caverns and rock caverns can also be used for intra-day, daily and weekly operation as well.

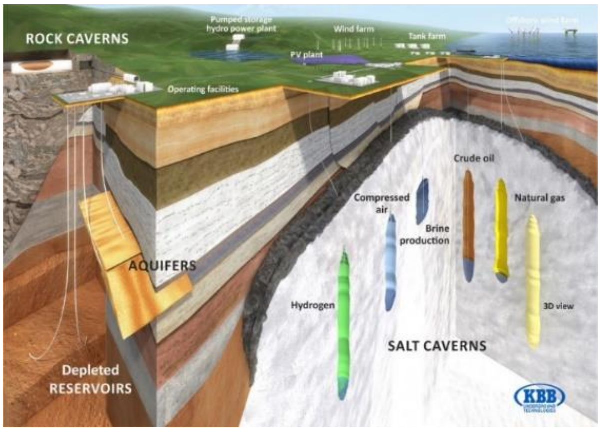

Figure 25: Underground hydrogen storage options[46]

The main determining factor in the use of these geological features is the stability of the cavern wall. This is to protect the walls from rapid changes in lithostatic pressure (the natural pressure in the surrounding rock – increases with depth). The lithostatic pressure defines the working volume; the working pressure is restricted to between 30% and 80% of the lithostatic pressure. The discharge rate varies by storage system. However, this has been generalised to approximately 10% of the contained volume per day (as long as the lithostatic pressure boundaries are maintained).

Of the storage options, salt caverns are the most promising as hydrogen purity is not compromised. An example schematic of underground hydrogen storage in salt caverns is displayed in Figure 25. In addition, artificially constructed cavities are not prone to leakages and require a lower operating pressure than other underground options.

[44] Element Energy 2018, Hydrogen supply chain evidence base
[45] Sandia National Laboratories 2011, A Life Cycle Cost Analysis Framework for Geologic Storage of Hydrogen
[46] Crotogino et al 2017, Renewable energy storage in geological formations

In all cases, compression is needed at the storage site. Salt caverns have been used in the UK, in the Tees Valley, for hydrogen storage, however, as these are fixed pressure sites, they are unlikely to be used for future hydrogen storage. Potential hydrogen storage sites for the UK and Europe are displayed in Figure 26.

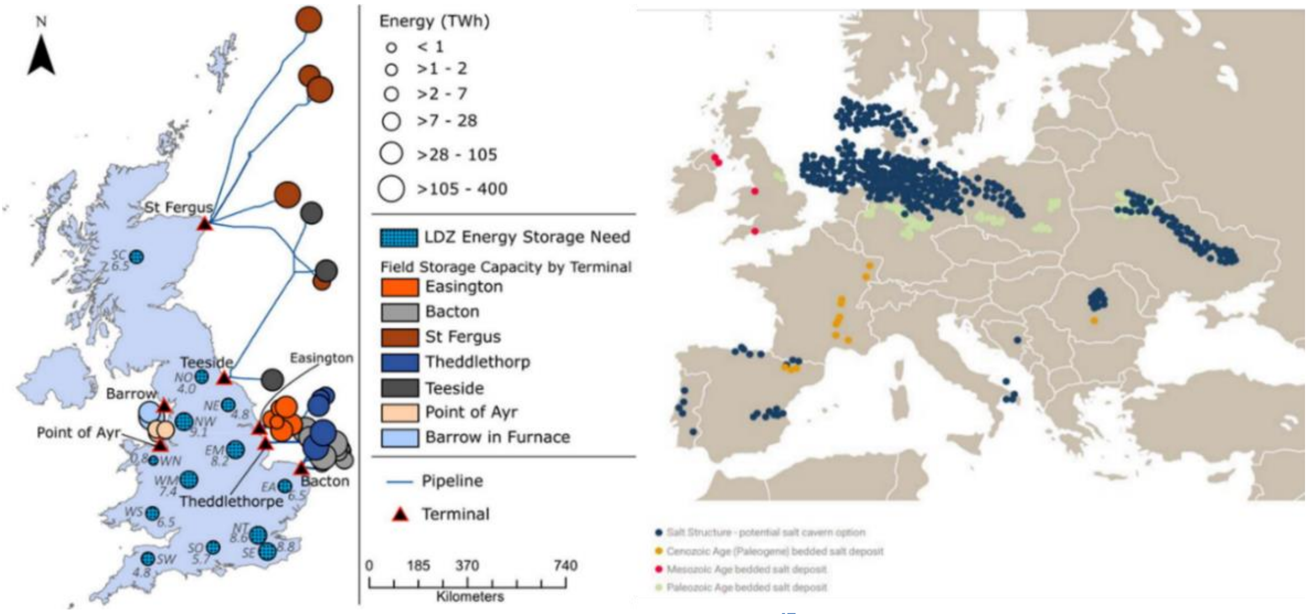

Figure 26: Mapping geological hydrogen storage in the UK[47] (left) and offshore salt structures in Europe[48] (right)

Pressurised Tanks and Compressed Cylinders

The storage of GH_2 in pressurised systems is well established and has a high technology readiness level. These systems are largely used in the transportation and industry sectors as they can be flexibly deployed. The transport sector uses individual cylinders to store GH_2 onboard vehicle and at small scales in hydrogen refuelling stations (HRS). Larger scale systems also feature at industrial sites and larger HRS. The capacity of these storage systems spans several orders of magnitude: from 10s to 1,000s of kilograms of hydrogen.

This technology is best suited for intra-day and inter-day storage, where hydrogen demand is relatively small and is required to be readily available. They can handle high cycle rates and do not suffer from hydrogen discharge. The costs of these systems increase as the storage duration and pressure of storage increases as shown by Figure 27.

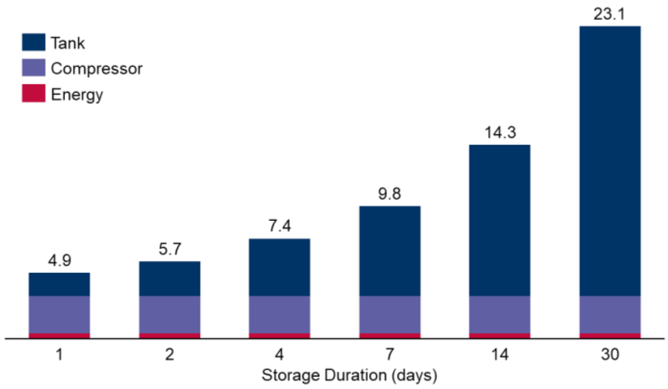

Figure 27: Levelised cost of storage according to storage duration with a fixed rate of production (€/MWh)[49]

[47] Mouli-Castillo et al 2021, Mapping geological hydrogen storage capacity and regional heating demands: An applied UK case study
[48] Caglayan et al 2019, Technical Potential of Salt Caverns for Hydrogen Storage in Europe
[49] SBC Energy Institute 2014, Hydrogen-Based Energy Conversion

There are different types of hydrogen cylinders and tanks; this is defined by their construction material. The cheapest and lowest pressure technology (Type I) is made of steel and has an upper limit of 200 bar. Types II and III use some amount of composite material, whereas Type IV is purely made of materials such as carbon fibre. This increases the cost but also the storage pressure (up to 700 bar)[50]. In addition to the cylinders and tanks, the storage site needs compressors, manifolds (high pressure piping) and storage racks.

Liquified Hydrogen Tanks

Liquifying hydrogen creates a medium with a an energy density over 200 times that of natural gas[51]. This is possible by reducing the temperature to -253°C at atmospheric pressure in an insulated, spherical tank. This is a well-established technology that is widely used in industrial settings. Over time, some of the hydrogen will boil off (evaporate) due to ambient heat transfer into the vessel. This hydrogen is vented off so that the pressure in the tank does not increase whilst the process of evaporation helps to keep the system cool. In certain applications, boiled off hydrogen can be utilised and so does not present an additional cost. For example, the IEA estimated that a hydrogen transporting ship could be powered by the 0.2% of its cargo that boils off each day[15]. These systems are expensive, both in terms of capital equipment and operating costs. It is therefore important to use these systems in industrial settings or large hydrogen refuelling stations with high utilisation rates.

Liquefied Ammonia Tanks

It is also possible to store hydrogen in the form of ammonia which contains approximately 18% hydrogen on a weight basis. The volumetric energy density of liquefied ammonia is approximately 35% greater than liquefied hydrogen[52] whilst also having the advantage to be stored at pressures of 10 bar and atmospheric temperatures. The conversion of hydrogen to ammonia via the Haber-Bosch process is well understood, as is the transportation and storage of ammonia. It is possible to use ammonia in various applications, such as fuel cells and internal combustion engines, however these are not yet commercial. Instead, it is possible to convert the ammonia back into hydrogen. This is technically viable but the large energy requirements and resulting hydrogen purity in the reconversion process remain still uncertain and a topic of further investigation by the emerging ammonia storage projects[53]. In addition, the conversion and reconversion processes carry energy penalties of up to 20% of the lower heating value of H_2[15].

Atmospheric Tanks

Liquid organic hydrogen carriers (LOHCs) also hold significant promise for both hydrogen storage and distribution. Reconversion costs are strongly linked with purity requirements and, as for ammonia (which is already understood and transported in bulk), there are a range of energy penalties depending on the LOHC. These liquids can be stored at atmospheric conditions It is therefore possible to reuse existing oil and gas infrastructure where the supply chains are already present, i.e. industrial clusters and gas terminals.

Figure 28:LOHC utilisation cycle[54]

[50] Composite World 2012, Pressure vessel tank types
[51] Assumed LH_2 density = 71 kg/m^3. LH_2 volumetric density = 71kg/m^3 x 33.3 kWh/kg (H_2 LHV) = 2,364 kWh/m^3. Assumed Natural Gas volumetric density = 10.9 kWh/m^3.
[52] Assumed liquefied ammonia volumetric density = 3,194 kWh/m^3. Wind Energy Storage 2021, Ammonia Storage.
[53] BEIS 2019, Ammonia to Green Hydrogen Project
[54] Mission Innovation, Liquid Organic Hydrogen Carriers

Metal Hydrides and Metal Organic Frameworks

Metal hydrides are an emerging storage technology and are currently low TRL. In these materials, the hydrogen molecules are broken down and bonds are formed with the metal hydrides. More advanced technologies include magnesium hydride and aluminium hydride. These technologies have historically been used in niche applications where storage weight is not an issue, such as forklifts, submarines and scooters. There are concerns with the limited reversibility, decomposition of the storage material and its slow reaction kinetics.

Metal organic frameworks (MOFs) are a developing class of crystalline materials providing systems with large overall pore volumes and surface areas. MOFs have favourable hydrogen release kinetics and thermodynamic properties compared to metal hydrides whilst still possessing high hydrogen uptake capacity. The large number of MOF configurations has delayed the optimisation process for developing MOFs as a hydrogen storage technology[55]. However, the many possible variations allow for significant design flexibility for tuning desirable properties for use in hydrogen applications and is therefore a key area of current research.

Further work is needed to advance metal hydride and MOF technologies in these areas.

Inter-Seasonal Storage

For inter seasonal storage volumes, i.e. of the order of TWh, considered in Figure 29, LOHCs and ammonia show lower costs than the majority of the GH_2 storage options. However, when considering the effects of conversion and reconversion costs, the levelised cost of storage (LCOS) is expected to be similar to GH_2 storage in compressed tanks and salt caverns. In addition to LCOS considerations, salt caverns are dependent on regional geological availability, unlike tank-based storage solutions. Aquifers and depleted oil and gas reservoirs are the lowest cost shown here. However, this does not include the purification steps required from this type of storage due to the impurities that are introduced to the gas.

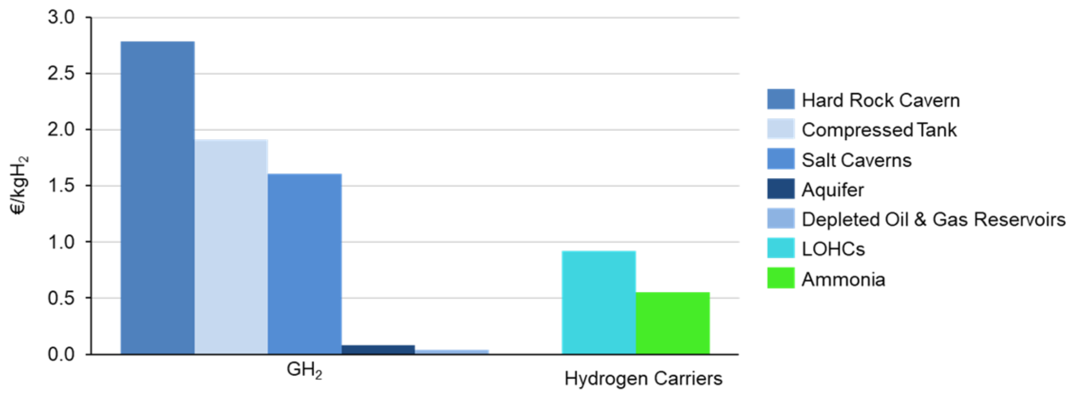

Figure 29: Levelised cost of hydrogen storage for inter-seasonal energy storage of hydrogen via GH_2 (*left*) and hydrogen carriers (*right*) – (€/kgH_2)[56, 57, 58, 59]

Intra-Day Storage

Intra-day storage economics are heavily dependent on cycle rates, hydrogen capacities, discharge and compression rate requirements. These operational costs are not explored below, only the levelised capital costs of the storage technologies are analysed as part of this study as shown in Figure 30. The error bars show the range of data points. This figure reflects the technical maturity of tube trailers and pressurised vessels

[55] Ahmed et al 2019, Exceptional hydrogen storage achieved by screening nearly half a million metal-organic frameworks
[56] Argonne National Laboratory 2019, System Level Analysis of Hydrogen Storage Options, GH_2 compressed underground pipes: 500 tonnes of H_2 and discharge cycle of 10 days (50 tpd).
[57] Bartels 2008, A Feasibility Study of Implementing an Ammonia Economy, Ammonia pressurised vessel capacity: 15,000 tonnes of ammonia, one full cycle per year.
[58] Reuss et al 2017, Seasonal Storage and Alternative Carriers: A flexible Hydrogen Supply Chain Model
[59] Sandia National Laboratories 2011, A Life Cycle Cost Analysis Framework for Geologic Storage of Hydrogen, Salt cavern: 6,200 tonnes of H_2 and discharge cycle of 37 days (120 tpd). Depleted oil and gas reservoir: 7,100 tonnes of H_2 and discharge cycle of 60 days (60 tpd). Aquifer: 7,100 tonnes of H_2 and discharge cycle of 60 days (60 tpd). Hard Rock Cavern: 6,200 tonnes of H_2 and discharge cycle of 37 days (120 tpd). Calculations account for cushion gas volumes.

used by industry however, liquified hydrogen and metal hydrides are expected to benefit from economies of scale and commercial maturity in the future. In addition, liquified hydrogen levelised cost is heavily dependent on the system capacity, shown by the significance of the error bars.

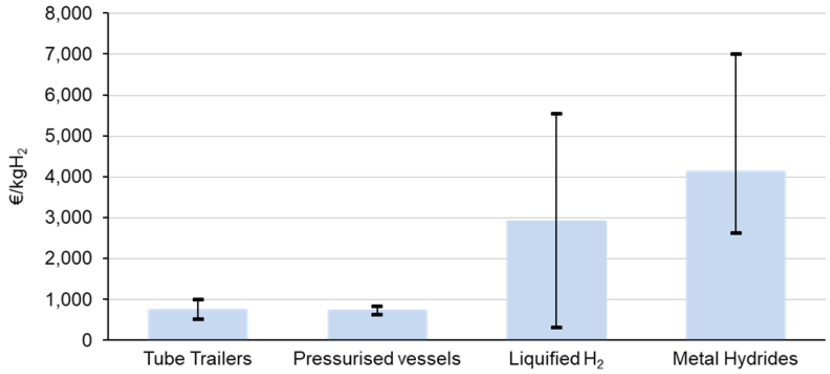

Figure 30: Average total capital cost of pressurised vessels normalised to storage capacity with upper and lower limits ($/kg$H_2$)[60, 61, 62]

Hydrogen Distribution and Transportation Summary

Suitability of the different hydrogen transportation and storage options is ultimately subject to key performance parameters such as technology cost-effectiveness, technology maturity level, suitability at different scales and ramp up availability (supply chain integration). Table 3 below provides a concise comparison between the different hydrogen transportation and storage methods.

Table 3: Comparison between hydrogen transportation and distribution methods. This gives a score of low, medium or high for each hydrogen archetype for different hydrogen storage options as well as the relative scales

		GH_2	LH_2	Ammonia	LOHCs	Metal Hydrides
Supply chain integration		High	High/Medium	High	Medium	Medium/Low
Storage TRL	**Tank:**	High	High	High	High	High
	Tubes:	High	-	-	-	-
	Underground:	Medium	-	-	-	-
Storage suitability at different scales	**Cavern:**	10 kt	-	-	-	-
	Tank:	1 t	5t	30t	80kt ($18kt H_2$)	10's kg

2.5 Flexible Hydrogen Production

In the transition to a net zero future where net emissions after accounting for greenhouse gas removals is equal to zero, energy storage is critical. Many countries are deploying renewable generation sources, such as solar and wind, at large scale due to the potential for low electricity costs and zero emissions. However, these intermittent energy supplies require energy storage over the course of days (for solar) and weeks (for wind) to balance supply and demand, replacing peaking plants in the process. As technology TRLs improve and costs continue to come down, electrical storage is expected to meet this demand[63]. However, questions remain over the security of inter-seasonal energy supply. This is especially important for colder regions, such as the UK and Germany, whose heating requirements vary significantly over the course of a year.

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[60] Tube trailers and pressurised vessels calculated using internal Element Energy analysis. Tube trailer capacity volumes: 320 kg H_2 to 1,100 kg H_2. Pressurised vessel capacity volume: 300 kg H_2 to 1,000 kg H_2.
[61] Liquefied storage tanks costs from Tzimas et al 2003, Hydrogen Storage: State-of-the-Art and Future Perspective. Liquefied tank capacity volumes: 1,000 kg H_2 to 150,000 kg H_2.
[62] Metal hydride storage tank costs from i) Ganda et al 2018, Economic Data and Modelling Support for the Two Regional Case Studies: Nuclear-Renewable Hybrid Energy Systems: Analysis of Technical & Economic Issues. Argonne National Lab, 2018 and ii) Nils Bornemann, GKN's Solid-state Hydrogen Storage System, 2017. Metal hydride capacity volume: 160 kg H_2 to 890 kg H_2.
[63] Element Energy and Cambridge Econometrics 2019, Towards Fossil-Free Energy in 2050

Increasing the deployment of renewables to address this issue is not expected to be economic and will lead to high curtailment in summer months. Hydrogen storage in salt caverns could meet this demand, as shown in the "High M"[64] scenario, which corresponds with greater degrees of hydrogen uptake for storage than electrical storage (termed "High E"), in Figure 31 and Figure 32 for Spain and Germany, respectively. These figures show that the energy storage increases over the course of the year due to intermittent renewables that would otherwise be curtailed. This energy is then available to generate electricity using hydrogen gas turbines during peak periods, fuel for fuel cell electric vehicles and in boilers for heat. This heat is particularly important in winter months, leading to storage depletion. Whilst focussed on electrolysers, blue hydrogen production could also contribute to these hydrogen stores which can then be used in these use cases. As expected, this is highly dependent on regions, with energy storage requirements predicted to reach 130TWh in Germany and 35TWh in Spain in the peak winter months. It is therefore important to understand how hydrogen production technologies can synergise with this demand for flexibility.

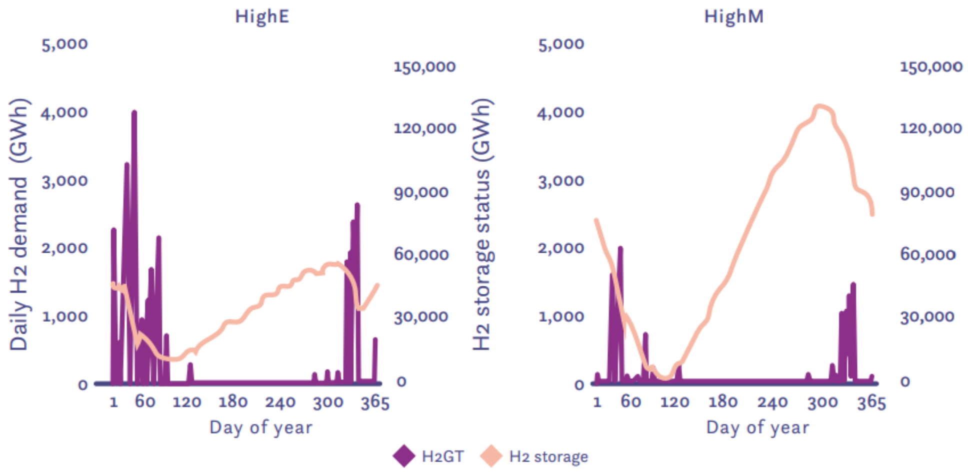

Figure 31: Annual H2 store status (right axis) and use of hydrogen gas turbines (H2GT) (left axis) to provide grid support in Germany[63]

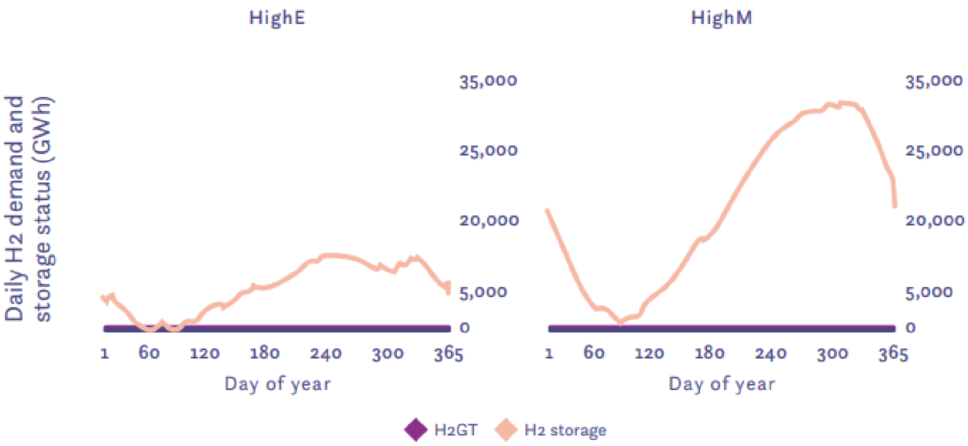

Figure 32: Annual H2 store status (right axis) and use of H2GT (left axis) to provide grid support in Spain[63]

Flexible Operation – Operating Modes

Electrolysers are inherently flexible, able to change their operational set point in sub second response times. This makes the technology viable for inter-day energy storage and, in the long-term, inter-seasonal energy

[64] High M = High Molecule, High E = High Electricity, H_2GT – Hydrogen Fuelled Gas Turbines

storage. However, electrolysis first needs to scale to meet current and forecasted demand in addition to seasonal demand. Instead, this demand is expected to be met by blue hydrogen production technologies such as SMR, ATR and POX. Various projects, such as H21, are exploring these blue hydrogen technologies for meeting inter-seasonal energy demand as well as inter-day energy demand. Configurations include but are not limited to:

- A constant hydrogen supply that meets end user demand and supplies excess hydrogen to the storage site. When demand exceeds capacity, the hydrogen is supplied from the storage site as shown in Figure 33 (left).
- Varying the set point of the production technology to follow demand and storage capacities as shown in Figure 33 (right).

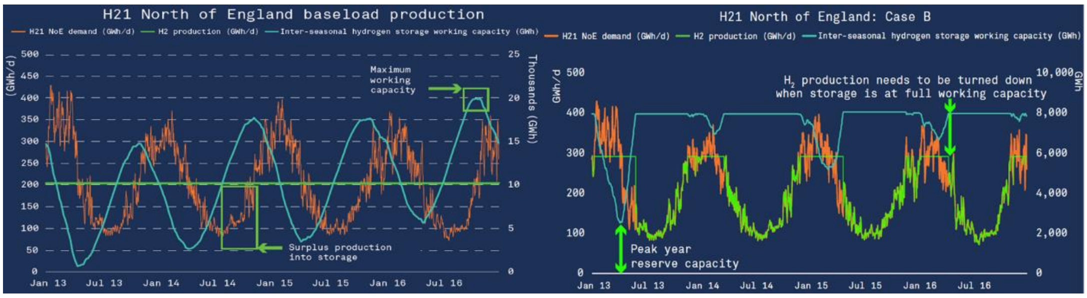

Figure 33: Hydrogen demand versus inter-seasonal hydrogen storage requirements and hydrogen production capacity for H21 North of England[65]

The configuration, hydrogen production facility capacity and operating philosophy becomes a function of technology choice, underground storage capacity, feedstock and energy availability and end user demand.

Flexible Operation – Production Technologies

In all cases for blue hydrogen, operators prefer to operate their assets at high load factors to improve economics. The most widely deployed hydrogen production technology, SMR, does not lend itself to flexible operation. The reaction within the SMR process takes place in tubes which are heated by burning natural gas. Although SMRs may generally run within 50 to 100% of their capacity with minor losses in efficiency, varying the production rate and process conditions in individual reactor tubes is particularly complex and not conducive for optimal hydrogen production. Therefore, flexible SMR operation requires flexible storage.

POX, ATR and ESMR are capable of more flexible operation. For ATR and POX, this is because the reaction takes place within one reaction vessel per reaction train. ESMR, on the other hand, is able to operate flexibly due to the removal of the heat reaction in the process' reactor. This is further discussed in Section 3.5. Pairing these technologies with salt caverns facilitates inter-seasonal as well as daily flexibility in operation. The UK's H21 North of England is exploring this concept with a circa 12.15GW ATR configuration along with salt caverns and offshore CO_2 storage to deliver blue hydrogen for industry and heat to the North of England.

[65] H21 North of England 2018, H21 NoE Report

3 Blue Hydrogen Production Technologies

3.1 Overview

In this section the technical details of different hydrogen production routes using natural gas as a feedstock are examined. Hydrogen production from natural gas feedstock is well understood. The range of hydrogen derived from natural gas feedstocks is 67% in this analysis to 76% in the 'IEA – Future of Hydrogen'[15], with the majority of the remainder coming from coal. This demonstrates the significant market penetration of SMR derived hydrogen as the most well-established hydrogen production technology. However, other technologies are emerging as competitors or improvements upon this process.

This study considers the conventional SMR process alongside POX, ATR and ESMR. This report collates findings from stakeholder engagement and a comprehensive review of literature on these technologies, covering:

- A description of the technology, including the key pieces of the equipment, scale, and operating conditions that may affect the compatibility with other infrastructure
- Achievable deployment scale and the expected purity levels
- The feedstock inputs and CO_2 outputs for the process
- Suitability with amine-based chemical absorption processes

One configuration for each technology (SMR, POX, ATR and ESMR) has been selected such that they are comparable in scale and boundary conditions. These configurations are suitable for deployment in the Netherlands and are compared in the TEA and LCA.

Hydrogen Functional Unit Definition

To maintain consistency between analyses of select technologies, the hydrogen product is defined based on the associated carbon intensity and hydrogen purity.

Hydrogen Carbon Intensity

Internationally, there are no formal definitions which distinguish hydrogen production technologies by carbon intensity. Instead, a selection of "colours" is used based on the technologies used. However, there are a wide range of these definitions used across industry and academia and they are not harmonised. Four of the most common forms of hydrogen production are:

- **Green** – Production via electrolysis using renewable electricity.
- **Blue** – Production using fossil fuels / biomass with CCS.
- **Grey** – Production using natural gas and no CCS.
- **Brown** – Production using coal and no CCS.

This study focuses on blue hydrogen production; however, the definition above leaves it open to interpretation on what carbon capture requirements actually constitutes as blue hydrogen. Using Europe as an example, organisations such as Hydrogen Europe[66] have recommended that formal definitions are introduced based on carbon intensity. Projects such as CertifHy[67] aim to develop a Guarantee of Origin for a new hydrogen market and have proposed a greenhouse gas (GHG) emission intensity 60% below the benchmark. However, discussions on policy in the European Union (EU)[68] are more focussed on capture rates greater than 90%.

Capture rates in excess of 90% are widely used in available literature and are achievable for a range of technologies utilising modern CCS systems. This study therefore uses a capture rate of 90% as a minimum. This significantly reduces the carbon intensity of the hydrogen, as shown in Section 5.3, when compared to grey hydrogen.

[66] Hydrogen Europe 2020, The Eu Hydrogen Strategy: Hydrogen Europe's Top 10 Key Recommendations
[67] CertifHy 2019, CertifHy - The First European Guarantee of Origin for Green & Low Carbon Hydrogen
[68] Euroactiv 2020, Renewable or 'low-carbon'? EU countries face off over hydrogen

Hydrogen Purity

The purity of the hydrogen is reliant on the downstream processing and is typically determined by the end use requirements. Methanation and Pressure Swing Adsorbers (PSAs) are two processes commonly used in industry to increase the purity of hydrogen from a syngas stream. The methanation reaction occurs at temperatures of approximately 300°C. Carbon monoxide (CO) and CO_2 react with hydrogen to produce methane and water as shown by the equations below[69]:

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O \qquad \Delta H^0 = -206.2\ kJ.mol^{-1}$$

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \qquad \Delta H^0 = -165.0\ kJ.mol^{-1}$$

The PSA process is based on the physical binding of gas molecules to an adsorbent material. The process works at an almost constant temperature and utilises the effects of alternating pressure and partial pressure to perform adsorption and desorption[70]. Heating and cooling are not required as part of the process allowing short cycle times and the removal of large amounts of impurities. Hydrogen is recovered at close to the feed pressure, whilst impurities are removed by reducing the PSA pressure. The tail gas containing the impurities can be recycled to refuel the system[71]. Where a PSA is used, purity can go beyond 99.999% whilst also meeting the requirements for fuel cell applications. If instead a methanation step is used, purity is in excess of 95%. This is suitable for some industrial processes and blending into natural gas grids.

The technology configurations and process descriptions from literature vary between using a PSA and methanation step. Therefore, a minimum purity of 97% has been specified. This is a limitation of this study. This limits the ability to draw direct comparisons between processes, however the impact is expected to be small.

3.2 Steam Methane Reforming

Process Description

SMR plants without CCS are widely deployed at scale industrially and account for nearly 50% of world hydrogen production[1]. Plants are typically sized between 25-500 tonnes of hydrogen per day (35-700MW) and are consistently cited in literature as one of the lowest cost methods of dedicated hydrogen production. Natural gas (which is made up of primarily methane) has traditionally been used as both a fuel and feedstock for the SMR process. Naphtha and other light oil-based hydrocarbons such as liquefied petroleum gas (LPG) and, in some cases, kerosene can replace natural gas as the feedstock in conventional SMR configurations[72].

The natural gas feedstock is first fed through a pre-treatment unit that ensures impurities in the feed are removed before entering the reformer. The treated natural gas feed is then fed into a pre-heater and pre-reformer alongside a recycled hydrogen stream. This allows the temperature of the feed stream to be increased sufficiently to ensure coke formation is eliminated from the process as this can cause undesirable catalyst deactivation. Heavier hydrocarbons are converted to methane, hydrogen and carbon oxides allowing the system to operate at reduced steam to carbon ratios, therefore reducing the overall energy consumption of the process[73]. The required reformer tube area is reduced by this stage, resulting in a reduced capital cost. This stream is then fed into the main reactor, with steam, for the steam reforming reaction. A schematic of this process is shown in Figure 34.

69 Wodolazski 2020, Modelling of Carbon Monoxide and Carbon Dioxide Methanation under Industrial Condition
70 Linde, Hydrogen Recovery by Pressure Swing Adsorption
71 Air Liquide, Pressure Swing Adsorption (PSA) - Hydrogen Purification
72 El-Shafie et al 2019, Hydrogen Production Technologies Overview
73 IEAGHG 2017, Reference data and Supporting Literature Reviews for SMR Based Hydrogen Production with CCS

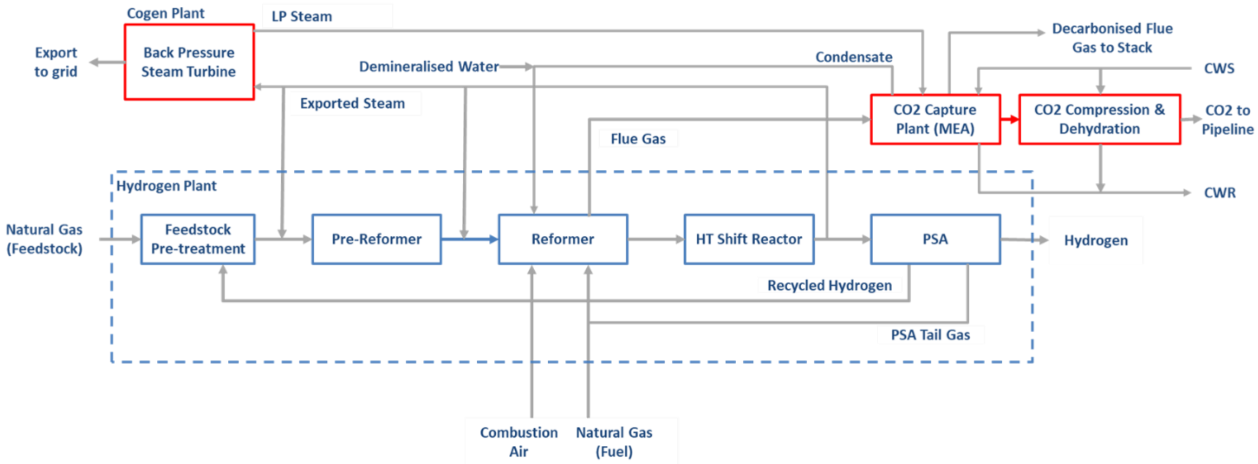

Figure 34: Steam Methane Reforming with CCS process flow[74]

The reforming reaction is endothermic. It therefore requires the transfer of energy into the system which, for this configuration, comes in the form of heat. This process is typically fuelled by natural gas and can result in an overall increase in efficiency if integrated with a steam boiler. The chemical equation for steam reforming of methane is shown below:

$$CH_4 + H_2O \rightarrow 3H_2 + CO \qquad \Delta H^0 = 206\ kJ.mol^{-1}$$ [72]

The gas mixture leaves the reformer with approximately 12% of the carbon monoxide remaining unconverted[41]. Product gas is cooled to approximately 340-350°C and fed into the water gas shift (WGS) reactor where catalytic reactions between carbon monoxide and steam facilitate the production of additional hydrogen and carbon dioxide.

$$CO + H_2O \rightleftharpoons CO_2 + H_2 \qquad \Delta H^0 = 206\ kJ.mol^{-1}$$ [72]

This process is slightly **exothermic** (heat is produced) and therefore requires a two-stage cooling process to ensure conversion efficiency is maintained.

In this configuration, high pressure steam is produced as part of the SMR process that is utilised for electrical power generation. This is shown in Figure 34 where steam is exported to a co-generation unit that exports power to the grid. In scenarios where excess steam can be utilised, additional revenue (other than hydrogen production) can be generated from the SMR process. However, excess process steam that is not utilised is a waste product of the SMR hydrogen production process.

Technology Readiness Level

SMR is at TRL 9 and is currently available at commercial scale and deployed widely for hydrogen production worldwide. SMR facilities with CCS are limited however projects include:

- **Port Arthur – Texas, USA –** H_2 production utilised at the Valero refinery and other industrial consumers along the Gulf Coast Connection Pipeline.
- **Port Jerome – France –** H_2 production utilised at the Esso Raffinage SAF refinery
- **Quest – Canada –** H_2 production utilised for upgrading bitumen into synthetic crude oil

Value Chain Position

Steam methane reforming is currently used for dedicated hydrogen production, primarily supplying refineries and chemical production facilities that produce products such as methanol and ammonia. As the process uses natural gas for both fuel and feedstock, the technology is easily deployed in regions with a natural gas network.

Both pre- and post-combustion capture configurations are suitable for SMR configurations, as shown for the Port Arthur, Texas hydrogen production facility in Figure 35.

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

- Pre-combustion carbon capture is located on the syngas or PSA tail gas streams, whereas post-combustion CCS is located on the flue gas stream.
    - It is important to note that, with appropriate process configurations (i.e. burning H_2 rich syngas, high temperature and low temperature shifts) that pre-combustion can achieve capture rates greater than 90%. The 60% is specific to the Port Arthur case.
- Post-combustion CCS is the most mature capture technology and is the most suitable option for retrofit[32]. This has the added benefit of higher capture rates of at least 90%. The configuration selected in this study integrates CCS on the reformer flue gas using chemical absorption technology that utilises mono-ethanol amine (MEA) as a solvent, as shown in Figure 34.

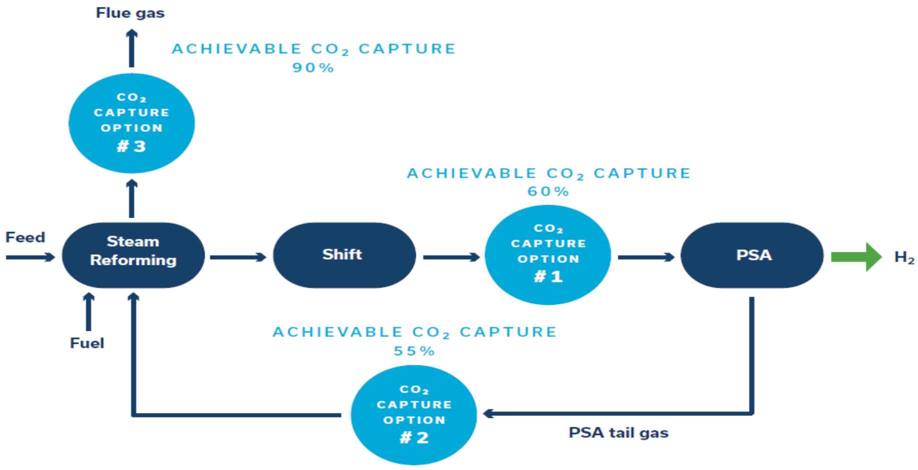

Figure 35: Potential locations for CO_2 capture for SMR technology[41]

The cost of CCS could make the SMR process uneconomic as a blue hydrogen production process if a region does not have any suitable sites for CO_2 storage nearby.

Technology Developers

There are a range of commercial steam reforming technologies available on the market from companies such as Air Liquide, Linde, Air Products, Wood and Johnson Matthey. Stakeholders are currently developing SMR processes that optimise CO_2 capture for blue hydrogen production.

Process Data

Process data was collected from a combination of literature and stakeholder engagement. Data collected for the SMR process is presented in in the Appendices, Section 7.2.2. Uncertainties within the process are analysed as sensitivities as part of the techno economic assessment of the technology.

3.3 Autothermal Reforming Configurations

Process Description

ATR has been used commercially to produce grey hydrogen, however, it has only recently been developed with the aim of producing blue hydrogen. In the UK, HyNet Phase 1 and Acorn Phase 1 are examples of the commercialisation of ATR configurations, with a focus on Johnson Matthey's "Low Carbon Hydrogen" (LCH) variation. ATR is a combination of SMR (endothermic) and POX (exothermic) reactions. ATR adds steam to the catalytic POX process, increasing the hydrogen yield. Heat required for the steam reforming reactions is generated using the POX process. As a result, the system does not require additional heat. ATR produces a greater proportion of hydrogen than POX whilst having faster response times than SMR (start-up and shut down), as discussed in Section 2.5.

In a similar process to the one outlined for SMR, the feedstock and a recycled H_2 stream are fed into the pre-heater and pre-reformer. These units ensure impurities are removed before entering the reformer and allow the temperature to be increased sufficiently to ensure coke formation is eliminated. This step reduces the oxygen consumption required in the reformer, therefore reducing cost. The ATR reactor produces no flue gases, as shown by the process configuration in Figure 36. An additional heater must therefore be installed to heat the feedstock. This heater is typically fuelled by a mixture of 90% hydrogen and 10% natural gas (to ensure flame stability).

Pure oxygen is required to produce hydrogen in an ATR reactor. This is typically produced by cooling and compressing the ambient air in a cryogenic ASU. The ATR reaction occurs at higher temperature and pressure than the SMR process which results in lower methane slip - this is the percentage of methane that flows through the process without being converted to hydrogen. The increased temperature and pressure also result in high methane conversion at lower steam to carbon ratios than SMR. This reduced steam requirement and higher pressure can result in higher process efficiencies. High pressure is an advantage as it reduces the downstream compression requirements of the hydrogen product.

A Gas Heated Reformer (GHR) is used to efficiently recover the high temperature heat produced in the primary reformer and can be integrated into both SMR and ATR production facilities. Heat is transferred in the GHR to the feed stream from the stream exiting the primary reformer. Approximately 30% of the methane is reformed in the GHR before entering the primary reformer resulting in increased conversion efficiency. ATR configurations that incorporate a GHR are also known as LCH. The process stream is then fed through the WGS reactor to where catalytic reactions between carbon monoxide and steam facilitate the additional production of hydrogen in a similar manner to the SMR and POX processes.

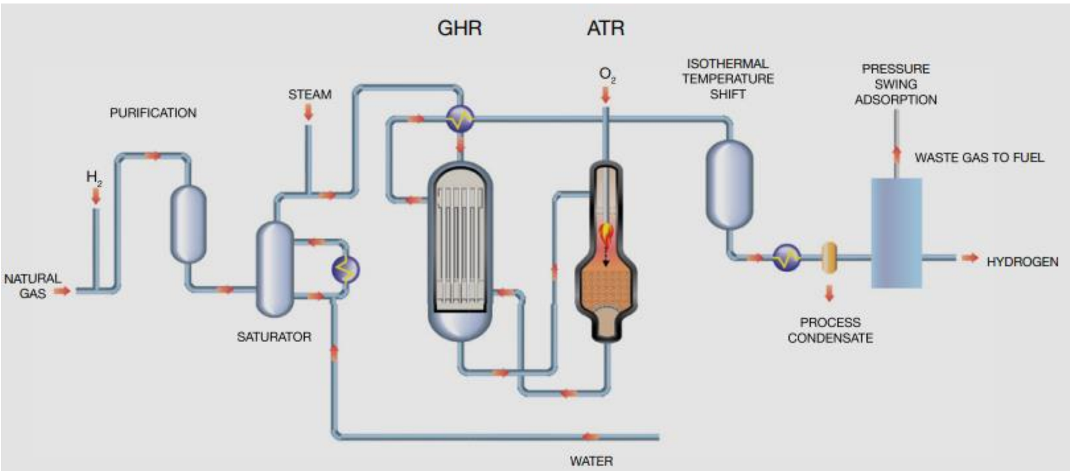

Figure 36: ATR + GHR, Low Carbon Hydrogen configuration[75]

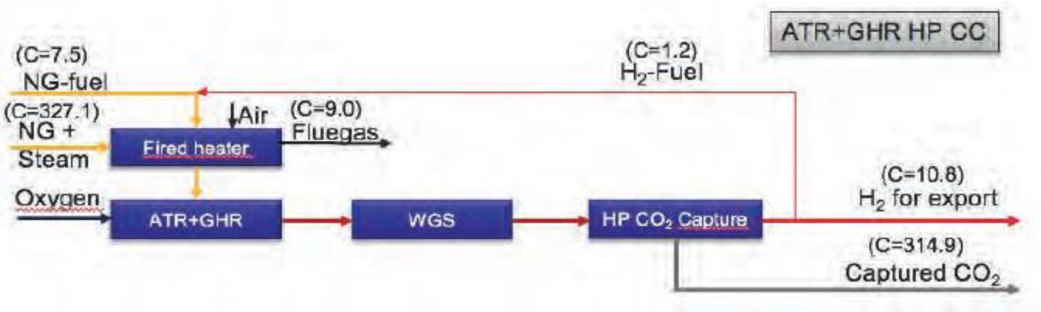

Figure 37: H21 ATR "Option 2" configuration includes a gas heated reformer[65]

Technology Readiness Level

ATR is between TRL 7 and 9, depending on the configuration and inclusion of CCS. It is currently available at commercial scale and deployed at large scale for hydrogen production. The LCH configuration is at a lower TRL but is expected to advance quickly through ongoing demonstration projects. ATR facilities with CCS are limited however there are a number of projects currently in development in the UK including:

[75] iChemE 2020, Hydrogen: The Future Fuel Today

- H21 North of England – looking to demonstrate hydrogen production and use in the gas network in the North of England
- Acorn – aiming to produce blue hydrogen at St Fergus, Scotland, for blending in the UK gas National Transmission System (NTS) and local use in the city of Aberdeen
- HyNet – developing a hydrogen cluster in the North West of the UK (Merseyside cluster)

Value Chain Position

ATR is currently used for dedicated hydrogen production at large-scale, primarily supplying refineries and chemical production facilities that produce products such as methanol and ammonia. As the process uses natural gas as a feedstock, the technology can be deployed easily in regions with a natural gas network.

The ATR process utilises pre-combustion CCS configurations located on the syngas stream in a similar manner to the POX process. This has many advantages over post combustion capture systems that are more common for conventional SMR hydrogen production facilities[35]. The syngas stream is at higher pressure to the flue gas stream which results in a higher partial pressure of CO_2. High capture rates can therefore be achieved with lower energy requirements. CO_2 captured from the syngas stream is also at higher pressure, reducing compression requirements for CO_2 T&S.

The selected ATR configuration captures CO_2 from the high-pressure syngas using activated Methyl DiEthanol Amine (aMDEA) solvent as shown in Figure 38. High pressure gas is passed through a reactor containing the alkaline aMDEA scrubbing solution. This causes the CO_2 to react with the aMDEA and remains in the absorbent solution. CO_2 is then removed from the absorbent solution so that it can be reused.

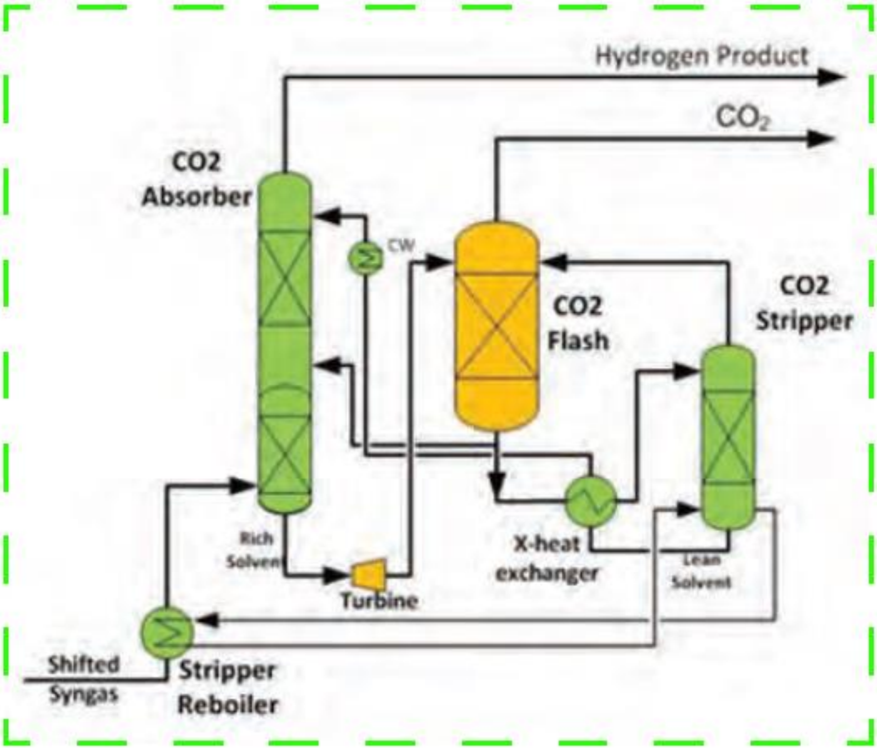

Figure 38: High Pressure aMDEA CO_2 removal[65]

The LCH configuration also offers a range of operating capacities. Johnson Matthey have developed a design for a plant with a capacity of $1.5GW_{LHV}$ in a single train.

Technology Developers

There are a range of commercial ATR technologies available on the market, provided by companies such as Air Liquide, Air Products and Johnson Matthey. Johnson Matthey is actively pioneering the LCH ATR configuration for blue hydrogen production in the UK.

Process Data

Process data was collected from a combination of literature and stakeholder engagement and is presented for the ATR + GHR (LCH configuration)process in the Appendices, Section 7.2.3. Uncertainties within the process are analysed as sensitivities as part of the techno economic assessment of the technology.

3.4 Partial Oxidation

Process Description

POX and gasification are exothermic processes (heat is produced during the reaction) where the feedstock is gasified at very high temperatures (1,300-1,500°C) in the presence of oxygen. The difference between the POX and gasification processes is determined by the state of the feedstock. POX refers to liquid and gaseous streams whilst the gasification process refers only to solid based feedstocks[76]. Gasification is one of the primary methods of hydrogen production in the world today with the gasification of coal feedstocks popular in regions where natural gas is higher cost than coal e.g. China[15].

A key advantage of the POX process is its ability to process heavy hydrocarbon feedstocks, with the process traditionally utilised in refineries to produce syngas[77]. Recently, there has been significant intertest in the process as a method of blue hydrogen production using both natural gas and low-value (or even waste) hydrocarbon feedstocks. The POX process does not require a catalyst for operation, unlike conventional SMR hydrogen production. The chemical equation of partial oxidation is shown below:

$$CH_4 + \frac{1}{2}O_2 \rightarrow 2H_2 + CO \qquad \Delta H^0 = -36.1 kJ.mol^{-1}$$ [72]

The POX process can process impurities within feedstocks such as sulphur compounds, olefins and hydrogen sulphide. Therefore, feed gas pre-treatment is not necessary[1].The process utilises oxygen as the primary reactant. The oxygen is typically produced by cooling and compressing the ambient air in an ASU. Oxygen purity of >99% is typically used to increase process efficiency, however, this is determined based on the facility requirements. This is a significant energy requirement of the process and has typically been the factor that has reduced further uptake of the technology. However, due to the exothermic nature of the reaction, no additional heat needs to be supplied to the process. The process also occurs at higher pressure and temperature than the SMR process which can be advantageous as it reduces downstream compression requirements.

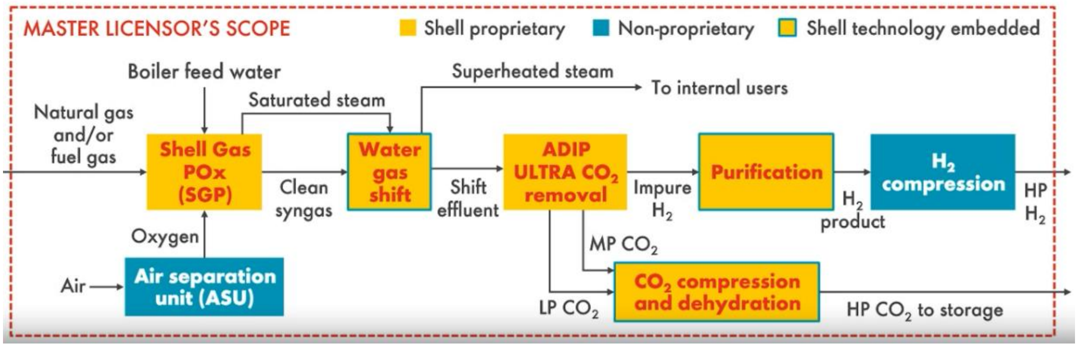

Figure 39: Shell Gasification Process (SGP) blue hydrogen production process[78]

The syngas stream leaving the reformer contains a mixture of primarily hydrogen and carbon monoxide. This is fed through the WGS reactor in a similar manner to the SMR process where catalytic reactions between carbon monoxide and steam facilitate the production of additional hydrogen. As there is no additional heat supplied to the process, pre-combustion CCS configurations can be utilised. This is shown by Shell's hydrogen production process in Figure 39. The hydrogen stream is subsequently purified using a methanation step where the remaining CO and CO_2 are converted to methane and raw water. The methanation step can achieve

[76] National Energy Technology Laboratory, Oil and Gas Partial Oxidation
[77] Linde 2007, Industrial Hydrogen Production and Technology
[78] Shell 2020, Affordable blue hydrogen production with the Shell Blue Hydrogen Process

purities of 95-97%, however if higher purities are required, a PSA can be utilised that can produce hydrogen purities of 99.999%.

Technology Readiness Level

Partial Oxidation, water gas shift and ADIP Ultra technology individually are at a technology readiness level 9. The integrated blue hydrogen process shown in Figure 39 has an overall TRL of 7. Gasification technology was developed in the 1950's by Shell and Texaco to produce hydrogen and syngas to supply to industrial processes. The process is typically deployed where low value waste products or heavy feedstocks can be utilised to produce valuable hydrogen or syngas. POX technology is currently available at commercial scale; however, blue hydrogen schemes based on gasification technology have recently been developed. Shell's Gas POX technology was deployed in Bintulu, Malaysia, and the Pearl Project, Qatar. In Qatar, eighteen-commercial size gas POX trains have operated since 2011; each train has a production capacity of 500tpd of pure hydrogen.

Value Chain Position

POX is typically used in refineries that process heavy hydrocarbon feedstocks, including low-value / waste oil feedstocks such as vacuum residue. Traditionally, the process has been located in refineries due to the high availability of feedstocks and demand for hydrogen and / or syngas as a product; however, the process could be utilised for dedicated blue hydrogen production from natural gas in the future. Economies of scale are achievable by siting the technology near to industries where hydrogen offtake will be readily available and shared CO_2 transport and storage (T&S) infrastructure is more likely to be developed.

Pre-combustion carbon capture can be located on the syngas stream. This has many advantages over post combustion capture systems that are more common for conventional SMR hydrogen production facilities[35]. The syngas stream is at higher pressure to the flue gas stream which results in a higher partial pressure of CO_2. High capture rates can therefore be achieved with lower energy requirements with capture rates >95% cited in literature.

The POX technology can also reach large production capacities, with options of more than $700MW_{LHV}$ achievable in a single plant.

Technology Developers

There are a range of commercial gasification technologies available on the market, provided by companies such as Shell and Air Products (formal GE). More than 170 of Shell's processes have been deployed globally.

Process Data

Process data was collected from a combination of literature and stakeholder engagement and is presented for the POX process in the Appendices, Section 7.2.3. Uncertainties within the process are analysed as sensitivities as part of the techno economic assessment of the technology.

3.5 Electrified Steam Methane Reforming

Process Description

As previously discussed, SMR is the most widely deployed technology for dedicated hydrogen production. Efforts to decarbonise this process have focussed on incorporating CCS into the configuration to capture emissions from the product stream and the flue gas. This flue gas arises from the combustion of natural gas around the reaction tubes (in a furnace) to meet the heating demand of the endothermic and energy intensive thermochemical conversion reaction[79]. Combined, these two streams produce 9.88kgCO_2/kgH_2, as discussed in the Appendices, Section 7.2.5. Of this, 44% comes from the flue gas stream[80].

An alternative to CCS for flue gas decarbonisation is to electrify the heating process using renewable power. Renewable power availability is continuing to increase and, as a result, costs for wind and solar generation are falling worldwide. This would decarbonise the 44% of emissions, in this case, from the process. It is estimated that replacing the natural gas fired process with renewable electricity could reduce global CO_2 emissions by up to 1%[81]. Haldor Topsoe is developing a technology that exploits this fact called ESMR^{TM}, short for electrified steam methane reforming. ESMR is a similar process to SMR, as shown in Figure 40.

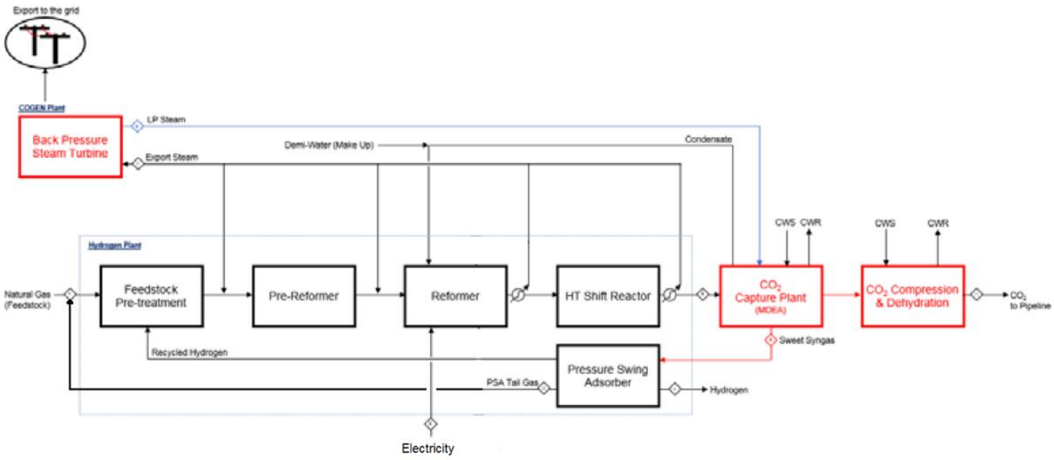

Figure 40: Adaptation of SMR configuration to demonstrate a plausible ESMR configuration

The process involves:

- Natural gas feedstock is initially fed through a pre-treatment unit that ensures impurities in the feed are removed before entering the reformer. The treated natural gas feed is subsequently fed through a pre-heater and pre-reformer alongside a recycled hydrogen stream. By removing natural gas as a fuel for heating, all of the natural gas is used as a feedstock for the reaction.
- The stream then enters the electrified reformer where methane conversions above 90% are predicted to be feasible[82] (a conventional reformer has a conversion rate of 86%[80]). This electrified reformer is smaller and, via the provision of electric heating, removes the flue gas stream. This electrification also reduces the thermal gradient and directly supplies energy to the catalytic sites, reducing the thermal limitations of the reaction.
- The syngas stream leaving the reformer contains a mixture of primarily hydrogen and carbon monoxide. This is fed through the water gas shift reactor to convert the remaining carbon monoxide into hydrogen.
- The high pressure shifted syngas is then fed into a carbon capture unit to facilitate blue hydrogen production. With the removal of the flue gas, higher overall carbon capture rates are possible; here 98.6%.
- The hydrogen stream is finally purified using a Pressure Swing Adsorber (PSA) which can produce hydrogen purities of 99.999%. Another benefit of removing the flue gas stream is that the PSA no longer needs to be integrated with the reformer itself, as the off gas is no longer recycled for combustion.

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[79] Combustion within the furnace must reach temperatures considerably above those required for steam reforming to generate the necessary heat flux through the reactor tubes. Steep temperature gradients are generated by low thermal conductivity of the reactor tubes alongside the endothermic nature of the reaction. This leads to poor catalysts utilisation whilst also increasing the risk of undesirable carbon formation on the catalyst surface.

[80] IEAGHG 2017, Techno – Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS, Case 1A was used from this paper for the SMR configuration

[81] Haldor Topsoe 2019, Article in Science: Extremely compact reactor has potential to reduce global CO2 emissions significantly

[82] Wismann 2019, Electrically heated steam methane reforming

Other benefits of this configuration include:

- The avoidance of natural gas as a fuel and the more integrated system design leads to greater operational flexibility. This is because the system operator no longer needs to harmonise the thermochemical conversion and combustion of natural gas for heat.
- Utilising electrical resistance heating leads to more compact reactors, with the potential to reduce the size of the system by up to 100 times due to reductions in void volume. It is approximated that a 1,100m^3 reformer producing 4.5 tonnes of hydrogen per hour can be replaced with a 5m^3 electrified reformer with the same hydrogen throughput, as shown in Figure 41.

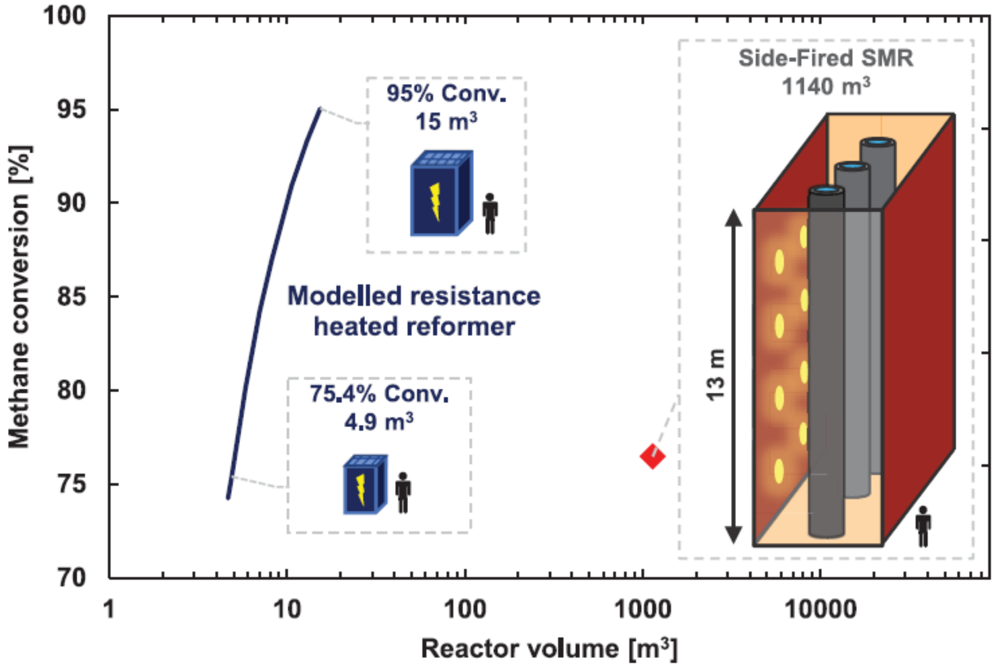

Figure 41: Potential scaling opportunities for ESMR reactor[83]

Technology Readiness Level

The ESMR process is currently at technology readiness level 4. This is based on Haldor Topsoe's laboratory scale demonstration activities. However, Haldor Topsoe is working with partners to construct a pilot plant which is expected to come online in Summer 2021. This is expected to increase the TRL from 4 to 7/8. Following a successful demonstration, technology development will continue to advance to commercial scale applications.

Value Chain Position

The ESMR process shares a lot of similarities with the conventional SMR process. Although the reactor is electrified, the majority of the other major equipment (e.g. water gas shift, hydrogen purification) remain the same. ESMR technology therefore has significant potential for modular expansion of existing SMR hydrogen production facilities, as well as for new installations. ESMR can be deployed in scenarios similar to conventional SMR technology for dedicated hydrogen production, primarily supplying refineries and chemical production facilities that produce products such as methanol and ammonia. Economies of scale are achievable by locating the technology near to industries where hydrogen offtake is readily available and shared CO_2 transport and storage infrastructure is more likely to be developed. The cost of CCS could make the ESMR process uneconomic as a blue hydrogen production process if a region does not have any suitable sites for CO_2 storage nearby.

To gain the benefits of the electrified reactor, the process needs to be located near to low carbon electricity sources and where there is capacity for the electricity demand. Industrial clusters are likely to be good locations for this, particularly where there are large-scale renewable electricity generating assets deployed. Examples

[83] Wismann et al 2019, Electrified methane reforming: A compact approach to greener industrial hydrogen production

include the Humber Region, with Hornsea 1&2 offshore wind farm, and Rotterdam Port, which has ambitions to increase offshore wind farm capacity to 300MW[84].

Technology Developers

Initial work on developing the ESMR technology was carried out in collaboration between Technical University Denmark and Haldor Topsoe[82]. This highlighted the potential to develop compact reactor designs, increase heating efficiency and reduce emissions by replacing a natural gas fired reformer with direct electrical heating. Haldor Topsoe are currently the main proponents of the technology and are actively advancing the TRL of its ESMR technology. It is unclear if any other organisations are developing a similar technology.

Process Data

Process data was collected from a combination of literature and stakeholder engagement and is presented for the ESMR process in the Appendices, Section 7.2.5. Uncertainties within the process are analysed as sensitivities as part of the techno economic assessment of the technology.

[84] Port of Rotterdam, Energy Industry

4 Technoeconomic Assessment

This analysis explores blue hydrogen production from natural gas feedstocks for four technologies in the Netherlands. The modelling considers: technology capital and operational costs; feedstock, electricity, fuel and carbon prices; and CO_2 T&S and hydrogen distribution infrastructure. This analysis results in a LCOH for each hydrogen production technology in a series of different cases and sensitivities.

4.1 Methodology and Key Sensitivities

4.1.1 Technoeconomic Assessment Methodology

This section outlines the key inputs and associated sensitivities for the technoeconomic analysis. The model used in this analysis uses the assumptions specified throughout this section and listed in the Appendices, Section 7. The two primary outputs are the LCOH and abated cost of CO_2.

Cost and Emissions Gateways

There are three hydrogen cost gateways in this study, as shown in Figure 42.

- **Gateway 1** only considers the hydrogen production facility and hydrogen compression.
- **Gateway 2** includes the hydrogen production facility, compression and the CO_2 T&S infrastructure.
- **Gateway 3** includes the entire value chain up to the point of end use.

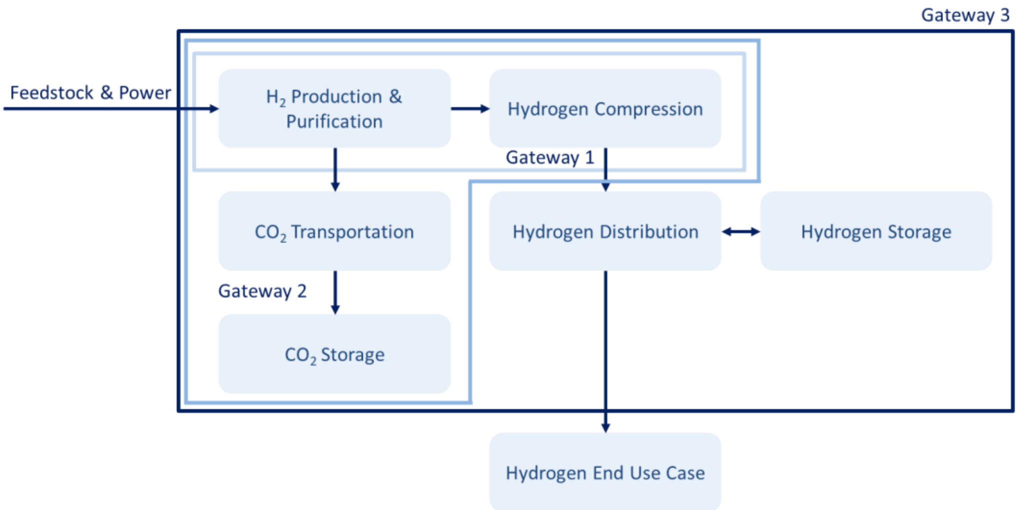

Figure 42: Model cost and emission gateways

Levelised Cost of Hydrogen

The technoeconomic model uses a cash flow to determine the LCOH and is calculated at the three different gateways, defined in Figure 42. This equation is shown below with the subscript denoting the gateway. This is the price that is necessary over the lifetime of the asset to give a zero net present value.

$$LCOH_n = \frac{|Net\ Present\ Expenditure_n| - |Net\ Present\ Revenue_n|}{Net\ Present\ H_2\ Production}$$

The following definitions are used throughout this analysis:

- **Net Present Expenditure** is the sum of the discounted cost of the feedstock, fuel, electricity, carbon price, capital, operations, CO_2 T&S fee and hydrogen distribution and storage fee over the asset's lifetime.
- **Net Present Revenue** is the sum of the discounted revenue obtained from exporting power to the grid over the asset's lifetime. This is only used in the context of the SMR, as described in Section 3.2.

- **Net Present H_2 Production** is the sum of the discounted production of hydrogen over the asset's lifetime.

The model uses cost trajectories from 2020 as inputs for:

- Cost of feedstock, fuel and electricity
- Carbon price
- Electricity grid carbon intensity

The assumptions to support these trends are described in this section and in the Appendices, Section 7.

Modelling Parameters

For consistency with other IEAGHG studies, the same technoeconomic parameters are used where possible.

- **Asset Lifetime –** A standard plant operating life of 25 years is used throughout this analysis. A plant life of 40 years was not considered due to uncertainties over variable trajectories.
- **Currency –** economic outputs and costs are presented in Euros in order to align with data collection. Where data was taken from previous years, inflation was accounted for. A conversion rate of $1.142/€[85] and €1.1248/£[86] was used, taken as the average exchange rates in 2020.
- **Discount Factor –** A standard discount rate of 8% is used throughout this analysis. Sensitivities of 10% and 5% are explored in Figure 43.

This study explored the impact of a discount factors of 5%, 8% and 10% on the LCOH, as shown for the central case for SMR in Figure 43. This figure shows that the range of discount factors considered has a small impact on the levelised cost of hydrogen in this study since the main cost components are the variable operational costs incurred over the asset's lifetime. These far outweigh the capital expenditure (CAPEX).

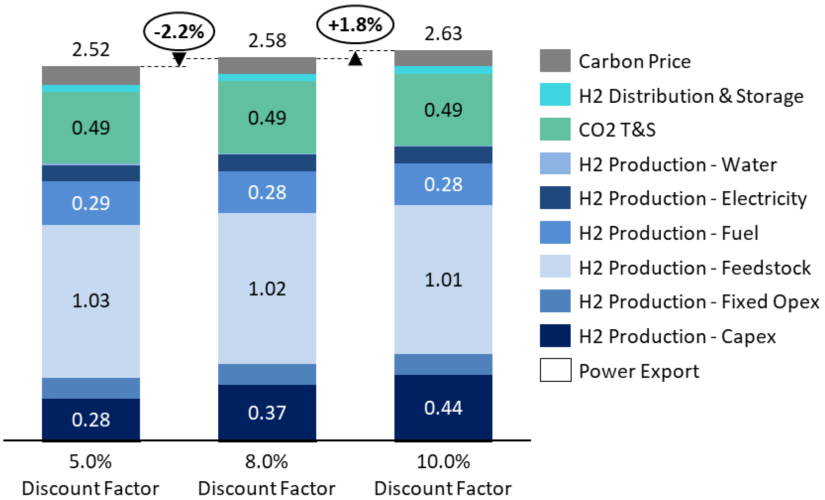

Figure 43: Levelised cost of hydrogen for SMR (TRL 9) in the Netherlands central case for varying discount factors in 2020 (€ / kgH_2)

Technology Readiness Levels

Three of the four hydrogen production technologies analysed in this report have a high TRL (7 to 9); these are SMR, ATR and POX. There is higher quality and availability of data for these technologies from stakeholders and publicly available literature. ESMR has a lower TRL of 4, however, this has the potential to rapidly advance due to the installation of a pilot plant in summer of 2021 which could advance the TRL to 7/8. Information on ESMR was significantly dependent on reports about lab scale demonstration and guidance from Haldor Topsoe and is therefore less reliable. This report therefore highlights in comparative analyses the respective TRLs for each technology.

[85] Exchange Rates 2021, Euro to US Dollar Spot Exchange Rates for 2020
[86] Exchange Rates 2021, British Pound to Euro Spot Exchange Rates for 2020

Sensitivity

For each variable, either a range of values, giving a maximum and minimum, or a single value were collected. Where a range of values have been collected, the sensitivity analysis uses Tornado Plots to show the possible range of costs and / or emissions. Where this range is less than +/-10%, a sensitivity of +/-10% is applied to show greater variation. Where only a single value has been found, the cost component / emissions is varied by +/-10% in the Tornado Plots to demonstrate the impact on the LCOH and abated cost of CO_2.

Reference Case

To compare with the incumbent and calculate the stored and abated costs of CO_2, the Base Case from IEAGHG's SMR[74] study was used. This does not include CCS. This is based on production in the Netherlands.

Presentation of Data

There are three ways in which the LCOH for each scenario is presented:

- **Stacked Bar Charts -** The LCOH is broken down by cost component up to Gateway 3, such as Figure 50.
- **Waterfall Chart -** The base case LCOH is broken down into the different gateways to highlight the different gateway costs, such as Figure 51.
- **Tornado Plot -** The range of costs for each cost component in the base case is shown, based on the specified data range. The list of components is the same as those in Gateway 3, such as Figure 52.

The abated cost of CO_2 also makes use of the gateways in Figure 42.

Production Facility Capacity

All case studies are based on a 300MW_{LHV} (79 ktonnes/year) hydrogen production facility at a 100% load factor. This capacity is comparable with other gas-based hydrogen production facilities identified in literature as shown in Figure 44 and ensures that the different production technologies are comparable.

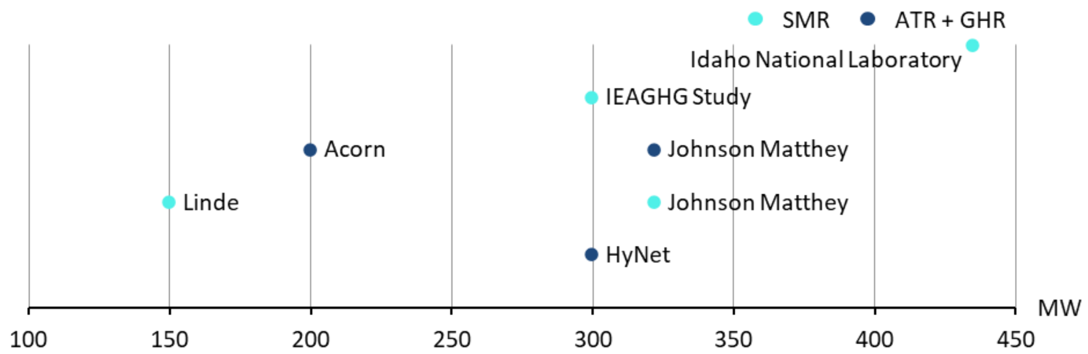

Figure 44: Hydrogen production capacities of announced SMR and ATR configuration facilities

4.1.2 CAPEX and Fixed OPEX

Capital expenditure (CAPEX) and fixed operational expenditure (OPEX) estimates for this technoeconomic study have been gathered from literature and stakeholder engagement. The assumptions are shown in the Appendices, Section 7.1 and 7.3 and central values are shown for all blue hydrogen production technologies in Table 4.

Table 4: CAPEX and Fixed OPEX for hydrogen production technologies with CCS - Central Case

Technology	CAPEX – Central Case [€ / kW_{LHV}]	Fixed OPEX – Central Case [€ / kW_{LHV} / yr]
Steam Methane Reforming	1,031	36
Partial Oxidation	886	34
Auto Thermal Reforming with Gas Heated Reformer	966	41
Electrified Steam Methane Reforming	676	26

As far as is possible based on literature reviews and stakeholder engagement, the definition for the CAPEX and fixed OPEX by technology has been homogenised in scope to facilitate comparable analysis. Where data is not available for fixed OPEX, a flat rate was used. This is based on the average of those rates for technologies where there is sufficient data. This was found to be 3.9% of the value of the technology CAPEX and varies between 5.2% and 3%.

4.1.3 Feedstock, Fuel and Electricity

Electricity Prices

Electricity prices for the Netherlands in 2020 are taken from literature with forecast provided up to 2030. Beyond 2030, the forecast for the European Union's electricity price is used to project prices out to 2050 using "EU Energy Outlook 2050"[87]. This is varied by +/-10% in our sensitivity analysis.

Both of the SMR cases are also able to export power to the grid. This is modelled in the technoeconomic model as another method of generating revenue, separate to the sale of hydrogen. The plausible revenue is based on selling the power at the Dutch wholesale price, as shown in Figure 45.

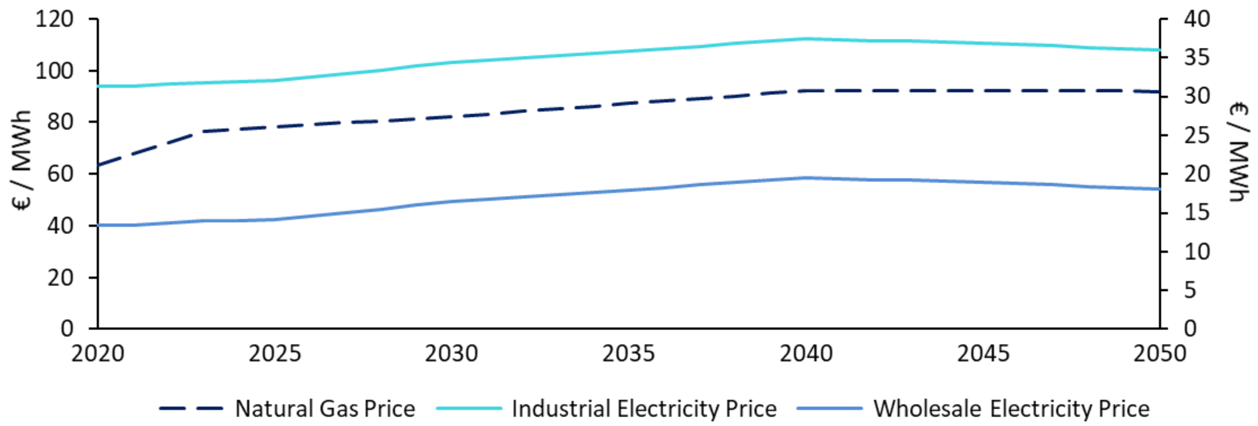

Figure 45: Feedstock price forecast for electricity (Left) and natural gas (Right) in the Netherlands (€/MWh)[87, 88, 89, 90, 91, 92, 93, 94]

[87] Energy Brain Blog 2019, EU Energy Outlook 2050 – How will Europe evolve over the next 30 years?
[88] Netherlands Environmental Assessment Agency 2020, Netherlands Climate and Energy Outlook 2020
[89] CE Delft 2017, Energy and Electricity Price Scenarios 2020-2023-2030
[90] EWI Energy Research and Scenarios 2018, The energy market in 2030 and 2050 – The contribution of gas and heat infrastructure to efficient carbon emission reductions
[91] Danish Ministry of Climate, Energy and Utilities 2018, Denmark's Draft Integrated National Energy and Climate Plan
[92] Statista 2021, Prices of electricity for industry in the Netherlands from 2008 to 2020
[93] Global Petrol Prices 2020, Netherlands electricity prices
[94] NREL, H2A: Hydrogen Analysis Production Models

Natural Gas Prices

Natural gas prices for the Netherlands in 2020 are taken from literature with forecasts provided up to 2030. Beyond 2030, global forecasts are applied to the Dutch natural gas price from “The Energy Markets in 2030 & 2050”[90]. The low and high-cost cases for natural gas in the Netherlands differ from the central case by +/- 10%. This is explored in the respective sensitivity analyses.

Steam and Water

Steam and water are also important for the production of hydrogen from natural gas for all analysed technologies. The origin of steam by site will vary greatly; in some cases, it will be possible to use steam that is produced by other industrial processes whilst in others new steam will be needed. The impact of the cost of water was tested on the SMR case. Assuming that the water is priced as the same as the NREL model[94] at €0.0018/kg water, and that the power input into the system is sufficient to generate steam, the inclusion of steam increases the Gateway 3 LCOH by less than €0.01/kg or 0.32%. Cooling water is not costed in this analysis.

4.1.4 Carbon Pricing

A carbon price is a critical tool for supporting the uptake of cleaner technologies. Carbon prices are projected at the regional level by the World Energy Council[95] and BP Energy Outlook 2020[96]. The carbon price forecasts for the Netherlands are shown in Figure 89. It is possible that the carbon price may be further updated in the future, following decisions from policy makers. For example, in the case of the UK, recent analysis show that carbon price could reach ~€250/tCO2 by 2050[97].

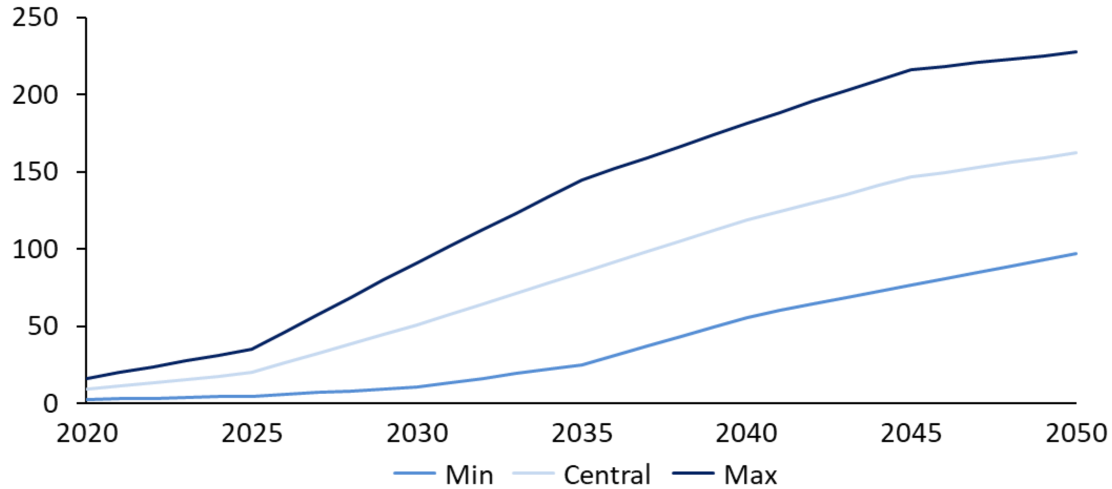

Figure 46: Carbon prices in the Netherlands (€/tCO_2)

This analysis applies the carbon price to emissions around Gateway 2. This includes:

- Feedstock and fuel supply by region
- Electricity consumption
- CO_2 T&S
- Direct emissions from the production process

The impact of the range of carbon prices is shown in the respective sensitivity analyses.

[95] World Energy Council 2013, World Energy Scenarios Composing Energy futures to 2050
[96] BP 2020, Energy Outlook 2020 edition
[97] BEIS 2021, Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal

4.1.5 CO_2 Capture Rate

The capture rates for the processes analysed in this report are taken from literature and stakeholder engagement. This leads to a range of different capture rates for different technologies as shown in Table 5. Variations in the capture rate of these technologies are not considered in these case studies as the data collected from literature and stakeholders did not provide a breakdown of plant capital and operational costs, as well as energy requirements by process unit.

As previously described in this study, all production technologies have a minimum capture rate of 90%, supporting the low carbon hydrogen narrative. The technology with the highest capture rate is the POX process, with a capture rate of 100%[98]. This means that there are no direct emissions from the production process, i.e. no scope 1 emissions. The ATR + GHR configuration has the potential to achieve capture rates of 97%[99], however, a capture rate of 94% was used in this study to correspond to the H21 North of England carbon capture facility performance. Other sources of emissions from these processes are also explored, as described in Section 4.1.6.

Table 5: Summary of CCS for oil-based hydrogen production technologies

H_2 Production Technology	SMR	ATR + GHR	POX	e-SMR
CCS Location	Post Reformer Flue Gas	Post Water Gas Shift (WGS)	Post Water Gas Shift (WGS)	Post Reformer Flue Gas
Separation Technology	Mono-ethanol amine (MEA)	Activated Methyl-diethanolamine (aMDEA)	Amine based	Methyl-diethanolamine (MDEA)
CCS Capture Rate	90%	94%	100%	98.62%

4.1.6 Cost of CO_2 Abatement

Another important factor for policy makers, technology developers and industrial operators is the cost of CO_2 abatement. This is the total cost to the process operator of reducing their emissions when compared with an incumbent technology. In this study, the reference case is SMR without CCS in the Netherlands. Two costs of abatement are given for each sensitivity; (1) where there is no carbon price inflicted on the process operator; and (2) where a carbon price is accounted for. The second of these two options results in a reduction in the cost of CO_2 abatement for the processes analysed in this study since the incumbent is more polluting.

The fraction of emissions that are associated with Gateway 1 and 2 of our analysis for SMR with CCS and the reference case in the Netherlands in 2020 are displayed in Figure 47. The carbon intensities of natural gas and the electricity grid in the Netherlands are shown in Table 6[100]. These include the upstream CO_{2e} emissions of natural gas (its production and transport) and all CO_{2e} emissions related to grid electricity generation. These results highlights:

- The importance of the CO_2 capture rate. By capturing 90% of the CO_2 emissions from the SMR process, direct emissions are reduced from 19,482 to 1,952 ktonnes of CO_2 over the 25-year lifetime of the asset.
- Where the capture rate is greater than 90%, emissions from the delivery of feedstock and fuel to the industrial site become important. Greater electrification and the minimisation of fossil fuel consumption is expected to limit this impact.

[98] 100% capture rate for scope 1 emissions from POX hydrogen production facilities.
[99] HyNet North West 2020, HyNet Low Carbon Hydrogen Plant
[100] Note that changes in the emissions associated with the delivery of natural gas are not accounted for through time. Grid carbon intensity is justified in the Appendices, Section 7.2.8. It is assumed that the intensity of the electricity grid in 2050 is equivalent to the carbon intensity of renewable electricity today.

- CO_2 T&S emissions in this scenario are only 0.5% of total emissions in Gateway 2.

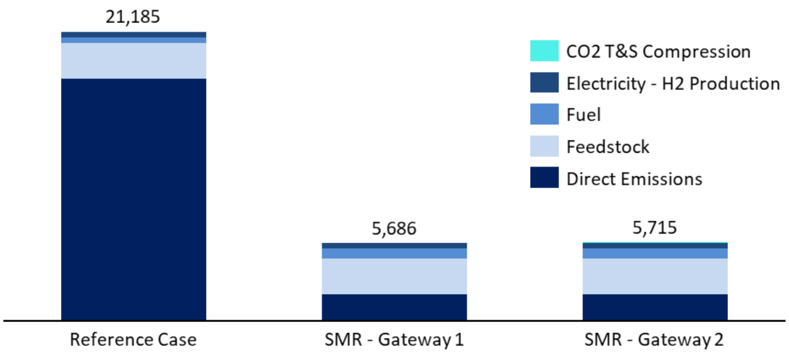

Figure 47: Emissions by source for the reference case and SMR (TRL 9) and the two gateways (ktonnes CO_2 over 25-year asset lifetime) – ($ktCO_2$)

Table 6: Carbon intensity of natural gas and electricity in the Netherlands

		2020	2030	2050
Natural Gas	*gCO_2/kWh*	35	35	35
Grid Electricity	*gCO_2/kWh*	480	160	33

The cost of CO_2 abatement includes emissions up to Gateway 2 and is calculated as shown by the equation below:

$$Cost\ of\ CO_2\ Abatement = \frac{LCOH_{Scenario} - LCOH_{Reference}}{Emissions_{Reference} - Emissions_{Scenario}}$$

The cost of CO_2 abatement is discussed for each technology, both with and without a carbon price at the end of this section. The emissions included in this analysis are:

- Feedstock and fuel supply
- Electricity consumption
- CO_2 T&S
- Direct emissions from the production process

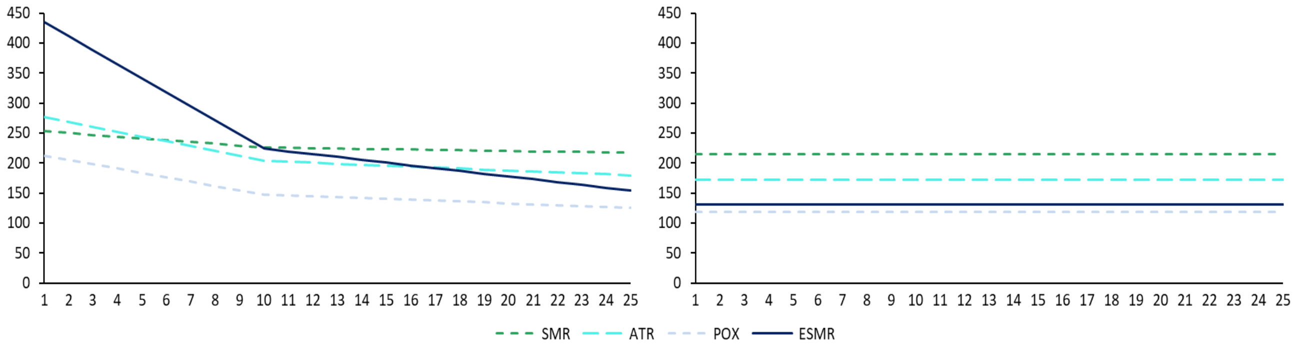

Figure 48: Emissions over the lifetime of the selected production technologies in the central case in the Netherlands with the carbon intensity of the grid (left) and a renewable electricity supply (right) – ktonnes CO_2/year

The carbon intensity of the electricity over time is the only component that varies across this analysis and is therefore responsible for the differences observed in the carbon intensity. As the grid is decarbonised, those technologies which are more reliant on electricity (ESMR, POX and ATR) are more quickly decarbonised than SMR which uses natural gas as a fuel. This is shown in Figure 48 where the fastest decarbonising technology is the ESMR. Where the electricity supply is renewable, POX is the least polluting due to its high capture rate. Further analysis on these emission factors and the abated cost of CO_2 is given in the conclusions.

4.1.7 CO_2 Transport and Storage

The literature review in this study has explored both onshore and offshore storage, the latter including CO_2 shipping and offshore pipelines. The cost for this transportation and storage is applied as a fee to the H_2 production facility. For the 2020 scenario, the range of costs quoted by the Porthos project are used to provide the upper and lower bound for the CO_2 T&S fee. This is publicly available information and shown in Figure 49.

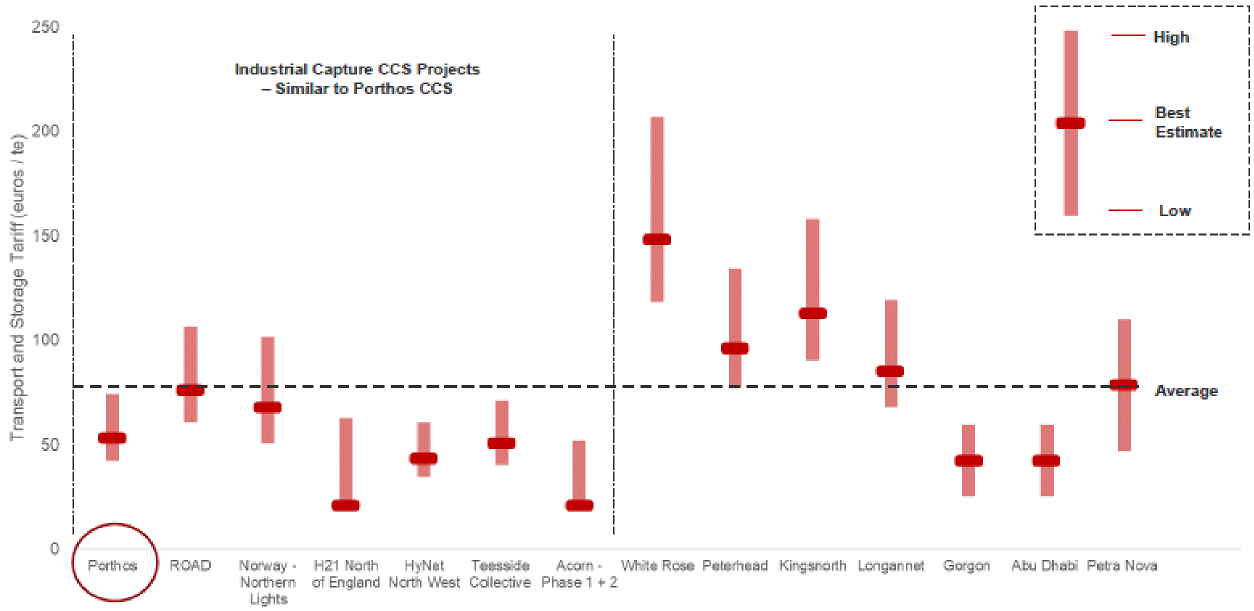

Figure 49: Transport and storage tariffs for industrial CCS projects (€/tCO_2)[101]

This was compared with Element Energy's report and model for BEIS, ""Shipping CO_2 – UK Cost Estimation Study"[102]. This model uses the CO_2 annual throughput, transportation, storage type and pressure drop to specify the cost of CO_2 transportation. This is further explained in the appendices, including the outputs.

The 2020 costs from public literature were higher than the Element Energy model which does not account for liabilities associated with leakage and the provision for the expansion of carbon capture in the industrial clusters. To account for this, the Element Energy calculations for the 2020 analysis is scaled to match these low, best case (used as the central case) and high-cost estimates. The best case is not the average of the high and low case, leading to asymmetric sensitivities on the cost of CO_2 T&S. The 2050 analysis is only based on this study's internal calculations.

The T&S fee used by each scenario is shown in Table 7. These values are asymmetric:

- **2020 / 50:** +39% and -20%

From this analysis, the CO_2 T&S fee is expected to significantly reduce through time.

Table 7: CO_2 transport and storage costs in the Netherlands

Year	Minimum [€ / tCO_2]	Central [€ / tCO_2]	Maximum [€ / tCO_2]
2020	43.4	54.6	76.0
2050	12.6	15.8	22.0

[101] Xodus Advisory 2020, Porthos CCS – Transport and Storage (T&S) Tariff Review
[102] Element Energy 2020, Shipping CO_2 – UK Cost Estimation Study

4.1.8 Hydrogen Distribution

In this study, it is assumed that hydrogen is produced in close proximity to high demand end users in the Rotterdam industrial cluster. Therefore, only short distance pipelines for hydrogen distribution are considered. As for the CO_2 T&S, the hydrogen distribution and storage cost is applied as a flat fee. This fee is proportional to the amount of hydrogen that is distributed in each scenario (79 tonnes per day). As the configuration is the same for all scenarios, the hydrogen distribution and storage fee also remains fixed at **€0.05/kgH$_2$**. A variation of +/- 10% is applied in the sensitivity analysis.

4.1.9 Technoeconomic Analysis of 2050 Deployment

This analysis also provides commentary on the supply of blue hydrogen from natural gas in 2050. By 2050, the hydrogen market is expected to have matured with uptake reaching similar levels across the globe. Resultingly, supply chains will have matured, technologies will have come down in cost and demand for hydrogen at a local level is predicted to be high (although there will also be significant opportunities for hydrogen export). The following sensitivities are therefore considered:

Capital Costs

Capital cost reductions are expected with increased levels of deployment, particularly for those which are low TRL. The extent to which cost reductions are realised depends on the ramp up in the deployment of each technology and the associated learning rate. For example, the SMR CAPEX reduces by between 8% and 29% where it is assumed that:

- The cost reduction is equal to[103]:

$$Cost_{2050} = Cost_{2020} \times \left(\frac{Capacity_{2050}}{Capacity_{2020}}\right)^{-Learning\ Rate}$$

- SMR has a 46% market share of today's 354Mtoe H_2 production.
- SMR keeps its market share of 46% of the global production of hydrogen of 1,959Mtoe in 2050
- Learning rates of between 5% and 20% are used[104].

For ease of comparison, it is assumed for each technology that their production capacity increases by a factor of 5.5[105], the same growth that is seen for the hydrogen sector, between 2020 and 2050. This leads to between an 8% and 29% learning factor for learning rates of 5% and 20% respectively.

Emissions

With the decarbonisation of the power grid, the average carbon intensity is expected to significantly reduce. In addition, large-scale energy users will have more opportunities to sign up to green energy tariffs. The carbon intensity of the grid is therefore reduced to a similar level as that of renewables in the Netherlands today (32.9gCO_2/kWh[106]), therefore reducing the carbon price applied to the hydrogen production technology.

CO_2 T&S Cost Reductions

As previously discussed, the costs associated with CO_2 T&S today are greater than Element Energy's inhouse calculations since the modelled costs do not account for expansion, liabilities, risks and the respective margins on the processes. Through time, these costs are expected to reduce with improved understanding of CCS projects. The associated fee in 2050 is therefore only based on Element Energy's "Shipping CO_2 – UK Cost Estimation Study"[102]. These costs are presented in the Appendices, Section 7.2.6.

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[103] European Commission 2020, Technology Learning Curves for Energy Policy Support
[104] Karali et al 2015, Using learning curves on energy efficient technologies to estimate future energy savings and emission reduction potentials in the U.S. iron and steel industry
[105] IEAGHG: Beyond the Plant Gate; based on an increase from 354Mtoe to 1,959Mtoe
[106] CE Delft 2020, Electricity emission indicators

Feedstock, Fuel, Electricity and Carbon Pricing

Since forecasts from 2050 onwards are sparse / not expected to be accurately representative, regional pricing is frozen at 2050 levels. This includes the cost of electricity, natural gas and the carbon price as shown in Figure 45 and Figure 46 respectively.

4.2 Technoeconomic Analysis Results

4.2.1 Steam Methane Reforming

2020 Scenario

The SMR case with integrated CCS is compared against a reference SMR case without CCS in Figure 50. The LCOH is shown for both cases, with and without the carbon price. The abated cost of CO_2 for SMR with CCS is also given in Table 8 with and without the carbon price. The carbon price alone is not enough to make the LCOH of SMR hydrogen production with integrated CCS cost competitive with hydrogen produced without CCS. The significant difference between the two technologies is the additional capital costs and the need for CO_2 T&S infrastructure. Further policy & regulation intervention is therefore required to make CCS integration with SMR cost competitive in the central carbon price case.

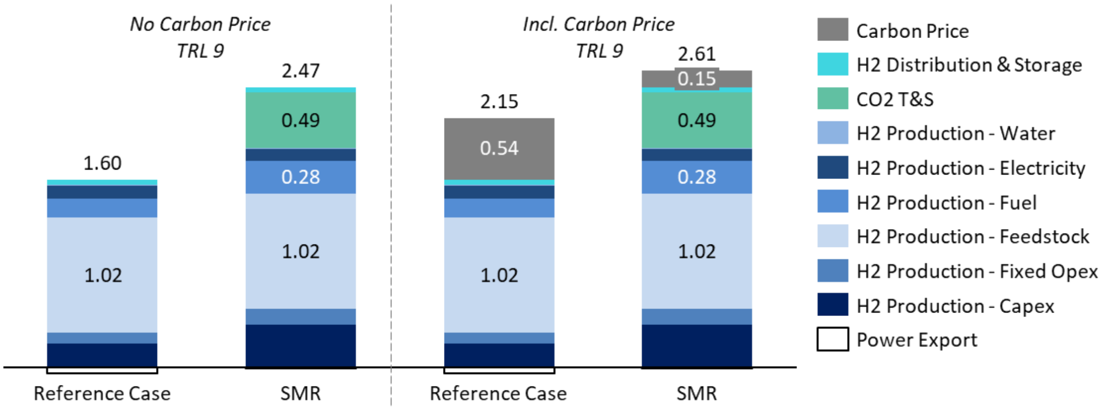


Figure 50: LCOH for SMR and the reference case in the Netherlands in 2020 (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2

Table 8: Cost of CO_2 abatement for SMR with CCS in the Netherlands in 2020

Variable	Units	SMR Without Carbon Price	SMR With Carbon Price
Lifetime Emissions	*ktCO_2*	5,715	
Lifetime H_2 Production	*ktH_2*	1,972	
LCOH	*€ / kgH_2*	2.47	2.61
Cost of CO_2 Abatement	*€ / tCO_2*	110.01	59.36

A breakdown of the LCOH for the SMR with CCS case is displayed in the waterfall chart in Figure 51. The most significant cost components are the cost of feedstock, CO_2 T&S and plant Capex. Combined, these cost components account for over 73% of the total LCOH. Cost reductions for these cost components are therefore needed to reach parity in the absence of additional regulation and policy interventions.

Hydrogen production costs account for over 74% of the total LCOH. The cost of CO_2 abatement and carbon price account for 19.0% and 5.7% respectively, with hydrogen distribution forming a minor 1.9% of the total LCOH. This highlights the importance of local demand and local access to CO_2 T&S infrastructure.

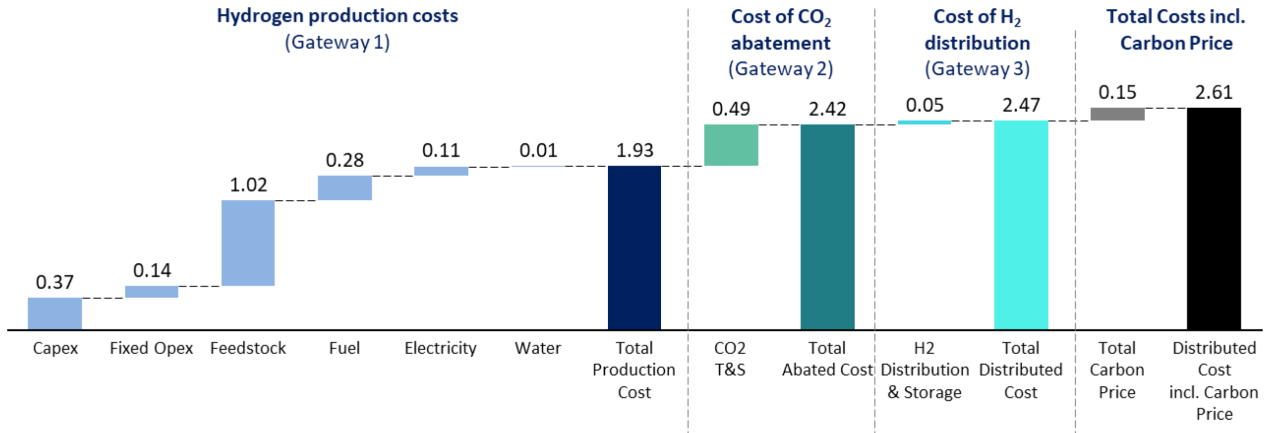


Figure 51: LCOH for SMR with CCS in the Netherlands in 2020 in the central case (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

The impact of varying each cost component by the specified sensitivity on the LCOH is displayed by the tornado chart in Figure 52. As previously discussed, the feedstock price, CO_2 T&S fee and plant Capex are the most significant cost components. However, the variation of the Capex cost components does not significantly impact the LCOH due to the lower uncertainty. The wider band for the carbon price leads to a larger impact on the LCOH; +/-3.7%. This highlights the significance of policy on the LCOH.

In all cases, the variation of the cost component does not change the LCOH by more than +/- 8%. The most significant variation comes from the CO_2 T&S fees with variations of +7.3 / -3.8%. Variation to the CAPEX, fixed OPEX, fuel, electricity demand, water and hydrogen distribution and storage has a cumulative impact of +/- 3.7% on the LCOH.

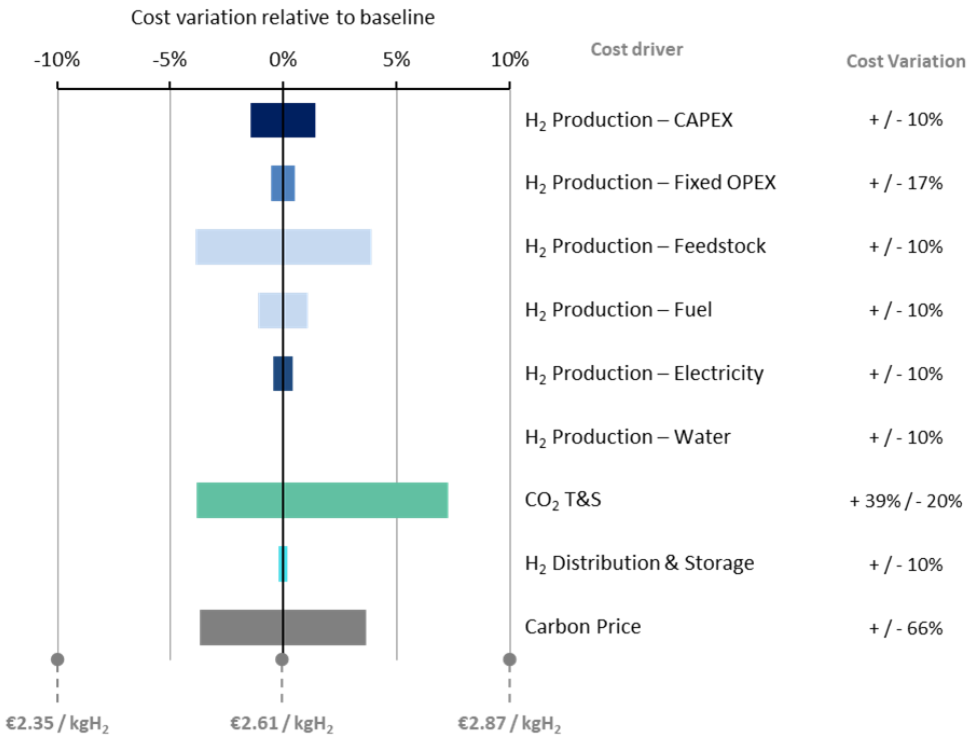


Figure 52: Sensitivity on the LCOH for SMR with CCS in the Netherlands in 2020 in the central case (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

2050 Scenario

The SMR case with integrated CCS is compared against the reference SMR case without CCS as shown in Figure 53. The LCOH is shown for both cases, with and without the carbon price. An additional case is also shown where the CAPEX is exposed to a 20% learning rate instead of a 5% learning rate. The cost of CO_2 abatement for SMR with CCS is also given in Table 9 with and without the carbon price (for a 5% learning rate). In 2050, the carbon price is large enough to make SMR with CCS lower cost than the grey hydrogen reference case. The impact of the carbon price on the SMR with CCS remains large due to the 90% capture rate and emissions associated with the natural gas fuel / feedstock. This is the lowest capture rate for all blue hydrogen production technologies analysed in this report.

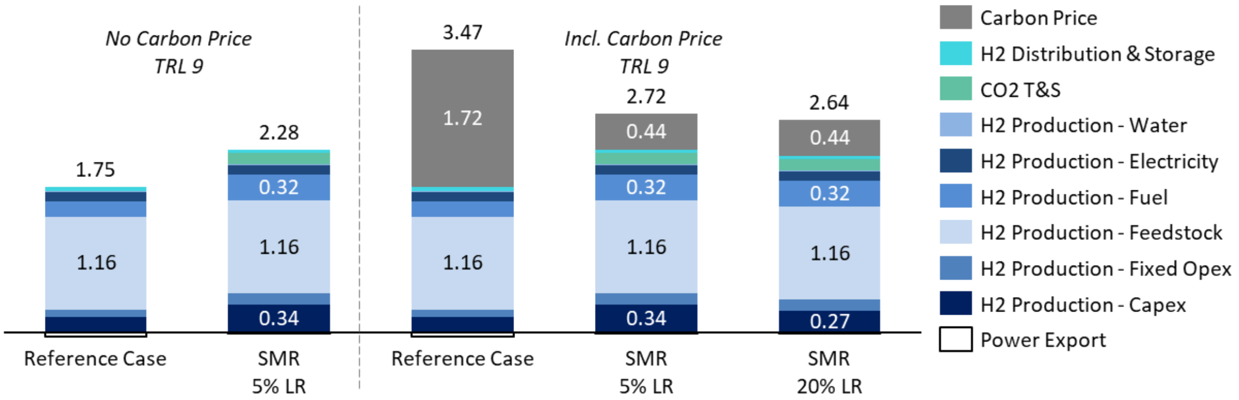


Figure 53: LCOH for SMR and the reference case in the Netherlands in 2050 for learning rates (LR) of 5% and 20% (€/kgH_2) *CO_2 Price in the Netherlands in 2050 - €162.46/tCO_2*

Table 9: Cost of CO_2 abatement for SMR in the Netherlands in 2050

Variable	Units	SMR Without Carbon Price	SMR With Carbon Price
Lifetime Emissions	*ktCO_2*	5,357	
Lifetime H_2 Production	*ktH_2*	1,972	
LCOH	*€ / kgH_2*	2.28	2.72
Cost of CO_2 Abatement	*€ / tCO_2*	83.83	-

4.2.2 Auto Thermal Reforming with Gas Heated Reformer

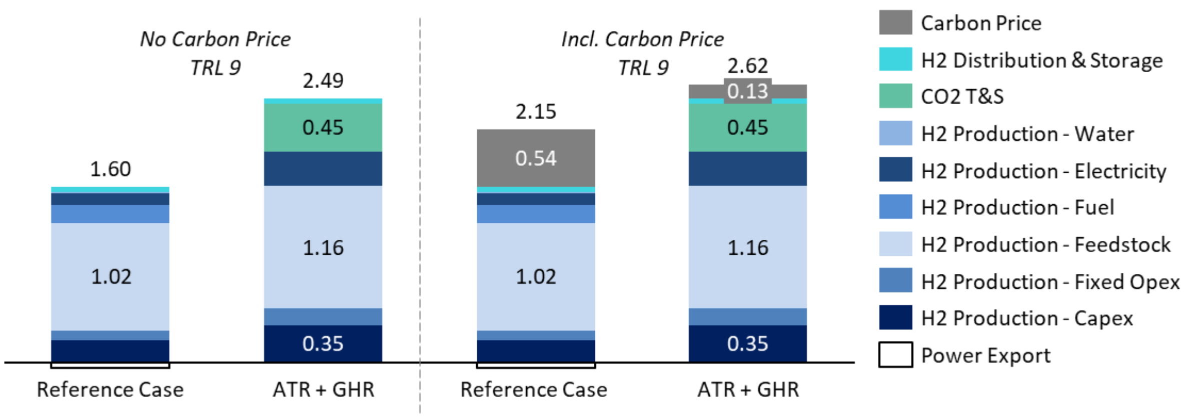


Figure 54: LCOH for ATR + GHR and the reference case in the Netherlands in 2020 (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

The ATR + GHR case with integrated CCS is compared against a reference SMR case without CCS as shown in Figure 54. The LCOH is shown for both cases, with and without the carbon price. The abated cost of CO_2 for ATR + GHR with CCS is also given in Table 10 with and without the carbon price. Without the carbon price, the LCOH for ATR + GHR is slightly greater than that for SMR with CCS. However, the ATR + GHR's higher capture rate means that once the carbon price is included, the two technologies are at parity. As for the SMR case, interventions in addition to the central carbon price are needed to make ATR + GHR with CCS lower cost than the reference case.

Table 10: Cost of CO_2 abatement for ATR + GHR in the Netherlands in 2020

Variable	Units	ATR + GHR Without Carbon Price	ATR + GHR With Carbon Price
Lifetime Emissions	*$ktCO_2$*	5,265	
Lifetime H_2 Production	*ktH_2*	1,972	
LCOH	*€ / kgH_2*	2.49	2.62
Cost of CO_2 Abatement	*€ / tCO_2*	109.55	58.57

A breakdown of the LCOH for the ATR + GHR with CCS case is displayed in the waterfall chart in Figure 55. The most significant cost components in the ATR + GHR case are the cost of the feedstock, CO_2 T&S and plant Capex. Combined, these cost components account for over 75% of the total LCOH. Cost reductions for these cost components are therefore needed to reach parity in the absence of additional regulation and policy interventions. There is a significantly greater electricity requirement compared to the SMR case (0.32 €/kgH_2 compared to 0.11 €/kgH_2) due to the need for the air separation unit (ASU). However, the ATR + GHR process benefits from zero fuel costs (from natural gas fired combustion) as a result. Hydrogen production costs account for almost 76% of the total LCOH. The cost of CO_2 abatement and carbon price account for 17% and 4% respectively, with hydrogen distribution forming a minor 2% of the total LCOH.

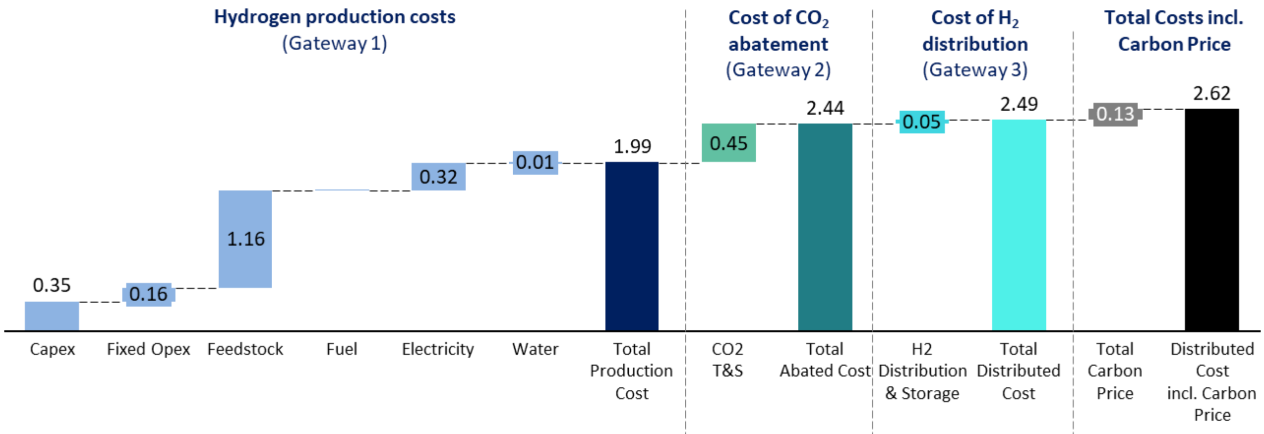


Figure 55: LCOH for ATR + GHR with CCS in the Netherlands in 2020 in the central case (€/kgH_2) **CO_2 Price in the Netherlands in 2020 - €13.5/tCO_2*

The impact of varying each cost component by the specified sensitivity on the LCOH is displayed by the tornado chart in Figure 56. These sensitivities are very similar to the SMR case. As previously discussed, the feedstock price, CO_2 T&S fee and plant CAPEX are the most significant cost components. However, the variation of the CAPEX does not significantly impact the LCOH due to the tighter band on the cost variation. Again, the wider band for the carbon price leads to a larger impact on the LCOH; +/- 3.3%. For ATR + GHR, this is smaller than for SMR due to its lower emissions. This highlights the significance of policy on the LCOH. In all cases, the variation of the cost component does not change the LCOH by more than +/- 7%. The most significant variation comes from the CO_2 T&S fees with variations of +6.9 / -3.6%. Variation to the CAPEX, fixed OPEX, electricity demand, water and hydrogen distribution and storage has a cumulative impact of +/- 3.4% on the LCOH.

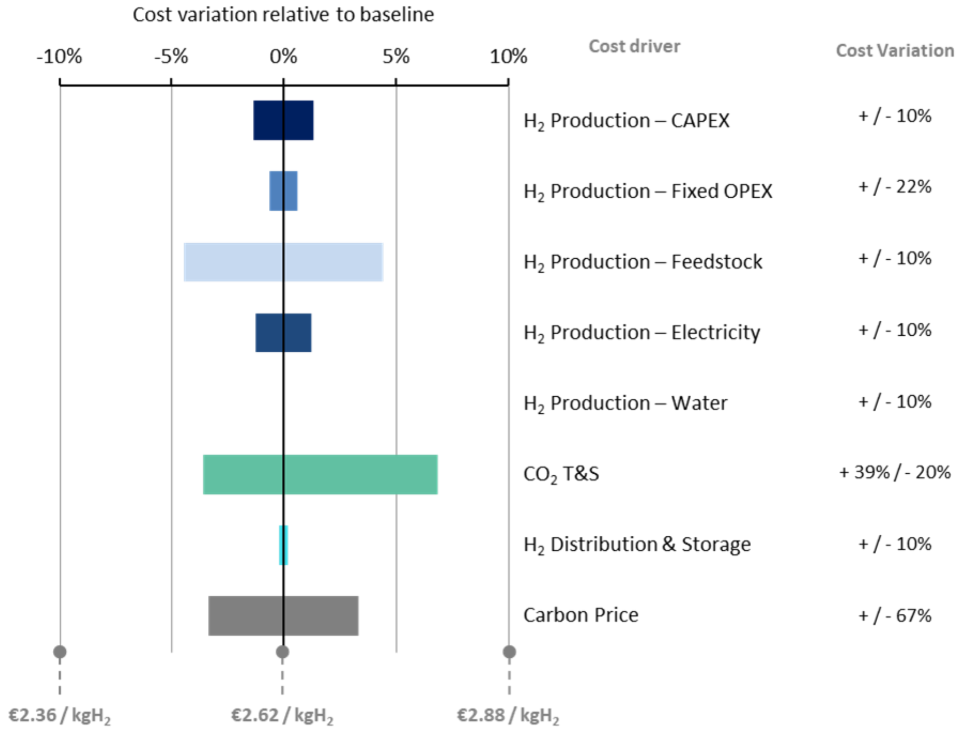


Figure 56: Sensitivity on the LCOH for ATR + GHR with CCS in the Netherlands in 2020 in the central case (€/kgH$_2$) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

2050 Scenario

The ATR + GHR case with integrated CCS is compared against the reference SMR case without CCS as shown in Figure 57. The LCOH is shown for both cases, with and without the carbon price. An additional case is also shown where the learning rate is 5% instead of 20%. The abated cost of CO_2 for ATR + GHR with CCS is also given in Table 11 with and without the carbon price (for 5% learning rate). In 2050, the carbon price is large enough to make ATR + GHR with CCS lower cost than the grey hydrogen reference case. The higher capture rate mitigates to a large extent the central carbon price from 2050.

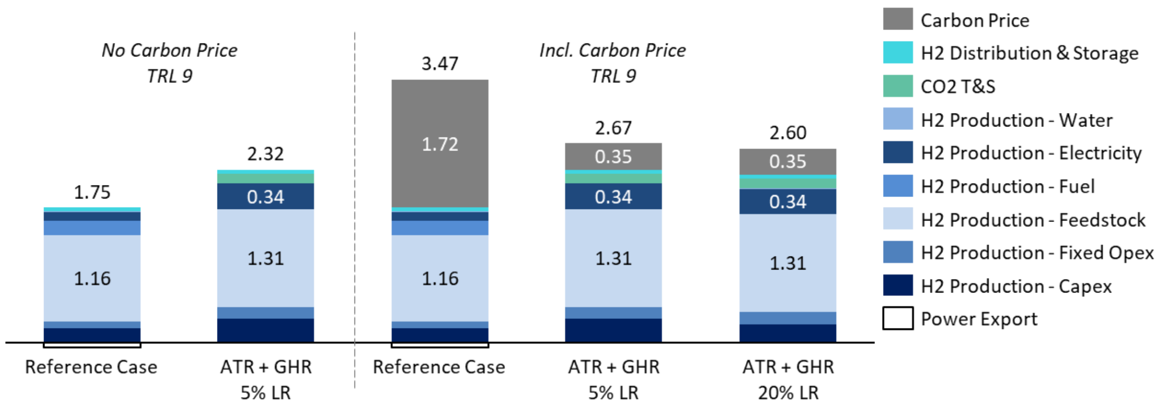


Figure 57: LCOH for ATR + GHR and the reference case in the Netherlands in 2050 for learning rates (LR) of 5% and 20% (€/kgH$_2$) *CO_2 Price in the Netherlands in 2050 - €162.46/tCO_2*

Table 11: Cost of CO_2 abatement for ATR + GHR in the Netherlands in 2050

Variable	Units	ATR + GHR Without Carbon Price	ATR + GHR With Carbon Price
Lifetime Emissions	*$ktCO_2$*	4,287	
Lifetime H_2 Production	*ktH_2*	1,972	
LCOH	*€ / kgH_2*	2.32	2.67
Cost of CO_2 Abatement	*€ / tCO_2*	83.26	-

4.2.3 Partial Oxidation

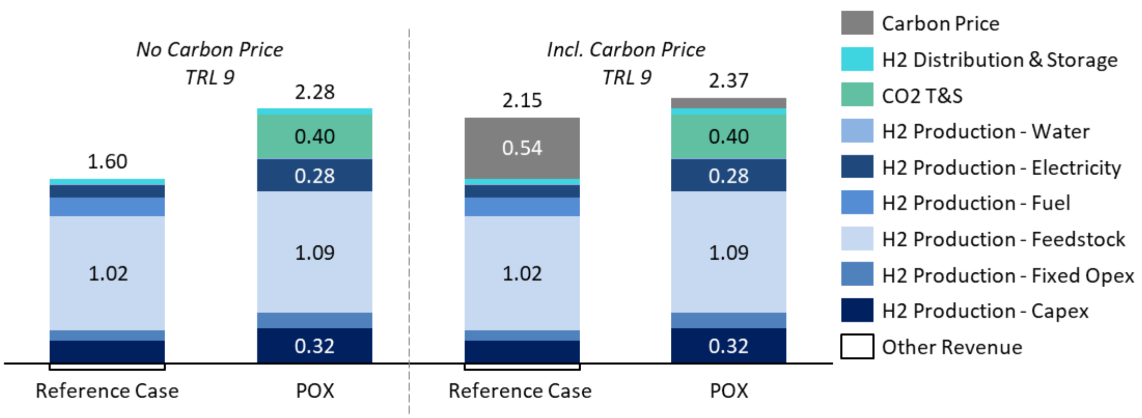


Figure 58: LCOH for POX and the reference case in the Netherlands in 2020 (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

The POX case with integrated CCS is compared against a reference SMR case without CCS as shown in Figure 58. The LCOH is shown for both cases, with and without the carbon price. The cost of CO_2 abatement for POX with CCS is also given in Table 12 with and without the carbon price. The POX case is competitive with other pathways in this analysis. This is due to the assumption that there are no scope 1 emissions[107] and the competitive feedstock consumption when compared with ATR + GHR (see the Appendices, Section 7.1, which demonstrate that POX has a lower reported fuel consumption than ATR). However, further interventions are needed to become lower cost than the reference case.

Table 12: Cost of CO_2 abatement for POX in the Netherlands in 2020

Variable	Units	POX Without Carbon Price	POX With Carbon Price
Lifetime Emissions	*$ktCO_2$*	3,836	
Lifetime H_2 Production	*ktH_2*	1,972	
LCOH	*€ / kgH_2*	2.28	2.37
Cost of CO_2 Abatement	*€ / tCO_2*	76.63	25.73

A breakdown of the LCOH for the POX with CCS case is displayed in the waterfall chart in Figure 59. The most significant cost components in the POX case are the cost of the feedstock, CO_2 T&S and, to a lesser extent,

[107] Due to the 100% capture rate; emissions are only accounted for in feedstock, electricity carbon intensity and CO_2 T&S

the plant CAPEX. Combined, these cost components account for 77% of the total LCOH. Cost reductions for these cost components are therefore needed to reach parity in the absence of additional regulation and policy interventions. As for the ATR case, the replacement of natural gas with oxygen as the fuel for the reaction increases the electricity demand, when compared with SMR, due to the need to power the ASU. Hydrogen production costs account for over 77% of the total LCOH. The cost of CO_2 abatement and carbon price account for 17% and 4% respectively, with hydrogen distribution forming a minor 2% of the total LCOH.

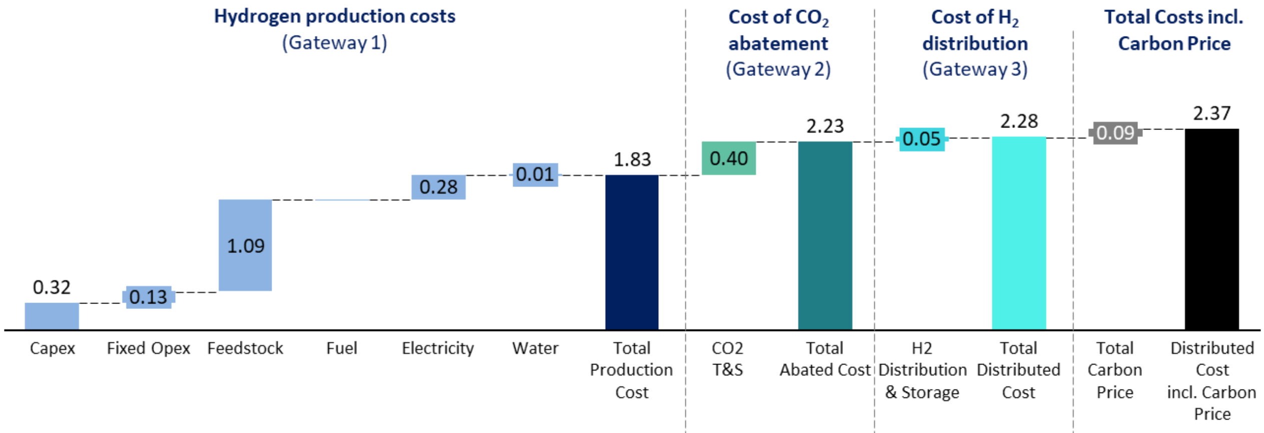


Figure 59: LCOH for POX with CCS in the Netherlands in 2020 in the central case (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

The impact of varying each cost component by the specified sensitivity on the LCOH is displayed by the tornado chart in Figure 60. The only cost components which are varied greater than 10% are the CO_2 T&S and the carbon price. The impact of the carbon price variation is the smallest out of all technologies analysed due to there being no scope 1 emissions. The CO_2 T&S infrastructure cost is one of the most impactful cost components due to the associated uncertainty. This is followed by the feedstock since this constitutes a large fraction of the overall LCOH. In all cases, the variation of the cost component does not change the LCOH by more than +/- 7%. Variation to the CAPEX, fixed OPEX, electricity demand, water and hydrogen distribution and storage has a cumulative impact of +/- 3.4% on the LCOH.

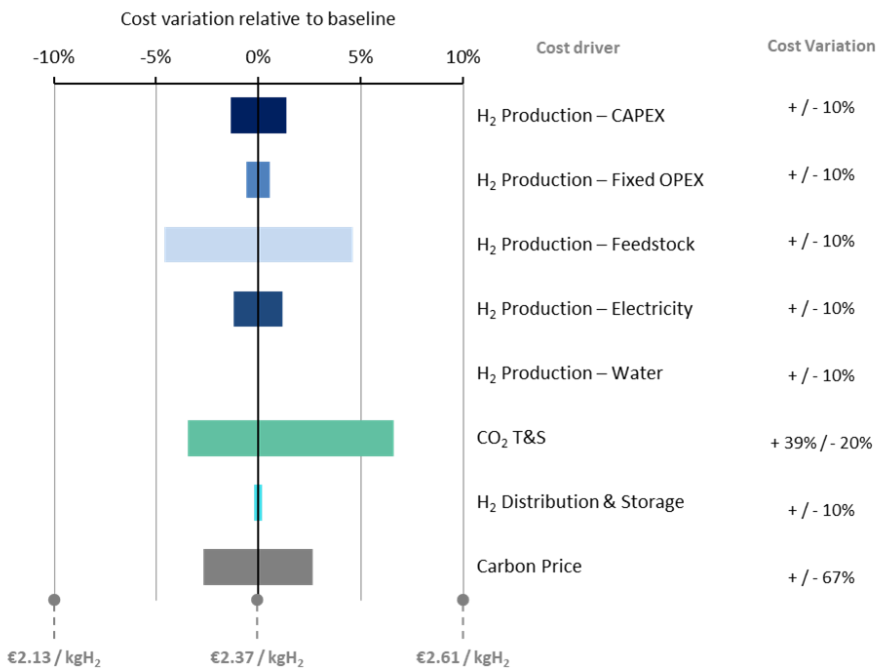


Figure 60: Sensitivity on the LCOH for POX with CCS in the Netherlands in 2020 in the central case (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

2050 Scenario

The POX case with integrated CCS is compared against the reference SMR case without CCS as shown in Figure 61. The LCOH is shown for both cases, with and without the carbon price. An additional case is also shown where the learning rate is 20%. The abated cost of CO_2 for POX with CCS is also given in Table 13 with and without the carbon price (for 5% learning rate). The assumption that the grid now has a carbon intensity the same as renewable electricity today means that POX has the lowest lifetime emissions of all technologies considered in this study. The exposure of POX to variations in the capture rate is discussed in the conclusions.

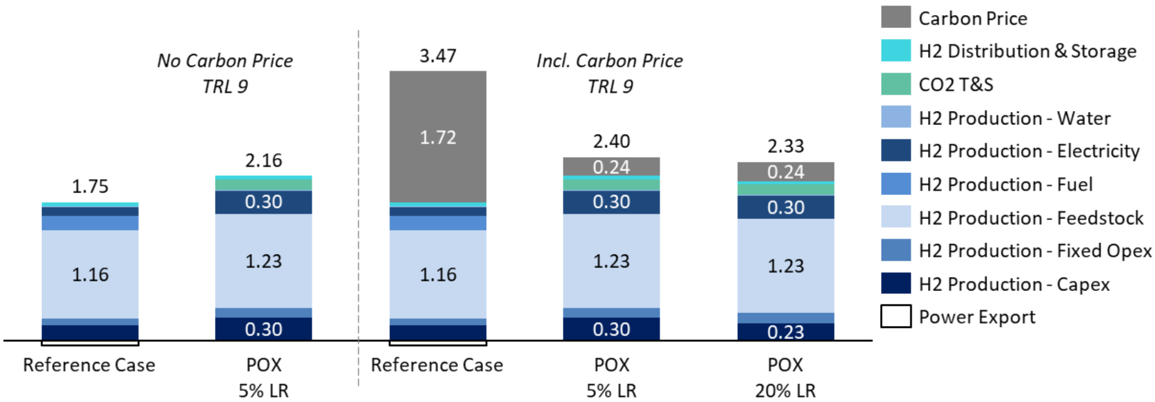


Figure 61: LCOH for POX and the reference case in the Netherlands in 2050 for learning rates (LR) of 5% and 20% (€/kgH_2) ***CO_2 Price in the Netherlands in 2050 - €162.46/tCO_2***

Table 13: Cost of CO_2 abatement for POX in the Netherlands in 2050

Variable	Units	POX Without Carbon Price	POX With Carbon Price
Lifetime Emissions	*ktCO_2*	2,962	
Lifetime H_2 Production	*ktH_2*	1,972	
LCOH	*€ / kgH_2*	2.16	2.40
Cost of CO_2 Abatement	*€ / tCO_2*	59.88	-

4.2.4 Electrified Steam Methane Reforming

The ESMR case with integrated CCS is compared against a reference SMR case without CCS as shown in Figure 62. The LCOH is shown for both cases, with and without the carbon price. The cost of CO_2 abatement for ESMR with CCS is also given in Table 14 with and without the carbon price.

The cost and process data used for this technoeconomic analysis is largely based on assumptions derived from laboratory data, stakeholder guidance and drawing parallels with SMR with CCS. This is further discussed in the Appendices, Section 7.3.1. As a result, it should be recognised that the results of this analysis carry greater degrees of uncertainty when compared with the other analysis carried out in this report. To highlight this, the technology TRL is highlighted in all figures.

Two cases for ESMR are presented, one where the carbon intensity of the electricity follows the grid's trajectory and the other where the electricity supply is from renewable energy sources. These are considered as the technology developer has the aim of reducing emissions where it is possible to access renewable electricity via direct connections to renewable energy sources or purchasing green purchase power agreements. This has no impact on the cost of the electricity in this analysis. The renewable electricity reduces the carbon price by 42%. However, as this is a minor cost component, the LCOH is only reduced by €0.06/kg (2%). The bigger impact is on the abated cost. The renewable electricity reduces the abated cost by 16% (without carbon price) providing the largest reduction in abated cost of CO_2 for the 2020 time period.

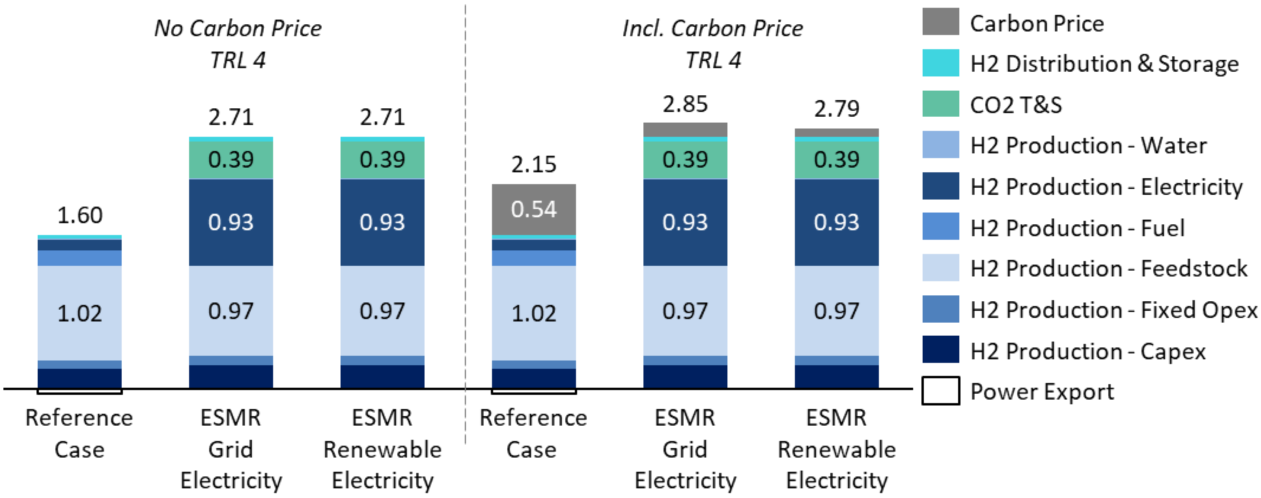


Figure 62: LCOH for ESMR and the reference case in the Netherlands in 2020 (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

Table 14: Abated cost of CO_2 for ESMR in the Netherlands in 2020

Variable	Units	ESMR Without Carbon Price	ESMR With Carbon Price	ESMR Without Carbon Price	ESMR With Carbon Price
Electricity Carbon Intensity Type	-	Grid		Renewable	
Lifetime Emissions	*ktCO_2*	6,096		3,279	
Lifetime H_2 Production	*ktH_2*	1,972			
LCOH	*€ / kgH_2*	2.71	2.85	2.71	2.79
Cost of CO_2 Abatement	*€ / tCO_2*	144.45	92.44	121.72	71.23

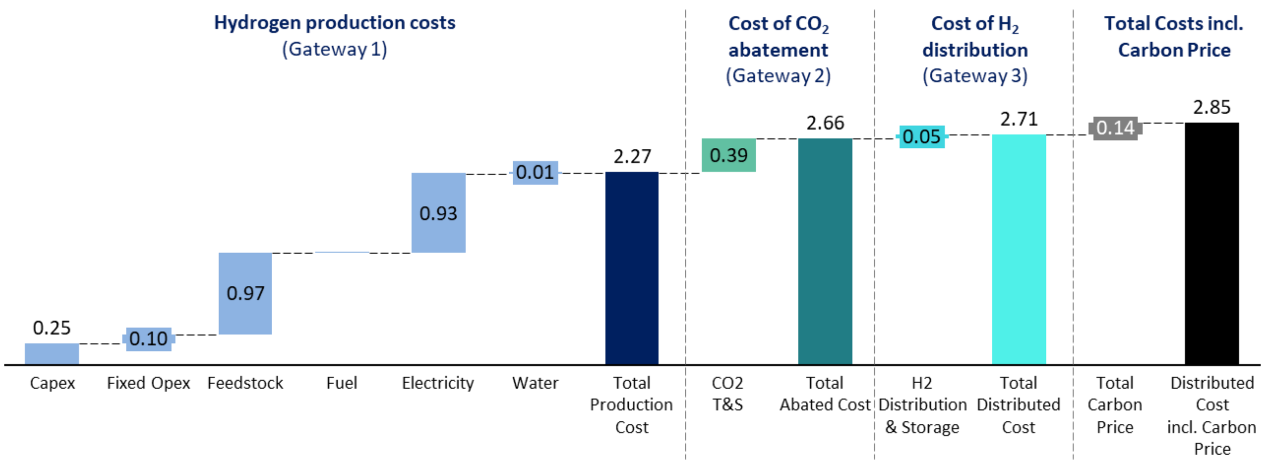


Figure 63: LCOH for ESMR with CCS in the Netherlands in 2020 in the central case (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

A breakdown of the LCOH for the ESMR with CCS case is displayed in the waterfall chart in Figure 64. The most significant cost components in the ESMR case are the cost of the feedstock, CO_2 T&S and electricity. Combined, these cost components account for over 80% of the total LCOH. Cost reductions for these cost components are therefore needed to reach parity in the absence of additional regulation and policy interventions. As expected, the cost of electricity for this production process is the most significant of the production technologies explored in this study. This exposes the technology to the highest LCOH as the cost of electricity is greater than the cost of natural gas in the Netherlands. Cheaper renewable power will significantly impact the LOCH of this technology.

The impact of varying each cost component by the specified sensitivity on the LCOH is displayed by the tornado chart in Figure 64. The feedstock, electricity, CO_2 T&S and carbon price sensitivities are all of the same order of magnitude in terms of their impact on the LCOH. The other processes considered in this analysis only have three cost components which impact the LCOH in this way. This increases the levels of risk for this technology as small increases in price for any of these four cost components have greater impacts on the delivered LCOH.

However, small decreases in these areas will also quickly accumulate to reduce the LCOH to be competitive with other blue hydrogen technologies. As for the other processes, the variation in CAPEX, fixed OPEX and hydrogen distribution & storage costs have a minimal impact on the LCOH in this scenario.

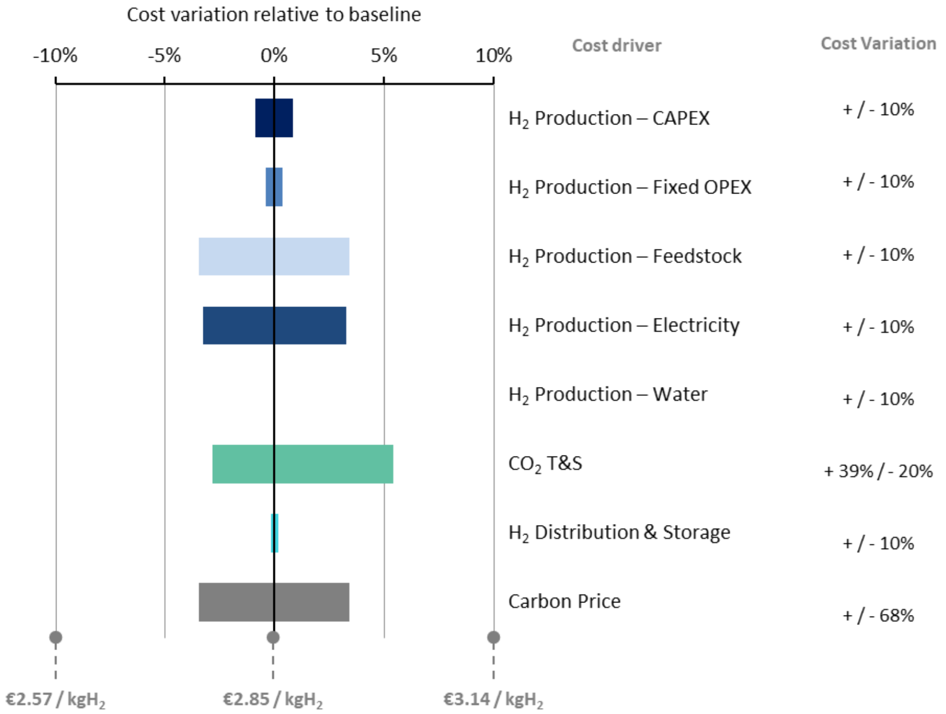


Figure 64: Sensitivity on the LCOH for ESMR with CCS in the Netherlands in 2020 in the central case (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

2050 Scenario

The ESMR case with integrated CCS is compared against the reference SMR case without CCS as shown in Figure 65. The LCOH is shown for both cases, with and without the carbon price. An additional case is also shown where the learning rate is 20%. The abated cost of CO_2 for ESMR with CCS is also given in Table 15 with and without the carbon price (for 5% learning rate). In 2050, our model assumes that the carbon intensity of the grid is the same as a renewable electricity supply. Hence, only one case is considered. The LCOH for ESMR is still the greatest of the technologies considered due to the high price of the electricity.

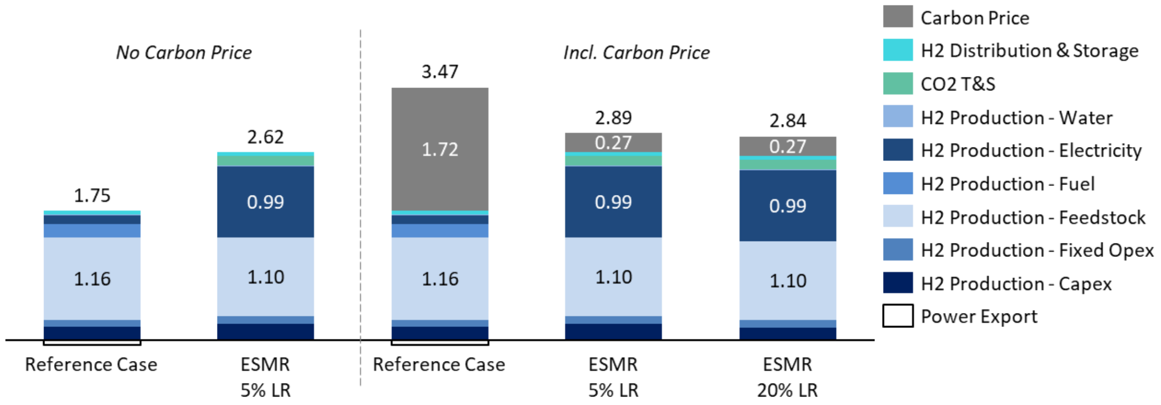


Figure 65: LCOH for ESMR and the reference case in the Netherlands in 2050 for learning rates (LR) of 5% and 20% (€/kgH_2) *CO_2 Price in the Netherlands in 2050 - €162.46/tCO_2*

Table 15: Cost of CO_2 abatement for ESMR in the Netherlands in 2050

Variable	Units	ESMR Without Carbon Price	ESMR With Carbon Price
Lifetime Emissions	*ktCO_2*	3,279	
Lifetime H_2 Production	*ktH_2*	1,972	
LCOH	*€ / kgH_2*	2.62	2.89
Cost of CO_2 Abatement	*€ / tCO_2*	112.09	-

5 Life Cycle Assessment

This section presents the methodology and environmental footprint results from CE Delft's LCA of the natural gas-based blue hydrogen production scenarios (including the benchmark – SMR without CCS), as defined in Section 3.

The LCA methodology is described in Section 5.1, the life cycle inventory data is discussed in Section 5.2 and the results of the impact assessment are discussed in Section 5.3. In Section 5.4, the LCA results in this study are compared with the parallel study done on oil-based and alkaline electrolysis hydrogen production routes. In Section 5.5, the uncertainties and limitations of this LCA are discussed.

5.1 LCA Methodology

The LCA methodology is used to determine the impact of a product or service on the environment throughout the entire life cycle. It is used to compare the environmental impact of different products or services that fulfil the same function.

This report contains a (screening[108]) LCA of the four different natural gas-based hydrogen production scenarios as well as of the benchmark. Natural gas-based SMR without CCS is chosen as the benchmark grey hydrogen technology, as this is currently the most common production process for hydrogen. The following scenarios are analysed, as described in Section 3:

- Benchmark: SMR without CCS
- SMR with CCS
- ATR +GHR with CCS
- ESMR with CCS
- POX using natural gas with CCS

All scenarios are investigated for the Netherlands.

This study is carried out in line with the ISO 14040/44 norms which provide the principles, guidelines and framework for LCA's. SimaPro (v9.1.1.1) software was used to model the scenarios and carry out the LCAs. This section describes the methodological choices of the LCA.

5.1.1 Goal and Scope Definition

Goal

The goal of this LCA study is to provide insight into the carbon footprints of four different natural gas-based hydrogen production scenarios (listed in Section 5.1) and compare these to a benchmark scenario (SMR without CCS). All scenarios and the benchmark are analysed as being located in the Netherlands.

Scope

Functional Unit

When comparing different scenarios, the basis of that comparison needs to be the same for each scenario. Therefore, a functional unit is defined which serves as the basis upon which the analysis of each of the hydrogen production scenarios is carried out.

The functional unit used in this study is: the production of 1 kg of hydrogen (H_2) compressed to 200 bar with a minimum purity of 97%. The hydrogen pressure is specified as 200 bar[109]. The rationale behind the hydrogen purity specification is described in Section 3.

[108] The screening LCA only applies to ESMR and POX. Please see Section 5.1.4 for more information on why these technologies are considered 'screening' LCA's.
[109] As defined by Valente et al 2017, Harmonised life-cycle global warming impact of renewable hydrogen

System Boundaries

The system boundaries describe which process steps as well as associated inputs and outputs related to the functional unit are included in the LCA.

In this study, cradle-to-gate system boundaries are used, in line with the LCA methodology for hydrogen production proposed by Valente et al[109], as shown in Figure 66. The cradle-to-gate system boundaries include all process steps from the extraction of the raw materials up to and including the production of compressed hydrogen[110]. This means that all processes that are required to produce (200 bar, >97% purity) hydrogen and to transport and store (part of) the captured CO_2 using CCS are considered (e.g. production of required fuel, feedstock and electricity).

The capital goods of the foreground system (i.e. equipment/infrastructure required in the hydrogen production facility) are not included in the scope of this LCA as these usually have a negligible share in the total carbon footprint of hydrogen production[111].

Capital goods are included in the background processes in the LCA database (Ecoinvent v3.6). These capital goods include, for example, the construction of pipelines and ships for transport and storage of CO_2, and the production of power plants and windmills for electricity production.

A cradle-to-gate system boundary stops at the ‘gate’ of the production facility. Therefore, transportation of hydrogen from the producer to the consumer, any additional hydrogen purification steps required for specific applications, consumption of the hydrogen and end-of-life treatment of hydrogen are not accounted for in this analysis.

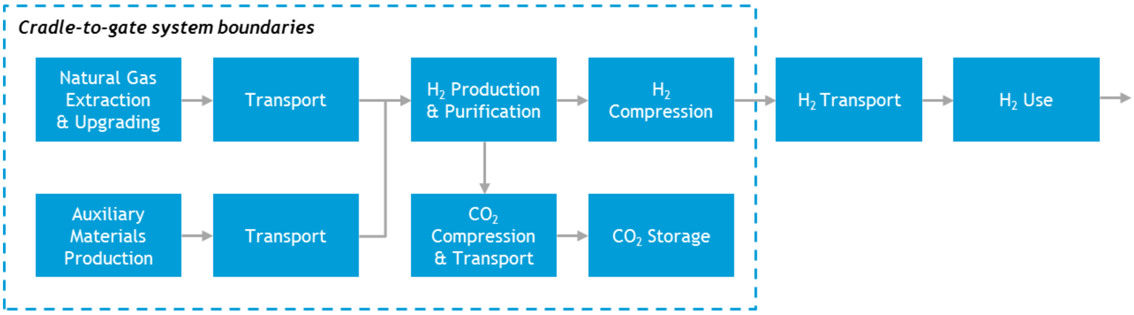


Figure 66: Cradle-to-gate system boundaries of hydrogen production from natural gas

Technological, Geographical and Temporal Scope

The technological, geographical and temporal scope of the LCA performed in this study are as follows:

- **Technological scope:** The technological specifications and assumptions for each of the analysed scenarios, including CCS, are given in Section 7.1. Not all technologies have the same TRL (as described in Section 3). In Section 5.5.2, the uncertainties involved with data collection of technologies with a low TRL are discussed in more detail. For electricity production, the average mix of the grid is used.

- **Temporal scope:** The hydrogen production scenarios are modelled for the current situation (2020). Additionally, a sensitivity analysis evaluates the effects of deploying the technologies in 2030 by modelling the expected electricity mix (and related carbon footprint) for 2030 (see Section 5.3.3). For CCS, it is assumed the captured CO_2 is stored underground for more than 100 years. According to the ILCD guidelines[112], the EU standard for LCAs, if CO_2 is stored underground for more than 100 years, the stored CO_2 leads to a CO_2 emission reduction[113]. As it is assumed that this is the case for CCS, CO_2 emission reduction can be applied.

[110] It is assumed that the H_2 is compressed at the H_2 production facility.
[111] Antonini et al 2020, Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis
[112] IPCC also generally uses a 100-year time horizon when calculating carbon footprints.
[113] ILCD 2010, ILCD Handbook - General guide on LCA - Detailed guidance (europa.eu)

- **Geographical scope:** As mentioned in the introduction of Section 5.1, the Netherlands is the location for which each of the scenarios is analysed. The data used for the assessments is – where available – country/region specific (e.g. for the carbon footprint of the electricity production, the Dutch electricity mix is used).

5.1.2 Environmental Impact Categories

LCAs can be used to calculate a range of different environmental impacts. This study focusses on the global warming potential (i.e. carbon footprint) of the selected production scenarios. The carbon footprint is expressed in kg CO_2 equivalents (eq.)/kg H_2.

Additionally, to show possible environmental trade-offs between carbon footprint and other impact categories, the LCA results for other environmental impact categories are provided in the Appendices, Section 7.1. The following impact categories are included there:

- Acidification
- Human toxicity (cancer effects)
- Human toxicity (non-cancer effects)
- Ozone depletion
- Particulate matter
- Ionising radiation human health
- Ionising radiation ecosystems
- Photochemical ozone formation
- Terrestrial eutrophication
- Freshwater eutrophication
- Marine eutrophication
- Freshwater ecotoxicity
- Land use
- Mineral, fossil and renewable resource depletion
- Water resource depletion
- Cumulative non-renewable energy demand

The following life cycle impact assessment methods[114] are used to calculate the results:

- Carbon footprint: IPCC 2013 GWP 100a V1.03;
- Cumulative energy demand: Cumulative Energy Demand V1.11;
- Other environmental impact categories: ILCD 2011 Midpoint+ V1.11 / EC-JRC Global, equal weighting.

5.1.3 Multifunctionality and Allocation

Next to production of the main desired product, some processes could also produce other products called co-products. When conducting an LCA for such multifunctional processes (e.g. when H_2 is a co-product in the chlor-alkali process), the carbon footprint of the production process has to be distributed between the different products. The ISO LCA standards specify different ways of 'solving multifunctionality', including subdivision, system expansion and allocation.

In this study, however, no co-products are produced and so there is no need to model any system expansion or allocation[115].

[114] In these impact assessment methods, hydrogen emissions do not contribute to global warming. Recent research suggests hydrogen does contribute to global warming, however this has not (yet) been adopted in common LCA methods.
[115] Some of the technologies analysed in this study produce steam and/or electricity. However, as these are used within the system itself, these are not considered co-products.

5.1.4 Data Collection, Quality and Uncertainties

The data collection and selection for the LCA, involving extensive literature review and stakeholder interviews, is described in Section 3. The quality and uncertainty associated with the selected data is described in Section 7.1.

The data quality of the benchmark (SMR without CCS), SMR + CCS and ATR + GHR + CCS is very high because of high TRL and excellent data availability, as described in Section 3. The same section explains that ESMR has a low TRL and that for both ESMR and POX, data availability is comparatively poor. Consequently, the LCAs of these technologies are relatively uncertain and difficult to verify. Therefore, the LCAs of ESMR and POX are considered to be screening LCAs. The term ‘screening LCA’ is used because of the relative uncertainty (see Section 5.5.2). The methodology and analysis remain exactly the same for all of the LCAs.

The collected data provided in Section 7.1 is combined with the environmental (background) data from the Ecoinvent v3.6 LCA database unless more recent/accurate data is available. The Ecoinvent/alternative LCA background data used for modelling is listed in the Appendices, Section 7.4.

5.1.5 Sensitivity Analyses

The results of an LCA depend on choices and assumptions made regarding the methodology and (process and background) data. To investigate the sensitivity of the results to these choices and assumptions, sensitivity analyses are conducted. The sensitivity analyses carried out in this study are given in Table 16.

Additionally, the effect of other important assumptions made in this study are addressed qualitatively in Section 5.5 ‘Uncertainties’.

Table 16: Sensitivity analyses for each of the natural gas-based blue hydrogen production scenarios

Hydrogen production scenario	Sensitivity analyses
SMR	- Electricity mix and carbon footprint in 2030 instead of 2020 - All natural gas imported from Algeria - All natural gas imported from Russia - Carbon capture rate of 99% instead of 90%
ATR	- Electricity mix and carbon footprint in 2030 instead of 2020 - All natural gas imported from Algeria - All natural gas imported from Russia
e-SMR	- Electricity mix and carbon footprint in 2030 instead of 2020 - All natural gas imported from Algeria - All natural gas imported from Russia
POX	- Electricity mix and carbon footprint in 2030 instead of 2020 - All natural gas imported from Algeria - All natural gas imported from Russia

5.2 Life Cycle Inventory

The life cycle inventory describes how the different hydrogen production scenarios are modelled in the LCA, for instance in terms of the process data implemented and background datasets used.

The inventory data and assumptions of the hydrogen production scenarios used to model the LCAs can be found in the Appendices, Section 7.1. The inventory data and assumptions for CO_2 T&S and compression of hydrogen can be found in the Appendices, Section 7.2.6 and 7.2.7, respectively. Additionally, the carbon footprint of feedstock and electricity production and conversion factors used for modelling can be found in the Appendices, Section 7.3.3.

5.3 LCA Results

In this section the results of the life cycle assessments and sensitivity analyses are presented. Section 5.3.1 explains how the results of the LCAs are presented using a waterfall chart. Section 5.3.2 shows and analyses the carbon footprint results of the life cycle assessments of all of the natural gas-based blue hydrogen technologies and the benchmark. Finally, Section 5.3.3 investigates the sensitivities of the results of the LCAs in the aforementioned sensitivity analyses.

This section focuses on the carbon footprint of the different technologies. Section 7.1 in the Appendices presents the effects of the hydrogen technologies on a selection of other environmental impact categories.

5.3.1 Example: Presentation of the LCA Results

This section explains how the results of the LCAs of the different blue hydrogen technologies are presented. One stacked bar graph is given to show the carbon footprint for each blue hydrogen production technology. The bar is split into different segments which represent the carbon footprint of different system inputs and outputs. These contribute to the total carbon footprint. This is called a contribution analysis.

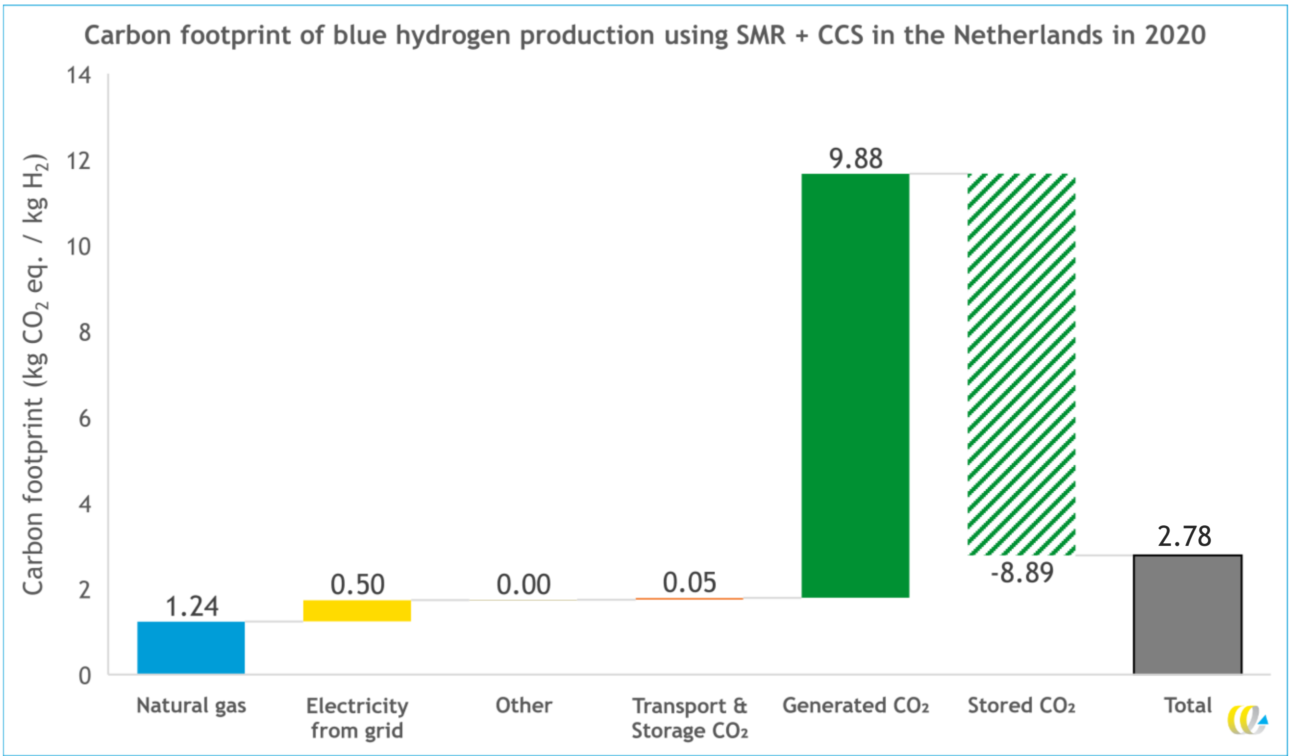


Figure 67: Explanatory waterfall chart on the presentation of the LCA results. The colours of the bars coincide with the colours used in stacked bar graphs below (e.g. Figure 68).

By presenting the results in this way, a better understanding is gained on which parts of the hydrogen production scenario contribute the most to the carbon footprint. Additionally, these results help in deciding where the main focus should be when aiming to reduce the carbon footprint.

Figure 67 is an explanatory waterfall chart in which the bar chart carbon footprint of one scenario (SMR + CCS) is broken down. In this example, the categories contributing to the total carbon footprint are:

- natural gas as the feedstock and fuel (including carbon footprint of the production and transport of natural gas);
- electricity from the grid;

- other (includes tap water and wastewater treatment);
- CO_2 T&S;
- generated CO_2; and
- stored CO_2.

The first five of these categories add up to a carbon footprint of 11.67 kg CO_2 eq./kg H_2. However, as a significant fraction of the generated CO_2 is stored, the category 'Stored CO_2' is subtracted from this footprint. This adds up to a total carbon footprint of 2.78 kg CO_2 eq./kg H_2.

5.3.2 Carbon Footprint of Natural Gas-Based Blue Hydrogen Technologies (2020)

In Figure 68 the contribution analyses of the carbon footprints for each of the studied natural gas-based blue hydrogen production scenarios are presented[116]. A table with these results is provided in the Appendices, Section 7.6.2. Below Figure 68 a more detailed description of the results is given.

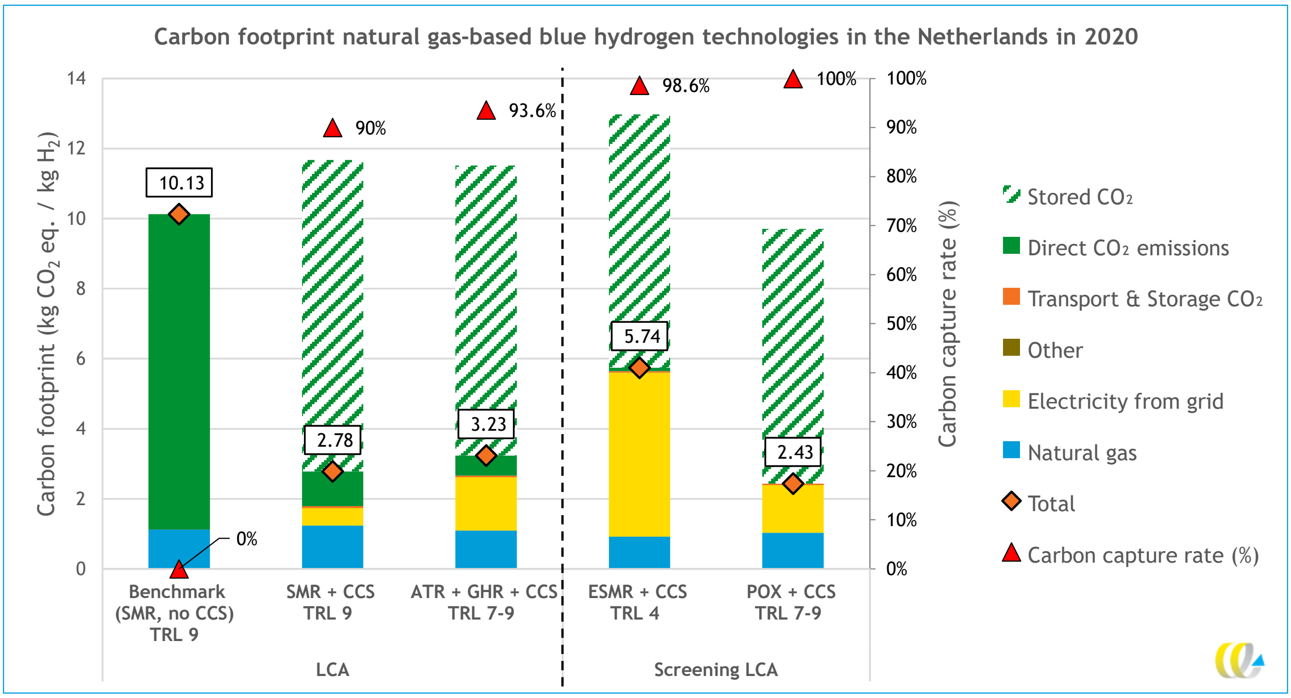


Figure 68: Contribution analysis of the carbon footprint of four natural gas-based blue hydrogen production scenarios and the grey hydrogen benchmark.[117]

Several aspects stand out in the overall carbon footprints of the different technologies. First of all, all of the blue hydrogen technologies produce hydrogen with a (significantly) lower carbon footprint than the grey hydrogen benchmark: a reduction of the carbon footprint ranging between 43-76% can be achieved in 2020.

The carbon footprints of blue hydrogen produced using SMR, ATR + GHR and POX are comparable, with POX achieving the best result. Blue hydrogen produced using ESMR has the highest carbon footprint. This latter result is the most uncertain, as the technology has a low TRL and a comparatively poor data availability. The relatively high carbon footprint of ESMR hydrogen is mainly caused by the electricity use, which is larger than that for the other technologies since electricity is used instead of natural gas to heat the reactor. Due to the high electricity use, the carbon footprint of ESMR hydrogen is highly dependent on the carbon footprint of electricity generation. For this analysis, the 2020 Dutch electricity grid mix was used. The share of renewably generated electricity is expected to increase in the coming years, leading to a decreased carbon footprint. To

[116] See Section 5.3.1 for an explanation about this method of presenting the LCA results
[117] 'Other' includes tap water and water treatment. 'Electricity' includes electricity used for H_2 production and compression, as well as electricity generation and O_2 production (ATR with GHR, POX).

investigate this, a sensitivity analysis was carried out in which all technologies are analysed with the expected Dutch electricity mix in 2030 (see Section 5.3.3).

The carbon footprint share of natural gas use (dark blue in Figure 68) is comparable for each of the blue hydrogen technologies. This only includes the production and transport of natural gas. For ESMR, this share is slightly lower as less natural gas is required for this technology as heat is generated using electricity.

In the sections below, a more detailed description of the results per hydrogen production scenario is given.

Benchmark – Steam Methane Reforming (without CCS) in the Netherlands (TRL 9)

- The carbon footprint of grey hydrogen produced using SMR in the Netherlands, is 10.13 kg CO_2 eq./kg H_2.
- Direct CO_2 emissions account for the largest share of the carbon footprint of the benchmark. These include both reaction emissions and emissions related to combustion of natural gas to heat the process.
- The category 'Other' includes tap water and wastewater treatment. The combined carbon footprint of this category is negligible compared to the impact of the other categories.
- The net electricity (electricity used minus electricity generated) is 0 kWh/kg H_2. Therefore, electricity does not contribute to the total carbon footprint.

Steam Methane Reforming with Carbon Capture and Storage (TRL 9)

- The carbon footprint of hydrogen produced using SMR + CCS in the Netherlands, is 2.78 kg CO_2 eq./kg H_2. This is a 73% reduction of the carbon footprint of the benchmark.
- Natural gas (production and transport) accounts for the largest contribution to the carbon footprint.
- As the carbon capture rate of SMR + CCS is modelled to be 90% (and consequently not all CO_2 is captured and stored), the direct CO_2 emissions still account for a large share of the carbon footprint. These include both reaction emissions and emissions related to combustion of natural gas to heat the process.
- The category 'Other' includes tap water and wastewater treatment. The carbon footprint of this category is negligible compared to the impact of the other categories.
- CO_2 T&S has a minor contribution to the carbon footprint.

Autothermal Reformation with GHR with Carbon Capture and Storage (TRL 7-9)

- The carbon footprint of hydrogen produced using ATR + GHR + CCS in the Netherlands, is 3.23 kg CO_2 eq./kg H_2. This is a 68% reduction of the carbon footprint of the benchmark.
- Electricity use accounts for the largest contribution to the carbon footprint. This includes electricity needed to run the ATR plant and H_2 compression. Additionally, it includes O_2 production using an ASU. Natural gas (production and transport) has the second largest contribution to the carbon footprint.
- As the carbon capture rate of ATR + GHR + CCS is modelled to be 94% (and consequently not all CO_2 is captured and stored), the direct CO_2 emissions still account for a share of the carbon footprint. These include both reaction emissions and emissions related to combustion of natural gas to heat the process.
- The category 'Other' includes tap water. The carbon footprint of this category is negligible compared to the impact of the other categories.
- CO_2 T&S has a minor contribution to the carbon footprint.

ESMR with Carbon Capture and Storage (TRL 4)

- The carbon footprint of hydrogen produced using ESMR + CCS in the Netherlands, is 5.74 kg CO_2 eq./kg H_2. This is a 43% reduction of the carbon footprint of the benchmark.
- Electricity use accounts for the largest contribution to the carbon footprint. This includes electricity needed to run the ESMR plant and for H_2 compression. The reason for the high contribution of

electricity (and relatively low contribution of natural gas) is that in an ESMR plant, heat is generated using electricity instead of natural gas. As a result, the carbon footprint of hydrogen produced in an ESMR unit strongly depends on the carbon footprint of the electricity production. In this study the current (2020) average electricity mix is used for the Netherlands. In a sensitivity analysis in Section 5.3.3, the carbon footprint is analysed with the expected Dutch electricity mix in 2030, containing a higher share of renewable electricity.

- As the carbon capture rate of ESMR + CCS is modelled to be 98.6%, the direct CO_2 emissions have a minor contribution to the carbon footprint. This is a realistic carbon capture rate, as carbon capture from an ESMR unit can be done at an earlier stage in the process and with a higher purity, making it comparatively easy to reach a high capture rate.
- The category 'Other' includes tap water and wastewater treatment. The carbon footprint of this category is negligible compared to the impact of the other categories.
- CO_2 T&S has a minor contribution to the carbon footprint.

Partial Oxidation of Natural Gas with Carbon Capture and Storage (TRL 7-9)

General

- The carbon footprint of blue hydrogen produced using POX in the Netherlands, is 2.43 kg CO_2 eq./kg H_2. This is a 76% reduction of the carbon footprint of the benchmark.
- As the carbon capture rate of POX + CCS is modelled to be 100%, the direct CO_2 emissions have no contribution to the carbon footprint.
- Electricity use accounts for the largest contribution to the carbon footprint. This includes electricity needed to run the POX plant and H_2 compression. Additionally, it includes O_2 production using an ASU. Natural gas (production and transport) has the second largest contribution to the carbon footprint.
- The category 'Other' includes tap water and water treatment. The combined carbon footprint of this category is negligible compared to the impact of the other categories.
- CO_2 T&S has a minor contribution to the carbon footprint.

5.3.3 Sensitivity Analysis

In this study, the following sensitivity analyses have been carried out in order to assess the effects of changing key parameters on the overall carbon footprint of the different technologies:

- Sensitivity Analysis 1: For all technologies (including the benchmark), the electricity mix has been adjusted to expected mix in the Netherlands in 2030.
- Sensitivity Analysis 2: The carbon capture rate of SMR + CCS is increased from 90% to 99%.
- Sensitivity Analysis 3: All of the natural gas used is imported from:
  - Scenario 1: Algeria.
  - Scenario 2: Russia.

These results are presented in a tabular format in the Appendices, Section 7.6.2. Additionally, the effect of some other important assumptions made in this study are addressed qualitatively in Section 5.5 'Uncertainties'.

Sensitivity Analysis 1 – Carbon Footprint of Natural Gas-Based Hydrogen Technologies (2030)

As shown in the results in Section 5.3.2, the carbon footprint of electricity production can have a significant impact on the total carbon footprint of blue hydrogen. As the Netherlands has signed the Paris agreement on Climate Change, the carbon footprint of electricity production in the Netherlands is expected to change in the coming years. This will in turn affect the carbon footprint of the different natural gas-based blue hydrogen technologies and could change the conclusions drawn in the 2020 analysis. To investigate this, the expected carbon footprint of electricity production in the Netherlands in 2030 has been modelled and a sensitivity analysis of the LCA has been performed. Based on our model of the electricity mix, the carbon footprint of electricity in the Netherlands is expected to reduce by 67% between now and 2030 (see Appendices, Section 7.3.3 for the methodology).

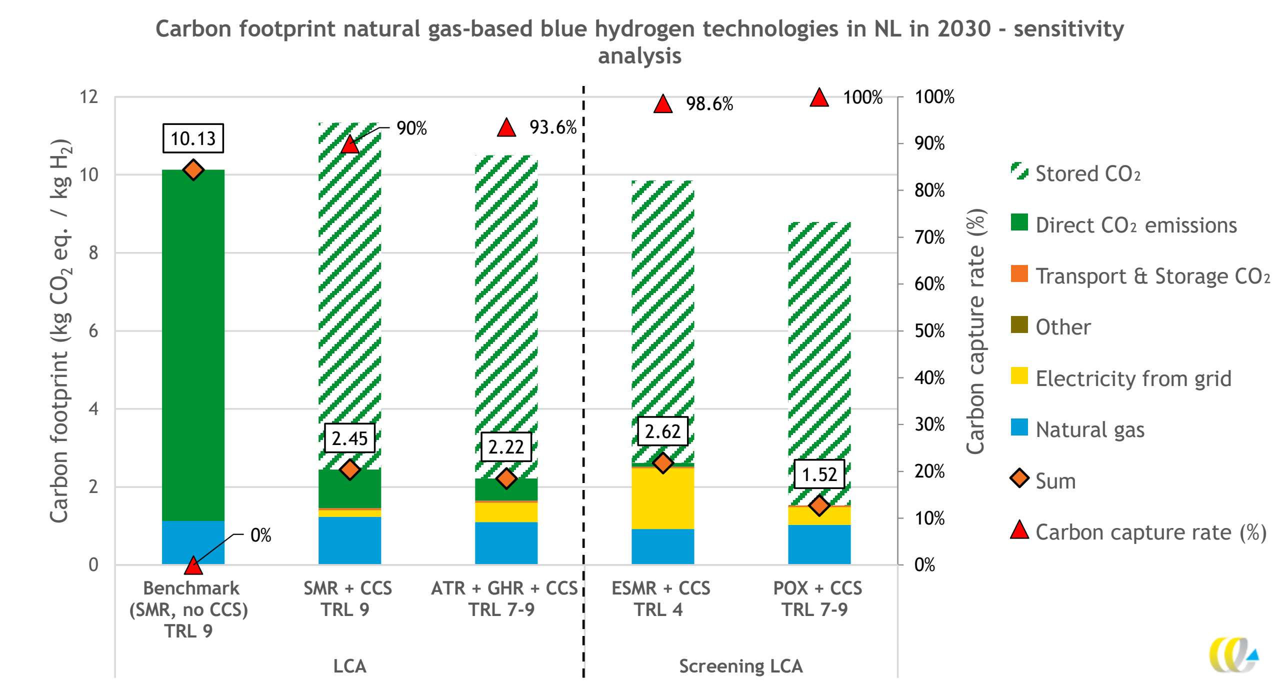


Figure 69: Sensitivity Analysis One – Carbon footprint natural gas-based blue hydrogen technologies with expected Dutch carbon footprint of electricity 2030

The results of this sensitivity analysis are presented in Figure 69. The following conclusions can be drawn from this analysis:

- As the benchmark has an electricity use of net 0 kWh/kg H_2, no change occurs in its carbon footprint. Therefore, the carbon footprints of the blue hydrogen technologies reduce further compared to that of the benchmark.
- Compared to the carbon footprint of the benchmark, the order (highest to lowest) of the carbon footprint of each technology changes: ATR + GHR now has a lower carbon footprint than SMR.
- Electricity production is a significant contributor to the total carbon footprint of (most) of the blue hydrogen production technologies in scope. The results of this sensitivity analysis show that having a sustainable electricity source is important when producing blue hydrogen.
- Even though ESMR has the largest absolute reduction compared to the analysis with the current electricity mix, the total carbon footprint of this hydrogen production scenario is still (slightly) higher than in the other scenarios. However, there still is a lot of room for improvement for this technology if the carbon footprint of electricity is further reduced (which, considering the commitment of the Netherlands to the Paris agreement, is expected to happen).
- The benchmark technology is kept at natural gas-based SMR without CCS, as this production scenario will likely still be used on a large scale in 2030.

The ESMR technology has been in part developed with the intention of connecting to renewable supplies of electricity (e.g. using solar or wind), thereby reducing the carbon footprint of electricity production significantly. If renewable electricity is used, to reduce the carbon footprint of ESMR with about 80-90% compared to the benchmark in 2020. Consideration should be given to the differences between direct connections to renewable energy generating assets and green purchase power agreements to understand the actual decarbonisation potential.

Sensitivity Analysis 2 – Steam Methane Reforming with 99% Capture Rate

As shown in the results in Section 5.3.2, the carbon capture rate has a significant impact on the total carbon footprint of blue hydrogen. To investigate the importance of the carbon capture rate, this sensitivity analysis shows the carbon footprint of SMR + CCS when the carbon capture rate is increased from 90% to 99%. As capturing more CO_2 leads to higher energy usage, an increase in the electricity consumption of the hydrogen production by 10% has been assumed. As we use an assumption for the electricity increase, this sensitivity analysis should be seen as an illustrative example. The relation between carbon capture rate increase and change in energy demand should be researched more thoroughly in further study or when designing a plant.

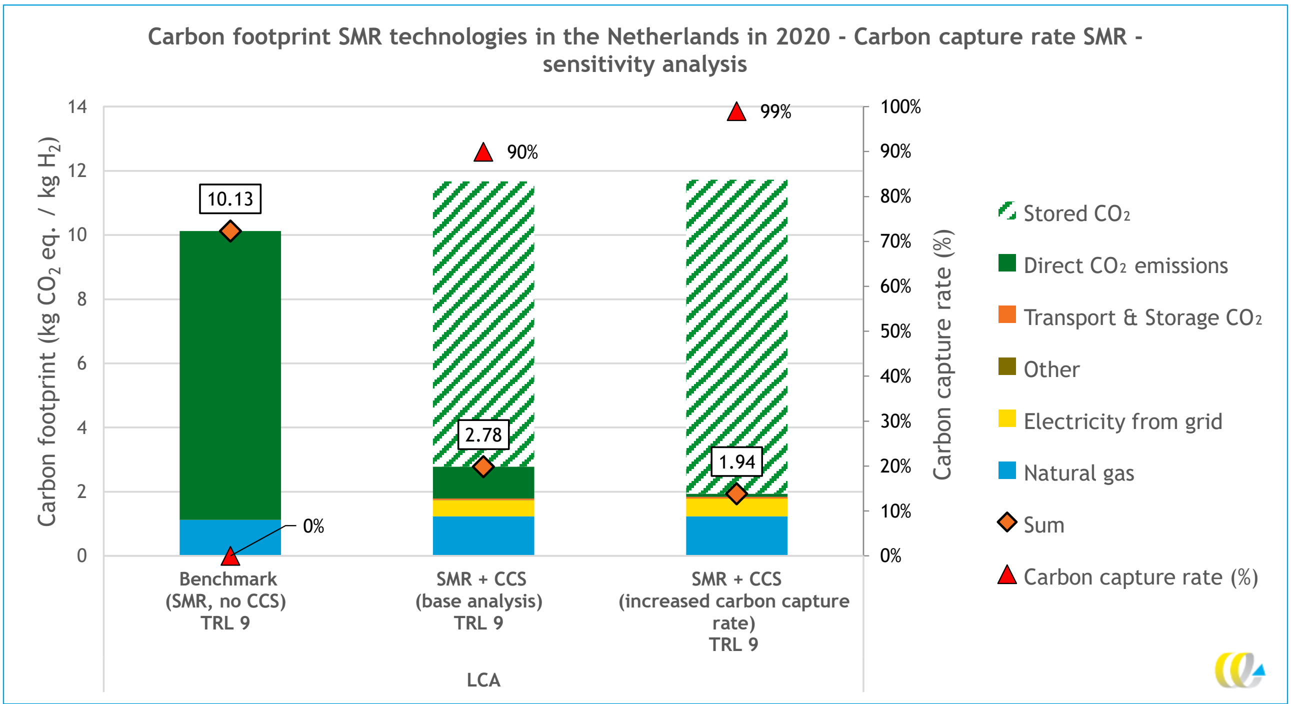


Figure 70: Sensitivity Analysis Two – Carbon footprint of blue hydrogen produced using methane reforming – carbon capture rate increased to 99%

The results of this sensitivity analysis are presented in Figure 70. The following conclusions can be drawn from this analysis:

- The carbon capture rate has significant effect on the carbon footprint of the blue hydrogen production technology SMR + CSS. The overall carbon footprint of hydrogen produced with the SMR technology is reduced by 8% when increasing the carbon capture rate from 90-99% (and assuming an increase in electricity use of 10%). This reduction is due to the direct CO_2 emissions becoming negligible.
  - This sensitivity analysis is carried out for SMR + CCS. However, changes in the carbon capture rate are possible for each blue hydrogen production technology in this study, and therefore the conclusion that changing the carbon capture rate has a significant effect on the overall carbon footprint is relevant for all blue hydrogen technologies.
- This sensitivity analysis is based on the rough estimation that an increase of the carbon capture rate from 90% to 99% leads to a 10% increase in electricity use. Even though this assumption should be assessed in more detail when designing a blue hydrogen SMR plant, it can be concluded that a higher carbon capture rate likely leads to an overall lower carbon footprint even if it increases energy (and auxiliary) use.

Sensitivity Analysis 3 – All of the natural gas used is imported from either Algeria or Russia

In the results presented in Section 5.3.2, the natural gas used in modelling the LCA was the Dutch mix as defined in Ecoinvent. This includes imported natural gas, as well as a large share of natural gas produced in the Netherlands itself. As in the near future the extraction of natural gas in the Netherlands will likely decrease, the share of imported natural gas is expected to increase. In this section, two (extreme) scenarios with imported natural gas use in the Netherlands are carried out:

- Sensitivity Analysis Three, Scenario 1: All of the consumed natural gas is imported from Algeria. (With a 29% increase of the carbon footprint of natural gas.)
- Sensitivity Analysis Three, Scenario 2: All of the consumed natural gas is imported from Russia. (With a 171% increase of the carbon footprint of natural gas.)

The results of these sensitivity analyses are presented in Figure 71 and Figure 72.

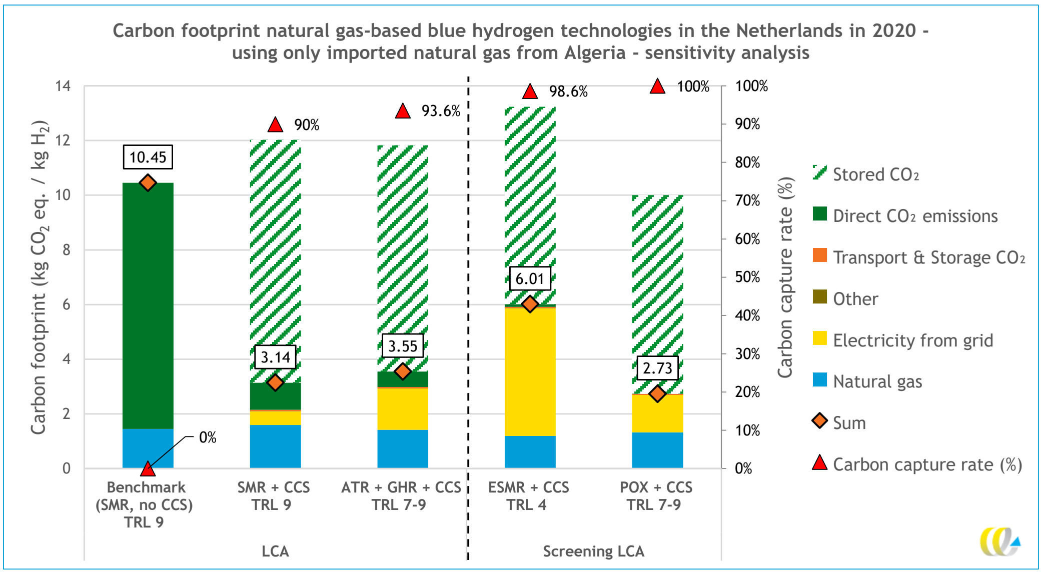


Figure 71: Sensitivity Analysis Three, Scenario 1 – Carbon footprint of blue hydrogen produced in the Netherlands, using only natural gas imported from Algeria

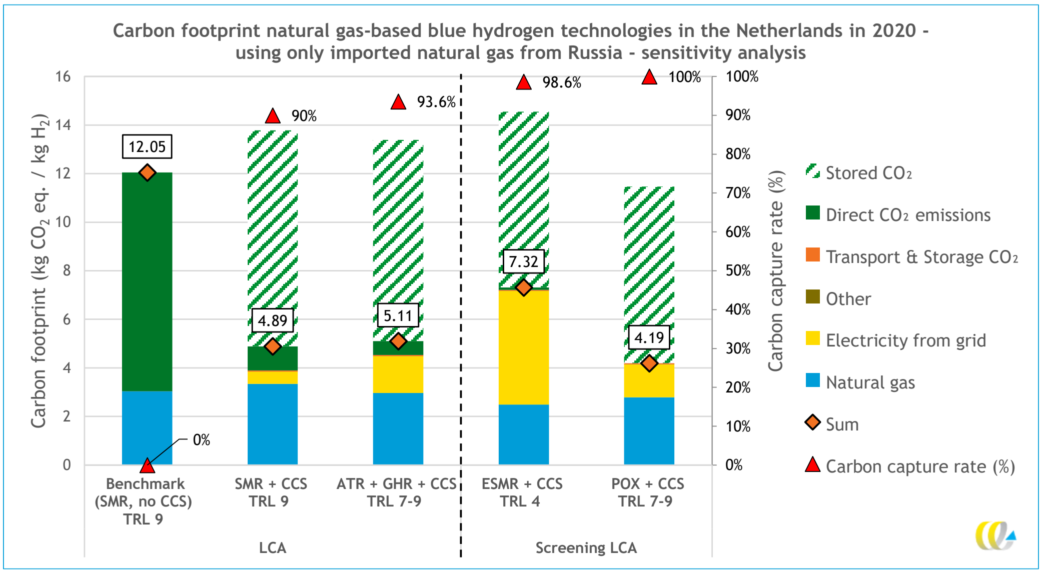


Figure 72: Sensitivity Analysis Three, Scenario 2 – Carbon footprint of blue hydrogen produced in the Netherlands, using only natural gas imported from Russia

The following conclusions can be drawn from this analysis:

- This sensitivity analysis shows that the origin of natural gas and the carbon footprint related to it can vary significantly and therefore has a big influence on the carbon footprint of the blue hydrogen technologies. The carbon footprint of all hydrogen production technologies (including the benchmark) increases when only imported natural gas from either Algeria or Russia is used. This effect is largest for Russian natural gas. The results show that for the Netherlands, a larger import share of natural gas leads to increased carbon footprints. One of the reasons for this is that further transport of natural gas is subject to more methane leakages (more information on methane leakages can be found in Section 5.5.2).
- Compared to the carbon footprint of the benchmark, the order (highest to lowest) of the carbon footprints of the technologies does not change for both scenarios.
- All blue hydrogen technologies still produce hydrogen with a (significantly) lower carbon footprint than the grey hydrogen benchmark:
    - When using only Algerian natural gas, a reduction of the carbon footprint ranging between 42-74% can be achieved in 2020. This is a slightly lower reduction compared to the base case (43-76% reduction).
    - When using only Russian natural gas, a reduction of the carbon footprint ranging between 39-65% can be achieved in 2020. This is a lower reduction compared to the base case (43-76% reduction).

5.4 Comparing results

In this section, the LCA results for gas-based blue hydrogen routes in this study are compared with the parallel study done on oil-based blue hydrogen production routes. Furthermore, the results are compared to the alkaline electrolysis production route.

5.4.1 Comparison with Parallel Study on Oil-Based Hydrogen Production Route

In the parallel study[7] similar LCAs are carried out for three different oil-based hydrogen production technologies in fifteen different countries. Even though both studies use the same LCA methodology, it is not possible to draw a direct comparison between the technologies in this study and the ones in the parallel study due to differences in region, carbon capture rate, purity of hydrogen, assumptions and uncertainties. It is, however, possible to make some cautious remarks on how the technologies in the studies compare.

- All of the studied blue hydrogen production scenarios (both oil- and natural gas-based) have significantly lower carbon footprint than the benchmark (SMR without CCS), as more than 90% of the – otherwise emitted – CO_2 is captured and stored. The blue hydrogen production technologies with a TRL of 7-9, have a carbon footprint reduction of 47%-77% compared to the benchmark, depending on the selected technology.
- All other things considered equal, hydrogen production routes that use oil as a feedstock instead of natural gas, generally have a (slightly) higher carbon footprint because of the higher carbon-to-hydrogen ratio of the oil feedstock. This is one of the reasons why for example SMR with CCS (in the Netherlands) has a 19% lower carbon footprint than SNR with CCS (in the Netherlands). Compared to the benchmark however, this difference in carbon footprint is relatively small (73% reduction for SMR+CSS and 66% reduction for SNR+CCS).
- Both the natural gas-based and oil-based hydrogen production technologies have the potential to further reduce their carbon footprint in the future, for example, by reducing the carbon footprint of electricity production. ESMR (natural gas-based) and HEE (oil-based) have the highest potential for carbon footprint reduction in the future. These technologies, however, also have the lowest TRL and, consequently, the highest uncertainties.

5.4.2 Comparison with Alkaline Electrolysis Production Route

Another hydrogen production route is the production of hydrogen using electrolysis. There are different types of electrolysis technologies, but the most common at this moment is the alkaline electrolysis. JEC reported that for this hydrogen production route, 51.4 kWh/kg H_2 is required (efficiency of 65%). Further compression to 200 bar requires an additional 1.1 kWh/kg H_2. Based on these inputs, the carbon footprint for hydrogen production via alkaline electrolysis can be calculated.

As the alkaline electrolysis process requires a large amount of electricity, the carbon footprint of 1 kg hydrogen depends on the carbon footprint of electricity production, and therefore depends heavily on the origin of electricity (fossil based, country mix or renewable electricity[118]) and period (e.g. 2020 vs 2030).

For example, renewable electricity produced from Wind & Solar in the Netherlands in 2020 has a carbon footprint of 0.0329 kg CO2 eq./kWh[119], whereas the country mix is 0.479 kg CO_2 eq./kWh[119] resulting in a carbon footprint of 1.723 and 25.06 kg CO_2 eq./kg H_2, respectively.[120]

These results show that electrolysis has the potential to reduce the carbon footprint of hydrogen production compared to benchmark by 80-90%, which is greater than most of the blue hydrogen production technologies.

5.5 Uncertainties

In this section the main limitations (Section 5.5.1) and uncertainties (Section 5.5.2) of the LCA results are discussed.

5.5.1 Limitations

- As discussed in Section 5.1.1, the **system boundaries** of the LCAs performed in this study are **cradle-to-gate**. This means it does not include the transport of hydrogen to its end-use location and the end-use itself. The reason for this is that hydrogen has many different applications: as a feedstock in industry, as an energy carrier for both heat and power production and a fuel in transport. In the present study this approach is sufficient, as the focus is on the difference between different hydrogen production technologies. If one were to compare the environmental performance of hydrogen to (conventional) alternatives in one of these specific applications, the transportation and end-use of hydrogen have to be considered as well. Additionally, depending on the purity of the hydrogen assumed for each of the technologies in the present study and requirements for different end-uses, additional purification steps might need to be included as well.
- The **capital goods of the foreground system** (i.e. equipment/infrastructure required in the hydrogen production facility) are **not included** in the scope of this LCA. Based on a comparable LCA study on blue hydrogen production[111], the carbon footprint of these capital goods is expected to be very limited.
- The **carbon capture rates** of all blue hydrogen technologies have a large impact on the overall carbon footprint. The carbon capture rate used for each of the scenarios in this study is based on publicly available data. It is not completely fair to compare different technologies with different carbon capture rates, as when designing a production scenarios, it is possible to adapt the capture rate by changing the capture technology used. A downside from increasing the carbon capture rate, is that this increases the energy demand and auxiliary usage. This trade-off is investigated in a sensitivity analysis (Section 5.3.3) where the carbon capture rate of SMR is increased from 90% to 99%.
- As discussed in Section 3, there are differences in **purity** of the produced hydrogen. Even though only hydrogen production scenarios are chosen which produce hydrogen with a purity higher than 97%, the potential difference in purity (97%-99.99%) still limits the comparability of the scenarios. However,

[118] In this study, electricity is only considered to be renewable when there is a direct link between the renewable electricity production and hydrogen production facility.
[119] CE Delft 2020, Electricity emission indicators
[120] See Appendix 9.2.8 for more information on the carbon footprint of electricity production in the Netherlands.

it is expected that the differences in purity do not significantly affect the LCA result, as additional purification steps will likely have limited effects on the LCA.

5.5.2 Uncertainties

This section lists the main uncertainties for each hydrogen production scenario and CCS. These uncertainties are mostly the result of the assumptions related to the data, as presented in the Appendices, Section 7.1.

SMR + CCS

- The data quality of this technology is very high because of high TRL and excellent data availability. No substantial uncertainties have been identified.

ATR with GHR + CCS

- As explained in the Appendices (Section 7.1), the electricity demand of an ASU for the production of 1 kg of O_2 is different in different sources, resulting in a range. The quantity used in this study is based on a recent value (representing an efficient ASU), at lower end of the range. The O_2-related electricity demand has significant impact on the carbon footprint and therefore LCA results could be an underestimation if less efficient ASUs are used.

POX + CCS

- Even though the technology has a high TRL, there is limited amount of data available as there have been few studies / deployments of dedicated hydrogen production using POX.
- It is assumed that the POX capture rate has no scope 1 emissions based on engagement with stakeholders in industry developing POX blue hydrogen production technology, i.e. no direct emissions from the process. This does not account for other emissions such as fugitive emissions, for example.

ESMR + CCS

- As this technology has a low TRL, there is limited amount of data available.
- In this study, as described in the Appendices, (Section 7.1), some of the data used to model the ESMR carbon footprint is based on using SMR + CCS as a proxy. This does introduce uncertainties, however, is an appropriate assumption due to the near-identical production configuration.

Steam methane Reforming Without CCS (benchmark)

- The data quality of the benchmark (SMR without CCS) is very high because of high TRL and excellent data availability. No substantial uncertainties have been identified.

Capturing CO_2

- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy used for the carbon capture process has been considered. Based on a comparable LCA study on blue hydrogen production[111], the carbon footprint of auxiliaries and absorbents is expected to be very limited.
- In this study, due to data availability, not all scenarios were analysed using the same carbon capture rate. As this has significant impact of the carbon footprint of the hydrogen produced, this introduces an uncertainty in the results of this study. The sensitivity of the results to changing the carbon capture rate of the SMR + CCS scenario was estimated in a sensitivity analysis (see Section 5.3.3).

CO_2 Transportation and Storage

- Pipelines are modelled as onshore pipelines in the LCA analysis. The production of offshore pipelines could result a larger carbon footprint per km pipeline. However, this assumption likely won't have a large impact on the total carbon footprint of the hydrogen production scenarios as the overall impact of CO_2 T&S is limited.

- Pipeline compressor power is a function of flow rate, pipeline utilisation, pressure drop and compressor efficiency[102]. The pipeline diameter is a function of flowrate and pipeline length. The final combination of compressor power and pipeline diameter are such that a pressure drop of 1MPa is maintained across the pipeline. As a result, the compressor power for each technology is fixed whilst the pipeline diameter varies. This is presented in the Appendices, Section 7.2.6.
- In the LCA model, the pipeline that is used for CO_2 transportation is modelled as a natural gas pipeline as the LCA database contains no information on pipelines for CO_2 transport. As the diameter and thickness of the CO_2 pipeline is different than the natural gas pipeline, the pipeline is scaled based on the differences in the area (intersection) of the pipelines. This scaling method gives a rough estimation and introduces uncertainty. However, this estimation likely won't have a large impact on the total carbon footprint of the hydrogen production scenarios as the overall impact of the CO_2 T&S is limited.

Methane leakages

- Methane leakages can occur when producing and transporting natural gas. Methane leakages are included in CE Delft's analysis based on the environmental database (Ecoinvent v3.6).
    - In this database, the methane leakages during extraction/production of natural gas from a gas field vary for each region/country. Methane leakage related to extraction/production are included in every case, however it is not always clear what value has been used exactly. For example, the Ecoinvent process for Algerian natural gas mentions leakage during respectively exploitation and production is estimated at 0.6% and 0.13% based on European sources from 1990-2000. It is not clear whether these leakage values have been used solely for methane or for all leaked compounds.
    - Additionally, the methane leakages during transport are based on the estimation that ~0.2% methane leaks per 1000 km transport via pipeline. As the natural gas (used as fuel for the oil-based blue hydrogen technologies) is imported from different countries, the methane leakage differs per country of origin.

- Currently, a lot of research is done on the amount of methane leakages involved in the production and transportation of natural gas, and some recent research suggests methane leakages to be higher than the estimate used in Ecoinvent v3.6. Additionally, the amount of methane leakage varies between locations and technologies. If methane leakage is higher than in Ecoinvent processes, this could have a substantial effect on the resulting carbon footprint of blue hydrogen production technologies which use natural gas.

6 Comparative Assessment of the Results

This final section compares the different production technologies analysed in this report as well as discussing how competitive these production methods are with alternative options. This concludes with a series of recommendations for progressing natural gas based blue hydrogen production.

6.1 Comparative Assessment of the Results

6.1.1 TEA Comparison

For the 'central case' scenarios in 2020 (outlined in detail in Section 4.2), all blue hydrogen production technologies have a higher cost than the reference grey hydrogen production case via SMR without CCS. This is shown in Figure 73 and is primarily due to the significant CO_2 T&S costs that arise from CCS projects in the early stages of development alongside the low carbon price in the Netherlands in 2020[121]. For ATR, POX and especially ESMR, the electricity costs are also significantly greater than the SMR reference case. The LCOH of blue hydrogen production technologies analysed in this study are relatively similar although there is greater variation between the individual cost components. Central costs range from €2.37 /kgH_2 (POX) to €2.85 /kgH_2 (ESMR) with significant overlap between the sensitivity bands.

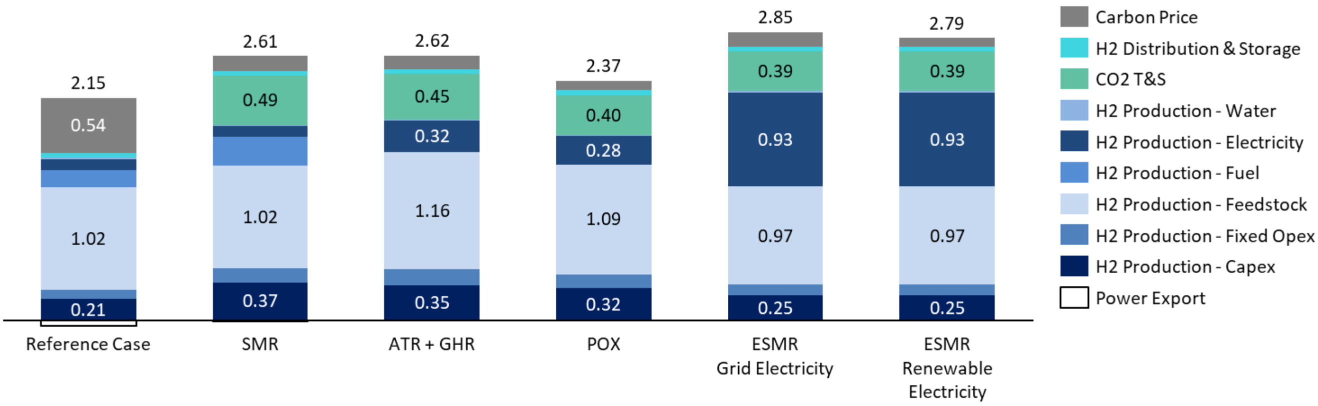


Figure 73: LCOH for natural gas based blue hydrogen production in the Netherlands compared against SMR without CCS reference case in 2020 (€/kgH2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2*

The primary costs components and uncertainty in data for each of the natural gas-based hydrogen production technologies analysed in this study is summarised below:

SMR

- SMR is most sensitive to feedstock/fuel costs and the price of CO_2 T&S. As this technology has the lowest CO_2 capture rate of the analysed technologies (90%), it is also the most sensitive to increasing carbon prices.
- SMR with CCS has been deployed successfully at scale and data reliability for this process is high.

ATR

- ATR is most exposed to feedstock costs and the price of CO_2 T&S. However, the process relies on oxygen supplied by an ASU and is therefore more sensitive to electricity costs.
- ATR with CCS is being developed for large scale projects in the UK that have undertaken detailed technical and economic analysis. Data reliability for the ATR process is therefore reasonably high.

[121] This is also the case for other industrial regions; it is not exclusive to the Netherlands.

POX

- POX is most exposed to feedstock costs and the price of CO_2 T&S. In a similar manner to the ATR process, POX relies on oxygen as a fuel source supplied by an ASU and is therefore more sensitive than SMR to electricity costs.
- POX is deployed commercially for grey hydrogen production however is yet to be integrated with CCS at scale. Data uncertainty around this process is therefore higher than for the SMR and ATR processes due to the lack of project specific analysis.

ESMR

- ESMR is exposed to feedstock and CO_2 T&S costs, however it is also the most sensitive of the analysed technologies to electricity costs.
- ESMR is currently at TRL 4 and is yet to be demonstrated successfully as a large-scale hydrogen production technology. Data uncertainty for the ESMR process is therefore the highest of the technologies analysed in this study.

The situation in 2050 is very different, as shown in Figure 74. The reference case SMR without CCS is significantly impacted by the higher carbon prices in the Netherlands and the analysed blue hydrogen production technologies have a 17% to 31% lower LCOH. The cost of CO_2 T&S is significantly reduced for all technologies as CCS projects are de-risked and significant learnings are learned from numerous deployment projects and economies of scale are realised. However, natural gas and electricity costs remain impactful. The technologies with lower capture rates are also exposed to higher carbon prices. Therefore, more aggressive policy measures are likely to force technology developers and operators to higher capture rates, despite higher capital and operational costs. The LCOH of blue hydrogen production technologies analysed in 2050 remains relatively similar although variation between the individual cost components remains. Central costs range from €2.40 /kgH_2 (POX) to €2.89 /kgH_2 (ESMR) with significant overlap between the uncertainty bands.

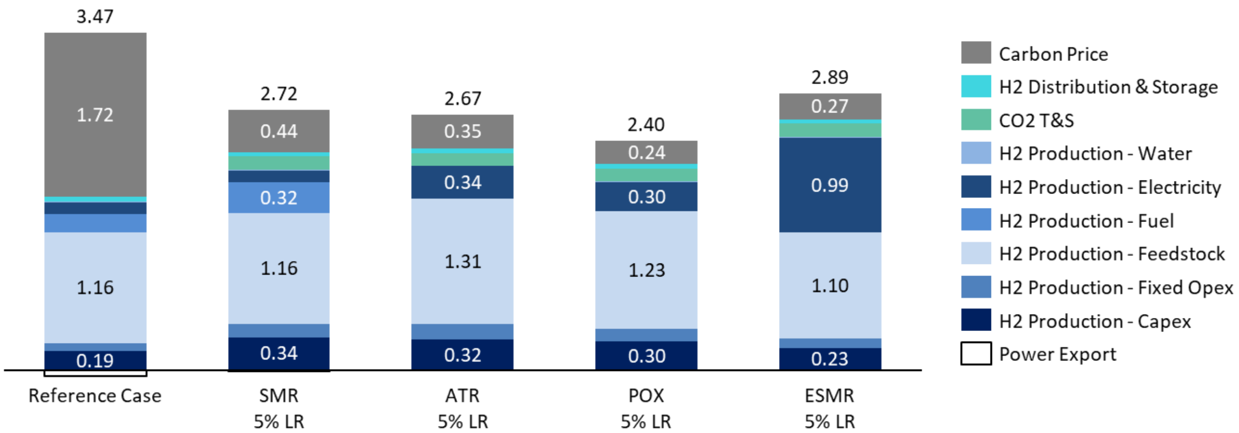


Figure 74: LCOH for natural gas based blue hydrogen production in the Netherlands compared against SMR without CCS reference case in 2050 (€/kgH_2) *CO_2 Price in the Netherlands in 2050 - €162.46/tCO_2*

The range of LCOH for each production technology in 2020 and 2050, assuming a 5% learning rate for the 2050 case, is shown in Figure 75. The bounds are based on taking the maximum and minimum ranges from each sensitivity in the Tornado plot analysis to form the upper and lower limits of the cost range. This shows that changes between 2020 and 2050 for each blue hydrogen production technology is expected to be minimal. Reductions in the CAPEX, fixed OPEX and CO_2 T&S are balanced by increased carbon pricing and higher feedstocks and electricity prices. In no case does the LCOH drop below €2.00/kg. POX is the lowest cost technology in 2020 and 2050, whilst ESMR is the highest cost in both scenarios. However, all four blue hydrogen production technologies show significant overlap in their LCOH range. This suggests that, in different scenarios (i.e. feedstock & electricity prices, H_2 production scale and carbon prices) there will be a variety of business cases that favour different technology options.

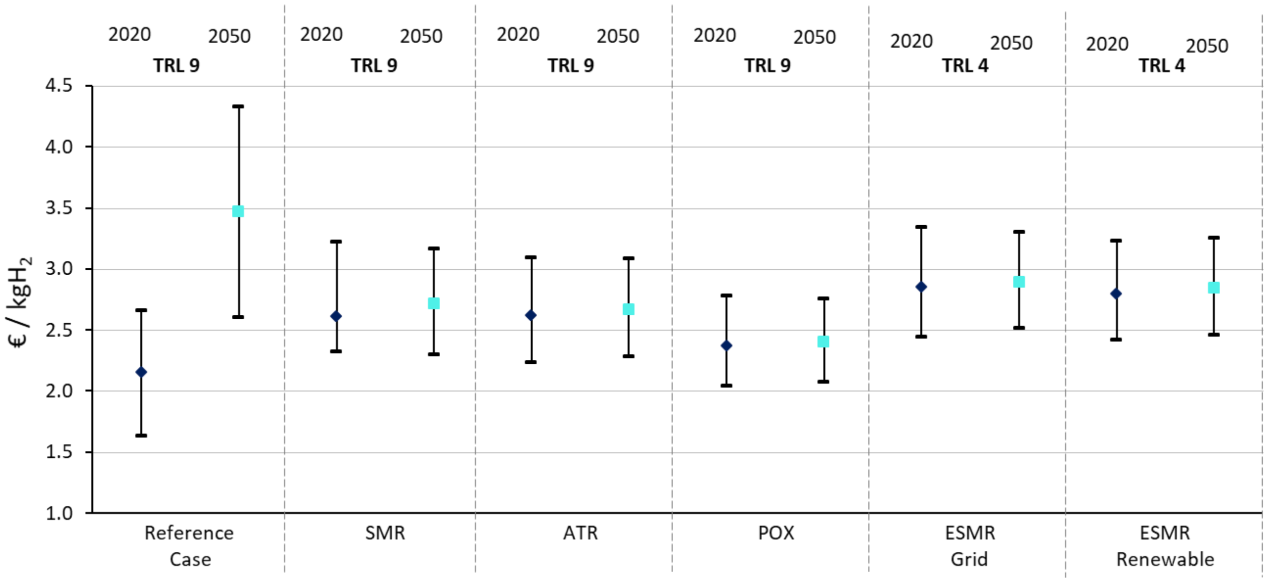


Figure 75: Range of LCOH for blue hydrogen production technologies compared to the reference case (without CCS) in 2020 (diamonds) and 2050 (squares) in the Netherlands with a carbon price (€/kgH_2) *CO_2 Price in the Netherlands in 2020 - €9.53/tCO_2 and 2050 - €162.46/tCO_2*

Cost of CO_2 Abatement

The cost of CO_2 abatement and total emissions are important factors for blue hydrogen production and are shown in Figure 76 and Figure 77 respectively. In the central case, POX is the most cost-effective process for avoiding CO_2 emissions, whereas ESMR is the highest cost. SMR and ATR both have a cost of CO_2 abatement of €110/tCO_2, however the lifetime emissions of the ATR process are almost 8% lower than SMR. However, these prices are very exposed to the capture rate and the emissions associated with the feedstock. In the central case, ESMR is the most expensive whilst SMR and ATR are between the upper and lower bounds. The error bars on the abated cost of CO_2 shows that, in different scenarios, all technologies can be competitive. With respect to total emission reductions in 2020, ESMR from 2020 demonstrates a pathway to significant emission reductions when coupled with renewable electricity (where the technology is expected to be deployed)Figure 48. For all processes, significant emission reductions are possible where the carbon intensity of the feedstock can be reduced, i.e. with biogas.

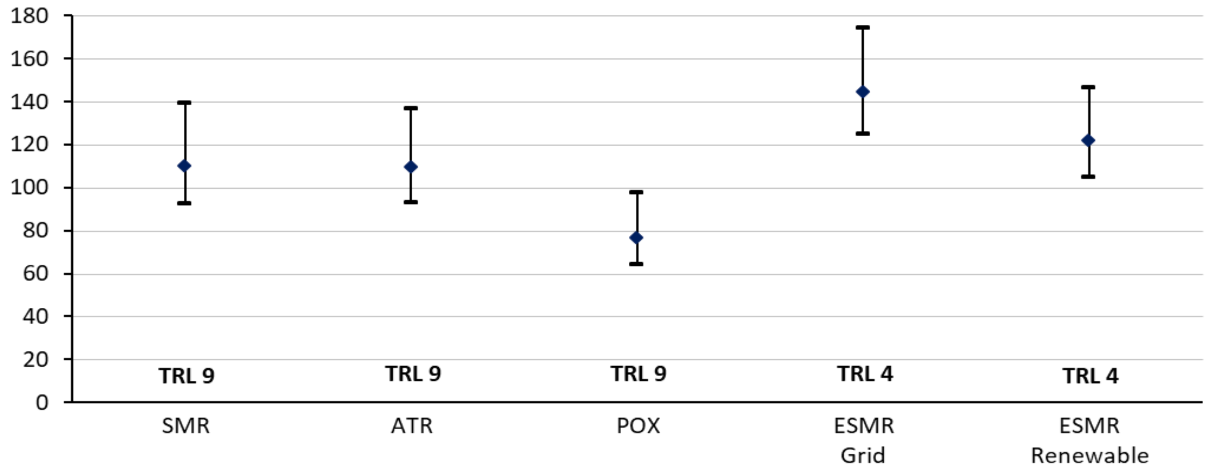


Figure 76: Range of abated cost of CO_2 for each technology in the Netherlands in 2020 (excluding the carbon price in the LCOH and relative to SMR without CCS with an LCOH of €1.61/kgH_2 and lifetime emissions of 21.2MtCO_2) – (€/tCO_2).

All processes are exposed to feedstock emissions as shown in Figure 77, however POX is the only process to not have any direct emissions due to the 100% capture rate. ESMR from the grid electricity has the highest lifetime emissions in 2020, however, if renewable electricity is utilised the lifetime emissions are reduced by approximately 46% resulting in ESMR from renewable electricity having the lowest lifetime emissions of all analysed production processes. As the electricity grid is likely to be significantly decarbonised in 2050, the ESMR process has the potential to significantly reduce the lifetime emissions of natural gas-based hydrogen production in the future.

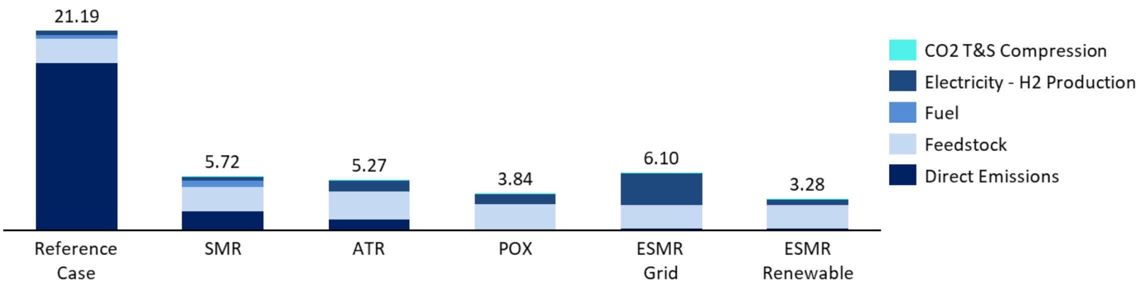


Figure 77: Lifetime emissions for each blue hydrogen production process in 2020 (MtCO2)

6.1.2 Direct Technology Comparisons

SMR is an established technology for hydrogen production and has been deployed successfully with integrated CCS. The process requires significant heat input that is supplied by burning natural gas and therefore has the highest lifetime CO_2 emissions of the analysed processes. The process is the most sensitive to increasing carbon prices and higher capture rates may be required if the process is to remain competitive in the future.

ATR is an established grey hydrogen production technology that has received significant interest for large scale blue hydrogen production in the UK however it is yet to be deployed at scale in a blue configuration. The process is predicted to be lower cost and with lower lifetime emissions than the SMR process in the long term.

POX is an established hydrogen production technology however it is yet to be deployed at scale with integrated CCS. The process is predicted to be the lowest cost form of hydrogen production in the central case, whilst also having the lowest abated cost of CO_2. However, cost differences between POX and alternative technologies analysed in this study are small whilst uncertainties around the process remain high. POX is the only analysed technology to produce no direct emissions resulting in lower lifetime emissions than both SMR and ATR processes. Further feasibility and Front-End Engineering Design (FEED) studies will be required to increase data reliability for this process.

ESMR is currently at low TRL and additional technology development will be required, including demonstration projects to prove the technology in the field and initiatives to raise awareness. However, initial analysis suggests that ESMR will be competitive with all other natural gas based blue hydrogen production technologies whilst also having the greatest potential for reducing lifetime CO_2 emissions when renewable electricity is utilised.

6.2 Market Competitivity

6.2.1 Policy

Hydrogen policy in Europe is focussed on developing green hydrogen production capacity with the European Commission's report "A Hydrogen Strategy for Climate Neutral Europe" setting a minimum target of 40GW of electrolysers to be installed by 2030[122]. Although developing renewable hydrogen production in Europe is the priority, the European Commission recognises the need for other forms of low carbon hydrogen production that will support the future uptake of renewable hydrogen. This would include all of the natural gas-based

[122] European Commission 2020, Communication from The Commission to The European Parliament, The Council, The European Economic and Social Committee and The Committee of The Regions

hydrogen production technologies analysed in this study, provided that CCS infrastructure is developed, and high capture rates are achieved.

Hydrogen policy in the USA does not directly support a particular hydrogen production method. However, incentives such as the 45Q tax credit could be utilised to increase the deployment of blue hydrogen production. The 45Q tax credit will encourage the development of CCS infrastructure where projects will be able to receive US$50/t$CO_2$ for geological carbon storage[123].

Hydrogen policy in East Asia varies by country however, the region has not discounted any form of hydrogen production method. The South Korean government aims to have 70% of the country's hydrogen demand met from clean production sources by 2040. This suggests that large portions of the country's hydrogen demand will be met by grey production sources in short to mid-term[24]. Japan is looking to increase hydrogen production capacity over the next 30 years. However, due to a lack of renewable generating capacity, blue hydrogen production utilising fossil fuel sources with CCS is likely to form a significant portion of both domestic production and international imports[124].

A limitation of this study is that it only focuses on natural gas based blue hydrogen production in the Netherlands. The technologies analysed in this study could potentially be deployed in other regions with large natural gas reserves that are also expected to develop CCS infrastructure such as the USA, Australia and the Middle East. Hydrogen produced in these regions could be exported to markets with proven demand such as East Asia, Western Europe and North America[7].

Box 2 Business Models for Blue Hydrogen Production

Blue hydrogen production technologies have not reached the commercialisation stage, and unfavourably low carbon prices reduce blue hydrogen competitiveness against alternatives with high carbon intensities. In some regions, complete lack of a carbon price further exacerbates this issue. These externalities are most effectively addressed by developing **suitable blue hydrogen business models.**

Taking the UK as a case study, the UK Government is in an advanced stage of business model development to support the growth of a hydrogen economy[125]. Currently, four broad categories are under consideration[126]. The options cover direct support for blue hydrogen producers, as well as indirect support by incentivising growth of hydrogen demand. Therefore, potential business models can lead to catalyse supply as well as long-term demand:

- **Contractual payments to producers**, where the hydrogen producer receives a subsidy to cover the cost difference between blue hydrogen production and high-carbon counterfactual. This category includes a Contract for Difference and Premium Payment models.
- **Regulated returns**, where the business model allows the producer to earn a regulated return on the costs. This category includes Regulated Asset Base and Cap and Floor Models.
- **Obligations**, where an obligation is imposed on non-production parties, such as end users, to supply or use a certain amount of low carbon hydrogen.
- **End user subsidies**, where a subsidy is provided to end users to consume blue hydrogen for a certain application (typically to offset additional fuel cost above natural gas).

Suitable business models will vary between locations, but optimal business models should consider that fuel costs comprise the largest portion of the cost structure of blue hydrogen production.

Private and public cooperation in deployment of blue hydrogen technologies should be encouraged, particularly where local governments are unable to provide direct financial support due to resource limitations. This will ensure that the development and deployment of these technologies accelerates.

[123] Global CCS Institute 2020, The US Section 45Q Tax Credit for Carbon Oxide Sequestration: An Update
[124] METI 2017, Japan - Basic Hydrogen Strategy (key points)
[125] BEIS 2020, Carbon Capture, Usage and Storage: A Government Response on potential business models for Carbon Capture, Usage and Storage
[126] Frontier Economics for BEIS 2020: Business Models for Low Carbon Hydrogen Production

6.2.2 Current Market

Blue hydrogen production technologies will have to compete with established grey hydrogen production technologies in the near-term as well as developing green hydrogen production from renewable sources in the future. SMR without CCS is currently the dominant production technology globally and is expected to remain lower cost in the short to mid-term until carbon prices increase. This, of course, is not the only pressure on transition to low carbon alternatives as direct competition with green production is increasingly common. The further development of a hydrogen economy may face significant challenges from other low carbon fuels and technologies e.g. biofuels and electrification.

Green hydrogen is gaining significant momentum. For example, the Northern Netherlands received €20 million subsidy from the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) to develop Europe's first hydrogen valley[127]. Further project funding of €70 million was provided by public-private co-financing in 2020, with the project development projected to last approximately 6 years.

Blue hydrogen production is predicted to remain cheaper than green hydrogen production in the near term, as shown in Europe in 2030 in Figure 78. However, the cost of renewable hydrogen production is predicted to fall and, in some cases, may be cheaper than blue hydrogen production e.g. in regions with high deployment of low-cost wind or solar or, equally, regions with high natural gas prices. The Netherlands benefits from high potential for renewable generating capacity, combined with high hydrogen demand from industry. Electrolysers have the potential for localised and on-site hydrogen production that can reduce hydrogen distribution costs e.g. for industrial applications and hydrogen refuelling stations. Green hydrogen production may therefore make up a significant portion of future market share.

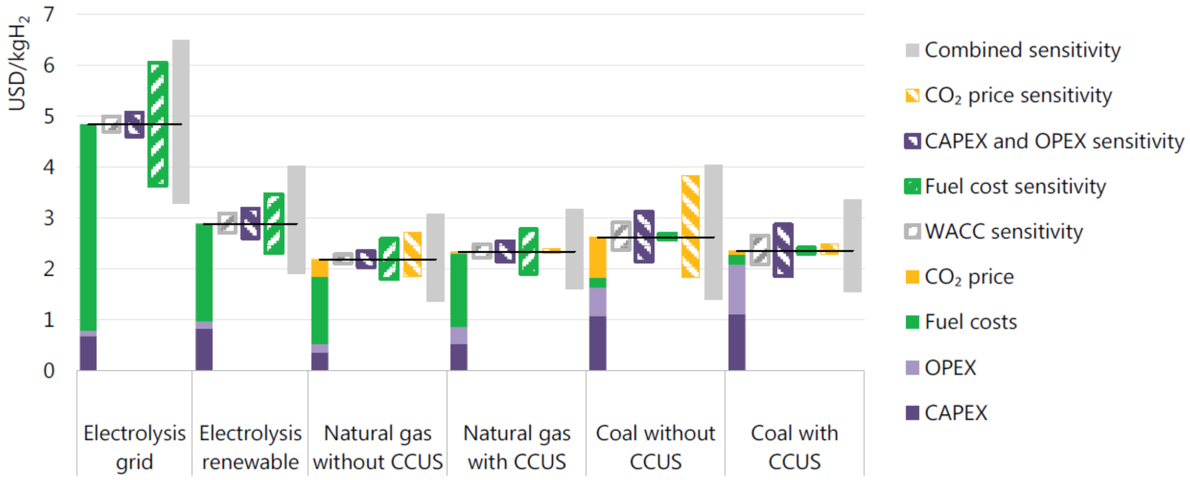


Figure 78: Hydrogen production costs for different technology options in Europe in 2030[15]

6.3 Conclusions and Recommendations

6.3.1 Competitivity

This study shows that in the short term, all of the natural gas based blue hydrogen production technologies analysed are likely to be higher cost than established grey hydrogen production without CCS in the Netherlands. However, as carbon pricing increases, CCS integration will be crucial for reducing the cost of natural gas-based hydrogen production. Policy support is therefore required to increase the uptake of blue hydrogen and bridge the time period gap, until carbon price increases result in grey hydrogen production being an unattractive economic option.

[127] New Energy Coalition, Hydrogen Valley

The CO_2 T&S "fee" is a significant costs component for all blue hydrogen production technologies in this study. Therefore, reducing costs in this area will be crucial to ensuring cost competitiveness with established grey hydrogen production. The development of shared CCS infrastructure in industrial clusters to take advantage of economies of scale will ensure CO_2 T&S costs are reduced. In the long term, blue hydrogen production will be lower cost than grey due to higher carbon prices.

In the longer term, the falling cost of renewable electricity is likely to make green hydrogen production increasingly competitive and lower cost than blue hydrogen production in cases where low-cost electricity is available. For example, North Africa and Southern Europe are expected to have high capacities of low-cost solar electricity that could be utilised for green hydrogen production via electrolysers. In the future, hydrogen pipelines connecting North Africa to Europe are expected to be developed to import low-cost green hydrogen to Europe's growing hydrogen market[128]. However, falling costs of electricity is also likely to make the ESMR process significantly more cost competitive.

Hydrogen production from natural gas with CCS in the Netherlands is expected to face significant competition from global hydrogen imports from regions where low-cost hydrogen production is available. This not only includes the import of green hydrogen, but also blue hydrogen production from oil-based feedstocks.

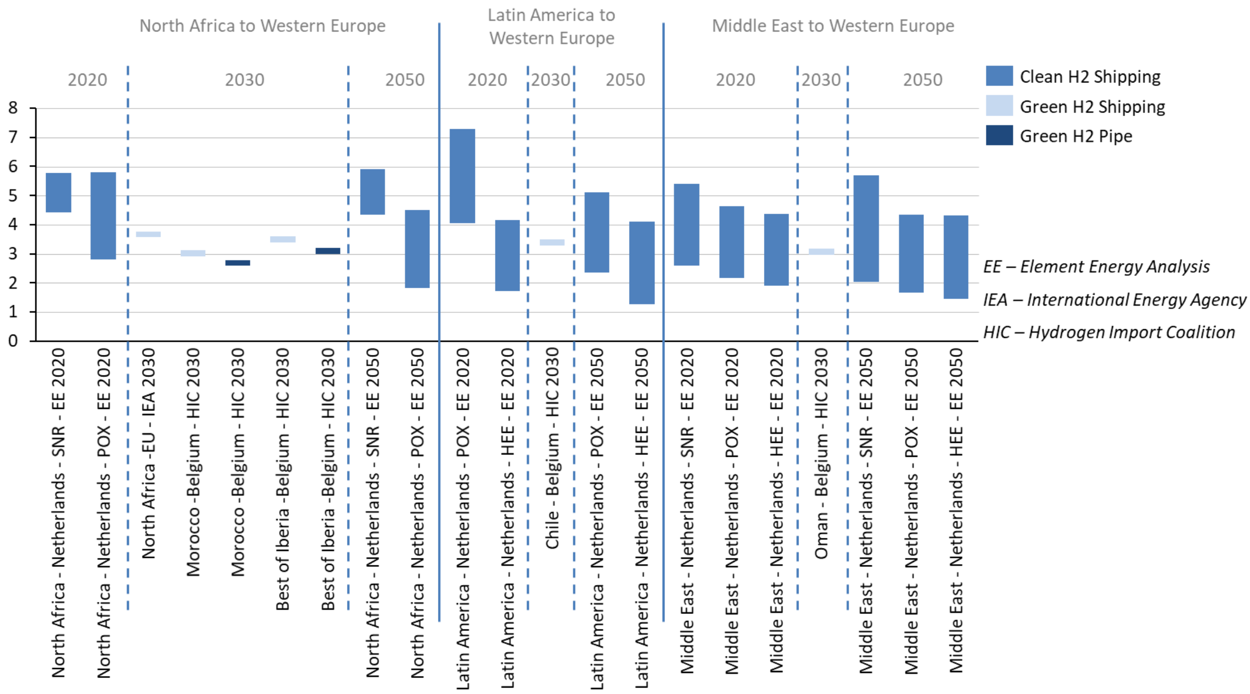


Figure 79: Comparison of hydrogen export costs to European countries by region and production type (€/kgH_2)[15, 129]

If the cost of hydrogen distribution over long distances can be reduced sufficiently, importing low-cost hydrogen may be more economical than local production in regions such as the Netherlands. This is shown in Figure 79 where blue hydrogen production from oil-based feedstocks is compared against green hydrogen production costs for export to European markets. Cost ranges are displayed for POX, steam naphtha reforming (SNR) and HEE based on data uncertainty. The large cost ranges for each technology represents the range of regional feedstock costs that can be utilised by the process, with the lowest cost representing the utilisation of waste feedstocks for POX and HEE processes. This shows that green hydrogen produced in Morocco and transported via pipeline to Europe (€2.68/kgH_2) in 2030 is likely to be competitive with blue hydrogen production in the Netherlands. The low-cost boundary for POX from North Africa with hydrogen imported to the Netherlands (€1.81/kgH_2) is also likely to be cost competitive with blue hydrogen production from natural

[128] Hydrogen Europe 2020, Green Hydrogen for a European Green Deal A 2x40 GW Initiative
[129] Hydrogen Import Coalition 2021, Shipping sun and wind to Belgium is key in climate neutral economy

gas. Whereas the low-cost boundary for HEE from the Middle East has the potential to result in LCOH as low as €1.44/kgH_2 where waste feedstocks can be utilised. However, this technology is still low TRL and yet to be deployed commercially at scale.

6.3.2 Recommendations

Production of blue hydrogen with a minimum CO_2 capture rate of 90% via technologies that use natural gas has not yet been demonstrated at scale. The successful deployment of these technologies relies on a multiplicity of factors such as: proving technical and financial viability, validating CO_2 footprint and assessing integration with the wider regional supply chains. **Government grants**, **risk mitigation measures** and **private industry funding** are essential to drive blue hydrogen demonstration projects forward. This is the first stage towards long-term, unsubsidised blue hydrogen production.

Areas of hydrogen demand, particularly in the near term may not necessarily be located adjacent to optimal locations for blue hydrogen production. This implies that support mechanisms are required to ensure connection of production to demand points. Key recommendations and actions to increase the deployment of natural gas based blue hydrogen production are summarised below.

Research, Development and Demonstration

- **Including blue hydrogen production technologies in CCS cluster plans** to take advantage of scales of deployment. This will reduce CO_2 T&S costs.
- **Further work is needed to explore optimal technology type by region.** This study explored four blue hydrogen production technologies. These technologies are not limited to deployment in the Netherlands and cost ranges show that all analysed technologies can be competitive options. Blue hydrogen producers should conduct further feasibility and FEED studies to optimise technology deployment choices.
- **Additional technology development, including demonstration projects, to prove the technologies in the field and raise awareness.** This includes resolving data gaps and uncertainties e.g. ESMR is currently TRL 4, and process data is therefore less reliable. This will ensure that these technologies are understood and included in national and international hydrogen strategies, facilitating international collaboration. Another area of work is continued consideration for conventional configurations for SMR and ATR and those which include a GHR. For example, ATR with the GHR produces hydrogen more efficiently but cannot self-generate any electricity, which the ATR without the GHR can, leading to a smaller demand from the grid.
- **Further evidence gathering around relative economies of hydrogen transportation**. Comparing hydrogen distribution methods at different scales, distances, operating parameters and archetypes.
- **Exploring local hydrogen demand scenarios and reducing costs in the value chain for lower cost hydrogen distribution**. This includes leveraging learnings and investments from ongoing projects such as Acorn which are demonstrating ways to reuse existing infrastructure for CO_2 T&S.
- **Exploring synergies between transporting CO_2 and hydrogen**. Opportunities to utilise the same port infrastructure and ships for shipping of hydrogen and CO_2.

Policy and Actions

- Governments should only support blue hydrogen technologies with sufficiently low carbon footprints as calculated from life cycle assessments. This includes sufficient high carbon capture rates (preferably >90%), use of electricity with low carbon content, and a strong focus on the reduction of methane leakages involved with extraction, transportation and consumption.
- **Including blue hydrogen production technologies in CCS cluster plans** to take advantage of scales of deployment. This will reduce CO_2 T&S costs.
- **Supporting aggressive carbon pricing to outcompete conventional production of "grey" and "brown" hydrogen production technologies**.
- **Business model development for blue hydrogen production is required to make low carbon hydrogen competitive with that produced from high carbon alternatives.**

- **International collaboration between global regions with low-cost hydrogen production and those with emerging hydrogen demand.** In the short to medium term, materialising these connections may require international trade of hydrogen to areas with more developed hydrogen strategies and with proven end-uses for hydrogen.
- Development of new grey hydrogen production facilities should be discouraged unless they have accompanying CCS retrofit strategies.
- CCS retrofits to existing grey hydrogen production facilities should be encouraged where hydrogen plats are expected to remain operational for many years.

6.3.3 Timelines

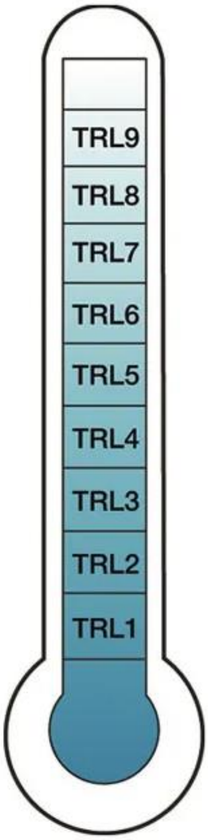
- In the short-to-medium term, SMR, ATR and POX have high TRLs and are therefore expected to be deployed where there is wider consensus and activity in industrial clusters to develop CCS infrastructure. This is an inherent requirement for blue hydrogen technologies as it is uneconomic for standalone infrastructure to only be developed for blue hydrogen production. This will therefore follow the deployment of CCS clusters.
- In the long-term, the deployment of natural gas based blue hydrogen production will be increased by reducing the LCOH, reducing the abated cost of CO_2 and reducing the lifetime emissions when compared to alternative technology options.

Beyond these production technologies, it is also important to scale the supply of hydrogen with hydrogen demand. Western Europe, North America and East Asia are regions with developed hydrogen strategies are expected to see reasonable increases in demand out to 2030 before significant increases in demand from transport and industrial fuel switching creates an exponential rise[7]. Memorandums of Understanding and international trade agreements are therefore important over this time period to ensure that blue hydrogen production is a feature in these discussions and is considered for bulk scale use in these regions.

7 Appendices

7.1 Technology Readiness Level

BEIS - Technology Readiness Levels (TRL)[130]



- TRL9 Operations
- TRL8 Active Commissioning
- TRL7 Inactive Commissioning
- TRL6 Large Scale
- TRL5 Pilot Scale
- TRL4 Bench Scale Research
- TRL3 Proof of Concept
- TRL2 Invention and Research
- TRL1 Basic Principles

Figure 80: BEIS - TRL scale

[130] UK Government 2014, Guidance on Technology Readiness Levels

7.2 Data and Assumptions used in TEA and LCA

All mass balances presented in this section are based on the schematic shown in Figure 81.

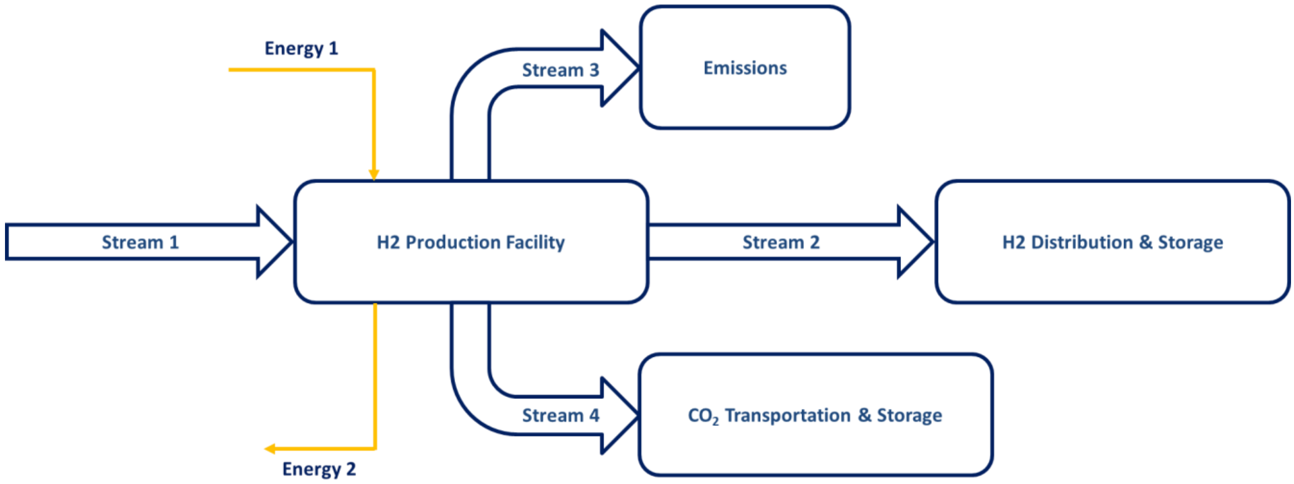


Figure 81: Mass and energy balance schematic for all production processes

In this section, assumptions used for the LCA, TEA, and both are differentiated by the headings.

7.2.1 Steam Methane Reforming without CCS – Benchmark

Table 17: SMR without CCS Technology Process Data

Variable	Units	SMR w/o CCS74
Inputs		
Feedstock	kWh_{th}/kg	37.67
Fuel	kWh_{th}/kg	6.22
Raw Water	kg/kgH_2	6.64
Cooling Water	kg/kgH_2	381.92
Energy		
Process Power Requirement	kWh_e/kg	0.18
System Power Generation	kWh_e/kg	1.28
Compression Power Requirement	kWh_e/kg	1.10
Emissions		
CO_2	kg/kgH_2	-
Products		
Hydrogen	kg/kgH_2	1.00
CO_2 Export	kg/kgH_2	9.00
Process		
Purity of Hydrogen	%	99.90%
Hydrogen Export Pressure	bar	200.00
CO_2 Export Pressure	bar	110.00
CO_2 Capture Rate	%	0.00%

Table 18: SMR without CCS Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO2 Emissions	4. CO2 Export
Feedstock	GWh / yr	2,971	-	-	-
Fuel	GWh / yr	491	-	-	-
Water	ktonne / yr	524	-	-	-
CO_2	ktonne / yr	-	-	710	-
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	99.99	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	N/A
CO_2 Purity	%	-	-	-	N/A
Energy Balance – Power					
Production Facility	GWh / yr	87	87	-	-

Joint LCA and TEA assumptions

- Feedstock and fuel are natural gas.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.
- SMR is based on “Base Case” from IEAGHG’s study on hydrogen derived from SMR[74].
- The power requirement CO_2 compression and some power for the hydrogen compression. Additional compression power requirement is needed to increase the pressure to 200 bar, the pressure of the functional unit.
- Assumed that electricity sold via export capacity is sold to the grid at the wholesale price

7.2.2 Steam Methane Reforming

Table 19: SMR process data

Variable	Units	SMR
Inputs		
Feedstock	kWh_{th}/kg	37.67
Fuel	kWh_{th}/kg	10.55
Raw Water	kg/kgH_2	4.68
Cooling Water	kg/kgH_2	1,205
Energy		
Process Power Requirement	kWh_e/kg	1.25
System Power Generation	kWh_e/kg	1.30
Power Export Capacity	kWh_e/kg	0.05
Compression Power Requirement	kWh_e/kg	1.10
Emissions		
CO_2	kg/kgH_2	0.99
Products		
Hydrogen	kg/kgH_2	1.00
CO_2 Export	kg/kgH_2	8.89
Process		
Purity of Hydrogen	%	99.99%
Hydrogen Export Pressure	bar	200
CO_2 Export Pressure	bar	110.00
CO_2 Capture Rate	%	90.00%

Table 20: SMR Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO2 Emissions	4. CO2 Export
Feedstock	GWh / yr	2,971	-	-	-
Fuel	GWh / yr	832	-	-	-
Water	ktonne / yr	369	-	-	-
CO_2	ktonne / yr	-	-	78	701
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	99.99	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	110
CO_2 Purity	%	-	-	-	99.0
Energy Balance – Power					
Production Facility	GWh / yr	87	4	-	-

Joint LCA and TEA Assumptions

- Feedstock and fuel are natural gas.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.
- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy use for the carbon capture process has been considered.
- SMR is based on "Case 3" from IEAGHG's study on hydrogen derived from SMR[74].

- The power requirement CO_2 compression and some power for the hydrogen compression. Additional compression power requirement is needed to increase the pressure to 200 bar, the pressure of the functional unit.
- Assumed that electricity sold via export capacity is sold to the grid at the wholesale price

7.2.3 Autothermal Reforming

Table 21: ATR Technology Process Data

Variable	Units	ATR
Inputs		
Feedstock	kWh_{th}/kg	42.81
Fuel	kWh_{th}/kg	-
Oxygen	kg/kgH_2	3.19
Raw Water	kg/kgH_2	4.65
Energy		
Process Power Requirement	kWh_e/kg	2.69
System Power Generation	kWh_e/kg	-
Compression Power Requirement	kWh_e/kg	0.45
Emissions		
CO_2	kg/kgH_2	0.57
Products		
Hydrogen	kg/kgH_2	1.0
CO_2 Export	kg/kgH_2	8.28
Process		
Purity of Hydrogen	%	98.4
Hydrogen Export Pressure	bar	80.0
CO_2 Export Pressure	bar	120
CO_2 Capture Rate	%	94.0

Table 22: ATR Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO2 Emissions	4. CO2 Export
Feedstock	GWh / yr	3,377	-	-	-
Fuel	GWh / yr	-	-	-	-
Water	ktonne / yr	367	-	-	-
CO_2	ktonne / yr	-	-	45	653
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	98.4	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	300
CO_2 Purity	%	-	-	-	98.0
Energy Balance – Power					
Production Facility	GWh / yr	247	-	-	-

Joint LCA and TEA assumptions

- Feedstock is natural gas.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.
- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy use for the carbon capture process has been considered.
- The electricity demand of an ASU for the production of 1 kg of O_2 is different in different sources, resulting in a range. The quantity used in this study is based on a recent value (representing an efficient ASU), at lower end of the range[131]. This is $0.245 kWh_e/kgO_2$ ASU power requirement[131].

[131] Linde 2009, Enhanced Cryogenic Air Separation a Proven Process Applied to Oxyfuel

- The power requirement therefore includes CO_2 compression, power for the ASU and some power for the hydrogen compression. Additional compression power requirement is needed to increase the pressure to 200 bar, the pressure of the functional unit.

7.2.4 Partial Oxidation

Table 23: POX Technology Process Data

Variable	Units	POX[132]
Inputs		
Feedstock	kWh_{th}/kg	38.5 – 41.0
Raw Water	kg/kgH_2	3.8 – 5.1
Oxygen	kg/kgH_2	3.2 – 4.0
Energy		
Process Power Requirement	kWh_e/kg	1.4 – 2.5
Compression Power Requirement	kWh_e/kg	0.90
Emissions		
CO_2	kg/kgH_2	-
Waste		
Water	kg/kgH_2	1.55
Products		
Hydrogen	kg/kgH_2	1.00
CO_2 Export	kg/kgH_2	7.27
Process		
Purity of Hydrogen	%	>97.00%
Hydrogen Export Pressure	bar	200
CO_2 Export Pressure	bar	150
CO_2 Capture Rate	%	100%

Table 24: POX Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO2 Emissions	4. CO2 Export
Feedstock	GWh / yr	*3,171*	-	-	-
Fuel	GWh / yr	-	-	-	-
Water	ktonne / yr	334	-	-	-
CO_2	ktonne / yr	-	-	-	*573*
Hydrogen	ktonne / yr	-	*79*	-	-
Hydrogen Conditions					
Export Pressure	bar	-	*200*	-	-
H_2 Purity	%	-	*97.0*	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	*150*
CO_2 Purity	%	-	-	-	*100.0*
Energy Balance – Power					
Production Facility	GWh / yr	222	-	-	-

Joint LCA and TEA assumptions

- Feedstock is natural gas.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.
- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy use for the carbon capture process has been considered.
- Even though the technology has a high TRL, there is limited amount of data available as there have been few studies / deployments of dedicated hydrogen production using POX.

[132] Information provided from various stakeholder engagement activities

- It is assumed that the POX capture rate is 100%, i.e. no direct CO_2 emissions from the process. This does not account for other emissions such as fugitive emissions, CO_2 and methane for example, which would increase the carbon footprint of the process.
- The power requirement CO_2 compression, power for the ASU and some power for the hydrogen compression. Additional compression power requirement is needed to increase the pressure to 200 bar, the pressure of the functional unit.

7.2.5 Electric Steam Methane Reforming

Table 25: ESMR Technology Process Data

Variable	Units	ESMR
Inputs		
Feedstock	kWh_{th}/kg	35.95
Fuel	kWh_{th}/kg	-
Raw Water	kg/kgH_2	6.80
Cooling Water	kg/kgH_2	253.95
Energy		
Process Power Requirement	kWh_e/kg	0.58
System Power Generation	kWh_e/kg	-
Compression Power Requirement	kWh_e/kg	1.1
Electrical Energy Additional for ESMR	kWh_e/kg	8.1
Emissions		
CO_2	kg/kgH_2	0.1
Products		
Hydrogen	kg/kgH_2	1.0
CO_2 Export	kg/kgH_2	7.23
Process		
Purity of Hydrogen	%	99.5
Hydrogen Export Pressure	bar	200.0
CO_2 Export Pressure	bar	110.0
CO_2 Capture Rate	%	98.6

Table 26: ESMR Mass and Energy Balance

Process Stream	Units	1. System Demand	2. System Output	3. CO2 Emissions	4. CO2 Export
Feedstock	GWh / yr	2,835	-	-	-
Fuel	GWh / yr	-	-	-	-
Water	ktonne / yr	536	-	-	-
CO_2	ktonne / yr	-	-	8	570
Hydrogen	ktonne / yr	-	79	-	-
Hydrogen Conditions					
Export Pressure	bar	-	200	-	-
H_2 Purity	%	-	99.5	-	-
CO2 Export Conditions					
Export Pressure	bar	-	-	-	110
CO_2 Purity	%	-	-	-	99.0
Energy Balance – Power					
Production Facility	GWh / yr	726	-	-	-

Joint LCA and TEA assumptions

- Feedstock is natural gas.
- It is assumed there are no waste products from this process. Based on experience with previous LCAs, CE Delft expects that this assumption has negligible effect on the results.
- Auxiliaries such as absorbents used in the process of capturing CO_2 are not included in this study, due to lack of data. Consequently, only energy use for the carbon capture process has been considered.
- As this technology has a low TRL, there is limited amount of data available.

- The eSMR data set is based on “Case 1A” in IEAGHG’s study on hydrogen derived from SMR[74] with the following changes made:
  - Conversion of natural gas is increased from 85.8% to 90%, as per literature from Haldor Topsoe
  - It is assumed that the efficiency of heating is increased from 90%[133] (via combustion) to 95% (via electrification). This determines the “Electric Energy Additional for ESMR”
  - Total CO_2 production is proportional to the carbon intensity of combusting natural gas. The capture rate is then based on a mass balance of “Case 1A”. Since the eSMR replaces the natural gas heating with electrification, there is no flue gas stream. The capture rate is therefore calculated as a mass balance over the carbon capture on the high-pressure syngas.
- The other power requirement includes CO_2 compression, and some power for the hydrogen compression. Additional compression power requirement is needed to increase the pressure to 200 bar, the pressure of the functional unit.

[133] Climate Change Committee 2019, Extension to Fuel Switching Engagement Study – Deep decarbonisation of UK industries

7.2.6 CO_2 Transport and Storage

Pipeline cost data for CO_2 transport was taken from previous studies conducted by Element Energy: 'Shipping CO_2 – UK Cost Estimation Study'[102] and 'Carbon Capture, Usage and Storage Deployment at Dispersed Sites'[134]. Technical data for CO_2 pipelines is displayed in Table 27 with the final CO_2 T&S cost figures given in Table 28.

Table 27: Technical data for CO_2 pipelines in analysed regions

CO_2 pipeline transport	Units	Netherlands (Porthos)
Compressor Power	*kWh/tCO$_2$/km*	0.18
Pipeline Diameter	*Inches (mm)*	10.0 (254.0)
Wall Thickness	*mm*	16.02
Area of intersection (wall only)	*mm^2*	11,978
Area of NG pipeline wall	*mm^2*	29,531
CO_2 Pipeline Materials/NG Pipeline Materials	*%*	41
Lifetime	*Years*	25

Table 28: CO_2 T&S costs by region and year

Storage Region	-	Netherlands (Porthos)
2020	*€ / tCO$_2$*	54.56
2050	*€ / tCO$_2$*	15.80

Joint LCA and TEA assumptions

- Lifetime of the pipelines is assumed to be 25 years.
- Pipeline compressor power is a function of flow rate, pipeline utilisation, pressure drop and compressor efficiency. The pipeline diameter is a function of flowrate and pipeline length. The final combination of compressor power and pipeline diameter are such that a pressure drop of 1MPa is maintained across the pipeline. As a result, the compressor power for each technology is fixed whilst the pipeline diameter varies.

LCA assumptions

- Pipelines are modelled as onshore pipelines.
- In the LCA model, the pipeline that is used for CO_2 transportation is modelled as a natural gas pipeline as the LCA database contains no information on pipelines for CO_2 transport. As the diameter and thickness of the CO_2 pipeline is different than the natural gas pipeline, the pipeline is scaled based on the differences in the area (intersection) of the pipelines.

[134] BEIS 2020, CCS deployment at dispersed industrial sites

7.2.7 Hydrogen Compression

Specific Energy of Compression

The hydrogen export pressures given by literature vary significantly by source. It is therefore important to homogenise these processes to have the same functional unit of hydrogen per technology. For pressure, this means hydrogen at 200 bar.

To calculate the specific energy requirement, an inhouse engineering tool was used based on the increase in pressure, the temperature of the stream, the isentropic coefficient of the gas and the efficiency of the compressor. It was assumed that:

- The compressor efficiency varied between 65% and 80%; an average was taken to give the specific energy requirement[135].
- The pressure ratio was restricted to six. This means that the output pressure from the compressor could not be greater than six times the input pressure. Where this occurred, the number of compression stages was increased until the pressure ratio criterium was satisfied.

To exemplify the impact of compression stages on the specific energy requirement, the specific energy required to compress hydrogen to 200 bar from different export pressures are shown below for three compression stages.

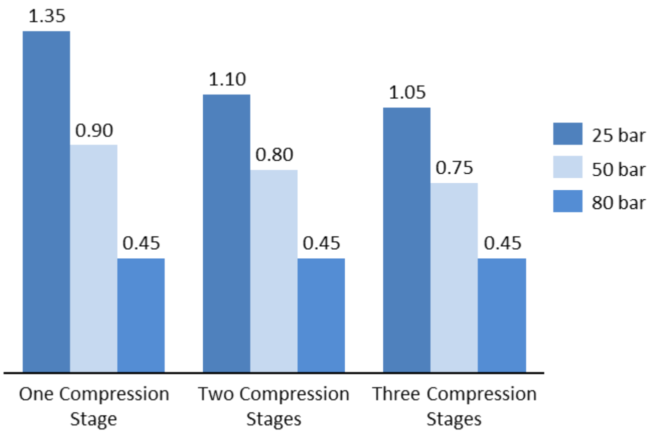


Figure 82: Specific compression energy needed to increase from stated inlet pressure to 200 bar (kWh/kgH_2)[136]

Capital Costs and Fixed Operational Costs

The capital cost of the compressors is based on the average of three correlations for determining capital cost of compressors. These are Yang & Ogden[137], NASFuture[138] and Towler & Sinott[139]. These correlations use the compressor power to determine the capital cost. CAPEX is presented as $(2020). To convert to Euros, an exchange rate of 0.8757€/$ is used[85].

Yang & Ogden

$$Capex = 2{,}341 \times Compressor\ Power(MW)^{0.9}$$

NASFuture

$$Capex = 3{,}099 \times Compressor\ Power\ (MW)^{0.8}$$

Towler & Sinott

$$Capex = 2.5 \times (304{,}800 + 1.69 \times Compressor\ Power^{1.5})$$

---

135 NREL 2014, Hydrogen Station Compression, Storage, and Dispensing Technical Status and Costs
136 Compression energy is a function of the pressure increase and the number of compression stages. The given energy requirement is for a one stage compression system, increasing the pressure from 50 to 200 bar.
137 Yang and Ogden 2006, Determining the lowest-cost hydrogen delivery mode
138 Thomas 2015, Sustainable Transport Options for the 21st Century and Beyond
139 Towler and Sinnott 2013, Chemical Engineering Design

Fixed OPEX is assumed to be 5% of CAPEX.

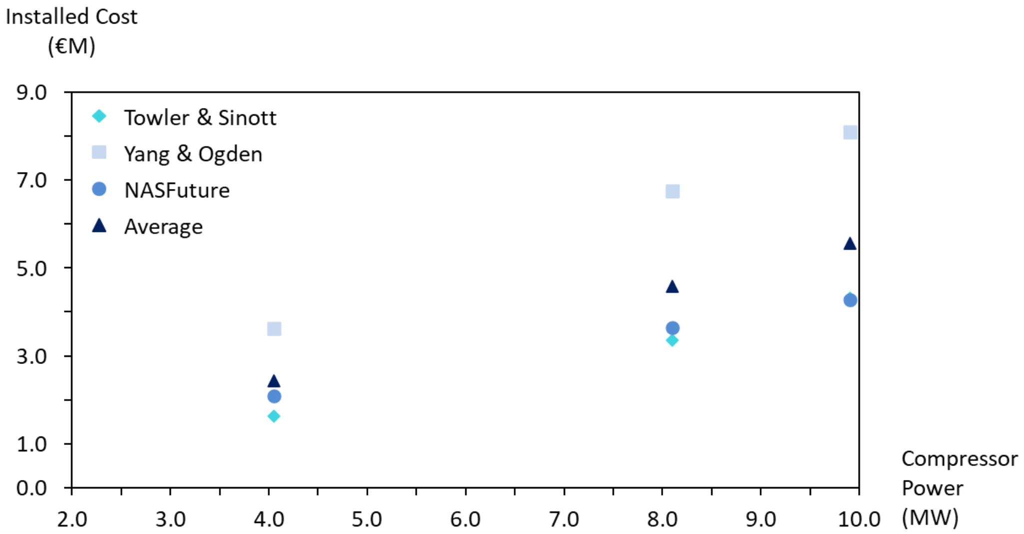


Figure 83: Capital cost of compressor by power (MW) and by methodology

7.2.8 Carbon footprint of feedstock and electricity production

Feedstocks

The carbon footprint for the feedstocks used in this study are given in Table 29.

Table 29: Carbon footprint of natural gas production and transport

		Carbon footprint
Natural Gas NL mix	*kgCO2-eq / m3*	3.0×10^{-1}
Natural Gas imported to the Netherlands from Algeria	*kgCO2-eq / m3*	3.9×10^{-1}
Natural Gas imported to the Netherlands from Russia	*kgCO2-eq / m3*	8.1×10^{-1}

Not all data used in this research was available in the same unit in different sources. Table 30 shows the conversion factors used in the LCA models.

Table 30: Conversion factors used in the LCAs

Variable	Value + Unit
HHV Natural gas[140]	11.68 kWh/m3

The Carbon Footprint of Electricity

The carbon footprints of electricity used in this study are presented in Table 31.

Table 31: Dutch electricity carbon footprint and source

Year	Carbon footprint of electricity (kg CO_2 eq./kWh)	Modelling / Ecoinvent process
2020 (grid)	0.48	See[141] footnote [143]
2020 (100% renewable, e.g. wind/solar)	0.0329	See footnote [143]
2030 (expected grid)	0.16	See footnote [143]

The 2020 grid carbon footprint is used in the TEA and LCA base analyses.

The 2020 renewable carbon footprint is used in Section 4.2, where the TEA 2050 scenario assumes a supply of 100% renewable electricity is available, equivalent to a 100% renewable electricity supply in the Netherlands in 2020. The carbon footprint of this electricity is 0.0329 kg CO_2-eq./kWh (only wind and solar)[141].

In Sensitivity Analysis One (see Section 5.3.3), the LCA of the different hydrogen production scenarios is estimated for 2030 by modelling the technologies using an expected carbon footprint of the Dutch electricity mix for 2030. The 2030 electricity carbon footprint is estimated using the following methodology: direct 2030 emissions based on PBL 2020[142], indirect 2030 emissions based on production mix in the same source (see footnote 142) and modelled using Ecoinvent processes[143].

[140] The sources used for the different technologies reported other lower heating values for natural gas. In Ecoinvent, the unit of natural gas is m^3 and as a default a **higher** heating value is used. Therefore, the average of the LHV's provided by the different sources to high heating value (HHV) and m^3 is converted using 1.08 HHV/LHV (H21 NoE) and the default density used in Ecoinvent, which is 0.84 kg/m^3.

[141] CE Delft 2020, Emission indicators electricity This source was used to determine the carbon footprint of the Dutch electricity mix rather than the Ecoinvent electricity process for the Netherlands, as it more recent information on the specific electricity mix of the Netherlands. This mix has been modelled using the existing Ecoinvent background processes to make sure that, next to the carbon footprint, other environmental impact categories are taken into account as well.

[142] PBL 2020, Klimaat- en Energieverkenning 2020

[143] The following Ecoinvent processes were used to model the indirect emissions of electricity:
Natural gas: Electricity, high voltage {NL}| heat and power co-generation, natural gas, combined cycle power plant, 400MW electrical
Nuclear: Electricity, high voltage {NL}| electricity production, nuclear, pressure water reactor
Other fossil: Electricity, high voltage {NL}| treatment of blast furnace gas, in power plant | Cut-off, U
Wind: Electricity, high voltage {NL}| electricity production, wind, 1-3MW turbine, offshore
Photovoltaic: Electricity, low voltage {NL}| electricity production, photovoltaic, 570kWp open ground installation, multi-Si

7.3 Data and Assumptions used in TEA

7.3.1 CAPEX and Fixed OPEX

CAPEX and Fixed OPEX data used for the economic assessment natural gas based blue hydrogen technologies is displayed in Table 32 and

Table 33 respectively. The cost components are not broken down in this study, i.e. differences between contingencies between two separate reports are not considered, only that the costs are accounted for.

Table 32: CAPEX data assumptions

Technology	CAPEX Min [€ / kW]	CAPEX Max [€ / kW]	CAPEX Average [€ / kW]	Range [+/-%]	Assumptions
SMR	993	1,070	1,031	+/- 3.7%	<u>H21</u> - Equipment, Bulk, Indirects, Construction, Home Office, CMT, Other, Owner's Cost, Project Management, Insurances, Contingency - Capture Rate, 91.2% <u>IEAGHG</u> - Direct Materials, Construction, EPC Services, Other, Contingency - Capture Rate, 90%
ATR	965	968	966	+/- 0.1%	<u>H21</u> - Equipment, Bulk, Indirects, Construction, Home Office, CMT, Other, Owner's Cost, Project Management, Insurances - Scaled costs to 300MW using scaling factor of ~0.7. - Capture Rate, 98.4% <u>HyNet</u> - OSBL & ISBL equipment, installation, bulk materials, labour, commissioning and contractors' and owners' costs. Also included Lang factors. - Capture Rate, 97.0%
POX	807	965	886	+/- 8.9%	<u>GTI</u> - Based on a natural gas and coal facility; assumed to be representative for an entirely gas-based plant. <u>Stakeholder Engagement</u> - Includes internal assumptions on scale, balance of plant & contingency
ESMR	646	707	676	+/- 4.5%	<u>IEAGHG</u> - Direct Materials, Construction, EPC Services, Other, Contingency - See below for range explanation

Biomass: Electricity, high voltage {NL}| heat and power co-generation, wood chips, 6667 kW, state-of-the-art 2014
Rest: Electricity, high voltage {NL}| heat and power co-generation, natural gas, conventional power plant, 100MW electrical

Benchmark SMR	570	N/A	<u>IEAGHG</u> - Direct Materials, Construction, EPC Services, Other, Contingency

Table 33: Fixed OPEX data assumptions

Technology	Fixed OPEX Min [€ / kW/yr]	Fixed OPEX Max [€ / kW/yr]	Fixed OPEX Average [€ / kW/yr]	Range [+/-%]	Assumptions
SMR	30	42	36	+/- 17.1%	<u>H21</u> - Fixed OPEX/CAPEX = 3% - Fixed OPEX breakdown not provided <u>IEAGHG</u> - Direct labour, Admin/general overheads, Insurance and taxes, Maintenance - Fixed OPEX/CAPEX = 3.9%
ATR	32	50	41	+/- 21.8%	<u>H21</u> - Direct labour, Maintenance, Operation, Miscellaneous, Contingency - Fixed OPEX/CAPEX = 3.3% <u>HyNet</u> - Fixed OPEX breakdown not provided but includes: Direct labour, Maintenance, Operation (excluding feedstock, power and CO_2) - Fixed OPEX/CAPEX = 5.2%
POX	31	37	34	+/- 8.9%	Limited data available on fixed Opex breakdown. - Fixed OPEX/CAPEX = 3.9% (Average of SMR & ATR breakdowns used)
ESMR	25	27	26	+/- 4.5%	<u>IEAGHG</u> - Fixed OPEX/CAPEX = 3.9% (Average of SMR & ATR breakdowns used)
Benchmark SMR		23		N/A	<u>IEAGHG</u> - Direct labour, Admin/general overheads, Insurance and taxes, Maintenance - Fixed OPEX/CAPEX = 4.0%

Steam Methane Reforming

The main sources of information are H21 North of England[65] and IEAGHG[74]. The range in CAPEX is less than +/- 10% and so a sensitivity of 10% is used in this analysis. The fixed OPEX is based on detailed estimates from IEAGHG's Technoeconomic Evaluation of SMR (Case 3 for the CCS case and the Base Case for the Reference Case) and H21 North of England's Report.

The IEAGHG paper and the H21 North of England report (assuming the SMR fixed OPEX has the same cost components as the ATR in the report) both include direct labour, maintenance and operations / overheads. There are some differences between the sources but the fixed OPEX spans a range of 3% to 3.9% of CAPEX, demonstrating close alignment. The range in fixed OPEX is +/- 17.1%.

Partial Oxidation

Data on the POX CAPEX is limited. The bound of costs shown in the Appendices is based on information from stakeholder engagement and proxies from literature, such as the University of Florida[144]. This report recognises the associated uncertainties around this capital cost and highlights these in the Appendices. The range in Capex is less than +/- 10% and so a sensitivity of 10% is used in this analysis.

Data on the fixed OPEX for POX is far more limited than other technologies. An average rate of 3.9% of fixed Capex is therefore used. As a result, the range in fixed OPEX follows that of the CAPEX and is less than +/- 10%. A sensitivity of 10% is used to understand the impact of variation.

Auto Thermal Reforming

The ATR capital cost is based on data from HyNet[99] and H21 North of England's Report[65]. The cost difference between these two variables is minimal, as expected since both are based on Johnson Matthey's LCH configuration with includes a gas heated reactor with the autothermal reactor. The range in CAPEX is less than +/- 10% and so a sensitivity of 10% is used to understand the impact of variation.

The ATR fixed OPEX cost is based on data from HyNet[99] and H21 North of England's Report[65]. The fixed OPEX component from these two sources vary more significantly, between 3.3% (H21) and 5.2% (HyNet) of fixed OPEX, however, the cost components are similar. The range in fixed OPEX is +/-21.8%.

Electrified Steam Methane Reforming

The capital cost for ESMR is based on literature and stakeholder engagement. The upper bound assumes that the cost of installation is the same as Case 1A from the IEAGHG's Technoeconomic Evaluation of SMR report[74]. This uses the Total Plant Cost. The lower bound assumes that there is a reduction in the cost of civils and installation due to the smaller reactor size that is required for the same methane conversion. Based on the dimensions highlighted in Figure 41, it is assumed the reactor takes up 5% of the land area. Cost reduction in capital equipment is not expected to be significant since the size reduction largely comes from reducing the void space in the fired SMR reactor. The range in CAPEX is less than +/- 10% and so a sensitivity of 10% is used to understand the impact of variation.

As for POX, data on the fixed OPEX for e-SMR is far more limited than other technologies. An average rate of 3.9% of fixed CAPEX is therefore used. As a result, the range in fixed OPEX follows that of the CAPEX and is less than +/- 10%. A sensitivity of 10% is used to understand the impact of variation.

[144] http://etd.fcla.edu/UF/UFE0002060/mirabal_s.pdf

7.3.2 Hydrogen Distribution and Storage

Hydrogen distribution costs were focussed on short range distribution within the Rotterdam Port industrial cluster. This was only focussed on gaseous hydrogen pipelines and did not consider LOHCs or ammonia.

Although the pipelines are only 30km, the pricing for medium distance pipelines were used as the annual throughput is ~79ktonnes/yr. The stream was multiplied by the transportation distance. The cost of hydrogen storage was assumed to be included in the hydrogen distribution cost component, as per the assumptions from the IEA's 'Future of Hydrogen[15].

7.3.3 Feedstock

Electricity Prices

- The central forecast for electricity prices in the Netherlands is reported in Table 34.
- 2020 price based on 'Global Petrol Prices'[93] and 'Statista'[92]. Outward trend to 2030 based on wholesale electricity price forecasts from 'Netherlands Climate and Energy Outlook 2020'[88] and data for the Netherlands provided by 'Denmark's Draft Integrated National Energy and Climate Plan[91]. Industrial electricity tax applied assuming that the ratio in 2020 remains constant for outward trends to 2050.
- Outward trend to from 2030 to 2050 based on forward looking trends from 'EU Energy Outlook 2050'[87].

Table 34: Electricity prices by region

Year		2020	2030	2050
Netherlands	*€ / MWh*	94.05	103.17	107.82

Natural Gas Prices

- The central forecast for natural gas prices in the Netherlands is reported in Table 35.
- 2020 and 2030 prices based on CE Delft's 'Energy and electricity price scenarios 2020-2023-2030'[89]. Outward trend to 2050 based on EWI Research Scenarios 'The Energy Market in 2030 and 2050'[90].

Table 35: Natural gas prices by region

Year		2020	2030	2050
Netherlands	*€ / MWh*	21.10	27.40	30.67

Steam Prices

- The central forecast for steam prices in the Netherlands is reported in Table 36.
- This is priced based on data from 'NREL – H2A: Hydrogen Analysis Production Models'[94].

Table 36: Steam prices by region

Year		2020	2030	2050
Netherlands	*€ / kg*	0.0018	0.0018	0.0018

7.4 Ecoinvent / Background Processes and Data Used

7.4.1 Benchmark: SMR NL (based on natural gas) without CCS

Table 37: Environmental impact modelling, sources for hydrogen production via SMR using natural gas as a feedstock in the Netherlands

Input	Modelling / Ecoinvent v3.6 process
Natural gas (feedstock + fuel)	Natural gas, high pressure {NL}| market for
Electricity	See footnote [143]
Raw water	Tap water {Europe without Switzerland}| market for
Cooling water	Water, cooling, salt, ocean
Output	**Modelling / Ecoinvent v3.6 process**
Carbon dioxide, fossil	Carbon dioxide, fossil
Wastewater	Wastewater, average {Europe without Switzerland}| market for wastewater, average
Electricity	See footnote [143]

7.4.2 Steam methane reforming + CCS

Table 38: Environmental impact modelling, sources for hydrogen production via SMR + CCS

Input	Modelling / Ecoinvent v3.6 process
Natural gas (fuel + feedstock)	Natural gas, high pressure {NL}| market for
Electricity	See footnote [143]
Raw water	Tap water {Europe without Switzerland}| market for
Cooling water	Water, cooling, salt, ocean
Output	**Modelling / Ecoinvent v3.6 process**
Carbon dioxide, fossil	Carbon dioxide, fossil
Wastewater	Wastewater, average {Europe without Switzerland}| market for wastewater, average
Electricity	See footnote [143]

7.4.3 Autothermal Oxidation + CCS

Table 39: Environmental impact modelling, sources for hydrogen production via autothermal oxidation + CCS

Input	Modelling / Ecoinvent v3.6 process
Natural gas	Natural gas, high pressure {NL}| market for
Oxygen	Based on Oxygen, liquid {RER}| market for, having changed the electricity demand in the subprocess “Oxygen, liquid {RER}| air separation, cryogenic" from 1,42 kWh/kg O_2 to 0.245 kWh/kg O_2 and Dutch electricity (see next row in this table)
Electricity	See footnote [143]
Raw water	Tap water {Europe without Switzerland}| market for
Output	**Modelling / Ecoinvent v3.6 process**
Carbon dioxide, fossil	Carbon dioxide, fossil (emissions to air)

7.4.4 Partial oxidation (POX)

Table 40: Environmental impact modelling, sources for hydrogen production via partial oxidation (POX) of natural gas

Input	Modelling / Ecoinvent v3.6 process
Natural gas	Natural gas, high pressure {NL}| market for
Oxygen	Based on Oxygen, liquid {RER}| market for, having changed the electricity demand in the subprocess “Oxygen, liquid {RER}| air separation, cryogenic" from 1,42 kWh/kg O_2 to 0.245 kWh/kg O_2 and Dutch electricity (see next row in this table)
Electricity	See footnote [143]
Raw water	Tap water {Europe without Switzerland}| market for
Output	**Modelling / Ecoinvent v3.6 process**
Carbon dioxide, fossil	Carbon dioxide, fossil (emissions to air)
Electricity	See footnote [143]
Wastewater	Wastewater, average {Europe without Switzerland}| market for wastewater, average

7.4.5 e-SMR + CCS

Table 41: Environmental impact modelling, sources for hydrogen production via e-SMR + CCS

Input	Modelling / Ecoinvent v3.6 process
Natural gas	Natural gas, high pressure {NL}| market for
Electricity	See footnote [143]
Raw water	Tap water {Europe without Switzerland}| market for
Cooling water	Water, cooling, salt, ocean

Output	Modelling / Ecoinvent v3.6 process
Carbon dioxide, fossil	Carbon dioxide, fossil (emissions to air)
Wastewater	Wastewater, average {Europe without Switzerland}| market for wastewater, average

7.4.6 Transport and storage of CO_2 (all technologies)

Table 42: Environmental impact modelling, sources for transport and storage of CO_2

Input	Modelling / Ecoinvent v3.6 process
Electricity	See footnote [143]
Pipeline	Pipeline, natural gas, long distance, low capacity, onshore {GLO}| construction | Cut-off, U Scaled to CO_2 pipeline (41% of the materials needed)

7.4.7 Sensitivity analyses Three (both scenarios, all technologies)

Table 43: Environmental impact modelling, sources for sensitivity analyses Three (scenario 1 and 2) (only natural gas, other in- and outputs stay the same)

Input	Modelling / Ecoinvent v3.6 process
Natural gas imported from Algeria to the Netherlands (sensitivity analysis, scenario 1)	Natural gas, high pressure {NL}| natural gas, high pressure, import from DZ | Cut-off, U
Natural gas imported from Russia to the Netherlands (sensitivity analysis Three, scenario 2)	Natural gas, high pressure {NL}| natural gas, high pressure, import from RU | Cut-off, U

7.5 Other Environmental Impact Categories

As explained in Section 5.1, the focus of the LCA in this study is on the carbon footprint as an environmental impact indicator. Additionally, to show possible environmental trade-offs between carbon footprint and other impact categories, the following impact categories are included in this appendix:

- Acidification
- Human toxicity (cancer effects)
- Human toxicity (non-cancer effects)
- Ozone depletion
- Particulate matter
- Ionising radiation human health
- Ionising radiation ecosystems
- Photochemical ozone formation
- Terrestrial eutrophication
- Freshwater eutrophication
- Marine eutrophication
- Freshwater ecotoxicity
- Land use
- Mineral, fossil and renewable resource depletion
- Water resource depletion
- Cumulative non-renewable energy demand.

In the results of each of the environmental impact categories listed above are provided for the different hydrogen production scenarios. Section 5.1.2 gives a more detailed description of the LCA methods used to calculate these results. These results are merely provided to facilitate a comparison of environmental trade-offs between the different scenarios. Comparisons between the impact categories are more difficult to make, i.e. weighing factors should be used in order to be able to compare the results.

The results are shown in Table 44. The most important conclusion to draw from these results is that even though the studied technologies can have lower carbon footprints than the benchmark technology, trade-offs in other environmental impact categories can occur. It is recommended to study this more thoroughly in further research.

Table 44: Effect of natural gas-based blue hydrogen technologies 2020 on all other environmental impact categories listed in Section 5.1.2.

Impact category	Method	Technology					Unit
		Benchmark (SMR, no CCS) TRL 9	SMR + CCS TRL 9	ATR + CCS TRL 7-9	ESMR + CCS TRL 4	POX + CCS TRL 7-9	
Global warming potential	IPCC	10.13	2.78	3.23	5.74	2.43	kg CO2 eq.
Ozone depletion	ILCD	9.43E-07	1.07E-06	1.03E-06	1.09E-06	9.60E-07	kg CFC-11 eq.
Human toxicity, non-cancer effects	ILCD	7.19E-08	1.70E-07	3.26E-07	8.32E-07	3.01E-07	CTUh
Human toxicity, cancer effects	ILCD	3.05E-08	5.46E-08	8.34E-08	1.77E-07	7.64E-08	CTUh
Particulate matter	ILCD	2.25E-04	3.25E-04	4.29E-04	7.79E-04	3.97E-04	kg PM2.5 eq.
Ionizing radiation HH	ILCD	3.84E-02	7.37E-02	1.29E-01	3.04E-01	1.17E-01	kBq U235 eq.
Ionizing radiation E (interim)	ILCD	2.36E-07	3.42E-07	4.71E-07	9.03E-07	4.34E-07	CTUe
Photochemical ozone formation	ILCD	4.10E-03	5.50E-03	6.77E-03	1.13E-02	6.25E-03	kg NMVOC eq.
Acidification	ILCD	4.34E-03	6.03E-03	7.77E-03	1.39E-02	7.16E-03	molc H+ eq.
Terrestrial eutrophication	ILCD	1.02E-02	1.51E-02	2.08E-02	4.00E-02	1.92E-02	molc N eq.
Freshwater eutrophication	ILCD	5.33E-05	2.13E-04	4.90E-04	1.37E-03	4.43E-04	kg P eq.
Marine eutrophication	ILCD	9.74E-04	1.43E-03	1.92E-03	3.73E-03	1.80E-03	kg N eq.
Freshwater ecotoxicity	ILCD	2.58E+00	5.52E+00	1.02E+01	2.38E+01	9.35E+00	CTUe
Land use	ILCD	2.67E+00	3.72E+00	4.83E+00	8.72E+00	4.46E+00	kg C deficit
Water resource depletion	ILCD	1.07E-03	1.12E-03	1.28E-02	3.96E-03	1.32E-02	m3 water eq.
Mineral, fossil & ren resource depletion	ILCD	1.77E-05	2.20E-05	2.53E-05	3.47E-05	2.36E-05	kg Sb eq.
CED, non-renewable	CED	1.76E+02	2.03E+02	1.98E+02	2.24E+02	1.85E+02	MJ

7.6 Results of the Analysis

7.6.1 TEA Tabulated Results

SMR

Tabulated results for the stacked bar charts presented in the TEA analysis for SMR in 2020 and 2050 are displayed in Table 45 and Table 46 respectively.

Table 45: SMR in the Netherlands 2020

		Reference Case	SMR	Reference Case	SMR
		No Carbon Price		*Carbon Price Included*	
Carbon Price	€/kg	-	-	0.54	0.15
H_2 Distribution & Storage	€/kg	0.05	0.05	0.05	0.05
CO_2 T&S	€/kg	-	0.49	-	0.49
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.11	0.11	0.11	0.11
H_2 Production – Fuel	€/kg	0.17	0.28	0.17	0.28
H_2 Production – Feedstock	€/kg	1.02	1.02	1.02	1.02
H_2 Production – Fixed OPEX	€/kg	0.09	0.14	0.09	0.14
H_2 Production – CAPEX	€/kg	0.21	0.37	0.21	0.37
Power Export	€/kg	-0.05	-0.00	-0.05	-0.00
Total	**€/kg**	**1.60**	**2.47**	**2.15**	**2.61**

Table 46: SMR in the Netherlands 2050

		Reference Case	SMR	Reference Case	SMR	SMR
		No Carbon Price		*Carbon Price Included*		
Learning Rate	%	*5*	*5*	*5*	*5*	*20*
Carbon Price	€/kg	-	-	1.72	0.44	0.44
H_2 Distribution & Storage	€/kg	0.05	0.05	0.05	0.05	0.05
CO_2 T&S	€/kg	0.00	0.14	-	0.14	0.14
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.12	0.12	0.12	0.12	0.12
H_2 Production – Fuel	€/kg	0.19	0.32	0.19	0.32	0.32
H_2 Production – Feedstock	€/kg	1.16	1.16	1.16	1.16	1.16
H_2 Production – Fixed OPEX	€/kg	0.09	0.14	0.09	0.14	0.14
H_2 Production – CAPEX	€/kg	0.19	0.34	0.19	0.34	0.27
Power Export	€/kg	-0.06	-	-0.06	-	-
Total	**€/kg**	**1.75**	**2.28**	**3.47**	**2.72**	**2.64**

ATR

Tabulated results for the stacked bar charts presented in the TEA analysis for SMR in 2020 and 2050 are displayed in Table 47 and Table 48 respectively.

Table 47: ATR in the Netherlands 2020

		Reference Case	ATR	Reference Case	ATR
		No Carbon Price		*Carbon Price Included*	
Carbon Price	*€/kg*	-	-	0.54	0.13
H_2 Distribution & Storage	*€/kg*	0.05	0.05	0.05	0.05
CO_2 T&S	*€/kg*	-	0.45	-	0.45
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.11	0.32	0.11	0.32
H_2 Production – Fuel	*€/kg*	0.17	-	0.17	-
H_2 Production – Feedstock	*€/kg*	1.02	1.16	1.02	1.16
H_2 Production – Fixed OPEX	*€/kg*	0.09	0.16	0.09	0.16
H_2 Production – CAPEX	*€/kg*	0.21	0.35	0.21	0.35
Power Export	*€/kg*	-0.05	-	-0.05	-
Total	***€/kg***	**1.60**	**2.49**	**2.15**	**2.62**

Table 48: ATR in the Netherlands 2050

		Reference Case	ATR	Reference Case	ATR	ATR
		No Carbon Price		*Carbon Price Included*		
Learning Rate	%	*5*	*5*	*5*	*5*	*20*
Carbon Price	*€/kg*	-	-	1.72	0.35	0.35
H_2 Distribution & Storage	*€/kg*	0.05	0.05	0.05	0.05	0.05
CO_2 T&S	*€/kg*	-	0.13	-	0.13	0.13
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.12	0.34	0.12	0.34	0.34
H_2 Production – Fuel	*€/kg*	0.19	0.00	0.19	-	-
H_2 Production – Feedstock	*€/kg*	1.16	1.31	1.16	1.31	1.31
H_2 Production – Fixed OPEX	*€/kg*	0.09	0.16	0.09	0.16	0.16
H_2 Production – CAPEX	*€/kg*	0.19	0.32	0.19	0.32	0.25
Power Export	*€/kg*	-0.06	-	-0.06	-	-
Total	***€/kg***	**1.75**	**2.32**	**3.47**	**2.67**	**2.60**

POX

Tabulated results for the stacked bar charts presented in the TEA analysis for SMR in 2020 and 2050 are displayed in Table 49 and Table 50 respectively.

Table 49: POX in the Netherlands 2020

		Reference Case	POX	Reference Case	POX
		No Carbon Price		*Carbon Price Included*	
Carbon Price	*€/kg*	-	-	0.54	0.09
H_2 Distribution & Storage	*€/kg*	0.05	0.05	0.05	0.05
CO_2 T&S	*€/kg*	-	0.40	-	0.40
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.11	0.28	0.11	0.28
H_2 Production – Fuel	*€/kg*	0.17	-	0.17	-
H_2 Production – Feedstock	*€/kg*	1.02	1.09	1.02	1.09
H_2 Production – Fixed OPEX	*€/kg*	0.09	0.13	0.09	0.13
H_2 Production – CAPEX	*€/kg*	0.21	0.32	0.21	0.32
Power Export	*€/kg*	-0.05	-	-0.05	-
Total	***€/kg***	**1.60**	**2.28**	**2.15**	**2.37**

Table 50: POX in the Netherlands 2050

		Reference Case	POX	Reference Case	POX	POX
		No Carbon Price		*Carbon Price Included*		
Learning Rate	%	*5*	*5*	*5*	*5*	*20*
Carbon Price	*€/kg*	-	-	1.72	0.24	0.24
H_2 Distribution & Storage	*€/kg*	0.05	0.05	0.05	0.05	0.05
CO_2 T&S	*€/kg*	-	0.14	-	0.14	0.14
H_2 Production - Water	*€/kg*	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	*€/kg*	0.12	0.30	0.12	0.30	0.30
H_2 Production – Fuel	*€/kg*	0.19	-	0.19	-	-
H_2 Production – Feedstock	*€/kg*	1.16	1.23	1.16	1.23	1.23
H_2 Production – Fixed OPEX	*€/kg*	0.09	0.13	0.09	0.13	0.13
H_2 Production – CAPEX	*€/kg*	0.19	0.30	0.19	0.30	0.23
Power Export	*€/kg*	-0.06	0.00	-0.06	-	-
Total	***€/kg***	**1.75**	**2.16**	**3.47**	**2.40**	**2.33**

ESMR

Tabulated results for the stacked bar charts presented in the TEA analysis for SMR in 2020 and 2050 are displayed in Table 51 and Table 52 respectively.

Table 51: ESMR in the Netherlands 2020

		Reference Case	ESMR Grid Electricity	ESMR Renewable Electricity	Reference Case	ESMR Grid Electricity	ESMR Renewable Electricity
		No Carbon Price			*Carbon Price Included*		
Carbon Price	€/kg	-	-	-	0.54	0.14	0.08
H_2 Distribution & Storage	€/kg	0.05	0.05	0.05	0.05	0.05	0.05
CO_2 T&S	€/kg	-	0.39	0.39	-	0.39	0.39
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.11	0.93	0.93	0.11	0.93	0.93
H_2 Production – Fuel	€/kg	0.17	0.00	0.00	0.17	-	-
H_2 Production – Feedstock	€/kg	1.02	0.97	0.97	1.02	0.97	0.97
H_2 Production – Fixed OPEX	€/kg	0.09	0.10	0.10	0.09	0.10	0.10
H_2 Production – CAPEX	€/kg	0.21	0.25	0.25	0.21	0.25	0.25
Power Export	€/kg	-0.05	-	-	-0.05	-	-
Total	**€/kg**	**1.60**	**2.71**	**2.71**	**2.15**	**2.85**	**2.79**

Table 52: ESMR in the Netherlands 2050

		Reference Case	ESMR	Reference Case	ESMR	ESMR
		No Carbon Price		*Carbon Price Included*		
Learning Rate	%	*5*	*5*	*5*	*5*	*20*
Carbon Price	€/kg	-	-	1.72	0.27	0.27
H_2 Distribution & Storage	€/kg	0.05	0.05	0.05	0.05	0.05
CO_2 T&S	€/kg	-	0.13	-	0.13	0.13
H_2 Production - Water	€/kg	0.01	0.01	0.01	0.01	0.01
H_2 Production - Electricity	€/kg	0.12	0.99	0.12	0.99	0.99
H_2 Production – Fuel	€/kg	0.19	-	0.19	-	-
H_2 Production – Feedstock	€/kg	1.16	1.10	1.16	1.10	1.10
H_2 Production – Fixed OPEX	€/kg	0.09	0.10	0.09	0.10	0.10
H_2 Production – CAPEX	€/kg	0.19	0.23	0.19	0.23	0.18
Power Export	€/kg	-0.06	-	-0.06	-	-
Total	**€/kg**	**1.75**	**2.62**	**3.47**	**2.89**	**2.84**

7.6.2 LCA Tabulated Results

In this appendix, all LCA results given in Section 5.3, are provided in tables.

Table 53 – Base analysis (Section 5.3.2). Carbon footprint (kg CO_2 eq./kg H_2) of each hydrogen production scenario.

	Benchmark (SMR, no CCS) TRL 9	SMR + CCS TRL 9	ATR+GHR + CCS TRL 7-9	e-SMR + CCS TRL 4	POX + CCS TRL 7-9
Natural gas	1.12	1.24	1.10	0.92	1.03
Electricity from grid	-	0.50	1.52	4.68	1.36
Transport & Storage CO_2	-	0.05	0.05	0.04	0.04
Direct CO_2 emissions	9.00	0.99	0.57	0.10	-
of which: Generated CO_2	(9.00)	(9.88)	(8.85)	(7.33)	(7.27)
of which: Stored CO_2	(-)	(-8.89)	(-8.28)	(-7.23)	(-7.27)
Other	0.00	0.00	0.00	0.00	0.00
Total	10.13	2.78	3.23	5.74	2.43

Table 54 – Sensitivity Analysis One (Section 5.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of each hydrogen production scenario – electricity 2030

	Benchmark (SMR, no CCS) TRL 9	SMR + CCS TRL 9	ATR+GHR + CCS TRL 7-9	e-SMR + CCS TRL 4	POX + CCS TRL 7-9
Natural gas	1.12	1.24	1.10	0.92	1.03
Electricity from grid	-	0.17	0.50	1.56	0.45
Transport & Storage CO_2	-	0.05	0.05	0.04	0.04
Direct CO_2 emissions	9.00	0.99	0.57	0.10	-
of which: Generated CO_2	(9.00)	(9.88)	(8.85)	(7.33)	(7.27)
of which: Stored CO_2	(-)	(-8.89)	(-8.28)	(-7.23)	(-7.27)
Other	0.00	0.00	0.00	0.00	0.00
Total	10.13	2.45	2.22	2.62	1.52

Table 55 - Sensitivity Analysis Two (Section 5.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of SMR with a carbon capture rate of 99%

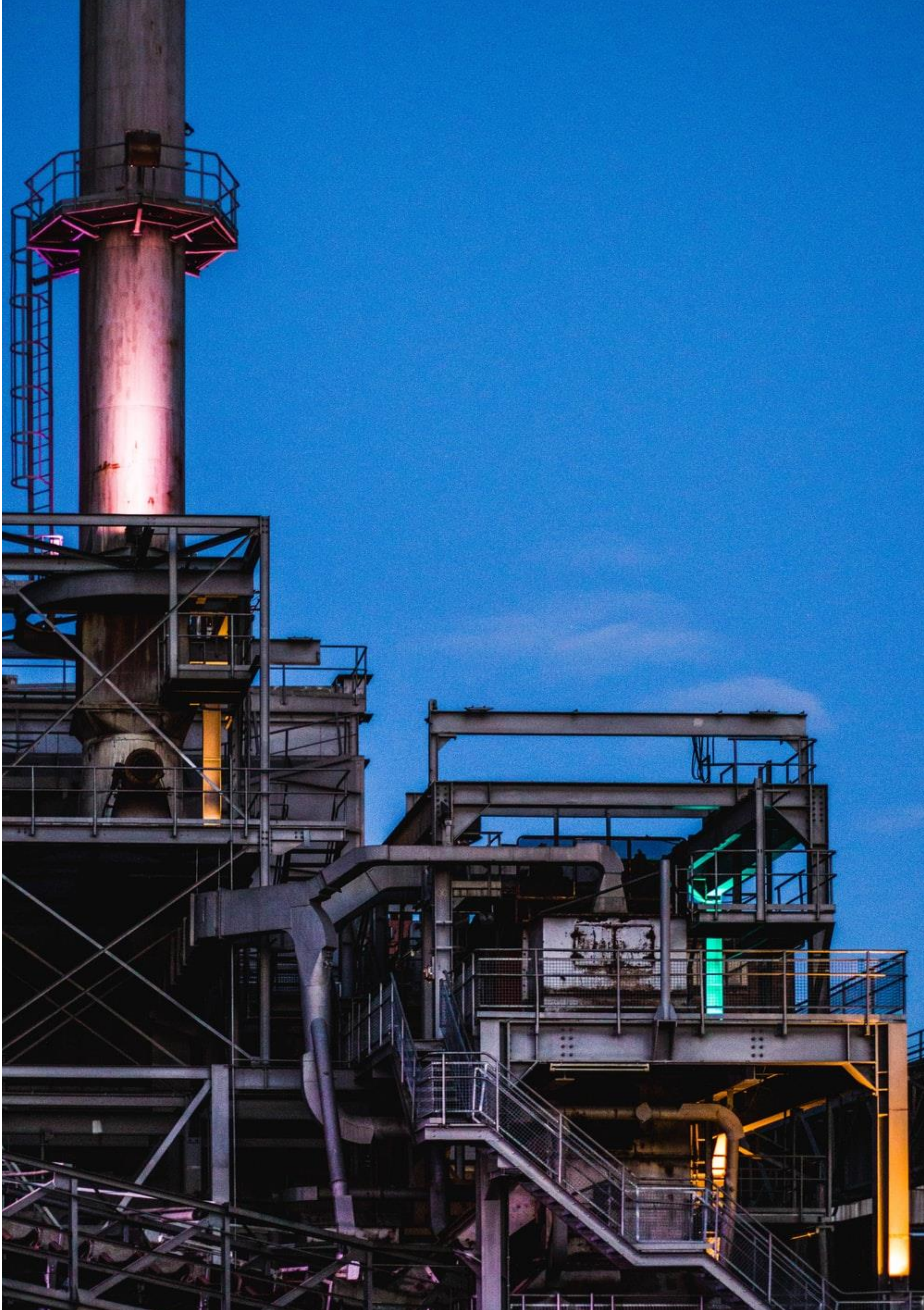
	SMR + CCS TRL 9 carbon capture rate 90%	SMR + CCS TRL 9 carbon capture rate 99%
Natural gas	1.24	1.24
Electricity from grid	0.50	0.55
Transport & Storage CO_2	0.05	0.05
Direct CO_2 emissions	0.99	0.10
of which: Generated CO_2	(9.88)	(9.88)
of which: Stored CO_2	(-8.89)	(-9.78)
Other	0.00	0.00
Total	2.78	1.94

Table 56 – Sensitivity analysis Three, scenario 1 (Section 5.3.3): Carbon footprint (kg CO_2 eq./kg H_2) of blue hydrogen produced in the Netherlands, using only natural gas imported from Algeria

	Benchmark (SMR, no CCS) TRL 9	SMR + CCS TRL 9	ATR+GHR + CCS TRL 7-9	e-SMR + CCS TRL 4	POX + CCS TRL 7-9
Natural gas	1.45	1.59	1.41	1.19	1.33
Electricity from grid	-	0.50	1.52	4.68	1.36
Transport & Storage CO_2	-	0.05	0.05	0.04	0.04
Direct CO_2 emissions	9.00	0.99	0.57	0.10	-
of which: Generated CO_2	(9.00)	(9.88)	(8.85)	(7.33)	(7.27)
of which: Stored CO_2	(-)	(-8.89)	(-8.28)	(-7.23)	(-7.27)
Other	0.00	0.00	0.00	0.00	0.00
Total	10.45	3.14	3.55	6.01	2.73

Table 57 – Sensitivity analysis Three, scenario 2 (Section 5.3.3): Carbon footprint (kg CO2 eq./kg H2) of blue hydrogen produced in the Netherlands, using only natural gas imported from Russia

	Benchmark (SMR, no CCS) TRL 9	SMR + CCS TRL 9	ATR+GHR + CCS TRL 7-9	e-SMR + CCS TRL 4	POX + CCS TRL 7-9
Natural gas	3.04	3.35	2.97	2.49	2.79
Electricity from grid	-	0.50	1.52	4.68	1.36
Transport & Storage CO_2	-	0.05	0.05	0.04	0.04
Direct CO_2 emissions	9.00	0.99	0.57	0.10	-
of which: Generated CO_2	(9.00)	(9.88)	(8.85)	(7.33)	(7.27)
of which: Stored CO_2	(-)	(-8.89)	(-8.28)	(-7.23)	(-7.27)
Other	0.00	0.00	0.00	0.00	0.00
Total	12.05	4.89	5.11	7.32	4.19



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Pure Offices, Cheltenham Office Park, Hatherley Lane,
Cheltenham, Glos. GL51 6SH, UK

Tel: +44 1242 802911
mail@ieaghg.org
www.ieaghg.org