HyDelta 2

WP2 – Hydrogen in the integrated energy system

D2.1 – Drivers of renewable hydrogen production in the Dutch integrated energy system

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Executive summary

This study tries to answer two fundamental questions related to the introduction of hydrogen in the Netherlands' energy system in the period until 2030:

- what is the likely order of magnitude of electrolyser capacity investment in the Netherlands and what are their main drivers; and
- given such investment, and given the different sizes of electrolyser installations (varying from a scale of some MWs to GW-scale), where will those investments most likely be located and what are the most likely drivers of the choices of location?

Both questions are highly relevant for the TSO and DSO's responsible for hydrogen transport. The more hydrogen will be produced domestically as opposed to imported via the main harbours, the more transport capacity will need to be developed to service the market. The better the understanding of where hydrogen production will most likely be concentrated, the better the TSO but the DSO's in particular will be able to plan their future hydrogen related transport capacities.

Magnitude of electrolyser capacity investment

So far virtually all investment in electrolyser capacity has been characterized by a spirit of pilot and demonstration activity. The commercial exploitation of electrolysers still is something of the future given the current stage of scaling up and learning. This means that serious investment in electrolyser capacity will not come off the ground without public support, either by way of subsidies or by way of command and control via prescribing the introduction clean hydrogen to replace grey hydrogen. In assessing what the main drivers are for investment in electrolyser capacity, public support therefore clearly will be the main factor, at least in the period considered i.e. until 2030.

In the Netherlands support policies to stimulate hydrogen value chain development and electrolyser investment in the country have come off the ground fairly intensively during the last years: the Netherlands is the first country in Europe to invest in a national hydrogen backbone linking most of the main industrial clusters with links to Germany and Belgium; the Netherlands introduced serious subsidy volumes (several billions of Euros) to support investment in electrolyser capacity and hydrogen transport capacity and also support measures have been introduced via a certificate system for hydrogen in mobility including hydrogen refinery for that purpose; the Netherlands recently doubled its 2030 targets for both offshore wind and electrolyser capacity (to 21 GW and 6-8 GW respectively); a wave of pilots related to small scale introduction of hydrogen in industry, mobility and the built environment meanwhile has been introduced to test hydrogen applications. All such support activity has boosted hydrogen developments. The question whether or not hydrogen support initiatives in the country have been relatively substantial compared to other EU countries was outside the scope of the current study. That the support measures have been effective is, however, clear: given the current information it seems very likely that the first GW cumulative electrolyser capacity in the country will already be operational by 2026.

In the study an extensive simulation has been carried out to assess for (the period until) 2030 how much public support/subsidy is probably needed per MWh of green hydrogen produced domestically to close the business case. Obviously the result was sensitive to many investment specific factors, but boiled down to figures ranging from close to zero to about 100 €/MWh with most simulations ranging between some 10-35 €/MWh H2, or some 0.5-1 €/kg H2. Key factors reducing subsidy needs turned out to be: the overall installed capacity of renewable energy in the country; national demand for hydrogen; national demand for electricity; and to a lesser extent the natural gas and CO2 prices. The simulations assumed that the hydrogen market until 2030 will be typically national because the international shipping transport systems are expected to initially focus on demand of the hydrogen carriers (e.g. ammonia or methanol).

Another fundamental factor that, next to public support measures, will most likely have a crucial impact on domestic electrolyser capacity built up is to what extent the country will rely on the imports of hydrogen and hydrogen carriers for satisfying domestic demand. It is still an open issue to what extent nationally produced hydrogen can compete with hydrogen imported from foreign sources. The assessment of HyDelta 1 7A.2 suggested that for at least 2030 hydrogen production based on North Sea wind capacity could compete well with almost all other sources of green hydrogen production because differences in transport costs more than compensated those of production costs. For hydrogen carriers the assessment concluded no clear difference in competitiveness between domestic and foreign sources. This may explain why in the various simulation studies on the issue, no clear answer is provided on the issue what share of hydrogen supply will be generated nationally. A major complexity in this respect is that hydrogen and hydrogen carriers are just commodities that will be traded internationally so that a significant part of hydrogen and hydrogen carriers entering the country as imports, will be transported further to the surrounding countries. All in all, the expectation is that 'pure hydrogen' may well be produced domestically typically based on North Sea wind capacities, whereas hydrogen derived chemicals such as ammonia and methanol will typically be imported.

Locations of electrolyser investment

It seems likely that different scales of electrolyser capacity clusters will be introduced in the future ranging from small electrolysers (say with capacities ranging from about 1 MW to several MWs), and medium sized electrolysers (say with capacities between some tens to some hundreds of MWs) to large electrolysers (with capacities anywhere between 250 MW and several GWs). Obviously the range of likely locations of such investment will differ depending on the scale of the investment clusters.

So far significant investment of electrolyser capacity of medium sized and large scale is foreseen to emerge in or near four of the five main industrial clusters (Eemshaven-Delfzijl, het Noordzeekanaalgebied (NZKG), the Rotterdam-Moerdijk area, the Schelde-Delta region in Zeeland, and Chemelot in Limburg). The locational advantages of these main industrial clusters are clear: large scale demand, the presence of major companies with considerable investment capacities, and a cluster scope supporting the economics of scale, logistics and permitting procedures. The few existing scenarios so far, for the after 2030 period on average suggest that the major part (60-75%, depending on the scenario) of the Netherlands electrolyser capacity in the future will be located in the four coastal industrial clusters and the region of Den Helder and/or offshore. The remaining, mostly smaller electrolyser capacities will be located at the Chemelot industrial cluster and elsewhere throughout the country.

Clearly, the backbone will act as another major catalyst for electrolyser investment in its neighbourhood; all coastal main industrial clusters mentioned are positioned close to the backbone. Also, all four clusters located near the coast are already connected to energy supply networks based on power, also from offshore wind capacities, which adds to their abilities to balance and to their strong locational advantage for large scale electrolyser capacities until 2030. After 2030, the future location of offshore wind capacities may be increasingly decisive which – due to windfarms increasingly being planned in the Northern part of the Netherlands North Sea continental shelf – explains why the scenarios and investment plans suggest an increasing focus of electrolyser capacities in the North of the country.

An interesting issue, also for the DSOs in view of their network investment planning, is where electrolyser capacities can be expected to emerge inland. Where are the clusters of industrial and other economic activities that may consider installing electrolyser capacities to secure stable, green and affordable energy by way of hydrogen as the optimal energy mode? An assessment showed that currently 27 small electrolyser projects are in operation or development, representing a total capacity of 100-150 MW. Clearly, factors determining such locational choices are: the threat of e-grid supply-side congestion becoming a problem, the presence of a serious industrial activity (usually referred to as cluster 6 locations) potentially in combination with a built environment, the availability of the production of green power in the area in combination with local demand for 'ultra-pure' hydrogen for mobility that cannot be delivered via the public grid (and purification may be considered too costly). This last category of cases could typically lead to the installation of small scale electrolysers for mobility; similarly small scale electrolysers may be introduced into the future to service pockets of the built environment looking for self-sufficiency, especially to be able to store and improve the use of locally produced renewable power capacities.

Given these various factors determining the locational profile of inland electrolyser capacities, the maps in Figure 1 indicate where these beneficial characteristics are located in the Netherlands. Although those maps show potential within certain areas in general, already a combination of few very specific local driving forces can make or break investment in a small scale electrolyser.

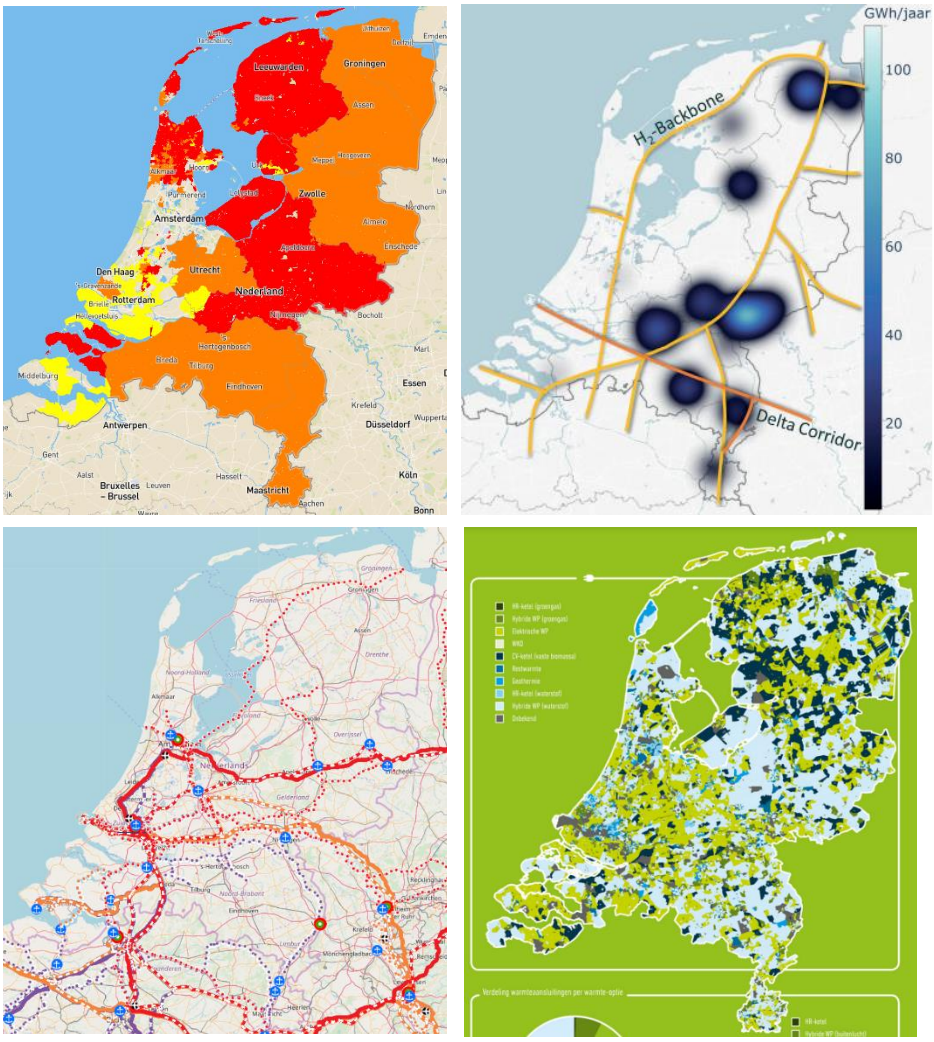

Figure 1 – Four maps showing areas with relevant characteristics for decentral electrolysis: top-left: supply-side congestion (red) ***Ongeldige bron opgegeven.****; top-right: decentral industrial demand (blue) and main hydrogen infrastructures [96]; bottom-left: the main road (filled), water (dotted) and rail (striped) related transport & mobility corridors* ***Ongeldige bron opgegeven.****; bottom-right: potential for hydrogen in the built environment (light blue) [99].*

Samenvatting

Deze studie probeert antwoord te geven op twee fundamentele vragen die samenhangen met de introductie van waterstof in het Nederlandse energiesysteem in de periode tot 2030:

- wat is de waarschijnlijke orde van grootte van investeringen in elektrolyse capaciteit in Nederland en wat zijn hun belangrijkste drijfveren; En
- gegeven dergelijke investeringen, en gezien de verschillende groottes van elektrolyse installaties (variërend van een schaal van enkele MW's tot GW-schaal), waar zullen die investeringen het meest waarschijnlijk plaatsvinden en wat zijn de meest waarschijnlijke drijfveren voor de locatiekeuze?

Beide vragen zijn zeer relevant voor de netbeheerders die verantwoordelijk zijn voor het transport van waterstof. Hoe meer waterstof in eigen land wordt geproduceerd in plaats van geïmporteerd via de belangrijkste havens, hoe meer transportcapaciteit er moet worden ontwikkeld om de markt te bedienen. Hoe beter men begrijpt waar de waterstofproductie zich hoogstwaarschijnlijk zal concentreren, hoe beter de transmissie-, maar met name de distributienetbeheerders, in staat zullen zijn om hun toekomstige waterstof gerelateerde transportcapaciteit te plannen.

Omvang van elektrolyse investeringen

Tot nu toe werden vrijwel alle investeringen in elektrolyse capaciteit gekenmerkt door een geest van pilot- en demonstratieactiviteit. Commerciële exploitatie van elektrolysers is gezien de huidige fase van opschaling en leren nog iets van de toekomst. Dit betekent dat serieuze investeringen in elektrolyse capaciteit niet van de grond komen zonder draagvlak, hetzij via subsidies, hetzij via het voorschrijven van de introductie van schone waterstof ter vervanging van grijze waterstof. Bij het beoordelen van wat de belangrijkste drijfveren zijn voor investeringen in elektrolyse capaciteit, zal overheidssteun dus duidelijk de belangrijkste factor zijn, althans in de beschouwde periode, d.w.z. tot 2030.

In Nederland zijn steunmaatregelen ter stimulering van de ontwikkeling van de waterstofwaardeketen en investeringen in elektrolysers in het land de afgelopen jaren vrij intensief van de grond gekomen: Nederland is het eerste land in Europa dat investeert in een nationale waterstof transmissiesysteem dat de meeste belangrijkste industriële clusters met elkaar verbindt met aftakkingen naar Duitsland en België; Nederland heeft serieuze subsidievolumes gereserveerd (enkele miljarden euro's) ter ondersteuning van investeringen in elektrolyse capaciteit en waterstoftransportcapaciteit en er zijn ook steunmaatregelen ingevoerd via een certificatensysteem voor waterstof in mobiliteit inclusief gebruik van waterstof binnen de raffinage voor dat doel; Nederland heeft onlangs zijn doelstellingen voor 2030 verdubbeld voor zowel offshore wind- als elektrolyse capaciteit (tot respectievelijk 21 GW en 6-8 GW); een golf van pilots rond kleinschalige introductie van waterstof in de industrie, mobiliteit en gebouwde omgeving is inmiddels ingezet om waterstoftoepassingen te testen. Al deze ondersteunende activiteiten hebben de ontwikkeling van waterstof vooruitgebracht. De vraag of initiatieven ter ondersteuning van waterstof in het land al dan niet relatief substantieel waren in vergelijking met andere EU-landen, viel buiten het bestek van de huidige studie. Dat de steunmaatregelen effect hebben gehad is echter duidelijk: gezien de huidige informatie lijkt het zeer waarschijnlijk dat de eerste GW cumulatieve elektrolyse capaciteit in het land al in 2026 operationeel zal zijn.

In het onderzoek is een uitgebreide simulatie uitgevoerd om voor (de periode tot) 2030 te beoordelen hoeveel overheidssteun/subsidie er waarschijnlijk nodig is per MWh in eigen land geproduceerde groene waterstof om de business case te sluiten. Het resultaat was duidelijk gevoelig voor veel

investering specifieke factoren, maar kwam neer op cijfers variërend van bijna nul tot ongeveer 100 €/MWh met de meeste simulaties tussen ongeveer 10-35 €/MWh H2, of ongeveer 0,5-1 €/kg H2. De belangrijkste factoren die de subsidiebehoefte verminderden, bleken te zijn: de totale geïnstalleerde capaciteit van hernieuwbare energie in het land; nationale vraag naar waterstof; nationale vraag naar elektriciteit; en in mindere mate de aardgas- en CO2-prijzen. In de simulaties werd ervan uitgegaan dat de waterstofmarkt tot 2030 met name nationaal zal zijn, omdat de verwachting is dat de internationale scheepvaarttransportsystemen zich in eerste instantie zullen richten op de vraag naar waterstofdragers (bijvoorbeeld ammoniak of methanol).

Een andere fundamentele factor die, naast steunmaatregelen van de overheid, hoogstwaarschijnlijk een cruciale impact zal hebben op de opgebouwde binnenlandse elektrolyse capaciteit, is de mate waarin het land afhankelijk zal zijn van de invoer van waterstof en waterstofdragers om aan de binnenlandse vraag te voldoen. In hoeverre nationaal geproduceerde waterstof kan concurreren met uit het buitenland geïmporteerde waterstof is nog een open vraag. De beoordeling van HyDelta 1 7A.2 suggereerde dat waterstofproductie op basis van windvermogen op de Noordzee in ieder geval in 2030 goed zou kunnen concurreren met bijna alle andere bronnen van groene waterstofproductie omdat verschillen in transportkosten die van productiekosten ruimschoots compenseerden. Voor waterstofdragers concludeerde de analyse dat er geen duidelijk verschil was in concurrentievermogen tussen binnenlandse en buitenlandse bronnen. Op de vraag welk deel van de waterstofvoorziening landelijk zal worden opgewekt, wordt in verschillende simulatiestudies geen duidelijk antwoord gegeven. Een grote complexiteit daarbij is dat waterstof en waterstofdragers handelswaren zijn die na import ook internationaal doorgevoerd zullen worden. Al met al is de verwachting dat voor vraag naar 'pure waterstof' binnenlandse waterstof geproduceerd middels Noordzee elektriciteit concurrerend kan zijn met import via schepen en dragers, terwijl van waterstof afgeleide chemicaliën zoals ammoniak en methanol doorgaans het eerst concurrentie zullen ondervinden van import.

Locaties van elektrolyse investeringen

Het lijkt waarschijnlijk dat er in de toekomst verschillende capaciteitsclusters van elektrolysers zullen ontstaan, variërend van kleine elektrolysers (bijvoorbeeld met een vermogen van ongeveer 1 MW tot enkele MW's) en middelgrote elektrolysers (bijvoorbeeld met een capaciteit van enkele tientallen tot enkele honderden MW's) tot grote elektrolysers (met capaciteiten tussen de 250 MW en meerdere GW's). Uiteraard zal de uiteindelijke omvang van dergelijke clusters afhangen van locatie specifieke karakteristieken.

Tot nu toe wordt verwacht dat aanzienlijke investeringen in elektrolyse capaciteit van middelgrote en grote schaal zullen plaatsvinden in of nabij vier van de vijf belangrijkste industriële clusters (Eemshaven-Delfzijl, het Noordzeekanaalgebied (NZKG), het Rotterdam-Moerdijk-gebied, het Schelde-Delta-gebied in Zeeland en Chemelot in Limburg). De locatievoordelen van deze belangrijkste industriële clusters zijn duidelijk: grootschalige vraag, de aanwezigheid van grote bedrijven met aanzienlijke investeringscapaciteiten en een clusteromvang die de schaalvoordelen, logistiek en vergunningsprocedures ondersteunt. De tot nu toe weinig bestaande scenario's voor de periode na 2030 suggereren gemiddeld dat het grootste deel (60-75%, afhankelijk van het scenario) van de Nederlandse elektrolyse capaciteit zich in de toekomst zal bevinden in de vier industriële kustclusters en de regio van Den Helder en/of offshore. De overige, veelal kleinere capaciteiten van elektrolysers komen op het industriecluster Chemelot en elders in het land.

Het is duidelijk dat de backbone zal fungeren als een andere belangrijke katalysator voor investeringen in elektrolysers in haar nabije omgeving; alle genoemde hoofdindustriële clusters aan de kust liggen dicht bij deze backbone. Ook hebben alle vier de clusters in de buurt van de kust al een sterke aansluiting op het elektriciteitsnet, inclusief aanlanding van offshore windcapaciteiten, wat bijdraagt aan hun sterke locatievoordeel voor grootschalige elektrolyse tot 2030. Na 2030 zal de toekomstige aanlanding van offshore windcapaciteiten in toenemende mate doorslaggevend zijn, wat verklaart waarom de scenario's en investeringsplannen over de tijd een relatief toenemende elektrolyse capaciteit veronderstellen in het noorden van het land.

Een interessante kwestie, ook voor de RNB's met het oog op hun netwerk investeringsplanning, is waar naar verwachting de capaciteit van elektrolysers in het binnenland zal ontstaan. Waar zijn de clusters van industriële en andere economische activiteiten die de installatie van elektrolyse capaciteit overwegen om stabiele, groene en betaalbare energie te verzekeren door middel van waterstof als optimale energiemodaliteit? Uit een inventarisatie bleek dat momenteel 27 kleinschalige elektrolyse projecten in bedrijf of ontwikkeling zijn, goed voor een totaal vermogen van 100-150 MW. Het is duidelijk dat de volgende factoren dergelijke locatiekeuzes bepalen: de dreiging dat congestie aan de aanbodzijde van het elektriciteitsnet een probleem wordt, de aanwezigheid van een serieuze industriële activiteit (meestal aangeduid als cluster 6-locaties) mogelijk in combinatie met een gebouwde omgeving, de beschikbaarheid van de productie van groene stroom in het gebied in combinatie met de lokale vraag naar 'ultra zuivere' waterstof voor mobiliteit die niet via het openbare net kan worden geleverd (en zuivering op locatie extra kosten meebrengt). Deze laatste categorie gevallen zou doorgaans kunnen leiden tot de installatie van kleinschalige elektrolysers voor mobiliteit; soortgelijke kleinschalige elektrolysers kunnen in de toekomst worden geïntroduceerd om gebieden van de gebouwde omgeving te bedienen die op zoek zijn naar een hoge mate van zelfvoorziening.

Gezien deze verschillende factoren die het locatieprofiel van de binnenlandse elektrolyse capaciteit bepalen, geven de kaarten in figuur 1 aan waar deze gunstige kenmerken zich in Nederland bevinden. Hoewel deze kaarten het potentieel laten zien van bepaalde gebieden in het algemeen, kan al een combinatie van enkele zeer specifieke lokale drijvende krachten een investering in een kleinschalige elektrolyser maken of breken.

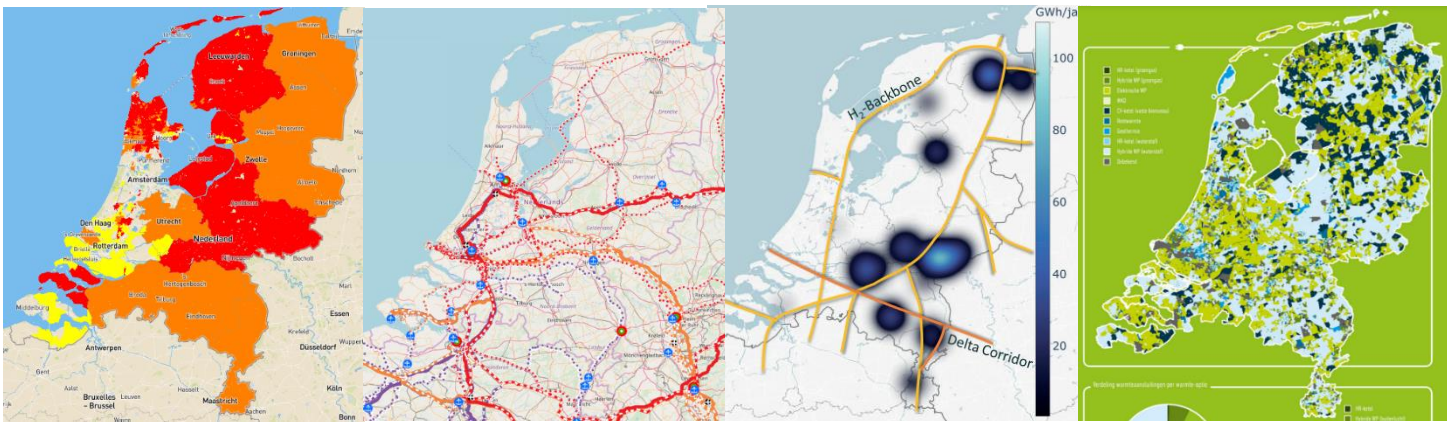

Figure 2 – Vier kaarten die gebieden laten zien met relevante karakteristieken voor decentrale elektrolyse: van links naar rechts, 1: aanbodzijde congestie (rood) ***Ongeldige bron opgegeven.****; 2: belangrijkste transportcorridors via weg (gevuld), water (stippelend) en spoor (gestreept)* ***Ongeldige bron opgegeven.****; 3: waterstofvraag decentrale industrie (blauw) en belangrijkste waterstof infrastructuur [96]; 4: gebieden met potentieel voor waterstof in de gebouwde omgeving (licht blauw) [99].*

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1. Introduction

Worldwide clean or carbon neutral hydrogen is increasingly seen as the missing link to overcome important energy decarbonization challenges, such as dealing with: renewables' intermittency, e-grid capacity (congestion) and (short and long term) balancing issues, and greening molecules needed for energy and feedstock purposes. In line with this development, also and especially in the Netherlands – a country: developing considerable (offshore) renewable energy capacity; facing now already serious e-grid congestion; and hosting a large, energy-intensive industrial base – the attention for national hydrogen value chain development is rapidly growing. Not only is implementing clean hydrogen expected to help meeting the 2030 climate targets set in the Dutch Climate Agreement [1], but also ambitious targets (6-8 GW) have been set with respect to national electrolyser capacity investment towards 2030. Given the plans and subsidies provided, it seems fair to assume that the first GW electrolyser will be installed in the country by 2026, a year before the national hydrogen backbone is scheduled to be ready in the spirit of the TSO's so-called Hyway 27 project. The various national hydrogen pilot and demonstration initiatives currently ongoing or in development do not only involve large-scale (>100MW) capacities, but also several dozens of projects of (much) smaller scales.

All these rapid developments and ambitions do raise the issue what can really be expected to happen towards 2030, when and how in terms of national clean hydrogen value chain development (ch. 2) and also at what locations in the country (ch. 3). Both issues are interesting in their own right, but especially relevant as well for the TSO and DSOs in determining when, how and where to invest in hydrogen transport infrastructure.

In answering the first question it is crucial to distinguish between the various drivers of hydrogen activity and electrolyser investment in particular, because each driver may have a different impact. Conceptually three categories of drivers can be distinguished that may reinforce (or weaken) each other, and the roles of which will likely change as the hydrogen value chain matures: policy drivers that directly try to promote clean hydrogen value chain activity; market drivers directly affecting hydrogen-related business cases and therefore investment; and drivers based on developments in the broader energy system that indirectly affect hydrogen activity as part of that energy system. In order to assess the various drivers' roles in the Netherlands' context, an extensive literature overview has been carried out (sections 2.1 – 2.4), also laying the ground for our own modelling for assessing what policy drivers may succeed in creating sound business cases for national electrolyser investment (section 2.5).

In answering the second question, where to expect concentrations of clean hydrogen activity, for various clean hydrogen applications and the same categories of drivers an assessment has been made of the likely spatial profiles of different types of clean hydrogen activity throughout the country. In doing so obviously also the different impacts of centralized versus decentralized electrolyser performances have been recognised.

So, more specifically, first the following research questions will be central:

How will the various drivers affect volumes of domestically produced and consumed hydrogen up to 2030 both from an individual and integrated energy system perspective?

This part actually builds upon HyDelta 1 research assessing costs of various hydrogen value chains and their components [2]. In this paper, instead of HyDelta 1 putting clean hydrogen production costs in the perspective of value chain costs, the focus is now on assessing the impact of various drivers on the degree mature business cases for conversion of electricity towards hydrogen can be achieved. The analysis is focussed on the period until 2030. Findings in HyDelta 1 concluded that the value chains importing hydrogen via ships will initially mainly compete for domestic demand for hydrogen carriers. Therefore, the focus of our analysis will be mainly on domestic activities.

In the second part the research question is:

At which locations in the Netherlands can hydrogen production and implementation in various end uses be feasible up to 2030 given the various locational drivers?

In this part the emphasis is on how drivers affect the locations of hydrogen activity. The assessment will first of all be based on the actual development of pockets of hydrogen activity emerging throughout the country, mostly so far by way of pilots and demonstration projects. Projections towards 2030 of likely further spatial development of hydrogen activity will also be based on the literature as well as our own analysis of the various locational drivers (including the routing of transport infrastructure, etc,). In doing so, a differentiation will be made between: use categories of hydrogen, large- and small-scale electrolyser activity, decentralised vs centralised hydrogen production activity and uptake.

After each assessment a conclusion will be drawn. The main implications and recommendations for stakeholders of both assessments will be synthesized in ch. 4.

2. Drivers of clean hydrogen activity

As was argued in chapter 1, conceptually three categories of drivers of clean hydrogen activity can be distinguished: policy and market drivers directly affecting hydrogen business cases and investment, and drivers affecting the wider energy system thereby indirectly affecting hydrogen investment activity. In chapter 2.1 we start with the role of hydrogen in future Dutch energy scenario's, which is the general driving force behind specific policy measures to stimulate clean hydrogen activity (2.2). Thereafter, we elaborate on relations between energy markets (2.3) and especially the market drivers that stimulate conversion of electricity towards hydrogen under the Netherlands energy systems' context (2.4). Finally, an extensive modelling assessment has been performed to quantify the impact of the market drivers and their effect on required public support measures to get business-driven clean hydrogen activity off the ground in the Netherlands (2.5).

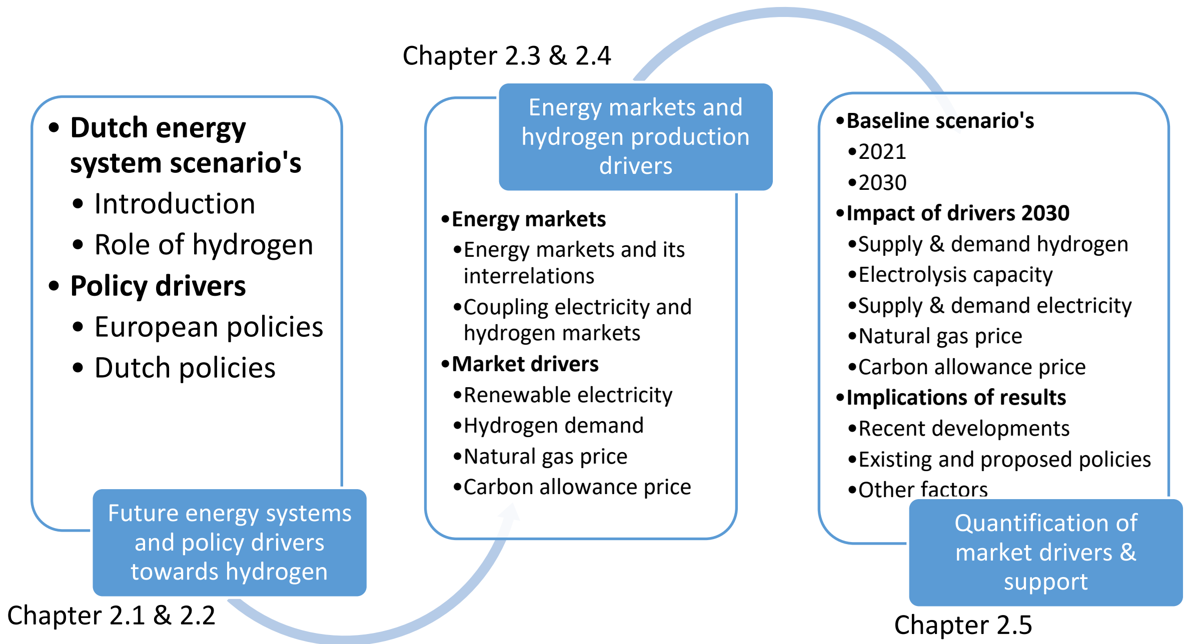


Figure 3 – Overview and reading guide content of chapter 2

2.1 The future Dutch energy system and roles of hydrogen

Before we start to discuss the major concrete policy drivers towards clean hydrogen production and its usage, it is important to understand the systemic drivers that determine the magnitude of the role of hydrogen in the future energy system. In this chapter a brief overview of the current Dutch energy system and the scenarios towards future energy systems are provided, including the factors that impact the role of hydrogen.

2.1.1 Brief introduction to the Dutch energy system

The Dutch energy and feedstock is a broad topic and therefore a lot can be mentioned about its characteristics. In Figure 4 provides an overview for the Netherlands (on the left side) of the used primary energy sources and the way energy and feedstock reached its end users; and (on the right side) the magnitude in which the two main energy and feedstock commodities are imported and exported. The energy system contains of primary energy sources that are produced domestically or imported, eventually converted to other energy carriers, and transported so that they are delivered to end users, or exported to other countries.

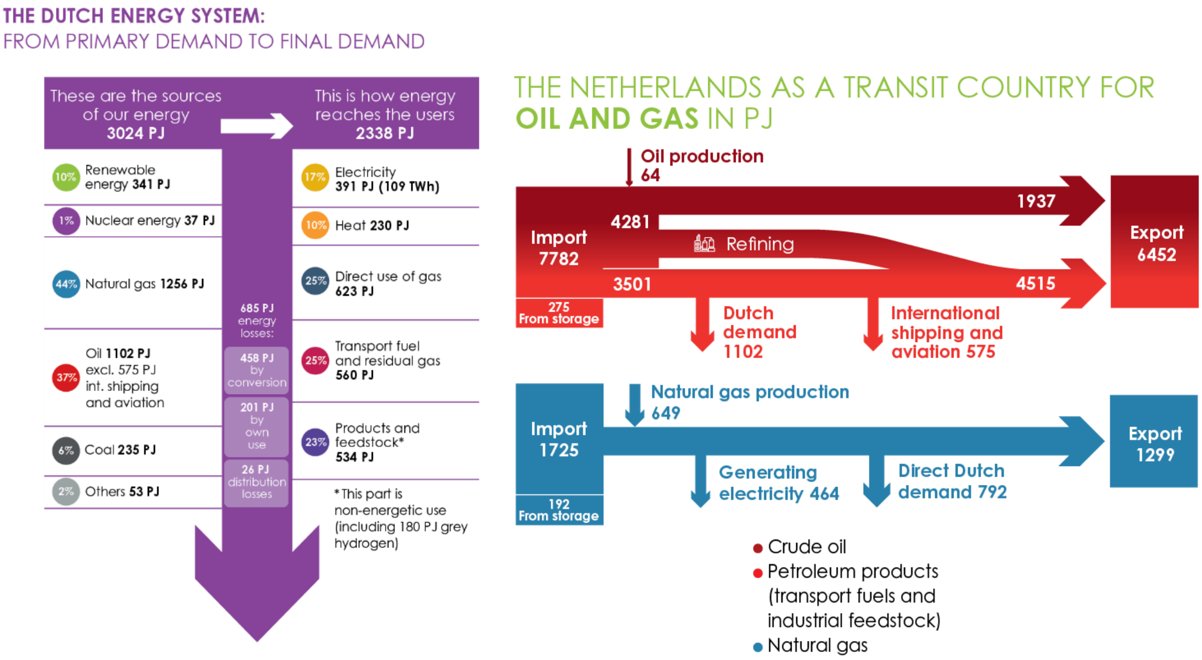


Figure 4 – Overview Dutch energy and feedstock system provided by EBN based on CBS data of 2021 [3]

Two characteristics of the current Dutch energy system should be well understood before future energy system scenarios are discussed in the next section:

The first aspect is that the current Dutch energy system (comparable to the European and world wide energy system) is very molecule (or: hydrocarbon) heavy and that currently the delivered electricity to end users is just a small part (17%) of the total energy flows that are transported and used. To put it in perspective, this means that the 27% of electricity provided by solar and wind that was produced in 2021 is just a fraction of 4.6% of the total delivered energy.

Secondly, the Dutch energy and feedstock system contains a lot of transit by import flows that are, sometimes after being processed, exported to other countries. The right side of the figure shows clearly that for the two main primary energy sources, namely oil and natural gas, respectively 83% and 75% (of its derived products) are being exported. This means that the Dutch molecule related infrastructures are significantly bigger than can be expected based on domestic demand and that the

Netherlands currently has an important role in the provision of energy molecules and chemicals to other countries.

The Paris Agreement to reduce the impact of climate change asks for a swift in this energy and feedstock system towards a system that is carbon neutral in 2050. Hence, the system has to be sure that no greenhouse gases, such as the carbon dioxide in the widely used hydrocarbon molecules, are emitted into the air. This future system should go hand in hand with the countries' vision and societal demands. In the next section an overview of these future Dutch energy system scenarios is given and factors driving the role of hydrogen are described.

2.1.2 Overview of Dutch energy system scenario studies and the role of hydrogen

In the past years several Dutch (integrated) energy system scenario studies have been performed. We will survey some of them shortly to give a flavour of the main findings recognising that those studies have been based on information changes over the time, for example due to policy developments.

Under the flag of the ESTRAC project[1], TNO [4] conducted a meta-analysis of 18 fairly recent (2014-19) energy system scenario studies including 25 future energy system scenarios for the Netherlands or larger/neighbouring regions. The scenarios are based on energy system models optimizing the energy system based on minimum system costs or based on specific visions or roadmaps. Although given the rapid energy developments of the last few years some of the modelling work surveyed is already outdated, it yet may be illustrative mentioning which generic parameters from a system perspective were at that time concluded essential for how significant the role of hydrogen may be in the Netherlands [4]:

1. Carbon emission reduction target: hydrogen will start playing a significant role in energy systems where is aimed for 85% of emission reduction or more.
2. Carbon capture and storage (CCS): the smaller the role or availability for CCS, the larger the need for synthetic hydrogen derived products.
3. Biomass potential: on the one hand biomass derived products do compete with hydrogen, but on the other hand can a large availability of biomass enhance hydrogen production via biomass gasification.
4. Variable renewable electricity (VRE) supply: the more VRE there is in an energy system, the higher the need for flexibility, which may be provided by hydrogen (e.g. demand response, storage and/or hydrogen-based dispatchable power).
5. Technology costs: adoption of hydrogen technologies depends on the hydrogen technology costs compared to the costs of competing energy demand and supply technologies, including CAPEX, OPEX and fuel costs. Also, higher fossil fuel prices could positively impact uptake of renewable hydrogen.

Besides these five factors, an important factor explaining the significance of the role of hydrogen in the future Dutch energy system is whether or not hydrogen for the production of synthetic bunker fuels (e.g. international aviation and shipping fuels) and products based on hydrogen and CO_2 are taken into account, or even are assumed to take place in the future Netherlands at all [5]. Excluding these options typically lead to Dutch hydrogen demand projections of 100 – 500 PJ in 2050, while including them leads to projected hydrogen demands of over 1000 PJ in 2050 [5].

[1] Which was a four year project on methodologies and tools to analyse and optimize transition to carbon neutral energy systems, in a consortium of NEC, TNO, RUG, Hanze University of applied sciences, EBN, NAM, Gasunie and GasTerra

In the four Berenschot-Kalavasta scenarios [6] used for the integrated infrastructure outlook 2030-2050 [7], directions for future Dutch energy system are determined by the degree to which regional, national, European or rather international factors will drive society towards carbon neutrality. Between these scenarios the role of hydrogen differs significantly. The regional scenario shows the lowest, and the international scenario the highest hydrogen demand level. In the regional scenario hydrogen is mainly used to balance the electricity grid, so primarily for storage and dispatchable renewable power. In the national scenario there is also a significant industrial demand for hydrogen that is fulfilled by domestic renewable hydrogen. This explains why in this scenario the electrolysis capacity and size of domestic green hydrogen production is highest. In the European scenario balancing of the electricity grid is mainly provided by biomass instead of by hydrogen, while the blue hydrogen production route is mainly used to produce the hydrogen. The international scenario uses the largest quantities of hydrogen but also relies for a large share on imported hydrogen. In this study it was concluded that the stronger the driving role of the national government in the energy transition, the more green hydrogen will be produced domestically.

The main conclusion that we can draw from these future energy system scenario studies is that it actually all scenarios foresee a role for clean hydrogen in decarbonized energy systems, but system factors (see the five described factors) **do impact the magnitude and exact role that hydrogen can potentially play.** There were only two scenarios mentioned by [4] that did not foresee any role of hydrogen in 2050. Meanwhile, both have been updating their projections: they currently foresee a role for hydrogen by 2030 already [8] [9].

Hence, clean hydrogen will have a role in a decarbonized energy system. However, such a system is not likely to evolve by itself. Unlike the earlier phased energy transitions in the Dutch history (e.g. wood to peat, peat to coal, coal to oil and natural gas), the main driving force of the energy transition from natural gas and oil to renewables is not driven by a direct economic or utility advantage of users. The energy transition that is faced today is mainly driven by policies and change of market regulation in order to prevent society from the damage of greenhouse gas emissions. Therefore, we will start discussing the main concrete policy drivers for hydrogen activity in the Netherlands in the next section.

2.2 Policy drivers towards renewable hydrogen

In the current stage of speeding up and scaling up of hydrogen activity in all sectors, little progress would be made without policy driven incentives. That is because many technologies and processes related to the hydrogen value chain components are still in the so-called 'valley-of-death' stage, i.e. an early, immature market in which private players tend to take a wait-and-see attitude in order not to lose external benefits to others while frontrunning. Policy drivers are therefore indispensable to make progress until market maturity will be reached. In this section the main concrete (considered) policies and regulations impacting hydrogen activity in the Netherlands are discussed.

2.2.1 European policy drivers towards renewable hydrogen

EU green deal, Fit for 55 and REpower-EU

At the end of 2019 the 'European Green Deal', aiming to make Europe the first climate-neutral continent by 2050, was launched as one of the five main strategic priorities of Europe [10]. Next, in September 2020, the new 55% EU emission reduction target was set for 2030 in order to get on track for the 2050 goal. In the same spirit, the 'Fit for 55' package was introduced, a broad revision of European legislations to provide the right framework to move towards the targeted emission reductions [11]. Some of this legislation is specifically stating ambitions towards hydrogen, which is in line with the EU strategies on hydrogen [12] and system integration [13]. Some of these ambitions are proposed to be sharpened by the recently announced REPowerEU plan, aiming to end EU's dependence on Russian fossils [14]. Next the 2030 targets on the production and use of hydrogen will be highlighted:

Production

- 2030 targets for installed capacities of renewables have been increased from 1067 to 1236 GW by REPowerEU [15].
- A commitment from the EU and electrolyser manufacturers to realise 17.5 GW of annual electrolyser manufacturing capacity by 2025, and to increase it further towards 2030 in line with projected demand [16].
- REPowerEU proposes targets of 10 million tonnes of domestic renewable hydrogen production[2] and 10 million tonnes of renewable hydrogen imports by 2030 [15], compared to the 5.6 million tonnes target earlier set by fit-for-55.

Consumption

- Proposed amendment of RED II (2021/0218) [17], article 22a:
  ''Member States shall ensure that the contribution of renewable fuels of non-biological origin used for energy and non-energy purposes shall be 50% of the hydrogen used for final energy and non-energy purposes in industry by 2030.'' (excluding *''hydrogen used as intermediate products for the production of conventional transport fuels.''*).
- Proposed amendment of RED II (2021/0218) [17], article 25b:
  A sub-target for RFNBOs used for transport is introduced: *"…, and the share of renewable fuels of non-biological origin is at least 2.6% in 2030."*.
- Proposed amendment of ReFuel EU (2021/0205) [18], article 4 and annex I:
  "Aviation fuel suppliers shall ensure that all aviation fuel made available to aircraft operators at each Union airport contains a minimum share of sustainable aviation fuel (SAF), including a minimum share of synthetic aviation fuel in accordance with the values and dates of application set out in Annex I." (*"From 1 January 2030, a minimum share of 5% of SAF, of which a minimum share of 0.7% of synthetic aviation fuels."*).
- Based on REPowerEU, the ambition has been proposed to increase the 2030 RFNBO targets for industry and transport towards 75% and 5% respectively [15].

The ambitions make clear that 1) there is a strong focus on (domestic and imported) renewable hydrogen (falling under the definition of a 'biomass fuel' or 'RFNBO'[3]); and 2) that binding targets proposed for several types of end users are the main type of stimuli used by the EU to drive uptake of hydrogen in the member states. There is proposed a definition of low carbon hydrogen by the EU Gas Directive, however there are no specific ambitions set for this category neither are there specific stimuli for these category of technologies (other than the more generic measures such as the EU ETS). Therefore, we can conclude that 'it seems that'[4] EU policies try to ensure a market for green hydrogen (or related fuels) in specific applications by setting binding targets for 2030. The development of low carbon hydrogen investments seems to be left over more towards the existing market and the emission trading scheme.

[2]This equals an electrolyser capacity of 140 GW of electrical input, assuming a 43% utilisation factor and efficiency rate of 70% [16].
[3] Renewable Fuel of Non-Biological Origin
[4] We use 'it seems that' because a lot of these EU legislations are still under discussion.

IPCEI support for renewable hydrogen production projects

In 2022, two IPCEI (Important Project of Common European Interest) projects have been approved by the European Commission related to hydrogen:

- 'IPCEI Hy2Tech' is the approval by the Commission under the EU State Aid rules for member states to provide €5.4 billion funding to 35 companies participating in 41 projects that perform research and innovation activities and first industrial deployment in the hydrogen technology value chain. It is expected that €8.8 billion of private investments will be unlocked [19].
- 'IPCEI Hy2Use' is the approval by the Commission under the EU Stade Aid rules for member states to provide €5.2 billion funding to 29 companies participating in 35 projects that (i) construct large-scale production, transport and storage infrastructure for renewable and low-carbon hydrogen, and (ii) that develop technologies to integrate hydrogen in hard-to-abate industrial processes. It is expected that €7 billion of private investments will be unlocked [20].

Especially the IPCEI Hy2Use is expected to lead to the first medium- to large-scale electrolysers starting their operations by 2024-2026 and to more innovative projects being deployed by 2026-2027. Eight Dutch projects are submitted for this IPCEI project of which seven are accepted, all aiming at building an electrolyser with a capacity between 100 and 250 MW [20]. In total this means that by 2026 1150 MW of electrolyser capacity can potentially be realised.

The third and fourth IPCEI waves will be based on 'Regional Hubs and Their Links' (RHATL)[5] and 'Mobility & Transport' (M&T) [21]. It is known that respectively three and five Dutch projects were involved in the pre-notification rounds. Potentially new IPCEI waves may be introduced in the future as well.

The fact that those hydrogen developments are allowed to receive more support than regulated under the staid aid legislations [22], shows that significant policy force is in place to start hydrogen activity.

The European Hydrogen Bank

During the 2022 State of the Union speech on behalf of the European Commission, it was mentioned that an European Hydrogen Bank will be developed with a €3 billion budget to support guarantees for the offtake of green hydrogen [23]. The specific details and characteristics of this proposed facility are not fully clear yet, but the Bank activities can potentially develop into a strong driver and market enabler of green hydrogen if, for instance, fixed-price offtake or a buyer of last resort can be guaranteed.

2.2.2 Dutch policy drivers towards renewable hydrogen

Netherlands' targets related towards renewable hydrogen

As EU member state the Netherlands has to contribute to the European ambitions. Initially, the Dutch climate ambitions for 2030 (49% emission reduction) have been set in the Dutch Climate Agreement [1] in 2019. Thereafter, the ambitions have been sharpened by the European fit-for-55 goal of 55% emission reduction by 2030, by also raising the Dutch 2030 emission reduction target to at least 55% and doubling the offshore wind capacity target from 10.5 to 21 GW[6]. Initially, in the Climate Agreement the following concrete targets related to hydrogen activity have been set:

- In accordance with the Dutch Climate Agreement one aims for 3-4 GW electrolyser capacity in 2030 [1];

[5] Mainly dealing with import terminals and large-scale storage.
[6] This is significant, as the existing installed capacity of offshore wind was around 4.5 GW in January 2023

- 50 hydrogen refuelling stations (HRS), 15,000 personal and 3,000 heavy duty FCEV's in 2025 moving towards 300,000 FCEV's and 141 kT of hydrogen demand for road transport in 2030 [1];
- 14% of aviation fuels tanked in the Netherlands should be renewable in 2030 [24].

As follow-up on the Climate Agreement, ambitions and actions on the hydrogen related developments have further been worked out in a National Hydrogen Program. This program started in the beginning of 2022, and published the National Program Hydrogen Roadmap on November 3th 2022. In this roadmap it was proposed to update and extend some of these targets in the Climate Agreement, e.g. raising the 3-4 GW electrolyser capacity target towards 6-8 GW in 2030 [25]. An overview of the Roadmap ambitions is shown in Figure 5. The roadmap clearly shows that ambitions in the Netherlands on hydrogen start to be more and more concrete. Also it seems that the political ambitions and measures to achieve them are strengthened over time.

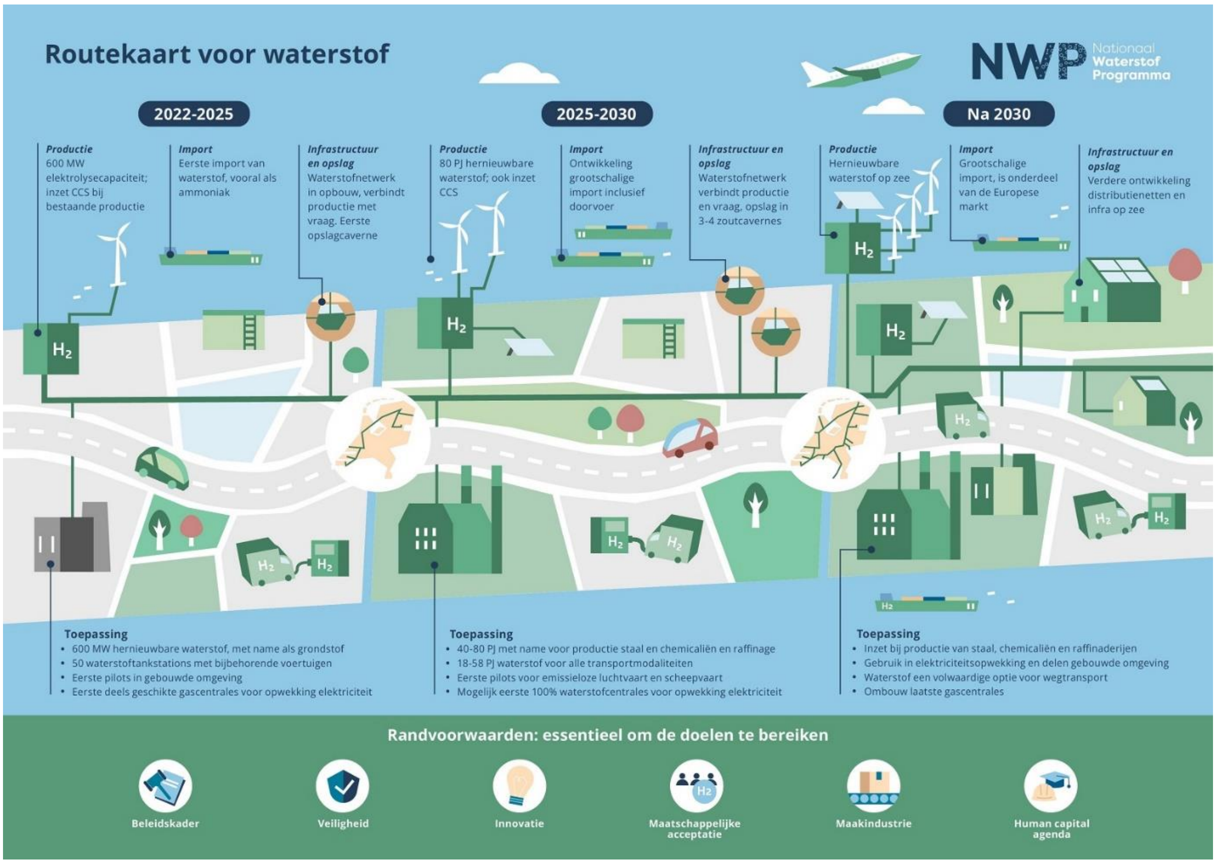


Figure 5 – Overview of the Dutch Hydrogen Program Roadmap and its ambitions [25]

Existing support schemes for renewable hydrogen

Besides the funds for innovation and demonstration, there are deployment support mechanisms in the Netherlands for green hydrogen:

- Since 2020 green hydrogen production projects can apply for SDE++ subsidy.
- A scale-up instrument for electrolyser projects <50 MW with a 250 million euro budget [26], of which the application should be finished in 2023.
- By 2022 renewable fuels of non-biological origin (such as green hydrogen) are accepted under the blending obligation for fuels [27]. Renewable hydrogen via the so-called 'refinery route' will also become accepted under this scheme from 2025-2030 [28].

Until now the SDE++ has not led to significant investments in electrolysers, because in this scheme the electrolysers are competing for funding with other, more mature carbon emission reduction technologies. The electrolyser scale-up instrument, which uses similar principles as the SDE++ but then with a dedicated budget for electrolyser projects, is expected to drive investments in 50-100 MW of electrolysis capacity [26].

The ministerial letter of summer 2022 mentions that for industrial hydrogen uptake two support schemes are considered to secure that the European goals are met: 'contracts for difference' and a 'blending obligation' [26]. Table 1 below indicates that such a support scheme, together with the blending obligation in the mobility sector – and dependent on the actual EU binding targets – could drive towards a significant use of renewable hydrogen in 2030. This excludes the expected 2030 demand for renewable hydrogen in the aviation sector required to meet the binding ReFuelEU target or ambition named in the Dutch aviation note. This will represent by expectation 0.9 TWh of renewable hydrogen [29]. It is yet unknown which specific Dutch policies are foreseen to comply to this EU binding target.

Table 1 – Impact of potential blending obligation targets on hydrogen demand in the Netherlands, partially retrieved from [25]

	Target mobility 2030	**Type of target**	**Impact demand mobility**	**Target industry 2030**	**Type of target**	**Impact demand industry**	**Total demand impact**
Origional proposal EC	2.6%	Binding	8 TWh	50%	Binding	14-27 TWh	22-35 TWh
EU council compromise	2.6%*	Indi-cative	5 TWh (due to scope limitation)	35% (+ scope limitation)	Binding	10-12 TWh	15-17 TWh
REPowerEU	5%	Binding	15 TWh	75%	Binding	20-41 TWh	36-56 TWh
Preference Dutch parliament	5.7%	Binding	16 TWh	50%	Binding	14-27 TWh	30-43 TWh

*Actually 5.2%, but including multipliers so physically still 2.6%

2.2.3 Conclusion of policy drivers on hydrogen activity in the Netherlands

All in all, we have shown that the European and Dutch policies towards renewable hydrogen activity tend to become stronger over the last years. In the end, it is the whole policy and regulation framework that could, if all measures work as expected, drive hydrogen activity towards the ambitions set by politicians. However, **to conclude this chapter we want to highlight the most concrete (potential) policies that are expected to drive the renewable hydrogen production activities in the Netherlands from demonstration to deployment**:

- Support for seven electrolyser projects by IPCEI could lead to 1150 MW electrolysis capacity by 2026.
- The first phase of the electrolyser scale-up instrument is expected to lead to 50-100 MW of electrolysis capacity investment in the coming 2-3 years.[7]
- Approving renewable hydrogen in the Dutch fuel blending obligation and the expected binding subtarget for RFNBO's in 2030 will generate 5-16 TWh of renewable hydrogen demand.

[7] The hydrogen produced via the scale-up instrument cannot be used to comply to the blending obligations, while the hydrogen from the IPCEI projects is allowed to be used to comply to these targets.

- The considered blending obligation/carbon contracts for difference in industry to meet the EU RFNBO target can potentially generate 10-41 TWh of renewable hydrogen demand.

2.3 Interrelations between (future) energy markets

In previous chapters we have seen that clean hydrogen has a role in decarbonized energy systems from a systems perspective and what the most relevant policies are that can help getting clean hydrogen production technologies through the valley of death in the Netherlands. In this chapter we dive further into the market conditions that are required to drive conversion of renewable electricity into hydrogen.

2.3.1 General explanation of energy markets and its interrelations

In order to discuss the market drivers for renewable hydrogen production it is crucial to understand the relations between energy commodity markets. Fundamental economic theory suggests that market prices will be a result of supply and demand: every timeframe suppliers bid its supply into the market at a price that makes it profitable to produce (higher than the marginal costs). The order of these bids at a specific moment is the so called 'merit order'. The demand of the energy commodity will be fulfilled with the lowest bids. The last producer that is required to fulfil demand is the price setting producer. Figure 6 illustrates an example merit order in an electricity market.

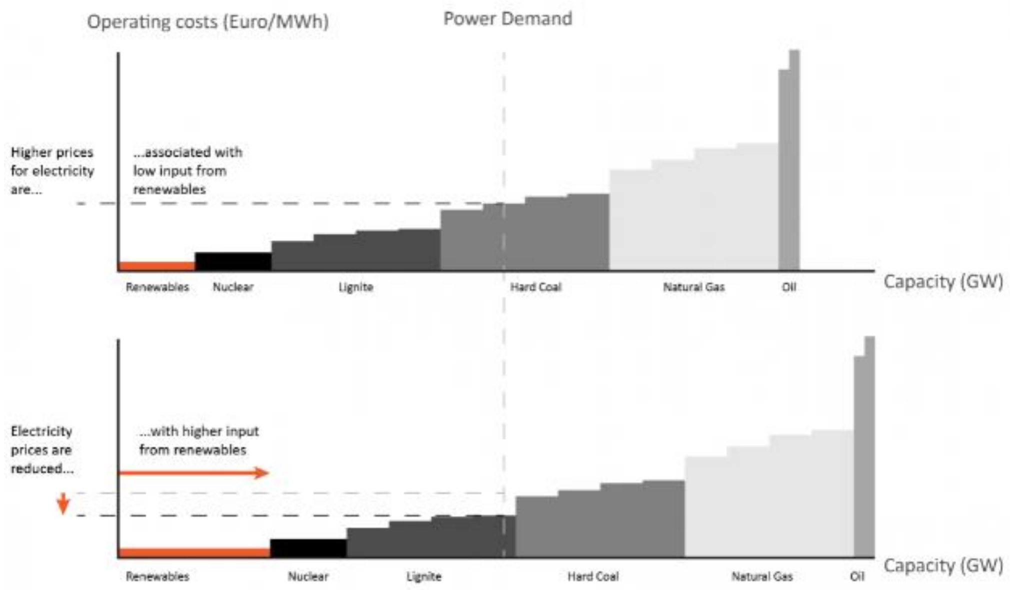


Figure 6 – Illustration of a traditional electricity generation merit order with a low share of renewables, illustrating a moment in time with (up) low availability of solar and wind and (bottom) high availability of solar and wind

In this example the marginal costs of most generation technologies depend on its fuel costs (uranium, coal, natural gas, oil). Therefore the electricity market is interlinked with the commodity markets for natural gas, coal, uranium and oil. Similar relations are seen between other commodity markets.

Figure 7 provides an overview of potential relations between commodity markets that are relevant for hydrogen conversion. For example: Electrolysis sources electricity in order to supply hydrogen; steam methane reforming sources natural gas or biomethane in order to supply hydrogen; hydrogen-fired power plants can be used to provide dispatchable renewable power to the electricity market. Obviously, this picture can be extended with infinite other commodity markets that could, directly or indirectly, impact the hydrogen market such as the ammonia, methanol, kerosine or raw biomass markets.

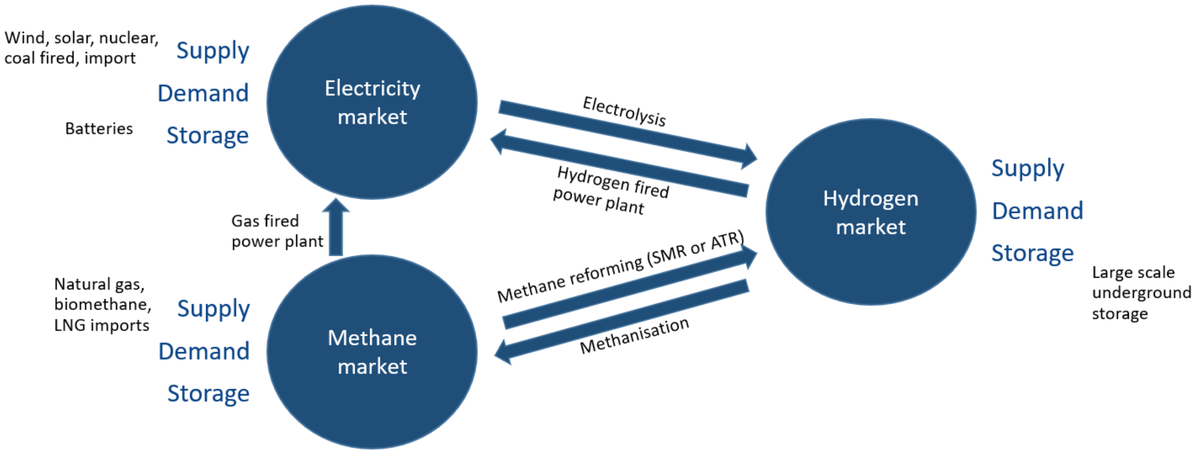


Figure 7 – Overview most relevant commodity market relations for hydrogen conversion

2.3.2 Studies on integrated electricity and hydrogen markets in the Dutch context

In the past decades several energy system models have been developed to analyse future energy markets including both electricity and hydrogen [30], [31], [32]. Examples of models for analysing future electricity and hydrogen markets, e.g. by partial equilibrium or least cost-dispatch, are E4cast, EnergyPLAN, MARKAL (or it derivatives MARKAL-MACRO, TIMES and SAGE), PRIMES, EnergyPATHWAYS, oemof and PyPSA-Eur-Sec. Even more fundamental market models will exist in the private sector. However, only few of these models have explicitly been used to analyse short-term interrelations between electricity and hydrogen markets in the case of the Netherlands and its surrounding countries, and published these findings [33] [34] [35]. We will list their main findings next.

The first analysis is based on integrated electricity, hydrogen and methane system modelling applied in the Dutch Infrastructure Outlook 2050 study of TenneT and Gasunie [34]. In this study the Dutch energy markets of 2050 are modelled according to the assumptions made in the Infrastructure Outlook study of the national grid operators. The I-ELGAS model is used, i.e. a market equilibrium model using linear programming with hourly price and volume interactions for production, conversion, transport and storage of electricity, hydrogen and methane. Next to the baseline scenario showing the interrelations between the commodity markets in a potential future energy system, a sensitivity analysis is performed showing the impact of the biomass price, energy demand and installed variable renewable energy (VRE) capacity on the commodity price projections. The results showed that both a decrease in demand and increase in variable renewable energy supply capacity decreased the average energy commodity prices. Hydrogen prices turned out to react stronger than electricity prices.

The second study uses the similar I-ELGAS model, but now input data from the TYNDP [36], II3050 [6] and national hydrogen strategies was used to run a scenario for 8 North-western European countries in the different timeframes of 2030, 2040 and 2050 [35]. The study analyses two main scenarios. The Global Ambition scenario assumes that international forces drive the energy transition which is expected to lead towards more imports and natural gas-based hydrogen conversion. The Distributed Energy scenario assumes that national forces drive the energy transition and therefore lead towards deployment of more local renewable energy sources and electrolyser capacities. A sensitivity analysis of factors potentially influencing the economic viability of the installed electrolyser capacities showed that adding additional VRE capacities would lead to bigger price impacts in the hydrogen market than in the electricity market under both the Distributed Energy and Global Ambition scenarios, due to differences in market saturation levels. Next, sensitivity analysis on the installed electrolyser capacity in the Distributed Energy 2050 scenario showed that the lower the electrolyser capacities, the higher the load hours and hydrogen market price, and therefore the better the business case. It was seen that using a CAPEX assumption of 450 €/kW only the cases with <40% of the initial assumed capacity had a positive NPV, requiring more than 5260 load hours and average hydrogen prices of over 85 €/MWh.

The third study uses a partial equilibrium model of integrated electricity and hydrogen markets, modelled as Mixed Complementarity Problem (MCP) [33]. The main differences with the model used in the previous two studies is that: the methane market is considered exogenous; for domestic transport of energy a copper plate is assumed; and certificate markets and a price elasticity of demand is included. The paper presents results for scenarios without power-to-gas, with low power-to-gas and with high power-to-gas capacities for both situations where power-to-gas is only used to provide flexibility to the electricity market and where it is also used to serve a share of the demand for hydrogen. It shows that including power-to-gas reduces price volatility in the electricity market with high penetration of VRE sources, but that this reduction is weakened if the produced hydrogen is also used to serve a large demand for hydrogen outside the electricity sector. The annual welfare effect is better for low than for high P2G because of the high capital costs of electrolysers. Moreover, the annual welfare effect is better if a large hydrogen demand outside the electricity sector can be served because of their higher revenues. Carbon emission reduction should be valued with 150-750 €/ton to make investments in P2G capacities profitable from a social welfare perspective.

From the sensitivity analysis performed in those three studies we can distinguish three potential market factors driving power-to-gas:

- The penetration of VRE in the electricity market;
- The significance of electricity and hydrogen demand;
- The price paid for methane.

In the next section we will discuss these, and other market drivers we found in literature in greater detail.

2.4 Market drivers towards renewable hydrogen

Besides the policy drivers, a second category of drivers consists of market drivers. In the previous section we discussed the relations between the energy commodity markets and in this section we dive deeper in each individual market driver for renewable hydrogen production. Based on existing literature the conceptual relations visualized in Figure 8 are described in the next sections.

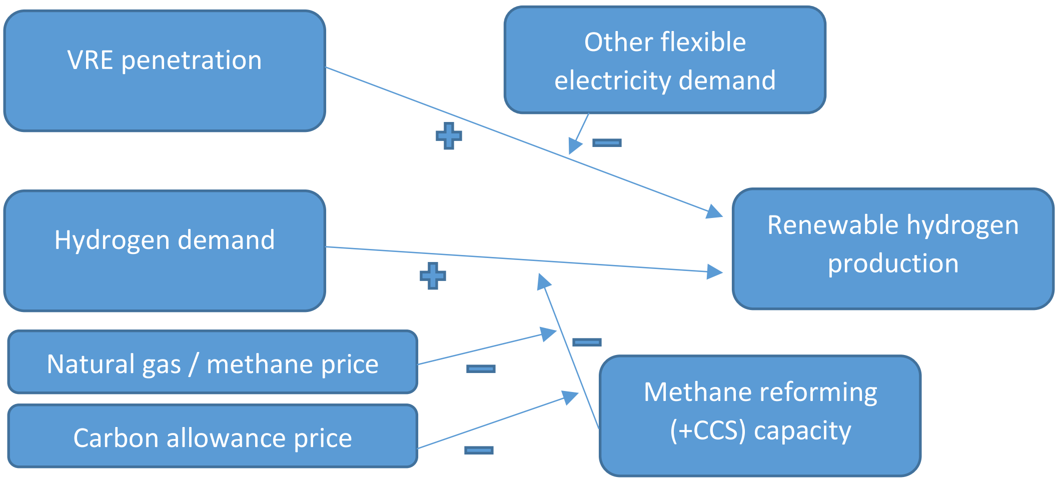


Figure 8 – Overview conceptual framework of short term market drivers for renewable hydrogen production. '+' means a positive relation between factor A and factor B. '-' means a negative relation. Arrow aiming at another arrow represents a moderating effect on the other relation.

2.4.1 Penetration rate of variable renewable electricity generation and demand

Several studies have assessed for various European countries how power-to-gas technologies can help accommodating much higher levels of intermittent renewable sources than in the past, e.g. [37], [38], [39], [40]. At some stage power production from renewable energy sources will occasionally start surpassing total national power demand potentially creating serious e-grid balancing issues. In the Netherlands the first moment on which this happened was April 2022 when at a peak moment 20% more electricity could have been offered than demand at that time. The planned rapid expansion of solar and wind capacities, both onshore and offshore will without doubt increase the number of such moments. In fact, by 2030, if the Climate Agreement target of 75% of electricity generated by solar and wind will be met, such moments may well be regular, causing formidable challenges to enhance the flexibility needed to satisfy grid balancing requirements.

All these developments may have a significant impact on the future electricity prices and their volatility as well. That is because currently at most times electricity prices on Dutch electricity markets are set by the marginal costs of gas-fired power plants. With an increasing penetration of intermittent renewables, solar and wind will instead be the main price setters at an increasing number of hours within the year. This was also already experienced in 2022 albeit during a limited number of hours: despite very high natural gas prices (due to the Ukraine crisis) still during some 170 hours electricity prices had declined to levels below 20 €/MWh. Figure 9 shows an electricity price curve from an older study, however it clearly represents the potential impact of the increased VRE penetration (as agreed in the Climate Agreement [1]) if no additional flexibility in demand (e.g. batteries, electrolysers, E-boilers, hybrid heat pumps) is developed.

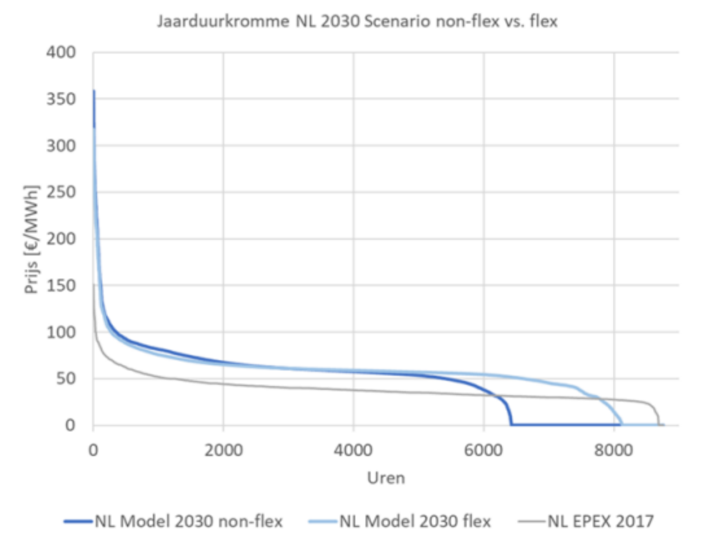


Figure 9 – Electricity price duration curves of potential 2030 electricity price scenarios with and without flexibility options. It indicatively shows that without flexibility options increased VRE sources will result in significant periods with electricity overshoots [41].

Hence, the more often supply of intermittent electricity sources surpasses electricity demand, the more hours with relatively low electricity prices that can be grasped by flexible electricity users such as electrolysers.

2.4.2 Hydrogen demand

The future demand for different types of hydrogen in the Netherlands is uncertain but what are their main market drivers? In the table below an overview of the main hydrogen demand drivers is provided for the various end-use sectors based on the idea that the main drivers are the availability and cost of clean hydrogen versus those of alternative energy carriers or systems [42] [4]. The more hydrogen is the favourable option for end-users, the more volumes of hydrogen are demanded while at the same time driving the production of hydrogen.

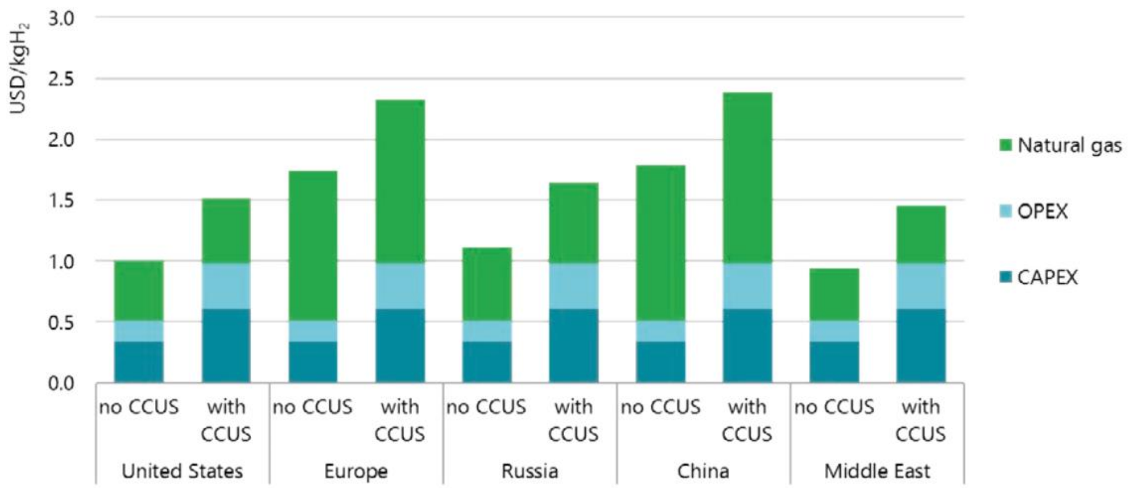
Sector	
Residential	• The rate and level of energy savings (insulation) and total energy demand for heating [4]. The fact that many buildings face technical and financial challenges in implementing insulation offers opportunities for introducing hydrogen in the built environment. •Decarbonization options for the heating sector include the use of hydrogen, renewable electricity, or a combination of them [43]. The availability of (low-carbon) alternatives to meet low temperature heat demand (and the number of buildings to apply these), such as electric heat pumps and boilers, geothermal heating systems, industrial waste heat via (district) networks, biogas, etc. [4] will strongly affect the adoption of hydrogen. • The costs of these alternatives, including the costs to deploy or modify the related electricity and gas infrastructure. • Dependence on spatial, local and regional characteristics, such as urban versus rural areas. Also, dependence on building (type, year) and neighbourhood characteristics.
Power [4]	• Share of intermittent renewable electricity production in total power mix. • Total power demand, including level of electrification in the end-use sectors. • Ambition level of the carbon reduction target for the power sector (up to 100%). • Performance and availability of alternative fuels (e.g., biogas). • Potential of other flexibility options than hydrogen (storage), such as flexible (dispatchable) power generation, demand response, other energy storage and (cross-border) power trade. • Availability and acceptance of CCS, and relative performance of pre- and post-combustion capture technology. • Availability of hydrogen storage.
Mobility [4]	• Availability and performance (costs, noise, pollution, driving range, comfort, etc.) of alternative zero- or low-emission fuels (e.g. biofuels). • Performance of BEVs and availability of charging points, including required electricity grid expansion. • Performance of synthetic fuels (availability, costs, sustainability) • Availability and investment costs of hydrogen filling stations.
Industry [4]	• Performance and availability of alternative, low-carbon technologies to supply heat. • Deployment of novel industrial processes, in which H2 is used as feedstock. • Scale-up of CO2 utilization industry to produce carbon-based chemicals and fuels.

	• Ambition of the emissions reduction target and related policies for industry. • Availability, performance and costs of CCS.

2.4.3 Natural gas prices

Production costs of clean hydrogen via SMR with the help of natural gas (so-called grey, or with CCS: blue hydrogen) are affected by various techno-economic factors, of which most of the literature considers gas prices and technology CAPEX to be the two most important ones. With a 45% - 75% contribution to clean hydrogen production costs, natural gas prices are the dominant cost factor of blue hydrogen [44]. This also explains the low level of blue hydrogen production costs in low-natural-gas-priced regions such as the Middle East or Norway and USA (fig. 9). In this figure prices of 3-11 $/MBtu were assumed (9-35 €/MWh), depending on the region. Due to the invasion of Russia in Ukraine, in 2022 these average prices have been more than tripled, and lead to more uncertainty of what the future might bring. The IEA World Energy Outlook scenario's expect that natural gas prices return to the values seen in 2019 before 2030 [45]. The Dutch 'Klimaat en Energieverkenning' (KEV) expects that Dutch prices for natural gas will move to 40 €/MWh (range of 20-45 €/MWh) compared to around 20 €/MWh during the last decades [46].

Figure 9. Hydrogen production costs using natural gas in different regions, 2018



Notes: kgH$_2$ = kilogram of hydrogen; OPEX = operational expenditure. CAPEX in 2018: SMR without CCUS = USD 500–900 per kilowatt hydrogen (kW$_{H_2}$), SMR with CCUS = USD 900–1 600/kW$_{H_2}$, with ranges due to regional differences. Gas price = USD 3–11 per million British thermal units (MBtu) depending on the region. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019.

The impact of natural gas price levels on costs of several clean hydrogen value chains was already assessed in HyDelta1 [2]. A key conclusion was that if by 2030 natural gas prices exceed some 115 €/MWh at carbon allowance prices of 60 €/tCO2 (or any comparable mix of gas and allowance prices), then by that time green hydrogen based on power from a directly coupled source can compete with natural gas if used for heating [47]. Another conclusion was that by 2030 green hydrogen from a directly coupled source can compete with grey hydrogen at 2030 CO2-allowance and natural gas prices of 60 and 75 €/MWh in 2030, respectively. Compared to the current (2022-3) natural gas and CO2 allowance price levels, the 2030 levels mentioned would seem quite feasible.

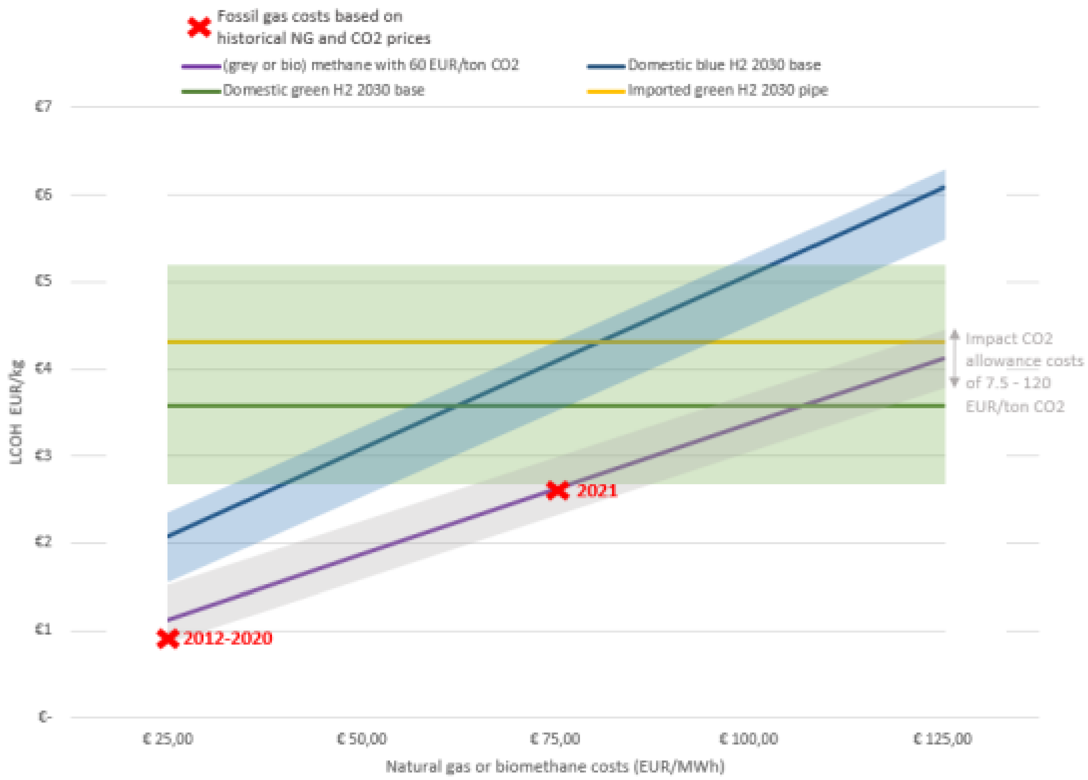


Figure 10 – Impact of the natural gas and carbon allowance costs on the green, blue and grey options for high temperature heat demand in decentral industries [2]

The results mentioned may differ at least on the short run if rather than power from directly connected sources, instead power from the grid is used to feed the electrolysers producing the green hydrogen. This is because then power price fluctuations will matter more, especially in the Netherlands' case where electricity market prices are dominated by gas-fired power production. Because of this fluctuations in natural gas prices cause even stronger fluctuations in electricity market prices (Figure 11) so that as gas prices suddenly rise, power prices may rise even more an therefore lowering the competitiveness of green hydrogen vs blue and grey hydrogen (as long as gas fired power plants are the price setting producer at that moment). The expectation is that the more the electricity market starts to rely on renewable production from solar and wind, the lesser the electricity prices will be influenced by the natural gas price, and therefore, reversibly, high natural gas prices will favour green hydrogen production versus blue/grey hydrogen. In chapter 2.4.3 results are shown of the impact of the natural gas price on green and grey hydrogen production in the expected Dutch energy system of 2030.

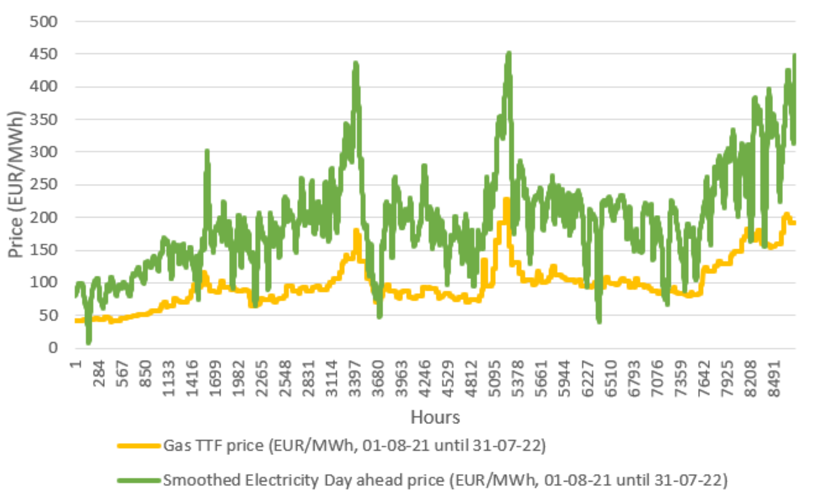
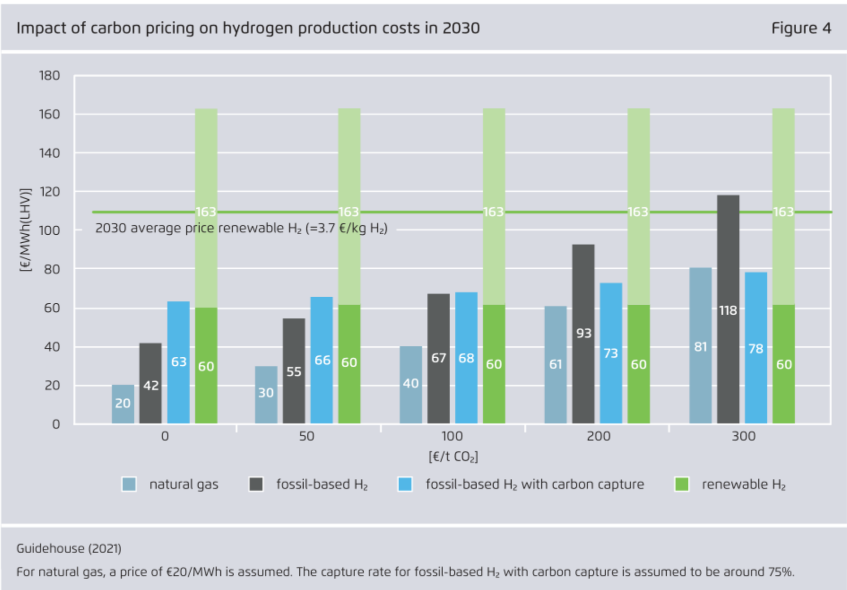


Figure 11 – Plot of the natural gas and electricity prices in the Netherlands over the last year (2021-2022)

2.4.4 Carbon allowance price

If carbon costs are some 50 euro per tonne, by 2030 a large share of the Dutch grey hydrogen production can be produced against a cost of €1.40 – 1.80/kg [42]. The figure below illustrates how carbon pricing affects hydrogen types' production costs in 2030, and compares with prices of the default fuel, natural gas. Up to a CO_2 price level of some €200/t, natural gas prices are lower than costs of all comparable hydrogen forms[8]. Historically EU ETS allowance prices have been much lower, ranging since the start of the system in 2005 until about mid 2020 from close to zero to some €50/tCO_2. In 2022 the European CO2 allowance prices, however, started rising to values between 70 and 100 €/tCO2 and more, but even CO_2 prices in the euro 100-200/t range are too low to make green gas outcompeting natural gas by 2030 [42]. However, with CO2 prices of 100 €/tCO2 or more green hydrogen is projected to already outcompete by 2030 both grey and blue hydrogen, if enough hours with relatively low electricity prices of <20 €/MWh can be captured. In our modelling activities (chapter 2.4) we investigated that this will not be a likely situation in the Netherlands in the coming decade.



[8] Still assuming a natural gas price of 20 €/MWh compared to the 40 €/MWh that we might expect in the Netherlands according to the projections in the Dutch 'Klimaat en Energie Verkenning' after the Ukraine crisis [46]

Some figures may help to illustrate cost price sensitivities of some commodities for CO2 allowance vs natural gas prices [47]:

- 1 €/tCO2 increase raises ammonia production costs with 1.75 €/t, whereas an increase of natural gas prices with 1 €/MWh raises ammonia production costs with 8 €/ton;
- Similar results for methanol production are 0.5 €/t and 7.68 €/t methanol, respectively;
- 1 €/tCO2 increase raises costs of natural gas for high-temperature heating with 0.66 €/MWh, whereas an increase of 1 €/MWh of natural gas obviously has a similar impact on natural gas used for the same purposes.

This information implies that a change of 1 €/MWh in natural gas price has a bigger impact on the costs of fossil energy and/or feedstock production than a change of 1 €/t in CO2 price.

CO2 prices also directly affect marginal costs of natural gas extraction and fossil power production as well as at the demand side the tendency for even low temperature industrial heating to switch to electric boilers, especially at carbon allowance price ranges of 100 €/tCO2 and more.

2.4.5 Conclusion on market drivers renewable hydrogen production

In the previous chapters we concluded the following market drivers for renewable hydrogen production (see Figure 8):

- The higher the penetration of VRE sources in the electricity market, the more beneficial for renewable hydrogen production. This relation is weakened by the degree in which other technologies are applied that provide flexibility in electricity demand.
- The more hydrogen demand, the more beneficial for renewable hydrogen production. This relation is weakened by the degree in which methane reforming (+CCS) technologies are available. The competitiveness of renewable hydrogen production and the latter technologies depends on the natural gas and carbon allowance prices in relation to the electricity price.

In order to get more insights in these relations in the Dutch context, we will model and quantify these market drivers and their impact on the required support levels in the next section.

2.5 Quantification of market drivers, its dynamics and impact on required support

In this section some additional market modelling work on (future) Dutch electricity and hydrogen markets in collaboration with CEER is performed to quantify the impact that the defined drivers have on the potential of renewable hydrogen production in the near future. First the modelling tool will be briefly introduced; secondly, the results of the baseline cases and a broad sensitivity analysis of the drivers is presented; and finally the results will be put in the perspective of the recent Netherlands' energy market and policy developments.

2.5.1 Introduction to the model

In order to investigate the dynamic impacts of the aforementioned drivers on electricity and hydrogen markets more deeply, the partial equilibrium model[9] composed of integrated international electricity and hydrogen markets by CEER has been assessed to be a suitable tool. Figure 12 provides an overview of the market participants in the model from both the supply and demand side; a detailed explanation of each participant is given in appendix B. It is important to note that the involvement of certain players changes depending on what scenario is considered. The policy aspects are taken into account by

[9] This is the technical term for a model that is able to quantify and analyse the impact of supply and demand in a market

providing insight in how much support would be required to close the business case of the installed electrolyser capacity.

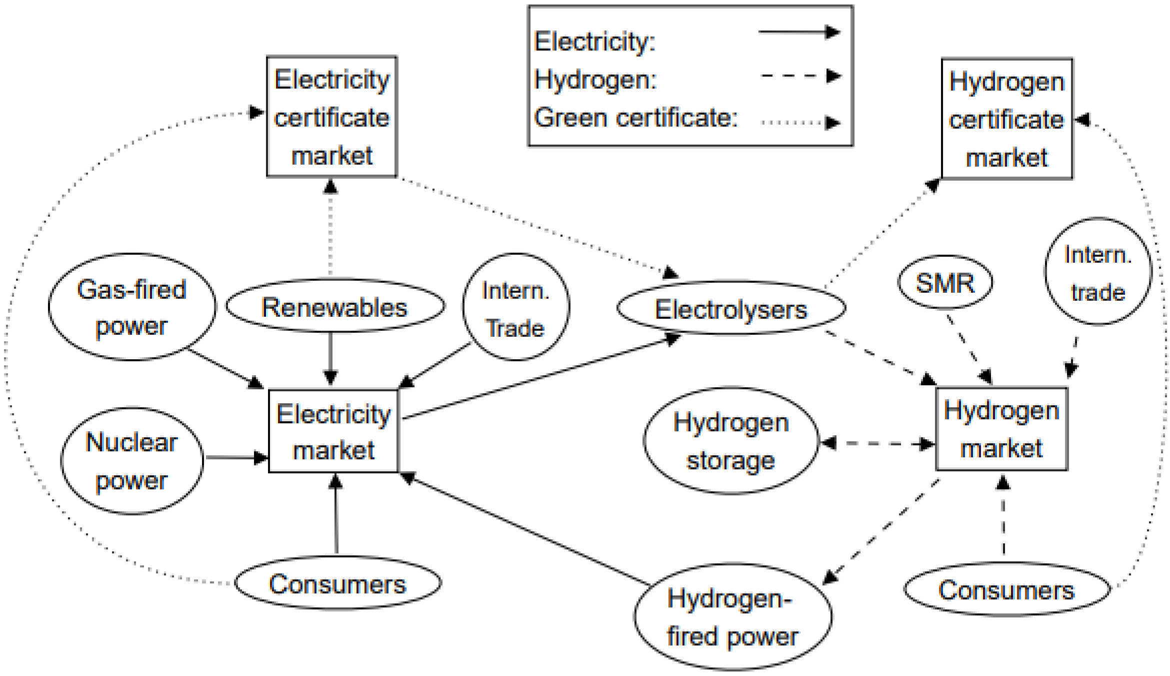


Figure 12 – Schematic overview of the market players involved in the CEER model [48]

In the model, profit maximizing producers and utility maximizing consumers both respond to market prices of electricity and hydrogen. This also holds for international traders from Norway, Denmark, the Netherlands, Germany, the UK, Belgium and France, carrying out arbitrage activities based on international price differences given the constraints of cross-border capacities[10]. Each country contains its own national electricity and hydrogen market. However, those individual markets are connected so that it is possible to trade. It is noteworthy to mention that the sensitivity analysis is mainly focussed on changes in the Dutch energy system, not on those of the surrounding countries.

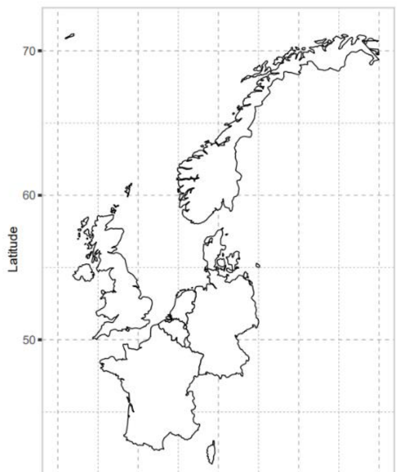


Figure 13 – Overview involved countries in the model

Table 2 provides an overview of what type of assumptions are made in the model and what output is generated[11]. From the model, information is derived on hourly electricity prices, hydrogen prices and on production volumes from electrolysers. This information is combined with the information on investment costs of electrolysers in order to calculate the Net Present Value (NPV) of electrolyser investment. Finally, for each scenario – regarding external circumstances – the subsidy is calculated required to make an investment in electrolyser capacity to break-even at the P2G system capital costs. We indicate the required subsidy by two different

[10] grid constraints within the countries are not taken into account.

[11] The actual input data can be found in Appendix B. For a more detailed description of the model and its exact formulation in mathematical equations, see: [33] and [48].

measures: based on a CAPEX subsidy (per MW of electrolyser capacity installed) and based on a OPEX subsidy (per MWh of renewable hydrogen produced during the lifetime of the electrolyser).

Table 2 – Overview types of in- and output data of the modelling tool

Model input data	Model output
• Indicative hourly electricity and hydrogen demand for every country • Indicative electricity and hydrogen certificate demand for every country • Price elasticity for electricity and hydrogen demand • Installed electricity and hydrogen generation capacities for every country • Installed hydrogen storage capacity • Interconnection capacities for electricity and hydrogen between countries • Wind and solar generation patterns for every country • Natural gas and carbon allowance prices • Technical characteristics of technologies such as availability factors and efficiencies.	• Hourly electricity and hydrogen prices for every country over a period of one year • Electricity and hydrogen green certificate prices • Per hour which types of producers are producing • Per hour how much electricity is in- and exported between the countries • Actual hourly electricity and hydrogen demand based on the market price formation

Two baseline scenarios are considered in order to evaluate the changes in the system between now and 2030. The 2021 baseline scenario is based on the actual 2021 situation and 2030 on the National Trends (based on the policies and ambitions of the EU countries) 2030 scenario of ENTSO-E and ENTSO-G. Below we highlight the main characteristics of both cases.

2021 baseline case

With respect to the first scenario three characteristics should be mentioned:

- The input data of the case is based on the real situation in 2021 (e.g. plant capacities, interconnection capacities etc). It should be noted that the gas and carbon allowance prices had strongly risen in the last months of this year.
- Hydrogen production is only via SMR without CCS (i.e. grey hydrogen), and hydrogen supply and demand involve the national market only.
- The research issue relates to determining the NPV of adding a 100MW electrolyser.

2030 baseline case

For the 2030 baseline scenario the following main characteristics apply:

- Electricity market is based on 2030 values, in accordance with the Climate Agreement ambitions and ENTSO-E data. There is chosen to use data on the international plant capacities only from this source, in order to ensure consistency.
- Compared to the input data of the 2021 case, the 2030 case assumes approximately a double solar and wind capacity over the seven countries and a decrease of gas fired power capacity of 20% (see Figure 14). Also, the electricity interconnection capacities between countries are increased with 72%. The Netherlands specifically triples its solar and wind capacity and reduces its gas fired power plant capacity with 50%. Note that the 'National Trends' scenario bases its VRE capacities on political goals known at the start of 2022, while these have been increased

for several countries in the last year [49].[12] Therefore we included a sensitivity on doubling the increased VRE capacities in the sensitivity analysis.

- Hydrogen production occurs via SMR and P2G (i.e. green hydrogen); the Dutch demand for hydrogen has risen significantly compared to 2021 [1]; in the base case we assume SMR capacity remains similar as in 2021 but we do perform sensitivity analysis for an increased SMR capacity as result of the risen demand; Also, one hydrogen storage salt cavern is installed; hydrogen supply and demand in 2030 also involve international markets with potentially significant interconnection capacities[13]. In our cases we kept the hydrogen interconnection capacities artificially low (300 MW) in order to analyse the researched drivers without the (potentially huge) impact of the political decisions that the involved countries can make on (supporting) hydrogen demand and supply (see [50] for more information). We therefore choose to include this relevant issue in the discussion section rather than making our modelling assumptions and analysis even more complex.
- In the cases we do not consider that capacities are established in 2030 to reconvert imported hydrogen carriers via shipping via shipping routes. This is not considered because there is no clear target for such activities in the Climate Agreement [1]. Based on HyDelta 1 research from an economic perspective it might be considered earlier that imported hydrogen carriers (such as ammonia and methanol) will replace demand for these commodities directly than that these carriers will be reconverted into gaseous hydrogen and sold on the hydrogen market. Therefore we focussed on investigating the impact if gaseous hydrogen demand would decrease (which could be the result if for example fertilizer plants determine to import green ammonia instead of using gaseous green hydrogen to produce the green ammonia domestically) rather than the impact if reconversion capacities for imported hydrogen carriers are established.
- The research issue relates to the NPV of 4GW electrolyser capacity.

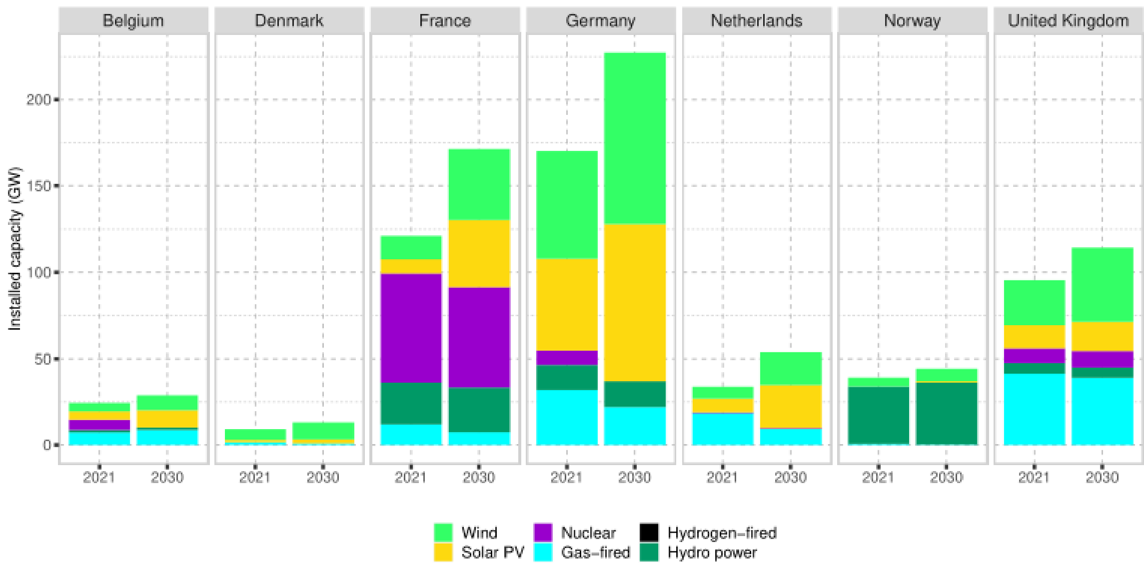


Figure 14 – Assumed installed electricity production capacities per country in 2021 and 2030 [48]

[12] For example: in the Netherlands the offshore wind target in 2030 has been increased from 10.5 GW to 16 GW in 2030 (and 21 GW in 2031).
[13] Because the capacity by expectation will be based on the diameters of the existing natural gas pipelines

2.5.2 Green hydrogen production in the Netherlands' energy systems of 2021 and 2030

The main difference between both scenarios' assumptions is that in 2030 (compared to 2021): significantly more renewable capacity has been installed; more well-functioning electricity interconnection capacity is available; the average prices of carbon allowances are higher; the natural gas price has been stabilized compared to the increasing gas price at the end of 2021; large-scale hydrogen storage capacity exists; and much more electrolyser capacity has been installed. The modelling assesses how the changed energy system conditions affect the economic viability of producing green hydrogen.

2021 baseline case results

Figure 15 presents the modelled electricity and hydrogen price duration curves. (All hourly electricity and hydrogen prices derived from the model are ordered from high to low resulting in these curves).

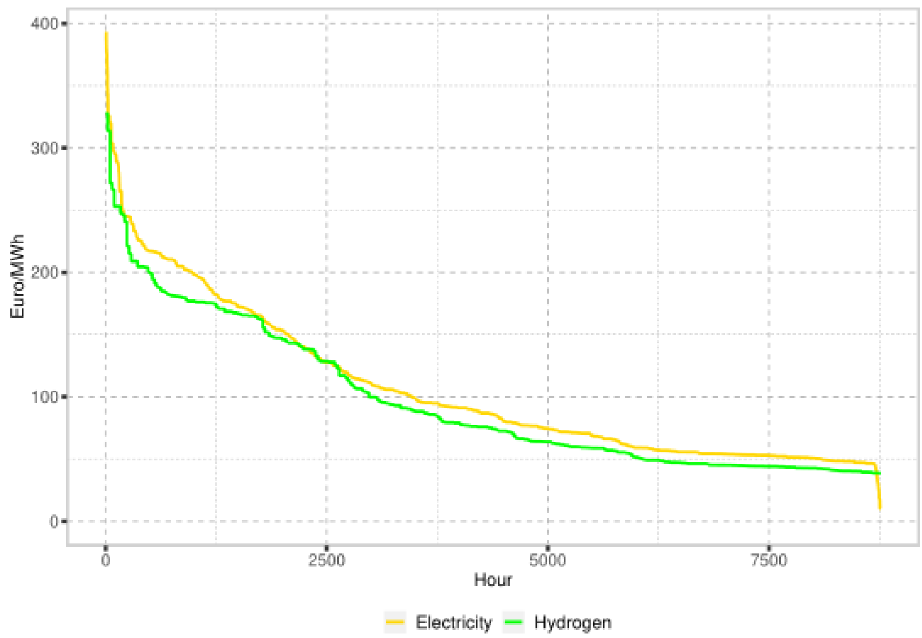


Figure 15 – Electricity and hydrogen price duration curves for the Netherlands, 2021 [48]. Validation of the 2021 electricity prices generated by the model (without 100 MW electrolyser capacity) by comparing these with the historical 2021 electricity prices is shown in Appendix C.

Since the main production capacity types of electricity and hydrogen in 2021 are gas-fired power plants and SMR installations respectively, those types are also considered to be the marginal production units most of the time. So, market prices are set by the marginal costs of these units being the highest-cost types of production units to fulfill demand at that moment. For both, gas-fired power plants and SMR installations, marginal costs are based on the same prices, namely those of natural gas and carbon allowances, which explains the strong relation between electricity and hydrogen prices modelled (i.e. hours with high electricity prices relatively often show high hydrogen prices and vice versa). On average, hydrogen prices are lower than the electricity price due to the lower marginal costs of SMR compared to gas fired power plants. This is because the conversion efficiency of natural gas to hydrogen (SMR: 70%) is higher compared to natural gas to electricity (gas-fired power plants: 50%).

Another noticeable result, when comparing the 2021 price duration curves with the 2030 price duration curves that will be presented in next section, is that relatively a lot of hours occur with high electricity and hydrogen prices in 2021. This is because the input 2021 natural gas prices show a sharp increase in the last months of the year. Hence, when we would have used 2019 as base case year (as chosen in this study [33], more stable electricity and hydrogen prices would be seen over the year (which is characterizable as well for the years before 2019).

The modelled 100 MW electrolyser is assumed to run only if the variable costs of production are less than its revenues, or, to put it differently, when the purchased electricity costs (including electricity lost during conversion) are less than the revenues of the hydrogen that has been produced with that electricity. Due to the strong relation between electricity and hydrogen prices, and because electricity prices were on average higher than hydrogen prices, the 100 MW electrolyser was only operational during 3.4% of its maximum full load hours. Although some margin was realized (see Table 3), the low load factor led to a relatively low overall profit margin on the investment (see Table 4).

Table 3 – Main financial metrics derived from operating a 100 MW Electrolyser for the 2021 scenario

Electrolyser criteria	Result
Yearly operational profits (excl. CAPEX)	0.63 M€
Average price, buy electricity	89 €/MWh
Average price, sell hydrogen	149 €/MWh (or: 4.47 €/kg, LHV)
Average profit per MWh of production[14]	21 €/MWh
Capacity factor	3.4%
Hydrogen produced	29.5 GWh

Since the electrolyser turned out to be barely running under the 2021 market circumstances, significant support would be required to close the business case. In terms of CAPEX subsidy this would mean that almost all investment (99.8%) should be supported to get to a zero NPV. Or in terms of OPEX subsidy this means that a support level of 270 €/MWh of hydrogen produced would be required. For indicational purposes: this is about three times the average price of the purchased electricity.

Table 4 – Required subsidies for the electrolyser

Required subsidies	Result
Required subsidy per MW installed[15]	998 €/kW (99.8% of investment costs)
Required subsidy per MWh hydrogen produced	269 €/MWh

Hence, it is clear that the modelled 2021 market situation was not ideal to convert electricity into hydrogen. Due to the developments, mainly due to the increased penetration of renewables and hydrogen demand that the 'National Trends' scenario assumes, these market characteristics are expected to change based on the results that we will discuss in the next section.

2030 baseline case results

Figure 16 shows the price duration curves for the 2030 scenario. The curve for hydrogen is at a higher price level than for electricity. This is the case for two main reasons. First, hydrogen prices rise due to increased demand at the given hydrogen production capacity: the assumed SMR capacity remains 3125 MW or similar to that in 2021, while the assumed additional 4 GW electrolyser capacity is not sufficiently covering demand so that hydrogen prices go up. Second, due to the relatively high increase of renewable capacity, and therefore supply of electricity, compared to electricity demand, the electricity prices are in a lower range than in the 2021 scenario. Also it plays a role that especially in

[14] The profit per MWh of sold hydrogen is as simple as the purchased electricity (incl. electricity lost due to conversion efficiency) minus the revenues for the sold hydrogen
[15] Assumptions: CAPEX 1000 €/kW, WACC 7%, lifetime 25 years.

the second half of 2021 the natural gas prices rose significantly and therefore led to higher electricity and hydrogen prices in the 2021 baseline case compared to the more stable natural gas price that was assumed in this 2030 baseline case.

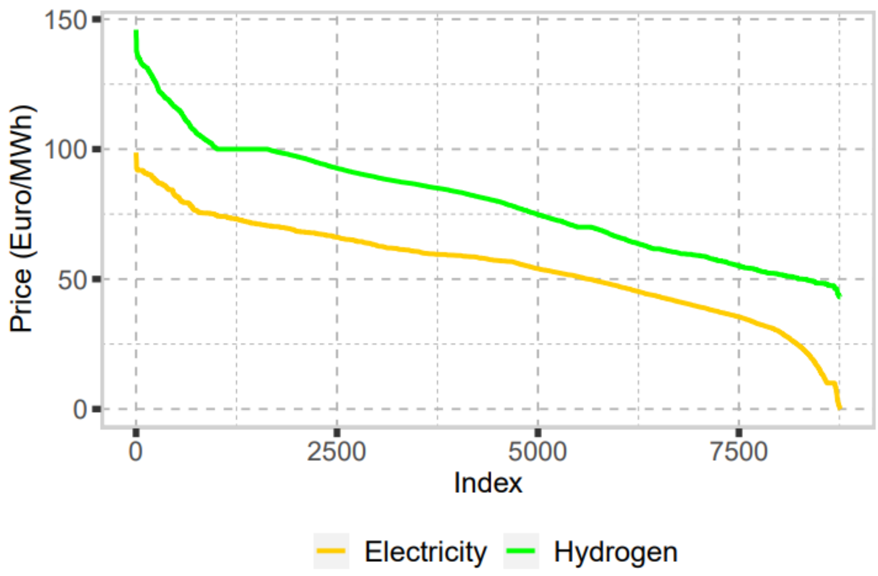


Figure 16 – Electricity price and hydrogen price duration curve in the Netherlands, 2030 [48]

Moreover, due to increased renewable capacity, the number of hours that producers of renewable power are setting the electricity price increase (while the number of hours that gas-fired power plants are setting the price decrease). This results in more hours with low electricity prices, increasing the number of hours in which electrolysers generate positive margins. To understand better what actually happens, we use Box 1 to explain the impact of the increased VRE capacities in greater detail.

Although the penetration of renewables has increased, natural gas fired power plants still play an important role in the electricity market. Most of the time the renewables (and also in combination with hydro and nuclear power) are not sufficient to serve the total electricity demand in the seven countries. A very considerable issue is that the running hours of gas fired power plants become less due to their partial replacement by renewables, but the demanded peak loads at moments without solar and wind become higher due to a general increase in electricity demand. Although this study mainly focusses on the business case of the electrolysers, the impact of this period of a 'double fossil-renewable' energy system on the business case of natural gas fired power plants might be of equal importance to secure security of supply.

Box 1 – Additional explanation and insights on the impact of increased penetration of renewables in the electricity system

In section 2.5.1 it was discussed that in the 2030 baseline case approximately twice as much intermittent renewable energy capacities are installed. What is exactly the impact of these sources on the electricity market and does this result in large numbers of hours with more extreme low and high electricity prices?

As discussed in section 2.4.1, it is expected that the 75% of VRE penetration aimed by the Dutch Climate Agreement with a similar electricity demand pattern would lead to about 2000-3000 hours with overshoots of electricity supply, if neighboring electricity markets and flexibility of demand are not taken into account [41]. This is also shown in an earlier study by the University of Groningen [33].

In our modelling we consider price elasticity. This means that demand will partially adapt if prices are high or low, based on a price elasticity that historically is seen in energy markets. Also, the electricity markets of neighboring countries are included and the ENTSO-E assumptions in the 2030 case electricity interconnection capacities are almost doubled. Figure 17 presents the electricity price duration curve for the 2030 baseline case and compares this with the same 2030 assumptions, but then excluding the electricity interconnection capacities and electrolyser capacities. It turns out that without the interconnection and electrolyser capacities the duration curve of the electricity price becomes significantly steeper. This means that these two types of flexibility, and especially the interconnection capacities (see later in Figure 18), significantly reduce the hours with more extreme high and low prices.

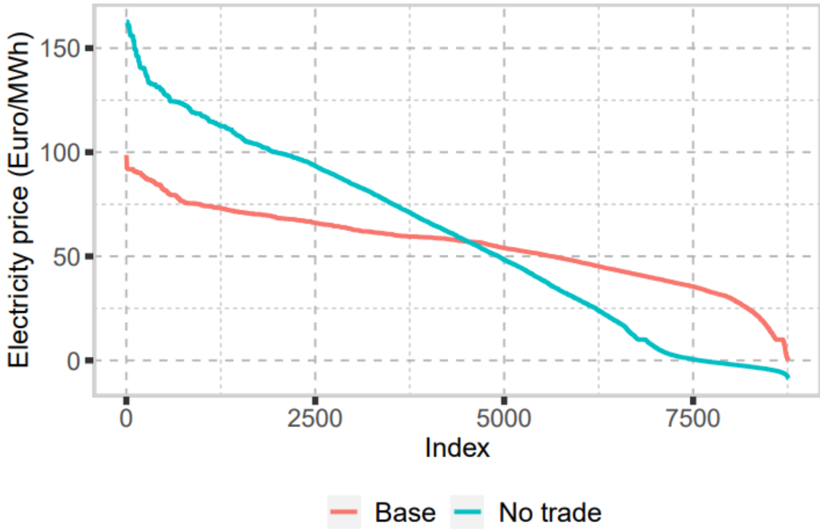


Figure 17 – Price duration curves of electricity prices in 2030 for the Baseline case and the baseline case without electricity interconnection and without electrolyser capacity

In order to explain why these electricity interconnection capacities reduce the magnitude of the extreme electricity prices, additional analysis has been performed to indicate the reasons. However, as all the markets are intertwined it should be noted that it is hard to talk about causalities.

The first analysis was a simple counting to get additional insights in the relative high availability of specific generation sources (with low marginal costs) compared to demand. We did this by counting the hours of which a high combined availability of solar and wind (first row: S+W) and a high combined availability of solar, wind, nuclear and hydropower (S+W+H+W) resulted in a low electricity price in the isolated countries. Table 5 shows that in the Netherlands (and the UK) the renewables in an isolated electricity system would more low priced electricity hours than the other countries. This seems understandable from the input data that indicates that the Dutch solar and wind capacity were increased relatively more towards 2030 (tripled) compared to the capacities of the total seven countries (that were doubled). If we also take into account hydropower and nuclear we see that also Norway and France have significant numbers of hours with high availability of electricity supply at low marginal costs. However, the marginal costs of solar and wind are considered the lowest in the modelled 2030 baseline case. Therefore, under our assumptions often a part of the Dutch electricity will be exported to other countries during the hours with high availability of Dutch solar and wind, because there the penetration of solar and wind seems not that severe.

Table 5 – % of hours in which a relatively high availability of specified sources compared to the demand resulted in electricity prices of 10 €/MWh or lower. S+W: solar PV and wind; S+W+H+N: Solar PV, wind, hydropower and nuclear.

	Country						
Capacity	Norway	Denmark	Netherlands	Germany	United Kingdom	Belgium	France
S + W	0.00	0.83	27.33	1.26	15.84	0.15	0.02
S + W + H + N	62.61	0.84	29.83	3.36	15.89	0.26	59.08

A second analysis is done to assess the simultaneousness of solar and wind availability[16] among the different countries included in the analysis. We did this by calculating the correlations between the availability factors of solar and wind on the set of hours over the year. Correlations have a number between 1 and -1. 1 means that the moments of wind or solar availability are similar to each other, -1 means that wind and solar availability occur at different moments. Looking at Table 6 and Table 7 that present the correlations of both solar and wind availability between the different countries, it turns out that the availability for both of the sources are correlated positively between all countries. However, the simultaneousness of wind availability is less strong than the availability of solar (which is logic because solar availability highly depends on day/night and summer/winter characteristics which are the same for all countries, but the cloudiness moments do differ sometimes. Wind speeds are generally relatively more weather depended than solar). As the wind availability is not correlated that strong between countries (sometimes 0.2-0.7), this shows that there is potential for electricity interconnections to balance the intermittent supply between countries. Next potential that is presented by the tables, it should be noted that also differences between installed wind and solar capacity between countries (see Appendix B) lead to a synergy in exchanging electricity between the countries.

Table 6 – Correlations between availability factors of wind energy between the involved countries

	Norway	Denmark	Netherlands	Germany	United.Kingdom	Belgium	France
Norway	1.00	0.40	0.22	0.22	0.26	0.15	0.16
Denmark	0.40	1.00	0.49	0.65	0.29	0.28	0.19
Netherlands	0.22	0.49	1.00	0.80	0.57	0.79	0.56
Germany	0.22	0.65	0.80	1.00	0.41	0.62	0.55
United Kingdom	0.26	0.29	0.57	0.41	1.00	0.55	0.41
Belgium	0.15	0.28	0.79	0.62	0.55	1.00	0.75
France	0.16	0.19	0.56	0.55	0.41	0.75	1.00

Table 7 – Correlations between availability factors of solar energy between the involved countries

	Norway	Denmark	Netherlands	Germany	United.Kingdom	Belgium	France
Norway	1.00	0.89	0.83	0.91	0.85	0.87	0.86
Denmark	0.89	1.00	0.83	0.91	0.85	0.87	0.86
Netherlands	0.83	0.83	1.00	0.86	0.84	0.93	0.85
Germany	0.91	0.91	0.86	1.00	0.85	0.92	0.90
United Kingdom	0.85	0.85	0.84	0.85	1.00	0.89	0.90
Belgium	0.87	0.87	0.93	0.92	0.89	1.00	0.90
France	0.86	0.86	0.85	0.90	0.90	0.90	1.00

These two reasons explain how the new VRE capacities are integrated in the electricity systems. The first reason, however, disappears when the countries head to higher wind and solar penetration in their electricity systems over time (which is the case already due to the increased 2030 offshore wind targets for most of the countries which are not taken into account in our baseline scenario). In the sensitivity analysis on installed renewable capacities (next chapter) the effect of this on the electrolyser business case is clearly visible.

We also looked specifically into the impact of the 4 GW electrolyser capacity on the electricity prices. Figure 18 clearly shows that especially for the lower electricity prices an increase in electricity price is seen compared to the electricity system with 1 GW electrolyser capacity installed. This is due to the additional electricity that is demanded by the electrolysers during the hours with lower electricity prices. Comparing the impact of figure xx to figure xx, we see that in our 2030 baseline scenario the flexibility impact of the interconnections is larger than the 4 GW electrolyser capacity. However, the higher the VRE penetration in the neighboring countries of the Netherlands, the more other types of flexibility measures than electricity interconnections would be required.

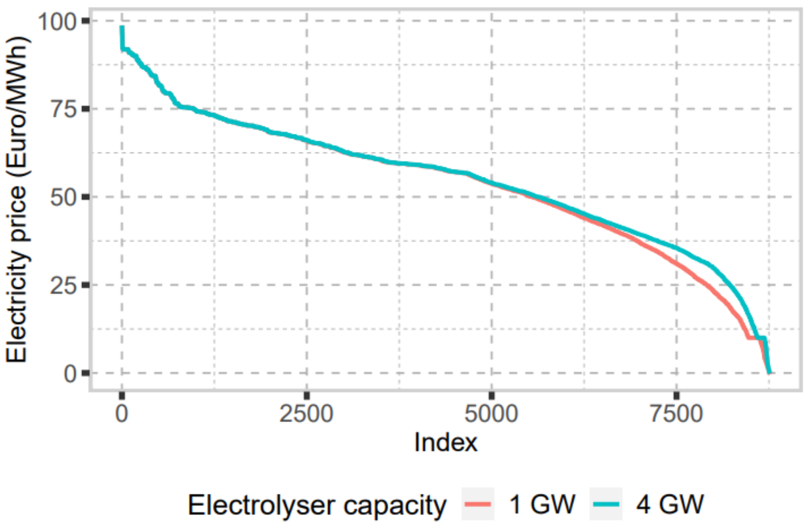


Figure 18 – Price duration curves of electricity prices in 2030, base-scenario and sensitivity case with 1 GW electrolysis capacity installed

Table 8 presents the levels of support (e.g. subsidy) required for operating the 4 GW of electrolyser capacity within these market circumstances. Compared to the 2021 baseline case the market characteristics in the 2030 baseline case are significantly better for the electrolyser investors. The average sell price of hydrogen reflects only that of green hydrogen. Operational profits of the 4 GW electrolyser capacity installed amount to 75.7 M€. Yearly profits are much higher than in the 2021 scenario, as well as the capacity factor. However, still those annual profits do not cover the total investment costs and therefore support is required to close the business case. The subsidy required to break even per MW installed is still relatively high. If theoretically all support needed to get to a closed business case would be provided by way of investment subsidy, then 75% of the initial investment costs would have to be supported. If instead the support would be provided per MWh of hydrogen produced, its level is significantly lower than in the 2021 situation due to the much higher volume of hydrogen produced per MW electrolyser capacity (see capacity factor). (Note that subsidy intensities are calculated after calibration of the market equilibrium; potential subsidies have not been included in the marginal costs of running the electrolysers).

[16] The availability factors over time of solar and wind in the different countries are based on historical weather data

Table 8 – Main financial metrics derived from operating 4 GW electrolyser capacity in the 2030 baseline case

Electrolyser criteria	Results
Yearly operational profits (excl. CAPEX)	75.7 M€
Average price, buy electricity	51 €/MWh
Average price, sell hydrogen	79 €/MWh (or: 2.37 €/kg, LHV)
Average profit per MWh of production	7 €/MWh
Capacity Factor	36%
Hydrogen produced	12.6 TWh
Subsidy per MW installed	750 €/kW (75% of investment costs)
Subsidy per MWh hydrogen produced	21 €/MWh

Another noticeable result relates to the number of hours in which the electrolysers run with a marginal profit of zero versus hours with positive marginal returns. Because electricity and hydrogen prices are endogenous in the model, situations with low electricity and high hydrogen prices will lead to more conversion of electricity into hydrogen, and thus additional demand for electricity and supply of hydrogen. This process either continues until the marginal revenues of the electrolysers are zero, or full capacity of electrolyser capacity has been reached. In the first case the electrolysers will produce with a zero marginal profit and in the latter case with positive marginal profit. In the 2030 baseline case, given the 3150 full load hours, some electrolyser capacity was running in around 8000 hours (against zero marginal returns), but total 4 GW capacity during some 1100 hours only (at positive marginal returns). The recognition of this difference between hours in which total electrolyser capacity is or is not able to close the gap between electricity and hydrogen prices, and the related number of hours at which either case applies is important, because it strongly determines electrolyser capacities' overall profitability.

2.5.3 Sensitivity analysis of factors affecting renewable hydrogen production opportunities

In order to assess the impact of 2030 values of drivers being different I from the baseline 2030 case, a sensitivity analysis was applied for the drivers:

- demand for hydrogen
- installed natural gas-based hydrogen production capacities (e.g. SMR)
- installed electrolyser capacities
- natural gas price
- carbon allowance price
- demand for electricity
- installed capacities of variable renewable electricity (VRE) sources

Also, an extra sensitivity was included to explore if the assumed storage capacity has a significant impact on the outcomes.

Table 9 summarizes the main impact of the sensitivities on the behaviour of the electrolysers in the market and its impact on the business case. The an overview of the quantitative outcomes is given in Table 10 and the relations are described in greater detail in the next sections.

Table 9 – Overview impact of sensitivities on the electrolyser business case and its required support

Relatively more/higher …	means…	Impact load hours	Impact buy/sell margin		Overall impact electrolysis business case*

Electrolysis capacity		−	−		− −
SMR capacity		−	−		−
Hydrogen demand		+	+/-		+ + +
Renewable capacities		+	+		+ + +
Electricity demand		−	−		− − −
Natural gas price		+	+		+ +
Carbon allowance price		+	+		+

***And therefore decreasing the required support intensity to close the business case (note that the strength is only for indicative purposes, most of the relations are non-linear and also interdependent on each other)**

Table 10 Summarizes the main outcomes of the sensitivity analysis. In the last column the numbers for the required subsidies are marked green if the sensitivity has a positive effect on the electrolyser business case compared to the 2030 baseline case, and red if the sensitivity had a negative effect.

Table 10 – Overview key outcomes of the sensitivity analysis. CF = capacity factor.

		CF	**Buy-sell price / margin**			**Required subsidy**	
Sensitivity	**Increase/ decrease**	**%**	**Electricity (€/MWh)**	**Hydrogen (€/MWh)**	**Margin (€/MWh)**	**CAPEX (€/MW)**	**OPEX (€/MWh)**
2030 Baseline (B)	-	36%	51	80	7	750	21
More H2 demand (HL)	+20%	58%	59	89	6	684	12
More SMR (MH)	+100%	21%	37	63	12	756	35
1 GW electrolysis	-75%	80%	60	103	17	0	0
8 GW electrolysis	+100%	22%	49	70	~0	995	45
High NG price (G)	+100%	52%	57	98	17	55	2
High CO2 price (C)	+100%	43%	53	89	13	447	10
More VRE (R)	+50%	81%	17	65	41	0	0
More E-demand (D)	+6.4%	30%	55	83	5	864	37

Hydrogen demand and natural gas-based hydrogen production capacities

With regardto the hydrogen demand a range of a low demand level of 40 TWh/y (-20%) and high demand level of 60 TWh/y (+20%) have been used to compare with the baseline 2030 value of 50 TWh/y. This range is similar to the 2030 hydrogen demand levels mentioned in the Dutch Climate Agreement [1]. The assumption that half of hydrogen demand is for green hydrogen was used similarly in all cases.

According to the model, an increase in hydrogen demand (see Figure 19 'HL') in a market with similar supply capacities results in an increased average hydrogen price compared to the baseline case, and thus higher revenue potentials for hydrogen producers. For the electrolyser operators this meant that the hydrogen could be sold against an average price of 89 €/MWh (compared to 80 €/MWh in the baseline case). This improves the business case of electrolyser operators: 12 €/MWh subsidy is required to close the business case of the 4 GW electrolyser capacity instead of the 21 €/MWh in the baseline case. A lower hydrogen demand in 2030 meant the opposite: less hydrogen is sold for a lower price and more support is required to close the business case of the 4 GW capacity. Less increase in pure hydrogen demand can be expected if hydrogen prices become too high for consumers which might drive them to go for alternatives (e.g. fertilizer plants importing green ammonia instead of producing the ammonia from hydrogen at their Dutch sites, or mobility applications swift towards electric-, bio- or imported synthetic fuels instead of gaseous hydrogen).

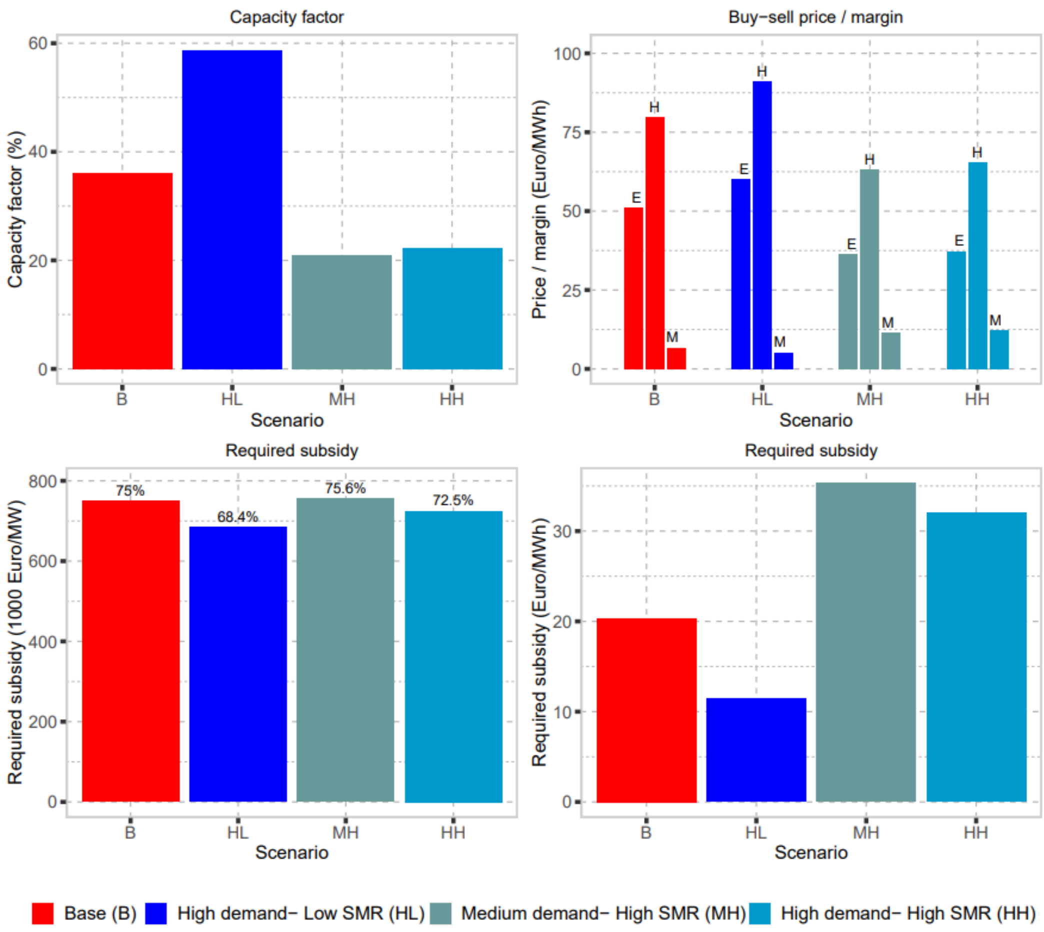


Figure 19 – Impact of hydrogen demand and SMR capacity on required subsidy per MWh of hydrogen produced. Notes: E = average price for which electricity is bought, H = average price for which hydrogen is sold, M = average profit per MWh of hydrogen produced [48]

With regards to the natural gas-based hydrogen production capacities, they increase in the sensitivity analysis from 3125 MW in the 2030 baseline scenario towards 6250 MW (+100%) (see Figure 19 'MH'). It was decided to consider for this driver increases only, because the considered increase in hydrogen demand between 2021 and 2030 was expected to attract new methane based hydrogen producers (if they will be grey or blue results from the CO2 price, and next to the new green producers) as well. This is in line with the Dutch hydrogen roadmap where one expects that existing hydrogen production capacities will still be needed in 2030 to: fulfil the increasing hydrogen demand; provide supply-side flexibility in the hydrogen market; and fulfil demand for CO_2 [25].

Opposite to an increase in hydrogen demand, an increase of natural gas-based hydrogen production capacity implies supply of hydrogen to increase compared to the demand. The increased competition results in lower average hydrogen market prices than in the baseline case. For the electrolyser operators hydrogen is now sold against an average price of 63 €/MWh (compared to 80 €/MWh in the baseline case). As a consequence more support is needed to close the business case of 4 GW electrolysis: namely 35 €/MWh at 6250 MW compared to 21 €/MWh in the baseline case.

The effects of both sensitivities may strengthening each other. In case of an higher demand and lower SMR capacity, the business case of electrolysers would depend on the least on support, and vice versa. 'HH' considers an additional case with the increased hydrogen demand (60 TWh) and increased SMR capacity (6250 MW) combinedly.

The differences in the number of zero-margin and positive-margin operation hours show that although the capacity factor of the electrolysers significantly increases at higher hydrogen demand levels (36% to 58%), yet the number of positive margin hours changes very little (Figure 20). When the SMR capacity increases, the load factor drops to 21% and also the number of zero-margin hours decreases significantly.

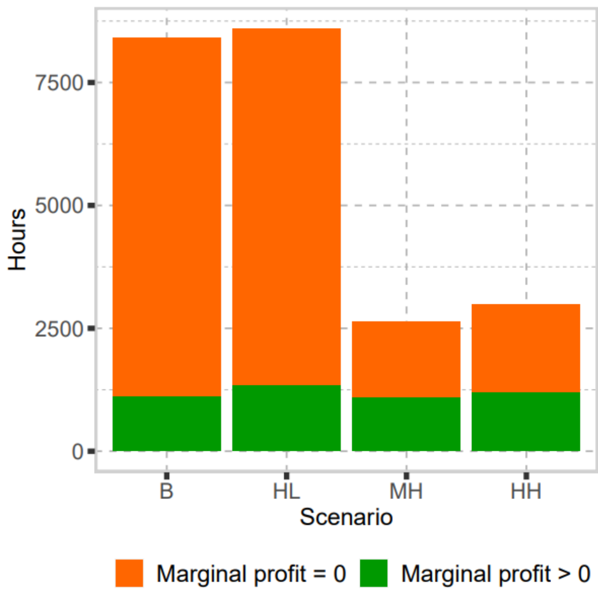


Figure 20 – Share of zero-margin and positive-margin hours under different hydrogen demand and SMR capacity sensitivity cases. Note: B = 2030 baseline, LH = 2030 high demand, MH = 2030 100% increase in SMR, HH = high demand and 100% increase in SMR [48]

Installed capacity of electrolysers

The impact of changes in the installed capacity of electrolysers is assessed by assuming a low (1 GW, or -75%) and a high level (8 GW, or +100%), compared to the 2030 baseline value of 4 GW. The 1 GW of electrolyser capacity figure corresponds roughly with the foreseen capacity based on the second wave of IPCEI (800-1000 MW) and electrolyser scale-up instrument (50-100 MW) combined [51], while the 8 GW figure corresponds with the highest electrolyser capacity level mentioned in the Dutch hydrogen Roadmap [25].

The impact of more electrolyser capacity is that the operators of the electrolysers face more competition: the electrolysers are bidding during the same hours to capture low priced electricity, which increases the electricity price compared to a scenario with lower electrolysis capacity (see Figure 18, as discussed earlier, for a visualization of this effect). Moreover, since we kept the hydrogen demand at the same level in these sensitivity cases: more electrolysers are serving the same demand which decreases the price of the sold hydrogen. Figure 21 shows that the 8 GW case results in an average electricity buy price of 49 €/MWh, an average hydrogen sell price of 70 €/MWh and 2000 full load hours. This case requires 45 €/MWh of support to close the business case of the total 8 GW of electrolyser capacity. The 1 GW case resulted in an average electricity buying price of 60 €/MWh, hydrogen selling price of 103 €/MWh and 7000 full load hours, and the requirement of just 2 €/MWh of support to close the business case. Although the average electricity market price is higher in cases with lower electrolysis capacity installed(e.g. comparing the 4 GW with the 1 GW case in Figure 18), the average electricity buying price of the electrolysers is higher in the 1 GW case compared to the 4 and 8 GW cases (see Figure 21). This is because the electrolysers are running significantly more in the cases with less electrolyser capacity. Thereby, the electrolysers are also purchasing electricity at higher prices to serve hydrogen demand at a higher price. In this 1 GW case the market is paying a relatively high price for hydrogen because there is relatively low supply compared to demand. Probably the 1 GW and 3125 MW SMR capacity will not be a likely situation if hydrogen demand of 50 TWh is established, because this situation seems to result in such good circumstances to invest in electrolyser and SMR capacities that these are likely to become larger (and we have seen that this will let the hydrogen price drop again, which at some point will stop the attractiveness of new investments).

The other way around, 8 GW seems a relatively high electrolyser capacity: the electrolysers compete such for the low electricity prices that almost no margin is made anymore on the sold hydrogen. Note that this is the case for a scenario with 10.5 GW offshore wind. If we increase the renewables capacities (see sensitivity on increased VRE capacity) we see that this also provides a very good market incentive to invest in more than 4 GW of electrolyser capacity.

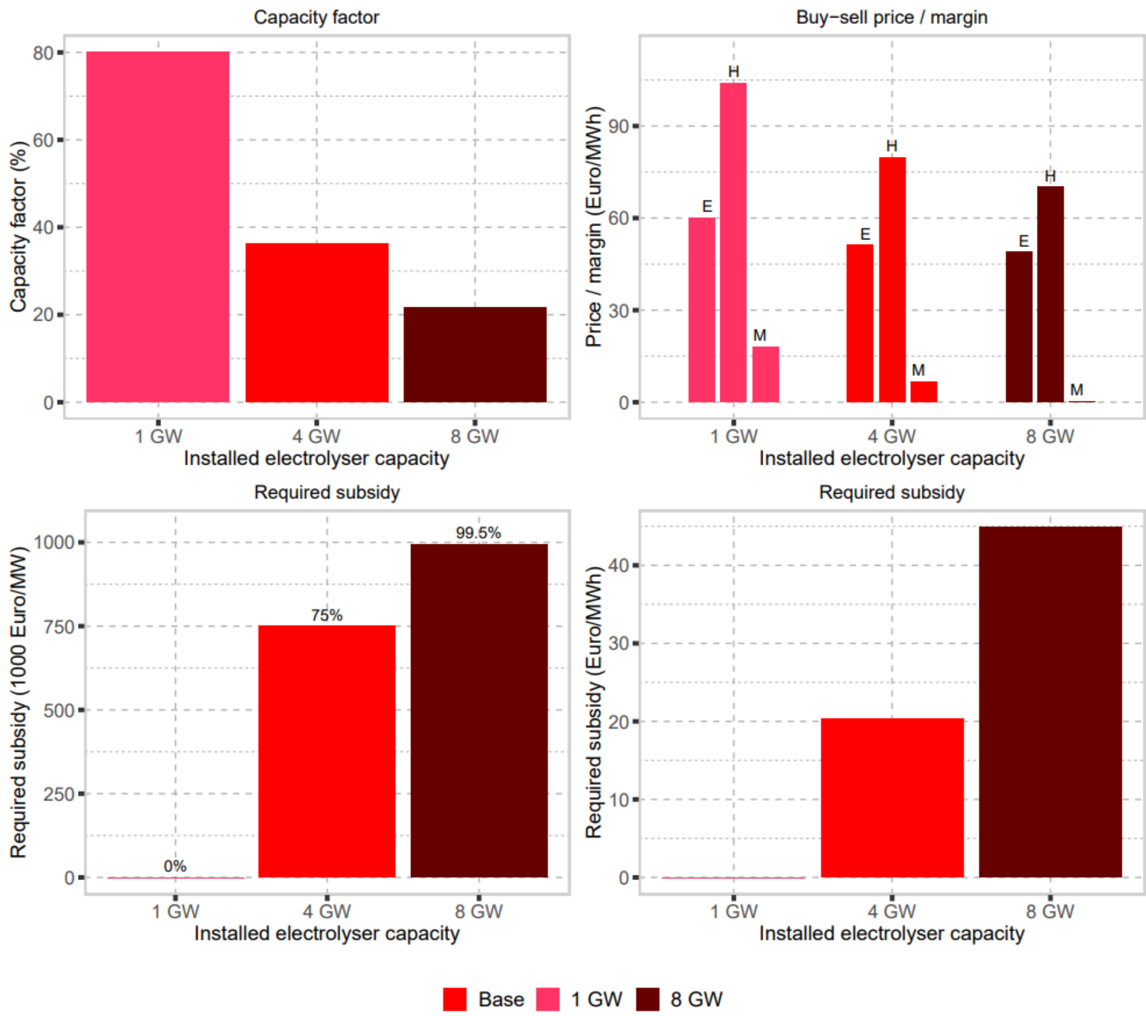


Figure 21 – Sensitivity impact of installed electrolyser capacity [48]

Natural gas and carbon allowance prices

The sensitivity of the green hydrogen production business case for changes in natural gas and carbon allowance prices is based on projections of these prices in the Climate and Energy Exploration (=*Klimaat en Energie Verkenning*) by the Netherlands Environmental Assessment Agency [46]. The high natural gas price is set at 40 €/MWh (+100%), compared to the initial value of 20 €/MWh in the 2030 baseline case. The high carbon allowance price is set at 125 €/ton (+100%), compared to the initial value of 62 €/ton.

The natural gas and carbon allowance prices both affect the marginal costs of gas-fired power plants and natural gas-based hydrogen production via SMR. For both prices a rise raises average electricity and hydrogen prices compared to the baseline levels (see Figure 22): the electricity buying price rises from 51 €/MWh (baseline) to 57 and 53 €/MWh for the natural gas and carbon allowance prices rises, respectively. The hydrogen selling price rises (from the 80 €/MWh baseline level) to 98 and 89 €/MWh, respectively. So, the hydrogen price rises more than the electricity price in both cases, which is beneficial for the business cases of operators of electrolysers and of renewable energy capacity. We saw the opposite in the 2021 case. The reason for this is that the electricity prices are still, but less strong connected to the natural gas price, especially in the hours (with relatively large share of solar and wind) that the electrolysers are producing. In both cases the required support for the 4 GW electrolyser capacity decreases, from 21 €/MWh to 2 €/MWh in case of a higher carbon allowance price, and 10 €/MWh in case of a higher natural gas price.

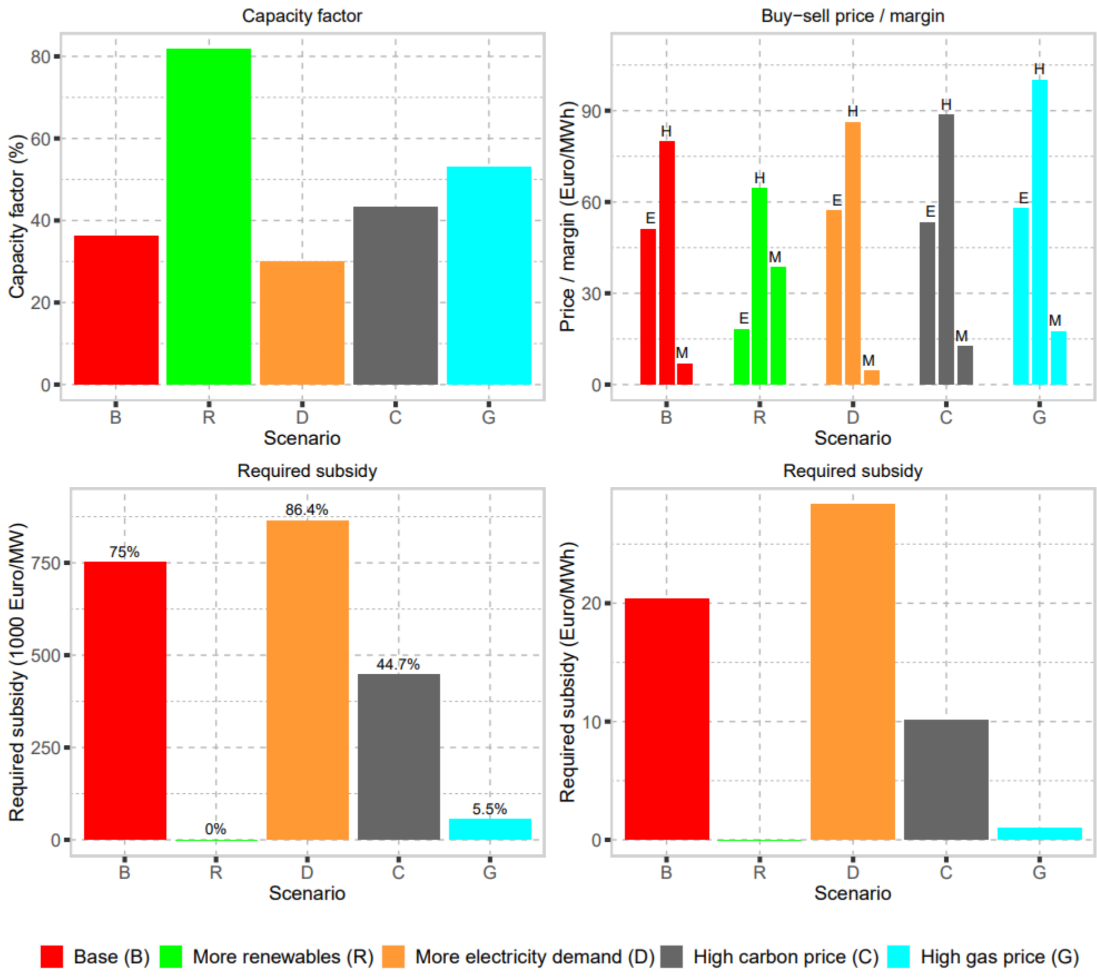


Figure 22 – Sensitivity impact of increased amount of renewables (R), increased electricity demand (D), high carbon allowance prices (C) and high natural gas prices (G) [48]

Demand and supply of VRE in the electricity market

Also sensitivities of the green hydrogen business case for changes in both the demand for electricity and the significance of VRE supply have been assessed. Note that this is the only sensitivity which the change in values have been applied to all the seven countries. For the high electricity demand case, the initially assumed electricity demand increase during 2021 - 2030 of ENTSO-E [52] has been doubled. The same was done for the increase of VRE capacities. The same high electricity demand and VRE capacity have then been adopted for all countries in the model. To illustrate, for the Netherlands this meant a 2030 high electricity demand case level of 145 TWh/y (+4.6%; note that overall electricity demand increase of all countries was higher, around 6.4%) compared to 139 TWh/y in the baseline case. The doubling of increased VRE capacities implies 42.1 GW of solar and 30.7 GW of wind installed capacity in the Netherlands in the 2030 high VRE case (compared to 25 GW solar and 18.8 GW wind in the 2030 baseline case). Based on some recent documents the '2030 high electricity demand' case seems somewhat conservative for the Netherlands [53]: the '2030 high VRE supply' case probably overestimates the installed capacity of solar PV [46] (see also next).

The impact of higher electricity demand (than the baseline case level) is that the electrolyser operators face more competition from other electricity users when buying electricity in the market so that average electricity prices tend to rise (to 55 €/MWh against the 51 €/MWh baseline case level, see Figure 22). Consequently profit margins of electrolyser operators decrease, and higher support levels (now 37 €/MWh) are required to close the unprofitable gap of the 4 GW electrolyser operations.

The impact of more VRE sources is the opposite to that of higher electricity demand: there is more supply, so less competition for electricity in the market. Moreover, now more countries than the Netherlands and UK only (see Table 5 describing this for the 2030 baseline case) are dealing with hours with low electricity prices due to the larger penetration of renewables into the electricity system. Hence the average electricity prices drop compared to the 2030 baseline case (17 €/MWh compared to 51 €/MWh in the baseline case). The profit margins of electrolysers thus increase, and no support is required anymore for electrolyser operators to break even.

Extra sensitivity: hydrogen storage capacity

In our initial assumptions one underground hydrogen storage cavern (250 GWh) was assumed to be in operation by 2030. In order to explore the impact of this assumption we performed an extra sensitivity analysis on the assumed storage capacity: the low value assumes that full load of the electrolysers can just be stored for one day (96 GWh) and the high value assumes that four underground hydrogen storage caverns are installed, like proposed in [25].

In the model the storage operator simply wants to maximize its economic gains by purchasing hydrogen when the hydrogen market price is low and selling hydrogen when the hydrogen market price is high. Thereby, the storage operator is stabilizing the hydrogen market prices. The electrolyser operator maximizes its profits by gaining margin from purchasing electricity at relatively low price and selling hydrogen and relatively high price. Combining the incentives of both types of actors makes the impact of the available storage capacity and the electrolyser business case not straightforward: during moments with relatively low electricity prices and low hydrogen prices the electrolysers have benefit from the availability of extra storage capacity. Namely, the storage operator is able to facilitate additional demand for hydrogen which relatively increases the hydrogen price during these moments compared to a market with less hydrogen storage capacity and therefore the revenues that the electrolyser operator can make during these moments. On the other hand, during moments with relatively low electricity prices and high hydrogen prices, the electrolyser operator would make its highest margins. However, the storage operator also wants to sell its hydrogen during these hours (high hydrogen prices) and therefore hydrogen prices will go down during these hours if more storage capacity is installed (meaning a decreased margin for the electrolysers). Hence, the degree of hydrogen storage capacity stabilizes the hydrogen prices, which is partially beneficial (if hydrogen prices otherwise would have been low) and partially unbeneficial (visa versa) for the electrolysers. These are balancing out each other and therefore we do not see significant changes in the average hydrogen selling price or the required subsidy intensity for the electrolysers (see Figure 23).

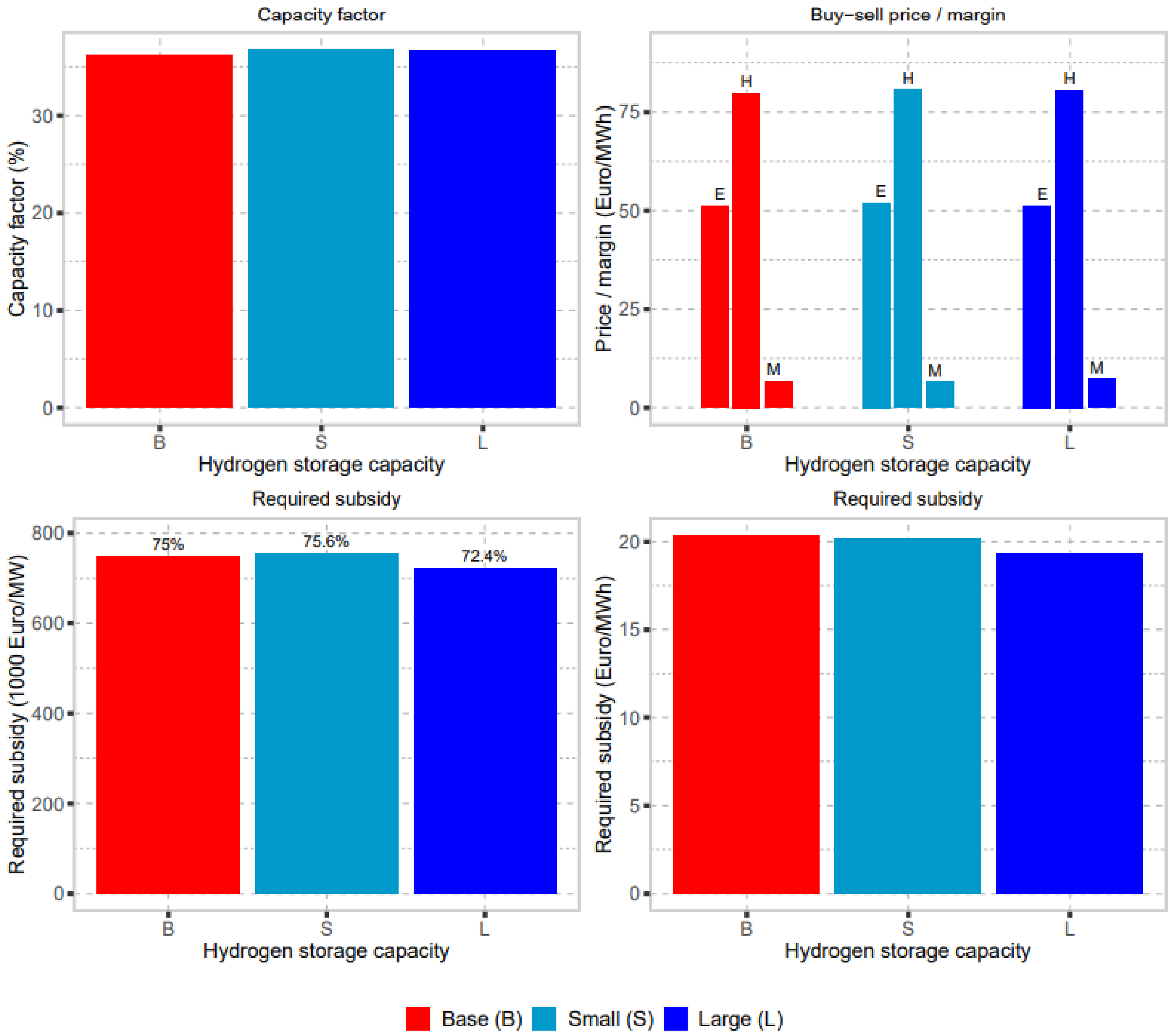


Figure 23 – Sensitivity impact of hydrogen storage capacity on electrolyser capacity factor, buy and sell prices and required support

It should be noted that in reality the storage capacity is sold via different types of services to a variety of clients. Traders that speculate on the market will behave like the storage operator in our model. However, in reality the electrolyser operators can also choose to book storage capacity giving them the freedom to withdraw and inject volumes of hydrogen based on the market conditions. Likewise can energy supplier or large industrial hydrogen off takers. Hence, the model sees the electrolyser operator and the storage operator as two different actors while in the reality the same private business can operate an electrolyser and capture value from operating (booked) storage capacity as well.

To conclude, from an energy systems perspective hydrogen storage capacities are seen to reduce fluctuations in hydrogen market prices and therefore provide more stable conditions for business cases of hydrogen market participants (e.g. producers and consumers).[17] However, from a market perspective there is no straightforward relation to the storage capacity and the value captured by operating the electrolyser. In order to say more about this, assumptions should be made on specific business decisions of the electrolyser and storage operators. This latter relates to research questions that will be answered in HyDelta D2.2.

[17] See also HyDelta D3.2 that also comes to this conclusion and assesses this from the actor risk perspective.

Comparing the impact of the investigated sensitivities

Figure 24 summarizes the impacts of the different drivers on the support per MWh renewable hydrogen produced required to get to a green hydrogen production break-even situation. Clearly one factor shows a stronger sensitivity result than another due to the assumed factor range (e.g. some assumed ranges were +20/-20% while others assumed +100%). Comparing sensitivities therefore only makes sense to the extent that consensus can be reached about feasible driver value ranges. Thereby, it should be noted that the actual impact of factors is mostly non-linear and depends on moderating effects of assumptions on other factors as well.

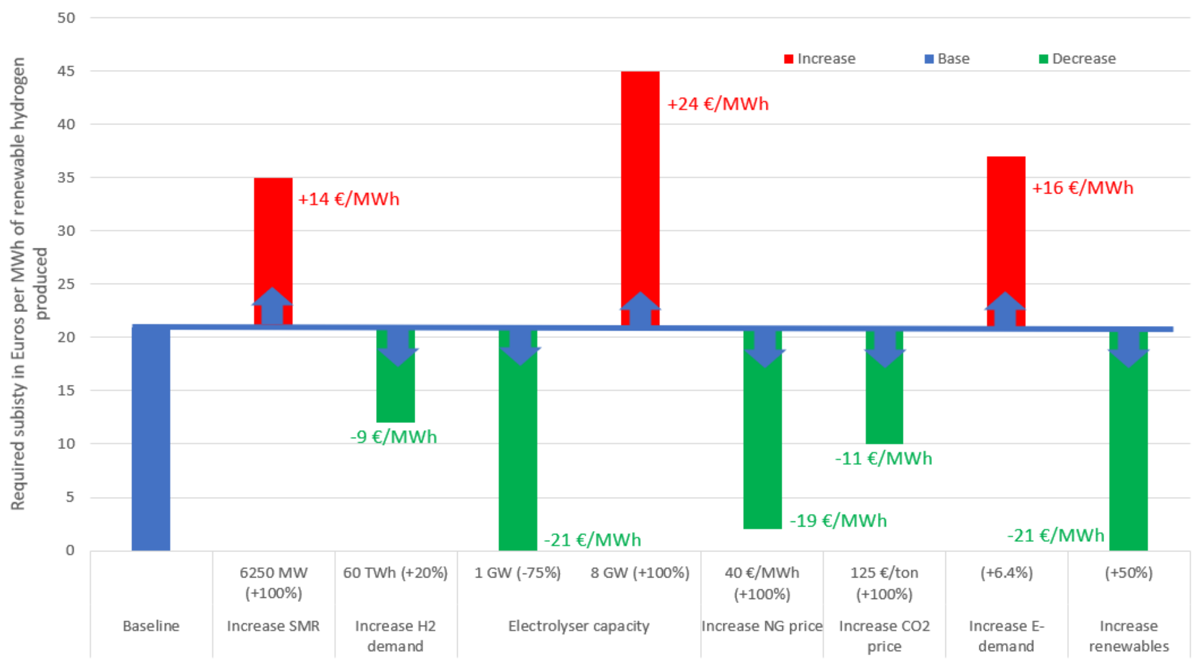


Figure 24 – Comparison of impact of the assumed sensitivity ranges between the different factors

The figure clearly shows that except the actual electrolysis capacity installed in the market, the change in renewable capacities and electricity demand under our assumptions had the strongest result on the support intensity required for the 4 GW electrolyser capacity. Developments in the electricity market therefore seem very relevant for the electrolyser business case. Especially, it was noticeable that the electricity demand was changed significantly less strong (6.4%) than the other sensitivities, but still has a significant impact. This is similar for the change in the demand of hydrogen: it was 'only' changed by 20%, which is less than the other sensitivities, but still has a significant impact on the required support to close the electrolyser business case.

The results show clearly the impact of the market drivers and its relation to the required additional support to create an economic case for 4 GW of electrolysis. Generally it seems the higher the electrolyser capacity targets the relatively more support has to be provided to close the business cases of these capacities. However, we see that some market drivers (which sometimes also have underlying policy drivers) have significant impact: if significant more renewable capacities are deployed we see that 4 GW of electrolysis can be operated without any support at all. Hence, the balance between all these market drivers will determine how much support in the end is required to achieve a certain magnitude of electrolyser capacity in 2030. To conclude all the relations that are described in simple guidelines:

- The more electrolysis capacity is to be installed, the relatively higher support intensity for electrolyser deployment is required;
- The more SMR capacity is operating in the hydrogen market, the relatively higher support intensity for electrolyser deployment is required;
- The higher the hydrogen demand, the relatively lower the support intensity for electrolyser deployment is required;
- The higher the natural gas price, the relatively lower the support intensity for electrolyser deployment is required;
- The higher the carbon allowance price, the relatively lower the support intensity for electrolyser deployment is required;
- The higher the electricity demand, the relatively higher the support intensity for electrolyser deployment is required;
- The higher the share of renewable capacities in the supply of electricity, the relatively lower the support intensity for electrolyser deployment is required.

These guidelines also work reversibly (if we would start with: 'the less …').

2.5.4 Discussion of results

The modelling results need to be interpreted with care and need to be put in the perspective of the real world to conclude on the main insights that can be obtained from it. This is why the relation with recent developments and the limitations of the performed modelling will be discussed next.

General limitations and considerations of modelling results

Equilibrium and dispatch models are suitable tools to investigate price setting of markets under different future scenarios. However, the outcomes of such models are determined by the input assumptions used. The assumptions in this study have been made with great caution and based on reliable sources. It moreover has been validated that if the right assumptions are made, the model results in prices that do match with historical prices (Appendix C). However, for future cases significant assumptions must be made on the installed capacities for each generation capacity, which are highly uncertain. Therefore, there is a uncertainty in the quantifications that should be acknowledged. The sensitivity analysis help to understand what the impact is if certain input parameters would change.

An important note with regard to zero-margin and positive-margin production hours of the electrolysers is that the model assumed the same technical specifications for all electrolysers in the market. In reality electrolysers will have different specifications in terms of efficiencies, water use and balance-of-plant designs, etc., and therefore have their own marginal costs, and even differences in marginal costs dependent on the load that they are running on. Hence, the zero-margin hours that are equal for all electrolysis capacity will differ (probably just slightly) in the real world to the degree that they will be 1) 'very small' margin hours, and/or 2) that certain electrolyser capacities with the lowest marginal costs in the market will capture most of the zero-margin hours and therefore could have a significant higher load factor than the electrolysers with relatively higher marginal costs.

A last important note is that the required subsidies should be taken as exogenous from the market equilibrium modelling. In other words, the subsidy is an output of the modelling activities in order to compare the economic viability of the electrolyser capacities. It is not evaluated to what degree (potential) subsidies may affect the marginal positions of the electrolysers, because this depends on the type of support and therefore requires additional research.

Moreover, the NPV of the installed electrolyser capacity has been determined based on the simulated year (2021 or 2030). This means that it has not been taken into account that the market could develop or change over time. Hence, if the market conditions for electrolysers will improve after 2030, less support would be required than concluded in this report; if the market conditions for electrolysers will get worse after 2030, more support would be required.

Impact of recent developments and trends

The energy transition is a highly prioritized political issue and due to the strong embeddedness of the energy system within society as a whole, a lot of rapidly following developments and disruptions do, and by expectation will, take place. Over the last years the general trend can be noticed that ambitions are becoming more extreme: more renewables, more electricity and hydrogen demand required for decarbonisation, higher electrolyser capacity targets and higher natural gas and carbon allowance prices than expected. The sensitivity analysis provides guidelines of how these developments might impact the required support for electrolysis capacity in 2030. The following paragraph illustrates some examples that can be considered to interpret the results.

Recent publications show that the expected Dutch demand for electricity should reach 206 TWh/y to align with the fit-for-55 target instead of 120 TWh/y assumed in the Climate Agreement [53]. This demand level will not be met even with the 2030 offshore wind target increased from 10.5 GW towards 21 GW (which was based on the maximum landfall potential of the Dutch electricity grid). Based on our modelling results we would expect that the increase in supply will be a driver towards deployment of electrolysers, but the increase of electricity demand will result in more competition for the renewable electricity. Several types of solutions are considered, such as additional offshore wind parks and electrolysis to land the energy in the form of hydrogen, stimulation of low carbon hydrogen production for gas-fired power plants or increasing the import of renewable hydrogen (carriers). It might be worthwhile to consider the market and support effects of the energy system including one or multiple of those solutions combined. Also, this should be considered in relation to the Dutch hydrogen roadmap proposal to increase the electrolyser target from 3-4 to 6-8 GW by 2030 [25].

Impact of other potential impactful factors: batteries, import and large-scale interconnections

Although the interactions between (future) electricity and hydrogen markets are considered in the modelling activity, there are three aspects that are not considered in great detail but are yet likely to be relevant for further consideration. Therefore, these are highlighted and discussed in this section.

The first one is the presence of electrical storage, especially in the form of battery electric storage and compressed-air energy storage (CEAS). Dutch grid operators currently have almost 20 GW of connection requests for battery capacity [54]. Previous research investigating different flexibility options showed that electrical storage and conversion and storage in the form of hydrogen provide different types of flexibility: batteries may be able to provide short-term flexibility more cost-effective, while conversion to hydrogen may provide more longer-term flexibility. However, also both technologies try to benefit from moments of low electricity prices. Hence, including the effect of batteries is expected to lead to less fluctuating electricity prices, potentially worsening the business case (and increasing the required subsidy intensity) of electrolysers.

The second one is the import of hydrogen carriers via ships. The Dutch hydrogen roadmap foresees that 100-167 TWh of hydrogen will be imported in 2030 [25]. This is an order of significance larger than the foreseen Dutch demand of 40-60 TWh [1]. A large share of the imported hydrogen carriers by ships is planned to be transited further into Europe. However, to what degree will these large, imported volumes affect the Dutch hydrogen market, if they will become reality. Part of it will be imported and used as ammonia or synthetic fuel, and will therefore never enter any future hydrogen transmission grid as central commodity marketplace. Under the Netherlands NSE 4 program a sensitivity analysis including shipped imports of ammonia and liquid hydrogen identified that both electricity and hydrogen prices will go down if shipping import routes will be established in 2050 [35]. Electricity prices drop because less electricity is demanded for hydrogen production and hydrogen prices drop because the supply of hydrogen increases. Because, as argued before, hydrogen prices tend to drop more than those of electricity, it seems likely that imports via ships worsen the business case of Dutch electrolysers if the other market characteristics remain the same. Also, cost-efficient importing corridors for commodities as green ammonia and methanol can replace domestic demand for gaseous hydrogen. In the sensitivity analysis we have seen that a decrease in hydrogen demand significantly impacts the business case of the electrolysers and thus the required Dutch support to get domestic electrolyser capacity off the ground.

The third one is the availability of large-scale interconnection capacities between countries. In order to limit the impact of uncertain foreign decisions on the Dutch hydrogen market in 2030, hydrogen interconnection capacities have been kept relatively low in the calculations (300 MW). If pipeline connections will be realised between countries based on existing natural gas pipeline dimensions, it can be expected that one pipeline can already provide more than 10 GW of interconnection capacity. Therefore, compared to the electrolyser capacity targets of 2030, potential interconnection capacity is significant. Simulations performed by the SuperP2G program suggest that due to differences in electricity prices among the North-Western European countries, in- and export volumes of hydrogen can be expected if international exchange becomes possible by 2030 [50]. It suggests that under these circumstances, countries with the lowest electricity prices will produce most of the green hydrogen and countries with the lowest natural gas prices will produce most of the blue hydrogen. Additional revenues for green certificates or due to support schemes are indicated to have significant impact on the business case of the electrolysers. It is worthwhile investigating in future research how this may affect exchange between the North-Western European countries. For example, differences between the support intensities of countries may drive electrolyser capacities to countries with the highest support intensities. Also, differences between countries applying supply-side support and others demand-side support, could lead to an increase in im- and export flows between countries, as was also witnessed with respect to biomethane in the past [55].

Reflection on the impact of recently proposed policies and support

In section 2.2 multiple political ambitions and policies have been discussed. In this section it will be reflected how the proposed policies in the Netherlands can influence the position of the electrolysers in the electricity and hydrogen markets. The following policies will be discussed: the IPCEI support for renewable hydrogen production, hydrogen under the fuel blending obligation and the proposed blending obligation for replacing grey hydrogen by renewable hydrogen in industry.

In December 2022 it was published that 7 Dutch IPCEI projects on the production of renewable hydrogen are granted considerable amounts of public support [56]. In total, the projects are expected to realize 1150 MW of electrolyser capacity and will receive 783.5 million Euros investment subsidy, or 681 €/MW. This support level is lower than the investment subsidy requirements of 998 €/MW and 750 €/MW that resulted for the modelling in 2021 and 2030 respectively.

A reason could be that the projects also consider the revenues for the green hydrogen certificates, which can be used since the beginning of 2022 to obtain HBE's[18], and potentially in the future also quota certificates for a blending obligation in industry. If the average 2020-2021 HBE price of 13-16 €/GJ is received including the multiplier bonus of 2.5 that counts for renewable hydrogen, an additional 117-144 €/MWh can be earned for the produced renewable hydrogen [47]. This level would in fact be

[18] *Hernieuwbare Brandstof Eenheid*, translated: Renewable Fuel Entity

significantly higher than the green hydrogen certificate price indicated in this study, which was in the range of 10 €/MWh based on experiences with historical green electricity certificates.

Given the required support level of 269 €/MWh of renewable hydrogen produced in 2021 (see Table 4 in the results chapter), the HBE revenue alone would not have been enough to close the business case of the electrolyser. The 2030 baseline modelling results suggest that in 2030 the electrolysers require less support (21 €/MWh) due to the increased capacities of renewables and increased demand for hydrogen. An important additional question for investors is now how the HBE prices will develop given the increased supply of renewable hydrogen and the increased blending target towards 2030. HBE prices may well remain fairly high, because recent research of TNO concludes that meeting the proposed sub-target of 2.6% RFNBO's for fuels [17] and 0.7% for the aviation fuels [18] will be a challenge given the supply options [57].

The Netherlands' ministerial letter of 5 december 2022 made clear that the Dutch government seriously considers starting a blending obligation in 2026 to replace a share of grey hydrogen in industry by renewable hydrogen [51]. The 2030 target of this obligation will be aligned with the European target that is proposed to be 50%. However, discussions are still going on: REPowerEU proposed to increase the target towards 75%, EU energy ministers proposed to decrease the target towards 35% and the preference of the Dutch parliament is to keep it at 50% (see Table 1 and the information in the section on the hydrogen policy drivers). The impact of such a blending obligation is that a dedicated demand for green hydrogen will be established in 2030. This means less chance that most potential new hydrogen demand will be filled in by new SMR or ATR activities, and a certain market share for renewable hydrogen producers. The Dutch demand for green hydrogen that we assumed in this study (25 TWh) falls in the middle of the broad range of potential renewable hydrogen demand that is expected to result from these policies (see again Table 1). Therefore, we think our assumptions give a good indication of the significance of renewable hydrogen demand that will be established by this policy driver. However, the exact impact of such a policy and the specific decisions made to apply the blending obligation can be a topic of further research. In previous HyDelta 1 research (D8.1) it was investigated that specific decisions in such policies could hugely impact the outcomes. The market implications of specific considered blending obligation policy designs are worthwhile investigating further before a final decision on implementation is made.

2.6 Take-aways and lessons learned

In part I of this report there has been shed a light on the driving factors of renewable hydrogen production in the Netherlands on order to answer the following research question:

''What are the drivers of hydrogen production usage in an integrated energy system, and how does this relate to the potential volumes of domestically produced hydrogen in the future?''

Based on the existing literature the most relevant market and policy drivers for renewable hydrogen production in the Netherlands for the coming decade have been evaluated. Energy system studies conclude that renewable hydrogen production via electrolysis mainly becomes beneficial in low carbon energy systems with high penetration of variable renewable energy sources [5]. In carbon-neutral energy system scenarios the renewable hydrogen option mainly competes with the use of biomass, fossil fuels applying CCS, or direct electrification. The degree in which electrolyser capacity will be established to electricity in renewable hydrogen will depend on: supply and demand characteristics in the electricity market; supply and demand characteristics in the hydrogen market; and factors such as the prices of natural gas and carbon allowances, and fees and premiums due to policy measures. A summary of these relations was visualized in Table 9.

Table 11 – Overview impact of sensitivities on the electrolyser business case and its required support

Relatively more/higher …		Impact load hours	Impact buy/sell margin		Overall impact electrolysis business case*
Electrolysis capacity		–	–		– –
SMR capacity		–	–		–
Hydrogen demand		+	+/-		+ + +
Renewable capacities		+	+		+ + +
Electricity demand		–	–		– – –
Natural gas price	**means…**	+	+		+ +
Carbon allowance price		+	+		+

***And therefore decreasing the required support intensity to close the business case (note that the strength is only for indicative purposes, most of the relations are non-linear and also interdependent on each other)**

The impact of these drivers and competing forces have been quantified for the period until 2030 by the applied modelling activities. It showed that:

- The expected increased penetration of renewables towards 2030 and increased demand for hydrogen will decrease the required support to make green hydrogen production economically feasible. This is because under these circumstances renewable energy capacities will become more often the price setting technologies instead of the natural gas fired power plants.
- However, under almost all the sensitivity cases the installed electrolyser capacity required support to close the business case Therefore it can be concluded that policy drivers are crucial for green hydrogen production in the Netherlands. The baseline case of 2030 resulted in a required support intensity of 21 €/MWh to economically deploy 4 GW of electrolysis capacity in the Netherlands.
- Hence, the total electrolyser capacity that can be operated profitably to produce domestic green hydrogen in 2030 will depend on the interrelations between market developments and the willingness-to-support of the government. It has been evaluated that more SMR capacity, lower hydrogen demand and higher electricity demand will increase the required support to deploy the same capacities of electrolysers in 2030; and less SMR capacity, more hydrogen demand, a higher carbon allowance price, a higher natural gas price and more installed VRE capacity will decrease the required support to deploy the same capacities of electrolysers in 2030.
- As far as the impact of different factors can be compared due to their interrelatedness, under our assumptions the demand for hydrogen and the deployment of renewable capacity had the biggest impact on the required support levels for electrolysers. A higher demand for electricity in 2030 also significantly impacted the required support levels for electrolysers due to the increased competition for the renewable electrons.

Discussion of the results made clear that further research on the following topics would be desirable:

- Research on the impact of different support schemes on the marginal position and operation of electrolysis in the integrated energy system.
- Research on the market and support impact of different solutions for meeting the fit-for-55 targets in the Netherlands considering specific combinations of measures such as: additional

offshore wind parks and electrolysis to land the energy in the form of hydrogen, stimulation of low carbon hydrogen production for gas-fired power plants, and/or increasing the import of renewable hydrogen (carriers), also in the light if the proposed 8 GW of electrolysis in 2030.

- Since the impact of batteries was excluded in the modelling activities, dedicated research can focus on the impact of installed battery and/or CAES capacities on the energy prices and the conversion of electricity towards hydrogen.
- As the impact of different support schemes and support intensities of neighbouring countries could have significant impact on the in- and export flows of renewable hydrogen between the countries, and so on domestic production, it is necessary to explore the proposed schemes in the neighbouring countries and to assess how well these align or harm the hydrogen ambitions of the Dutch government.

3. Drivers for renewable hydrogen production locations

In this chapter we will assess where in the Netherlands the future central and decentral electrolyser capacities are likely to be located. To clarify, the issue how much central versus decentral capacities may emerge is not discussed in this study, but merely the issue if such capacities are installed at what locations this is likely to happen. Obviously such information is important for TSO and DSOs in preparing for expanding hydrogen and electricity infrastructure. With central electrolysers large (>250MW) electrolysers are meant that typically primarily operate in and for the primarily coastal main industrial cluster areas; decentral electrolysers are smaller, from a few hundred up to some MWs only, and typically used for hydrogen activity in so-called cluster 6 industries, local built environment and as a fuel for diverse local mobility activity.

Currently, the trend is seen that in terms of capacity, most electrolyser projects in the Netherlands are being developed at four clusters in the coastal areas (see Figure 25), especially near the harbours and main industrial clusters. The reasons are that such locations are close to: landfall locations of (planned) offshore wind capacities; existing infrastructure in the harbour areas for electricity, gas and chemicals; and the locations with the largest projected concentrated future demand for green hydrogen. The seven supported IPCEI electrolyser projects mentioned in the former chapter are, for instance, all located near the coast and the main industrial clusters throughout the country. All such investment can be seen as the start of the national central electrolyser capacity. These locations are characterised as ‘central’ hydrogen production locations, because they are concentrated at four clusters and involve significant planned capacities of initially already over 250 MW per cluster. Also, it is seen that a potential fifth (and maybe after 2030 even more) significant cluster is aimed to be developed offshore (by the H2opZee project). The exact offshore location of this cluster is not determined yet.

At the same time various pilots are popping up throughout the country focussing on local industry, mobility and built environment. Most of them are experimental, subsidy-driven and with a focus on testing and demonstration, but they may often be considered as promising starting points of broader local, decentral green hydrogen production and use. Obviously locations near the hydrogen backbone may have the benefit of stable hydrogen supply and relatively short-distance from that supply, but also further away from the backbone interesting new initiatives are meanwhile emerging everywhere. This makes it ever more interesting trying to understand what determines location choices of decentral electrolyser investment and hydrogen activity.

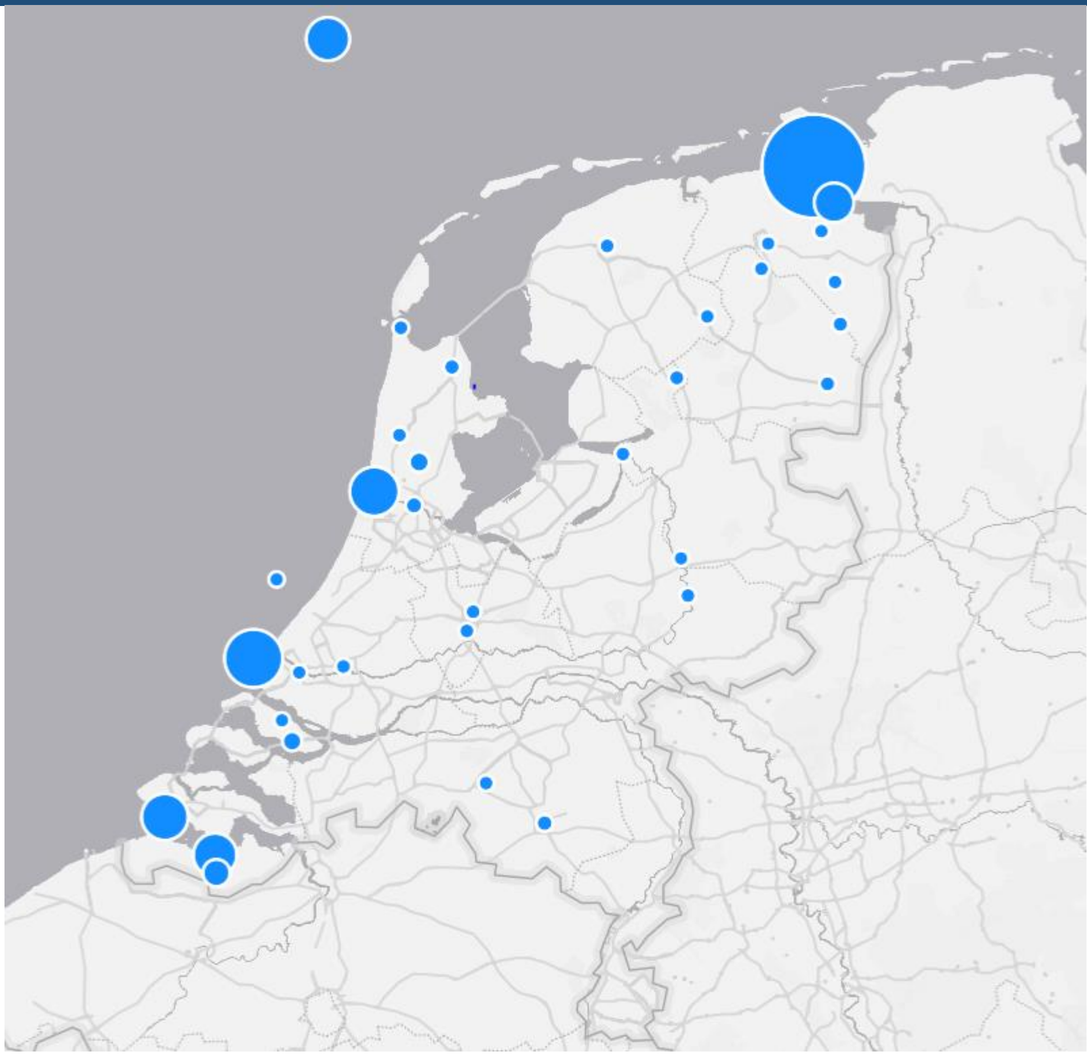


Figure 25 – Overview capacity distribution of existing and aimed electrolyser projects in the Netherlands until 2030, based on [58] and project specific publications.

In total Figure 25 shows 53 projects containing a total of around 8.5 GW electrolysis capacity by 2030. A large proportion, namely 4 GW, of this capacity is aimed to be developed by the NortH2 project [59]. As part of the NortH2 consortium, RWE – until now – is the first and only party of this consortium to announce concretely that 600 MW electrolysis is aimed to be located in Eemshaven by 2027 [60]. Further, the four other aimed and realised electrolysis projects in this Northern cluster add up to 950 GW in Eemshaven and 300 MW in Delfzijl. In the IJmuiden area two projects add up to 600 MW. In the Maasvlakte area four projects add up to 1150 MW. The fourth main cluster in the South of Zeeland involves five projects adding up to 1000 MW of aimed electrolyser capacity by 2030. The remaining 27 inland projects together represent a total capacity in the magnitude of 100-150 MW, mostly considering electrolysers of 1-5 MW, and in a couple of cases 10 MW or 30 MW.

In the literature, various location aspects of green hydrogen production and use have been discussed, also partly with a typical focus on the Netherlands situation. Studies to be mentioned are, for example, discussing: to what extent electrolysis business cases may benefit from e-grid congestion [61]; how electrolysers may help integrating renewable sources more cost-effectively [37], [38], [39], [40], [62], [7], [63]; and if clean hydrogen should optimally be produced on- or offshore [64], [65], [66]. There seems to be consensus that the location choice of electrolyser investment does matter: local conditions may affect the business case [61]; it may decisively determine to what extent electrolysers contribute to integrating renewables into the (local) energy system, and to saving societal costs; and the presence of local electrolyser capacity may have a crucial impact on local greening and whether or not additional grid reinforcements are or even grid expansions are required to service the local energy system [62].

Although issues of the optimal location of electrolysers have been discussed in various studies, to our knowledge an overview of the main drivers of electrolyser location decisions in the Netherlands was not part of that. That is why in this chapter we will try to provide a first desktop-based snapshot assessment of the main factors driving electrolyser location decisions in the Netherlands' context. In doing so, we will use the data from existing literature as well as the most recent information on planned and considered investment. Chapter 3.1 starts with an overview of general drivers and preconditions of electrolyser locations and chapter 3.2 continues with specific drivers for central and decentral electrolysis (see Figure 26).

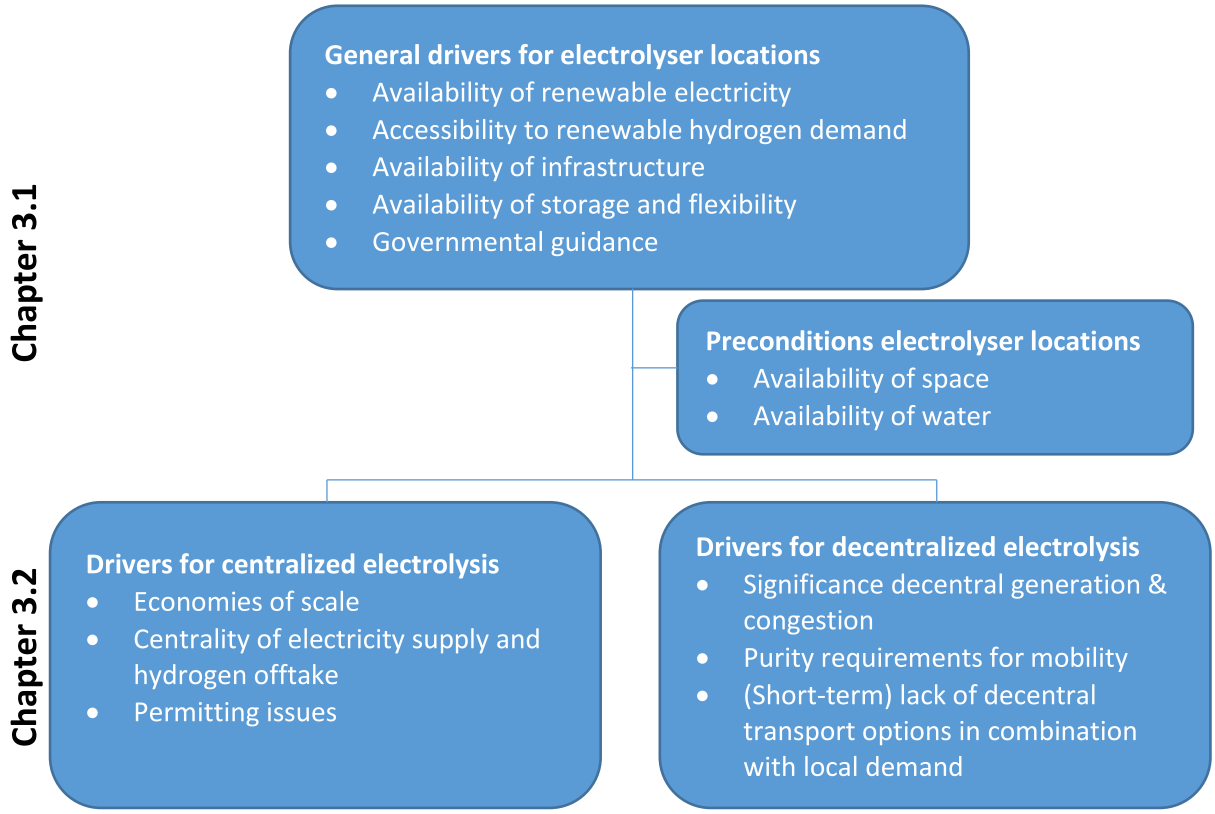


Figure 26 – Overview and reading guide chapter 3

3.1 General drivers for renewable hydrogen production locations

This chapter explains general factors that impact the value of electrolyser capacity at certain locations, independent if these locations are centrally in clusters or distributed decentral. Table 12 provides an overview of the main five general drivers that will be described in this chapter. Also, the table summarizes the type of locations where the driver is applicable (location determinants). In the next subsections each driver will be discussed in greater detail. First, starting with an explanation why this driver is relevant with regards to the system value and business value of the electrolyser. Secondly, it is described where the relevant location determinants are for the driver and, if relevant, how these might develop in the future.

Table 12 – Overview of location drivers described in chapter 3.1: general location drivers and the specific aspects determining these locations

General location driver	Location determinants
Availability of renewable electricity	Landfall offshore wind; offshore wind farms & hubs; onshore renewables.
Accessibility of renewable hydrogen demand	Central industrial clusters; decentral industries; mobility hubs; built environment; agriculture.
Availability of infrastructure	On- and offshore gas pipelines and handling infrastructure; gas and electricity grid connections; lack of electricity grid capacity.
Availability of storage and flexibility	Large scale storage; dispatchable hydrogen production capacities.
Governmental guidance	Landfall decisions offshore wind; support hydrogen backbone; (in)direct locational aspects in market regulation, support criteria and permitting.

3.1.1 Availability of renewable electricity

For green hydrogen production access to sufficient green electricity is key. But that is not the only reason why electrolysers are often typically located, or planned, close to green electricity sources. System advantages are:

- Electrolyser offtake may reduce risks of intermittent energy sources overburdening the local e-grid capacity or balancing conditions, and thus congestion risks, if located close to the sources of green power production.
- Because hydrogen transport costs are much (10-15 times on average) lower than transporting comparable energy content by way of power, it by definition is the most cost effective – if conversion to hydrogen is feasible - to locate conversion capacity as close to the green power sources as possible. Note also that in the case of the Netherlands the existing Dutch gas grid has over ten times more energy transport capacity than the electricity grid.

Besides the energy system arguments there are also business arguments locating electrolysers relatively close to green electricity production sites:

- If the wind and/or solar park as well as the electrolyser are (physically) integrated because operated by one and the same firm or owner (or operators of both collaborate closely contractually) risk-return combinations can be improved because volumes and price risks of the delivery of the electricity inputs can be mitigated (while something similar may or may not be feasible when selling the hydrogen). In such cases energy transport costs can be reduced by aligning the operation of the electrolyser with the renewable electricity source

Offshore locations of renewable energy in the Netherlands

Appendix A shows the locations of the dominant source of future national green power production, the >21 GW Dutch offshore wind capacity planned to be operational in 2030. The bulk of it (16.7 GW) is planned north-west of the country; a considerable share (5.3 GW) north of the Waddensea area, and some small (1.5GW) capacity west of Zeeland. Obviously the landfall of these capacities will determine where its green energy will become available onshore, which is not yet decided. In this regard an exploratory study is worth mentioning [63][19] in which two potential scenarios for the landfall

[19] This study is discussed in particular because the Dutch government asked for this study as input for their plans on offshore wind development in the period 2030-2040 and the study provides clear insights on the

of the assumed 38.5 GW offshore wind capacity in 2040 are given (for an illustration, see Figure 27). The first (right) scenario focusses the main landfall in Eemshaven (in the north of the country), and the second (left) at Maasvlakte (the much more crowded west of the country). The major backdrop of the Maasvlakte scenario compared to the Eemshaven scenario turned out to be that Maasvlakte requires significantly more additional electricity grid reinforcements and therefore costs and risks than the Eemshaven main landfall.

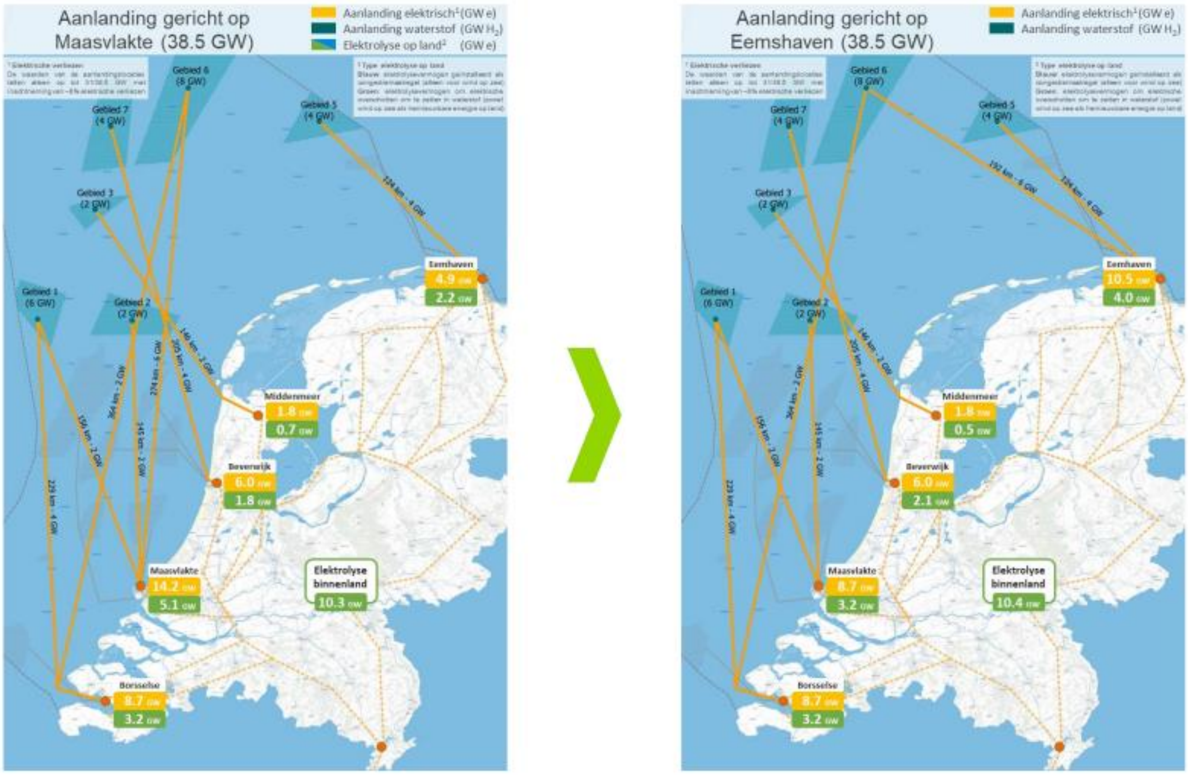


Figure 27 – Overview of two potential landfall scenarios of 38.5 GW offshore wind in the future Dutch energy system, based on the Dutch energy scenario with national steering and grid-integrated electrolysis only [63].

The table below shows the distributions of landfalls of offshore generated electricity among the Netherlands, based on the current realised and planned wind farms and the 2030 and 2040 projections of the Guidehouse & Berenschot [63].[20] It should be taken into account that the study only looks towards landfall from the perspective of the energy system, while it seems realistic that spatial constraints in harbours might become another decisive constraint for the landfall of energy [67].

*Table 13 – Overview of landfall offshore wind in the Netherlands. *for the increased amount of offshore wind the same landfall is considered as in [63]. Obviously for most wind parks the actual location of landfall is not determined yet. **these numbers are including electricity transmission losses.*

Location	End 2022	2030 plans*		2030 acc. [63]	2040 acc. [63]
Eemshaven	0.6	5.3		1.4	10.5**
Den Helder (Middenmeer)	0	0		0	1.8**
Amsterdam (Beverwijk)	0.35	3.1		2.5	6**
Rotterdam (Maasvlakte)	0	9.6		5.4	8.7**

landfall of electricity in relation to the potential locations of electrolysers based on Dutch electricity and hydrogen demand projections

[20] The Guidehouse & Berenschot study was mainly focussed on 2040. But provided a single baseline scenario for 2030 based on the political plans at that time (which are currently outdated, see column '2030 plans')

Zeeland (Borssele)	1.5	5.5		1.4	8.7**

The scenarios of [63] also provide perspectives on the potentials and locations of electrolyser capacities in the main harbour areas, based on the projected regional demand for electricity and hydrogen and grid constraints. These energy system optimisation based projections suggest that around 60% of future electrolyser capacity is likely to be located coastal, near landfall locations of offshore electricity. So, the remaining 40% of future electrolyser capacity is projected to be located inland. Part of the latter capacity will be linked to the inland industrial cluster in Limburg (one of the group of main industrial clusters of the country); the remainder will be elsewhere throughout the country and potentially decentral.

Other scenarios developed in [52] that included the option of hydrogen imports suggested (much) lower 2040 electrolyser capacities, namely 5 GW in the coastal regions and 2.7 GW inland [63]. However, disregarding imports but instead including a direct (contractual or ownership) link between offshore windfarms and onshore electrolysers[21], raised 2040 electrolyser capacity figures considerably to 17.1 GW in the coastal regions (incl. Den Helder with 7.6 GW) and 7.8 GW inland. Note that in all other scenarios the Den Helder area was not considered to become a main landing point due to the limited electricity transmission grid capacity in this area.

Another distinction with respect to electrolysers locations if offshore wind is available, is whether electrolysers are located at the coast or rather offshore by way of (see also [68], [69], [70]): in-turbine electrolysis, electrolysis on platforms, or electrolysis on (artificial) islands.

Table 14 – Overview of Dutch electrolyser pilots and projects related to the landfall of offshore wind

Onshore electrolysis		
Eemshaven area	Rotterdam/Maasvlakte area	Zeeland (Borssele area)
• NorthH2* • HyNetherlands • Eemshydrogen • Energiepark Eemshaven West	H2 Conversion Park: • Shell Hydrogen Holland I • Uniper • CurtHyl • H2 Fifty	SeaH2Land
Offshore electrolysis		
In-turbine electrolysis	Electrolysis on platforms	Electrolysis on artificial islands
• Hydrogen Wind Turbine (Wieringermeer)	• PosHydon • H2opZee	• Danish North Sea Energy Island**

*Not certain yet to what degree electrolysis will be performed offshore as well.
**This is not a Dutch, but a Danish project and it is not sure to what degree electrolysis or other forms of Power-to-X or electricity storage will be performed on this artificial island. However, it is the most concrete example that shows that this option is considered in the North Sea area.

In fact, various studies have analysed the pros and cons of onshore versus offshore electrolysis [64], [65], [66]. For a summary of the main considerations by the North Sea Wind Power Hub, see Figure 15.

[21] This avoids the need of specific electricity grid reinforcements.

Consideration	Onshore landing zone	Offshore
Costs	HVDC cables Offshore HVDC and transformers Onshore HVDC and transformers Compression cost Operational and maintenance costs	Marinization costs Substructure and topside costs Pipeline cost Compression cost Operational and maintenance costs Power infra - PtG interconnections
Performance	Electrical transmission losses Onshore utilities	Offshore utilities, (incl. desalination) Availability considerations
Trading	Grid connection capacity Heat integration in district system	Grid connection capacity
Environmental and OSBL	Cables and cable crossings to shore. Availability of onshore land. Re-use of side products Oxygen and low temperature heat (e.g. for residential heating).	Offshore structures Cooling water and salt water discharge.

Figure 28 – Considerations in locating electrolysers onshore or offshore [66]

Clearly distances do matter a lot. It generally holds true that the longer the distance between the offshore wind park and the shore is, the higher the cabling costs will be compared to the additional costs of performing Power-to-Gas offshore. So, the longer that distance is, the more cost-effective offshore electrolysis becomes [71]. Especially when existing pipelines can be reused for transporting hydrogen to shore, offshore hydrogen production becomes more economically feasible than onshore [65]. The North Sea Energy program projections suggested that large-scale hydrogen production (~4 GW) on islands would be slightly more cost-efficient than on platforms [67]. However, this conclusion also depended on: the exact offshore location; whether or not capacity is built in phases; and the degree to which cabling costs and/or space on platforms can be saved by smart positioning [67].

Figure 29 – Landfall scenario including offshore coupled electrolysis, onshore coupled electrolysis and grid-integrated electrolysis, based on national steering [63]

The in-turbine option was evaluated to be less economically attractive than offshore conversion on platforms, because of the lower economies of scale and the relatively high distribution and compression costs of collecting the hydrogen from the single turbines [68]. However, other experts highlight the economic advantages of in-turbine production due to the reduction of electrical transport and AC-DC and reverse conversion losses [72] [73].

Many experts expect that large-scale offshore electrolysis will technically and economically be feasible after 2030 only [63], [66]. Combining the arguments mentioned, it seems likely that if offshore hydrogen production will take place in the Dutch Exclusive Economic Zone (EEZ), this will be at locations relatively far away from shore (e.g. the A, E and F blocks). As large-scale onshore electrolysis is expected to be developed earlier than offshore electrolysis, an open question is to what degree offshore electrolysis will eventually outcompete onshore electrolysis.

The scenario of [63] that does include offshore electrolysis suggests that grid-integrated electrolysis in the coastal areas is still needed to adsorb offshore wind power in the electricity grid. This scenario resulted in: 12 GW of electrolysis capacity being located offshore at 'search area 6' (the produced hydrogen could either be landed in Eemshaven or Den Helder); 7.2 GW in the coastal areas; and 7.4 GW at inland locations (see Figure 29).

Two other research projects, namely the North Sea Wind Power Hub and North Sea Energy 4, also assessed potential offshore electrolysis locations in the (Dutch part of the) North Sea. North Sea Wind Power Hub mainly analysed this from the point of view of how significant volumes of offshore wind can be integrated in national electricity and gas grids of countries around the North Sea (see left side of Figure 30). The North Sea Energy 4 program analysed potential locations mainly in combination with other offshore energy activities, such as platform electrification and CO2 storage, and the potential of re-using existing infrastructure in the Dutch part of the North Sea. Three offshore energy hub locations with P2G potentials were identified (see right side Figure 30).

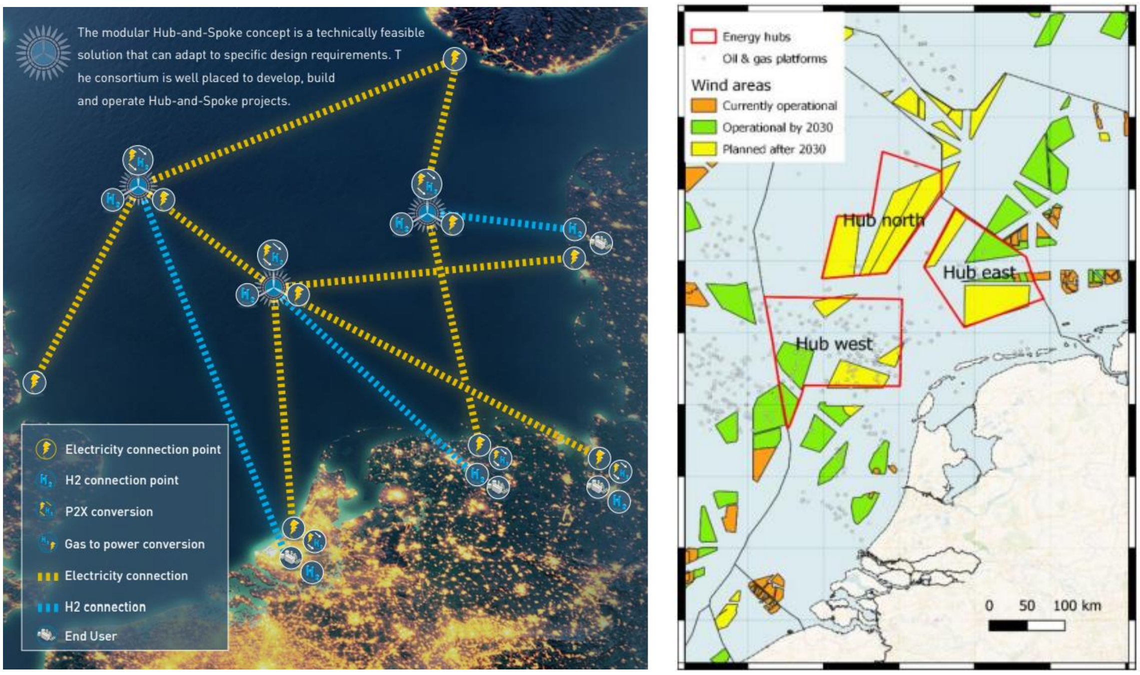


Figure 30 – Vision on Hub-and-Spoke concept (left) [74] and Dutch offshore energy hubs [67] including offshore P2G locations

Onshore locations of renewable energy in the Netherlands

In the Dutch Climate Agreement there are no clear targets for onshore wind and solar PV capacities, because these will be based on the Regional Energy Strategies in order to ensure public acceptance [1]. Yet it was prognosed that 3.7 GW of onshore wind and 14.3 GW of solar PV will be up-and-running in 2030 [1]. Respectively and assuming the typical number of load hours for these type of installations these capacities will result in approximately 12 and 12.2 TWh of electricity generated annually. However, at the end of 2021, due to a sharp increase of capacities in the preceding three years, it turned out that 5.3 GW of onshore wind and 14.3 GW of solar PV had already been realised [75], [76]. Figure 31 – Locations of wind turbines (left) and solar PV (right) in the Netherlands throughout the Netherlands (2021 situation). Onshore wind capacities are clearly located near the coastline, as wind speeds are generally higher. Solar PV is distributed more throughout the country, although the major clusters can be found in less populated areas. If both sources are combined, four major renewable energy generation clusters can be defined: Groningen-Drenthe, Flevoland, Noord-Holland Noord and Zeeland.

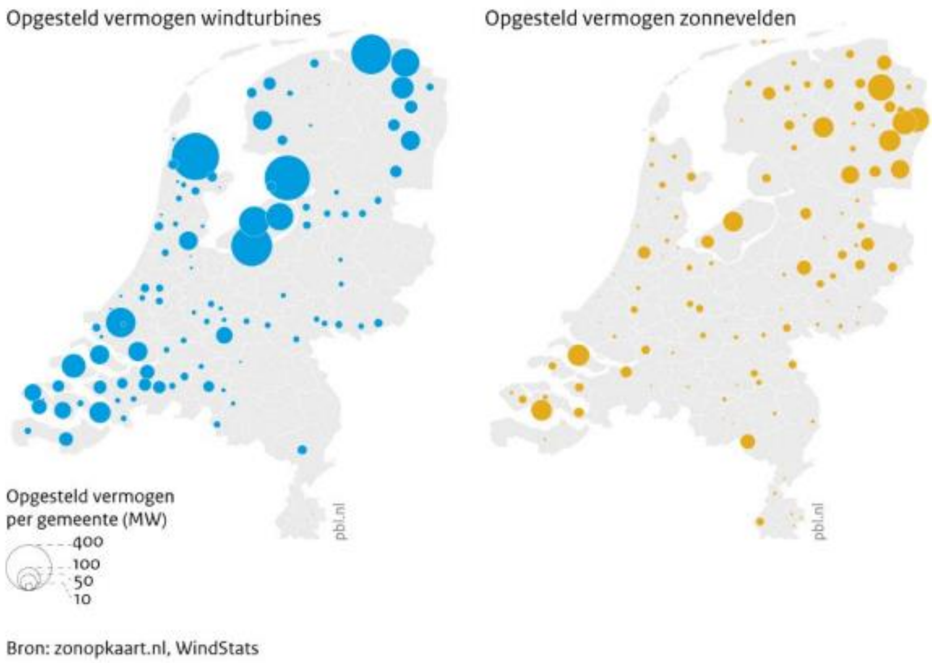


Figure 31 – Locations of wind turbines (left) and solar PV (right) in the Netherlands [77]

Combined the 30 Regional Energy Strategies include plans to produce 55.1 TWh of renewable electricity from wind and solar by 2030 [77]. This increase surpasses the target of 35 TWh mentioned in the Climate Agreement.

Error! Reference source not found. shows the renewable production capacities aimed for in the various Renewable Energy Strategies. The five highest ambitions for solar and wind have been highlighted in yellow. If these regions fulfil their ambitions, by 2030 the same regions as we already mentioned in Figure 31 will remain the mainstay of local renewable electricity production.

However, it will be a challenge to integrate all new renewable capacity into the electricity grid. A grid analysis of the Distribution System Operators (DSOs) concluded that one can integrate between 31 and 46 TWh of renewable energy by 2030 [77]. This range is based on uncertain factors, such as electricity demand and flexibility measures. Next to the availability of distributed renewable energy, the locations of electrolysers inland are expected to be strongly affected by renewable hydrogen demand and local limitations of the electricity grid. These factors, as well as examples of related pilots and other projects, will be further discussed next.

Table 15 – Aimed renewable production (in GWh) by individual Renewable Energy strategies [77]

RES-regio	**Wind-molens**	**Zon-pv** totaal	**Zon-pv** op daken	**Zon-pv** op velden	**Zon-pv** op daken of op velden	**Wind-molens of zon-pv**
Achterhoek	546	350	350	0	0	454
Alblasserwaard	157	163	127	0	36	0
Amersfoort	417	512	210	278	24	0
Arnhem Nijmegen	471	1.145	490	655	0	0
Cleantech regio	110	960	510	450	0	0
Drechtsteden	0	210	210	0	0	160
Drenthe	1.123	2.142	893	1.249	0	234
Flevoland	4.640	1.170	140	950	80	0
FoodValley	254	710	409	262	39	0
Friesland	1.903	592	279	313	0	505
Goeree-Overflakkee	706	147	61	86	0	0
Groningen	3.430	2.270	0	1.880	390	0
Hart van Brabant	119	431	340	81	10	450
Hoeksche Waard	335	51	30	21	0	0
Holland Rijnland	90	363	290	3	70	687
Metropoolregio Eindhoven	234	1.089	973	116	0	677
Midden-Holland	26	407	190	164	53	0
Noord- en Midden-Limburg	338	622	481	46	95	240
Noord Holland Noord	1.689	1.707	796	498	413	204
Noord Holland Zuid	567	2.312	1.099	663	550	0
Noord Veluwe	220	310	120	190	0	0
Noord-Oost Brabant	140	870	400	17	453	590
Rivierenland	750	584	301	283	0	0
Rotterdam-Den Haag	1.867	1.336	782	554	0	0
Twente	421	923	336	587	0	156
U16	542	1.360	595	765	0	0
West Overijssel	651	1.175	608	567	0	0
West-Brabant	1.238	1.242	838	404	0	200
Zeeland	1.950	970	485	485	0	0
Zuid-Limburg	170	1.160	710	450	0	0
Kolomtotaal *)	**25.104**	**27.283**	**13.053**	**12.017**	**2.213**	**4.557**

3.1.2 Green hydrogen demand

Integrated electricity and gas grid studies typically recommend that flexibility providers, such as P2G installations, should be located as close to the source of variability, commonly the intermittent power production site, as possible in order to minimize transport costs and avoid overburdening the grid [78], [7]. There may, however, be exceptional cases where e.g. electrolysis near demand locations is desirable, such as:

- If the by-products of electrolysis such as oxygen offer very attractive business opportunities, e.g. using oxygen as feedstock (e.g. for medical gases [79] or the production of organonitrogen chemicals [80]), or to achieve the right flame conditions in industries that require high temperature heat (e.g. glass melting, melting and glowing of metals, and in the production of ceramics and cement [81]). Another by-product of electrolysis, heat, can also be highly valuable in industry or for heating the built environment [82].
- Hydrogen produced by electrolysis has a purity of >99.99% [83] [84]. It will, however, be difficult to maintain such high purities in a grid based on existing pipelines [84]. Therefore, it may be desirable for end-users requiring high purities (e.g. fuel cells in mobility or specific industrial feedstocks) to produce hydrogen themselves near uptake locations instead of purifying hydrogen from the grid or retrieving it via tube trailers.
- Currently still very little transport and storage infrastructure for hydrogen is available. So, early adopters of green hydrogen may locate their electrolyser on-site for that reason.

Potential hydrogen demand locations in the Netherlands

In the current situation in the Netherlands, grey hydrogen is typically produced in the regions in which it is demanded, i.e. in the main industrial clusters [85]. **Error! Reference source not found.** shows moreover that 63% of national hydrogen demand in 2019 was located in the Maasdelta and Zeeuws Vlaanderen only.

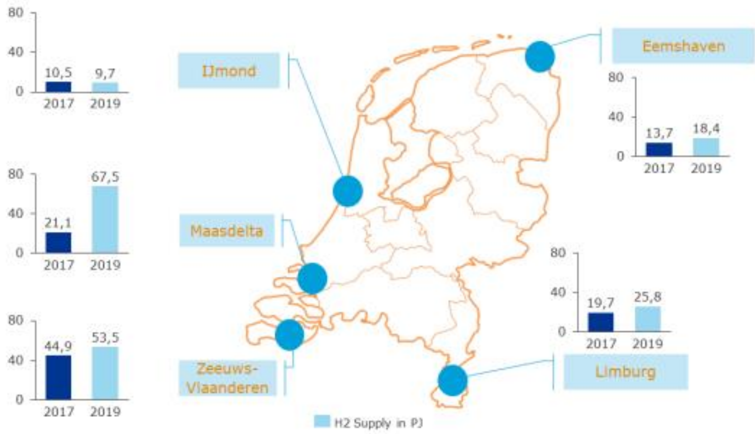


Figure 32 – Grey hydrogen supply and demand in 2030 [85]

The prognoses in the Cluster Energy Strategies (CES) of the main industrial clusters give an impression of the future demand for hydrogen. Figure 33 shows the (actual and) projected green and blue hydrogen production and demand in each cluster: the Rotterdam area and Zeeland are expected to stay the main hydrogen demand centres. However, the highest published ambition of green hydrogen production capacity in 2050 is at Eemshaven. Combined, the five clusters aim for 9 GW of electrolysis capacity to be deployed by 2030, next to the production of 190 petajoules of blue hydrogen [86]. Note that the CES were published before the Ukraine-Russia war and depend on plans of individual industries that remain uncertain until final investment decisions are made.

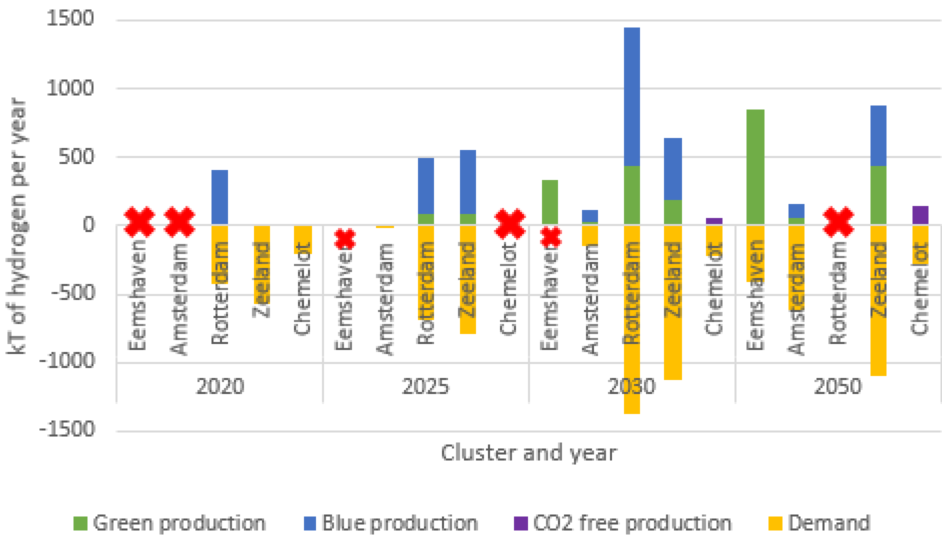


Figure 33 – Overview of projected hydrogen production and consumption in the five central industrial clusters according to their Cluster Energy Strategy [87] [88] [89] [90] [91] [92]. The figures exclude imports of hydrogen in the port areas. Red crosses indicate that no data was included in the CES.

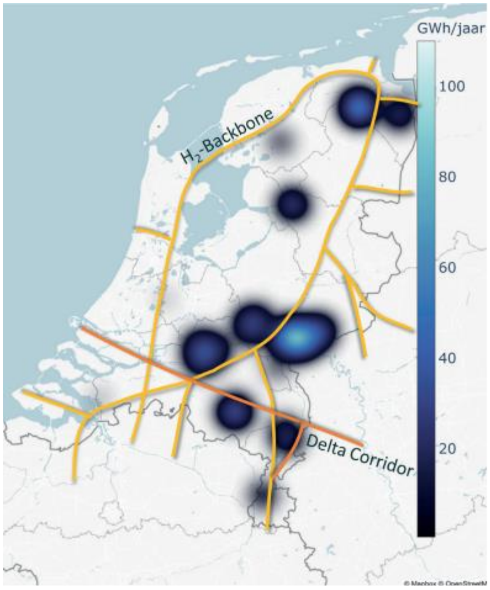
So, there are several electrolyser projects due to be developed in the five industrial clusters. Next the projects will be described of which the location is assumed to be linked to local industries in these clusters (because these industries are directly connected to the electrolysers as end-user of hydrogen, and often themselves involved in the electrolyser activities).

Djewels I & II is a project developed by HyCC. Formerly Nouryon (the chemical division separated from AkzoNobel) originally developed this project (of which next activities were concentrated in Nobian. and later in the company specialised in hydrogen, HyCC). Through its origin, Djewels could therefore use existing expertise on large-scale production of salt, chlor-alkali and chloromethane. Based on this knowledge the project developed into an unit specialised in producing green hydrogen. Djewels I & II are still located at the site of the mother company, and therefore near green energy production and chemical sites.

H2ero (150 MW, Zeeland Refinery), Haddock (100 MW, Yara) and H2ermes (100 MW, TATA Steel) are also projects developing electrolyser activities on industrial sites. The sizes of the planned electrolyser capacities are by far not enough to decarbonize the connected plants. Yara, for example, is very clear in its vision to in due time obtain low carbon hydrogen via the backbone rather than producing it itself [93]. Also the NZKG cluster strategy assumes that large imports of hydrogen are needed to enable TATA Steel to switch to hydrogen completely [90]. One motive for the hydrogen route of the three projects is to become a frontrunner in scaling up the related technologies [93]; another to use the oxygen in their own full industrial processes [94] [95].

Potential hydrogen demand and production by distributed industrial locations

In decentral industries there are still many uncertainties on if and how their future demand for low carbon hydrogen may develop. Previous HyDelta1 research concluded that if all current natural gas demand for high-temperature heating (>600 °C) by the decentral industries would be replaced by hydrogen demand, this would lead to an annual hydrogen demand of some 360 kton [2]. The Cluster 6 Strategy estimated the volume (and locations) of hydrogen demand by decentral industries willing to cooperate [96] to be max. 27 kton by 2030 and 50 kton by 2050. Figure 34 shows that almost all of this demand is located near one of the two large national hydrogen infrastructure projects. Note, that this information is based on responses only and thus probably incomplete. For example, it is known that the industry at GETEC in Emmen is planning to use hydrogen as well in the coming years, but not yet shown on the map. Another reason why information still may be incomplete is that industries further away from the backbone do not yet consider hydrogen by 2030 because delivery is still too uncertain for them.



In kton/y	2025	2030	2050
Conditional projects	1.5	6.3	17.8
Uncertain projects	0.3	20.7	32.6
Total	1.8	27.0	50.3

Figure 34 – Expected hydrogen demand by decentralized industries in 2030 according to the CES [96]

Another HyDelta1 finding was that there were no electrolyser projects specifically located at decentral plants. Some decentral plants have started experiments using hydrogen, such as the GETEC park and Nedmag, but they obtain the hydrogen from elsewhere rather than producing it onsite [97] [98].

Potential hydrogen demand by other applications

There are several smaller, decentral hydrogen demand cases where an onsite investment in an electrolyser at some stage may be considered even if they typically involve a bigger commercial challenges.

A first case relates to the demand for hydrogen by mobility at hydrogen refuelling stations (HRS). In the Climate Agreement [1] a target of 300,000 FCEVs by 2030 has been set involving an annual estimated hydrogen consumption level of 141 kton. HRS locations are expected to be spread all over the country to cover future demand for hydrogen in mobility. It can be worthwhile for HRS sites to explore local production of renewable hydrogen on or near site. HyDelta1 concluded on this that costs of a local route did not differ significantly from those of obtaining the hydrogen from central locations [2]. The cost advantages of local production were that no additional purification step was needed, nor incurring the costs of the relatively expensive last-mile distribution. An example of locating an electrolyser at the refuelling station is Bornholmstraat in Groningen where the HRS of Holthausen Energy Points obtains its green hydrogen from an electrolyser directly connected to a local solar park.

Next to road transport there are also interesting hydrogen developments at airports and ports. At the airports, examples are the WAviatER and NXT Airport initiatives at Airport Eelde and the H2 Air Base Leeuwarden initiative. Both airports plan to locate large solar parks around the airport area and convert its electricity into hydrogen to be used as fuel for the diverse vehicle fleets in and around the airports. A similar approach is seen at some ports: Hy4Am in Amsterdam, a 2.5 MW electrolyser at Den Helder, an electrolyser at the Kampense Zuiderzeehaven and VoltH2 in Terneuzen (starting at 25 MW to scale up towards 80 MW in 2030). Both, airports and ports, shared the advantage of being logistical nodes where multiple types of transport can mutually benefit from the hydrogen infrastructure.

In the Netherlands the discussion is still ongoing if introducing hydrogen at short notice in the built environment is part of a decarbonisation solution. Especially in the 'National' and 'International' energy transition scenarios of CE Delft [99](that assume the availability of large volumes of hydrogen), the large-scale use of hydrogen in the built environment via hybrid heat pumps is considered highly promising.

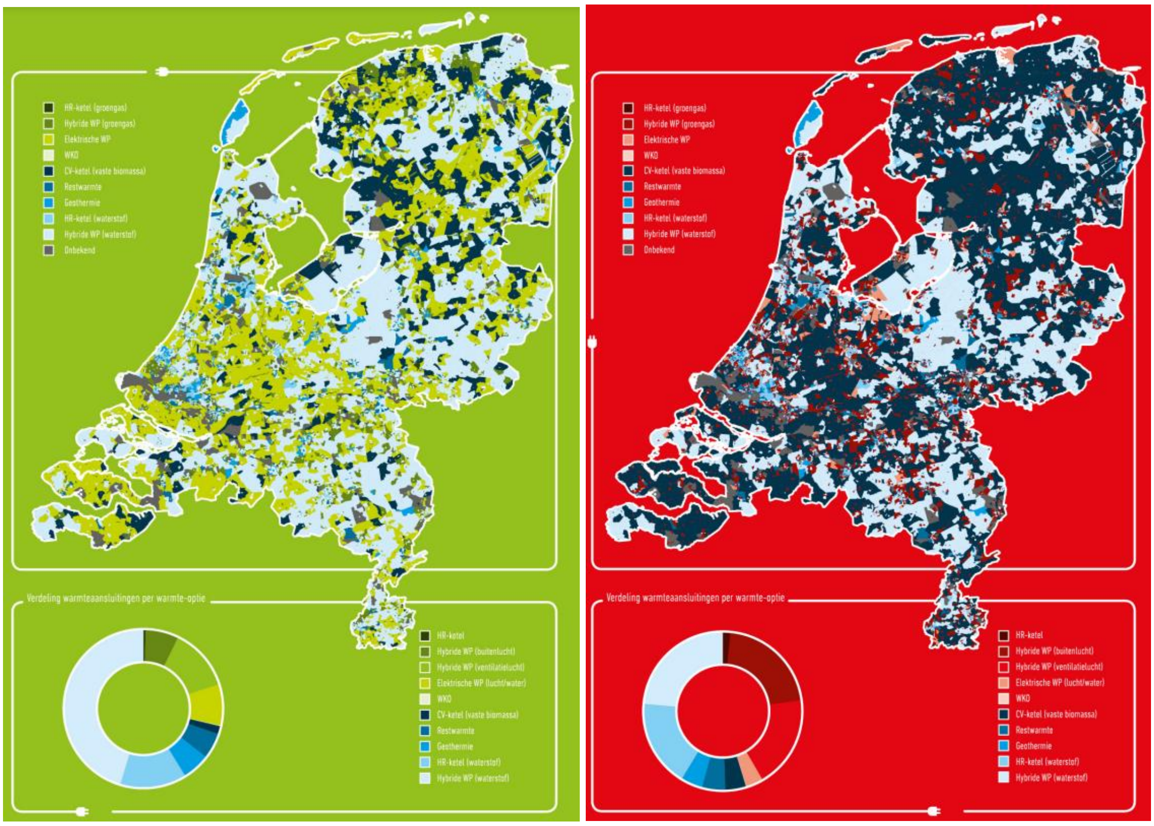


Figure 35 – Regional hydrogen demand (via hybrid heat pumps, see light blue colour) of the built environment in the national (right) and international (left) energy transition scenarios [99]

Figure 35 shows that in these scenarios in Flevoland, Gelderland, Noord-Holland Noord and the North of Limburg the uptake of hydrogen in the built environment is projected to be relatively large (light blue). However, the largest share of demand is expected to come from the main cities, such as

Amsterdam, Rotterdam, Eindhoven and Nijmegen, where, rather than of hybrid heat pumps, demand for hydrogen of boilers is foreseen to be more suitable.

Also decentral electrolysis near hydrogen demanding neighbourhoods can sometimes be a feasible option if local renewable power is available [100]. Then the efficiency of using hydrogen in the built environment (and the business case of the local electrolyser) will improve if waste heat from the electrolyser (30-70 °C) can be utilized in local district heating. Due to the intermittency and seasonal fluctuations in both renewable power supply and demand from the built environment, a connection with a central hydrogen grid and storage is mostly needed to overcome huge local storage requirements [2]. A specific example of promising electrolysis in the built environment is the so-called Green Whale ('De Groene Walvis') project, which aims to build a 10 MW electrolyser and 5000 kg hydrogen storage facility in Noord-Holland [101]. Here, waste heat of the electrolyser is foreseen to be used in a heating grid, while the storage problem is solved by a virtual connection between the electrolyser and an offshore wind park and a connection with the hydrogen backbone. From a business perspective the issue is if the decentral hydrogen production can compete with the central production route; from a system value perspective the issue if sufficient green electricity can be received from offshore wind. The main driver for choosing this location seems to be the local involvement in speeding up and to be in charge of decarboning residential heat in the area.

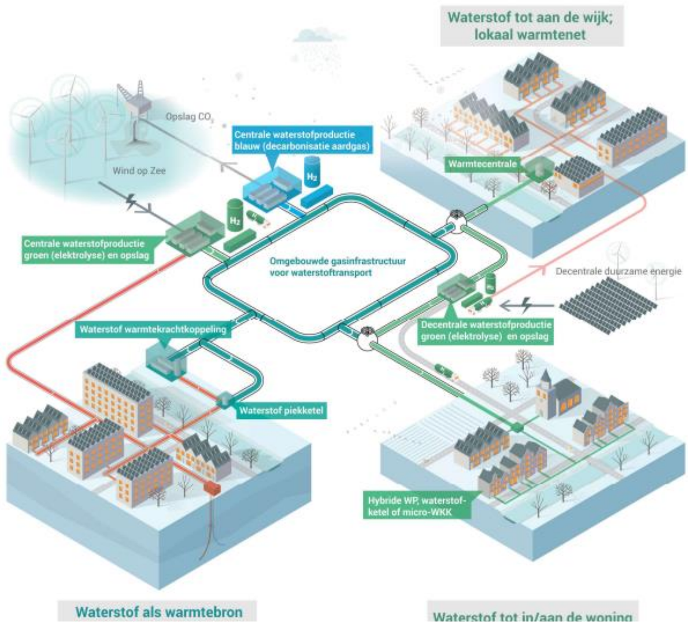


Figure 36 – The roles of central and decentral electrolysis in options to decarbonise neighbourhoods by using hydrogen [100]

Besides electrolyser projects aimed for satisfying a specific local hydrogen demand, sometimes, in the spirit of the so-called 'ecosystem approach', electrolysers are introduced just to support the introduction of hydrogen in the area. Mostly the driver is local decarbonization goals or trying to stimulate the local economy by specific innovation. Ideally in such cases there is a relatively large off-taker such as a logistic hub or industry to kickstart demand, from which smaller local applications, such as a HRS or in the built environment, can benefit. Examples are: Hydrogen Easerwold (Steenwijk), Hy4Am (Amsterdam), GROHW (Deventer), GldH2 (Zutphen), GreenH2ub (Eindhoven) and Green Hydrogen Chain Terneuzen (Terneuzen). Whether or not such electrolyser locations are just temporal or lasting, depends a.o. on

Figure 37 – Example creation of a 'hydrogen ecosystem' in Deventer [129]

the value that can be provided also by delivering flexibility to local energy sources, the broad utilization of the hydrogen, and the use of the by-products, oxygen and heat.

Finally, it is important to consider a potential end-user category with a mostly small demand per location: the agricultural sector. This sector has a large potential of supplying renewable energy. In 2016 it supplied already 7.4 TWh of energy, while some quarter of agricultural companies had installed solar panels [102]. As these companies are typically located in rural areas, there are often challenges in connecting them to the e-grid. Multiple solutions for this have been considered, but especially for arable farming, locating a small electrolyser (<1MW) producing hydrogen for heavy tractors and other equipment could be a beneficial solution to not only match supply and demand of energy, but also overcome unnecessary transport of electricity and hydrogen [103]. A typical arable farming company would use 4100-8000 kg of hydrogen per year to fuel its tractor(s). This means that running at full load hours, a 1 MW electrolyser could serve 17-33 companies [103]. Given the about 11,000 arable farming companies in the Netherlands [104] a theoretical potential of 400 MW FLH (Full Load Hour) electrolysis capacity is required to supply these vehicles. H2Agro is a project of two agricultural companies investigating if they could setup a local chain on their farms. Other innovative concepts are H2ARVESTER (moving solar panels used for hydrogen production), and the modular concepts of very small electrolysers by Adsensys.

3.1.3 Availability of infrastructure

The availability of transport (and storage) infrastructure in determining the locations of electrolysers is another important factor. The advantages of re-using infrastructure, both from energy system perspective and business perspective, are that they considerably drive energy transport costs and reduce throughput times for initiating and realising various new projects and plans. This section will take a look into this.

Onshore gas pipeline infrastructure

In the Netherlands an extensive, cross-border transport infrastructure is available for natural gas. The natural gas transmission pipeline system is made up of 12,000 km of parallel pipelines, and is sub-divided based on pressure ratings into the high-pressure gas grid (HTL) and the intermediate-pressure gas grid (RTL). The regional distribution systems are made up of approximately 130,000 km of low-pressure pipelines (0.03 – 8 bar) operated by regional network operators.

At present, hydrogen can (due to legal and technical reasons) only to a certain limit be injected in the natural gas grid. It is possible, however, to convert natural gas pipelines into hydrogen pipelines (DNV GL 2017; KIWA, 2018). Gasunie, responsible for operating the high-pressure natural gas network in the Netherlands is expecting to free up existing natural gas transmission pipelines for (some 98% pure) hydrogen transport between the five major industrial clusters, and on multiple connection points to neighbouring countries. These pipelines can serve as a transport ring enabling suppliers to feed in carbon neutral hydrogen for high-volume users to use. In certain areas, new pipelines will have to be laid to fill gaps in stretches of pipeline or create connections to industrial clusters [105].

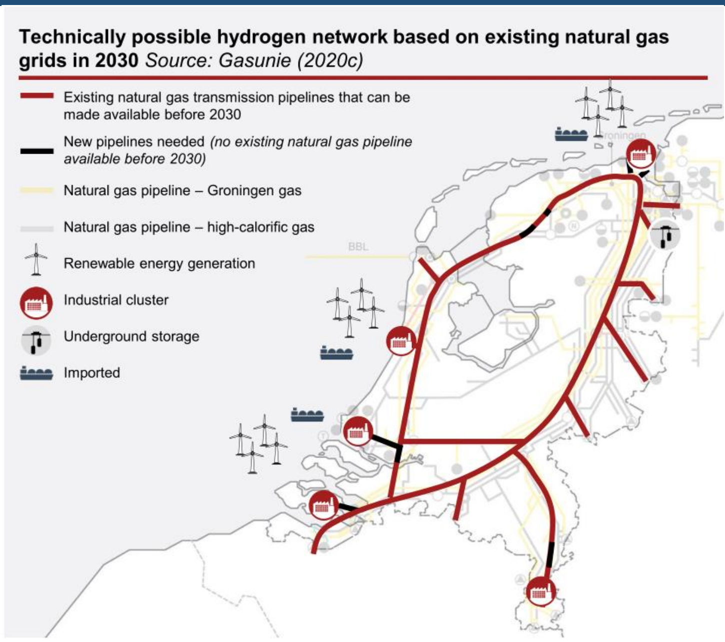


Figure 38: Possible hydrogen pipelines based on the existing natural gas grid in 2030 [105]

A large number of pipelines will for that reason be repurposed before 2030, because the planning is to have a national hydrogen transmission ring up and running well before 2030. The number of new pipelines required represents roughly just 17% of the total number of kilometres of the pipeline. After 2030, more existing natural gas pipelines can be freed up [105].

Several rollout topologies can be considered on the aspect of how electrolysers will be positioned and dispersed alongside the grid (**Error! Reference source not found.**). 'Centralizing' hydrogen P2G systems around the five main industrial clusters of the Netherlands is a common-sense approach since their large industries have the highest demand for hydrogen and can support a quick feasibility of the national hydrogen backbone. Through time, a central-to-local mechanism can cause the main network to be branched out into further distribution networks and end points [106].

Stereotype (naam)	Visualisatie	Mechanisme	Waar/hoe starten?	Doorkijk infrastructuur
Olievlek		Bottom-up, cluster gedreven (hoge connectiviteit, geïntegreerd) nieuwe infra.	Start in de regio's waar nu al een waterstofcluster is; pas later koppeling met G.O. en/of mobiliteit.	Mogelijk tot 2030 gefragmenteerde netten met andere kwaliteit en druk; voorlopig geen backbone of opslag.
Lokaal → Centraal		Bottom-up, unit gedreven (lage connectiviteit, gefragmenteerd) nieuwe infra	Mogelijke start met waterstofprojecten die regionaal nabij zijn.	Mogelijk tot 2030 gefragmenteerde netten met andere kwaliteit en druk; voorlopig geen backbone, opslag of blauwe waterstof.
Centraal → Lokaal		Top-down nieuwe infra, start met backbone /hoofdnet gevolgd door vertakkingen (distributie).	Starten met grote verbruikers op het hoofdnet. Langzaam steeds meer distributienetten koppelen.	Snel een backbone met waterstofopslag realiseren. Tot 2030 beperkte vraag vanuit gebouwde omgeving, dus cavernes voor opslag voldoen.
Bijmengen in aardgasnet (fysiek)	% ▸ % ▸ %	Gebruik van en invoeging in bestaande infra.	Steeds meer waterstof bijmengen in het hele aardgasnetwerk.	Alle installaties aanpassen om met waterstof te kunnen werken. Synergie met Europese beleid.

Figure 39: Variations in roll-out topologies for hydrogen production systems

An 'oil-slick' type roll-out on the other hand would show a bottom-up expansion pattern in which clusters can create high connectivity within their own network by repurposing existing infrastructure and may link with local mobility or built environment demands. This type of expansion would lead to fragmented networks with different operating characteristics (such as gas quality and pressure) with initially no or little development of a backbone or significant storage network.

A 'local to central' expansion would involve initiating hydrogen projects that are regionally close but would also lead to a similar outcome as the 'oil-slick' type expansion. Another type of integration lies in gradual blending into the natural gas network whereby all installations need to be adapted to be able to work with hydrogen. The limitations of this option lie in the maximum amount of gas that can be blended (currently this value still is at 0.02 mol%).

Onshore gas purification plant

The GZI Next project investigates the transformation of a former central gas purification plant in Emmen into a renewable energy production, transportation and storage site. One of the main opportunities of the project involves testing the value chain for green hydrogen from production to use, enabling the decarbonization of different sectors [107]. The GZI project is contributing to hydrogen value chains in the context of the HEAVENN project by realizing an electrolyser. Its green hydrogen can be delivered as a sustainable fuel or sustainable raw material to various customers via a 350 bar public HRS, with Qbuzz (a bus operator) being the main mobility customer.

Offshore gas transport infrastructure

Several offshore building blocks play a key role in the offshore hydrogen value chain of the Netherlands. They are all located in the Dutch maritime region of the North Sea they are envisioned to be clustered in hubs to carry out various functions in production, conversion and storage of energy.

The cost advantages of offshore hydrogen production relate to the notion that production of hydrogen at the intermittent source (offshore wind) involves not only less transport and potentially conversion costs, but makes many activities also more practical from the perspective of e.g. safety risks, public perceptions and availability of space. Advantages of offshore P2G also lie in circumventing electrical grid congestion that typically characterizes the Netherlands' onshore electrical grid networks. Different existing offshore infrastructure can play a role such as offshore platforms, offshore pipelines and offshore underground salt caverns.

Offshore gas extraction platforms

The potential for re-use of existing offshore oil and gas platforms depends on a number of factors. First, the timing at which these platforms become available should align with wind developments in the same regions, and second, the size of the platforms do matter: production platforms have a greater potential since they have a greater carrying capacity. Third, platforms may be claimed for other system integration solutions such as CCS [108]. Another significant factor when considering offshore electrolysis on existing platforms is a platforms capacity to host a certain capacity of electrolysers. Re-utilizating these platforms will mostly involve removing the topside of a platform and installing a dedicated newly designed topside [109].

The technical lifetime of existing platforms needs to be considered when considering utilization of existing offshore platforms for P2G related activities. An extension of the jacket structure lifetime for hosting the topside can sometimes be considered if diving inspections prove that there are no severe accumulated damages [108].

A study by DNVGL mentions a platform jacket mass of 35,221 tonnes enabling to install 2 GW hydrogen conversion capacity [110]. By applying a correction factor of 2, the estimated jacket mass of the supporting topside for 2GW installed capacity is some 70,462 tonnes. Based on this a shortlist of relevant platforms is listed in the table below.

Table 16: Potential platform capacity for conversion processes based on jacket mass/weight substructure

	<50 MW	50 MW> <100 MW	100MW> <200 MW	>200 MW
Existing Platforms [111]	A12, AME, AWG, F15, G14, G16, K17, L02, L04, L06, L11, L15, P09, P18, Q16, K04	J06, D12, F16, G17, K07, K09, L05, P02, K18, K05, K06, K08	F03, K10, P06, P11, P15, K15, L08, L07, K13, Q01	K12, K14, L09, L10, P11

Other reasons than jacket mass can also limit the reuse of platforms such as costs of topside refurbishing. Regarding the costs of refurbishing platforms, studies suggest to first considering the costs of replacing the topside of the platform [109]. If an existing jacket and pile would be reused and the topside redesigned and installed, this would cost about 200k euro per MW installed electrolyser capacity. An additional 15% increase in costs is considered for the installation of the new topside. In case of re-use, once could save some 21% on the jacket costs of the platform [108].

Existing electricity and gas grid connections

The costs of providing the electricity and gas grid connections for electrolysers are not to be neglected. Therefore, costs can be saved if existing connections can be reused, or waiting times for grid connections can be saved if the location of the electrolyser is selected based on areas that already have strong electricity and gas grid connections.

An example is the HyNetherlands project of Engie where a 100MW electrolyser will be installed in Eemshaven next to the existing gas fired power plant. Another advantage of this location is that it is also close to both the landing point of offshore wind and onshore wind. This setup will play an important role in balancing the electrolyser system: if the wind farms supply more electricity than needed, it can be converted into hydrogen and stored. Engie is now engaged in the preparatory activities for taking the final investment decision for the 100MW electrolyser early 2023; commissioning is scheduled for mid-2025.

(A potential) lack of capacities within the existing electricity grid

Due to its historic development the existing Dutch gas system has a significantly larger transport capacity than the Dutch electricity grid (some 10-20x depending whether export capacity is included). Due to the significant increase of renewable power supply (and thus supply-side congestion) and electrification especially in mobility and industry (causing demand-side congestion), demand for timely and significant electricity grid reinforcements is growing rapidly. This involves not only massive public investments, but also trained manpower and dealing with all kinds of procedures (permitting).

It has been investigated several times whether a link between local/national gas networks and electricity grids can offer a solution to supply-side congestion in regional electricity grids. The idea is that during excess power or off-peak power sourced from wind-turbines and solar arrays, electric power is converted into hydrogen through electrolysis utilized in local/national gas distribution networks, hydrogen fuelling stations, and storage sites. This way P2G solutions can mitigate electricity grid congestion and provide flexibility for congested parts of the grid.

Various projects are underway looking into this options such as the H2Stroom project, a project looking into converting green electricity into hydrogen when the grid is congested and storing it locally. Once the grid is free again, the options for converting it back to electricity and feeding it into the grid is undertaken. Furthermore, the hydrogen produced is also used in other sectors such as mobility and therefore the construction of hydrogen filling stations will be a part of the project.

Other projects such as GROHW look into decentralized production of hydrogen via locally produced green hydrogen to end-user applications such as an asphalt factory and in-combination with an innovative heat pump for the built environment. The project involves a local electrolyser supplier and an energy trading platform, whereby its hydrogen ecosystem counters grid congestion.

The Zephyros project looks into the development of a maritime hydrogen hub in Den Helder. The project aims to realize a local solar park, an electrolyser, a pipeline from the electrolyser to an inland port and a public refuelling facility, and a hydrogen-electric vessel for use by a pool of maritime service providers and knowledge institutions. The electrolyser is used for flexibility for services and congestion management to reduce the hydrogen price with revenues. The aim is to have the hub operational by the beginning of 2022.

3.1.4 Availability of storage & flexibility

The location where flexibility in the hydrogen infrastructure exists is likely to affect the location of electrolyser activity. Clearly, flexibility is needed to the extent that green hydrogen production is ramped up and down by fluctuations in renewable electricity production. Via power to gas such flexibility can be provided e.g. by storing excess surpluses in electricity production via underground storage of the green hydrogen produced. Such storage not only adds to overall system flexibility but also to dealing with the seasonality of green hydrogen production. However, the flexibility needed is not available at every location in equal amounts. So, significant additional hydrogen transport flows are conceivable if significant electrolysis activity is located in areas without flexibility [105]. From a commercial value perspective the location of the storage/flexibility provider might matter because additional transport fees for booked capacity have to be paid if a lot of transport from and to the storage is required. Moreover, in one way or another enough flexibility should be available to ensure off-take of the generated hydrogen.

Large scale underground storage locations

In the existing natural gas network, buffering for peak demand is primarily done by storage in underground gas fields and salt caverns. Analogous to natural gas, hydrogen can be stored underground, in compressed gaseous form, in salt caverns and possibly also in depleted gas fields. In such underground storages tens of millions (caverns) to (potentially) billions of m^3 (depleted gas fields) of hydrogen can be stored [112]. To illustrate, a salt cavern can store an equal amount of hydrogen as 13,900 compressed vessels [105]. In theory there is sufficient space in the Dutch soil to develop around 320 onshore salt caverns for hydrogen storage [105]. These 320 caverns are expected to provide an effective hydrogen storage capacity of 14.5 billion cubic meters [105]. It is, however, unlikely that all these caverns will be utilized. In the IP2022 climate agreement scenarios, a storage capacity of approximately 3 to 6PJ is envisioned for 2030. Assuming an average storage capacity of 0.5 to 1 PJ per cavern, this need could be met with 3 to 12 caverns [105]. It is clear that later on storage is likely to play a growing role in dealing with the weather and season dependency of green hydrogen production.

Currently the HyStock in Zuidwending, Groningen is the only location in the Netherlands where the potential of underground salt caverns for storing hydrogen is explored. At that site a first cavern can be operational by 2026 and by 2030 four caverns. If this location turns out to be the only location in the Netherlands where large-scale storage of hydrogen will take place, this will have a significant impact on national hydrogen transport capacity requirements, especially if major electrolyser capacities will be located elsewhere. This is also shown in a modelling exercise in the HyWay27 study, demonstrating that significant hydrogen transport volumes are due to differences in supply and demand potentials of the various industrial clusters. In fact, 41%, 41% and 26% in the considered scenarios (see Figure 40) of national hydrogen transport flows was due to the need to balance supply and demand of renewable hydrogen over time, which could just be done by large-scale underground storage at one location in the Netherlands. So, the more regions other than Northern Netherlands are facing an electrolyser overcapacity compared to local demand, the higher the transport flows from and to the storage location in Zuidwending will be.

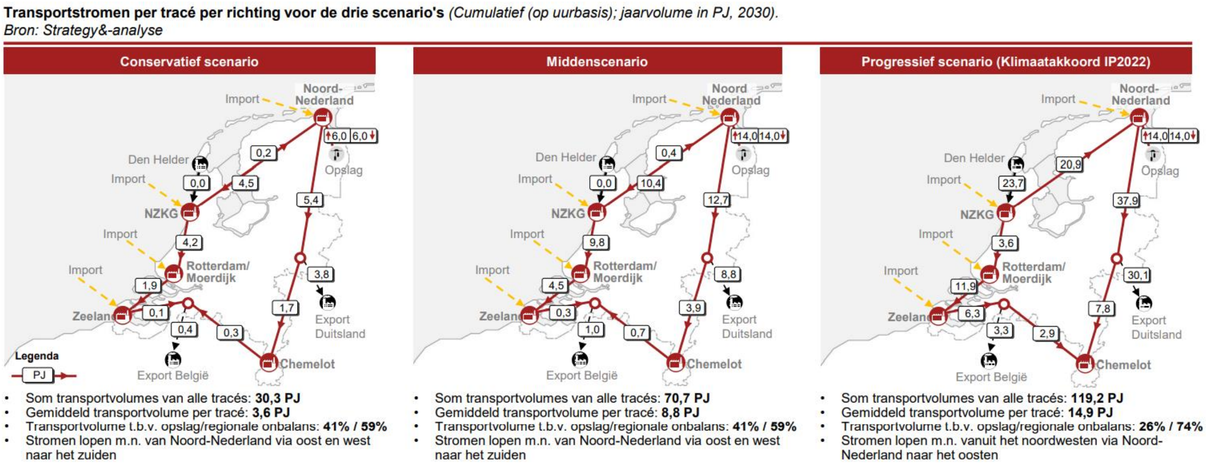


Figure 40 – Potential flows between the industrial clusters and storage based on three scenarios [105]

Whether or not other storage options and thus locations for hydrogen may be feasible, such as offshore salt caverns, depleted gas fields and aquifers (Figure 41), is still to be seen.

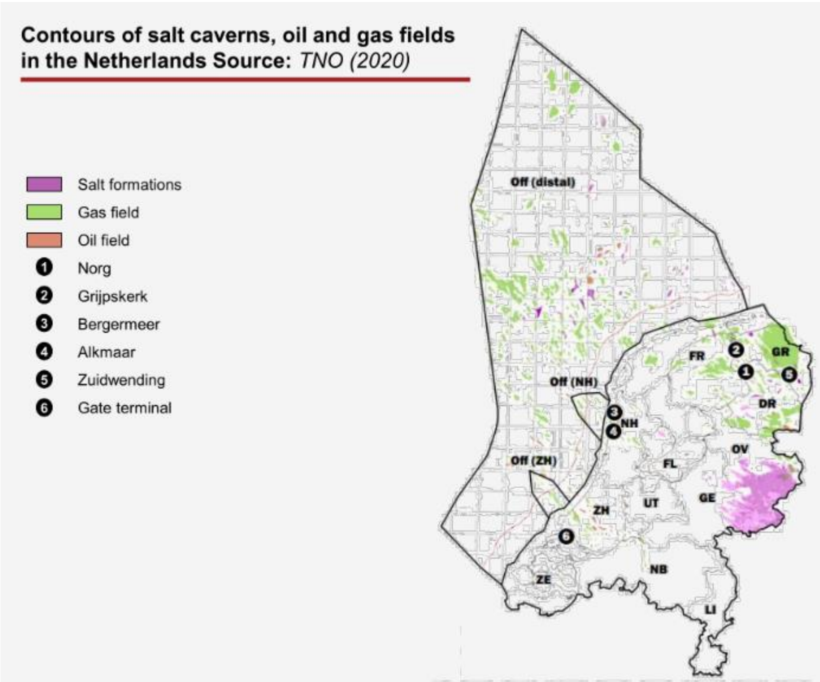


Figure 41: Offshore underground storage sites

Flexibility by blue hydrogen production

From an energy system perspective, also blue hydrogen can smooth out the intermittency of the production of renewable hydrogen production. This is also because the underlying intermittency of green power production is a restricting factor for full-time utilization of electrolysers [42]. Setting up blue hydrogen production facilities often requires less investment than capacities for green hydrogen to the extent that existing SMR and ATR plants can effectively be coupled with CCS. The risk of lock-in effects can be mitigated by clear policies, while producing blue hydrogen can already introduce carbon neutral hydrogen while green hydrogen production is still expanding. So, matching locations of 'peak shaving' electrolysers with those of flexibly producing blue hydrogen plants can theoretically help in achieving an optimal planning and use of hydrogen pipeline infrastructure.

Hydrogen pipelines need to last well into the mid and long term. The diameter of the pipelines therefore need to be sufficient to handle future hydrogen volumes. This will have to include flows based on blue hydrogen imports (that also may be wanted to function as a base load of hydrogen in the network, reducing the impact of renewable hydrogen volatility on prices in [42]).

3.1.5 Governmental guidance and interventions

Policies and market regulations can have significant impact on the locations of future electrolysers. In the last letter of the Dutch ministry of Climate and Energy on the organisation of the Dutch hydrogen market, location aspects of electrolysers received specific attention [26]. Although no specific measures have been announced, it was clearly stated that grid operators can have a signal function in identifying and communicating the most beneficial electrolyser locations from the electricity and hydrogen grid perspective. It was also stated that in existing planning programs, such as 'Programma Energiehoofstructuur', the Energy Strategies and the National Plan Energy System, locations of electrolysers and their spatial integration will need be taken into account.

It seems that currently the focus still is on providing information rather than already putting incentives on specific locations for electrolysers. However, the following location-related incentive ideas were proposed by public and private stakeholders during a recent public consultation [113]:

- A more active role for GOPACS (pricing based on congestion)[22]
- Dynamic contracts for new installations to be connected to the grid
- A producer tariff coupled to the peak load of supply to the grid
- Enabling that the total costs of connection are reflected in the tariff of connecting electrolysers (hence, make it unattractive to locate electrolysers at places that lead to large grid reinforcements)
- Include a transport indication in support instruments for electrolysis such as the SDE++
- Reserve dedicated space for electrolysers near the landing points of offshore wind in harbours, based on what is desired and available from the grid and on social and environmental perspectives, and tender parts of these sites similar as offshore wind tenders (this includes only the large-scale and central electrolysis locations).

So far two policy decisions can be identified that indirectly have affect the size and locations of electrolysers. The first one is the scale-up instrument to support electrolyser projects up to 50 MW. It supports smaller projects to develop the learning curve for future larger project. The second one is to already start the development of hydrogen transport infrastructure via the national backbone. It is expected that in the early phases of electrolyser capacity development locations close to the backbone have an advantage in acceding large clusters of demand.

[22] Currently the GOPACS initiative does not provide enough certainty to invest in new electrolysers at specific locations, some additional (more long term) pricing incentives could be considered to incentivize investments of electrolysers at the most beneficial locations

3.1.6 General pre-conditions for electrolyser locations

There are a number of pre-conditions for electrolyser locations to be taken into account: the availability of space, the availability of water, the venting options of oxygen, and permits and licenses.

Availability of space

Spatial issues and planning is more and more considered as one of the main challenges of the energy transition. The spatial demand of electrolyser capacities is no exception. The ISPT 1 GW electrolyser design, for example, requires a space of some 10 hectares [114]. This is significant, especially if put in the perspective of the GWs of electrolyser capacities foreseen to be installed at the landing points of offshore wind. There are now already plenty of activities going on in such areas, while moreover often a lot of other new activities are planned in the same areas as well, such as: electrical landfall of offshore wind, operation & maintenance warehouses, and facilities dealing with decommissioning offshore platforms and wind turbines [67]. Spatial constraints may therefore be a limiting factor on how much electrolysis can be performed in harbour and landfall areas. This factor therefore no doubt will have a crucial impact on the distribution of electrolysers over the coastal areas and the degree to which they will be located offshore.

For inland electrolysers spatial planning issues may play a role as well in the future. However, as currently the planned quantities are smaller and locations less clear, there are so far few cases of inland spatial issues. Although future inland electrolysis may lead to safety concerns and thus spatial planning challenges, such issues are expected to be less than those of the related electricity infrastructures. Sometimes relabelling may be sufficient: in some cases of local electrolyser projects only the zoning plan needed to be changed into ‘industrial activity’ to get permission to start.

Availability of water

Next to electricity, an electrolyser uses 8.9 litres of water to produce 1 kilogram of hydrogen. Hence, sufficient water availability is required, so that electrolysers will typically be located near decent sources of water. Large industries and electricity plants in the Netherlands mainly collect sweet surface water to operate their processes. This, however, becomes increasingly problematic due to the rising number of dry summers [115]. Compared to that water use of electrolysers will remain modest. Studies show, for instancer, that the water use of electrolysers in a mature hydrogen economy will not strongly affect average total water use (0-5%) [116] [117].

Yet, it is expected that due to increasing shortages of sweet water at specific moments of time one may start to use salt water in the large electrolysers. Moreover, a legal risk for electrolyser operators using sweet is that they will be obliged to reduce production during future dry summers for that reason. This risk depends on how the electrolysis activity will be characterised under the ‘verdringingsreeks droogte’ as part of the Dutch Water law: if it is seen as an industrial activity the chance of being restricted is rather high (like in 2018 and 2022), while if it is considered as an energy utility this chance is much lower.

Figure 42 – Dutch 'Verdringingsreeks Droogte' as part of the Dutch water law

3.1.7 Conclusion on the drivers of electrolysis locations

Table 17 below summarizes the location drivers of electrolysers and shows both the energy system value and electrolyser operator value of each driver.

Table 17 – Overview of location drivers from both the system value and electrolyser operator value perspective

Location driver	Energy system value	Electrolyser operator value
Availability of renewable electricity	• Relieve the electricity grid from fluctuations of intermittent sources • Transport costs of hydrogen in general lower than electricity	• Optimizing market revenues by selling either electricity or hydrogen • Reduction of cabling costs
Availability of renewable hydrogen demand	• Limited system value in locating electrolysers near demand • Accessible value chain is pre-condition to harvest the system value	• Opportunities in utilizing by-products oxygen and heat[23] • Avoiding hydrogen quality loss by pipeline transport • Currently still limited hydrogen transport infrastructure available
Availability of existing infrastructure	• Reduction of costs and time	• Reduction of costs and time
Availability of flexibility and storage	• Decrease hydrogen transport distances and required capacities	• Security of hydrogen off-take

The table and analysis show that there is quite some overlap between the expected electrolyser locations from a system value and an electrolyser operator value perspective. It also shows that at some locations multiple positive spatial conditions come together, such as: the landfall of offshore wind combined with the [presence of a large industrial cluster of (potential) hydrogen demand, where the required infrastructure is already in place.

[23] If for 'system' a broader definition is used than the energy system, utilization of by products can be perceived as 'system value' if the net benefits of the system increase. This has not been part of this study.

A second observation is that the location choices of electrolysers have a much stronger impact on the energy system costs than on those of the electrolyser operators. The reason is that for private investors in electrolysers the electricity grid typically acts as a copper plate: at any place electricity can be obtained from the grid against the same prices in the whole Dutch bidding zone. From the energy system perspective, instead, it does make a huge difference at what locations electrolysers are installed, because the location choices significantly determine the costs of electricity grid reinforcement [62].

In fact, ignoring that the electrolyser system value can strongly differ from the electrolyser operator value can be one of the main electolyser spatial planning pitfalls. From the electrolyser operator perspective it can, for instance, be highly beneficial to locate the electrolyser at or near the hydrogen demand site, e.g. to be able to: utilize by-products; exclude the need (to wait) for hydrogen transport infrastructure; and/or to secure off-take potential. However, from the energy system costs perspective significant electricity grid expansions are typically required if electrolysers are located near hydrogen demand rather than supply sites (see **Error! Reference source not found.**). True, sometimes electrolysers can without undue grid costs be located near demand sites if there is sufficient available renewable electricity generation at that location, and/or a sufficiently strong electricity grid connection. But in many cases such conditions do not apply, so that from a societal cost perspective one should preserve that unnecessary electricity grid reinforcement costs have to be made to allow electrolysers to be located at demand sites, while such infrastructure costs could have been prevented if the same capacities would instead have been installed near the production point, i.e. the locations of the renewable sources providing their green power input.

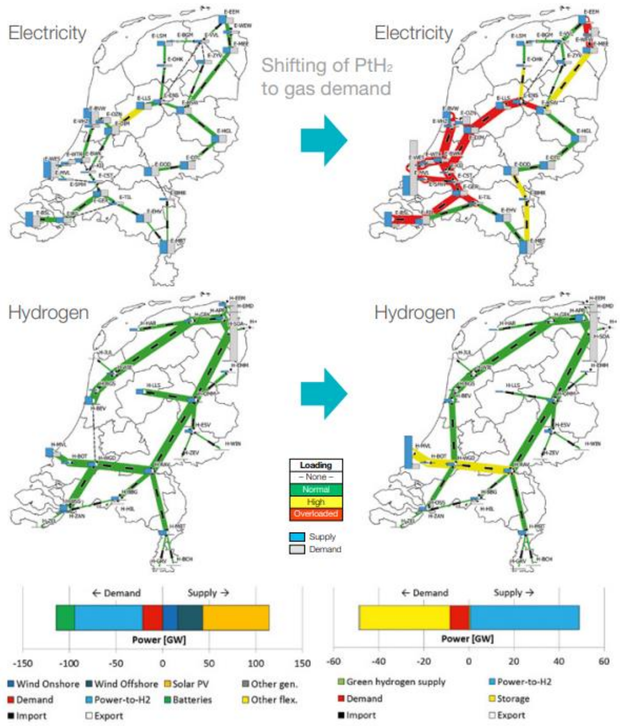


Figure 43 – Impact of locating electrolysers near electricity generation locations (left) versus gas demand locations (right) [62]

The above pitfall is a serious concern, because so far the analysis of the impact of governmental decisions and measures on location decisions of electrolysers does suggest that no specific policies, plans or incentives to steer electrolyser locations are foreseen yet. The only thing happening in this field comes from the grid operators by creating information transparency on the optimal locations from their grid perspective, but the impact of this on actual private decisions is unclear. Significantly more public steering of electrolyser locations to keep public grid costs under control, therefore seems indispensable.

In order to conclude on answering the research question set in the introduction: '*At which locations in the Netherlands can hydrogen production and implementation in various end uses be feasible up to 2030 given the various locational drivers?*' We summarized the main types of locations based on the identified drivers in Table 12.

Table 18 – Overview of location drivers described in chapter 3.1: general location drivers and the specific aspects determining these locations

General location driver	Location determinants
Availability of renewable electricity	Landfall offshore wind; offshore wind farms & hubs; onshore renewables.
Accessibility of renewable hydrogen demand	Central industrial clusters; decentral industries; mobility hubs; built environment; agriculture.
Availability of infrastructure	On- and offshore gas pipelines and handling infrastructure; gas and electricity grid connections; lack of electricity grid capacity.
Availability of storage and flexibility	Large scale storage; dispatchable hydrogen production capacities.
Governmental guidance	Landfall decisions offshore wind; support hydrogen backbone; (in)direct locational aspects in market regulation, support criteria and permitting.

Because we think the topic of centralized and decentralized electrolysis is one that deserves more attention. We highlight specific drivers that are seen for both types of projects in the next chapter.

3.2 Drivers for central and decentral electrolysis

So far several general electrolyser location drivers have been discussed, and we already touched upon the different location drivers of large-scale, central vs smaller-scale decentral electrolysis. Now we will assess these differences somewhat deeper, and provide an overview of studies exploring them in the context of the Dutch energy system.

3.2.1 Drivers for central electrolysis

Economies of scale

Electrolyser stacks are known to be difficult to scale up, because of issues such as leakage, mechanical instability and complexities of manufacturing large-scale components [118]. Although for that reason large-scale electrolyser designs typically consist of a park of electrolyser stacks [114], there are significant scaling advantages in the balance of plant of the electrolyser, such as the compressors, electrical equipment and grid connection. Figure 44 shows that for small-scale electrolyser the balance of plant includes 55% of the total investment costs, while for electrolysers of 100 MW this is just 35%. Overall the investment costs per kW of a 100 MW electrolyser could be 60% lower than a 1 MW electrolyser, or 35% lower than a 10 MW electrolyser. Hence, the economies of scale are a competitive advantage of large-scale electrolysers, which also drives them more towards central locations. According to IRENA the maximum economies of scale of electrolyser modules is reached at 1020 MW [118], so beyond this capacity the economies of scale for a single electrolyser plant at one location stop.

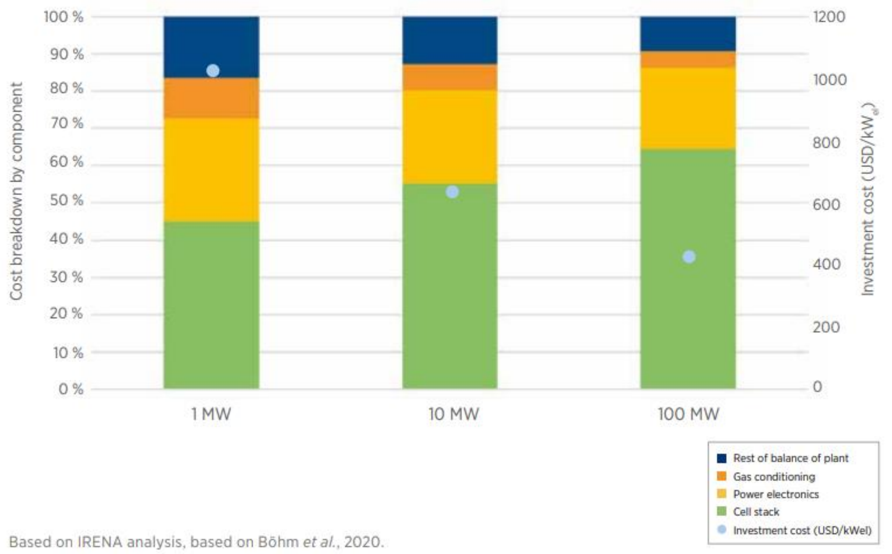


Figure 44 – Economies of scale of electrolysers [118]

Centrality of electricity supply and hydrogen off-take

As discussed in the previous sections, availability of renewable electricity and hydrogen demand, or at least the infrastructure to export the hydrogen, are typically considered to be essential in choosing the locations of electrolyser sites. So, the more large-scale solar and wind parks are developed and the more hydrogen demand is clustered, the higher the potential to successfully develop large-scale central electrolysis sites. Given the identified Dutch locational characteristics, e.g. locations where landfall of offshore wind comes together with large industrial offtake clusters (e.g. Maasvlakte, Borssele and Eemshaven), it comes to no surprise that those locations are considered to provide good conditions for large-scale central electrolysis. In fact, large-scale electrolyser project are already in the pipeline or even developed at these locations.

Permitting issues

The more difficult it is to obtain permits for electrolyser projects, the less easy especially small electrolyser projects will come off the ground. Moreover, It is often less time- and money-consuming to obtain one permit for a large project than, for example, 100 permits for small projects. Even if permits for investment are provided, new challenges may emerge in receiving permits to continue with projects, especially if they involve storage tanks as well. It is still unclear if such procedural hick-ups are due to the relative newness of the technology and procedures, or that this will remain a major issue also in the future. If so, also on the longer term larger electrolyser projects will have an advantage as compared to the smaller ones.

3.2.2 Drivers for decentral electrolysis

Significance of decentral renewable generation and congestion in local electricity grids

Just like central production of renewable electricity generally seems to support nearby central electrolyser locations, so will more decentral renewable electricity generation typically support nearby decentral electrolysis. But the locations of such decentral electrolyser capacities are also impacted by the (in time) availability of electricity infrastructure to transport the electrical energy loads and thus e-grid congestion issues. The II3050 shows in this respect that due to this in the future time profiles of local generation and demand of electricity will often not match, and therefore lead to the need for local batteries (short-term storage) and/or local power-to-gas (longer-term storage) [7].

Purity requirements of hydrogen for mobility applications

For hydrogen fuel cell vehicles – e.g. cars, trucks, buses, inland barges or specific vehicles like fork-lifts - high purity (>99.997) hydrogen is technically required. It is highly likely that this quality cannot be guaranteed by hydrogen transported through the main pipelines [84]. Therefore, local electrolysis can have a cost advantage for transport applications because then no additional purification step is required [2]. The degree to which the latter may often be the case obviously determines how this will act as a driver towards decentral electrolysis.

Lack of cost-efficient means of transport in combination with decentral demand development

Scattered, small-scale demand for hydrogen will often face significant last-mile hydrogen transport costs [2], especially since currently hardly any local infrastructure to transport hydrogen has yet been developed. This may lead end-users to look for options to source the hydrogen locally, and thus to locate electrolysers at or near the own location, and use the electricity grid rather than an (ineffective) hydrogen grid. This might be mainly a more temporary issue, as the decision by the Dutch government is already taken to develop national hydrogen transport infrastructure. If, probably at a later moment, also decisions will be made to convert specific sections of the natural gas distribution grids into hydrogen, then this might be less of an issue. Still, at that time some regions probably will not get a hydrogen distribution grid, but for example go all-electric or convert the grid towards green gas (biomethane). In the meantime (probably at least until 2030), regions with small scale decentral hydrogen demand might depend on transport solutions such as the H2Tap initiative, or decentral production.

3.2.3 Studies on central and decentral electrolysis in the Netherlands

Despite the richness of energy system studies and scenario modelling on the Netherlands' electricity system [4] [5], there so far are only two studies that clearly focussed on a the spatial profile of electrolysers. Even in these studies assessing future locations of electrolysers was not the main aim, so that methodologies used for this aspect are rather straightforward.

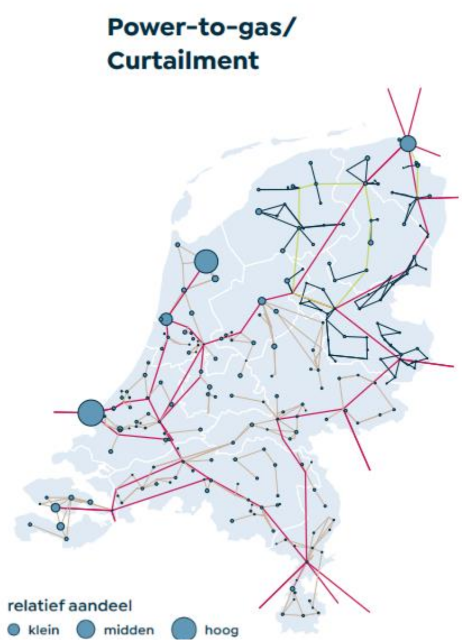


Figure 45 – Regionalisation of electrolyser capacities in the II3050 study [7]

In the II3050 study the amount of energy system flexibility required is determined via a flex-analysis assuming that roughly a distinction could be made between imbalances <24 hours requiring short-term flex options, and longer-term imbalances requiring long-term flex options [7]. In the modelling the locations of flexibility capacities are based on the imbalances between supply and demand per region; for power-to-gas this means that such capacities are typically located where a large amount renewable electricity is generated [7]. The spatial profile of power-to-gas locations is rather similar for the four scenarios (regional, national, European and international); only their capacities differ. How electrolyser capacity is divided over the central clusters is mainly determined just by the (rather arbitrary) assumptions about where offshore wind will land. The semi-big dots correspond with the locations that were named to deploy most renewable energy on land: remaining area's in North-Holland North and Zeeland, Flevoland and West-Friesland. The study does specify where electrolysers are expected to be located exactly within the regional grids (e.g. next to solar farms or near the High-voltage to Medium voltage stations).

In the 2021 Guidehouse & Berenschot study on system integration of offshore wind a similar approach has been taken as the II3050 report, except from an additional electrolyser capacity economic optimization step after the flex-analysis [63]. Another addition is that four scenarios including different operation modes of the centrally located electrolysers have been taken into account. The results of the scenarios with respect to central and decentral electrolyser capacities are shown in the table below.

Table 19 – Scenario results on central and decentral electrolyser capacities (GW) in [63]

Operation of electrolysers	National scenario (38.5 GW)			International scenario (31 GW)		
	Central	Decentral	% Decentral	Central	Decentral	% Decentral
1: Oversupply only	13	10.4	44%	5	2.7	35%
2: Including coupled	17.1	7.8	31%	6.7	2	23%
3: Including congestion	17.3	8	32%	6.7	2.2	25%
4: Including offshore	15.8	7.4	32%	n/a		

Note: offshore electrolyser capacity in scenario 4 has been considered as 'central' electrolysis.

The table shows that using this methodology to assess electrolyser capacities leads to more central electrolysis in the international scenario compared to the national scenario. This is because in the national scenario relatively more electricity is generated by smaller-scale onshore parks compared to large-scale offshore parks (45% in the national scenario compared to 30% in the international scenario). Another notion is that in the baseline scenario, when power-to-gas is only performed with oversupplies of electricity, relatively more electrolyser capacity is located decentral in both the national and international scenario. This is mainly due to the assumptions made: for example in the scenario with electrolysers directly coupled to offshore wind farms (i.e. the electricity source is connected to the electrolyser only) it is only assumed that certain central electrolysis capacities are coupled to offshore wind farms. By contrast, no inland electrolysers were assumed to be directly coupled to onshore parks, because considered to be outside the scope of the study. When directly coupled electrolysis is performed generally more electrolysis capacity is needed at given renewable capacities, because then electrolysers also run when there is no oversupply of electricity. Then less electricity is available to fulfil electricity demand so that (renewable) gas-fired power will have to be switched on more often to satisfy electricity demand. In the study the increased hydrogen supply is only generated by the directly coupled central electrolyser capacities because this coupling is assumed absent for decentral capacities. In general, the study shows that the more directly coupled electrolysis takes place the more electrolyser capacity is needed, and the higher the share of central capacity.

3.2.4 Conclusion and framework on the development of central and decentral electrolysis

As was already mentioned, in the literature on the future Dutch energy system, except from our own assessment based on the various drivers above, there are just two studies (partly using the same assumptions and method) that try to provide some insight in the potential future division between central and decentral electrolysis and their locations. It is therefore fair to say that especially with respect to the potential of decentral electrolysis and its locations more research is needed. In doing so, one will need to include the perspectives of the stakeholders, such as regional grid operators, local off-takers and potential investors in local electrolysers to better understand their energy perspectives and business cases. This is important because, for example, distribution grid operators may want to know if regions with low potential hydrogen demand but high supply of renewable electricity may need a local distribution hydrogen grid to boost hydrogen from excess local electricity to the backbone. Local off-takers on their turn may want to know, if they close contracts with a local electricity supplier, how this competes with potential hydrogen supplies (from the backbone or otherwise). Finally, the local green hydrogen suppliers may want to know where and how they can best sell their product given grid availability, etc.

Three perspectives can be used to get a better understanding of the perspectives of smaller decentral electrolysis as compared to the development of large electrolysers at central locations:

The optimal infrastructure perspective: This perspective was taken in the studies analysed in the previous chapter: the degree to which decentral vs central electrolysis will take place depends on the additional electricity grid investment needed and its costs compared to the alternative. The studies showed that how much decentral electrolysis is likely to be developed in this perspective typically depends on the ratio between large-scale offshore wind and smaller-scale onshore wind and solar [7] [63]. Given the Climate Agreement figures [1] and the (increased) national 2030 offshore wind target of 21 GW, one aims to have some 95 TWh offshore wind and 35 TWh onshore wind and solar capacity to be installed by 2030. This would imply that by that time about 80% of the variable renewable electricity will land at the central locations. According to this view the majority of electrolyser capacity will be centrally located. A future analysis will have to clarify if this projection is realistic in view of electricity infrastructure reinforcement delays and costs, and in view of decentral decentral electrolyser perspectives also given congestion concerns.

The competitiveness of decentral electrolysis hydrogen value chains with the central ones: Another perspective is the commercial value for private parties and off-takers. In this view decentral electrolysis will only take place to the extent that it can create more benefits (or less costs) for the final end-users than the central alternative. Several factors have been found benefitting decentral value chains (e.g. purity requirements[24], utilization of by-products[25], lack of cost-effective transport options, availability of local congestion, etc.), or instead complicating that option (e.g. economies of scale, costs of storages and their availability, etc.). An extensive comparison of decentral and central value chains per hydrogen application option may be required, involving sensitivities on locational characteristics and on impacts of policies and potential technological innovations, to get realistic perspectives on the deployment potential of decentral electrolysis per region and application.

Developments, decisions and priority setting in the energy transition: The third perspective typically looks at the impact of influential policy decisions and social developments on the locations of future electrolysis. Examples are: priorities when providing regulations and support for hydrogen for specific sectors; the degree to which innovation is concentrated in large-scale or rather small-scale electrolyser activity; decisions by national or local governments on spatial energy capacity plannings; congestion issues; or local public resistance issues. That policies are crucial in this also can be illustrated by the fact that effective incentives to roll out offshore wind before 2030 undoubtedly will boost central electrolysis in the coastal areas, especially if offshore will only develop slowly. Such developments and the underlying decisions and their timing are, however very hard to predict.

[24] Currently, a purity specification is not set for dedicated hydrogen transport in the Dutch distribution grids. However, it is known that very high purities, such as the 99.997% required for fuel cells, can not be guaranteed if the existing distribution grid will be re-used for distribution of hydrogen.
[25] At quite some central electrolysis locations it also will be possible to utilize by-products.

4. Stakeholder recommendations

This extensive report provide a lot of specific insights that can be useful for a wide variety of stakeholders that are in one way or another related to the hydrogen value chain. In both section 2 and 3 we concluded already the main findings and the remaining issues for further research and in the management summary we conducted the main take-away from this report. The research topic in this paper is generic and therefore a lot of insights cannot directly be translated to stakeholder recommendations. Therefore, we recommend to not stick to reading this chapter alone: in this section we highlight what the findings mean for different stakeholders generically, and provide some specific insights/recommendations that can be retrieved from the report.

4.1 Policy makers

The analysis has clearly shown that probably until 2030 but maybe longer much of the hydrogen activity will not come off the ground by private parties without subsidies or other support mechanisms. The business at the moment does not yet lead to private parties investing in electrolysis in almost all cases. Moreover, technologies often have not yet reached maturity either, and value chains are typically still incomplete. For public authorities this means that they should be prepared to support the first movers with the help of additional funding to get hydrogen development through the valley of death. Such support may either focus on CAPEX of the technology investment, or on the OPEX e.g. by guaranteeing or supporting the costs of inputs or the returns of the output. Support can also be provided by creating a market via, for instance, mandatory blending.[26] What governments also can do is to improve the value chain conditions by ensuring that the transport and storage capacity needed will be available in time. Also this will cost money and may involve public support. In short governments will have to prepare budget for their supportive role probably for another decade or so.

Since we have seen in this report that the policy drivers will be very determining in the coming decade which and how hydrogen activities will be deployed, coordination of such support is essential. This insight and recommendation might seem trivial. However, we noticed during our modelling work and discussion of the results in relation with previous published studies that due to the relatively low transport costs and large potential cross border capacities if existing transmission pipelines are reused, hydrogen production investments and future transport flows are expected to very much depend on the implementation of national policy schemes among neighbouring countries. For instance, if one country stimulates hydrogen production whereas a neighbouring country government supports demand, then there is a risk that all supply is channelled to one and the same country.[27] Therefore, the recommendation is to align and harmonize the foreseen Dutch support scheme with its neighbouring countries, in terms of intensity and type of scheme.

Given the impact of electrolyser locations on the total energy systems costs, we strongly recommend policy makers to consider how future electrolyser locations can be steered more actively to ensure that business value and system value of electrolysers are aligned. This can be done in various ways: 1) integrating locational aspects in requirements of subsidy schemes; 2) integrating locational aspects in conditions and contracts for grid connections; 3) assigning and/or tendering certain electrolyser locations together with the grid operators. This is because ‘wrong’ locations could lead to serious

[26] Physically or administratively. Administrative blending, using binding targets and blending obligations, seems to become one of the stronger policy drivers towards hydrogen in the EU and the Netherlands. See HyDelta 1.0 D8.1-D8.5 for more information on mandatory blending.
[27] A similar effect is seen with developments in biomethane

electricity grid expansion requirements, while other locations can even save significant investments in electricity grids.

4.2 Investors in electrolysers

Investors in electrolysers, especially the larger ones, are currently almost all first-movers. They carry the risks of immature business cases and unforeseen bottlenecks. They will only start investing, if somehow the business cases or the long term perspectives of them are good enough, and if they can be certain enough to have access to the required volumes of affordable green power and sufficient guarantees to sell the hydrogen against acceptable prices.

This paper provide a good overview of the major European and national existing and considered policy schemes and regulations that are aimed to increase the security to invest in electrolyser capacity (chapter 2.1 and 2.2). Also, the most critical market factors are described that determine the magnitude of electrolyser capacity that can be operated in a profitable manner in 2030 in the Netherlands (chapter 2.3 and 2.4). Moreover, aspects of electrolyser location decisions are discussed extensively (chapter 3). Finally, the whole report provides an overview of the role of hydrogen production and locations within the whole (near future) energy system.

The specific condition of currently proposed policies are not set yet and therefore it is hard to make statements if 4 GW would be economically viable in 2030 based on the proposals and market conditions discussed in this paper. However, based on our analysis we can say that the increase of offshore wind targets and the potential binding targets that establish a dedicated demand for green hydrogen will favour electrolyser investments compared to two years ago. On the other hand, if competition for electricity becomes stronger than expected under the climate agreement due to increased electrification, it will have a disadvantage effect on the electrolyser business case.

Finally, we want to highlight some specific insights for small scale, decentral electrolyser investors. A scale-up instrument is expected to support electrolysis projects up to 50 MW. However, we also see first-phase 50 MW electrolysis projects being developed at the central locations, potentially to make use of this subsidy as well. Therefore, although we have identified some locational aspects that suggest that decentral electrolysis in the Netherlands might be beneficial from a system point of view, it is unclear if the from a business point of view the decentral drivers can outweigh the economies of scale benefits of central electrolysers under certain circumstances. The best strategy for decentral electrolyser projects is to integrate as good as possible in the regional energy system (by the examples described in chapter 3.1.1, 3.1.2 and 3.2.2). One of the most promising examples is to integrate electrolysis with supply-side congestion locations near local mobility demand hubs (HRS, ports or public transport facilities), due to the high purity requirements, willingness-to-pay and relatively expensive last-mile transport costs.[28]

4.3 Grid operators (TSO's and DSO's)

The decision for developing the hydrogen backbone throughout the Netherlands has already been taken and is close to reaching an FID. For the DSOs many issues with respect to transporting and possibly storing hydrogen still remain, however. Such as: how much green gases need to be transported, now that not only in industry, but equally in transport and the built environment, users are uncertain what to choose. Will they go for electrification, or wait for a heat grid, or hope for access to green gases to satisfy their future energy demand? These choices will strongly affect their need for transport and storage modes to be offered by the DSOs. The uncertainty at demand therefore translates itself into uncertainty for the DSOs about where, when and how to invest in their grid. To a

[28] This is supported by mobility value chain cost calculations performed in HyDelta 1 D7A.2

certain extent this paralyses investment which contributes to the electricity grid congestion problems in the Netherlands. This is even more a problem for the DSOs because they strongly focus on the built environment of which the role in the hydrogen system is the least clear. Some pilots suggest that hydrogen to the built environment can be a serious option at relatively short notice, whereas government reports suggest that not much activity can be expected on this before 2030 at the earliest.

Paradoxically grid operators on average would benefit from electrolyser installations, both small and larger capacities, because they may help them not only to be better able to balance the electricity grid, but also to reduce the need for grid reinforcement if instead the move would have been electrification. Throughout the country both at the supply and demand side the role of electricity is growing so rapidly that technically and economically it is impossible for the DSOs to keep pace with it (simply because the lead time of installing solar parks or electric installation is shorter than the lead time of expanding the electricity grid). As a consequence both supply and demand congestion is rapidly spreading around much to the frustration of the potential users that either cannot put their intermittent renewable power on to the grid, or are unable to get the guarantees from the DSOs that sufficient offtake capacity will be available in due time. The congestion issue is rapidly developing in to one of the major energy headaches in the country with no clear sight on a proper solution.

All this asks for a national congestion strategy in which a clear relationship between energy flows and transport and storage capacities needed is established. The DSOs should therefore reach out to local and national authorities to address this issue. A good step is taken by looking to energy infrastructure more integrally by the II3050 initiative. However, grid operators should be very clear upfront what is possible and what not, including the consequences if legislations or political decisions will not change in time. For example, it can be assessed now already in what pace and where electrification is possible. It seems clear that electricity grid capacity will remain scarce for the coming decades and therefore decisions have to be made how to use the available capacity such that as much emission reduction as possible can be established. This view is fundamentally different than the methodology that currently is used to create or expand customers connections.

Anyhow one increasingly is realizing that the rapidly emerging e-grid congestion crisis in the Netherlands in itself may act as a serious incentive for industry and possibly also mobility and the built environment to move to the main alternative: hydrogen. The simple reason is that while the security of supply of electricity is worsening by the day, and therefore the perception of it, the reverse seems to be true for hydrogen the security of supply of which does not seem to meet a similar doubt even if hydrogen supply still is in its infancy.

Congestion can be caused by a great variety of reasons. The DSOs can play an important role in the development of solutions by providing more information on the specific problems that are faced in specific areas. The congestion maps provide a quick overview on the status, but do not state why, when and where capacity limitations or voltage issues are (expected) to be faced and in which regions congestion may stay an issue for the coming decades. Sharing information and data can help local governments, local stakeholders and research to come up with more structural solutions for the problem.

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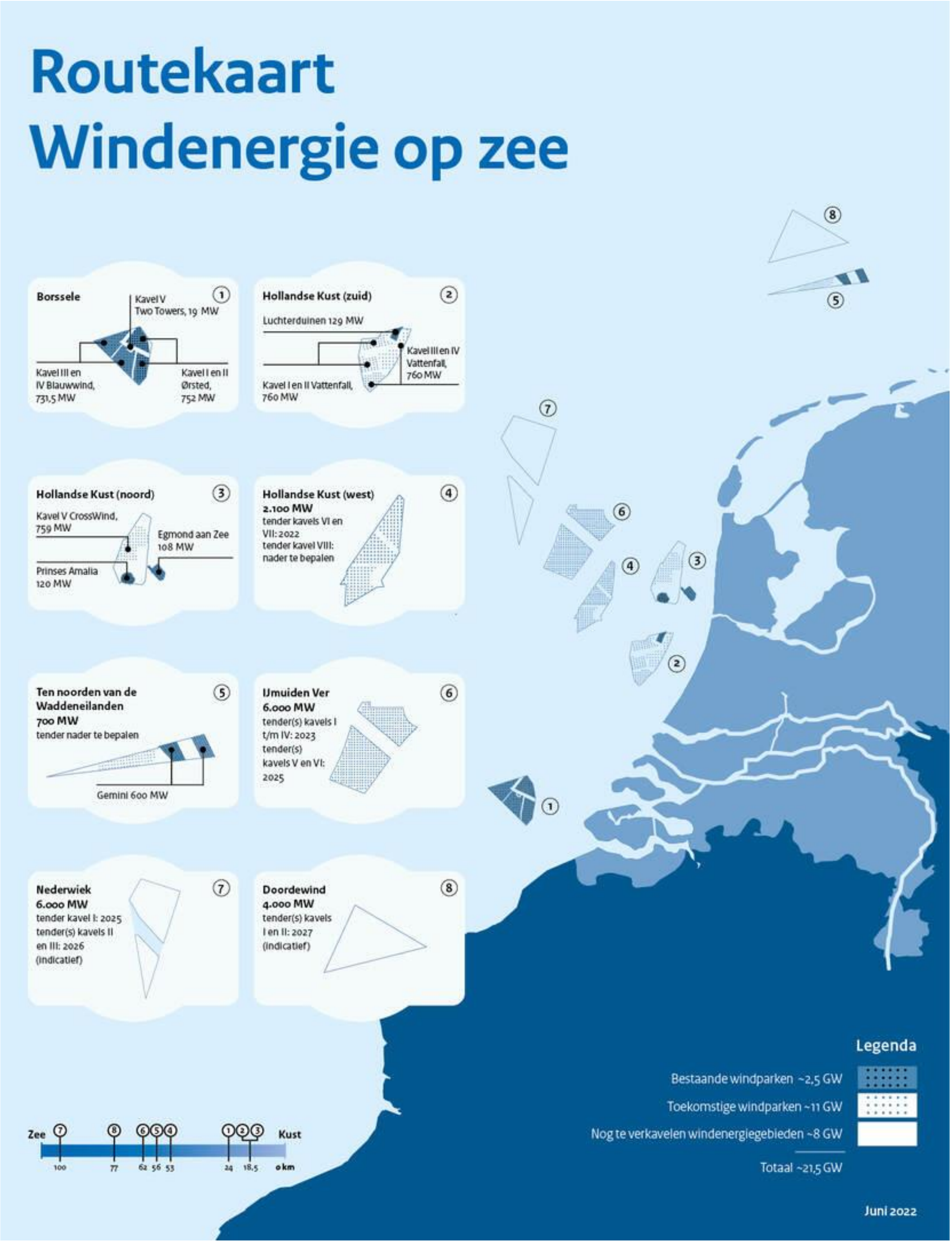
Appendix A – Overview planned Dutch offshore wind



Appendix B – Technical information regarding the setup of the model and the undertaken assumptions

General descriptions of the model

A stylized model of the CEER was used to simulate equilibrium price points in an hourly wholesale electricity and hydrogen market, where hydrogen as an energy carrier is able to shift electricity from low-price periods to high-price periods via P2G, hydrogen storage, and hydrogen-to-power (hydrogen-fired producers). For the hydrogen market, the supply of hydrogen comes from two sources: SMR and P2G. The demand for hydrogen comes from both external users, reflecting the demand from industry or transport, and demand from hydrogen-fired power plants. In this way, P2G and hydrogen-fired power plants connect electricity and hydrogen markets. Hence, the electricity and the hydrogen markets are both modelled, such that prices and quantities are determined endogenously. The gas and carbon prices are treated as exogenous variables, as both are based on international markets which do not much depend on the circumstances in one market (i.e. our market of analysis). We assume, therefore a series of daily gas and carbon prices, based on actual data and scenarios regarding the gas market and international climate policy. In addition, we also include markets for green-electricity certificates and green-hydrogen certificates to model the demand for green electricity and green hydrogen [33].

Table 20 had provided an overview of markets included in the model and the participants in each market.

Table 20 – Overview of markets and its participants included in the model

Market	Supply	Demand
Electricity Market	Renewable producer Gas-fired producers Hydrogen-fired producers Nuclear-power producers International traders	P2G producer International traders Other consumers
Hydrogen Market	SMR hydrogen producers P2G producers Hydrogen storage operator International traders	Hydrogen-fired producers Hydrogen storage operators International traders Other consumers
Green-electricity certificates	Renewable producers	Consumers
Green-hydrogen certificates	P2G producers	Consumers

It is assumed that the electricity spot market is a competitive market where no player is able to raise profits by behaving strategically. Production and consumption of electricity respond to prices, but are also affected by exogenous factors such as weather circumstances. Climate policy measures are included by assuming an external carbon price (added as a time-varying exogenous value to the marginal costs of the electricity producers) and an energy/carbon tax on energy use. The hydrogen market is also assumed to be a competitive spot market where no player is able to raise profits by behaving strategically. Hydrogen producers are distinguished in two types of producers: P2G producer and SMR producer. There is one aggregate demand for hydrogen demand [33].

We also include two certificate markets: one for green electricity and the other for green hydrogen. In the electricity certificates market, supply comes from renewable producers. In the hydrogen certificates market, supply comes from P2G producers. In both markets, the demand for certificates is represented by an aggregated demand function. The certificate prices are added to the marginal revenues of their suppliers [33].

In all markets, each producer maximizes its profits by choosing an optimal production (quantity) given the price and its capacity constraint. In each market prices balance the demand and supply [33]. The specific mathematical equations of the model are published in: [33].

The section below provides a more detailed look into the input assumptions used for various market players.

Electricity Market

Electricity producers utilize a number of generation techniques, each with a constraint on available generation capacity: renewable power producers with a small variable cost; conventional gas-fired plants with variable costs related to the gas and carbon allowance price; hydrogen-fired power plants with variable costs related to the hydrogen price [33] and nuclear power plants with variable costs related to the uranium and waste storage costs. In addition, the market is connected to neighbouring markets, which results in a potential net import supply. This supply is modelled as a net import which is a function of the spread between the domestic hourly electricity price and the foreign hourly electricity price [33]. The renewable power production is also a function of weather circumstances with a small marginal cost, which means that its production stops when the market price is very low [33]. Consumers of electricity include a P2G producer and an aggregate demand from other consumers which is a function of the electricity price. In addition, the intercept of the demand function depends on time of the day and exogenous information on weather circumstances. The model is deterministic, but a time pattern of wind speed/sun shine is included based on historical data, which implies that both actual renewable production and load change from hour to hour [33]. The installed capacities of the different electricity producers for each scenario are presented in the Table 21 and Table 23. The international transmission capacities are given in Table 22 and Table 24.

Data on solar and wind production was used in 2021 to create an hourly availability factor.

Table 21 – Electricity generation capacity per country (MW) in 2021 scenario [119]

Countries	Generation Type				
	Solar PV	Wind	Hydro	Nuclear	Gas
Norway	0	5105	33360	0	639
Denmark	1300	6181	7	0	1654
Netherlands	7900	6857	38	485	18500
Germany	53302	62273	14534	8114	31942
United Kingdom	13470	26092	6228	8256	41371
Belgium	4788	4883	1484	5943	7282
France	8188	13610	24257	63130	11952

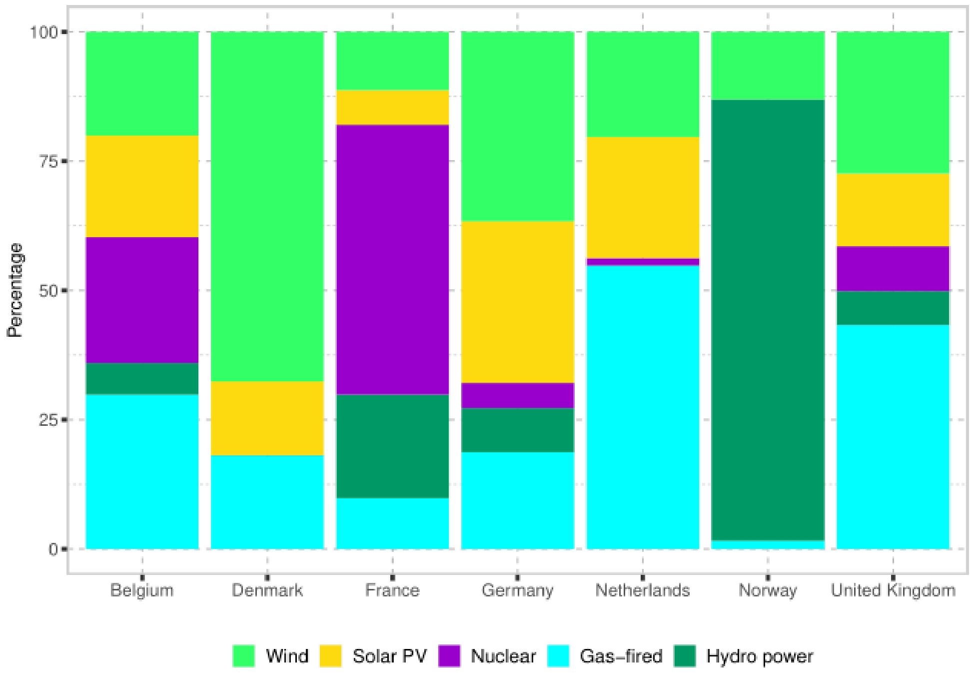


Figure 46 – installed electricity production capacity per country in 2021, relative

Table 22 – Electricity transportation capacity between countries (MW) in 2021 scenario[29] [119]

		To						
		Norway	Denmark	Netherlands	Germany	United Kingdom	Belgium	France
From	Norway	0	2372	700	1000	1400	0	0
	Denmark		0	700	2265	0	0	0
	Netherlands			0	4250	1000	1700	0
	Germany				0	0	1000	2000
	United Kingdom					0	1000	3000
	Belgium						0	2000
	France							0

Table 23 – Electricity generation capacity per country (MW) in 2030 scenario [52]

Countries	Generation Type				
	Solar PV	**Wind**	**Hydro**	**Nuclear**	**Gas**
Norway	800	7200	36000	0	270
Denmark	2300	9800	7	0	950
Netherlands	25000	18800	47	490	9300
Germany	91000	99000	15000	0	22000
United Kingdom	17000	43000	6000	9300	39000
Belgium	10000	8600	1500	0	8700
France	39000	40900	26000	58000	7400

[29] Capacity from country I to j equals capacity from country j to i

Table 24 – Electricity transportation capacity between countries (MW) in 2030 scenario[30]

		To						
		Norway	Denmark	Netherlands	Germany	United Kingdom	Belgium	France
From	Norway	0	2372	700	2400	3200	0	0
	Denmark		0	700	4600	1400	0	0
	Netherlands			0	5150	1000	4700	0
	Germany				0	1400	2000	3800
	United Kingdom					0	1000	4000
	Belgium						0	3500
	France							0

Electricity Demand

The slope and intercept for electricity demand is based on a calibration of model prices on actual observed electricity prices in 2021. For this calibration we assume a price elasticity of -0.3 [33]. **Error! Reference source not found.** shows the expected increase rates per country.

Increased electricity demand profiles in 2030 compared to 2021 are shown in Table 25.

Table 25: Change of intercept for electricity demand in 2030 compared to 2021 per country [94]

	Norway	Denmark	Netherlands	Germany	United Kingdom	Belgium	France
Increase Rate	19.8%	38.0%	4.6%	2.7%	5.3%	7.5%	9.0%

Electricity Certificate Market

A green certificate, also called a renewable-energy certificate or Guarantee of Origin, is a tradeable asset that proves energy has been produced from a renewable energy source. In a green certificates market, renewable producers receive certificates for each megawatt-hour (MWh) of produced energy and the certificates can be sold to consumers/retailers, which may result in extra income for the renewable producers depending on the price of the certificates. In the model, the supply of the green-electricity certificates equals the production by the renewable producer. P2G producers demand green-certificates of electricity when it supplies green hydrogen to the hydrogen market and the other demand for green-certificates of electricity is represented by an aggregated demand function [33].

Criteria considered for electricity green certificates is based on the approach of [33] and is presented below:

- Average green certificate demand is 50% of the load
- Price elasticity is -1
- Average price is 10 €/MWh

[30] Capacity from country I to j equals capacity from country j to i

Hydrogen market

The hydrogen market for 2021 is modeled as a national market where demand and supply is solely considered in the Netherlands.

- It is assumed that all hydrogen is produced the SMR producers, who use natural gas to produce hydrogen.
- In 2019, the Dutch industry produced around 26 TWh of hydrogen per year [120]. Assuming a capacity factor of 95% [121], this implies that the installed capacity of SMR producers is equal to 3125 MW.
- In 2021, gas prices were much higher than in 2019: the average natural gas price increased with 244%. We assume that the demand for hydrogen responded to this increase. More specifically we assumed that the price elasticity of demand is equal to -0.10. This implies that the total hydrogen consumption in 2021 decreased with 24.4% to about 20 TWh.
- We assume that the installed capacity of SMR remain 3125 MW.

For the 2030 scenario, the supply of hydrogen comes from two main sources: SMR and P2G. Hence, the electricity and the hydrogen markets are both modelled, with endogenous hourly equilibrium quantities and prices. Important criteria related to the hydrogen market is listed:

- We consider the construction of 4 GW electrolyser capacity.
- Demand characteristics of green hydrogen:
    - In the Dutch 'Klimaatakkord', estimates for hydrogen demand in 2030 range from 40 TWh to 60 TWh.
    - For the baseline 2030 scenario, we consider a demand of 50 TWh.
    - Different increases of hydrogen demand is considered under the sensitivity analysis
- Demand characteristics of grey hydrogen:
    - Initially, we assume that the installed capacity of SMR stays the same
    - Later, we consider different increases of SMR capacity

For the hydrogen market among the international traders, we initially only consider the production of grey hydrogen by SMR. Using a similar approach as for the Dutch grey hydrogen market, the yearly demand and installed capacities are in Table 26. The trading of hydrogen among other countries is also considered. The cost of trading is dependent on the distance between the countries. We assume that the international trading capacity is equal to 300 MW between all countries, which is relatively limited compared to the capacity of a single transmission pipeline. The reason for this is that if we would assume larger interconnection capacities, the results would be very much dependent on capacity assumptions made within the other countries, which are very uncertain and like the Dutch prognoses changing from time to time. To obtain insightful results on the factors of analysis in the Netherlands, we limited the impact of decisions that neighbouring countries would make and leave this as a topic for dedicated research.

Table 26: Hydrogen demand and installed capacity of SMR in 2030, per country

Country	Yearly demand (TWh)	SMR capacity (MW)
Norway	7.2	900
Denmark	2.4	300
Germany	25.3	6600
United Kingdom	52.8	3200
Belgium	8.3	1000
France	28.5	3600

Hydrogen Certificate market

Similar to the green certificate for renewable electricity, we assume that there is a green-certificates market for green hydrogen. A green-certificate hydrogen certificate is a tradeable asset that proves hydrogen has been produced from a renewable energy source. In a green-hydrogen certificate market, green hydrogen producers such as P2G receive certificates for each MWh of produced hydrogen and the certificates can be sold to consumers/retailers, which may result in extra income for the green hydrogen producers depending on the price of the certificates. In the model, the supply of the green-hydrogen certificates equals the production of the P2G, while demand is represented by a liner demand function [33].

Criteria considered for green hydrogen certificates is based on the approach of [33] and is presented below:

- Average green certificate demand is 50% of demand (of countries where green electricity is produced)
- Price elasticity is -1
- Average price is 10 €/MWh

Assumptions electrolyser investments and NPV calculations

Table 27: Assumptions for the Electrolyser

Electrolyser assumptions	Result
CAPEX	1M€/MW
Lifetime	25 years
WACC	7%
Conversion efficiency	70%

Hydrogen Storage

To provide flexibility to the electricity market, P2G plants have to be combined with hydrogen storage and hydrogen-fired power plants. When electricity prices are low, P2G plants use electricity to produce hydrogen which is stored afterwards. When electricity prices are high, the produced and stored hydrogen can be used by hydrogen-fired power plants [33]. Hence the hydrogen storage operator acts in arbitrage. For the 2021 case no hydrogen storage capacity is assumed and for the 2030 case the capacity of 250 GWh of hydrogen storage is assumed, representing one underground salt cavern.

Gas and Carbon prices

The gas and carbon prices are treated as exogenous variables, as both are based on international markets which do not depend on the circumstances in one market (i.e., our market analysis). Therefore, a series of daily gas and carbon prices are input into the model which are based on actual data and scenarios regarding the gas market and international climate policy [33].

Following 'Klimaat- en Energieverkenning 2021' [122], we assume that the average gas price is equal to 20€/MWh. We therefore take the gas prices from 2019 (average of 14€/MWh) and scale them by a factor of 1.4. For the carbon prices, we follow the 'Klimaat- en Energieverkenning 2021' [122] and assume that the average carbon price is equal to 62 €/MWh: we take the carbon prices in 2019 and scale them by a factor of 3.

Appendix C – Validation CEER model by calibrating historical electricity prices

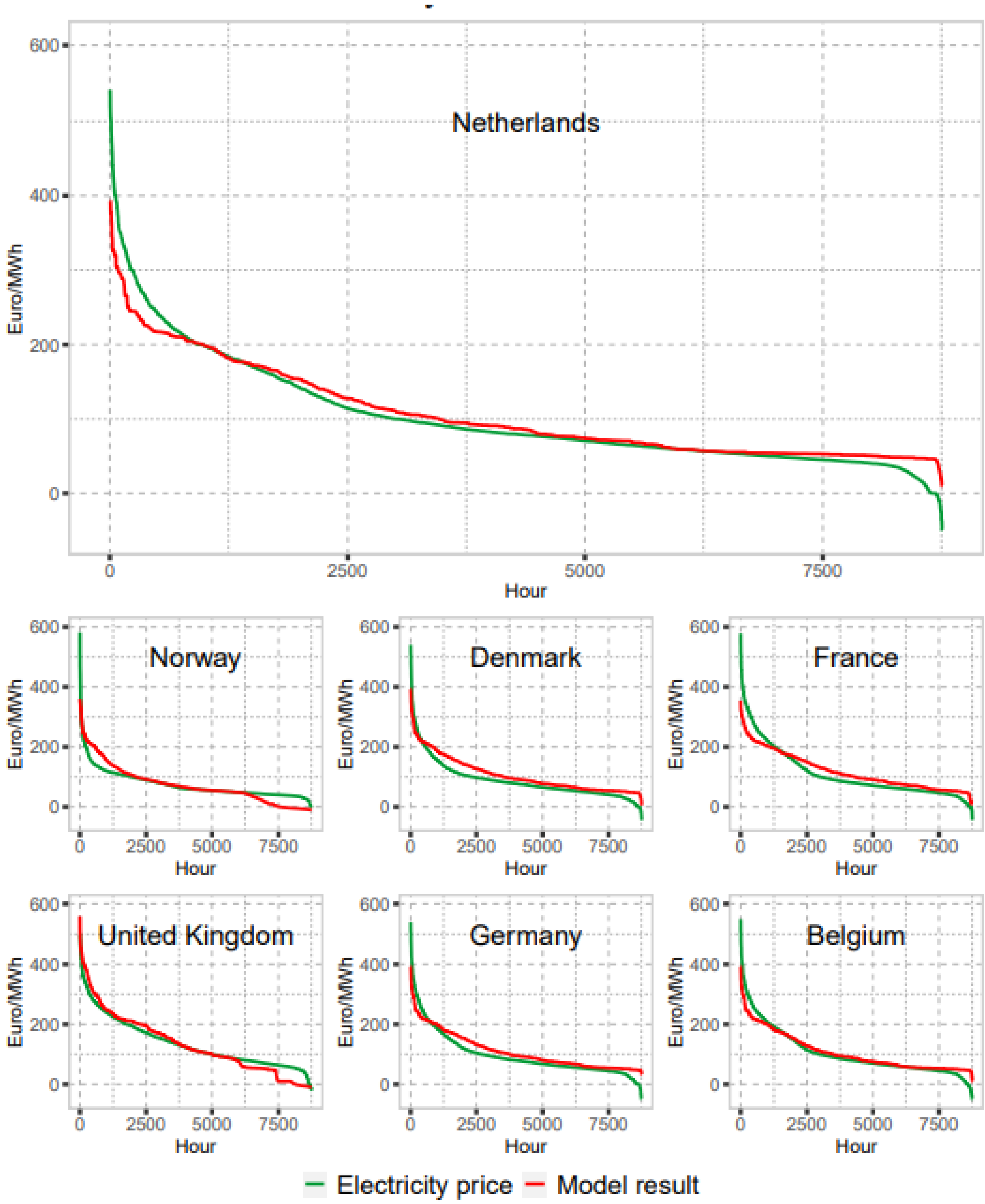


Figure 47 – Real and modelled electricity price duration curves in the national electricity markets in 2021 [48]