Feasibility study report

H-vision

July 2019

# Blue hydrogen as accelerator and pioneer for energy transition in the industry

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# Foreword

Sixteen companies have been committed to the H-vision project since July 2018, with the overall objective to make a considerable contribution to realising the Dutch national climate goals through large-scale use of hydrogen in the port of Rotterdam industrial area. The involved parties aim to accelerate the development of solutions that enable the decarbonisation of the industry in the short term.

H-vision studied the feasibility of using low-carbon hydrogen instead of fossil fuels for the energy supply of the chemical industry, refineries and power plants, thereby using the knowledge, expertise and efforts of all parties involved.

The H-vision approach has the sheer potential to give the hydrogen economy in and around Rotterdam a flying start, by establishing the production of hydrogen in combination with $CO_2$ capture and storage, known as “blue hydrogen”, and by paving the way towards the large-scale use of hydrogen made with renewable electricity, known as “green hydrogen”. This is an important contribution to both the climate goals and the sustainable economy of the future.

The energy transition calls for a fundamental change in our energy system as a key step in the roadmap towards a renewable and circular economy. This is a crucial challenge for the industry in the port of Rotterdam, which makes an important contribution to the national economy. These activities, however, also result in considerable greenhouse gas emissions. Successful solutions are therefore being sought in the balance between a drastic reduction in $CO_2$ emissions and the retention, or even enhancement, of the business climate. In this way, we can ensure the prosperity of the port of Rotterdam and add value for the Dutch society.

It should be mentioned that the production and use of blue hydrogen is not considered the long-term solution to climate change by the parties involved. Our aim is to kick-start the low-carbon hydrogen economy based on technology that is available today, thereby enabling rapid large-scale reduction of $CO_2$ emissions while paving the road for the green hydrogen economy of the future.

In the past 10 months, five working groups, composed of approximately 40 people in total, worked extensively on this study. Each of the working groups was headed by an independent expert party: Berenschot, TNO, e-Risk Group, EBN and Solo ta hari. The project management was done by Deltalinqs.

As the chairman of the H-vision Steering Board, I am proud to conclude that the teams - building on both proprietary industry input and on a number of important studies on the market - succeeded in generating in-depth knowledge with respect to the financial, commercial and technical aspects of the production and application of blue hydrogen, including the decarbonization of industrial residual gases. The results of this study serve as a starting point for the next phase of H-vision.

We are grateful to the Netherlands Enterprise Agency (RVO), the Province of South Holland and the Municipality of Rotterdam for their financial support.

**Steven Lak**
*Chairman of Deltalinqs and chairman of the H-vision project Steering Board*

*On behalf of all involved parties: Air Liquide, BP, Deltalinqs, EBN, Engie, Equinor, Gasunie, GasTerra, Royal Vopak, Port of Rotterdam, Linde, OCI Nitrogen, Shell, TAQA, TNO and Uniper.*

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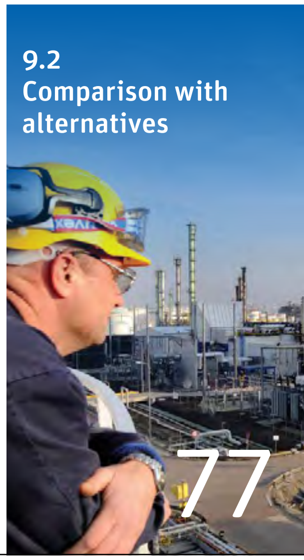



## Annexes
All annexes referred to from this report can be found at www.h-vision.nl

# 1

# Management summary

# H-vision: kick-starting the hydrogen economy in Rotterdam

**The H-vision project has the clear potential to kick-start the hydrogen economy in the Rotterdam area. With the construction and operation of large-scale blue hydrogen production facilities, the industry in Rotterdam will have the ability to make huge strides in decarbonising industrial production processes. This will be achieved by introducing low-carbon hydrogen as an energy source for high temperature heat and power generation.**

**Sixteen parties have joined forces in the H-vision project. This final report of their study states that it is feasible, from a technical perspective, to use large-scale production of so-called “blue hydrogen” to supply the industry and power sector with low-carbon energy. In order to achieve sound economics and finances, government and/or EU support will be required.**

**Implementing this blue hydrogen concept would bring the desired hydrogen economy forward by at least 15-20 years and would significantly help the Dutch government to realise the climate change targets set out for 2030. The H-vision project paves the way for a hydrogen economy that will ultimately be based on green hydrogen.**

**The ambition of the involved parties is to start operating the first H-vision facility late 2025 and increase production capacity towards 2030, thereby offering the industry the option to significantly reduce $CO_2$ emissions well before 2030. Realizing this project would lead to short-term, large-scale $CO_2$ emission reductions increasing from 2.2 Mt per year in 2026 to 4.3 Mt per year in 2031 for the reference scope. The $CO_2$ avoidance costs for this scope vary from 86 to 146 €/tonne (depending on the macro-economic scenario).**

**Implementing this blue hydrogen concept would (...) significantly help the Dutch government to realise the climate change targets set out for 2030**

In August 2018, sixteen parties started the H-vision feasibility study with the key objectives to come up with a clear solution to decarbonize high-temperature heat and power generation, realise large-scale emissions reduction, accelerate the energy transition within the industry and find a pathway towards the sustainable hydrogen economy of the future, that will ultimately be based on green hydrogen. This was made even more challenging by imposing the constraint of doing all of this in a cost-effective manner while using existing assets to a maximum extent.

Over time, the project working groups developed deep insights into the concept of using blue hydrogen. This energy carrier would be produced in one or more production plants by reforming large quantities of high-caloric natural gas (hence not the low-caloric gas from the Groningen field) and industrial residual gases into separate streams of hydrogen and $CO_2$. The blue hydrogen would then be used for industrial processes in mainly refineries and power plants. By doing so, hydrogen could replace natural gas, refinery fuel gas and coal for heat and power generation, and thus help to drastically cut back $CO_2$ emissions.

The stream of $CO_2$ resulting from the hydrogen production process is not released into the air, but instead captured and subsequently stored in depleted gas fields under the North Sea seabed (Carbon Capture and Storage). On this topic, H-vision will work closely together with the Porthos project in Rotterdam that is planning to implement a backbone infrastructure to transport $CO_2$ to the offshore storage locations. The captured $CO_2$ can also partly be reused, for instance in the greenhouses in the Westland, or exported to other $CO_2$ storage facilities in e.g. Norway or the UK.

## Towards a hydrogen hub

Industrial heat is needed as a stable, constant and predictable flow. This is an ideal basis for a steady commercial market position for H-vision facilities in the short- to medium term. The realisation of the H-vision concept would enable the port of Rotterdam to develop its role as a future hydrogen hub, where hydrogen is produced, used, traded, distributed and imported in large quantities by multiple parties.

A strong upside of the H-vision concept is that the infrastructure developed for transporting and storing blue hydrogen, as well as the technical adaptations required by its users, can be seamlessly used for green hydrogen. Green hydrogen is made using renewable electricity to power electrolysers that split water into hydrogen and oxygen.

The production of zero-emission green hydrogen on a large scale in the Netherlands becomes possible when electricity from wind and solar is available abundantly and against competitive costs. This will likely not be the case in the short to medium term. Blue hydrogen can be made available relatively quickly and will introduce a hydrogen infrastructure that over time can be used for green hydrogen.

The H-vision project is therefore a stepping stone for the future hydrogen economy, paving the road for the large-scale introduction of green hydrogen in due time.

## Preferred technology

From a technical point of view, the H-vision approach is feasible and makes optimal use of existing industrial infrastructure. The industrial processes reviewed in this study can switch to blue hydrogen as their primary energy feed. Only limited modifications are necessary for industrial high temperature heating and major modifications are required for power generation, including a challenging transition to biomass as an alternative for coal.

The preferred technology for the large-scale H-vision plant(s) is high-pressure Auto Thermal Reforming (ATR). This approach offers distinct advantages over alternative technologies, primarily with respect to economy of scale and operational flexibility. ATR is not yet a final choice at this stage, as more detailed technical work and cost estimates during the next project phase are required to select the final optimal technology.

To realise this concept in which blue hydrogen substitutes natural gas, refinery fuel gas and coal at a large industrial scale, would require one or more world scale production plants. A single large-scale central production site in the area of the Maasvlakte is envisaged. This enables maximum use of economy of scale benefits, as well as steam and utilities integration with one or more power plants. As the production of blue hydrogen is based on highly mature reforming technology, the scale-up in manufacturing is seen as relatively low-risk.

From a user point of view, the H-vision approach is achievable by using existing industrial infrastructure that will need limited modifications. A key adjustment is that gas-fired burners will have to be replaced by fuel-flexible burners which are suitable for gas with a very high hydrogen content.

The hydrogen will be mainly used in refineries and power plants. Application in power plants seems to be a technically feasible option by either co-firing (next to biomass) or installing additional new hydrogen turbines and connecting these to existing plants. A complexity is that many power plants may have to run as peak-

producers, leading to large and rapid fluctuations in fuel demand. This requires flexible hydrogen production or coupling with hydrogen storage capacity. Combining base-load demand from industry with variable load from the power plants ensures a smoother operation of the hydrogen production plant. This report concludes that a flexible hydrogen supply is achievable.

## Development concepts and scenarios

In order to structure the approach of the study, the project team generated four development concepts (*do nothing, minimum scope, reference scope and maximum scope*) that were tested against three different macro-economic scenarios (*As Usual World, Economical World, Sustainable World*).

These scenarios are based on the existing scenarios of the International Energy Agency coupled with specific pricing forecasts that the PBL Netherlands Environmental Assessment Agency developed for the draft National Climate Agreement.

This methodology gave strong insights into which trajectories are feasible and which are not-feasible. Some key features are as follows (only the reference case examples are shown here):

- The H-vision economic feasibility depends largely on the desired rate of return, which reflects the risk profile and political and macro-economic developments, as well as the impact thereof, particularly on the price of natural gas and the price of $CO_2$ emissions rights. An ETS price of €86 to €146 per tonne is required to make the business case NPV neutral.
- The $CO_2$ avoidance cost in the reference scope varies from €86 to €146 per tonne (depending on the scenario). This is in fact a strategic investment in building up the hydrogen economy. In all three scenarios the use of blue hydrogen is more cost effective than most of the decarbonization options that are included in the current 2019 SDE+ scheme, for the investigated applications.
- Unit costs for compression, transport and storage of $CO_2$ are in the range of €17 - €30 per tonne.
- Realizing this project would lead to short-term, large-scale $CO_2$ emission reductions increasing from 2.2 Mt per year in 2026 to 4.3 Mt per year in 2031 for the reference scope. This case is equivalent to 50% of the current refinery sector $CO_2$ emissions in Rotterdam.
- The reference scope represents a maximum hydrogen demand of the power sector and industry of just over 3200 MW. In terms of production capacity, this would translate into the construction of two hydrogen production trains with an output capacity of 1460 MW each, which can operate at 110% capacity. Per year, the hydrogen production would then be 700 kt.
- Construction of such production facilities would come with an expected investment figure of €1.3 billion. Including additional costs such as infrastructure, compressors, hydrogen turbines and furnace modifications would bring the total investment figure to approximately €2.0 billion.

It is important to note that at this stage, no development concept has been selected. These concepts and scenarios, including the numbers as outlined above, have been drawn up in order to be able to assess the feasibility in various options, and are not presenting final financial figures.

## Next steps

During the next project phases, the team will select the optimum development concept, define the conceptual design, execute the detailed engineering, prepare for the Final Investment Decision and execute the construction of

**The H-vision project has the clear potential to kick-start the hydrogen economy in the Rotterdam area**

the production facilities. The current ambition is to take a Final Investment Decision in 2021 and to start operating the first hydrogen production facility in late 2025.

In the follow-up of this project, there are several challenges to overcome, including uncertainties about commodities and $CO_2$ emissions rights pricing, but also political direction and macro-economic developments. Support from the public sector in the form of participation, contracts for differences, risk bearing loans or subsidies are required to get H-vision started in view of the non-commercial rate of return on the investment.

Against that background, the parties involved in H-vision will play a key role. Other key roles will be held by the Government as policy maker, insurer & funder, regulator, advocate and facilitator. In the short term, it will be vital to get clarity on political choices for the energy transition roadmap, such as regarding the roles of carbon capture and storage (CCS) and blue hydrogen in particular, but also on the availability of innovative financial instruments.

The taking of further steps by the parties currently involved in H-vision, possibly newly interested parties and the government will all be key in making H-vision a success as the kick-starter of the hydrogen economy in the Rotterdam area.

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# Management-samenvatting

# H-vision: vliegende start waterstofeconomie in Rotterdam

**Het H-vision project heeft de potentie om als vliegende start te fungeren voor de waterstofeconomie in de regio Rotterdam. Met de bouw en exploitatie van grootschalige blauwe waterstofproductiefaciliteiten is de industrie in Rotterdam in staat om enorme stappen te zetten in de decarbonisatie van industriële productieprocessen. Dit wordt bereikt door koolstofarme waterstof te introduceren als energiebron voor hoge-temperatuurwarmte en elektriciteitsproductie.**

**Zestien partijen hebben hun krachten gebundeld in het project H-vision. Dit eindrapport van hun studie stelt dat vanuit een technisch perspectief, de grootschalige productie en toepassing van zogeheten 'blauwe waterstof' om de industrie en elektriciteitssector te voorzien van koolstofarme energie haalbaar is. Voor een sterke economische en financiële basis is ondersteuning nodig van de overheid en/of de EU.**

**Implementatie van dit blauwe waterstofconcept zou de gewenste waterstofeconomie met tenminste 15-20 jaar naar voren halen en zou de Nederlandse overheid aanzienlijk helpen met het realiseren van de klimaatdoelen die voor 2030 zijn gesteld. Het H-vision project is wegbereider voor een waterstofeconomie die uiteindelijk gebaseerd zal zijn op groene waterstof.**

**De ambitie van de betrokken partijen is om de eerste H-vision faciliteit eind 2025 operationeel te hebben en de capaciteit te vergroten tot 2030, zodat de industrie in staat wordt gesteld om de $CO_2$-uitstoot ruim vóór 2030 aanzienlijk te verminderen. Het project kan op relatief korte termijn een forse $CO_2$-emissiereductie realiseren die toeneemt van 2,2 miljoen ton (Mton) per jaar in 2026 tot 4,3 Mton per jaar in 2031 in de referentievariant. De $CO_2$-vermijdingskosten voor deze variant variëren van 86 tot 146 €/ton (afhankelijk van het macro-economische scenario).**

**Implementatie van dit blauwe waterstofconcept zou (...) de Nederlandse overheid aanzienlijk helpen met het realiseren van de klimaatdoelen die voor 2030 gesteld zijn**

In augustus 2018 zijn zestien partijen gestart met de H-vision haalbaarheidsstudie met als belangrijkste doelstellingen te komen tot een duidelijke oplossing voor de decarbonisatie van hoge temperatuur¬warmte- en elektriciteitsproductie, het realiseren van grootschalige $CO_2$-emissiereductie, het versnellen van de energietransitie binnen de industrie en het effenen van de weg naar de duurzame waterstofeconomie van de toekomst die uiteindelijk gebaseerd zal zijn op groene waterstof. Dit alles werd nog uitdagender door de beperking dat dit op kosteneffectieve wijze met optimaal gebruik van bestaande middelen moet worden gedaan.

Gedurende de studie hebben de projectwerkgroepen diepgaand inzicht verkregen in het concept van toepassing van blauwe waterstof. Deze energiedrager wordt geproduceerd in één of meerdere productie-installaties door het omzetten van grote hoeveelheden hoogcalorisch aardgas (dus niet het laagcalorische aardgas van het Groningenveld) en residuele raffinagegassen in waterstof en $CO_2$. De blauwe waterstof wordt gebruikt voor industriële processen in hoofdzakelijk raffinaderijen en elektriciteitscentrales. Op deze manier worden aardgas, raffinaderijgas en kolen vervangen door waterstof voor de opwekking van warmte en elektriciteit. Daarmee wordt de hoeveelheid $CO_2$-uitstoot drastisch verlaagd.

De $CO_2$ die afkomstig is uit het waterstofproductieproces komt niet vrij in de lucht, maar wordt afgevangen en vervolgens opgeslagen in lege gasvelden onder de Noordzeebodem (koolstofafvang en opslag, CCS). H-vision werkt op dit onderwerp nauw samen met het Porthos project in Rotterdam, waarbij een backbone-infrastructuur wordt ontwikkeld voor transport van $CO_2$ naar de offshore opslaglocaties. De afgevangen $CO_2$ kan ook deels worden hergebruikt, bijvoorbeeld voor de kassen in het Westland, of worden geëxporteerd naar andere $CO_2$-opslagfaciliteiten in bijvoorbeeld Noorwegen of Groot-Brittannië.

## Naar een waterstofhub

Industriële warmte is nodig als stabiele, constante en voorspelbare toevoer. Dit is een ideale basis voor een stabiele, commerciële marktpositie van H-vision faciliteiten op de korte tot middellange termijn. Realisatie van het H-vision concept zou de haven van Rotterdam in staat stellen haar rol op te pakken als toekomstige waterstofhub, waar waterstof door meerdere partijen in grote hoeveelheden wordt geproduceerd, gebruikt, verhandeld, gedistribueerd en geïmporteerd.

Een groot voordeel van H-vision is dat de infrastructuur die is ontwikkeld voor transport en opslag van blauwe waterstof alsmede de technische aanpassingen benodigd bij de gebruikers ervan, probleemloos kunnen worden gebruikt voor groene waterstof. Groene waterstof wordt geproduceerd met elektrolysers waarbij water wordt gesplitst in waterstof en zuurstof met gebruikmaking van elektriciteit uit hernieuwbare bronnen.

Productie van emissieloze groene waterstof op grote schaal wordt in Nederland mogelijk als zonne- en windenergie overvloedig beschikbaar zijn tegen concurrerende kosten. Dit is waarschijnlijk nog niet het geval op de korte en middellange termijn. Blauwe waterstof kan relatief snel beschikbaar worden gemaakt én zorgen voor een infrastructuur die na verloop van tijd voor groene waterstof kan worden gebruikt.

Het H-vision project vormt daarmee een opstap naar de toekomstige waterstofeconomie en maakt op termijn de weg vrij voor de grootschalige introductie van groene waterstof.

## Voorkeurstechnologie

Vanuit technisch oogpunt is de H-vision aanpak haalbaar en wordt er optimaal gebruik gemaakt van de bestaande industriële infrastructuur. De industriële processen die in deze studie worden behandeld, kunnen overschakelen op blauwe waterstof als primaire energiedrager. Voor industriële hoge temperatuurverwarming zijn beperkte aanpassingen nodig, terwijl voor elektriciteitsopwekking grote aanpassingen en een uitdagende transitie naar biomassa nodig zijn (als alternatief voor kolen).

De voorkeurstechnologie voor de grootschalige H-vision installatie(s) is hogedruk ATR (Auto Thermal Reforming). Deze aanpak biedt duidelijke voordelen boven alternatieve technologieën, vooral met betrekking tot schaalvoordelen en operationele flexibiliteit. ATR is in dit stadium nog geen definitieve keuze, omdat meer gedetailleerde technische werkzaamheden en kostenramingen nodig zijn in de volgende projectfase om de optimale technologie te kunnen kiezen.

Realisatie van dit concept waarbij aardgas, raffinaderijgas en kolen op grote industriële schaal worden vervangen door blauwe waterstof vereist één of meerdere fabrieken op wereldschaal. Er zijn plannen voor centrale, grootschalige productie op de Maasvlakte. Dit biedt de mogelijkheid tot maximaal gebruik van schaalvoordelen evenals integratie van stoom- en nutsvoorzieningen met een of meer elektriciteitscentrales. Omdat de productie van blauwe waterstof is gebaseerd op bewezen reforming technologie wordt het opschalen van de productie beschouwd als een relatief laag risico.

Vanuit gebruikersoogpunt is de H-vision aanpak realiseerbaar door gebruik te maken van de bestaande industriële infrastructuur waarbij beperkte aanpassingen nodig zijn. Een belangrijke aanpassing is dat gasgestookte

branders moeten worden vervangen door branders die geschikt zijn voor zowel (aard)gas als gas met een zeer hoge waterstofinhoud.

De waterstof wordt vooral gebruikt in raffinaderijen en elektriciteitscentrales. Toepassing in elektriciteitscentrales lijkt een technisch haalbare optie door enerzijds bijstoken (bij biomassa) óf het installeren van nieuwe waterstofturbines en deze te verbinden met de bestaande installaties. Een probleem is dat veel elektriciteitscentrales in de toekomst moeten fungeren als piekproducent, hetgeen leidt tot grote en snelle fluctuaties in de vraag naar brandstoffen. Dit vereist een flexibele waterstofproductie of de combinatie met waterstofopslag. Het combineren van base-load vraag vanuit de industrie in combinatie met variabele belasting van de elektriciteitscentrales verzekert een soepelere operatie van de waterstofproductie.

Dit rapport concludeert dat een flexibele waterstoftoevoer realiseerbaar is.

## Ontwikkelingsconcepten en -scenario's

Om structuur aan te brengen in de aanpak van de studie heeft het projectteam vier ontwikkelings-concepten gemaakt (niets doen, minimumvariant, referentievariant en maximumvariant), die werden getest aan de hand van drie verschillende macro-economische scenario's ('As Usual' Wereld, Economische Wereld, Duurzame Wereld).

Deze scenario's zijn gebaseerd op de bestaande scenario's van het International Energy Agency in combinatie met specifieke prijsprognoses die het PBL ontwikkelde voor de conceptversie van het nationale Klimaatakkoord.

Deze methodiek verschafte helder inzicht in welke trajecten haalbaar en welke niet-haalbaar zijn. Enkele belangrijke kenmerken (alleen voorbeelden van de referentievariant worden hier getoond):

- De economische haalbaarheid van H-vision hangt grotendeels af van het gewenste rendement dat een weerspiegeling is van het risicoprofiel en de politieke en macro-economische ontwikkelingen, evenals de impact ervan op met name de prijs van aardgas en de prijzen van $CO_2$-emissierechten. Een ETS prijs van € 86 tot € 146 per ton is nodig om het businessmodel NPV-neutraal te maken.
- De $CO_2$-vermijdingskosten in de referentievariant variëren van 86 tot 146 €/ton (afhankelijk van het scenario). Dit is in feite een strategische investering in het opbouwen van de waterstofeconomie. Het gebruik van blauwe waterstof is voor alle drie de scenario's kosteneffectiever dan de meeste decarbonisatie-opties die zijn opgenomen in het huidige 2019 SDE+ schema, wat betreft de onderzochte toepassingen.
- Unitkosten voor compressie, transport en opslag van $CO_2$ liggen tussen de € 17 - € 30 per ton.
- Realisering van het project leidt op korte termijn tot een forse $CO_2$-emissiereductie van 2,2 Mton per jaar in 2026 tot 4,3 Mton per jaar in 2031 in de referentievariant. Dit is gelijk aan 50% van de huidige $CO_2$-emissie van de raffinaderijsector in Rotterdam.
- De referentievariant vertegenwoordigt een maximale waterstofvraag van de elektriciteitssector en de industrie van iets meer dan 3200 MW. Wat betreft productiecapaciteit zou dit vertaald moeten worden naar de bouw van twee waterstofproductie-units, die ieder een output van 1460 MW hebben en kunnen opereren op 110% van hun capaciteit. De waterstofproductie zou dan 700 kton per jaar zijn.
- De bouw van dergelijke productiefaciliteiten zou gepaard gaan met een verwachte investering van € 1,3 miljard. Bijkomende kosten, zoals infrastructuur en aanpassingen aan compressors, waterstofturbines en ovens, zouden het totale investeringsniveau op ongeveer € 2 miljard brengen.

**Het H-vision project heeft de potentie om als vliegende start te fungeren voor de waterstofeconomie in de regio Rotterdam**

Het is belangrijk te vermelden dat er in dit stadium nog geen ontwikkelingsconcept is gekozen. Deze concepten en scenario's inclusief de aantallen zoals bovenstaand geschetst zijn opgesteld om de haalbaarheid van verschillende opties in te schatten en geven geen definitieve financiële cijfers.

## Volgende stappen

In de volgende projectfasen zal het team het optimale ontwikkelingsconcept kiezen, het conceptuele ontwerp bepalen, de detailengineering uitvoeren, voorbereidingen treffen voor het definitieve investeringsbesluit en het project uitvoeren. De huidige ambitie is om een definitief investeringsbesluit te nemen in 2021 en om de eerste waterstofproductiefaciliteit eind 2025 op te starten.

In de follow-up van het project zijn diverse uitdagingen te slechten, waaronder de onzekerheid over grondstoffen en $CO_2$-emissierechten, maar ook de politieke koers en macro-economische ontwikkelingen. Overheidssteun in de vorm van participatie, contracts for differences, risicodragende leningen of subsidies is gezien het niet-commerciële rendement van de investering vereist om H-vision van de grond te krijgen.

Tegen die achtergrond spelen alle betrokken H-vision partijen een sleutelrol. Andere sleutelrollen zijn er voor de overheid in haar rol als beleidsmaker, verzekeraar & financier, regelgever, pleitbezorger en facilitator.
Op korte termijn is het essentieel om duidelijkheid te krijgen over politieke keuzes betreffende de routekaart energietransitie, zoals over de rol van koolstofafvang en -opslag (CCS) en blauwe waterstof in het bijzonder, maar ook over de beschikbaarheid van innovatieve financiële instrumenten.

Het nemen van volgende stappen door zowel de betrokken H-vision partijen, mogelijk nieuwe belangstellenden en de overheid is essentieel om H-vision tot een succes te maken als vliegende start van de waterstofeconomie in de regio Rotterdam.

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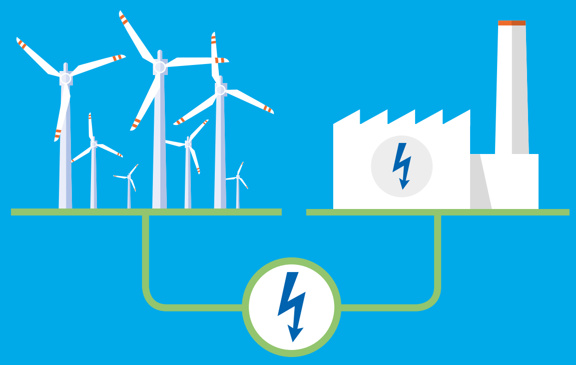
# Introduction

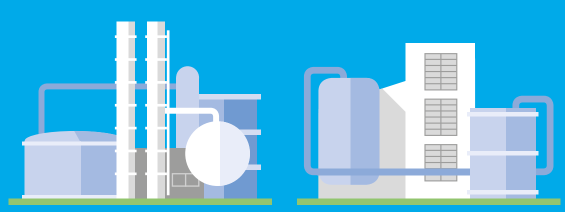
## Where do we need Blue Hydrogen?

### Electricity production



Why Blue Hydrogen:
- Provides low-carbon power
- Flexible operation possible

### Refineries and chemical industry



Why Blue Hydrogen:
- Solution for high temperature heat
- Solution for industrial residual gases

Our energy supply is changing fundamentally. The Dutch government has decided to reduce greenhouse gas emissions by 49% in 2030 (compared to 1990) and by 95% in 2050. The Paris Climate Agreement objective to reduce global warming to below 2 degrees Celsius, with a target value of 1.5 degrees, lies at the foundation of this.

This is a complex challenge for the industry. The energy supply needed for production processes, particularly for heat production, still relies heavily on the use of fossil fuels, namely oil, coal and natural gas. In the elementary transition to a new $CO_2$-neutral energy system, the element of time plays a key role.

Time is needed for additional technological developments to be realised and to implement an efficient scale-up to large-scale systems. However, there is only limited time available. The refining and chemical industries infrequently have extensive maintenance breaks which can be used for such a radical conversion operation, as these occur just once in every five to six years.

Coinciding with this, there is an increasing shortage of time. In essence, global warming is a cumulative issue. The growing accumulation, and thus concentration, of greenhouse gases in the atmosphere results in a limited carbon budget: the amount of global $CO_2$ emissions that should be permitted from now on in order to have any chance of meeting the Paris Climate Agreement objective is steadily decreasing.

Against this background, it is important to develop transition projects that contribute to considerable greenhouse gas emissions reductions in the short term and at the same time prepare the way for a sustainable and climate-neutral energy supply by 2050. This is the strength of H-vision and also the motivation for the sixteen companies working actively in this project.

## Important building blocks

The Rotterdam-Moerdijk Industry Cluster working group advised the government in its July 2018 report *'Three steps towards a sustainable industry cluster by 2050'* that electrification and the use of hydrogen as an energy carrier will be important building blocks for a new energy system that will enable the industry to meet the government's climate objectives.

The use of hydrogen is particularly necessary for the generation of high temperature industrial heat. This hydrogen can be produced from wind and solar electricity, but in the coming decade(s) the availability of this green hydrogen will still be well below what is needed for these applications. Considering this shortage of 'green electricity', industry will initially need to use blue hydrogen, obtained from reforming natural gas or residual gases from industry into carbon dioxide ($CO_2$) and hydrogen ($H_2$). The $CO_2$ released in the production of blue hydrogen should be captured and stored (carbon capture and storage, or CCS) or reused (carbon capture and utilisation, or CCU).

## H-vision's goal and scope

The goal of the H-vision project is to establish the feasibility of the decarbonization of the industry in the port of Rotterdam using blue hydrogen. The overall concept entails one or more large hydrogen production facilities being built which produce hydrogen out of natural gas and refinery fuel gas while capturing the $CO_2$. The $CO_2$ would be stored under the North Sea seabed and the hydrogen would be used as a fuel in the refining, chemical and power production sectors. The focus of this project is on hydrogen as an energy carrier; feedstock hydrogen (hydrogen as raw material) is considered out-of-scope, since it requires a higher quality compared to hydrogen as an energy carrier.

In this study, refineries and power plants are the main consumers of the produced hydrogen. However, the concept is scalable and can be extended to other industries, such as the chemical industry. Furthermore, this study focusses on the Rotterdam area, but a connection with a national hydrogen backbone is also taken into account in one of the development concepts.

The H-Vision study takes the conversion of coal power plants into biomass plants as the baseline for those power plants. Furthermore, the study assumes certain power plant operational modes without a deeper cost and benefit analysis. While these assumptions are sufficient for H-vision's scope, further in-depth research is required to determine the optimal operational concepts. Because the existence of biomass power plants is assumed in this study, the cost of conversion from coal to biomass is outside the scope of the study.

The H-vision project team worked in five working groups to study the technical, financial and commercial feasibility of the construction of one or more new facilities in Rotterdam-Rijnmond to produce large quantities of fuel-grade hydrogen. The extent to which residual gases from the refining and chemical industries can be decarbonized is also part of the study.

The central idea at the start of the study was that H-vision would aim to contribute towards accelerating the energy transition in the Netherlands by decarbonizing industry. The entire value chain for this is also examined in depth for the first time. In particular, this concerns the following components in the study:

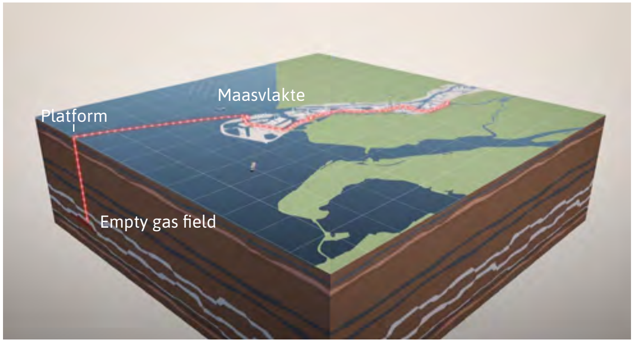
- Technology for hydrogen production;
- Infrastructure for hydrogen production facilities, including possible locations and a hydrogen distribution network;
- Business model;
- Economic feasibility;
- Necessary infrastructure for $CO_2$ transport and storage and connections to other CCS or CCUS projects, particularly Porthos; and
- Possibilities for the creation of a hydrogen hub.

For knowledge generation, the project team used in-house expertise from the participating partners, expertise from independent consultants and various existing public reports, including reports by TKI New Gas, Berenschot, TNO, PBL and CE Delft.

H-vision intends to collaborate with the CCUS Porthos project[1] in the port of Rotterdam. There is also the option for collaboration with the H2M project, which aims to use hydrogen as a fuel for the Magnum power plant in Eemshaven in Groningen. The Chemelot industrial site in South Limburg could be an additional collaborator and become a user of the hydrogen from Rotterdam. In the future, there are clear opportunities for collaboration with other hydrogen projects in industry.

The Netherlands Enterprise Agency (RVO) awarded a subsidy in 2018 for the establishment of the H-vision feasibility study. This project was also financially supported by the Province of South Holland and the municipality of Rotterdam

*CCUS Porthos project, Courtesy of EBN*




1 www.rotterdamccus.nl

## Outline of this report

Chapter 3 of this report examines the opportunities and possibilities of blue hydrogen in the port of Rotterdam industrial area. This is followed by Chapter 4, which discusses various application scenarios.

Chapters 5-7 address the market situation, choices in the area of applicable technology and how $CO_2$ transport and storage will be implemented, respectively.

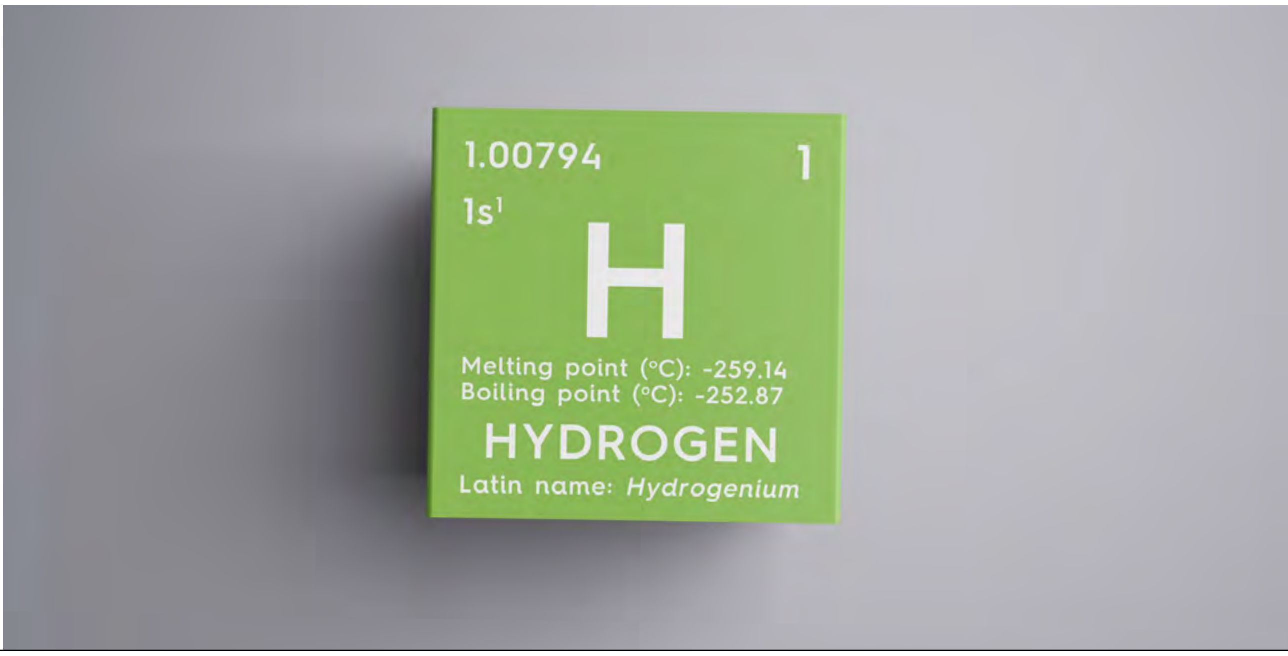
Chapter 8 & 9 focus on the business model and project economics. These also focus on the drivers of the entire hydrogen chain, the role of government, risk management and options for the future organisation of H-vision.

Chapter 10 provides a summary of the main conclusions of the H-vision feasibility study.

All annexes referred to from this report can be found at www.h-vision.nl.

# 3

# Role of blue hydrogen in the port of Rotterdam





| Grey hydrogen | Blue hydrogen | Green hydrogen |
|---|---|---|
| Reform natural gas into $CO_2$ and hydrogen. | Reform natural gas into $CO_2$ and hydrogen.<br>Residual gases also in H-vison scope | Split water into hydrogen and oxygen using electrolysis powered by wind and sun |
| $CO_2$ emitted in the atmosphere. | $CO_2$ stored or re-used<br>Link H-vision with Porthos project for storage under the sea | No $CO_2$ emitted |

The ambitious $CO_2$ emissions reduction targets of both the Paris Agreement and the Dutch government require a drastic transformation of existing industries in the port of Rotterdam. Large investments will be needed for the introduction of new installations to decarbonize production processes, based on new and conventional technologies. There is no one-size-fits-all solution; no one single technology performs best in all circumstances. In our opinion, no options should be excluded as *all* known and proven technologies will be needed to meet the most ambitious goals.

There are several arguments to support the use of hydrogen as an energy carrier, especially for the generation of high temperature heat. While wind and solar power are being developed at an unprecedented speed, in the short-to medium term, these sources will not be able to deliver the energy required to keep the industry running. In the critical years ahead, it seems unlikely that hydrogen production from electrolysis, known as green hydrogen, can supply a major fraction of the required low-carbon hydrogen. Decarbonized hydrogen production from fossil sources, such as natural gas, can increase the supply of low-carbon hydrogen using existing technology.

The H-vision concept of blue hydrogen includes building one or more world-scale hydrogen production facilities in the Rotterdam-Rijnmond region. These facilities would reform large volumes of high-caloric natural gas (thus not gas from Groningen) and industrial residual gases into fuel-grade hydrogen and $CO_2$ suitable for storage. The generated $CO_2$ would subsequently be stored in depleted gas fields under the North Sea using the planned infrastructure of the Porthos project. The captured $CO_2$ could also be reused, for example, by using it in the greenhouses in the Westland area. The blue hydrogen produced in the H-vision concept would be intended for use as a fuel in industrial processes on the one hand, and for flexible power production on the other hand.

*Figure 3.1: Applicability of decarbonisation options to applications in the Port of Rotterdam*

| Decarbonisation options | Applications in the Port of Rotterdam: Feedstock hydrogen | Firing refinery fuel gas | Other high temperature firing | Power production |
|---|---|---|---|---|
| Blue hydrogen | | H-vision | | |
| Green hydrogen | | | Comparison: Section 9.2.1 | |
| Biomass | | | Comparison: Section 9.2.2 | |
| Power to heat | | | Comparison: Section 9.2.3 | |
| Post combustion CCS | | Comparison: Section 9.2.4 | | |
| Storage of electricity | | | | Comparison: Section 9.2.5 |

Out of scope | Not applicable | Partly applicable | Fully applicable

By using the H-vision approach, existing industrial infrastructure can be significantly decarbonized with maximum reuse of existing infrastructure. As the concept builds upon existing technology which is already deployed at large scale throughout the world, the energy transition will be accelerated and high impact, cost-effective decarbonisation will be achieved.

Blue hydrogen and green hydrogen are not mutually exclusive but can complement and even reinforce each other. After 2030, when massive deployment of solar and wind energy makes the production of green hydrogen economically viable, blue hydrogen can be supplemented and eventually replaced by green hydrogen, using the hydrogen infrastructure built by H-vision. Blue hydrogen can thus be an enabler of the energy transition in the port of Rotterdam and can pave the road towards a low-carbon economy with green hydrogen as a central building block.

## 3.1 Blue hydrogen – a solution for industrial applications with limited alternatives

Hydrogen is at the heart of the industrial activity in the port of Rotterdam. With current annual production estimated at 8 billion $m^3$ (720 kt), the Netherlands is a large producer and consumer of hydrogen and will most likely keep this position in the future. The industry in the port of Rotterdam uses around 300-400 kt of hydrogen per year as feedstock. Hydrogen is currently mainly (>85%) produced from natural gas (through steam methane reforming) and as a by-product in the production of chlorine and crude oil refining. Almost all the hydrogen is used by crude and bio–oil refineries. To realise most of the possible decarbonization pathways, hydrogen needs to be used in high volumes, but also in new roles, such as power and heat generation.

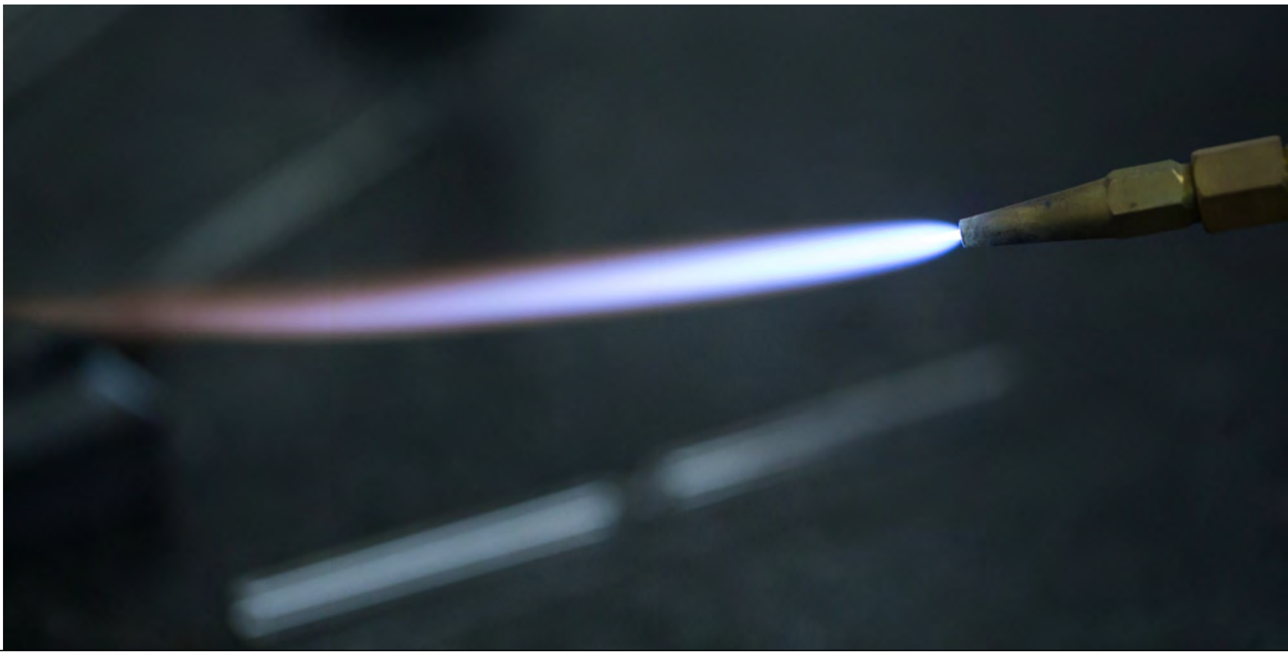
For some industrial applications, the options to decarbonize are limited. High temperature heat, power generation and chemical feedstocks are currently highly dependent on fossil fuels. Steam generation at refineries involves firing residual streams (refinery fuel gas, or RFG) and natural gas. Feedstock applications of hydrogen in chemical chains are left out of the scope of this study (see Chapter 2). The H-vision feasibility study focuses on future newly built blue hydrogen production plants and new infrastructure for supplying low-carbon energy to refineries and the chemical industry, as well as for low-carbon power generation.

Figure 3.1 summarizes to what extent the various alternatives can help decarbonize industrial processes. Whereas hydrogen is applicable for high temperature heat supply and power generation using current technology, electrification is not yet practically useful for these applications. The alternatives in Figure 3.1 are discussed in more detail in Section 9.2. Note that these alternatives have not been studied in depth. The analysis is a qualitative comparison based on expert opinion.

### 3.1.1 Heat supply

Natural gas and RFG currently provide gigawatt-scale heat in the port of Rotterdam. Any decarbonization alternative must be able to guarantee a steady supply of energy at this scale to meet the needs of a large variety of industrial consumers. As blue hydrogen is derived from natural gas and RFG, it can ensure the required volumes and capacities are available for many years to come. The production of blue hydrogen is based on highly mature reforming technology, so the scale-up of blue hydrogen therefore does not present a significant technology risk.

**Firing RFG**
RFG is a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous components and



is a by-product from the refining of crude oil and other downstream processes. RFG is generally used as fuel for boilers and process heaters throughout the refinery or chemical plant. Without carbon capture, this results in large $CO_2$ emissions from boilers and process heaters. The H-vision study shows that substantial amounts of RFG and natural gas can be used for producing hydrogen, while capturing and storing the $CO_2$.

**Considered alternatives**
Several alternatives to blue hydrogen are considered in this study. These include green gas, green hydrogen, solid biomass, post-combustion CCS, and electricity storage. Blue hydrogen is seen to have certain advantages regarding scalability and cost competitiveness for producing high-temperature heat. This is discussed in further detail in Section 9.2. In addition, blue hydrogen has significant potential to decarbonize (excess) RFGs, which is not the case for the other de-carbonization alternatives.

As for green power-to-heat, electrical heating equipment for furnaces and boilers still needs further development, scale-up and de-risking. Suitable technologies are currently in the development stage and have not been built and operated at the required duties (10-150 MW per unit). Furthermore, the electrical infrastructure required for such duties is neither available outside nor inside the refinery fence yet. These limitations must be taken into account when comparing technologies with direct electrification.

### 3.1.2 Power supply

The purpose of dispatchable power plants (power plants that can generate power on demand) in the energy system is to provide a flexible power supply and thus help maintain the balance between supply and demand. The attractiveness of using blue hydrogen for power production depends on fluctuating market prices and is inherently an irregular part-load process.

Power plants use high temperature heat and therefore the same decarbonization alternatives as mentioned before can be considered. The exception is green power-to-heat, as it would be very inefficient to use green electricity to produce heat to generate electricity. Flexible power supply using various types of battery storage is also considered in the comparison to smoothen output fluctuations from renewable power sources. Redox flow batteries (RFBs) deserve special attention, as large, industrial-scale RFBs are being deployed in Asia and the technology looks promising in terms of costs and scalability.

This chapter showed what role blue hydrogen could play in the port of Rotterdam. In the next chapter the different considered development concepts and scenarios will be discussed.

# 4

# The solution space - a scenario approach

*Figure 4.1: The H-vision solution space. Green areas are the options that have been considered for this study, red areas are options that have not been considered based on expert opinion.*

| **Solution space** | | **Development concepts**<br>Our world that we control, we decide | | | |
|---|---|---|---|---|---|
| | | **0. Do nothing** | **1. Minimum scope**<br>Refineries only | **2. Reference scope**<br>No regret, accelerated $CO_2$ reduction | **3. Maximum scope**<br>Refineries + powerplants |
| **Scenarios**<br>The outside world that we cannot control | **A. As Usual World** | A0 | A1 | A2 | A |
| | **B. Economical World** | B0 | B1 | B2 | B3 |
| | **C. Sustainable World** | C0 | C1 | C2 | C3 |

Not considered for this study Considered for this study

To limit the possible solutions and to focus on the most important value drivers, the "solution space" for the project was assessed at the start of H-vision.

The term 'solution space' captures the conceptual model behind the *Assess and Select* phase of H-vision. It may be portrayed by the area with on one axis the development concepts ('*our world*' which we control, we decide) and on the other axis the scenarios ('*outside world*' which we cannot control). By defining the solution space at an early stage of the project, a common understanding on the project objectives, assumptions, development concepts, market scenarios and important stakeholder value drivers was provided.

The solution space that has been assessed for the H-vision project appears broad in terms of development concepts and (macro-economic) scenarios. The solution space limits the number of development concepts to four and focusses on the main value drivers, i.e. large-scale emissions reduction in a short timeframe and paving the way for a hydrogen economy that will ultimately be based on green hydrogen. The methodology and terminology of the 'solution space' is further explained in Annex 1.1.

The H-vision solution space shown in Figure 4.1 is made up of 12 cases, where each case is a development concept combined with a certain scenario. The cases which are perceived as feasible are coloured green and have been evaluated as part of this feasibility study.

## Development concepts

Four development concepts for blue hydrogen were considered in the solution space:

1. **'Do nothing'** - represents the situation where the existing coal-fired power plants in the port of Rotterdam area have been converted to biomass and the subsequent deficit in electricity production is covered by the existing gas power plants (business as usual).

2. **'Minimum scope'** – consists of minimal modifications to the existing refineries and power plants. Leads to roughly 2 Mt of stored $CO_2$ per year.

3. **'Reference scope'** – consists of significant transformation of the existing refineries and power plants. Leads to roughly 6 Mt of stored $CO_2$ per year.

4. **'Maximum scope'** – consists of maximum transformation of the existing installations of the H-vision participants plus adjustments to the installations of parties that are currently non-participants (Exxon, Gunvor and other nearby natural gas users). Leads to roughly 10 Mt of stored $CO_2$ per year.

## Scenarios

Three scenarios for how the world will develop in the coming decades were considered:

1. **'As Usual World'** - no ground-breaking new policies or developments; prices and key technologies follow the current trend and there is no accelerated $CO_2$ reduction. A $CO_2$ emissions price of up to 44 €/t and a gas price of up to 29 €/MWh in 2045 are used.

2. **'Economical World'** – strong economic growth and a continuous ambition to meet climate goals lead to resource constraints, increasing prices (both commodities and $CO_2$ certificates) and accelerated development of key technologies. A $CO_2$ emissions price up to 149 €/t and a gas price up to 34 €/MWh in 2045 are used.

3. **'Sustainable World'** – the implementation of ground-breaking climate policies leads to shortage on the $CO_2$ market on the one hand, but also to economic distress on the other hand. The result is an increase in $CO_2$ emissions prices and a decrease of all other prices (e.g. natural gas, electricity). A $CO_2$ emissions price up to 149 €/t and a gas price up to 24 €/MWh in 2045 are used.

More details on the development concepts and scenarios can be found in Annex 1.2 & 1.3. The decision table can be found in Annex 1.4 and the detailed development concept tables can be found in Annex 1.5, 1.6 and 1.7. This chapter showed the different development concepts and scenarios that were considered in the H-vision study. The next chapter will look at the market development and potential for blue hydrogen.

*June 2019: aerial view of the floating forest in Rijnhaven harbour with trees growing in colorful buoys*

# 5

# Markets

The energy market is a continuously changing entity. This makes the valuation and the feasibility assessment of the H-vision project more challenging. In order to circumvent this issue, a comprehensive power market model has been used to determine the power prices based on different scenarios for commodity prices (e.g. natural cases). Based on price data from the model, the different development concepts of the H-vision project have been valuated.

## 5.1 Hydrogen Market Development

### 5.1.1 Hydrogen market potential

In the efforts to reduce $CO_2$ emissions, the most focus so far has been on reducing the $CO_2$ footprint of the electricity production and converting energy demand to electricity. However, for the Netherlands to reach its climate targets in 2030 and 2050, there is increasing awareness that full electrification is not a realistic scenario and that there will remain a need for other energy carriers, in the form of molecules. Various studies (*Berenschot, 2018a*) have shown that a combination of 'clean molecules', such as hydrogen, and 'clean electrons' is needed in the future to limit the cost of the energy transition.

Today, there is an established hydrogen market where hydrogen is primarily used as a feedstock and primarily produced by natural gas reforming (for more market info, see Annex 2.1). Using hydrogen as a fuel to decarbonize the industry will expand this market. In the Rotterdam industrial area, the current natural gas consumption is 117 PJ per year for industry and 30 PJ per year for power production. In addition, there are 120 PJ of energy used in the form of residual gases (*Rotterdam-Moerdijk industry cluster work group, 2018*). Converting these natural gas and residual gas streams to hydrogen and removing the $CO_2$ could lead to a potential reduction in $CO_2$ emissions of 12-15 Mt per year. Furthermore, there is potential to use hydrogen for the decarbonisation of the two coal power plants. The H-vision concept therefore increases the market potential and availability of 'clean molecules' and contributes to a substantial $CO_2$ emission reduction.

There is a limited number of producers selling hydrogen to a limited number of consumers via bespoke bilateral contractual arrangements. In the Netherlands, the pricing of hydrogen is being done via net-back gas and oil formulas in privately owned transportation systems, mainly in the Rotterdam area. However, when the market develops further and matures, it will eventually be required to move to a more commodity wholesale trading environment. The next paragraphs describe which steps typically need to be taken and which developments need to take place to go through this development successfully.

### 5.1.2 Hydrogen trading hub development

Mature trading hubs, generally speaking, have high volumes and liquidity; have multiple suppliers and users; function as import, export and distribution points and can show high volatility. Often, they are a price benchmark, as well as a marketplace that is reflective of supply/demand trends. They can function as a physical transfer point and can also attract 'speculative' trading.

Open and transparent markets facilitate trading and over time guarantee transparent and trustworthy prices at any given time. This occurs since the market depth and the bid-offer spread facilitate this at all times. Open markets attract many different types of participants that bring liquidity. Liquid markets allow for the ability to physically adjust portfolio volumes over time and financially risk manage commodity portfolios. Mature commodity markets can provide security of supply and, most of all, they provide secure risk management tools.

In the same way that Rotterdam is today a hub in the global oil and gas market, it could fulfil a similar function in a future hydrogen market. H-vision supports the development of this hub function.

In Annex 2.2, "Typical development steps of a successful hub", a detailed description is provided of the typical development steps, evaluation criteria, and success factors of North West European trading hubs for Gas. This was provided to the project as a model that the hydrogen hub could follow.

## 5.2 Blue hydrogen potential for H-vision

This section will identify the potential for blue hydrogen in the port of Rotterdam from a market perspective. Both the demand potential for heat generation and power generation will be discussed. A case study on hydrogen as feedstock for OCI Nitrogen can be found in Annex 2.3.

### 5.2.1 Heat Demand

The potential hydrogen demand for heat generation is based on the Davidse report from 2012 (*Davidse Consultancy, 2012*), ordered by VNCI, VNPI, VNP and Deltalinqs. This report focuses on the national industrial heat demand and a 2020 forecast of that heat demand. Deltalinqs added a specific request to also look at Rotterdam port area. Around 92% of the heat demand in the port of Rotterdam is represented in the study.

#### 5.2.1.1 Study results

For the Rotterdam area, industrial heat demand is estimated at around 139 PJ/yr in 2020. This is in line with other studies on heat demand in the area.

The majority of the heat demand is in the 200-400°C range (74%), mainly supplied by boilers/furnaces (55%) with Cogeneration a distant second (27%). The fuel source used is split between NG (55%) and residual gases, such as refining fuel gases or product gases (45%).

*Figure 5.1: Average electricity prices in the Netherlands*

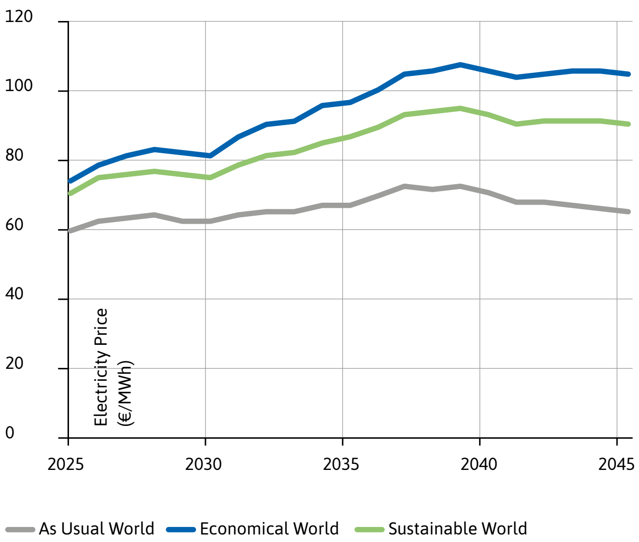
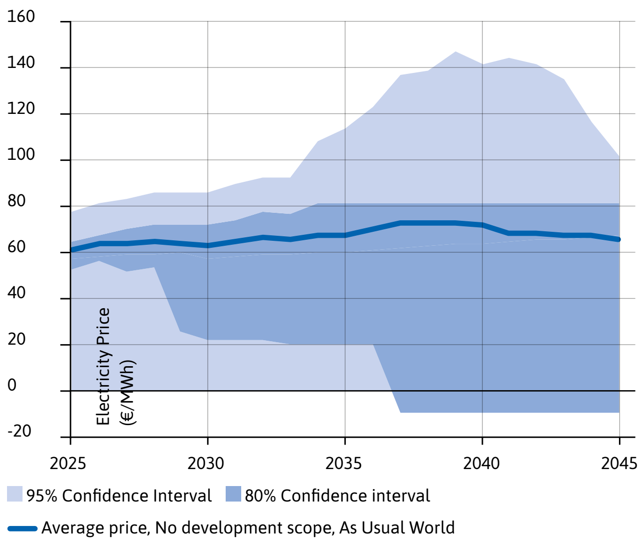



*Figure 5.2: Electricity price variation*




To ensure the data from the report is applicable for the H-vision study, a number of corrections haven been applied to the data. These corrections can be found in Annex 2.1.

#### 5.2.1.2 Comparison of market potential with technical potential

The heat demand in the technical options focusses on refinery fuel gas conversion to hydrogen. All three scenarios fit into the numbers from the Davidse report. The Davidse report shows a maximum offtake of 154 PJ, or 4,88 GW baseload equivalent, excluding a peak factor correction and excluding fuel used to Cogen power. The maximum scope development concept amounts to 2,7 GW, which is approximately 50% of the industrial heat demand in the Rotterdam area.

The Davidse report also shows that there is significant industrial heat produced by natural gas, showing large potential for blue hydrogen demand besides re-using refinery fuel gas.

### 5.2.2 Blue hydrogen for electricity production

Blue hydrogen can be combusted in conventional power plants to produce electricity. The amount of hydrogen that can be used for this purpose is dependent on the type of power plant. For instance, a power plant cofiring hydrogen will need less hydrogen than a power plant equipped with a gas turbine. The operation of these plants also depends on developments in the rest of the Dutch and European power sector, such as price developments.

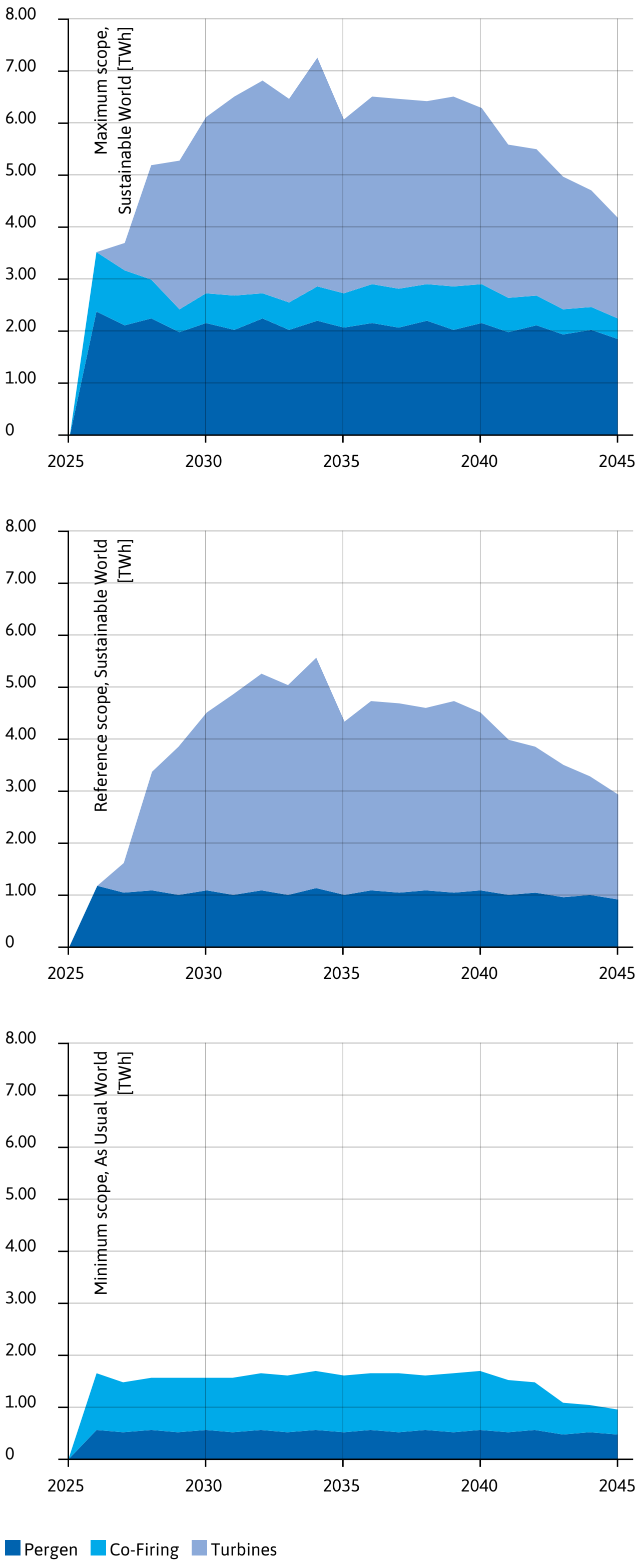
A model called PPSGen (Power Price Scenario Generator) from eRisk Group was used to assess the potential demand for hydrogen for the different scenarios and development concepts. More details about this model can be found in Annex 2.4.

### 5.2.3 Electricity price developments

Figure 5.1 shows the average electricity prices in the Netherlands for the 3 scenarios used in this study. The hourly electricity price is set by the most expensive plant producing in that hour, which is usually a gas plant in the Netherlands. Therefore, the price developments largely depend on the gas and $CO_2$ emissions price assumptions. In the As Usual World, the average electricity prices remain at a level between 60 and 70 €/MWh, caused by relatively stable gas and $CO_2$ emission prices. Both the Economical World and Sustainable World scenarios have far higher $CO_2$ emissions prices and therefore show higher electricity prices. However, because the gas price remains low (under 25 €/MWh) in the Sustainable World scenario, the price increase is less than the Economical World scenario, which has both high gas and high $CO_2$ emissions prices. Instead of yearly average prices, Figure 5.2 shows the variation in the electricity prices during the year in the *As Usual World*. The different lines show how much the electricity price varies in the *As Usual World* scenario. The average price is shown in blue; the variation around that price is shown in greyscale. Due to increasing shares of wind and solar electricity, prices are negative during an increasing number of hours per year. On the other hand, due to the decrease in firm capacity, such as nuclear and coal, price spikes are both higher and more frequent. So even if the average price seems to be relatively stable, hourly variations in prices increase. The same increase in price variation is observed in the *Economical World* and *Sustainable World* scenarios (not shown in Figure 5.2).

The fluctuations in hydrogen demand from power plants can be substantial. Depending on the flexibility of the hydrogen production facilities and the flexibility in other demand processes, more or less storage is required to make optimum use of the flexibility that these power plants can generate.

*Figure 5.3: Yearly hydrogen demand in the power sector for different development cases.*




#### 5.2.3.1 Conclusions – Possible demand for hydrogen for power production

The insight in the possible developments of the electricity price allows for an estimation of the hydrogen demand for the power sector. As the different scopes have a much larger influence on the power sector hydrogen demand than the different scenarios for prices, the hydrogen demand for the maximum and reference scope is investigated assuming the Sustainable World scenario while the minimum scope is investigated assuming the As Usual World scenario.

Figure 5.3 shows the yearly volumes of hydrogen demand from the power plants that are considered in this study. The minimum scope development concept foresees a yearly demand less than 2 TWh from 2026 onwards, slowly declining to 1 TWh in 2045. This decline is mainly caused by a reduced number of running hours from the converted biomass power plants.

The reference scope development concept (average development) starts a bit slower, as the hydrogen gas turbines connected to the coal plants need more time to reach their capacity. Secondly, the Pergen plant increases its hydrogen in the gas mix to 50%. This leads to a hydrogen demand from the power sector of 4.5 TWh in 2030. Again, the hydrogen demands slowly declines to approximately 3 TWh in 2045, due to lower running hours for the converted biomass power plants.

When the converted biomass power plants combine the new hydrogen gas turbines with 15% hydrogen co-firing (pre-heating) the demand starts of at 3.5 TWh in 2026, rising to a maximum of 7 TWh in 2030 when both the demand from the coal plants and Pergen is at its peak. Demand drops to approximately 4 TWh in 2045 due to lower demand from the coal plants.

This shows that, depending on the development concept, there is significant potential for low-carbon blue hydrogen in the power sector.

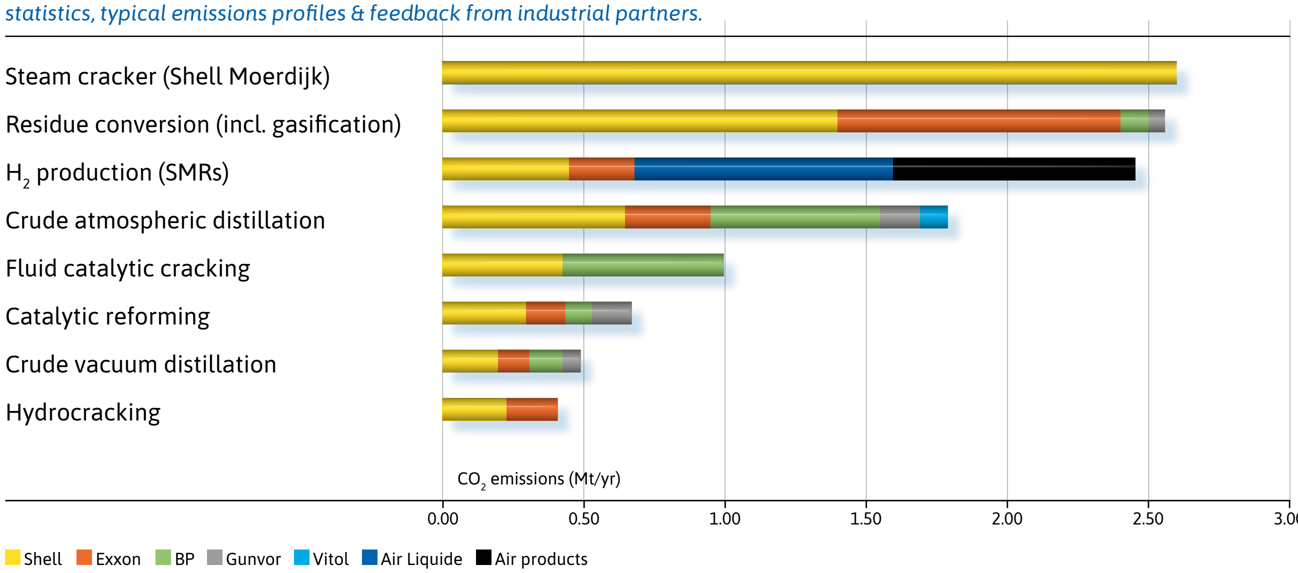
## 5.3 Conclusions

- The potential for blue hydrogen for industrial heat is significant and should contribute significantly to the business case for H-vision. The base load consumption characteristic of industrial heat demand is also an ideal foundation for an H-vision business case, ensuring a stable, constant and predictable offtake.
- In a future where gas- and coal-fired power plants are converted to allow for the use of low-carbon fuels, the demand for hydrogen from these power plants can be significant.
- In view of the large (potential) use of hydrogen, its location in a large industrial cluster and the available infrastructure, Rotterdam is a prime location to develop into a hydrogen hub.

# 6

# Technology

*Figure 6.1: $CO_2$ emissions from petrochemical processes in the Rotterdam area (+ Shell Moerdijk). TNO estimates based on CBS statistics, typical emissions profiles & feedback from industrial partners.*




This chapter introduces the technology needed for the H-vision project. First, the demand for hydrogen as a fuel is discussed from a technological perspective. This includes demands from refineries and for power generation, in which the implementation of hydrogen will also be discussed. Second, the technology for producing blue hydrogen efficiently are presented. This includes the transportation and storage of hydrogen. Third, integrated blue hydrogen chains are investigated, including the supply of natural gas and the transportation of hydrogen & carbon dioxide. Fourth, a CAPEX estimate is given for the different conceptual designs. The final section consists of the conclusions of the full chapter. An overview of related or similar projects can be found in Annex 3.1.

## 6.1 Potential for using blue hydrogen

Blue hydrogen is a viable alternative to deploying post-combustion $CO_2$ capture for existing power plants, as will be further discussed in Section 9.2.4. Additionally, it can substitute natural gas and other fuels currently used to generate high-temperature heat at industrial sites.

The refining sector alone emits over 12 million tonnes of $CO_2$ per year (Mtpa), over a third of all industrial emissions in the Rotterdam area. As blue hydrogen can replace (part of) the fuels that cause those emissions, there is ample potential for using blue hydrogen in the industry. The H-vision project can achieve rapid decarbonization by supplying a low-carbon fuel that replaces:

- **High-temperature process fuels:** natural gas, refinery fuel gases (RFGs) and naphtha cracker gas, which are currently being burned in the petrochemical industry to obtain high temperature heat; and
- **Power generation fuels:** coal and natural gas currently used for power generation.

In line with the solution space approach (Chapter 4), this chapter covers the bottom-up approach that was used to provide hydrogen demand estimates corresponding to the three cases:

- **Minimum scope:**
  roughly 2 Mtpa of $CO_2$ captured and stored
- **Reference scope:**
  roughly 6 Mtpa of $CO_2$ captured and stored
- **Maximum scope:**
  roughly 10 Mtpa of $CO_2$ captured and stored

To estimate the potential demand for blue hydrogen, models were developed based on publicly available data for $CO_2$ emissions and fuel usage. These models were reviewed by various project partners. It is our view that a combination of different end-users is the best approach for each case. Base load demand from industry is essential to efficiently operate the production facilities.

### 6.1.1 High temperature heat for the industry

An estimate of $CO_2$ emissions can be made using public data for site and sector emissions, typical refinery emissions profiles and feedback from industrial partners. A breakdown of $CO_2$ sources in the port of Rotterdam area and Moerdijk was made, as can be seen in Figure 6.1.

This is not an exhaustive overview as it does not include other large industrial sites, such as Huntsman in Rozenburg and Covestro / LyondellBasell on the Maasvlakte. This breakdown only contains emissions from the largest point sources on the mentioned sites, not accounting for smaller furnaces. Refineries also have indirect emissions, for example due to electricity imports from the grid, which are not considered here. An exception is PerGen steam and power, operated by Air Liquide and serving the Pernis refinery, which is taken into account for the study.

While forecasting refinery operations lies outside the scope of this H-vision feasibility study, in our view, the position of the Rotterdam refineries can be strengthened by implementing decarbonization solutions.

Demand estimates for using blue hydrogen as a low-carbon fuel are based on current energy consumption data. About two thirds of these industrial $CO_2$ emissions result from burning natural gas or refinery fuel gases (naphtha cracker gas in the case of Shell Moerdijk) in high temperature furnaces, to heat up various process streams.

There are four main options for reducing these $CO_2$ emissions:
1. Electrification
2. Hydrogen as fuel (pre-combustion $CO_2$ capture)
3. Post-combustion $CO_2$ capture
4. Synthetic fuels or biofuels / biogas

A mix of all of these solutions could end up being implemented, in order to reach a significant reduction of $CO_2$ emissions from petrochemical sites in the Rotterdam area. In consultation with representatives from project partners BP and Shell, it is our view that pre- and post-combustion $CO_2$ capture will play a dominant role compared to the other two options.

The total annual emissions for the three largest refineries (operated by BP, Exxon and Shell) add up to about 8.7 Mtpa $CO_2$. Of this total, roughly 3.5 Mtpa $CO_2$ are process emissions that do not directly result from burning either natural gas or RFG (refinery fuel gas) for energy. The remaining 5.2 Mtpa $CO_2$ are primarily emitted from various fired heaters, as well as steam boilers and gas turbines, or combined heat & power units.

Industrial installations, such as atmospheric and vacuum distillation units, hydrotreating and hydrocraking units, catalytic reformers and solvent de-asphalting units all require high temperature furnaces to operate. Furnaces are typically interconnected via one or more RFG distribution networks, which have import lines for natural gas as a balancing fuel.

The realistic potential (e.g. without replacing existing gas turbines) to replace natural gas by blue hydrogen was estimated to be on the order of 50-100 MW for Shell Pernis and roughly 40 MW for the BP refinery. In consultation with Shell and BP, the following low and high estimates were defined for replacing RFGs with blue hydrogen:
- Low estimate: 250 MW for each refinery
- High estimate: 520 MW for BP and 650 MW for Shell Pernis

These estimates take into account the current configuration of various furnaces and fuel grids at the refineries, as well as the previously estimated potential for deploying post-combustion technology for large flue gas stacks.

The values for the Shell and BP refineries are used for the total blue hydrogen demand estimates for each of the three cases, as summarized at the end of this chapter. Demand for blue hydrogen from the ExxonMobil and Gunvor refineries is taken into account for the high case only and is roughly estimated based on available (public) data and correlations with BP and Shell estimates.

There is also the potential to further reduce emissions in the area by replacing natural gas use at various sites with blue hydrogen fuel. A possible future expansion of the H-vision scope could include the Shell Moerdijk site, as well as potential users further away that are connected to the to-be-developed nation-wide hydrogen grid. The naphtha cracker complex at Shell Moerdijk is the nearest large industrial site that could be connected to the H-vision network, with ample potential for reducing $CO_2$ emissions.

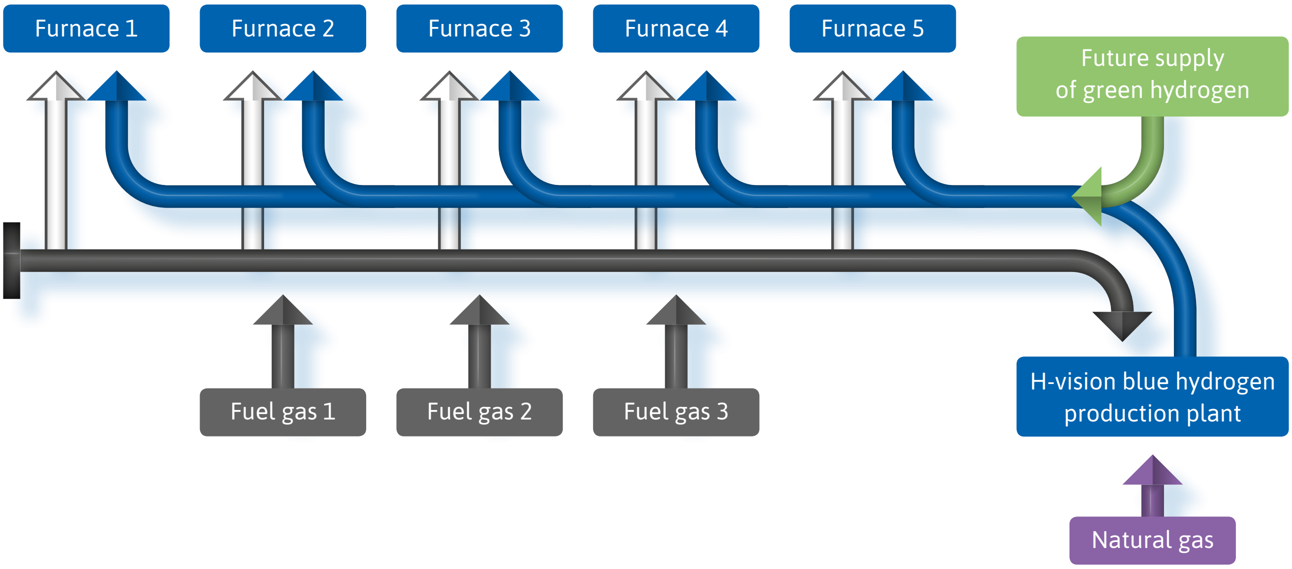
Four large steam cracker furnaces at Moerdijk (with a combined duty of 360 MW) could be converted to fire hydrogen-rich fuel, within the timeline considered in the H-vision study. Converting these furnaces is considered to be similar in complexity and cost to converting the refinery furnaces that are already included in the proposed H-vision scope. An additional 650-700 MW of fired duty could theoretically be replaced by hydrogen fuel in the future, but for those furnaces, more complex modifications are required. It might also be possible to supply part of this duty by admixing hydrogen fuel into the existing fuel gas grid, but this option needs to be further studied.

The option of compressing and transporting cracked gas fuel from Moerdijk to the central hydrogen production plant at the Maasvlakte will also have to be evaluated against the alternative of having a dedicated reforming plant for blue hydrogen, either on site or in the vicinity of the Moerdijk complex. The optimal solution will strongly depend on the total duty to be replaced by blue hydrogen. Either way, at least one pipeline will have to be added. There is potential for cost reductions by linking this to an ongoing project for replacing existing pipelines between Moerdijk and Pernis.

### 6.1.2 Hydrogen infrastructure at refineries

Reducing $CO_2$ emissions from refineries and petrochemical sites through the use of pre-combustion technology requires that certain technical challenges will be overcome:
- A very high overall system reliability is required.
- Fired heater burners have to be replaced by fuel-flexible burners which can fire fuel with a very high hydrogen content.
  - Instrumentation, safeguarding and controls around the furnaces also have to be upgraded to enable

*Figure 6.2: The proposed way to integrate the H-vision concept within existing fuel gas grids. Natural gas and refinery fuel gas feed the blue hydrogen production plant. The blue hydrogen is then used in the furnaces. In case there is imbalance on the hydrogen grid, refinery fuel gas can still be used in the furnaces.*




  seamlessly switching between fuels while in operation.
  - In addition to replacing burners, new fuel distribution systems have to be installed to supply hydrogen fuel.
- Firing a hydrogen-rich fuel increases burner flame temperatures, resulting in higher NOx emissions.
  - This is generally not regarded as a show-stopper and ultra-low-NOx burner technology is under development. A high margin was applied to cost estimates for furnace modifications to account for this.
- Fuel gas containing $H_2S$ has to be exported from the refineries to a central hydrogen production plant. As a consequence of various process upsets, the $H_2S$ concentration in RFG frequently spikes up to levels of 10.000 ppm and above. The current frequency is several times per year, so it's important to address this.
  - The design of the pre-treatment section of the H-vision hydrogen production plant should take the concentration spikes into account.
  - Alternatively, perhaps also due to HSE restrictions, the refinery in question could temporarily stop exporting fuel gas to the hydrogen plant, and switch back to RFG firing in the furnaces (fall back to the existing situation) until the cause is remedied. This will lead to a temporary increase in $CO_2$ emissions.
  - The hydrogen production plant needs to cope with a broad range of feedstock compositions, which reflect different refinery operating modes, turnaround cases and upset scenarios.

Maintenance stops, such as turnarounds, provide the opportunity to carry out furnace modifications, but for large/complex refineries, turnarounds don't involve all units. Not all the furnaces in the scope of H-vision will be shut down at the same time during such an event, so the transition of existing RFG networks towards blue hydrogen must take place in phases.

A separate distribution network is therefore needed to supply blue hydrogen to the furnaces that have been upgraded. Figure 6.2 shows schematically how such a dual fuel distribution network could work, minimizing the impact of switching to the low-carbon fuel. This also allows for introducing renewables-based green hydrogen as it gradually becomes available in the future.

### 6.1.3 Power generation

Power generation at the port is carried out by gas- and solid fuel-fired assets. As presented in Table 6.1, there is around 4430 MW of total installed capacity. The maximum theoretical potential to use blue hydrogen for power generation was estimated based on these existing power plants in the Rotterdam area.

Only two of the gas-fired power plants are capable of partially running on hydrogen since the type of gas turbine technology used in these two plants has a proven track record. These are the gas-fired power plants of Air Liquide Pergen and Shell Refinery Per+ and are as such identified as hydrogen switch options. With their track record, these units can be revamped to be able to utilise hydrogen without major modifications, such as replacement of the gas turbine. The remaining gas-fired power plants in Rotterdam are based on gas turbine technologies with limited operational references and might require much more time and effort to be revamped for hydrogen, and consequently are not identified as short-term switch options.

For the coal-fired power plants, hydrogen is listed in the proposed bill that prohibits the use of coal for power generation[2] as one of the options for an alternative to coal. Hydrogen combustion in the existing coal-fired units will require partial replacement of the fuel system and burners. For the H-vision project, it is assumed that both coal-fired power plants will be switched to biomass as a feedstock, which will then be combined with hydrogen firing. It is worth noting that the efficiency of the total system (i.e. the hydrogen production facility combined with the power plants) can be improved via clever integration with the hydrogen production units, e.g. steam integration.

*Table 6.1: List of coal- and gas-fired power generation plants in the Rotterdam area*

| Unit | Power output (installed capacity) [MWe] | Fuel type | Hydrogen (partial) switch option |
|---|---|---|---|
| **Uniper Maasvlakte 3** | 1070 | Coal / biomass | Yes |
| **Eneco Enecogen** | 870 | NG | No |
| **Rijnmond Energie CV** | 820 | NG | No |
| **Engie MaasStroom** | 800 | Coal / biomass | Yes |
| **Air Liquide Pergen** | 300 | NG | Yes |
| **Shell Refinery Per+** | 142 | Syngas | Yes |
| **Eurogen** | 88 | NG | No |

Relative to the total power generation capacity in the Rotterdam area, a realistic estimate for replacing existing fuels with hydrogen will be smaller, because:

- As already mentioned, 3 out of the 5 gas-fired power plants in this list have turbines that cannot be easily retrofitted for hydrogen firing;
- It is not possible to completely replace existing coal-fired capacity with hydrogen, without replacing the existing boilers. This chapter lists four concepts to partially replace coal with blue hydrogen + biomass cofiring for the conventional coal-fired power plants;
- Actual power production is much lower than installed capacity. Many of these power plants are expected to run as peak-producers, leading to large and rapid fluctuations in fuel demand. Hydrogen production has to be either flexible or coupled with hydrogen storage to cope with these fluctuations; and
- Some of the power generation capacity in this area might be decommissioned because of the projected increase in renewable energy generation. Adding more renewables to the electricity mix, however, also increases the need for flexible power generation, which could be provided by turbines running on blue hydrogen.

The two coal-fired units at the Maasvlakte are currently scheduled to phase out coal by 2030. There is an opportunity to maximize the potential of these power plants, while still adhering to decarbonization targets, by replacing coal with solid biomass fuel. Since biomass has a lower heating value than coal, this will result in a lower energy input to the boilers and a lower utilization of the existing steam turbines. This is where blue hydrogen can play a role, by supplying additional heat input with low $CO_2$ emissions. However, the first step is to use the surplus of steam that comes along with hydrogen production.

The surplus of steam that is generated by the hydrogen production units will be sent to both coal-fired power plants. The steam is produced at the hydrogen production plant at two pressure levels, 100 bar and 30 bar. Both steam flows will be slightly overheated before being sent through dedicated pipelines to the two power plants. The high pressure steam will be further superheated at the power plant via the re-heat section of the steam system. The low pressure steam will be sent to the boiler feed water (BFW) pre-heating sections of the power plants.

For the hydrogen firing revamp options, the following concepts were reviewed:

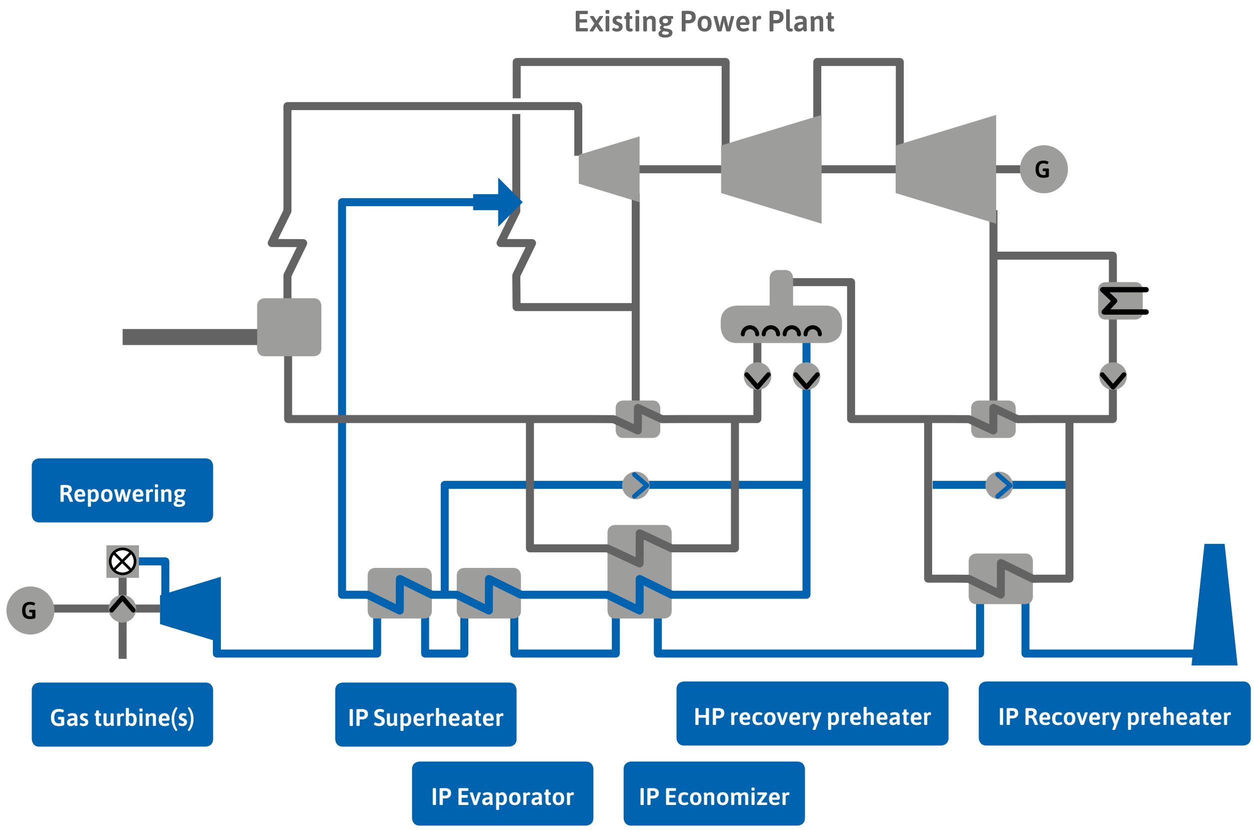
- **Concept 1: Hydrogen firing in existing boilers**
  This concept is straightforward but implies replacing or upgrading burners in the boiler and a rearrangement of the heat exchangers in the boiler. The impact of hydrogen firing in the boiler is unknown and therefore would require computational fluid dynamics (CFD) analyses. Hydrogen would be co-fired together with biomass in the boilers.

- **Concept 2: Integrating a gas turbine (GT) in the BFW preheater cycle**
  Hydrogen is fired in one or more new gas turbines, and the flue gas is used to pre-heat the BFW.

- **Concept 3: Full integration of a GT in the BFW preheater cycle and IP steam cycle**
  This concept is an expansion of Concept 2, increasing the level of heat integration between the new turbines and the existing power plant. Hydrogen is fired in one or more new gas turbines, and the flue gas is used not only for preheating BFW, but also for steam generation, topping up the existing steam cycle. See Figure 6.3 for more details.

2 Voorstel van wet houdende een verbod op het produceren van elektriciteit met behulp van kolen

*Figure 6.3: Integration of a GT in the BFW preheater cycle and IP steam cycle*




- **Concept 4: Topping GT / Replacement for Boiler Air Preheater**
  Finally, the last option considered is a topping cycle repowering concept, through which a thermal power plant can be upgraded without replacing the existing boiler. The existing boiler and steam turbine are retained while the overall steam cycle is upgraded to achieve a higher efficiency and additional power capacity.
  This can be achieved by installing a new gas turbine, sized to compensate for the loss of heat input, due to firing of biomass instead of coal, and directing the hot flue gas to the boiler. Large power plants with higher, more efficient steam pressures benefit from this repowering concept and the overall efficiency of the repowered cycle increases compared to the existing unit.

The different concepts for existing coal units will have to be assessed based on a high level thermodynamic system model in a next phase of the study. The most likely repowering concept will then be used for the detailed business case assessment. More detailed analyses evaluating the boiler performance with a validated model based on hydrogen and biomass firing will also have to be done in any next steps.

A first preliminary estimation of hydrogen capacity has been made for the power plants that are able to switch to hydrogen. The nominal hydrogen production will be in the range of 2 GW up to 2,8 GW for power generation. The total hydrogen utilization, subject to the running hours of the power plants, will be in the range of 20 PJ up to 40 PJ.

The potential of using hydrogen in gas-fired power plants has also been investigated. The PerGen plant has been identified as the best candidate for the H-vision project for two main reasons. The first of these is the two new GE Frame 9 turbines that have a high fuel flexibility. These are expected to easily accommodate 25 - 50% hydrogen with minimal investment or modifications. The second reason is that the base load operating profile of the heat & power unit is also advantageous.

Other gas-fired power plants (e.g. Enecogen and Rijnmond energie) could in principle be added to the hydrogen network in the future, but it is expected that new gas turbines will have to be installed or the technology provider will have to improve their gas turbine capabilities to allow for running on hydrogen.

### 6.1.4 Repowering options of the solid fuel power plants in Rotterdam

The coal/biomass-fired power stations in the Netherlands are among the most modern production units in the world, however these units are optimized for solid fuels, like coal and pelletized biomass. Using an alternative feedstock requires plant modifications (known as “repowering”) and might not be the most optimal choice. The repowering options for coal-fired power plants listed in the “Memorie van Toelichting” alongside the proposed bill “Voorstel van wet houdende een verbod op het produceren van elektriciteit met behulp van kolen” are: biomass, biofuels, ammonia, hydrogen, renewable gas, waste and iron powder.Last three options are not considered in this study.

Both coal-fired power plants in the Rotterdam port, Maasvlakte 3 (Uniper) and MaasStroom centrale (Engie), have been recently commissioned and it is possible that in the near future these power plants will need to be operated on alternative fuels. From the list above, biomass is the only technically credible option as an alternative fuel for these two plants. At the same time, the formation of carbon monoxide must be minimized, which makes this a challenging engineering task. Additionally, and maybe more importantly, $CO_2$ emissions reduction for these cases would require post-combustion $CO_2$ capture.

At this time, bio-based liquid fuels are not yet applied in large-scale coal-fired boilers. This is because the willingness to pay a high price for biofuel is generally higher in other sectors, such as mobility. Due to the higher fuel cost when using biofuel, the power plant operational hours could be very limited because of the high marginal cost price of electricity that would result.

Direct firing of ammonia is not yet feasible at large scales for pulverized fuel (PF) boilers, due to the high concentration of NOx formed in the process. Ammonia needs to be cracked into hydrogen and nitrogen before it is combusted. In the case of cracking, the produced hydrogen might follow the previously discussed hydrogen revamping options.

For the H-vision project, it is assumed that both power plants mentioned above could be switched to biomass firing. Biomass has generally been co-fired up to 20 – 30% mass percentage concentration levels. However, it is worthwhile to note that firing 100% (mass basis) biomass in modern ultra-supercritical coal-fired power plants has not yet been applied. At this time, 100% firing of biomass applies only to older type boilers with lower steam pressure and temperatures. Therefore, it will require extensive research and development time to increase the biomass content. Also, perhaps more important, is the impact on the efficiency of the power plant. Biomass has a lower heating value which limits the heat input, and consequently the power output will be impacted. This has the further effect of decreasing the power plant commercial availability due to fouling and corrosion issues that result from biomass firing.

Nevertheless, in the H-vision scenarios, both power plants would be operated on different amounts of biomass firing, which is always a part-load operational condition on the boiler and steam system. As such, steam integration and additional firing of blue hydrogen or a topping cycle are interesting theoretical repowering options in combination with biomass firing.

At this stage of the study, the amount of biomass and the necessary modifications for hydrogen firing are determined based on a generic approach. In the next phase, a more detailed approach needs to be followed, and thus the amount of biomass or alternative solid fuel firing and the necessary power plant modifications might be changed.

For the H-vision conceptual designs, the steam produced at the (blue) hydrogen production facility will be integrated with both power plants. The steam from the hydrogen plant(s) will be sent via dedicated steam pipelines to the power plants. The tie-ins for the steam supply will be in the re-heat section, where the hydrogen plant steam is mixed with the reheated steam from the boiler and directly sent to the steam turbine section. The steam sent to the power plants might need some additional overheating to accommodate for an appropriate steam mixing.

The topping cycle repowering is based on the gas turbines type MH701D. Both power plants are repowered with two gas turbines which provide a good operational range. The flue gas from the gas turbine is mixed with the air inlet system of the boiler and a smaller part of the flue gas heat is sent to the boiler feed water pre-heat section.

The operational performance of the gas turbine running on natural gas is used to calculate the operational performance with hydrogen, based on data from the Gas Turbine World Handbook (*Gas Turbine World 2019 GTW Handbook, 2019*). The gas turbine open cycle efficiency on natural gas is approximately 35%. Running the turbine on hydrogen fuel in a topping cycle configuration is expected to slightly increase the open cycle efficiency to 36.5%, because the turbine exhaust is sent directly to the boiler, thereby reducing the power consumption for combustion air compression.

A detailed overview of the modelling results for the proposed approach to repower the two solid fuel power plants, for the three H-vision cases, is presented in Annex 3.2.

### 6.1.5 Combined estimates for blue hydrogen demand

To determine the combined estimates for blue hydrogen demand, a selection has to be made of end-users and the volume of hydrogen they will need. This was done for each of the development concepts, where the annual volume of $CO_2$ stored was used as the limiting factor.

For every GW of hydrogen fuel produced, the proposed ATR + CCS concept captures roughly 210 t/h of $CO_2$, to be transported for storage. If operated continuously (8760 operational hours per year), each GW of hydrogen fuel production capacity is then equivalent to about 1.84 Mtpa of $CO_2$ captured. This correlation was used to define the mix of power plants and industrial end users for each case in such a way that the maximum rate of $CO_2$ captured is close to the values in the development concept cases established in the solution space, as presented in Chapter 4. The total amount of $CO_2$ captured annually depends on the actual utilization factor of the hydrogen plant, related to the demand from industry and the actual operational hours of the power plants. Using a mixture of RFG and natural gas as feedstock is also expected to have a slight impact.

Breakdowns of the demand considered per end user are presented in Table 6.2, Table 6.3 and Table 6.4, together with a brief explanation of how the estimate was made.

*Table 6.2: Breakdown of estimated demand for blue hydrogen for the minimum scope, for power plants and industry*

**Blue hydrogen demand for power plants and industry: Minimum scope**

| Description | Max [MW] | Details |
|---|---|---|
| **Engie Maasvlakte power plant** | 174 | 10% hydrogen firing (calculated based on the existing coal-fired duty) for additional heat input in the BFW preheat section of the power plant, in addition to steam integration with the H-vision plant. |
| **Uniper Maasvlakte power plant** | 233 | |
| **Pergen steam and power** | 143 | Pergen has 2 x GE 9E.03 turbines with a total capacity of 200 MWe at 35% thermal efficiency. Assumed 25% replacement of NG with hydrogen. |
| **BP refinery RFG** | 250 | Minimum modifications for replacement of RFG and with hydrogen-rich fuel. Replacement of NG imported to balance the fuel gas grid (excluding NG duty of gas turbines). |
| **BP refinery NG** | 40 | |
| **Pernis refinery RFG** | 250 | Minimum modifications for replacement of RFG and with hydrogen -rich fuel. Replacement of NG imported to balance the fuel gas grid (excluding NG duty of gas turbines). |
| **Pernis refinery NG** | 50 | |
| **Total demand** (rounded up) | **1139** | |

*Table 6.3: Breakdown of estimated demand for blue hydrogen for the reference scope, for power plants and industry*

**Blue hydrogen demand for power plants and industry: Reference scope**

| Description | Max [MW] | Details |
|---|---|---|
| **Engie Maasvlakte power plant** | 805 | 2 x 147 MWe gas turbines (36.5% open cycle efficiency) added to each power plant, running on hydrogen fuel and fully integrated with the existing boilers (topping cycle + heat integration), in addition to steam integration with the H-vision plant. |
| **Uniper Maasvlakte power plant** | 805 | |
| **Pergen steam and power** | 286 | Pergen has 2 x GE 9E.03 turbines with a total capacity of 200 MWe at 35% thermal efficiency. Assumed 50% replacement of NG with hydrogen. |
| **BP refinery RFG** | 520 | Maximum modifications for replacement of RFG and with hydrogen-rich fuel. Replacement of NG imported to balance the fuel gas grid (excluding NG duty of gas turbines). |
| **BP refinery NG** | 40 | |
| **Pernis refinery RFG** | 650 | Maximum modifications for replacement of RFG and with hydrogen -rich fuel. Higher replacement of NG imported to balance the fuel gas grid (excluding NG duty of gas turbines). |
| **Pernis refinery NG** | 100 | |
| **Total demand** (rounded up) | **3207** | |

*Table 6.4: Breakdown of estimated demand for blue hydrogen for the maximum scope, for power plants and industry*

| Blue hydrogen demand for power plants and industry: Maximum scope | | |
|---|---|---|
| Description | Max [MW] | Details |
| **Engie Maasvlakte power plant** | 1066 | 2 x 147 MWe gas turbines (36.5% open cycle efficiency) added to each power plant, running on hydrogen fuel and fully integrated with the existing boilers (topping cycle + heat integration), in addition to steam integration with the H-vision plant.<br><br>15% hydrogen firing (calculated based on the existing coal-fired duty) for additional low-carbon heat input in the BFW preheat section of the power plants, or direct hydrogen firing in the boilers. |
| **Uniper Maasvlakte power plant** | 1154 | |
| **Pergen steam and power** | 571 | Pergen has 2 x GE 9E.03 turbines for a total capacity of 200 MWe at 35% thermal efficiency. Assumed full replacement of NG with hydrogen. |
| **BP refinery RFG** | 520 | Maximum modifications for replacement of RFG and with hydrogen-rich fuel. Replacement of NG imported to balance the fuel gas grid (excluding NG duty of gas turbines). |
| **BP refinery NG** | 40 | |
| **Pernis refinery RFG** | 650 | Maximum modifications for replacement of RFG and with hydrogen-rich fuel. Higher replacement of NG imported to balance the fuel gas grid (excluding NG duty of gas turbines). |
| **Pernis refinery NG** | 100 | |
| **Exxon + Gunvor refineries (RFG)** | 600 | Rough estimate for RFG replacement (correlated based on emissions profile and refinery configuration, relative to BP and Shell). |
| **Additional users of NG** | 500 | Rough estimate for additional potential of blue hydrogen to replace natural gas of other nearby end users, such as Exxon & Gunvor, Air Liquide, Air Products, Huntsman & LyondellBasell. |
| **Total demand** (rounded up) | **5202** | |

*Figure 6.4: High-level block diagram for blue hydrogen production (Northern Gas Networks, Equinor, 2018)*

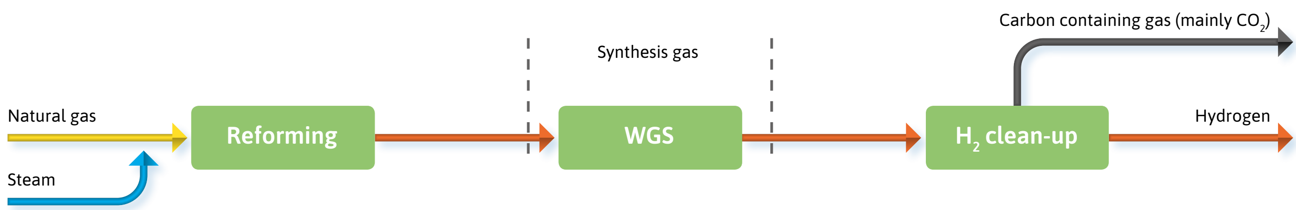
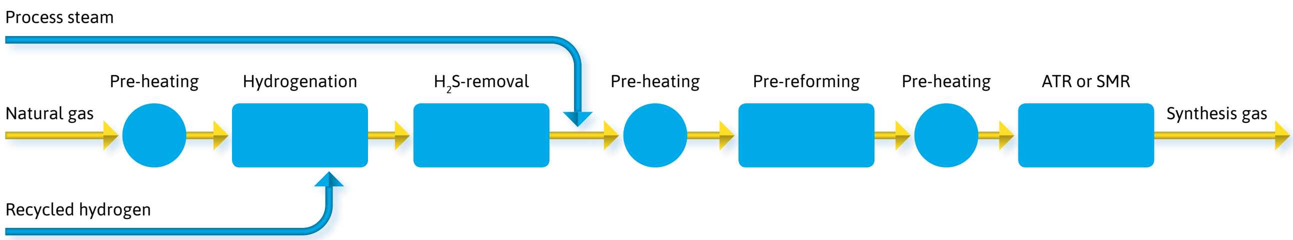



*Figure 6.5: Block diagram for the front section of a reformer (Northern Gas Networks, Equinor, 2018)*




## 6.2 Blue hydrogen production technology

### 6.2.1 Introduction to reforming technologies

Converting natural gas, refinery fuel gas (RFG) or naphtha cracker gas to hydrogen consists of three main steps:

1. Pre-treatment and reforming of the feedstock gas (combined into one block in the diagram below, with more details for the front section shown in Figure 6.5).
2. Syngas processing and heat recovery section
3. Hydrogen clean-up and $CO_2$ capture section, including export compressors

The complexity (and thus the cost) of the pre-treatment section depends on the quality of the gas feedstock used, but it will generally contain a sequence of steps such as those shown in Figure 6.5.

Sulphur, from molecules such as $H_2S$ and mercaptans, is a poison for the reformer catalyst and causes irreversible deactivation, so it is removed from the feed down to concentrations <1 ppm. This is generally achieved by running the feed through a hydrodesulfurization reactor followed by a ZnO guard bed. As mentioned in the previous chapter, RFG contains significant amounts of $H_2S$, so this is an important design consideration. Additionally, the design should take upset scenarios into account (i.e. situations in which the $H_2S$ concentration is high for a short period of time, due to abnormal operation of one of the units producing fuel gas).

The treated feed gas stream is heated and then, depending on the composition, passed through a pre-reforming reactor before entering the main reformer. The reactions that take place in the reforming reactor are presented in Annex 3.3, with some differences depending on the type of technology selected. Regardless of the type of reactor however, the raw syngas will primarily contain a mixture of hydrogen, CO, $CO_2$, water and unconverted methane. More hydrogen can be obtained at this phase by subjecting this mixture to the water-gas shift (WGS) reaction (Annex 3.3) in a dedicated reactor. This also minimizes the amount of CO present in the hydrogen fuel, thereby reducing residual $CO_2$ emissions for the end users. The final steps in the process are $CO_2$ capture and hydrogen purification, the extent of the latter depending on the final use of the hydrogen product.

### 6.2.2 Technology selection for H-vision

Based on the literature review carried out by TNO, simplified models developed in-house, and input received from Equinor and Air Liquide, a high pressure Auto-Thermal Reforming (ATR) unit is considered most suitable and recommended for the H-vision project. High pressure ATR stands out compared to the alternatives and has several advantages. See Annex 3.3 for more information.

First and foremost, at the capacity required for the H-vision project, economy of scale is crucial for limiting CAPEX, and ATRs have by far the highest capacity per train for the following key reasons:

- SMR and POX technologies encounter manufacturing limitations at lower scales.
- A plant operating at high pressure is CAPEX efficient, but comes at the expense of $CO_2$ capture, because a higher percentage of methane is present in the blue hydrogen fuel.

Next to this, ATRs have demonstrated extremely high reliability in operation for mega-methanol plants, with recorded availabilities as high as 99.7%. They also have a broad operating range and very high flexibility, due to the following key features:

- An ATR can be operated at 30 - 110% of its nominal capacity, with minor design adjustments.

- Even a very large unit can be operated with ramp-up and ramp-down rates as fast as 1.5% (of its capacity) per minute.

These two points are both very important for H-vision, considering the complex phasing of the project and the expected intermittency in demand for the hydrogen-rich fuel. Additional advantages are that high pressure operation reduces the cost of capturing $CO_2$ from the syngas, as well as the cost of compressing the hydrogen-rich fuel, while a higher carbon conversion is realised as compared to an SMR. Furthermore, ATRs have better maintainability as SMRs have more components in the creep range, limited to ~100,000 operating hrs, and the burner lifetime is much longer as compared to that for POX.

A high pressure ATR is suitable for producing hydrogen from a mixture of NG with RFG, but the gas pre-treatment section must be adapted to cope with the higher $H_2S$ content and $C_{2+}$ molecules in RFG. This is fairly standard technology for reforming plants and is expected to increase the CAPEX by less than 5%.

Considering the scale of H-vision units and the operating pressure, it is recommended to use Rectisol physical absorption technology to capture the $CO_2$, instead of high pressure amine capture. This is expected to have a lower CAPEX and a higher energy efficiency but needs to be reviewed during the conceptual design phase of the H-vision project. For possible future technology developments, please see Annex 3.7.

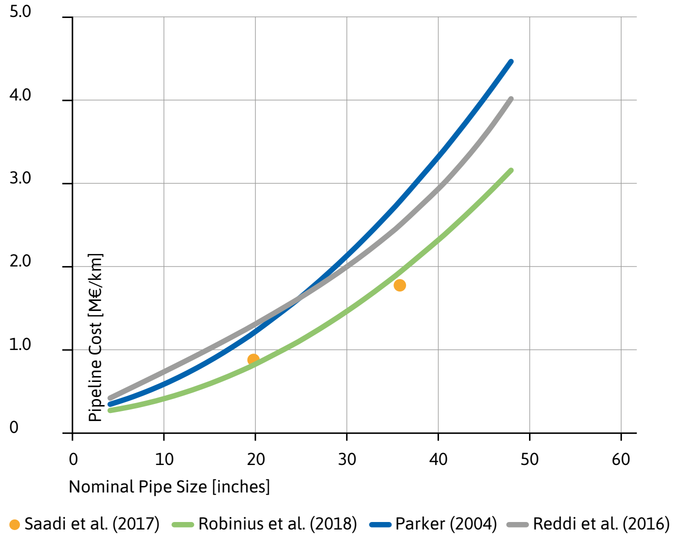
## 6.3 Hydrogen transport and storage

### 6.3.1 Hydrogen transport by pipeline

Within H-vision, only transport by pipelines is addressed, since transport by trucks or rail is not suitable for the required scale and shipping of hydrogen is not in scope. A number of correlations for estimating the cost of hydrogen transport pipelines have been evaluated and we selected the correlation proposed by Robinius et al for estimating pipeline costs for this study (see Figure 6.6, which summarizes the results obtained with correlations found in literature).

The pipeline diameter can be calculated as a function of hydrogen flowrate, initial pressure, temperature and flow speed. These variables are used as input in an Excel spreadsheet tool developed by TNO's Heat Transfer and Fluid Dynamics department. The hydrogen flowrate can also be expressed as an energy transfer term in GW, using the Lower Heating Value (LHV) of hydrogen (33.3 MWh/t $H_2$). The relation between the nominal pipe size and hydrogen transport capacity can be estimated using this tool, with an example shown in Figure 6.7.

*Figure 6.6: Comparison between different correlations for hydrogen pipeline cost estimates. The two points in Saadi et al.[1] represent real data points for hydrogen pipeline costs. For Parker[2] and Reddi et al.[3], the cost was originally reported in USD in their respective publication years, and has been updated to current EUR in 2019, including inflation. Reddi et al.[7] reported a correlation that also includes pipeline length; a value of 100 miles was taken to calculate the cost per km.*




1 Saadi, F. H., Lewis, N. S. & McFarland, E. W. *Relative costs of transporting electrical and chemical energy*. Energy Environ. Sci. *11*, 469–475 (2018).

2 Parker, N. *Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs*. 86 (2004).

3 Reddi, K., Mintz, M., Elgowainy, A. & Sutherland, E. *Challenges and Opportunities of Hydrogen Delivery via Pipeline, Tube-Trailer, Liquid Tanker and Methanation-Natural Gas Grid*. Hydrog. Sci. Eng. Mater. Process. Syst. Technol. *2*, 849–873 (2016).

*Figure 6.7: Calculated hydrogen transport capacity of a pipeline (in GW thermal, i.e., using the LHV for hydrogen), for a given velocity (in this case 15 m/s), as a function of Nominal Pipe Size [in] and initial pressure. Reproduced from a tool developed by the Heat Transfer & Fluid Dynamics department of TNO.*

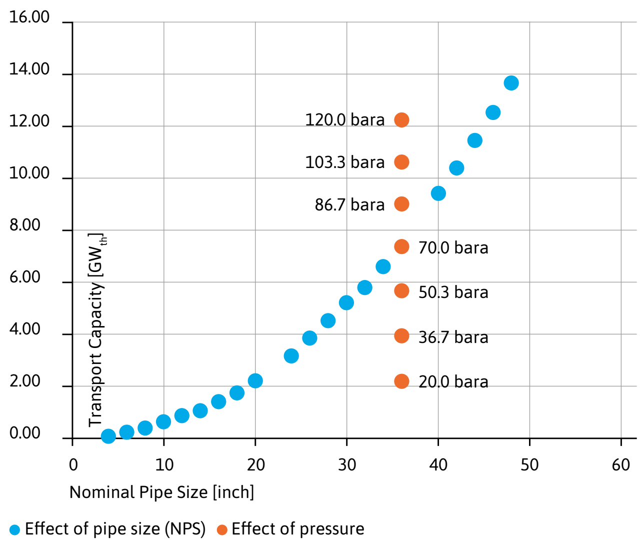


*Figure 6.8: Envisaged hydrogen backbone pipeline network, ca 2030 (source: Gasunie).*

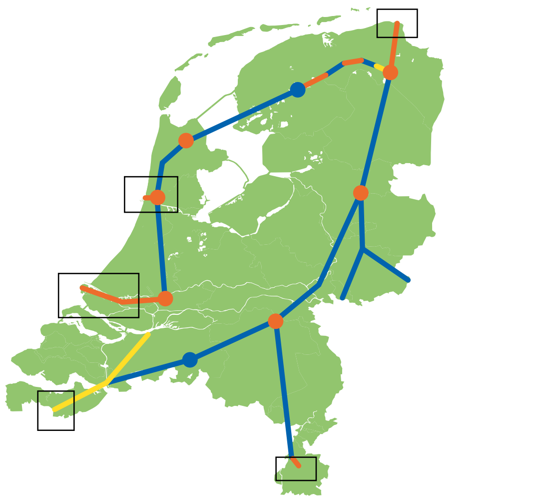
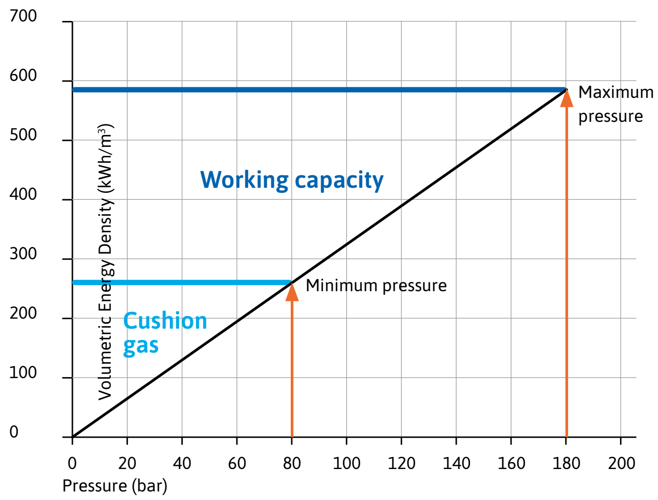



*Figure 6.9: Salt cavern capacity at 20°C*




The hydrogen delivery pipelines considered in this project in the Rotterdam port area are short enough not to require recompression, because the final use is in fired equipment at low pressure. Diameters were nevertheless selected to limit pressure drops to a maximum of 0.5 bar per km.

Connecting the H-vision hydrogen network with underground salt cavern storage facilities near Groningen (see next chapter) is only taken into account for the maximum scope and expected to be available starting in 2030. Hydrogen balancing lines to and from the salt caverns are not part of the project scope and the link is assumed to be made via the hydrogen backbone infrastructure proposed by Gasunie, which is shown in Figure 6.8.

## 6.3.2 Underground storage of hydrogen

For the minimum and reference scope development concepts, it was determined that storage would not be necessary. The required flexibility needed to serve varying demand could be provided by ramping the production plant up or down. For the maximum scope development concept, large-scale hydrogen storage was investigated. For this case, underground salt caverns seem to be the most cost-effective option for storing very large volumes of hydrogen. Depleted gas fields are unlikely candidates for this purpose, because of contamination with undesired components, such as $H_2S$ and other sulphur-containing molecules. Salt caverns are better suited for hydrogen storage as they are highly gas-tight and hydrogen itself can be used as a cushion gas to ensure high purity.

Already today, salt cavern storage is used in the chemical industry, with high standards for both safety and hydrogen purity, which are in line with H-vision project requirements. For an example cavern with the working pressure range given in Figure 6.9 (80 – 180 bar), the working capacity is ~430 kWh/m³ with 310 kWh/m³ of cushion gas required (HHV basis).

In the Netherlands, there is also ample potential for underground hydrogen $H_2$ storage, at Zuidwending. Gasunie evaluated the technical feasibility of developing hydrogen storage facilities there and provided preliminary cost estimates for the facilities required to store hydrogen. The key parameters are summarized in Table 6.5.

*Table 6.5: Parameters of storing hydrogen in underground salt caverns at Zuidwending (data supplied by Gasunie)*

| Key design parameter | Value |
|---|---|
| Cavern size | 600,000 – 1,000,000 m³ |
| Depth | 1,000 – 1,500 m |
| Number of caverns | Starting with 1 for hydrogen storage. Room for at least 10 caverns (based on amount currently available for NG storage) |
| Minimum operating pressure | 80 - 84 bar |
| Maximum operating pressure | Approximately 180 bar |
| Maximum daily differential pressure | 10 bar (expected) |
| Gas volumes | Based on one 600,000 m³ cavern |
| Cushion gas | 156,000 MWh |
| Working gas | 195,000 MWh |
| **Total gas** | **351,000 MWh** |
| Withdrawal capacity | Max. 18,000 MWh/day (based on one 600,000 m³ cavern) |
| Injection capacity | Max. 19,500 MWh/day (based on one 600,000 m³ cavern) |

*Table 6.6: Cost estimates for the natural gas booster compressor and supply pipelines, for the three development concepts.*

| | | | Minimum scope | Reference scope | Maximum scope |
|---|---|---|---|---|---|
| NG feed | Equivalent calorific value | [MW] | 1000 | 2950 | 3620 |
| | Mass flow | [t/h] | 75.6 | 223.1 | 273.8 |
| Required compression duty | | [MW] | 1.4 | 4.1 | 5.1 |
| Estimated compressor CAPEX | | [M€] | 3.8 | 6.5 | 7.3 |
| Pipeline diameter | | [inch] | 12 | 24 | 28 |
| NG supply pipeline CAPEX (estimates provided by Gasunie) | | [M€] | 54 | 102 | 125 |

Hourly capacities for injection and withdrawal would be limited by the daily capacities stated in Table 6.5 and will be chosen depending on project requirements. The primary factors influencing injection and withdrawal rates are the overall salt cavern volume and the maximum daily differential pressure. According to Gasunie estimates, a single salt cavern with a 600,000 $m^3$ volume can provide more than 800 MW of flexibility ($H_2$ LHV basis).

Depending on the required injection/withdrawal cycle time (demand profile) the required amount of storage capacity/caverns can be determined.

### Costs of hydrogen storage in salt caverns

For a typical cavern size, as indicated in Table 6.5, the investment costs are estimated by Gasunie to be around 150–160 M€ (including above ground facilities, such as compressors and chillers; excluding first fill). Every extra cavern would require about 35 M€ additional investment.

A fixed OPEX for one system (one salt cavern + associated above ground facilities) is estimated to be around 7 M€ per year. Adding an extra cavern to increase storage volume alone would only increase this cost by 2-3%.

The national hydrogen pipeline grid, described in Annex 3.6, will be limited to a pressure of up to 66.7 barg (bar gauge). The maximum compression power required to inject hydrogen delivered at pipeline pressure into a salt cavern operating at 180 bar was estimated to be about 20 kWe per MW hydrogen (LHV basis).

**Steam integration ... can lead to higher efficiencies and a better business case**

## 6.4 Integrated blue hydrogen chains

### 6.4.1 Gas compression and transport

**6.4.1.1 Natural gas**

The operating pressure of the HP ATR-based hydrogen production plant is 60 bar (a compressor outlet pressure of 65 barg was used), but the natural gas grid guarantees a delivery pressure of 44 bara (bar absolute). The required compression duty for the booster compressor (see Table 6.6 for results) was calculated with Aspen Plus™, assuming a polytropic efficiency of 80%.

The existing H-gas (high caloric natural gas) distribution grid is not expected to cover the higher demand for the H-vision plant. Additional CAPEX would then be required to install a new supply pipeline for natural gas, covering the distance of approx. 61 km between Europoort and Wijngaarden, where it connects to the national NG roundabout. Conservative estimates were made for the entire length, but it is possible that part of this segment can already support the increased flow. As shown in Table 6.6, the pipeline CAPEX is much higher than the investment required for the NG booster compressor.

**6.4.1.2 Refinery fuel gas**

The project concept is to convert refinery fuel gases (RFGs) from BP and Shell (and also from the Exxon and Gunvor refineries in the maximum scope) into blue hydrogen at a central plant. Transfer pipelines will have to be added to connect the refineries with the H-vision hydrogen plant located at the Maasvlakte. RFG grids operate at low pressure (4-5 barg typically), so compressors would also need to be installed to transport these gases. Due to the

*Table 6.7: Cost estimates for the RFG compressors and transport pipelines, for the three cases*

| | | | Minimum scope | | Reference scope (and part of maximum scope) | | Maximum scope |
|---|---|---|---|---|---|---|---|
| | | | **BP** | **Shell** | **BP** | **Shell** | **Exxon/ Gunvor** |
| RFG feed | Equivalent calorific value | [MW] | 250 | 250 | 520 | 650 | 600 |
| | Mass flow | [tph] | 18.1 | 19.5 | 37.6 | 50.6 | ~ 45 |
| Required compression duty | | [MW] | 2.8 | 3.5 | 5.9 | 7.3 | - |
| Estimated compressor CAPEX | | [M€] | 5.9 | 7.1 | 8.4 | 10.2 | 12* |
| RFG transport pipeline diameter | | [inch] | 4 | 6 | 8 | 10 | - |
| RFG transport pipeline cost | | [M€] | 1.8 | 11.3 | 2.8 | 15 | 10* |

* These are placeholder estimates to reflect the additional costs expected. There isn't sufficient information available at this point to define the required input for the cost models.

higher compression ratio (approx. 14), a compressor with three stages and inter-stage cooling (down to 40°C) is proposed. The associated cooling duty/cooling water costs are not taken into account for the OPEX estimates.

The same approach as for the natural gas booster compressor was used to estimate the CAPEX of the RFG compressors, see Table 6.7. This is a highly simplified approach, but well within the accuracy of the overall H-vision cost estimate. Similarly, a shortcut approach was used to estimate the cost of the RFG transport pipelines based on equivalent hydrogen flow rates. The transport capacity for a pipeline of a given diameter, expressed in MW, is a factor of 2.5 - 3 larger for RFGs versus hydrogen.

The outlet pressure (70 barg) is based on the operating pressure of the ATR, plus a margin to account for the pressure drop across the pipelines and in the pre-treatment section of the reformer. The required compression duty was calculated using Aspen Plus™.

#### 6.4.1.3 Blue hydrogen fuel gas

Selecting a central production plant implies that the hydrogen-rich fuel needs to be transported and distributed to the end users in the industrial area. A dedicated hydrogen distribution network is proposed and included in the project cost estimate. For the maximum scope case, we assumed that the H-vision network would be connected to the nation-wide hydrogen infrastructure network planned by Gasunie, granting access to the hydrogen storage facilities at Zuidwending. Using underground hydrogen storage reduces the overall CAPEX by reducing the required capacity of the H-vision plant.

Locating the H-vision plant in the area around the Maasvlakte has the advantage of minimizing the length of the pipelines transporting hydrogen fuel to the two large power plants. Cost estimates for the entire distribution network range between 28.3 M€ for the minimum scope case to 72.7 M€ for the maximum scope case. An overview map showing the reference scope case is shown in Figure 6.10. The maps for the minimum and maximum scope cases can be found in Annex 3.4.

#### 6.4.1.4 $CO_2$ export

$CO_2$ export facilities are in this phase assumed to be out of scope and instead part of the Porthos project. However, export of $CO_2$ may be an option in the case that CCS using Porthos would not be an option, or if Porthos offered insufficient storage capacity. The H-vision site is intended to deliver high purity $CO_2$ at a pressure of approximately 20 bar, but this can be varied easily in the design, if necessary.

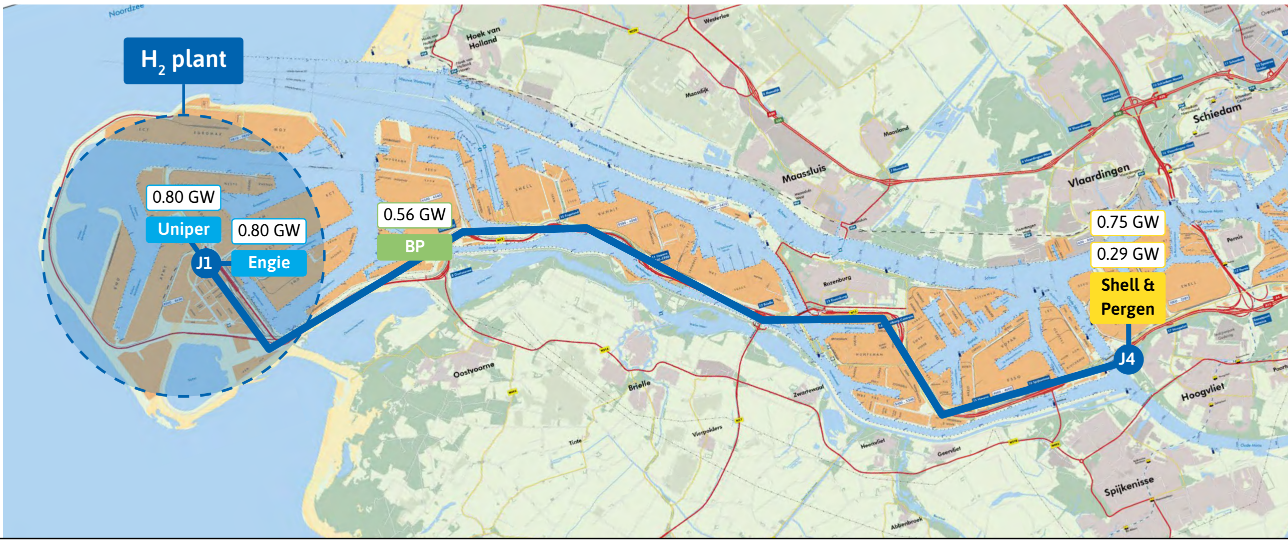
No additional CAPEX related to $CO_2$ compression or to $CO_2$ transport lines is taken into account. A tie-in line to reach the main Porthos pipeline from the location of the H-vision plant is a cost that easily falls within the accuracy margins of the current estimates.

Given the location and scale of the H-vision project, a dedicated export facility with a separate offshore pipeline landing could be a solution if the available capacity is insufficient to discharge the $CO_2$ via the Porthos facilities.

### 6.4.2 Steam integration

Steam integration between the H-vision production plant and the power plants can lead to higher efficiencies and a better business case. The possibilities for steam integration have been investigated to a limited extent. The most important conclusion is that the surplus of steam that is generated by the hydrogen production units can be integrated with the existing power plants. Therefore, the large-scale production of hydrogen might be best located near the power plants. For more details, see Annex 3.5.

*Figure 6.10: Reference scope case overview of the blue hydrogen production and transport infrastructure for the Rotterdam port, including both RFG and NG heating demand from end users. 'J#' are identifiers for junction points where the transmission pipeline splits into smaller lines going directly towards the plants.*




### 6.4.3 Hydrogen production

The technology selected for the large-scale H-vision plant is the high-pressure ATR concept, as described in section 6.2.2 and Annex 3.3. This design offers distinct advantages over alternative technologies, primarily regarding economy of scale and operational flexibility.

This does not imply, however, that a final choice has been made for the project, since the cost estimates produced within this study rely on a broad range of assumptions. More accurate cost estimates should form the basis for rigorous technology selection, as well as a better definition of the design cases, project phasing and integration options.

For the purpose of this feasibility study, a single concept was evaluated. The scale and operating performance of the HP ATR concept make it suitable for all three cases. The characteristics of the proposed design are summarized in Table 6.8. Note, this is the largest possible plant. For the other H-vision concepts, smaller plants are also considered.

The parameters were estimated for a single-train production plant, with a total output of 2.4 GW of hydrogen-rich fuel. For the three H-vision cases, the following plant capacities would be required, as also summarized in Table 6.10:

*Table 6.8: Key parameters of a mega-scale ATR plant for blue hydrogen production based on natural gas feedstock. Operating parameters and cost estimates provided by Air Liquide. For fuel gas as feedstock, these numbers will be slightly different, with minimal impact, however, on the business case at the current level of accuracy.*

| Key parameters of hydrogen production via HP ATR | | |
|---|---|---|
| HP ATR plant capacity (as hydrogen output) | 700,000 | $Nm^3/h$ $H_2$ |
| Hydrogen purity in the outlet stream | 95.5 | % |
| HP ATR plant capacity (as total fuel output) | 2,400 | $MW_{th}$ (LHV) |
| Overall thermal efficiency | 78 | % on LHV basis |
| | ~82 | % on HHV basis |
| Total feedstock (input of NG + RFG) required | 3,130 | MWth (LHV) |
| Excess steam production (available for export, with 20°C superheating) | 305 | t/h HP steam (100 bar) |
| | 100 | t/h MP steam (30 bar) |
| Electricity import | 128 | $MW_e$ |
| Direct $CO_2$ emissions at the H-vision plant | 6 | t $CO_2$/h |
| $CO_2$ captured at the H-vision plant | 498 | t $CO_2$ /h |
| $CO_2$ capture & export factor | 0.208 | t $CO_2$/MWh |
| $CO_2$ purity in the export stream | 99 | % |
| Overall capture rate (including residual carbon) | 88 | % |
| Overall $CO_2$ emissions factor | 0.028 | t $CO_2$/MWh |
| Total plant cost | 910 | M€ |
| Fixed OPEX (2.5% of CAPEX annually) | 22.8 | M€ |

*Table 6.9: Overview of variable OPEX for the H-vision hydrogen plant. All values are calculated on LHV basis. Annual costs are calculated based on 8760 operating hours at 100% throughput. $CO_2$ emissions represents the overall chain emissions, both at the H-vision plant and at the end users.*

| Overview of variable factors & example calculation for the reference concept | | | |
|---|---|---|---|
| Type | Factor | Unit | Reference concept |
| NG/RFG feedstock | 1.282 | MWh feed/MWh $H_2$ | 2573.6 MW* |
| Electricity (+5-10% for the NG and RFG compressors) | 0.053 | MWh el/MWh $H_2$ | 155.7+17.3 MWe** |
| $CO_2$ export (captured $CO_2$) | 0.208 | t $CO_2$/MWh $H_2$ | 608.3 t/h $CO_2$ |
| $CO_2$ emissions | 0.028 | t $CO_2$/MWh $H_2$ | 83 t/h $CO_2$ |

* RFG feedstock is subtracted from the total required, since this is not an additional cost

** Some of the required power will be generated using steam exported from the H-vision plant, and could be therefore supplied at a lower-than-market cost

- **Minimum scope:** a single train with a hydrogen-rich fuel output capacity of 1040 MW (LHV)
- **Reference scope:** two trains with a hydrogen-rich fuel output capacity of 1460 MW (LHV) each
- **Maximum scope:** two trains with a hydrogen-rich fuel output capacity of 1910 MW (LHV) each. Because large-scale storage is used as a buffer, 1000 MW (LHV) less total output capacity is needed.

A flexible HP ATR unit is expected to reliably operate at 110% of the design capacity on which the investment estimate is based on. As such, the corresponding values for the maximum natural gas import, rate of captured $CO_2$, power import, etc. are based on 110% of the design values listed above for each case. The values were chosen such that the plant can supply sufficient hydrogen-rich fuel to match the estimated maximum hydrogen demand.

Fixed costs, such as wages, maintenance & spares, etc. (fixed OPEX), are approximated as 2.5% of the CAPEX. Variable costs (variable OPEX) are proportional to the plant throughput and depend on the various markets they draw input from. Table 6.9 summarizes the main variable cost factors for blue hydrogen production.

For all the cases considered, a single “mega-scale” central production site is recommended, located in the area of the Maasvlakte, for the following reasons:

- This enables maximum use of economy of scale benefits;
- Steam and utilities integration with the power plants is a very attractive option, so the site has to be in the vicinity of the coal-fired units at the Maasvlakte. The potential for integration with other sites is seen as being very limited; and
- The costs of transporting hydrogen are far smaller as compared to the benefits of having a single site (integrated utilities, simplified construction and simplified project planning and management).

The costs of transporting RFG are comparable to those for captured $CO_2$ transport, so there is very limited potential for savings by locating a hydrogen production unit close to one of the end users.

### 6.4.4 Costs of modifications

**Power plants**

The proposed modifications for the solid fuel power plants are reflected in three cost items:

- Investment in and installation of new gas turbines;
- Modifications to enable hydrogen firing in the preheat section; and
- Cost of (full) steam integration between the hydrogen production plant and the power plants, plus steam transfer and condensate return lines

The cost of the required hydrogen-fired gas turbines is estimated to be on the order of 60 M€ per 147 MWe unit, including installation costs. Per power plant, the total investment cost is then 120 M€. The required modifications for hydrogen firing were roughly estimated to cost 25 M€ per power plant, based on experience from previous projects in the power sector. The overall cost of the new tie-ins required for steam integration, plus the necessary transfer pipelines, was estimated at 40 M€ for full steam integration. For the minimum scope case, 75% of this cost estimate was used.

For the PerGen gas-fired turbines, placeholder cost estimates were used for the reference scope (5 M€) and maximum scope (15 M€) in order to reflect the modifications to the burners and fuel supply systems required to fire 50% and 100% blue hydrogen, respectively. For the minimum scope, it is assumed that the turbines would be able to fire a fuel mix containing 25% hydrogen, without modifications.

*Table 6.10: Overview of expected required capacity per case, and resulting CAPEX estimates for the different blue hydrogen chain elements described earlier in this chapter.*

| | | | Minimum scope | Reference scope | Maximum |
|---|---|---|---|---|---|
| Hydrogen demand | Ref / petrochem replacing RFG | [MW] | 500 | 1170 | 1770 |
| | Ref / petrochem replacing NG | [MW] | 90 | 140 | 640 |
| | Pergen steam & power | [MW] | 143 | 286 | 571 |
| | Engie & Uniper power plants | [MW] | 407 | 1611 | 2221 |
| | **Total (max)** | **[MW]** | **1139** | **3207** | **5202** |
| Capacity reduction enabled by underground hydrogen storage buffer | | [MW] | - | - | 1000 |
| **Installed hydrogen production capacity (10% lower than max demand)** | | **[MW]** | **1040** | **2920** | **3820** |
| Max NG + RFG input required (rounded up) | | [MW] | 1470 | 4120 | 5390 |
| Max NG supply to the hydrogen plant (rounded up) | | [MW] | 970 | 2950 | 3620 |
| Total plant cost for hydrogen production | | [M€] | 528.4 | 1317.5 | 1568.9 |
| Costs of furnace modifications | | [M€] | 88.5 | 196.5 | 361.5 |
| Power plant upgrade costs | | [M€] | 110 | 325 | 385 |
| Salt cavern storage CAPEX | | [M€] | - | - | 190 |
| NG supply pipeline CAPEX | | [M€] | 54 | 102 | 125 |
| RFG transfer pipelines | | [M€] | 13.1 | 17.8 | 27.8 |
| NG & RFG compressors | | [M€] | 16.8 | 25.2 | 37.9 |
| Hydrogen distribution costs | | [M€] | 28.3 | 49.8 | 72.7 |
| **Total CAPEX** | | **[M€]** | **839.1** | **2033.8** | **2769.0** |

**Refineries and petrochemical sites**
Several modifications would be required to enable existing furnaces, currently firing residual gases or natural gas, to produce high temperature heat by firing blue hydrogen. Apart from retrofitting fuel-flexible burners for the furnaces, new fuel distribution networks would need to be added and several modifications would also be expected for instrumentation, safeguarding and control systems. Additionally, new or upgraded deNOx units could be required.

These technical considerations are indicated in Section 6.1.2. The combined cost of all these modifications is roughly estimated to be in the range of 0.1 - 0.15 M€/MWth of installed thermal duty. Conservatively, the high value of 0.15 M€/MWth was used for the economic model of the H-vision study, and the resulting costs of modifications per case can be found in the CAPEX overview in Table 6.10.

### 6.4.5 Overview of the total project CAPEX

The CAPEX items discussed so far in this chapter are summarized and added up in Table 6.10, giving an indication of the overall blue hydrogen chain investment costs for each of the cases.

## 6.5 Conclusions

The blue hydrogen technology concept in H-vision requires one or more world-scale hydrogen production units that could be located at a single plot at the Maasvlakte. These units would produce hydrogen from natural gas and refinery fuel gas and at the same time capture $CO_2$. The captured $CO_2$ could be stored in depleted gas fields under the North Sea using the planned infrastructure of the Porthos project.

The H-vision approach is technically feasible, as it uses existing industrial infrastructure with limited modifications in the industrial processes for high temperature heating and power generation. In addition, all the technical building blocks at end users have already been deployed on a large scale with hydrogen as the primary energy feed. The surplus of steam that is generated by the hydrogen production units can be integrated with the existing power plants. Therefore, the large-scale production of hydrogen might be best located near the power plants.

For the minimum and reference scope development concepts, it was determined that storage would not be necessary. The required flexibility needed to serve varying demand could be provided by ramping the production plant up or down. For the maximum scope development concept, large-scale hydrogen storage was investigated. For this case, underground salt caverns seem to be the most cost-effective option for storing very large volumes of hydrogen. These salt caverns would be an integrated part of a nation-wide hydrogen backbone to be developed in the next decade.

# 7

# $CO_2$ transport and storage

## 7.1 Most appropriate storage sites and transport networks

### 7.1.1 Introduction and approach

This section presents an analysis of potential development scenarios for a $CO_2$ transport and storage network on the Dutch Continental Shelf (DCS). The first elements of such a network are being studied by the Porthos consortium[3], which currently focuses on the first phase of storing $CO_2$ in the gas fields of the offshore P18 cluster. Porthos aims to develop a multi-user network. $CO_2$ resulting from blue hydrogen production is assumed to be delivered to an upscaled version of that network, rather than to a separate network.

The impact of the additional $CO_2$ derived from the production of blue hydrogen has been analysed for the case of adding this additional $CO_2$ to the baseline Porthos supply curve (base case) and developing a network that is capable of transporting and storing the larger amount of $CO_2$[4] to more incremental connected clusters of fields. This approach delivered insights to the following key questions:
- Given different scenarios for the volume of $CO_2$ to be stored, what are the likely storage locations to be considered for use and what is the expected timing of successively adding locations?
- What is the additional infrastructure that is required to develop the larger network capacity?

The additional costs involved are addressed in Section 7.3. Information on the physical delivery and composition of the $CO_2$ can be found in Annex 4.1.

### 7.1.2 Supply scenarios

First of all, a base case model was built for the scenario in which only the current Porthos development ('Porthos-phase 1') would take place without any additional $CO_2$ due to an H-vision development. Hence this scenario does *not* include any H-vision hydrogen production.

Subsequently, three different scenarios for the supply of $CO_2$ were taken into account which correspond to the three H-vision scenarios described in Chapter 4 (i.e. 2, 6 and 10 Mt per year $CO_2$ stored). In this analysis, a duration of 20 years of $CO_2$ storage was assumed for all cases.

**The base case ('Porthos-phase 1') – 4 Mtpa $CO_2$**
In this scenario, the $CO_2$ supply grows to a plateau rate of 4 Mtpa within 4 years. Implicit assumptions are 1) that blue hydrogen generation is not among the $CO_2$ suppliers and 2) that no sources of $CO_2$ outside the port area are considered. The supply profile is shown in Figure 7.2.

Since the volumes for the three H-vision scenarios of 2, 6 and 10 Mtpa $CO_2$ (plateau rate) needed to be added to the base case (4 Mtpa), the following scenarios for the total annual and cumulative storage of $CO_2$ result in the following total stored quantities:

1. **Minimum scope:** 4+2 Mtpa
   Stored quantity over 20 years: 120 Mt

2. **Reference scope:** 4+6 Mtpa
   Stored quantity over 20 years: 204 Mt

3. **Maximum scope:** 4+10 Mtpa
   Stored quantity over 20 years: 288 Mt

It should be noted that none of the scenarios take into account incremental supplies connecting to the Rotterdam infrastructure from the Netherlands, Belgium or Germany, nor do they take account any of the "competing" requirements for storage capacity offshore from other sources.

Finally it must be noted that the H-vision concept can be seen as independent from the Porthos project. For example, if the Porthos project is not carried out in its fully envisioned form, H-vision may implement an extra or alternative dedicated pipeline from the hydrogen production facilities on the Maasvlakte to connect with the $CO_2$ storage network on the DCS. However, in this study it is assumed that Porthos would provide the network connection for the $CO_2$ captured by H-vision. Vice versa, if H-vision would not be carried out in its fully envisioned form, Porthos could possibly connect to different sources of $CO_2$ in the Rotterdam area to fill its (what would be smaller) pipeline.

### 7.1.3 Candidate storage fields

A recent study demonstrated that for the annual volumes of $CO_2$ of up to 14 Mtpa, there is more than sufficient storage volume available for a period of 20 years or more (*EBN/Gasunie, 2017*). The total available storage volume in a selection of suitable gas fields in the Dutch part of the North Sea was estimated at 1.6 Gt.

A list of likely candidates in the DCS is given in Table 7.1 and visualized in Figure 7.1. The total storage capacity represented by the fields in Table 7.1 is 470 Mt. The candidate fields were selected from screening studies, which provided the results of analysing the feasibility of storage of $CO_2$ in a number of offshore gas fields and

3 See, e.g., https://rotterdamccus.nl/ and the concept reikwijdtenotitie en detailniveau at https://www.rvo.nl/sites/default/files/2019/02/Porthos%20concept%20NRD%20-%20versie%20finaal.pdf.

4 It is assumed here that H-vision hydrogen results in an increase of $CO_2$ supplied to the Porthos network. Blue hydrogen may displace other fuel in the Rotterdam port area or change investment decisions of future capture operations, potentially reducing the supply of $CO_2$ to Porthos. Such analyses are outside the scope of this report.

*Figure 7.1: Left: map of candidate $CO_2$ storage depleted field clusters considered in this study (indicated by red arrows). The map shows the timing of start of injection in the three clusters P18, P15 and Q1 in the base case scenario. Right: same map, now for the 'maximum scope' scenario, in which case an additional cluster of fields would be developed for $CO_2$ storage.*

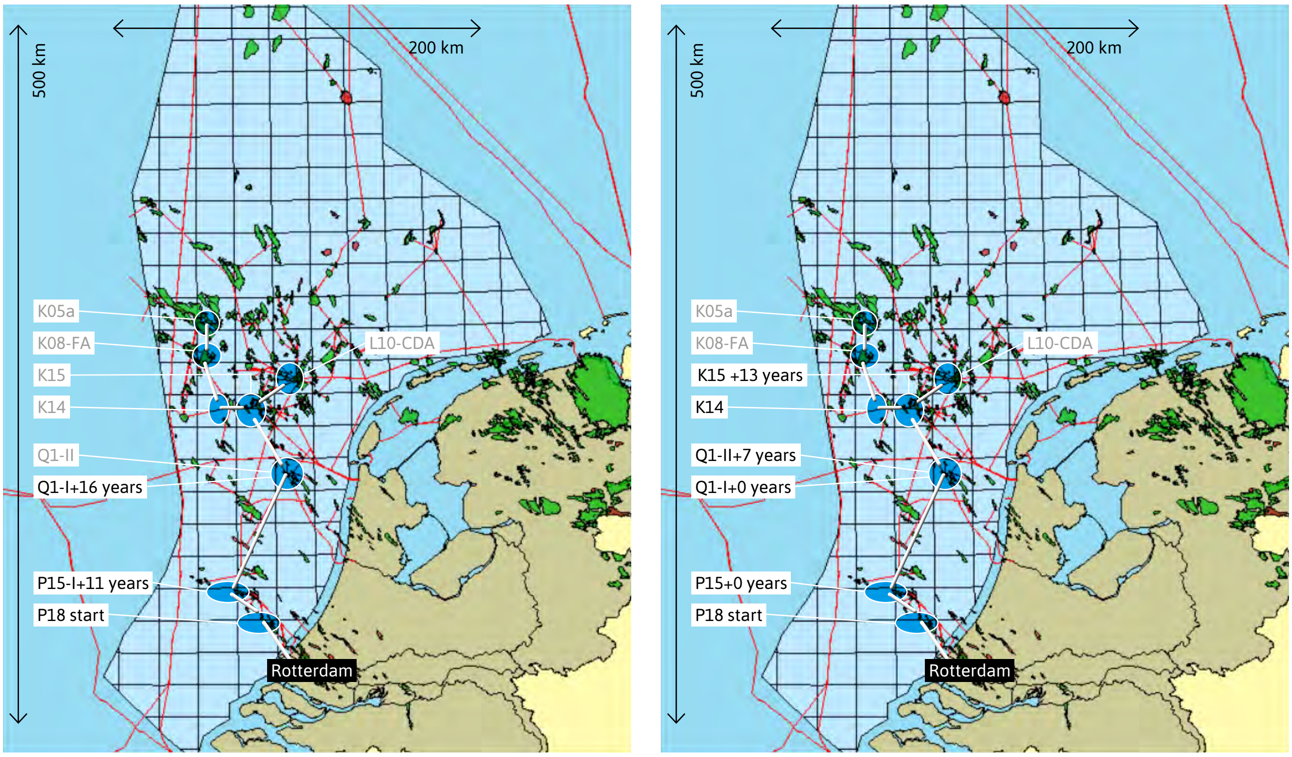



*Table 7.1: Overview of the candidate $CO_2$ storage fields considered in this study. Total storage capacity is close to 500 Mt.*

| Field | $CO_2$ storage capacity (Mt) | Field | $CO_2$ storage capacity (Mt) |
|---|---|---|---|
| P18-I | 8 | K15-II | 15 |
| P18-II | 32.5 | K15-III | 30 |
| P15-I | 11.4 | K15-IV | 15 |
| P15-II | 17.1 | K14-I | 35 |
| P15-III | 8.9 | K14-II | 15 |
| Q1-I | 35 | L10-CD anchor field | 125 |
| Q1-II | 114 | K08-FA anchor field | 130 |
| K15-I | 54 | K05a-A anchor field | 40 |

aquifers (*Neele et al., 2011a*)(*Neele et al., 2012*). Storage feasibility was based on high-level risk analyses, using information about the number and status of wells, storage capacity and expected injection rates[5].

It should be noted that the list of fields given in Table 7.1 and Figure 7.1 is not definitive, complete or fixed – the suitability of a field for $CO_2$ storage and the (economic) feasibility of developing a field for $CO_2$ storage should be based on a detailed, site-specific analysis, which remains to be performed for almost all fields considered here.

The gas fields in the central part of the DCS are organised in clusters, with several satellite fields connected to a central processing platform. For H-vision, we have focussed on the clusters K14-K15, L10, K08 and K05. In Table 7.1. only the K14-K15 cluster is represented with separate satellite fields. The other clusters are represented by the central (anchor) fields. For the purpose of the feasibility study, more detail was unnecessary.

### 7.1.4 Network development

The $CO_2$ supply scenarios are used to drive network development. The network is assumed to be developed so

5 The results presented in the screening studies mentioned in the text suggest that the fields in the P6 and Q4 blocks, which are located between the P15 and Q1 clusters, may result in higher storage cost due to relatively small storage capacity or to cost of re-entering abandoned wells to render them sealing for $CO_2$.

*Figure 7.2: Graph showing the supply profile (blue curve) and the storage profiles for the fields connected to the network, for the base case without any H-vision $CO_2$. Figure 7.1 (left map) shows the network and clusters that are to be developed.*

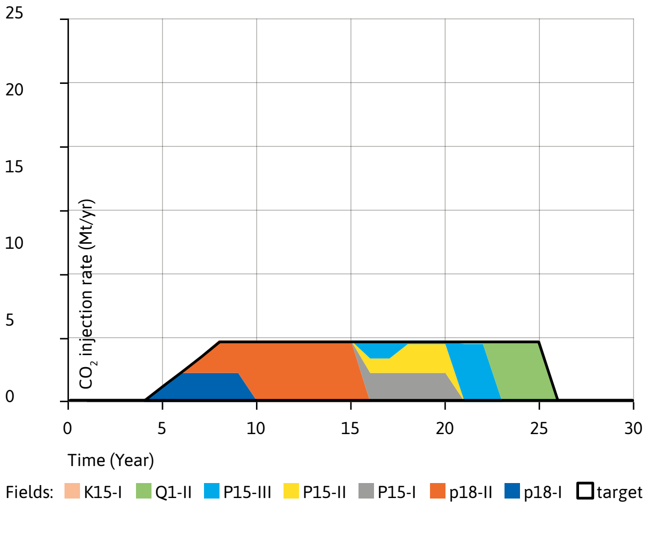
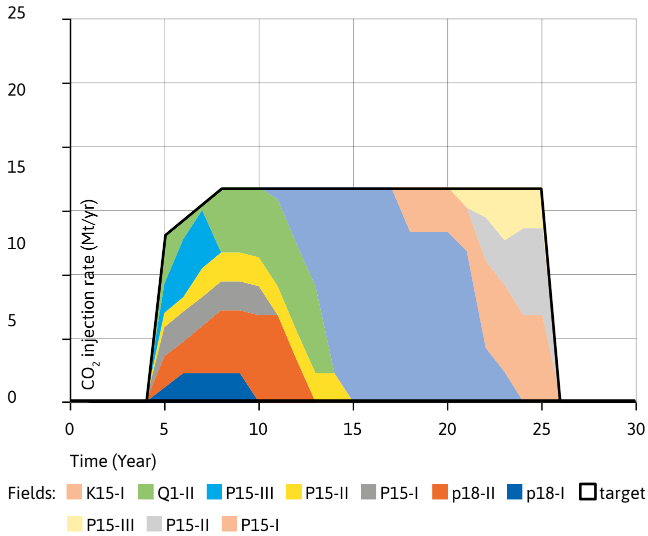



*Figure 7.3: Graph showing the supply profile (blue curve) and the storage profiles for the fields connected to the network for the maximum scope. For this case, the K15 cluster would be required 13 years after the start of the network. Figure 7.1 (right map) shows the network and clusters that are to be developed for this scenario.*




as to assure availability of storage capacity at a rate that is equal to or larger than the supply rate. Storage capacity determines the duration of plateau injection in each field and the next field is connected to the network as soon as the previous field or fields can no longer provide sufficient injection capacity. Given the lead time of field appraisal and development of typically 5-7 years (*Neele et al., 2012*), this means that field development activities should commence much earlier than when injection should begin. Depending on the size of the fields used, and on the injection rate, field development for storage would be a continuous activity.

## 7.1.5 Base case without H-vision $CO_2$

The injection profile that could be developed for the base case $CO_2$-supply scenario is shown in Figure 7.2. Development occurs step by step: as each new field or cluster of fields is developed, the network extends further out into the DCS. For the 20-year duration of the scenario, the furthest extension of the network is the Q1 offshore block. The total stored amount of the $CO_2$ over the 20 years is about 78 Mt. The graph in Figure 7.2 shows how 6 fields are used to create storage capacity at the rate needed.

## 7.1.6 Scenarios with H-vision blue hydrogen production

### 1.1.1.1 Middle and maximum cases

Figure 7.3 shows the stack of fields that is needed to provide the storage capacity and injection rate needed for the maximum scope development concept. This scenario has a plateau rate of 14 Mtpa. To accommodate the high early injection rates, as well as the high plateau rate, 6 fields would need to be online from the start of the operations, with the seventh field to be connected after 7 years. Three additional fields, in the K15 cluster in the list of fields used here, would need to be developed and brought online 13 years after the start of injection (see map in Figure 7.1).

### 7.1.6.1 Network descriptors

Table 7.2 lists a few basic parameters describing the networks needed to transport and store the $CO_2$ captured in the scenarios considered. Stored volumes range from about 80 to 290 Mt, for which between 6 and 10 offshore depleted fields are sufficient, in view of both cumulative storage capacity and required injection rate. Stored quantities would be slightly different from those mentioned in Section 7.1.2, due to the large time step (1 year) used in the modelling.

Table 7.2 also lists some descriptors of the pipeline network. Due to the additional field clusters to be developed, the reference and maximum scope development concepts would require more (new) trunklines to be constructed. An obvious result of the higher volume of $CO_2$ stored due to blue hydrogen production is the larger size of pipelines that would be needed. Rather than the 18” lines used in the base case scenario much larger capacity pipes would be needed to accommodate H-vision $CO_2$.

If the Porthos network would be completed before the start of supply of H-vision $CO_2$, this would imply the need for either early planning and oversizing to prepare the network for growth in supply or for a doubling of pipelines.

*Table 7.2: Key indicators of the network required to transport and store the $CO_2$ capture in the four scenarios considered.*

| | Base case (no blue hydrogen production) | Minimum scope | Reference scope | Maximum scope |
|---|---|---|---|---|
| $CO_2$ stored (Mt) | 78 | 120 | 204 | 288 |
| Number of fields used | 6 | 7 | 7 | 10 |
| Length of trunk pipelines used (km) | 118 | 118 | 171 | 171 |
| Diameter (inch) | 18 | 22 | 24 | 28 |
| Max flow capacity (Mtpa) | 5.3 | 8.8 | 11 | 16.2 |

### 7.1.7 Network development: discussion

**Storage**
The networks described in the previous section would all be capable of transporting and storing the supplied volumes of $CO_2$. The addition of $CO_2$ from hydrogen generation to the stream from other capture facility operators would more than double the supply rate from Rotterdam, in the scenarios used here. While this also requires a doubling of the effort in network development, relative to the base case scenario, this would be well within the capacity of the DCS to store $CO_2$. The results lead to the following conclusions:

- The largest amount of $CO_2$ to be stored in the 20-year time frame is about 250 Mt. This is well within the total storage capacity, which has been estimated for all offshore gas fields to be on the order of 1600 Mt (*EBN/ Gasunie, 2017*). The fields listed in Table 7.1 have a combined storage capacity of close to 500 Mt.
- The additional effort to develop a larger network than would be needed in the base case ('Porthos only') can be expressed in terms of developing the fields, working over wells, adapting platforms, extending the network of pipelines and installing dense-phase $CO_2$ pumps. Whereas the base case, with a plateau rate of 4 Mtpa requires 6 fields to be developed for injection, the most ambitious maximum scope case would require an additional 200 Mt of storage to be developed. In the list of fields used here, due to their location, this would be feasible by adding four fields.

**Transport**
Four major trunklines are required in the scenarios considered: 1) Maasvlakte to P18; 2) P18-to P15; 3) P18 to Q1, and 4) Q1 to K15. Around the K15 central platform, a number of shorter pipelines are needed to connect satellite platforms; reuse of existing pipelines may be possible, so these connections have not been included in the numbers given in Table 7.2. It is assumed that the trunklines are installed new, as existing gas transport lines would not be available.

Conclusions regarding the transport of $CO_2$ are the following:

- The additional volume of H-vision $CO_2$ can be transported by a upscaled version of the Porthos network. Depending on the timing of the first H-vision $CO_2$, the sizing of the network may take into account the blue-hydrogen-derived $CO_2$. The numbers related to the transport network given here assume that H-vision $CO_2$ would be included in the planning and construction of the network.
- Oversizing of the base case network to provide capacity for the H-vision $CO_2$ that would be supplied at a later time would mean installing lines of at least 24", rather than 18" lines. It is noted that this holds already for the first trunklines installed – assuming that the network continues the use the first trunklines (i.e., connecting the P18 and P15 clusters) when injection has moved to the Q1 and, later on, the K15 cluster.

The overall conclusion regarding network development and offshore storage capacity is that there are no showstoppers to developing blue hydrogen generation capacity from the point of view of storage capacity and network development.

### 7.1.8 Possible alternative – shipping the $CO_2$

A possible alternative for transporting $CO_2$ through a pipeline network to storage sites on the DCS would be to ship the $CO_2$. From both the UK and Norway, it has been reported[6 7] that there is also ample underground storage capacity in those countries.

Norway has openly communicated the willingness to import $CO_2$ from European sources. The Northern Lights project (transport and storage solution in the Norwegian CCS demonstration project) is developing an onshore receiving terminal for $CO_2$ transported by ships. The project is designed to allow for additional storage beyond the demonstration project. Here the storage site is a saline aquifer which requires the $CO_2$ to be in liquid phase. It is not clear whether the maximum scope development concept could be accommodated. For the minimum and reference scope development concepts this would be an option.

To be able to be exported to Norway, the $CO_2$ from H-vision would therefore need to be chilled, compressed and

6 Norwegian Storage Atlas : https://www.npd.no/globalassets/1-npd/publikasjoner/atlas-eng/co2-atlas-north-sea.pdf
7 UK $CO_2$ Storage Database: http://www.co2stored.co.uk/home/index

*Table 7.3: Technical unit costs for storage, transport and transport plus storage, for the base case and three scenarios and 'tariffs' in the bottom row. The latter represent a first-order estimate of the costs for the users and are obtained by applying a multiplier to the technical unit costs.*

| Cost estimates (€/t) | Base case | Minimum scope | Reference scope | Maximum scope |
|---|---|---|---|---|
| **Storage** | | | | |
| Technical cost of storage | 5.3 | 4.3 | 2.8 | 2.9 |
| 'Storage tariff' | 10 – 13 | 9 – 11 | 6 – 7 | 6 - 7 |
| **Transport (including compression)** | | | | |
| Technical cost transport | 3.2 | 2.7 | 2.5 | 2.2 |
| 'Transport tariff' | 13 - 17 | 13 – 16 | 12 – 15 | 11 – 14 |
| **Transport + storage** | | | | |
| Total technical cost | 11.9 | 10.6 | 8.8 | 8.6 |
| Total 'Transport + Storage tariff' | 24 – 30 | 21 – 27 | 18 – 22 | 17 – 22 |

buffered before transport by ship out of the harbour. Hence for this solution, the following infrastructure (all existing technology) should be included at or close to the H-vision site:

- Liquefaction system
- Metering system
- Liquid $CO_2$ storage tanks (for temporary storage between arriving ships)
- $CO_2$ transfer pump (for onloading to ships)
- $CO_2$ loading arms
- A Jetty

The ratification of the 2009 resolution to amend the London Protocol (entered into force in 2006, replaced the London Convention and included no dumping of $CO_2$) to allow $CO_2$ transport across borders for dumping (storing) at sea (beneath the seabed) has been slow. In order for the resolution to take effect, two thirds of the 50 member nations need to ratify it. So far only Norway, the UK, the Netherlands, Iran and Finland have ratified. Alternative bilateral solutions to allow $CO_2$ transport and storage across boundaries have been evaluated and should be in place when needed. The "London Protocol" is often cited as a legal barrier, but a common-sense solution will be found in time.[8]

## 7.2 Risks of $CO_2$ transport and storage

Developing blue hydrogen requires the transport and storage of the $CO_2$. To make sure any risks are mitigated, a risk analysis has been performed (for analysis and Risk Registers for $CO_2$ infrastructure development, $CO_2$ Transport and $CO_2$ Storage, see Annex 4.2). The transfer of title and transfer of risk have also been investigated, see Annex 4.3. From the point of view of H-vision, most, if not all, of these risks will have been resolved by the Porthos consortium by the time blue hydrogen produces the first H-vision $CO_2$. As a first mover in $CO_2$ transport and storage, Porthos will have to resolve a number of key issues with $CO_2$ suppliers, transport and storage operators and local and national governments, well before the start of operations of the network. There will be an important role for H-vision in supporting Porthos, adding weight in the discussions and negotiations to ensure an outcome that is positive for the development of both Porthos and H-vision concepts.

## 7.3 Costs for $CO_2$ transport and storage

The default solution for $CO_2$ storage is to make use of the Porthos system. The actual costs for $CO_2$ transport & storage will therefore be determined by Porthos. At this stage, Porthos is developing its business case and is not yet able to provide any reference costs for their first phase, Porthos-Phase 1. H-vision would supply $CO_2$ to the Porthos network in Porthos-Phase 2. The feasibility study for Porthos-Phase 2 has not yet been started.

This report includes an analysis of what the transport & storage costs might be for H-vision, based on the cost parameters given in a report by EBN and Gasunie (*EBN/ Gasunie, 2017*) and using TNO's in-house model.

It should be emphasized that the 'technical costs' shown in Table 7.3 should not be interpreted as the final commercial costs. A first-order estimate of the true cost of storage ('tariffs') for a network similar to the one developed in this study was obtained by a multiplication factor of 2 – 2.5 over the technical costs. This factor represents the ratio between technical costs and the cost derived from a proper storage business case analysis. Table 7.3 shows the estimated true cost ('tariff' in the table) of storage, transport (which includes compression) and transport plus storage.

8 https://ieaghg.org/ccs-resources/blog/slow-progress-again-on-ratification-of-the-london-convention-s-export-amendment-for-ccs

For the base case plus the three scenarios, the cost of transport plus storage is in the range of 17 – 30 €/t. Economies of scale in transport (larger capacity pipeline resulting in lower unit transport cost) and storage (larger capacity fields have lower unit storage cost) lead to lower overall costs in the H-vision scenarios. A more detailed discussion on the cost of $CO_2$ transport and storage can be found in Annex 4.4.

### 7.3.1 Discussion

The results presented in this section give a first impression of the cost of transporting and storing $CO_2$ in depleted fields on the DCS. The estimates lie in the cost range reported by EBN and Gasunie (*EBN/Gasunie, 2017*).

The addition of H-vision as a supplier to the Porthos network would lead to a significant increase in the amount of $CO_2$ to be transported and stored. With the list of candidate fields used here, the cost of storage, on a per tonne $CO_2$ basis, would decrease. This is due to the fact that even though the transport distance would increase relative to the Porthos fields, larger fields would be used as the network grows to handle the H-vision $CO_2$. In this report, the primary factor in field selection was distance from Rotterdam, using the model of a network expanding stepwise towards the K and L blocks. In reality, the choice of fields may depend more on availability, unit cost of storage and, more importantly, the overall cost of network development. This would be likely to lead to a different choice of fields for storage, resulting in a potentially less pronounced decrease in storage costs following the supply of H-vision $CO_2$ to the Porthos transport and storage network.

In a transport and storage network that connects several or many depleted fields for storage, economies of scale apply only at the field level (with lower storage cost for larger capacity fields), not at the overall network level, although some cost decrease would follow from increasing expertise and optimized workflows. Due to economies of scale in transport, the results show an overall decrease in the combined cost of transport and storage, with costs in the range of 17 – 30 €/t $CO_2$ stored.

### 7.3.2 Conclusions

The conclusions regarding the cost of transport and storage of H-vision $CO_2$ are the following.

- Adding $CO_2$ from blue hydrogen production will not significantly change the unit cost of storage (i.e., the cost per tonne $CO_2$). The dominant factor controlling the cost of storage is the capacity (size) of the depleted field. The recommendation, following EBN and Gasunie (*EBN/Gasunie, 2017*), is to select the larger depleted fields for $CO_2$ storage as much as possible and to use existing infrastructure as much as possible.
- Economies of scale can be reached for transport. The addition of H-vision $CO_2$ to the Porthos project would decrease the transport unit cost.
- The total technical cost of transporting and storing $CO_2$ has been estimated to be in the range of 9 – 12 €/t$CO_2$, in agreement with the results presented in EBN and Gasunie (*EBN/Gasunie, 2017*).
- A reasonable estimate of the actual (commercial) cost of transport and storage is expected to be in the range of 17 – 30 €/t$CO_2$, where the difference with technical cost is due to factors like discounting, return rate on capital and operational risk.

It is to be noted here that all of these cost estimates have been derived without any input from the Porthos project.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# Business model

*Figure 8.1: Business Model Canvas*

# Business Model Canvas

## Value proposition

- Mton-scale emission reduction
- Acceleration of energy transition
- Solution for high-temperature firing in the industry
- Pathway to a hydrogen energy carrier economy
- Maximal use of existing assets

## Key risks

- Risk register live with 68 risks, categorized in critical, severe and small risks
- 5 risks critical in this phase: CAPEX estimates, changing economics, emissions reduction %, public safety perception and the 'fossil stigma'

*Risk matrix - H-vision*

| | | | | |
|---|---|---|---|---|
| 1 | 1 | 1 | 0 | 2 |
| 6 | 7 | 4 | 7 | 0 |
| 2 | 4 | 9 | 5 | 0 |
| 2 | 4 | 1 | 4 | 0 |
| 3 | 0 | 0 | 0 | 1 |

Impact [1-5]

Probability [1-5]

## Key partners & value chain

### Drivers

Decarbonisation of current business

New business in hydrogen

### Risks

Economic feasibility

Security of supply

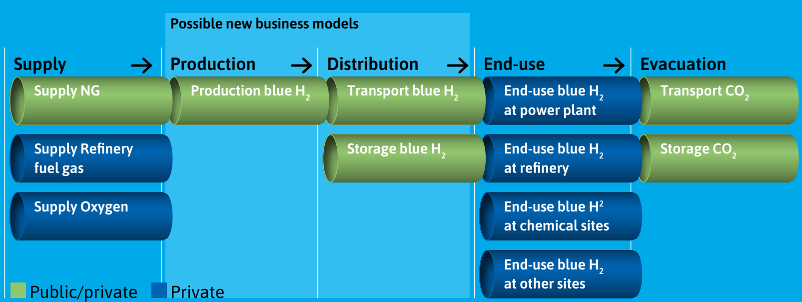
## Structure & ownership

### Business options:

**Access:** Third party access can create a hydrogen market and infrastructure

**Roles:** tolling, merchant, operator and joint venture

**Ownership:** Public/ private/mixed ownership in production and distribution




## Role of the government

Governmental organisations should cover 4 roles: policy maker, insurer & funder, regulator, and advocator & facilitator

Many public authorities are involved, but the cabinet and ministries have a key role.

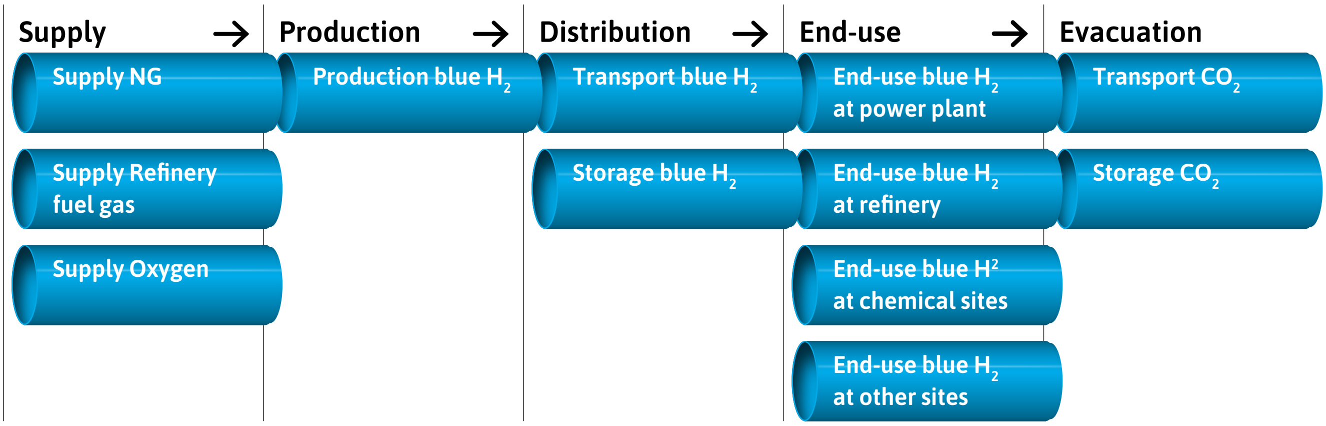

## Cost structure (reference dev. scope)

- Investments: 1-3 B€
- Yearly gas input (reference): 1.2 BCM
- $CO_2$ T&S tariffs: 80-165 M€/yr
- Other OPEX: 60 M€/yr

## Revenue streams (reference dev. scope)

- Revenue from 2.6 Mt/yr worth of $CO_2$ certificates
- Revenue from 5 MWh/yr worth of power production
- Financial gap: 0-78 €/tonne

*Figure 8.2: Value chain for blue hydrogen*




The business model has been studied in this project by making use of the 'business model canvas', as developed by Alexander Osterwalder (*Osterwalder, 2004*). The business model canvas is a way to describe and analyse the foundations of an organization that creates value. The original business model canvas structure has been slightly adjusted. Clients are not specifically included, since almost all of them are already partners in the H-vision consortium. Furthermore, we have analysed the key risks, since it is required that these risks are well managed in order to achieve a feasible business model. We also specifically looked at the role of the government, since this role is very important for H-vision to succeed.

In this chapter, we discuss the five upper boxes of the business model canvas as shown. We elaborate on the value proposition of H-vision (what does H-vision bring to society), the main risks that could obstruct H-vision in succeeding, the key partners that are required within H-vision, how the ownership structure should be shaped and what the role of the government should be. A description of the lower two boxes (cost structure and revenue streams) can be found in Chapter 9, Project Economics. The numbers mentioned in these boxes are based on the reference scope development concept in the Economical World scenario.

**With the nine partner roles of H-vision, all activities in the value chain can be covered**

## 8.1 Value proposition

The consortium assessed the H-vision feasibility with five key objectives in mind:

- **Mt-scale emissions reduction**
  High impact decarbonisation of the energy system can be achieved through the large-scale use of low-carbon blue hydrogen.

- **Acceleration of the energy transition**
  To reach the climate objectives, the energy system will have to radically change in a short timeframe. H-vision aims for a potential $CO_2$ emissions reduction of 2 Mt per year already in 2026, rising to 4.3 Mt per year in 2030.

- **Solution for high temperature firing in the industry**
  High temperature firing in the industry is difficult to decarbonize, but H-vision offers a solution for these applications

- **Transition pathway to a hydrogen economy**
  Blue hydrogen is seen as a stepping-stone to the future hydrogen economy, that ultimately will be based on green hydrogen.

- **Maximum use of existing assets**
  The H-vision project uses existing industrial installations in the port of Rotterdam area to a maximum extent, such as power plants, refineries and chemical plants.

## 8.2 Key partners and the value chain

The H-vision blue hydrogen value chain is portrayed in Figure 8.2. For the realisation of the H-vision project, it is key that all elements of the value chain are covered.

*Table 8.1: Key roles and their activities in the value chain.*

| Key partner role: | Example for H-vision: | Supply of NG | Supply of refinery fuel gas | Supply of oxygen | Production of $H_2$ | Transport of $H_2$ | Storage of $H_2$ | End use of $H_2$, power plant | End use of $H_2$, refinery | End use of $H_2$, chemical sites | End use of $H_2$, other sites | Transport of $CO_2$ | Storage of $CO_2$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural gas supplier (wholesaler) | Equinor | Core | | | | | | | | | | | |
| Industrial gas supplier | Air Liquide | | | Possible | Possible | | | | | | Possible | | |
| Power plant operator | Uniper | | | | Possible | | | Core | | | | | |
| Refinery plant operator | Shell and BP | | Core | | Possible | | | | Core | | | | |
| Chemical industry operator | Shell | | Core | | Possible | | | | | Core | | | |
| Other blue hydrogen off-takers | ExxonMobil | | | | | | | | | | Core | | |
| Hydrogen storage service supplier | Vopak | | | | | Possible | Core | | | | | Possible | Possible |
| $CO_2$ transport and storage supplier | Port of Rotterdam | | | | | | | | | | | Core | Core |
| Transmission system operator gas | Gasunie | | | | Possible | Core | Core | | | | | Possible | Possible |

No activity  Possible activity  Core activity

To cover this entire value chain, nine partner roles are necessary; from the natural gas supplier (wholesaler) at the beginning to the $CO_2$ transport & storage provider at the end of the value chain. One partner role can cover one or more activities, e.g. the industrial gas supplier may supply oxygen, produce hydrogen and may also be an end user for hydrogen. In the same way, a refinery plant operator may supply refinery fuel gas, produce hydrogen and be an end user for hydrogen. With the nine partner roles of H-vision, all activities in the value chain can be covered, as shown in Table 8.1.

Based on an assessment among the H-vision participants, the current situation, key drivers, potential risks and bottlenecks were elucidated and are described below.

### 8.2.1 Current situation and key drivers

In the current situation, there are two main drivers for participants to develop the H-vision technology:

- **Decarbonization of current business.** Current coal-fired power plants are relatively new and will lose their license to operate on coal in 2030. Next to this, refineries draw attention in the political debate, since they are in the top 10 of ETS emitting companies in the Netherlands. H-vision is a potential breakthrough solution to kick-start the decarbonization of their current business.

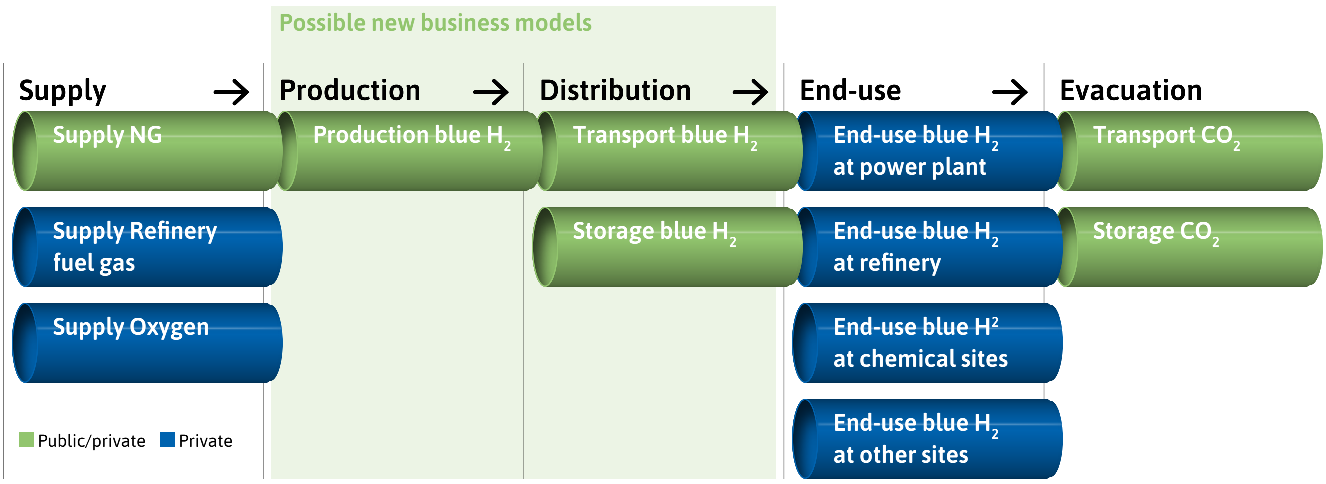
- **New businesses in hydrogen.** H-vision gives companies the opportunity to have a role in the future hydrogen economy.

### 8.2.2 Bottlenecks

Two bottlenecks for the value chain partners are identified as showstoppers:

- **Security of supply.** The industrial processes of the hydrogen off-takers should be able to run at all times.

*Figure 8.3: Ownership structure for the blue hydrogen value chain*




This implies that the hydrogen supply needs to have a large uptime and back-up systems should be in place.

- **Economic feasibility.** The economics of the H-vision project should not harm the competitive edge of the industries in the port of Rotterdam area. This means that the companies are willing to pay for decarbonization, but not at the cost of losing their competitive edge.

## 8.3 Business structure and ownership

The H-vision project requires new investments in hydrogen production and distribution. The project works under the assumption that ownership, control and modifications to existing assets (e.g. replacements of burners, boilers and connections within the fence of the factory) all happen within the current business models.

The envisaged ownership structure in the various parts of the value chain is illustrated in Figure 8.3.

### 8.3.1 Production

To realise the H-vision concept, gigawatt-scale blue hydrogen production facilities will need to be built and paid for. At this stage of the project, the ownership and control of these facilities has been left open.

In the current business environment, without government support and at the anticipated ETS prices, blue hydrogen is not competitive in the chemical, refinery and power generation processes, when compared to conventional fossil fuels (e.g. natural gas). As a result, an investment in a blue hydrogen production unit will require policy support to make it economically feasible, especially in the early years when ETS prices are expected to be lower than the cost of running the H-vision system.

Given the interests of the government, public sector and private sector, investment models combining public and private investments are even possible options. Given the large scale and risk profile of the project, co-investments and innovative methods of support may be required to offset the risks to a level acceptable to private sector investors.

### 8.3.2 Distribution

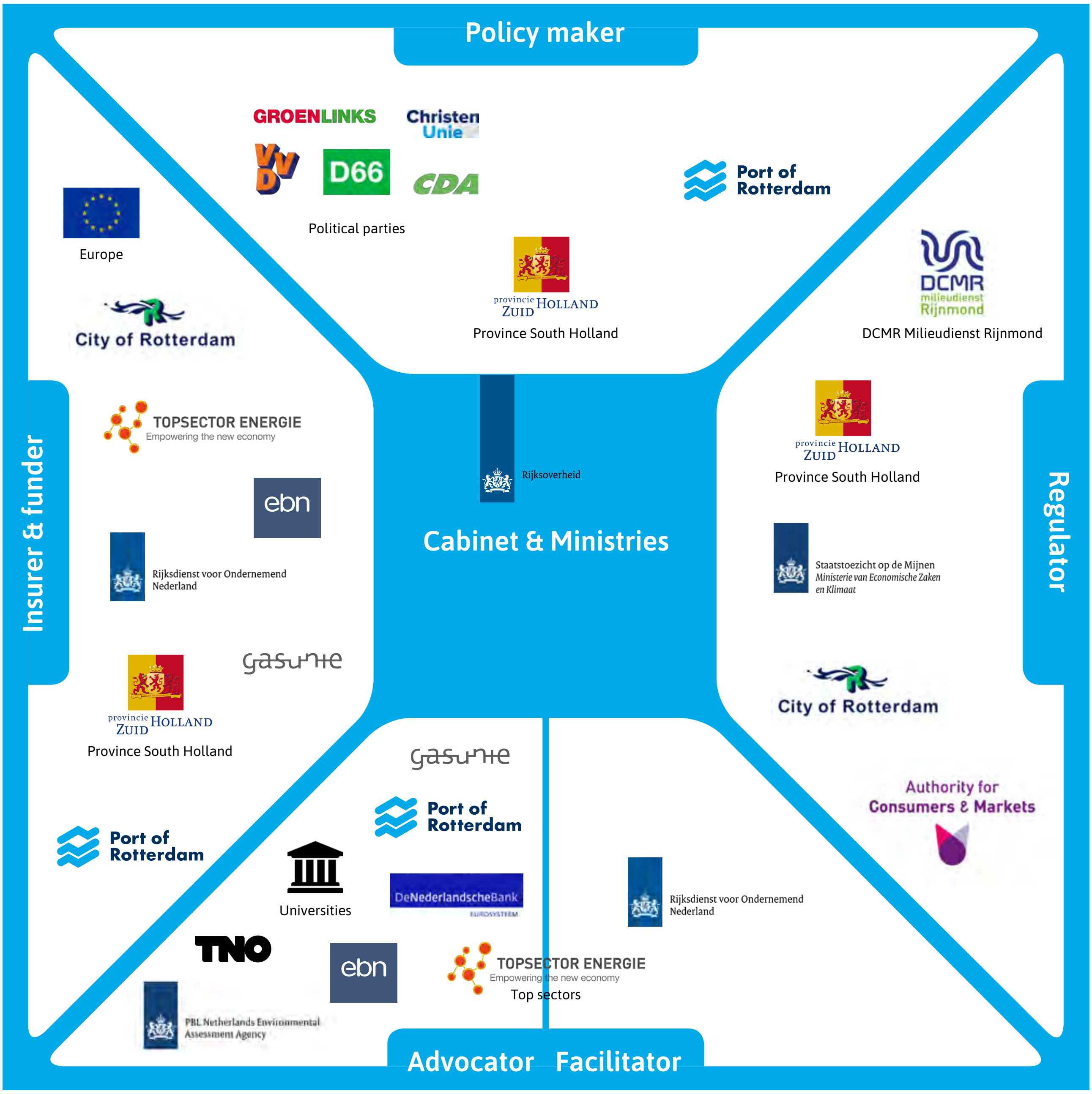
The existing pipeline distribution network for hydrogen in The Netherlands only carries ‘grey hydrogen’ and is privately owned by only one or a few large suppliers.

Apart from possible hydrogen specs requirements (feedstock vs. burner fuel quality), the current network is strongly lacking in the capacity needed to be able to meet the potential demands from the H-vision system. As a result, a new pipeline network (and possibly storage) would need to be constructed or made available (in the case of a revamp of an existing gas pipeline).

The primary scope of the H-vision project is one or more large-scale hydrogen production plants linked to a few large off-takers of the blue hydrogen (e.g. refineries, chemical plants and/or power plants). Compared to the total project investments, the investments in the hydrogen distribution network are relatively small. As a result, investments in this network could be made by a single party controlling the capacity of the network, possibly in cooperation with the hydrogen producer and/or the hydrogen end users.

However, the H-vision project also aims to support the kick-start of a hydrogen economy (regional, national and international) and to pave the way for green hydrogen. For this, third party access is of importance so that also other future producers of blue and green hydrogen can link into the network, as well as other customers. In this way, the

*Figure 8.4: Governmental organizations and their roles*




H-vision concept solves the ‘chicken and egg’ dilemma of supply and demand; aspiring blue/green hydrogen producers require security of demand and can reduce their risk by having a few large customers committed to purchasing the hydrogen, as well as the infrastructure to transport the hydrogen efficiently and economically. The end users, on the other hand, require security of supply through large-scale hydrogen production. The H-vision concept can facilitate incremental hydrogen supply and demand and therefore also smooth the way for much needed investments to support the decarbonization of the industry.

## 8.4 Role of the Dutch government

Governmental organizations have an essential role in enabling H-vision. Four vital roles have been identified, which are crucial to the success of H-vision.

The national government (Cabinet and Ministries) has a key role in all four activities. A pro-active position and working closely together with the value chain is of vital importance in the realization of H-vision. Various governmental organizations, local and (inter)national, should contribute to one or more of the roles, as indicated in Figure 8.4.

### 8.4.1 The government as policy maker

For H-vision, three policy areas are essential:

- **Decarbonisation of industry.** The main objective of H-vision is the decarbonization of industry in the Rotterdam area. Therefore, clarity on incentives to meet decarbonization goals is required. Due to the impact on the national economy and employment, such policies should be neutral with regard to technology, and must reflect the importance of a level playing field for the industry. The ETS credit system and implementation of the SDE++ subsidies are clear examples of such policies.

- **Carbon capture and storage (CCS).** Clarity is required for the role of CCS in the decarbonisation of the Netherlands. CCS plays an important role in the ongoing coalition agreement. However, in the 'Hoofdlijnen van het klimaatakkoord' (Klimaatberaad, 2018), lower priority seems to be given to CCS. Even limitations on the maximum $CO_2$ storage volume are discussed. Blue hydrogen cannot be produced locally without CCS, and therefore clarity of the position of CCS is required soon.

- **Hydrogen.** Currently, a dedicated policy around hydrogen does not exist. However, if hydrogen is used as a fuel, market regulations are required to enable third party access to the hydrogen infrastructure against reasonable terms and conditions. A policy in line with that would be to include hydrogen in the Dutch Gas Act, such that an infrastructure company must give access to their transport & services network to commercial gas suppliers.

**The government's role as advocate & facilitator is essential**

### 8.4.2 The government as advocate and facilitator

The government's role as advocate & facilitator is essential. H-vision should be strategically positioned as an enabler of the transition pathway to a green hydrogen economy. Organizing societal support is also key to the success of H-vision. For example, it will help if blue hydrogen would be included explicitly in the final Climate Agreement. The necessary storage of $CO_2$ to make blue hydrogen happen should also be part of this message. The government should take a leading role in all of these aspects.

Additionally, as the large-scale introduction of hydrogen is new to industrial users, the government can play a role as a facilitator. Substance to this role can be given by connecting parties in the value chain and providing data and independent information.

### 8.4.3 The government as insurer and funder

Investments in blue hydrogen are significant, and the business case will not naturally be positive. Therefore, the government will have to play a role of co-funder and/or insurer. Specific financial instruments are needed to initiate commercial investments in blue hydrogen. The following instruments (or a combination thereof) could help realise the H-vision system:

- **Subsidies.** There are several ways in which the government can grant a subsidy. One way would be a lump-sum amount to be paid to the investing parties, i.e. CAPEX support. Another way would be a variable

*Figure 8.5: Government roles in the different project phases*

| Project phasing | Identify | Assess | Select | Define | Execute | Operate |
|---|---|---|---|---|---|---|
| | Do we understand what we are starting? | Have we looked wide enough | Have we selected the optimum solution? | Is everything in place to ensure success? | Are we ready to operate? | What have we learned? |
| Government role and timing | 2018 | 2019 | 2020 | 2021 | 2024 | |
| Policy making | | | | | | |
| Advocacy | | | | | | |
| Regulatory framework & permits | | | | | | |
| Guarantees & funding | | | | | | |
| Facilitating | | | | | | |

Darker shades of blue mean larger involvement

amount which would be received based on the avoided $CO_2$ emissions (€/t). A third way would be to (partly) compensate for the incremental average cost (CAPEX and OPEX) when producing blue hydrogen. The type of subsidy scheme is important, since it influences the marginal cost of power production, and therefore the market behaviour of these installations.

- **Contract for differences.** By a contract for differences, risks can be transferred to the government. An example of this is the SDE+ grants, which transfer the risks of changing commodity prices. Transferring these risks leads to companies using a lower Weighted Average Cost of Capital (WACC), which reduces the financial gap. A contract for differences involving the ETS price would also help, since this is one of the key financial risks.

- **Shareholder and partner.** In order to actually influence the operations after the investment decision has been made, the government can also participate and become a shareholder or partner in a project. The creation of a hydrogen backbone, as announced by Gasunie, can be seen as an example of such a project.

- **Loan.** The government can provide the investing partners soft loans with low interest rates to stimulate investment.

### 8.4.4 The government as regulator

In addition to the roles discussed above, the government must make appropriate adjustments to the existing legal and regulatory framework that would enable the application of CCS and hydrogen. This should include clear regulations, guidelines and boundary conditions. Also, an effective licensing and permit system around the production, transport and storage of $CO_2$ and hydrogen must be established by the proper governmental organization.

### 8.4.5 Timing

Timing will be essential in order to start H-vision operations in 2026. The planned phasing of the H-vision project and the perceived role of the government is illustrated in Figure 8.5. During this study, our goal was to 'Assess' the feasibility and, during the next phases, we will 'Select' the optimal concept, 'Define' the detailed design, 'Execute' the project and, by 2026, start to 'Operate' the facilities.

The different roles of the government in H-vision are mapped to these phases:

- The government should start fulfilling its roles of policy maker, advocator and facilitator already today, in the 'Assess' phase. Now is the time that government and society should clarify their positions about the energy transition in general, and the roles of CCS and blue hydrogen in particular.

- The government will have to take on the role as insurer and funder in the 'Select' phase. In order to continue the project to the next phase, there has to be the likelihood of a suitable financial instrument and sufficient willingness to consider this.

- The work on regulatory framework and permits is required to start during the 'Select' phase. In order to enable a final investment decision at the end of the 'Define' phase in 2021, there must be absolute clarity and no ambiguities around the government policy, the regulatory framework and permits and the funding and guarantees.

## 8.5 Risks

A total of 68 risks have been identified to date: 13 risks are considered 'critical', 45 'severe' and 10 risks are considered 'small'. The mitigation of 16 of the risks must be initiated during the current 'Assess' phase; 5 of these risks are considered 'critical', 10 'severe' and 1 'small'.

Table 8.2 describes the 5 critical risks and mitigations of the 'Assess' phase. The topics of the critical risks that must be addressed during the current 'Assess' phase are CAPEX estimate, changing economics, emission reduction, public safety perception and fossil stigma. An extended discussion of the risks is available in Annex 5.1.

*Table 8.2: Risk table*

| Category | Work Package | Critical risk description | Mitigation Description | Mitigation Project phase |
|---|---|---|---|---|
| 11. Life-cycle cost | 2. Technology | CAPEX estimate: The total CAPEX is grossly underestimated in the pre-FID phase, which has an adverse effect on the project economics | Use an appropriate cost breakdown structure;<br>Work with service/ equipment suppliers;<br>Take into account a sufficiently wide range of CAPEX uncertainty | 2. Assess |
| 12. Scheduling | 1. Business | Changing economics: Changing economics during the construction or lifetime of the project no longer support the business case | Validate economic input parameters;<br>Stress test project economics against various scenarios;<br>Government contracts for difference to control risks;<br>Direct pass through of costs to clients and price indexing | 2. Assess |
| 41. Government | 5. Strategic Stakeholder Management | Emissions reduction % not accepted: Emissions reduction % achieved by H-vision is lower than will be accepted and supported by government | Liaise with NL government as soon as possible;<br>Design the technical solution and development concept such that it meets the NL government's requirements | 2. Assess |
| 43. Communication | 5. Strategic Stakeholder Management | Public safety perception: The public perceives that hydrogen in large quantities may not be safe | | 2. Assess |
| 43. Communication | 5. Strategic Stakeholder Management | "Fossil stigma":<br>- Blue hydrogen is linked to CCS - is this what we want? Is CCS an interim solution and for how long?<br>- Blue hydrogen is produced from natural gas - While in the Netherlands we want 'off-the-gas' . What about blue hydrogen wrt Groningen?<br>- Perceived lock-in of blue hydrogen since green hydrogen cannot compete with blue hydrogen; this will not go away and therefore there may be insufficient political support | "Early stakeholder involvement of governmental organisations in particular;<br>Crisp clear communication that blue hydrogen is ultimately an enabler for the (green) hydrogen economy | 2. Assess |

# 9

# Project economics

The goal of the economic model is to assess the economic feasibility of the H-vision project, by quantifying the sources of cost and revenue. This leads to the establishment of the avoidance costs, delta levelized energy costs, and ultimately the extent of the financial gap. The main objective for this business model is thus to create clarity concerning the financial gap and its root causes, while determining the level of governmental support necessary to make H-vision feasible. The economic model is based on the pre-tax discounted cash flow (incremental to the business-as-usual situation). It comprises the valuation of all incremental costs (CAPEX and OPEX) and all incremental benefits (revenues and subsidies) from a 100% project perspective. This means that the project internal commodity and cash flows between the separate H-vision participants are not taken into account for the time being. In practice, this means that, for example, the price of refinery fuel gas (RFG) is not taken into account; in the business case only the *additional* natural gas that is required to produce hydrogen with the same energy content as the original refinery fuel gas stream is taken into account. Details of the economic model can be found in Annex 6.1.

## 9.1 Results

In this paragraph, the results of the economic model are presented. Some of the main terms and abbreviations are summarized in the box below. A more detailed description of metrics used can be found in Annex 6.6.

**WACC**
Weighted Average Cost of Capital

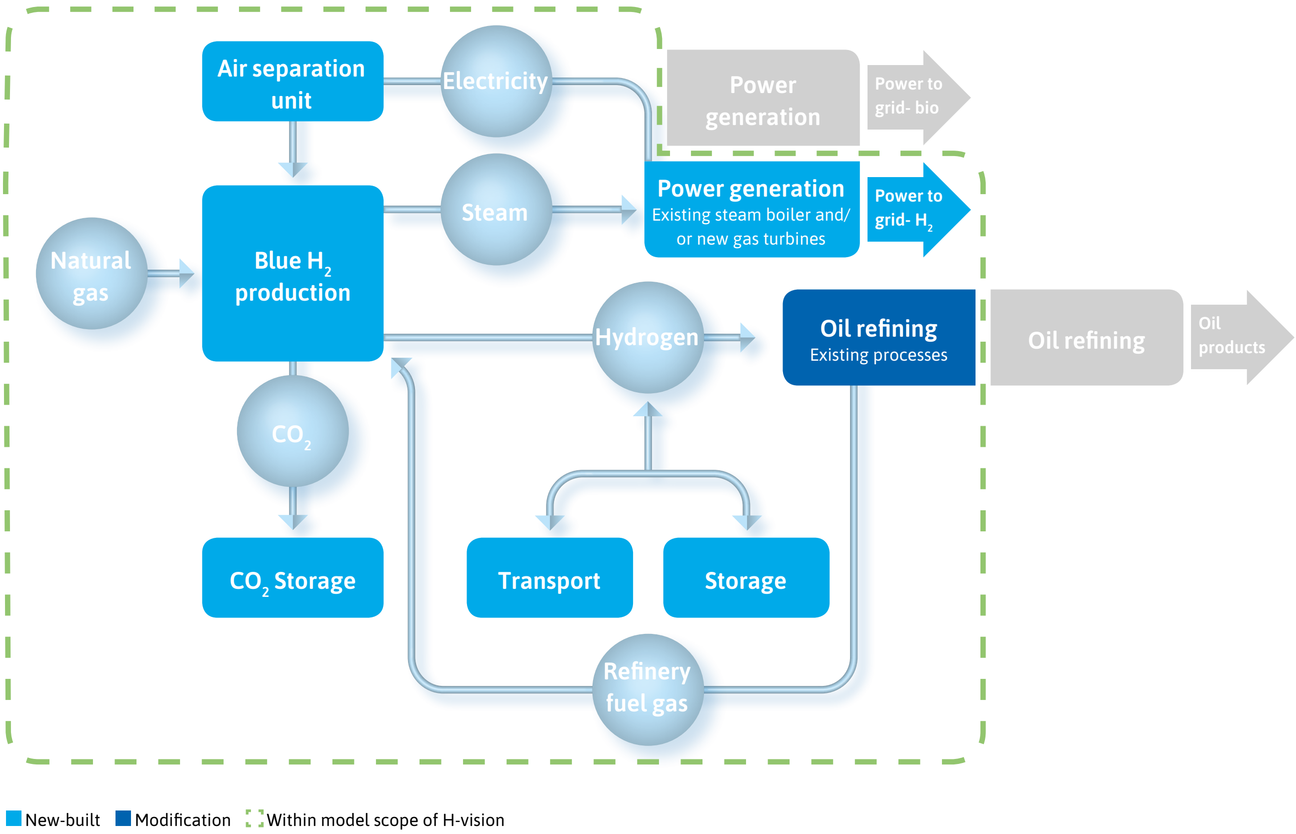
**NPV**
Net Present Value

**LCOE**
Levelized Cost of Energy/Electricity

**(EU) ETS**
European Union Emissions Trading System

An overview of the model is shown in Figure 9.1.

*Figure 9.1: The economic model is based on the pre-tax discounted cash flow (incremental to the business-as-usual situation). It comprises the valuation of all incremental costs (CAPEX and OPEX) and all incremental benefits (revenues and subsidies) from a 100% project perspective*



### 9.1.1 Main results

As described in the chapter about the solution space (Chapter 4), we calculate seven out of the nine possible combinations of development concepts and scenarios. The net present value (NPV), avoidance costs (separated for power plants and refineries), and difference in levelized cost of energy (LCOE) are presented in Table 9.1. In the table, the results are given for a weighted average cost of capital (WACC) of 3%. Results tables for a 6% and 9% WACC are available in Annex 6.5. A sensitivity analysis of the results can be found in Annex 6.2.

For interpretation of the results, it is important to note that in the As Usual scenario, $CO_2$ market prices up to 44 €/t are used in combination with a gas market price up to 29 €/MWh in 2045. In the Economical World scenario, an ETS price of 149 €/t and a gas market price of 34 €/MWh in 2045 are assumed. In the Sustainable World scenario, a $CO_2$ emissions price of 149 €/t and a gas market price of 24 €/MWh in 2045 are assumed.

Table 9.1 shows that the results for the avoidance costs of $CO_2$ range from 86 €/t $CO_2$ to 190 €/t $CO_2$. The range for the Reference scope development concept itself is somewhat smaller, with avoidance costs ranging from 86 €/t $CO_2$ to 146 €/t $CO_2$. In contrary to the As Usual and Economical World, we also see that in the Sustainable World there even exists a positive business case at a WACC of 3% (an NPV above zero). When such a WACC would be applicable to the H-vision project, no subsidy would be required. It can also be seen that the avoidance costs are highest in the Economical World, due to high gas prices, and lowest in the Sustainable World case because of the low gas prices.

The total $CO_2$ avoidance is independent of the scenario and increases from 27 to 79 to 130 Mt $CO_2$. We note that the avoidance costs show a larger variability with respect to the scenario than with respect to the development concept. From this, we may conclude that the H-vision economic feasibility is largely dependent on uncertain political and macro-economic future developments.
In order to be developed, the H-vision project requires more certainty, through clear government policies and regulations (around industrial decarbonisation, CCS, and hydrogen market regulations) and government-backed financial instruments.

The most important inputs used to obtain the results in Table 9.1 can be found in Table 9.2 below.

*Table 9.1: Main results of the seven calculated combinations of development concepts and scenarios*

| | | | Minimum scope | Reference scope | Maximum scope |
|---|---|---|---|---|---|
| | $CO_2$ abatement | Mt | 27 | 79 | 130 |
| As Usual | NPV (WACC 3%) | Billion € | -1.8 | -2.8 | |
| | Avoidance costs | €/t $CO_2$ | 146 | 111 | |
| | Avoidance costs power plants | €/t $CO_2$ | 271 | 103 | |
| | Avoidance costs refineries | €/t $CO_2$ | 122 | 116 | |
| | Delta LCOE | €/MWh | 19.6 | 15.0 | |
| Economical | NPV (WACC 3%) | Billion € | -1.3 | -0.7 | -2.1 |
| | Avoidance costs | €/t $CO_2$ | 190 | **146** | 151 |
| | Avoidance costs power plants | €/t $CO_2$ | 333 | 131 | 132 |
| | Avoidance costs refineries | €/t $CO_2$ | 162 | 155 | 160 |
| | Delta LCOE | €/MWh | 15.0 | 8.02 | 8.98 |
| Sustainable | NPV (WACC 3%) | Billion € | | 2.5 | 3.1 |
| | Avoidance costs | €/t $CO_2$ | | 86 | 91 |
| | Avoidance costs power plants | €/t $CO_2$ | | 71 | 73 |
| | Avoidance costs refineries | €/t $CO_2$ | | 95 | 98 |
| | Delta LCOE | €/MWh | | -3.56 | -2.58 |

*Table 9.2: Summary of main inputs for the economic model*

| | Minimum scope | Reference scope | Maximum scope |
|---|---|---|---|
| Hydrogen demand, max. (GW) | 1.2 | 3.2 | 5.3 |
| $CO_2$ capture, max. (Mtpa) | **2.2** | **5.5** | 9.4 |
| $CO_2$ avoided over 20 years (Mt) | 27 | 79 | 130 |
| CAPEX (Mln €) | 1,300 | 3,110 | 4,260 |
| OPEX fixed (Mln €) | 18 | 43 | 63 |

*Figure 9.2: Components of the economic model. This diagram gives the costs (orange) and revenues (green) for the complete project, how these are distributed to the participants is to be decided.*

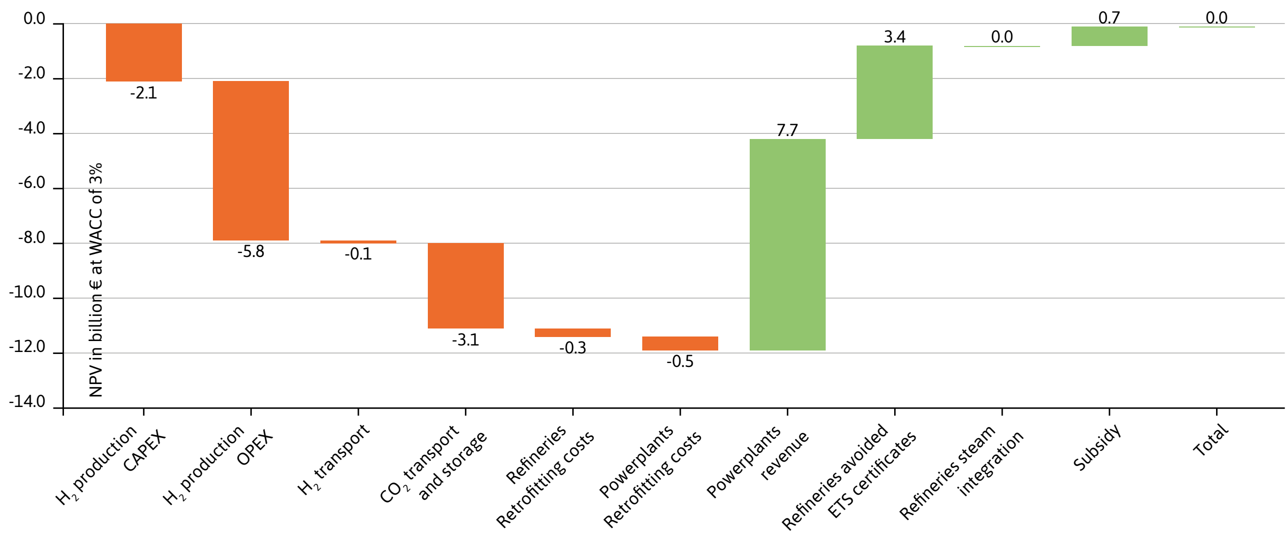



Figure 9.2 shows a waterfall diagram for the components of the economic model. These are the costs and revenues for the complete project, how the costs and revenues are distributed among the participants will have to be decided in future steps.

The waterfall diagram shows that most costs are related to the OPEX of hydrogen production (mostly natural gas), the $CO_2$ transport and storage costs and the CAPEX for hydrogen production. On the other hand most value is earned by the powerplants who run on hydrogen and a bit of steam in a electricity market with very high electricity prices. Most of this revenue in generated by firing the hydrogen to produce steam. The steam generated by the ATR also contributes to electricity generation, however this electricity is almost completely used in the oxygen production for the ATR. This oxygen is in turn used for the production of hydrogen in the ATR. The surplus of power from steam production for hydrogen intended for refineries is attributed to refineries. The refineries also contribute to the business case by saving on required ETS certificates. In the business case power plants do not earn avoided ETS certificates directly, but indirectly do, due to increased revenue made on the electricity markets, since the costs for ETS emissions are priced in.

## 9.1.2 Benefits of the H-vision concept

The main driver for developing the H-vision project is to realise on a relatively short-term, large-scale $CO_2$ emissions reduction in the industry within the port of Rotterdam.

The steam integration between the hydrogen production unit and the power plants is a large benefit. Large amounts of high pressure steam are produced in the process of reforming natural gas and refinery gas into hydrogen. The residual high pressure steam is transported from the ATR via pipeline to the power plants in order to generate electricity, which is mainly consumed in producing oxygen for the ATR. This interconnected design contributes to a higher efficiency, both on a technical and a financial level.

Alternatively, it is possible to decouple the hydrogen production units and the power plant completely. In this case, all of the steam would be integrated into the hydrogen production plant itself. Most of it would be used to generate the electricity used by the air separation units, and the rest would go to heat integration. The needed electrical power would need to be generated on-site or imported from the grid. Technically, this is a mature option, but it would lead to fewer benefits compared to the steam integration with the existing power plant infrastructure.

In the H-vision feasibility study, the baseline is the integrated design, due to its larger benefits. However, this integrated design may also lead to some complications. First, the power plant is required to be an outlet for the steam. This is balanced, but that also means that the ramp-up of hydrogen production for refineries would need to be proportional to that for power plants. Second, the hydrogen demand for power plants could not grow faster than that for refineries, because in that case the ATR would not have enough flexibility, e.g. the ATR would not be able to switch from 0% load to 110% load. On the other hand, the hydrogen demand from industries could not grow faster than that of power plants, since the power plants would be needed as outlets for the steam. This shows how well-integrated and connected the H-vision project is.

If the power plant were not operational, the steam would need to be condensed. This steam would be condensed by using the on-site condensers at the connected power plants, in order to avoid additional CAPEX. In the case that steam is condensed, the energy content of the steam would be lost. In the case of a shutdown of the ATR, power

*Figure 9.3: Applicability of decarbonization options to applications in the port of Rotterdam*

| Decarbonization options | Feedstock hydrogen | Firing refinery fuel gas | Other high temperature firing | Power production |
|---|---|---|---|---|
| | **Applications in the Port of Rotterdam** | | | |
| Blue hydrogen | | | H-vision | |
| Green hydrogen | | | Comparison: Section 9.2.1 | |
| Biomass | | | Comparison: Section 9.2.2 | |
| Power to heat | | | Comparison: Section 9.2.3 | |
| Post-combustion CCS | | Comparison: Section 9.2.4 | | |
| Storage of electricity | | | | Comparison: Section 9.2.5 |

Out of scope · Not applicable · Partly applicable · Fully applicable

plants wouldn't be able to fire hydrogen during that period of time and refineries would switch to refinery fuel gas, leading to some $CO_2$ emissions during that short period.

The H-vision reference scope development concept is comprised of a hydrogen production that would be the largest on earth. This prospectively leads to enormous economies of scale and reduces the CAPEX for the installation by 50% compared to a plant which is 10 times smaller. This leads to very large reduction in the avoidance costs for $CO_2$.

The calculated incremental efficiency of the retrofitted H-vision power plants is around 60%, due to additional placed hydrogen turbines. With this incremental efficiency, it would be possible to get a very large $CO_2$ reduction when comparing the H-vision power plants to generic CCGT power plants.

### 9.1.3 Alternative development concepts

The minimum scope development concept differs from the reference development concept in terms of a lower demand, smaller economies of scale and higher unit costs, e.g. more expensive ATRs per MW. The lower demand is not only caused by less hydrogen demand at the refineries, but also by the fact that no gas turbines are installed at the power plants. Hydrogen is in this case only used for pre-heating. This also means that the very high incremental efficiency of firing hydrogen (around 60%) in the reference scope cannot be realised in the minimum scope. This leads to relatively high avoidance costs for power plants.

The maximum scope also differs. In this case, the demand for hydrogen is higher due to additional refinery demand and due to additional pre-heating. Furthermore, in this concept, long-term hydrogen storage is included whereby salt caverns would be used to store hydrogen. These salt caverns are situated in the province of Groningen and would be maintained and operated by Gasunie. The hydrogen backbone would be used to transport the hydrogen to the caverns. This would lead to reduced CAPEX for the hydrogen production unit. However, of course this also would lead to additional CAPEX for development of the salt cavern and additional operational costs, such as compression costs. In theory, this could be beneficial. However, the capacity of the salt caverns is limited, thus it was not possible in this case to select the 5,000 best operating hours. Instead, the 5,000/8,760 best operating hours per month were selected, leading to a somewhat lower revenue than in the maximum scope case. This results in somewhat higher avoidance costs for power plants in the maximum scope case.

## 9.2 Comparison with alternatives

In this section, blue hydrogen will be compared with alternative methods of decarbonizing the energy supply for the industry in the port of Rotterdam area, with a focus on refineries, the chemical industry and the power sector. The alternatives considered are green hydrogen, post-combustion CCS, biomass and power-to-heat using green power. Each alternative has unique characteristics, which are compared against blue hydrogen using a set of relevant qualitative criteria. The discussion of the alternatives can be found in the following sections, the criteria for the comparison of the alternatives and the comparison tables can be found in Annex 6.3. Considered criteria include techno-economic aspects, integration with the energy system and societal aspects. For the reader's convenience, the option table in Figure 3.1 has been reproduced here as Figure 9.3.

### 9.2.1 Green hydrogen

Technically, both blue and green hydrogen have potential to be used for large-scale decarbonization of industrial processes, which is of particular interest to the Netherlands' large petrochemical sector (*World Energy Council, 2019*). Blue and green hydrogen have very similar specifications, and therefore both can function as low-carbon energy carriers for the industrial processes found in the port of Rotterdam.

It is important to note that green hydrogen is in competition with other decarbonization technologies for a renewable electricity energy supply, whereas blue hydrogen is not. This means that every megawatt of renewable power used for green hydrogen production cannot be utilized for other decarbonization applications, such as power-to-heat or E-mobility. Therefore, green hydrogen is only considered sustainable if produced from surplus and cheap renewable electricity. Currently, surpluses of green electricity do not exist – in the Netherlands, the share of renewable electricity is only 15% of the total electricity generation (*CBS, 2019*).

The scale of electrolysis is currently insufficient to meet the demand for energy purposes. It should be noted that well over 1000 MWe of electrolysis capacity would be required to meet the hydrogen demand of a single large refinery complex such as Pernis (*de Graaf et al., 1999*). In contrast, the world's leading post-FID projects for green hydrogen supply are currently at the 10 - 20 MW scale (*Gasworld, 2018, 2019*).

Meanwhile, the technical readiness level of blue hydrogen is very high. The primary reformer technologies are already applied in the feedstock industry. This technology can us the existing infrastructure and supply chain, which operates at a comparable scale to that required for H-vision blue hydrogen production (*Northern Gas Networks, 2018*). There are no expected limitations on the natural gas supply or the $CO_2$ storage capacity that may affect the production of blue hydrogen in the envisaged timescale (*Neele, 2011b*).

Green hydrogen is currently significantly more expensive than grey or blue hydrogen. The $CO_2$ abatement costs of heat production using green hydrogen are estimated to be in the range of 1134 – 1579 €/t $CO_2$ (*Navigant, 2019*). These high costs are largely due to green electricity costs, which are usually more than double the equivalent cost of the natural gas feed required to produce the same amount of blue hydrogen in reformer processes. Overall, the production cost of blue hydrogen is expected to be less than a third of the production cost of green hydrogen with current technology (*Northern Gas Networks, 2018*).

The transition to hydrogen requires new infrastructure, since existing infrastructure may only be partly reused. The existing hydrogen infrastructure in the port of Rotterdam, despite including several of the world's largest sources, is of a small scale when compared to the scale contemplated for an ambitious 2050 renewables-based economy (*Fuel Cells and Hydrogen Joint Undertaking, 2019)*. Reaching this level would require at least an order of magnitude scale-up of the current hydrogen infrastructure.

Another important aspect of green hydrogen is that it cannot decarbonize refinery fuel gases. This is because the process of electrolysis used for green hydrogen does not reform gases, so the $CO_2$ from the refinery fuel gases would still be emitted (or would have to be captured in some other way). Producing blue hydrogen does make it possible to also decarbonize refinery fuel gases.

A development based on proven and cost-effective blue hydrogen technology will enable a much more rapid establishment of hydrogen infrastructure, due to the fact blue hydrogen is expected to be less than a third of the cost to produce compared to green hydrogen (*Northern Gas Networks, 2018)*. Green hydrogen can then feed into this ready-made system, first complementing and then gradually replacing blue hydrogen, when it becomes dominant in an era of abundant renewable energy.

### 9.2.2 Biomass

This section compares the application of blue hydrogen with biomass as an alternative source of energy for decarbonization. Biomass has the following limitations with respect to sustainability:

- **Limited renewable sources.** Biomass sources are renewable, but only if they are produced sustainably, for example from waste streams. Virgin biomass usage can cause deforestation or competition with food

production. Biomass also requires abundant water to grow, competing with land irrigation or even the supply of potable water. The potential for freely available biomass in the Netherlands was estimated to be on the order of 200-230 PJ (Berenschot, 2018b).

- **Limited scalability.** Biomass sources such as waste streams and sewage sludge can provide low-carbon energy. However, due to the nature of being residual streams, the availability and scalability of these options is limited.

- **Larger land footprint.** Biomass from wood or crops has a substantially larger land footprint compared to blue hydrogen. Relying on biomass for energy could have very serious negative environmental impacts worldwide.

- **Larger $CO_2$ footprint.** Biomass has a $CO_2$ footprint ranging between 36-46 $gCO_2e$/MJ9 (Derks, 2018), depending upon the source of biomass. Blue hydrogen, on the other hand, carries approx. 10-20 $gCO_2e$/MJ, depending on the source of natural gas, overall efficiency of the reforming process and overall rate of $CO_2$ capture.

A transition to biomass would have pros and cons. The advantage is that energy dense on-site storage of biomass would provide the flexibility to quickly respond to changing energy demand and supply. For example, this would provide the capability to timely ramp up and down power production, providing grid stability services. The disadvantage is that the transition to biomass would introduce challenging requirements for the supply chain and central infrastructure.

Biomass is extensively used as a fuel for power generation and is highly flexible in use. Hydrogen as a fuel source for power generation isn't that common, but is successfully applied in multiple cases (*Enel, 2009*). Excluding the supply chain drivers, both biomass and hydrogen offer almost the same flexibility, with hydrogen carrying the advantage of quick and clean burning.

It is questionable whether the use of biomass is scalable. It is important to note that the demand for bioenergy in the EU has been largely driven by political targets and subsidies. As mentioned under 'sustainability', if the same regulatory support would be provided to increase the share of biomass in the EU energy mix, the land footprint of biomass would have to increase dramatically, causing much greater competition with other land uses and other regions (*Schutter & Giljum, 2014)*.

### 9.2.3 Green power-to-heat

This section compares the application of blue hydrogen with yet another decarbonization alternative i.e. green electrification of heat supply or green power-to-heat. Here the heat for industrial processes is provided directly by electrical furnaces/boilers or heat pumps, instead of boilers firing natural gas, refinery gas or hydrogen.

The Dutch Draft Climate Agreement (*Klimaatberaad, 2018*) explicitly refers to power-to-heat. It states that the electrification of heat processes in the industry offers important opportunities to make the industrial production more sustainable, under the condition that there is sufficient generation of renewable electricity.

The climate agreement states that electrification of the industry in the Netherlands can reduce $CO_2$ emissions by 5.3 million tonnes in 2030 (technical potential) with a savings of 93 PJ. However, this concerns mostly heat pumps that generate temperatures below 300 °C, drying and separation technologies, electrical boilers and mechanical vapor compression.

In addition to the condition that enough renewable power must become available, a main concern with green power-to-heat is that the current power grid does not have the capacity to support massive electrification, while costs to upgrade the electrical grid are prohibitively high. A study executed by DNV-GL examines the potential of linking offshore wind directly to power-to-heat for an industrial cluster, like the Rotterdam-Moerdijk area (*DNV-GL, 2018*). This would reduce the strain on the transport grid through the creation of demand at the point of feed-in, though still with its own challenges.

The study concludes that the utilization of power-to-heat technology is a method of decarbonizing the industry that simultaneously can facilitate the integration of offshore wind in the power system, albeit with a cost gap compared to the current usage of gas. The avoidance costs are 59 €/t $CO_2$ for a situation with integration of renewables during 4500 hours per year. Using grid electricity in the residual hours causes the avoidance costs to rise to 181 €/t $CO_2$, due to high electricity prices and the use of grid electricity instead of renewables.

### 9.2.4 Post-combustion Carbon Capture & Storage (CCS)

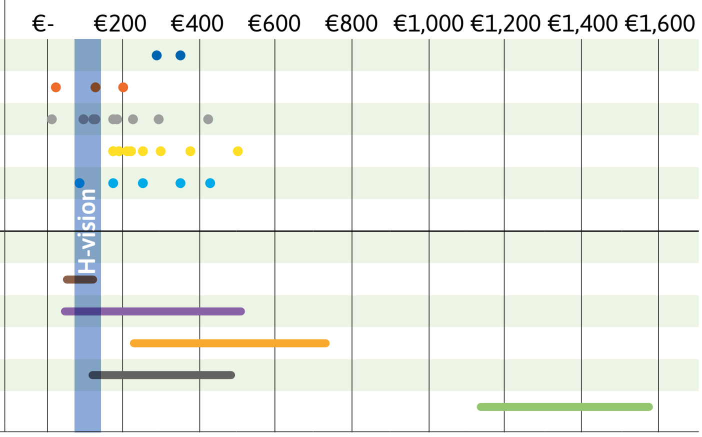
This section compares the application of blue hydrogen, which requires pre-combustion CCS, with post-combustion CCS after the use of fossil fuels. CCS requires capital intensive investments at specific industrial installations, which requires a long-term perspective for each installation. Furthermore, if investments are done, only the installation with retrofitted CCS can benefit from the $CO_2$ reduction capacity.

On the other hand, the investments in blue hydrogen are decoupled from the existing industry. The large investments are done at the reformers to produce

9 Based on final energy consumption for power generation

*Figure 9.4: Comparison of the base tariff of H-vision with alternatives based on (Navigant, 2019). The colours used are visual assists and have no meaning.*

| | Base tariff €/MWh | |
|---|---|---|
| **Current SDE+ categories** | min | max |
| Thermal solar | € 85 | € 98 |
| Geothermal | € 32 | € 67 |
| Combustion biomass | € 30 | € 113 |
| Fermentation biomass | € 62 | € 127 |
| Other | € 44 | € 98 |
| **Possible widening to SDE++** | | |
| Post-combustion CCS | n.a. | n.a. |
| Heat pump - < 90 degrees | n.a. | n.a. |
| Heat pump - 90-140 degrees | n.a. | n.a. |
| Electric boilers | n.a. | n.a. |
| Heat production with green hydrogen | n.a. | n.a. |




hydrogen, and relatively minor investments are required at the industrial installations. If changes occur, the hydrogen can be used to decarbonize other applications, such as other industries, electricity production, mobility or residential heat.

Post combustion CCS is applied to specific industrial installations. The nature of the industrial installation, e.g. size, location, transport distance, running pattern and concentration of $CO_2$ in the flue gases, determines the investment and energy costs for post-combustion CCS. Market consultations and literature review have led to the conclusion that this results in widely varying investment (10-100 €/t$CO_2$) and energy costs (10-35 €/t $CO_2$). The bulk of the investments in blue hydrogen are in the hydrogen production facilities, rather than at various specific industrial installations. Therefore, the $CO_2$ abatement costs are more predictable.

A likely decarbonisation strategy could be to use both post-combustion CCS and blue hydrogen, each according to their strengths. Post combustion CCS could be used at installations where it is cost-effective (e.g. large, base-load installations with high $CO_2$ concentrations in the flue gas), while blue hydrogen may be better used at other installations (e.g. smaller installations, part-load installations and/or installations with low concentrations of $CO_2$ in the flue gas). Both post-combustion CCS and blue hydrogen are readily applicable for the large-scale decarbonization of industrial processes, which is of particular interest to the Netherlands' large petrochemical sector.

Carbon capture for blue hydrogen is more efficient than post-combustion CCS, because the capture occurs at high pressures and high concentrations of $CO_2$ downstream of the water-gas shift unit, rather than at low pressure and low concentration in post-combustion capture processes. A downside of blue hydrogen is that it requires a total reforming process to be in place. Still, blue hydrogen performs slightly better in terms of energy efficiency.

### 9.2.5 Storage of electricity

In the Dutch Draft Climate Agreement (*Klimaatberaad, 2018*), several energy sources are mentioned as possible candidates to generate the 15-17 GW adaptable capacity needed. Large-scale electricity storage is also explicitly mentioned as a possible solution. Concepts for electrical energy storage include various forms of batteries and flywheels (small scale to medium scale) and large energy storage systems (pumped hydro, compressed air energy storage, compressed nitrogen energy storage).

Energy storage is necessary to create system flexibility, but it is not clear to what degree large- or small-scale (local) electrical storage technologies can be used to solve the flexibility problem. In addition, further development is needed to create advanced battery concepts with a larger capacity and faster load/onload speed. On the other hand, larger systems, such as Pumped Hydroelectric Storage (PHS), Compressed Nitrogen Energy Storage (CNES) and Compressed Air Energy Storage (CAES), do have potential considering their large capacity.

The business cases for these energy storage systems are still very limited. While the larger technologies have the benefit of a large capacity, they do require ideal geographic (underground) areas for installation. With regards to smaller scale storage, the Levelized Cost of Electricity (LCOE) of large-scale lithium-ion battery projects has decreased since mid-2018 by 35% to $187/MWh (*Duurzaam Nieuws, 2019*), and other forms of batteries are following suit, such as the 'lead-acid battery'. Compared to lithium ion batteries, which comport substantial risks, flow batteries offer longer storage (from 4 hours onwards), which makes them cheaper than Li-Ion per kWh. Furthermore, they have no thermal runaways (and explosion risks) and hardly any degeneration. These characteristics make flow batteries better candidates to cover day-night patterns for electricity use and flatten the peaks in electricity use (and supply). For more information on flow batteries, see Annex 6.4.

Currently, energy storage in gas fields and other technologies with great infrastructural consequences are a matter of public debate; implementation of these technologies would require substantial stakeholder participation processes (*Geurds, 2018*). This puts the potential of technologies such as CNES and CAES at risk, but also increases the potential of blue hydrogen.

### 9.2.6 Results in perspective

In this section the economics of the H-vision project are compared to other decarbonization options. The objective of this comparison is to gain insight into whether the $CO_2$ avoidance costs are in a range for the project to be economically feasible. To compare this, an analysis was done on the decarbonization options which are included in the current SDE+ subsidies. The SDE+ is the major arrangement in the Netherlands in which subsidies are granted to decarbonization options.

Subsidies which are currently being granted are analysed using the concept advise SDE+ 2019 from the PBL. From this, the 'base tariffs' are drawn per category of renewable production. This reflects the cost price of renewable production. For heat producing categories, this is translated into avoidance costs using the costs and $CO_2$ emissions of natural gas. A gas price of 26 €/MWh was used, comparable to the discounted gas price in 20 years of operation in the As Usual World. Only 5 out of the 29 categories which produce heat have lower avoidance costs with respect to the reference scope development concept in the As Usual World (107 €/t). Therefore, in comparison to subsidies currently being granted, H-vision is either more cost effective or of similar cost.

It is considered to widen the SDE+ subsidy to applications which reduce $CO_2$ emissions instead of producing renewable heat. Examples are electrification options (heat pumps, electric boilers) and CCS. Navigant did an analysis of the bandwidth of the avoidance cost of the categories which could be added, as shown in Figure 9.4 (*Navigant, 2019*). From the selected options, electrical options have higher $CO_2$ avoidance costs, except possibly heat pumps for low temperatures. Post-combustion CCS options have comparable or slightly lower reduction costs, whereas the heat production with green hydrogen has tremendously higher avoidance costs. Important to note is that the avoidance costs associated with post-combustion CCS are very contingent and situation dependent. Only in very specific cases can post-combustion have a lower avoidance cost than the H-vision project.

In general, post-combustion CCS is more expensive for most industrial processes. The H-vision concept is feasible for most kinds of industrial processes, whereas post combustion is only feasible for specific cases. Therefore, in comparison to subsidies considered to be granted, H-vision is either more cost effective, or similar in costs.

## 9.3 Required policy instruments

$CO_2$ avoidance is one of the main drivers of H-vision. The project economics are NPV negative, with a 3% WACC, in both the 'As Usual World' and the 'Economical World' scenarios. Yet, the 'Sustainable World' scenarios result in a positive NPV with a 3% WACC. When taking into account the uncertainty of electricity market prices and the ETS prices, the development of H-vision would not be feasible without policy instruments.

The results of the business case calculations have a large dependency on uncertain factors. The business case could for example turn negative when the ETS price differs from the assumed ETS price. These uncertainties make the business case unattractive for investors, since their benefits are also uncertain. Some of the uncertainties can be taken away by the government. For example, a contract for difference on the ETS price could take away the uncertainty around the ETS price.

In the analysis, 5,000 running hours are assumed for power plants on running on hydrogen. However, it is possible that power plant owners decide to run their power plant less than 5,000 hours, in order to save costs when electricity prices are too low. That would lead to a lower $CO_2$ reduction than calculated in the business case. To avoid power plants deciding to run less than 5,000 hours, policy instruments are required. One could foresee, for example, SDE++ subsidies on power production from hydrogen.

The cost of capital is key to the feasibility of the H-vision project. In business, the Weighted Average Cost of Capital (WACC) is determined by the debt/equity ratio and the risk profiles of these capital components. There are several options for how H-vision could be funded as a company and also options to control the risk of the debt and equity portions of the company's capital structure. Since the funding structure is unknown at this stage, we have decided to show results of a 3% WACC. That is comparable with the WACCs used in governmental cases and studies, and therefore aligns with the calculations of the effects of the climate agreement (*Klimaatberaad, 2018; PBL, 2019*). Furthermore, a sensitivity is done on a range of possible WACCs, representing various risk levels related to various structures of the funding. This enables the determination of the impact of several WACC levels on the project.

Achieving an appropriate balance between public and private risk sharing is crucial, as this will determine the WACC for the H-vision project. It is important to realise that large-scale carbon capture on the scale of H-vision has not yet been achieved anywhere in the world, despite being crucial for the Paris Agreement targets. Therefore, the risk of this project is substantial and, unless this is mitigated, high returns may be required by equity investors. This strongly suggests that the formula for success will require innovation, not just of the technology and business model, but also in project finance.

The government is in a unique position to accept risks that private parties would have difficulty in assuming, such as the carbon emissions price risk. In the end, this risk is a political construct which responds to policies that the government puts in place, rather than an industry-controlled risk. The transfer of this risk, possibly through contracts for difference, and other risks would allow private parties to invest at a lower return than would be demanded if all risk related to the project were to lie with the eventual H-vision entity. Access to low-rate debt funding, either through green bonds or other government-backed financial instruments, is another key area where the government can decrease the capital costs for the H-vision project.

These financial innovations would allow the owning entity to tap a higher portion of very low rate funding than would be possible for a new enterprise with limited backing. By optimizing the risk profile of the debt and equity investments, government can mobilize the capital from private sources required for this world leading infrastructure and keep the WACC at the lower levels necessary to realise the project. The preferred composition of ownership, capital funding, revenue model, and risk profile should be determined in a standalone analysis. This remains to be done in the Selection phase of the H-vision project. We refer to the study by Pale Blue Dot as an example of how this could be done (*Pale Blue Dot, 2018*).

## 9.4 Conclusions

- The H-vision project is a competitive solution to decarbonize the industry in the port of Rotterdam area:
  - The project realises on a relatively short-term, large-scale $CO_2$ emission reductions increasing from 2.2 Mtpa in 2026 ramping up to ca. 4.3 Mtpa in 2031 for the reference development concept. The amount of $CO_2$ stored is somewhat more than the $CO_2$ avoided due to inherent inefficiency in the conversion of refinery fuel gas and natural gas into hydrogen. The total $CO_2$ avoidance from 2026 till 2045 depends on the development concept and ranges from 27 Mtonne for the minimum scope development concept to 79 Mtonne for the reference development concept to 130 Mtonne for the maximum scope development concept. This is equal to the ramp-up from 5-year ramp-up period from 2026-2030 plus the period running at full capacity from 2031-2045.
  - The total avoided $CO_2$ emissions over 20 years depends on the development concept and ranges from 27 to 79 to 130 Mt.
  - The $CO_2$ avoidance costs in the reference concept depends on the scenarios and varies from 86 to 146 €/t $CO_2$. This is more cost effective than most of the decarbonization options that are included in the 2019 SDE+ scheme. The avoidance costs are higher for refineries than for power plants, since power plants earn back money using hydrogen on the electricity market and the electricity market is favourable for $CO_2$-free power production.
  - H-vision offers an outlet for refinery fuel gases since these are used, together with natural gas, as feedstock for the hydrogen production.

- The economic feasibility depends largely on the Weighted Average Cost of Capital (WACC) and the political and macro-economic developments, and the impact thereof, particularly on the natural gas and $CO_2$ emission prices.
- The minimum scope development concept is less cost effective than the reference concept because no gas turbines are used, which means that hydrogen is used with a significant smaller electrical efficiency. In addition, the smaller capacity of the natural gas reformer limits the economy of scale effect.
- The maximum scope development concept is comparable with the reference case in terms of cost effectiveness; the concept does not profit from the additional economy of scales because it includes the underground storage of hydrogen in salt caverns, which results in a relatively large increase in the project CAPEX and OPEX.

# 10

# Conclusions

**Short-term, large-scale $CO_2$ emission reductions increasing from 2.2 Mt per year to 4.3 Mt per year**

**H-vision can kick-start the hydrogen-as-energy-carrier economy and pave the way for the use of green hydrogen**

**Before 2030, large scale $CO_2$ emissions reduction for industry in the port of Rotterdam in a cost-effective manner**

## H-vision project is technically feasible

In this study we analysed the feasibility of the H-vision project and concluded that it is technically feasible. The H-vision concept makes use of existing industrial infrastructure with limited modifications in the industrial processes for high temperature heating and major modifications for power generation combined with a challenging transition to biomass as an alternative for coal. All technical building blocks in the chain are either already deployed at large scale in other countries or are at a high technology readiness level. A first blue hydrogen production unit could be on-line in late 2025.

## World-scale hydrogen production units

The blue hydrogen technology concept in H-vision requires one or more world-scale hydrogen production units that could be located at a single plot at the Maasvlakte. These units, with a combined capacity of 2920 $MW_{th}$ in the reference scope, will produce hydrogen from natural gas and refinery fuel gas, while capturing carbon dioxide. This would lead to short-term, large-scale $CO_2$ emission reductions increasing from 2.2 Mt per year to 4.3 Mt per year. The captured $CO_2$ would be stored in depleted gas fields on the Dutch Continental Shelf, while using the planned infrastructure of the Porthos project.

**Low-carbon solution for high-temperature firing in the industry**

## Underground salt caverns most cost-effective for storing very large volumes of hydrogen.

For the minimum and reference scope development concepts, it was determined that storage of hydrogen would not be necessary. The required flexibility needed to serve a varying hydrogen demand could be provided by ramping the production plant up or down. For the maximum scope development concept, large-scale hydrogen storage was investigated. For this concept underground salt caverns seem to be the most cost-effective option for storing very large volumes of hydrogen.

## Economies of scale

The sheer size of the project would lead to substantial economies of scale and therefore to substantial reduction of the CAPEX per tonne of avoided $CO_2$ emissions. The surplus of steam that would be generated by the hydrogen production units can very likely be integrated with existing power plants. For integration purposes, the large-scale production of hydrogen is best located near the power plants.

## More than sufficient $CO_2$ storage space in gas reservoirs on the Dutch Continental Shelf

There is more than sufficient $CO_2$ storage space in gas reservoirs on the Dutch Continental Shelf. With a yearly maximum storage amount of 14 Mt, 288 Mt of $CO_2$ would be stored by the end of the 20 year project lifetime. This represents less than 20% of the estimated total available storage volume of 1600 Mt in a selection of suitable gas fields in the Dutch part of the North Sea. There are no major concerns about dealing with the quality of the $CO_2$ for sequestration. Transport and storage risks are known and manageable and the unit costs for compression, transport and storage are estimated in the range of

17 – 30 €/tonne $CO_2$.These costs are unlikely to change significantly when the total annual volume of $CO_2$ is increased.

## Significant potential for industrial heat

The potential of blue hydrogen for industrial heat is significant and plays a key role in the economic feasibility of the H-vision project. The baseload consumption characteristic of industrial heat demand forms an ideal foundation for the H-vision business case, ensuring a stable, constant and predictable offtake. Hydrogen demand from power plants could be comparable in scale but variable. Blue hydrogen could therefore be part of a future with flexible, $CO_2$ free power generation.

## Cost effective decarbonization option

The $CO_2$ avoidance costs in the reference scope depend on the selected scenario and vary from 86 to 146 €/tonne. This is more cost effective than most of the decarbonization options that are included in the 2019 SDE+ scheme. A comparison with alternatives shows that blue hydrogen is a potentially valuable solution for industrial applications in the port of Rotterdam.

## Large scale $CO_2$ emissions reduction

We may conclude that the H-vision project makes it possible to achieve, before 2030, large scale $CO_2$ emissions reduction for industry in the port of Rotterdam in a cost-effective manner. This allows the Netherlands to stay within its national carbon budget until 2050. Furthermore H-vision can kick-start the hydrogen-as-energy-carrier economy and pave the way for the use of green hydrogen. H-vision is a low-carbon solution for high-temperature firing in the industry.

## Key role Government

However, the H-vision economic feasibility depends largely on political and macro-economic developments. Especially the large long-term uncertainties about commodity and $CO_2$ emission prices are an obstacle to get H-vision started as they have a major impact on the business cases. Public support in the form of participation, contracts for differences, risk baring loans or subsidies are required to get H-vision started given its low, non-commercial rate of return. The Government can play a key role in kick-starting the hydrogen economy by adopting the role of policy maker, insurer and funder, regulator, advocate and facilitator to make H-vision successful.

**Before 2030, large scale $CO_2$ emissions reduction for industry in the port of Rotterdam in a cost-effective manner**

# 11

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