Feasibility study into blue hydrogen

Technical, economic & sustainability analysis

CE Delft

Committed to the Environment

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This report was prepared by:
Lucas van Cappellen, Harry Croezen, Frans Rooijers

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Further information on this study can be obtained from the contact person Harry Croezen (croezen@ce.nl)

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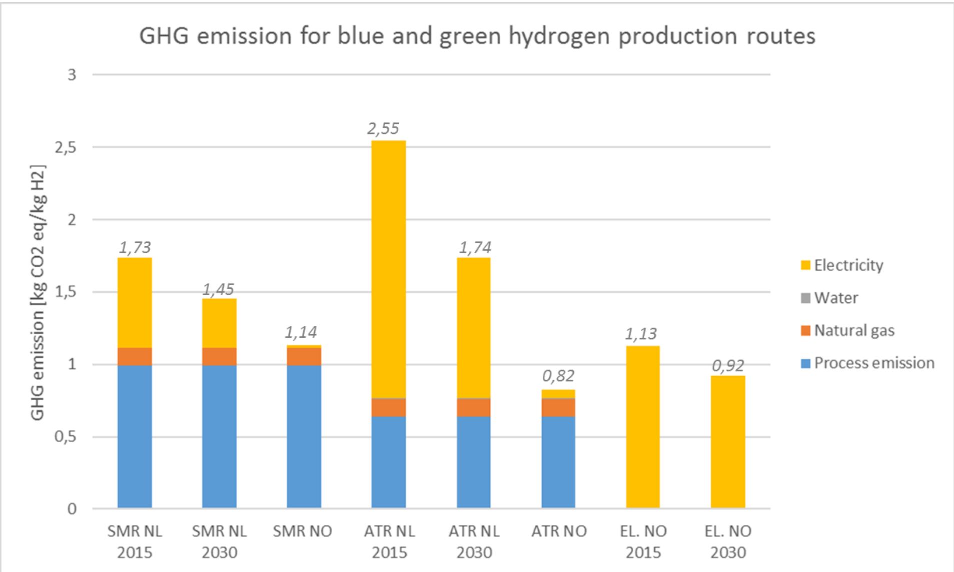
Management summary

CE Delft has performed a study on the techno-economic feasibility and sustainability of blue hydrogen; hydrogen produced from natural gas with CCS. Blue hydrogen is an economically advantageous and feasible method to implement hydrogen in the industry, for which it is one of the few CO_2 reduction strategies. The study shows that the CO_2 footprint of blue hydrogen (0.82-1.12 kg CO_2-eq./kg H_2) is comparable with hydrogen produced via electrolysis with renewable electricity sources (0.92-1.13 kg CO_2 eq./kg H_2) now and towards 2030. Blue hydrogen offers the potential of solving downstream hydrogen challenges regarding transport and applications now, enabling the transition towards green hydrogen in the future. Blue hydrogen should be supported as a transition measure that enables a large CO_2 reduction in industrial areas, such as the harbor of Rotterdam or at the Magnum central.

The challenges ahead require strong governmental policy and support on multiple topics.
Policy focused on CO_2 reduction instead of fossil fuel usage reduction is needed for blue hydrogen to succeed. The interconnection between the transition to hydrogen of the grid, connected industrial applications and hydrogen production units requires an advanced conversion strategy.
This downstream conversion enables hydrogen implementation, however parallel policy is required to guarantee the integration of green and phasing out of blue hydrogen in the upcoming decades.
Furthermore public support for CCS, fossil fuel usage and hydrogen transport are required for the implementation of blue hydrogen.

The research is a system analysis on the five process steps: production via steam reforming, carbon capture and storage, transport in pipelines, daily and seasonal storage and industrial applications. This has been done via extensive literature study, a CO_2 footprint analysis and stakeholder interviews. The chain is viable and can guarantee industrial volume and economic attractive production many years before green hydrogen. The conversion of the gas grid to hydrogen requires research into the replacement of critical components and degradation of pipelines via pilots. Especially research into 100% hydrogen turbines is required, however most applications can be converted (retrofit or renewed) to hydrogen. Hydrogen storage will only limited be required on a system level and would be feasible in cryogenic tanks or salt caverns.

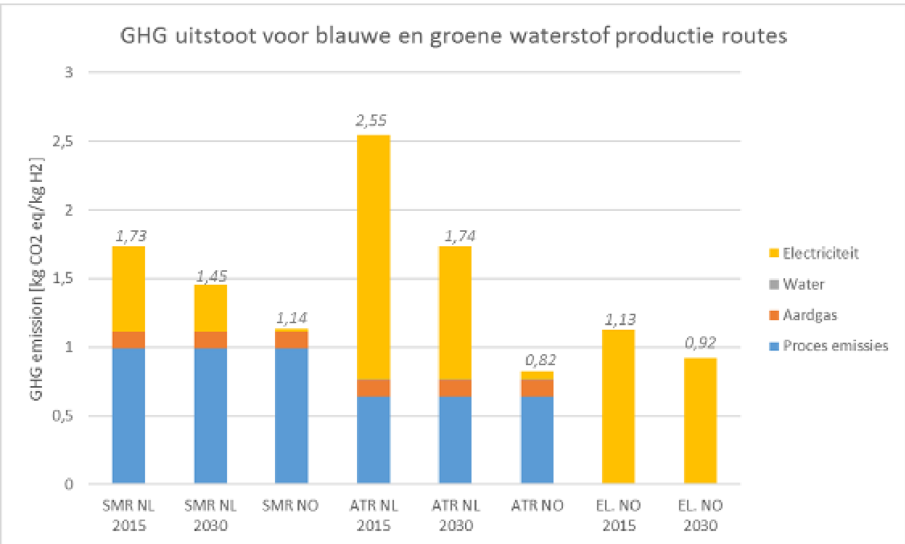


Managementsamenvatting

CE Delft heeft een studie uitgevoerd betreffende de techno-economische haalbaarheid en duurzaamheid van blauwe waterstof; waterstof geproduceerd uit aardgas met CCS. Blauwe waterstof is een economisch voordelig en haalbare methode om waterstof te implementeren bij de industrie, waarvoor het een van de weinige CO_2-besparingsstrategieën is. The studie toont aan dat de CO_2-voetafdruk van blauwe waterstof (0,82-1,12 kg CO_2-eq./kg H_2) vergelijkbaar is met waterstof geproduceerd met elektrolyse uit duurzame bronnen (0,92-1,13 kg CO_2-eq./kg H_2) voor zowel nu als in 2030. Blauwe waterstof creëert de mogelijkheid om downstreamuitdagingen op te lossen in transport en toepassingen nu, waardoor een latere transitie naar groene waterstof mogelijk is. Blauwe waterstof moet worden gesteund als een transitiebrandstof dat een grote CO_2-besparing mogelijk maakt in industriële gebieden, zoals in de haven van Rotterdam of rond de Magnumcentrale.

De uitdagingen vereisen sterk overheidsbeleid en steun op verschillende gebieden. Beleid gefocust op CO_2-reductie in plaats van fossiele brandstoffenreductie is noodzakelijk voor de succesvolle implementatie van blauwe waterstof. Een toegespitste strategie is noodzakelijk voor de gelijktijdige conversie van de gasinfrastructuur, industriële toepassingen en blauwe waterstofproductiefaciliteiten. De downstreamconversie maakt waterstofimplementatie mogelijk, echter is parallel beleid nodig om de integratie van groene waterstof en uitfasering van blauwe waterstof te garanderen. Verder is publieke steun nodig voor CCS, het gebruik van aardgas en waterstoftransport om blauwe waterstof te implementeren.

Het onderzoek is vormgegeven als een systeemanalyse op vijf processtappen: productie via stoomreformatie, koolstofdioxide-afvang en -opslag, transport in pijpleidingen, dag- en seizoensopslag en industriële toepassingen. Hiervoor zijn een literatuurstudie, een CO_2-voetafdrukanalyse en interview toegepast. De procesketen is haalbaar en kan industriële schaalproductie economisch haalbaar garanderen, jaren voordat dit mogelijk is met groene waterstof. De conversie van de gasinfrastructuur vereist onderzoek naar het vervangen van kritieke componenten en aantasting van de pijpleidingen door het uitvoeren van pilots. Voor applicaties is voornamelijk additioneel onderzoek nodig naar turbines waarin 100% waterstof gebruikt kan worden, aangezien de meeste applicaties kunnen worden vervangen of worden omgebouwd. De opslag van waterstof in een industrieel systeem zal beperkt nodig zijn en zou mogelijk zijn in vloeibare waterstoftanks of zoutcavernes.



1 Introduction

In the past months, interest in blue hydrogen has spiked in the Netherlands and internationally. Blue hydrogen is produced from natural gas, usually via steam-reforming, with carbon capture storage (CCS). Blue hydrogen has the potential of large-scale, CO_2-lean hydrogen production with proven, high TRL technologies. Blue hydrogen still requires fossil fuels and CCS, which are under heavy public debate, however can lead to a significant CO_2 reduction.

The use case of this research is the usage of hydrogen in the industry, since it is one of the few options industry has to reduce their CO_2 emissions. Applications are identified in the industry as feedstock and as fuel in burners, fuel cells or turbines. The industry is in need of a sustainable energy carrier to meet their heat demand, leading to momentum for hydrogen. The industry has several intrinsic characteristics that enable a smooth transition towards blue hydrogen. Industry does not have large seasonal fluctuations reducing the need for (seasonal) storage and thus significantly reduces investment cost compared to a use case for the built environment. Industry is often centralized and connected to existing gas infrastructure enabling symbiose and limiting required investment in grid conversion and reinforcements. To ensure a reliable and secure delivery the transport and storage of hydrogen are studied in-depth.

An area in the Netherlands that is considering blue hydrogen and has these characteristics is the Rotterdam region. Additionally, the area is at close proximity to CCS locations in the North Sea which are however limited to tens of megatons for this region. This research will in some parts focus on the Rotterdam Harbour region and a short introduction into the existing initiative in the harbour is discussed at the end of this chapter. The feasibility and sustainability results can however be applied to many regions in the Netherlands and abroad.

1.1 Research questions and methodology

This research should be seen as an assessment of the state-of-the-art technology in the blue hydrogen chain and an outlook into the development of technology. The goal of the research is to formulate key challenges in the chain and related required research. The sustainability will be assessed to determine the CO_2 reduction potential of the blue hydrogen chain and enable comparison with hydrogen from electrolysis. The final goal is to determine the feasibility and form a managerial advice on future blue hydrogen projects in the Netherlands.

To reach these goals three research questions are defined:

1. What are the key challenges in the blue hydrogen chain?
   Paragraph 1.2
2. What is the CO_2 footprint and CO_2 reduction potential of blue and green hydrogen?
   Paragraph 1.3
3. What are the key system and sustainability considerations related to blue hydrogen?
   Paragraph 1.4

The methods that have been used in this research are an extensive desk study, qualitative interviews with approximately fifteen stakeholders and CO_2 footprint calculations in SimaPro. Per chapter the applied methods will be described. An introduction regarding the relevance per research question is given below.

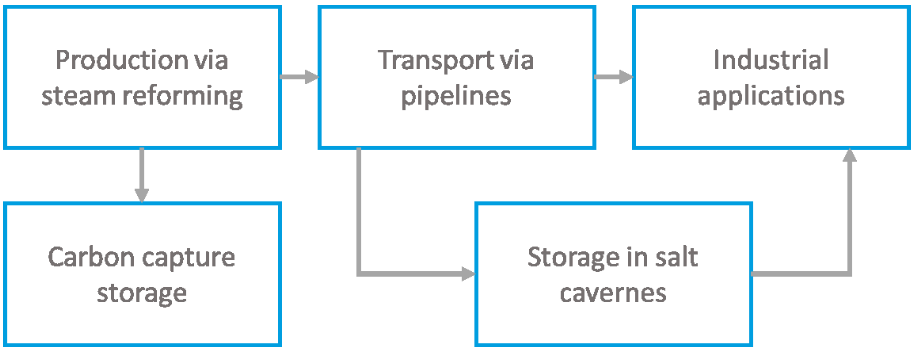
1.2 Challenges in the blue hydrogen chain

The process chain of blue hydrogen exists of five steps: production, CCS, hydrogen transport, daily and seasonal storage and industrial applications. The recent state of technology and challenges per system are determined, based on a literature review and interviews with stakeholders. The process chain analysis can be found in Chapter 3-7. The five process steps that are researched are:

1. Production via steam-reforming (SMR and ATR): Natural gas reacts with hot steam leading to the production of syngas. SMR and ATR are chosen as technology due to their TRL and market share.
2. Carbon capture storage: Based on existing knowledge of CE Delft a brief analysis has been done on the CCS potential in the Netherlands.
3. Transport: Transport of hydrogen via the existing natural gas infrastructure and a new hydrogen network are researched.
4. Storage: Daily and seasonal storage methods are researched.
5. Industrial applications that could potentially use hydrogen as feedstock or fuel are identified and their feasibility to implement hydrogen is analysed.

The process flow of blue hydrogen is shown in Figure 1. In Chapter 2-6 the processes in the chain are discussed. In Chapter 7 the challenges at a system level are identified.

Figure 1 - Process diagram blue hydrogen



1.3 Carbon footprint analysis

A carbon footprint analysis is performed to determine the CO_2 footprint of multiple hydrogen production routes. The goal is to compare different production routes on their sustainability impact. Furthermore, the future hydrogen production mix could be optimized and the CO_2 footprint could be used in managerial decisions. Multiple studies indicate that when CCS is applied, the CO_2 footprint per kilogram hydrogen for SMR, ATR and electrolysis are in the same range. To establish and confirm these results the analysis will be conducted on multiple production routes:

1. **SMR Netherlands:** Hydrogen produced from natural gas with the Steam Methane Reforming process with CCS. The electricity is supplied from the Dutch electricity mix.
2. **ATR Netherlands:** Hydrogen produced from natural gas with the Auto Thermal Reforming process with CCS. The electricity is supplied from the Dutch electricity mix.
3. **SMR Norway:** Hydrogen produced from natural gas with the Steam Methane Reforming process with CCS. The electricity is supplied from the Norwegian electricity mix.
4. **ATR Norway:** Hydrogen produced from natural gas with the Auto Thermal Reforming process with CCS. The electricity is supplied from the Norwegian electricity mix.
5. **Electrolysis Netherlands:** Hydrogen produced from the existing electricity mix in the Netherlands.
6. **Electrolysis Norway:** Hydrogen produced from the Norwegian electricity mix.

Option 1, 2, 5 and 6 will also be performed with state-of-the-art technology for 2030. This enables a future outlook in the development of the CO_2 footprint. The carbon footprint analysis can be found in Chapter 8.

1.4 System and sustainability considerations

Blue hydrogen offers the possibility to enable a large reduction in CO_2 emission. However, the implementation of blue hydrogen raises multiple system and sustainability related questions, which are discussed in Chapter 9. These include the fossil fuel and CCS basis, the necessity of blue hydrogen on a system level and potential symbioses or exclusion between blue and green hydrogen.

To gain a deeper understanding of the potential and social relevance of blue hydrogen, two blue hydrogen initiatives are discussed. These are the H-vision and Hydrogen to Magnum initiatives.

H-vision initiative

The H-vision is discussed here since it is the first potential blue hydrogen project. The project results from a desk study by TNO into large-scale blue hydrogen production in the Rotterdam harbour. The renewed consortium has set the goal to further develop this project and realize it by 2030. The consortium contains fourteen parties from within the harbour and contains parties in the entire process chain. The project is now under guidance of Deltalinqs, a network organization in the Port of Rotterdam supporting inter-organizational collaboration in the harbour. In 2018, a feasibility study will be started on the business case, technological challenges, hydrogen markets and CCS. H-vision's feasibility study could be seen as a more applied and in-depth version of this CE Delft study.

The H-vision project is set out is to realize four steam-reforming plants, at a total capacity of 150,000-200,000 Nm^3 hydrogen per hour, store the CO_2 under the North Sea via the Porthos backbone (Paragraph 3.2) and deliver the hydrogen to industrial parties in the harbour. The first plant is planned to open in 2025 and the hydrogen produced will be transported to parties within the harbour or elsewhere in the Netherlands. The final goal is to capture and store 8 megaton CO_2, for which cooperation of power plants owners in the harbour are needed. The consortium tries to present a hydrogen strategy for the entire Netherlands, which could include for example green hydrogen from the Northern Netherlands, to contribute to the CO_2 reduction required to meet the Paris climate goals.

Hydrogen to Magnum (H2M)

H2M is a collaboration between Nuon, Equinor and Gasunie. Nuon has set the goal to convert their power plant Magnum, located in Eemshaven, to hydrogen. Equinor will develop an ATR plant where hydrogen will be produced and the CO_2 is captured. This CO_2 will be transported to consumers via infrastructure developed by Gasunie. The goal is to integrate a salt cavern to enable system flexibility. This project offers a wide field of applications of hydrogen and would be a first of a kind blue hydrogen project in the world.

2 H_2 production

In this paragraph two standard syngas production processes – ATR and SMR – and associated CO_2 capture technologies are discussed. Production via PO_x methodology is excluded since this process at the moment is used much less in practice. The goal is to assess costs, CO_2 reduction potential, energy efficiencies and possibilities for integration in the blue hydrogen chain. The paragraph is based on recent papers (IEA, 2017; NTNU, 2016) and discussions with two steam-reforming plant producers, Technip FMC and Topsoe.

2.1 Techno-economic analysis

Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) are standard production processes for syngas production from gaseous and light liquid fuels. SMR is utilized primarily for production of syngas with a H_2: CO ratio (vol% : vol%) above 2, as utilized in production of H_2.

ATR is utilized primarily for syngas production with H_2: CO ratio below 2, as for production of CO or CO-containing syngas. Both processes are combined in natural gas-based NH_3 production.
A few other process such as PO_x and CO_2 dry reforming are under research, however limited or no industrial scale plants are available at this moment. ATR and SMR follow approximately the same process which is in-depth discussed in two recent studies (IEA, 2017) (NTNU, 2016). An overview of the process steps is:

1. **Natural gas pre-treatment**
   During the pre-treatment, sulphur and other impurities are removed from the gas to prevent damaging of to the catalyst.

2. **Pre-reforming**
   The pre-treatment often occurs in a adiabatic pre-reformer. In this pre-reformer the gas is pre-heated to increase the energy efficiency and with steam large hydrocarbon molecules are converted to methane.

3. **Reformer**
   In the reformer the methane is converted into syngas, a combination of carbon dioxide and hydrogen gas, using heated steam. ATR and SMR use different techniques for the reforming step.
   a Steam methane reforming (SMR)
   In a SMR reforming step a mixture of hydrogen and carbon monoxide is produced using an endothermic reaction. The process operates in a range of 500-900°C for which heat is generated via the burning of natural gas. Capturing the CO_2 of these flue gasses outside the reformer is difficult, among other because of the large nitrogen percentage and lower operating pressure.
   The chemical reaction of the process is: $CH_4 + H_2O \leftrightarrow CO + 3H_2$ (endothermic)

   b Autothermal reforming (ATR)
   ATR produces hydrogen via an endothermic and exothermic reaction creating a heat balance. The process temperature is between 900-1,150°C. ATR requires oxygen as input, however does not require the burning of natural gas for heat input. All the CO_2 is contained in the reactor at elevated pressure enabling high-capture percentages.
   The chemical reactions for the process are:
   $CH_4 + H_2O \leftrightarrow CO + 3H_2$ (endothermic)
   $C_mH_n + \frac{m}{2}O_2 \leftrightarrow mCO + \frac{n}{2}H_2$ (exothermic)

4. **Water-gas-shift reaction**
   In both processes carbon monoxide is produced which is converted to carbon dioxide using a water-gas-shift reactor. The process takes places at 350-500°C and requires additional water input. The reaction is slightly exothermic. The reaction rate is higher at higher temperatures however then the equilibrium moves to the carbon monoxide side.
   The chemical reaction for this process is: $CO + H_2O \leftrightarrow CO_2 + H_2$ (exothermic)

5. **Hydrogen separation**
   The hydrogen needs to be separated from the syngas which is often done using a Pressure Swing Absorber. The process takes places at high pressure and low temperatures. Normally hydrogen with purities of above 99.95% are reached with maximum CO impurities of 10 ppm.

CO_2 is captured after the water-gas-shift reactor or after the hydrogen separation step. The flue gas of SMR of burning natural gas also contains carbon dioxide which can be captured, however is more difficult due to the high nitrogen percentage. Therefore MEA technology is required. CO_2 separation is done via pressure swing absorption, membrane filtration, cryogen separation or amine processes. The CO_2 capture percentage is higher for ATR than for SMR leading to a lower CO_2 footprint, unless additional measures are taken. A consideration regarding ATR is the need for O_2 input, which can be supplied via an additional factory or industrial symbiosis. This will require electricity for O_2 production and compression, which is also included in the greenhouse gas emission calculations.

Flexibility is an important parameter for steam-reforming plants in future hydrogen scenarios in which intermittent renewables are also implemented. Both SMR and ATR have a cold start-up time of approximately 15-24 hours. Their flexibility during operation is approximately 1% capacity change per minute, so within an hour the production could shift from 40 to 100% of the maximum capacity. The processes have a minimum capacity at around 30-40% due to instrumental and control limitations, however with a special design this could be decreases till 15-20% of the maximum capacity.

Combing multiple techno-economic studies leads to the overview in Table 1. An additional SMR+ scenario is modelled in a Norwegian study enabling higher carbon capture percentage (NTNU, 2016). This requires hydrogen as combustion fuel for heating and separation of flue gasses with MEA technology.

Table 1 - Techno-economic overview steam-reforming

	CO_2 capture	Levelled cost H_2 (€/m³)[1]	CO_2 avoidance cost (€/kg CO_2)
SMR (without capture flue glass)	50-70%	0.135-0.146	0.037-0.060
SMR(with capture from flue gas or H_2 as fuel)	85-90%	0.154-0.165	0.049-0.070
ATR	>90%	0.143	0.048

Technip FMC states that higher capture rates for the SMR processes are possible with additional engineering. The maximum is seen between 85-90%, which is confirmed by scientific studies (IEAGHGH, 2017). Crucial in this discussion is balancing the CO_2 capture percentage versus the additional cost. The capture percentage is seen by the manufacturers as an economic optimization and not as a technical challenge. In Chapter 3 these technical data will be used to determine the life cycle impact of the production methods. The levelled cost of the production methods are in the same range with a slight advantage for SMR. SMR furthermore has the advantage that at the moment it is more widely applied. ATR has a larger CO_2 capture potential and there are indications that ATR could be price competitive above 200,000 Nm^3 per day production, which is much below the plants considered in the studies.

2.2 Market developments

The sizes of SMR and ATR plants vary in a range of 15,000-300,000 nm^3/hour. In literature, a value of 100,000 nm^3/hour or 450 tonnes/day is often found. Both Technip FMC and Topsoe have years of experience in building steam-reforming plants. In the market there is very limited demand for blue hydrogen plants. CO_2 separation is only applied if the CO_2 can also be used as feedstock in a related process. There is an increase in plants were applying CCS retrofit is taken into account during the design process and should be viable, however at the moment there is no business model for capturing the CO_2 for CCS purposes. This requires an ETS CO_2 price at which CCS is feasible. In Port Arthur, Texas USA, in 2011 the first SMR plants with CCS was delivered by Air Products capturing 3 million tonnes in 2016, subsidized by the US government with an investment subsidy. The captured CO_2 is used for Enhanced Oil Recovery (Carbon Capture & Sequestration Technologies, 2016).

In the market an increasing interest in ATR is seen in among other the Norwegian Hyper project and research into the Magnum electricity plant. These projects are aimed at sustainability which largely explains there preference for ATR since the CO_2 capture rates feasible are higher thus leading to less CO_2 footprint.

A change in the hydrogen usage can also lead to changes in required hydrogen specifications concerning impurities and pressures. This might lead to additional process steps concerning purifying and (de-) compression. For example, fuel cells require high grade hydrogen with CO levels below 1 ppm while at the moment the impurities of hydrogen from SMR are around 10 ppm CO.
A feasible implementation strategy is to determine the impurities and process parameters based on the largest consumers and if needed on-site additional purifying should be done. The required output pressure will be determined on the set pressure in the gas grid.

An important design parameter is the purity of the hydrogen, depending on the production facilities configuration following the requirement per application. The consideration for the quality and usage of hydrogen are further discussed in Paragraph 6.4.

2.3 Conclusions

Steam reforming is a proven and widely applied technology. ATR seems to bear the most potential for a blue hydrogen chain since it enables higher CO_2 capture percentage. The maximum capture percentage is an economic optimization and not a technical challenge. At the moment very little plants are built with CCS, however retrofit is often possible. The key challenges in this process of the process chain are:
- The ETS CO_2 price needs to be at a price level at which CO_2 capture is economically feasible.
- The CO_2 capture percentage is an economic optimization and not a technical limitation. Thus increasing capture percentage can be done by CO_2 pricing, subsidies or technological development. The capture percentage of ATR is higher than SMR with the-state-of-the-art technology.

3 Carbon capture storage

CCS is the process in which CO_2 is captured, transported to empty gas field via pipelines or boats and stored indefinitely underground. CCS is essential for blue hydrogen and therefore an analysis on its feasibility in the Netherlands is essential. Furthermore, this chapter discusses political developments in the Netherlands. Finally, this paragraph discusses CCS projects in the Netherlands.

A study from CE Delft concludes that in the Netherlands 30 Mton of CO_2 per year could be stored based on the existing available CO_2 sources. There is a total available capacity of 1,400 Mton offshore. (CE Delft, 2014). CO_2 capture from gasses with high CO_2 percentage is viable. Challenges for the Netherlands are building the needed gas infrastructure and enabling storage in the gas fields. In the Netherlands CO_2 storage below land is prohibited and thus storage under the North Sea or in other countries' territory is required. Several countries are interested in storing CO_2, such as Norway, which could offer the potential to store hydrogen if this is no longer psychically or economically feasible. A challenge is clarity on the liabilities for long-term storage of CO_2 underground, however multiple studies indicate no potential threats.

Scalability is an important parameter for CCS since the feasibility increases with larger volumes, therefore requiring clusters of CO_2 sources. CCS has large fixed and investments cost however the operation costs are low. A larger size pipeline requires only small extra investments. In the Netherlands several clusters can be identified were large-scale CO_2 producers (>50 kton CO_2/year) are centralized in industrial regions enabling efficient carbon capture and transport. A blue hydrogen plant could potentially be part of a larger CCS project in one of these regions. An overview per region and sector for 2017 is displayed in Table 2. The Rotterdam region has the largest potential for CCS. Also towards 2030 when electricity production plants are closed or switched to other fuels, following governmental policy, this region has the largest CCS potential.

Table 2 - Overview potential CCS locations with CO_2 emission above 50 kton/year. All numbers in Mton/year

	Rotterdam	Zeeland - Sloe en Kanaalzone	Moerdijk/ Dordrecht	Chemelot	Delfzijl + Eemshaven	Noordzeekanaal, Amsterdam	Non-clustered	Total
Refineries	9.3	1.5						10.8
Steam crackers		2.7	2.0	1.7				6.4
Production H_2 and NH_3	1.5	3.7		1.6				6.8
Other chemical	1.9	0.4	0.1	0.8	0.4	0.1	0.5	4.2
Base metal industry						12.1		12.1
Building mat. and glass industry			0.1				0.5	0.5
Paper industry						0.1	0.7	0.9
Food industry	0.2	0.2	0.1			0.2	0.7	1.4
	12.8	8.5	2.3	4.1	0.4	12.5	2.4	43.1
STEG	3	2.4	0.6		1.4	1	1.3	9.7
Conventional power plants	7.9		3.5		8.3	3.8		23.5
	10.8	2.4	4.1	0	9.7	4.8	1.3	33.2
AVI's	1.6	0	1.8	0	0.3	1.2	3.4	8.2
	25.2	10.9	8.2	4.1	10.4	18.4	7.2	84.5

Source: (CE Delft, 2014).

In general, per company multiple CO_2 sources in process gas will be found at different process parts. This requires multiple capture locations and a companywide gas network to collect all the captured CO_2. Blue hydrogen has the advantage that a large portion of the CO_2, for ATR all the CO_2, is produced in the reformer leading to a single production point and relatively easy capture strategy.

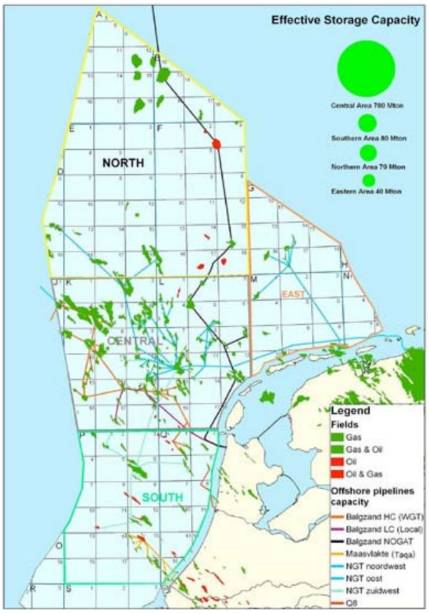
The costs of CO_2 capture at blue hydrogen are expected to be in line with the price at industrial product gasses. The price of € 40-50 per kg CO_2 for pre-combustion is below post-combustion capture at around € 100 per ton CO_2 (CE Delft, 2014). This strengthens the economic feasibility of blue hydrogen, since it applies pre-combustion, over post-combustion at company sites. The post-combustion methodology will require more investment, retrofit built and an on-site CO_2 gas network. At the moment the ETS CO_2 price is around € 10 per ton, meaning that CCS is not economically feasible at the moment and only will be at a price level of € 50 per ton CO_2.

An important necessity for CCS is governmental support and possible also financial support. The Dutch government has stated the objective to capture and store 18 megaton CO_2 per year in 2030. NGO's and experts have reacted surprised on this high amount and there is little conviction this target will be met. The government is reconsidering reducing the target to 7.3 megaton, however this consideration creates additional uncertainties for CCS projects. These large-scale projects are benefited by clear, definite and long-term governmental policy.

3.1 CCS projects in the Netherlands

In the Netherlands there are possibilities for CO_2 storage in empty gas fields in Northern Netherlands and the North Sea. The capacity is 1,400 Mton under sea and 900 Mton for land. In 2028, 600 Mton of the offshore capacity will be available for CCS (EBN & Gasunie, 2010). The fields are displayed in Figure 2 and extend to several 10s of kilometres into the North Sea. The government considers multiple pipelines with a capacity of around 10 Mton from Rotterdam, Amsterdam and Northern Netherlands. The existing natural gas infrastructure could be used to transport the CO_2 from inland towards the coast. Potentially the offshore gas infrastructure can be used for transporting CO_2 gas to the offshore fields. Essential for the future of CCS in the Netherlands is a change in regulation concerning the transfer of ownership of gas fields and closing off of the gas field after it depleting. Both could seriously decrease the CCS potential and hinder CCS projects.

Figure 2 - Gas fields fit for CCS in the Dutch North Sea



Several projects regarding CO_2 capture have been studied, however at the moment none have been realized. In 2010 the first CCS project under land in the Netherlands underneath Barendrecht was cancelled by the government, mostly due lack of social support. Following Barendrecht, CO_2 capture under land was prohibited in the Netherlands. Another setback for CCS in the Netherlands was the cancellation of the ROAD project by Uniper and Engie. In ROAD, CCS would be applied to coal-fired power plants in the Port of Rotterdam but after three years of delay Engie and Uniper could no longer justify additional investment and started research into other alternatives for their power plants, including transfer to gas powered power plants.

At the moment the Port of Rotterdam is working on a new CCS project and backbone named Porthos. This is at the moment the most promising and furthest developed CCS project in the Netherlands.

Porthos
Porthos is a project initiated by the Harbour of Rotterdam and continues on the ROAD CCS project. The goal is to develop a 10 Mton pipeline connected to offshore-depleted gas fields. In 2021 or 2022 the pipeline should be operational, however not yet at full capacity. In total the harbour produces 30 megatons CO_2 per year, from which 15 megatons from power plants and 15 megatons from industry. Carbon capture will take place at some of the largest industrial parties which cover over 95% of the CO_2 emissions from industry. Potential blue hydrogen projects, such as H-vision, could be connected to this CO_2 backbone. The goal of the harbour is to take responsibility from the gate of the industrial partner. There is public support from the harbour, municipality and province for the project and CCS in general.

3.2 Conclusion

The Netherlands has a need for CCS to meet the targets of the Paris agreement. Large-scale, CO_2-rich gas flows have a large potential for CCS. The key challenges in this process of the process chain are:

- The technical challenges are the CO_2 transport infrastructure and enabling CO_2 storage in the depleted gas fields.
- The Netherlands at the moment has no experience with CCS projects and thus pilots are needed to create enough hands on knowledge to implement large-scale CCS projects.
- At a CO_2 price of around 50 euro CCS is feasible with as interesting locations Rotterdam, Amsterdam and Northern Netherlands. This requires a multiplication of the ETS CO_2 price for CCS to be economically feasible.
- There no conclusive social acceptance for CCS in the Netherlands, also if the CO_2 is stored under the North Sea. A renewed view on CCS is a necessity to meet the Paris agreement goals for blue hydrogen to succeed.

4 H_2 transport

There are two feasible scenarios for creating a hydrogen infrastructure. The existing Dutch natural gas grid can be converted to be able to transport hydrogen or a new hydrogen network can be built parallel to the existing grid. The transport of hydrogen is seen by parties in the process chain as one of the key challenges. At the same pressure hydrogen has less than a quarter of the energy-content of natural gas. There are concerns regarding the capacity and the suitability of the existing infrastructure and the conversion strategy.

4.1 Converting natural gas infrastructure

To determine the feasibility firstly the existing gas infrastructure is discussed. Then the technical, legal and social considerations will be discussed.

4.1.1 Existing natural gas grid

The natural gas grid in the Netherlands can be divided into the high-caloric gas (H-gas) and low-caloric gas grid (L-gas), also known as Groningen Gas (G-gas). Low-caloric natural gas is extracted from the Groningen gas field and high-caloric gas is often imported from for example Norway and Russia. H-gas and L-gas networks are connected at mixing stations were nitrogen is added to the H-gas before entering the L-gas network. The H- and L-network are physically comparable and a change in configuration is easily possible. The existing grid is displayed in Figure 3 with in yellow the H-gas network and in black the L-gas network. A second dichotomy is the transmission grid network (HTL and RTL) and distribution grid network. The transmission grid is managed by TSO Gasunie and connects to the distribution grid via around 1,000 gas distribution points (GOS) to the RTL level.
The distribution grid contains low-caloric gas. Local DSO like Stedin, Enexis and Alliander manage the distribution grid.

Figure 3 - Dutch natural gas network

An important parameter to determine the feasibility of hydrogen in the gas infrastructure is the availability of capacity. Gasunie Transport Services performed a quick scan and determined that in the future HTL-pipelines could be made available to a maximum of 15 GW in the upcoming years (DNV GL, 2017). A recent development in the market is the governmental decision to stop gas extraction in Groningen from 2030 and a gradually decrease in extraction in the upcoming years. This lowers the export of L-gas to neighbouring countries and will require more H-gas from abroad. Additionally the gas demand will decrease 1% per year according to GTS. It can be expected that there will be a decrease in volume flow through the L-network which could potentially lead to availability of pipelines. The H-network is also used for international transit and thus the developments are also related to geopolitical developments. Neighbouring countries do have direct connections to gas-exporting countries, for example the pipeline from Norway to Belgium, creating possibility to also decrease the volumes in the H-network leading to potential availability in the network. Since the H-gas network is mostly used for transport to power plants and industrial sites this network is most interesting for the transition of blue hydrogen in the industry. Gasunie expects that in the future three networks (H-gas, L-gas and hydrogen) will exist alongside each other.

Pipelines can be converted from H-gas to L-gas with little effort, which is also done sporadically in the Netherlands. The largest challenge is converting the applications connected to the grid. For the HTL these are often a limited amount of industrial sites. The existing strategy is to switch all the connected burners during a certain period of time and during this operation the renewed burners operate under non-ideal conditions on the old gas. If all the burners are converted the gas is changed from L-gas to H-gas or the other way around. This strategy enables the possibility that if the volumes in the L-gas and H-gas network both decrease these could be combined to enable more available pipelines for other applications. However this does require strong top-down governmental intervention and will have an impact on all the connected sites.

Gasunie Transport Services has created a new subsidiary, GTS Waterstof, which is responsible for hydrogen transport projects. Their first conversion in the Netherlands is 'Waterstof in de Regio', on which an information bulletin can be found on page 20. NAM owns and operates a gas grid that links production locations to a central processing hub which might be suitable for transporting renewable gases. In the GZI Next study, NAM investigates re-purposing their Assets (including pipelines) around Emmen, which could result in re-use for biogas or hydrogen production, storage and transport.

4.1.2 Technological feasibility conversion

Hydrogen has intrinsic different properties than natural gas influencing the gas pipelines and other components in the grid. As is often mentioned hydrogen is the smallest molecule and therefore people intuitively identify problems regarding hydrogen infrastructure. Important considerations are the integrity of the pipelines, integrity of other components in the gas network, regulation and safety and the capacity of the network.

The DNV GL report and Leeds h21 research have shown that the existing pipelines have surprisingly limited challenges regarding hydrogen transport (DNV GL, 2017; Leeds City Gate, 2016). Research in the NaturalHy project has shown that hydrogen will lead to more fatigue of the pipelines, however the process can be performed safe and reliable (NaturalHy, 2010). The fatigue is strongly related to pressure changes in the tubes which can be an important parameter regarding line packing, described in Paragraph 5.1. Transporting hydrogen can lead to hydrogen embrittlement however research has shown this is not of large influence. Embrittlement could be prevented if a mixture is transported however no in-depth research is found in this topic. The existing infrastructure is built from steel with the characteristics with the steel types X42-X70 for which no large challenges can be identified under constant pressure.

The other components in the gas grid are compression and reduction station, measurement instruments/stations and plastic components. At the moment piston and centrifugal compressors are used in the Dutch gas network. Hydrogen will require a higher flow for which the centrifugal compressors are not designed. For piston compressors it is uncertain if the components are suited for hydrogen compression. Research is needed into all compressors to determine their applicability and replacement. It is expected that measurement instruments need to be replaced due to the nature of the gas. The plastics in the gas grid such as O-rings and gaskets in for example valves will lead to higher gas losses if hydrogen is applied, however it needs to be determined if these losses are excessive. The effect will be larger in distribution grids due to a larger quantity of these components.

Another critical parameter is to determine if the existing capacity of the grid is adequate when hydrogen is transported. Hydrogen has an energy intensity (higher heating value) of 12 MJ/Nm^3 compared to approximately 40 MJ/Nm^3 for H-gas and 35 MJ/Nm^3 for L-gas. This creates the need for a three times higher volume flow. The density of hydrogen is a factor 9 lower than natural gas.

The pressure drop is the critical design parameters for a gas grid, since the pressure drop determines the needed tube diameter and compressors power. The higher volume flow and lower density compensate each other in the pressure drop calculations and is thus most likely in the acceptable range. DNV GL concludes that 80% of the H-gas and 98% of the L-gas energy capacity can be transported with hydrogen in a grid with the same volume. This does require a higher speed in the gas grid which can result in more vibration-related issues and erosion of the pipelines. This could also result in more pressure drop and thus a too low pressure in the end of the pipeline. Additional research beforehand and monitoring during operation is needed to determine these effects. The gas speed in the network is at the moment limited by regulation at 20 m/s while the transport of hydrogen would require 30 m/s to meet the same energy capacity as natural gas. A regulatory change is therefore needed.

The final consideration is the relative safety of hydrogen compared to natural gas and the related regulation. The flammability of hydrogen will require specialized maintenance with specific tools and more precaution. Potential leakages of a gas and its flammability danger leads to a risk contour around a pipeline. Hydrogen is classified as chemical and thus has different regulation than natural gas pipelines leading to higher risk calculations and contours. There is little research on the dangers of hydrogen in and outside of the risk contours, effects of a rupture and radiation effects. The different classification can lead to significant issues if natural gas is replaced, however scientific research leads to believe that the safety issues of hydrogen are at minimum comparable with natural gas. Therefore additional research and new regulation regarding the risk contours should be made. Otherwise parts of the grid cannot be converted to hydrogen due to buildings and inhabitants in the risk contour.

4.1.3 Economic and social consideration

Conversion of the existing natural gas network to hydrogen requires an economic investment but also offers a change to give new value to existing assets. The utilization of the Dutch natural gas grid will decrease, leading to huge write offs if the infrastructure is not reused. Hydrogen offers the potential of reusing the gas infrastructure in a sustainable economy. The costs of converting the grid are still unknown for the case in this study. The first conversion of natural gas pipelines to hydrogen is undertaken at the moment in the 'Waterstof in de Regio' project. Therefore no economic data is available on the price of converting the gas infrastructure. This is also strongly dependent on the amount of critical components, such as compressors and measurement instruments, age and status of the network. Interviewees indicated that the conversion cost will be between 5-30% of investment cost of a new natural gas network. The expectancy is that the cost of a new hydrogen network will be comparable or higher than a natural gas network. Another important economic parameter is the conversion time, both for the network operator as gas consumers. However at the moment Gasunie does not have estimates for conversion duration on large-scale.

Social acceptance and support of the hydrogen grid is essential. The projects will require governmental support, which will therefore also require public support. Hydrogen projects such as 'Aardgasbuffer Zuidwending' and 'Waterstof in de regio' show that social support for hydrogen (infrastructure) projects can be created by sharing information and dialogues with surrounding inhabitants and municipalities. The social acceptance of larger hydrogen infrastructure is difficult to determine and will be influenced by the determination of the risk contours and what lies within these contours. Social acceptance will be higher at industrial sites.

4.1.4 Ownership and organizational considerations

An important development regarding the hydrogen market is who will be the asset owner and the organization set-up of the gas market. The set-up of large-scale blue hydrogen requires an extensive network with an operator. Gasunie operates the natural gas network at the moment and Air Liquide and Air Products operate private hydrogen networks. From a system view, Gasunie would be the preferred owner of the gas network since it can make investment in the grid, which are not directly connected to a contractor, has experience with operating a national gas grid, might be able to convert some parts of their natural gas grid to hydrogen and could speed up the energy transition. Air Liquide and Air Products have no business in operating a gas grid and have also a different target consumer. It is to be expected that Gasunie will be the owner of the gas infrastructure. Depending on the market type of the future hydrogen market an operating strategy and operator will have to be selected. In the future, integration between the operation of Air Liquide, Air Products and Gasunie could be an option.

4.1.5 Market design considerations

The natural gas market has developed in the past decades from a closed market existing of bilateral contracting between big parties towards an open TTF market (Title Transfer Facility). The existing hydrogen market in the Netherlands is also based on bilateral contracting. The expectancy it is in the interest of government and parties in the natural gas industry for the hydrogen market to develop in the same manner as the natural gas market. An open trading market enables protection of small consumers and enable price competition between different producers and blue and green hydrogen. The market also enables the government to guide the transition to renewable sources. An important requirement is a state-owned gas network, as Gasunie is now, is obliged to connect all producers and consumers.

4.1.6 Implementation strategy conversion

The conversion of the gas grid is both a technical and operational challenge. The h21 Leeds research touches upon the conversion of the gas grid (Leeds City Gate, 2016). Their strategy is to convert separate areas in the medium and low-pressure network. Inserting the hydrogen is done on different points than the natural gas, enabling the potential of moving the separation point in the network. This strategy could be viable and could minimize the outage time of consumers. It does require planning and operational excellence, to ensure delivery security and pressure stability during the entire conversion strategy.

The conversion of the grid will have to go exactly parallel to the conversion of all connected industrial consumers of these parts of the grid. This firstly requires consensus between all parties regarding conversion to hydrogen, or strong governmental intervention forcing connected parties, and matching of operation and conversion of these parties. These parties have a stop every 4-20 years at which conversion would be the least-worst moment. The planning of multiple connected parties maintenance moment with the grid development require strong management and planning.

It also means that there are 1-3 moments for conversion until 2030 for most parties, or would require an additional and expensive stop for the conversion to hydrogen.

The implementation of a hydrogen conversion is very case- and location-dependent.
The conversion of the gas grid creates additional planning and management issues. At this moment the implementation strategy remains one of the large uncertainties and debates related to hydrogen implementation.

4.1.7 H-grid connections

From the analysis of the natural gas market and network it is determined that converting the H-gas HTL network has the largest feasibility and impact. An analysis has been made of the 81 connected parties to the H-gas network on 1-1-2018 (Gasunie Transport Services, 2018). An overview of the connections per region is displayed in Table 3. The sector of these companies is based on the company and site characteristics and the applied technologies are estimated. These results are displayed in Table 4. A strong clustering in the Rotterdam region can be seen. Most of the companies connected to the H-gas network are situated in the specifically Botlek region.

Converting the industry in the Rotterdam region to blue hydrogen via the gas network would thus lead to the largest CO_2 savings, however also requires support from the parties connected to the grid.
There is a legal obligation to connect consumers to the gas grid and it is uncertain what will happen to a grid conversion project if some of the connected parties do not want to convert to hydrogen.
For a successful transition, all the connected parties would have to convert to hydrogen or an alternative.

Table 3 - Connections to H-gas network in the Netherlands

Region	Location	Amount of connections
Rotterdam	**Total**	**52**
	Botlek	23
	Europort	9
	Maasvlakte	5
	Pernis	7
	Rijnmond	1
	Rotterdam	6
	Rozenburg	1
Delfzijl	**Total**	**8**
	Delfzijl	7
	Eemshaven	8
Geleen	**Total**	**7**
	Geleen	6
	Maasbracht	1
Ijmuiden	**Total**	**5**
	Ijmuiden	2
	Velsen	3
Remain	**Total**	**8**
	Amsterdam	2
	Harlingen	1
	Lelystad	1
	Nieuw Hinkeloord	1
	Schoonebeek	1
	Sluiskil	2

Table 4 - Sector and technology for the connections

Sector	Amount	Technologies
Industry	24	Burners, turbines, engines
WKC	20	Turbines
Terminals	10	Burners, turbines
Power plants	7	Turbines
Refineries	6	Feedstock, turbines
Unknown	4	-
Methanol production	3	Feedstock
Ammonia production	2	Feedstock
Hydrogen production	2	Feedstock
Bio refineries	1	Feedstock
OER NAM	1	Feedstock
Palm oil refineries	1	Burners, turbines
Total	81	

'Waterstof in de Regio'

The first conversion from a natural gas pipeline to a hydrogen pipeline has been done in the 'Waterstof in de Regio' project. This experience is a first step towards a hydrogen infrastructure. The project in Zeeland is called 'Waterstof in de Regio' meaning 'hydrogen in the region'. In the project, a redundant natural gas pipeline is extended to connect the industrial sites of Yara and Dow, two chemical companies, over a distance of 10 kilometers. 4.5 kiloton excessive hydrogen per year will be transferred from Dow to Yara for fertilizer production. The project enjoys local governmental support and will lead to a 10,000 kiloton CO_2 reduction. The pipeline is managed by Gasunie Waterstof Service (GWS), which is new subsidiary of Gasunie. The pipeline is relatively simple since no critical components such as compression and measurement stations are situated on the pipeline. The project is a unique change for the Netherlands to create hands-on experience regarding hydrogen infrastructure and implementation.

4.2 New hydrogen infrastructure

The alternative to converting the existing natural gas grid is to build a specific hydrogen grid. At the moment there are two hydrogen grids in the Netherlands operated by Air Liquide and Air Products. These grids connect producers and consumers of hydrogen via a dedicated network. Air Liquide operates the largest European network in France, Belgium and the Rotterdam region with a total length of 1,000 km. Air Products operates a 140 km long pipeline system in the Rotterdam region. These networks are designed specifically to the bilateral contracts of these parties. Therefore it is not expected that there is enough reserve capacity for addition of large-scale hydrogen factories.

A pathway for large-scale implementation could be that the Air Liquide pipeline network functions as the start of the hydrogen infrastructure. It is however questionable if Air Liquide would be interested in selling their infrastructure. The network contains now industrial grade hydrogen and it is uncertain if the new gas network will also contain industrial grade or energy generation rate, more consideration on this topic can be found in Paragraph 6.4.

A dedicated hydrogen network is technically and could be economically feasible. Such a network has been realized on large-scale internationally and in the Netherlands. It will however require a larger investment than when the existing natural gas grid can be converted. Interviewees indicated that conversion of the existing grid require 5-30% of the cost of a new infrastructure. In the h21 Leeds project, studies have been done regarding transmission hydrogen systems. The costs were estimated at 1 million pounds per kilometre. If an additional network is built this should be made parallel to the existing natural gas grid, thereby enabling an easier conversion strategy for industrial consumers.

Additional research should be done in the techno-economic feasibility of a new hydrogen network if there is no availability in the natural gas network. This should also contain the feasibility of line packing (Paragraph 5.1).

4.3 Conclusion

Two feasible paths for large-scale hydrogen are identified: conversion of the natural gas network and building a new hydrogen infrastructure. The economics of both options are still very uncertain, however the costs of conversion are estimated to be between 5-30% of building a new infrastructure. The development of the national and international market will determine the capacity of the existing grid that can be made available for hydrogen transport.
The key challenges in this process of the process chain are:
- Pilots are needed to gain more experience on large-scale infrastructure conversion, mostly regarding critical components, maintenance, and operation.
- Conversion and the management of this conversion of the gas network and connected applications remains one of the main challenges, if a new hydrogen network is built this enables a smoother transition pathway for industrial consumers.
- New scientific-based regulation needs to be developed and applied so that possible incorrect policy will not block a hydrogen infrastructure.
- Based on market developments, parts of the network that can be converted need to be identified and the needed adaptions have to be determined.
- Politics has and will influence the gas market in the Netherlands. The government can influence the gas usage decrease in the Netherlands and limit the transit of gas via the Dutch gas network to create more available capacity.

Policy decisions have to be made on the characteristics of the grid such as the design of the hydrogen grid, including decision on the basis of the grid, and the hydrogen purity.

5 Storage

Storage of hydrogen is needed to compensate a mismatch between supply and demand on timescales from minutes to seasons. Storage can be used to enable flexibility in supply and demand and thereby ensure security in delivery and purchase. The first and most important question is if and in which quantity hydrogen storage will be needed in our industrial system. There are only small daily variances in industrial processes and except for industries based on natural growing process, such as sugar production, there are no seasonal variances. The steam-reforming process has a certain flexibility (~1% of the capacity per minute) which could be sufficient to cover the needed flexibility. For a blue hydrogen project it will be essential to determine the cumulative flexibility demand and the related storage volume and pattern. The needed volume and the filling and evacuation speed will be the essential parameters in selecting a storage method.

To determine feasible storage techniques, existing natural gas storage techniques are identified. Natural gas can also be stored in aquifers but are not used in the Netherlands, due to excessive capacity in natural gas fields and salt caverns. Therefore these are excluded from the research. Three daily buffer methods are identified, one seasonal buffer strategy and salt caverns could be used for both daily and seasonal storage. The identified techniques are:

- Line packing (daily storage): Storage in the gas network by varying the operating pressure.
- Tanks for compressed gas – gaseous (daily storage): Small scale storage in for example cylinders in gaseous phase.
- Liquid natural gas (daily storage): Storage in tanks of LNG exist in both small and large-scale. Gasunie operates a large-scale LNG storage in the Rotterdam harbour.
- Salt caverns (daily and seasonal storage): Underground storage mostly for daily buffering in caverns originated from salt extraction.
- Depleted gas field (seasonal storage): The NAM operates two depleted gas fields where very large portions of natural gas are stored for seasonal buffering. Taqa in Bergen (NH).

For these five technologies research has been conducted to determine their applicability in a hydrogen scenario. Hydrogen could also be stored in aquifers, however these need to be developed and are at the moment not present in the Netherlands.

5.1 Line packing

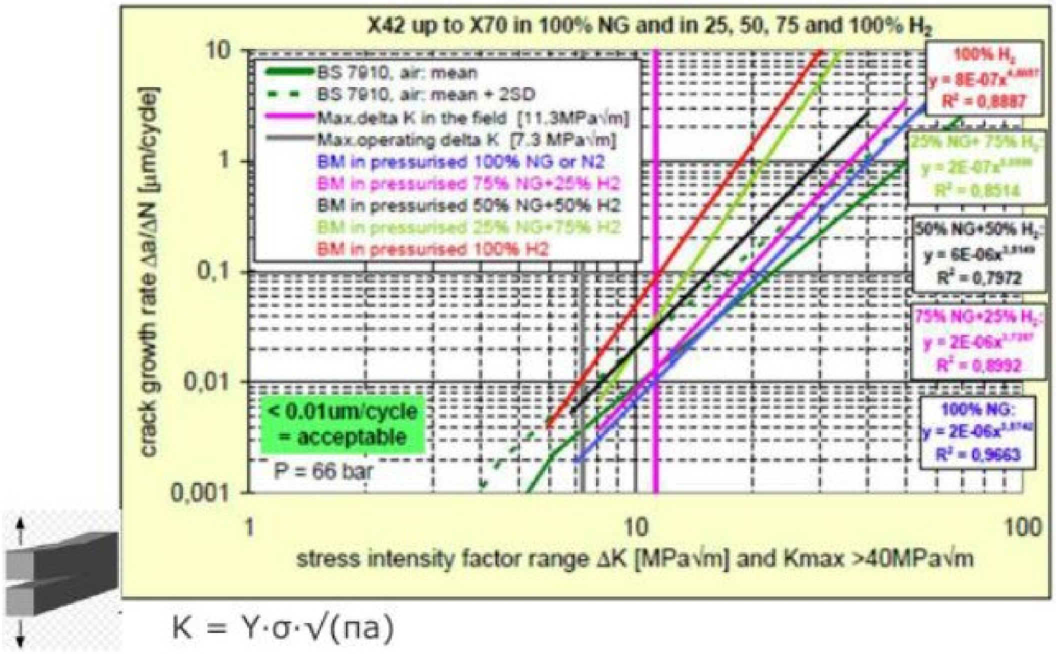
Line packing is the process in which the pressure in the gas network is changed and thus the volume present in the grid. The capacity of this storage method depends on the volume of the network, the maximum pressure differentiation and the speed in the pipelines. Line packing is only used for daily storage to compensate for small variations. Hydrogen can be stored in the same manner as natural gas via line packing. However due to the lower energy intensity and related higher speed in the pipelines the storage capacity via line packing is only 1/3 compared to natural gas in the same pipeline at the same pressure.

Another limiting factor for line packing capacity is the maximum pressure variation. A pressure variation leads to a force on a crack in the pipe leading to an increase in crack length. This parameter can be interpreted as fatigue and damage to the material and will lead to additional losses and need for maintenance or replacement. Research in the NaturalHy project shows a strong relation between pressure changes (horizontal axis) and growth of cracks in pipeline material (vertical axis) in Figure 4. The red line is 100% hydrogen and the blue line is 100% natural gas. Pressure changes in hydrogen pipelines will thus lead to approximately ten times larger crack growth rate per pressure change cycle.

This could further decrease the maximum pressure differentiation or amount of switch cycles making line packing less attractive as alternative. The pressure itself is not the main challenge.

A careful consideration has to be made whether hydrogen line packing is safe and does not lead to excessive deterioration. Additional investments on storage need to be compared with additional investment in infrastructure reinforcements, maintenance and replacement. A new infrastructure can be designed to withstand line packing and therefore offer an additional (economic) advantage over conversion of the existing natural gas grid.

Figure 4 - Relation between pressure changes and crack growth. In red 100% hydrogen and 100% natural gas



5.2 Gaseous tanks

Storing hydrogen in tanks, in gaseous phase, is used for small-scale delivery and storage. Many gas sellers deliver hydrogen in cylinder or tube trailer which can be delivered as such or filled on-site via trucks. Air Liquide cylinders have a capacity of 50 litre, a pressure of 200 bar and are available in trailers of 16 cylinders. Suppliers offer cylinders varying in size and working pressure. Hydrogen cylinders can be used for small demand industrial processes and fuel cells. In the development of pilot fuelling stations cylinders are also often used. Cylinders seems feasible for local storage, however for daily storage at a system level the capacities will be too limited at a working volume of 10 m^3 working volume per cylinder. An advantage over liquefied hydrogen is that gaseous tanks do not require the conversion steps. Based on the capacity required of a party it is decided between these two relatively small storage methods.

5.3 Liquefied hydrogen

Hydrogen as a gas can prove difficult to store and needs to be stored at high pressures to increase the relatively low-energy content. An option is to store hydrogen in the liquid phase (LH_2) at a temperature below -252.9°C. The volumetric energy density increases by a factor 4 compared to 200 bar gas storage. Liquefaction requires significant cooling and more advanced storage methods, but is an often applied technology for larger consumers. The conversion losses are approximately 15% which are a significant downside of liquid hydrogen. The hydrogen is stored in cylindrical, vacuum-insulated tanks with capacity ranging from 5 up to 100 m^3 (Air Products, 2014).

Liquefied hydrogen can be transferred using trucks with a capacity of 45-65 m^3. Furthermore, LH_2 ships are being developed by among others Kawasaki, which aims at a capacity of 2,500 m^3 set for 2020 (Platt, 2017). Research has been conducted into the design of a 200,000 m^3 tanker (Abe, et al., 1998). The development of these ships enables international trade in hydrogen and also large-scale storage.

Liquid hydrogen storage is feasible for larger consumers. At the moment the volumes are too small for storing hydrogen at a system level, however no reason is found to indicate that the volumes of these storage tanks could not be increased. The loss in efficiency and more sophisticated tanks are the main disadvantages of liquid hydrogen. Locally storage of hydrogen in cryogenic tanks seems feasible and could be used to compensate for daily differentiation for individual users. There are however significant projects researching the potential of liquid hydrogen as energy carrier such as Hyper.

Hyper Project

Hyper is a Norwegian research project which focusses on fundamental research regarding liquefying hydrogen using heat exchangers. The goal is to perform fundamental research on the liquefaction process and design a pilot project. Transporting hydrogen in its liquid phase has the advantage that the energy density is 200 times higher but has several technical challenges. The hydrogen is produced from natural gas via ATR to reach higher capture rates. Their research indicates that the Norwegian electricity price needs to decrease from 30 NOK to 10-15 NOK for electrolysis to be price competitive with blue hydrogen. The hydrogen will be produced and liquefied in the north of Norway and could then be exported to Europe or Japan. This creates a new value proposition for the available natural gas reserves in Norway. The project teams view is that pipelines are not feasible because of the long distances and thus explores the liquefaction pathway. At the moment no LH_2 tankers are available which is a necessity. The development in liquefied hydrogen offer potential for storage in the future however is not feasible on an international, industrial scale in the upcoming years

5.4 Salt caverns

In the Netherlands there are two underground methodologies for storing natural gas namely salt caverns and depleted gas fields. Salt caverns are large columns in salt layers from 300-1,500 meter below ground created by the extraction of salt for human consumption. Salt is a fully gas tight material for most gasses and has therefore been used extensively to store gasses. Since the 1970s hydrogen has been stored in caverns in among others Texas, USA. The empty caverns are typed by a high injection- and production speed since the gas flow does not experience any resistance of a rock matrix (TNO, 2014). Furthermore salt caverns are very clean and salt is inert, meaning it will not react with the hydrogen that is stored.

In the Netherlands a total of five caverns is used for natural gas storage (Aardgasbuffer Zuidwending) and one for nitrogen storage in Winschoten. Zuidwending has a total volume of 620 million m^3 volume capacity, of which half is cushion gas. The injection capacity is 1.1 million m^3/hour and the production speed is 1.8 million m^3/hour. At Zuidwending there is potential for five more caverns, of which one is already planned. Salt caverns generally have a working pressure between 80-180 bar, with a

maximum pressure change of 10 bars per day. There is a large dependency of the working pressure on the above ground installation and stability of the salt layers. The maximum pressure is determined based on a pressure factor, normally around 0.18, multiplied by the depth of the cavern.
The energetic losses due to compression are approximately 7-10%. Although salt caverns have a much larger capacity than tanks, the capacity is still very small compared to the depleted gas fields that are now being used for seasonal storage of natural gas. Because of the stability of the salt, caverns can be used for daily storage since this storage type requires higher injection and extraction speeds and more cycles.

TNO has conducted research into the potential of salt caverns in the Netherlands of which the results are displayed in Figure 5. It has done studies to determine the storage capacities of all these areas and determined the maximum amount of salt caverns that can be realized. The assumption are that there needs to be a distance of 210 meters between the caverns, a cap of 100 meter salt above the cavern, 150 meters from the cavern to the sides of the salt layer and a cavern depth of 90 meter. The study did not consider the quality of the salt, the impact of soil subsidence and above ground usage. Therefore it can be expected that 25-50% of the potential caverns can in practice be realized.
A differentiation has been made between large caverns (size >300 meters) and small caverns (50-300 meters).

The results can be found in Table 5. In total the maximum amount for large and small caverns are 545 and 160 caverns respectively. The realistic amount for large and small caverns are respectively 136-272 and 40-80 caverns. A study from CE Delft 'Net voor de toekomst' has indicated that a capacity of approximately 9 PJ or 150 large salt caverns filled with hydrogen are required for a stable grid (Netbeheer Nederland, 2017). This implies that if all the possible salt caverns are built, seasonal buffering would be viable taken into account the other defined measures in the 'Net voor de Toekomst' study.

Figure 5 - Overview of location in the Netherlands suited for salt caverns (TNO, 2014)

Table 5 - Overview potential maximum number of salt caverns in the Netherlands (NLOG, 2018)

Location	Potential caverns (>300 m)	Potential caverns (100-300 m)
Anloo	29	18
Gasselte-drouwen	-	-
Hoogeveen	3	19
Hooghalen	74	32
Onstwedde	133	4
Pieterburen	78	13
Schoonloo	16	3
Ternaard	63	37
Winschoten	44	17
Zuidwending	105	17
Total	545	160
Realistic estimation	135-272	40-80

An existing natural gas salt cavern can be converted into hydrogen storage or a new cavern can be created. If an existing cavern is converted it is first filled with brine salt after which the above ground installation is replaced. The brine salt is pushed out with hydrogen after which the salt cavern is operational. The above ground installation has to be suited for hydrogen and has a different energetic balance. The pressure in the aboveground installations needs to be altered to match the grid pressure. The temperature of natural gas decreases with a pressure decrease, will the temperature of hydrogen gas increase (known as the Joule-Thompson effect). In conversion of the salt cavern the largest costs are in the above ground installation. These costs depend largely on the required injection- and production speed. The conversion of a natural gas fields requires the extraction of existing gas, without creating disturbances in the rock layers, and the insertion of large amount of hydrogen as cushion and working gas. This will require a significant operation and will require vast amounts of energy. (Amid, et al., 2016) estimate 4-5 GWh to fill a normal size reservoir if the cushion gas is already in place.

HyStock

The natural gas buffer in Zuidwending is operated by Energy Stock. Third parties can use its services to store and trade natural gas. Two years ago it has started a project with Gasunie New Energy called HyStock. The HyStock project has two objectives. Firstly to gain experience with hydrogen by producing it via electrolyse from solar panels. This hydrogen is distributed to a local hydrogen fuelling station via tube trailers. The second goal is to determine the feasibility to convert one of their caverns to hydrogen storage. This cavern has a volume of 1 million Nm^3 in which it could store 6.100 ton H_2 with an energetic capacity of 240,000 MWh. At the moment a solar and electrolyser installation are being installed. The results of the study are expected in the end of 2018. There are no indications that the existing caverns are not suited for hydrogen storage technically and much knowledge is generated regarding converting the cavern towards hydrogen.

5.5 Gas fields

In the Netherlands natural gas is stored in empty gas fields for seasonal differentiations or peaks. These gas fields are filled during summer and evacuated during the winter. The Netherlands contains three gas fields used for natural gas storage in Norg (NAM, L-gas), Grijpskerk (NAM, H-gas) and Alkmaar (TAQA). The installation in Alkmaar is a peak installation with a peak production capacity of 36 million cubic metres per day and working gas inventory of 500 million cubic meters. In Grijpskerk the NAM operates a seasonal storage facility with a peak production capacity of 61 million cubic meters per day and a storage capacity of 2 billion cubic meters. The seasonal storage facility in Norg has storage capacity of 7 billion cubic meters with a maximum production capacity of 96 million cubic meters. GasTerra has long-term contracts with TAQA to use their capacity and is the owner of the capacity of Norg and Grijpskerk to balance the gas market in the Netherlands.

The basic concept for hydrogen storage in gas fields is that these structures have proven capable of gas storage over millions of year. Due to the large volumes the empty gas fields could be an interesting option to store green and blue hydrogen in the future. If hydrogen would be used in sectors with a higher seasonal differentiation, such as low-temperature heating, storage will be essential. The main challenges for storing hydrogen in depleted gas fields that we identify are:

- Hydrogen leakage from the gas fields. Studies find relatively small percentages of hydrogen leakages at 0,035% after twelve months (Amid, et al., 2016). This however is dependent on the geographical configuration of the gas field and needs to be studied per field. Furthermore the fields are situated below land in the Netherlands in a region that has little social acceptance for underground activities. The potential leakages of hydrogen could thus be a social barrier.
- Organic reactions in the gas fields and impact on rock composition. (EnergieSpeicher, 2017; Amid, et al., 2016; Stone, et al., 2009). Residues, such as natural gas, in the gas fields and the sand structures itself can lead to organic reactions between hydrocarbons and hydrogen and present substances. The result will be the production of micro-organism, H_2S and methane. This will contaminate the hydrogen and can also lead to microbiological, chemical and mineralogical reactions potentially influencing storage capacity and reservoir sealing. Natural gas could also contaminate the hydrogen if it does not lead to chemical reactions via mixing, although this is generally seen as a smaller probability. Pressure changes in the field can also lead to disturbances in the rock layers and potentially lead to surface disturbances.

From interviews conducted the general consensus is that storing hydrogen in depleted gas fields could be feasible, however a lot of additional research is needed. The key challenges require research into exact mineralogical and microbiological research per location to determine the feasibility. The NAM at this moment has not done any study regarding the feasibility of hydrogen in their assets. Therefore the potential of storing hydrogen in the Netherlands in depleted gas fields is uncertain, however definitely challenging.

5.6 Conclusion

Multiple storage techniques for hydrogen have been identified and analysed. An overview of the techniques can be found in Table 6.

Table 6 - Overview of technologies for hydrogen storage

	Storage function	Capacity/unit (m^3)	Feasibility
Line packing (NG grid)	Daily	-	Uncertain
Gaseous tanks	Daily	0.05	Proven
Liquefied hydrogen	Daily	5-100	Proven
Salt caverns	Daily/seasonal	300,000-500,000	Proven
Gas field	Seasonal	2-7 billion	Uncertain

The remaining question is if based on your system scope storage is needed in the system. Based on the needed characteristics the optimal storage methods can be selected:

- Storage necessity and characteristics have to be determined, in the use case of blue hydrogen for industry there might be no need for storage.
- Line packing requires no to small additional investment, however the feasibility is uncertain for hydrogen due to degradation of the pipes. Degradation would result in increased cost for maintenance and replacement.
- Tanks for gaseous hydrogen have a too limited capacity for storing hydrogen on a system level.
- Cryogenic hydrogen tanks have the capacity to store hydrogen for seasonal differentiation on a local scale.
- Salt caverns are present in the Netherlands, can be built converted to hydrogen and have a capacity large enough for day buffering and maybe seasonal storage on the system level.
  An in-depth study is required to determine the amount of salt caverns that can be realized.
- Gas fields have a large capacity however very little is known whether the fields are stable enough for hydrogen. Furthermore, potential reaction between hydrogen and organic materials in the fields are unknown and a threat.

6 Applications

Natural gas is used in the Dutch industry as fuel and as feedstock. If natural gas is used as feedstock it is often converted into hydrogen using steam-reforming. As a fuel it is burned with burners, in furnaces or turbines. Hydrogen can be used in fuel cells which could be another usage compared to natural gas.

If the natural gas is used as feedstock for hydrogen production it can be easily switched. If natural gas is used as a raw material it will be more challenging to replaced, and 'green gas' would be a more feasible sustainable alternative. Sites that are now connected to a steam-reforming plant will most likely not be interested in converting to hydrogen supplied via the gas grid. This requires a strategy to connect existing hydrogen infrastructure to a new infrastructure based on the existing gas grid.
The different usage methods will be analysed in their feasibility for hydrogen usage.

6.1 Burners

Hydrogen is an intrinsically different gas than natural gas and will require burners with a different configuration. The temperature, flame length and colour are different for hydrogen. Many stakeholders have identified these as significant issues and as a potential barrier for hydrogen implementation. Therefore, the usage of hydrogen in industrial burners will require new burners or new furnaces. Stork employees have been interviewed regarding the feasibility of hydrogen burners and they indicate no large issues. In the industry they have built multiple large-scale hydrogen burners (3-50 MW) with state-of-the-art technology. There is extensive experience with mixtures including hydrogen and pure hydrogen in burners and furnaces.

The operation, and thus the design, of the burners and surrounding furnaces need to adhere to the same regulation as for natural gas. This is identified as the main challenge for the conversion to hydrogen. In many cases, it is possible to retrofit the burners but sometimes a new furnace will be needed. The regulatory limit that is exceeded firstly is regarding NO_x emissions. The production of NO_x is higher for hydrogen due to its higher adiabatic flame temperature. A lot of company and scientific research has been done in minimizing the NO_x emission for hydrogen burners and the most feasible option is exhaust gas recirculation (EGR) (Igawa & Seo, 2011; TU Delft, 2018; Heffel, 2003). EGR means the flue gasses are reintroduced in the burner and thereby the oxygen level and temperature decreases. This reduces the NO_x emission levels. If a lower NO_x level needs to be met, reduction catalyst can be implemented. These filters are however expensive and will lead to additional energy losses.

6.2 Turbines

At the moment turbines are capable of handling hydrogen mixture, normally with natural gas.
To understand the challenges of hydrogen turbines it is firstly important to discuss the two largest challenges for turbines:

- NO_x emissions: NO_x are created in flames at high temperatures when fuel is burned in the present with nitrogen-containing air. NO_x emission are harmful for the environment and therefore limited by legislation.
- Flashback: A flashback is the occurrence when flame travels upstream, so contrary to the normal flame direction. This can lead to potential damage to the combustion chamber and combustor, requiring more maintenance and quicker replacement. There are two types of flashbacks:

- Free stream flashback: In front of the combustor the flame travels into the combustor since the flame speed is larger than the speed with which the fuel is injected. The combustor is damaged by multiple flashback.
- Boundary level flashback: On the edges of the flame in the combustion chamber, the flame speed is lower. Therefore flashback could occur due to variations in gas flows and disturbances in the sides of the combustion chamber.

Furthermore, it is also important to make a distinction between two types of turbines:

- Non-mixed turbines: Fuel is injected in the centre of the combustion chamber and air on the side of the start of the chamber. Where the air fuel ration is one the fuel ignites. To prevent excessive NO_x emissions if hydrogen is burned, the flame needs to be cooled using steam. This steam would normally be used in the turbine and therefore leads to significant efficiency losses. Efficiencies of these turbines could drop to 30-35%.
- Pre-mixed turbines: Fuel and air are mixed before entering the combustor leading to a lower flame temperature. Therefore additional cooling is not needed which increases the efficiency. The maximum efficiency of pre-mixed turbines at the moment is 60-65%.

Turbines are designed for operation at maximum load. Therefore operation in a flexible mode will potentially lead to higher NO_x emissions and more flashback. Turbines are seen in some future energy system scenarios as flexible production as compensation for intermittent renewables sources. Therefore research is required into how turbines can operate within technical and emission limits on lower load. This is especially needed for hydrogen turbines since little information is known at this moment.

The largest challenge for hydrogen turbines is the development of combustors that can ensure stable operation, within NO_x and flashback limits, without reducing the efficiency. If additional cooling is required this will lead to significant efficiency losses. There are no physical limitations that create a maximum hydrogen percentage, however more research time and funding is required. Therefore additional research is required in pre-mixed hydrogen turbines.

Several manufacturers are working on turbines capable of handling hydrogen rich or pure hydrogen. Siemens has tested up to 40 and 50% hydrogen-rich mixtures. Ansaldo is working on commercializing combustors for hydrogen percentages up to 60% and is developing 100% hydrogen turbines.
A researcher at TU Delft estimates that a minimum of ten years is required to develop 100% hydrogen turbines. Combustors need to be developed that can be used in pre-mixed turbines to ensure that hydrogen is used efficiently.

An important advantage for the implementation of hydrogen turbines is that combustor can be retrofitted into existing turbines. This enabling an economic feasible conversion, if there are no large additional efficiency losses, and relatively quick implementation into the industrial processes.

In conclusion, existing turbines can handle hydrogen mixtures and several companies are developing turbines and combustors capable of handling hydrogen-rich mixtures. Significant research is required before 100% hydrogen turbines can be realized with a research time of at least ten years. The main challenge is developing turbines that operate within NO_x emission limits and without excessive amount of flashbacks, on partial and full turbine capacity.

6.3 Fuel cells

Fuel cells offer the potential to produce electricity and heat from hydrogen for industrial parties. Large-scale fuel cells could potentially be an interesting alternative for combined heat-power cycles. An additional notion is that if the heat can be used, as in many industrial processes, the efficiency of fuel cells is a less prominent issue. The heat can be used and thereby a significant increase in energy efficiency occurs and the cooling issues are diminished. The industrial processes have a larger demand for high-temperature heat and thus in the industrial systems high-temperature fuel cells will be preferred.

At the moment the largest available fuel cell is 80 kWel produced by SunFire. These units are still in the pilot phase and will require significant scale up to be relevant for the industrial processes discussed. The industry will also require improvements regarding investments and lifespan.

Using hydrogen as a transport medium for electricity production should be seen in the light of limitations to the existing electricity grid. There will be additional losses in the conversion steps, however there are also indications by many grid operators that the grid will be a limiting factor in the future for further electrification. In these cases the conversion to hydrogen and local usage in fuel cells could be an interesting future method, especially with the localized heat usage that could be met.

6.4 Hydrogen quality considerations

Hydrogen can be used as feedstock and fuel. The requirements per application differ greatly and three qualities can be identified:

1. Fuel cell quality: Pure hydrogen without any contamination of for example CO.
2. Industrial grade: Hydrogen with a purity of above 99.95%, the standard Air Liquide and Air products quality. Now mostly used as feedstock in the industry.
3. Energy production grade: This category contains all the hydrogen mixture with a lower purity hydrogen > 95%. This is hydrogen standard produced in steam-reforming processes.

Purification of hydrogen requires of course additional investment. There is often discussion, also during the interviews, regarding hydrogen usage as fuel or as feedstock. Fuel cell quality and industrial grade are high-quality chemicals and therefore there is logically some resistance for it to be used in turbines or furnaces. Multiple interviewees indicated a preference for feedstock over fuel. Interestingly from a CO_2 reduction perspective there will be little differences between usage as fuel or feedstock.

In a gas network the quality will be the same per location and over time, which is also of importance for the design and operation of industrial processes. It is to be expected that the quality in the gas network is determined by application group with the largest consumption. Local purification could be considered to connect hydrogen-fuelling station, requiring fuel cell grade, in case of industrial grade hydrogen. If the goal of a blue hydrogen project is to maximize the impact, all applications should be connected. However for energy production grade it would also be viable to compare alternatives, as electrification, from a CO_2 reduction and energy efficiency perspective and determine the optimal scenario.

6.5 Conclusion

The usage of hydrogen as feedstock is very common in industry and will not lead to any other problems. The usage of hydrogen as fuel in the industry can be challenging and requires more additional research. An important system parameter is the hydrogen quality:

- Hydrogen burners are available and are already installed in multiple industrial installations. The integration in furnaces requires mostly handling of emission and could therefore require adaptations.
- 100% pure hydrogen turbines are in development, however the maximum hydrogen purity is at the moment between 40 and 60%.
- Fuel cells could potentially be interesting for combined heat-power production for industry, however a lot of technological development is required.
- The conversion and conversion strategy for industrial users is uncertain and requires additional research.

7 Feasibility conclusion & system challenges

The process chain analysis has led to a determination of the key challenges per process. An overview of these challenges can be found in Figure 6. On a process level the conclusions are:

- **Production:** Steam-reforming is on a high TRL level. For CCS to be added to these plants an increase in ETS CO_2 price level is required. The capture percentage depends on the CO_2 price and is an economic, not a technical, optimization.
- **Carbon capture storage:** CCS is a proven technology however with no existing project in the Netherlands. Therefore demonstration projects are required to realize a CCS pipeline and open up CCS fields. The ETS CO_2 price will determine the economic feasibility and volumes realisable. Public acceptance in the Netherlands is not uncontested and is a threat.
- **Hydrogen transport:** Hydrogen transport in natural gas pipelines is feasible, but requires replacement of most likely all other components of the grid. The conversion and implementation of the grid and connected applications requires much additional detailed research. New safety regulations based on scientific methods need to be made for hydrogen as energy carrier. Finally the specific capacity and its location in the existing gas network needs to be determined. Building a new, parallel hydrogen infrastructure is feasible at significant higher cost. The roll out and design of the hydrogen grid needs to be decided, as well as the hydrogen purity which will largely depend on the connected consumers.
- **Hydrogen storage:** Hydrogen storage in salt caverns is feasible and could be realized relatively quickly in the Netherlands. Line packing with hydrogen will lead to additional wear out of existing pipelines and requires additional investigation into the precise effects. Gas fields are likely to be unfeasible for hydrogen storage. However if research shows that hydrogen could be stored it would significantly increase the potential of hydrogen for among other low-temperature heat since it enables large-scale seasonal storage. The main overall question is whether storage is needed in the system if the consumption is season-independent and the production has a certain flexibility.
- **Industrial applications:** Manufacturers are able to realize hydrogen burners and furnaces. Hydrogen turbines are being researched however not technical feasible at the moment. Industrial fuel cells offer potential for combined power and heat applications, but need significant scale-up and further development. The conversion of industrial applications is technical feasible however the economic impact and implementation strategy is still uncertain.

On a system level, four key challenges are identified. These challenges are cross-sectional and vital for the realization of a blue hydrogen chain. They are combinations of problems from different processes and require significant research and actions from stakeholders across the chain.

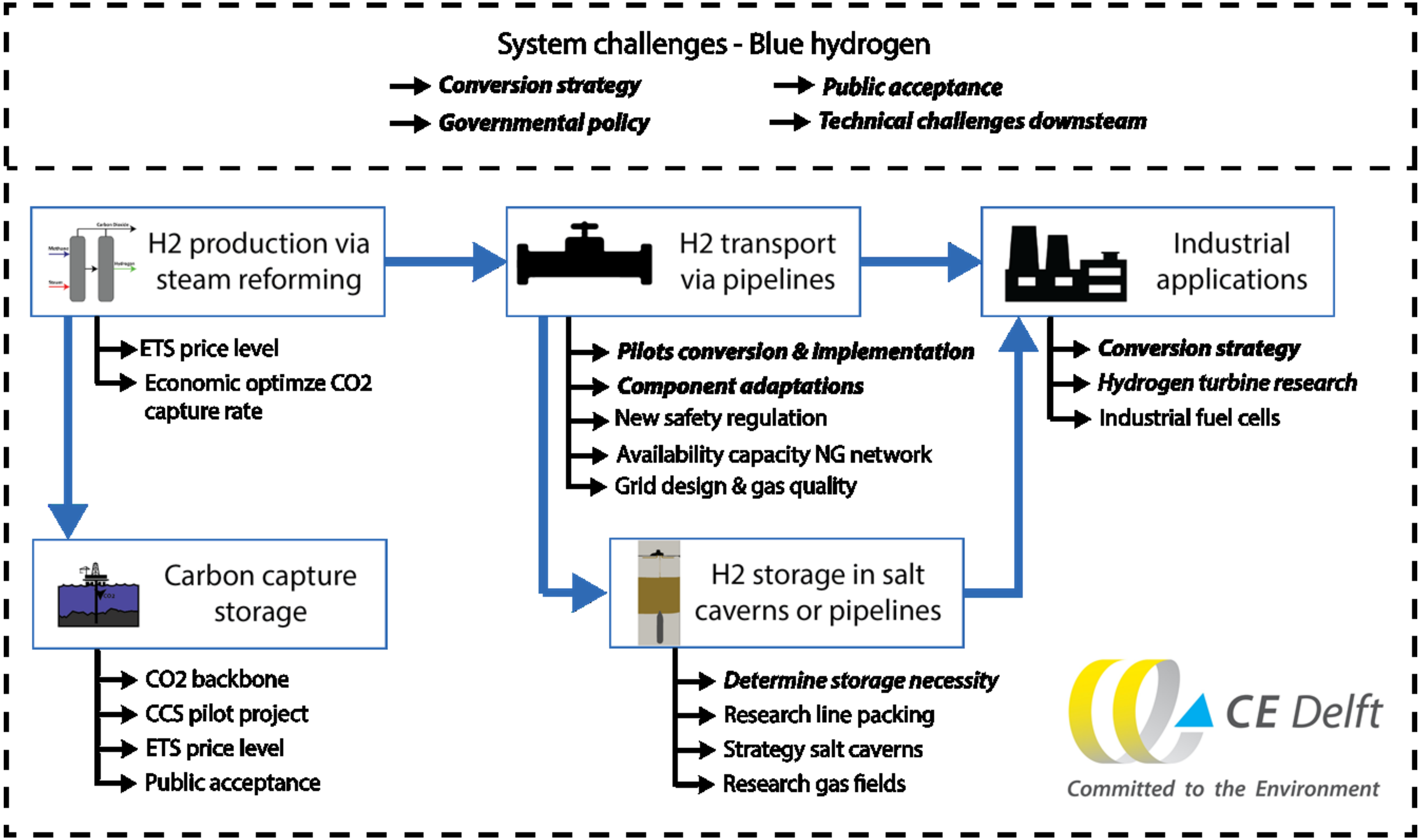
A **conversion strategy** for the region has to be made to unite the connection of production plants, conversion of the infrastructure and conversion of the applications. A change in a system as large as the harbour of Rotterdam requires exact planning and agreement between all the stakeholders.
The conversion needs to overcome multiple technical challenges of which some are a world's first at this scale. Such a project is a pilot but can have huge influences on the operation and finances of both infrastructure owners and industrial consumers. The interdependency of especially transport and applications are very strong and issues in the chain could significantly obstruct a smooth integration.
A conversion strategy is required to create reliability for stakeholders and prevent delays, to ensure participation and investment.

A blue hydrogen project will require clear long-term **governmental policy**. The government has a responsibility to meet the Paris agreement goals, however also has an obligation towards its citizens and companies to protect their income and competitive position. A large-scale blue hydrogen project will require governmental support and investment in among other infrastructure conversion, CCS and subsidies for different steps in the process chain. If the government cannot support companies in the right manner, there is a change of movement to other countries or a decrease in profit and employees. The government will also have to make clear statements regarding its position on the usage of fossil fuels and CCS targets. To ensure the integration of green hydrogen, parallel policy is required on the integration of green hydrogen in the system to ensure long-term sustainability.
To battle climate change and reduce CO_2 emissions, the government will have to make decisions on which measures to take and how these measures can be taken without damaging the Dutch economic position too much. Industries will require long-term commitment from the government to make the needed investments and process changes.

Public acceptance is important in the context of blue hydrogen since some process steps are contested. The fossil fuel basis, CCS, hydrogen transport, hydrogen storage and connected safety risk in all these processes are disputed and under debate in the Netherlands. This report has shown that many of these measures are needed to battle climate change and people understand that action has to be taken. It will be the responsibility of both the project partners as the government to inform the (local) population of both the necessity and risks of any measure to reduce CO_2 emission.
Especially for the identified process steps dialogues, information prevision and risk analysis are extremely important to create public acceptance.

The **technical challenges downstream** in the hydrogen process chain need to be resolved, which are the same for green as blue hydrogen. Before steam-reforming plants will be built and connection can be made with CCS project, it is essential to have consumers of this hydrogen process chain and be able to supply them via a reliable grid. Testing and pilots are needed regarding applications, large-scale burners and newly development turbines, and conversion of pipelines, including critical components. These technical challenges require both scientific research from universities or institutions and testing in practice with industrial parties.

Figure 6 - Overview key challenges in the process chain of blue hydrogen



8 Carbon footprint analysis

In the Norwegian project Hyper research is conducted regarding blue hydrogen to be exported via LH_2 ships. This study indicates, although official announcements are not published yet, that the CO_2 emission of blue hydrogen would be in the same range as green hydrogen produced from the Norwegian electricity mix. The Norwegian electricity has a very low emission factor at 17 g/kWh sparking interest on what the carbon footprint analysis would give for the Dutch electricity mix (NVE, 2016) . This indication is confirmed by a review study of Bhandari in which amongst others SMR plants with CCS are compared with electrolysis processes (Bhandari, et al., 2014).

Therefore the analysis will be conducted on multiple production routes:
1. **SMR Netherlands:** Hydrogen produced from natural gas with the Steam Methane Reforming process with CCS. The electricity is supplied from the Dutch electricity mix.
2. **ATR Netherlands:** Hydrogen produced from natural gas with the Auto Thermal Reforming process with CCS. The electricity is supplied from the Dutch electricity mix.
3. **SMR Norway:** Hydrogen produced from natural gas with the Steam Methane Reforming process with CCS. The electricity is supplied from the Norwegian electricity mix. This case has been selected so the results can be compared with the Hyper project. Furthermore, the emission factor for Norway is comparable with complete sustainable production via windmills).
4. **ATR Norway:** Hydrogen produced from natural gas with the Auto Thermal Reforming process with CCS. The electricity is supplied from the Norwegian electricity mix.
5. **Electrolysis Netherlands:** Hydrogen produced from the existing electricity mix in the Netherlands.
6. **Electrolysis Norway:** Hydrogen produced from the Norwegian electricity mix. This option is thus comparable with hydrogen produced from windmills, which have an emission factor of 14 g CO_2/kWh compared to 17 g CO_2/kWh for the Norwegian electricity mix.
7. **Electrolysis Netherlands 2030:** Based on the development pattern of the electricity market and fuel cell development.
8. **Electrolysis Norway 2030:** Based on the development pattern of the electricity market and fuel cell development.
9. **SMR Netherlands 2030:** Little technological progress is expected, however change in electricity market and thus CO_2 emission factor is expected. Since the emission factor for Norway will most likely not change, a scenario Norway 2030 is not include.
10. **ATR Netherlands 2030:** Little technological progress is expected, however change in electricity market and CO_2 emission factor will occur.

8.1 Method and software

The selected method is a screening life cycle analysis with a focus on CO_2 footprint during the hydrogen production phase. The result will be a CO_2 emission per kilogram of hydrogen produced. The software package that has been selected is SimaPro. Where possible the emission factors from the program are used. For electricity emission factors data have been determined and used as input in SimaPro. The data found are more accurate and up-to-date than the available data in SimaPro. The data are based on scientific papers and reliable grey online sources.

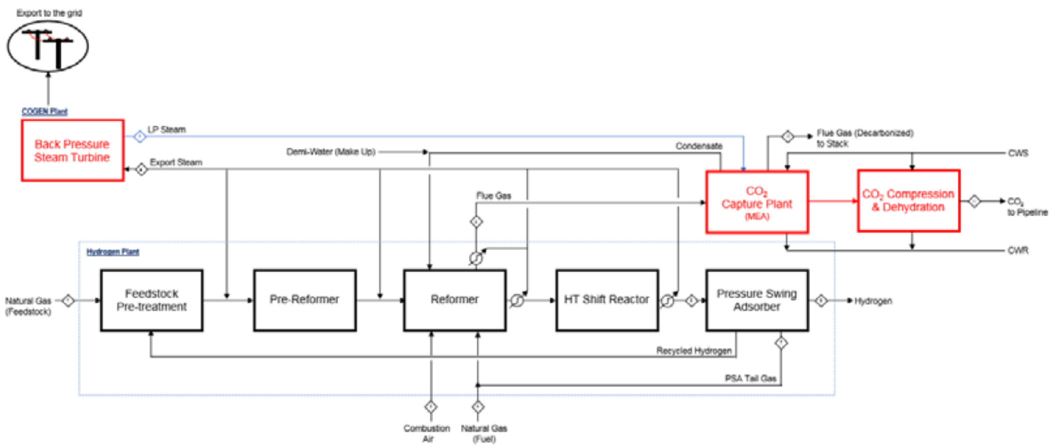
8.2 Input variables

The basis for this CO_2 footprint are multiple scientific reports. The assumptions used as inputs will be discussed per subject/technology.

Steam methane reforming

This option is based on a report by IEAGHG (2017) on SMR hydrogen plant with CCS including flue gas capture using MEA. The plant that is modelled produced 100,000 Nm^3/h hydrogen, will operate for 25 years and the process flow is displayed in Figure 7. The excess steam is used to produce electric power. The achieved CO_2 capture percentage is 90% leading to a process emission of 0,99 kg CO_2/kg H_2. The exit pressure is 2.5 MPa for hydrogen and 11 MPa for CO_2. Pressuring the hydrogen up to 100 bar is included in the electricity demand.

Figure 7 - Process flow SMR with flue gas CO_2 capture (IEAGHGH, 2017)



Autothermal reforming

The carbon footprint analysis for autothermal reforming is based on report by NTNU (2016) and verified by a report of IEAGHG's technical review (2017). In the NTNU study the plant is modelled at a hydrogen production of 500 tonnes/day. A CO_2 capture rate of 95% is determined, leading to process emissions of 0,64 kg CO_2/kg H_2. The power consumption is given, leading to a final electricity balance. Pressuring the hydrogen up to 100 bar is included in the electricity demand.

Electrolysis

For all electrolysis scenarios the same performance and efficiency factors are used. Schmidt et al., (2017) indicate an electricity usage of 53.6-78.6 kWh/Nm^3 for state-of-the-art technology. An average is taken leading to an electricity consumption of 66.07 kWh/kg H_2. The paper by Schmidt has discussed future trends with experts and predicts that in 2030 the electricity consumption will decrease to the bottom of the interval. Therefore it assumed that in 2030 the electricity consumption will be 53.6 kWh/kg H_2. These inputs variables lead to the final input-output table.

Table 7 - Input-output table for CO_2 footprint calculations

Input	SMR	ATR	Electrolyzer 2017	Electrolyzer 2030
Inflow NG (m^3/kg H_2)	3.73	3.69	0,0	0,0
Inflow raw water (kg/kg H_2)	4.68	7.07	9.0	9.0
Inflow sea water (m^3/kg H_2)	1.18	0.0	0,0	0,0
Electricity demand (kwh/kg)	1.17	3.36	66.07	53.6
Oxygen (kg/kg H_2)	0.0	0.53	0.0	0.0
Output	**SMR**	**ATR**	**Electrolyzer 2017**	**Electrolyzer 2030**
Hydrogen (kg)	1.0	1.0	1.0	1.0
CO_2 process emission (kg/kg H_2)	0.99	0.64	0.0	0.0
CO_2 capture rate (%)	0.9	0.95	0.0	0.0
Waste water (kg/kg H_2)	1.83	0.0	0.0	0.0
Return sea water (m^3/kg H_2)	1.18	0.0	0.0	0.0
Oxygen (kg/kg H_2)	0.0	0.0	8.0	8.0

CO_2 emission factor for electricity

An important parameter for all options is the emission factor of the electricity mix. An overview of the emission factors can be found in Table 8. Norway is already relying on renewable energy sources, with 98% hydro energy, so no changes in the electricity mix and emission factors is expected.

Table 8 - Overview of emission factors for carbon footprint analysis

Option	Emission factor (g_{CO2}/kWh)
Netherlands (CBS, 2017)	530
Norway (NVE, 2016)	17
Netherlands 2030 (ECN, 2017)	290
Norway 2030	17

8.3 Results

The final results are generated by SimaPro. The results are displayed in Figure 8. The CO_2 footprint is the largest for hydrogen from electrolysis with the Dutch electricity mix in 2015 and 2030. To create a more comparable overview these are excluded in Figure 9. The results show that SMR and ATR both have a set CO_2 emission due to natural gas usage and process emission. These are 1.11 kg CO_2-eq./kg H_2 for SMR and 0.76 kg CO_2-eq./kg H_2 for ATR. ATR has a larger differentiation in CO_2 footprint per alternative electricity source due to a larger electricity consumption.

The most important conclusion is that the CO_2 footprint is the smallest for ATR, followed by electrolysis and SMR. This is true for all scenarios including the Norwegian electricity mix, which is comparable with electricity from wind and lower than electricity from solar. Therefore, it can be concluded that the CO_2 footprint of blue hydrogen is at the least comparable with the most sustainable production route of green hydrogen.

Figure 8 - GHG emissions for blue and green hydrogen production routes

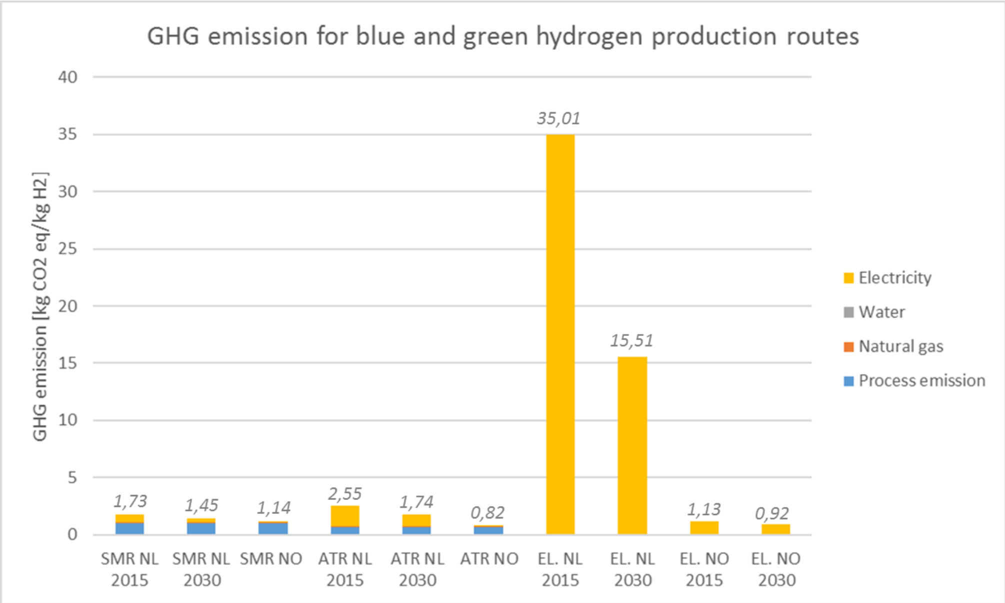
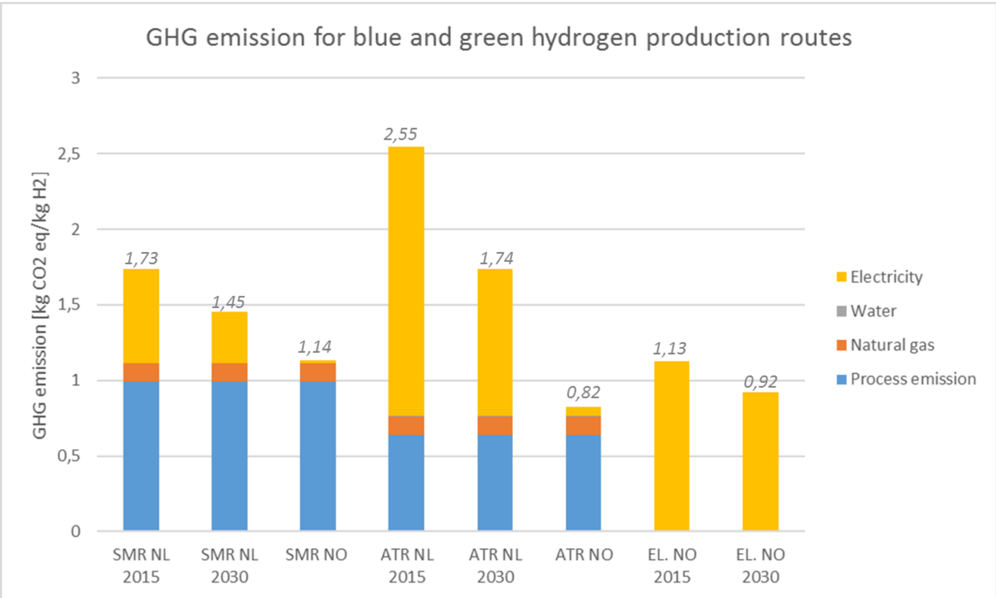


Figure 9 - GHG emission for blue and green hydrogen production routes excluding electrolysis with the Dutch electricity mix



9 System and sustainability considerations

This report has indicated a feasible scenario for blue hydrogen. Furthermore, it has indicated that the CO_2 footprint is comparable for production from the Norwegian electricity mix, which is composed for 98% of hydropower. This is a clear indication that implementing blue hydrogen could lead to a significant CO_2 reduction in the Dutch industry. There are however some significant system and sustainability considerations, with pro's and con's, that have among other been identified by the interviewees. The goal in this chapter is to discuss these considerations to place this research into a wider context.

9.1 Fossil fuel basis & CCS

Blue hydrogen relies on two inputs that are perceived by some stakeholders as non-renewable or unsustainable: fossil fuels and CCS. Fossil fuels are largely responsible for the excess in CO_2 emissions, which is leading to climate change. A reduction or substitution in fossil fuel usage is therefore often leading to a CO_2 reduction. The fossil fuel sources also have a finite nature. The finity and non-sustainability are important considerations regarding the blue hydrogen chain.

Another measure is to reduce the CO_2 footprint of a fossil fuel-based process by capturing and storing that CO_2. The opposition to CCS is that it is a measure to battle the consequences instead of the source. Furthermore, the measure is seen as not-sustainable due to the fact that the available storage sites will be filled one day. Additional fears exist for the leakage of CO_2 and potentially geological effects of underground storage. The past two arguments have been debunked by scientific research and shown in practice on multiple occasions, but can still influence the public debate. Furthermore, there are multiple reports showing that if the Netherlands wants to reach the goals of the Paris Climate agreement, CCS is a necessity (CE Delft, 2014). A shift in the opinion of non-profit organizations is seen towards larger support for CO_2 capture.

Blue hydrogen leads to a debate regarding if a policy focussed on CO_2 reduction or renewables increase should be set in. Blue hydrogen is not relying on renewable sources but does offer the potential of a large, relatively economic efficient reduction measure. The world is aware that a transition towards renewables is needed, however in the upcoming decades there is a need for a reliance on finite resources to mitigate climate change. Therefore, a focus on CO_2 policy is required in which the maximum CO_2 reduction should be accomplished within the available budget. At the same time a parallel policy is required to determine the pathway of renewables and how these can be integrated at a system level, in such a way that from 2030 onwards renewables will replace the finite sources.

If the debate shifts from a focus on renewables towards a focus on climate change mitigation, this research has shown that blue hydrogen has a comparable CO_2 footprint compared to hydrogen from wind and a much lower footprint than hydrogen from the Dutch electricity mix. Blue hydrogen is based on existing and economic feasible technology, which makes it one of the most effective large-scale CO_2 reduction measure in the Netherlands.

9.2 Blue hydrogen necessity

In this research an often heard counter question is 'Why should we want blue hydrogen?' related to the fossil fuel and CCS considerations. In this research an overview of the process chain of hydrogen in general and blue hydrogen specifically has been made. An important conclusion is that the problems are found downstream, in transport and applications, while upstream there are limited problems for blue hydrogen using technologies with high TRLs. The upstream problems of green hydrogen, for example from wind, are more significantly and related to price and volume. By implementing blue hydrogen in the upcoming decades, time is realized to develop a hydrogen infrastructure and for industrial parties to switch to hydrogen. This process will take years and will enable a smoother integration of green hydrogen in the future.

Meanwhile the upstream challenges of green hydrogen can be resolved. The price of green hydrogen at the moment is too high, especially to be used in the industry. Furthermore, at the moment it is not possible to produce via electrolysers at the scale required for industrial implementation. This is both due to the worldwide capacity of electrolysers themselves as the available wind energy. A business case based on an overproduction of wind will not be feasible due to the small operation time.
For green hydrogen to produce base load hydrogen requires huge increases in the amounts of windmills in the North Sea.

From the interviews and literature study an image has become clear that big steps are needed for the Netherlands to reach the climate goals. Industrial parties require security in delivery of resources and large-scale sources. These are both advocates for blue hydrogen since it can offer these characteristics.

Another consideration indicated is the usage of hydrogen. There are many advocates for the usage of pure, industrial grade hydrogen for industrial process, maybe for process heating and definitely not for electricity production. A preference for feedstock over fuel. This view is based on the fact that hydrogen is a molecule with a large economic potential, which is not used in full if it is burned. Another argument is that hydrogen production for electricity production automatically includes significant conversion losses. On a national level, the transport of energy via hydrogen or electricity will depend on the required investment in the transmission and distribution grid. These investment costs will have to be compared with the additional cost of the conversion steps. A connected consideration has to be made whether the produced hydrogen will be of this industrial grade or energy production grade (turbines and burners) which will be an economic optimization for the production and transportation processes. Transport of energy production grade and purification at industrial sites could also be an option.

9.3 Blue and green hydrogen

The finite nature of natural gas requires a long-term strategy for the phase out of blue hydrogen and increased production of green hydrogen. Blue hydrogen is a transition energy carrier to be replaced by the same molecule with another origin. Interviewees have diverging views on whether green hydrogen should overtake the market when it is technical or economical feasible. Our view is that blue and green hydrogen will be beneficial to each other and an open market will be created.

Blue hydrogen is a transition energy carrier to be replaced by the same molecule with another origin.

In the field, there is a strong discussion on the lock-in of blue hydrogen. A lock-in is defined as a process that was set out as the creator of a transition but eventually is not replaced but sustained as technology. A potential lock-in of blue is seen by some stakeholders as a treat while others perceive it as an economic optimization without preference for a technology. If steam-reforming plants are being built they will be utilized until it is no longer profitable or they are written off. The price development and moment of price equilibrium depend on the electricity and natural gas price, which are very uncertain. This will also largely depend on the system design of renewable electricity production and the role of hydrogen in this system. The expectancy is that with the depletion of natural gas, increased costs for opening gas fields for CCS and renewed investment in steam-reforming plants the price of blue hydrogen will increase.

There thus is a change for a lock-in of blue hydrogen for several years which will temper implementation of green hydrogen, purely from an economic perspective. From a CO_2 reduction perspective, this is acceptable while from a renewable perspective this is a major disadvantage. The implementation of blue hydrogen will require strong governmental policy regarding the path to go which will need to exist from parallel policy on green and blue hydrogen. This can be based on economic CO_2 reduction optimization or a time horizon regarding renewable sources. This policy is required to enable investment in blue hydrogen plants and reassurance for the renewable integration in the system in the upcoming decades.

There are several factors that support the implementation of both green and blue hydrogen. Blue hydrogen is a relatively flexible process that can be the base load of the hydrogen market. Especially during the start of large-scale green hydrogen production this could increase its chances of success. It enables security of supply for industrial consumers and enables a stable, low-priced market.

The reliability of the energy system is increased with a diversification in energy sources. Additionally process symbioses could occur between blue and green hydrogen. During green hydrogen production oxygen is produced that could be used in ATR processes. The excess oxygen could also be used for oxyfuel combustion. This process enables higher efficiencies but also creates dependency that could alter the usage of blue hydrogen as base load.

9.4 Conclusion

Blue hydrogen offers the potential of large-scale CO_2 reduction but has some justifiable system and sustainability considerations. Blue hydrogen is however effective in the transition towards green hydrogen while it contributes to meeting the Paris agreement goals.

- Blue hydrogen requires fossil fuel input and CCS, however is from a CO_2 reduction perspective a good option based on technical and economic feasibility.
- Blue hydrogen enables creation of a hydrogen infrastructure and conversion of applications, leading to the required CO_2 reduction, enabling a smoother integration of green hydrogen when it is feasible on industrial scale.
- A lock-in of blue will depend on the electricity and natural gas price, however can also be influenced by clear and strong governmental policy regarding integration of renewable sources.

10 Conclusion

CE Delft has performed a study on the techno-economic feasibility and sustainability of blue hydrogen; hydrogen produced from natural gas with CCS. Blue hydrogen is an economically advantageous and feasible method to implement hydrogen in the industry, for which it is one of the few CO_2 reduction strategies. The study shows that the CO_2 footprint of blue hydrogen (0.82-1.12 kg CO_2-eq./kg H_2) is comparable with hydrogen produced via electrolysis with renewable electricity sources (0.92-1.13 kg CO_2-eq./kg H_2) now and towards 2030. Blue hydrogen offers the potential of solving downstream hydrogen challenges regarding transport and applications now, enabling the transition towards green hydrogen in the future. Blue hydrogen should be supported as a transition measure that enables a large CO_2 reduction in industrial areas, such as the harbour of Rotterdam.

In the first part of the report, Chapter 2-7, key challenges in the process chain of blue hydrogen are identified. This analysis has resulted in four key challenges on a system level:
1. Governmental policy and support is required to realize the blue hydrogen chain. Policy is required regarding CCS, the fossil fuel usage and parallel policy to guarantee integration of green hydrogen.
2. A conversion strategy on the transition towards hydrogen for the existing gas grid and connected industrial parties is required, while ensuring reliable and CO_2-lean hydrogen production.
3. Technical challenges downstream in the hydrogen chain need to be resolved. These are mostly regarding hydrogen transport and industrial applications. Blue hydrogen offers the potential of resolving these challenges by scaling up the hydrogen market, enabling a smoother transition towards green.
4. Public acceptance and support on CCS, hydrogen transport, fossil fuel usage, possible hydrogen storage and the blue hydrogen chain in general is required.

In Chapter 8 the CO_2 footprint of multiple blue and green hydrogen production routes are assessed. The study shows that the CO_2 footprint of blue hydrogen (0.82-1.12 kg CO_2-eq./kg H_2) is comparable with hydrogen produced via electrolysis with renewable electricity sources (0.92-1.13 kg CO_2-eq./kg H_2) now and towards 2030. This is a strong argument for the implementation of blue hydrogen to enable a very feasible and significant CO_2 reduction.

In Chapter 9 the system and sustainability consideration identified by stakeholders are discussed. A policy on CO_2 reduction instead of fossil fuel usage reduction is required to meet the Paris climate agreement. Blue hydrogen and CCS can play a vital role in this CO_2 reduction. Blue hydrogen is a necessity to enable large volumes of hydrogen to start the hydrogen transition, however parallel policy is needed to ensure scale-up and integration of green hydrogen in the future.

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