Statement TenneT & Gasunie n.a.v. het rapport Power-to-Hydrogen IJmuiden Ver

Betrokken partijen: TenneT, Gasunie, DNV GL

Aanleiding: *DNV GL heeft een studie gedaan naar een mogelijke rol van P2H$_2$ van een 4-6 GW windpark in het gebied IJmuiden Ver dat 60-80 km uit de kust komt te liggen. Volgens de Routekaart windenergie op zee 2030 wordt dit windpark in de periode 2027-2030 volledig operationeel. Een rekenmodel heeft op basis van een groot aantal aannames verschillende scenario's doorgerekend om te kijken naar de optimale balans van de infrastructuur voor IJmuiden Ver.*

Statement
Op verzoek van TenneT en Gasunie heeft DNV GL onderzocht of een eiland of platform in de Noordzee dan wel een locatie aan de kust - waar elektriciteit wordt omgezet in waterstof (Power to Hydrogen) - bijdraagt aan het energietransportsysteem voor IJmuiden Ver dat tussen 2027 en 2030 volledig operationeel moet zijn.

De belangrijkste conclusies uit het rapport zijn:
- Power to Hydrogen is technisch haalbaar, zowel op een eiland/platform op zee als aan de kust. Er zijn geen technische belemmeringen en er kan gebruik worden gemaakt van bewezen technieken.
- Als onderdeel van het huidige <u>energietransportsysteem</u> levert Power to Hydrogen voor IJmuiden Ver bij de huidige aannames geen economisch/financieel voordeel op. Uitgangspunten voor andere tijdsvensters en andere windenergiegebieden kunnen tot andere resultaten leiden.
- Volgens de modellen kan de omzetting van groene elektriciteit in groene waterstof via een <u>losstaande</u> elektrolyser tot 500 MW op land vanaf de tweede helft van de jaren ’20 wel positief bijdragen aan de <u>waardeketen</u>.
- Concluderend, er wordt op basis van deze studie voor IJmuiden Ver nog geen rol voor elektrolyse als onderdeel van het huidige energietransportsysteem gezien. De studie geeft wel de potentie aan voor de verdere ontwikkeling van Power to Hydrogen en geeft aanleiding om de mogelijkheid voor aanlandige Power to Hydrogen te onderzoeken, bijvoorbeeld nabij een groot industrie cluster. Hetgeen een belangrijke stap is richting de verdere ontwikkeling van grootschalige elektrolyse.

ENERGY

Power-to-Hydrogen IJmuiden Ver

Final report for TenneT and Gasunie

06 July 2018

Executive summary

Background

In 2023, 16% of the Dutch energy need should be supplied by renewable energy sources, as agreed within the Dutch energy agreement of 2013. Offshore wind is one of the pillars for achieving the renewable energy targets of the Netherlands. In 2030, it is the goal to have 11.5 GW installed capacity offshore wind. A major contribution to realize an additional 7 GW of installed capacity offshore wind should come from the area IJmuiden Ver. IJmuiden Ver is an area in the North Sea that can offer wind power capacity of around 4GW and approximately 60-80 km off the coast of the Netherlands.

It is investigated whether an island could be developed at IJmuiden Ver that could facilitate several purposes like nearby maintenance capabilities, electricity connections, a location for a HVDC convertor station, and could provide room for innovative functionalities like a power-to-hydrogen installation producing 'green' hydrogen to transport to shore.

Power can be converted into hydrogen using electrolysers, which can be attractive for a number of reasons like: the potential to avoid investments in the power network, the potential to fully utilize renewable energy, the potential to accommodate large amounts of offshore wind energy, the potential to offer flexibility services, the potential to store energy. P2H_2 can take place either offshore or onshore, and new or existing gas infrastructure could be used to transport this ‘green’ hydrogen for use in industry (e.g. the Rotterdam area is developing plans for sustainable hydrogen use), mobility (e.g. hydrogen filling stations) and other applications.

Objective

The key objective of this study was to assess the techno-economic feasibility of a concept for a hybrid and integrated energy supply from offshore wind farms in hydrogen at an artificial island at IJmuiden Ver and use of the existing gas/oil infrastructure to transport to shore. The following items have been assessed:

- Technical and economic feasibility of P2H_2, both offshore and onshore
- Comparison of the P2H_2 installation, either offshore platform bases, on an artificial island or onshore
- Comparison of different ways of transportation
- Onshore electricity and gas grid capabilities
- Market readiness and development of electrolysers
- Different scenarios for wind capacity, P2H_2 capacity, future electricity prices and hydrogen developments (both market and prices)

This research aimed for an assessment on the optimal balance between electrical infrastructure and use of (existing) gas infrastructure and whether this could reduce transmission costs, i.e. the potential to avoid investments in the power network.

Starting points

The base case is the transmission of power from the wind farms to the onshore electricity grid using HVDC export cables and an offshore high-voltage station based on a platform. Six main project alternatives have been proposed, with the main variables being:

1. The high-voltage station and P2H_2 plant either on a platform, or on an artificial island.
2. Onshore or offshore location of the P2H_2 –plant.
3. The use of existing pipelines or the construction of a new dedicated pipeline.

Each alternative has been assessed for various scenarios, varying the following factors :

- Wind capacity: the standard scenario is the 4 GW of installed capacity for IJmuiden Ver, in line with the Offshore Wind Energy Roadmap. This Roadmap indicated that another 0.9 GW has to be determined, but in this study an other scenario of an additional 2 GW is assumed.
- Capacity of the P2H_2 installation: the following capacities have been considered: 100 MW, 400 MW, 500 MW, 1 GW, 2 GW, and 4 GW and 6 GW for the full P2H_2 alternative.
- Connection / landing point: given the wind capacity and the P2H_2 capacity, the connection point with the electrical grid is either along the coast (approximately 110 km distance) or more land inward to prevent congestion (approximately 185 km distance).
- Use of the P2H_2 installation: Base-load, peak-load, price-dependent, or a combination.

Accordingly, in total 84 cases have been constructed.

Assessment

Both a technical and economic assessment has been performed. As part of the technical assessment, the following tasks have been undertaken:

- The technical feasibility of P2H_2, both offshore and onshore, has been investigated
- The technical feasibility of offshore P2H_2 based on a platform has been investigated
- The grid connection concept as proposed by TenneT has been assessed from a high level perspective
- The technical feasibility of different ways of transportation has been investigated, for instance the comparison of new dedicated hydrogen pipelines with existing gas pipelines

As part of the economic assessment, the following items have been studied:

- Market study for hydrogen, including prices
- The market readiness and development of electrolysers
- Simulation of future electricity prices, with the increase in offshore wind energy in line with the Offshore Wind Energy Roadmap 2030.

Executive summary

Assessment
To compare the results for the different project alternatives and to compare the electrical system with the hydrogen system, the following scope is applied:
- The costs, both investments (CAPEX) and operational costs (OPEX), for the electricity transmission infrastructure (both high-voltage stations and cables) are within scope
- The costs (both CAPEX and OPEX) for the gas transport infrastructure are within scope
- The costs (both CAPEX and OPEX) for the P2H$_2$ installation are within scope
- The costs (both CAPEX and OPEX) for the offshore platform and island are within scope
- The costs for the wind farm are not within scope
- The remuneration for TenneT via tariffs is not included
- The market value of the generated electricity brought onshore is not included
- The market value of the produced hydrogen is included
- The potential flexibility value of P2H$_2$ (e.g. providing Frequency Restoration Reserve) is not included

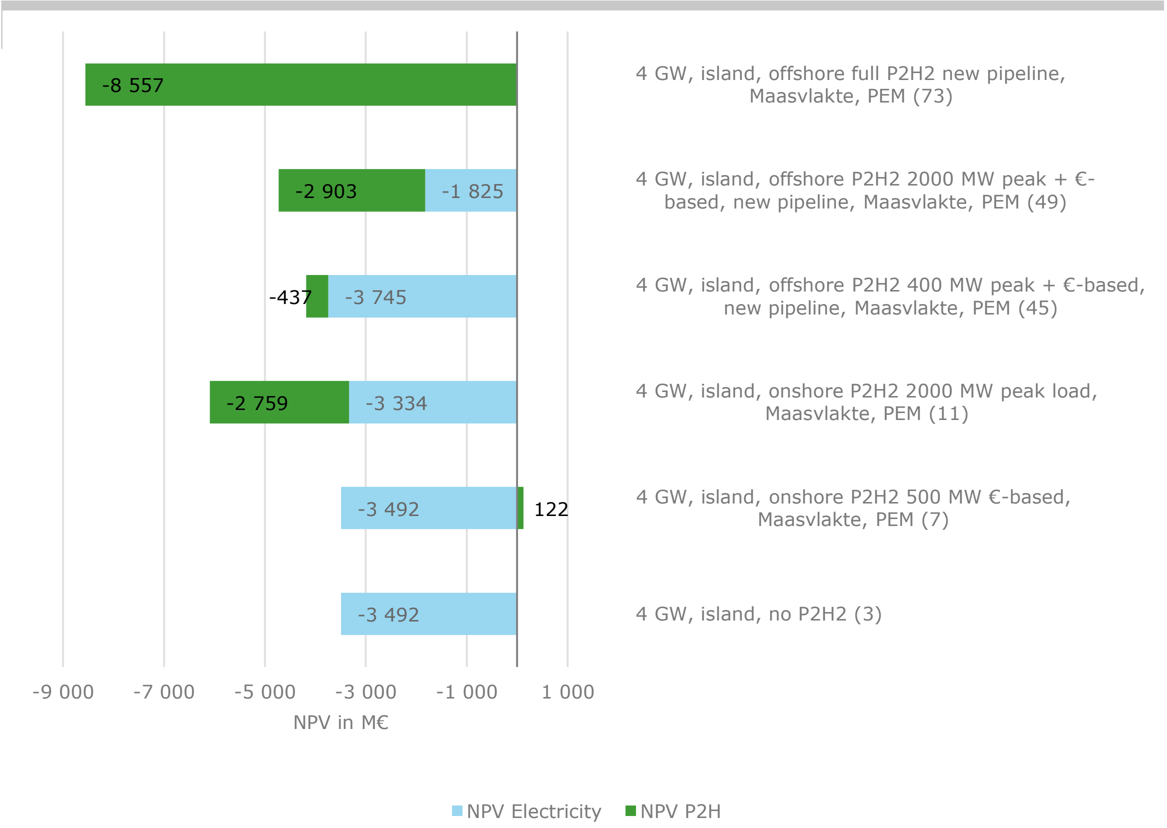
Based on those cost and benefit items, the Net Present Value has been compared, the investments has been compared, and the costs and benefits have been compared.

Findings and conclusions
Based on this high-level assessment, in can be concluded that power-to-hydrogen is technical feasible, both offshore and onshore, and that economic feasibility is nearby. No technological issues are foreseen as the considered technologies are already proven and do not pose issues when combining this with fluctuating electricity generation from the wind farm. With respect to HVDC technologies, the proposed concept is proven and feasible. Where the use of platforms is well-known for HVDC stations or oil and gas platforms, part of this study looked into the use of a platform to house a P2H$_2$ facility. A high-level assessment indicated that this is possible.

The total NPV (electrical and hydrogen system) of the main cases are presented to the right. The findings are the result of the inputs used and the model that was constructed and used for this assignment.

In general, adding P2H$_2$ does not lead to a total better NPV (electric system + hydrogen system), except for the onshore P2H$_2$ case with low P2H$_2$ capacity. For the hydrogen system, for these smaller onshore P2H$_2$ capacities there is a positive business case due to the utilization of cheap electricity when market prices are low. The addition of more P2H$_2$ capacity does not lead to an overall better NPV, though it can reduce the NPV of the electrical system as more nearby (in case of onshore P2H$_2$) or less connections (in case of offshore P2H$_2$) are required. This is the case when adding 2 GW P2H$_2$, offshore or onshore, as this leads to the most cost efficient grid connection. In other words, it can be concluded that offshore placement of the electrolyser facilities offers a larger price reduction to the transmission system than onshore placement since a duplication of infrastructure is avoided. For higher P2H$_2$ capacities, offshore P2H$_2$ is better than onshore P2H$_2$, while the full P2H$_2$ case has the most negative NPV. The business case for P2H$_2$ is dependent on the operation mode of the P2H$_2$ facility and main assumptions like prices of electricity and hydrogen, the electrolyser CAPEX and efficiency and the start year.

NPV of the main cases



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Introduction

Background

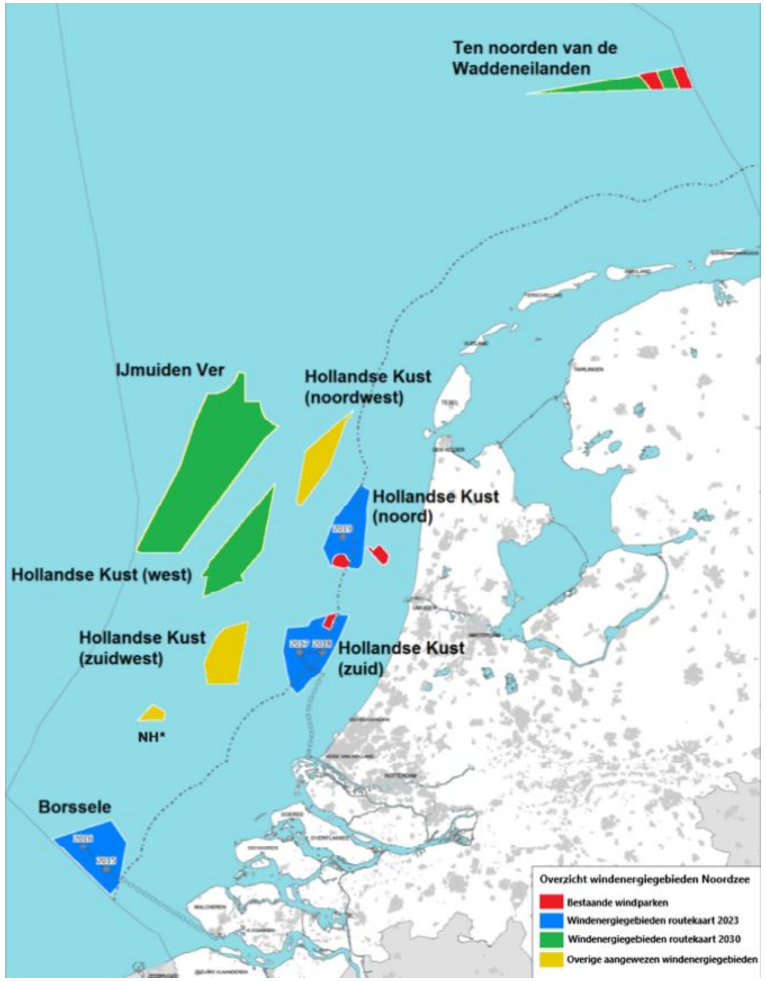
Offshore wind in the Netherlands
In 2023, 16% of the Dutch energy need should be supplied by renewable energy sources, as agreed within the Dutch energy agreement of 2013. Offshore wind is one of the pillars for achieving the renewable energy targets of the Netherlands: By 2023, another 3.5 GW of installed capacity of offshore wind will be realized, on top of the existing 1 GW. In 2030, it is the goal to have 11.5 GW offshore wind. In March 2018, the Dutch government presented its plans for the further development of offshore wind energy for the period 2024 – 2030 in the Offshore Wind Energy Roadmap 2030.

The IJmuiden Ver Area
A major contribution to realize an additional 7 GW of installed capacity offshore wind should come from the area IJmuiden Ver. IJmuiden Ver is a location in the North Sea with a contiguous area of 1,170 km2. Accordingly, the area can offer wind power capacity of around 4GW. Moreover, the area is close to the East Anglia area (Great Britain) with plans for about the same amount of offshore wind capacity. The IJmuiden Ver area is approximately 60-80 km off the coast of the Netherlands (see Figure).

The option of an island
Within the North Sea Power Hub consortium (TenneT TSO B.V. - Netherlands, Energinet - Denmark, TenneT TSO GmbH - Germany, Gasunie - Netherlands, and Port of Rotterdam - Netherlands), the possible development of a large-scale, sustainable European energy supply system in the North Sea is investigated. This initiative includes the options to develop an energy island and to deploy Power-to-Gas solutions. A first pilot of such an offshore power hub could be developed at the location IJmuiden Ver, which is part of the scope of this study. The artificial island in the area could facilitate several purposes like nearby maintenance capabilities, electricity connections, a location for a HVDC convertor station, and could provide room for innovative functionalities like a power-to-hydrogen installation producing 'green' hydrogen to transport to shore.

The option of Power-to-Hydrogen ($P2H_2$)
Power can be converted into hydrogen using electrolysers, which can be attractive for a number of reasons like: the potential to avoid investments in the power network, the potential to fully utilize renewable energy, the potential to accommodate large amounts of offshore wind energy, the potential to offer flexibility services, the potential to store energy. $P2H_2$ can take place either offshore or onshore, and new or existing gas infrastructure could be used to transport this 'green' hydrogen for use in industry (e.g. the Rotterdam area is developing plans for sustainable hydrogen use), mobility (e.g. hydrogen filling stations) and other applications.

Offshore wind energy areas in the Netherlands [1]



Introduction
Objective

The Roadmap hydrogen (TKI, March 2018) indicates among others that hydrogen could play an important role to realize the 2050 carbon emission targets, advocates an integral approach and calls for action. The recently published manifest Hydrogen of the Hydrogen coalition puts this into practice and presents some proposals to boost the deployment and use of green hydrogen.

TenneT is responsible for the connection of the offshore wind farms and for the transmission of the generated electricity, since TenneT is the offshore grid operator. TenneT has already investigated a number of options to connect the offshore wind farms and for the transmission of the generated electricity offshore, and is now exploring the option of $P2H_2$ together with Gasunie. Gasunie can provide transportation services, e.g. from the location of production to the location of consumption, as well as conversion services and storage capacity.

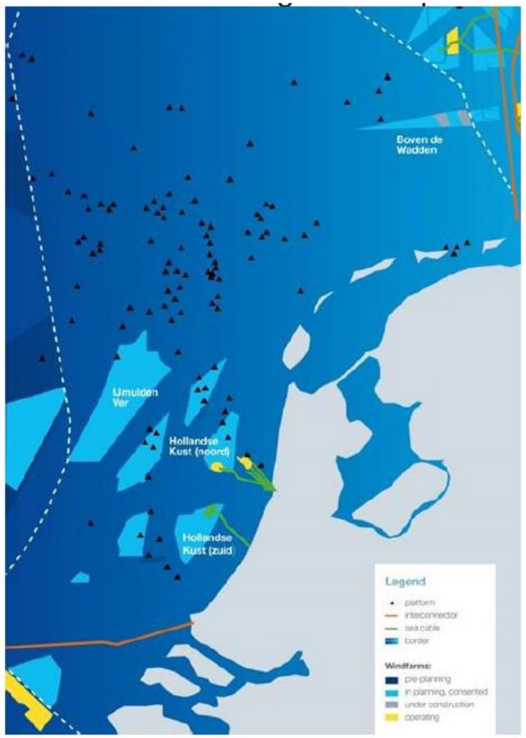
Objective of the study
The key objective of this study is to assess the techno-economic feasibility of a concept for a hybrid and integrated energy supply from offshore wind farms in hydrogen at an artificial island at IJmuiden Ver and use of the existing gas/oil infrastructure to transport to shore. The following items will be assessed:

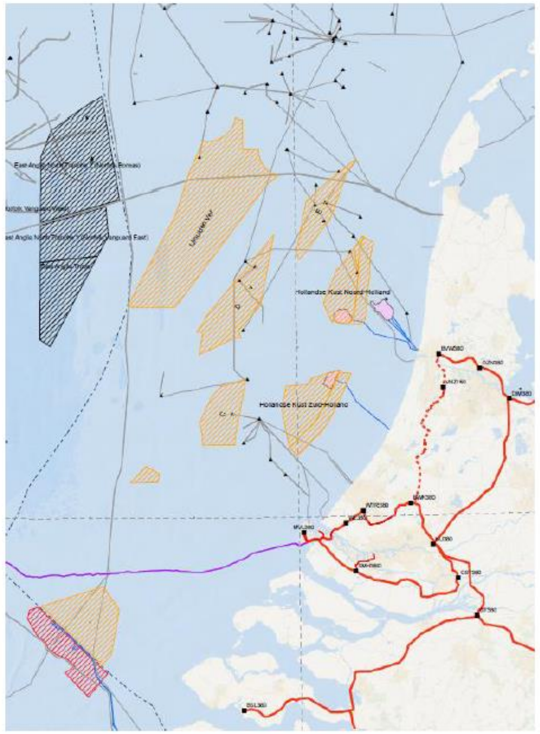
- Technical and economic feasibility of $P2H_2$, both offshore and onshore
- Comparison of the $P2H_2$ installation, either offshore platform bases, on an artificial island or onshore
- Comparison of different ways of transportation
- Onshore electricity and gas grid capabilities
- Market readiness and development of electrolysers
- Different scenarios for wind capacity, $P2H_2$ capacity, future electricity prices and hydrogen developments (both market and prices)

This research aims for an assessment on the optimal balance between electrical infrastructure and use of (existing) gas infrastructure and whether this could reduce transmission costs, i.e. the potential to avoid investments in the power network.

Report outline
The report is structured as follows: first the methodology is explained including a description of the model. Subsequently, the technical assessment is provided, where the technical feasibility is investigated and various input parameters are determined. Hereafter the economic assessment describes the market study for hydrogen including an outlook on price developments. Then the results are presented, after which conclusions are drawn.

Map of offshore wind energy areas including platform locations (left) and existing pipelines (right) (RFP, TenneT and Gasunie, January 2018, NLO-TTB-04878)





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Methodology

General approach and scope

The approach consists of the different stages as depicted in the figure to the right. For each stage the scope is indicated.

After project initiation, the project alternatives, scenarios and performance indicators have been determined. The project alternatives and the different scenarios are explained in more detail on the following pages. As a next step, a model was set up to determine the costs and benefits for the project alternatives (and all the variations within each alternative) compared to the zero alternative. The model is described later on in this chapter.

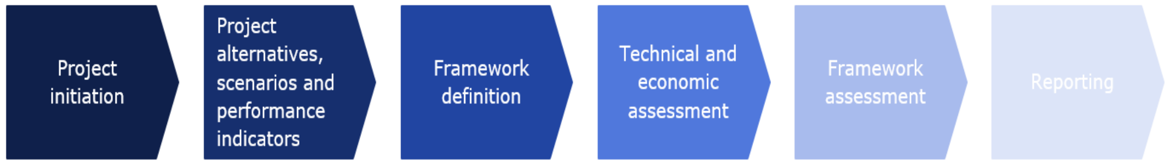
As part of the technical assessment, various tasks have been performed:
- The technical feasibility of $P2H_2$, both offshore and onshore, has been investigated
- The technical feasibility of offshore $P2H_2$ based on a platform has been investigated
- The grid connection concept as proposed by TenneT has been assessed from a high level perspective
- The technical feasibility of different ways of transportation has been investigated, for instance the comparison of new dedicated hydrogen pipelines with existing gas pipelines

As part of the economic assessment, the following items have been studied:
- Market study for hydrogen, including prices
- The market readiness and development of electrolysers
- Simulation of future electricity prices, with the increase in offshore wind energy in line with the Offshore Wind Energy Roadmap 2030.

The comparison of the results for the different project alternatives is based on the so-called performance indicators. Starting from the question how to compare and evaluate the different alternatives and how to compare the electrical system with the hydrogen system, the following is decided how to compare the outcomes:
- The costs, both investments (CAPEX) and operational costs (OPEX), for the electricity transmission infrastructure (both high-voltage stations and cables) are within scope
- The costs (both CAPEX and OPEX) for the gas transport infrastructure are within scope
- The costs (both CAPEX and OPEX) for the $P2H_2$ installation are within scope
- The costs (both CAPEX and OPEX) for the offshore platform and island are within scope
- The costs for the wind farm are not within scope
- The remuneration for TenneT via tariffs is not included
- The market value of the generated electricity brought onshore is not included
- The market value of the produced hydrogen is included
- The potential flexibility value of $P2H_2$ (e.g. providing Frequency Restoration Reserve) is not included

Based on those cost and benefit items, the Net Present Value (NPV) will be compared, the investments will be compared, and the costs and benefits will be compared.

Approach



Activities & Goals

Project initiation	Project alternatives, scenarios and performance indicators	Framework definition	Technical and economic assessment	Framework assessment	Reporting
Kick-off meeting	Progress meeting	Progress meeting	Intermediate meeting	Progress meeting	Final meeting
Discuss project approach and schedule	Determine project alternatives to investigate	Set up of feasibility model	Technical and economic assessment of wind production, P2H installation, ways of transportation, onshore grid connection, market readiness.	Calculation of the model	Deliver draft and final report
Determine starting points and boundaries	Determine scenarios for the electricity prices and hydrogen market		Determine parameters to use in feasibility model	Determine and compare results for the performance indicators, for the project alternatives and scenarios	Present findings
	Determine performance indicators to evaluate the feasibility				

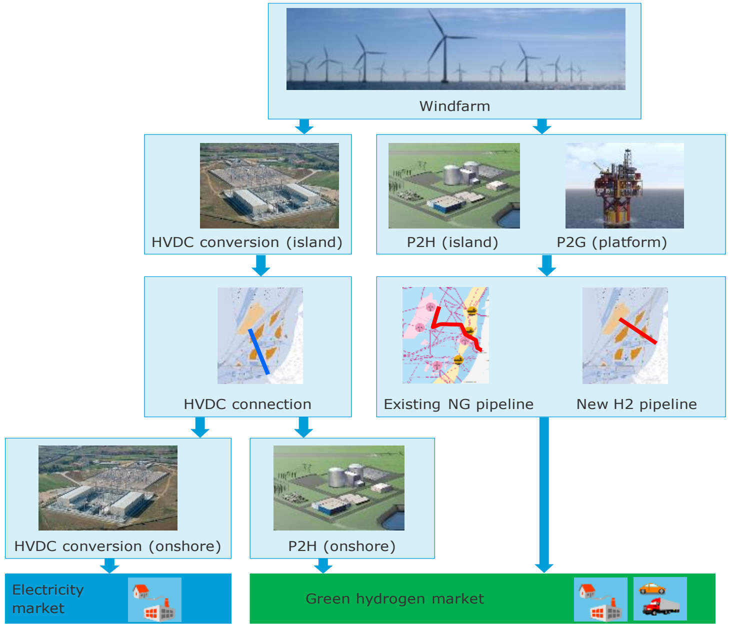
Methodology
Project alternatives

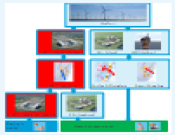
The base case (or the zero alternative) is the transmission of power from the wind farms to the onshore electricity grid using HVDC export cables and an offshore high-voltage station based on a platform.

Six main project alternatives are proposed, with the main variables being:
1. The location of the substation and P2H$_2$ plant either on a platform, or on an artificial island.
2. Onshore or offshore location of the P2H$_2$ -plant
3. The use of existing pipelines or the construction of a new dedicated pipeline

These different configurations are shown below in the Figure, and are described in more detail in the table on the right-hand side. In addition, also the full P2H$_2$ alternative is considered, implying that all offshore wind energy is converted into hydrogen (on an island).

Overview of project alternatives



No.	Schematic	Description	Hydrogen production	Energy transport to shore
1		All electricity produced by the wind farm is brought to shore. Transport is done by an HVDC cable and convertor stations are built offshore—on an artificial island—and onshore. The site of the onshore convertor station will be determined based on available grid capacity and distances.	None	• Electricity using HVDC
2		All electricity is brought to shore as electricity. Transport is done by an HVDC cable and convertor stations are placed offshore and onshore at the Maasvlakte. At the Maasvlakte, different amounts (e.g. using electrolyser capacities of 100, 500 and 1000 MWe) will be converted to hydrogen and transported to new markets.	Onshore	• Electricity using HVDC
3		Part of the electricity produced at IJmuiden Ver will be converted to hydrogen using an ***island based*** power-to-hydrogen facility with different capacities (e.g. 100, 500 and 1000 MWe). This hydrogen will subsequently be transported to shore using ***existing oil or gas pipelines*** that are likely to be abandoned.	Offshore, island based	• Electricity using HVDC • Hydrogen using existing O&G pipeline
4		Part of the electricity produced at IJmuiden Ver will be converted to hydrogen using an ***island based*** power-to-hydrogen facility with different capacities (100, 500 and 1000 MWe). The hydrogen will be transported to shore using a ***dedicated hydrogen pipeline*** that needs to be constructed for this project. The onshore gas connection site will be selected based on available grid capacity and distances.	Offshore, island based	• Electricity using HVDC • Hydrogen using a new hydrogen pipeline
5		Part of the electricity produced at IJmuiden Ver will be converted to hydrogen using a ***platform based*** power-to-hydrogen facility with different capacities (100, 500 and 1000 MWe). The hydrogen will be transported to shore using ***existing oil or gas pipelines*** that are likely to be abandoned.	Offshore, platform based	• Electricity using HVDC • Hydrogen using existing O&G pipeline
6		Part of the electricity produced at IJmuiden Ver will be converted to hydrogen using a ***platform based*** power-to-hydrogen facility with different capacities (100, 500 and 1000 MWe). This hydrogen will be transported to shore using ***a dedicated hydrogen pipeline*** that needs to be constructed for this project. The onshore gas connection site will be selected based on available grid capacity and distances.	Offshore, platform based	• Electricity using HVDC • Hydrogen using a new hydrogen pipeline

Methodology

Scenarios

Alternatives and scenarios

Each alternative can be assessed for various scenarios, varying the factors below:

- Wind capacity: the standard scenario is the 4 GW of installed capacity for IJmuiden Ver, in line with the Offshore Wind Energy Roadmap. This Roadmap indicated that another 0.9 GW has to be determined, but in this study an other scenario of an additional 2 GW is assumed.
- Capacity of the P2H$_2$ installation: the following capacities have been considered: 100 MW, 400 MW, 500 MW, 1 GW, 2 GW, and 4 GW and 6 GW for the full P2H$_2$ alternative. It is assumed that there is a linear relationship between the capacity of the 'electrical route' and the capacity of the 'P2H$_2$ route', meaning that the sum of both always add up to the maximum installed capacity of offshore wind (either 4 GW or 6 GW).
- Connection / landing point: given the wind capacity and the P2H$_2$ capacity, the connection point with the electrical grid is either along the coast (approximately 110 km distance) or more land inward (approximately 185 km distance).
- Use of the P2H$_2$ installation: Base-load, peak-load, price-dependent, or a combination. This is explained in more detail on the following slides.

84 cases

Accordingly, in total 84 cases have been constructed. Below the different variations within each project alternative are summarized.

The table below applies to both the Zero-alternative (offshore HVDC station on platform; no P2H$_2$) and Alternative 1 (offshore HVDC station on platform/island; no P2H$_2$).

Wind capacity	• 4 GW	• 6 GW
Voltage rating	• 525kV	• 525kV
HVDC connection	• 2 x 2 GW	• 3 x 2 GW
Connection point	• 185 km	• 185 km for 4GW • 110km for 2GW

The table below applies to Alternative 2 (offshore HVDC station on platform/island; onshore P2H$_2$)

Wind capacity	• 4 GW	• 6 GW
Voltage rating	• 525kV	• 525kV
HVDC connection	• 2 x 2 GW	• 3 x 2 GW
Onshore P2H$_2$	• 100MW • 500MW • 1000MW • 2000MW	• 100MW • 500MW • 1000MW • 2000MW
Connection point E	• 1GW P2H$_2$: 1GW coast (110km), 3GW land (185km) • 2GW P2H$_2$: 2GW coast (110km), 2GW land (185km) • 100/500MW P2H$_2$: 4GW 185km	• 1GW P2H$_2$: 2GW coast (110km), 4GW land (185km) • 2GW P2H$_2$: 2GW coast (110km), 4GW land (185km)
Location P2H$_2$	• P2H$_2$ close to offtakers – Maasvlakte / IJmuiden	• P2H$_2$ close to offtakers – Maasvlakte / IJmuiden
Use of P2H$_2$	• Price-dependent for 100/500 MW • Not price-dependent for 1/2GW	• Price-dependent for 100/500 MW • Not price-dependent for 2GW

Methodology

Scenarios

The table below applies to alternative 3-6 (offshore $P2H_2$):

Wind capacity	• 4 GW	• 6 GW
Voltage rating	• 320kV for 1 GW • 320kV for 1.2 GW • 525kV for 2 GW	• 525kV for 2 GW
HVDC connection	• 3 x 1 GW • 3 x 1.2 GW • 1 x 2 GW	• 2 x 2 GW
Offshore $P2H_2$	• 1000MW • 400MW • 2000MW	• 2000MW
Connection point E	• 1GW $P2H_2$: 3GW land (185km) • 400MW $P2H_2$: 3.6GW land (185km) • 2GW $P2H_2$: 2GW land (185km)	• 2GW $P2H_2$: 4GW land (185km)
Connection point G	• Maasvlakte / IJmuiden	• Maasvlakte / IJmuiden
Pipeline	• Existing • New – dedicated hydrogen pipeline	• Existing • New – dedicated hydrogen pipeline
Use of $P2H_2$	• Peak-load and price-dependent	• Peak-load and price-dependent

The table below applies to the full $P2H_2$ alternative:

Wind capacity	• 4 GW	• 6 GW
Voltage rating	• Na	• Na
HVDC connection	• Na	• Na
Offshore $P2H_2$	• 4 GW	• 6 GW
Pipeline	• Existing / New	• Existing / New
Connection point G	• Maasvlakte / IJmuiden	• Maasvlakte / IJmuiden
Use of $P2H_2$	• 100%	• 100%

Methodology
Model description

Introduction
The model is built in Excel and comprises asset, market and general project data. A simplified scheme of all relations is shown on the right. The CAPEX data of the assets and their related OPEX are included in each of the scenario's. Dependencies such as the weight and surface of the $P2H_2$-plant on the size and price of the platform or island are introduced, as well as the transport options for hydrogen and electricity. The project data and results have a clear division between the electric transport system and the $P2H_2$ system. For shared assets, the costs are allocated to the different systems by means of capacity.

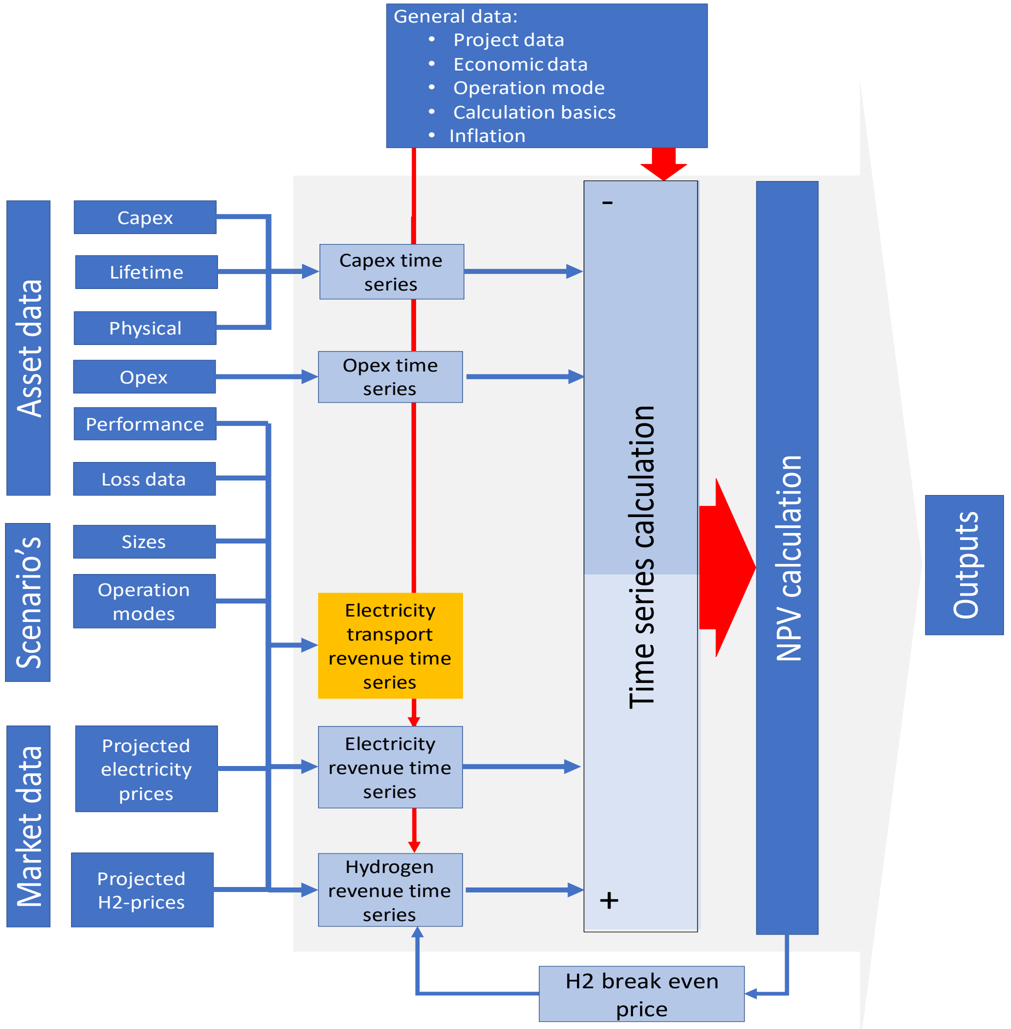
The projected market data for hydrogen and electricity are combined with the different energy flows to calculate the costs and revenues over time.

The general data govern all the scenario's to ensure a similar approach. The model has been designed for flexibility where different parameters can be changed and (de)activated such as start and end year, hydrogen prices (SMR based, green gas, etc.), inflation, include break-even prices or include remaining value. The maximum allowed timescale is 100 years in which a later start year for the $P2H_2$ system can be selected. The main project inputs are given below:

Start year	2027
End year	2051
Start year P2H2	2027
Inflation	2%
Discount rate	3%

A number of 84 different cases are included. A 85th option has been added to the model where a new case can be altered manually to make deeper and further analysis more convenient. Different case characterisation such as capacities, $P2H_2$ location, transport distance and $P2H_2$ operation mode can be altered. All cases and model inputs are presented in an enclosed Excel document.

The next slides give a further explanation of the methodology and the model.



DNV·GL

Methodology
Model

The $P2H_2$-plant can run using operation modes of which the viability is determined by technical and commercial considerations. In total, 5 different operation modes are identified which are explained on the following slides.

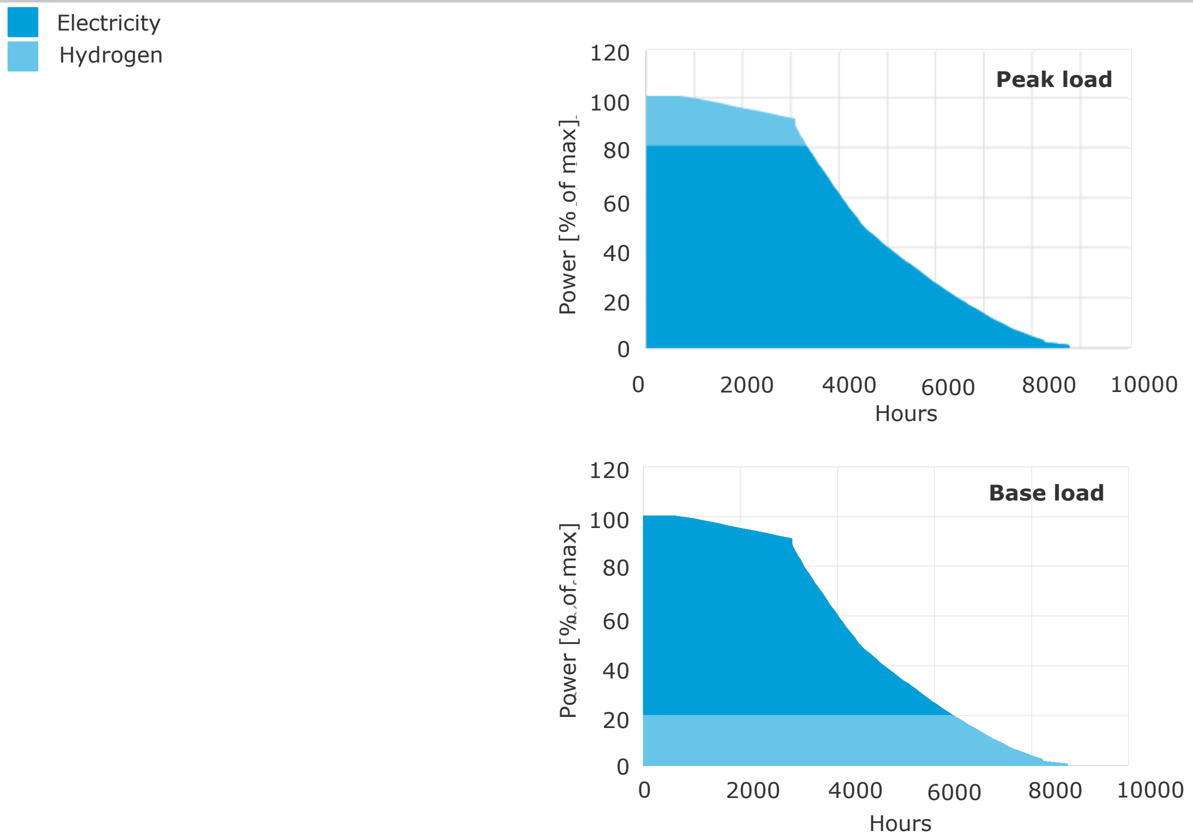
Operation modes
The $P2H_2$-plant can be run under different operation modes. There are technical and commercial considerations that could determine when the power from the wind farm is brought ashore to be injected into the electricity grid or alternatively converted to hydrogen. The preference of either option is determined by transport or price circumstances. A main part of the costs of hydrogen production is the price of electricity. As the electricity price varies with supply and demand variations, it could be beneficial to only produce hydrogen when prices are low enough.

For this study this resulted in 5 different operation modes:

1. **Peak load**
   Under this operation mode, the preferred option is to produce electricity. The transport capacity for electricity from the offshore location can be limited to a certain capacity so that the surplus production from the wind farm will be converted to hydrogen. An example is shown on the right (top) graph. It shows the expected load duration curve for the IJmuiden Ver windfarm. Up to around 3000 hours the $P2H_2$-plant is producing almost its maximum capacity (as a result of the wind turbines characteristics). For increasing hours, the load decreases to zero.

2. **Base load**
   In this operation mode the preferred option is to produce hydrogen (see bottom graph on the right for an example). As can be seen, the number of full load hours is higher (7660 hours). This could result in higher utilization, but the average electricity prices paid for producing hydrogen are expected to increase.

Different operation modes



Methodology
Model

This slide discusses the three other operation modes.

3. €/production based.
In this operation mode, hydrogen is produced when the electricity price is low: if the market price for hydrogen is 2 €/kg, the corresponding marginal cost for electricity is around 37.8 €/MWh (assuming an electrolyser efficiency of approximately 75%). Producing at higher electricity prices will only increase the loss of the P2H_2-plant exploitation. At lower electricity prices, the profitability will increase, but may -- depending on the number of full load hours -- be low.

There are two options for this:

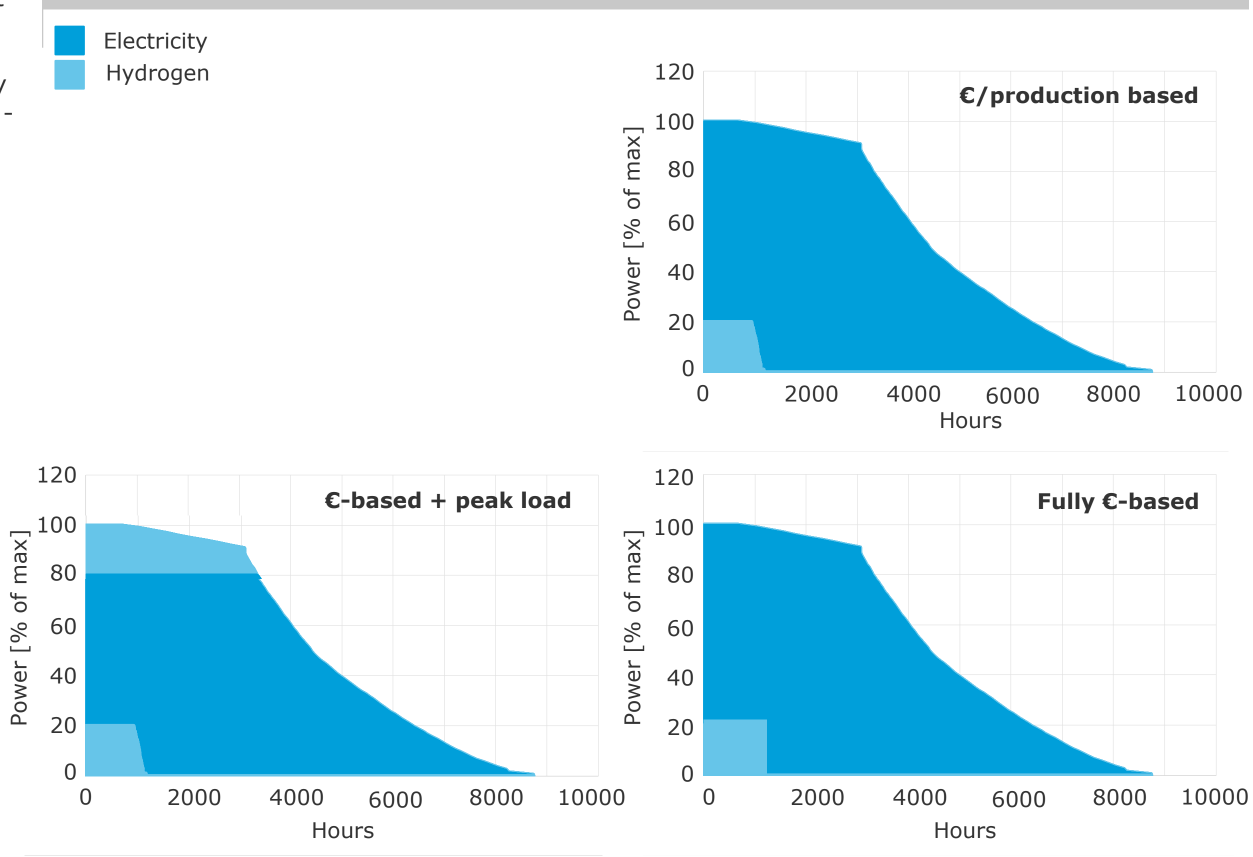
A. Only the electricity produced at the IJmuiden Ver windfarm is used for conversion to hydrogen. This is what is meant by €/production based. This is shown in the graph on the right (top) as an example.

B. If more electricity is available (at an onshore located P2H_2-plant), the full capacity of the plant can be utilized, profiting of low electricity prices. This is shown in the graph at the bottom right: the light blue box at the left part of the graph is a rectangle. This operation mode is called €-based here (see next point 3).

3. €-based
In this case the P2H_2-plant is fully utilized when prices are low. This option is especially applicable when the P2H_2-plant is onshore, with a separate electricity grid connection.

4. €-based + peak load
This is a combination of operation modes 1 and 3. This is especially applicable on an offshore location. Hydrogen is produced when the electricity is cheap and when the wind-electricity production is high. See the graph on the right.

Different operation modes



Methodology

Model

A key parameter to the financial viability and preferred operation mode of the P2H$_2$-plant is the electricity price throughout the year. This slide explains the relationship between the operation mode, electricity prices, and number of full load hours of the P2H$_2$-plant.

Landing points
The capacity of the electricity transmission network near the coast may not be sufficient to facilitate a future additional load of 4 or 6 GW. Two alternatives are compared to understand the capability of hydrogen production and transport:

1. No or little hydrogen production and electricity brought to inland points. The total cable distances for locations deeper land inwards would be around 185 km.
2. There is sufficient capacity to unburden the near coast capacity of the electricity transmission network. Total cable length of 110 km.

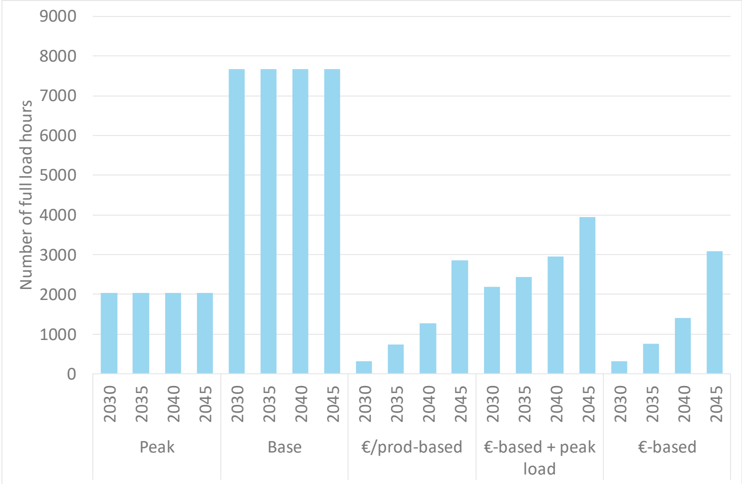
For hydrogen, the selected landing points are Maasvlakte, which is a smooth connection with the Rotterdam port area, and IJmuiden, where also a hydrogen infrastructure is available (mainly coke-oven-gas though). These distances are 110 and 75 km respectively.

Market prices for electricity and hydrogen
A key input to the model are the prices of both hydrogen and electricity. The electricity prices are based on DNV GL's Energy Transition Outlook and DNV GL's European market model and provided on slide 46; the hydrogen prices are explained in more detail on slide 45 and 46. Appendix B provides more background and information about DNV GL's European market model.

It can be expected that in future years the amount of wind and other renewable energies – which depend on weather conditions – will increase and the number of periods each year with low electricity prices will increase as well.

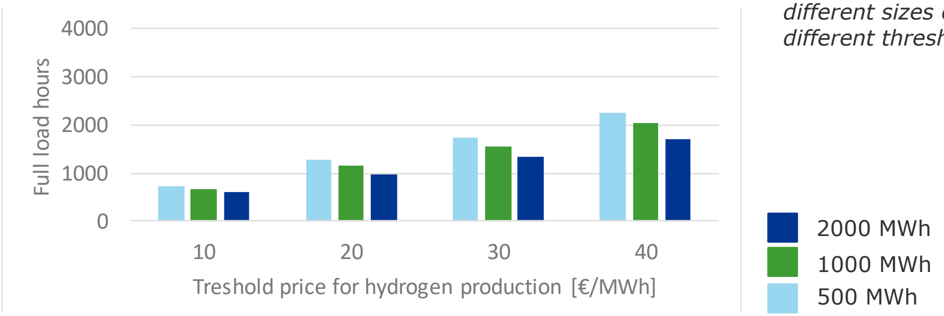
In the graph on the right (top) this dependency is shown for a threshold electricity price of €/MWh (€ price based on 2016) for a 400 MW P2H$_2$-plant and a total windfarm capacity of 4 GW. In the model this situation is assumed to be constant for the five years around the dates for which the simulation was done (so from 2028 to 2032 the calculated results of 2030 are similar, etc.) In the bottom graph the number of full load hours is calculated for different sizes of the P2H$_2$-plant and different threshold prices for the simulation of electricity prices in 2040. As can be expected the number of full load hours increases with a higher threshold price and decrease with the size of the plant.

Different operation modes lead to different number of full load hours.



Number of full load hours for electricity prices below € /MWh, 400 MW P2H$_2$ capacity and 4 GW windfarm capacity.

The bottom figure gives results for different sizes of the P2H$_2$ plant and different threshold prices .



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Technical assessment
HVDC grid connection

Intro
For the IJmuiden Ver $P2H_2$ study, HVDC connections and $P2H_2$ facilities are envisioned for the transmission of the offshore wind energy to the shore. However, the comparison of electricity connections and gas connections cannot be compared equally. The differences in infrastructure and the associated markets need to be taken into account to make the comparison equal. For the HVDC connection the power is transmitted through a converter and a DC cable. The converter constitutes a critical component in an HVDC system, in both functional and economical terms. Two different types of HVDC converters are available on the market: Line Commutated Converter and Voltage Source Converter. The cable connection constitutes a critical part of a HVDC transmission system since an associated failure on the cables can terminate the transmission of power. The number of cables, cable capacity and reliability have a direct impact on the economics of an HVDC link, therefore it is of fundamental importance to investigate different potential solutions (e.g. system ratings and voltage/current levels) and find an optimal one.

Connection points
To avoid congestion issues in the transmission network, a limited amount of power can be installed near the coast. The rest of the power can be installed more inland thus increasing the length of the cables. Power cables in principle can be connected at many different points in the electricity grid as long as you can place a converter station within a small range from the connection point. This, offers flexibility, since better usage of the AC network is achieved. The possibility of connecting in many different places is also the biggest difference from the gas option, where the connection to the grid is bounded by the gas conversion point in the grid. Moreover, if HVDC connections can also be shortened by selecting an alternative connection point, then this alternative should be pursued as it will decrease the cost of the infrastructure.

Voltage level
The selection of the voltage ratings for the converter stations were based on discussions between TenneT and DNV GL and the fact that only mature technologies will be considered at this moment since the functional specifications of the connections linking IJmuiden Ver to shore are to be drafted by the end of 2018. The voltage levels that were considered are 320kV and 525kV. An additional voltage of 640kV was considered by DNV GL since the maturity level of this voltage is the same as of the 525kV. Accordingly, DNV GL advises to also consider the 640kV voltage level.

System Configuration
For the IJmuiden Ver area, the construction of an artificial island or the construction of platforms with both the HVDC converters and the $P2H_2$ facilities is envisioned. For the determination of the best technology regarding the converter stations several aspects need to be discussed. The offshore grid needs to be as simple as possible since the quality of the power transferred on shore will be controlled by the onshore converter, and enable the possibility to look into the future in case of upgrades. The selection of an LCC converter station for both the offshore and onshore converter will decrease the cost in cables and equipment and prohibits the possibility of updating the equipment. Thus, DNV GL assesses that the best option for this study is the VSC technology which will increase the utilization levels and give more options in the future when potential links to other islands or other countries are realized. DNV GL also proposes that the VSC converter station located offshore does not need to be a full converter with all the capabilities but rather a simple converter since the configuration of the grid is also rather simple.

IJmuiden Ver is an offshore wind farm zone with a planned capacity of up to 6 GW. The wind energy is collected in a hub before it is transported to shore. Currently, this is done by using platforms with either HVAC or HVDC installations. However, the HVDC installations can also be positioned on an artificial island reducing the construction cost of the converter station offshore and taking advantage of the onshore-like conditions. There are two types of HVDC converter technologies: Line Commutated Converter (LCC) which uses a thyristor-based current source converters and Voltage Source Converter (VSC) which uses insulated-gate bipolar transistors (IGBT). Even though the LCC converter offers a set of associated advantages over the VSC converter (lower losses, lower cost, higher ratings), the VSC converter technology is more suitable for the transportation of offshore wind energy since the footprint of the converter station is significantly smaller, and thus it is more suitable for the island and offshore applications since the size of the system plays a significant role, it allows the capability of providing ancillary services to the grid such as frequency and voltage support for the smooth operation of the wind generators with the reduction of harmonics, it has black start capability without requiring additional equipment, and it is able to independently control the active and reactive power at the AC side. These features will also allow the possibility of the bi-directional flow to/from the platform/island and is looking to the future where potential connections to other energy islands or even countries via the means of VSC HVDC connections are realized. In this case, a bi-directional power flow would enhance the reliability and stability of the newly created networks.

Nowadays, the standard industry practices regarding the construction of VSC HVDC converters are:

Figure: Monopole with metallic return: One converter per station; one pole and metallic return.

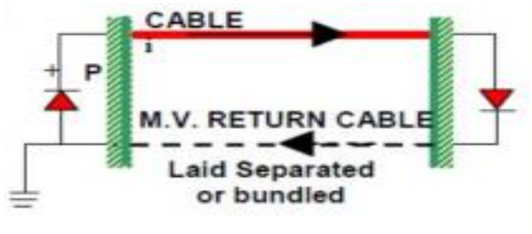
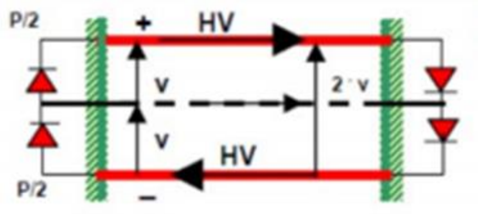
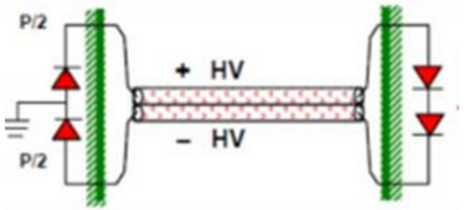


Figure: Bipole with metallic return



Two converters per station series connected with two poles output and metallic return between the midpoints of the two series-connected converters. The metallic return cable allows the possibility in operation in monopole scheme.

Figure: Bipole without metallic return:



Two converters per station series connected with two poles output without metallic return.

High voltage DC cables

There are three main types of cables used for HVDC connections: mass-impregnated, self-contained fluid-filled and extruded. Of these, the mass-impregnated cable and the extruded cable are the most commonly used cable types.

- Mass-Impregnated cable (MIND): It is the most commonly used and capable of operation in LCC HVDC schemes. It has been in service for more than 40 years and has proven track record as highly reliable technology. Voltages up to 600 kV and current ratings of 1800 A DC are available, corresponding to a maximum pole rating of 1100 MW and bipole rating of 2200 MW. The insulation is paper, impregnated with a high-viscosity compound.
- Extruded cable (XLPE): The technology has been applied to voltages up to 320 kV. Currently, XLPE cables at higher voltages, up to 640kV have withstood successfully the testing and are available on the market price.

Generally, there is no maintenance on power cables except when repairing the failures. However, this depends on the quality of the connections and is determined by the number of the failures. The Operational Expenditure (OPEX) associated with the HVDC cables is related to the selection of the connection points. In case that the connection point is near the area where the sea floor behaviour is dynamic, then the OPEX is dedicated to the maintenance of the burial depth which is dependent on the dynamic behavior of the sea floor. In case the connection points is to an area where the dynamic behavior of the sea floor is not that severe, then there is associated expenditure for the operation of the cable. DNV GL assesses that the associated OPEX for the HVDC cables is significantly small and is dependent on the connection point.

Availability and losses

Based on CIGRE Technical Brochure 379 – Update of Service Experience of HV Underground and Submarine Cable systems, the repair time for a submarine cable system is approximately 1440 hours which is translated in 60 days. DNV GL assesses that this is in line with the current repair duration time assumed by TenneT of +-60 days. Based on the same source, the estimated failure rate for DC submarine cable systems is 1 failure per 10 years. DNV GL assesses that this is also in line with the failure rate assumed by TenneT of 1 failure per 10 years.

Technical assessment

HVDC grid connection

Calculation of the number of cables per alternative
For the different alternatives, the number of cables required based on the different HVDC converter configuration and the combination of HVDC connections and $P2H_2$ was calculated. The HVDC connections that were considered, were 1000MW at 320kV, 1200MW at 320kV, and 2000MW at 525kV. For an overview see Appendix D.

The use of a 1200 MW connection at 320 kV is marked by DNV GL as a mature technology since a project of the same capacity and the same voltage level is available (see Caithness-Moray HVDC link).

For the selection of the best HVDC configuration, DNV GL based its opinion on the number of cables required per each alternative. The increased cost associated with the production and installation of the metallic return makes the monopole with metallic return and bipole with metallic return configuration costly for the purposes of this study. Moreover, since it is important to keep the costs as low as possible, DNV GL suggests that the bipole configuration without metallic return is the best solution. However, DNV GL believes that a cost benefit analysis is important for the determination of the additional costs of the metallic return for the monopole with metallic return and bipole with metallic return configurations. Furthermore, the choice of the bipole configuration without metallic return does not offer redundancy since in case that one of the two pole fails then the whole connection is lost and this is also something that needs to be added in the cost benefit analysis.

DNV GL believes that is also important to understand the cost of the infrastructure in case a single point of connection is considered. In this study, multiple connection points are considered which increases the cost of the infrastructure.

Possible advantage of hydrogen transport for energy transmission
There are two ways in which hydrogen transport can support the transmission of electricity:

1. It can replace the construction of expensive cables (€ per km for 2 GW HVDC). This is especially advantageous for large capacity windfarms at far shore locations.
2. It can help avoid the need for longer inland cables to connect the windfarm with connection points with sufficient onward capacity.

These advantages are favoured by long distances and large capacities.

Technical assessment

Inputs HVDC grid connection

The inputs for the electrical systems are obtained from TenneT from earlier studies on the IJmuiden Ver connection. This slide describes these assumptions in more detail.

The expertise of TenneT was used to determine the inputs for the electrical transport system. Also findings from earlier studies could be used in this study.

Offshore high voltage station
The offshore high voltage station is situated between the wind farm collection system and the export cable and transforms and converts the 66 kV AC electricity to either 320 or 525 kV DC. A distinction could be made between a platform based station and an island based system.

1. The platform-based system already included the platform and all other necessary equipment. This was case c (320 kV) or e (525 kV) from the TenneT study. The prices from this report were scaled linearly with the capacity and were assumed to be €/MW for the 320 kV system and €/MW for the 525 kV system. OPEX is assumed to be % and % respectively.
2. The island-based station could be separated from the island and the utilities. The station itself is scaled linearly with the capacity and is assumed to be €/MW for the 320 kV system and €/MW for the 525 kV system. OPEX is assumed to be % and % respectively.
3. The island with its utilities was assumed to be € with a total area of ha. It is not clear which part of this area can be used but it is assumed that it is sufficient to facilitate the (additional) area for the $P2H_2$ (full $P2H_2$ is ha.). OPEX is assumed to be % The costs of the island are divided between the electric and $P2H_2$ system in terms of capacity.

The lifetime of all stations is assumed to be years, except the island is assumed to never perish. The utilities on the island also have a lifetime of years. The efficiency of the stations is assumed to be %

Cables
The CAPEX of the cables is assumed to be €/km for the 1 and 1.2 GW (320 kV) cables and €/km for the 2 GW (525 kV) cables. OPEX is assumed to be %, lifetime years and the efficiency is assumed to be %. A technical assessment was already given in the slides above. A distance of 185 km more land inwards and 110 km along the coast was assumed.

Onshore high voltage station
The onshore high voltage station is situated at the location of the connection point and converts the electricity from 320/525 kV DC to 380 kV AC and is connected to the grid. The prices included all the required equipment and the price is scaled linearly with capacity. A CAPEX of €/MW was found for the 320 kV system and €/MW for the 525 kV system. OPEX is assumed to be % and % respectively. The stations have a lifetime of years and an efficiency of % was assumed.

Technical assessment
Electrolysis

The usefulness and reliability of the outcomes of the model depend on the quality of the input data. The data should be accurate, fact-based, and state-of-the-art. To accomplish this, DNV GL has (especially for the key figures) made a thorough assessment. In the following slides the key inputs are discussed, including the approach, sources and quality.

Electrolysers
The key assets in this study are the electrolysers in which electric energy is converted into chemical energy in the form of hydrogen. To get the key inputs from the market, DNV GL has obtained information from four large electrolyser manufacturers (NEL, ITM, Hydrogenics and Siemens). Two of these (Hydrogenics and Siemens) were also visited at their manufacturing sites.

A questionnaire was set up and discussed with the companies for details of the electrolyser performance and its expected performance. Not all questions could be answered in detail. For instance, the weight of the electrolyser unit and its optimization has not been a key issue so far (but will be when put on a platform), and as such, little attention has been given to this element by the manufacturers. The main results from the questionnaire are discussed below; the questionnaire is given in Annex C.

Technologies
Three technologies for electrolysis are available.

1. Alkaline based electrolysis is most mature. NEL is the key manufacturer in this.
2. PEM (polymer electrolyte membrane) technology is runner-up and the outlooks are promising. This is supported by all four electrolyser firms.
3. Solid oxide technology is still in its early days and no manufacturer input could be sourced.

Alkaline versus PEM
NEL claims to be the world leader for both PEM and alkaline electrolysers. They posit that alkaline technology is by far the most competitive in terms of both CAPEX and OPEX for large-scale hydrogen production. Alkaline-based electrolysis is a mature and proven technology while large PEM electrolysers are not fully commercial today. Only a limited number of units have been installed in demonstration projects. The potential for cost reduction however is interesting. The next table on gives a comparison between the two technologies.

For both technologies a factor of 1.25 is assumed regarding the offshore costs versus the onshore costs. This is the same for the electrical equipment.

	Alkaline	**PEM**
State of technology	Mature	Market penetration
Available sizes	2 MW	1 MW
H2-treatment	Last lye traces washed from hydrogen in a scrubber. Dryer and deoxidizer are added if high purity gas is required	De-oxidizer (not for NEL). Dryer may be required

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Technical assessment

Electrolysis

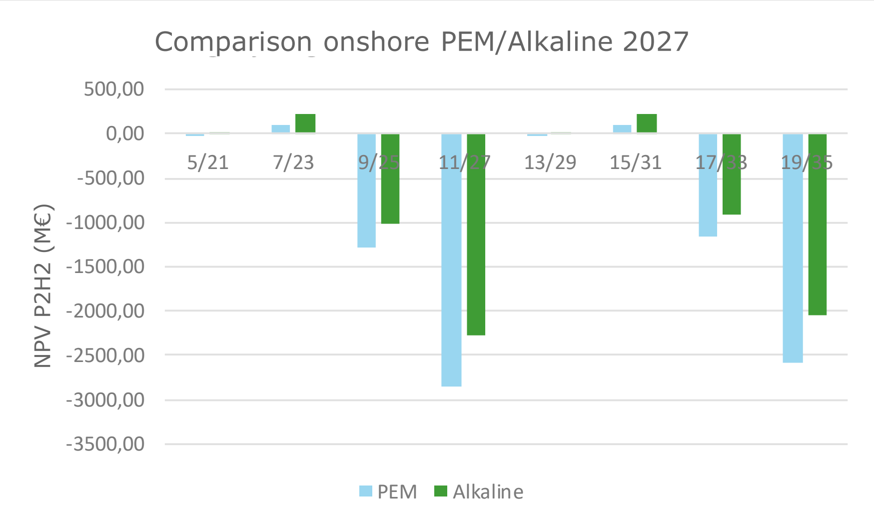
A comparison between the NPV of both an Alkaline and PEM electrolyser reveals that PEM electrolysers are still less cost efficient than alkaline electrolysers. However it can be expected that this will change in the next 10 to 20 year. The differences are small and given the expected benefits of PEM over Alkaline, like reaction time, the further improvement in costs and efficiency, the footprint, the operating hours, PEM is used in the results section.

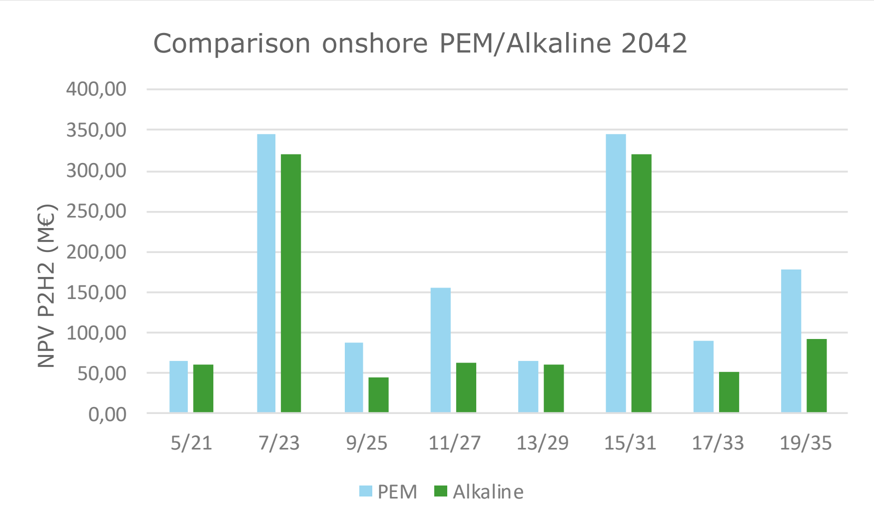
Both alkaline and PEM technology are fit for large scale application. This has been confirmed by several large electrolyser firms (see Appendix C for questionnaire). Both technologies have been introduced into the model as different cases. Alkaline is more mature, needs lower specific investments and has a higher efficiency for atmospheric hydrogen production. To increase the pressure to 30 bar a compressor was added, which lowered the overall efficiency from 80 to 76.5% and added Capex to the feasibility model. PEM technology is less efficient and has higher specific cost but the outlook of these aspects are positive. It is expected that the efficiency will increase to an overall of 80% and the specific investment may decrease with 30% in the next 10 to 20 year. For this a comparison has been done between alkaline and PEM for a construction of the plant in 2027 and 2042. As can be seen the alkaline is the better option for the (relatively) short term but is the lesser option for the future. Still the differences are small. The main parameter in the approach is the electricity price for which hydrogen can be produced.

Given the generation of the wind farms the electrolyser should be capable of quick response times. Here PEM has a clear advantage as typical response times for Alkaline electrolysers are in terms of minutes. Besides, the operation and maintenance of the alkaline system requires higher intervals as for example the electrolyte needs to be refilled (with KOH) every once in a while. Furthermore, the weight and dimensions of the alkaline system are larger. Given these features and the expected learning curve, PEM is considered as the main electrolyser technology in this study.

Comparison between Alkaline and PEM electrolysers. The case numbers refer to PEM/Alkaline, both in the table and the graphs

Case #	Description
5/21	4 GW, island, onshore P2H$_2$ 100 MW €-based, Maasvlakte
7/23	4 GW, island, onshore P2H$_2$ 500 MW €-based, Maasvlakte
9/25	4 GW, island, onshore P2H$_2$ 1000 MW peak load, Maasvlakte
11/27	4 GW, island, onshore P2H$_2$ 2000 MW peak load, Maasvlakte
13/29	6 GW, island, onshore P2H$_2$ 100 MW €-based, Maasvlakte
15/31	6 GW, island, onshore P2H$_2$ 500 MW €-based, Maasvlakte
17/33	6 GW, island, onshore P2H$_2$ 1000 MW peak load, Maasvlakte
19/35	6 GW, island, onshore P2H$_2$ 2000 MW peak load, Maasvlakte





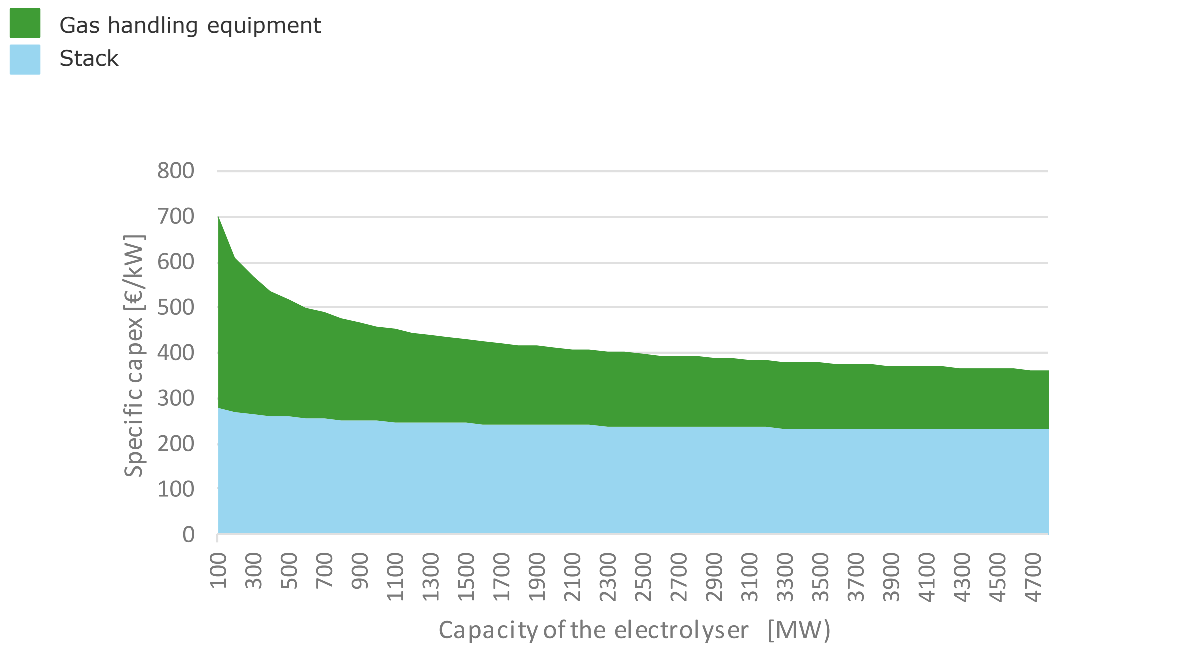
Technical assessment
Electrolysis

The characteristics of the electrolysers used as a basis in our model are shown in the table below. We assume gains in efficiency and technical lifetime and a reduction in capex in the future as the technology matures and production quantities increase.

Scaling of the electrolyser
Based on the inputs of the electrolyser manufacturers, the following data are used in the model for the PEM electrolysers. It is expected that the following innovations are possible at the indicated years:

1. Higher overall efficiency from % in 2020 to % in 2040
2. A longer lifetime for the stack (from to hours) as well as the hydrogen conditioning part
3. An overall cost reduction of €/kW to €/kW.

Scaling effect on the CAPEX of the P2H_2-plant.



The stack is almost linear with size and the gas handling equipment is expected to follow an exponent of 0.7 with size. On top of that the overall price is expected to come down. This is due to an increased penetration of automation. The selected drop in price is conservative. Breakthrough investments in production if the market is expanding fast may lead to higher decrease rates.

Technical assessment

Electrolysis

Electrolysers have the highest efficiency at the low loads. However, as the load on the electrolysers will not be its maximum throughout an entire year, we consider an increase in efficiency at partial loads in the model. The relationship between efficiency and load is shown on this slide.

Electrolyser efficiency at partial loads
The presented efficiencies are at full load. At lower loads, the electrolyser performs with a higher efficiency. This is shown in the chart on the right where the load expressed in a percentage of maximum load is plotted against the efficiency of the electrolyser. Depending on the operation mode, this effect can increase production volume with 5%.

Water treatment
The water requirements differ for each electrolyser since some manufacturers already include a water purification step in their system. Clean demineralized water is needed for the electrolysis process as this influences both the hydrogen production performance and hydrogen purity. Especially offshore, the availability of clean water is somewhat limited since seawater contains salt (typically 35,000 PPM). Direct electrolysis of seawater is possible but this will affect the hydrogen purity and will produce chlorine as a (by)product. This does not only affect the electrolyser efficiency but could also affect the electrolyser lifetime as chlorine is highly corrosive.

The electrolyser uses approximately liter water per m³ H_2 and requires a water conductivity of <1,000 μS/cm as an input to the electrolyser unit. Further purification is included in the electrolyser unit itself before it is fed to the cell stack. With these specifications a water purification unit (based on reverse osmosis) price of €/kW was obtained where a 1 kW system can feed a 1 MW electrolyser. The energy consumption is assumed to be kWh/m³ of water which results in a loss of about % for hydrogen production.

It is assumed that there are no negative environmental consequences of releasing the highly saline reject stream back into the sea. Attention should be paid that the reject stream will not contaminate the inlet and causing clogging of the filters.

Waste heat
Waste heat from the electrolysers could be applied as low temperature heat for use in heating the accommodations or in water desalination. However, this is not well balanced and is not further taken into account.

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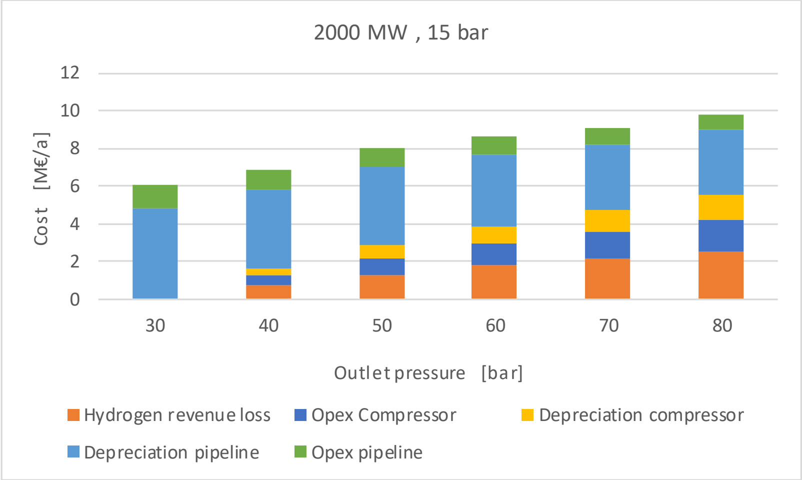
Technical assessment
Pressure regime

The pressure regime has been assessed. For all cases the use of a compressor leads to higher cost and therefore this option was not taken into account in the model.

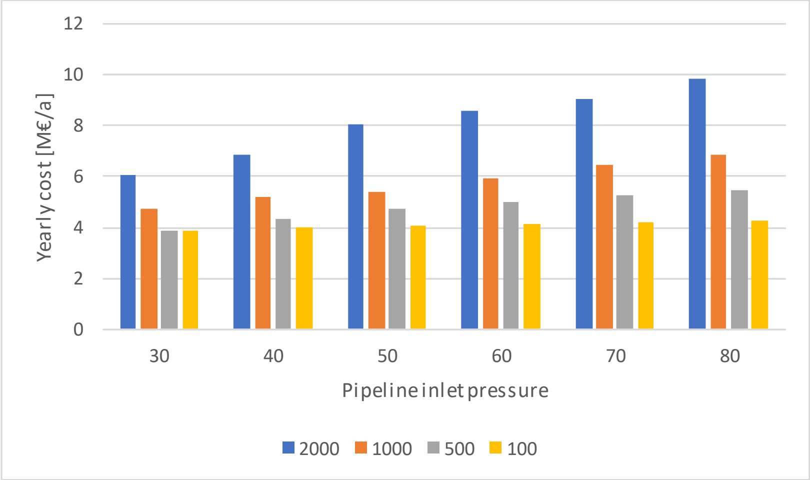
Compressor and pipeline optimization
The compressor and pipeline configuration can be optimized. If the inlet pressure of the pipeline is higher the diameter and with that the investment and OPEX can be lower. However there are extra cost to increase the pressure. These are for the IJmuiden Ver case the investment and OPEX of the compressor and the loss of revenues for hydrogen sales because electricity is required to run the compressor. This configuration can be optimized with the inlet pressure as variable parameter. This is done for both the PEM (with 30 bar electrolyser output) and the alkaline technology (atmospheric).

Results
In the graphs below the results are shown. The left graph shows the calculation outcomes for PEM technology for pressures ranging from 30 to 80 bar (for a 2000MW electrolyser with 15 bar outlet pressure). Although the pipeline cost decrease with higher pressures, the increase of the compressor cost is higher . The graph in the middle shows the totals for different capacities.
The graph on the right shows the case for an electrolyser running at atmospheric outlet pressures.
As can be concluded, the use of a(n extra) compressor leads in all cases to higher cost. This option is not added to the model.

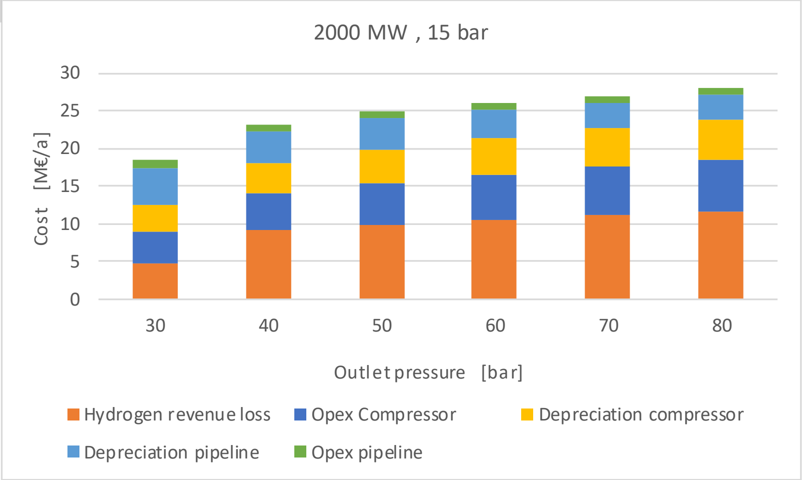
Increasing differentiated cost for pressurized hydrogen transport (2GW electrolysis with 30 bar outlet pressure)



Increasing total cost for pressurized hydrogen transport for different capacities of the electrolyser.



Increasing differentiated cost for pressurized hydrogen transport (2GW electrolysis with atmospheric outlet)



Pipelines
There are a considerable amount of pipelines already in place in the North Sea. Recently, TNO has presented the North Sea Energy Atlas. One of the inventories which was made was the applicability for hydrogen or CO_2-transport. The data that was provided has been assessed and the advantage for their re-use has been estimated.

The approach to compare the viability of using existing pipelines or constructing new pipelines consisted of three steps:
1. Investigation of suitability of existing pipelines
2. Capacity assessment of existing pipeline
3. Cost comparison between new and existing pipelines

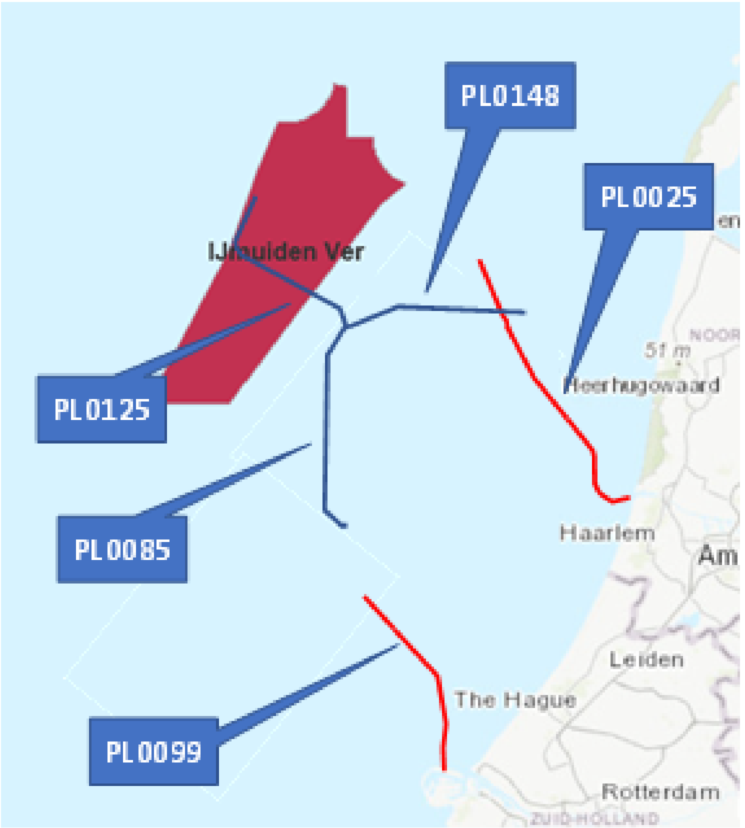
1. Investigation of suitability of existing pipelines
The pipelines as presented in the atlas have been investigated for their use on the basis of location and size. Five pipelines were identified as possible candidates for hydrogen re-use. These are shown in the map on the right. Their characteristics are given in the table below.

	PL0125	PL0148	PL0025	PL0085	PL0099
Operator	Wintershall	Wintershall	Chevron	Wintershall	Taqa
Status	Abandoned	Active	Active	Active	Active
Medium	Gas	Gas	Oil	Gas	Gas
Diameter	10″	14″	20″	12″	26″
Length	38.2 km	35.2 km	57.7 km	42.1 km	40.1 km
Relevant length	10.6 km	29.9 km	46.9 km	42.1 km	40.1 km
Construction year	1996	2000	1982	1996	1993

2. Capacity assessment of existing pipelines
For the different production scenarios, calculations were done to assess whether the capacity of the existing pipeline was sufficient for transportation of hydrogen to the two different landing points in respectively IJmuiden and Maasvlakte.

The assessment is discussed in the following two slides.

Existing pipelines relevant for the transport of H_2 to IJmuiden and/or the Maasvlakte.



Technical assessment

Existing / new pipelines

Landing point: IJmuiden
For IJmuiden, three configurations appear to be relevant, which are shown in the maps on the right:

1. **Configuration 1**: Parts of pipelines PL0125, PL0148 and PL0025 can all be used.

2. **Configuration 2**: Only a part of pipeline PL0025 can be used. A new pipeline is constructed to connect the wind farm with PL0025

3. **Configuration 3**: The capacity of PL0025 is not sufficient and a new pipeline is constructed

The results of the assessment of the 5 possible capacities are summarized in the table below.

$P2H_2$-capacity [MW]	H_2-flow [Nm^3/s]	Configu-ration	Inlet pressure [bar]	Outlet pressure [bar]	Length new pipeline [km]	Diameter new pipeline [inch]
400	25	1	30	23,0	N/A	
1000	63	2	30	18,0	37,0	16"
2000	126	2	30	15,1	37,0	36"
3200	201	3	N/A			
4800	301	3	N/A			

The existing pipelines can only be fully utilized for the 400 MW $P2H_2$ case. For the 1000 MW and 2000 MW case, a new pipeline of 37 km must be constructed. For the 4 GW and 6 GW case, the 20” PL0025 is lacking sufficient capacity.

Three suitable configurations for IJmuiden landing point

New pipeline
IJmuiden
Used existing pipeline

IJmuiden configuration 1 | **IJmuiden configuration 2** | **IJmuiden configuration 3**

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Technical assessment

Existing / new pipelines

Landing point: Maasvlakte
For Maasvlakte, again three configurations appear to be relevant, which are shown in the maps on the right:

1. **Configuration 1**: A part of pipelines PL0125 and the complete PL0085 and PL0099 can be used. A new pipeline is needed to connect PL0099 and PL0085.

2. **Configuration 2**: Only PL0099 can be used and a new pipeline is constructed to connect PL0099 with IJmuiden Ver.

3. **Configuration 3**: A complete new pipeline is to be constructed.

The results of the assessment of the 5 possible capacities are summarized in the table below.

$P2H_2$-capacity [MW]	H_2-flow [Nm^3/s]	Configu-ration	Inlet pressure [bar]	Outlet pressure [bar]	Length new pipeline [km]	Diameter new pipeline [inch]
400	25	1	30	15,1	14,2	12
1000	63	2	30	22,5	59,2	18
2000	126	2	30	15,9	59,2	22
3200	201	2	30	16,8	59,2	30
4800	301	2	30	6,3	59,2	48

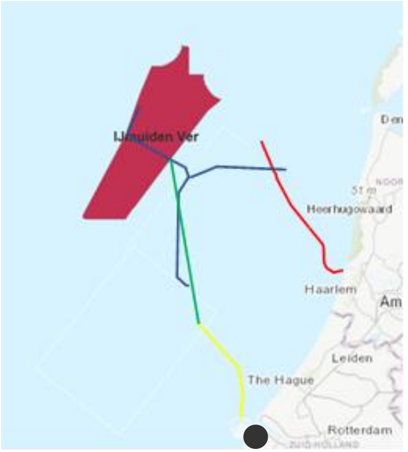
The use of existing pipelines can only be fully utilized for the 400 MW $P2H_2$ case, with a new pipeline of 14.2 km of 12”. For the 1000 MW, 2000 MW and 3200 MW case a new pipeline of 59.2 km must be constructed. For the 4800 MW case, the 26” PL0099 is lacking sufficient capacity.

Three suitable configurations for Maasvlakte landing point

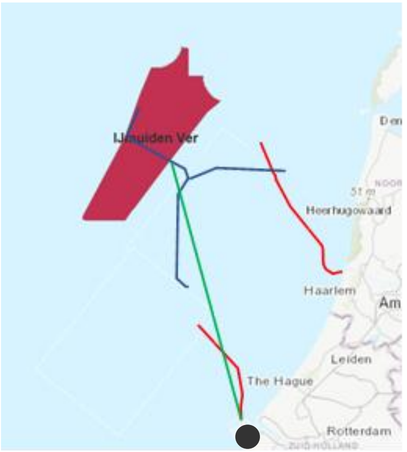
New pipeline
Maasvlakte
Used existing pipeline

Maasvlakte configuration 1

Maasvlakte configuration 2



Maasvlakte configuration 3



Technical assessment
Existing / new pipelines

3. Cost comparison between new and existing pipelines
The unit investment costs for a new pipeline are shown in the chart on the right.

We furthermore assume:
- A lifetime of 50 year for both new and existing pipelines.
- A compensation for the handover of the existing pipeline of 50% of its remaining asset value, based on linear depreciation.
- A 15% investment for cleaning and adaption of the pipeline such that it can be used for transporting hydrogen.

A comparison was made between the existing and new pipelines. In the table below presents the details of this comparison.

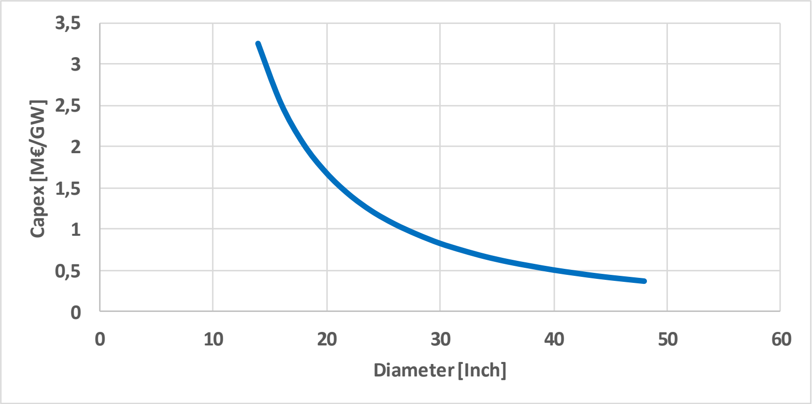
Pipeline	Length [km]	Diameter [inch]	Needed for	New construction costs [M€]	Remaining lifetime in 2027 [year]	Acquisi-tion price [M€]	Replace-ment year
PL0025	46,95	20	IJm	88,6	5	17,7	2032
PL0148	29,91	14	IJm.	42,1	23	16,0	2050
PL0125	10,6	10	IJm. + MV	11,5	19	3,9	2046
PL0085	38,21	12	MV	47,7	13	13,4	2040
PL0099	40,11	26	MV	95,0	16	29,4	2043

In the graph on the right, the present costs of the two alternatives over 50 years are presented. As can be seen there is no significant advantage in using the existing pipelines. This is due to three reasons:

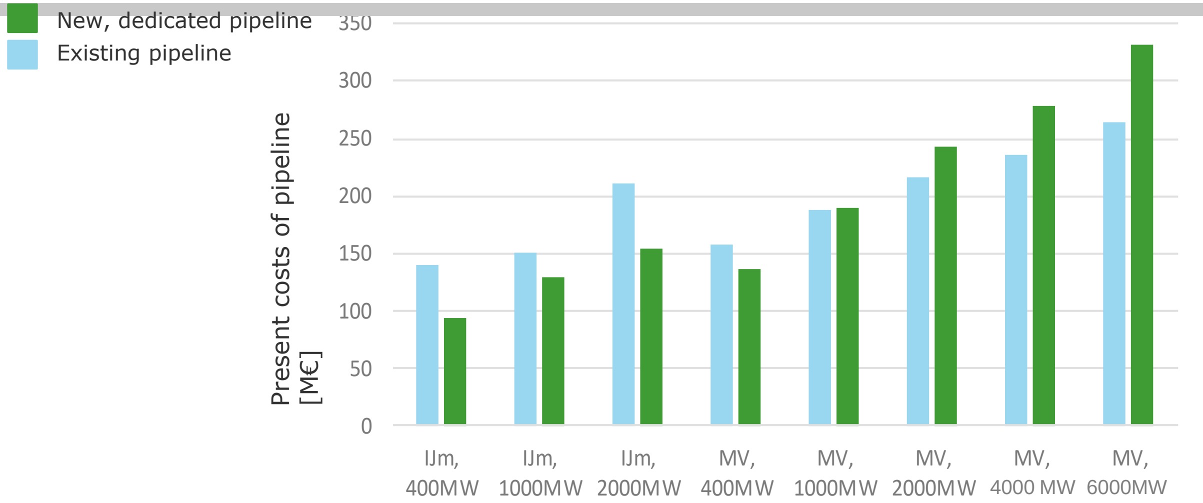
1. The existing pipelines will have to be replaced in 5 to 23 years after the construction of IJmuiden Ver.
2. The existing pipelines only partly can accommodate the produced hydrogen due to small diameters
3. The length of the existing pipelines is higher than the length of a new dedicated pipeline.

The existing pipelines are not separately introduced in the model.

Unit investment costs for new, dedicated pipelines (based on a 110 km pipeline with 30 bar inlet pressure and 15 bar outlet)



Comparison of NPVs of a hydrogen connection with existing or new, dedicated pipelines.



Technical assessment
Platform – results summary

The design and cost of offshore platforms to house high-voltage stations is known by TenneT. However, it is not known for $P2H_2$, since the weight and dimension of the $P2H_2$ components are different compared to the electrical components. Accordingly, a high-level assessment has been performed to determine the basic design, size and cost of a platform for $P2H_2$. First the results and trends are presented, after which the assessment is described in more detail.

HVDC topside mass estimation

Option	Topside Power Rating (MW)	Estimated topside volume for HVDC equipment (m3)	Estimated Structural Steel Mass (tonnes)	HVDC Equipment (tonnes)	Auxiliary Equipment, cladding, gratings, protection etc. (tonnes)	Estimated HVDC Topside Mass (Tonnes)
HVDC 1	100	6,799	842	363	446	1,651
HVDC 2	500	61,896	4,209	1,816	2,228	8,254
HVDC 3	1,000	193,542	8,419	3,632	4,457	16,507
HVDC 4	2,000	666,084	16,837	7,263	8,914	33,015

$P2H_2$ topside mass estimation

Option	Power Input (MW)	Estimation Mass of Electrical Equipment (tonnes)	Estimated Mass of Processing Plant (tonnes)	Estimated Mass of Cooling Equipment (tonnes)	Estimated Topside Volume (m3)	Total Mass of Hydrogen Production Plant (tonnes)	Estimated Mass of Supporting Steelwork (tonnes)	Auxiliary Equipment, cladding, gratings, protection etc. (tonnes)	Total Mass Estimation (tonnes)
$P2H_2$ 1	100	565	565	150	19,355	1,280	1,325	660	3,265
$P2H_2$ 2	500	2,825	2,825	750	96,775	6,400	6,624	3,302	16,326
$P2H_2$ 3	1,000	5,650	5,650	1,500	193,550	12,800	13,248	6,604	32,652
$P2H_2$ 4	2,000	11,300	11,300	3,000	387,100	25,600	26,496	13,209	65,305

Topside Costing Assumptions

Steel Rate (euro / te)	Cladding rate (euro / te)	Grating rate (euro / m2)	Coating Rate (euro / m2)
3,500	3,000	180	120

Pile Mass and Cost Estimation

Option	Estimate Steelwork, Te	Total Cost (euro)
HVDC 1	333	666,000
HVDC 2	708	1,416,000
HVDC 3	1,477	2,955,000
HVDC 4	2,988	5,976,000
$P2H_2$ 1	541	1,082,000
$P2H_2$ 2	1,458	2,915,000
$P2H_2$ 3	3,234	6,468,000
$P2H_2$ 4	6,502	13,004,000

Technical assessment

Platform – results summary

Topside Costing Estimation

Option	Steelwork (Te)	Rooms and Cladding (Te)	Gratings (m2)	Estimated Coating Area (m2)	Total Cost (euro)
HVDC 1	842	446	748	16,402	6,387,000
HVDC 2	4,209	2,228	6,809	82,011	32,485,000
HVDC 3	8,419	4,457	21,290	164,022	66,351,000
HVDC 4	16,837	8,914	73,269	328,044	138,227,000
$P2H_2$ 1	1,325	660	2,129	25,290	10,036,000
$P2H_2$ 2	6,624	3,302	10,645	126,448	50,180,000
$P2H_2$ 3	13,248	6,604	21,291	252,895	100,361,000
$P2H_2$ 4	26,496	13,209	42,581	505,791	200,721,000

Substructure and Pile Cost Assumptions

Primary Rate (euro / te)	Secondary Rate (euro / Te)	Anodes Rate (euro / te)	Coating Rate (euro / m2)
2,000	2,500	6,500	120

Jacket Mass and Cost Estimation

Option	Water Depth (m)	Topside Mass to support (tonnes)	Estimated Jacket Mass (tonnes)	Secondary Steel Estimation (tonnes)	Anode Estimation (tonnes)	Coating Area Estimation (m2)	Total Cost (euro)
HVDC 1	30	1,651	429	91	12	1,054	1,287,000
HVDC 2	30	8,254	4,039	125	46	4,904	9,276,000
HVDC 3	30	16,507	8,552	158	89	9,715	19,241,000
HVDC 4	30	33,015	17,577	316	175	19,338	39,399,000
$P2H_2$ 1	30	3,265	1,311	91	20	1,996	3,220,000
$P2H_2$ 2	30	16,326	8,453	125	88	9,609	18,940,000
$P2H_2$ 3	30	32,652	17,379	158	173	19,127	38,570,000
$P2H_2$ 4	30	65,305	35,231	316	342	38,161	78,057,000

Technical assessment
Platform - trends

The following trends were used to estimate the HVDC and $P2H_2$ platform sizes.

HVDC:
- HVDC Topside Mass (tonnes) = 16.50 * Power (MW) (based on installed HVDC platforms)
- HVDC Topside Volume per MW (m3 / MW) = 0.1395 * Power (MW) + 54.042 (based on installed HVDC platforms)
- HVDC Topside Steel Mass (tonnes) = 0.51 * HVDC Topside Mass (tonnes) (based experience on engineering judgement)
- HVDC Topside Electrical Equipment Mass (tonnes) = 0.22 * HVDC Topside Mass (tonnes) (based experience on engineering judgement)
- HVDC Topside Auxiliary Equipment Mass (tonnes) = 0.27 * HVDC Topside Mass (tonnes) (based experience on engineering judgement)

$P2H_2$:
- $P2H_2$ steelwork mass (tonnes) = 1.035 * equipment mass (tonnes) (based experience on engineering judgement)
- $P2H_2$ Topside Electrical Equipment Mass = 5.65 * Power (MW) (based on information from suppliers)
- $P2H_2$ Auxiliary Equipment, gratings, cladding and control room mass (tonnes) = 1.1689 * electrical equipment mass (based experience on engineering judgement)
- $P2H_2$ Topside Processing Plant Equipment Mass = 5.65 * Power (MW) (based on information from suppliers)
- $P2H_2$ Topside Cooling Equipment Mass = 1.5 * Power (MW) (based on information from suppliers)
- $P2H_2$ Topside Volume (m3) = Power (MW) * 193.55 (based on information from suppliers)

Topsides (both HVDC and $P2H_2$):
- Topside Coating Area (m2) = 12.74* (Steel Mass (tonnes) + Aux. Equipment (rooms and cladding) mass (tonnes))
- Grating area (m2) = 0.11 * volume (m3) (based on review of TenneT supplied information)

Jacket and Piles:
- Jacket Mass per unit water depth (tonnes / meter water depth) = 0.018225 * topside mass (tonnes) - 15.792785 (based on installed HVDC platforms)
- Jacket Anode mass = 0.0095 * jacket mass + 7.5265 (based on experience on engineering judgement)
- Jacket Coating Area = 1.0662 * jacket mass + 597.33 (based on experience on engineering judgement)
- Jacket Secondary steel mass is based on experience, water depth and number of boat landings and j-tubes/pipes.
- Pile length is based on the compressive resistance of dead load per pile * 2 (to account for live loading). Assumed skin friction of 40kPa (0m to 20m depth, and 81kPa 20m+ depth. End bearing 4800kPa at 30m+ embedment.

Conclusions - Lifetime and life extension (substructure)

The lifetime was assumed to be the same as the lifetime of installed substations, it has been assumed to be 30 years. Life extension of the jacket can be achieved through diving inspections to prove that there's been no severe accumulated damage, or by studying measured wind/wave data to show that the conditions it has been subjected to were less severe than those it was designed for. The first option (diving inspection) will be more expensive, but neither will be a significant proportion of the CAPEX. An estimate of a diving inspection campaign is circa 500-700k EUR assuming 4 weeks and a 20k vessel & equipment day rate and 2k for the divers' day rate. There's no guarantee that this will extend the life but it is likely due to the high safety margins assumed in design codes.

Conclusions - Trends

The following remarks shall be noted concerning the estimated weights:
- The uncertainty in the mass estimation is +25%/-30%. As the maximum capacity available from other projects is 900 MW, the uncertainty for the 2 GW $P2H_2$ is quite high.
- In above charts are values derived from other comparable projects, the substructure concept other than a jacket has not been estimated. There could be overall cost savings for alternative installation methods (self-installing or floating).
- It may be viable to house the 100MW $P2H_2$ on the larger HVDC platforms (500MW and 1000MW). But generally, it was found that separate platforms would ease installation and help control risks of processing hydrogen gas.

The size and cost of supply and fabrication of the different options are presented in the results tables below. Cost assumptions have been based on fabrication in Europe and steel supply from Europe. Cost saving in steel supply could be made if sourcing the material from China, however in this case it would be recommended that the material specification is well defined and the steel is inspected to ensure it meets the requirements. For installation, it can be assumed the cost is circa 15% of the fabrication and supply.

Technical assessment
Platform

Topside and Substructure Study
The size of the foundation and topsides are dependent on various choices that are made early in the design process. For this study, some assumptions have been made to size the topsides and foundations, which are discussed below. These assumptions should be investigated in more detail during the FEED or Pre-FEED to define the requirements for detail design and future tendering.

Decking and Tier Options.
Due to the size of the equipment required a pancake / single-tier configuration is not considered feasible. Therefore, this assessment assumes a multi-tiered topside. With this option, it will be necessary to check the under-hook height of the installation crane vessel against the height of the topside during the design process. The smaller footprint will reduce the required horizontal reach of the installation vessel crane. The structure is stiffer in the lifting condition due to the greater depth. The upper deck can be open for ease of equipment replacement if desired, or have a retractable roof. The High Voltage Direct Current (HVDC) and Power to Gas ($P2H_2$) platforms have equipment that can be split across different deck levels which will allow for a smaller footprint minimising weight eccentricities for installation. Alternative arrangements of the equipment and different numbers of levels are possible. To date most High Voltage Alternating Current (HVAC) substations have been limited to at most three levels whilst HVDC connection platforms are circa 6 decks.

Cladding, Flooring and Roof
Fully cladding the HVDC platform and $P2H_2$ platform will protect personnel and equipment during installation, commissioning, operation and decommissioning. HVDC equipment is more sensitive to environmental factors compared to HVAC equipment. For the $P2H_2$ platform the risk of gaseous environments should be considered in more detail before, an open deck will allow any leaked hydrogen to escape risking any associated risks.
The cladding and supporting steel does however add more mass and increase wind loadings compared to an open deck option. Further benefit of cladding is an enhanced level of corrosion protection for the equipment and modules. The coolers and diesel generator will be exposed allowing the heat and fumes to be removed by the wind.
Partly clad is a hybrid between the fully clad and open decks. The cladding locations can be chosen to protect areas where there is a high consequence if the coatings breakdown. Alternatively, this can be completed to streamline the appearance of the platform or provide a separation between the gas production equipment and electrical, control, Heating Ventilation and Air Conditioning (HVAC) and protective equipment.
An open deck option will have the lowest mass. The open structure of the deck also allows for easy replacement of transformers during repair and maintenance operations.
Glass-reinforced plastic (GRP) / steel plate: plate will be required in bunds and in laydown areas. GRP could be used for the cladding material to reduce the total weight.
A roof protects the platform from the elements and marine bird guano. This option will add weight. During the design process accessibility to areas for inspections, replacement of equipment should be considered.

<u>Conclusion</u>: this study assumes that cladding and roof are provided and the trends lines are derived on HVDC platforms that are clad to provide a protective environment.

Helideck
Helicopter access is considered as a complementary means of access to boats for granting access to maintenance personnel and delivery of small pieces of equipment. The following cases have been considered:
Heli Hoist: this is a designated for winching a person to safety or for small items of equipment. This area is located at the highest point of the structure and away from heat sources such as the coolers or diesel generators.
Helideck: this option will allow access to the platform by helicopter when the waves and currents make access difficult. It is likely that this will not include refuelling but would require several safety systems such as firefighting. This area is also located at the highest point of the structure and away from heat sources such as the coolers or diesel generators.
None: this will only allow access/egress from the platform by crew transfer vessel. This is not preferred and would only be considered acceptable for a nearshore location with a benign sea climate.

<u>Conclusion</u>: based on the general location this study assumes that the helideck would be beneficial. The construction is expected to be aluminium, circa 25 tons. The location will be at the highest point of the structure; the design process will need to consider where this is located relative to the wind direction, platform craneage and heat/exhausts from the platforms. The consideration of use of helicopter should be considered with the operation and maintenance strategy. The trend lines are derived on HVDC platforms that have helicopter landing areas.

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Cranes
Crane system will be required, to allow delivery of heavy packages during operation and maintenance. The following options are considered:
Cranage (above boat landings): small cranes with a working capacity of approximately 1 ton are considered beneficial above all boat landings, for the transfer of small tools and equipment
Main crane: the choice in terms of location, reach, size, depends on the operation and maintenance strategy. If provided, it would be located on the roof and have access to all or most decks. Design shall consider the optimum location of a service vessel for unloading via the crane.
Laydown areas: these are steel plated areas strengthened to handle loads imposed from lifted loads.
Man-riding: the choice of the cranes being certified for man riding depends on the evacuation strategy and will not affect the masses and allowances in this study.

Conclusion: two small davits above two boating landings and one main crane. Internal cranes may also be required. The trends lines are derived on HVDC platforms that have at least a main crane located on the roof. Two large crane maybe required for the largest platforms to be able to reach all area of the platform.

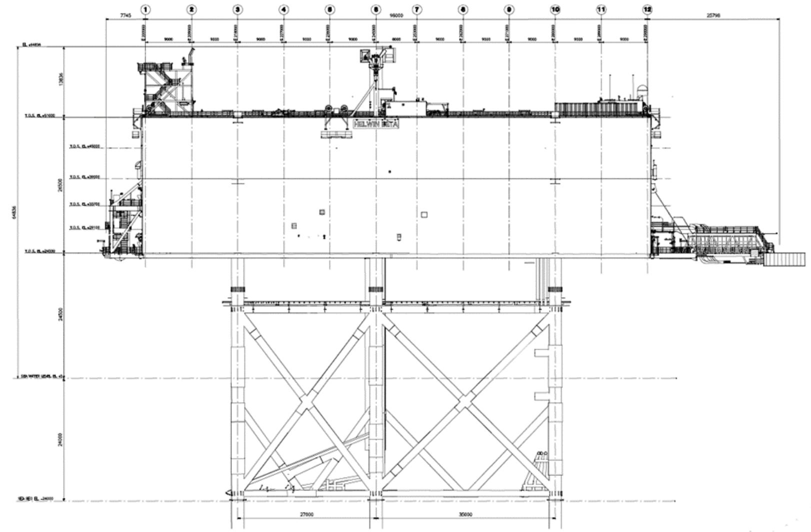
Manned / Unmanned Platform
For this study the platform has been assumed to be an unmanned installation. The need for living quarters is therefore excluded. Housing living quarters on the $P2H_2$ platform is considered a higher risk to the personnel because of the production of explosive hydrogen gas.
A refuge serving as shelter for personnel in case of storm as a well as workshop and storage room for maintenance tools shall however be provided. The need shall be assessed with respect to compliance with applicable regulations and results from a risk assessment to be performed on the complete platform.
The refuge, workshop, HVAC and storage room sizes will need to be considered during the design stage.

Fire and Explosion protection
Active fire protection system will be required to protect the most sensitive areas (diesel tank, transformer). DNVGL-ST-0145 and similarly ISO 13702 require that fire and explosion hazards are identified and the associated risks are evaluated and managed.
Various options exist for the fire protection of the platform, such as compressed air foam, water deluge system, water mist system, inert gas. These all have their pros and cons such as the size of the dump tank, how the system may affect operatives on the platform. This is not within the scope of this feasibility study. Consideration shall be made also during the design phase of other safety aspects, such as muster points and evacuation means (life rafts, helicopters).
Blast and fire wall ratings have not been considered in detail, but their mass has been allowed for in this study as this items are already included in the trend lines.

Cable Pulling Area
The size and location of an area for cable pulling should be chosen to allow cable pulling / routing operations, especially as live cables may be in place at different times as different sites are installed and commissioned. These areas shall be kept mainly free apart to aid cable pulling/handling, removing of cable armour and cable routing. The final area and height requirement will need to be considered during the design process.

Jacket Substructures
Jacket type substructures have been examined in outline for the substations. The HelWin Beta 6-leg jacket is illustrated below.

Figure: Example HVDC Connector Substations (HelWin Beta, image source Tennet).



Technical assessment
Platform

Jacket Substructures - continued
The arrangement above illustrates a jacket which is through leg piled at each leg. Pile diameters are normally sized to minimise pile embedment and lateral pile displacements at the mudline. The advantage of through leg piling is that pile sleeves are avoided. Pile sleeves are relatively heavy and fabrication-intensive components. The disadvantage of leg piling is that pile lengths are increased due to the need for greater embedment and substantial excess pile length within the jacket legs. It also means that jacket legs would need to be increased in diameter substantially to accommodate the necessary pile diameter internally. This increases hydrodynamic loading on the structure.
Jacket variants have included options where legs are inclined to increase the structure footprint on the seabed, thereby reducing pile loads, and at the same time reducing brace lengths in the jacket. The straight leg jacket simplifies fabrication but reduces the pile lever arm in resisting overturning moment. The pile embedment length will increase with such an approach.
A significant advantage of the jacket is the flexibility it offers in accommodating equipment deck growth or modification. Alternate jacket configurations can be employed if there is significant change to equipment requirements, either before construction, or if required retrospectively during service. A jacket structure is better able to accommodate highly eccentric equipment, such as an offset helideck.

<u>Conclusion</u>: through leg piled jackets are considered as the most flexible approach for this study.

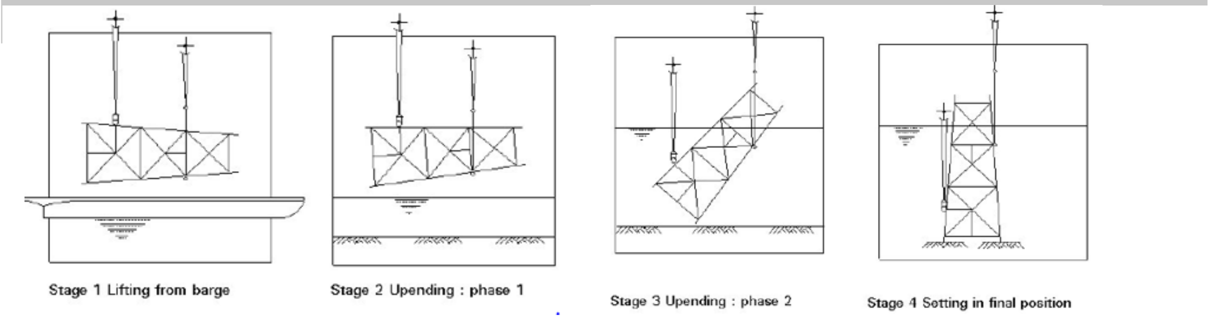
Cable and Pipeline Free Zone
A cable and pipeline free area around the platforms should be allocated to allow space for jack-up vessels to position themselves during installation or for major maintenance of items. Therefore, the area of seabed on one face of the jacket should be free of seabed obstructions.
Environmental design
There is limited data available for the site under consideration. In all cases, these parameters should be verified from site specific measurements before the detail design phase.
The following parameter have been assumed for the design / sizing purpose:
- Highest Astronomical Tide (HAT) = 2.0 m
- Water Depth relative to Lowest Astronomical Tide (LAT) = 30 m
- Maximum water current speed = 0.8 m/s (depth averaged)
- Average wind speed = 8 m/s
- Extreme Wind Speed = 25 m/s
- Extreme Wave height (Hmax) = 11.2 m
- Sand waves = 1m to 3.5m

Using this information, the underside of the platform is estimated to be 12.0 m (0.6*Hmax (7m) + tide (2m) + air gap (2m) + surge (1m)), with the top of grating of the cable deck to be circa 14.5 m LAT. This assessment should be reviewed once site data has been collected.

Foundation Design - Piles
The nature of seabed is assumed to be sandy surface with medium to dense sand to depth. Very long driven piles are not expected to be drivable to depth as with the likelihood of forming a soil plug increases with depth and increase in skin due to it is length increases the pile's resistance to driving. There are several choices to reduce the risk of pile refusal, such as seabed footprint size, number of piles per leg and the choice of hammer size. Relief drilling (i.e. removal of end bearing and internal skin friction), is an installation method available should the detail designer no be able to reduce the risk of pile refusal.
Given the likely sandy soil conditions, vibro-pile installation should be considered. This installs the pile to depth by vibrating the pile to effectively liquefy the soil next to the pile to allow it to penetrate under its own self weight.
The final installation method could affect the pile lengths and temporary stability conditions. However, the installation method is not expected to affect the results of this study due to the high-level assessment of this study. It can be concluded that piles are a suitable method to transfer the loads into the ground and can be installed by either method.

Jacket installation
After offshore transportation to site, installation comprises the series of activities required to place the structure in the final offshore location. These activities include jacket launch / lift and upending, positioning, pile installation, jacket levelling and grouting, together with support services for these activities.

Figure: jacket installation by lifting



Technical assessment
Platform

Topside Installation
Reviewing the installation of current large HVDC topside the following methods may be suitable, but have not considered in detail during this phase of the project: Floating (e.g. DolWin2 HVDC), Float Over (e.g. HelWin1 HVDC), Self-installing (e.g. BorWin2 HVDC). For this study, it has been assumed that a heavy lift with single lift or multiple lifts (topside comes as two components) or float over is the installation method to allow for sizing of a jacket support structure.
Floating crane vessels might be considered for the task of installing the offshore platforms. In either case, it is recommended that a comparative review be undertaken to identify units which would be suitable for the task.
During the detail design of the layout of the platform’s topside, the Centre of Gravity (CoG) relative to the physical centre is important for the installation by a heavy lift vessel. The closer the CoG is to the topside’s centre the more straightforward is the lifting and rigging design. The levelling of the topside once placed onto the jacket should also be considered to ensure that the topside is installed within tolerance for the electrical equipment and personnel. These details are normally defined during the design phase.

Figure: Float Over with a barge or semi-submersible

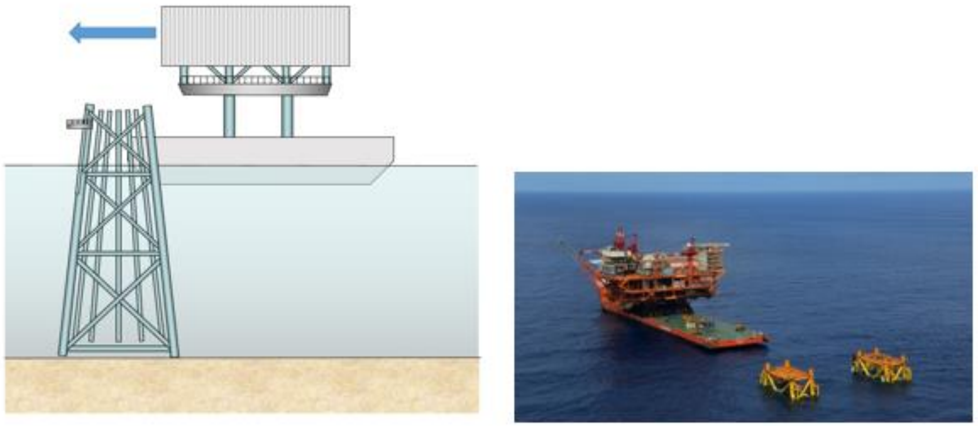


Photo source: https://www.dnvgl.com/news/dnv-gl-helps-cnooc-perform-first-dp-floatover-installation-in-china-6555

Figure: Floating Installation, transported by tug or on a semi-submersible

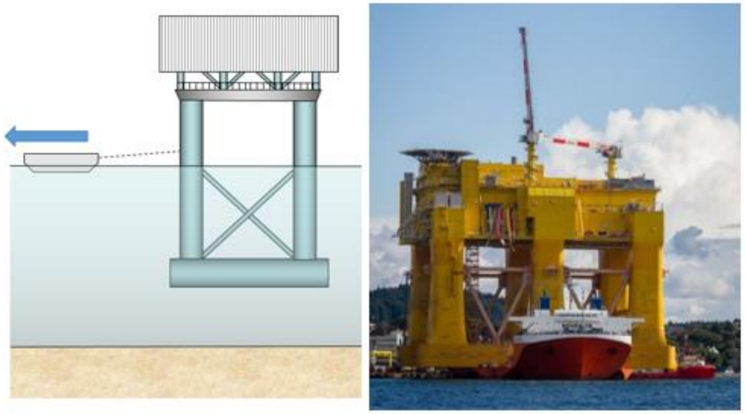


Photo by Sten Dueland from Haugesund and Stavanger, Norway - Dolwin Beta, CC BY-SA 2.0, https://commons.wikimedia.org/w/index.php?curid=34981564

Figure: Self installing (jack-up) towed to site or transported on a semi-submersible

Photo by kees torn - Hoek van Holland., CC BY-SA 2.0, https://commons.wikimedia.org/w/index.php?curid=33222893

Technical assessment
Platform

Examples of crane vessels characteristics (to be confirmed with vessel operators):

Vessel Name	Max Lift (tonnes)	Vessel Type,	Positioning system	Draft	Max current (m/s)	Max wave height (m)	Company Name
Sleipnir (new build, due 2019)	20,000	Semi-submersible heavy lift crane vessel	DP3	DP3. Working draft c.50m	Minimal on DP	3.0m Hs fully submerged	Heerema
Thialf	14,200	Semi-submersible heavy lift crane vessel	DP3 with anchors	DP3 with anchors. Draft 11.8-31.6m	Minimal on DP	3.0m Hs fully submerged	Heerema
Saipem 7000	14,000	Semi-submersible heavy lift crane vessel	DP3 with mooring	27.5m	Minimal on DP	3.0m Hs fully submerged	Saipem
Oleg Strashnov	5,000	Heavy lift crane vessel	DP3 with mooring	8.5-13.5m	1.5 knot on DP3 for installation 5 knots for DP1 station keeping	1.8m Hs	Seaway Heavy Lifting
Seven Borealis	5,000	Heavy lift crane vessel	DP3	8.5– 11.4m		2.0m Hs	Subsea 7
Asian Hercules III	5,000	Shear-leg crane barge	Mooring	Min.draft assumed c.5m (Based in Asia)		1.2m Hs	Asian Lift (Smit Singapore + Keppel Fels)
Gulliver (new build, due 2018)	4,000	Shear-leg crane barge	DP2 with mooring	4.9m		1.4m Hs	Scaldis (part of Jan de Nul Group)

The much larger lifting capacity available from some of the fleet of floating crane vessels should be able to lift the entire topsides as an integrated deck with considerable benefits in terms of speed of hook-up.
Potential vessels for the topside installation are summarized in the table above. High capacity shear leg crane floating crane vessels are also included, although unlikely to be suitable for the installation due to operation constraints.
These are typically dynamically positioning (DP) vessels of DP class 3, meaning the highest system redundancy which is required when the operation is high risk, and has the potential to cause loss of life, severe pollution or major economic consequences. It is considered that the lifting of a topside for these projects would require a DP3 system.

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Economic Assessment

Market study Hydrogen

Latest available figures estimate current demand for hydrogen around 10 bcm per annum virtually all produced onsite for industrial purposes, mainly methanol and ammonia production, and used for cracking processes in refineries. In addition, hydrogen becomes available as a by-product. More limitedly, hydrogen is produced to be subsequently sold to other companies. Two separate hydrogen networks in the Port of Rotterdam and surrounding areas transport such hydrogen to various companies.

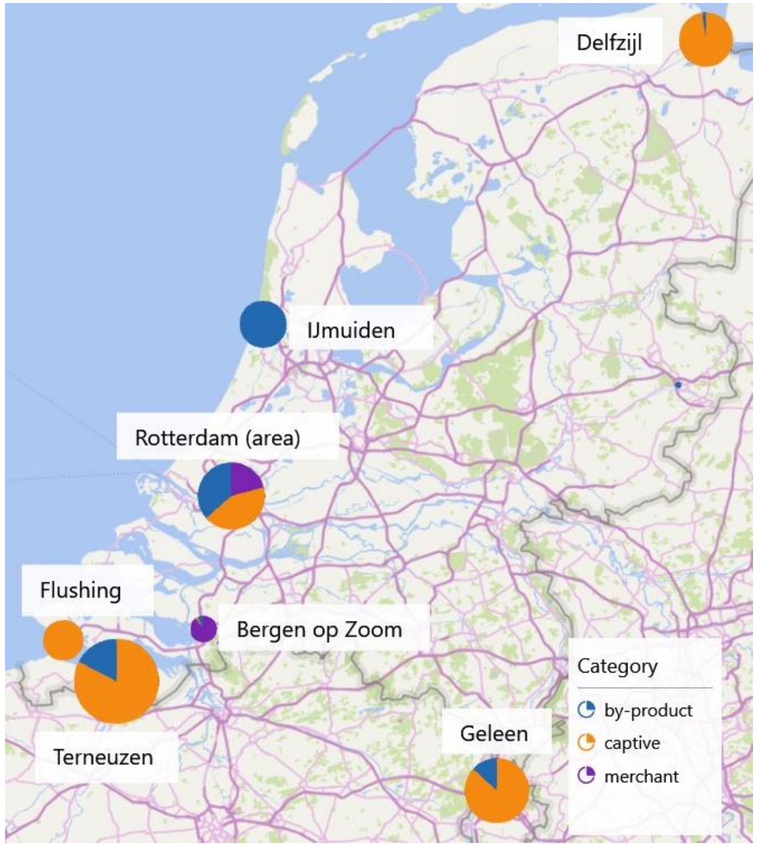
Current hydrogen demand
The Roads2Hy.com study took stock of the existing hydrogen production capacity in Europe. According to this study, around 10 billion cubic meters of hydrogen is produced annually in the Netherlands, making it the second largest producer of hydrogen in Europe only to be surpassed by Germany. In 2007, total European hydrogen production stood at 90 billion cubic meters, most of which finds its way to refineries (~50%) and ammonia producers (32%).

Locations of hydrogen demand in the Netherlands are shown in the figure on the right. The figure distinguishes three different categories of hydrogen production sources. Firstly, captive sources entail processes which use hydrogen as feedstock. These processes are found in ammonia producers (in the provinces of Limburg and Zeeland), at refineries in Rotterdam and Flushing, and a methanol factory in Delfzijl. Together, these factories represent around 68% of the total hydrogen production capacity in the Netherlands; which is thus highly concentrated at only several locations.

Secondly, hydrogen is produced as a by-product in steel production such as the TATA factory located in IJmuiden. Finally, a third category entails the so-called merchants. Merchants are hydrogen producers supplying hydrogen to other industries. Virtually all presently existing hydrogen production is based on fossil fuels. Usually, natural gas is used and converted into hydrogen using steam methane reforming.

In the Rotterdam/Zeeland area several producers and users of hydrogen are connected to each other by a hydrogen network. Air Liquide operates the largest hydrogen network in Europe covering around 1 000 km. It stretches from Northern France, to Belgium and the Rotterdam/Zeeland area. The network has pipelines with a diameter of 154 mm and an operating pressure of around 100 barg. In addition, Air Products owns a pipeline network of approximately 140 km in the Rotterdam area.

Overview of existing hydrogen production in the Netherlands



Region	Volume [bcm/year]
Delfzijl	1.3
IJmuiden	1.0
Rotterdam	2.0
Zeeland	4.2
Geleen	1.8
Total (rounded)	**10.2**

Economic Assessment

Market study Hydrogen

ECN assessed the maximum potential hydrogen demand in the Netherlands to be 710 PJ or around six times current demand. The assessment indicates a large, technical, potential for the uptake of hydrogen in various sectors, but lacks a clear timeline or analysis of financial viability for the aforementioned demand to arise. As such, the figures are very indicative.

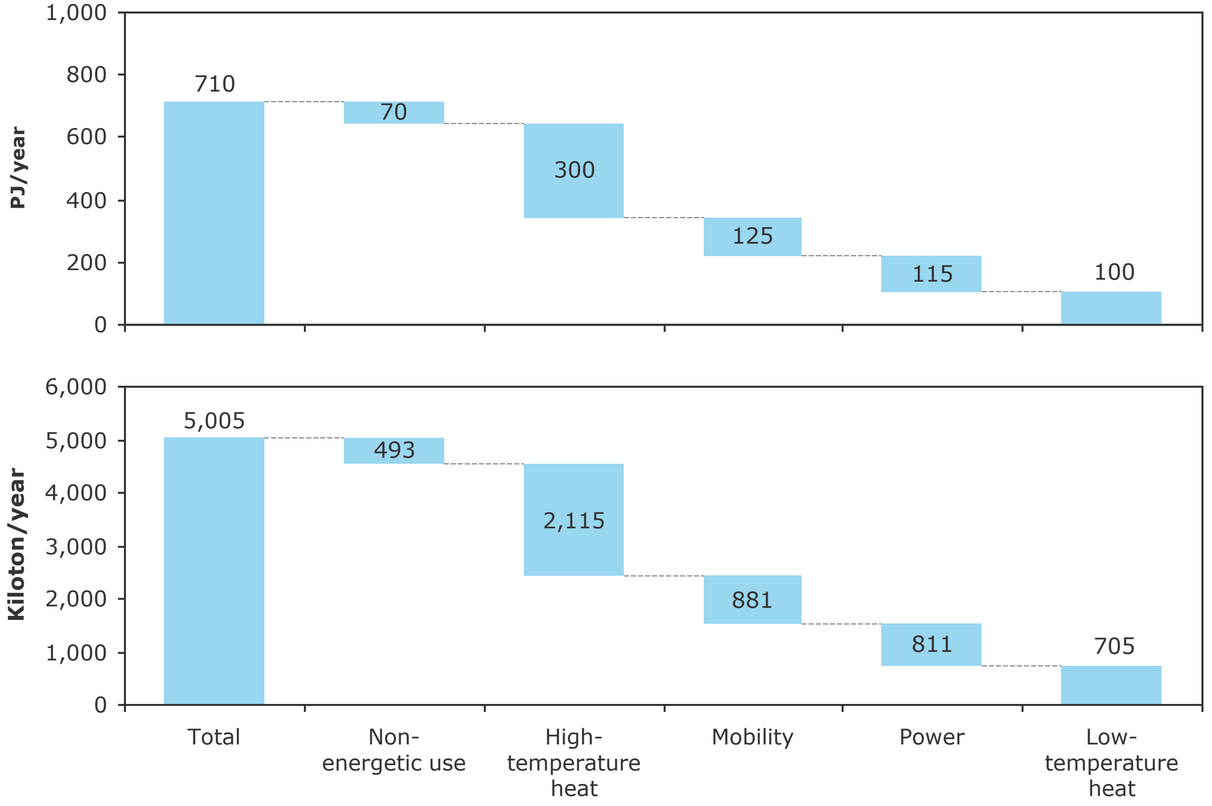
ECN – Maximum potential hydrogen demand
ECN calculated an indicative maximum potential demand for hydrogen in the Netherlands. This estimation departs from the current non-energetic demand for hydrogen and its development, and is supplemented by a very indicative estimate for various energetic applications/sectors in the Netherlands. The estimations lack a timeline for its implementation as it only concerns a maximum potential for which limited constraints are taking into account. For instance, the origin of hydrogen has not been considered. Nevertheless, the estimation results in a maximum potential of 710 PJ or approximately 66 billion cubic meters. This is more than six times current hydrogen demand in the Netherlands.

The estimation builds on the following assumptions:

- Present non-energetic use: Hydrogen used as a feedstock for the industry will see a small decline mainly due to a decline in refinery processes.
- High-temperature heating: high-temperature heating (>250°C) can switch from natural gas to hydrogen. Low-temperature will be electrified.
- Mobility/transport: The existing demand for diesel will be replaced by hydrogen. Gasoline cars will be replaced by battery electric vehicles (BEVs) instead for fuel cell electric vehicles (FCEVs).
- Power: hydrogen is expected to be used in flexible/fast-ramping gas-fired power plants and CHPs in order to support variable renewable electricity generation.
- Low-temperature heating: It is assumed that mostly heat-pumps will be used for heating the built environment. Demand for hydrogen is estimated at an equivalent of 2 million households.

The presented figures are very indicative. With respect to mobility and low-temperature heating, the general consensus seems to be that these sectors will be mostly all-electric. This may reduce the hydrogen demand compared to the above estimations. In contrast, non-energetic use may increase as a result of a new bio-based chemical industry and low-carbon steel production.

Maximum potential hydrogen demand in the Netherlands



Source: ECN, "Notitie: Indicatieve potentiële vraag naar waterstof," 2017.

Economic Assessment

Market study Hydrogen

The Northern InnovationBoard presented a plan to initiate a hydrogen economy in the northern regions of the Netherlands. Dutch demand for hydrogen in 2030 is estimated to be 250 PJ per annum with industrial demand representing the largest share (~70%) followed by mobility.

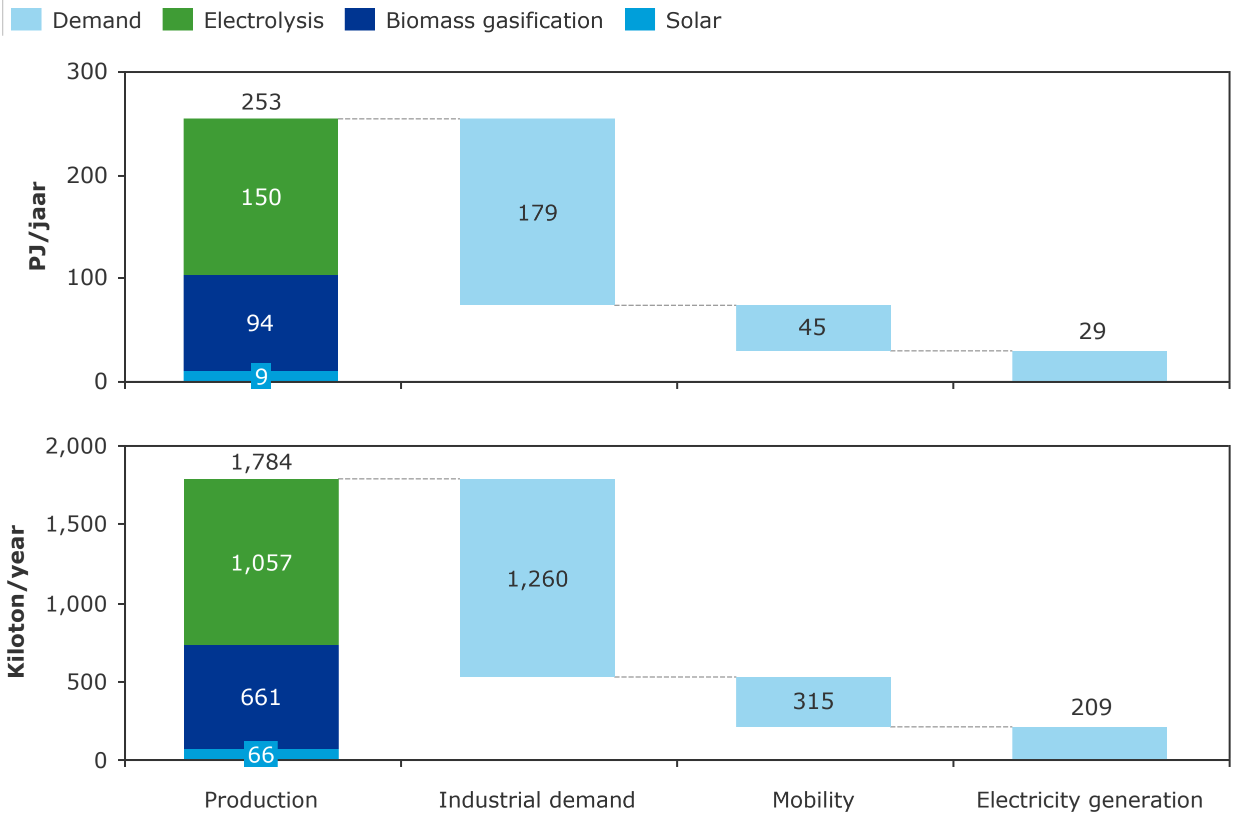
Northern InnovationBoard – Plan Van Wijk

The Northern Innovation Board (NIB) commissioned Professor Ad van Wijk to develop a green hydrogen vision for the Northern Netherlands. This vision was published in April 2017 and presents a vision for a green hydrogen economy for the North of the Netherlands. According to the NIB, the Northern Netherlands are uniquely positioned to develop a green hydrogen economy. The primary factors are the presence of large-scale renewable electricity production by means of offshore wind generation, chemical clusters, and import capacity for electricity and natural gas.

The vision foresees the development of large-scale hydrogen production which will be utilized locally, but also exported to other parts of the Netherlands. According to the NIB, the Northern Netherlands will produce around 32 PJ annually of which 12 PJ will be transported to other parts of the country. Most suitable candidates for receiving this green hydrogen are expected to be the industrial users in the Rotterdam area and in Geleen or the Ruhr-area. Natural gas or grey hydrogen currently consumed will be replaced.

The NIB estimates that the total Dutch hydrogen demand in 2030 will be around 250 PJ/yr, which would indicate a doubling of current demand. While the NIB only provides volumes for the Northern Netherlands, these values were scaled for the Netherlands as a whole prorated across each demand sector. The results are shown in the figure on the right.

Estimation of hydrogen production and demand in Northern Netherlands



Source: NIB

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Economic Assessment
Market study Hydrogen

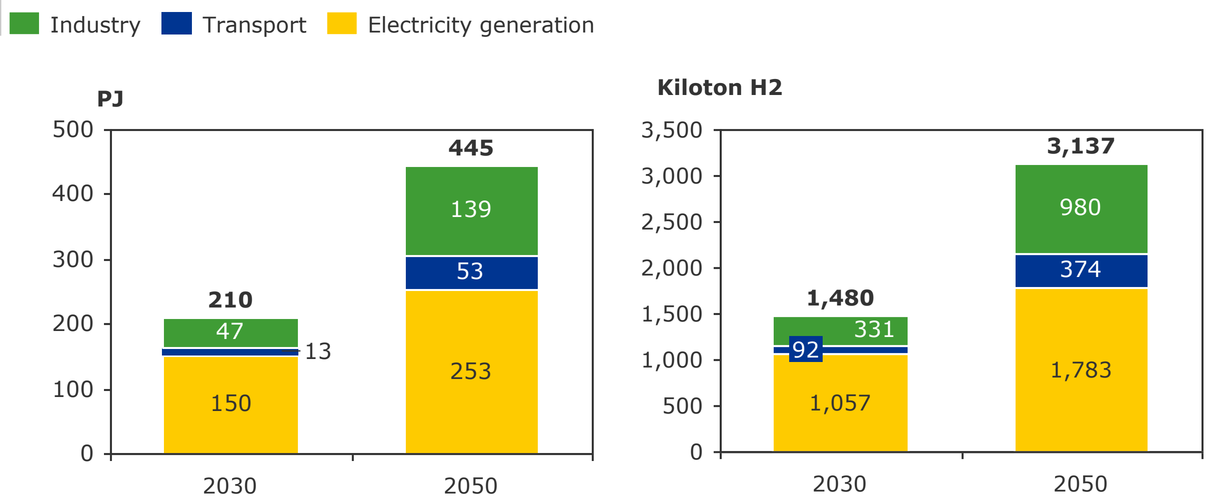
Gasunie presented their vision for a CO_2-neutral energy supply towards 2050 and sees a large role for hydrogen in both 2030 and 2050. In contrast to the NIB, Gasunie expects most demand for electricity generation (~71%) and to a lesser extent industrial demand and hydrogen for mobility.

Gasunie – Survey 2050 (Edition 2018)
The Survey 2050 (Edition 2018) presents Gasunie's vision for an affordable and reliable CO_2-neutral energy supply in 2050. Although its primary focus is on 2050, the study sets apart a vision for the energy system in 2030 as well. In both years, hydrogen is expected to play a role in selected sectors and applications.

Gasunie expects hydrogen to be part of the energy supply to industrial users (47 resp. 139 PJ) as well as the transport sector (13 resp. 53 PJ) in 2030 and 2050. In other sectors, such as the built environment or the agricultural sector, hydrogen is not foreseen to be utilized. Furthermore, electricity generation is expected to occur using hydrogen (150 resp. 253 PJ). Electricity plants consuming hydrogen will mainly be used for back-up purposes to guarantee security of electricity supply. Gasunie expects these plants to run for about 1 month net per year. This likely requires storage of hydrogen.

The results of the Survey 2050 (Edition 2018) study are shown in the chart on the right.

Hydrogen demand from Gasunie's Survey 2050 (Edition 2018)



Economic Assessment

Market study Hydrogen

A limited number of studies currently quantitatively assess the potential role for hydrogen in the future of the Dutch energy supply. Nevertheless, three studies are publicly available which all paint a different picture regarding the demand for and sectors using hydrogen.

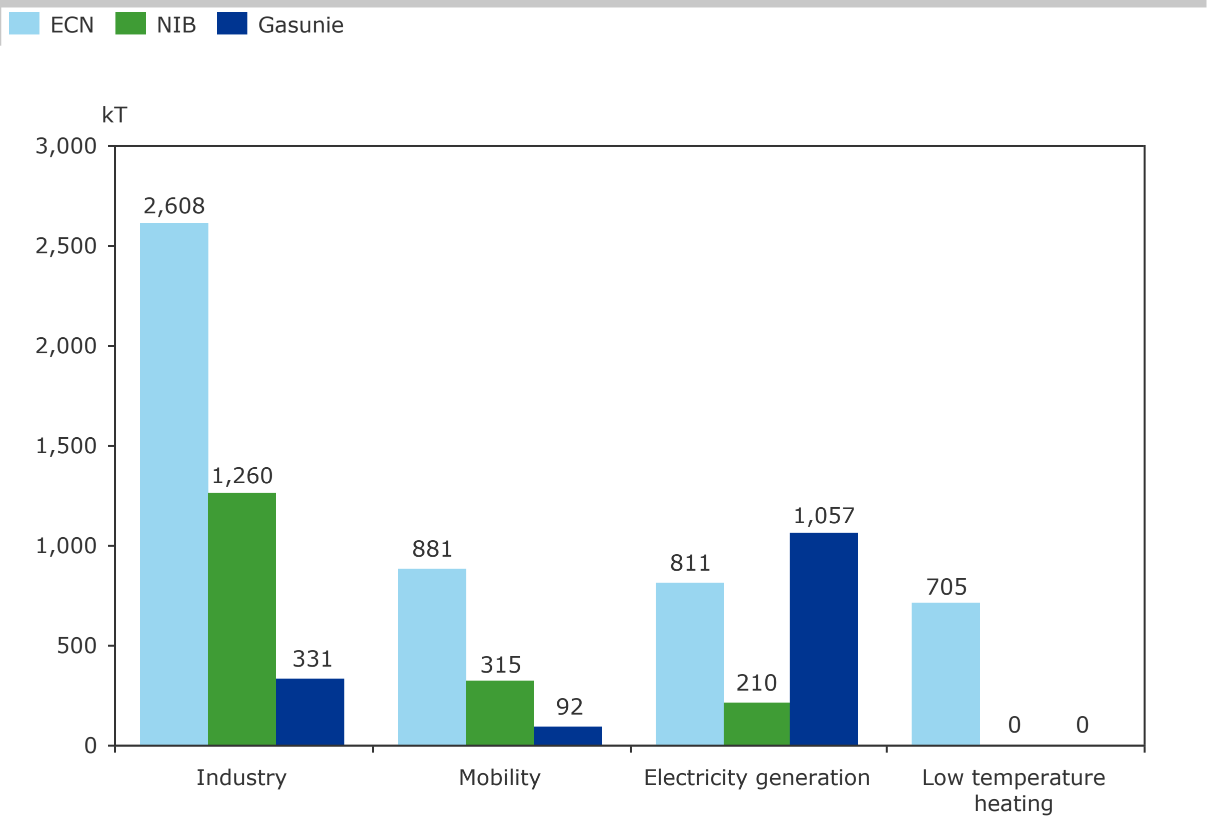
Comparison of market demand studies
Whilst limited studies are available projecting future hydrogen demand in the Netherlands, the three studies above have been compared on their outcomes. ECN's maximum potential study clearly shows highest demand of the three studies.

The NIB study projects a total demand in the Netherlands of 1,784 kilotons divided across three different sectors. The industrial sector is expected to be the major consumer of hydrogen with an annual demand of 1,260 kilotons.

Finally, Gasunie estimates demand for hydrogen 1,480 kilotons in the Netherlands in 2030. While overall hydrogen demand is within the same range as estimated by the NIB, industrial demand for hydrogen is much smaller as compared to the estimations of ECN and NIB. In contrast, Gasunie expects most hydrogen to be used in the electricity generation sector for back-up purposes where, especially the NIB, expects much less use of hydrogen.

As ACM only expects hydrogen to become a part of the Dutch energy system in 2035 and beyond, those numbers are not included.

Comparison of Dutch hydrogen projections for 2030



Economic Assessment
Hydrogen prices

Hydrogen is presently mostly derived from natural gas using a process called steam methane reforming, in which natural gas (methane) reacts with steam under high temperature and moderate pressures to form hydrogen and carbon monoxide. In a subsequent step, carbon monoxide reacts with steam to produce more hydrogen and carbon dioxide. As such, the production of hydrogen is currently usually associated with carbon emissions.

Hydrogen produced by the SMR process is currently the lowest cost solution for large scale (industrial) applications. Costs are mainly determined by the price of natural gas, which accounts for the majority hydrogen's costs. In a future where carbon emissions should be minimized, the production of hydrogen using SMR and natural gas ('grey hydrogen') might not be a viable option. Therefore, other ways to produce hydrogen need to be considered. Several options to produce 'green' hydrogen using SMR are identified:

1. Using green gas instead of natural gas
2. Install carbon capture and storage in combination with natural gas ('blue hydrogen')
3. Buy emission allowances

Producing hydrogen using green gas is the most expensive option, but arguably the only true green option as well. A key component of hydrogen's cost price under this options, is the price of green gas, which was assumed to be sold at a premium of EUR/MWh_{2017} compared to natural gas. As this is an important aspect, the green dotted line shows the sensitivity of hydrogen's cost price for green gas at a premium of EUR/MWh_{2017}.

Furthermore, the availability of green gas to produce hydrogen is important. It might well be the case that green gas is used directly for energy purposes instead of converting it to hydrogen first. Therefore, electrolysis may not just compete with other forms of hydrogen production, but with other energy carriers as well. These carriers may be different for each sector and thus the value of hydrogen may differ per sector. In this respect, the mobility sector seems most promising where prices between to EUR/kgH_2 can be obtained. Injection in the natural gas grid seems less promising where the maximum price for hydrogen is likely less than EUR/kgH_2 based on energy content.

DNV·GL

Economic Assessment

Hydrogen prices

For the calculation of hydrogen cost prices, various assumptions were made regarding the CAPEX, OPEXand technical characteristics of the SMR plant and CCS components. In addition, energy and carbon prices from DNV GL's Energy Transition Outlook were included as well.

Cost assumptions for SMR
For each of these options, the cost price for 2028 to 2047 was assessed and the results are shown in the chart on the right. The following parameters were used (cf. Tractebel, 2017):

CAPEX	Value
Efficiency	70%
Operating hours	8,600 hours/year
Start-up expense	2.0%
Capex	300 EUR/tH_2 (2017)
Depreciation	20 years
Loan repayment	20 years
Fraction equity	50%
Return on equity	15%
Loan interest rate	8%
Corporate tax rate	25%

OPEX	Value
Labour	0.9 FTE/t/h
Labour costs	60,000 EUR/FTE/yr
Maintenance	4.3% of CAPEX
Maintenance (annual)	13.2 EUR/yr/tH_2
Insurance	2.0% of CAPEX
Insurance (annual)	6.1 EUR/yr/tH_2
Power	0.4 MWh/tH_2
Process water	14000 Liter/tH_2
Cooling water	20000 Liter/tH_2
Emissions	8.9kg CO2e/kg H_2

CCS
In addition, the unit costs for carbon capture, transport and storage were calculated based on the costs provided in Jakobsen and Åtland (2016).

Installation	Value	
Carbon capture facility	146	Million EUR
Carbon transport and injection	219	Million EUR
Drilling and injection well	110	Million EUR
Total Capex	**475 Million EUR**	

Using these numbers, CCTS adds 0.57 EUR/kgH_2 to hydrogen's cost price. Naturally, specific CCTS costs and possibilities may be different from the ones used in Jakobsen and Åtland (2016), either increasing or decreasing hydrogen's cost price.

Source: Jakobsen, D. and V. Åtland, "Concepts for Large Scale Hydrogen Production", June 2016, Tractebel, Hinicio, "Study on early business cases for H2 in energy storage and more broadly power to H2 applications", June 2017

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Results

Base cases

The NPV of the base-cases is negative, as the remuneration through the network tariffs are not included, and ranges from ~-3.5 to ~-7.6 billion Euro, depending on the capacity and whether an island or platforms are used. The consideration of an island, opposed to a platform, to facilitate all the required equipment shows better results and is therefore used to compare with most other cases. The results of the 84 different cases are divided into sub-groups (Onshore P2H_2, Offshore P2H_2, Full P2H_2 and Main cases). Due to a minor difference in NPV between the cases with connection to or production on IJmuiden or Maasvlakte for P2H_2, further analysis of the results is only considering the Maasvlakte cases as this location seems more relevant.

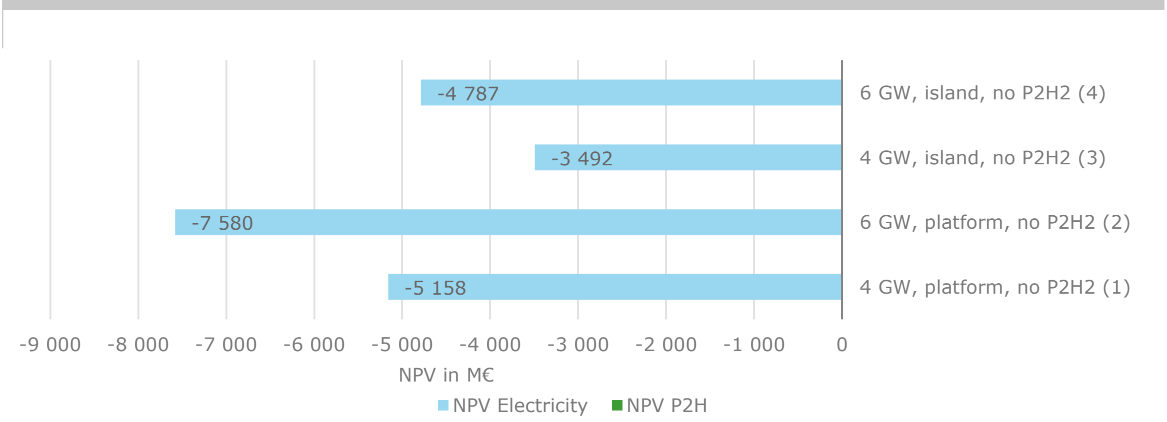
Results of the base cases

All different cases are compared to a number of base-cases in which only an electric connection from IJmuiden Ver to the shore and no P2H_2 is included. The NPV after 24 years can be seen in the bar chart below and includes all the CAPEX, OPEX (including electricity losses) and takes into account the remaining value of all assets. The figure clearly shows a negative outcome for all the base-cases. This is because the investments can be retrieved through the network tariffs, but in this study these tariffs are not taken into account.

It can be seen that the total NPV is better for the cases with an island, rather than a platform. In addition, an island has other advantages over a platform (like options for maintenance, space for other facilities). Accordingly, most cases are only compared to the base-cases with an island.

An overview of all the results is given in an enclosed Excel document.

NPV of the base cases



Comparison and grouping of the results

Results have been produced for all 84 different cases. To give a clear overview and to make relevant comparisons, the results have been divided into a number of sub-groups.

1. **Main cases**, containing the most characteristic cases.
2. **Onshore P2H_2**, containing all the relevant cases in which the H_2 is produced onshore;
3. **Offshore P2H_2**, containing all the relevant cases in which the H_2 is produced offshore;
4. **Full P2H_2**, containing the relevant cases in which all energy is converted to H_2;

A first filtering of the results can be done by comparing the cases in which H_2 is transported to or produced at either IJmuiden or Maasvlakte. The difference in location mainly affects the trajectory of the pipelines and does not have an effect on any other inputs. The table below shows the difference in NPV after 24 years for the smallest and largest capacities.

NPV in M€	Maasvlakte	IJmuiden	Difference
4 GW, island, offshore P2H2 400 MW peak + €-based, new pipeline, PEM (45/46)	-4181	-4151	0.68%
4 GW, island, offshore P2H2 2000 MW peak + €-based, new pipeline, PEM (49/50)	-4727	-4665	1.29%
4 GW, island, offshore full P2H2 new pipeline, PEM (73/74)	-8557	-8483	0.86%

It can be seen that the difference between the cases is almost negligible since the pipelines only account for a small part of the investment. Looking only at the investment for pipelines a difference of 30-40% can be found between the two locations, which corresponds to the difference in transport distance (75km to IJmuiden and 110km to Maasvlakte).

Although the distance to IJmuiden is smaller and results in a better business case, the cases for the Maasvlakte are further considered for result comparison. From the economic assessment it could be seen that the H_2 production/demand is the largest at the Maasvlakte, compared to IJmuiden. It is therefore more realistic to consider Maasvlakte for the offset of large H_2 volumes. Furthermore, in the case of onshore H_2 production, the load on the electricity network might affect this system. At the Maasvlakte the BitNed cable is connected which might be convenient when connecting a large (fluctuating) load at this location. No analysis has been done on this and is not within the scope of this work.

Results

Main cases

Overall, the addition of $P2H_2$ does not have a positive influence on the total NPV. For the hydrogen system, only for the smaller onshore $P2H_2$ capacities there is a positive business case due to the utilization of cheap electricity when market prices are low. The addition of more $P2H_2$ capacity does not lead to an overall better NPV, though it can reduce the NPV of the electrical system as more nearby (in case of onshore $P2H_2$) or less connections (in case of offshore $P2H_2$) are required. For higher $P2H_2$ capacities, offshore $P2H_2$ is better than onshore $P2H_2$, while the full $P2H_2$ case has the most negative NPV.

This section is considering the most characteristic cases, i.e. an island is assumed and for both onshore and offshore $P2H_2$ different capacities of $P2H_2$ are presented. It is observed that the onshore 500 MW $P2H_2$ case has the most optimal NPV since the $P2H_2$ part is actually positive. The optimized use of low prices on the electricity market plays a significant role in this result. A further explanation is given in the Results – Onshore $P2H_2$ section. The addition of 500 MW $P2H_2$ does however not influence the NPV of the electric part.

The addition of 2,000 MW onshore $P2H_2$ has a negative impact on the results since it does not optimally utilize the advantage of low electricity prices as it is operating only at peak+price-based. It also has a small influence on the NPV of the electrical part as less cable distance is required. One of the 2 GW export cables is now connected to 110 km instead of more land inwards (185 km).

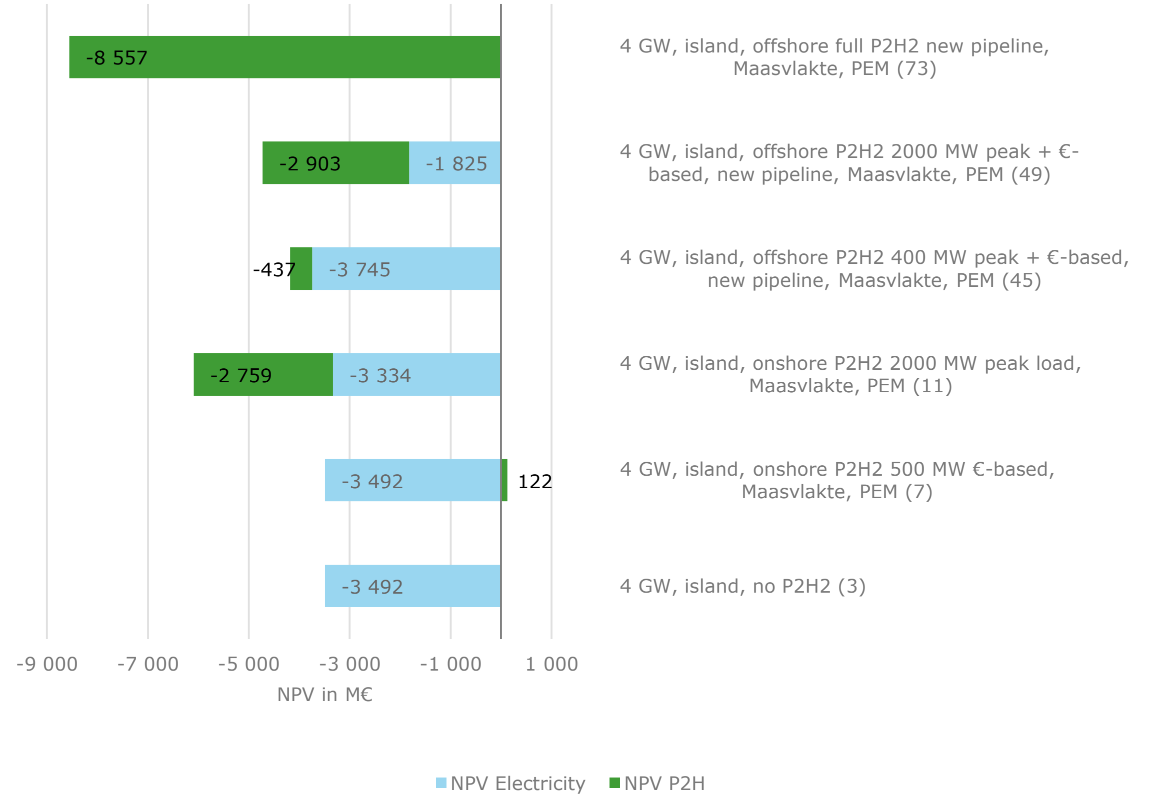
The addition of offshore $P2H_2$ results in a better NPV compared to onshore $P2H_2$ for higher capacities. The $P2H_2$ part will become more expensive since additional pipelines and the island should be realized, but there is a strong reduction on the electrical part as a lower transport capacity needs to be built. For the lower $P2H_2$ capacities this is not the cases since a different configuration of the export cables increases the costs for the electrical part. When choosing the same price-based operation mode of the $P2H_2$, the offshore cases show a better influence on the NPV since a cost reduction on the electrical transport system is possible. The price based operation mode, in which a positive NPV would be achieved for $P2H_2$, is however not possible as the starting point is that all generated electricity should be utilized and brought onshore.

The full $P2H_2$ case shows the worst NPV as investments are high and no flexibility in use of cheap electricity is possible. This option is further discussed in the Full H_2 section on later slides.

The figures on the next sheets show a breakdown of investments, costs and revenues and show an overview of H_2 production and electricity consumption.

The case description on the right graph indicates the wind farm rated capacity, the facility on which the converters and the P2H are built, onshore or offshore $P2H_2$ and its capacity, the pipeline, the operating mode, the connection point of the H2 pipeline, the electrolysis technology, and finally the case number.

NPV of the main cases

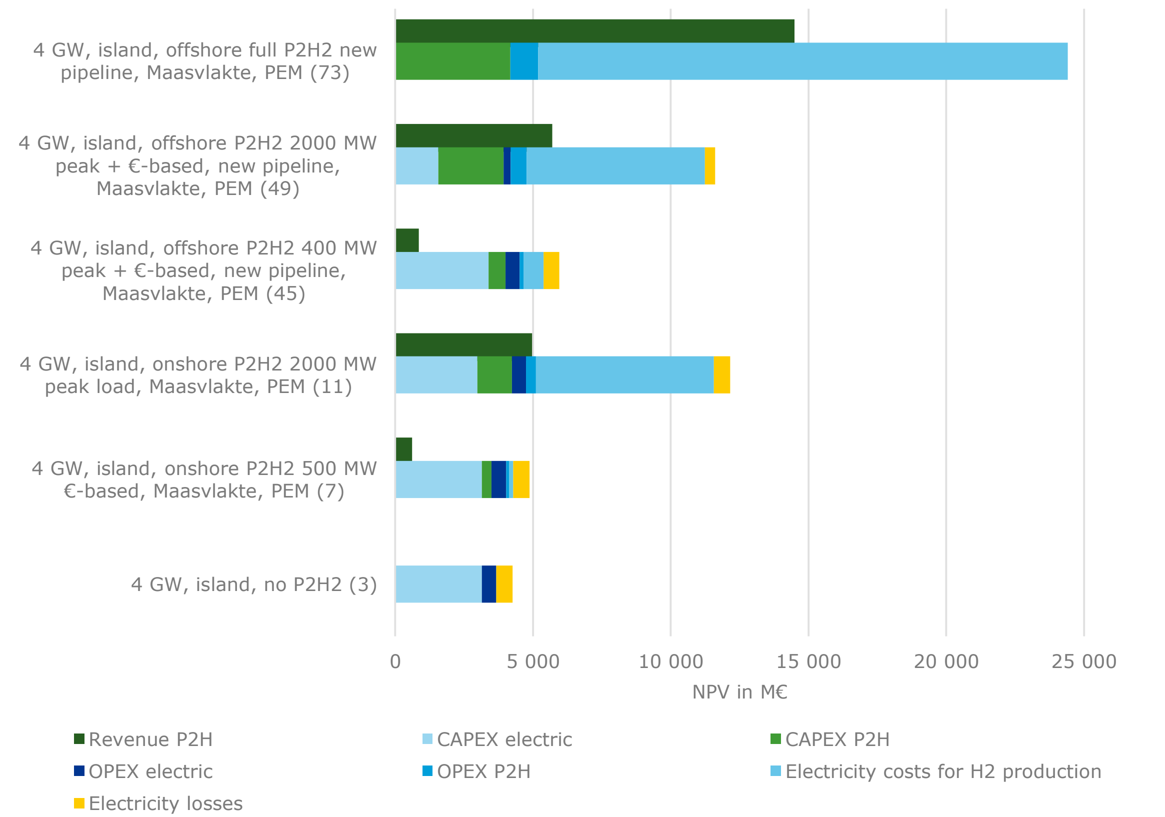


Results

Main cases

This slide shows the results of the main cases. Two figures are given with a breakdown of investments and a breakdown of costs and revenues.
It can be observed that the zero $P2H_2$ case has the lowest investment costs, while the onshore 2,000MW $P2H_2$ the highest.
Furthermore, the offshore 4 GW $P2H_2$ shows the highest revenues, but also the highest costs.

Breakdown of the costs and revenues of the main cases



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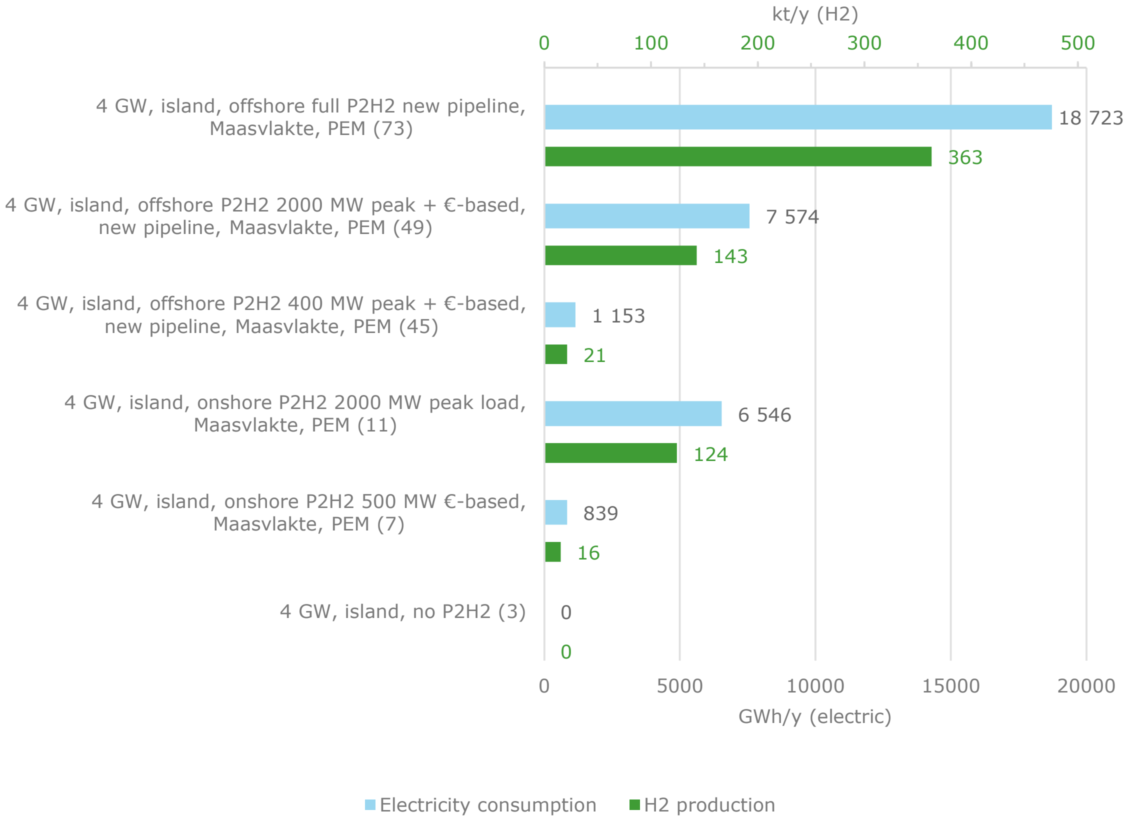
Results
Main cases

This slide shows the results of the main cases. The figure shows the energy production and consumption. The two energy flows are plotted on two different axes which are scaled in such a way that they are comparable. As the P2H_2 facility becomes larger, more electricity is consumed and more hydrogen is produced.

P2H_2 energy production and consumption of the main cases



Results

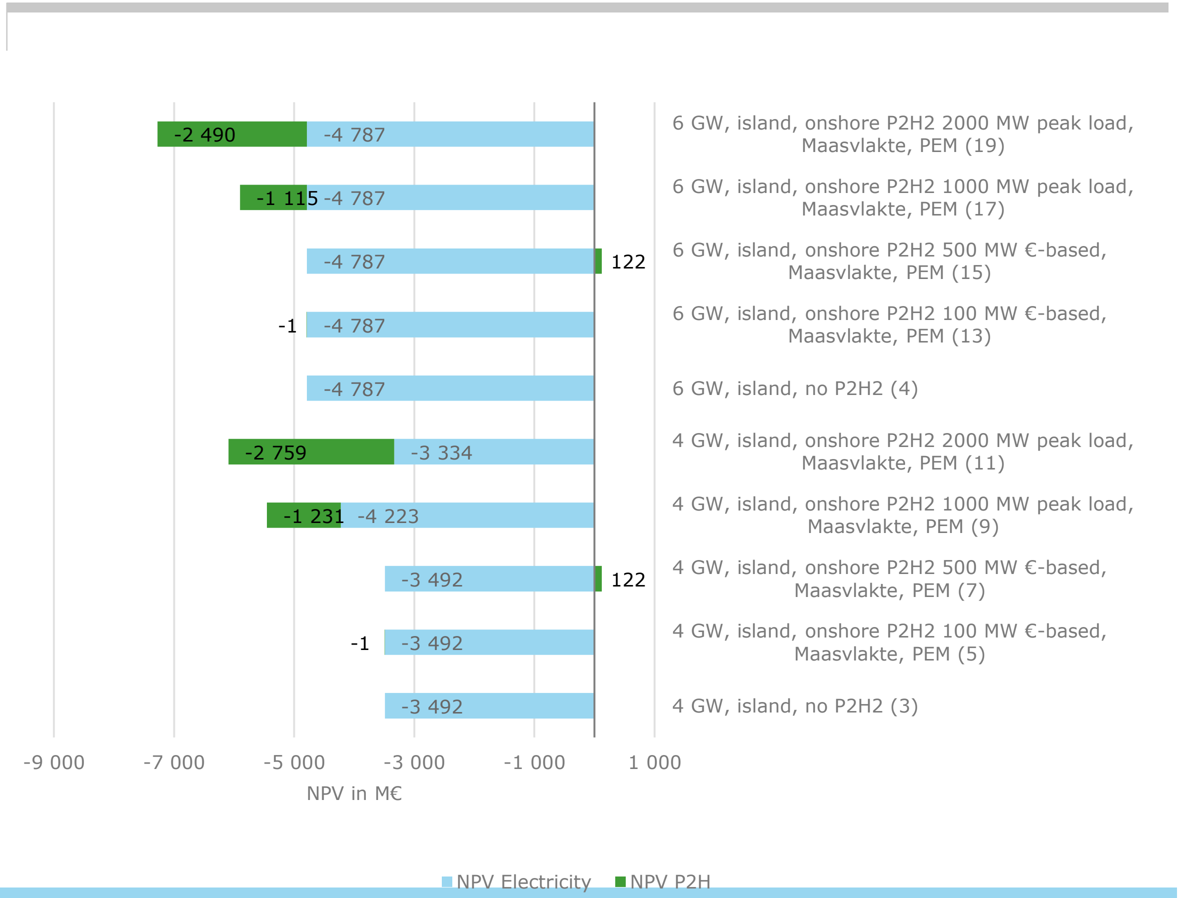
Onshore $P2H_2$

A better NPV is found for the smaller $P2H_2$ capacities. This can be explained due to the operation mode where H_2 is produced for cheap electricity prices. In the cases where this price advantage is not used, the electricity costs for H_2 production are one of the biggest cost drivers. In terms of investment, the CAPEX for the electrolyser is dominant for the $P2H_2$ system.
The addition of 2GW $P2H_2$ reduces the NPV of the electric system in case of 4GW wind.

The onshore $P2H_2$ cases consider various capacities and operation modes of the $P2H_2$ system for the cases in which the $P2H_2$ is located onshore on the Maasvlakte. The 100 and 500 MW $P2H_2$ cases are only in operation (€-based mode) when the electricity price is below the threshold of 26 €/MWh. Although the electricity prices are below this threshold for only a short period per year, the electricity is so cheap that H_2 production is most optimal. Especially when the prices fluctuate more, which is expected in the future, the amount of time in which H_2 can be produced increases (full-load hours: 311h in 2030, 771h in 2035 and 1411h in 2040). Especially in the future years a positive cashflow can be found, covering the cost of the $P2H_2$ system and electricity use. The 500 MW onshore case therefore even results in a positive NPV for the $P2H_2$ part only. It is important to note that the remaining value of the assets is included. Excluding this will result in a negative NPV.

The 1,000 and 2,000 MW $P2H_2$ systems are operated in peak+€ mode and do not optimally utilize the advantage of low electricity prices, resulting in a negative NPV. There is a small difference between the ones with the 6 and 4 GW wind farm. This can be explained due to the operation hours and electricity price paid during $P2H_2$ operation. In the 4 GW case, the amount of operation hours is slightly higher since the $P2H_2$ capacity takes up a larger part of the wind farm capacity where electricity prices are usually found to be higher. The 4 GW wind farm cases therefore have slightly higher costs for electricity, used to produce H_2. This can also be seen in the figures on the next page.

NPV of the onshore $P2H_2$ cases

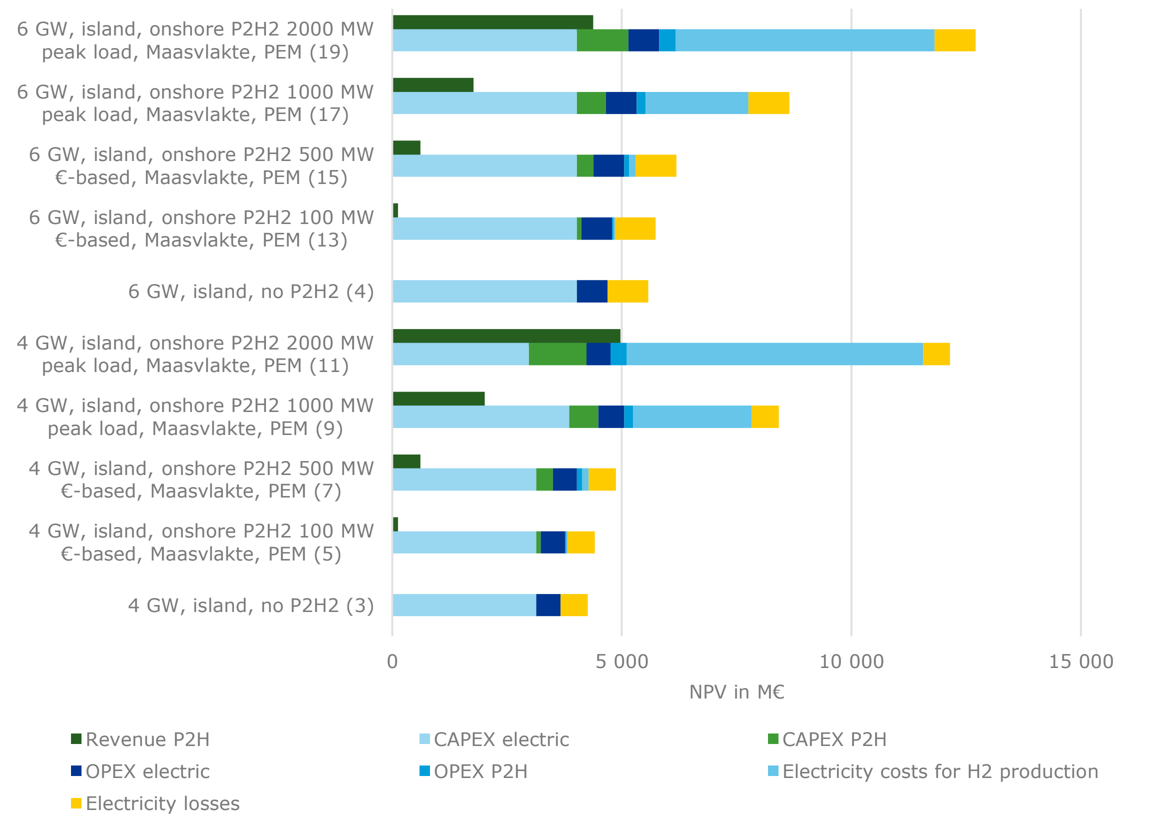


Results

Onshore $P2H_2$

The left bar chart shows a breakdown of the investments, where it can be observed that the largest part of the investment are for the electrical transport system. For the $P2H_2$ system the investment for the electrolyser is dominating. On the right chart a breakdown of all the costs and revenues for the onshore $P2H_2$ cases is depicted. Besides the large CAPEX for the electric transport system, significant costs come from the electricity consumption for $P2H_2$ in the 1000 and 2000 MW $P2H_2$ cases.

Breakdown of the costs and revenues of the onshore $P2H_2$ cases



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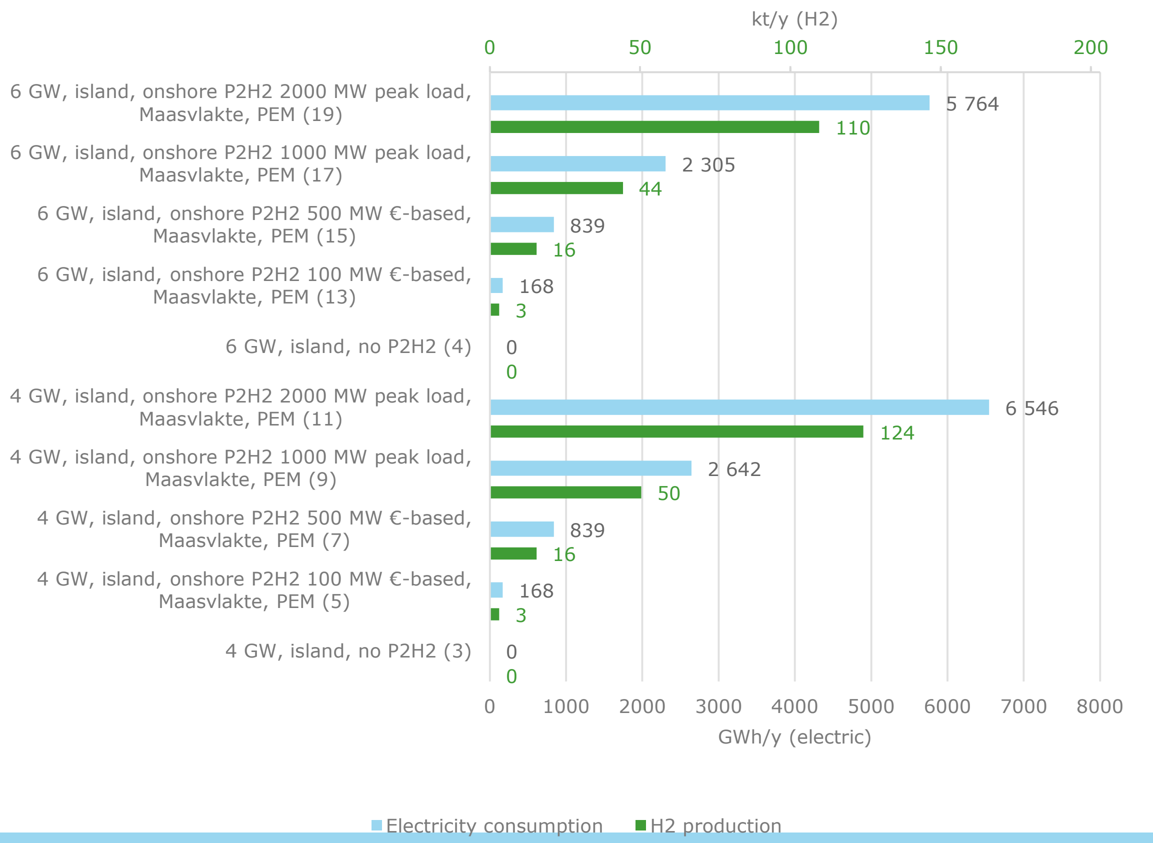
Results
Onshore P2H_2

This slide shows the results of the onshore P2H_2 cases. The figure shows the energy production and consumption. The two energy flows are plotted on two different axes which are scaled in such a way that they are comparable and interchangeable.

P2H_2 energy production and consumption of the onshore P2H_2 cases



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Results

Offshore P2H$_2$

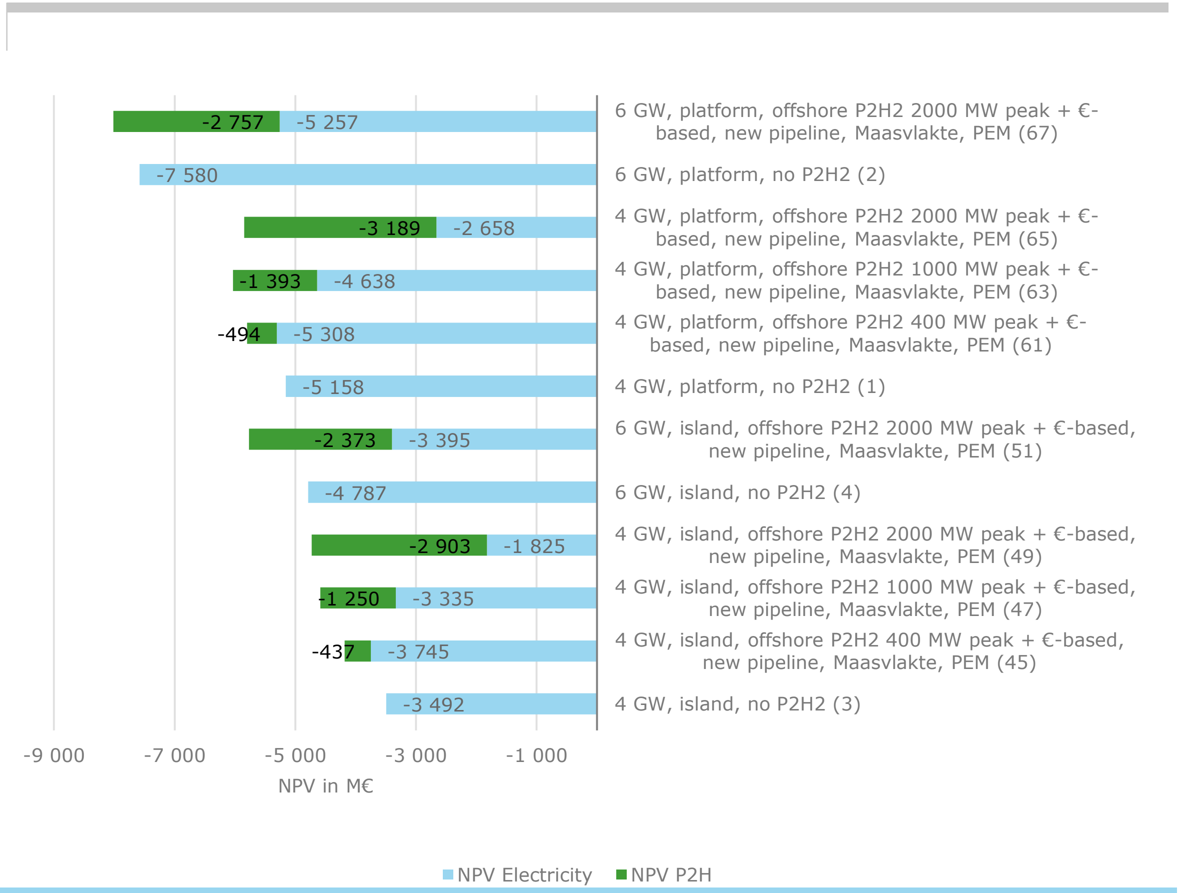
The offshore P2H$_2$ cases are operating in peak+€ mode which is more convenient for the smaller P2H$_2$ capacities. This is due to lower electricity prices which are usually found at higher peak loads. The addition of P2H$_2$ in the 4GW and 6GW wind case does not improve the total NPV compared to the base-case.

The offshore cases differ in terms of capacity and whether an island or a platform is used. For all these cases the operation mode is set to peak+€ based. All the cases result in a negative NPV where the smaller P2H$_2$ capacities (400 MW P2H$_2$) are less negative. This could be expected since the investments for smaller capacities is less, but for the 400 MW P2H$_2$ cases it should be expected that the NPV would be about half of the 1000 MW P2H$_2$. This is not the case. A similar explanation can be given as for the onshore cases. The smaller P2H units are operating in a smaller part of the peak load, where electricity prices are usually found to be lower. When operating in peak load, a smaller P2H$_2$ capacity might therefore be better. The only advantage a larger capacity P2H$_2$ unit would have is a scaling advantage where CAPEX can be reduced for higher capacities. Further analysis will result in an optimum P2H$_2$ capacity. This again also explains why the 2000 MW P2H$_2$ in the 6GW wind farm is less negative as compared to the 4GW wind case.

For some cases it is seen that the addition of P2H$_2$ also makes the NPV of the electric part more negative. This is explained on the next page.

Comparing the cases which are built on an island to the ones built on a platform, it can again be seen that the island has the advantage. This was already described for the base-cases.

NPV of the offshore P2H$_2$ cases



Results

Offshore $P2H_2$

The NPV for the electric part is more negative some cases compared to the base-case because of another cable configuration when adding some $P2H_2$ capacity. Optimization of the cables should allow for a better (less negative NPV) comparison.
Although the investment for the platforms is lower than the island (for the $P2H_2$ part), the NPV for the platform cases is more negative as the island is not subject to depreciation and a lower OPEX.

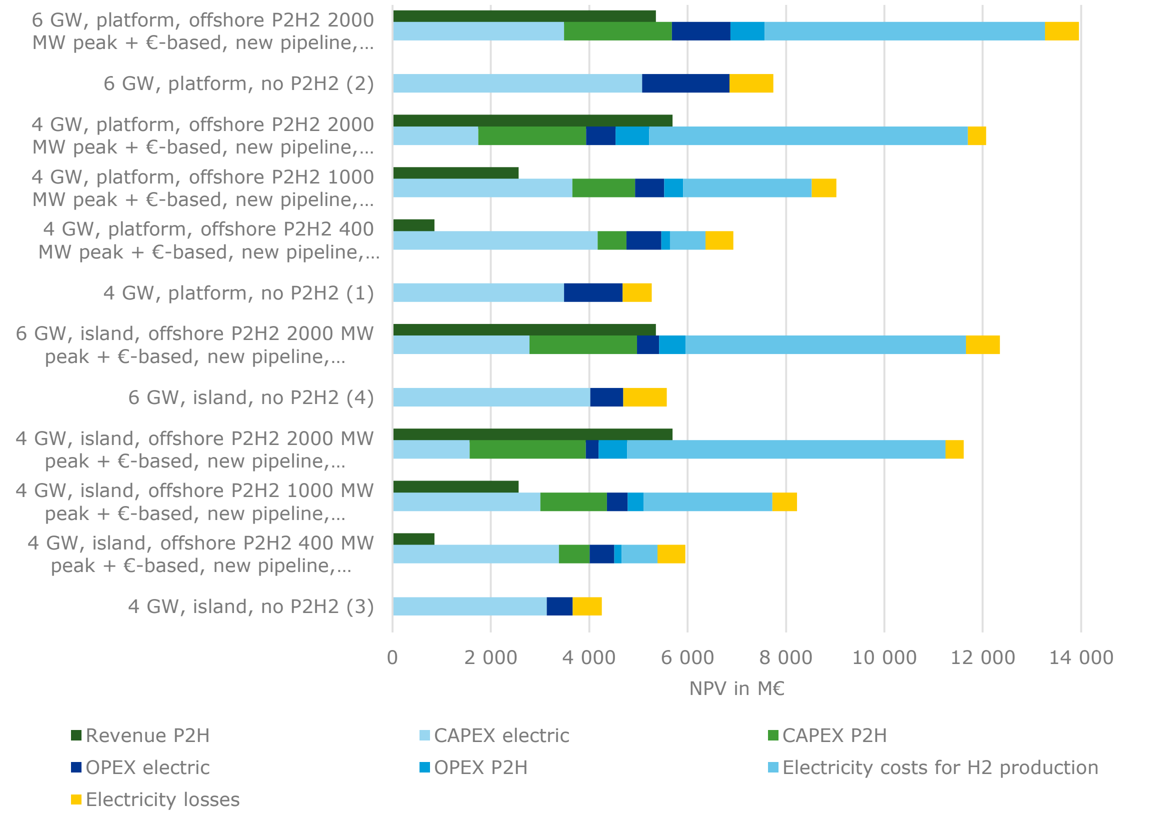
A breakdown of the investments is given on the right. As introduced on the previous slide, for some cases it is seen that the addition of $P2H_2$ also makes the NPV of the electric part more negative. The crucial factor is the different configuration for the export cables. Because of the addition of 400 or 1000 MW $P2H_2$ it is not logical to use 2 GW (525 kV) export cables. For these lower $P2H_2$ capacities 1 GW and 1.2 GW (320 kV) cables were selected. An optimization of the cable configuration should improve the business case. It might also be reasonable to assume a bigger difference in price for the 1/1.2 GW and 2 GW cables.

Furthermore, in the figure on the right it can be seen that both the platform and the island account for a considerable part of the costs. The island is not subject to depreciation since it was assumed that it does not perish and therefore has a higher remaining value compared to the platform.

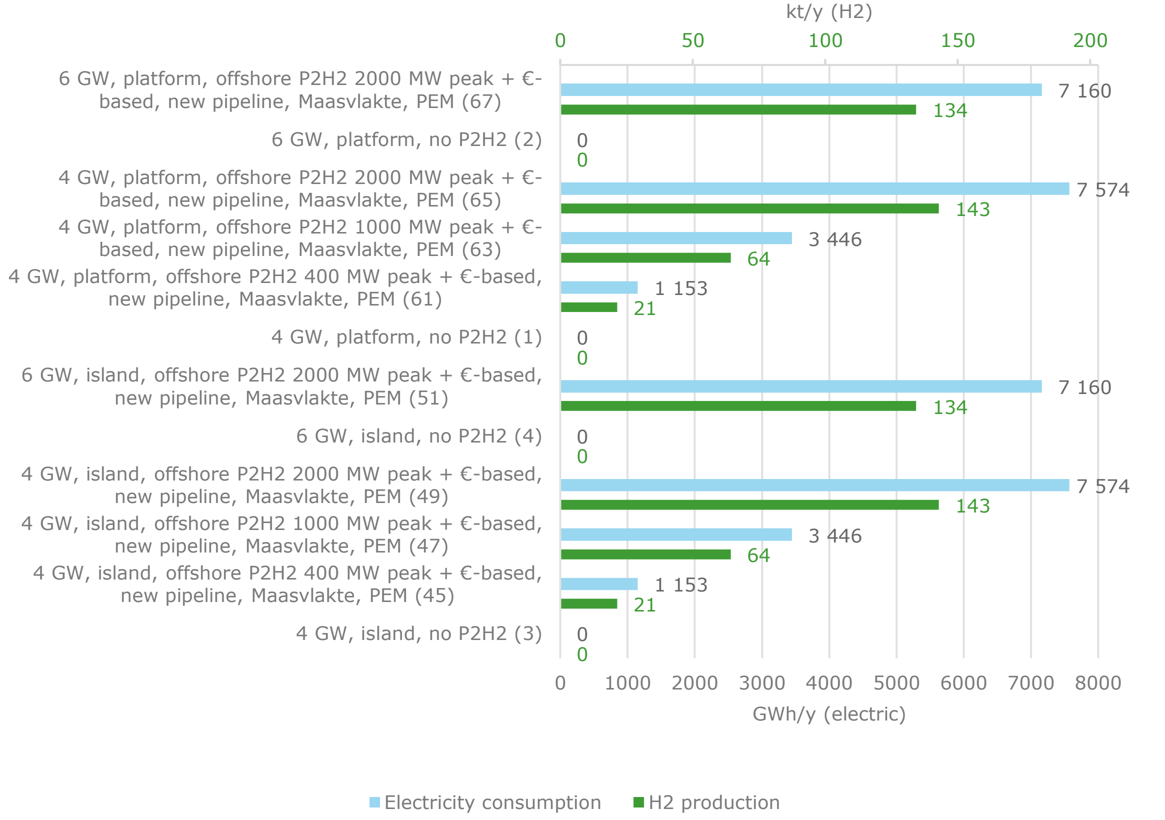
Results
Offshore $P2H_2$

This slide shows the results of the offshore $P2H_2$ cases. The left figure shows a breakdown of the costs and revenues. The right figure shows the energy production and consumption. The two energy flows are plotted on two different axes which are scaled in such a way that they are comparable and interchangeable.

Breakdown of the costs and revenues of the offshore $P2H_2$ cases



P2H energy production and consumption of the offshore $P2H_2$ cases



Results
Full P2H_2

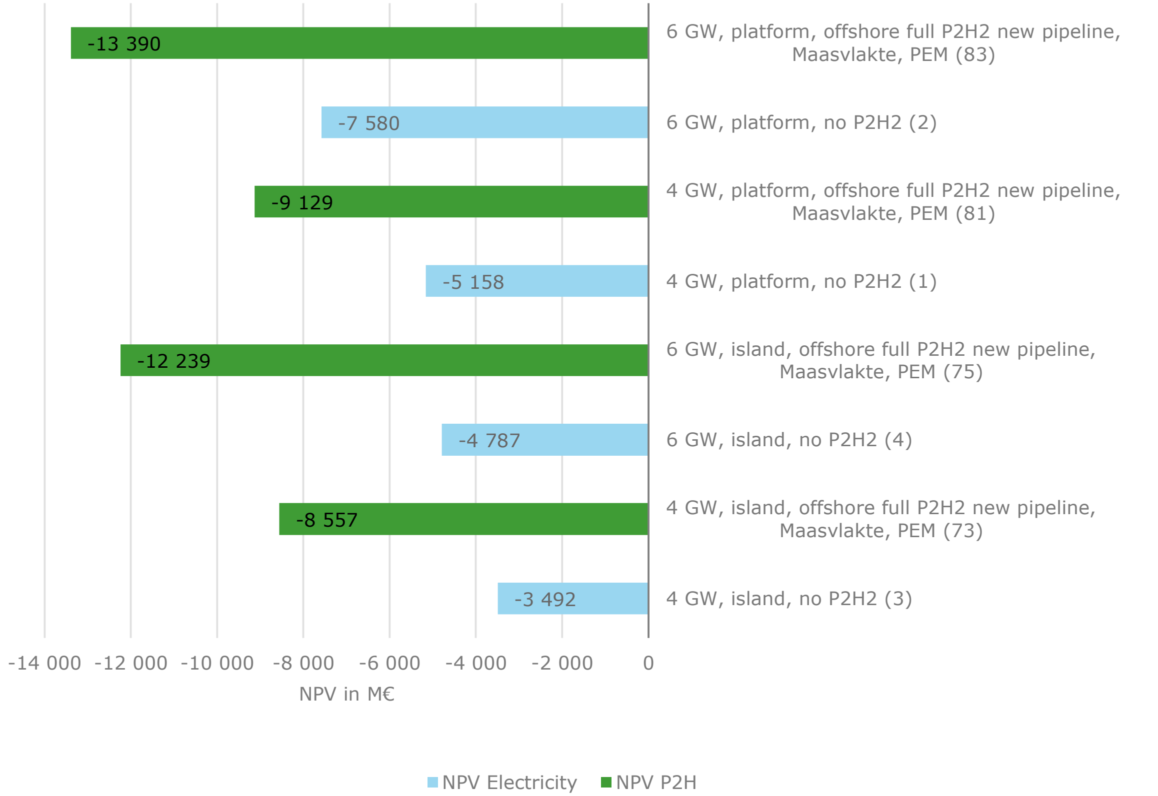
Substituting the electric export system for a full P2H_2 system does not result in a better NPV. The H_2 revenues are not enough to cover the costs of the electricity consumption due to the high electricity prices paid to produce H_2.

In the full P2H_2 cases there is no electric connection between IJmuiden Ver and the main land. All the wind energy is converted to H_2 and is transported to the Maasvlakte by pipeline. The P2H_2 unit is not dependant on price and therefore does not utilize the advantage of low electricity prices. For all these cases a negative NPV (highest of all cases) is found and compared to the base-cases, the option of full P2H_2 does not have any positive influence. As can be seen on the right chart (next page), the H_2 revenues are not enough to cover the costs of the electricity consumption due to the high electricity prices paid to produce H_2.

The difference between the options with an island or a platform is again clear and the island has the advantage when the remaining value is included.

NPV of the full P2H_2 cases

(note that this chart has a different scale than the other results)



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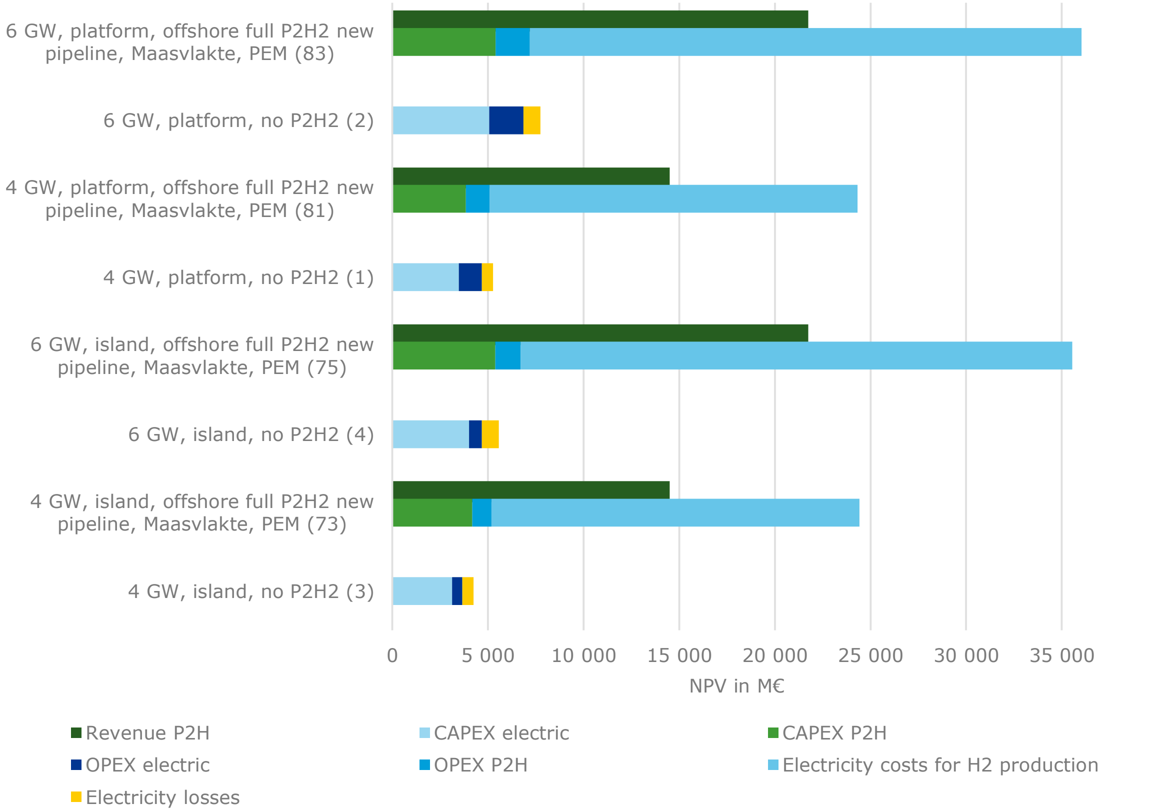
Results

Full $P2H_2$

This slide shows the results of the full $P2H_2$ cases. Two figures are given with a breakdown of investments and a breakdown of costs and revenues.
Note that the right figure is plotted on a larger scale than the figures of the other groups.

Breakdown of the costs and revenues of the full $P2H_2$ cases

(note that this chart has a different scale than the other results)



Results

Full $P2H_2$

This slide shows the results of the full $P2H_2$ cases. The figure shows the energy production and consumption. The two energy flows are plotted on two different axes which are scaled in such a way that they are comparable and interchangeable.
Note that this figure is plotted on a larger scale than the figures of the other groups.

Results

Sensitivity Analysis

Various sensitivities have been specified and are analysed for the main cases.

To asses the robustness of the results and to identify the driving inputs a sensitivity analysis has been performed. Restricting the number of cases to be analysed allows for an effective and clear insight in the most sensitive inputs. Therefore, the sensitivity analysis have been conducted for the main cases.

The following aspects were identified as most interesting/important for the sensitivity analysis;

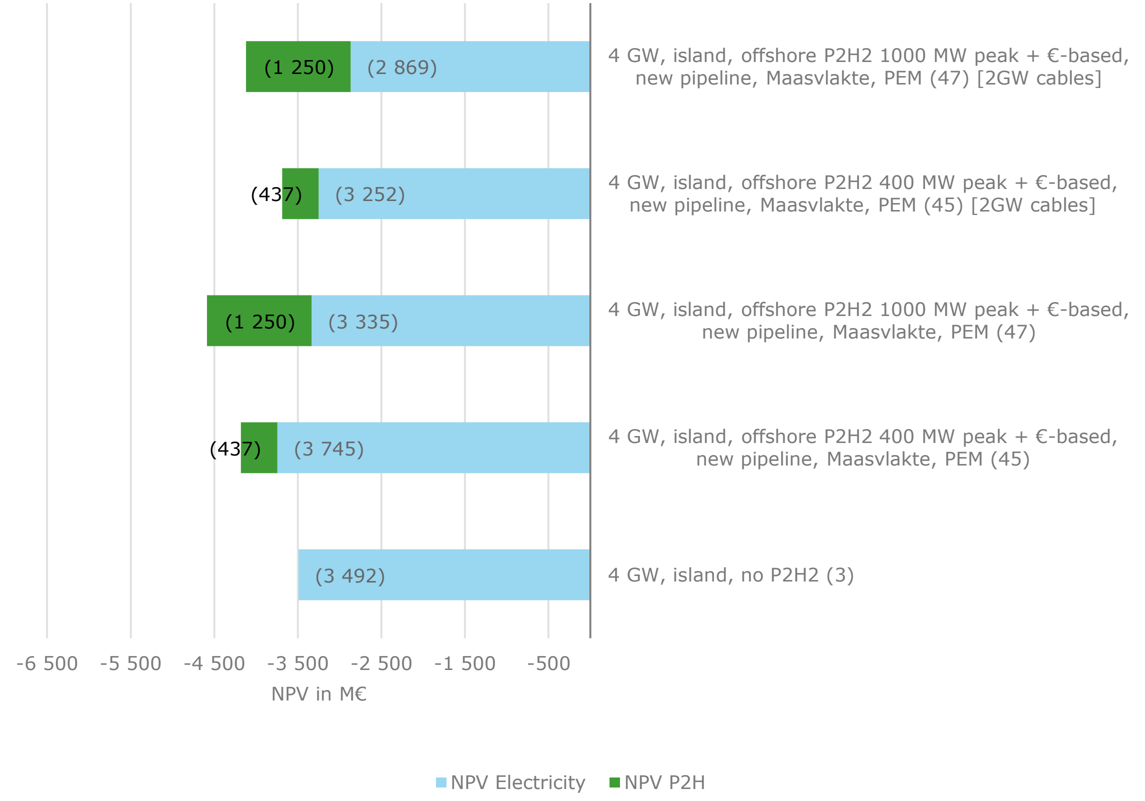
1. Optimal cable configuration
2. Hydrogen prices
3. Electricity prices
4. Break-even price
5. Electrolyser CAPEX
6. Electrolyser efficiency
7. Later $P2H_2$ start year

Optimal cable configuration
As mentioned in the results the cable configuration was different than the base-case for some $P2H_2$ cases. This resulted in a worse NPV, while one would expect lower CAPEX for the cables and thus an improved NPV.

The base-case for 4 GW wind assumes two 2 GW export cables (525 kV) while, with the addition of $P2H_2$, three 1/1.2 GW (320 kV) cables are selected. Since the costs for these cables only have a minor difference, the option with 2 GW cables is less expensive while a higher capacity is also installed. This is shown on the right figure where the 400/1000 MW offshore $P2H_2$ cases show a worse NPV for the electric part, while the electric capacity is lower. Selecting the same cable solution for these cases results in a fair comparison and a lower investment for the electrical part (capacity is still reduced for the converter stations).

Although the NPV for the electrical part has improved, the additional $P2H_2$ still results in a more negative business case.

Cable optimisation comparable to base-case



Results

Sensitivity Analysis – Hydrogen price

The hydrogen price is evaluated in the sensitivity analysis and proves to have a large impact on the NPV for the hydrogen part. This slide describes the sensitivity and the influence.

The hydrogen price which was assumed is not entirely certain as different options and markets were indicated earlier in this report. Initially a hydrogen price of €/kg for SRM + CO_2 was assumed. Other options could be;

- €/kg (price for SMR)
- €/kg (price for SMR based on green gas)
- €/kg (might be expected in mobility)

The sensitivity analysis is performed, assuming the above alternatives, resulting in strong fluctuations of the NPV. Especially if the hydrogen price would approach a similar price to what could be expected in the mobility sector, a strong business case could be achieved.

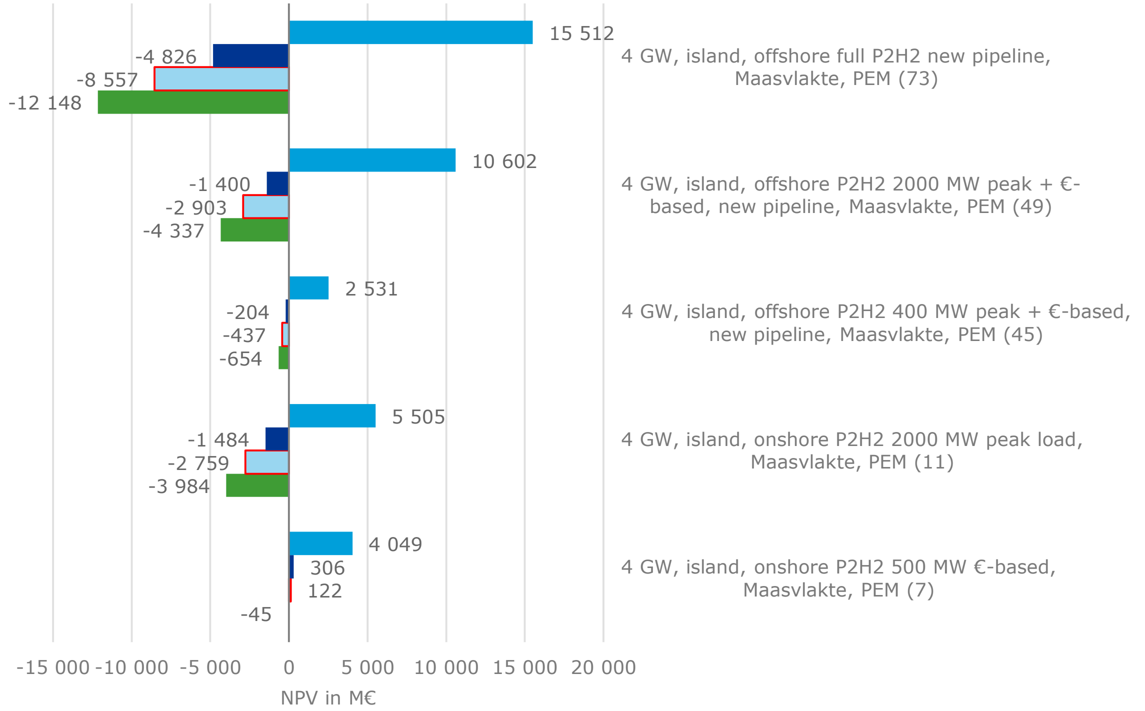
When the hydrogen price increases, higher marginal costs are allowed, setting a higher electricity price threshold for hydrogen production. The $P2H_2$ system will reach more operating hours when an electricity price based operation is chosen. The figure on the next slide shows that the amount of full-load hours per year strongly increases for some cases.

The average price paid for the electricity and the electricity costs increase but the hydrogen revenues have a stronger increase which results in this improved NPV.

The table below shows the effect on the total NPV.

Total NPV in M€ (electric+P2H2)	Initial			
4 GW, island, no P2H2 (3)	-3,491.59	-3,491.59	-3,491.59	-3,491.59
4 GW, island, onshore P2H2 500 MW €-based, Maasvlakte, PEM (7)	-3,369.50	-3,536.72	-3,185.43	557.51
4 GW, island, onshore P2H2 2000 MW peak load, Maasvlakte, PEM (11)	-6,093.54	-7,318.23	-4,817.75	2,170.49
4 GW, island, offshore P2H2 400 MW peak + €-based, new pipeline, Maasvlakte, PEM (45)	-4,181.65	-4,399.50	-3,949.38	-1,214.15
4 GW, island, offshore P2H2 2000 MW peak + €-based, new pipeline, Maasvlakte, PEM (49)	-4,727.86	-6,162.31	-3,224.90	8,776.55
4 GW, island, offshore full P2H2 new pipeline, Maasvlakte, PEM (73)	-8,557.27	-12,147.90	-4,826.04	15,512.08

H2 price sensitivity on NPV of the main cases ($P2H_2$ only)

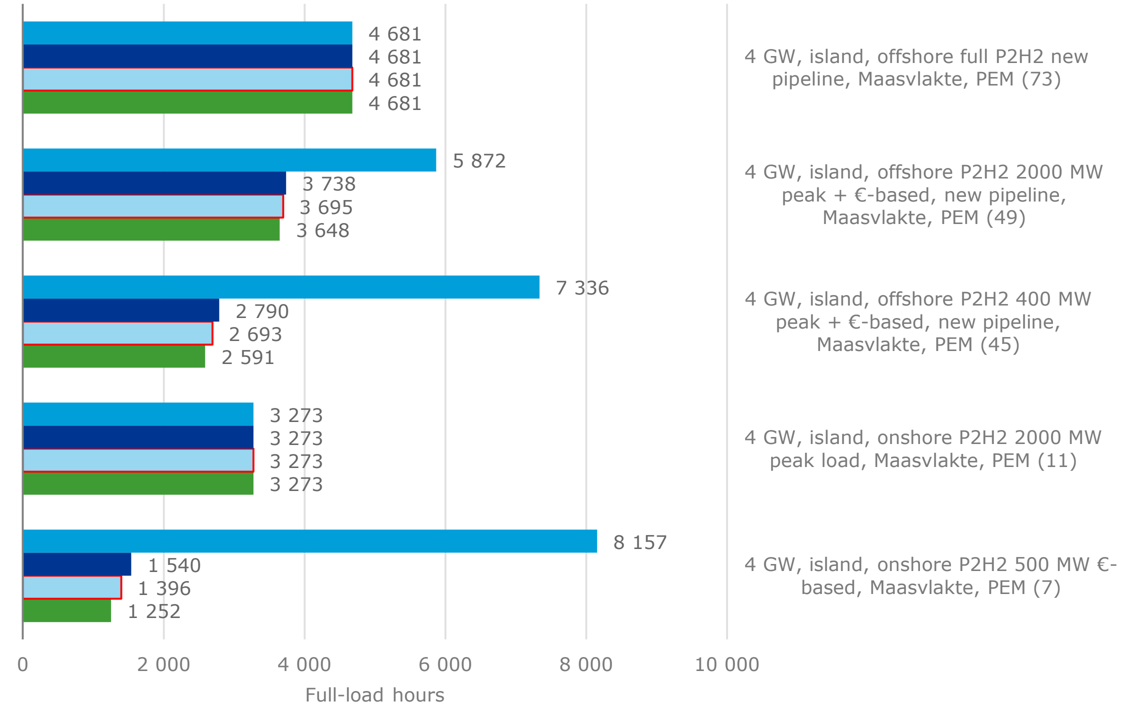


Results

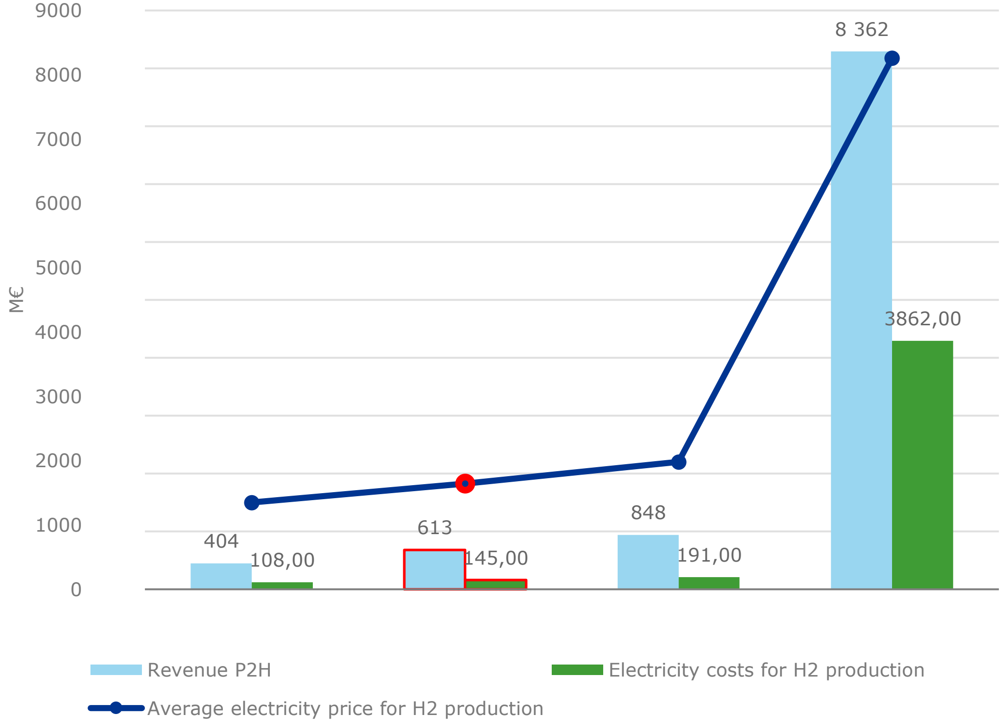
Sensitivity Analysis – Hydrogen price

The figures below show the sensitivity of different hydrogen prices for the amount of full-load hours (left) and the costs/revenues of the hydrogen production (right).

H_2 price sensitivity on full-load hours of the main cases ($P2H_2$ only)



Costs/revenues with different H_2 prices 500 MW onshore P2H (Maasvlakte)



Results

Sensitivity Analysis – Electricity price

The electricity price is evaluated in the sensitivity analysis and proves to have a large impact on the NPV for the hydrogen part. This slide describes the sensitivity and the influence.

The electricity prices were generated in the PLEXOS model assuming future developments. The following alternatives are considered;

- 25% less renewable energy than could be expected in the future
- 25% extra renewable energy than could be expected in the future
- The influence of 2 GW added $P2H_2$

If less renewable energy is added to the electricity market, prices are expected to fluctuate less. Therefore there will be less moments on which low electricity prices are found for hydrogen production, resulting in a worse NPV and less operating hours of the $P2H_2$ system.

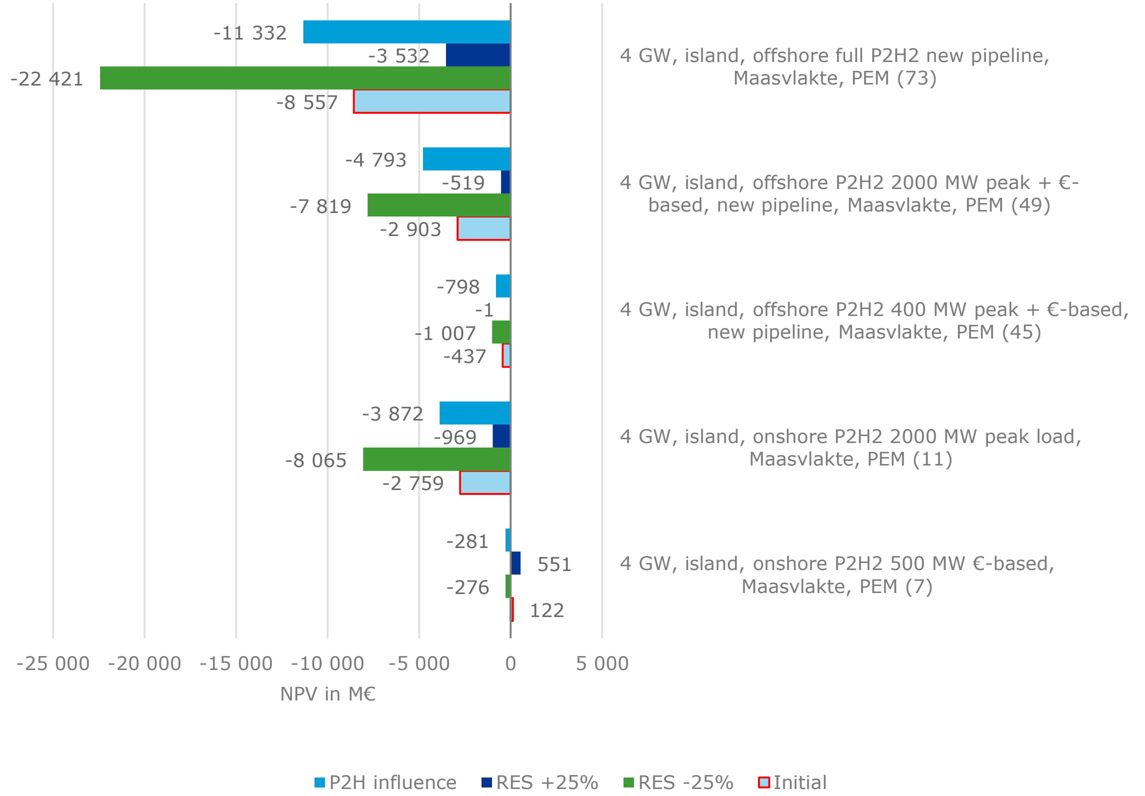
On the contrary, adding renewable energy to the market results in more fluctuations and more moments on which electricity is cheap. The opposite effect can be seen.

If a large capacity of $P2H_2$ would be added the demand curve for electricity will be more or less smoothed, resulting in a more constant electricity price. This also results in less moments on which the electricity is cheap and the average electricity price increases.

The table below shows the effect on the total NPV.

Total NPV in M€ (electric+P2H2)	Initial	RES -25%	RES +25%	+ 2 GW P2H2
4 GW, island, no P2H2 (3)	-3,491.59	-3,491.59	-3,491.59	-3,491.59
4 GW, island, onshore P2H2 500 MW €-based, Maasvlakte, PEM (7)	-3,369.50	-3,767.64	-2,940.83	-3,772.94
4 GW, island, onshore P2H2 2000 MW peak load, Maasvlakte, PEM (11)	-6,093.54	-11,398.81	-4,303.30	-7,205.79
4 GW, island, offshore P2H2 400 MW peak + €-based, new pipeline, Maasvlakte, PEM (45)	-4,181.65	-4,752.04	-3,745.75	-4,543.15
4 GW, island, offshore P2H2 2000 MW peak + €-based, new pipeline, Maasvlakte, PEM (49)	-4,727.86	-9,643.63	-2,344.42	-6,618.51
4 GW, island, offshore full P2H2 new pipeline, Maasvlakte, PEM (73)	-8,557.27	-22,421.04	-3,532.21	-11,332.09

Electricity price sensitivity on NPV of the main cases ($P2H_2$ only)

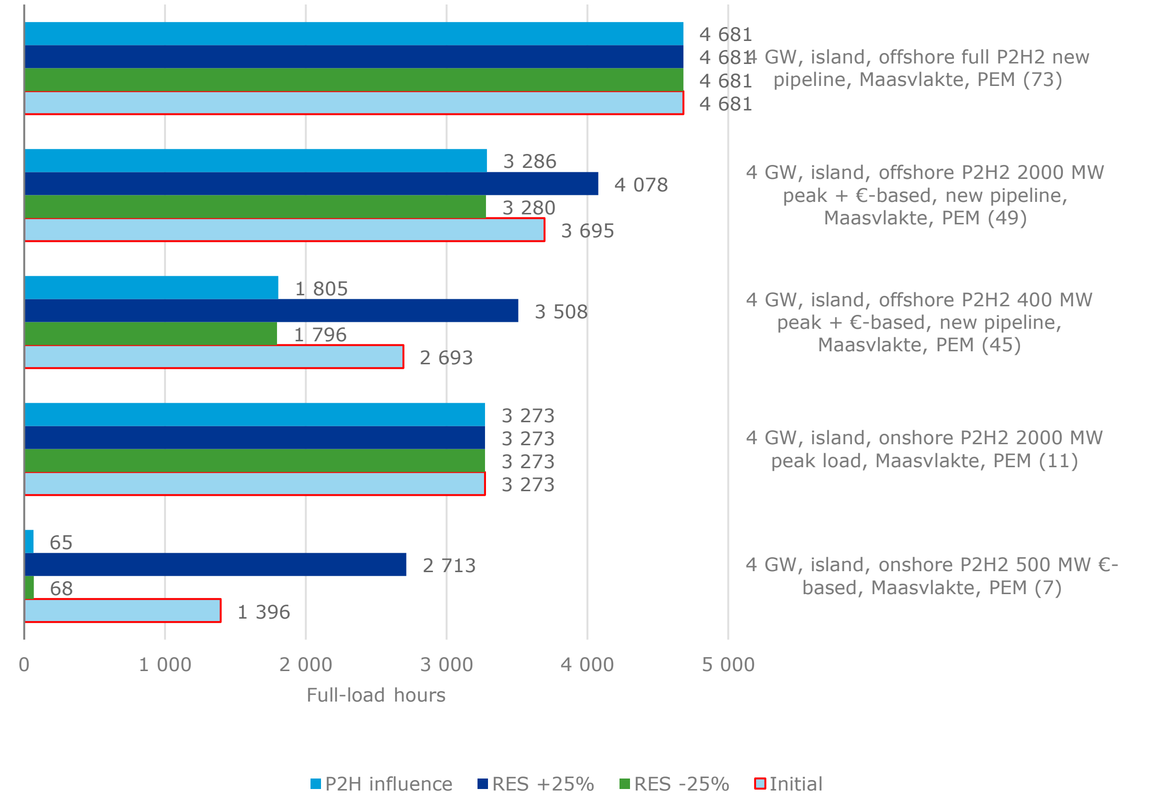


Results

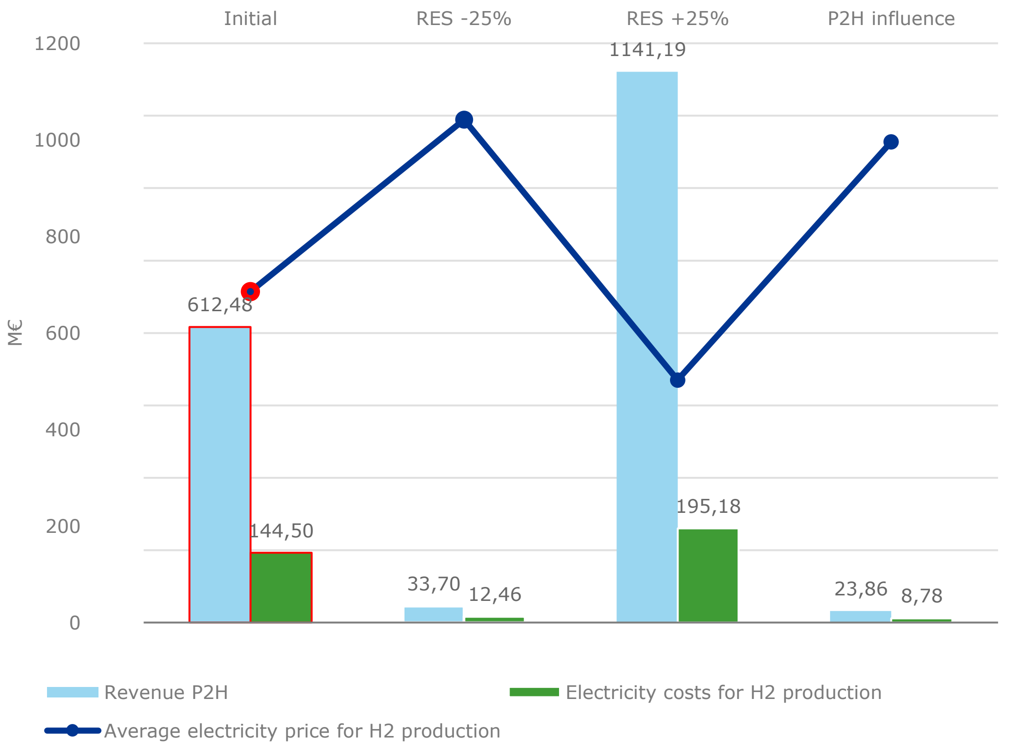
Sensitivity Analysis – Electricity price

The figures below show the sensitivity of different electricity prices for the amount of full-load hours (left) and the costs/revenues of the hydrogen production (right).

Electricity price sensitivity on full-load hours of the main cases ($P2H_2$ only)



Costs/revenues with different electricity prices 500 MW onshore $P2H_2$ (Maasvlakte)



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Results

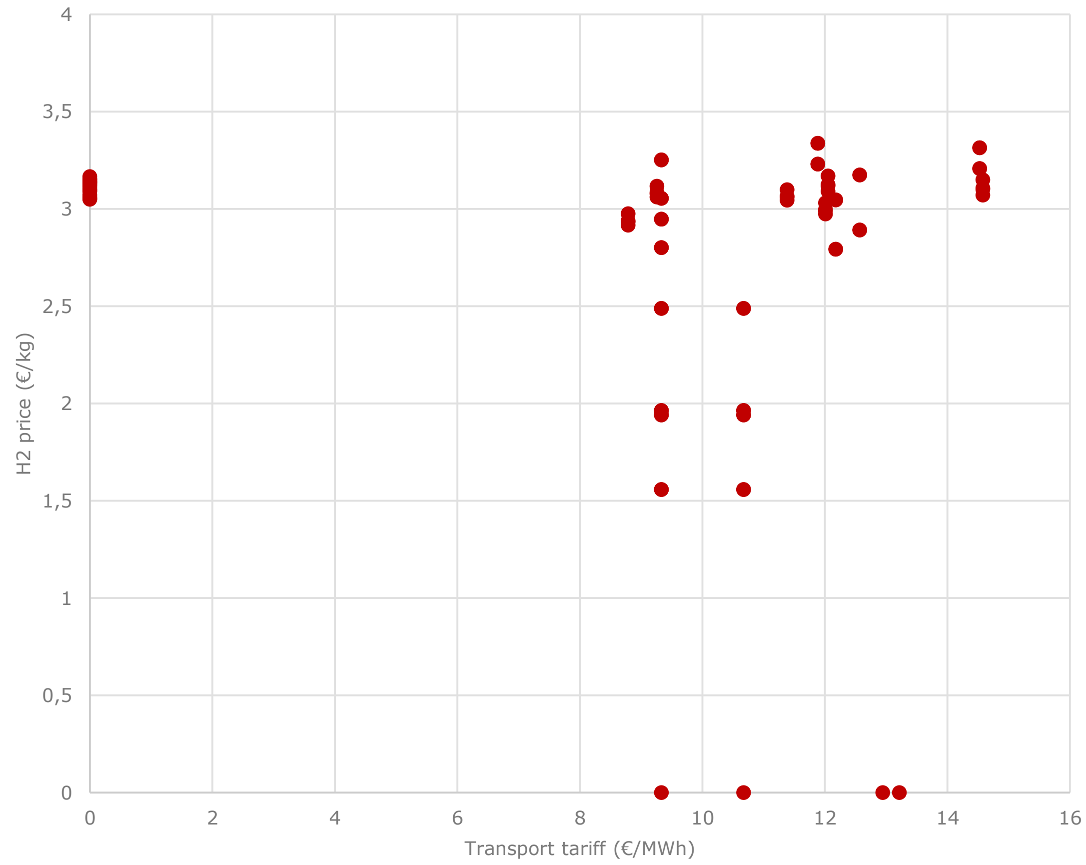
Sensitivity Analysis - Break-even price

This slide describes the break-even prices for the electricity and $P2H_2$ system. It is seen that most of the transport tariffs are between 9 and 15 €/MWh and hydrogen prices vary between 1.5 and 3.5 €/kg

The project can be split in two parts, electricity and $P2H_2$, each generating it's own revenues. The revenue for the electricity system (remuneration via tariffs) was not considered in the results earlier in this report but are shown now in the figure on the right.

The plot on the right shows the break-even tariffs and hydrogen prices of all the 84 different cases. It is seen that most of the transport tariffs are between 9 and 15 €/MWh and hydrogen prices vary between 1,5 and 3,5 €/kg.

Start year sensitivity on NPV of the main cases ($P2H_2$ only)



Results

Sensitivity Analysis – Electrolyser CAPEX

The electrolyser CAPEX is evaluated in the sensitivity analysis and proves to have a moderate impact. This slide describes the sensitivity and the influence.

The information from the electrolyser manufacturers showed overall correspondence on the electrolyser CAPEX, but this is still a parameter with a lot of uncertainty. The cost developments are highly dependant on the demand for electrolysers and if this is high, lower costs can be expected. It is also uncertain if the factory line will be robotized and what the effects on CAPEX will be.

The sensitivity of the electrolyser CAPEX is evaluated by multiplying or dividing the initial CAPEX by a factor 2. The following numbers can then be found;

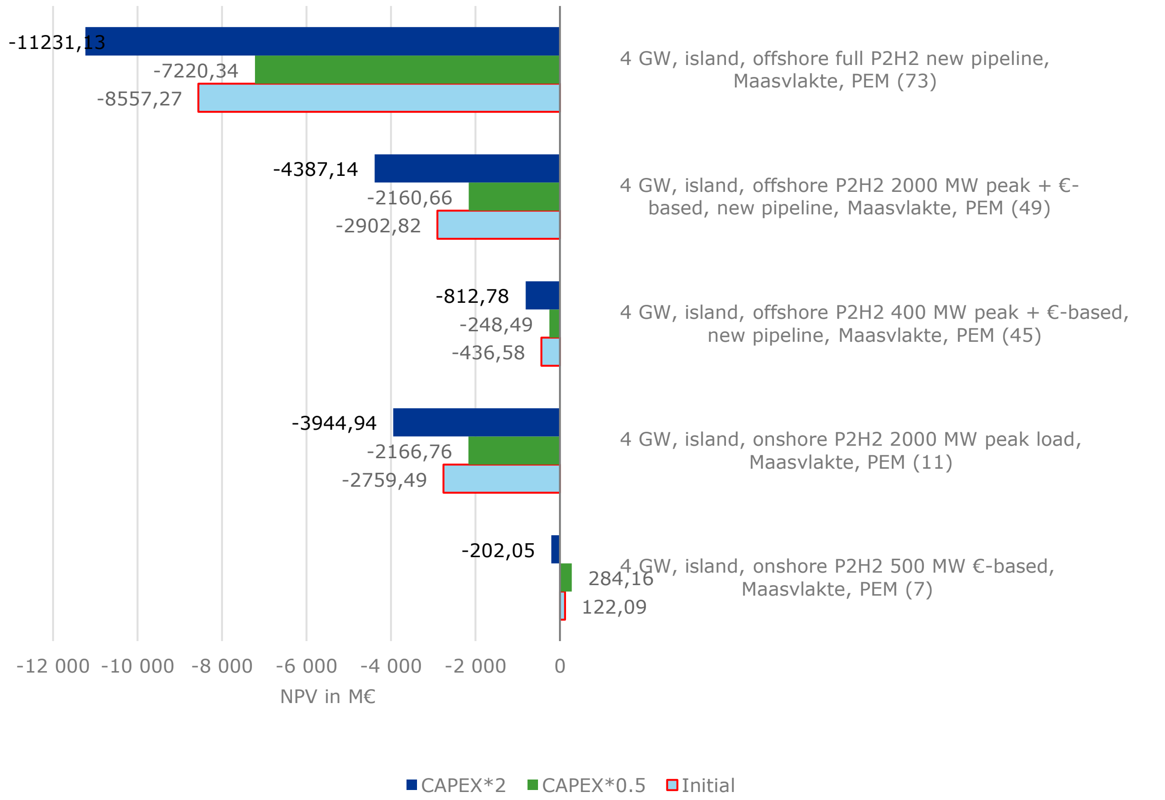
- €/kw (divide by 2)
- €/kw (initial)
- €/kw (multiplied by 2)

As the electrolyser is one of the main cost drivers there is a strong to moderate influence. The hydrogen and electricity price still represent the mayor derivers and therefore have a higher influence.

The table below shows the effect on the total NPV.

Total NPV in M€ (electric+P2H2)	Initial	CAPEX*0.5	CAPEX*2
4 GW, island, no P2H2 (3)	-3,491.59	-3,491.59	-3,491.59
4 GW, island, onshore P2H2 500 MW €-based, Maasvlakte, PEM (7)	-3,369.50	-3,207.43	-3,693.64
4 GW, island, onshore P2H2 2000 MW peak load, Maasvlakte, PEM (11)	-6,093.54	-5,500.81	-7,278.99
4 GW, island, offshore P2H2 400 MW peak + €-based, new pipeline, Maasvlakte, PEM (45)	-4,181.65	-3,993.55	-4,557.84
4 GW, island, offshore P2H2 2000 MW peak + €-based, new pipeline, Maasvlakte, PEM (49)	-4,727.86	-3,985.70	-6,212.19
4 GW, island, offshore full P2H2 new pipeline, Maasvlakte, PEM (73)	-8,557.27	-7,220.34	-11,231.13

Electrolyser CAPEX sensitivity on NPV of the main cases ($P2H_2$ only)

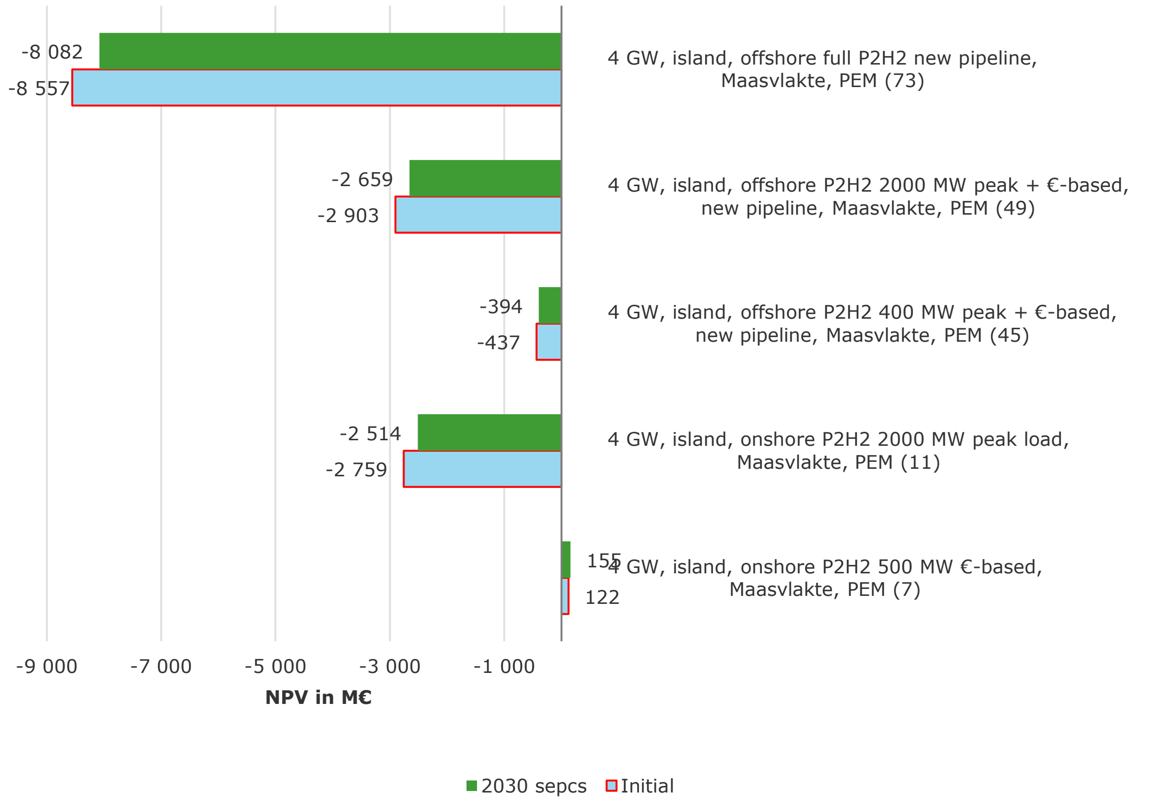


Results

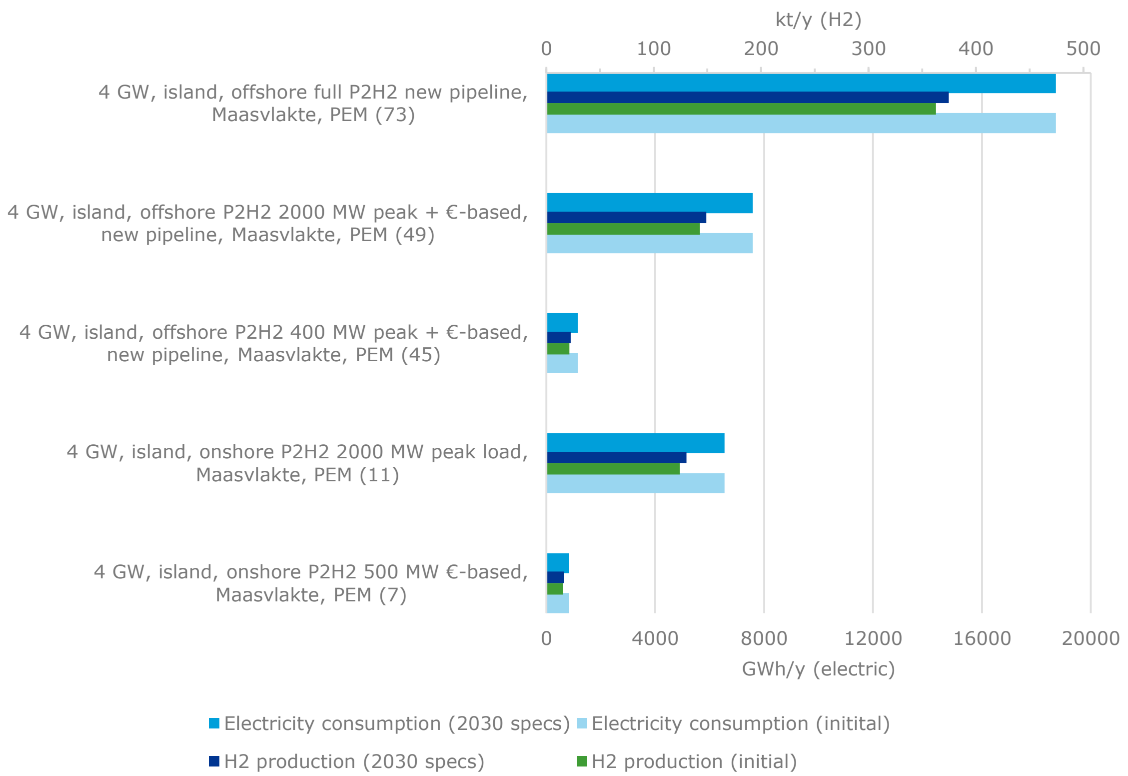
Sensitivity Analysis – Electrolyser efficiency

The figure below show the sensitivity of the electrolyser efficiency. The efficiency which could be expected in 2030 has been used and it is seen that this has a moderate influence. Since the electricity consumption is the main cost driver, an improved efficiency has a noticeable influence.

Electrolyser efficiency sensitivity on NPV of the main cases ($P2H_2$ only)



Electrolyser efficiency sensitivity on energy consumption/production of the main cases ($P2H_2$ only)



Results

Sensitivity Analysis – Start year

The start year of the $P2H_2$ system is considered in the sensitivity analysis and it is seen that later start years have a positive effect on the business case. The effect is moderate.

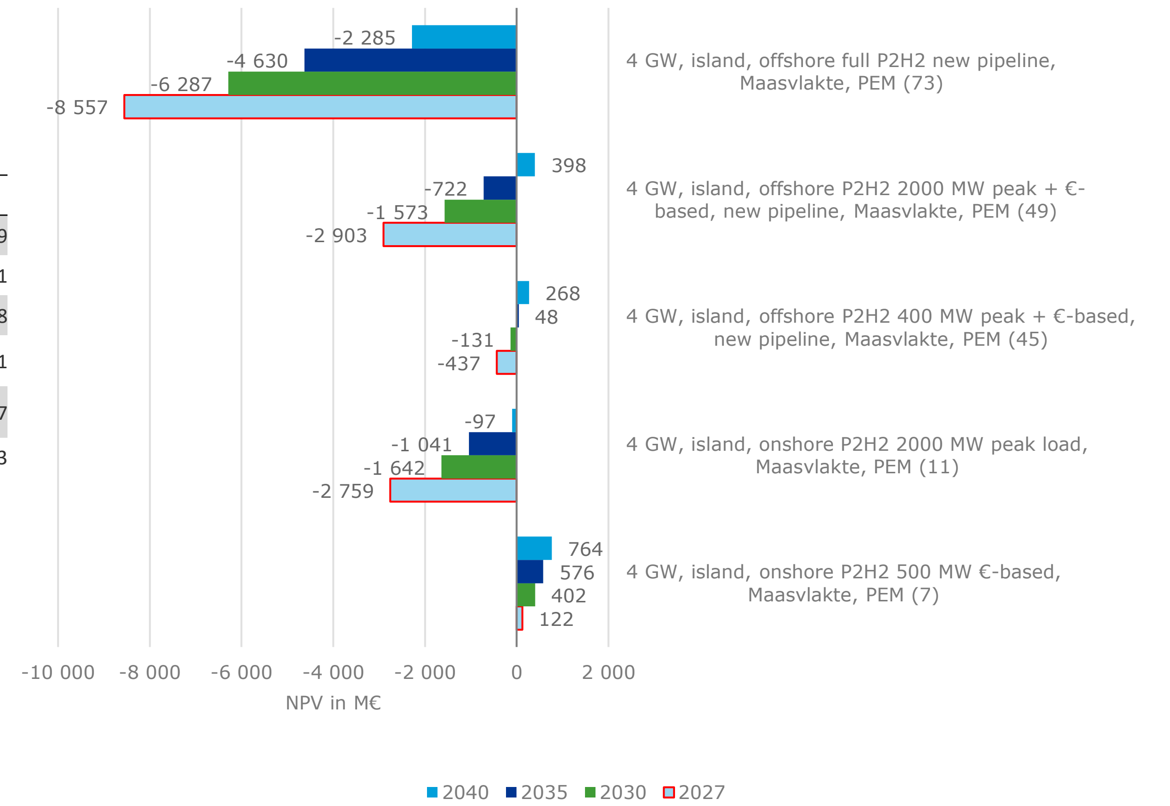
As the electrolyser expectations improve and electricity prices are expected to show more fluctuations in the future, building the $P2H_2$ system at a later year might improve the business case. This has been evaluated in the sensitivity analysis where 2027 is the initial case and for the later years, 2030, 2035 and 2040 have been chosen.

For the later start years it is seen that the business case will improve and in some offshore cases will even result in a positive business case.

The table below shows the effect on the total NPV.

Total NPV in M€ (electric+P2H2)	Initial	2030	2035	2040
4 GW, island, no P2H2 (3)	-3,491.59	-3,491.59	-3,491.59	-3,491.59
4 GW, island, onshore P2H2 500 MW €-based, Maasvlakte, PEM (7)	-3,369.50	-3,090.05	-2,915.44	-2,727.61
4 GW, island, onshore P2H2 2000 MW peak load, Maasvlakte, PEM (11)	-6,093.54	-4,976.26	-4,374.99	-3,430.88
4 GW, island, offshore P2H2 400 MW peak + €-based, new pipeline, Maasvlakte, PEM (45)	-4,181.65	-3,876.36	-3,697.08	-3,476.91
4 GW, island, offshore P2H2 2000 MW peak + €-based, new pipeline, Maasvlakte, PEM (49)	-4,727.86	-3,397.77	-2,546.76	-1,427.07
4 GW, island, offshore full P2H2 new pipeline, Maasvlakte, PEM (73)	-8,557.27	-6,287.09	-4,630.08	-2,284.83

Start year sensitivity on NPV of the main cases ($P2H_2$ only)



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Conclusions

Technical and economic assessment

No technological issues are foreseen as the considered technologies are already proven and do not pose serious issues when combining this with fluctuating energy from the wind farm.
In general, adding $P2H_2$ does not lead to a total better NPV (electric system + hydrogen system), except for the onshore $P2H_2$ case with low $P2H_2$ capacity. The power-to-hydrogen option can improve the NPV of the electrical system when adding 2 GW $P2H_2$, but will lower overall NPV. The business case for $P2H_2$ is dependent on the operation mode and the assumptions regarding prices of electricity and hydrogen, the electrolyser CAPEX and efficiency and the start year.

The key objective for this study was to assess the techno-economic feasibility of a concept for a hybrid and integrated energy supply from offshore wind farms in hydrogen at an artificial island at IJmuiden Ver and use of the existing gas/oil infrastructure to transport to shore. In short it can be concluded that based on this high-level assessment, it is technical feasible and economic feasibility is nearby. It would be useful to investigate this in more detail and in practice.

Technical assessment
Regarding power-to-hydrogen, the technologies included in this assessment are already proven and only the combination of fluctuating energy flows from the wind farm introduce a new aspect.

While alkaline systems are claimed (by some manufacturers) to have a lower CAPEX, future developments and expectations for PEM look more promising. The future developments for PEM promise a lower CAPEX and improved specifications such as lifetimes to 120,000 operating hours and efficiencies of 80%. Furthermore, the footprint of the PEM systems is expected to be smaller which is crucial when installing the electrolysers on an island or platform.
An important aspects is the response time of the electrolysers. Here the alkaline system has a disadvantage as the typical response time is within minutes. Besides, it is expected that the alkaline system would require more maintenance compared to PEM. Furthermore, a disadvantage of the alkaline system is the atmospheric output pressure which requires extra investment in compressors and results in extra energy loss.

With respect to HVDC technologies, the proposed concept is proven and feasible. Where the use of platforms is well-known for HVDC stations or oil and gas platforms, part of this study looked into the use of a platform to house a $P2H_2$ facility. A high-level assessment indicated that this is possible.

Economic assessment
In general, adding $P2H_2$ does not lead to an improved total NPV (electric system + hydrogen system), except for the onshore $P2H_2$ case with low $P2H_2$ capacity. These cases (for both 4 GW and 6 GW wind) have the most optimal NPV (i.e. better compared to the base case without $P2H_2$), with a positive NPV for the hydrogen part. This is due to the utilization of cheap electricity when market prices are low. These options are operated independently of the offshore grid concept.

As the platform options clearly showed a more negative NPV compared to the island options, it can be concluded that an island is the preferred option.

The addition of more $P2H_2$ capacity does not lead to an overall better NPV, though it can reduce the NPV of the electrical system as more nearby (in case of onshore $P2H_2$) or less electrical connections (in case of offshore $P2H_2$) are required. This is the case when adding 2 GW $P2H_2$, offshore or onshore, as this leads to the most cost efficient grid connection. In other words, it can be concluded that offshore placement of the electrolyser facilities offers a larger price reduction to the transmission system than onshore placement since a duplication of infrastructure is avoided. Accordingly, when adding higher $P2H_2$ capacities, offshore $P2H_2$ is better than onshore $P2H_2$, though the full $P2H_2$ case has the most negative NPV.

As observed from the sensitivity analysis, the results of the business case of $P2H_2$ depend on the assumptions made regarding the prices of electricity and hydrogen, the electrolyser CAPEX and efficiency and the start year. The business case of $P2H_2$ is mostly dependent on the price of hydrogen and the price of electricity, with CAPEX and efficiency having a slightly lower effect.
Increasing volatility of electricity prices act in the advantage of $P2H_2$ when H_2 is produced at low electricity prices. Higher cashflows are seen in the years after 2032 as electricity costs for H_2 production decrease. The use of this price advantage actually results in a positive business case for $P2H_2$ (where H_2 is sold at 1.72 €/kg, SMR+CO2 price).
Since it is expected that the CAPEX for electrolysers will decrease over the years (and can drop even further when demand increases for especially PEM electrolysers, an analysis has been done from which year power-to-hydrogen would lead to a positive NPV for the hydrogen system. The NPV for the smaller onshore $P2H_2$ capacities become more positive, as those were already positive. The NPV for the larger onshore $P2H_2$ capacities remain negative, but the NPV for offshore $P2H_2$ becomes positive as of 2035. Accordingly, it can be argued that power-to-hydrogen is near commercial feasibility, and that changes in some key inputs (e.g. more RES and hours with low electricity prices) could improve the attractiveness of power-to-hydrogen.

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Conclusions

Market assessment and discussion

The demand for H_2 is currently most present in the industrial sector where H_2 production is done by means of methane reforming, offered at 1.5 €/kg H_2. This price is expected to rise only slowly as prices for natural gas in Europe are expected to remain relatively flat. It is unclear whether a vivid H_2 market will arise but it could still be a promising way to decarbonise various sectors where higher prices could be expected.
Besides the conclusion for the market analysis, a discussion of the results is also given.

Market assessment Hydrogen
Latest available figures estimate current demand for hydrogen around 10 bcm per annum virtually all produced onsite for industrial purposes. Also, hydrogen becomes available as a by-product and is, more limitedly, produced to be subsequently sold to other companies.

A limited number of studies currently quantitatively assess the potential role for hydrogen in the future of the Dutch energy supply. Nevertheless, three studies are publicly available which all paint a different picture regarding the demand for and sectors using hydrogen. Where some see a vivid role for hydrogen already as early as 2030, others do not predict any significant share before 2035. Furthermore, some studies foresee a major role for hydrogen in industrial process whereas others predict most demand to occur for the production of electricity. On this basis, the size of future hydrogen demand is presently highly uncertain as well as which sectors will be the main consumers of hydrogen.

Hydrogen is presently mostly derived from natural gas using a processes referred to as methane reforming. Hydrogen produced by methane reforming is currently the lowest cost solution for large scale (industrial) applications. Costs are mainly determined by the price of natural gas, which thus account for the majority hydrogen's costs. In a future where carbon emissions should be minimized, the production of hydrogen using methane reforming and natural gas ('grey hydrogen') might not be a viable option.

Current costs of hydrogen using SMR are between 1.5 and 2.5 EUR/kgH_2 depending on whether reformers are existing or should be built and whether certificates for green gas are used. Our analysis suggests that costs are likely to rise limitedly in the future mainly as we believe that natural gas prices in Europe remain relatively flat.

On the other hand, hydrogen may be regarded as a way to decarbonize other sectors than the industry, such as mobility. Various sources claim than the mobility sector is willing to pay a higher price for hydrogen as green alternatives are more limited; values between between 5 to 10 EUR/kgH_2 are foreseen. Finally, injection in the natural gas grid seems less promising where the maximum price for hydrogen is likely less than 1 EUR/kgH_2 based on energy content in comparison with natural gas.

Discussion
In the current state of development, the PEM electrolysers are still assembled by hand. The demand for electrolysers is growing and therefore it is expected that the CAPEX will reduce, but this does not yet include a factory line assembly with robots. A same trend as for solar panels with even lower CAPEX is possible, but this strongly depends if several GW scale P2H_2 projects will be realized.

Power-to-hydrogen could potentially provide various flexibility services to the power system. Increasing fluctuation in residual demand creates the need for rapidly available ramp-up and -down resources on both small and large scale. Electricity balancing services such as frequency containment reserves (FCR) and frequency restoration reserves (FRR) are essential for a safe operation of the power system. These services could be provided by electrolysers like PEM, as these are able to respond on a sub-second level. Electricity network operators could therefore use electrolysers to balance supply and demand. This potential flexibility value is not included in this study and could be investigated in more detail or in practice.
The H_2 output is now assumed to be absorbed by the market, regardless of the timing and fluctuations in supply. Further analysis and the consideration of storage would take this (more realistic) aspect into account.

The selection of cables in the different cases is not optimized as some cases require a higher investment while capacity is reduced. In the 4 GW base-case, two 2 GW (525 kV) are selected while in the case with 400 MW offshore P2H_2, three 1.2 GW (320 kV) cables are selected. Since the differences in CAPEX for the cables were assumed to be not that large, the three 1.2 GW cables result in a higher investment.

Electricity prices are expected to fluctuate more in the future, after 2030-2035, which would have a strong impact on the business case of P2H_2. Additionally, a CAPEX reduction, longer lifetime and higher efficiency of the electrolyser is expected. This would mean a higher revenue stream and lower costs for the P2H_2 system. Further analysis where P2H_2 would be installed after 2030-2035 could improve overall benefits. It could be the case for instance that only part of the IJmuiden Ver wind capacity is installed and operational by 2027, where later additional capacity could be connected with a P2H_2 system.

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Appendix A – Glossary

TERM	DESCRIPTION
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
EJ	Exajoule
GW	Gigawatt
GJ	Gigajoule
H_2	Hydrogen
HVDC	High Voltage Direct Current
kW	Kilowatt
MW	Megawatt
MWh	Megawatt hour
PEM	Polymer electrolyte membrane
$P2H_2$	Power-to-Hydrogen
RES	Renewable energy source
TJ	Terajoule
TWh	Terawatt hour

Appendices

Appendix B – DNV GL’s European power market model

The developed most likely future scenario, has been implemented in DNV GL’s European power market model. This model contains detailed representations of the electricity generation, transmission and demand for most European countries, divided in core (generation modelled by plant > 50MW) and non-core (generation modelled aggregated per technology) countries.

General description of the model

- The European market model contains detailed representations of the electricity generation, transmission and demand for most European countries (i.e. core countries). For the Nordics and South-East Europe, the generation capacities are aggregated by technology-fuel categories.
- Power plants in the core countries are modelled on an individual basis with detailed techno-economic characteristics. For example: flexibility parameters, such as ramp rates and minimum stable level, heat rate curves, maintenance availability parameters, variable operation & maintenance and start costs.
- Different types of combined heat and power plants (CHP) are distinguished in the model: district heating, industrial CHP and horticultural CHP (especially in the Netherlands). These power plants have must-run requirements due to the heat delivery, but they have different levels of flexibility provided by heat-only boilers and/or heat storage for district heating.
- Renewable generation takes volatility into account through the use of historical or re-analysed time-series of e.g. wind-speeds and solar-irradiation data for different locations. These profiles take the geographical correlation into account.
- Market exchanges between countries (i.e. bidding zones) is limited based on net-transfer-capacities (NTC). Within bidding zones, no grid constraints are taken into account.
- The demand consists of an hourly fixed demand profile and a flexible “demand side management” component due to flexible charging for electric mobility, household battery storage and heat storage.

Geographic area

Appendix B – DNV GL's European power market model

DNV GL's European power market model is a fundamental market model that simulates the day-ahead spot price by optimizing the unit commitment and economic dispatch of the electricity generation. The optimization is based on the minimization of the total generation costs: the cheapest generation is used first. A perfect competition situation is simulated for the European power system within an energy-only market.

Input and output

- DNV GL's Energy Transition Outlook is implemented in DNV GL's European power market model. It is a fundamental market model that simulates the day-ahead spot price by optimizing the unit commitment and economic dispatch of the electricity generation.
- The optimization is based on the minimization of the total generation costs: the cheapest generation is used first. An overview of the (main) inputs required for this optimization is shown on the right. The optimization is performed with an hourly time resolution for several focus years.
- It is assumed that generators price their generation based on their short-run marginal costs, i.e. the power price is set by the cheapest (marginal) power plant that does not run at its maximum capacity.
- These assumptions simulate a perfect competition situation within an energy-only market. Capacity markets and balancing markets are not explicitly modelled. However, the revenues from the capacity markets are taken into account when determining new investments.
- Based on the dispatch of the generation assets, the (hourly) power price is calculated for each bidding zone. In addition to the power price, the power market model also provides insights in the electricity generation per type of asset, the generation weighed price per asset and also import/exports of a bidding zone.
- By adjusting the input data, sensitivities on e.g. the power price are assessed.

Workflow power market model

Input data

- Load data
- Reserve margin
- Generation structure
- Detailed power plant characteristics
- Network constraints
- Fuel and CO_2 prices
- RES profiles

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Power market model

Outputs

- Spot price (time-weighted)
- Unit commitment and dispatch
- Generation weighted price (i.e. capture price)
- Commercial exchanges

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Appendices

Appendix C – Questionnaire electrolyser companies

Introduction

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Recently DNV GL was assigned a feasibility study to large scale hydrogen production using offshore wind electricity as an input. The electrolyser units are to be installed at offshore platforms or on an artificial island in the North Sea. As you will understand the capabilities and economics of the electrolyser units are key inputs for this study. The hydrogen production size may vary from 100, to 500, to 1000, to 3000 MW.

Although we are aware that electrolyser technology is still in an early stage and that we are looking for insights that still have a certain amount of uncertainty, we would like to receive your answers to the following questions. Please, feel free, that if you have no exact figure available, to give a range or an estimate.

Of course, we are available for clarifying the background of the question or the question itself. After we received your response, we would like to discuss the subject in a conference call or a physical meeting.

Confidentiality

We are aware that some of the information we ask for, could be commercially or otherwise sensitive. Although we need to report the outcomes of the feasibility study to our client, we are not required to report in detail, and we will, if requested by you report on high level outcomes and/or anonymized. Of course, we are willing to sign a confidentiality agreement on your request first.

Questions

1. What technologies are applicable (PEM, SO, Alkaline)? What technology has the best outlook? What advantages and hurdles are to be considered?
2. What capacities are available? What is the largest size available now and what is planned? How can this be scaled to the sizes mentioned in the introduction (100, 500, 1000 and 3000 MW)?
3. What is the balance of plant of your electrolyser unit?
   Water process (water treatment (quality, temperature, pressure), pipelines, storage tanks, water catchment tanks, pumps, heat exchangers, etc.)
   Electricity input (cables, transformers, rectifiers, thyristors, power distribution, control, etc..)
   Gas treatment (hydrogen and oxygen: pipelines, separator, drying, cooling, valves, purification, storage, etc.)
4. What is the layout (A typical drawing would be helpful)?. What are the sizes/dimensions (lxwxh) for a normal design and maybe for a compact design (on a platform)? What is the weight?
5. What is the energy and water use per kg hydrogen? What is this figure for full load as well as part loads (is there a diagram)?
6. What are response times? Cold start, stand-by mode, response to variable input loads?
7. What is/are the outlet pressure(s) for hydrogen? Could this be scaled to 60 bar or 80 bars?
8. What initial investments are required for the units? What are the outlooks of these figures on the long term (depending on time or number of units produced per year)? What are replacement investments for each of the main components? What decommissioning cost may be required?
9. What is the OPEX (assuming land based units)? What part of this is equipment cost and what for man hours (maintenance hours, inspection hours)? What activities are foreseen in inspection and maintenance?
10. What safety regime is required? Design, measurements, control, competence?
11. What measurements and controls are foreseen? What is required, what is nice to have? What is the control philosophy (on site, remote)?
12. What utilities are required? What civil works are required (accessibility, precipitation, protection, ..)?
13. What are the expected lifetimes of the main components?
14. What are water input requirements (quality parameters, specific impurities)? If seawater is used, what extra water treatment is needed?
15. What electricity quality is required (Voltage, voltage variation, frequency, frequency variation, higher harmonics, current variations, etc)?
16. What are hydrogen and oxygen output conditions (pressure, temperature, water dew point, purity, impurities, fluctuations, etc..)?
17. What ambient conditions are required? Temperature (min, max), wind speed, salinity (water, air), sun radiation, precipitation, etc.

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Of course, the list above is not exhaustive. If you think that there is information that we may have omitted, we would be grateful for your inputs.

Concluding

DNV GL is of the opinion that the subject of the study could be a major step in the development to maturity of hydrogen as part of the energy transition. We therefore would like to offer our expanded thanks to you in advance for your efforts to answer the questions above and for any other support.

Appendices

Appendix D – Overview number of cables per alternative

Zero-alternative

Capacity	Configuration	Connections	Voltage level	Current	Nr. Cables
4 GW	Symmetrical monopole	2x2000MW	525 kV	1,9kA	4 power cables
	Asymmetrical monopole	2x2000MW	525 kV	3,8kA	4 power cables 4 metallic returns
	Bipole	2x2000MW	525 kV	1,9kA	4 power cables 2 metallic returns
6 GW	Symmetrical monopole	3x2000MW	525 kV	1,9kA	6 power cables
	Asymmetrical monopole	3x2000MW	525 kV	3,8kA	6 power cables 6 metallic returns
	Bipole	3x2000MW	525 kV	1,9kA	6 power cables 3 metallic returns

Alternative 1

Capacity	Configuration	Connections	Voltage level	Current	Nr. Cables
4 GW	Monopole with metallic return	2x2000MW	525 kV	3,8kA	4 power cables 4 metallic returns
	Bipole with metallic return	2x2000MW	525 kV	1,9kA	4 power cables 2 metallic returns
	Bipole without metallic return	2x2000MW	525 kV	1,9kA	4 power cables
6 GW	Monopole with metallic return	2x2000MW	525 kV	3,8kA	4 power cables 4 metallic returns
	Bipole with metallic return	2x2000MW	525 kV	1,9kA	4 power cables 2 metallic returns
	Bipole without metallic return	2x2000MW	525 kV	1,9kA	4 power cables

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Appendix D – Overview number of cables per alternative

Alternative 2

Capacity	Configuration	Connections	Voltage level	Current	Nr. Cables
4 GW	Monopole with metallic return	2x2000MW	525 kV	3,8kA	4 power cables 4 metallic returns
	Bipole with metallic return	2x2000MW	525 kV	1,9kA	4 power cables 2 metallic returns
	Bipole without metallic return	2x2000MW	525 kV	1,9kA	4 power cables
6 GW	Monopole with metallic return	2x2000MW	525 kV	3,8kA	4 power cables 4 metallic returns
	Bipole with metallic return	2x2000MW	525 kV	1,9kA	4 power cables 2 metallic returns
	Bipole without metallic return	2x2000MW	525 kV	1,9kA	4 power cables

Alternative 3 - 5

Total Capacity	$P2H_2$ Capacity	Configuration	Connections	Voltage level	Current	Nr. Cables
4 GW	1 GW	Monopole with metallic return	3x1000MW	320 kV	3,125kA	6 power cables 6 metallic returns
		Bipole with metallic return	3x1000MW	320 kV	1,56kA	6 power cables 3 metallic returns
		Bipole without metallic return	3x1000MW	320 kV	1,56kA	6 power cables
	0,4 GW	Monopole with metallic return	3x1200MW	320 kV	3,75kA	6 power cables 6 metallic returns
		Bipole with metallic return	3x1200MW	320 kV	1,875kA	6 power cables 3 metallic returns
		Bipole without metallic return	3x1200MW	320 kV	1,875kA	6 power cables
	2 GW	Monopole with metallic return	1x2000MW	525 kV	1,9kA	2 power cables 2 metallic returns
		Bipole with metallic return	1x2000MW	525 kV	3,8kA	2 power cables 2 metallic returns
		Bipole without metallic return	1x2000MW	525 kV	1,9kA	2 power cables

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Appendix D – Overview number of cables per alternative

Alternative 3 - 5

Total Capacity	$P2H_2$ Capacity	Configuration	Connections	Voltage level	Current	Nr. Cables
6 GW	2 GW	Monopole with metallic return	2x2000MW	525 kV	1,9kA	4 power cables 4 metallic returns
		Bipole with metallic return	2x2000MW	525 kV	3,8kA	4 power cables 2 metallic returns
		Bipole without metallic return	2x2000MW	525 kV	1,9kA	4 power cables

Alternative 6

Total Capacity	$P2H_2$ Capacity	Configuration	Connections	Voltage level	Current	Nr. Cables
4 GW	1 GW	Monopole with metallic return	3x1000MW	320 kV	3,125kA	6 power cables 6 metallic returns
		Bipole with metallic return	3x1000MW	320 kV	1,56kA	6 power cables 3 metallic returns
		Bipole without metallic return	3x1000MW	320 kV	1,56kA	6 power cables
	0,4 GW	Monopole with metallic return	3x1200MW	320 kV	3,75kA	6 power cables 6 metallic returns
		Bipole with metallic return	3x1200MW	320 kV	1,875kA	6 power cables 3 metallic returns
		Bipole without metallic return	3x1200MW	320 kV	1,875kA	6 power cables
	2 GW	Monopole with metallic return	1x2000MW	525 kV	1,9kA	2 power cables 2 metallic returns
		Bipole with metallic return	1x2000MW	525 kV	3,8kA	2 power cables 2 metallic returns
		Bipole without metallic return	1x2000MW	525 kV	1,9kA	2 power cables
6 GW	2 GW	Monopole with metallic return	2x2000MW	525 kV	1,9kA	4 power cables 4 metallic returns
		Bipole with metallic return	2x2000MW	525 kV	3,8kA	4 power cables 2 metallic returns
		Bipole without metallic return	2x2000MW	525 kV	1,9kA	4 power cables