North Sea Energy

An analysis of the value of offshore hydrogen production in relation to alternatives

The role of hydrogen as part of a portfolio of climate change mitigation solutions for the Netherlands towards 2050

As part of Topsector Energy:
TKI Offshore Wind & TKI New Gas

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1 Executive summary

In this report the potential role of offshore system integration options in the national energy system are analysed. The focus is on offshore hydrogen production using electricity produced from offshore wind turbines in the Dutch Economical Exclusion Zone. It is addressed in this study under which circumstances offshore hydrogen production is attractive from a national system perspective. Carbon Capture and Storage (CCS) also is foreseen to play a role in the North Sea in the energy transition and achieving the climate targets for the Netherlands. Special attention is therefore given to also better understand this role in the future national energy system.

An national energy system model, OPERA, has been applied using a modified version of an existing scenario: the National Management scenario. Insights, about why, how much and under which circumstances offshore hydrogen production might have a role within the Dutch energy system, have been analysed by using several sensitivity cases of this central scenario. The main focus of this study is on the year 2050. Calculations have only been performed for a Dutch energy system that corresponds to deep Greenhouse gas (GHG) emissions reductions: 95% reduction compared to the 1990 level. Besides 2050, also analysis has been done for the years 2030 and 2040, but since offshore hydrogen is expected only to play a potential role in case of very large emission reduction and more likely at large scale after 2030, the focus has been put on 2050.

In general, it can be concluded that green hydrogen production offshore is a robust outcome in our study for the year 2050, however, transmission of offshore wind energy as electricity will remain dominant. Furthermore, the cost benefit in case offshore hydrogen production is excluded, is small. This means that from a system perspective there is not a big preference for offshore green hydrogen production over onshore green hydrogen production. In 2040 offshore green hydrogen does not appear in the system yet, but this might be related to the aforementioned small cost difference between onshore and offshore green hydrogen production in 2050. In 2040 the balance might just be the other way around.
The potential role of offshore hydrogen production depends on several factors and choices. For example, if an international hydrogen market will be developed and hydrogen prices are very low, offshore hydrogen production might not be an attractive option. Besides the importance of the hydrogen market, the following factors appear to be the most important:

- The cost of an offshore high voltage electricity grid. In case of high cost for an offshore grid, it could be attractive to produce a significant amount of hydrogen offshore. In case of low offshore grid cost offshore hydrogen production might be absent.

- Choices that are made in society and in the industry that have a large impact on the hydrogen demand. In particular the potentially large, but uncertain, role of hydrogen demand in the built environment. In case steel production uses hydrogen as reducing agent, it will have an enormous upward effect on the hydrogen demand and on offshore hydrogen production.

- Competing abatement options. In particular large amounts of biomass, combined with CCS, will have a downward effect on the hydrogen demand and production of hydrogen offshore.

In several cases green hydrogen production offshore is the most dominant hydrogen producing option in 2050. However, since the cost parameter of some relevant technologies are such, that from a system perspective onshore and offshore hydrogen are more or less equally attractive, it is in some cases difficult to be conclusive about the role of offshore hydrogen production. For the cases where offshore hydrogen appears, values range from 16 – 80 TWh/yr (0.48 – 2.4 Mton)[1]. Blue hydrogen production has an important role to play, mainly as a stable provider of hydrogen for feedstocks. Its role is mainly limited by the caps on natural gas import and CCS that have been applied. On average the role of onshore green hydrogen production is similar to offshore hydrogen production with values ranging from 21 – 83 TWh/yr in 2050. The role of onshore versus offshore hydrogen production is very case specific.

The most important applications of hydrogen are expected to be in the transport and built environment sectors. Feedstock applications, in particular the fertilizer industry and the production of synthetic fuels,

[1] Assuming an energy content of 120 GJ/ton (LHV). Source: http://www.h2data.de/

present a significant share of the demand as well. The admixing of hydrogen in the natural gas grid is not expected to have a substantial role in 2050, this is likely related to the extreme GHG emission reductions. If an international hydrogen market is developed, the Netherlands might export hydrogen as well, but this will depend very much on the market price.

CCS is very important, in particular in combination with biomass, but in a system with 95% GHG reduction and limited imports of hydrogen and biomass, direct air capture in combination with CCS might be an important option as well. The deployment of such net atmospheric CO_2 removal options (referred to as carbon dioxide removal (CDR) technology in the recent IPCC reports) is also seen in scenarios in the most recent IPCC reports (IPCC, 2018). These technology options contribute to limiting global warming to 1.5°C but are prone to high uncertainty. This should be taken into account when interpreting the outcomes of our study. Furthermore the role of CCS in combination with hydrogen production from natural gas (blue hydrogen) is limited by the applied cap on natural gas import.

The scenario that was chosen in this study describes a future in which the dependence on import of energy carriers is limited. Several resources or import caps reach there bound. In such a future, a reduction of fossil fuel consumption for aviation and maritime is impossible *or* the Netherlands can't keep its current position in bunker fuel supply.

In this study the total system cost have been analyzed as well. There are several factors that can significantly increase the total system cost and several factors that will reduce the total system cost. The following factors will significantly reduce the cost for a future energy system with deep GHG reductions:

- Large amounts of wind offshore
- A large availability of biomass
- A large availability of CCS
- The presence of an international hydrogen market

The model that has been applied gives a cost optimal solution from a national perspective. It does not include environmental/ecological or spatial constraints explicitly into account (although indirectly via chosen potentials). Furthermore it does not result in a system configuration which is optimal or most preferred for all actors in society.

2 Introduction

The Netherlands has a rather large potential for offshore wind energy (Matthijsen, J., E. Dammers & H. Elzenga,2018) and a limited amount of renewable resources onshore. According to Dutch Climate Agreement (Klimaat Akkoord, 2019) an installed capacity of 11.5 GW wind offshore in 2030 is foreseen and significant growth towards 2040 and 2050 is expected if the Netherlands want to comply to the greenhouse gas (GHG) emission reductions as agreed upon in Paris in 2015 (UNFCC, 2015). Next to wind offshore and other sources of renewable energy also a large role of carbon capture and storage (CCS) might be expected for the Netherlands (Ministerie van Economische Zaken, 2016).

This study mainly focusses on the role of wind offshore, the potential production of hydrogen at sea using wind energy, the role of hydrogen for the future energy system in general and the role CCS might play. This study complements other analysis that has been in the North Sea Energy program that focus mainly on certain energy chains or cases by considering the Dutch energy system.

So far in the North See Energy project (see NSE1 and NSE2) has mainly focused on the role of offshore system integration from a business case perspective, focusing on one specific technology or one specific site. In NSE1 and NSE2 a system perspective '*What is the cost optimal outcome for the Netherlands as a whole*' is still missing. A system perspective is important as well, since the energy system is a system with many interaction. Using a national integral analysis, interaction on the national scale are implicitly taken into account. This is in particular relevant for resources that are limited (wind energy, CO_2 storage capacity), prices for secondary energy carriers that not static (electricity, hydrogen) and since there is GHG restriction on a national level.

If offshore hydrogen production is included in the energy system, there are several factors that make it potentially attractive to apply this technology and there are several factors which make the business case for this technology potentially less attractive as compared to onshore hydrogen production. The potentially positive and negative effects can be found in Table 1 Potentially positive and negative effects of offshore hydrogen production for the total energy system.

Table 1 Potentially positive and negative effects of offshore hydrogen production for the total energy system

Positive effects	Negative effects
Avoidance of high voltage electricity transmission investments offshore	Higher investment cost for offshore electrolysis
Avoidance of offshore electricity transmission losses	Investments in offshore hydrogen pipelines
Potential avoidance of the onshore investments in the high voltage transmission grid	Potentially lower capacity factor for electrolysis, since lack of complementary electricity supply

The last potential positive effect depends very much on the location if electrolysis would be applied onshore. If onshore electrolysis is assumed to occur in or next to a harbour, it might very well be that no or hardly any expansion of the onshore high voltage grid is needed. This of course will depend very much on the opportunity to physically locate large electrolyser capacity close to a harbour.
The last potential negative effect will on the other hand depend a lot on the onshore connection to other electricity supply options (in particular wind onshore, solar PV, large scale electricity storage and import of electricity). It might very well be that this effect from a system perspective is not very beneficial.

The factors given in Table 1 Potentially positive and negative effects of offshore hydrogen production for the total energy system are simply a qualitative description of factors that might make offshore hydrogen production more favourable or less favourable as compared to onshore hydrogen production.

2.1 Aim of the work

The main research question that this study wants to address is the following:
How attractive is it to produce hydrogen offshore instead of onshore from a national energy system perspective?

Next to this main question several sub-questions have been addressed:

- Under which circumstances does offshore hydrogen production show up?
- What are the most important competing chains for GHG reduction?
- What range of offshore hydrogen production can be expected in 2050?
- How much hydrogen will be consumed in 2050 and what are the main end users?
- How much CO_2 will be captured and subsequently stored underground (CCS) in/towards 2050?
- How are total system cost affected by the implementation or exclusion of GHG reduction options and offshore system integration?

2.2 Approach

To answer the questions addressed in the previous an existing scenario has been utilized and energy modelling has been executed. For the purpose the national energy system model OPERA has been applied. Next to one central scenario, which has been applied for the years 2030, 2040 and 2050, several sensitivity cases have been analyzed for the year 2050. The focus of this study is the year 2050. All cases that have been studied correspond to 95% reduction of GHG emissions compared to the 1990 level.

2.3 Outline of this report

In chapter 3.1 the followed methodology is described including a description of the used model and data assumptions. The used scenario, including scenario specific parameters, is presented in chapter 4. Results of the scenario and of sensitivity analysis, including a discussion and limitations, can be found in chapter 5. A wrap up of the report can be found in the concluding chapter, chapter 6.

3 Methodology

3.1 Analysis approach

The analysis approach that has been used in this study is shown in Figure 1. Initially a scenario framework has been developed. This scenario framework is described in chapter 4. In this study one central scenario was choses, the Base scenario. In the following step the OPERA model was applied to this Base scenario. A description of the OPERA model is given in section 3.2 and the results of the Base scenario can be found in section **Error! Reference source not found.**. Since one scenario is not enough to draw robust conclusions several sensitivity cases have been developed and calculated using OPERA. The description of the sensitivity case is given in 5.2.1 and the results are given in section 5.2.2. Analysis of the results can be found in chapter 5. An overall discussion of the results is given in 5.3. In this section an overview of the answers to the research questions is given as well.

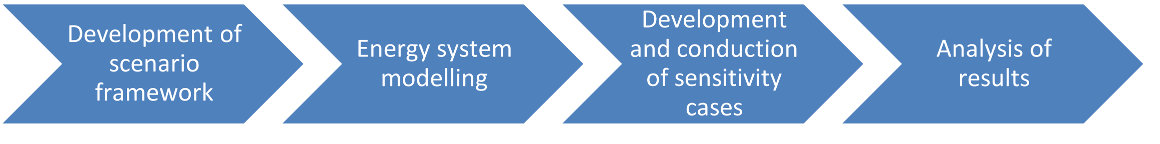

Figure 1 Analysis approach of this study

3.2 Brief model description OPERA

For the energy modelling the OPERA model has been applied. OPERA is an energy system model structure that can in principle be used to analyze possible low-carbon futures for any region in the world, provided that the necessary input data are available. In its current implementation the model contains a comprehensive database specific for the Netherlands, and to this date it has only been applied in the Dutch context. OPERA is a Linear Programming (LP) optimization model, which currently uses the interior point method to solve the LP set-up. It computes the cost-optimal energy and GHG system configuration, under specific constraints, by minimizing an objective function that expresses the total system costs for a given future year. In contrast to other energy system models, like MARKAL (e.g. Loulou et al., 2004) or TIMES (Loulou, 2005) .OPERA does not optimize over a time horizon, but rather for a single future year, for example 2030 or 2050. In other words, the model is static instead of dynamic. The best overview of the capabilities of the model can be found in Sijm *et al.* (2017), Ros en Daniëls (2017) en Daniëls (2019) and a peer reviewed paper is forthcoming on the most recent updates of the model van Stralen *et al*. (forthcoming).

The OPERA model needs to fulfil sectoral final energy demand or demand for energy services, see section 8.1. Important constraint to the model are the availability of resources (for example wind offshore capacity, availability of biomass, CCS potential, etc.) and policy targets, like GHG targets, renewable energy targets, etc. The OPERA model covers the full GHG balance of the Netherlands, so not only CO_2 but also other GHG gasses like methane and not only the energy related emissions, but also non-energy related emission (like methane emissions from the agricultural sector). Abatement options for non-energy related emissions are present in the model as well.

Since the model is a national model, it does not implicitly deal with trade of electricity between neighbouring countries, however a link with the European electricity market model COMPETES (Özdemir *et al.* 2013) has been established previously (Sijm *et al*., 2017)

Since demand and supply of energy are often not on the same location, energy needs to be transported. In Opera electricity, methane and hydrogen can be transported over long distances. To properly address the balance, from a system perspective, to invest in extra electricity transmission capacity versus converting electricity in hydrogen or methane and transporting these energy carriers to demand centers, geographical regions have been applied in OPERA. The onshore and offshore area of the Netherlands has been split up into seven onshore areas and seven offshore areas, as depicted in Figure 2.
Improved geographical resolution will increase computational time of the model and requires data at the sub provincial level which difficult to obtain.

To optimize both data requirements and computational time, a regional split was decided based on the following elements:

- Large Industrial clusters are represented individually (Zeeland (I), Zuid-Holland (II), North-Holland (III), North of the Netherlands (IV), Brabant (VI) and Limburg (VII))
- Onshore connection points are represented (Zeeland (I), Zuid-Holland (II), Noord-Holland (III) and North of the Netherlands (IV))
- Regions that do not have a direct offshore connection are represented (Middle of the Netherlands (V), Brabant (VI) and Limburg (VII))
- A distinction has been made to near/middle shore offshore areas and there vicinity to onshore connection points (respectively areas a-c and g)
- Far from shore areas are individually represented (areas d-f)

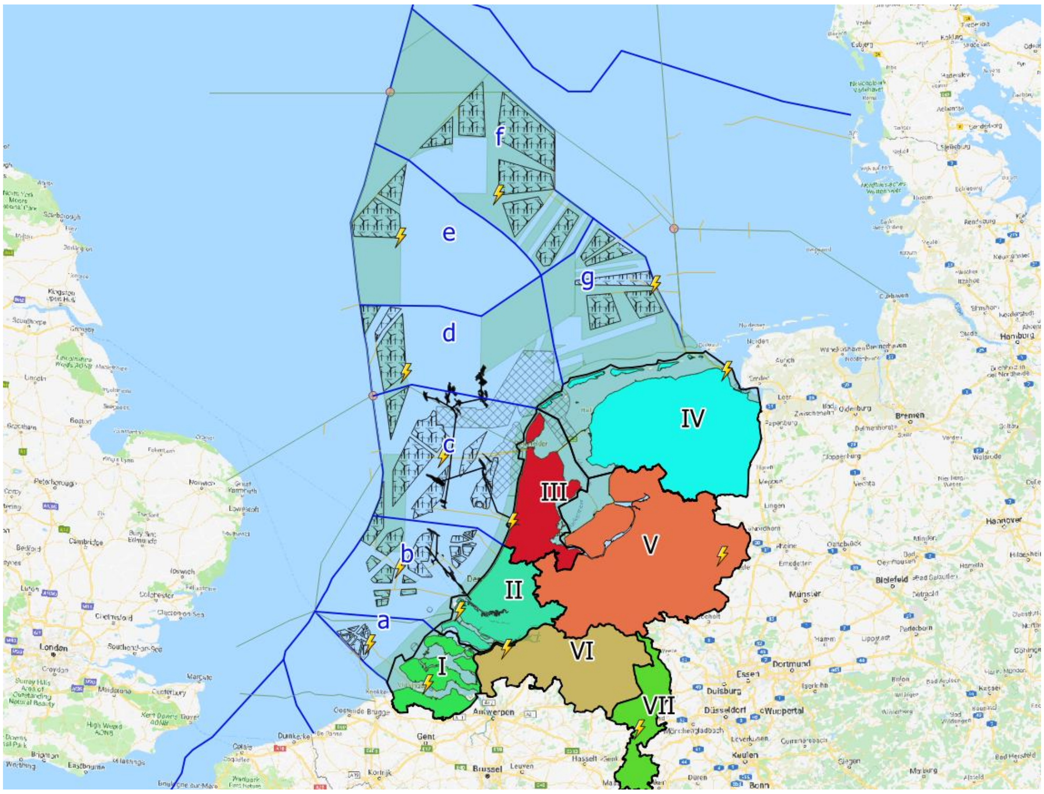

Figure 2 Geographical representation used in this study

Some elements of the OPERA model are further highlighted in Appendix I.

3.3 Data and assumptions

The OPERA model requires a significant amount of data related to technologies, demand levels and reduction targets. These data items are briefly described in this section.

3.3.1 Emission reductions

The greenhouse gas (GHG) emission reduction used for 2030 corresponds to 49% GHG reduction with respect to the 1990 level. This reduction is in line with ambitions of the current government. For the year 2050 an emission reduction of 95% was choses. At the moment of writing this report, this was a level as deemed necessary for the EU to the ambition to keep global warming limited to 1.5 ◦C (Ministerie van Economische Zaken, 2016), however, on the 11th of December 2020 the EU Green Deal was presented (EC, 2019), which states that the EU should be climate neutral by 2050. The emission reduction for 2040 is simply an average of the 2030 and 2050 values. Remaining GHG emissions can be found in Table 2 GHG emission reductions and remaining GHG emissions. Emission reduction correspond to emissions, excluding emissions from international bunker fuels (maritime and aviation).

Table 2 GHG emission reductions and remaining GHG emissions used in this study

Year	GHG reduction wrt 1990	Remaining GHG emissions [Mton CO_2-eq/yr]
2030	49%	114
2040	72%	62
2050	95%	11

3.3.2 Energy service demand

The OPERA model can use National Energy Outlooks (NEO) as a background scenario for the sectoral commodity and final energy demand. The demand figures used in this study have been derived from the NEO 2016 (Schoots, Hekkenberg & Hamming, 2016) since this outlook, in contrast to the outlook from 2017, was executed until 2050. The NEO 2016 results are provided until the year 2035, but calculations have been done until 2050 and are available in the modelling system used for the NEO. For the year 2030 the recently published Climate and Energy Outlook (Schoots & Hamming, 2019) has not been utilized since its publication data was too late to be able to include in this study.

3.3.3 Techno-economic parameters

The OPERA model contains about 500 technologies and it is outside the scope of this work to sum them up and report the techno-economic parameters that have been used in this study. Currently TNO is updating the technology factsheets of many energy technologies and all technologies that have been updated and published have been used in the OPERA database as used in this project. The factsheets that have been used can be found at www.energy.nl (TNO, 2019). In general many other technologies have been updated in 2017 for the purposes of other projects (Sijm *et al.* (2017) and Ros and Daniëls (2017)).

The MIDDEN project (PBL, 2019a) has been used to extract and update industrial process data in the OPERA database. Process data for the fertilizer industry (Batool and Wetzels, 2019), large volume organic chemicals (Wong and van Dril, 2019) and (Oliviera and van Dril, 2019) and the steel industry (Keys, Daniëls and van Hout, 2019) have been utilized.

For offshore wind energy and offshore hydrogen production the techno-economic parameters that have been applied can be found in chapter 9 (Appendix II). For offshore HV transmission cables and hydrogen pipelines a factor of 1.5 has been used as compared to the onshore values. For offshore electrolysis a factor of 1.25 has been used. Hourly wind speeds at hub height (155 m) have been derived by the wind energy department of TNO (Bulder and Bot, 2019).

4 Scenario framework

Instead of designing one or more new scenarios, it was an explicit wish of the project consortium to build upon an existing scenario. It was decided that the National Management (NM) scenario, that was developed by CE Delft for the 'Net voor de Toekomst' study (CE Delft, 2017) was the preferred starting point for the current analysis. It is a scenario that makes sense to apply for this study because of the large role that is foreseen for wind offshore in that scenario. This scenario is also one of the scenarios that has been used by Gasunie and Tennet in the Infrastructure Outlook 2050 (Gasunie and Tennet, 2019). The NM scenario can be briefly described by:

The National Management scenario:

This storyline assumes that national governments take the lead in the energy transition and aims for a high degree of energy self-sufficiency. There is an emphasis on centralized wind power and electrification of final energy demand. Besides electricity, there is a substantial demand for hydrogen and methane (bio-methane or methane from methanation of hydrogen) from renewable sources. Hydrogen is used in the industry as a feedstock, process fuel for spatial heating and a transport fuel. Hydrogen and methane are also used as fuel for back-up power plants during periods with a low infeed of wind power. Due to the strong dependence on variable wind power, there is a need for a considerable amount of flexibility from power-to-hydrogen and battery storage.

Source: Infrastructure Outlook 2050, page 20. Gasunie and Tennet (2019)

In our study it was not possible to exactly stick to the National Management scenario. For example, not all demand figures that are needed for OPERA can be derived from the corresponding reports. Since the OPERA model can extract data from the National Energy Outlook Modelling System, a logical choice for OPERA is to use demand figures from related to one of the National Energy Outlooks (NEO). As explained in section 3.3.2, the demand figures from the NEO 2016 represent a consistent set for OPERA and are therefore used.

There are, however, several elements that have directly been used from the NM scenario. For the year 2050 values of scenario parameters are given in the fourth column of Table 3 **Scenario parameters and restrictions for 2030 and 2050 as used in this study. The last column indicates if the 2050 value is in line with the value as used by the National Management scenario CE Delft (2017) and Gasunie and Tennet (2019)**. Whether these value are in line with the NM scenario can be concluded by comparing the one but last and the last columns of this table. An import deviation from the NM scenario is CCS. In contrast to the NM scenario, this study assumes CCS to be available. The CCS roll out is in line with Work Package 1.5 of this project. For the expansion of the onshore high voltage (HV) transmission grid an expansion of 2.5 times the current capacity between regions is feasible. In the 'Net voor de Toekomst' study (CE Delft, 2017) an expansion of the onshore HV grid of 2x is foreseen. Since the OPERA model is not able to decide about international electricity trade flows, since it only covers the Netherlands, import-export flows from a former project have been utilized (Sijm *et al.*, 2017). It is not clear what has been utilized in the NM scenario. The 75% EV, 25% hydrogen cars for passenger cars from the NM scenario has been applied. For heavy duty vehicles (HDV) it was decided to deviate from the NM scenario: 100% hydrogen instead of 50% hydrogen and 50% green gas. From the NM scenario it is not clear what has been applied for light duty vehicles (LDV). To the authors it seemed more logical to apply the fuel mix that was used for passenger car than the fuel mix that was used for HDV, therefore 75% electric and 25% hydrogen is used for LDV. From the NM scenario it is unclear what maximum hydrogen admixture percentage has been applied in 2050. In the current study 15% volume based has been applied in line with the report from New Energy Coalition (2019).

For the year 2030 we have used scenario specific assumptions that are mostly in line with the Dutch Climate Agreement for the year 2030. For 2040 averaging of the 2030 and 2050 values has been applied.
Prices for primary energy carriers are an input for the OPERA mode, but prices for secondary energy carriers, such as electricity and hydrogen are not input for OPERA, since the demand and supply of these carriers is a results of the model and therefore also a shadow price for these energy carriers is an output and

and not input of the model. The prices of primary energy carriers used for 2030 and 2050 is presented in Table 4

To make a distinction with the real National Management scenario we use the name Base scenario for our central scenario.

Table 3 Scenario parameters and restrictions for 2030 and 2050 as used in this study. The last column indicates if the 2050 value is in line with the value as used by the National Management scenario CE Delft (2017) and Gasunie and Tennet (2019)

Item	Unit	2030	2050	2050 value NM scenario (CE Delft, 2017)
Capacity wind offshore	GW	11.5	53	53
Capacity wind onshore	GW	8	14	14
Capacity PV	GW	22	34	34
CO_2 storage capacity CCS	Mton/yr	7	30	No
Biomass availability	PJ/yr	160	298	298
Maxiumum import of natural gas	TWh/yr	No restrictions	55	55
Onshore High Voltage transmission expansion (between regions) as compared to current levels	-	1.2x	2.5x	2x
Max capacity offshore HV transmission to shore	GW	No restrictions	No restrictions	No restrictions
Trade profiles electricity	TWh/yr	Flexnet project[a]	Flexnet project[a]	-
Trade hydrogen	TWh/yr	Not allowed	Not allowed	Not allowed
Max share district heating for the built environment[c]	-	12%	12%	12%
Passenger cars	-	Max 1.5 Mln EV	75% EV, 25% H2	75% EV, 25% H2
Light duty vehicles	-	No restrictions	75% EV, 25% H2	Unclear
Heavy duty vehicles	-	-	100% H2	50% H2, 50% green gas
SMR w/o CCS[d]	-	Allowed	Not allowed	Not allowed
Maximum admixture of H2 %vol in the methane grid	-	0.1%	15%[b]	Unclear

[a]Source: Sijm *et al.*(2017)
[b]Source: New Energy Coalition (2019)
[c]The % of final heat demand in the built environment that is provided by district heating on a an annual basis
[d]SMR w/o CCS is steam methane reforming without CCS

Table 4 Prices for primary energy carriers

Energy carrier	Unit	2030	2050	Source
Biomass[a]	€/GJ	8	20	2030: Schoots, K. & P. Hammingh (2019) CE Delft (2017)
Coal	€/GJ	2.9	2.6	2030: Schoots, K. & P. Hammingh (2019) 2050: Ros and Daniëls (2017)
Crude oil	€/GJ	14.6	10.4	2030: Schoots, K. & P. Hammingh (2019) 2050: Ros and Daniëls (2017)
Natural gas	€/GJ	7.5	5.0	2030: Schoots, K. & P. Hammingh (2019) 2050: Ros and Daniëls (2017)

[a]The price corresponds to the price for wood pellets as these are expected to be the most import type of biomass for the Netherlands

5 Results and discussion

5.1 Results for the Base scenario

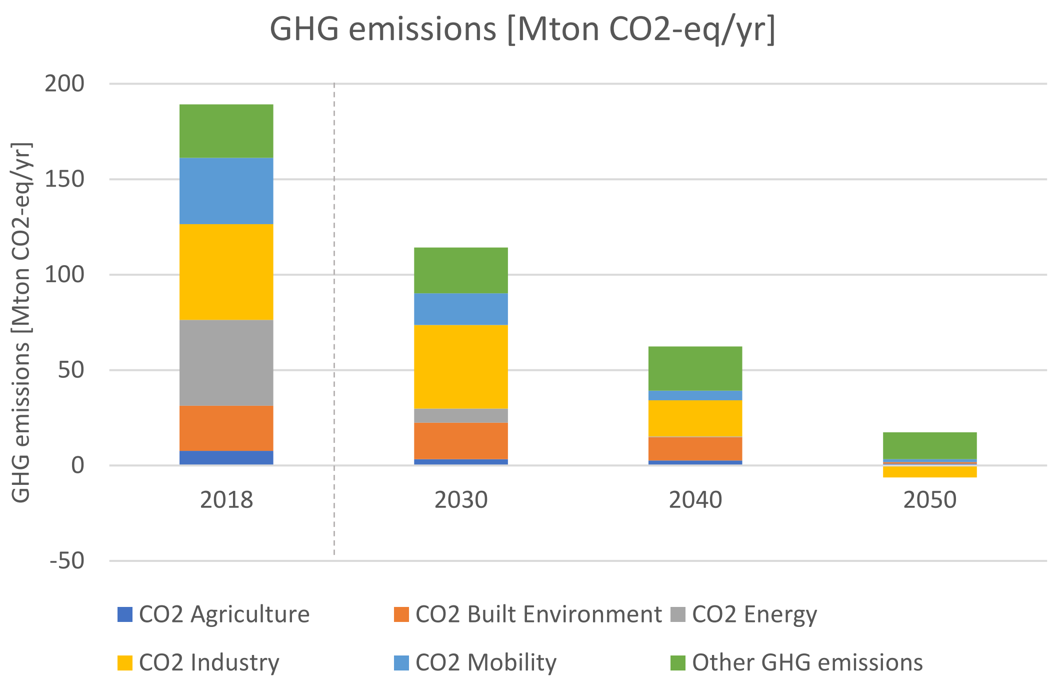

Figure 3 GHG emission [Mton CO_2-eq/yr] for 2018 and for the years 2030, 2040 and 2050 from the Base scenario. 2018 values are extracted from CBS. The industry sector includes refineries and the waste sector.

In Figure 4 the electricity supply is presented. Already in 2030 a significant share of the electricity supply will be from wind and solar energy: 74%. In 2040 and 2050 this percentage is respectively 98% and 99%. In particular in this scenario the growth of offshore wind is very large. Other supply of electricity (using natural gas, biomass, waste and waste gasses) in 2040 and 2050 has a very small contribution. Electricity storage also plays a role in the supply. Although on a yearly basis the net effect of storage is zero, the role of large scale electricity storage is presented in Figure 4. Since back delivery of electricity from electricity to the grid (vehicle to grid) is not covered in this study, the role of storage in electrical vehicles is not covered in Figure 4. The role of large scale electricity storage is 6 TWh/yr in 2050.

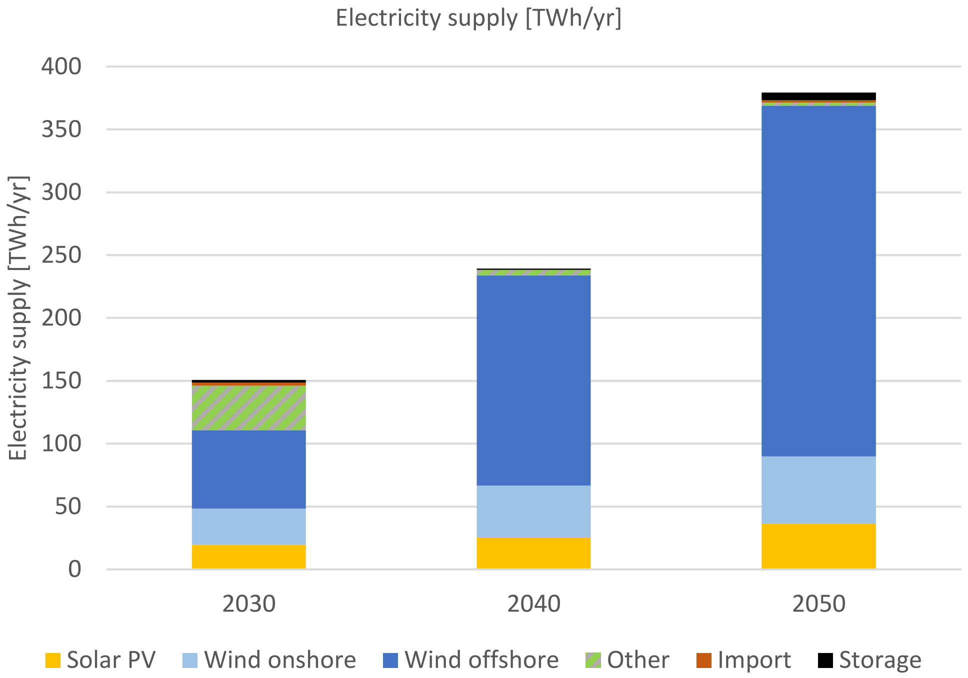

Figure 4 Electricity supply for the Base scenario in TWh/yr. Figures are excluding network losses.

Figure 5 presents how the electricity from wind offshore actually comes to shore, as electricity or as hydrogen. Both in 2030 and 2040 no hydrogen comes to shore according to the Base scenario. In 2050 almost 20% of wind energy that comes to shore is hydrogen. Note that compared to Figure 4 the total amount of offshore energy is smaller (279 TWh/yr versus 253.6 TWh/yr), because of conversion losses for electrolysis offshore and because Figure 5 includes electricity network losses.

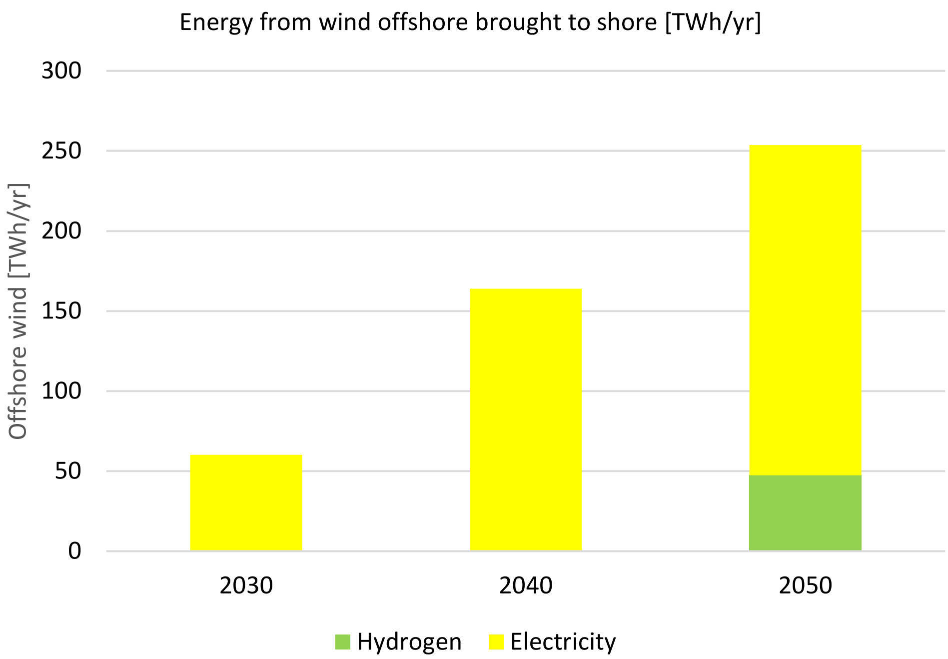

Figure 5 The amount of energy [TWh/yr] that is produced offshore and is brought to shore in the form of hydrogen (green) and electricity (yellow) for the Base scenario. Energy losses are included.

The source and the total volumes of hydrogen can be found in Figure 6. In 2030 almost all hydrogen will still be grey, with a little bit of blue (2.2 TWh/yr) and very small amount of onshore green hydrogen. Note that this is not in line with the ambition as stated in the Dutch Climate Agreement (Klimaat Akkoord, 2019), which has an ambition of 3-4 GW electrolyser capacity available. In modelling 2030 this electrolyser capacity was not forced into the model, since it is an ambition and it is not clear yet if such a large amount of electrolyser capacity solely needs to be promoted via the SDE++ subsidy scheme. In 2040 more green hydrogen (53 TWh/yr) is produced than blue (27 TWh/yr), but the green hydrogen is all produced onshore. In 2050 blue, onshore green and offshore green hydrogen all appear in the system to a significant extent. Offshore green hydrogen is the largest. The exact values for 2050 can be found in Figure 6.

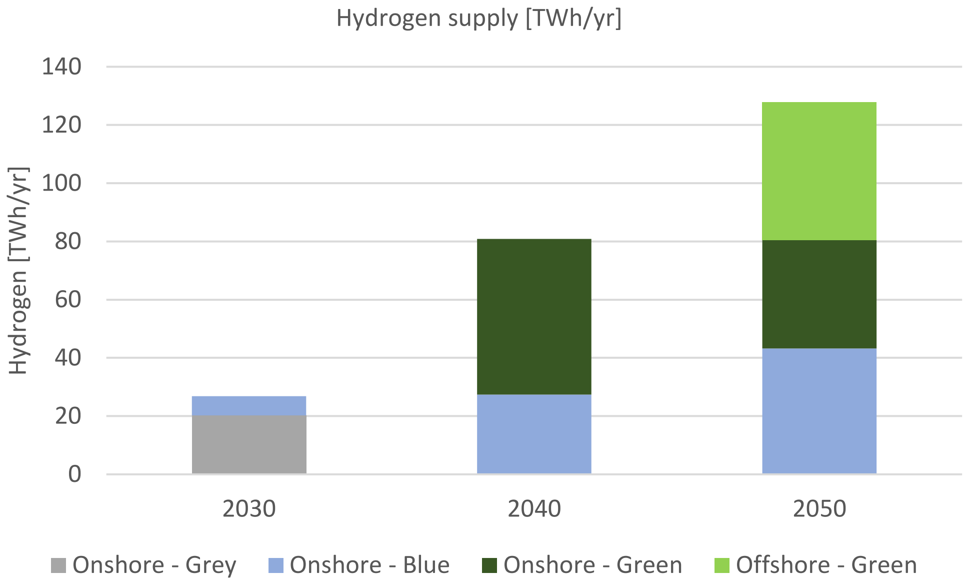

Figure 6 The supply of hydrogen [TWh/yr] for the Base scenario in 2030, 2040 and 2050. A distinction is made between supply sources.

In particular from 2030 towards 2040 a large change in the application of hydrogen can be expected, see Figure 7. In 2030 hydrogen is almost solely used for feedstocks, with a small amount for transport and in the built environment. In 2040 its application in particular in transport and the built environment is large according to the results of the Base scenario. A small amount of hydrogen in expected to be admixed in the natural gas grid: 1.7 TWh/yr. For the year 2050 the distribution over different application is rather similar to the 2040 distribution, the main difference being larger volumes and the appearance of hydrogen use for synthetic fuels.

An important note to mention about the hydrogen demand levels is that not all hydrogen demand is covered in this analysis. According to a recent update from Gasunie (2019) the current hydrogen demand (in 2019) is 48.6 TWh/yr, significantly higher than assumed earlier (30.6 TWh/yr). This updated current consumption level is significantly higher than the 2030 value presented in Figure 6 (26.8 TWh). The reason is that the hydrogen use for the production of methanol (5 TWh/yr) and use in refineries (16.4 TWh/yr) is not covered in our analysis. Methanol is not explicitly part of the OPERA model, but is part of the rest of the chemical sector, effectively the model only sees the natural gas input (for grey hydrogen production). In refineries a significant share of hydrogen is produced from internally produced residual gasses, but also from natural gas (grey hydrogen). For the analysis of 2050 the exclusion of hydrogen demand in refineries does have to mean an issues, since fossil based refineries should be phased out to a large extent by that time.

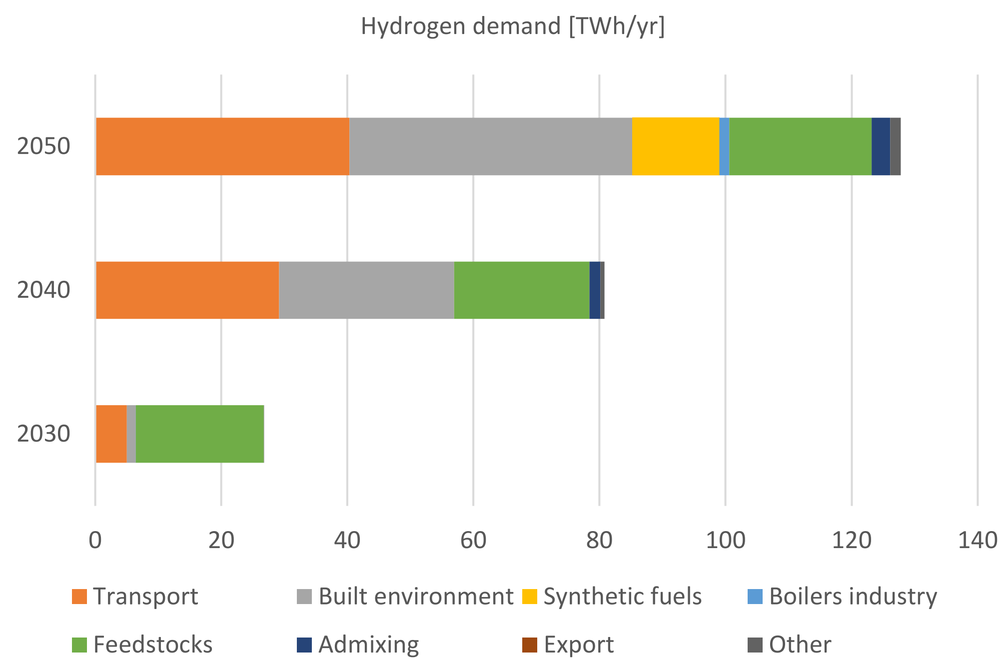

Figure 7 The demand for hydrogen [TWh/yr] for the Base scenario for 2030, 2040 and 2050 for different types of applications. Excluding hydrogen demand for methanol and refineries

The application of CCS in the Base scenario is shown in Figure 8. For all years we see that CCS is used in combination with municipal solid waste (MSW) incineration. This might be related to the abatement options for MSW in OPERA. In OPERA MSW needs to be combusted, there are no other options (like additional recycling, conversion to pyrolysis oil, etc.). In 2030 a small amount of CCS is used for blue hydrogen production. The total use of CCS is 4.1 Mton/yr, smaller than the 7 Mton/yr from the Climate Agreement. In 2040 we see a slightly lower level of MSW incineration with CCS, because of an assumed reduced availability of MSW. This trend continues towards 2050. In 2040 steel production uses CCS to lower the CO_2, but CCS is used as a transition technology, since in 2050 an entirely other type of process is used to produce steel, ULCOLYSIS, in which electrochemical reduction of iron ore is applied (Keys, Daniëls and van Hout, 2019). The utilization of CCS for blue hydrogen production in 2040 is higher than in 2050 (9.0 versus 7.3 Mton/yr). Both in 2040 and in 2050 the combination of CCS with biomass is the most dominant application of CCS: 11.0 Mton/yr in 2040 and 12.2 Mton/yr in 2050. The main application are large scale wood pellet boilers in industry. In 2050 a small amount of biogenic CO_2 comes from the production of bio-SNG. In 2050 the system is under so much stress to comply with the GHG reductions that even direct air capture followed by storage underground (DAC-CCS) is an option in the solution, 6.0 Mton/yr of CO_2 is directly captured from the air and stored offshore.

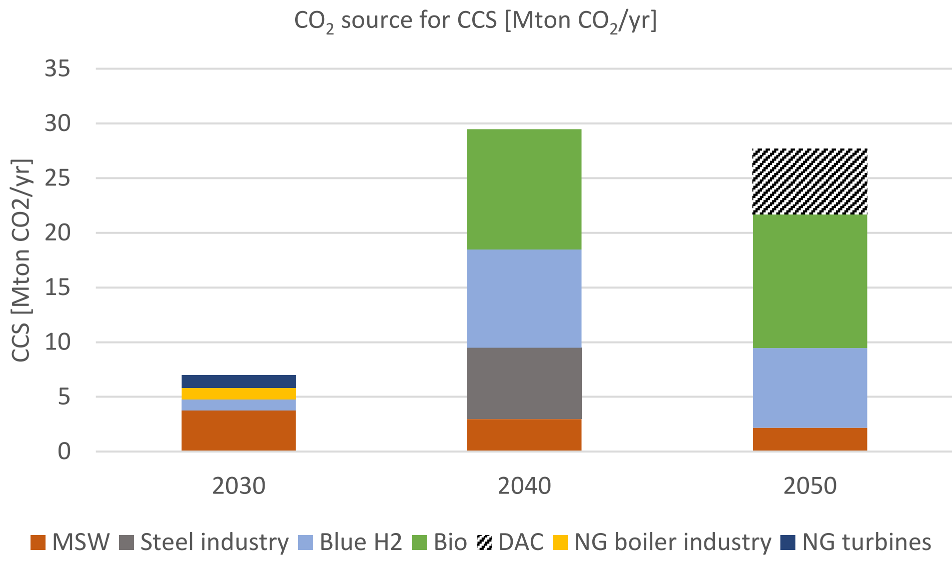

Figure 8 Source of CO_2 that is captured and stored for the Base scenario, numbers are given in Mton/yr CO_2. MSW = Municipal Solid Waste incineration, Blue H2 = SMR/ATR with CCS, DAC = Direct Air Capture and Bio = Biomass, NG = Natural Gas.

Since most of the electricity supply comes from wind and solar and a share of wind offshore electricity is directly converted to hydrogen one might wonder what the role of flexibility and storage are. This issue has not been analyzed in great detail in this study, but several things can be observed (this concerns the Baseline for 2050):

- Almost 13 TWh/yr of wind energy is curtailed. Curtailment is a cheap option to avoid excessive peaks in the system
- On an annual basis 6.1 TWh/yr of electricity is stored via large scale storage
- Demand response plays a role: for example in the case of electrochemical production of steel, not a full flat production profile is observed. Demand response also plays a role in the charging of electrical vehicles
- On an annual basis 6 TWh/yr of hydrogen is stored (both large and small scale storage)
- A little bit more than 3 GW of gas fired power plants remain still available as back-up.

5.2 Sensitivity cases

First the sensitivity cases are defined in section 5.2.1. Results and discussion of the result and a comparison with the Base scenario is given in section 5.2.2.

5.2.1 Description of analysed sensitivity cases

Several sensitivity cases have been analysed in this study. All sensitivity cases are only executed for the year 2050 and are based on the Base scenario combined with one or a few variations of parameter values. Table 5 describes all the sensitivity cases that have been analysed in this study. The cases have been defined on the basis of which factors might be expected to have a significant impact on the role of offshore hydrogen production and/or are based on initial results and outcomes which might be less plausible or uncertain to happen in reality. An example of the latter is the application of hydrogen in the built environment. In principle this might be a rather cost effective option, since hydrogen boilers are rather cheap[2].
It is worthwhile mentioning that initially several cases were foreseen in which GHG emissions of bunkers fuels were reduced. However, it appeared that, without additional imports of hydrogen and/or biomass this is impossible using the Base scenario as a starting point. Using the Base scenario as a starting point only a very limited amount of GHG emissions from bunker fuels can be reduced.

[2] The cost of future hydrogen boiler are expected not to deviate to much from the cost of gas boilers.

Therefore the bunker fuels cases have not been analysed further. Furthermore sensitivity case with high or low cost for offshore hydrogen pipeline have been excluded, since the cost of offshore hydrogen are small in comparison to the cost of an offshore HV grid and offshore electrolysers. Therefore variation in the cost of these components was as more important.

Table 5 Sensitivity cases for the year 2050 and their difference with the Base scenario

Sensitivity case label	What is difference with respect to the Base scenario?
No offshore H2	Offshore hydrogen production is excluded
Expensive offshore H2	Investment cost for offshore electrolysers and hydrogen pipelines are 2x the onshore investment cost per unit of installed capacity, compared to 1.25x and 1.5x onshore electrolysers and hydrogen pipelines respectively as used in the Base scenario.
Cheap offshore HV grid	The cost of offshore HV cables are the same as onshore HV cables, compared to a factor 1.5x as used in the Base scenario
Expensive offshore HV grid	The cost of offshore HV cables are 2x the cost of onshore HV cables, compared to 1.5x as used in the Base scenario.
High Bio	700 PJ/yr of biomass instead of 298 PJ of biomass. 700 PJ/yr is in line with the variant Max Biomass as used by Ros and Daniëls (2017).
High Wind	60 GW wind offshore. This figure is equal to the scenario with the highest wind offshore potential from Matthijsen, J., E. Dammers and H. Elzenga (2018)
Low CCS	The amount is CCS is maximized to 18 Mton CO_2/yr
Trade H2 – low price	Import and export of hydrogen at a certain market prices is included. There is a low market price of 1.5 €/kg. Both import and export are capped at 250 PJ/yr hydrogen.
Trade H2 – high price	Import and export of hydrogen at a certain market prices is included. There is a high market price of 3.0 €/kg. Both import and export are capped at 250 PJ/yr hydrogen.
Cheap Green H2	Investment cost of electrolysers are reduced by 50%
High efficiency	Efficiency of electrolyser is 5% point higher in absolute terms
Freedom	Several restrictions are released: -Maximum amount of biomass is put at 500 PJ/yr (average between Base and High Biomass) -Potential of wind offshore is put at 60 GW -No restrictions to the amount of electrical and hydrogen vehicles -The potential solar PV is put at 60 GW (arbitrary value) -The maximum share of district heating is doubled
Limit H2 in BE	The use of hydrogen in the built environment is limited to 25 PJ/yr
Steel making using H2	Steel making using ULCORED with hydrogen as reducing agent (Keys, Daniëls and van Hout, 2019)

5.2.2 Results and discussion of the sensitivity cases

In this subsection several graphs will be presented including results for the different sensitivity cases. Basic results from these graphs will be discussed. After this general discussion each sensitivity case will be analysed and discussed individually.
The amount of electricity and hydrogen that is produced offshore and transported to shore is presented in Figure 9 for the Base scenario and all sensitivity cases. Most cases show a signification proportion of offshore energy that is converted offshore into hydrogen.

The cases in which no offshore hydrogen are produced are:
-The case where offshore hydrogen is explicitly excluded (No offshore H_2)
-The case where offshore electrolysis is expensive (Expensive offshore H_2)
-The case where trade if hydrogen is included and the market price is low (Trade H_2 – low price)

For case in which offshore hydrogen appears, the offshore production ranges between 16-80 TWh/yr (0.48 – 2.4 Mton/yr). Offshore hydrogen production is the largest in the case that enforces steel making using hydrogen (the 'steel making using H2 case'). In general we can conclude that in most cases large volumes of hydrogen are produced offshore, however, in all cases significantly more electricity comes to shore than hydrogen.

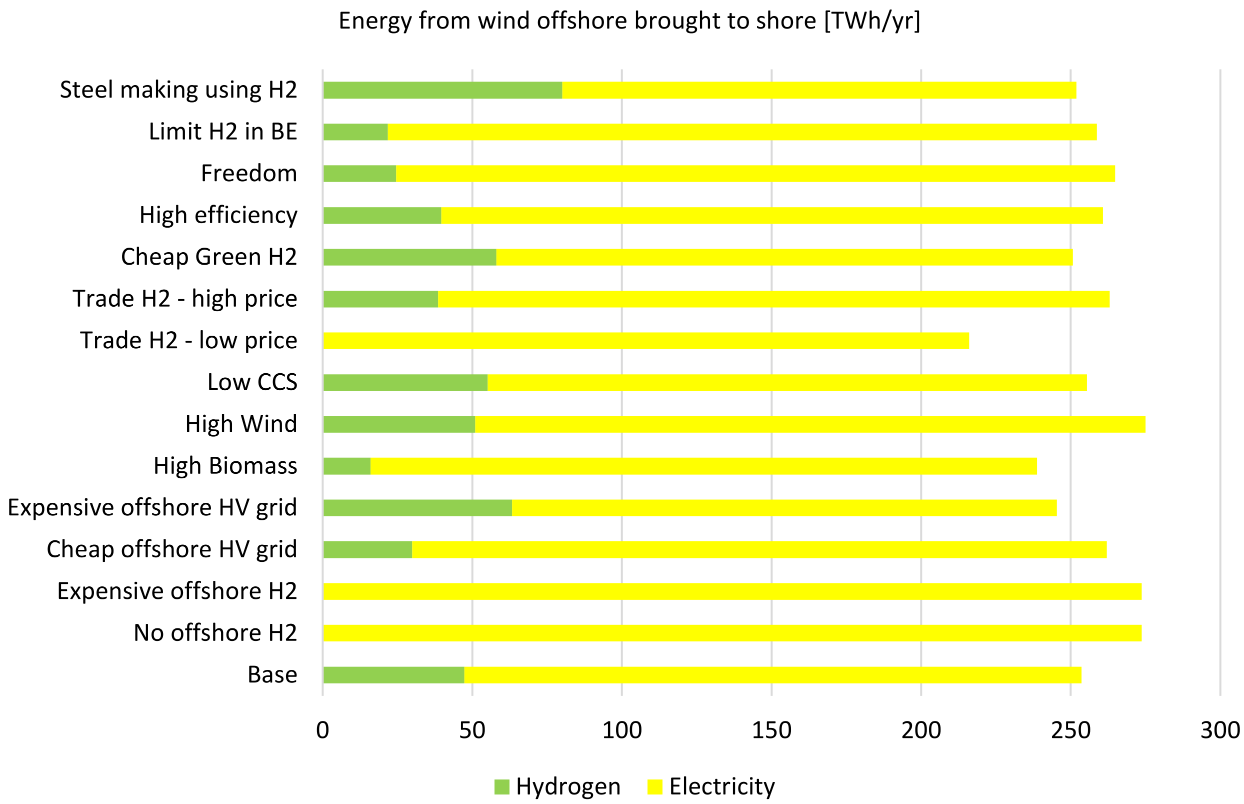

Figure 9 The amount of energy [TWh/yr] that is produced offshore and comes onshore in the form of hydrogen (green) and electricity (yellow) for the Base scenario and different sensitivity cases in 2050.

In Figure 10 the supply of hydrogen for the sensitivity cases is presented, distinguishing between onshore and offshore produced green hydrogen, onshore produced blue hydrogen and imported hydrogen. It can be seen that blue hydrogen and onshore green hydrogen appears in all analysed cases. It is worthwhile to mention that in all cases, except the 'High biomass' and 'Trade H_2 – low price' the capped amount of natural gas (see table 3) is utilized. Most of the natural gas is utilized for feedstocks, this means that there is hardly additional room for blue hydrogen than the volume achieved in the Base scenario. The demand for hydrogen is presented in Figure 11 including a distinction between final application.

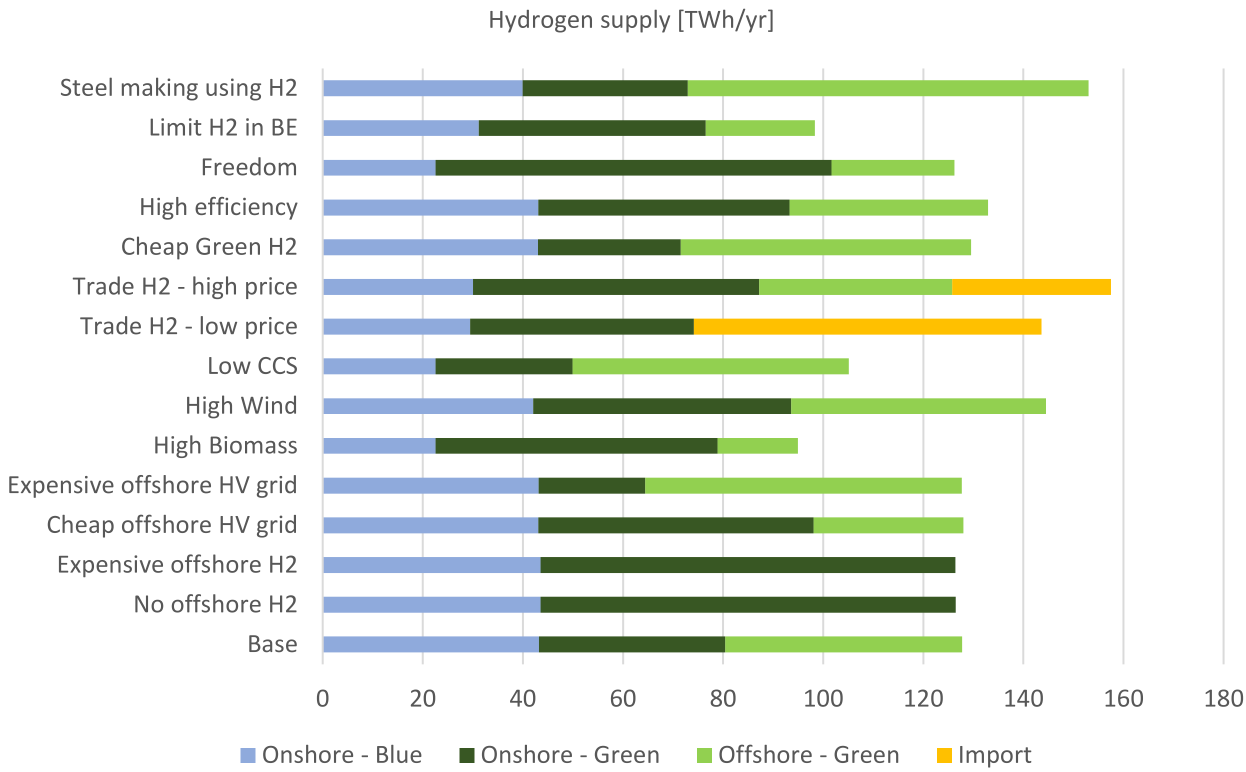

Figure 10 The supply of hydrogen production [TWh/yr] for the Base scenario and the different sensitivity cases. A distinction is made between supply sources.

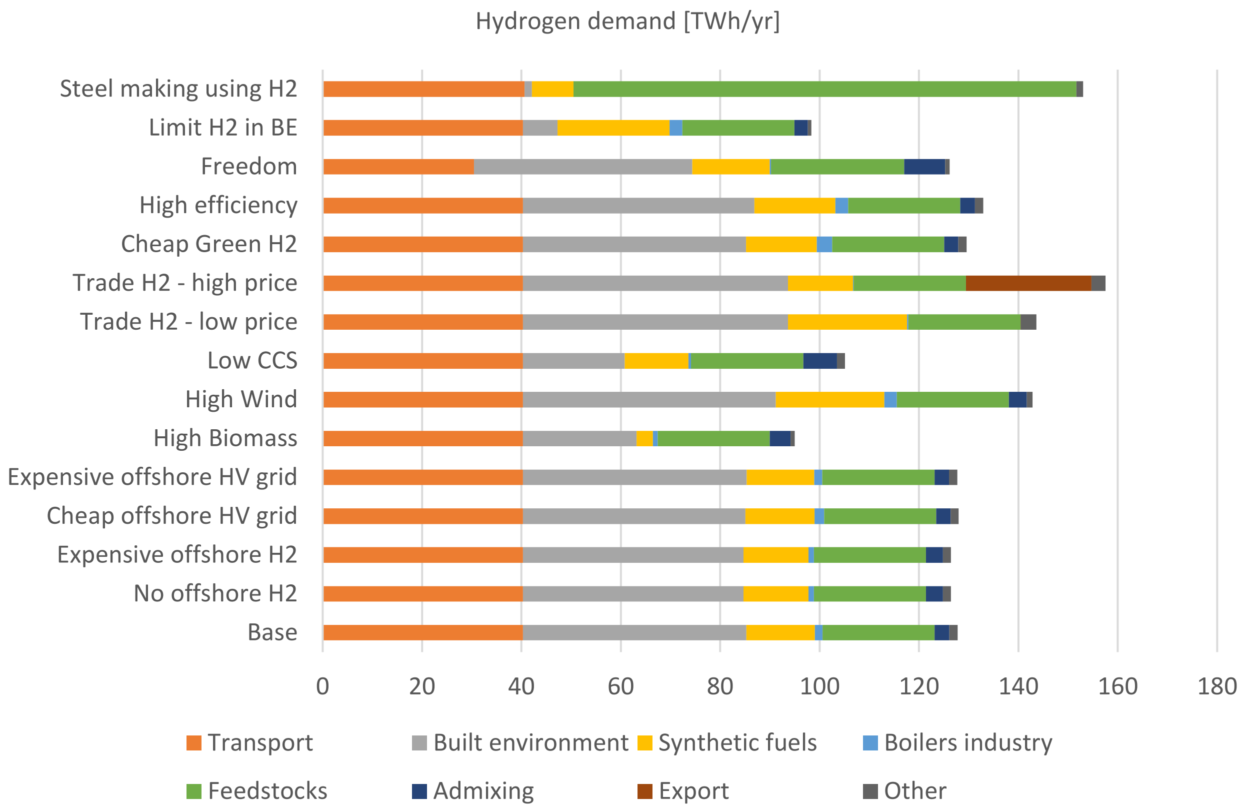

Figure 11 The demand for hydrogen [TWh/yr] for the Base scenario and the different sensitivity cases for different types of applications.

Besides offshore energy production and hydrogen production another focus point of this study is CCS. The amount of CCS and the source of CO_2 can be found in Figure 12. Besides the ‘Low CCS’ case in which CCS is capped at 18 Mton/yr, the amount of CO_2 that is captured, transported and stored is in all cases above 27.2 Mton/yr CO_2. In the ‘High biomass’ case the cap of 30 Mton/yr is fully utilized.

In all cases a fraction of CCS is reserved for the incineration of municipal solid waste (MSW), but this might be related to fact that in the model other means than incineration of waste are not available (i.e. an increased amount of recycling, conversion to pyrolysis oil, etc.). In all cases, expect the ‘Low CCS’ case, the utilization of CCS in combination biomass is the most attractive option from a system perspective. The Base scenario apparently already describes a system under so much stress that also the direct capture of CO_2 from the air (DAC) and subsequent underground storage is needed. Since blue hydrogen is produced in all cases, Figure 10, blue hydrogen pops up in all cases in Figure 12.

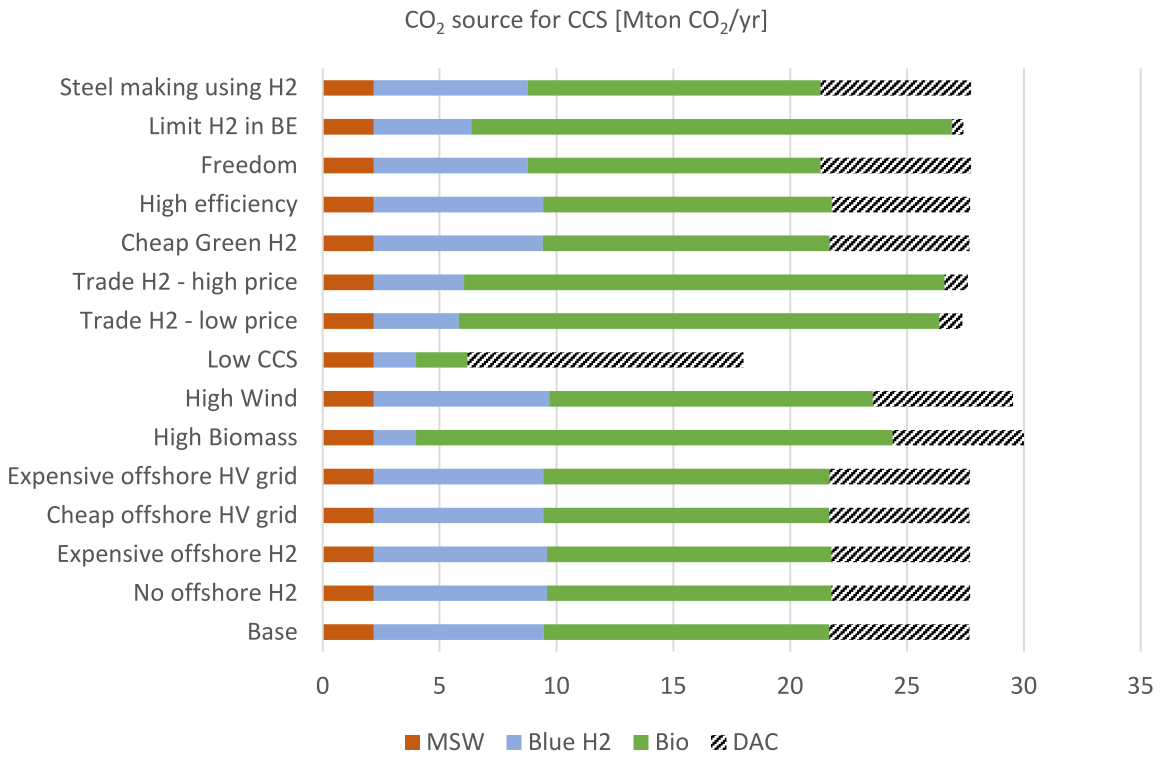

Figure 12 Source of CO_2 that is captured and stored, numbers are given in Mton CO_2/yr. MSW = Municipal Solid Waste incineration, Blue H2 = SMR/ATR with CCS, DAC = Direct Air Capture and Bio = Biomass.

It needs to be mentioned that the role of biomass in general and also in combination with CCS is uncertain. At the moment of writing the role of biomass (in particular wood) for energy applications is under discussion, see for example (PBL, 2019b). Furthermore a switch to biomass needs well developed supply chains and storage space at locations to deliver these vast amounts of biomass.

A critical statement about bio-CCS (BECCS) is extracted from IPCC (2018) and presented in the following text box. More information about negative emissions can be found in Detz and van der Zwaan (2019).

In pathways limiting global warming to 1.5°C with limited or no overshoot, BECCS deployment is projected to range from 0–1, 0–8, and 0–16 $GtCO_2$/yr in 2030, 2050, and 2100, respectively, while agriculture, forestry and land-use (AFOLU) related CDR measures are projected to remove 0–5, 1–11, and 1–5 $GtCO_2$/yr in these years (medium confidence). The upper end of these deployment ranges by mid-century exceeds the BECCS potential of up to 5 $GtCO_2$/yr and afforestation potential of up to 3.6 $GtCO_2$/yr assessed based on recent literature (medium confidence). Some pathways avoid BECCS deployment completely through demand-side measures and greater reliance on AFOLU-related CDR measures (medium confidence). The use of bioenergy can be as high or even higher when BECCS is excluded compared to when it is included due to its potential for replacing fossil fuels across sectors (high confidence).

Source: IPPC (2018)

The total system cost with respect to the Base scenario is presented in Figure 13. The cost of the case 'Steel making using H2' are excluded since the system cost are 8 Billion €/yr higher than the Base case and would make the results for the other cases less visible. From this graph it can clearly be concluded that certain options are essential to reduce the cost of an energy system with only a few GHG emissions. The options or resources that appear to lower the system cost significantly are:

- An international hydrogen market
- A large amount of wind offshore
- A large availability of biomass in combination with CCS
- A lowering of restriction as set according to the NM scenario. The effect is a combination of the 2nd and 3rd bullet, but likely also the availability of a large amount of solar PV.

In the case of low cost of an offshore HV grid, the cost are substantially lower as well. However, this is excluded from the bullet list above since it is mainly a sensitivity case to test its effect.

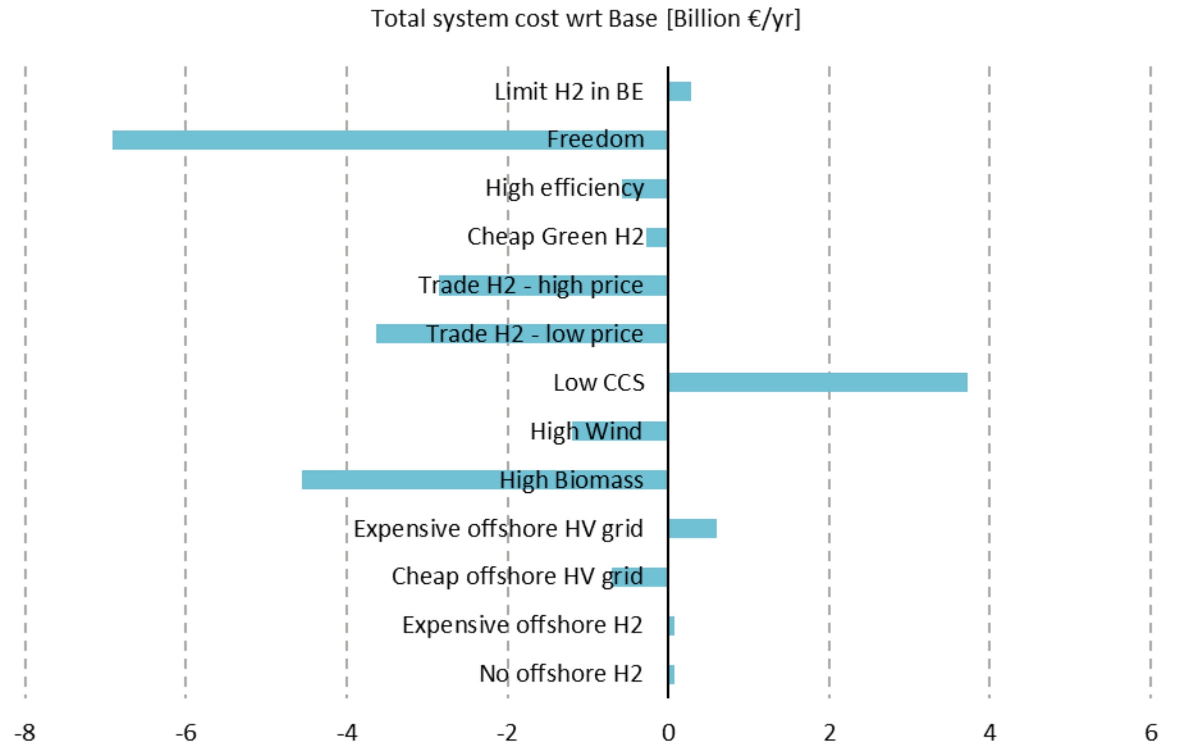

Figure 13 Difference in total system cost for different cases as compared to the Base scenario for the year 2050 in Billion €/yr. The values for the case 'Steel making using H2' have been excluded.

No offshore H_2
If offshore production of hydrogen is excluded the demand level of hydrogen remains stable. Onshore green hydrogen production can replace the role of offshore hydrogen production. The most remarkable result from this sensitivity case the low increase in system cost as compared to the Base scenario: only 82 Mln €/yr. This means that differences in onshore and offshore parameters as given in Appendix II and used in the Base scenario are such that pro's for offshore hydrogen production (avoidance of offshore HV infrastructure costs, avoidance of offshore electricity transmissions losses) are only slightly more beneficial than the cons of offshore hydrogen production (additional hydrogen pipeline cost, higher cost for offshore electrolyser cost than onshore). This in general means that the results of the Base scenario might be sensitive to parameter changes and in some cases make the it difficult to interpret the role of offshore versus onshore green hydrogen production.
Except from a shift in offshore green hydrogen production to onshore green hydrogen production and the small increase in total system cost, other results are almost equal.

Expensive offshore H_2
If the investment cost of offshore electrolysis are not 1.25x more expensive than onshore electrolysis investment costs, but 2x more expensive, it is enough to have a negative case of offshore hydrogen production: there is no offshore hydrogen production and the results are identical to the case 'No offshore H_2'. Location wise the offshore hydrogen production is mainly shifted to the province South Holland and the North of the Netherlands (not visible in any of the graphs, but available as model output). These areas have a direct connection to sea (harbour) and a large energy (South Holland) or rather high demand and good connection to other areas of the Netherlands (North of the Netherlands). In case of electrolysis in a harbour or close to shore extension of the onshore HV grid is avoided.

Cheap offshore HV grid
The cost of the offshore high voltage grid have a very important impact on potential offshore hydrogen production. If the cost of an offshore high voltage grid is relatively low, the green hydrogen production onshore increases, as reflected in Figure 10.This result is logical, since the avoided investment cost in offshore HV cables is less than in the Base case. The benefit of offshore hydrogen production is therefore also lower. As described in the analysis of the 'Expensive offshore H_2' case above, offshore green hydrogen production shift from sea to the province South Holland and the North of the Netherlands.
Lower cost for an offshore HV grid, has its main effect in shifting part of the hydrogen production from sea to shore. Since the cost of the offshore HV grid is lower per unit, the total system cost are of course also lower than the Base scenario (700 Mln €/yr)

Expensive offshore HV grid
This case has exactly the opposite effect as the case 'Cheap offshore HV grid'. By producing more green hydrogen offshore, the investments in HV electricity cables that avoided are larger than in the Base scenario. This effect can be seen in Figure 10 in which part of the onshore green hydrogen production shift to green hydrogen production offshore. The effect on the total hydrogen supply and demand and how the demand is distributed over different application is marginal as compared to the Base scenario. The effect on CCS is very small.

High Biomass
A large availability of biomass results in a smaller need for hydrogen, in particular in the built environment and for the production of synthetic fuels (Figure 11). A larger availability of biomass pushes synthetic fuels out of the market and more biomethane is produced, allowing for a larger role of methane in the built environment. The large amount of biomass is preferably applied in combination with CCS, because if gives negative emissions. The high biomass case is the only case in which the cap of 30 Mton CCS per year is fully utilized. However, because of the favourable combination of CCS with biomass there is less room for CO_2 storage from blue hydrogen, consequently the amount of blue hydrogen is lower in this case. Onshore green hydrogen production compensates the decrease in blue hydrogen production. So the total amount of hydrogen that is produced onshore remains at the same level as the Base scenario, but the amount of hydrogen that is produced offshore drops significantly: from 47 TWh/yr to 16 TWh/yr.
In the 'High biomass' case the cap of 30 Mton/yr is fully utilized.

High Wind

Increasing the wind offshore capacity from 53 to 60 GW increases offshore hydrogen production, but the ratio between hydrogen and electricity to shore remains the same. The amount of blue hydrogen decreases only slightly, but the most remarkable change is that onshore green hydrogen increases even more than offshore green hydrogen. It has not been investigated in detail, but underlying results from the model reveal that the additional onshore green hydrogen production solely occurs in near shore locations. Since the offshore parameter for electrolysis and offshore transmission of electricity and hydrogen are such that the benefits of offshore versus onshore hydrogen production are not very large (see the analysis of the 'No offshore H_2'), it does not make sense to draw very solid conclusions from this result.
Regardless of the location of the green hydrogen production, an increase in hydrogen supply and demand is seen (Figure 10 and 10). The additional hydrogen is mainly consumed in the built environment and for the production of synthetic fuels. In the built environment the additional hydrogen replaces electricity (heat pumps and electrical boilers) and the additional hydrogen for synthetic fuels replace natural gas consumption for busses.

Low CCS

In case of a low cap on CCS, system 'Low CCS' the system is put under even more pressure and as a consequence more DAC is applied giving the system room to utilize the limited amount of biomass in another way. Also the application of blue hydrogen is reduced because of the limited availability of CO_2 storage capacity. The marginal CO_2 price of the system is very high: 2500 €/ton CO_2 indicating the high stress on the system. Because of the high stress and since no additional import of energy carriers is allowed, resources need to be utilized efficiently. This is reflected in shift towards more utilization of ambient heat (heat pumps) in the built environment. Heat pumps provide a very efficient way of heating. Due to this increased use of heat pumps, a lower amount of hydrogen is needed in the built environment. The main reduction in hydrogen demand, as compared to the Base scenario, is indeed found in the demand of hydrogen in the built environment. High efficiency and reducing energy losses to a large extent is also reflected in a shift from onshore electrolysis towards offshore electrolysis. Due to this shift offshore electricity transmission losses are avoided.
Another indicator of the challenge to reach the GHG reductions for this case are the total system cost, these are 3.7 Billion €/yr higher than the Base scenario, indicating that a large amount of CCS (as in the other cases) is import to keep the cost low.

Trade H_2 – low price

In case trade of hydrogen at a low price is allowed, it will release the stress on the system: total system cost drop by 3.6 Billion €/yr and only 1.0 Mton/yr of CO_2 is directly captured from air and stored underground (DAC-CCS). As can be seen from Figure 11, no hydrogen is exported at this low price (1.5 €/kg H_2), however, a significant amount of hydrogen is imported as can be seen in Figure 10 (69 TWh/yr). This amount is equal to the import volume cap that has been applied (see Table 5).
Overall domestic consumption of hydrogen is higher than in the Base scenario. The main increase in demand is seen in the built environment and for the production of synthetic fuels, the overall figures are very similar to the 'High wind' case.
The cheap hydrogen import fully pushes out offshore green hydrogen production and also pushes out blue hydrogen to a large extent as stable hydrogen supplier for industry. Since the volume of imported hydrogen is large, the imported hydrogen can also cope with the variations in green hydrogen production.
Trade of hydrogen will increase the domestic consumption of hydrogen. It will keep the onshore hydrogen production stable, but there will be a shift from onshore blue to onshore green hydrogen production. Probably this is related to the variability in electricity prices. If there are hours with a large amount of solar and wind energy the price of green hydrogen can better compete with imported hydrogen than grey hydrogen. If there is trade of hydrogen and the price is low, there is no offshore green hydrogen production.

Trade H_2 - high price

In case of trade at a high hydrogen price (3.0 €/kg H_2) both import and export is observed (Figures 9 and 10). The import volume is 31.7 TWh/yr, the export volume 25.3 TWh/yr. Similar to the case with trade and a low price, the case with a high price has a reduced role for blue hydrogen. Apparently trade of hydrogen has a stabilizing effect on the hydrogen market, resulting in less fluctuations. Fluctuations in green hydrogen supply can be compensating by trade of hydrogen. The total volume of green hydrogen production is 11 TWh/yr larger than in the Base scenario, however, the amount produced offshore is smaller.

It is not exactly clear why it is smaller. The trade of hydrogen has a positive effect on the total system cost: they are 2.8 Billion €/yr lower than the Base scenario.
The total demand for hydrogen is larger than in the Base scenario, since there is a significant share of hydrogen exported. The total domestic demand for hydrogen is 132.5 TWh/yr, which is more than the demand of the Base scenario. Additional demand for hydrogen is seen in the

Cheap green H_2

The cost of electrolysers assumed in 2050 are already low (Appendix II), lowering the cost will therefore not have a very large cost benefit. Since offshore electrolysis is assumed to be 1.25x higher than onshore hydrogen production, the cost decrease in absolute terms for offshore wind electrolysis is larger than onshore electrolysis. Of course it might be that a cost reduction in electrolysis will have a similar effect on both offshore and onshore investment cost, but in this case we simply applied a general reduction factor. Due to the higher cost reduction in absolute terms for offshore electrolysis, a shift towards more green hydrogen production offshore is observed (Figure 10).
The role of blue hydrogen production remains the same (probably again because of its stable supply for industry) and hydrogen demand is not significantly from the Base scenario. Since cost of electrolysis has been reduced, the total system cost are lower: 274 Mln €/yr. This is rather small amount, but as mentioned before the cost figures for electrolysis for the Base scenario are already quite low, so there is not so much to gain anymore.

High efficiency

Increasing the efficiency by 5% point has a larger effect on the system than further reduction of the electrolysis cost in 2050. Total hydrogen demand increases by 5 TWh/yr and total system cost decrease by 570 Mln €/yr. The volume of blue hydrogen demand remains the same and the role of onshore green hydrogen increases, while the role of offshore green hydrogen decreases. Since the benefits of offshore green hydrogen production are small as we have seen by comparing the Base scenario with the ‘No offshore H_2’ it is difficult to explain why this is happening. The additional demand for hydrogen is consumed in the built environment and for the production of synthetic fuels.

Freedom

The Base scenario uses several elements from the National Management scenario from the Net voor de Toekomst study (CE Delft, 2017). If some elements are relaxed as in the ‘Freedom’ case the hydrogen demand slightly decreases. The reduction is caused by the transport , 10 TWh/yr, due to more electrical vehicles. On the other hand a larger amount of hydrogen is admixed in the gas grid (+ 5 TWh/yr).
If more solar PV is allowed in the system, as in the ‘Freedom’ case, a larger amount of onshore green hydrogen production is seen, at the cost of blue hydrogen. This might be related to the fact that solar PV and wind energy partially complement each other by the moments of electricity production, resulting in a larger capacity factor for onshore electrolysis.
The Freedom case is the case with the lowest system cost (6.9 Bln €/yr lower), this effect is caused be the higher amount of wind and biomass (see also the lower cost for the ‘Low wind’ and ‘High biomass’ cases), more solar PV and lower cost in the transport sector.

Limit H_2 in the built environment

The amount of hydrogen in the built environment is large, if this application is limited (‘Limit H2 in BE’), it also has an effect on the total demand. The total demand in the built environment is 38 TWh/yr lower, however, the consumption of hydrogen for synthetic fuel production is almost 9 TWh/y higher. Due to the lower demand for the built environment, the price for hydrogen will drop and consequently the application of hydrogen for other sectors will become more attractive.
Both the supply of blue hydrogen (-12 TWh/yr) and offshore green hydrogen (-25.6 TWh/yr) decreases. The supply of onshore green hydrogen increases (+8 TWh/yr). It might be that blue hydrogen decreases, since part of the blue hydrogen is used in the Base scenario to compensate for the seasonal fluctuations in hydrogen demand for the built environment which can’t always be provided at all instants by green hydrogen. The cost will significantly increase in case of limited consumption of hydrogen by the built environment (Figure 13).
As was mentioned before the application of hydrogen in the built environment might be controversial. It also needs to be mentioned that in the Base scenario the amount of district heating is assumed to be rather low. The combined amount of external heat to the built environment and agricultural sector is 38 PJ/yr in the Base scenario. The amount in 2018 was about 23 PJ/yr (Schoots & Hammingh, 2019) and the ambition in the

Climate Agreement for 2030 is 42 PJ/yr. The level of district heating is therefore not in line with the ambitions in the Climate Agreement and a slightly higher value as starting point would have been more realistic.

Steel making using H_2

If the model is enforced to apply steel production using hydrogen (‘Steel making using H2’) a strong increase in the hydrogen demand is seen and the additional hydrogen is provided by green hydrogen produced onshore and offshore. Such a large increase in demand will increase the price of hydrogen and makes hydrogen less attractive for other applications. The demand for hydrogen in the built environment almost completely disappears, it’s role is replaced by full electric and hybrid heat pumps. The demand for hydrogen for synthetic fuel production is also reduced (-5 TWh/yr). Underlying results that reveal that a reduction in the consumption synthetic diesel for machines in the agricultural sector is replaced by application of more hybrid agricultural machines, reducing the diesel consumption.
Both onshore green and blue hydrogen production have a small reduction in supply (respectively 4 and 3 TWh/yr), but offshore hydrogen production increases significantly (+32.7 TWh/yr). The reason why the increase comes from offshore and not onshore green hydrogen production is probably related to the location. Steel production is fully assigned to the province North Holland, which has limited HV electricity expansion opportunities, but is directly connected to sea.
An interesting observation is that the capacity factor of the steel making process significantly drops in case of switching to steel making using hydrogen (ULCORED process) compared to the electrochemical process that is applied in the Base scenario (the ULCOLYSIS process). In case of the ULCOLYSIS process a capacity factor of 94% is observed, in the case of ULCORED an capacity factor of only 48% is observed. Since the amount of natural gas is capped to 55 TWh/yr (see Table 3 Scenario parameters and restrictions for 2030 and 2050 as used in this study. The last column indicates if the 2050 value is in line with the value as used by the National Management scenario CE Delft (2017) and Gasunie and Tennet (2019)) and natural gas is already almost fully utilized for feedstock production, there is no additional room for blue hydrogen to increase and provide a more stable supply of hydrogen. Furthermore large scale hydrogen storage in salt caverns is not in the vicinity. Apparently it is more optimal for the system the apply over dimensioning of the steel factory than to apply other means of flexibility and increase the capacity factor. How feasible this is in reality is of course uncertain. Due to this over dimensioning and burden on the rest of the system (less hydrogen for the built environment), the system cost are significantly higher than the Base scenario: 8 Billion €/yr (not visible in Figure 13).

5.3 General discussion and limitations

In this subsection first the research questions that were raised in section 2.1 are repeated and subsequently answered. Next several limitations are discussed. In Table 6 the research questions and answers are given. This table presents a wrap up of results presented in sections **Error! Reference source not found.** and 5.2.

Table 6 Research questions and their answer

How attractive is it to produce hydrogen offshore instead of onshore from a national energy system perspective?
Answer: Yes, this can be attractive in a future with a lot of wind offshore like analysed in this study
Sub-question: If offshore hydrogen production shows up, why is this the case?
Answer: The expected demand for hydrogen in an energy system with very low GHG emission is large. Since in 2050 many options are needed to realize GHG reduction, the available CCS potential is preferably utilized in combination with biomass and direct air capture (because negative emissions can be accounted), therefore the supply of blue hydrogen will be limited. The largest share of hydrogen needs to come from green hydrogen. Wind offshore is by far the largest source for renewable electricity in this scenario. By converting a significant share of this electricity at sea to hydrogen, the capacity of the offshore HV grid can be smaller thereby avoiding cost.
Sub-question: Under which circumstances does offshore hydrogen production show up?
Answer: Offshore hydrogen is not expected to play an important role before 2040. After 2040 there are several important factors impacting the production of offshore hydrogen production. There should be a large demand. This also means that certain developments in certain sectors need to occur. For example, the demand for hydrogen in the built environment is preferable large. Furthermore, the installed capacity of wind offshore needs to be large and the availability of competing abatements options should be somewhat limited: in particular the amount of CCS and biomass.

If there is an international hydrogen market and the market price is very low, offshore hydrogen production at the Dutch part of the North Sea is not expected to play a role. The role of onshore versus offshore green hydrogen production depends very much on the balance between factors that make offshore hydrogen production attractive, in particular: -The cost of the HV offshore electricity grid, that should be high to make offshore hydrogen production attractive -The difference between offshore electrolyser investment cost compared to the onshore situation, that should be small to make offshore hydrogen production attractive
Sub-question: What are the most important competing chains for GHG reduction?
Answer: Competing chains for a low GHG energy system are district heating for supplying heat for the built environment (since it will lower the demand for hydrogen), bioCCS since it gives negative emissions, large amounts of CCS and natural gas (blue hydrogen) and the transmission of wind offshore electricity to shore which is in particular attractive if the cost of offshore electricity cables are low
Sub-question: What range of offshore hydrogen production can be expected in 2050
Answer: The range is large: 0 – 80 TWh/yr in the analysed cases
Sub-question: How much hydrogen will be consumed in 2050 and what are the main end users?
Answer: 95-158 TWh/yr in the analysed cases. The main end users are the transport sector, the built environment, feedstocks and synthetic fuels.
Sub-question: How much CO_2 will be captured and subsequently stored underground (CCS)?
Answer: In this study we put a cap at 30 Mton CO_2/yr. Most of the analysed cases show 28 Mton/yr of CCS being utilized. An important restriction is the gap of 55 TWh natural gas import.
Sub-question: How are total system cost affected by the implementation or exclusion of GHG reduction options and offshore system integration?
Answer: The effect on the total system cost by implementation (or reduction of restrictions) or exclusion of GHG reduction options can be large. The following elements result in a significant reduction (> 1 Billion €/yr) of total system cost: -International hydrogen trade (or an international hydrogen market) -A large availability of biomass, -A large amount of wind offshore, -A reduction of several restrictions, in particular in the transport sector, The following elements result in a significant increase (>1 Billion €/yr) of total system cost: -A limited amount of CCS potential -A limited utilization of hydrogen in the built environment -An entire shift of steel production using hydrogen as reducing agent

As for all (modelling) studies, this analysis has several limitations. The aim of the study is not to predict the future, but to get insights in factors that might have a large impact on a potential role of offshore hydrogen production. The most important limiting factors are presented here.

An important limitation is that only one scenario has been analysed. Different scenario often present entire different futures. In this study all cases have a large amount of wind offshore. In the 'Net voor de Toekomst' (CE Delft, 2017) and the Infrastructure Outlook 2050 (Gasunie & Tennet, 2019) futures with a different mix of (renewable) electricity are presented. These other futures or pathways will have a different role of offshore hydrogen production. Therefore our main research question should be read as 'How attractive is it to produce hydrogen offshore instead of onshore from a national system perspective *in a future with a large amount of wind offshore?* '

As was seen in the two sensitivities that allowed hydrogen to be imported and exported at a fixed price, the international component might be very important. Since OPERA is a national model it was not possible to include this element in a dynamic way. Also international electricity trade has not been included in a dynamic way. In a previous TKI project that used OPERA, the Flexnet project, it was seen that a link with an European electricity market might have an important effect on the flexibility of the national electricity system, see Sijm *et al.* (2017). It can be expected that the dynamic inclusion of electricity trade will also impact the role of green hydrogen production. It was outside the scope of this project to do a link with an European electricity market model. However, since international electricity can provide a lot of flexibility for the electricity system it is expected that a dynamic inclusion of international electricity trade will increase the role of green hydrogen, since the capacity factor for green hydrogen production can potentially increase. Since the electricity interconnection are likely to be mainly connected onshore, it is expected that international electricity trade will be mainly beneficial for onshore green hydrogen production, but an in depth analysis is needed to be more conclusive on this.

The scenario that was chosen for this project, combined with the very large GHG emission reductions, give an energy system that is under high stress and radical choices are needed to comply with the GHG emission reductions. It would have been interesting to analyse the system under slightly lower GHG reduction, for example 85% and 90% reductions. Similarly it would have been interesting to have an additional sensitivity analysis using a higher cap on natural gas import. Since the CCS cap is in general not fully utilized it might be expected that with more natural gas the role of blue hydrogen would have been larger.

In this study, analysis has been done on a system with a large amount of wind offshore. The two chains that have been included for offshore wind electricity are transmission of electricity to shore and offshore hydrogen production. In WP 3 of the North Sea Energy 3 program other offshore Power-to-X options have been investigated: Power-to-Ammonia and Power-to-Methanol. It was outside the scope of this study to include these Power-to-X routes in the OPERA model.

An important assumption that is made in this study is that in case onshore hydrogen production occurs in a region connected to sea, electrolysis can happen close to the location where offshore electricity comes to shore. This means that, in principle, there is no need to expand the onshore HV grid in such a situation.

Furthermore, the OPERA model has several foreseen improvements which are not yet available, but which might have an impact on the results:

- Heat is simply one energy carrier, there is no differentiation between low, medium, high and ultra-high temperature.
- Heat storage is not covered in the model
- There is no explicit CO_2 grid available in the model. Therefore there is no link between the location of the CO_2 emission and the (offshore) storage location and also no cost differentiation.
- Methanol is not explicitly covered as a chemical product, but is simple part of the remaining part of non-energetic applications. Therefore, the hydrogen demand for methanol is not present in this study, which gives an underestimation of the use of hydrogen for feedstocks.
- Time resolution for the OPERA model can further be improved. This would allow for a better dynamic modelling of the energy system. And probably will result in a better understanding of the market dynamics of electricity and (coupled) hydrogen markets.
- Optimization is done for a single year and not over a horizon 2030 - 2050.

6 Conclusions

In this report the potential role of offshore hydrogen production at the Dutch Economical Exclusion Zone, using electricity produced from offshore wind turbines, is analysed. The main research question that has been addressed in this study is if offshore hydrogen production is attractive from a national system perspective. To tackle this question a national energy system model has been applied. For this purpose a modified version of an existing scenario, the National Management scenario, has been used. Since in this study only analyses has been done using very large amounts of installed offshore wind capacity and for an energy system in which GHG emission reductions are in line with the Paris agreement, conclusions only hold in such circumstances.

Furthermore, this scenario analysis reflects (optimal) outcomes from a techno-economic perspective and does not take into account societal preferences or location specific optimal business cases. Its outcomes serves to understand what future roles system integration options could bring to the energy system under different assumptions.

In general it can be concluded that offshore green hydrogen production is a robust outcome in our study for the year 2050, however, transmission of offshore wind energy as electricity will remain dominant. Model results indicate that up to 2030 hydrogen is mainly grey hydrogen, complemented with some blue hydrogen. Afterwards blue hydrogen and green hydrogen grow significantly. In 2030 it is not expected that offshore hydrogen production will play a large role, except maybe from small scale or demonstration facilities. Towards 2040 offshore green hydrogen still does not appear as a beneficial option and hydrogen production will be dominated by blue hydrogen and green hydrogen that is produced onshore. Using the HV offshore electricity cost, the offshore pipeline cost and the relative cost increase for offshore electrolysers, a relatively small cost reduction is observed by producing hydrogen offshore, However, since the cost benefit is small, the role of offshore versus onshore green hydrogen production is in some cases difficult to justify and to interpret. For cases in which these parameters are changed the results are more clear. On the other hand, if the cost of a high voltage electricity grid are rather low, the cost savings on the grid are limited, and transmission of electricity to a harbor followed by subsequent electrolysis onshore is more attractive. If the cost of the offshore high voltage grid are high, offshore hydrogen production becomes an attractive option. Similarly in case the additional cost for offshore electrolysis investment is too much different from onshore investment cost, offshore hydrogen production is also not attractive. For the cases in which offshore hydrogen appears, values range from 16 – 80 TWh/yr. Blue hydrogen is in most cases constant in size and mainly limited by the applied import cap on natural gas. In all cases onshore green hydrogen production appears. Since the parameter settings are not very exclusive on the role offshore versus onshore hydrogen production, the size of onshore hydrogen production is very case specific. If an international hydrogen market will be developed and prices are very low, offshore hydrogen production might not be an attractive option, but an international hydrogen market might reduce the total system cost significantly

Besides from being very sensitive to some cost parameters and the presence of on an international hydrogen market, the level of offshore hydrogen production is mainly impacted by the demand for hydrogen, the availability of biomass and CCS. Indirectly it has also been concluded that the amount of natural gas that can be imported will have an impact (blue hydrogen). The demand level for hydrogen also depends on choices made by society. Potentially application of hydrogen in the built environment can be a cheap option, but it is questionable if heating of buildings will play a large role in the phasing out of natural gas in the built environment. If there is a large availability of CCS in combination with biomass and Direct Air Capture (DAC), the stress on the rest of the energy system is lower, since these options result in negative emissions. This results in a lower need for hydrogen.

Apart from hydrogen and offshore green hydrogen production, another focus point of this research has been on CCS. CCS is a very robust outcome in the modelling results, in particular in combination with biomass. In a system with 95% GHG reduction and limited imports of hydrogen and biomass, direct air capture in combination with CCS might be an important option to utilize the underground storage capacity for CO_2. CCS also seems to play a large role in reducing the system costs. An important limitation of this study is that all 2050 cases have been analyzed with the same cap on natural gas import.

Besides the availability of CCS, the outcomes of the analyses also vary significantly when changing assumptions on the availability and use of biomass. Excluding biomass will likely increase total system cost, again mainly since the combination of CCS with biomass gives negative emissions; and is from techno-economic point of view an attractive solution to reduce GHG emissions. It should be noted that the deployment of net atmospheric CO_2 removal, including bio-CCS and DAC, are also seen in scenarios in the most recent IPCC reports (IPCC, 2018). These technology options contribute to limiting global warming to 1.5°C but are prone to high uncertainty. This should be taken into account when interpreting the outcomes of our study.

In the scenario that was analyzed, which focusses on national energy resources and in which imports of energy carriers are limited, reduction of fossil fuel consumption for aviation and maritime is impossible. Sustaining the large role in bunker fuel supply that the Netherlands has in combination with low CO_2 emission for the maritime and aviation sector, is only possible if the Netherlands imports large amounts of hydrogen and solid and/or liquid biomass.

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8 Appendix I – The Opera model

8.1 Energy service demand

Demand for energy is represented in OPERA via energy services (see Table 7). In most cases final energy demand is given as exogeneous input. In order to allow maximum flexibility, demands can also be expressed in the units that best suit the nature of each energy service. For example, the most straightforward determinant of road transport energy demand is the need for mobility expressed in total amount of kilometers driven yearly. Therefore the unit billion vehicle kilometers (B(v)km) is used for road freight and passenger vehicles, instead of the corresponding final electricity and heat demand in petajoules (PJ). Due to unavailability of input data, the remaining energy services in the transport sector (buses, motorbikes, trains, inland shipping and aviation, which only account for a small fraction of total demand) are grouped together in one single entity, for which the demand is expressed in PJ. These remaining subsectors can be singled out whenever input data becomes available.

Table 7 Energy service demands in OPERA; final energy demand is specified for both electricity and heat.

Sector	Energy Service Demand	Unit
Households	Final energy demand	PJ
Services	Final energy demand	PJ
Services	Mobile machinery	PJ
Transport	Road passenger cars	B(v)km[a]
Transport	Road heavy duty transport	B(v)km
Transport	Road light duty transport	B(v)km
Transport	Remaining final energy demand	PJ
Agriculture	Final energy demand	PJ
Agriculture	Mobile machinery	PJ
Industry	Steel production	Mt
Industry	Fertilizer (ammonia) production	Mt
Industry	High Value Chemicals[b]	Mt
Industry	Mobile machinery	PJ
Industry	Municipal solid waste incineration	PJ
Industry	Chemicals	PJ
Industry	Remaining final energy demand chemicals	PJ
Industry	Remaining final energy demand metals	PJ
Industry	Remaining final energy demand ETS	PJ
Industry	Remaining final energy demand non-ETS	PJ

[a]B(v)km = billion vehicle km.
[b]High Value Chemicals consider: ethylene, acetylene, propylene, butadiene, benzene

8.2 Geographical representation

Since demand and supply of energy are often not on the same location, energy needs to be transported. In Opera electricity, methane and hydrogen can be transported over long distances. To properly address the balance, from a system perspective, to invest in extra electricity transmission capacity versus converting electricity in hydrogen or methane and transporting these energy carriers to demand centers, geographical regions have been applied in OPERA. The onshore and offshore area of the Netherlands has been split up into seven onshore areas and seven offshore areas, as depicted in Figure 2. A more refined split up has been has not been applied to avoid excessive calculation times and demand and supply data at the provincial level are often easily accessible via cbs.nl and klimaatmonitor.databank.nl, but is difficult to get more refined geographical data for the entire Dutch energy system of consistent quality.

As can be seen in Figure 2 seven onshore region are applied. Some of these regions contain one province, some of them more than one province. The regions are:

- I - Zeeland
- II - South Holland
- III - North Holland
- IV - Region North (Friesland, Groningen, Drenthe)
- V - Region East (Overijssel, Gelderland, Flevoland, Utrecht)
- VI - North Brabant
- VII – Limburg

In the database of OPERA national demand figures and national resource potentials are available. In this section a description is given how this national demand and potential are distributed over the different regions. For all data items OPERA applies a distribution key, which adds up to 100%, the national total.

Klimaatmonitor provides regional data on energy consumption and renewable generation. Subsector detail is limited. For more detail on for example industrial subsectors Emissieregistratie.nl can be used. Emissieregistratie.nl only provides regional data on emissions, so its CO_2 emission data can only be used to attribute fuel consumption to regional subsectors, not electricity consumption.
The approach to distribute demand over the different regions in presented in Table 8.

Table 8 Approach to distribute sectoral demand over sectors

Sector	**Topic**	**Data type**	Remarks	**Data source and URL**
Households	Electricity demand	Electricity consumption by dwellings		Klimaatmonitor source table
	Heat demand	Natural gas demand and district heating		Klimaatmonitor Gas demand / District heating
	Electricity savings	Same as electricity demand: Electricity consumption by dwellings		Klimaatmonitor source table
	Heat savings	Same as heat demand: natural gas demand and district heating		Klimaatmonitor Gas demand / District heating
Agriculture	Electricity demand	Electricity consumption		Klimaatmonitor Source table
	Heat demand	Gas supply		Klimaatmonitor Source table
	Emission reduction potential non-CO_2	Livestock	Amount of cattle per region	CBS Source table
Transport	Cars, trucks, light vehilces	Vehicle kms		Klimaatmonitor Source table
	Other	Also vehicle kms, because it is small		Klimaatmonitor Source table
Steel industry	Steel production	Share of production	North-Holland = 100%	CBS
Ammonia producing industry	Ammonia production			Source: 'Energy conservation potential of the nitrogen fertiliser industry'
Waste incineration	Municipal solid waste	Amount of delivered heat	Waste input for waste incinerators	Source: 'afvalverwerking_in_Nederland_geg

				evens_2017_def.pdf'
Non-energetic use				
Organic chemistry	Energy consumption	CO_2 emissions		Emission registration http://www.emissieregistratie.nl
Food and beverage industry	Energy consumption	CO_2 emissions		Emission registration http://www.emissieregistratie.nl
Refineries		CO_2 emissions	CO_2 emissions refineries	Klimaatmonitor Klimaatmonitor
Other industries	Energy consumption	CO_2 emissions		Source: http://www.emissieregistratie.nl
Services sector	Electricity demand	Electricity consumption		Source: Klimaatmonitor
	Heat demand	Gas consumption		Source: Klimaatmonitor

The resource potential is distributed, per type of resource, via the approach as indicated in Table 9**.**

Table 9 Approach to distribute potentials of resources over regions

Sector	Data type	Remarks	Data source and URL
Electricity supply	Wind onshore potential capacity	According to 6 GW target wind onshore	Table 2 in report 'structuurvisie-windenergie-op-land-1.pdf' Source
Electricity supply	Wind offshore potential capacity	Scenario IV is chosen to distribute the wind offshore capacity over the offshore regions	Matthijsen, J., E. Dammers & H. Elzenga (2018) https://www.pbl.nl/publicaties/de-toekomst-van-de-noordzee
Electricity supply	Ground based PV potential capacity		ENSPRESO RES database from JRC. (Ruiz, 2019) https://data.jrc.ec.europa.eu/collection/id-00138
Built environment	Roof top PV potential capacity		ENSPRESO RES database from JRC. (Ruiz, 2019) https://data.jrc.ec.europa.eu/collection/id-00138
Agriculture	Manure potential	Number of cattle and pigs per region	CBS Source table
Industry	Potential for digestible waste streams form	Population based	CBS Population
Heat supply	Geothermal heat potential		ThermoGIS TNO https://www.thermogis.nl/mapviewer

8.3 Time resolution

OPERA explicitly deals with the need to achieve a match between energy supply and demand at any moment in time. For this purpose, supply and demand are provided as input to the model as hourly profiles, for a whole year, theoretically enabling the user to run the model on an hourly basis. Running the model with an hourly resolution, requires high computation capacity and time requirements. In order to achieve a suitable compromise between temporal resolution and computation time, the hours of a year can be grouped into a set with an arbitrary number of elements, called time-slices.

A more extensive description of the time-slice approach is presented in found in appendix D of the Flexnet report (Sijm *et al.*, 2017). The same distribution of hours over time-slices as was used in Flexnet is used in this project, however, the choses time-resolution for this project was higher: 85 time-slices compared to the 61 time-slices that have been used in Flexnet.

9 Appendix II – Updated factsheet offshore hydrogen production and transport

This appendix briefly describes what assumptions have been on offshore hydrogen production as input for the energy system modelling in WP 1.2. The techno-economic parameters off the following technology options are described:

- Offshore wind energy
- Offshore electrolysis
- Offshore high voltage grid
- Offshore hydrogen pipelines

Note that only the parameters that are needed as input to the OPERA model are presented.

The assumed techno-economic parameters for offshore wind energy are presented in Table 10. The TNO factsheet for wind offshore is not yet available at www.energy.com, but its source is the study by Witteveen+Bos and ECN-TNO (Witteveen-Bos & ECN-TNO, 2019). Hourly wind speeds at hub height (155 m) have been derived by the wind energy department of TNO (Bulder and Bot, 2019).

Table 10 Techno-economic parameters of wind offshore.

Item	Unit	2030	2050	Source
Investment cost	k€/ MW	1710	1710	Witteveen-Bos & ECN-TNO (2019)
Fixed operational cost per year	k€/ MW	45	45	Witteveen-Bos & ECN-TNO (2019)
Typical full load hours	Hrs/yr	5250	5250	Witteveen-Bos & ECN-TNO (2019)
Lifetime	yr	25	25	

To convert hourly wind speeds at hub height to power output a power velocity curve of a wind farm of 1005 MW is used (ECN wind energy, 2018) and includes wake effects. The farm corresponds to wind turbines of 15 MW, rotor diameter of 250 m and a hub height of 155 m.

Techno-economic parameters of offshore electrolysis are presented in Table 11. To convert onshore cost to offshore cost a factor of 1.25 is applied (Bilfinger Tebodin (2019)). The offshore lifetime and efficiency are assumed to be the same as onshore. The lifetime of the PEM stacks is 7 years and cost are assumed to be 50% of the total CAPEX. This means that during the lifetime of 20 years the stacks need to be replaced two times.

Table 11 Techno-economic parameters offshore PEM electrolysis

Item	Unit	2030	2050	Source
Investment cost	k€/ MWinput	875	500	Bilfinger Tebodin (2019)
Fixed operational cost per year	%	2%[a]	2%	Bilfinger Tebodin (2019)
Efficiency electricity to hydrogen	-	68%	68%	Bilfinger Tebodin (2019)
Lifetime electrolyser	yr	20	20	Bilfinger Tebodin (2019)

Lifetime stacks	Yr	7	7	Bilfinger Tebodin (2019)
Stack price	%	50%[b]	50%	Bilfinger Tebodin (2019)

[a]Share of total investment cost in Mln €/MWinput
[b]50% of the total investment cost

Techno-economic parameters for an offshore HV grid are presented in Table 12. In the analysis it is assumed that all offshore cables are DC. Cost correspond to a 525 kV connection. It is assumed that the cost for an onshore HV grid is 1.5 times less expensive.

Table 12 Techno-economic parameters of an offshore HVDC grid

Item	Unit	2030	2050	Source
Investment cost	k€/ (MW*km)	5.3	5.3	Appendix I of van der Veer *et al* (2020)
Losses	%/km	0.003%	0.003%	Appendix I of van der Veer *et al* (2020)
Lifetime	yr	25	25	Appendix I of van der Veer *et al* (2020)

Techno-economic parameters for an offshore hydrogen pipeline are presented in Table 13. Cost have been extracted from (EBN, 2018).

Table 13 Techno-economic parameters of offshore hydrogen pipelines

Item	Unit	2030	2050	Source
Investment cost	k€/ (MW*km)	0.64	0.64	(Gasunie and EBN, 2018)
Lifetime	yr	25	25	(Gasunie and EBN, 2018)