

North Sea Energy D3.6

Towards sustainable energy production on the North Sea - Green hydrogen production and CO₂ storage: onshore or offshore?

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

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Preface

This study has been carried out in the framework of the North Sea Energy 1 project, which was a collaborative effort of a large number of players from the knowledge sector and from the category of oil and gas operators on the Netherlands continental shelf of the North Sea (TNO, ECN, CAB, NEC, RUG, EAE, EDI; and NOGEPa, Shell, NAM, Huisman, Siemens, VBMS, Gasunie, Gasterra, EBN, Total E&P, TAQA). This report specifically covers the main results from work package 3.1 (Techno-economic status of potential offshore energy system integration options).

Various potential offshore energy options have been assessed, in all cases with the help of Excel models in order to assess the net present value of potential energy system integration technology investment. The Excel models have also been used to consistently carry out sensitivity analyses in order to assess how changes in parameter values would alter the economic feasibility of the various options. Typical critical variables throughout the cases considered were the future development of electricity prices, of CO₂ penalties, of CAPEX of technical equipment, and of incentive schemes towards greening the energy system. In a number of cases the issue whether or not externalities could hypothetically be internalised also turned out to be of a decisive impact on the economic return of the investment.

The main research activities related to the case in which power from an adjacent wind farm would be completely or in part channelled towards an oil and gas platform for conversion via electrolysis and subsequent transport of hydrogen to shore was carried out by Kees Wouters and Miralda van Schot; the case study in which the economics of positioning electrolyser capacity in the wind turbine itself has primarily been carried out by Malte Renz; and the case study of offshore and onshore steam reforming of natural gas and subsequent CO₂ capture, transport, and storage has been analysed by Gert-Jan Kok.

The project covered the period from the beginning of 2017 to the end of March 2018. During this period, the team benefitted from intensive collaboration with the colleagues of TNO and ECN, as well as the numerous talks with the various operators, that provided valuable information needed for the calculations.

We thank all colleagues for the pleasant collaboration and all information provided, and also the project sponsors (in particular TKI Gas, Gasunie, Gasterra, EBN, NAM, Total E&P, and the others who contributed in-kind) for their support.

Groningen, 30 March 2018

Catrinus J. Jepma, team leader work package 3.1

Table of Contents

Preface	2
Table of Contents	3
Executive summary	4
1 Introduction	7
1.1 Concrete initiatives in the spirit of smart combinations offshore	8
1.2 Outline	9
2 Research philosophy and common approach	11
2.1 Generic assumptions	11
2.1 NPV model	13
2.2 Platform electrification: some generic remarks	14
3 Offshore power-to-gas activities on platforms	17
3.1 Introduction	17
3.2 The various cases related to wind farm-platform connections	19
3.3 Assumptions	23
3.4 Results	29
4 Power-to-gas in or on offshore wind turbines	36
4.1 Introduction	36
4.2 Comparing offshore (turbine) and onshore conversion	37
4.3 Main assumptions	38
4.4 Results	44
4.5 Ecological implications	48
5 Hydrogen production and offshore CCS	50
5.1 Introduction	50
5.2 Offshore natural gas production and CCS	50
5.3 The two options considered	51
5.4 Specific cases and assumptions	52
5.5 Business case evaluation	56
6 General overview and outlook	61
6.1 The perspective of the study	61
6.2 Main findings	62
7 References	64
Appendix A: Business canvasses	68
Battery storage – chapter 3	68
Trade services by electrolyzers - chapter 3	71
Efficiency & hydrogen production location- chapter 4	75
SMR and CCS - chapter 5	77

Executive summary

The development on the North Sea, which is marked by declining oil and gas production activity and rapidly-increasing offshore wind investment, has given rise to a number of new business opportunities in the area of energy conversion and storage of gases, in part of which the offshore wind and oil and gas operators can join forces to benefit both.

In this study, four offshore conversion/storage technologies have been explored, in order to assess if, and under what conditions, such activity may generate positive returns to the investors.

The first technology considered relates to a close cooperation between the investor in an offshore wind farm on the one hand and the owner of a nearby set of oil and gas installations on the other hand. The assumption has been made that all the power of the wind farm is channelled towards the oil and gas installations needed, which in their turn are filled with electrolyzers to convert the wind power into hydrogen that subsequently is transported to shore via the existing gas grid. Obviously, the production costs of the hydrogen depend on the overall investment in the installation and the required e-grid extension, etc.. An important benefit in this case, however, is that the investment that otherwise would have been needed to connect the wind farm to shore with an e-grid connection, is now no longer necessary. This may imply a considerable public saving that, from the societal perspective, would need to be included in the business case. Important sensitivities in this case are: the future development of power prices, the future CAPEX values of the installations, the distance of the conversion activity from shore, and the degree to which platform refurbishment is needed.

The second technology is similar to the former one, but with the important difference that the wind farm has the option to channel max. half of its capacity to shore via an e-grid connection (typically if power prices are high), while the remaining other max. half of the power that can be produced can be channelled towards a nearby platform for conversion into hydrogen (typically if power prices are low, or if the flexibility market makes this beneficial). In this case, the assumption is made that the platform can benefit from the grid connection of the wind farm too, and therefore has access to electricity from shore that can be used to optimise the running hours of the electrolyser, and in doing so optimise the business case. This hybrid solution, where the electron and molecule system are combined to provide a system solution, seems to offer (for now) one of the most profitable solutions.

The third technology is based on the notion that substantial investment in the e-grid connection relates to AC/DC conversion, which costs can be reduced if one would succeed in putting the electrolyser in, or on the gallery of, the turbine. This case requires a slightly more complex process of combining the various sources of hydrogen (each of the turbines). The hydrogen is then transported to a nearby oil and gas platform for compression and further transport to shore. However, it can benefit the most from the fact that most of the transport is done via the existing gas grid rather than via a probably newly constructed e-grid. It also allows for standalone wind parks in offshore areas where installing an e-grid connection would be complex.

The fourth technology focuses on the massive underground storage potential that the North Sea area may provide. In this technology, steam reforming is used to separate natural gas into hydrogen and CO₂, whereby the CO₂ subsequently is stored underground offshore (CCS). The issue is, in this case, if the steam reforming process, rather than being located onshore (e.g. near a harbour), could be shifted to an offshore location, e.g. on a platform or on an installation near a platform. Obviously, space restrictions are more pertinent

offshore than onshore, but taking this into account, the question is which of the both locations could be preferred if all costs including those of transport of the CO₂ would be taken into account.

In all four technologies an extensive Net Present Value (NPV) analysis was carried out including a sensitivity analysis in order to analyse if, and under what conditions, investment in such a technology would be commercially feasible. An important other variable calculated in the simulations was what the cost price would be of the hydrogen produced offshore and brought to shore.

The main conclusions were the following.

The first technology turned out to be highly beneficial under the assumption that the savings on e-grid investment that otherwise would need to have been made are taken into account in the NPV calculus (impact on the 'green' hydrogen production costs about € 1.50 per kg). In this regard, the assumption was used that the offshore e-grid savings would be matched by similar onshore e-grid savings, an assumption considered conservative by most of the experts. Under this assumption, the production costs of 'green' hydrogen delivered at shore turned out to be nearly competitive with current production costs of 'grey' hydrogen (€ 1-1.50/kg), under current conditions, as the break-even price for 'green' hydrogen turned out to be between € 1 and 1.75 per kg. Sensitivity analysis show that even lower cost price figures for the 'green' hydrogen were found for future cases in which the distance from shore was more than 100 km, refurbishment costs for the platform limited, and electrolyser CAPEX values less than € 0.5 million per MW. Under such conditions, the modelling found 'green' hydrogen having the potential to outcompete 'grey' hydrogen. Obviously, policy measures are required to make sure that somehow the e-grid savings can be monetised by the investors in the offshore conversion capacity.

The second technology offers less benefit in terms of e-grid savings (some € 100 million for a platform about 100 km from shore), but offers the option of flexibility, because in this system one has the choice to deliver the power to shore directly or to the platform for conversion, as well as the choice to import power from shore to optimise the electrolyser running hours. In addition, the system has the benefit, next to selling the hydrogen and the power, to also offer flexibility services to the TSO (in our case via the so-called primary and secondary reserve). The business case therefore obviously is more complex than the former one, but also delivered potentially positive returns under likely future conditions. The overall break-even price of 'green' hydrogen turned out to range between € 1.75 and 2.25 per kg.

The third technology, installing conversion technology in the turbine itself, showed a more favourable picture than the comparable case in which the conversion would take place onshore near the entry point of the electricity cable. The explanation is similar to the one provided with regard to the two earlier mentioned technologies: e-grid savings can be considerable, and transport runs through the existing gas grid. In addition, savings could be achieved on AC/DC conversion. Whether this option produced better results than installing conversion capacity on oil and gas platforms is still to be seen, but depends on typical case-specific circumstances.

The fourth technology basically assesses the best location for a steam reformer: onshore or offshore (via a new platform linked to an existing oil and gas platform). The main advantage of an onshore location is that there is virtually no limit to the capacity of the steam reforming installation, and that CO₂ flows from other sources and co-siting can be added to the CO₂ generated in the steam reformer process. This opens the option of massive economies of scale. In the offshore case, space limitations will restrict the options to relatively small-scale processes, in our base case a steam reforming capacity equivalent to 40,000 Nm³

hydrogen production per hour. On the other hand, offshore steam reforming offers savings on CO₂ transport capacities. All in all, offshore steam reforming turned out to provide a better business case, but only if compared with onshore steam reforming at a comparable scale. For larger-scale steam reforming processes (to capture the economies of scale), onshore locations are the only option.

1 Introduction

For a long time, oil and gas exploration not only were the major energy activities in the North Sea, but they also consisted of rather straightforward energy activities: oil and gas was produced from platforms and related installations, compressed on the platforms, and pumped onshore via dedicated pipeline infrastructure. This practice has started to change since about 2015, for various reasons. First, platform activities were partly finalised because the end of the exploration phase had been reached, so that decommissioning of the installations became necessary. Second, ongoing oil and gas production, compression, and transport increasingly met with criticism and new regulations, which related to the need to reduce the massive platform emissions, not only of CO₂ but also of NO_x and related gases. Third, offshore wind energy production started to grow rapidly since about 2010, generating options for collaboration including options to link the wind farms and oil and gas platforms together with e-grid connections. Fourth, the increasing pressure to reduce CO₂ emissions also inspired the launch of new ideas to transform the natural gas molecules from the North Sea into carbon-neutral molecules via chemical conversion, thereby extending the 'license to operate' and therefore continue production of natural gas and oil from the North Sea. The option to use the North Sea underground for large-scale CO₂ storage met with increasing interest such that the pilot stage so far seems to be taken over by larger-scale CCS demonstration activities in the North Sea, based on either onshore or perhaps even offshore conversion of natural gas into hydrogen and CO₂.

In this report, an analysis will be made of a number of the options that are currently explored to make North Sea energy activities an active part of the European energy transition, based on collaboration with other players in the energy world in harmony with the economic activities of other North Sea stakeholders, while respecting safety requirements, ecological and climate concerns, and overall legal and regulatory requirements. In all cases the fundamental questions that we will try to answer based on an extensive economic/business analysis are what offshore investment towards greater sustainability will be feasible under what set of conditions; what the direct business impact of such investment will be; as well as other (partly non-monetary) benefits and costs.

Essentially, three categories of new offshore investment activities will be assessed:

1. Activities to set up intensive collaboration schemes between offshore platforms/installations and nearby offshore wind farms. Such collaboration requires wind farms to have an e-grid connection with the oil and gas installations, and offshore oil and gas operators to completely or partly **redesign their offshore platform/installations** use, by introducing energy conversion and/or storage facilities on the platform structures. Clear examples are cases in which platforms where oil and gas production is terminated, will be used as locations for wind energy conversion, e.g. converting offshore wind energy into hydrogen or related chemical substances (chapter 3).
2. Activities to install electrolyser capacity as close to the power source offshore as possible, namely by **power-to-gas conversion in or on** (e.g. on the gallery of) **the wind turbine**. In this case, e-grid and AC/DC conversion costs can be saved; the energy will be brought to shore as hydrogen (chapter 4).
3. Activities in which platforms are used for underground storage of gases to be reinjected in the exploration fields, i.e. the **underground storage of CO₂** (CCS), specifically the CO₂ derived from the natural gas-based hydrogen production itself (chapter 5).

Activities in the spirit of just platform electrification are not the subject of this report, and therefore have only been lightly touched upon in chapter 2 (for an extensive assessment of this option you are referred to the internal business analysis called “the value of electrification of offshore gas platforms”, which is also part of the larger NSE1 programme.

Activities in which platform activities are initiated to just generate power from the produced natural gas (so-called gas-to-wire activities), to offer that power to a connecting e-grid and in doing so also make a contribution to e-grid balancing, will not extensively be discussed in this report either. An extensive assessment of this option has been executed within the NSE 1 programme. In addition, this option will be covered elsewhere (Energy Delta Institute, ‘Cranberry gas-to-wire offshore case study’, 2018 forthcoming). The same applies for options currently put to the fore in which offshore islands are constructed as a new location for power conversion, energy conversion, energy storage, and possibly other functions.

Finally, power-to-gas conversion can take place onshore, e.g. at or near the area where the e-grid comes to shore, which is often near harbours or comparable coastal areas. The advantage of such location can be that conversion can relatively easily be combined with industrial or other activities, and also that one may benefit from existing facilities and easy accessibility. A potential drawback of onshore conversion can, however, be that specific licenses are required, safety restrictions, or public resistance. Moreover, if onshore conversion applies the energy from the wind farms will in any case need to be transported to shore via e-grid connections, which commonly require a relatively costly offshore e-grid extension. Also this option will not extensively be analysed in this report, although it will be used as a benchmark in for instance the assessment of power-to-gas in or on wind turbines. Also, in our assessment of CCS, onshore steam reforming will specifically be addressed as a benchmark.

1.1 Concrete initiatives in the spirit of smart combinations offshore

A few concrete related initiatives could be mentioned (Hoogma, 2017).

First, the Norwegian government has carried out a feasibility study in 2016, for a full scale CCS project in Norway. Meanwhile, based on a tender, Statoil, together with among others Shell and Total, is exploring to start offshore CCS, based on CO₂ collected from the Norwegian industry. The CO₂ is scheduled, if the project goes on, to be transported to the offshore storage location by pipeline. Obviously, the project can be combined with the production of blue hydrogen (hydrogen from natural gas + CCS), which may add to the feasibility of the project. The initiative illustrates the increasing interest in CCS and in producing blue hydrogen from natural gas.

Second, NUON/Vattenfall is considering to fuel one of its current gas-fired power production units at Eemshaven, Netherlands (the so-called Magnumcentrale), with hydrogen coming from the North Sea. The concept is to use Norwegian natural gas produced from the North Sea that has been separated (pre-combustion) into CO₂ and blue hydrogen, whereby the CO₂ will be stored in the North Sea underground. This way, green power can be produced from North Sea natural gas. It is still to be seen whether the steam-reforming process will be located in Norway, and therefore the hydrogen transported to the Netherlands, or instead in the Netherlands, so that the CO₂ will need to be transported back to Norway. The go-/no go-decision for the Norwegian project is scheduled for 2019, and for the Netherlands application project for 2020. Hydrogen production/application in Eemshaven could then be operational by 2023.

Third, the Port of Rotterdam is investigating how to decarbonise the port area by introducing steam reforming technology to split natural gas into hydrogen and CO₂, and transport the CO₂ to offshore gas fields (notably P15 and P18, operated by TAQA with a theoretical storage capacity of more than 60 Mton CO₂, and Q1, operated by Petrogas, 35 Mton CO₂ storage capacity) and reuse existing platforms and wells. The annual CO₂ storage is projected to be 8 Mton. If a new 2500 MW power plant fuelled by blue hydrogen would be installed, 5.5 GW extra SMR capacity would be needed. If approved, the project can be operational on a relatively short time.

Fourth, on behalf of among others BP Refinery and Uniper, an analysis has been carried out to see if there is a business case for a 20 MW electrolyser potentially connected to the power supplied an offshore wind farm, that would generate hydrogen for an oil refinery in Rotterdam. The petrol produced could then be recognized as being 'green', just as petrol with admixed fuel from biomass, although the European Commission does currently not yet acknowledge this option.

Fifth, in the HyStock project of Gasunie daughters EnergyStock and Gasunie New Energy, together with TenneT and other private parties, a project has been set up at Zuidwending (near Groningen), where currently natural gas is stored in salt domes, to produce hydrogen with electrolysis using green power, and to analyse if (such) hydrogen can be stored in salt domes.¹ The project could also contribute to grid balancing by using its conversion flexibility and storage capacity. Actual conversion is scheduled to start by September 2018, operating a 1 MW pilot electrolyser, while simulating a larger operation of 300 MW that could provide serious balancing services across the North Sea area, such as via the COBRA cable linking the Northern Netherlands grid to that of Denmark.

Sixth, TenneT (the Netherlands/German TSO for the e-grid), Energinet.dk (the Danish TSO for the e-grid and gas grid), Gasunie (the Netherlands TSO for the gas grid), and various others have launched the idea to create an island at the Dogger Bank location in the North Sea to connect most of the North Sea wind farms in order to integrate the North Sea countries' power markets and to transport the power and balance the grid against lower costs. The project also intends to install conversion and possibly storage facilities on the island by converting renewable power into green gases to be transported to shore via existing gas infrastructure, to the extent feasible as well as electrical interconnection².

Seventh, project developer HYGRO develops an integrated plan for electrolysis inside wind turbines. A wind turbine of Lagerwey (4.8 MW) will be developed such that it contains an electrolyser in its basement to produce hydrogen 'on the spot'. This technology will be tested in Wieringerwerf by ECN and is expected to be operational by early 2019. The benefit of the technology is to save on AC/DC conversion steps and possibly also on the transport of power. In principle the technology can be implemented both onshore and offshore. Examples of testing of the latter option are not yet planned, to the authors' knowledge.

1.2 Outline

In the following, first the main research philosophy, generic research aspects and complexities, data, and main generic assumptions will be discussed (chapter 2), since together they provide the consistency between

¹ Note that a full-size salt cavern can store some 7,200 tonnes of hydrogen (240,000 MWh). In the North of Germany and the Netherlands, dozens of such caverns can be developed.

² <https://www.tennet.eu/nl/nieuws/nieuws/gasunie-treedt-toe-tot-north-sea-wind-power-hub/>

the various options' analyses. Only by using a consistent common framework and dataset it is possible to mutually compare the various offshore technology options. The idea is to not only get to a consistent set of assumptions that is as uniformly as possible implemented in the various business analyses, but also to provide maximum transparency on the assumptions that have been made in order to get to the business case/economic analysis.

A complication is that most of the investment technologies analysed can only feasibly be implemented in the future, i.e. taking into account the usual investment lead times. Since most of the technologies are still in their infancy, it is fair to assume that whatever future investment is going to be initiated around the oil and gas platforms and offshore wind farms, it will take at least a number of years before such investment will actually materialise. The analysis therefore by definition will have to relate to a future case, e.g. anywhere between 2020 and 2030, in which learning curve effects will potentially shape cost curves quite different from the current ones. Another complexity relates to the economies of scale: if new technologies are, in the course of time, introduced at a large(r) scale, economies of scale may equally have a declining impact on costs. At the same time, policies and measures may differ as well as we move to future conditions, which also would need to be taken into account in future-oriented business analysis. That is why in chapter 2 not only the current data, but also potential future parameter values of data will be discussed.

In chapters 3 to 5, the three approaches mentioned above will be discussed, analysed, and put in a comparative scenario perspective. In all cases, the various assumptions, modelling approaches, and results will be reported. The most detailed, publicly available, information with regard to the various approaches have further been registered in annexes to each of the chapters.

Finally, in chapter 6, we will try to look into the future by assuming large-scale implementation of the specific technologies, that may equally benefit from the learning curve and from optimal international coordination between the various North Sea country operators of both oil and gas and wind. By sketching various scenarios of new technology implementation, it will be tried to provide a picture of the various technology options' economic feasibility if they would be implemented full-size and full-scale. By doing so, the different technologies can be mutually compared with respect to what conditions will determine their future business case.

2 Research philosophy and common approach

As was argued already in the introduction, it was considered important in the analysis of the various offshore technology options to introduce consistency by, among others, using the same assumptions as much as feasible. In order to, additionally, provide transparency about the assessment, all the assumed parameter values have been listed below, whereby – except from the generic ones – the assumptions have been structured along the three key technologies distinguished: offshore power-to-gas activities on platforms (chapter 3) and in/on wind turbines (chapter 4), and offshore CCS (chapter 5).

2.1 Generic assumptions

Assumptions regarding financing, return requirements, and economic conditions

- inflation rate: 2%
- tax rate: 20%
- overall discount factor: 5%
- oxygen is not valued³

Assumptions regarding platform refurbishment

- costs related to preparing a platform for installation of electrolysers: €10/kg
- costs related to adding a complete new deck: €40/kg
- part of the deck not replaced (direct gas-specific installations): 25% of platform weight (assumed also 25% of costs). Hence, costs in the order of €40/kg are applied when new topside structure are installed, while refurbishment costs data that relate to re-use of existing decks are estimated to be in the order of €10/kg.
- On the whole, this ‘decommissioning bonus’ of about €20 billion (for a production platform) and about €4,5 billion (for a satellite platform) remains relatively limited, because it is assumed that the only gain is that decommissioning is postponed, but not cancelled.

Assumptions regarding electricity prices

Electricity prices are assumed to be similar to those in the scenarios by Frontier Economics Ltd. (2015).

- For the trade - cases (chapter 3) – future price levels are assumed to follow a stationary path, whereby the mean reversion model could be used to filter out the fixed parts of the electricity price and thereby estimate future price levels. Manual adaptations to this model could be made to include analysis for trade-cases depending on different price levels of Frontier (2015) and EV projections (ECN, 2017), as well as on different volatility levels. In the trade options, the switch price levels of € 40, € 60, € 70, and € 90/MWh have been used.
- For the primary reserve, capacities of 1, 10, and 30 MW have been assessed.

³ However, oxygen might be very valuable for system processes. For instance, burning natural gas in oxygen rather than air generates a higher concentration CO₂ stream which could require less costly separation before injecting CO₂ underground. Hence, green hydrogen production may help clean up multiple locked-in hydrocarbon users by distributing the oxygen “waste” product.

For the analysis in chapter 4, where the wind farm/turbine is connected to the oil and gas platform, it has been assumed that there is a single operator, so that the system boundaries include the respective wind park CAPEX and OPEX as well as its connection to the platform.

See Appendix A for the complete system boundaries of the different business cases.

Assumptions regarding hydrogen prices

The 'grey' hydrogen price as commonly used for bulk volumes by the chemical industry is assumed to be €1.56/kg or €25.20/MWh, while the 'grey' hydrogen price as used in mobility is assumed to be €4.67/kg or €75.55/MWh (Jansen, 2015; Jepma, 2015, pp. 22-23; Meerman, 2012; Jakobsen & Atland, 2016) (for an early price estimate for green hydrogen see also Smolinka et al. (2011), who arrived at per kg cost prices ranging between €3 and about €9). Because the mass of CO₂ emissions related to the production of 'grey' hydrogen (generated via traditional steam reforming) is about 10 times higher than the mass of the produced hydrogen, the price impact of the CO₂ footprint of the production of a kg of 'grey' hydrogen is about €0.06, if one would assume that hydrogen production is subject to the EU ETS, and that allowance prices are €6/tCO₂.

Based on average Dutch subsidy rates for 'green' versus 'grey' energy supply, for 'green' hydrogen a mark-up of 30% on the price of 'grey' hydrogen is assumed. This implies a price for 'green' hydrogen of €2.03/kg or €32.76/MWh for the low hydrogen price cases, and €6.07/kg or €98.22/MWh for the high hydrogen price cases. To further illustrate why the assumed about €6/kg for 'green' hydrogen to be used in mobility could be considered to be still relatively conservative, the following reasoning could apply. The energy content of 1 kg of hydrogen is roughly sufficient to drive a modern hydrogen car (with fuel cell) about 100 km. If the same distance is covered with the help of an average car fuelled by petrol or diesel, the average costs for fuels range anywhere between €8 and €10, as ballpark figures. The assumed about €6/kg for 'green' hydrogen therefore is relatively low, if a direct price comparison is made. This comparison is, however, of course complicated by the tax component of the petrol/diesel price, which is not yet included in the €6/kg for the hydrogen. But then again, the hydrogen is a 'green' fuel unlike the petrol/diesel, so that a less heavy tax regime would seem fair. All in all, the about €6/kg is therefore considered an acceptable proxy level for a future high, niche market 'green' hydrogen price.

If the allowance price would increase, the 'grey' hydrogen price per kg will roughly increase with €0.01 for every €1 of increase of the EU ETS allowance price. So, for the chemical industry, the price of 'grey' hydrogen would increase to levels similar to that of the assumed 'green' hydrogen price (€2.03), if the EU ETS allowance price would rise to €53. This is not unlikely, given the fact, the Dutch government has reported the introduction of a minimum price starting with €18 per ton CO₂ in 2020 going up to €43 per ton in 2030.

Assumptions related to CAPEX and OPEX of conversion equipment

- CAPEX of Silyzer 300: €1255/kW (2017). This assumed CAPEX figure is automatically adjusted depending on the time of investment and the respectively applied learning curve, suggesting considerable scope for cost reduction if conversion technology can be implemented on a large scale and for a long period. In comparable conversion technologies cost reductions of over 50% within a decade are no exception (Tractebel Engineering S.A., 2017; E4tech Sàrl with Element Energy Ltd,

⁴ Regeerakkoord 2017-2018 'Vertrouwen in de Toekomst', oktober 2017.

2014). This learning effect resulting from technological innovations and practical experiences has been taken into account in the sensitivity scenarios.

- CAPEX desalination unit: €61,200 for a 2000L/h capacity unit which is about €0,02 per kg of produced hydrogen.
- maintenance costs of Silyzer 300 and a related desalination unit (projection): 2.5% of CAPEX. This figure does not include the costs of electricity intake (Jepma, et al, 2017.)
- hydrogen production per unit of power: 1 kg/54.18 kWh, leading to an energy efficiency of 73% (HHV)⁵.
- depreciation period of electrolyser and related equipment: 10 years.
- residual value of the same equipment: €0 (at least if operation time exceeds 60,000 running hours; otherwise depreciation in proportion with running hours).

Assumptions related to transport and project externalities

The investment costs of grid connections, whether pipeline or electric grid, are monetised depending on the capacity of the wind farm and the distance to shore. For the used methodology, see Renz (2017).

- CAPEX of gas separation station (PSA): €1,000 per capacity of 1 Nm³/h
- OPEX of gas separation station (PSA): 5% of CAPEX

CAPEX of new hydrogen compressor:

- $CAPEX_{Compressor;2014} \left[\frac{\text{€}}{\text{kW}} \right] = \frac{2545}{x}$ With the exchange rate x in 1.33 €2014 / USD2014
- Annual maintenance costs for hydrogen compressor: 3% of CAPEX
- $CAPEX_{Pipeline;2014} [\text{€}] = 1.75 \times l_{pipeline} \times \frac{(418,869 + 762.8 \times d_{pipeline} + 2.306 \times d_{pipeline}^2)}{x}$
- OPEX of dedicated hydrogen pipeline: 2% of CAPEX

2.1 NPV model

The net present value (NPV) method is a suitable and commonly applied tool to analyse the different business cases of energy system integration. It basically subtracts the initial investments from the sum of future discounted cash flows (Equation 1).

$$NPV = \sum_{t=1}^T \frac{FCF_t}{(1+r)^t} - I$$

with

FCF = free cash-flow

r = discount rate

I = initial investment

Equation 1: Calculation of the net present value

Since the free cash-flow is based on forecasts which are by nature imprecise to a certain extent, a sensitivity analysis is a mandatory part of the research to show the range of NPV with regard to changing circumstances.

⁵ This figure can be considered conservative; in DNV GL AS (2015, p. 24), the theoretical system efficiency is estimated to be 81%.

As far as future projected electricity market prices are concerned, increasing prices are expected (Frontier Economics Ltd., 2015) and included in the NPV calculation (for further details, see Figure 8). Besides, technology learning rates for offshore wind turbines and electrolyser systems are taken into account as well (Figure 1).

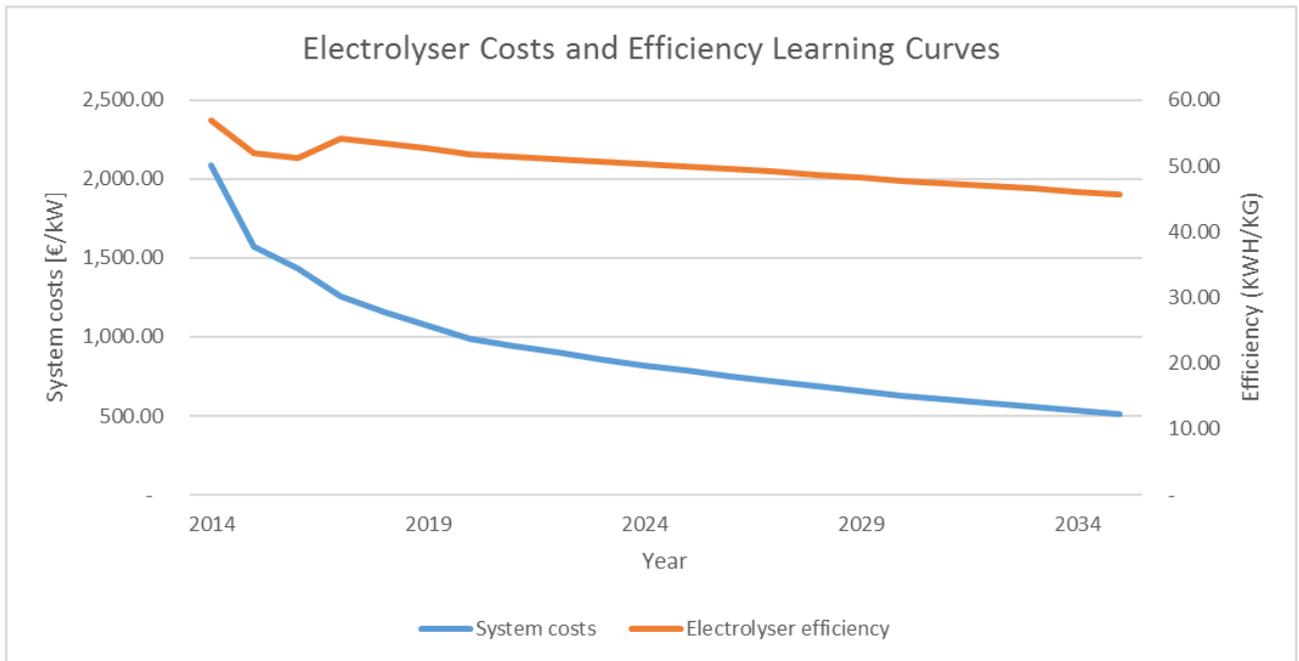


Figure 1: Electrolyser costs and efficiency learning curves, author’s figure based on (E4tech Sàrl with Element Energy Ltd, 2014; Tractebel Engineering S.A., 2017)

Focusing on the NPV, the free annual cash-flows composed by the sum of revenues and expenses are discounted with a discount factor including return of investment, opportunity costs and project risk.

2.2 Platform electrification: some generic remarks

The various options of system integration often have a common starting point: the electrification of gas platforms. The platform can then also be refurbished so that hydrogen can be produced from electricity. Also it becomes possible to use the electricity to support capture and storage processes of CO₂. These functionalities could lengthen the lifetime of a platform after the production of gas has ended. An extensive assessment of this option has been analysed within this NSE 1 programme.

There are various reasons why operators may consider platform electrification. First, the platform itself obviously will need energy for the daily operation. If there is no connection with the offshore e-grid, power can be produced from the natural gas and oil production via relatively small-scale gas-to-power installations, installed on the platform itself. Also, compression of the natural gas produced will require substantial volumes of energy. To illustrate, it has been estimated that the about 150 platforms (including satellite installations) in the Netherlands Continental Shelf (see Figure 2) need, if taken together, about 7 TWh per year in terms of energy, just to compress the natural gas to the desired level for gas grid injection (some 60

bar). To the extent that natural gas will be used for such energy needs, the CO₂ footprint can be substantial. A rough estimate of the CO₂ emissions of all the platforms and installations on the Netherlands Continental Shelf would suggest that collectively the North Sea activities are responsible for some 0.5% of all Netherlands CO₂ emissions.

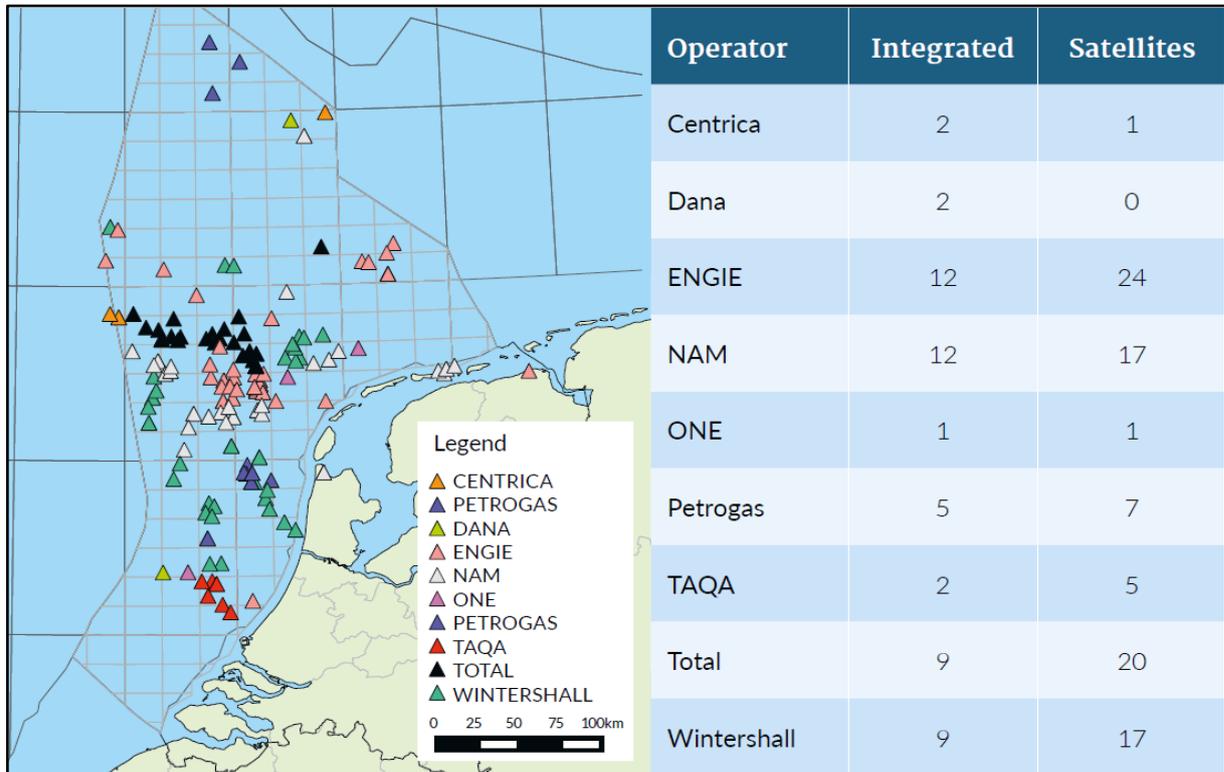


Figure 2. Platforms on the Netherlands Continental Shelf (EBN, 2016, p. 52)

If the operator wants to reduce its offshore CO₂ footprint, one of the options is to try to electrify the platform and preferably use green power rather than natural gas as an energy source for platform activity. Green electricity obviously has a very limited CO₂ footprint compared to natural gas use. But also, even if fossil-based power will be used for compression, electrification will enable to decommission former low-efficiency gas-to-power installations, which raises the energy efficiency of compression enhancing another source of CO₂ emission reduction.

Yet, in actual practice, CO₂ footprint concerns so far do not seem to be the only reason why electrification of platforms is considered by a number of operators in the Netherlands Continental Shelf. An important reason is linked with the EU Medium Combustion Plant (MCP) Directive 2015/2193. This directive, which for the Netherlands situation led to the 19 August 2017 amendment of the so-called *Activiteitenbesluit milieubeheer*, enforces offshore operators to comply with substantially stricter NO_x emissions norms (the option of an exemption for gas compression plants in article 6 of the *Activiteitenbesluit* has been disregarded by the Netherlands government). These norms effectively imply in various cases that operators have to adjust their traditional natural gas-fuelled compression by either introducing NO_x filters, or by compressor activity electrification. Otherwise, it will not be possible for them to comply by the due date, 1 January 2019, with the NO_x norm of maximum 50 mg/Nm³, or 75 mg/Nm³ for offshore turbines installed before 1 April 2010 (Article 3.10d.3). At the request of NOGEPa, compressors that will be closed down before 1 January 2022 will

not be subject affected by the new directive regime. In addition, the *Activiteitenbesluit* introduces a norm for SO₂ (15 mg/Nm³), which equally will need to be respected.

Electrification of platforms, if implemented to comply with the new *Activiteitenbesluit*, obviously will require substantial investment in both equipment and e-grid connection. The costs of such investment will have to be weighed against the option to terminate oil and gas production, maybe not by the end of 2018 but then in any case by the end of 2021. The complexity of this assessment relates to the mix of private and public costs and benefits. Oil and gas production generates returns not only for the operators (private) but also for the government (public). This equally applies to the investment costs, because part of the grid extension will be funded by the transmission system operator (TSO), which is a state-owned and state-funded organisation. The assessment whether or not to continue after 2022 therefore is a complex calculus that can easily develop into a negotiation game between the operators and the government. The complexity even increases further by economies of scale: if a range of platforms can be linked together via one e-grid connection, costs per platform may seriously come down thanks to proper coordination and shared infrastructure services. This is why the assessment of this range of technologies can become rather complex and the results rather sensitive for the degree to which effective cooperation between the various stakeholders can be achieved, as well as the distance between the anticipated grid extension and the existing grid, or even the distance to and from new sources of offshore wind power.

3 Offshore power-to-gas activities on platforms

3.1 Introduction

There is increasing doubt if the expected massive offshore power production from the North Sea wind farms can effectively be transported via e-grid towards the end user of that power. The grid capacity investments that would be necessary to transport the expected volumes of power will not only be very significant offshore, but will most likely also need to be accompanied by substantial onshore grid extensions. Especially the latter may turn out to be not only technically complex and costly, but also difficult from the perspective of social acceptance, and – given the considerable lead times (see Figure 3 for offshore conditions) – of planning⁶. Note that the beneath figure only covers the offshore grid planning. Onshore grid planning requires even longer lead times. That is why increasingly a discussion has emerged on the issue if it would be a good idea to – next to the e-grid for energy transport – also use the (existing) gas grid to transport the offshore wind energy towards its destination. The benefit of that concept would not only be that the transport of gases per unit of energy is substantially cheaper than transport of power over the same distance, but also that gases can be stored much easier and cheaper in large volumes than power (as well as virtually any other large-scale storage option).

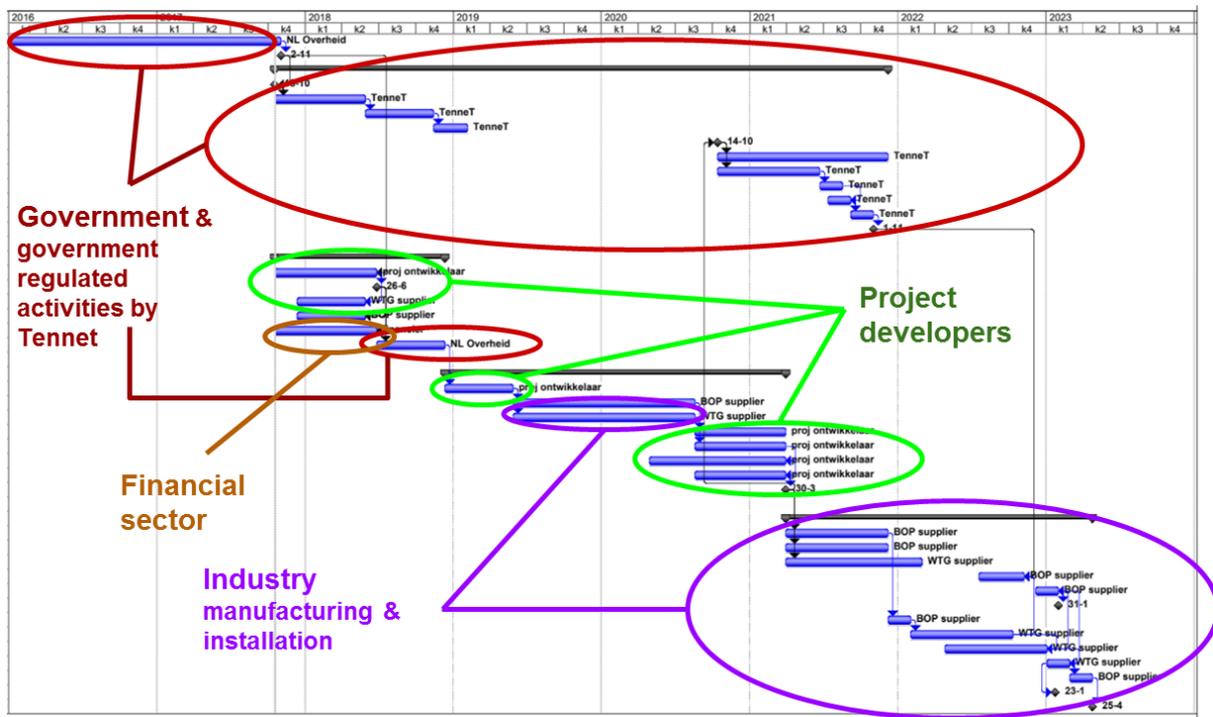


Figure 3. Lead times for e-grid extensions (Verhagen & Gardener, 2018)

⁶ The lead time for offshore wind farm development is not dominated by the offshore electricity system, but is a sum of factors such as the supply of the wind turbine generators, spatial planning, financing and permitting.

If part of the transport and storage of North Sea energy will be by way of gases, obviously part of the power generated by the wind farms will need to be converted from electrons into molecules. The obvious technology, electrolysis, is well-known; energy losses in conversion on average are in the order of 25%, which is a relatively small figure compared to various other conversion technologies (E4tech Sàrl with Element Energy Ltd, 2014; Tractebel Engineering S.A., 2017). In order to benefit the most from such conversion, transport by e-grid should therefore be replaced by transport via a preferably existing gas grid as much as possible. This implies that theoretically the conversion mentioned should be taking place as near as possible to the location of the power production, the offshore wind farm.

Various locations can be thought of for the conversion process. The most nearby location obviously is the wind turbine itself. That is why in this study an analysis has been made of the technical and business perspectives of putting electrolyser capacity in and/or on a wind turbine. The advantage of this approach is that on average two fewer AC/DC conversion steps are needed than in all other location options for conversion; the disadvantage may be that access to the electrolyser and space may generate some technical restrictions. In addition, a gas grid connection towards individual wind turbines, as well as compression capacity, is required, which may pose another restriction on this option. This option is discussed in chapter 4.

An alternative location, which on average is also relatively close to the offshore wind farms, are the existing oil and gas installations in the North Sea. This chapter focuses on this location option for installing conversion capacity. Some of those installations are already in the process of decommissioning or are already decommissioned⁷ because of depletion of the wells or by lack of a business case to continue oil and gas production; others are foreseen to be decommissioned in the foreseeable future, because most of the wells will no longer provide a production business case in the upcoming two decades. For an overview, see Figure 4.

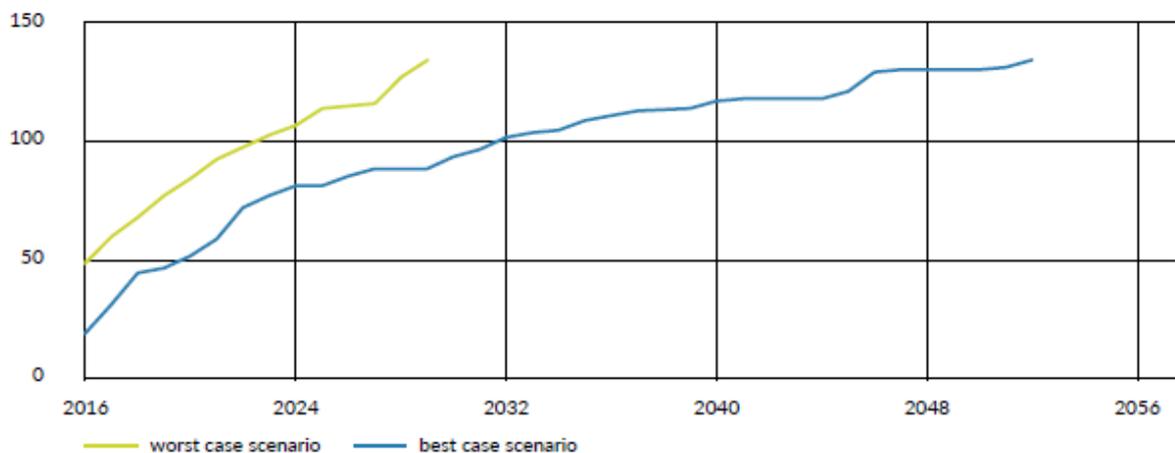


Figure 4. Number of installations that reach Cessation of Production in upcoming years: best and worst case scenarios (EBN, 2016, p. 45)

⁷ Note that the interval between cessation of production and actual satellite removal has been four years on average, with a maximum of 12 years.

So, substantial offshore capacity may be available for ‘a second life’,⁸ if it is still technologically usable. This would not only make sense because it could be considered a waste of resources – and indeed marine life-linked infrastructure – to remove otherwise stranded assets, but would also postpone decommissioning costs, which are projected to be substantial indeed.⁹ Such a ‘second life’ could be a variety of options, of which hosting substantial electrolysis capacity could be an interesting one. In a former study by Jepma & Van Schot (2017), it was demonstrated that a production platform has the capacity to host some 250MW modern (e.g. Siemens Sylizer 300) electrolyser capacity and related equipment, and that satellite platforms could host some 60-70MW electrolyser capacity¹⁰.

Given the average size of a wind farm, some 700MW, and given that optimal electrolyser capacity was found to comprise some 78%¹¹ of the capacity of the linked wind farm, the above data suggest that two mother platforms could host sufficient electrolyser capacity to absorb all energy from an average-sized wind farm. Obviously, if the distance between a specific wind farm and oil and gas platforms is limited, the costs for an e-grid link between the wind farm and the platforms can remain limited as well; if the existing gas grid can subsequently be used for transporting the gases to shore, investments in additional grid capacity can remain limited. At the same time, the platforms will need to be refurbished for being able to host massive electrolyser capacity, which obviously leads to additional costs that will need to be taken into account in the business case analysis. In this option, it may be quite complex to connect all individual wind turbines to the platform because of the multifold sources of power supply, which need to be collected and connected to a substation. The most common way to collect the power at a central collection point is to connect the individual turbines in a string cluster (Bresesti et al., 2007, p. 38). This means that several turbines are connected in series with a so called feeder that leads to the central collection point which in this case will be an existing oil and gas platform.¹²

3.2 The various cases related to wind farm-platform connections

Case 1: Batteries on platforms

Wind farms and platforms can be connected in various ways. First, batteries can be installed on platforms, either existing ones or new ones, to store the excess power generated by the wind turbines (or possibly, if the platform itself is electrified, from the platform itself) on the moments at which power prices are relatively low. The stored energy can be put to market again if prices are sufficiently high. If a platform is required as a location for the batteries to be used by a nearby wind farm, obviously the platform needs to be linked to shore with an electric cable (either directly or via the wind farm). If this requires new investment in e-grid

⁸ Note that existing offshore platforms need to be assessed on a case-by-case basis for their suitability, technically and economically, as an energy conversion, compression, and/or storage location.

⁹ For some further information on decommissioning cost estimates, see for instance Jepma (2015, pp. 11-12); for the UK continental shelf, Walker & Roberts (2013, p. 10) estimated costs at GBP 28.7 billion by 2040, with GBP 10.3 billion of that to be spent in the next decade.

¹⁰ For more details on the distribution of electrolysers per platforms, see Jepma & van Schot, 2017.

¹¹ In the case of an optimal ratio of the electrolyser capacity vis-à-vis the windfarm capacity (some 78% in the base case), 6% of the wind power is curtailed. As was argued before, it is assumed in the simulations that the operator of the electrolyser fully compensates the offshore wind operator for the missed returns due to power being curtailed.

¹² If, instead, the power would be transported to shore via the e-grid, the collection point, usually an offshore substation, will be used to increase the voltage level to enable long-distance transmission.

connection, this adds to the investment in batteries and in the refurbishment of the platform for positioning the batteries.

Given investment costs, a break-even can only be achieved if the arbitrage function of the batteries pays off sufficiently, i.e. the benefit of the power price differential in time is sufficiently high, and if there is sufficient benefit from less cable capacity needed, because of the storage option, possibly in conjunction with returns on flexibility services. Various calculations have been made to assess the business case of offshore battery installation, with varying power prices and their volatility.

The main conclusions of the battery storage calculations were the following. First, the capacity of the batteries turned out to be insufficient for the energy storage capacity needed. The maximum size possible on a platform, 100 MW, would be just enough to save 8 minutes of energy in case of full capacity utilisation of the wind farm. This would not allow for any meaningful savings on the e-grid connection to shore (Dougas, 2017; Kubic 2017). Second, batteries would simply be too expensive compared to the potential savings. In a number of scenarios, the initial investment on batteries, € 175m (assuming a replacement every 2 to 3 years, annual costs amount to some € 70m), have been compared with the annual power trading benefit. In all studied cases, a break-even could not be reached. In fact, not even close (in all studied scenarios the annual trade benefit is less than € 5m). The option to add the possibility of primary and secondary reserve did not alter this conclusion.

So, in none of the studied scenarios a business case for offshore batteries that offer trade services could be achieved. On the whole, savings on the power cables are in practice quite limited, investment needed in batteries and platform refurbishment rather substantial, and the margin achieved on buying and selling against different power prices rather small in our assumptions, due to the short storage cycles of hours or within a day. An extra complication was that batteries often did not fit well on the platforms. This case, where batteries are used for the provision of trading services, therefore has not been assessed any further.

Although, batteries have insufficient capacity for substantial energy storage, they can be used for short-term purposes, like enhancing balancing, ramp-rate limitation, and covering grid outages. For instance, wind turbines with integrated batteries are already on the market to supply system services to the electricity grid. Note that such system services were not taken into account yet.

Case 2: Hydrogen production on platforms, if all wind energy from a particular windfarm is channelled towards the platform¹³

This case builds on an earlier study (Jepma & van Schot, 2017), but has been refined and extended in a number of ways. The concept of the simulation is a situation in which a substantial oil and gas platform that has terminated oil and gas production is turned into a location for substantial energy conversion activity. The surface of the production platform is completely used for hosting electrolyzers and related equipment up to a capacity of 250 MW¹⁴ Obviously, a desalination plant and compressor will be part of the platform equipment. Based on the algorithm used in Jepma & Van Schot (2017), electrolyser capacity represents 78% of the

¹³ The current wind farm are about 700MW, if planned wind-farms become bigger you might need a cluster of platforms to channel all wind energy

¹⁴ The installed capacity of electrolyzers is very dependent on the size of platforms. Platforms that could host up to 250 MW are relatively large in comparison to the smaller satellite platforms. For more information on the size restrictions of platforms, see Jepma and van Schot, 2017.

installed capacity of the offshore wind farm delivering its wind power to the platform (so, the wind farm has an assumed capacity of about 315 MW).

In some of the simulations of this study the assumption has been made that all the power produced by the wind farm is transported to the platform via a substation for conversion into green hydrogen, and that the existing gas grid can – with minor adjustments only – be used to transport the hydrogen to shore (and possibly further). The benefit of this concept typically lies in the fact that an electricity cable connection towards the offshore wind farm is no longer needed, neither connecting the wind farm with shore, nor the further assumed grid reinforcement onshore. In addition, there is obviously the ‘decommissioning bonus’, i.e. the monetary value of the postponement of the decommissioning of the platform. On the whole, this ‘bonus’ remains relatively limited, because it is assumed that the only gain is that decommissioning is postponed, but not cancelled.

The business aspects of this case are crucially determined by the price of the power input and how this price will develop into the future. Next to this, the current and future price of the green hydrogen is a crucial variable: will the green hydrogen market develop such that substantially higher prices can be acquired for the green hydrogen (say, anywhere between €5 and 10/kg), than the current market price range for grey hydrogen (between some €1 and 2/kg)? And in addition, the savings on the electricity cable seem to be crucial for the business case as well, so that the business case will improve as wind farms will be increasingly located far from shore¹⁵.

The main difference in the business case analysis in this study in which all power is channelled towards the platform for conversion, if compared to the comparable analysis in the earlier study mentioned (Jepma & van Schot, 2017), is the notion that the e-grid savings are not limited to the offshore part of the grid, but potentially also relate to e-grid savings in the onshore trajectory towards the final destination of the offshore energy. On the whole, e-grid investment onshore can be more complex in terms of licensing and public acceptance (and therefore costs and time needed can be higher), than comparable offshore investment. For that reason, by way of assumption, the overall savings on e-grid investment for this case where all wind power is converted into hydrogen, have been put *twice* the value of the offshore e-grid savings.¹⁶ Given the circumstantial information on onshore e-grid costs, the latter assumption still seems quite conservative.

Case 3: Alternating power trading and hydrogen production

An interesting case to be explored is the one in which a wind farm already is connected to shore with an electric cable, but also linked to a platform on which electricity can be converted into green hydrogen. The main advantage of this case, compared to the former, is that the two entities, the wind farm and the platform, are no longer completely condemned to each other, but instead will be able to flexibly service each other, or not, depending on the economic and technical circumstances. The major disadvantage of this case, however, is that the substantial savings on e-grid will no longer apply, although some grid savings can be feasible to

¹⁵ Externalities increase with greater distances (more installation work, more crossings and higher material usage. Internalising the savings on these cable cost can lead to lower prices for hydrogen

¹⁶ This assumption is based on a recent public news article of Tennet in ANP, 2017. In this source, they indicated that offshore e-grid investment will increase with about €2 billion in the next ten years, whereas investments in the onshore grid will grow with €3,5 – €4,5 billion.. During the NSE 1 inspiration-session with experts it was mentioned that spatial planning, (societal) costs and longer lead-times are main factors affecting this cost difference between offshore and onshore e-grid development..

the extent that on average less peak power volume will need to be transported to shore via the e-grid, because it can be transferred via the platform.

The economics of this case obviously are more complex than those of the former case, because of the complexity to determine when the offshore wind power is directly delivered to shore via the e-grid, or instead delivered to the electrolyser on the nearby platform. Obviously, the ratio between the power price and the expected hydrogen price is the most crucial variable determining the switching behaviour of the electrolysis. Next to that, the flexibility of the electrolyser will be crucial in determining its absorption capacity. Because PEM electrolysers on average are more flexible in ramping up and down, the assumption has been made that the platform will use that electrolyser technology (see Box 1 for some details).

A final complexity of this case where the platform operator can choose between two options of energy delivery, is that he/she will have the option to not only put the power on the market on the moment that offers the best price, but also to sell the primary and secondary reserve, i.e. put the flexibility of the electrolyser capacity on the market. It has been assumed that the wind operator can channel max. half of power production at full capacity (500 MW) via the e-grid to shore, and equally half of power production to the platform (which has a 250 MW capacity electrolyser). The additional costs of offering reserve capacity are considered to be absent, because the installation is available anyhow, so that the returns for providing the primary and secondary reserve (both positive and negative nominations) can be seen as a bonus on top of selling the power. In this case the operator of the electrolyser has the additional option to use power from shore to fuel the electrolyser if there is insufficient power supply from the wind farm and if this adds to profit, thereby benefitting from the fact that the platform is linked to power supply from shore via the e-grid connection with the wind farm.

In the analysis of this case, extensive sensitivity analysis has been carried out, depending on: the projected power price – 6 options, all based on Frontier (2015) and EV projections (ECN, 2017) – and hydrogen prices (7 options, ranging from € 1 to € 4/kg).

To optimise the returns, the platform operator channels (as much as possible) electricity to shore if the power price is higher than a certain level. If the price is lower than that level, as much as possible of the electricity is channelled to the platform for electrolysis. To empirically identify the optimal switch price, a sensitivity analysis has been carried out, in which for all combinations of power and hydrogen prices the NPV and the break-even combination of prices of the overall conversion investment has been assessed. In this assessment, the switch price levels of € 40, € 60, € 70, and € 90/MWh have been used.

In addition to the switching option, the additional option to channel power from shore to the electrolyser in typical cases in which little wind power would be available for the electrolyser, has been included. This way it is secured that the electrolyser runs the optimal number of running hours. Furthermore, the primary and secondary reserve switching capacity option has been added to the case, because this can generate extra returns on top of the returns from the hydrogen production and power sales. The reason why the offering of the primary and secondary reserve will always add to profit is that the system always has the option to deliver or not deliver the power, because of the degrees of freedom to transfer power to the electrolyser, that moreover can be ramped up (to about 160% of capacity, for a brief period) within the timeframes required

for the reserve capacity offered to the TSO¹⁷. For the primary reserve, capacities of 1, 10, and 30 MW have been assessed.

3.3 Assumptions

In the following, the main assumptions of the analysis will be outlined briefly.

Box 1. Main differences between alkaline and PEM electrolyser technology

Alkaline

- Electric efficiencies 62-82% HHV (Tonen, 2015, p. 3)
- Inability to produce at lower partial load range (Tonen, 2015, p. 3)
- Less suited to cope with renewable intermittent power: conventional systems tend to have long start-up times (minutes to hours, depending on whether starting from stand-by or cold-start), and usually they have trouble keeping up with rapidly changing power inputs (Noujeim, 2014, p. 15)
- The alkaline water electrolyser typically operates at 60–80 °C with a corresponding thermodynamic voltage for water splitting of 1.20–1.18 V. The terminal cell voltage of an alkaline water electrolyser is 1.8–2.4 V at the typical operational current density of 0.2 to 0.4 A cm⁻² (Xiang, Papadantonakis, & Lewis, 2016)

PEM

(Tonen, 2015, p. 3):

- Technical performance is comparable to Alkaline
- Except: Flexible operation possible
- Deployment time in seconds
- Requires costly noble metals but expected to be minimised in future
- within the same temperature range (50–80 °C) as alkaline water electrolysers (Xiang, Papadantonakis, & Lewis, 2016).
- For instance, a PEM Siemens Silyzer 300 unit with a 10 MW capacity would require an area of about 70 m², excluding 1.5 m at one side at least of the electrolyser for maintenance access, etc. (Jepma & van Schot, 2017, p. 17; E4tech Sàrl with Element Energy Ltd, 2014, p. 11)

The electrolyser assumption relates to the characteristics of the prospective PEM Siemens Silyzer 300 electrolyser; see Table 1 below, copied from Jepma & Van Schot (2017).

¹⁷ Negative nominations mostly occur due to short-term (seconds or minutes) mismatches between supply of energy and the demand for energy services. The wind turbines could offer these negative nomination by curtailing the energy use, whereas electrolysers could offer negative nominations by ramping-up their production. Hence in both cases electricity is retrieved from the grid. However, in contrast to wind turbines, electrolyser could also offer positive nominations by decreasing their power consumption.

Electrolyser characteristics

Table 1. Characteristics of electrolysers

	Siemens Silyzer 200 high-pressure ¹⁸	Etogas Alkaline ¹⁹	Siemens Silyzer 300 PEM (expected to be available by 2018)
Stack capacity:	1.25 MW	1.2 MW	10 MW (for 10-20 minutes 160% of capacity can be reached)
Fresh water infeed:	1.5l/Nm ³ H ₂ = 337.5l/h	350l/h	1.5l/Nm ³ H ₂
Hydrogen produced under nominal load:	225 Nm ³ /h	250Nm ³ /h	1800Nm ³ /h
Oxygen produced under nominal load:	112,5 Nm ³ /h	125 Nm ³ /h	900Nm ³ /h
Skid dimensions:	6.3x3.1x3 m (=58.59 m ²)	15x30m Housing: 2 x 40 ft. and 1 x 20 ft. container	70 m ² (height about 5 m)
Weight:	17 tonnes		102 tonnes
Start-up time:	<10 sec		<10 sec
Pressure (bar):	Up to 35 bar	Up to 15 bar	Up to 35 bar
Purity levels:	H ₂ : 99.5-99.9%	H ₂ : > 99.9% O ₂ : > 99.1%	H ₂ : 99.5-99.9%
Lifetime:	>80.000 h; >9,1 years	20 years	>80.000 h; >9.1 years
Maturity:	Commercial	Commercial	Under development
Efficiency :	75%	62% 4.8 kWh _{el} /Nm ³ H ₂ (AC)	75%
Grid connection:	10 kV/20 kV/33 kV	20 kV AC, 1.4 MVA transformer included	
Temperatures:	>4°C	Outdoor: -20°C up to +40°C	>4°C

¹⁸ The electrolyser technology based on Proton Exchange Membrane (PEM) contains the advantages of: achieving higher cell efficiency levels; high current densities at low corresponding cell voltages; high power densities; and the ability to provide highly compressed hydrogen (Lehner, et al., 2014). Moreover, the PEM is very flexible due to fast start-up and shut down cycle times. Although these advantages perfectly fit the requirements of an average power-to-gas installation, there are some limitations. The PEM has: a short lifetime of 80,000 operating hours (9-10 years); high cost of investment; but is now at a commercial stage. The total investment cost of a PEM are higher than the investment cost of the commercially available Alkaline. However, one has to take into account the advantages provided by the PEM for a fair comparison of investment costs, since PEM technology does not require any investment in external compression systems. PEM-based electrolysers are currently being developed with increasingly larger capacities (10 MW and much more).

¹⁹ The Alkaline water electrolysis has a lifetime of 10 to 20 years and operates under relatively low cost. Two critical disadvantages of this technology are: low current densities and low operation pressure (Lehner, et al., 2014). The first aspect affects the size of the system. Low operation pressure suggests the need for additional external compressors to

Hydrogen transport via pipelines

With regard to hydrogen transport via pipelines, compared to via the existing natural gas pipeline system, the operation of a dedicated hydrogen pipeline is in general more complicated because of several factors. The low volumetric mass of hydrogen (0.0899 kg / Nm³) implies a high volatilization of the medium which can be critical for existing pipeline materials because of seal issues and steel embrittlement whereas the latter can lead to a complete failure of the component part (Krieg, 2012, pp. 88, 97; Takahashi, 2009).

In order to avoid such failures, admixture of hydrogen to natural gas pipelines is limited (Noujeim, 2014, p. 10). Still, experiences show that the limitation level could be lifted to 20% and that even admixture rates of about 60% could be possible (Krieg, 2012, p. 88).

For dedicated pipelines stainless, austenitic steels can be used for hydrogen transportation which are stable on a long-term and not prone to embrittlement (Krieg, 2012, p. 96).

According to personal contact with N.V. Nederlandse Gasunie (Kiel & Huitema, 2017), a compressor outlet pressure of 100 bar for long distance hydrogen transportation is expected to be sufficient. Furthermore the compressor and the pipeline system can be sized as such that the pressure drop equals 33 bars since the operating pressures for most onshore pipelines operated by Gasunie are about 67 bar.

Losses during transportation, e.g. caused by compressor or pipeline leakages, are included in the calculations of the respective sub-modules as well.

In the business analysis in this study, the assumption has been used that existing gas pipelines can be used for the transport of hydrogen.

Trading options

Compared to the capacity of the wind farm, the electrolyser capacity is set at 50%, so that at 100% capacity, the wind farm will need to channel half of its energy to shore via the electricity grid (e-grid). This implies that the cable connecting the substation and thus wind farm to shore should have at least half of the capacity of the wind farm. This results in a cost savings of about € 100 million for the platform case considered in this analysis, which is about 100 km from shore.

It is also assumed that, if the wind farm produces anywhere between 50 and 100% of its capacity, the ratio of the price of power (compared to the expected hydrogen price) determines what part of the power is transported to the platform for conversion. If the wind farm produces less than 50% of its capacity, the electricity is transported to shore via the e-grid if the electricity price is sufficiently high. If, however, prices are low, it will be sent to the electrolyser. The operator of the electrolyser in such cases does have the option to supplement the power available from the platform with cheap power from shore to the extent that it pays to also turn that power into hydrogen, so that the electrolyser can operate at its full capacity.

Trading: reserve capacities

The economic return of using the electrolyser capacity in cases of too high power supply and/or too low power prices to make direct power delivery to shore attractive for the offshore platform operator, is not only based on the combination of selling power and hydrogen, but also on monetising the flexibility of the system via the deliveries of primary and secondary reserve. The latter basically is the compensation paid for

compress hydrogen further thereby adding cost to the power-to-gas system. Nowadays, R&D activities are involved to increase current densities by a factor of 1.5–2, and raise operating pressure up to 60 bar (Lehner, et al., 2014).

contributing to balancing the e-grid, whereby primary reserve relates to the very short-term response (seconds) and the secondary reserve to somewhat slower response (up to 15 minutes). In the case analysed, technical conditions have been assumed to be such that one can benefit from both the primary and secondary reserve function.

With respect to the return on making reserve capacity available, it is assumed that the average shift up/shift down is approximately the same. This would mean that the average revenue from other activities stays the same.

With respect to the return on making primary reserve available to the TSO, the assumption has been made that the future primary reserve price will be roughly in line with the price on the auction market throughout 2016 and 2017 (see Figure 5), i.e. € 2,000 per MW per week. Most experts expect the currently auctioned capacity of primary reserve (some 30 MW per week) to grow, but such that both supply and demand will grow (due to increased volatility) more or less to a similar extent, thereby not affecting average capacity price levels.²⁰

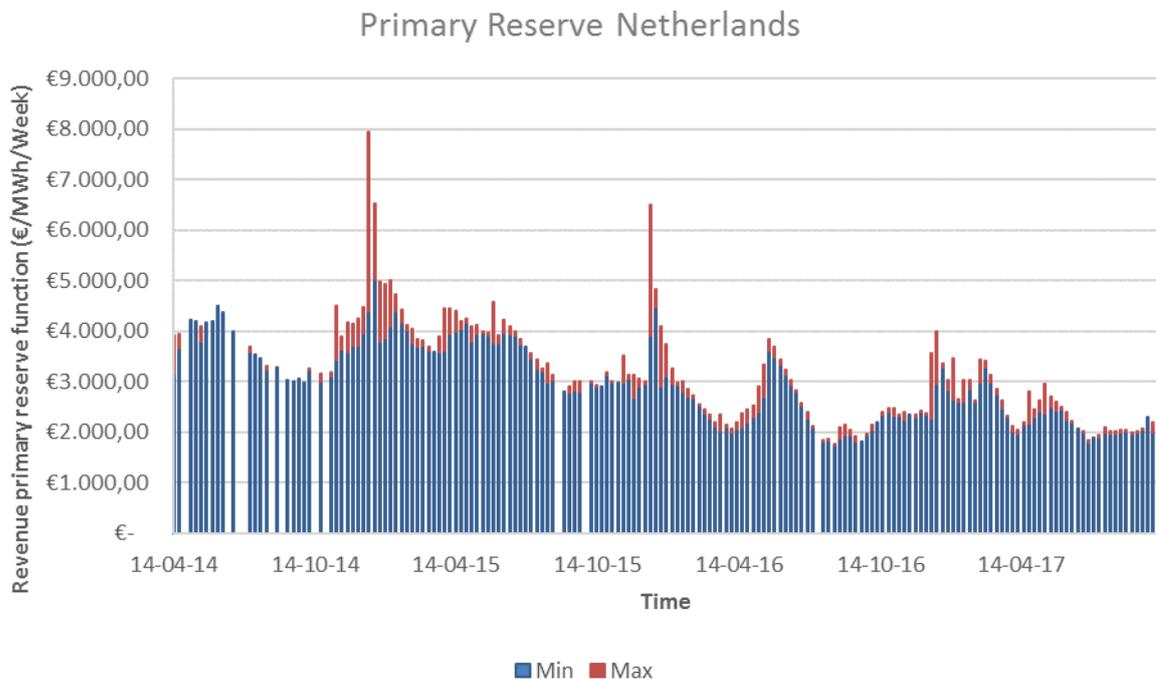


Figure 5. Primary reserve auction prices (Authors figure based on regelleistung.net).

With respect to the secondary reserve, the story is broadly similar to the one with respect to the primary reserve, with the main differences that auction volumes are much less, that the daily rates for regulating up and down differ quite substantially (€ 300 and € 1100 respectively on average), and that prices are defined per day rather than per week. Again, the assumption is made that making secondary capacity available does

²⁰ Since future levels of primary and secondary reserve markets are set by the TSO, it is hard to predict its future pattern. In the analysis studied we therefore took the current/past reserve profile as a basis. Currently primary reserve tenders are weekly, however, the primary market may change as these tenders become daily or even hourly.

not affect the overall return on the sales of power, and therefore creates an additional positive impact on the business case.

Electricity price stochastics and scenarios

For the business analysis of this case of flexible use of the wind power, the current and future power prices are obviously of crucial importance. This relates not only to the trend values of the power prices themselves, but also to power price volatility trend and to the bonus that can be earned by contributing to grid balancing (the so-called primary and secondary reserve mentioned). In designing future power price volatility based on the mean reversion concept, it is important to be aware that power price stochastics relate to random parts and fixed (predictable) parts. To use the mean reversion model, one therefore needs to filter out the fixed parts of the electricity price. The latter relate to the impact of the hour of the day (day and night rhythm of human and business behaviour) and the month of the year (seasonal patterns) on the power price profile.

So, in order to filter out the fixed parts, a statistical analysis has been carried out so that the ‘true random’ profile of electricity prices could be determined. To illustrate, Figure 6 presents the fixed parts of power price for the Netherlands case during the last decade.

It can easily be seen from the figure that during night time, the prices are lower independent of the month of the year, and that prices are above average in the evening, especially during winter time.

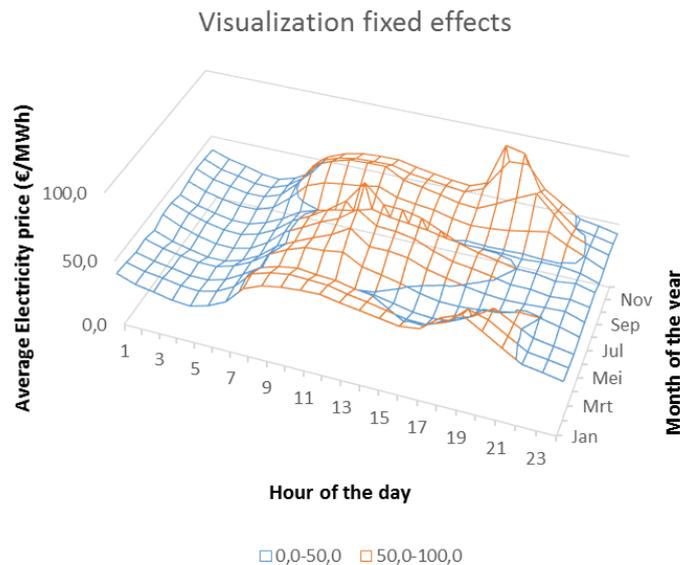


Figure 6. 3D visualization of the fixed effects in the electricity price traded on the Dutch APX, retrieved from Amsterdam Power Exchange (APX) from the Thomson Reuters data stream.

The fixed effects shown above have been subtracted from the historical figures to come to a price string with only variable effects. This string can be used to simulate future random electricity price volatility. By adding the fixed (hourly and seasonal) effects again, one can arrive at a correct forecast of future electricity prices, based on the mean reverting principle, as shown in Figure 7.

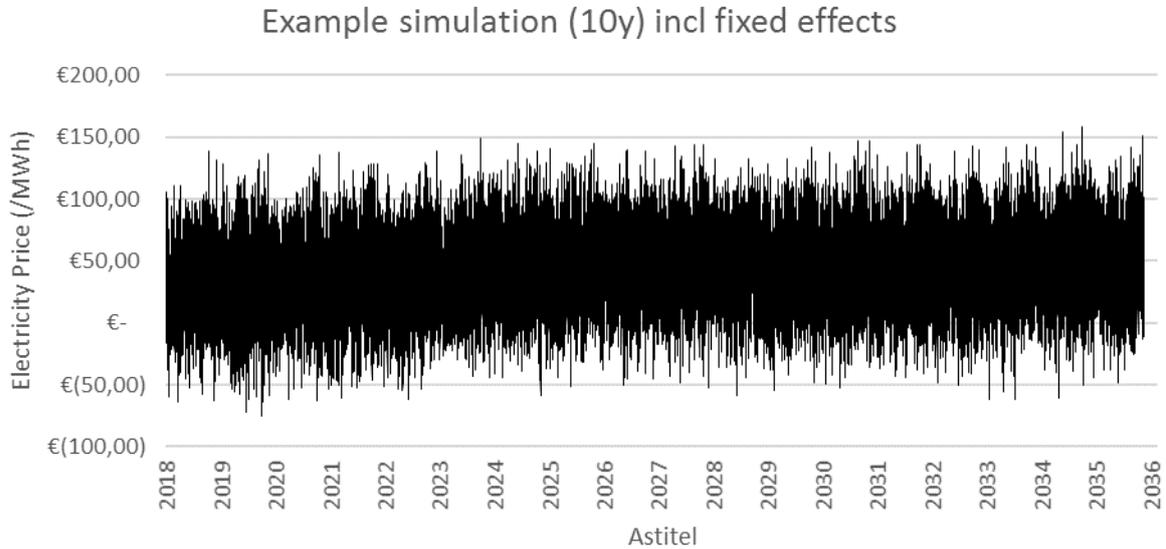


Figure 7. Example simulation (10y) including fixed effects

With regard to the electricity price trend, two sources of average electricity price scenarios have been used: Frontier Economics Ltd. (2015), where 4 future scenarios are described and the NEV (ECN, 2017) where 2 scenarios are described for either with or without the not yet confirmed policy. These scenarios can be combined with the volatility projections described. In doing so, three different future volatility regimes have been distinguished (continuation of the current situation; more volatility; and less volatility).

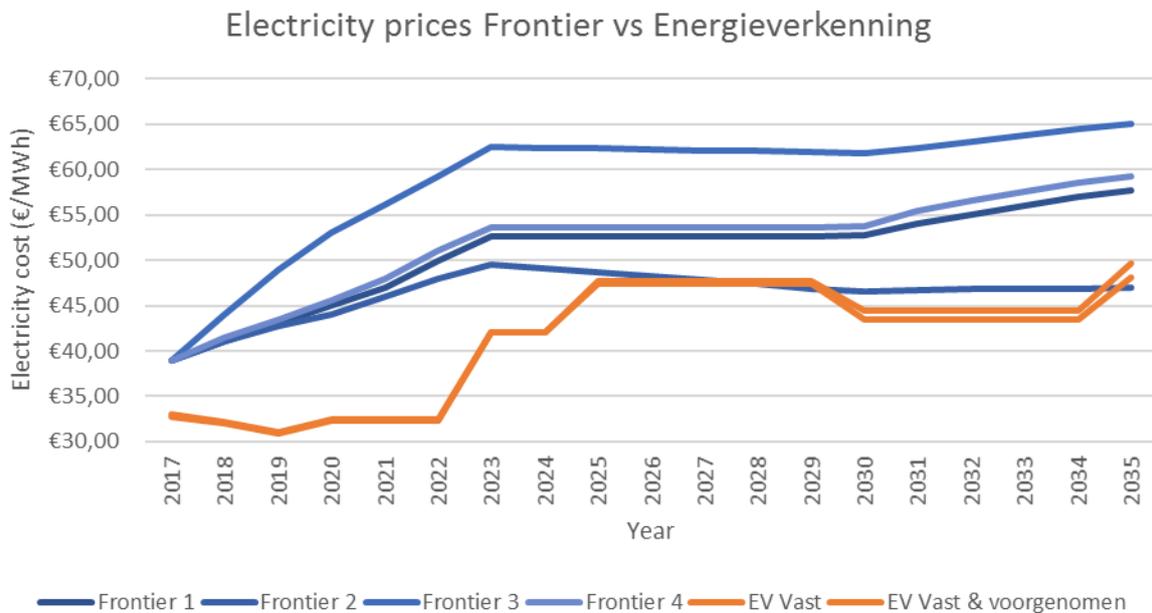


Figure 8. Electricity price scenarios for the Netherlands 2017-2035

3.4 Results

Case 1: Batteries

As was argued before, the business case of installing batteries on platforms for energy storage turned out to be absent in all studied APX-trading scenarios, and will therefore be further disregarded. Although, batteries have insufficient capacity for substantial energy storage and trading services, they can be used for short-term purposes, like enhancing balancing, ramp-rate limitations and covering grid outages. For instance, wind turbines with integrated batteries are already on the market to supply system services to e-grid balancing. Next to that, batteries provide important system services as a back-up source for the electrification of satellite platforms which have limited electricity demand, i.e. these type of platforms are equipped with compressor systems. One must note that the value of these systems services were not taken into account yet, but if taken into account they could be very valuable by system avoidance costs. Further research towards the value of system services from batteries would be needed.

Case 2: All wind energy converted to hydrogen on platforms

The analysis once again showed that if the e-grid savings incurred by the TSO (both offshore and onshore) will be fully translated into the business case, break-even values of generating green hydrogen and bringing this to shore look quite promising. While in the Jepma and Van Schot (2017) study break-even values were found in the €3-5/kg range for green hydrogen, this time – mainly due to the larger e-grid savings – the green hydrogen cost price range turned out to be even lower: between about € 1 and €1.75/kg, and even less in case the future electricity prices would not trend upward as assumed in the Frontier and NEV scenarios (ECN, 2017; Frontier Economics Ltd., 2015).²¹ The bottom line conclusion therefore seems to be that offshore production of green hydrogen may well develop into a quite positive business case, but typically requires some kind of mechanism/policy framework via which the positive externality which is gained by society due to the significant savings on e-grid investment is somehow translated into a monetary incentive towards offshore conversion and production of green hydrogen.

The results of the sensitivity analysis are reflected below in Table 2. The table clearly shows that if electricity prices, although trend-wise still increasing towards levels of about € 50/MWh by 2035 (see figure 8), would remain at the low end of the range considered, and if at the same time per kg green hydrogen prices would rise to levels in the order of € 3.50 or more, the resulting NPV over the total project duration 20 years boils down to about € 1 billion. This would seem to be very substantial given the overall CAPEX involved with the installation of the electrolyser on the platform, etc., which is in the order of € 315 million.

²¹ For details see also chapter 5.

Table 2. Results of the sensitivity analysis for case 2 based on electricity price scenarios and hydrogen price levels

Sensitivity (NPV in €ln)								
Variable 1	Price scenario							
Variable 2	Hydrogen price							
	€ 1,00	€ 1,50	€ 2,00	€ 2,50	€ 3,00	€ 3,50	€ 4,00	
Frontier 1	-128	53,9	255	445	625	808	1002	
Frontier 2	-70	111	306	497	680	869	1050	
Frontier 3	-258	-74	126	305	493	681	874	
Frontier 4	-145	46,9	237	429	610	788	989	
EV Vast	20,9	209	391	586	769	964	1143	
EV Vast & voorgenomen	24,7	217	404	595	787	963	1146	

A potentially additional attractive feature of the business case is how profit develops over time. In Figure 9, this time profile has been projected, which is related to a € 2/kg hydrogen price and the EV Vast price scenario. It is clear that most of the profit relates to the savings on the e-grid. A major caveat, however, is that this profit in fact represents an externality, i.e. it is a savings for the TSO and therefore the tax payer, that – without additional regulation – will not automatically accrue to the investor in the conversion capacity.

If this externality would not be taken into account, the break-even hydrogen price – in the above table about € 1 and €1.75/kg – would increase to a range of € 2.50 to € 3.50/kg.

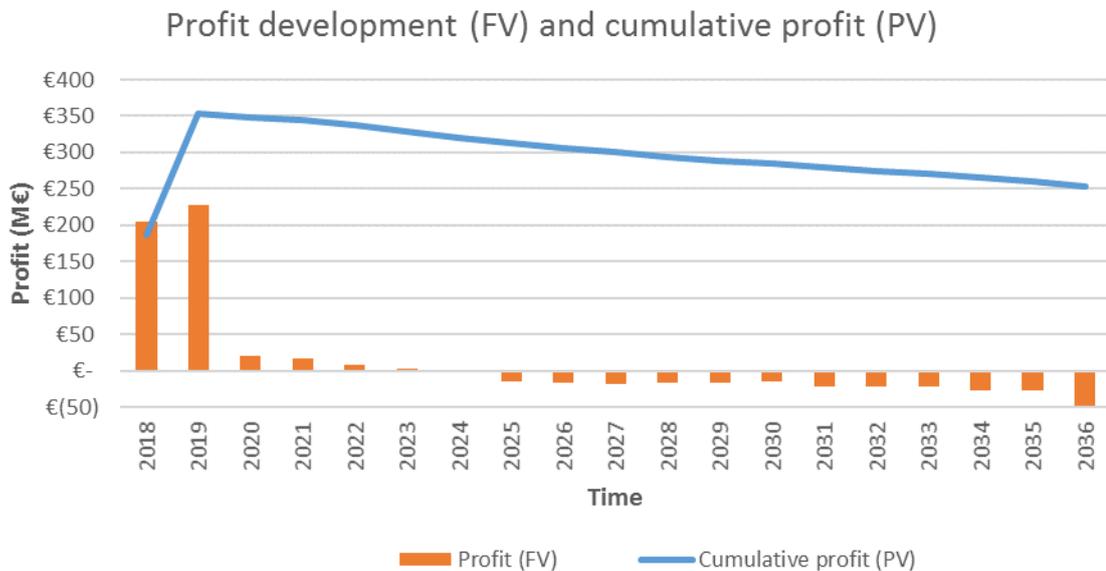


Figure 9. Profit development over time based on the EV Vast price scenario and a € 2/kg hydrogen price. The future value of profits (depicted in red bars) is very high in the beginning of the project, which is caused by the internalisation of externalities. This implies that the internalisation of savings on the e-grid has great impact on the business-case. Figure 11 highlights the distribution of the NPV over the main cost elements.

Some additional sensitivity analyses have been carried out for this specific case, leading to the main following results:

- If a new dedicated hydrogen pipeline system will need to be installed, the impact on the break-even hydrogen price is relatively limited (from slightly more than € 1 to slightly less than € 2/kg).
- If the wind farm size increases from about 315 MW (base case) to 700 MW (average size of current tenders in the Dutch continental shelf), break-even hydrogen prices increase because the externality has to be shared with more offshore wind supply capacity. This increases break-even values to about € 2 to € 2.75/kg of green hydrogen.
- If the volatility of power prices increases or decrease considerably, given that the mean value remains the same, then the impact on the break-even price of hydrogen is almost negligible. Note that single upward volatility has not been analysed, but if so it may change the conclusion, at least if it leads to higher mean values for the APX-price.
- The impact of higher conversion efficiency of electrolyser systems (e.g. from the assumed 80% to 90%) on break-even hydrogen prices also turned out to be quite limited.

Case 3: Alternating power trading and hydrogen production

A first question that a electrolysis operator faces if it has the option to either sell its power directly to shore, or to the operator of the nearby platform, is to what option it will give priority. This obviously depends on the price for power and for hydrogen. The higher the price for power, and the lower the price for hydrogen, the more attractive it is to send the power directly to shore and vice versa. In a sensitivity analysis to assess at what electricity price priority would be given to delivery to the platform, while the residue would then be

sold via the e-grid, the broad conclusion was prices below € 60 to € 70/MWh. With these 'switch prices', break-even values of the prices for hydrogen were in the order of € 2.50 to € 2.75/kg (see Table 3)²².

Table 3. Results of the sensitivity analysis for case 3 based on electricity price scenarios and hydrogen price levels

Sensitivity (NPV in €mln)								
Variable 1	Price scenario							
Variable 2	Hydrogen price							
€	€ 1,00	€ 1,50	€ 2,00	€ 2,50	€ 3,00	€ 3,50	€ 4,00	
67								
Frontier 1	-281	-198	-119	-35	40,6	123	201	
Frontier 2	-267	-183	-101	-16	65,3	150	232	
Frontier 3	-310	-240	-162	-87	-12	62,4	138	
Frontier 4	-286	-204	-122	-47	37	118	193	
EV Vast	-237	-153	-67	22,8	105	188	279	
EV Vast & voorgenomen	-240	-152	-65	18,5	109	196	280	

Obviously, the above results will improve more if the operator of the platform has the option to use power from shore to fuel the electrolyser in cases in which there is insufficient wind power to operate the system at the desired capacity, and the electricity prices are below the 'switch price'. In Table 4, the results of the sensitivity analysis of this case have been presented. It clearly shows that using power from shore as an additional option further optimises the system, such that the break-even values of hydrogen now drop to a range of about € 2 to € 2.50.

Table 4. Results of the sensitivity analysis for case 3 if the electrolyser can also consume power from shore

Sensitivity (NPV in €mln)								
Variable 1	Price scenario							
Variable 2	Hydrogen price							
€	€ 1,00	€ 1,50	€ 2,00	€ 2,50	€ 3,00	€ 3,50	€ 4,00	
12								
Frontier 1	-317	-195	-71	53,1	174	300	422	
Frontier 2	-306	-179	-46	89,1	225	346	471	
Frontier 3	-351	-244	-133	-19	85,3	199	308	
Frontier 4	-324	-204	-80	48,1	171	290	420	
EV Vast	-267	-131	10,7	139	284	420	554	
EV Vast & voorgenomen	-269	-131	8,77	148	284	423	559	

²² These switch-prices are calculated via the goal-seek function.

In addition, further optimisation of the system can be achieved if the flexibility of the electrolyser conversion system is turned into money by making the primary and secondary reserve capacity available to the TSO. Because of the ramp-up capacity of the PEM electrolyser, and because a standard slight underutilisation of the e-grid capacity, the returns on this facility are assumed to fully add to the profit of the conversion process. So, the question is, what the value of flexibility represents.

As far as the primary reserve is concerned, prices of returns of making capacity available are determined via weekly auctions (see Figure 5). Based on the 2016-2017 average price levels of € 2,000/MW/week, for the business case in addition to the cumulative (over the 20 years project horizon, and taking discounting into account) profit resulted in a profit of about € 27 million for an available capacity of 30 MW (Tennet via Regelleistung.net, 2017). For smaller capacities, profit is lower in proportion. If the 27 million is translated into a reduction of the break-even price for the green hydrogen, this boils down to about € 0.15 to € 0.20/kg.

The secondary reserve capacity can of course also be made available. In the past, prices on the market for making this capacity available on a daily basis were on average some € 300 for regulating up, and some € 1,100 for regulating down. Assuming that both options will be made available for all days of the year, the return will be for $365 \times € 1,400 =$ about € 510,000. On the whole 20 year project duration, and after discounting, this amounts to some € 4.5 million, or if expressed in impact on the break-even price of hydrogen some € 0.05/kg.

So, the total NPV of our case improves by some € 32 million. Equally the break-even price of green hydrogen drops with some € 0.20 to € 0.25/kg. The overall break-even value of green hydrogen therefore drops to € 1.75 to € 2.25 for the case in which the reserve option and the use of power from shore are both activated. Finally, the profit development over the project duration time has been simulated for what can be considered a fairly realistic case, i.e. the case in which the primary and secondary reserve options are activated, power from shore will be used to the extent feasible, the power price develops according to the EV Vast & Voorgenomen scenario, and the green hydrogen price is € 3/kg (see Figure 10). The overall NPV of € 300 million turns out to build up in time in a fairly linear way, except from the first two years in which expenditures and receipts (including receipts related to the less costly e-grid) are more or less in balance.

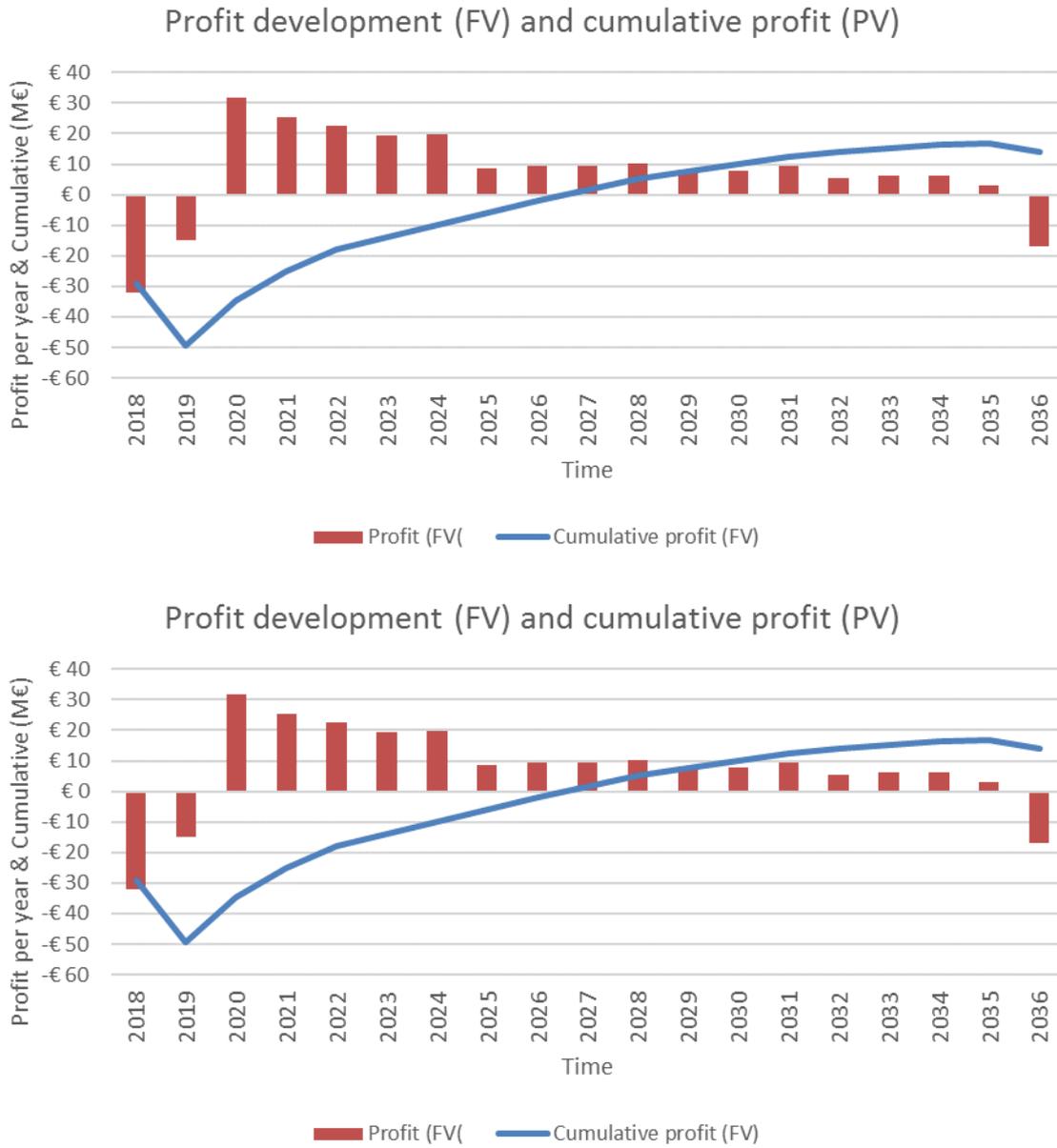


Figure 10. Profit development over time based on the EV Vast & Voorgenomen price scenario and a € 3/kg hydrogen price

It may additionally be illustrative to show how CAPEX and OPEX components can be valued for a comparable business case, viewed from the perspective of the offshore operator responsible for converting the power acquired from the windfarm into hydrogen, and assuming that the savings on e-grid investments are monetized and somehow transferred to the same operator. The results of this case have been shown below. Figure 11 shows:

- That without the externality there is no business case;
- That about a third of the costs consists of payment for the electricity and about 40% for CAPEX of the equipment;
- And that platform costs, i.e. costs related to refurbishment of existing platforms to make them suitable for hosting electrolyser capacity, dominate CAPEX. With respect to the latter it should be mentioned that information about the refurbishment costs is not always altogether clear. Various sources generally assume costs in the order of €40/kg if a new topside is installed, while refurbishment costs data that relate to re-use of existing decks are estimated to be in the order of €10/kg. The base case models assumes that topsides could be re-used and thus refurbishment costs of €10/kg are applied.

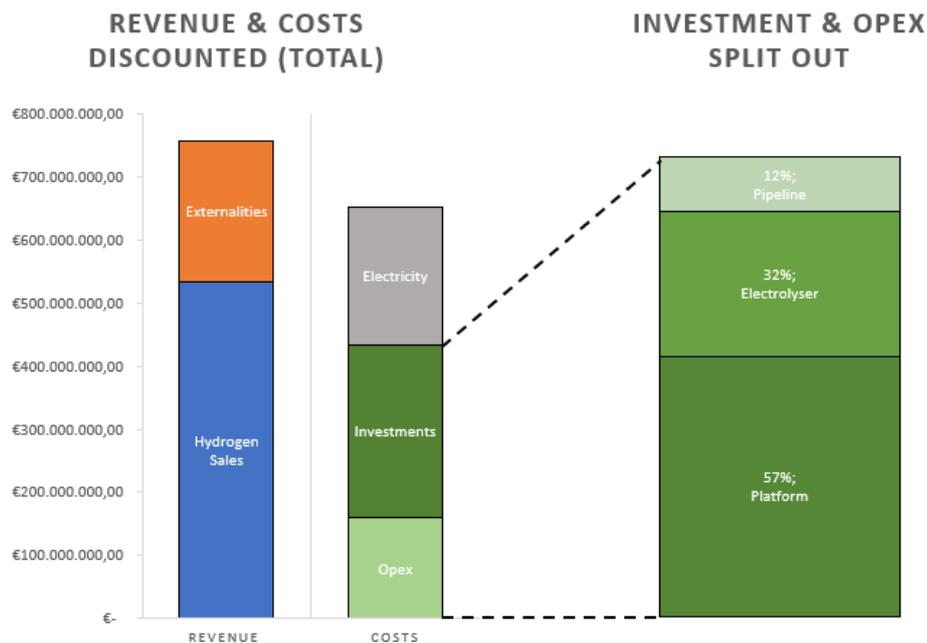


Figure 11. NPV Cost and revenue distribution

4 Power-to-gas in or on offshore wind turbines²³

4.1 Introduction

The assessment of the business case of energy conversion by putting electrolyzers in or on offshore wind turbines has been made on a comparative basis. That is to say, the assessment of electrolysis in the turbine has been compared to onshore conversion. This way, it is possible to assess under what conditions which of the options provides the best returns.

The offshore electrolysis cases considered also differ in other respects from onshore conversion, because their business case can be quite sensitive for the location of the collection point from which the hydrogen is transported to shore. If the hydrogen is brought to shore via the gas grid, existing oil and gas installations can be used as collection points of hydrogen, in combination with the existing gas pipelines; it is, however, equally possible to construct new collection points if their location advantages surpass the costs of installation. That is why calculations have been done with both existing and new collection platforms (the latter to be placed on the optimal location).

The offshore-onshore comparison of electrolysis location is illustrated with the help of real-life North Sea locations where (planned) wind farms are relatively close to existing platforms: the Gemini wind park (also known as ‘North of the Wadden Islands, location 6 on the map), and IJmuiden Ver (location 2). In addition, existing platforms are used to transfer the hydrogen as well as hypothetical new platforms (respectively existing platform 5 and new platform 9 for Gemini, and existing platforms 1 and 3, and new platform 8 for IJmuiden Ver). Clearly, the ‘new’ collection platforms are superior in terms of the remaining transport distance to shore, but then again, they will need to be constructed.

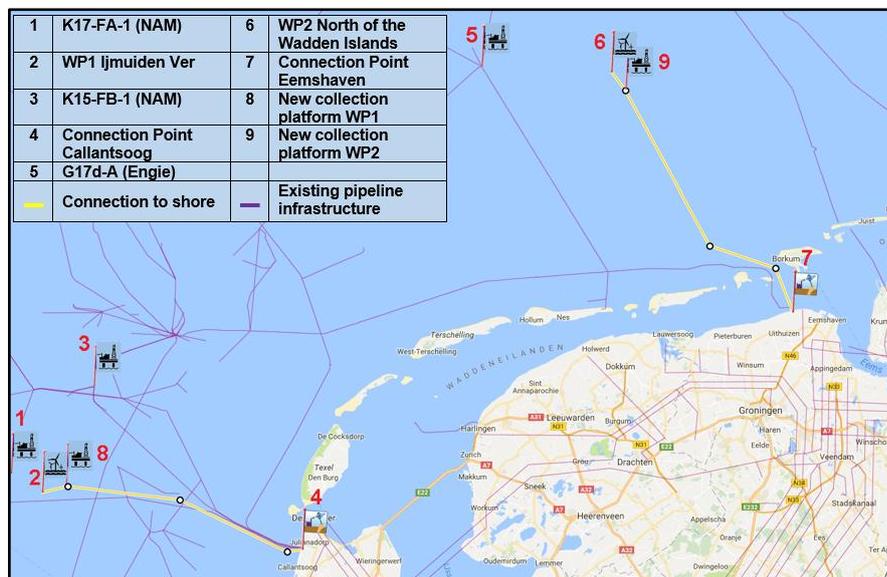


Figure 12. North Sea locations analysed (Ecofys Netherlands, 2015). Adaptions have been made to show the route and the legenda

²³ A more extensive description of the research work reflected in this chapter can be found in Renz (2017).

4.2 Comparing offshore (turbine) and onshore conversion

The two cases that have been compared in the business case assessment can now be illustrated with the help of the figures below. In Figure 13, the offshore conversion is projected within the wind turbine, so that the hydrogen can be transported to a collection platform to be transported further to shore after compression. Figure 14 assumes that the power produced will be brought to shore in order to be converted into hydrogen on land (near the onshore substation). The transport of power from the wind farm via the collection point to the shore via the transmission cable requires two AC-DC conversion steps: the AC power generated in the wind mill is converted into DC first to flatten the frequency, and then converted back to AC so that it can be fed into the array cables with a 50 Hertz frequency. Thereafter, it will need to be converted to DC again if fed into an onshore electrolyser, as the electrolyser requires DC power input. Note that the second and third steps are not necessary if the electrolysis takes place in the wind turbine (irrespective if long-distance power transport will be via AC or DC cable), which may create a cost saving. Another cost saving that results from placing the electrolyser in the wind turbine relates to the difference between the transport costs to shore of hydrogen on the one hand (Figure 13) or power (either via an AC or a DC cable) on the other hand (Figure 14). With regard to the differences in cost between long-distance hydrogen and power transport, it is important to note that not only on average pipeline transport requires much less CAPEX and OPEX than comparable power transport, but also that energy losses of hydrogen transport are negligible if compared to the average losses of e-grid transport (AC/DC and voltage conversion and heat losses) (Krieg, 2012; Rodrigues, 2016). Obviously, the cost differential between e-grid and pipeline energy transport becomes even bigger if existing pipelines can be used.

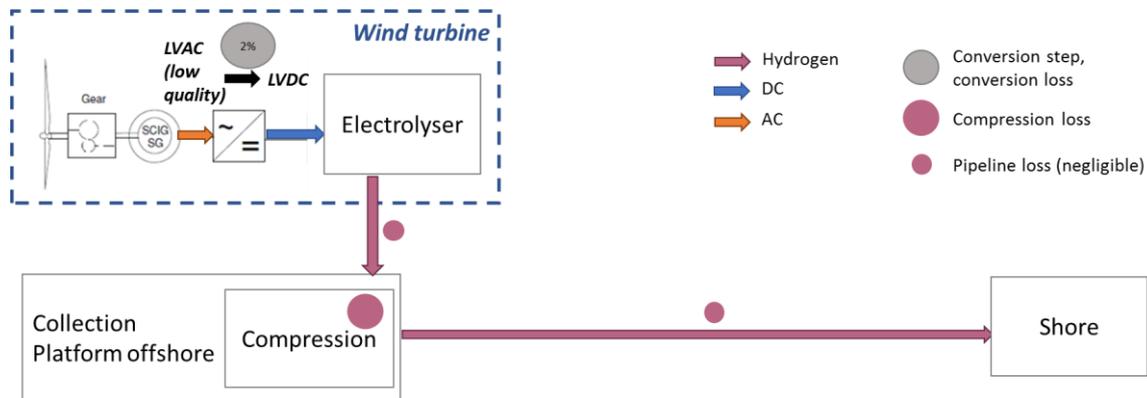


Figure 13. The energy conversion process with the electrolyser in the turbine.

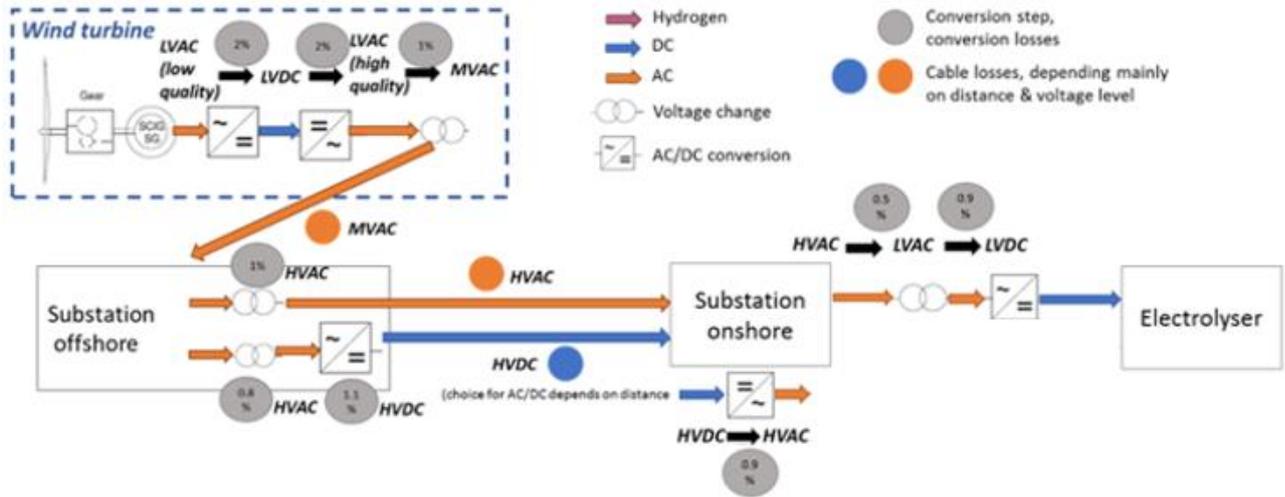


Figure 14. The energy conversion process with the electrolyser onshore, near onshore substation. Note that onshore you will need an intermediate step to transform HVAC to MVAC and then to LVAC

4.3 Main assumptions

In order to assess the business cases of electrolysis either within or on the wind turbine, or onshore near the onshore substation, an NPV analysis has been carried out, the parameter values of which will subsequently be discussed. Generic details and assumptions have been covered already in chapter 2, and general data and assumptions with regard to the electrolysis process and e-grid and pipeline transport in chapter 3.

Technical feasibility (space constraints)

Given the size of even the modern generation of electrolyzers, it is clear that space in the turbine can be an issue, that, however, generally seems possible to resolve. That is why in this report, it has been assumed that space limitations can be overcome. Experts from electrolyser producing companies have indicated that space can be found not only within the turbine but also on a gallery surrounding the turbine. Tests off the coast of Nigeria have shown how to place power-to-gas installations on such a gallery. It is important to note that PEM electrolyzers may offer some advantages in this regard next to the assumed greater flexibility, because they are organised in separate stacks which could be distributed over the nacelle, the tower itself, and the gallery²⁴.

Hydrogen compression

Compression is needed in this case: to transport the gaseous hydrogen over a certain distance a pressure difference between the point of injection and extraction is necessary which requires usually a compressor at the injection point and due to pressure losses over long distance transportation even intermediate compressor steps. In this research the distribution of hydrogen is arranged via a wind turbine connection to a nearby platform and from there further to shore.

With regard to the first pipeline section from the wind turbine to the collection platform, pressure levels of about 10-30 bar could be sufficient, as shown by existing pipeline systems of certain industrial areas in the US and a pipeline system in Germany (Amos, 1998, p. 32). For long distance transportation, pipeline pressure

²⁴ The Sylizer 300 – a 10 MW system – is based on the combination a number of stacks. This implies that systems can be easily scaled- and that system services can be shared, e.g. balance of plant system.

levels of about 70-100 bar are common (U.S. DRIVE partnership, 2013, p. 13; Krieg, 2012, p. 101). The compressor systems which are usually used for hydrogen compression are piston compressors that can operate in a broad range of pressure levels (Krieg, 2012, p. 102).

Selected wind farm, wind turbine and electrolyser parameters

For both wind parks, the model parameters are illustrated below (Table 5).

Table 5: Main variable input parameters for the baseline scenario

Parameter	IJmuiden Ver	North of the Wadden Islands	
<i>Bathymetry:</i>	28 m	33 m	
<i>Wind speed measurement point:</i>	Meteomast IJmuiden	FINO 1	
<i>Connection distance collection point to shore:</i>	66.62 km (Figure 12, Point 4 to 8)	75.62 km (Figure 12, Point 7 to 9)	
<i>Number of wind turbines:</i>	100 Siemens SWT-7.0-152		
<i>Total installed wind capacity [MW]:</i>	700		
<i>Sizing of electrolyser:</i>	100% of max. power output (Offshore: Turbine, Onshore: Substation)		
<i>Crossings</i>	<i>Offshore-pipeline / cable</i>	3 (existing pipelines)	1 (NorNed transmission cable)
	<i>Offshore-shiping lane</i>	2	2
	<i>Trenching to beach</i>	1	1
<i>Average distance turbine-collection point [km]:</i>	16.33 ²⁵		
<i>Turbines connected to same collection vein:</i>	10		
<i>Cable cross sections [mm²] (onshore electrolysis):</i>	30%: 240 70%: 800 ²⁶		
<i>System availability:</i>	86% ²⁷		
<i>First year of investment²⁸:</i>	2018		
<i>Electrolysis system:</i>	Siemens Silyzer 300		
<i>Electrolyser capacity:</i>	100% of wind turbine capacity (to be adjusted manually for simulation)		
<i>Desalination Unit System:</i>	Lenntech Reverse Osmosis System		
<i>Compression variables: (Offshore Electrolysis):</i>	30 bar Compressor inlet (278 K) 100 bar outlet (2 stages) ²⁹ Pressure level onshore: 67 bar Dimensionless coefficient of friction: 0.014 ³⁰		
<i>Basic electricity price [€/MWh]:</i>	42.8, annually increasing according to (Frontier Economics Ltd., 2015)		

²⁵ Based on a 140 km collection system length for the 600 MW Gemini wind park (4C Offshore, n.d.)

²⁶ In percent of total cable length, cross sections according to internal calculations of ECN

²⁷ Product of average availabilities wind turbine: 97% [50]; transmission system: 98% (KPMG, 2012); Electrolysis: 90% (assumption)

²⁸ Investments are evenly distributed over two years, OPEX and revenues are allotted afterwards

²⁹ Two stage compression according to preliminary design, Howden Netherlands B.V. (Reichert, 2017)

³⁰ For gas transportation usually between 0.013-0.015 (Kiel & Huitema, 2017)

Discount factor: 10 %

Wind speed data

Data for the wind mass flow calculation are based on the database related to different measuring points in the North Sea provided by the Royal Netherlands Meteorological Institute (KNMI, 2014).

From that database, three measuring points are selected for the preliminary implementation in the model which are the locations “Borssele”, “FINO 1”(Germany, close to the Gemini wind park), and “Meteomast Ijmuiden” due to their closeness to designated wind development areas.

The retrieved hourly data of the time frame 2004-2013 is used to make further projections for the upcoming years. For that purpose for every location the most significant historic year is determined by comparing the 10-year mean wind speed to the individual 10 yearly mean wind speeds. The year that demonstrates the lowest deviation between its mean wind speed and the mean wind speed over 10 years is assumed to be significant for the following time period. Figure 15 shows the example of the measurement point ‘Borssele 5’ from which the year 2012 is closest to the mean and hence its wind speed pattern would be base for further calculations. This method has been preferred to the use of mean wind speed data as it enhances the representativeness of the used data, while at the same time not weakening the stochastic profile, which is in this case important to determine potential peak capacities for electrolysis and compression units.

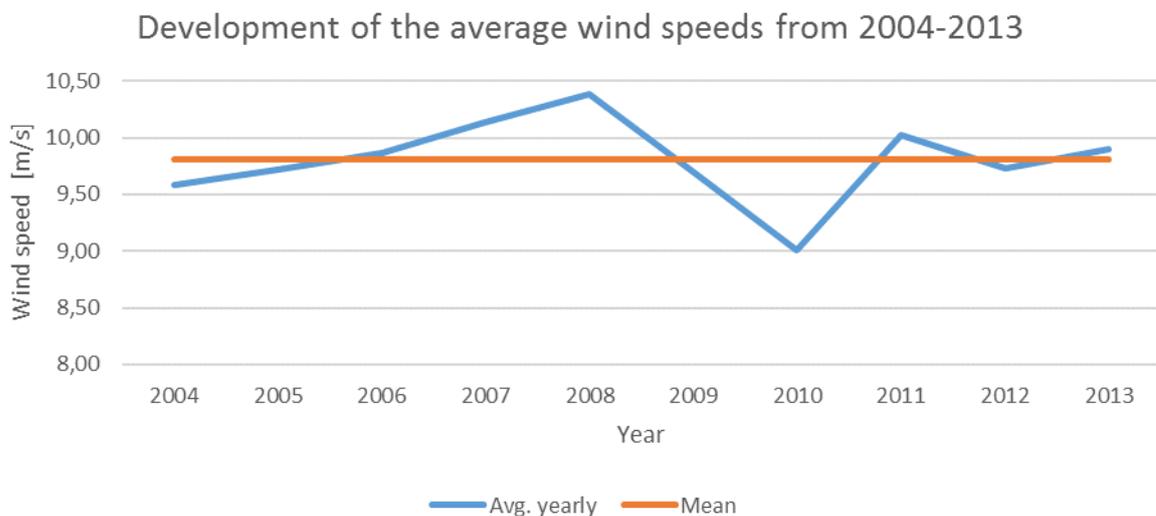


Figure 15: Development of the average wind speeds at measurement point Borssele 5 (author’s figure)

The output flow ‘wind mass flow’ is then calculated using the wind data and a standard air density of 1.225 kg/m³ (sea level standard atmospheric pressure and temperature).³¹

³¹ The wind mass flows is the mass of wind passing through a given area of a surface for a given amount of time.

Turbine conversion efficiency

Within the model, the electric power as a function of wind speed $P_{el}(v)$ is based on wind turbine specific power curves which are deposited in the installation database (e.g. Figure 16).

The rotor efficiency is then determined for various wind speeds according to Equation 2:

$$\eta_{rotor, x=v} = P_{el}(v) \div \eta_{gear\ box} \div \eta_{generator} \div \eta_{conversion} \div \eta_{transformer}$$

Equation 2: Efficiency of the rotor as a function of wind speed

At first view this procedure might seem confusing because when the electric power of certain wind speeds is known based on the power curve, one does not have to know the mechanic and electric conversion efficiencies of the relevant components. Nevertheless, it is intended to avoid a 'black box' calculation, which implies that for a certain input parameter the output parameter can be defined without further knowledge of the process within the black box.

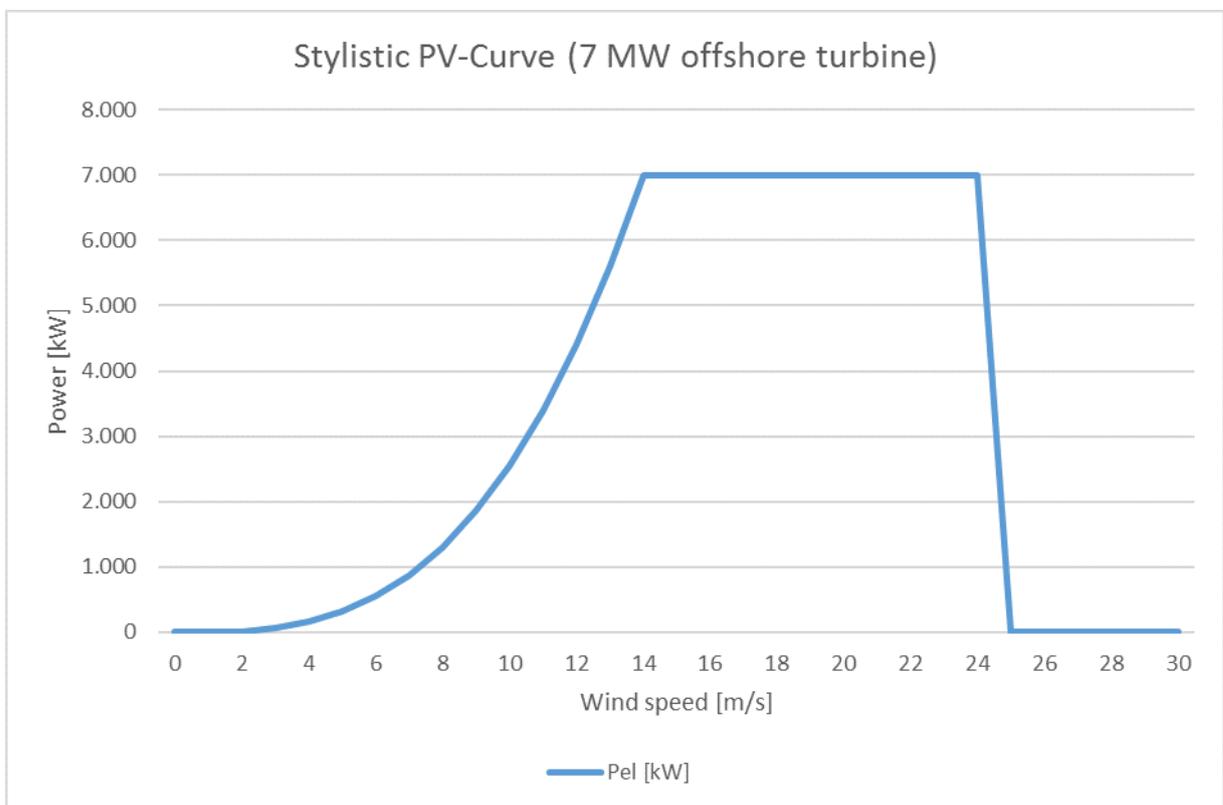


Figure 16: stylistic Power-Velocity (PV) curve for a 7MW offshore turbine (author's figure; based on operational data Siemens SWT 7.0.152³²)

³² https://www.siemens.com/content/dam/internet/siemens-com/global/market-specific-solutions/wind/data_sheets/data-sheet-wind-turbine-swt-7.0-154.pdf

The electric conversion chain of the wind turbine takes the mechanic power as a base and with respect to the user's selection of the electrolysis location the required power conversion devices (generator, converters, transformer) are adapted.

Energy conversion and transport losses

See Figure 13 and Figure 14 where the losses (%) of energy have been indicated within the circles. For compression losses, see chapter 3.

Platform costs

In the assessment two assumptions have been made with regard to the platform locations to be used for power conversion: either existing platforms, or newly to be constructed offshore platforms will be used to host conversion or compression equipment. With respect to new power conversion platforms (in the onshore electrolysis case), the following assumptions have been used with respect to their costs. A distinction has been made between a platform that only converts the voltage of the AC power, and a platform that also has the equipment for AC-DC conversion (the power to be transported further to shore can benefit from such conversion because DC transport on average is cheaper). Because the costs depend on the overall volume of wind power supplied to the platform, fixed and variable costs have been distinguished.

Table 6. Costs of power conversion platforms (Rodrigues, 2016).

New Platform HVAC			
Fixed costs	€	2.828.600	EUR
Variable costs	€	69.300.000	EUR
CAPEX	€	72.128.600	EUR
OPEX	2%		
Technical lifetime	40		Years
New platform HVDC			
Fixed costs	€	5.232.910	EUR
Variable costs	€	128.205.000	EUR
CAPEX	€	133.437.910	EUR
OPEX	2%		
Technical lifetime	€	40	Years

In the offshore conversion case, the hydrogen collection and compression platform costs for new platforms have estimated as follows.

Table 7. Costs of hydrogen compression platform (Zandbergen, 2017).

Compression platform			
Fixed costs	€	20.000.000	EUR
Variable costs	€	-	EUR
CAPEX	€	20.000.000	EUR
OPEX	4%		
Technical lifetime	€	40	Years

4.4 Results

Hydrogen production: offshore vs onshore conversion

The main results of the hydrogen production based on the two wind farm locations, and depending on onshore or offshore conversion, have been presented in the table below. The table shows that the hydrogen production from the wind area north of the Wadden Islands is superior to that from IJmuiden Ver due to higher average wind speeds in the former area. The table also shows that conversion in the turbines ultimately leads to more hydrogen production (about a difference of 4.000 tonnes per year), simply because transport and conversion power losses and therefore less hydrogen production are prevented. Note that in the calculation the assumption has been made that the electrolyser capacity equals the maximum supply of power from the wind farm (but can be changed in the model in order to optimise the NPV).

Table 8: Energy efficiency comparison of offshore and onshore electrolysis

Parameter	IJmuiden Ver		North of the Wadden Islands	
	Offshore	Onshore	Offshore	Onshore
<i>Annual power generation [GWh]:</i>	2.753	2.675	2.853	2.770
<i>Annual hydrogen production [t]:</i>	51.373	47.460	53.233	49.132

The fundamental economic question is if the larger hydrogen production due to conversion in the wind mill is sufficient to guarantee that also the business case of that setup is superior. In order to answer that question, obviously also the infrastructure costs will need to be taken into account, specifically conversion costs and the difference between hydrogen transport capacity and electric grid connection.

Economic comparison of offshore and onshore electrolysis

In order to assess the business case, a green hydrogen price will need to be *a priori* determined. It will be assumed, cf. Jepma & Van Schot (2017) that the hydrogen can be consumed close to the onshore connection points Callantsoog and Eemshaven for a price of €1.56/kg H₂ (industry market) respectively €4.67/kg H₂ (mobility market) (Jepma & van Schot, 2017, p. 27). Next, the costs are split in the investment costs for the installations such as infrastructure and electrolyser systems and their respective OPEX. In assessing the optimum electrolyser capacity given the offshore wind capacity, the assumption has been made that the hydrogen price is €4.67/kg. In this case, the optimum ratio turned out to be 58% only (in case of the lower hydrogen price, marginal benefits not even surpassed marginal costs).

Figure 17 clarifies whether the energy efficiency benefit of offshore hydrogen production implies an economic benefit as well, in this case for the location north of the Wadden Islands.

NPV Comparison Offshore and Onshore Electrolysis (North of the Wadden Islands)

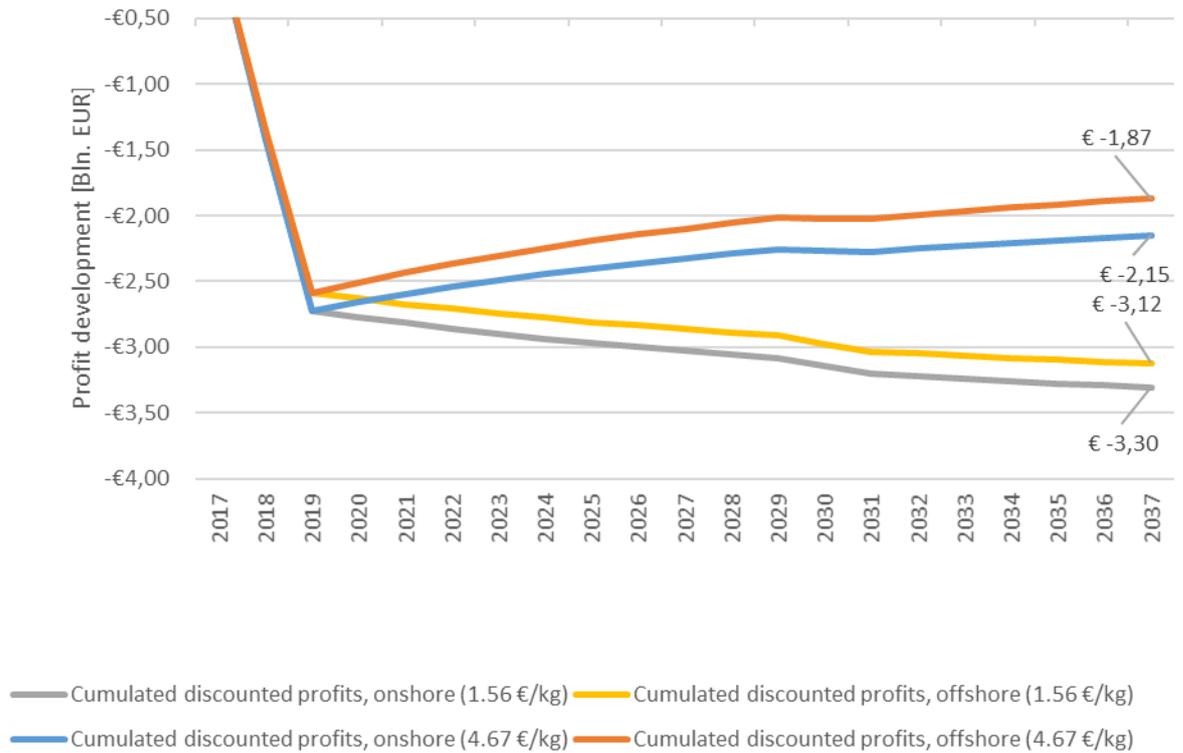


Figure 17. Cumulated discounted profits offshore and onshore electrolysis (author's figure)

The figure shows that the project investments for onshore electrolysis are higher than for offshore electrolysis, in case of the baseline scenario North of the Wadden Island even up to about € 230 million. The NPV over 20 years appears also to be relatively beneficial for the offshore electrolysis. These findings also apply to a similar extent to the economic outcomes of the wind park in the Ijmuiden Ver region.

Sensitivity analysis

A separate issue is whether the business case improves if an existing platform is used for compression, using the existing gas grid to shore, rather than a new infrastructure for compression as well as a new hydrogen transport system. The business cases for both locations investigated, North of the Wadden Islands and Ijmuiden Ver, do not differ a lot, which is due to the fact that the refurbishing costs of existing platforms, pipeline maintenance costs, as well hydrogen separation costs onshore on the whole will cost even somewhat more than introducing new devices. For the case North of the Wadden Islands, this result has been illustrated in Figure 18 below.

What has also been illustrated in the figure below is the impact of the scenario conditions, assuming that the overall investment in the offshore project will only be effective by 2025. Because the investment is projected into the future, various conditions that apply right now will have been changed due to the ongoing greening

of the economy, as well as learning and economies of scale effects, and possible policy developments. The following assumptions have therefore been made in comparing the current (2018) with the 2025 situation³³:

- Due to learning curve effects, CAPEX of electrolyser is some 37% less.
- Also, energy input required per kg of hydrogen produced is 8% less.
- The expected grid connection costs are internalised.
- Certificate values for green hydrogen and EU ETS allowance prices are taken into account; prices based on NorthSeaGrid (2014) – leading to an increase of €0.19/kg H₂ by 2035.³⁴

In addition to the comparison of the current (2018) to the future (2025) scenario, a sensitivity analysis has been carried out to account for the possibility of lower CAPEX/OPEX costs, and increasing electrolyser efficiency. In the ‘greener future’ situation, the CAPEX of the wind park and electrolyser are assumed to be 20% lower, the CAPEX of infrastructure 30% lower, the overall OPEX 25% lower, and electrolyser efficiency 20% higher. These assumptions are in line with the estimates brought forward by Tractebel Engineering S.A., 2017.

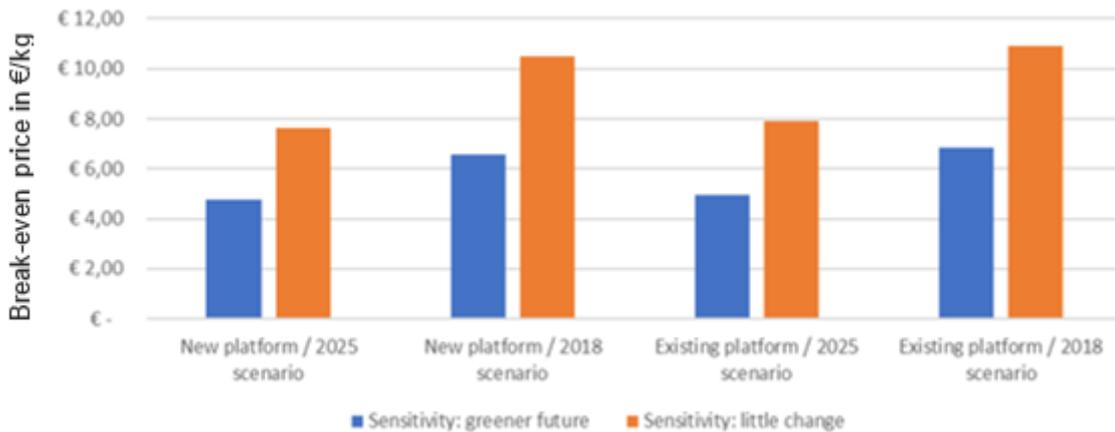


Figure 18. Business case sensitivity for the north of the Wadden Islands location

The results turn out to be quite insensitive to whether or not the compressor is situated on an existing or a newly built dedicated platform. Apparently the mix of higher CAPEX, but lower OPEX costs for a new platform provides roughly comparable results as compared to the data linked to using an existing platform. In the figure, that relates to North of the Wadden islands case, the four left side bars relate to a case in which a new platform needs to be installed, the bars at the right hand side reflect the result for cases in which an existing platform can be used as compressor location. It is clear that in the latter case costs will be less. The difference between the blue and orange bars is that only in the blue case the green future condition apply, which on the whole are more favourable for conversion. The results clearly show that the conversion of offshore wind energy into hydrogen, effective by 2025 and under ‘green’ circumstances will lead to the production of

³³ The time horizon of the studied cases are expected to be 20 years.

³⁴ For an investment in 2025 and the coherent start of green hydrogen production in 2027 a market price increase due to increased allowance prices of 0.07 € / kg can be expected. Yet, at the end of 2035 the difference would already add up to about 0.19 € / kg (ECN, 2017).

hydrogen against prices in the order of € 4-5/kg. Irrespective whether a new or existing platform is used to host the compression capacity.

Compared to the results found in Jepma & Van Schot (2017), where conversion took place on existing oil and gas platforms, this result is slightly less favourable, because in that case hydrogen production costs had been found in the order of €3/kg.³⁵ The explanation simply is that in the Jepma & van Schot study the externality related to e-grid savings has been included in the cost price calculus, whereas this has not been done in the above case. This raises the more general question how the production costs of green hydrogen depends on the conversion location if one distinguishes three options: conversion in the wind turbine; conversion on a nearby gas platform; or conversion onshore, under otherwise comparable conditions. In order to illustrate this the figure below can be useful. It makes the location comparison for two different areas: one area with generally less wind speed (left hand side); and one area with higher average wind speeds (right hand side). The figure clearly shows that as expected hydrogen production is largest if conversion is as close to the source of power production as possible, i.e. in the wind mill itself. From the business analysis it turned out this also applies for the overall NPV for most of the scenarios. The option to start installing electrolyzers in or on wind turbines should therefore be taken seriously indeed, assuming that logistical restrictions can be overcome.

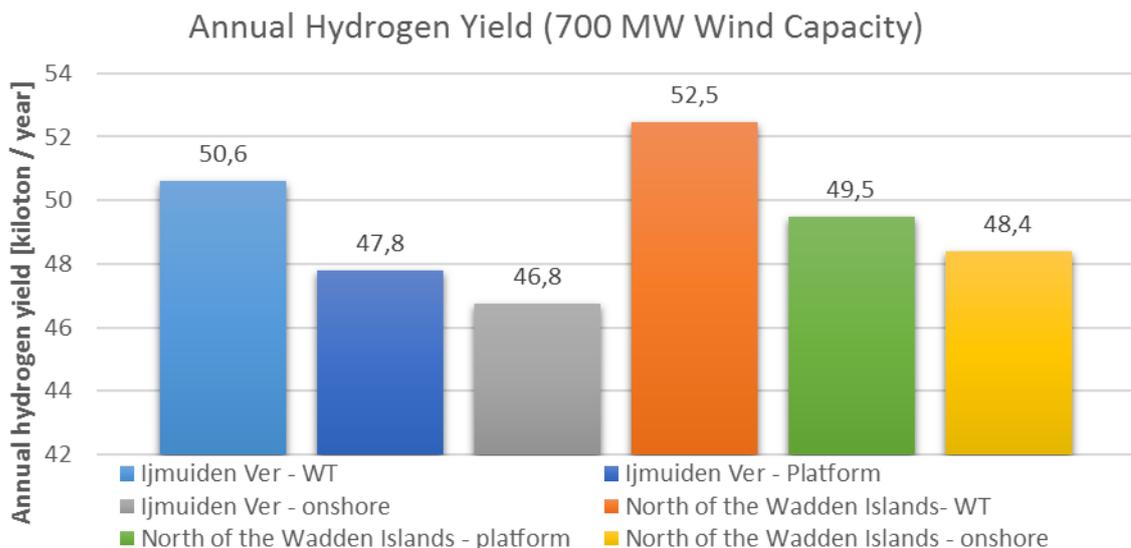


Figure 19, Annual hydrogen yield per location per area

³⁵ Primarily this is the case because the SDE+ feed-in premium for offshore wind is not taken into account. This makes it possible to calculate the actual subsidy need of a particular project.

4.5 Ecological implications³⁶

A final issue is what the CO₂ impact is of generating green hydrogen and subsequently using this for instance in mobility. Based on the assumption that per kg of hydrogen produced in the traditional way, from natural gas with the help of steam reforming, some 10 kg of CO₂ is released into the atmosphere,³⁷ the benefits of generating green rather than grey hydrogen are clearly similar to that. If a passenger car is assumed to drive some 100 km with the help of 1 kg of hydrogen, the emissions saved compared to a petrol/diesel car are about 17 and 14 kg CO₂ respectively (NGVA, 2017).

To be more specific, the actual potential of emissions saved can be quantified and is exemplarily described for the substitution of grey hydrogen produced by MSR and for diesel and petrol in the transport sector (Table 9).

Table 9: Emissions saved by green hydrogen (author's table, passenger fuel consumption, according to Tractebel Engineering (2017, p. 112).

<i>Substitution by Green Hydrogen</i>	<i>Emissions saved</i>
<i>Methane Steam Reforming:</i>	10 kg CO ₂ -eq / 1 kg H ₂
<i>Petrol passenger cars:</i>	16.87 kg CO ₂ -eq / 1 kg H ₂
<i>Diesel passenger cars:</i>	14.04 kg CO ₂ -eq / 1 kg H ₂

Taking the cost-price of sensitivities for offshore hydrogen production north of the Wadden Islands (2025) we arrive at the following incentive needs:

Table 10: Incentive need per tonne CO₂-eq saved (author's table)

<i>Substitution by Green Hydrogen</i>	<i>Incentive requirement³⁸</i>
<i>Methane Steam Reforming:</i>	205.21 - 998.87 € / tonne CO ₂ -eq
<i>Petrol passenger cars:</i>	0 - 407.75 € / tonne CO ₂ -eq
<i>Diesel passenger cars:</i>	0 - 489.95 € / tonne CO ₂ -eq

Another comparison to already existing governmental incentives to decrease greenhouse gas emissions shows clearly that incentives for the selected case of offshore hydrogen production could be in the best case not necessary or are in the other cases within range of current undertakings (Table 11) and thus might be worth to be considered by the Dutch government.

³⁶ The CO₂ impact reduction is not included in the business case for the electrolysis operator, but it has great societal value, for which one may choose to compensate the operator. This redistribution is taken into account in figure 18.

³⁷ Note that the CO₂-eq. emissions per MJ of hydrogen are 103.4 grammes when using natural gas and traditional steam reforming, whereas the emissions of hydrogen production from power-to-gas with the help of renewable energy are only 9.1 g CO₂-eq./MJ of hydrogen; or 91% less (Hoogma, 2017, p. 13).

³⁸ The previously implemented internalisation of grid connection costs has been excluded again for this calculation in order to avoid double incentive accounting

Table 11: Selection of Dutch governmental measures to reduce greenhouse gas emissions; author's table, based on Rijksoverheid (2016)

<i>Governmental measure</i>	<i>Government costs [€ / tonne CO2-eq]</i>	
	<i>2020</i>	<i>2030</i>
<i>SDE+ offshore wind:</i>	<i>166</i>	<i>67</i>
<i>Salderingsregeling solar PV small consumers:</i>	<i>418</i>	<i>970</i>
<i>STEP39:</i>	<i>930</i>	<i>950</i>
<i>Zero emission cars:</i>	<i>5700</i>	<i>-</i>

³⁹ Energieprestatie Huursector (STEP): Stimulation of energy efficiency of real estates

5 Hydrogen production and offshore CCS⁴⁰

5.1 Introduction

After a decade of somewhat less attention for Carbon Capture and Storage (CCS) activity as a result of public resistance in the 2000-2010 period, especially in North-Western Europe, it looks like CCS as a part of the mitigation portfolio to achieve the EU mitigation targets is coming back on the political agenda again. For instance, in the Netherlands, the new government that took office in the autumn of 2017 expressed the goal to store 20Mt CO₂-eq underground by 2030 (18Mt from industry and 2Mt from waste processing) (PBL & ECN, 2017, p. 11). Also, the Norwegian government initiated a substantial project to capture emissions from natural gas based hydrogen production and industrial emissions with offshore CO₂ storage in order to produce serious volumes of power, heat, and hydrogen *without* a carbon footprint (commonly referred to as 'blue hydrogen'). A consortium of companies led by Norwegian state enterprise Gassnova is expected to carry out the various activities involved in this Norwegian tender project. Also in the UK quite recently, the government has announced via Claire Perry (Minister of State at the Department for Business, Energy and Industrial Strategy) that it puts CCS on the British political agenda again. In addition, the Leeds city council initiated plans to convert the gas grid to run on hydrogen replacing natural gas, and incorporate CCS to generate emission-free hydrogen. Other cities in the UK like Manchester and Liverpool are considering to follow this route.

Given the concerns with CCS activities onshore so far, it seems logical that any successful resurrection of North-West European CCS activity would primarily focus on offshore storage, i.e. storage in the North Sea area, either in empty gas fields, or in aquifers (OECD/International Energy Agency, 2011; IPCC, 2005). In fact, combinations of offshore CO₂ storage with high purity sources and existing infrastructure could lead to new insights. As far as decommissioning is concerned, once the platforms and empty gas fields have been decommissioned it will be technically complicated and costly to re-use the field for CO₂ storage (DHV; TNO, 2008), which makes it even more timely to assess offshore CCS options now. Moreover, there is some evidence that from the capture cost perspective, pre-combustion capture of CO₂ is a preferred option compared to post-combustion capture of CO₂, the more so as in cases of pre-combustion capture, a large array of options for capturing the CO₂ is available, including chemical scrubbing, cryogenic separation, selective adsorption on solid sorbents, and separation by selective membranes (Gaudernack & Ilyum, 1998). This suggests that an interesting CCS approach could be to separate the carbon from natural gas or oil at or near the production site, where commonly underground storage is also relatively easy. A natural gas offshore production site, if combined with pre-combustion carbon capture and storage on the same spot, would, by doing so, be converted into a 'green' or 'blue' hydrogen production facility. Some studies on the feasibility of such offshore storage are currently being or have been carried out (for some early studies, see (DHV; TNO, 2009; 2008; EBN & Gasunie, 2010). In the next chapters an extensive analysis of combinations of offshore oil and gas production with CCS activity will be assessed.

5.2 Offshore natural gas production and CCS

For carbon storage, a significant CO₂ source is required. In this study, the focus will be on hydrogen production as CO₂ source. An offshore setting will be used where steam reformers convert natural gas from

⁴⁰ A more extensive description of the research work reflected in this chapter can be found in Kok (2018).

upstream gas fields into hydrogen and store the remaining CO₂ underground. The choice for hydrogen production as the source of CO₂ is:

1. The pre-combustion carbon capture costs are estimated to be lower than post-combustion capture costs, derived from, for example, coal- or gas-fired power plants. The exhaust gases of hydrogen production already contain 99_{wt}% CO₂ (Spath & Mann, 2001). Moreover, in hydrogen production, the combination of separation and storage technologies is already operational in several setups (European Zero Emission Technology and Innovation Platform, 2017);
2. There is a very substantial experience with hydrogen production worldwide, releasing substantial volumes of CO₂: 96% of all hydrogen produced is made out of fossil fuels with a 49% stake for natural gas (Weeda & Gigler, 2016);
3. Large amounts of low costs 'clean' hydrogen could trigger a 'green' hydrogen economy to come off the ground (European Zero Emission Technology and Innovation Platform, 2017).
4. The combination of offshore natural gas production, offshore separation into hydrogen and CO₂, and offshore CCS also may carry the advantage that it avoids the need to heat the CO₂. In situations in which CO₂ injection is at a different location than separation, preheating of dense phase transported CO₂ is necessary (in the initial phase) before injection to avoid fracking (González Díez, 2017)

As far as the CO₂ storage location is concerned, this study will focus on depleted gas fields, because these fields already have a connection with the offshore platforms and therefore do not need further exploration (DHV; TNO, 2008), and because depleted gas fields generally are considered more secure in terms of leakage risks than aquifers. Regarding the costs for CO₂ storage in gas fields, the Zero Emission Platform, which is the advisor of the European Commission on CCS, states that offshore depleted oil or gas fields storage costs are estimated at some €2-14/ton. This is partly due to the fact that the majority of suitable sites have small capacities, so that multiple fields are required (European Technology Platform for Zero Emission Fossil Fuel Power Plants, 2011). In a report on the Netherlands continental shelf, the average price for CCS transport and injection is estimated at €8 per ton CO₂ if existing infrastructure is used (DHV; TNO, 2009). Similar results have been found in Loeve et al. (2013), analysing CCS-related transport and storage from the Rotterdam and Eemshaven ports.

5.3 The two options considered

A specific issue addressed in this chapter is under what conditions it may pay to turn the 'grey' hydrogen produced from natural gas produced offshore into 'blue' hydrogen, i.e. to remove the CO₂ footprint attached to the 'grey' hydrogen via offshore CCS. In doing so, two options will be distinguished: in one option the steam reforming to split the natural gas into hydrogen and CO₂ will take place onshore, whereas in the second option steam reforming is positioned on the offshore natural gas production platform itself. By comparing both options, it will hopefully become clearer which would be the preferred one from the economic perspective. A complexity with regard to the comparison is that the space on a platform limits the potential size of the steam reformer in the offshore case, whereas onshore such space and therefore scale limitations may be less or even virtually absent. That is why, in the comparison, steam reformer capacities have been used which may be considered representative for both circumstances.

Option 1: CCS with onshore source

In this option the CO₂ source will be a steam methane reforming plant onshore, separating the hydrogen and CO₂ from natural gas. From this point the CO₂ will be captured and transported by pipeline to a gas platform

that is out of use. The CO₂ will be compressed at the source and depending on the distance will need to be recompressed at the platform or in between. Due to the high pressure and the dense phase of the CO₂ at that state, it may be required to heat the CO₂ before injection. It is assumed that the platform has an electricity connection and is connected to the upstream natural gas pipelines, the reasoning behind this is that we see electrification as an important stepping stone in the system integration process. The costs for electrification have been identified in more detail in the report on **“the value of electrification of offshore gas platforms”**. In NSE2 a detailed analysis of the combination of platform electrification and CO₂ storage will be performed to give more insight in the diverse integration steps and their joint business opportunities.

In this option, CO₂ transport will be required. Such transport is possible either by ship or by pipeline. Transport by ship starts to become viable at distances over 180 km for small scale application and some 1,500 km for large scale application. The transport costs of CO₂ via a short offshore pipeline (180km) and in small (2.5 Mt CO₂/a) volumes are about €9.50 per tonne. This reduces to €3.50/tonne for a large system (20 Mt/a). For large ships (20Mt/a) the cost are some €11/tonne for 180 km; €12/tonne for 500 km and some €16/tonne for very long distances (1500km), including liquefaction (European Technology Platform for Zero Emission Fossil Fuel Power Plants, 2011). In the IPCC special report on CCS, the transport costs for ships and offshore pipelines are in the same order of magnitude (IPCC, 2005). In case of pipeline transport the CO₂ will mostly be in the liquid or dense phase, which implies a pressure level above the saturation line (Knoope, 2015).

Option 2: CCS with offshore source

This option will assess the feasibility of natural gas extraction and transforming it with the help of steam reforming into hydrogen offshore. This is a concept that has not yet been applied. The hydrogen will be transported to shore via a pipeline and the CO₂ released from the steam reforming process will be captured and injected in a nearby depleted gas field. It is assumed that the platform is already electrified and gets its power from offshore wind park transmission stations.

Comparison

Given these two options, the issue is under what conditions there is a viable business case for CO₂ capture, transport, and storage in offshore gas fields, using existing infrastructure with either onshore or offshore hydrogen production from North Sea natural gas as CO₂ (and hydrogen) source?

5.4 Specific cases and assumptions

Cases selection

The case selected for the assessment of the gas production, SMR, CO₂ capture and storage, and production of hydrogen chain was based on the need to find a production and storage location with a considerable amount of natural gas production for at least 20 years after the start of the project. Based on that criterion, the WGT pipeline (WestGasTransport, that connects to shore at Callantsoog in North Holland province) seemed a suitable connection because of the most assured and sufficient size natural gas production after 2025 in different scenarios. Of the 31 platforms connected through the WGT pipeline, it has been focused on one specific platform of the most dominant operator, NAM, in the K14 block: this block will produce sufficient natural gas to facilitate a gas demand of 0.35 bcm/year for the coming 20 years. The gas quality is relatively high in this block.

Because in the K14 block no fields are available for CO₂ storage in the near future, the neighbouring processing platform K15-FB was selected for CO₂ storage assessment. There is an existing natural gas pipeline

between K14 and K15-FB, so the natural gas can easily be transported to the SMR facility, that will be positioned on a new platform immediately next to K15-FB.

For the onshore option, K15-FB will also be used as injection platform. platform. For the offshore option, K14 will provide the gas to an additional jacket next to K15-FB for the SMR process. The CO₂ will be injected via K15-FB itself. See Figure 20 for a map overview.

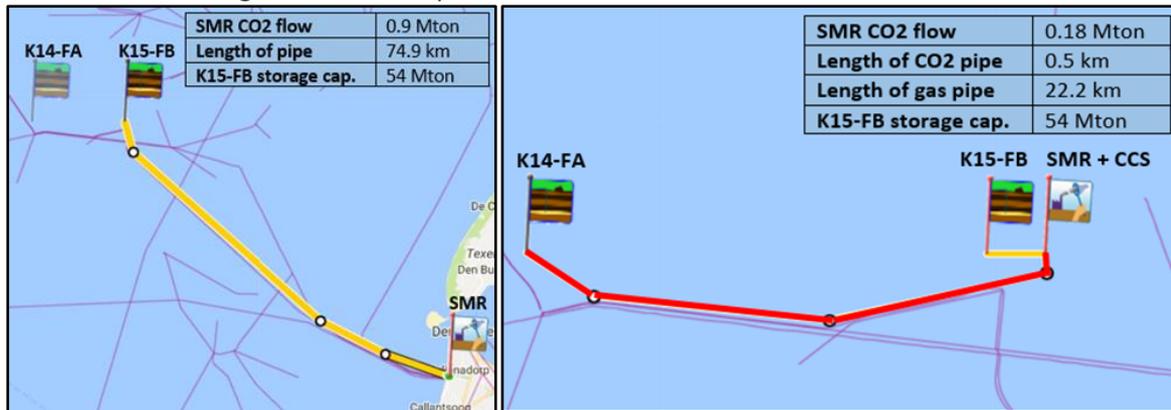


Figure 20. Graphical illustration of K14-FA/K15-FB situation in the onshore case (left) and offshore case (right).

For the offshore setting the SMR has a capacity of 40,000 Nm³ hydrogen per hour. This is the largest small-scale hydrogen production plant that is available ‘off the shelf’ provided by Airliquide. In the onshore setting the total capacity is 200,000 Nm³ hydrogen per hour. This is the largest large-scale hydrogen production plant that is available ‘off the shelf’ at Airliquide. If in the following we assume larger SMR capacities, the assumption has been made that a number of similar reformers are operating in parallel, and therefore without significant economies of scale.

Revenue from CO₂ capture

The core CCS revenue is the reward for CO₂ reduction. The current CO₂ allowance price in the EU ETS is considered to be quite low (some €5-10/t), which is why some Member States (UK and the Netherlands) decided to introduce minimum allowance prices. A major issue is how allowance prices will evolve in the future. Examples of projections are a scenario study by Frontier Economics Ltd. (2015) and the ‘NEV’, an annual projection for the Netherlands government (ECN, 2017). These studies project 2020 allowance prices of €11.2 and €7 respectively, and similarly 2035 prices of €31.6 and €25.

With respect to the Netherlands situation, it is important to note that in the official coalition agreement of the new Rutte III government, it is stated that the subsidy regime for renewable energy (SDE+) will be extended to also include mitigation projects that do not involve renewable energy production. This implies the option to subsidise CCS projects.⁴¹ This could contribute to filling the gap between the market CO₂ allowance price and the cost price of CO₂ capture systems. The SDE+ subsidy level is based on the difference between the required CO₂ break-even cost price of the industry standard according to the recommendation of the CATO-2 studies and the EU ETS price. The CATO2 study concluded that for the CCS chain a break-even price of €60/ton is required.

⁴¹ Although the scope of the subsidy scheme has been extended, the overall budget size will not (PBL & ECN, 2017).

Next to the revenue that could be generated for mitigating CO₂ emissions, it is also possible that low carbon hydrogen will be valued higher than 'grey' hydrogen. In October 2016, the first plan for a European-wide Guarantee of Origin (GoO) for certification of low carbon hydrogen was presented. In order to be certified "low carbon H₂" the related emissions should be 38.4 gram_{CO₂eq}/MJ_{H₂} at maximum (CertifHy, 2016). If this GoO can be combined with the subsidy of CCS mentioned, it could further contribute to the CCS business case.

CO₂ capturing process

It has been assumed that the CO₂ is captured from the syngas before hydrogen purification (in that case, eventually about two-third of the direct emissions are captured). The remaining gases in the CO₂ lean syngas is separated from the hydrogen (using PSA purification) and is used as fuel gas to feed the heat demand for the steam reforming system, and therefore carries a CO₂ footprint. The compressor and the electricity demand of the steam reforming system are assumed to be covered by platform electrification (which is an important factor for the required space)⁴². The hydrogen itself is distributed to its customers.

The captured CO₂ is pressurised by a compressor to attain the required feed-in pipeline pressure. It is then transported from shore to the offshore storage location, and injected. In case of an offshore steam reforming setting, the CO₂ is directly stored in a depleted gas field near the platform. In both cases, the CO₂ will need to be pressurised to a pressure that meets the feed-in conditions for either the pipeline or the storage facility. For the CO₂ transport, dense phase pipeline transport is used, which means that the CO₂ will be compressed above its condensation pressure.

This case study only considers depleted gas fields as storage facility and not aquifers. These fields are connected to a platform, that will need to host installations for CO₂ injection, and in the offshore case also a steam reforming plant.

Capture technology

The ADIP-X absorption solvent method has been considered in the model calculations. The setting where the syngas would be at a pressure of 25 bar with a 20 mol% is used (Meerman, et al., 2012) In the study two cases with different steam reforming capacities have been distinguished: small scale offshore and large scale onshore. Small scale will be 2,500 kmol.

⁴² The costs for electrification have been identified in more detail in the report on "**the value of electrification of offshore gas platforms**". In NSE 2 a detailed analysis of the combination of platform electrification and CO₂ storage will be performed.

Table 12. Economic figures used for the ADIP-X CO₂ capture solvent (Meerman, et al., 2012)

ADIP-X solvent		25 bar, 20 mol%	
Case	Unit	1,000 kmol, offshore situation	10000 kmol onshore situation
CO ₂ captured	kg CO ₂ /s	2,3	23
CAPEX Capture + CHP	M€	€ 11,79	€ 38,15
O&M costs	M€	€ 0,47	€ 1,53
CAPEX per kgCO ₂ /s	€	€ 5,12	€ 1,66
Heat and electricity Capture	MJ(th)	2,17	2,00
plant/kg CO ₂ captured	MJe	0,01	0,02
CO ₂ capture eff.	%	95%	95%
Extra CO ₂ from CHP	t/yr/kg/s	3913,04	4086,96
H ₂ prod.	MJ(hhv)	53,00	534,00
Hydrogen production costs	High range €/kg	1,82	1,09
(without CC)	Low range €/kg	1,01	0,61

CO₂ compression

With regard to compression, CO₂ after onshore capture needs higher pressure than the CO₂ captured offshore, because the CO₂ will be transported in the dense phase which makes it desirable to stay above 85 bar. Moreover, one has to take into account the pressure loss during transport (assumed loss 0.3 bar per km, so for the about 75 km of pipeline this would result in a pressure loss of some 22 bar) (Knoope, 2015). That is why in the onshore version, CO₂ will need to be put to 110 bar; for the offshore version this is less. Precise pressure requirements depend on the depth of the injection well and the volume of CO₂ already stored. Since the overall scale of steam reforming and therefore CO₂ capture is smaller in the offshore version, the economies of scale that can be achieved with onshore conversion cannot be achieved.

CO₂ pipeline transport

Long distance CO₂ transport is only needed for the onshore case since for the second option the CO₂ is generated offshore near the storage locations. Ship transport has already been ruled out, since this only becomes feasible for distances above 180km (European Technology Platform for Zero Emission Fossil Fuel Power Plants, 2011). For pipeline transport generally two options are possible, gaseous phase transport (<60 bar) or dense phase transport (>85 bar). Disadvantages of gaseous phase transport are that at atmospheric pressure the volumes are large and bring therefore high material costs. By transporting the CO₂ at high pressure (dense phase), injection in the depleted gas fields can take place without the requirement of additional boosters. If the pressure would drop below the required value, the inlet pressure is increased to avoid the need for boosters. Therefore, it has been chosen to base the assessment on dense phase transportation (for the onshore case).

It is assumed that for dense phase transport of CO₂, the existing natural gas pipelines cannot be used. This assumption is related to safety standards for the pipelines. This means that new, dedicated pipelines will need to be installed, of which the diameter is assumed based on dense phase transport of 110 bar. Transport costs have been determined based on the standard calculus for pipeline systems, including the effects of crossings offshore (e.g. beach, other pipelines or shipping lanes) (Van den Broek, et al., 2010; ElementEnergy, 2010; Heddle, et al., 2003; Seevam, 2008; DHV; TNO, 2009).

CO₂ injection and storage

For CO₂ injection, the following specifications are important: the amount of wells, the status of these wells, the well injection rate, the size of the fields, and the need for CO₂ heating. CO₂ heating is required since the CO₂ from shore is transported in the dense phase while the initial pressure in the well is lower than 35 bar and CO₂ arrival temperature is expected to be between 4-12 °C (DHV; TNO, 2008). This will require heating equipment, and therefore carries related costs.

Regarding the platform, mothballing and space are the most important factors. The so-called mothballing occurs if the platform becomes available a couple of years before the CCS infrastructure is in place. The costs relate to the maintenance during hibernation and an investment to prepare the platform for hibernation. Typically, space and CAPEX/OPEX of the platform have a large impact on the costs. For the offshore SMR case the limited space on existing platforms leads to the need for a new jacket (€20-40 million). Depending on the size of the heater for the onshore case, an additional (temporary) platform may also be required in this case.

5.5 Business case evaluation

The issue is how the business case looks like for the two variants distinguished: steam conversion onshore or offshore. In order to do so, a break-even analysis has been carried out with the related CO₂ price as the endogenous factor. In the NPV analysis, the two options are compared in several settings.



Base case option 1 and 2

In Figure 21, the base cases of the two options are presented, at which break-even CO₂ price is reached. It is important to note that in the base case, the capacities to produce blue hydrogen are assumed to differ because of the clear space limitations if the steam reformer is put on the platform as compared to the virtual absence of such limitations if the steam reformer is placed onshore. That is why it has been assumed that hydrogen production capacity is 40,000 Nm³/h for a typical offshore situation, and 200,000 Nm³/h for a typical onshore conversion process. The figure shows that the onshore option 1 requires a CO₂ price of €70/tonne to break-even and the offshore option 2 €132/tonne (for a comparison where conversion

capacities onshore and offshore are similar, see next). These prices are not including the decommissioning bonus.

The capture costs are the highest in both options with about 55% share of the total costs. The costs difference between the options however is significant with €33/tonne of CO₂. The main components of the capture costs are the capture unit and the compressor. The CHP CAPEX is included in the capture unit. For both the capture unit and compressor CAPEX, economies of scale play a significant role. For the compressor costs this scale effect translates in a CAPEX per MW compressor capacity for option 1 of € 2 million per MW and for option 2 of € 4 million per MW.

The scale effect of the capture unit is even larger. The CAPEX calculation is based on three capture unit sizes. The CAPEX of the lowest capture unit size is € 5 million per kg/second CO₂ captured, while the CAPEX in the highest capture unit size only costs € 1.7 million per kg/second CO₂ captured.

The benefit for the offshore option is for a large part based on the costs of CO₂ transport. The transport costs for option 1 are rather high compared to literature (Zero Emissions Platform, 2011; EBN & Gasunie, 2010). The reason is that a dedicated pipeline is considered for just 0.9 Mton/year (total captured CO₂), while most other studies consider larger capacities. Below, potential benefits of shared infrastructure with larger flows are assessed. Another variable for pipeline costs is distance: the effect of additional transport distance for option 1 is assessed hereafter as well.



Figure 21. Base cases

The difference between the options for storage costs are the highest. Storage costs for option 1 only accounts for 14% of the total costs, while in option 2 the storage costs accounts for 45%. This translates in a €49/tonne difference. Again the flow rate plays an important role for the costs related to the injection at platform K15-FB. The CAPEX and OPEX costs are largely fixed. The fixed costs for option 2 are higher than option 1, since option 2 includes an additional jacket needed for the additional compressor capacity (which in option 1 takes place onshore). Again there is a certain economies of scale for capacity increase versus increasing platform sizes, this is further outlined below.

Capacities

So, how does the break-even point relate between the offshore and onshore steam reforming process if one uses the assumption that capacities to produce hydrogen are similar? For various capacities, the results of the NPV analysis have been illustrated in Figure 22 below.

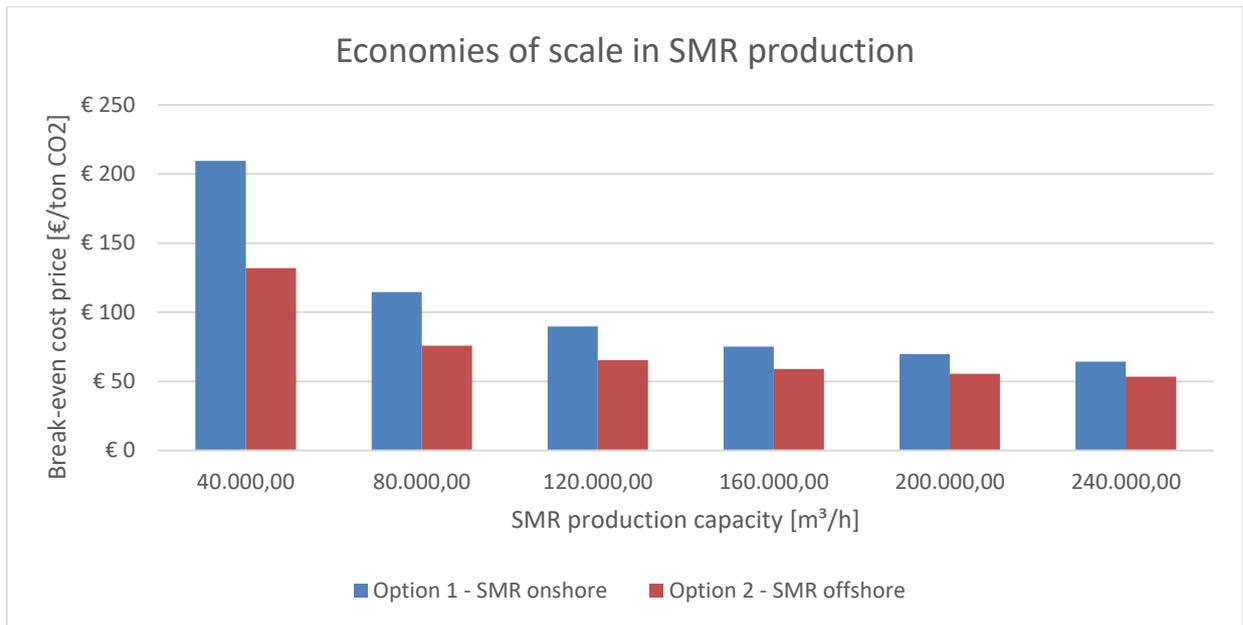


Figure 22. Results of the break-even analysis for onshore and offshore options.

The figure clearly shows that for comparable onshore and offshore capacities, the offshore version scores better, i.e. breaks even at a lower CO₂ penalty level. This systematic difference has mainly to do with the high fixed investment costs for the pipeline. For the offshore option, these pipeline costs are replaced by the additional platform for compression, but the latter costs are a factor 10 smaller than those for transport pipelines to shore. Increasing capacity limits this effect considerably, due to increasing platform costs at high capacities for the offshore option: the related increase in CAPEX is only modest if platform extensions remain limited, but increase substantially if larger installation vessels are required to install the platform. To take this increase into account the following assumptions are made:

- Every 40,000 m³/h hydrogen production capacity increase adds about 550 tonnes of weight to the base case installation weight.
- The added costs for every capacity increase of 40,000 m³/h adds 13% to the CAPEX level, for cases in which all platform facilities can be used (information from NAM).
- At a total topside weight of an assumed amount of 2,000 tonnes (SMR capacities above 120,000 m³/h) a larger installation vessel is required. This is assumed to cause an increase of costs by a factor 1.4. From there the platform costs are increased again by 13% for every step of 40,000 m³/h SMR capacity increase.

In Figure 22 the highest SMR capacity (H₂ capacity of 240,000 Nm³/h) only led to about 1 Mton CO₂ captured and stored per year. A further cost decline can be reached by even larger CO₂ streams (see **Error! Reference source not found.**). As a result the transport and storage costs (excluding capture) are lowered to €8/tonne, thereby lowering the break-even price for CCS towards €46/tonne. So shared transport of CO₂ to offshore locations obviously allows for substantial economies of scale benefits. Although current CO₂ penalties under the EU ETS are much lower than this break-even figure, the current policy initiative of the Netherlands

government to put a minimum price on EU ETS allowances for domestic purposes introduces a minimum price starting with €18 per ton CO₂ in 2020 going up to €43 per ton in 2030⁴³.

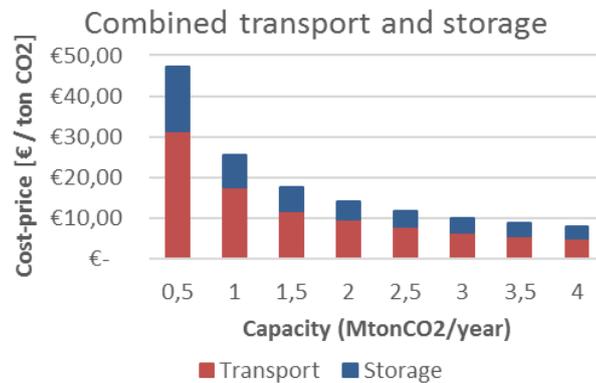


Figure 23 Combined transport and storage costs

Trade-off point regarding distance from shore

The cases discussed in this chapter are all applied for the storage field K15-FB. Although many factors need to be taken into account when choosing a suitable platform, it may be sensible to compare different distances from shore for reasons of comparison between onshore (base case) and offshore conversion (case with H₂ production of 80,000 Nm³/h). For the comparison all input parameters are kept constant except for the distance from shore. The in- or decrease in crossings has been neglected. The trade-off point between onshore and offshore SMR in combination with offshore CCS can be found just above the 100 kilometre from shore. It should be noted that this comparison is only related to the CCS chain and does not include the hydrogen production.

⁴³ Regeerakkoord 2017-2018 'Vertrouwen in de Toekomst', oktober 2017.

Sensitivity

Sensitivity analysis by using various other input parameters (platform CAPEX, pipeline and crossing CAPEX, and natural gas prices) to assess their impact on the NPV for the onshore and offshore conversion cases revealed on the whole little differences in the impact on NPV values, and have therefore further been disregarded.

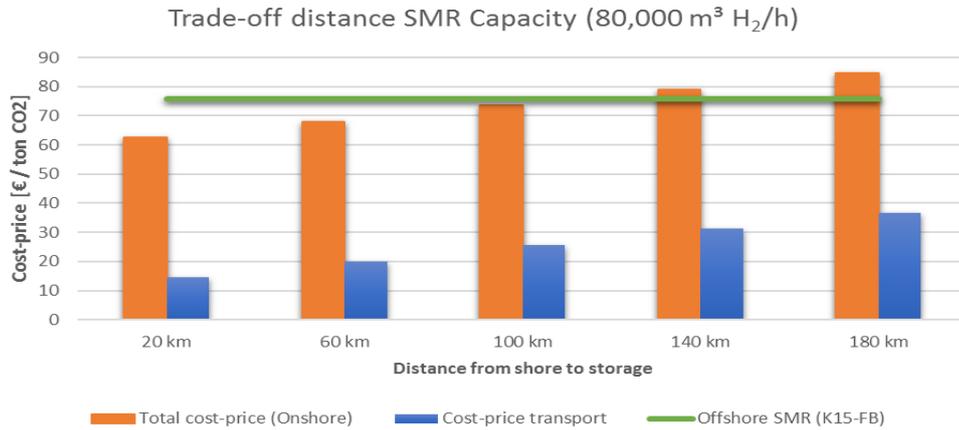


Figure 24. NPV depending on distance from shore

Decommissioning bonus

The decommissioning bonus is the value of postponing the decommissioning of the platform and some of the wells. For both options the decommissioning bonus is estimated to be € 12 million. This results in a decrease of CO₂ price required of €2/tonne for the onshore option (base case) and €5/tonne for the offshore option (case with H₂ production of 80,000 Nm³/h).

6 General overview and outlook

6.1 The perspective of the study

The wind, oil and gas operators on the North Sea as well as the surrounding energy companies seem on the whole quite strongly involved in discussions about how to proceed in the energy transition. Smart combinations is one of the buzz words inspiring this process. In other words, private parties are investigating whether collaboration with others may lead to win-win results. This study has been inspired by the search by private energy players to new ways of generating, converting, storing, and implementing energy that is generated in or near the North Sea.

The search for smart offshore combinations traditionally focused on optimising e-grid configurations. This search was inspired by the practice to connect subsidised wind farms to the subsidising mother country shore only, in order to prevent domestic subsidy from leaking away abroad. Increasingly, it was recognised that this led to sub-optimal grid configurations, unless countries would collaborate to share funding and revenues. So, a wave of studies has been carried out to assess if linking the various North Sea e-grid connections would save not only CAPEX but also reduce carbon emissions⁴⁴.

More recently, the focus shifted to studies investigating if, and to what extent, the offshore power sector and the offshore oil and gas sector could work together to integrate the energy system better, to the benefit of all. The classical concept of turning gas into power was supplemented by the reverse concept of turning power into gas. The benefit of the latter was increasingly recognised because of the lower transport costs and lower storage costs of gases. In addition, existing infrastructure from the oil and gas sector, both installations and the gas grid, was considered a potentially valuable asset, even if natural gas production would substantially decline, to the extent that such infrastructure could be used for conversion and transport, rather than new e-grid equipment. This explains why since about 2015 several studies have been carried out to analyse how, and to what extent, offshore wind energy could be converted into green hydrogen and related products.

In addition, attention increased for the potential role of the North Sea to store CO₂ underground. As a reaction on the public resistance against CCS onshore, the perspective to rather focus on CCS offshore gradually grew in importance after about 2015. Both developments – converting offshore wind into ‘green’ hydrogen, and initiating offshore CCS – have come together in some recent initiatives, to advocate steam reforming (or autothermal reforming) technology to separate natural gas into ‘blue’ hydrogen and CO₂. The latter could then be stored under the North Sea.

This study has been carried out in the spirit of the recent energy development and zooms in on three specific options, which are subsequently analysed from an economic perspective:

- Using oil and gas platforms for energy conversion (specifically power generated by nearby wind farms converted into hydrogen), to be transported to shore using the existing gas grid
- Installing energy conversion equipment (electrolyser) inside offshore wind turbines

⁴⁴Meshed grids, which are technically possible in 2020, can reach much higher utilization rates than 50%. For more information see: Synergies at Sea project: [SP 1.1 Feasibility of a combined infrastructure for offshore wind and interconnection \(Nuon Vattenfall, 2017\)](#)

- Using steam reforming technology to separate (either on offshore platforms or onshore) natural gas into 'blue' hydrogen and CO₂, to be stored underground under the North Sea

These options are not only the topic of more academic research, but also currently analysed elsewhere by potential private sector investors, as the following section illustrates.

6.2 Main findings

If an offshore wind farm and a substantial combination of an oil and gas mother platform and related satellite platforms would decide to intensively work together, this would effectively mean the offshore integration of work that used to be carried out by different operators, and therefore an energy system integration effort. In the special case in which virtually all the energy produced by that wind farm would be channelled to the platform setting to be converted into 'green' hydrogen with the help of electrolysis, obviously substantial volumes of 'green' hydrogen can be produced that, after compression, can be transported to shore, either via the existing gas infrastructure, or alternatively via a new dedicated hydrogen transport system.⁴⁵ This specific case makes it no longer necessary for the wind farm to be connected to shore other than via the platform, which in practice involves a relatively short-distance e-grid connection compared to the alternative in which a new e-grid would need to be constructed to link the same wind farm to shore. The potential savings on e-grid investment are therefore very substantial and, especially for wind farms far from shore, represent very substantial monetary value, easily in the order of hundreds of millions of euros. If somehow policies and measures would be installed to make such grid savings somehow part of the return calculus of the conversion investment, the 'green' hydrogen can be produced against relatively attractive conditions. For the case analysed in this study, cost price figures of 'green' hydrogen have been found in the order of € 1 to 1.75/kg for wind turbines/oil and gas platform combinations located at an about 100 km distance from shore. Obviously, the business case improves for cases in which the location distance would be higher. If somehow the externality mentioned would not be internalised in the business case, the corresponding range with respect to the 'green' hydrogen cost price is € 2.50 to 3.50/kg. This implies a price difference of €1-€2.5/kg with 'grey' hydrogen

In the reality, e-grid connections linking offshore wind farms to shore often already exist. If, in addition, an e-grid connection is made between the wind farm and an adjacent oil and gas platform system, from the perspective of the electrolysis operator there are two options to sell the power: either directly to shore via the e-grid, or via the platform and after conversion via the existing gas grid. A typical advantage of such a case is that the electrolysis operator can monetise the flexibility to change the amount of power delivered to the e-grid depending on the balancing conditions, and by doing so benefit from the so-called reserve market. This adds to the returns on the power itself. Also, the operator of the electrolyser system is assumed to be flexible, such that the electrolyser system can run the optimal number of running hours per year, because this operator is assumed to have access to power from shore that can be delivered via the wind farm e-grid connection. In this case, there is the additional bonus that the e-grid cable capacity linking the wind farm to shore can be more limited than the alternative case in which all power would need to be transported via the e-grid. The Excel model for this case provided surprisingly low cost price data for the 'green' hydrogen generated. Depending on the assumed future electricity prices, cost price figures resulted in the range of € 1.75 to € 2.25/kg. This result was based on assumed electricity price ranges for 2035 in the order of € 45-

⁴⁵ Note that the quantity of green hydrogen produced on a platform is very dependent on platform size

65/MWh. If, instead, power prices would remain at the current levels of about € 35-40/MWh, the cost price of the 'green' hydrogen could even tend towards levels just slightly above € 1.50/kg, which is in the same order of magnitude of the cost price of bulk 'grey' hydrogen produced with the help of steam reforming.

When it comes to the issue what the most economically optimal location of conversion capacity of offshore wind power would be, there are various options, apart from onshore conversion, namely: conversion on offshore islands, conversion in the wind turbine, or conversion on existing oil and gas installations. Theoretically, the energy system can optimize the benefits from the fact that e-grid transport on the whole is much more expensive than gas pipeline transport, by letting the conversion of electrons into molecules taking place as close to the source of renewable power as possible, i.e. in the wind turbine. This way, effectively two AC/DC conversion steps can be prevented, which constitutes a serious cost saving. Obviously, various cost profiles will then be different from conversion on other locations. The Excel model developed for assessing the optimal location, however, corroborated what theory would suggest, namely that locating electrolysers in wind farms is likely (i.e. for most of the scenarios considered) to be economically superior to other alternatives. This option therefore seems worth to be explored further to see if in practice it may work and generate no unsurmountable issues related to maintenance costs, hydrogen compression, etc.

There is increasing interest coming back again on the mitigation policy agenda in setting up CCS activity offshore. After all, the North Sea hosts a substantial number of empty or nearly empty gas fields, and in addition enormous aquifers, all of which could be used for CO₂ storage. This raises the obvious question if platforms, rather than primarily being used for conversion, could also, or perhaps even exclusively, be given a second life as basis from which CO₂ is stored in the underground that in earlier time was used for gas extraction. In such cases, the question is if it would be an idea to use those platforms for steam reforming activity in order to split natural gas flows into hydrogen on the one hand and CO₂ to be stored underground on the other hand. It turned out that this option indeed seems feasible, but that given the average sizes of platforms and other offshore constructions the capacity of steam reforming will have its limitations. However, given such limitations, offshore steam reformers seem to be competitive compared to similar capacities installed onshore. The main reason why is the lesser need for the transport of CO₂. If, however, larger steam reforming capacities would need to be installed or larger volumes of CO₂ to be stored, obviously the offshore option as a location of steam reformers would not be the better one.

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Appendix A: Business canvasses

Battery storage – chapter 3

The first case analysed from the trade option was battery trade. In this case the business opportunities for the platform owner to operate a battery storage solution. The analysed business case is that of the platform owner. The power is delivered from the substation, so no direct connection from the wind farm should be established. The picture below shows the outline of the system, whereas the blue part highlight the business case



Figure A1 Business vs system model

The following assumptions were made:

- Battery storage is placed on a gas platform and electricity is retrieved from a nearby substation.
- The business model includes:
 - For the trade - cases (chapter 3) – future price levels are assumed to follow a stationary path, whereby the mean reversion model could be used to filter out the fixed parts of the electricity price and thereby estimate future prices levels. Manual adaptations to this model could be made to incl. analysis for trade-cases depending on different price levels of Frontier (2015) and EV projections (ECN, 2017), as well as on different volatility levels. In the trade options, the switch price levels of € 40, € 60, € 70, and € 90/MWh have been used.
 - For the primary reserve, capacities of 1, 10, and 30 MW have been assessed. We could however, add the possibility of primary and secondary reserve to increase the business case, however, there is no point in doing this offshore. Also if you apply primary & secondary reserve, there is no option to trade anymore. Using full primary reserve (30mW) would give a yearly revenue of 3 million approximately, this will not push the NPV into green figures (at all).
 - Part of the deck not replaced (direct gas-specific installations): 25% of platform weight (assumed also 25% of costs). Hence, costs in the order of €40/kg are applied when new topside structure are installed, while refurbishment costs data that relate to re-use of existing decks are estimated to be in the order of €10/kg.
 - CAPEX price incl. auxiliaries (e.g. converter etc.) are given by Siemens as €1,75/Wh for a battery cell and €2,20/Wh for a power cell
 - Maximum size possible on a platform is 100MWh, this would be enough to save 8 minutes of energy in case of 100% wind.
 - The grid operator benefits by a reduction in cable size with a more constant flow by capturing energy. The benefits of the grid operator (which is in the Netherlands owned by the

government), are not monetised yet, since they could only store for 8 min. and thus not included in the business case.

The value web:

The trade-solution of offshore gas platforms by battery storage of offshore gas platforms involves a number of stakeholders. Each stakeholder bears a different role, different interests, and are confronted with diverse barriers. The value of battery storage is therefore different for each stakeholder. This is discussed in the following section. In general, the following business and societal value will be generated by battery storage of offshore gas platforms, see Figure A2.

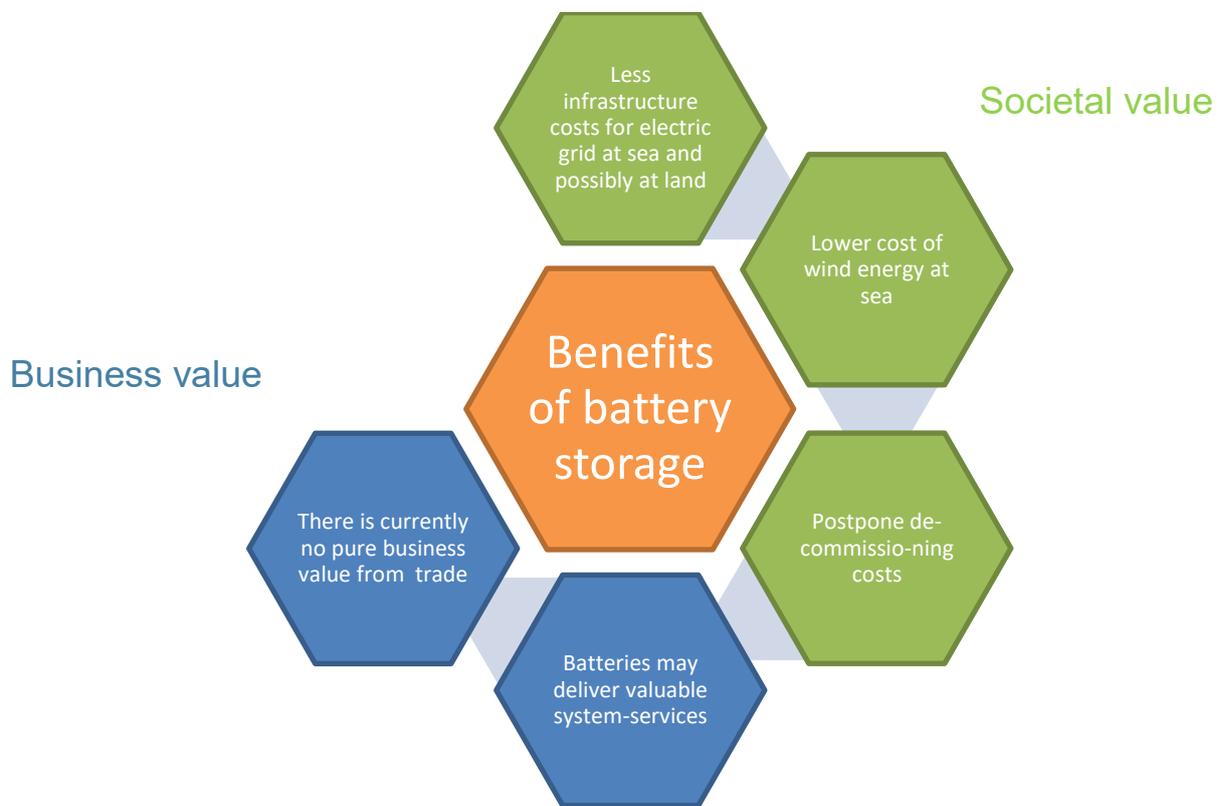


Figure A2 Values of batteries

Wind farm operator

- **Role in the process:** Currently wind farm operators can be operated by small batteries to optimize the generation profile. Smart combinations incl. economies of scale can be generated by combining balancing activities on central locations. The role depends on the type of wind farm. If an existing wind farm will be involved, they are equipped with their own balancing system, and they might have less value from joint trade and/or balancing. If it concerns a new wind farm, it is possible to let the electricity flow from the substation (run by the TSO) to the gas platform without a contract with the wind farm. The wind farm would then not have a role in the balancing/trade process.

As wind will become installed further and further from shore, the costs for connecting, and balancing the output of, these windfarms increase. Next to that, the increase of wind capacity is expected to have an effect on the volatility of electricity prices. Since more and more windfarm operators receive zero- or near zero subsidy, they could reduce price risks by searching for smart system solutions, such as battery storage to reduce price risks and trade their electricity at a later moment.

- **Affected by battery storage:** The gas platforms, which are equipped with a battery, represent new services for trading, balancing purpose and congestion management for the wind-farms. In the case, the pure trade value for platform owner has been analysed, rather the full system value. E.g. if wind turbines are connected with a central balancing point, they might not have to be equipped with batteries themselves.
- **Barriers:** Subsidy is received over electricity that flows to land because of the location of the metering point. A negative business case caused by a low price could be a show stopper. If electricity would stay offshore, there is the risk of losing subsidy, especially as in the above case the electricity changes ownership. These risks becomes lower or nihil with the subsidy-free wind farms.
- **Necessary actions:** A contract with agreements such as price, risks and compensation is necessary between the wind farm and the gas platform incl. battery operator.

Government – Society

- **Role in the process:** Stimulate the growth of sustainable energy supply and specifically wind at sea.
- **Affected by electrification: Battery storage** reduces the congestion problems that arise with the continuing developments in the area of wind at sea. The levelized costs of energy of wind energy at sea will decrease because of battery storage: less electricity needs to be transported to shore and this leads to lower costs of building and maintaining the electricity grid at sea and at land. Also, electrification creates balancing and optimization options that could reduce the energy system costs at sea. Moreover, battery storage could open up a second life for gas platforms which could postpone decommissioning and its associated costs, which can be regarded a societal cost.
- **Barriers:** The public perception could be a show stopper by extending the lifetime of the fossil infrastructure. The societal and ecological costs and benefits associated with decommissioning a platform are controversial.
- **Necessary actions:** Modify regulation regarding subsidy to remove barriers (if necessary needs to be studied in more detail). Stimulate a positive debate and campaign at large public and provide coordination activities between the different parties.

TSO

- **Role in the process:** Balancing any changes in electricity supply and demand that result from the new connection between the wind farm and the platform incl. battery operator. If it concerns a new wind farm: the cable from the gas platform/battery will feed in into the substation run by the TSO.
- **Affected by electrification:** battery storage could lead to less costs for the electric grid at sea and at land because, on average, less electricity has to flow to shore which could help to optimize the grid. The connected gas platform/battery storage could provide back-up power for the substation. Maintenance on the grid and wind farms and on gas platforms (incl. battery system) could be combined which could lead to reduction of those costs for both parties. The costs of the required connection for electrification could partly be incurred by the TSO which would lead to societal costs.

- **Barriers:** Battery storage of multiple platforms could mean arrangements are needed with multiple parties. A clear mandate from the government may be required.
- **Necessary actions:** The TSO needs to modify substations to be ready for a cable from the gas platform (incl. battery storage) and to let electricity also run from shore to sea for back up functionalities.

Gas platform operator

- **Role in the process:** Offers trade services from battery storage to make use of the volatility.
- **Affected by electrification: battery storage reduces the congestion problems of the grid operator.** The net present value of battery storage with the sole purpose of trade services is however negative. It's potential to deliver system services e.g. back-up capacity to the other stakeholders is not sufficiently researched.
- **Barriers:** A negative business case could be a show stopper. It is dependent on the specific situation and market conditions. In addition, operators would need to align their interests with all the other involved stakeholders and get them on board.

Trade services by electrolyzers - chapter 3

The second case analysed from the trade option was by electrolyzers. In this case the business opportunities for the platform owner to operate electricity conversion solution. The analysed business case is that of the platform owner. The power is delivered from the substation, so no direct connection from the wind farm should be established. The picture below shows the outline of the system, whereas the blue part highlight the business case

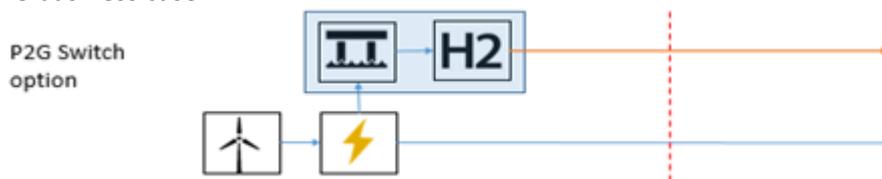


Figure A3 Business vs system model

The following assumptions were made:

- Electrolysis is placed on a gas platform and electricity is retrieved from a nearby substation.
- The business model includes:
 - For the trade - cases (chapter 3) – future price levels are assumed to follow a stationary path, whereby the mean reversion model could be used to filter out the fixed parts of the electricity price and thereby estimate future prices levels. Manual adaptations to this model could be made to incl. analysis for trade-cases depending on different price levels of Frontier (2015) and EV projections (ECN, 2017), as well as on different volatility levels. In the trade options, the switch price levels of € 40, € 60, € 70, and € 90/MWh have been used.
 - For the primary reserve, capacities of 1, 10, and 30 MW have been assessed. We could however, add the possibility of primary and secondary reserve to increase the business case, however, there is no point in doing this offshore. Also if you apply primary & secondary reserve, there is no option to trade anymore. Using full primary reserve (30mW) would give a yearly revenue of 3 million approximately, this will not push the NPV into green figures (at all).

- Part of the deck not replaced (direct gas-specific installations): 25% of platform weight (assumed also 25% of costs). Hence, costs in the order of €40/kg are applied when new topside structure are installed, while refurbishment costs data that relate to re-use of existing decks are estimated to be in the order of €10/kg.
- The grid operator benefits by a reduction in cable size with a more constant flow by capturing energy. The benefits of the grid operator (which is in the Netherlands owned by the government), are monetised and included via the redistribution principle to the platform operator.
- Future CAPEX estimations of the Silyzer 300 are assumed which go to a €600/kW (Jepma., et al. 2017), since the installations are not expected to be realized in the near future and since major economies of scale can be realized in a case of 250MW.
- CAPEX desalination unit: €61,200 for a 2000L/h capacity unit which is about €0,02 per kg of produced hydrogen.
- maintenance costs of Silyzer 300 and a related desalination unit (projection): 2.5% of CAPEX. This figure does not include the costs of electricity intake (Jepma, et al, 2017.)
- Please see appendix B for all cost estimated for pipeline and e-grid.
- In the base case the electrolysis are scaled at 50% of the windfarm (Chapter 3.1), so about 500 MW (average size of current tenders in the Dutch continental shelf). However, if all the wind energy of the would be channelled to the platform (Chapter 3.2) about 315 MW (could be served).

The value web

The trade-solution of offshore gas platforms by electricity conversion technology at offshore gas platforms involves a number of stakeholders. Each stakeholder bears a different role, different interests, and are confronted with diverse barriers. The value of electricity conversion is therefore different for each stakeholder. This is discussed in the following section. In general, the following business and societal value will be generated by electrolysis on offshore gas platforms, see Figure A4.



Figure A4 Values of batteries

Wind farm operator

- **Role in the process:** As wind will become installed further and further from shore, the costs for connecting, and balancing the output of, these windfarms increase. Next to that, the increase of wind capacity is expected to have an effect on the volatility of electricity prices. Since more and more windfarm operators receive zero- or near zero subsidy, they could reduce price risks by searching for smart system solutions, such as power-to-gas, rather than having to curtail their produced energy.
- **Affected by power-to-gas:** The gas platforms, which are equipped with a electrolysis, represent new services for trading, balancing purpose and congestion management for the wind-farms. In the case, the pure trade value for platform owner has been analyzed, rather the full system value.
- **Barriers:** Subsidy is received over electricity that flows to land because of the location of the metering point. A negative business case caused by a low price could be a show stopper. If electricity would stay offshore, or at least not reaches land as an electron, there is the risk of losing subsidy, especially as in the above case the electricity changes ownership. These risks becomes lower or nihil with the subsidy-free wind farms.
- **Necessary actions:** A contract with agreements such as price, risks and compensation is necessary between the wind farm and the gas platform incl. electrolysis.

Government – Society

- **Role in the process:** Stimulate the growth of sustainable energy supply and specifically wind at sea.
- **Affected by power-to-gas:** Conversion technology reduces the congestion problems that arise with the continuing developments in the area of wind at sea. The levelized costs of energy of wind energy

at sea will decrease because of energy conversion: less electricity needs to be transported to shore and this leads to lower costs of building and maintaining the electricity grid at sea and at land. Also, electrification creates balancing and optimization options that could reduce the energy system costs at sea. Next to that, coordination and planning problems arise even more when the offshore energy needs to be integrated in the onshore electricity system. This process includes long lead times and often receives public resistance. Moreover, energy conversion could open up a second life for gas platforms which could postpone decommissioning and its associated costs, which can be regarded a societal cost.

- **Barriers:** The public perception could be a show stopper by extending the lifetime of the fossil infrastructure. The societal and ecological costs and benefits associated with decommissioning a platform are controversial.
- **Necessary actions:** Modify regulation regarding subsidy to remove barriers and stimulate project evolvments through the value of death (if necessary needs to be studied in more detail). Stimulate a positive debate and campaign at large public and provide coordination activities between the different parties.

TSO

- **Relevant interests:** Operating and maintaining a stable electric grid at the Dutch North Sea and high voltage grid in the Netherlands.
- **Role in the process:** Balancing any changes in electricity supply and demand that result from the new connection between the wind farm and the platform incl. electrolysis operator. If it concerns a new wind farm: the cable from the gas platform will feed in into the substation run by the TSO.
- **Affected by power-to-gas:** conversion technology could lead to less costs for the electric grid at sea and at land because, on average, less electricity has to flow to shore which could help to optimise the grid. The connected gas platform could provide back-up power for the substation. Maintenance on the grid and wind farms and on gas platforms (incl. battery system) could be combined which could lead to reduction of those costs for both parties. The costs of the required connection for electrification could partly be incurred by the TSO which would lead to societal costs.
- **Barriers:** the installation and usage of conversion technology at multiple platforms could mean arrangements that are needed with multiple parties. A clear mandate from the government may be required.
- **Necessary actions:** The TSO needs to modify substations to be ready for a cable from the gas platform and to let electricity also run from shore to sea for back up functionalities.

Gas platform operator

- **Relevant interests:** Run a profitable business and reduce the carbon footprint.
- **Role in the process:** Uses trade services from battery storage to make use of the volatility.
- **Affected by power-to-gas:** power-to-gas reduces the congestion problems of the grid operator. The net present value of power-to-gas with the sole purpose of trade services is however positive, if savings on the electricity grid may be internalized.
- **Barriers:** The inability to capture part of the savings on the E-grid could be a show stopper. In addition, operators would need to align their interests with all the other involved stakeholders and get them on board.

Efficiency & hydrogen production location- chapter 4

The third case analysed focused on efficiency of the hydrogen value chain w.r.t. different production locations and a common source of wind power. In order to make a comparison at best, the whole value chain is taken into account, thus, including also the production and investment costs of the wind operator and the TSO. The picture below shows the outline of the system, whereas the blue part highlight the business cases.

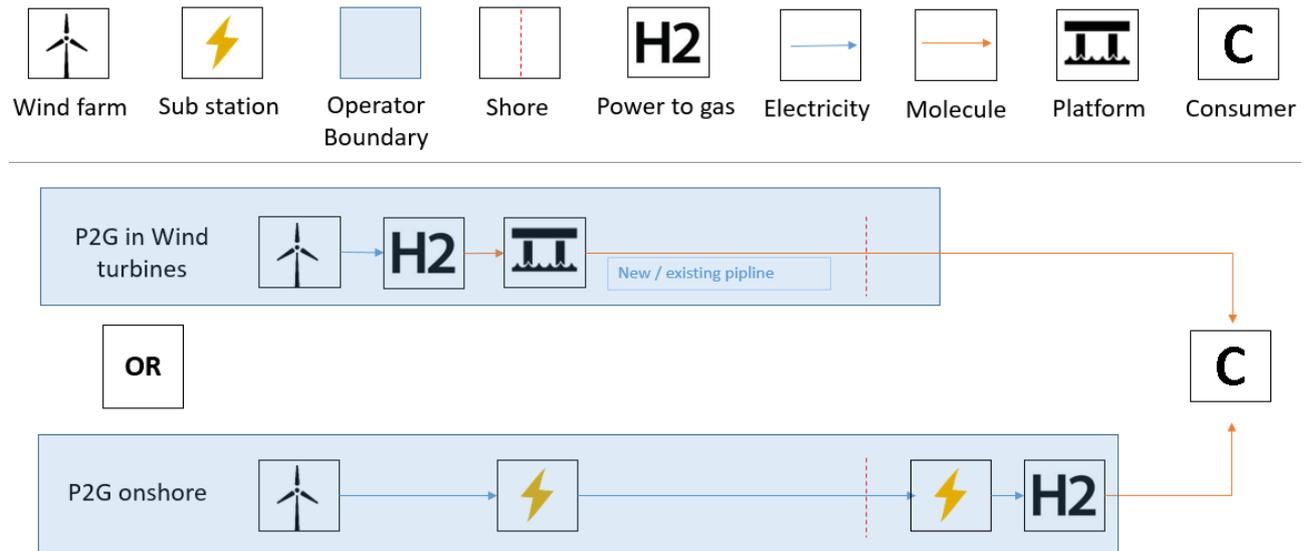


Figure A5. Business vs system model

Within the scope of our study, options for a full power-to-hydrogen conversion are analysed which vary in terms of the location of the energy conversion device and the respective type of energy distribution system. To these options belong the conversion of power to hydrogen within each wind turbine of a wind park, conversion on a platform and the conversion onshore. The business case is analysed from a single operator's point of view including power generation, conversion and distribution to shore. Appendix B provides an overview of the main assumptions. The onshore distribution of hydrogen is out of this study's scope and not included in cost calculations.

As a comparison, a second case of onshore electrolysis using the offshore generated electricity will be considered to specify and assess the impact of the electrolysis location. Moreover, different parts of the production process and the necessary transportation infrastructure are combined to define a cost price per kg of hydrogen.

The value web

The integrated conversion solution within wind-turbines, the compression activities on a gas platform, pipeline operators offshore gas platforms are all involved in this business case, and it is assumed that the complete system is operated by a single consortium, and thus the involvement of other external stakeholders is limited to the government. Although the different consortium partners of this value chain bear different roles different interests, and are confronted with diverse barriers, they all receive a

proportion of the profit. Currently these internal value streams between consortium partners are not discussed in detail, but can later on be determined via transfer price systems. The value-web therefore includes only societal value for the government, see Figure A6.

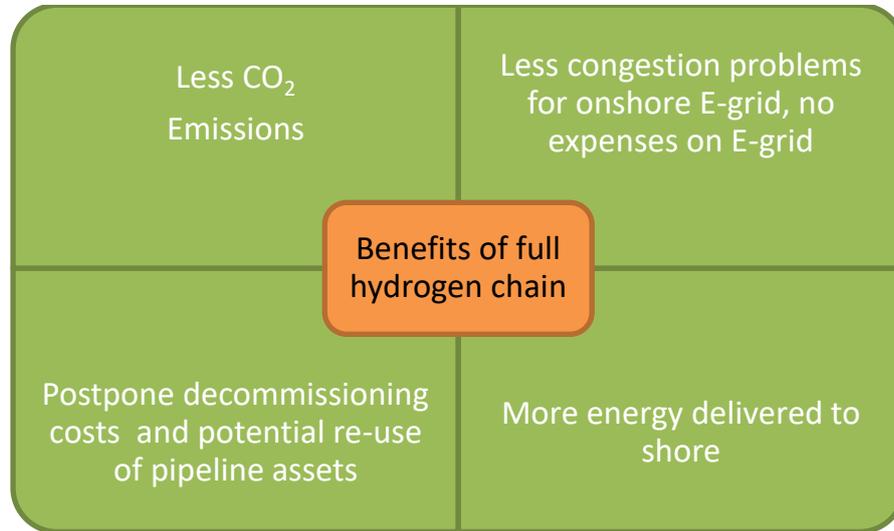


Figure A6 Values of batteries

Government – Society

- **Role in the process:** Stimulate the growth of sustainable energy supply and specifically wind at sea.
- **Affected by electrification:** Conversion technology reduces the congestion problems that arise with the continuing developments in the area of wind at sea. The levelized costs of energy of wind energy at sea will decrease because of energy conversion: less electricity needs to be transported to shore via a new system (it can be transported as molecules through the existing pipeline network), and this leads to lower costs of building and maintaining the electricity grid at sea and at land. Next to that, coordination and planning problems arise even more when the offshore energy needs to be integrated in the onshore electricity system. This process includes long lead times and often receives public resistance. Moreover, energy conversion could open up a second life for gas platforms which could postpone decommissioning and its associated costs, which can be regarded a societal cost.
- **Barriers:** The public perception could be a show stopper by extending the lifetime of the fossil infrastructure. The societal and ecological costs and benefits associated with decommissioning a platform are controversial. Moreover, it will be a challenge to coordinate the different private consortium partners, the government might play a role in this.
- **Necessary actions:** Modify regulation regarding subsidy to remove barriers and stimulate project evolvments through the value of death (if necessary needs to be studied in more detail). Stimulate a positive debate and campaign at large public and provide coordination activities between the different parties.

SMR and CCS - chapter 5

The fourth case analysed focused on the economics of Steam Methane Reforming in combination with CCS and mostly w.r.t. the different locations. In order to make a comparison at best, the whole chain is taken into account, thus, including also the production and investment costs of the SMR plant toward CCS. The pictures below shows the outline of the systems, whereas the blue part highlight the business cases.

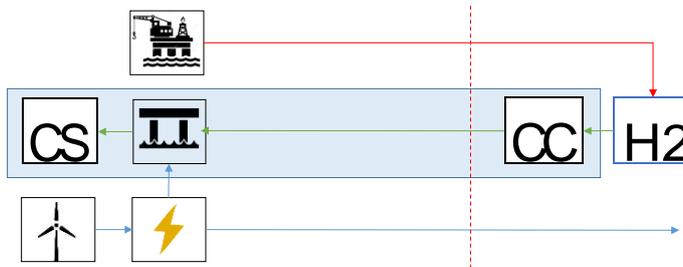


Figure A7, Option 1 CCS + onshore steam methane reforming

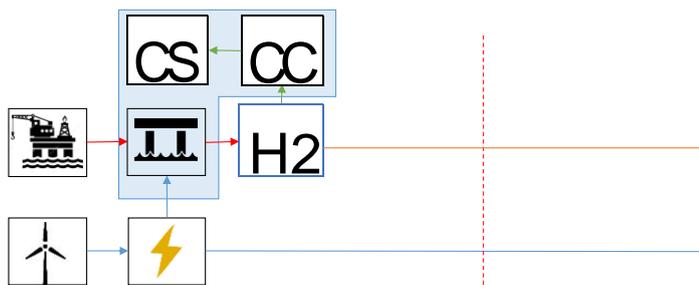


Figure A8. CCS with offshore steam methane reforming

In option 1, the CO₂ source will be a steam methane reforming plant onshore, and from this point the CO₂ will be captured and transported by pipeline to a gas platform that is out of use. The CO₂ will be compressed at the source and dependable on the distance will need to be recompressed at the platform or in between. Due to the high pressure and low temperature in the dense phase, it might be required to heat the CO₂ before injection to mitigate the risk for fracking the well. This option will include CO₂ capture (from onshore hydrogen production), compression, transport and storage.

In option 2, the analysis will calculate the feasibility to extract natural gas from upstream pipelines that are fed by producing platforms and transform the natural gas into hydrogen offshore. By separation of natural gas into hydrogen, carbon dioxide is emitted. The hydrogen will be transported to shore with pipeline and the CO₂ will be captured and injected in the depleted gas field. It is assumed that the platform gets its power from offshore wind park transmission stations. In this option CO₂ capture (from offshore hydrogen

production), transport and storage will be included in the research. The exploration + processing of the natural gas and electrification of the platform are kept out of scope in this research.



Value-web

Government – Society

- **Affected by SMR+CCS:** CCS technology is one of the potential routes to realize the paris-agreements. This has also been notices by the Dutch government. Although current CO2 penalties under the EU ETS are much lower than this break-even figures realised in our report, the current policy initiative of the Netherlands government to put a minimum price on EU ETS allowances for domestic purposes introduces a minimum price starting with €18 per ton CO₂ in 2020 going up to €43 per ton in 2030 could change this.
- **Barriers:** The public perception could be a show stopper by extending the lifetime of the fossil infrastructure. The societal and ecological costs and benefits associated with decommissioning a platform are controversial.
- **Necessary actions:** Great initiative is taken by initiating an allowance price, which is however still too low.

Gas platform operator

- **Relevant interests:** Run a profitable business and reduce the carbon footprint.
- **Role in the process:** Offers it's installation for CCS purposes
- **Affected by CCS:** CCS extends the life-time of the gas platforms and the wells.
- **Barriers:** One of the conditions of offshore CCS is that platforms have been electrified. If this is not the case, than the cost for CCS will be substantially higher.