Hydrogen gas production from offshore wind energy

A cost-benefit analysis of optionality through grid connection

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by

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Preface

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Summary

The decarbonisation of the Dutch power system cannot be accomplished by electrification alone. Although offshore wind power is to play a leading part in the future Dutch power system, long-term energy storage and hard-to-electrify energy consumers are in need of other energy carriers as well. Hydrogen gas is able to provide this system essential. For the production of green hydrogen gas, offshore wind is a promising option because it has a high capacity factor, relative to other sustainable energy technologies. Vice versa, hydrogen production can strengthen the business case of offshore wind as the average power price will decreases as a result of increasing power grid penetration from renewable energy power generators. Furthermore, the expansion of offshore wind in the Netherlands may lead to high cable costs with increasing distances to shore and onshore grid congestion. Hydrogen production can circumvent these problems while continuing the decarbonisation of the Dutch energy system. This study aims to determine the most profitable offshore hydrogen wind hub configuration for 2030 and 2040.

To determine the optimal configuration, this thesis evaluates two main considerations. First, whether onshore or offshore electrolysis is more profitable. Second, whether a bidirectional or unidirectional grid connection may increase the profitability of respectively the onshore or offshore electrolysis configuration. For this evaluation, six configurations are examined that aim to represent the spectrum of possibilities on how a 12 GW hydrogen wind hub could be integrated in the energy system. These configurations vary in their positioning of the electrolyser (onshore/offshore), electrolyser capacity (11.5/9.5/5.6 GW) and grid connection capacities (0/2/6 GW). To compare the profitability of each configuration, this thesis evaluates their cost and revenues. The cost analysis is conducted through a literature study. The revenue analysis is performed by modeling the hydrogen production of each configuration for a given weather year in order to establish the hydrogen production cost. Additionally, for the grid-connect configurations, the power revenues are estimated using the Plexos power market model. This evaluation reveals whether the grid connection configurations can profit from both volatile power prices (sell & buy) and a stable hydrogen price. All analyses use a screenshot approach on the year 2030 and 2040. Thus, annual cost and annual revenues are expressed for these years. In the cost analysis, cost variations are taken into account for the HVDC-components, offshore installation factor and WACC. Also, different distances to shore of the wind hub are taken into account (i.e. 88, 209 & 330 km). For the power revenue analysis, the power system state data on 2030 and 2040 are used from the 'Ten-year network development plan' of ENTSOG/ENTSO-E, which span over more than ten years. From this data, the 'Global ambition' scenario and the weather year 1982 are used. This 'Global ambition' scenario represents a pathway of centralised innovation. In order to establish future power prices, the Plexos power market modelling tool is used to solve an hourly Unit Commitment Economic Dispatch problem by Mixed Integer Linear Programming. This nodal model consist of 59 EU- and surrounding non-EU countries. Additionally, a hydrogen market price is established in which the feedstock sector is assumed to be price-setter as an international hydrogen market is non-existent for now.

In 2030, onshore electrolysis is more economical than offshore electrolysis as the electrolyser investment cost and accompanying offshore installation cost are high. The dedicated hydrogen configurations and the grid connection configurations have equal hydrogen production cost; 3.10 €/kg. In 2040, onshore and offshore electrolysis are equally economical up to about 200 km from shore. At larger distances, offshore electrolysis is more economical. Uncertainty in the system cost and differences in system cost between onshore and offshore electrolysis and per distance to shore are found to mainly result from uncertainty in the offshore installation factor, the cost of HVDC component and the WACC. The bidirectional 2 GW grid connection of onshore electrolysis and the unidirectional 2 GW grid connection of offshore electrolysis both result in the same hydrogen production cost as the dedicated hydrogen configuration; 2.50 €/kg. Overall, considering the operation of a hydrogen wind hub through 2030 and 2040 within one life cycle, there is no significant advantage of grid connection as the break-even prices of the 2 GW grid connected configurations and the dedicated hydrogen configurations are

similar. Nevertheless, a 2 GW grid connection might provide risk spreading for the investor and a lower total hydrogen subsidy amount to achieve a profitable configuration. The larger grid connection of 6 GW is definitely less profitable operating through 2030 and 2040. When assuming the future technological maturity of turbines with DC output, efficient electronic power converters (DC-DC) and electrochemical compression combined with optimistic cost reduction of the electrolyser, the hydrogen production cost decrease to 2.65 €/kg in 2030 and 2.30 €/kg in 2040. Given these production cost, the 2 GW grid connected configuration and dedicated hydrogen configuration become competitive with grey hydrogen production in 2040 based on natural gas price of 7.31 €/GJ and 80 €/tCO_2. An important note is that the current CO_2 price already surpassed the price trajectory for 2030 as used in this study. Variations in turbine cost will affect the production cost as well. However, in this thesis the emphasis is more on the comparison of the configurations than on the absolute level of the production cost. For different turbine cost, the comparison remains similar as the turbine capacity is equal for all configurations. Therefore, a fixed cost reduction is used for the wind turbines. Future techno-economic development of in-turbine electrolysis will determine whether decentralised electrolysis becomes beneficial over centralised electrolysis.

It is recommended that the North Sea offshore wind infrastructural planning must take into account the broader potential of 60 GW Dutch North sea wind in 2050 (+ 450 GW onshore in Europe) and the forthcoming power grid challenges in all North sea countries. For specifically offshore wind-based hydrogen production, electrolyser capacity planning towards and beyond 2050 should be considered as the economies of scale of hydrogen pipelines might favour offshore electrolysis as the overall cost might be lower. Future onshore electrolysis provides possible symbiosis with solar PV, nuclear & natural gas power generation and industry thereby limiting grid congestion and increasing the electrolyser load factor. Future modelling efforts that aim to value the benefits of combined hydrogen and power production should focus on different demand-side-response and power-to-gas capacities as both affect the volatility of the power prices. Also, alternative trajectories of the CO_2 price and energy system scenarios should be incorporated in the power price modelling. Furthermore, the power market model can be improved by including the recovery of long run marginal cost, strategic bidding behaviour and sector coupling of power and heat.

Contents

1
Introduction

1.1. Context

The Dutch energy system of 2050 requires to be powered by renewable electrons and molecules to achieve a 95% reduction of carbon emissions, as stated in the Dutch climate agreement [1]. Hydrogen may play an important role in attaining this goal. This is illustrated by a report by Gasunie and Tennet, who developed three scenarios on the role of hydrogen as renewable molecule-based energy carrier for the power system of 2050 [29]. In these scenarios, the share of hydrogen in the final energy demand is substantial, ranging from 24% to 38%. They also foresee a role for domestic production, with production volumes ranging from 4 to 158 TWh [29]. The expectation that hydrogen gas will be an energy carrier of importance relies on its potential to be a solution for hard-to-electrify and hard-to-abate energy consumers. In addition, hydrogen gas can provide a system essential role in long-term energy storage. Therefore this thesis examines one possibility for future domestic hydrogen production; through offshore wind energy.

Offshore wind seems a promising options since its capacity factor is high with respect to utility solar photovoltaics and onshore wind. This ensures a high operational load for the electrolyser, resulting in larger volumes of hydrogen gas. Thus, offshore wind provides a viable power source for green hydrogen production. Vice versa, hydrogen gas production can be of use for the business case of offshore wind for several reasons. First, hydrogen production might increase a wind farm's profitability compared to power-only production. A shift from power to hydrogen production from offshore wind might be reasonable as average capture power prices will drop [3] as the total offshore wind capacity increases towards its potential of 60 GW [39]. As such, revenues from hydrogen production may improve the business case of offshore wind. Second, a further increase of offshore wind capacity requires costly expansion of the onshore electricity grid due to the limited onshore power transmission capacity. Hydrogen production circumvents this problem. Third, the increasing distance of offshore wind farms requires costly investment in subsea HVDC cables. Fourth, hydrogen gas transport might ease the congestion of the electricity grid. In sum, the integration of offshore wind and hydrogen production offers advantages.

Yet, the question remains how power to hydrogen facilities and offshore wind farms should be optimally integrated. Several considerations need to be made. First, there are roughly two options on how to place the electrolyser. The Transmission Systems operators Gasunie and Tennet argue that, to prevent congestion in the electricity grid, it is necessary that the electrolyser is located either near offshore wind farms or near their onshore grid connection location. In this tradeoff, the increasing distance to shore of post 2030 wind farms (>100km) [39] becomes more relevant as the cost of the transmission system increases. Second, it should be considered whether combined power and hydrogen production (i.e., connection to the power grid) provides benefit over full hydrogen production. This will depend on the investment cost and revenues from power and hydrogen production. Given these considerations, this thesis aims to investigate; what will be the most profitable hydrogen wind farm hub configuration?

1.2. Thesis perspective

Hydrogen production from offshore wind is a complicated proposition in both hybrid configuration (power & hydrogen) and dedicated production. In hybrid production, the electrolyser is regularly downsized and often grid connected to increase its load factor. Even then, current electrolyser capex makes its business case strand. In dedicated production, revenues from hydrogen production need to recover windfarm cost and electrolyser cost while facing power losses in the conversion. As thus the levelized cost of electricity is part of the levelized cost of hydrogen, the combination of offshore wind and hydrogen production is difficult to market for both the off-shore wind business case as the electrolyser business case. This especially the case when reviewing the different entities of a hydrogen wind farm hub configuration (i.e., windfarm, electrolyser, and transmission system operator) as different private or public/private companies. However, as mentioned before, long-term infrastructural challenges and energy system decarbonization targets make hydrogen societally and economically more valuable on the long term. To take a more societal approach in reviewing ‘primary’ hydrogen production, this thesis will evaluate the economics of the different configuration entities as one system. This thesis thus takes a system perspective that abstracts from current market regulations and cost socialization. To evaluate full hydrogen configurations, the hydrogen production cost can be established for different market conditions and system designs. Beside this evaluation of full hydrogen production, this study aims to evaluate the system performance of grid connected configurations. In other words, whether these grid connected configurations result in lower hydrogen production cost as a result of the optionality of volatile market power prices and a (assumed) stable hydrogen price. Besides finding the hydrogen production cost, an expected market hydrogen price is established and forthcoming system revenues are determined.

1.3. Existing research

Research with a system perspective (windfarm, electrolyser and transmission infrastructure) on full hydrogen versus grid connected hydrogen production with power market modelling has not been done before. However, different aspects that relate to this research have already been studied. The next paragraphs describe earlier academic- and policy papers with adjacent perspectives.

Future energy infrastructure of the Netherlands

Studies on the future energy infrastructure of the Netherlands form high-over reconnaissances on how a future decarbonised energy mix looks like and what infrastructure is needed to accommodate this. These strategic papers review energy use in international perspective, consider optimal long term infrastructure investments that follow projected demand trajectories of the use of different energy sources. As a result, these papers from the landscape in which more detailed research can be done.

Two outlook studies have included a review of the role of electrolysis-sourced hydrogen in the future energy infrastructure of the Netherlands, conducted by transmissions system operators Gasunie & Tennet [29] and research institute CE Delft [12]. These studies underline the necessity of hydrogen in a well-functioning energy and/or power system, legitimising further research into a possible sourcing of hydrogen gas. The Gasunie & Tennet report has a strong focus on preventing congestion of the power grid and creating energy storage whilst RES penetration increases. It does so by using the Energy Transition Model (Quintel) to perform power flow calculations with grid reliability as a priority. The CE Delft study takes into account the production cost of hydrogen from offshore wind based on the installed electrolyser capacity and the load factor of the electrolyser. However, these studies have not considered power grid connected configurations (combined power and hydrogen production).

From the perspective of the increasing offshore wind capacity in the North Sea, the North Sea Wind Power Hub consortium has analysed possible new offshore wind hub locations and transmission systems including all electric, all hydrogen and combined production [45]. Although this policy paper does not mention figures or model results, this paper concludes that there is an advantage of electrolysis w.r.t. grid congestion. However, the hydrogen solution is thought to be too costly in 2030 but more likely to reduce total system cost post-2030 as electrolyser capital cost decrease. Again, project-based figures on cost and revenues are missing that are essential to favor a specific hydrogen configuration besides the infrastructural argument.

These strategic papers pave the ground for project specific research that includes future hydrogen production cost and power market prices that can be used to evaluate the viability and profitability of offshore wind hydro-gen production.

Power market modelling

In order to evaluate the value of combined power and hydrogen production, modelling of the power prices is necessary. Earlier research has included power price or system cost modelling of (a part of) the European power system using different models, methodologies, emphases and horizons.

Ozdemir et. al modelled the power market prices in order to determine the integration cost of renewables in the Netherlands using the ECN's COMPETES model including 118 nodes [47]. The study reviewed the effect of different amounts of RES penetration and cross-border transmission capacity. Demand data stemmed from 2014 and the horizon is limited to 2030.

Other studies focused on minimizing the system cost for the European power system of 2050. In this way, Tom Brown et al. [10] performed an extensive cross-border and cross-sectoral study by using the PyPSA-Eur-Sec-30 model to minimize system cost for a 95% decarbonized European power system of 2050. A significant range of scenarios have been modelled in which hydrogen electrolysis has been taken into account. Hereby, hydrogen storage has been found to be a necessary option to cope with RES fluctuations. However, other hydrogen demand, such as industrial (heat) demand is not included whilst these sectors are of significant size in the Netherlands [16]. Furthermore, demand data of this study was based on 2011 figures. Another study in which hydrogen functions primarily as supplementary to the power sector is from the Nordic countries that used the Balmorel and TIMES model to simulate different scenarios up to 2050 [42]. In all scenarios, hydrogen opts for a limited role in mobility and heat but is seen vital as energy storage to offer flexibility to the power system. However, the study does not consider transmission limits between countries/nodes. A recent scenario report by ENTSOE/ENTSOG on the future European power and gas system is the 'Ten-year network development plan' 2020 (spanning over more than ten years) [28]. Datasets from this study are based on the most recent National Energy and Climate Plans of the EU member states and derived from carbon reduction ambition levels. (In fact, this thesis also uses these data.) The study includes power-to-hydrogen dynamics from both excess electricity (after performing power market simulations) as well as dedicated RES generation for hydrogen electrolysis. However, these dedicated electrolysers are assigned based on country-specific gas demand and a as a fixed ratio of the installed RES capacity. This effort results in limited electrolysis capacity since the offshore wind capacity is at most 16 GW in 2040 and does not take into account the benefits of avoiding power grid congestion.

In contrast, other studies consider hydrogen both as a commodity supplemental to the power market and as a standalone commodity. In this way, Larscheid et al. reviewed the profitability of electrolysis for different hydrogen prices and potential additional profits from cross-commodities arbitrage [37]. Hereby, no consideration is made from which generator the electrolysis input power is sourced from and the modelling horizon is 2034. Another study by Sgobbi et al. [52] used the JRC-EU-Times model to review the effect of different CO2 price scenarios on the hydrogen penetration in the power sector, transport sector and industry in 2050.

In order to compare the profitability of different grid connected hydrogen wind hub configurations, a power model must be able to incorporate additional wind power while its power system data based on recent data with a horizon spanning multiple decades.

Hydrogen market development

The comparison between different wind hub configurations inevitably also depends on the revenues from hydrogen gas production. However, an open hydrogen market is non-existent for now. Earlier research shows that there are different possible hydrogen market pathways and different methods to establish the hydrogen production cost for hydrogen from offshore wind from the North Sea. This is important to evaluate the profitability of offshore wind hub configurations.

Qualitative arguments for this hydrogen market development are given by IRENA and the Clingen-dael International Energy Program/ IRENA. They stress the potential benefit of combining offshore wind and hydrogen production in the North-sea region to prevent grid congestion as a niche market without further calculations [35]. Also, the Clingendael International Energy Program stresses the importance of large-scale electrolysis to lower the societal cost of offshore and onshore power grid expansion [57].

Quantitative analyses are made with different perspectives. First, ECN & HYGRO provides a local perspective that stresses the potential of hydrogen in competing with diesel in heavy transport [32]. This study also stresses the benefit of in-turbine electrolysis and the benefit of a separate wind-to-wheel infrastructure with the advantage of energy storage and the avoidance of power grid congestion. Second, CE Delft provides a perspective on hydrogen production chains, comparing blue, green and import hydrogen [13]. This study states that the marginal production cost of green hydrogen will be lower than blue hydrogen from 2030 onwards. This study focused on production cost from North-Sea offshore wind but used a fixed LCoE for offshore wind without considering far-offshore multi-GW wind-farm LCoE or infrastructural challenges. Third, A more project-based perspective is taken by Machiel Mulder et al. [41] who calculated the required hydrogen price for electrolysis from North-Sea offshore wind including the benefit of grid savings. However, the study takes a fixed LCoE for offshore wind and does not consider hybrid configurations (power and hydrogen production) which potentially benefit from fluctuating power prices and a stable hydrogen price.

Offshore wind-based hydrogen production optimization

Different combinations of offshore wind and electrolyser capacity have been investigated in previous research. Kroninger et al. have optimized hydrogen production from offshore wind in Germany, showing that small scale electrolysis was only profitable (in 2014) at a significant hydrogen price and at a 100% utilisation of the electrolyser, achieved by adding electricity storage between the windfarm and the electrolyser [36]. For wind-based hydrogen production in the Netherlands, a long-term outlook on North sea offshore is performed by ECN [59]. This outlook revealed that electrolysis is best conducted using a power system state of 250 GW North Sea wind power resulting in a 25% curtailment factor. Furthermore, offshore hydrogen gas infrastructure could reduce energy transport cost by a factor of 1.5. Other studies reviewed more specific locations with a higher level of detail. In this way, Jepma reviewed the use of existing de-commissioned North sea platforms for offshore electrolysis of a 60 MW and 250 MW electrolyser [11]. In the same way, DNVGL reviewed the profitability of onshore and offshore electrolysis (500 & 2000 MW) for the planned IJmuiden offshore wind farm (4-6 GW) [17]. The profitability of the electrolyser with different operating modes were analysed with a horizon of 2045.

Despite these optimization efforts, an analysis on the profitability of large-scale electrolysis from hybrid configurations is lacking. Hereby, a detailed cost breakdown and revenue modelling is essential to provide a valid comparison between full hydrogen and combined power and hydrogen production from offshore wind in the Netherlands.

1.4. Research questions & report structure

Existing research has shown the vital role for hydrogen in a long-term energy storage in the development of a decarbonised European energy system in 2050. Besides energy storage, other potential sectors for hydrogen usage are heavy transport and industry. For the production of hydrogen, offshore wind in the North-sea area has been depicted as a niche opportunity as the power grid connection capacity cannot keep up with the increasing offshore wind capacity. This thesis aims to give the Dutch gas transmission system operator Gasunie insight into the economic dynamics of domestic offshore wind hydrogen production towards 2050 by performing a screenshot analysis of the years 2030 and 2040. This research aim can be translated in the following research question: **What is the most profitable configuration of an offshore hydrogen wind farm hub in 2030 and 2040?**

In order to answer this question, this thesis compares the cost and revenues of different wind farm hub configurations. Each configuration has the same starting point: a wind farm hub capacity of 12 GW. This capacity is based on the most recent North Sea Wind Power Hub consortium ambitions and is calculated to be the optimal size for a wind farm hub, following a trade-off between sand island sizing and inter-array cable length. Six different configurations are set up that aim to represent the spectrum of possible configurations. These configurations differ in two respects. First, the electrolyser is positioned either onshore or offshore, since it is not yet known which position would be most profitable. Second, they vary in their grid connection capacity, which is set at 0 GW (i.e., dedicated hydrogen), 2 GW (i.e., limited hybrid), or 6 GW (i.e., full hybrid). By including hybrid configurations, this study explores whether the profitability of a hydrogen wind farm hub may be increased by combining hydrogen production, which is assumed to have a stable price, with power production, which prices are volatile. The capacity of 2 GW was chosen based on the current maximum power grid connection capacity. The capacity of 6 GW was chosen as the estimated maximum power grid connection capacity for the decades to come anticipating on multiple debarkation locations. The combination of the two electrolyser locations and three grid connections lead to six different configurations as presented in table 1.1. As a consequence of the combination of the electrolyser location and the grid connection capacity, the configurations use different transmission systems (gaseous, hybrid or electric).

To compare each configurations profitability, a cost analysis is done through a literature study and a revenue analysis is performed using the Plexos power market model to evaluate the grid connected configurations. The main input data for the power market model is the 'Ten-year network development plan' 2020 report of ENTSOE/ENTSOG comprising of 2030 and 2040 data on the European power system. This data is used to perform full-year market simulations at a 1 hour resolution.

Table 1.1: Offshore hydrogen wind farm hub configurations

Configuration	PtG location	Transmission system	PtG installed capacity	Direct grid connection	Electrolyser feed in source
1 (hydrogen only)	Offshore	Gaseous	11,52 GW	No	OWF
2a (hydrogen + power)	Offshore	Hybrid	9,56 GW	2 GW	OWF + 2 GW grid
2b (hydrogen + power)	Offshore	Hybrid	5,62 GW	6 GW	OWF + 2 GW grid
3a (hydrogen only)	Onshore	Electric	11,50 GW	No	OWF
3b (hydrogen + power)	Onshore	Electric	9,50 GW	2 GW	OWF + 2 GW grid
3c (hydrogen + power)	Onshore	Electric	5,56 GW	6 GW	OWF + 2 GW grid

The report structure is formed by two stages (cost & revenues), that follow up on the overall methodology and scope of the study as described in chapter 2. The cost are discussed in chapter 3 and evaluated in the interim conclusion, chapter 4. Then, the methodology of the revenue modelling is described in chapter 5, followed by the modelling results in chapter 6. The results of the cost analysis and the revenue modelling are combined in chapter 7 to assess the profitability of the configurations. The report findings are discussed in chapter 8 and conclusions are drawn in chapter 9.

The analysis of the configurations is driven by six sub research questions.

1. **Is offshore or onshore electrolysis more profitable?**

The profitability of offshore versus onshore electrolysis depends on the system cost of the configuration and the energy losses caused by the different transmission systems (see table 1.1). Offshore electrolysis is likely to have higher investment and operation cost, however, the forthcoming gas transmission system might be more economical than its electric equivalent. A comparison between offshore and onshore electrolysis is done through an economical cost assessment presented in chapter 3.

2. **Does the distance to shore of the offshore wind farm hub affect the profitability of the configurations?**

This study chose three offshore wind farm locations that differ in their distance to shore. These locations are based on potential future offshore wind farm sites for 2050 that were mapped by the Netherlands Environmental Agency. The cost analysis in chapter 3 is based on these locations and includes an evaluation to what extent this distance to shore and accompanied water depth influences the profitability between the configurations.

3. **Is hybrid production more profitable than full hydrogen production?**

Hybrid production (i.e. combined hydrogen and power) might profit from the volatile power prices and a stable hydrogen price. The assumption of this stable hydrogen price is made anticipating on a hydrogen market of (inter-)national coverage with significant storage possibilities. The hybrid configuration can sell power at high power prices and buy power at low power prices to increase hydrogen production and revenues. However, a double infrastructure compromises the load factor of both infrastructures. The revenue modelling results of chapter 6 are combined with the cost figures from chapter 3 to evaluate the profitability of hybrid production compared to full hydrogen production in the conclusion in chapter 9.

4. **Does a grid connected electrolyser increase the profitability of hybrid configurations?**

As mentioned above, a grid connected electrolyser can profit from additional power input from the grid at low power prices, besides the wind farm power. The additional hydrogen revenues from this power flow are presented in chapter 6 and weighed against with the additional infrastructural investment cost. Chapter 6 thus assesses the change in profits upon connecting the eletrolyser to the grid. Then, in chapter 7 the cost and revenues are combined to answer the question whether the overall profitability increases because of grid connection.

5. **What are the hydrogen production cost for each hydrogen wind hub configuration?**

It is important to know at which point a configuration is economically viable. This can be assessed through the hydrogen production cost. These hydrogen production cost are determined for all configurations in chapter 6.

6. **What are the most influential technological and economical developments for the profitability of each configuration?**

The future profitability of offshore wind hydrogen production is uncertain. Some uncertain factors can be identified upfront of which the effect on the profitability can be assessed by sensitivity analyses. This report therefore includes sensitivity analyses of the system cost in chapter 3, and a qualitative analysis of the effects of grid capacity expansion on the power prices in chapter 6. Besides these factors, other developments can be identified that are also of significant influence on the power and hydrogen market price. These are reviewed in chapter 8.

2

System cost: Methodology

This chapter describes the methodology to determine the system cost of the six wind hub configurations. Since this report focuses on the configurations' profitability in two specific years (i.e., 2030 and 2040), the total system cost over the configurations' lifespan will be expressed in annual cost. The system cost are determined based on the most costly system components. The selection and properties of the system components are based on assumptions on offshore wind hub sizing, power losses and end-state requirements that are mentioned in paragraph 2.1. Given these assumptions, the components and their properties are presented in paragraph 2.2. Paragraph 2.3 describes how cost figures for each component are retrieved and how these figures are translated to annual cost. The different wind hub locations are presented in paragraph 2.4.

2.1. System assumptions

The system assumptions consider 1) the sizing of the offshore wind hub, 2) the energy losses of the transmission system, and 3) the end-state requirements of the transmission system.

First, the capacity of all six wind hub configurations is set to 12 GW. This assumption is based on a framework for the future North Sea offshore wind state, developed by the North Sea Wind Power Hub consortium. The North Sea Wind Power Hub consortium study follows the ambition of 60 GW offshore wind in the Dutch part of the North sea, in which spatial planning is a key challenge. The consortium opts for 'energy hubs'; multiple artificial islands to which offshore wind farms are to be connected. The optimal capacity of such an offshore wind energy hub is determined to be 12 GW, a capacity at which the inter-array cables can still be directly fed to the island instead of requiring an additional substation [45].

Second, power losses are considered as a fixed percentage per component. A specific consideration is the power usage of the compressor that will be calculated. Other power quality parameters (e.g., total harmonic distortion & displacement factor) are not considered as they are not the focus of this study.

Third, the end state requirements for the power grid connection are 380 kv AC 50 Hz (current Tennet grid mapping) or 525 kv DC (possible future onshore grid). The end state requirement for the hydrogen grid connection is 50 bar and a 99,97% purity (ISO 14687-2) for the hydrogen gas. This 50 bar pressure is the estimated pressure for a hydrogen backbone in the Netherlands using the existing natural gas infrastructure [Gasunie internal]. The required purity ensures the usability of the hydrogen gas for all users, including fuel-cells use in the mobility sector.

2.2. Configurations & components

The system cost are determined based on the most costly system components. These components are presented in figures for each configuration (figures 2.1 to 2.4). As the offshore wind hub is equal for all configurations (left-side blue area), the main focus of the system cost analysis is on the transmission system (middle red area). This red area also indicates the system boundary.

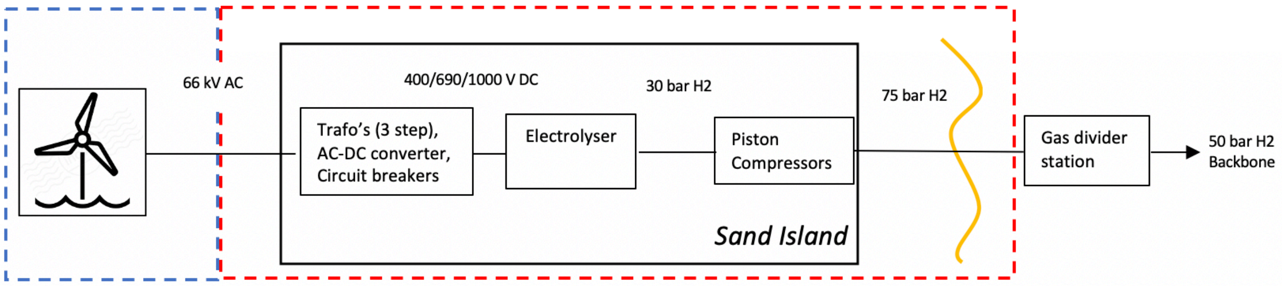

Figure 2.1: Configuration 1: Offshore electrolysis, fully gaseous transmission

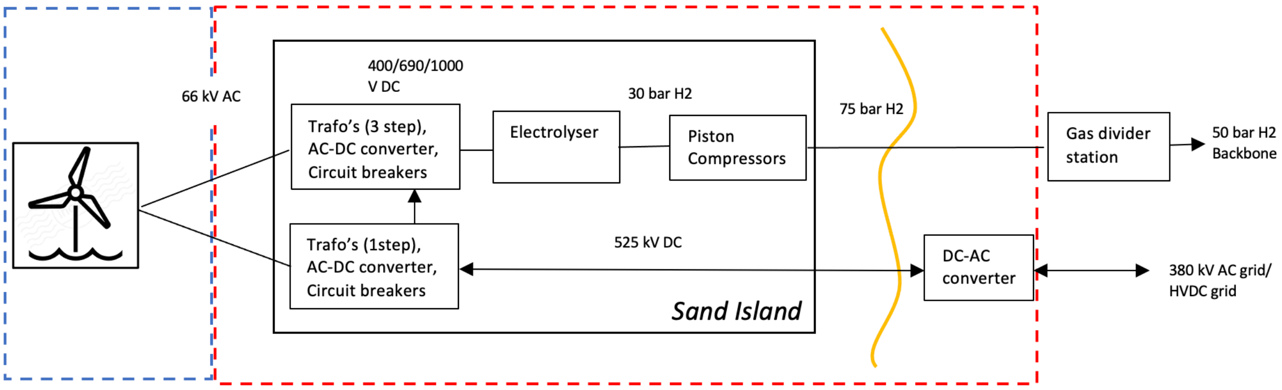

Figure 2.2: Configuration 2a/b: Offshore electrolysis, hybrid transmission (2/6 GW grid connection)

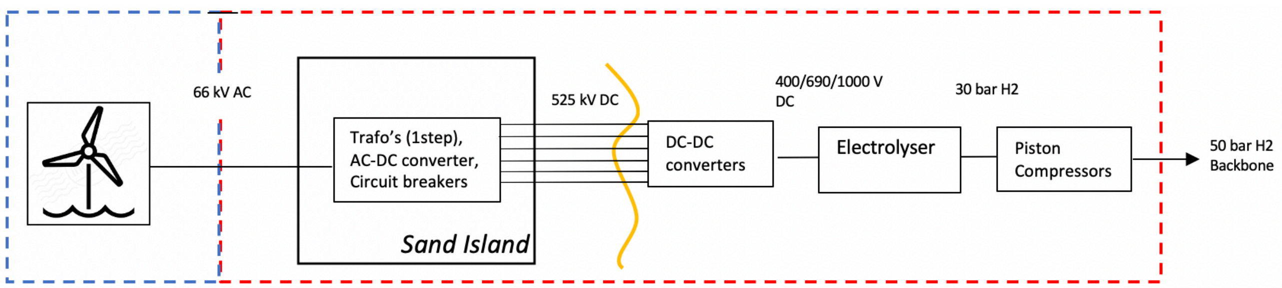

Figure 2.3: Configuration 3a: Onshore electrolysis, fully electric transmission

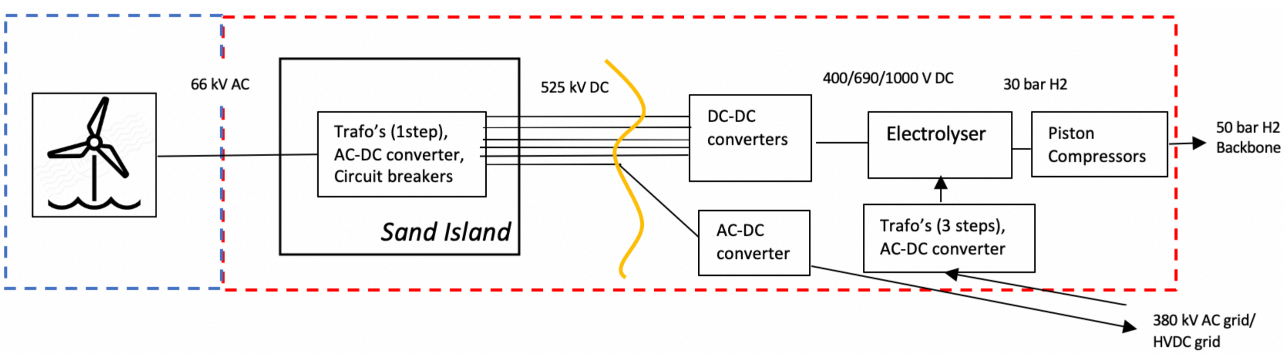

Figure 2.4: Configuration 3b/c: Onshore electrolysis, hybrid transmission (2/6 GW grid connection)

In sum, the following components are taken into account; transformer, converter, circuit breakers, reverse osmosis desalination unit, electrolyser, compressor, sand island, gas pipeline and HVDC cable. The costs of the following components are considered insignificant and are therefore neglected:

switchgear, filters, reactive compensation, fault current delimeters, tapping equipment, supervisory control and data acquisition equipment and the costs of water for onshore electrolyser.

2.3. Cost analysis

The cost analysis is based on a literature study of public sources and project-based information from within Gasunie. In the effort of establishing cost figures, current or near-futures technologies are used which are realistic to scale up to GW-size. A more optimistic perspective that assumes drastic innovation that is combined with upscaling is evaluated in paragraph 7.3.

The cost analysis aims to establish the annual cost of each configuration by incorporating the Capex (Capital Expenditures), Opex (Operational Expenditures), installation cost and financial cost of each component or stated otherwise. The Opex are yearly cost expressed as a percentage of the Capex. The installation cost are accounted for by multiplying the Capex with a cost-factor for onshore or offshore installation.

To establish the annual cost per component, the cost over its lifetime must be discounted to express annual cost as present value, as shown in equation 2.1. The present value is calculated using the annuity factor, which discounts these cost over time (equation 2.2 given a component's lifetime 'n' and a rate per period 'r'). This rate is established by a cost of capital 'R' and interest rate 'i' in equation 2.3. From a corporate perspective, the financial cost is expressed by the WACC (Weighted Average Cost of Capital).

$$Annual\ cost = \frac{CapEx}{a} + OpEx \tag{2.1}$$

$$a = \frac{1-(1+r)^{-n}}{r} \tag{2.2}$$

$$r = \frac{(1+R)}{(1+i)} - 1 \tag{2.3}$$

In the annual cost calculation of specifically the electrolyser, the Capex is calculated taking the economies of scale into account. The reason for this is the electrolyser's low technological readiness level and small manufacturing capacity that does not benefit from economies of scale yet. For other components, the economies of scale are neglected as their technology is mature and GW-scale cost figures are available. The scaling factor equation 2.4 expresses the cost 'C', size 'S' and scaling factor 'f'.

$$C_b = C_a * \left(\frac{S_b}{S_a}\right)^f \text{ [8]} \tag{2.4}$$

Other than the transmission system components, the cost of the wind turbines is expressed not as annual cost, but as the LCOE (Levelised Cost of Energy). The LCOE is a clear and widespread cost indicator (equation 2.5) that incorporates the annual energy production (AEP).

$$LCoE = \frac{(\frac{CapEx}{a} + OpEx)}{AEP} \tag{2.5}$$

In order to understand the uncertainty of the total system cost, a sensitivity analysis will be performed, both for the years 2030 and 2040. This analysis aims to revail the possible effects of cost variations of specific components or cost types is calculated. An important cause for cost uncertainty is that cost of especially offshore wind infrastructure is very project specific. The unprecedented scale in capacity and geographical (marine) coverage enlarges this effect. There a five factors identified as most prominent factors of cost uncertainty. These cost factors are: turbine cost, electrolyser cost, HVDC-component cost, installation factor and the WACC level. These cost factors are varied in the sensitivity analyses, except for the turbine and electrolyser cost, which are equal for all configurations. Turbine cost are determined for 2030 and 2040 as the LCOE (excluding transmission) continues to decrease. Electrolyser cost are determined for 2030, and again for 2040 given the expected rapid decrease of cost. No additional electrolyser cost variations are analysed as the 2030 value represents a conservative upper limit that is academically supported and the 2040 value is an optimistic consultancy- and policy-based cost value near the material cost value. In the transmission system cost analysis, an in-between value will be presented as well. The other three cost factors are included in the sensitivity analyses. The following cost variations were chosen for these three factors:

- HVDC-components +/- 25 %
- Installation cost factor, varied from 1.75 to 1.5 and 2.0
- WACC varied from 4.8% to 2% and 8%

The basis of HVDC cost variance is its strong dependency on metal market prices given their metal-intensive cost. The variance of the offshore installation factor is chosen to represent the uncertainty of offshore highly project-specific cost. A rule of thumb for offshore components is to use twice the cost of its onshore equivalent as a result of its installation cost (installation vessel, workforce, weather-dependancy, etc.). The range of this cost factor is based on cost figures from [43] and [Gasunie internal] sources on offshore projects. The WACC variance lower value is based on the current low interest rates on the capital market. The higher WACC value is based on common conservative value for renewable energy projects. Given the significance of the WACC-based financial cost and the complexity of the 'valid' WACC value, the WACC is elaborated on in more detail in the next section.

Specific consideration: WACC

The baseline WACC is used by companies as a proxy for their discount rate. The discount rate annualises future cost and revenues to evaluate the viability of an investment. In other words, the chosen discount rate represents the time value of money, so that future money can be expressed in today's money. Since companies finance their project through debt and equity, the WACC defines the minimum return of an investment for it to be worthwhile based on these cost of debt and cost of equity. However, a perspective on societal value is relevant given the public value of renewable energy and the partly public financed infrastructure for offshore wind. Nonetheless, this corporate WACC represents the preference of capital markets, which are distorted from the social preference. This distortion can be attributed to externalities, market failures and the necessity for private companies to earn a risk-premium. In contrast to corporate discounting, the social discount rate is a way to evaluate the cost and benefits for the society as a whole from an inter-temporal perspective. Inevitably, this entails a judgement on current versus future value. For renewable energy investments, the marginal benefits and marginal cost of emission abatement are important parameters in realizing such a social discount rate that maximises social welfare. However, establishing this social rate is outside the scope of this study. Specifically, the social discount rate is expected to be significantly lower than the corporate discount rate.

The WACC value in this study is based on an International Energy Agency study on WACC values for offshore wind in different countries [34]. This value (i.e., 4.8% real WACC, pre-tax) is applied to the entire system. Besides this value, a lower societal WACC (2%) and higher, private (8%) WACC are used. The 2% WACC are estimated to be a representative value for a social discount rate, fueled by the prolonged low interest rates on the financial markets. The 8% discount rate is a common discount value for renewable energy investments renewable energy as adopted by International Energy Agency and International Renewable Energy Agency among others. In this report the term Weighed Average Cost of Capital (WACC) is used instead of the discount rate.

2.4. Locations

In order to evaluate the effect of the distance to shore on the profitability of the wind hub, three locations are chosen that comply with the geographical and spatial limitations of the North Sea. A map for potential wind farm sites for is developed by the Netherlands Environmental agency (PBL), shown in figure 2.5. The distances to shore are 80, 190 and 330 km. These distances effect the cable and pipeline cost. These locations also differ in water depth. The water depth of the locations has the most profound affects on the turbine and sand island cost. This water depth for each location is estimated using the bathymetry tool from EMODnet [21]. The geographical scope for the offshore wind farm configurations in this study is limited to the Dutch North Sea. Interconnection between North Sea countries is excluded. Furthermore, onshore spatial planning and onshore power or hydrogen grid cost are excluded.

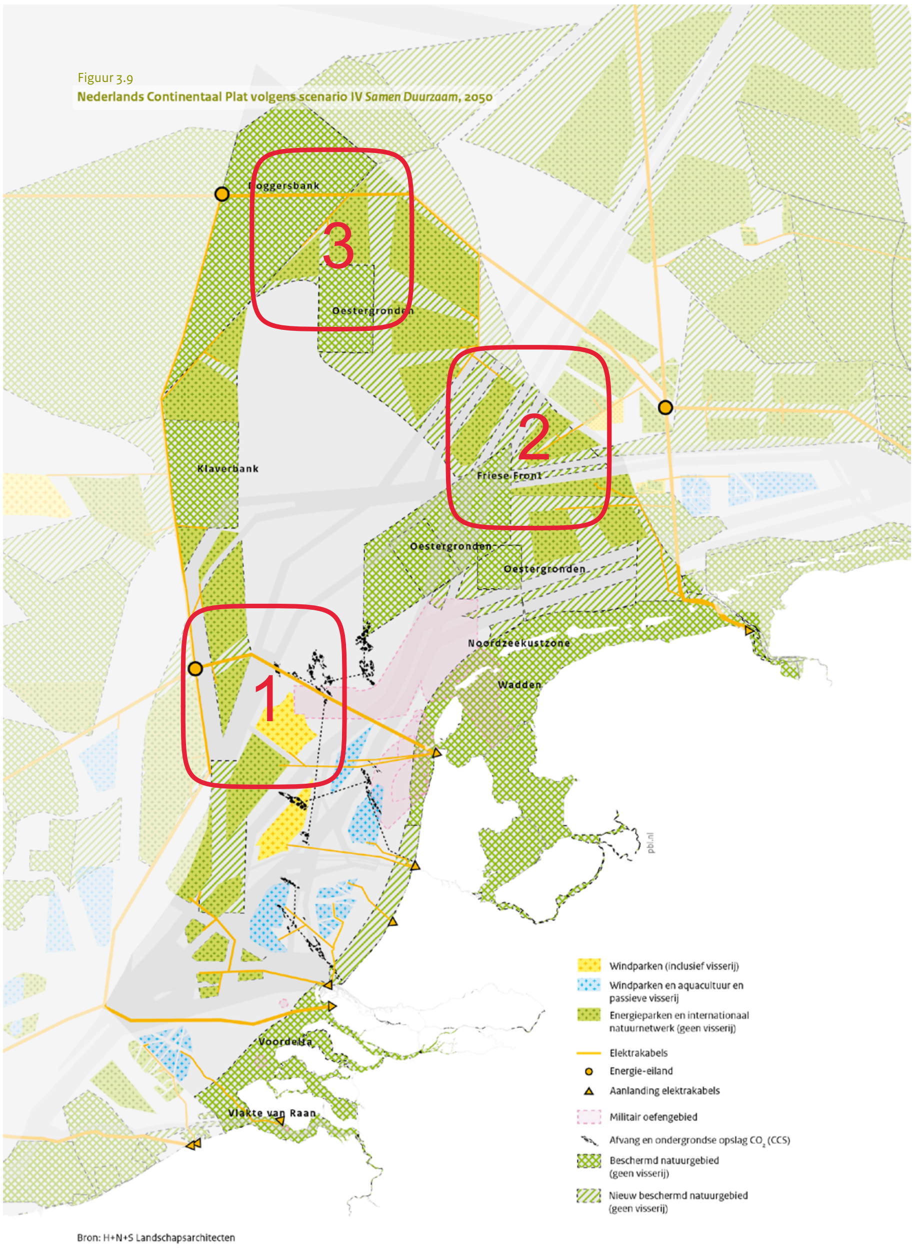

Figure 2.5: Spatial plan of the most ambitious offshore wind scenario for 2050 as stated by the Netherlands Environmental Assessment Agency (PBL)

[39]

3 System cost: Results

This chapter presents the results of the literature study on the system components cost of each configuration. By comparing the total system cost of the configurations, it is possible to assess the cost-effect can be weighed of the electrolyser location (Research Question 1), wind hub distance to shore (Research Question 2), and grid connection capacity (Research Question 3). The results of this total system cost analysis are interim results that can pre-sort the configurations that are worth to review further in the revenue analysis. The offshore wind farm cost are equal for all configurations. Therefore only a brief analysis of these cost is performed in paragraph 3.1. Then, paragraph 3.2 presents the cost figures of all the transmission system components. The total system cost of each configuration are presented in paragraph 3.3.

3.1. Offshore wind farm cost

The offshore wind farm cost are determined for the three offshore locations. The offshore wind farm cost are expressed by the levelised cost of electricity (LCOE) to provide a common cost indicator (see table 3.1). Although investment cost of offshore wind farms are highly project specific, only the variations in water depth are accounted for as the effect of the distance to shore is much smaller [45]. The water depth of the locations is estimated using the bathymetry tool from EMODnet [21]. Furthermore a fixed cost reduction is taken into account between 2030 and 2040. The LCOE of offshore wind is calculated using the annuity method as shown by the equations 2.2, 2.3 and 2.5 in paragraph 2.3. In these, CAPEX and OPEX are used from PBL's 'IJmuiden Ver' cost projection [38] with a capacity factor of 0.525 and an offshore wind farm lifetime of 25 years and a WACC of 4.8%. The 'IJmuiden Ver' figures are chosen as this wind farm is expected to be completed in 2029/2030. These offshore wind cost include the turbine costs, foundation costs and the costs of 66 kV inter-array cables. The financial costs of offshore wind farm projects are a significant contribution to its levelised cost of electricity. The weighted average cost of capital (WACC) represents these financial costs, which are mainly influenced by project risk and financial market conditions. The value of WACC is project-specific, however, it is very much influenced by national financial and regulatory schemes. For the Netherlands, a nominal WACC of 6.7 % [34] is used, resulting in a real WACC of 4.8 %. The LCOE of offshore wind is expected to reduce with 10% between 2030 and 2040 on a global scale [61]. The major factors of this cost reduction are: larger turbine capacity, foundation design, reduced financial costs, economies of scale via project size and increased component reliability [61]. This cost reduction of 10% is assumed to be valid for techno-economic development in the Dutch North Sea wind sector.

Table 3.1: Wind farm reference locations and LCOEs

Reference location	Distance to port [km] (port name)	Transmission distance to onshore connection = + 10 % [km]	Average water depth of location [m] [21]	LCOE [€/MWh] [38][1] 2030 real WACC, pre tax = 4.8% [34][2]	LCOE [€/MWh] [1] 2040 real WACC, pre tax = 4.8%
Location 1: Northeast of IJmuiden Ver wind farm	80 (IJmuiden or Den Helder)	88	30	40.0	36.0
Location 2: Friese Front	190 (Den Helder or Groningen)	209	45	42.0	37.8
Location 3: Doggersbank	300 (Den Helder or Groningen)	330	30	40.0	36.0

3.2. Transmission system cost

An overview of the component-specific values is presented in table 3.2. The cost figures are explained per component in the paragraphs 3.2.1 to 3.2.9. These cost figures result in the total annual cost of the six configurations.

[1] See page 6 of [38], based on costs of offshore wind farm 'IJmuiden ver'. Costs differentiation between reference locations, caused by differences in water depth, based on [45].

[2] See page 49 of [34], inflation= 1.9 %.

Table 3.2: 2030 Economic parameters offshore and onshore configuration. A pre-tax WACC of 2%, 4.8% and and 8% is used to annualize the cost. All Capex values are given in 2020 euros.

Component (Installed in 2030)	**Capex**	**Opex**	**Lifetime** [years]	**Efficiency**[1] [%]
onshore installation cost factor = 1.25 offshore installation cost factor = 1.75				
Transformer	offshore = 9.1 M€/GW onshore = 7.3 M€/GW [43] *1.25/ *1.75	0.15 % [43]	25	99.5 [49]
AC-DC converter DC-DC converter	80 M€/GW [43] *1.25/ *1.75	onshore= 0.70 % offshore= 2.0 % [43]	25	98.5 [6]
Circuit breakers	21.1 M€/GW [14] *1.25/ *1.75	onshore= 2.0 % offshore= 4.0 %	25	n.a.
R/O Desalination unit	90 M€ (offshore configuration, (2 166 500 l/h)) [Gasunie internal] *1.25/ *1.75	4.0 %	25	impact negligible
AEC/PEM Electrolyser	200 €/kW$_{el}$ 500 €/kW$_{el}$ 700 €/kW$_{el}$ *scale factor= 0.885* *1.25/ *1.75	onshore = 2.0 % + 1 cell stack replacement offshore = 4.0 % + 1 cell stack replacement (estimates based on [18])	30 [18]	48.5 kWh/kg H2 [18]
Compressor	18 M€/15MW [Gasunie internal] *1.25/ *1.75	onshore = 2.0 % offshore = 4.0 %	25	average offshore= 99.4 % onshore= 99.5%
Sand island	offshore config.= 4 ha/ GW > 48 ha 160 M€/GW (RL1, RL3) 180 €M/GW (RL2) onshore config.= 2 ha/ GW > 24 ha 100 M€/GW (RL1, RL3) 120 M€/GW (RL2) [Gasunie internal]	3 M€/year [56]	100	n.a.
Pipeline, steel, 48 inch	2.0 M€/km (48 inch) 1.0 M€/km (30 inch) ("all-in cost" incl. installation and operation) [59] [5]	-	50	impact negligible
HVDC cable, 525 kv	0.7 M€/km per cable + 1.4 M€/km inst. per cable pair [59] [43]	-	40 [53]	99

3.2.1. Transformer

The most significant cost driver of a transformer is its power rating [4]. The changes in cost as a result of different voltage and frequency levels are neglected. Moreover, the benefits of multi-GW installations due to economies of scale are neglected because of the high technological maturity and the significant cost share of the metal intensive bulk material. Therefore, the cost figures of 1000 MW transformers are used to create multi-GW cost figures.

[1] A efficiency of 99% is considered for the inter-array cables.

3.2.2. AC-DC/DC-DC converter

It is assumed that the converter cost depend on the power rating and that DC-DC converter cost are equal to AC-DC converter cost. This assumption is made as no GW-scale DC-DC converters exist yet. An value of 80 M€/GW is used based on North Sea Grid (2014) [43]. As for the transformer cost, the benefits of multi-GW installations due to economies of scale are neglected because of the metal-intensive bulk material. Other cost predictions show large variations; Realisegrid (2011), ENTSO-E (2011), NSOG (2014), and ETYS (2015). However, these cost predictions for HVDC converters do not indicate whether installation costs are included. The chosen cost value is therefore based on the most transparent source, considering that converter cost projections tend to underestimate the real cost [31]. A costs range of +/- 25% is considered for the sensitivity analysis since this component forms a significant cost share. Moreover, the predominantly chosen VSC type converter technology is still maturing and cost data show high uncertainty.

3.2.3. HVDC circuit breaker

Due to the lack of cost data on HVDC circuit breakers, the costs for the circuit breakers are assumed to be 1/6 of the converter cost. This assumption has been made in previous work [14].

3.2.4. Electrolyser

To establish the electrolyser cost, the different electrolyser technologies are reviewed below. Then, its cost reduction pathway is established before adjusting the cost for scale-up effects. Finally, techno-economic parameters are established.

Electrolyser technologies

Electrolyser technologies vary in their technological maturity, commercial readiness, operating conditions and output characteristics. Currently, four electrolyser technologies exist: anion exchange membrane (AEM), solid oxide electrolysis (SOE), alkaline electrolysis cells (AEC) and proton exchange membrane (PEM). The AEM technology is commercially available for kW-size capacities. However, little is known about its techno-economic development and further research seems to have stalled. Therefore, this technology is neglected. The SOE technology is still in demonstration phase, shows high cost, low cell stack life (<10 000 hrs) and requires a high operating temperature (650 - 1000 degrees Celsius). The development of this technology and its cost show great promise but with very high uncertainty [50]. The required high operating temperature might be suitable when operating in symbiosis with a heat producing power plant or industry cluster. Therefore, SOE might become suitable for the onshore electrolyser configuration. However, due to its low maturity and uncertain future costs projections, this technology will be neglected in this study. Nevertheless, this technology might be a game changer for the electrolysis industry on the long term. The AEC and PEM electrolysis are both currently operable in an on- and offshore configuration using power from a wind farm. For both technologies, cost reductions are expected as a result of improvements in supply chain and production-volumes and techniques. Furthermore, both technologies show potential technological improvement, especially PEM, being the more immature technology. Therefore, AEC and PEM are further considered here. [18] [50]

Cost reduction pathways

The cost projections for AEC and PEM of academics, industry and consultants show significant differences indicating the uncertainty of the future cost reductions. Figure 3.1 and 3.2 present recent cost projections showing this uncertainty.

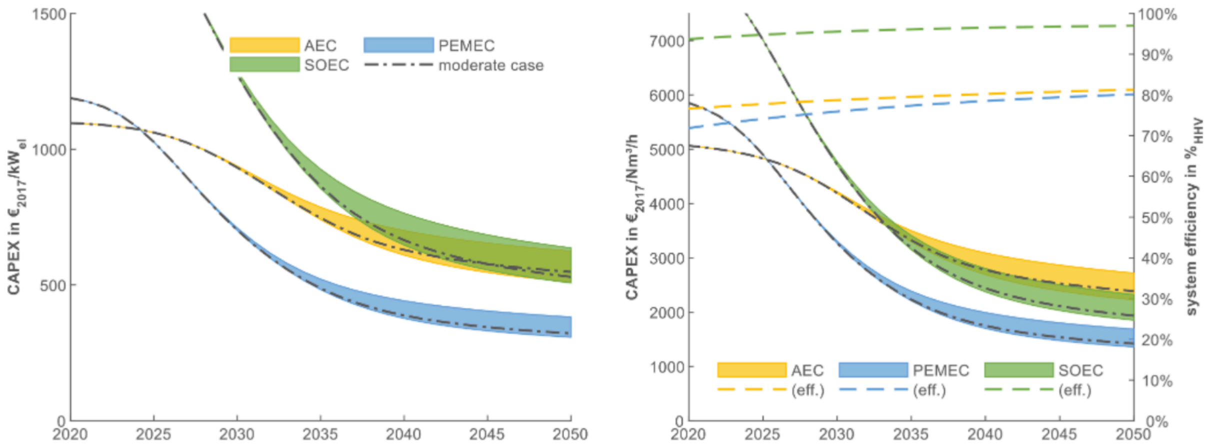

Figure 3.1: CAPEX cost projection per kW$_{el}$ and per Nm^3/h [8]

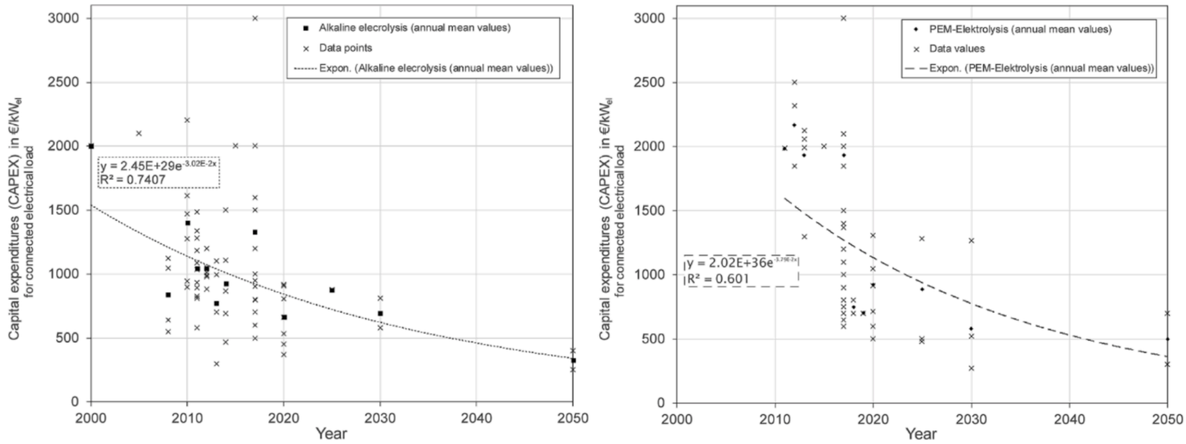

Figure 3.2: CAPEX cost projection per kW$_{el}$, AEC (left) and PEM (right) [55]

Since neither the AEC nor the PEM technology is dominant for the application in offshore wind and their techno-economic parameters could be interchangeable towards 2030/2040, the Capex and techno-economic parameters for this study are based on the average of the PEM and AEC electrolyser type. Given the time-dependent Capex development, fixed values for 2030 and 2040 are chosen. The 2030 value represents a conservative upper limit that is academically supported and the 2040 value is an optimistic consultancy- and policy- based cost value near the material cost value. For a cost indication between 2030 and 2040, in-between value will be presented as well. The 2030- and 2040 values are 700 €/kW and 200 €/kW respectively, and were based on several papers; [50], [30], [48], [55], [26], Gasunie internal sources and an industry focused study [18]. The minimum value is of 200 €/kW has to be interpreted as a situation where the CAPEX depend mainly on material costs when economies of scale, supply chain- and technological improvements have reduced labour costs to a minimum.

Scaling to GW size

So far, cost projections are based on kW- or MW-scale electrolysers. However, the configurations in this study are GW-scale. Böhm, et al. ([8]) estimated the future costs for GW-scale electrolysers through deduced learning rates and component specific scale factors. The learning rates were formed based historic data. Scale factors were determined to represent cost reduction as a result of economies of scale. The effect of the scaling the production on cost reduction can be calculated using equation 2.4 shown in paragraph 2.3. This equation shows that the unknown costs of an component C_b can be calculated using the cost of a reference component C_a, their respective scales and a scale factor f.

For most chemical appliances, a cost factor of 0.6 is used as guideline. But, for both the AEC and PEM electrolysis, the scale factor is higher, hereby reducing the effect of economies of scale. This is mainly caused by the scale factor of the cell stack module, which amounts for 60% (PEM) and 50 % (AEC) of the cost share and has a scale factor of 0.89 (PEM) and 0.88 (AEC) [8]. The total scale factor for the hybrid electrolyser is then 0.885 including power electronics, gas conditioning and balance of plant. This scale factor is used in this thesis to scale the CAPEX from a reference electrolyser of 5 MW in [8] to 12 GW.

Techno-economic parameters

The projections for most techno-economical parameters of both AEC and PEM for 2030 and beyond show high uncertainty, with no dominant candidate for near-offshore wind operation. For some parameters, such as cell size, there are significant differences between AEC and PEM, but the influence of these differences on the footprint of the electrolyser plant is uncertain. Furthermore, the system responses of AEC and PEM are also different. However, for the application of offshore wind this effect is negligible. So, given the minor differences in the projections and their uncertainty, average techo-economical parameters of the PEM and AEC electrolyser are used in this study (see table 3.3). These values are estimates for the year 2030. Improvements between 2030 and 2040 are neglected and their economic advantage is only represented by a Capex reduction to limit the amount of variables.

The values presented in table 3.3 are based on several assumptions. The estimation of the Opex is based on [18], assuming that the offshore Opex are twice as high as onshore. The cell stack lifetime for AEC and PEM under dynamic operation are highly uncertain. So far, cell stack lifetimes are given for continuous operation. The cell stacks are assumed to endure the same amount of hours for dynamic as for continuous operation. For a system lifetime of 30 years, replacement of the cell stacks will be necessary. The electrolyser in the full gas and full electric configuration will operate at the offshore wind farm capacity factor of 0.525 . For these configurations, it is expected that only one cell stack replacement is necessary over the lifetime of the electrolyser. For the electrolysers in the grid connected configurations, the capacity factor is expected to increase as a result of power input from solar PV. Therefore the capacity factor is expected to increase. For these configurations it is estimated that two cell stack replacements are necessary in the components lifetime. The system efficiency is not fixed over the operating range of the electrolyser; instead, it is higher at lower power entries. However, for the purpose of this study, the system efficiency is assumed to be constant. The output pressure of the electrolyser is an optimisation between the marginal costs of building a pressurised container and the costs of compression at the electrolyser output. The given value is assumed realistic to represent both technologies. The minimum system load, system response and cold start time differ between AEC and PEM, but their difference is expected to be insignificant for both configurations. Furthermore, their influence on the total volume of produced hydrogen is neglected for modeling purposes.

Table 3.3: Electrolyser techno-economic parameters
* Assumptions for the hydrogen modelling.

Parameter	Value
CAPEX	(200, 500, 700) €/kW$_{el}$
OPEX	onshore: 2 %, offshore: 4 %
Cell stack lifetime (dynamic operation)	80 000 hours
Cell stack replacements during lifetime	onshore: 1, offshore: 1
Cell stack replacement costs	55% of CAPEX
System lifetime	30 years [18]
System efficiency	48.5 kwh$_{el}$/ kg H2 [18] [1]
Output pressure	30 bar [58]
Average cell stack degradation over lifetime	2.5% (estimated to be half of current degradation [18])
Minimum system load	0%*
System response	instantaneous*
Cold start time	none*

3.2.5. Water infeed

Equation 3.1 shows the chemical reaction of electrolysis in which one water molecule is converted to one molecule hydrogen gas. Desalinated water is an essential raw material for the production of hydrogen gas. The offshore production of hydrogen gas requires either offshore desalination of seawater or the transport of fresh water from shore to the offshore location. A quick review of the required amount of water and the costs of both solutions follows.

$$2H_2O\ (l) > 2H_2\ (g) + O_2\ (g) \tag{3.1}$$

Lets consider a 8 GW flow of hydrogen gas as output. Using the higher heating value (HHV) of hydrogen gas (0.142 GJ/kg), this results in 56.3 kg/s. When including the molar masses of these molecules, it shows that 9 gr of $H_2O\ (l)$ is needed for 1 gr of $H_2\ (g)$. Therefore, 507.0 kg/s of water is needed when operating at maximum capacity. Using a water density of 997 kg/m^3, this leads to 43 936.6 m^3/day when producing at full load.

Total cost of desalination depends mainly on the installed capacity of the desalination plant. When using a reverse osmosis (RO) desalination power plant, the total costs of desalination for the water flow mentioned above are estimated to be 1.6875 €/m^3 [1] [2], while using a margin factor of 1.5 for extra purification treatment and to compensate for the offshore siting. A calculation of the energy input for the RO desalination shows that roughly 0.07 % of the wind farm output energy is needed at a specific energy of 3.4 kWh/m^3 [2]. Therefore, this energy drain is assumed to be negligible.

Fresh water delivery cost (pre-tax) in the Netherlands is set to be 0.72 €/m^3 (2020) [46]. Additional costs are needed for further purification. For the transport of water through a submarine pipeline, a cost value of 0.5 M€/km [59] is used for a 10 inch pipe. This leads to 44 M€ when transporting the water over 88 km, being the shortest distance to shore in this study, while neglecting the costs for the pumping of the water. When assuming a lifetime of 40 years and OPEX of 1 %, the total costs to produce 8 million m^3 (with the capacity factor offshore wind farm set to 0.5), using fresh water from shore is not more economical than offshore desalination. Furthermore, the technically feasibility of extracting this amount of water from the water network at preferred locations is an additional challenge. Therefore, water desalination is the chosen water infeed technique. As the cost of water desalination are negligible, they are excluded.

3.2.6. Compressor

Pressurisation from 30 bar to +/- 75 bar is done in one pressurisation step using piston compressors. Conventional centrifugal compressors are not able to accelerate the hydrogen gas molecule because of its small size. Therefore, more expensive piston compressors are required. A redundancy of 100 % is applied due the high impact of compressor failure, a common practice at gas compressor stations. The maximum power use is translated to a compressor efficiency that is used at all offshore wind farm power levels. Figure 3.3 shows the logarithmic compression - work characteristic for hydrogen gas during adiabatic compression. The compression power per configuration per reference location can be found in tables 3.5 and 3.6 in paragraph 3.2.8.

[1] excl. external compression & water treatment.

[1] 1 US$ = 0.90 €

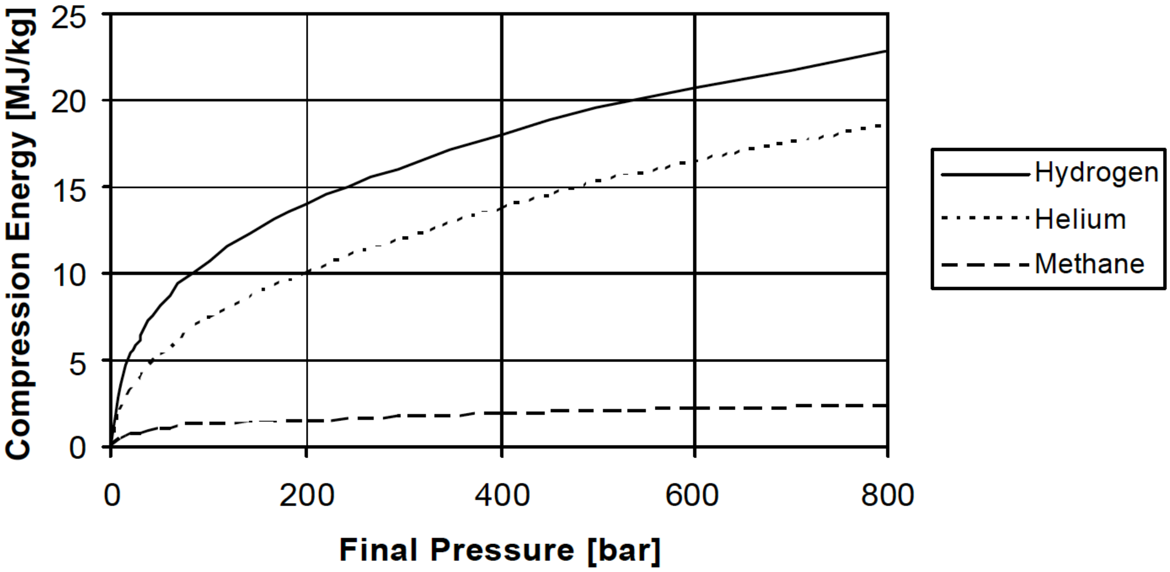

Figure 3.3: Adiabatic compression work for hydrogen compared to helium and methane [9]

3.2.7. Offshore island

The current north sea strategy consisting of several energy hubs of 10-15 GW, is stated to be the optimal amount of offshore wind farm capacity connected. To facilitate a capacity of this size, the construction of a sand island is necessary as argued by the size limits of all hub types in table 3.4. The cost of an artificial island depend mainly on the revetment (45-55%) and the sand fill (30%) [45]. These cost depend respectively on the island surface area and the water depth. Due to the difference in water depth of the reference locations, the island costs of reference location 1 & 3 are lower than for reference location 2. The difference in Capex and Opex due to larger shipping times of further offshore locations are neglected. The ground cost for the onshore electrolyser are also neglected, as its surface area might be twice the size of the onshore compressor station, even then, at 300 €/m^2, the annual cost are negligible.

Table 3.4: Parameters of different hub configurations [45]

Parameter	Caisson island	Sand Island	Platform	Gravity Based Structure
Water depth limit [m]	<25	<40	<45	>100
Construction time [years]	3-4	6-8	3-4	3-4
Size limit [GW]	6	>36	2	<6
Maturity	Middle	Middle	High	Units-High/Linking-Middle

3.2.8. Hydrogen gas pipeline

The equipment and installation cost of a submarine hydrogen pipeline depend mainly on the length of the pipe and its diameter. At a fixed flow rate, the required diameter of the pipe depends on the input and output pressure. All together, an optimization problem arises between offshore/onshore compression cost and the cost of different pipeline diameters for the three different reference locations. To simplify this tradeoff and at the same time attain realistic transmission system properties, the following conservative requirements have been established:

- All compression is done offshore if the electrolyser is located offshore.
- Maximum offshore pressure is 75 bar to reduce compressor power, risk of failure of compressors and pipeline leakage and embrittlement.

- Minimal onshore infeed pressure is 50 bar.

Table 3.5 shows the pipeline cost for the different pipeline diameters adhering to the different locations.

Table 3.5: Offshore compression and pipeline parameters per configuration and per distance to shore

Parameter	Configuration 1: Full gas (88/ 209/ 330 km)	Configuration 2a: Hybrid (2 GW cable) (88/ 209/ 330 km)	Configuration 2b: Hybrid (6 GW cable) (88/ 209/ 330 km)
Max H2 gas flow [GW] (LHV)	7,89	6,55	3,85
Offshore pressure [bar]	52,38/ 55,36/ 58,18	53,34/ 57,22/ 60,94	55,96/ 63,02/ 69,38
Offshore compressor power [MW]	53,09/ 58,49/ 63,42	45,37/ 51,28/ 56,54	29,05/ 34,91/ 39,83
Pipeline diameter [inch]	48	42	30
Pipeline cost [M€/km] [59]	2	1.5	1

Table 3.6: Onshore compression and pipeline parameters per configuration per distance to shore.

Parameter	Configuration 3a: Full electric	Configuration 3b: Electric 2 GW - grid connection	Configuration 3c: Electric 6 GW - grid connection
Max H2 gas flow [GW] (LHV)	7,88	6,51	3,81
Onshore pressure [bar]	50	50	50
Onshore compressor power [MW]	48,56	40,11	23,48
Pipeline diameter [inch]	48	48	48

The Opex of the subsea hydrogen pipeline is assumed negligible. Maintenance is necessary, consisting of inspections and for example necessary rock dumpings (to cover the pipes that have moved as a result of e.g. sea bed movement) [19]. These Opex are expected to be a few million a year maximum, but cost data is absent.

3.2.9. HVDC cable

For the IJmuiden ver offshore wind farm (operational in 2030), Tennet announced their ambition for a 525 kV 2GW HVDC cable [54]. Following this ambition, the cable voltage in this study is assumed to be 525 kV with a power rating of 2 GW per cable. So, a 12 GW island will require 6 cables/ 3 cable pairs. The costs are estimated to be 0.7 M€/km equipment costs per cable and 1.4 M€/km installation costs per cable pair. These cost figures are based on [43] and [59]. A cost range of 25% is taken into account to deal with the uncertainty of this still maturing transmission technology. The opex of the HVDC cable is assumed negligable for the same reasons as the pipeline opex. It is arguable that the failure rate of power cables are higher, however, there is no real argument why the overall configurations failure rate would differ significantly (let alone the risk coverage through TSO contracts and hedging).

3.3. Total system cost of the configurations

The different configurations vary in their electrolyser- and grid connection capacity as defined in paragraph 1.4 and illustrated paragraph 2.2. These design characteristics lead to different compositions of components that result in different total system cost that depend on: 1) the year built (electrolyser cost), 2) the location (i.e., onshore or offshore and the distance to shore), and 3) cost variations of HVDC-components, offshore installation factor and WACC. By varying the location, its influence on the total system cost of each configuration can be evaluated for 2030 and 2040, as electrolyser cost decrease. The same analysis can be done with the cost variations of the HVDC-components, offshore installation factor and WACC. The development of the (baseline) total system cost of the six configurations is presented in the subfigures of figure 3.4. The 2030 electrolyser cost value is 700 €/kW and 200 €/kW for 2040. An additional value of 500 €/kW is given as in between (2035) value. A breakdown of these total system cost into the cost per component is presented in figure 3.5.

In general, transmission system cost increase with distance to shore as longer pipes and cables are needed, as well as compressor power. Besides this, the higher water depth of reference location 2 (w.r.t. 1 & 3) causes higher sand island cost, resulting in a relative increase of total transmission system cost. The marginal increase of cost is mainly influenced by the share of cables versus pipes. The pipeline cost show strong economies of scale with increasing distance to shore, in contrast to the cable cost.

In 2030 the electrolyser price is 700 €/kW. Consequently, electric transmission (onshore electrolysis) is more economical than hybrid or gas transmission for each of the investigated electrolyser capacities due to the installation factor. At this electrolyser price, the share of the electrolyser cost forms a large share in the transmission system cost. This results in a large difference between the configurations that mainly depends on the electrolyser capacity and forthcoming cost of the electrolyser, converter and transformer.

In 2040 (200 €/kW), the cost of other components become more significant as electrolyser cost decrease. The cost difference between cable and pipeline is now of significance as shown in figure 3.5. As a result, the additional cost of offshore electrolysis (i.e., the installation cost) is canceled out by the more economical pipeline cost and smaller required offshore converter capacity. This effect applies to all three investigated electrolyser capacities. The difference in cost between the electric and and hybrid transmission systems is small up to 200 km from shore. Further from shore, the gas or hybrid transmission system (offshore electrolysis) of the dedicated hydrogen and 2 GW configuration are more economical.

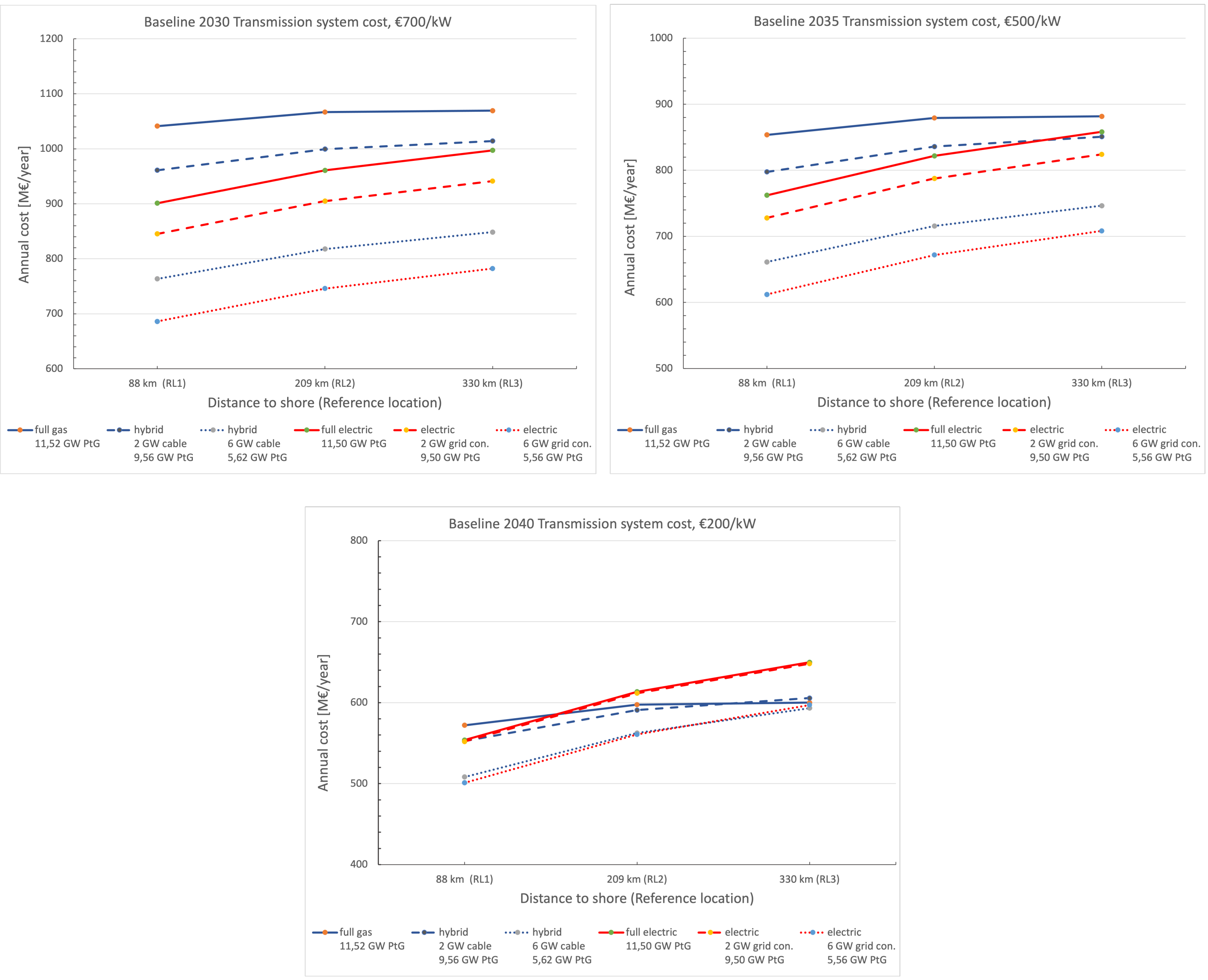

Figure 3.4: Total annual transmission system cost from 2030 to 2040 with different electrolyser Capex

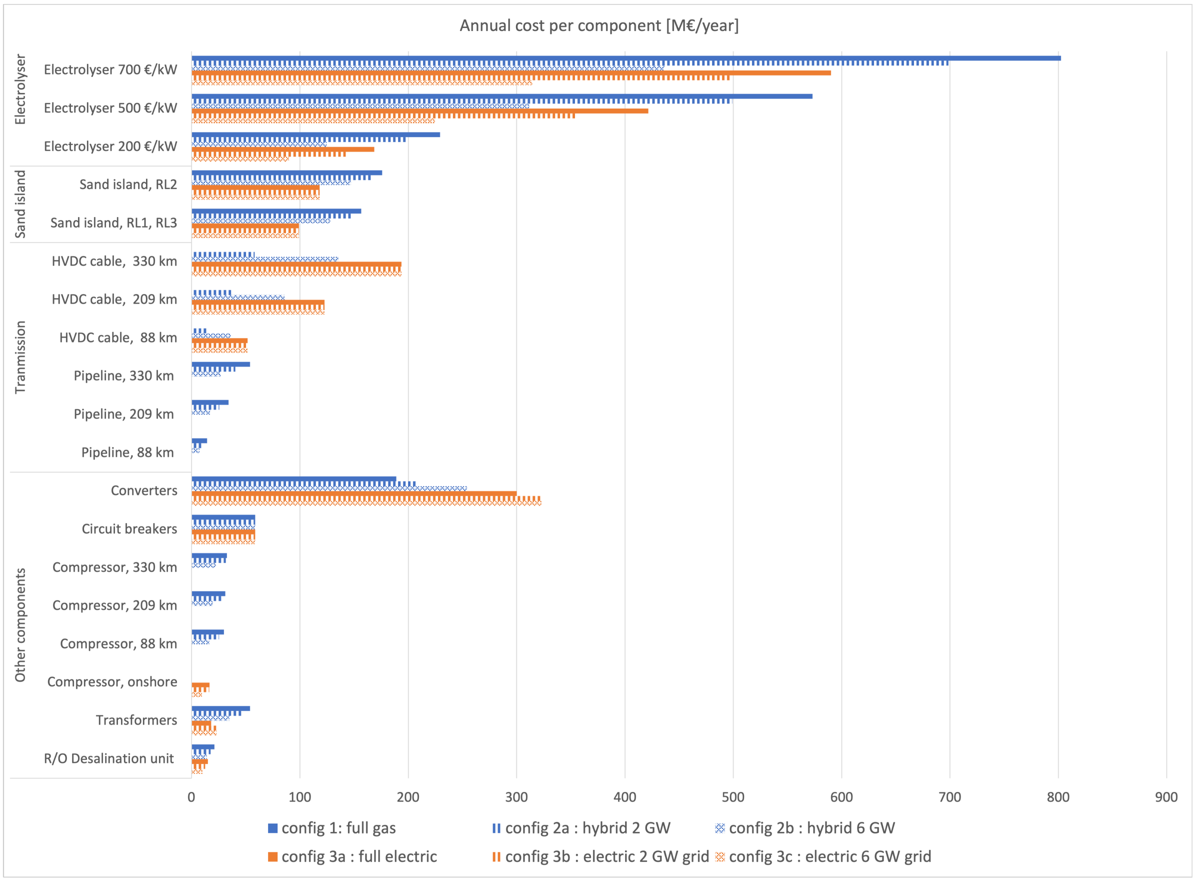

Figure 3.5: Total annual cost of all transmission system components

Cost variations affect the transmission cost of 2030 and 2040. These variations are most relevant in 2040 as electrolyser cost are lower (200 €/kW) and offshore and onshore electrolysis compete. For the 2040 situation, the cost variations of the annual transmission system cost are presented in figure 3.6.

Offshore installation factor

The offshore installation factor influences the cost of all configurations. The configurations with the most costly offshore components are affected the most by this cost variation. When the offshore installation factor decreases to 1.5 instead of 1.75, the difference in electrolyser cost between onshore and offshore decreases. Consequently, other offshore components become more relevant. This is the case for the offshore converter cost, of which the installed capacity is most prominent in the configurations with full electric transmission (11.5 GW PtG & 9.5 GW PtG) configurations. When the offshore installation factor increases to 2.0 instead of 1.75, offshore electrolyser cost increase significantly, making onshore electrolysis (and thus full electric transmission) more economical.

HVDC components

Cost variations in HVDC components (cables and converters) have more impact on the configurations with electric transmission as in these configurations, two large power conversions take place; from windfarm to cable and from cable to electrolyser. An increase in HVDC cable cost is becomes more significant with increasing distance to shore.

WACC

Variations in WACC effect all configurations equally.

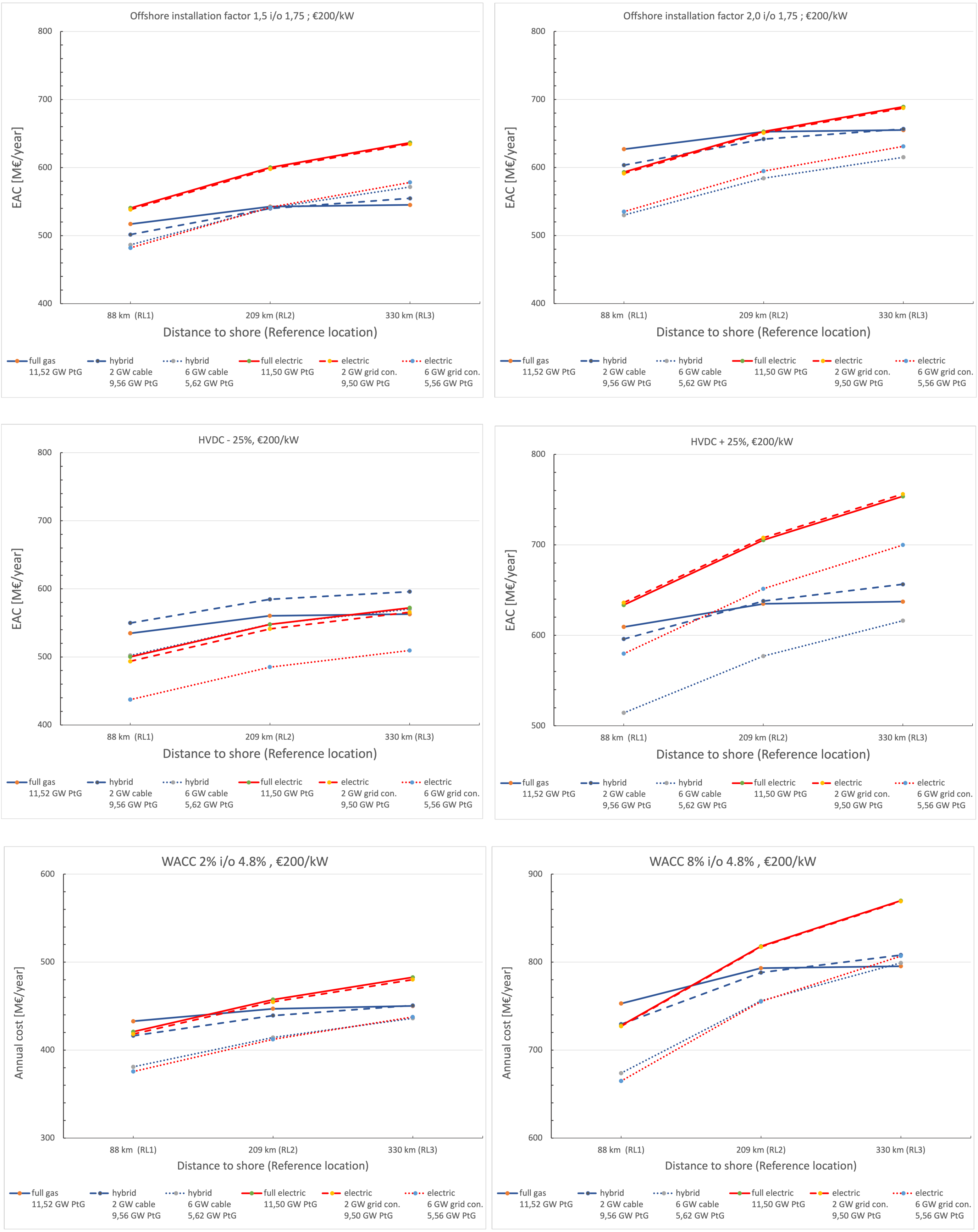

Figure 3.6: Annual cost of the transmission system per configuration in 2040, (200€/kW) for cost variations in offshore installation factor, HVDC material cost and WACC

4 Interim conclusion

The system cost analysis aimed to provide insight into the cost differences between offshore and onshore electrolysis, and to how the cost of all configurations are affected by the distance to shore. Additionally, cost variations have been reviewed to consider the effect of certain economical developments on the profitability of the six configurations under study. The following paragraphs present interim conclusions for these sub research questions, and use these conclusions to select which configurations are promising enough to be evaluated in terms of their revenues.

1. **Is offshore or onshore electrolysis more profitable?**

Up to 2040, the cost of onshore electrolysis (and full electric transmission) is lower than for offshore electrolysis for all distances to shore and all electrolyser capacities. In this time window, any advantages of more economical 'gas' transmission system components are canceled out by the high electrolyser capital cost. This also accounts for the cost variations in 2030 and 2035. However, in 2040 the cost of onshore versus offshore electrolysis become more similar as electrolyser cost decrease. Especially from 200 km for shore, the full gas (11.52 GW PtG) and hybrid (9.56 GW PtG) configuration are more economical than their full electric counterpart due to the high cable cost at these distances. These full gas and hybrid configurations even remain significantly more economical at the lower offshore installation factor, higher HVDC cost and lower and higher WACC. The general trend is that in 2040, the difference in cost between offshore and onshore electrolysis are releatively small, except when operating further than 200 km from shore.

2. **Does the distance to shore of the offshore wind farm hub effect the profitability of the configurations?**

The distance to shore affects both the turbine cost and the transmission system cost. The turbine cost depend mainly on the water depth, however, which is related to the distance to shore. Although the turbine cost are equal between the configurations, the higher water depth at reference location 2 (209 km), will result in slightly lower hydrogen production cost in comparison with reference location 1 & 3. For the transmission system, cost increase with distance to shore as longer pipes and cables are needed, as well as compressor power. Besides this, the higher water depth of reference location 2 (vs 1 & 3) causes higher sand island cost, resulting in a relative increase of total transmission system cost. The pipeline cost show strong economies of scale with increasing distance to shore, in contrast to the cable cost. In 2030, full electric transmission (onshore electrolysis) is most economical for all electrolyser capacities. In 2040, full electric, full gas or hybrid transmission have about the same cost at the reference locations at 88 and 209 km from shore location. At the 330 km from shore location, the full gas (11.52 GW PtG) and hybrid (6.56 GW PtG) configuration are more economical than their full electric counterpart as cable cost increase significantly. The energy losses as a result of the long transmission distance are insignificant for both power and gas transport.

Pre-sorting configurations

The transmission system cost together with the revenues of each configuration results in a profitability per configuration. These revenues will be determined through the power market modelling as describes in the next chapters. However, based on the calculated transmission system cost and the system design characteristics, a pre-sorting of the onshore electrolysis configuration can be legitimized. The reason for this pre-sorting is its ability for bidirectional power flow whereas the offshore configurations can only transport power to the grid from the offshore wind hub. Nevertheless, as in several cases, offshore electrolysis with grid connection is more economical, the benefit of unidirectional grid connection can be deduced from the performance of the onshore electrolyser.

Given the calculated baseline cost for the full electric - full hydrogen producing configuration, the LCOH is 3.10 €/kg in 2030 and 2,50 €/kg in 2040 (weather year 1982). However, a comparison with the grid connected configurations cannot be based on this levelised cost indicator as the grid connected configurations will produce both power and hydrogen as their end product. In a cost based comparison, LCOE and LCOH of grid connected configurations will always be lower than their dedicated counterpart, as the configuration's design is compromised. However, benefiting from both volatile power prices and a stable hydrogen price might yield a higher profitability. So, the total revenues are then translated to a hydrogen production price per configuration. For this comparison, it is necessary to model the power prices in a power market model.

5 Power market model: Methodology

In order to optimize the revenues of the grid connected configurations in 2030 and 2040, it is necessary to conduct power price simulations. This chapter explains how a power market model is used to simulate the power prices. First, paragraph 5.1 explains the background of the input data. Then, paragraph 5.2 presents the geographical scope that the model aims to represent. Paragraph 5.3 describes how the Plexos power market model approximates the real power markets and how different simulation phases contribute to the problem optimisation. Paragraph 5.4 describes the modelling settings that have been chosen to optimize computational efficiency while retaining reliability. Paragraph 5.5 contains a summary of the input data of 2030 and 2040 to provide insight into the key power system properties that are modeled. Furthermore, in order to keep the optimisation problem manageable, paragraph 5.5 also describes the assumptions that were necessary to simplify or approximate the problem. Paragraph 5.6 describes the chosen threshold values that defines the strategy of the configurations, including the transmission limits and efficiencies. Paragraph 5.7 establishes a hydrogen market price based on the production cost of Steam Methane Reforming (SMR) and the cost development of the CO_2 price as defined in the Ten-year network development plan 2020 scenario. Paragraph 5.8 describes that modelling omissions has occured, and how this is dealt with using a re-analysis of the model output data.

5.1. Power system scenario storyline

In the strongly connected European power sector, the regional or national market prices are a result of intra- and international generation and demand. The future power prices of 2030 and 2040 depend on how this energy system will develop. The European Network of Transmission System Operators for Electricity and Gas (ETNSOG & ENTSOE) has worked out three different scenarios for the development of the energy system until 2040. The data of this study, the 2020 Ten-year network development plan (covering more than 10 years) is used for the power price modelling in this research. The purpose of the Ten-year network development plan scenarios is to explore the uncertainties in the future energy system. Their objective is to understand how the gas- and electricity generation and demand develops along different energy transition storylines. In each of the scenarios the system cost are optimized while admitting to the scenario specific political ambition. This optimization is technology- and energy-carrier neutral.

The three storylines of the Ten-year network development plan 2020 study are; National trends, Global ambition and Distributed energy. The difference between the scenarios is the combination of their decarbonization targets and whether this is achieved through centralized or decentralized innovation. The National trends scenario is based on the current National Energy Climate Plans of the EU-member states. This scenario assumes centralised innovation and is compliant with the long-term EU strategy to have reduced CO_2 emissions in 2050 with 80-95% compared to 1990 levels. The Global ambition and Distributed energy scenarios follow emission reduction target that aim to limit global warming by 1.5°Celsius. The Global ambition scenario represents a pathway of centralised innovation that is characterised by economies of scale and energy imports. In contrast, the Distributed energy scenario represents a pathway of decentralized innovation that is characterized by 'prosumers' and small scale solutions.

This thesis focuses on the annual revenues from electricity and hydrogen in 2030 and 2040 and considers the **'Gobal Ambition storyline'** of the Ten-year network development plan data and the **weather year 1982** (other Ten-year network development plan weather years are 1984 and 2007). The Plexos power market modelling tool is used to solve a Unit Commitment Economic Dispact by Mixed Integer Linear Programming.

5.2. Power system geographical scope

The 59 countries that are included in the power market modelling are shown in figure 5.1. For the hydrogen modelling, it is assumed that hydrogen gas can be transported and stored without capacity limitations or energy losses in a hypothetical hydrogen backbone. In establishing the market price of hydrogen, the possibility of hydrogen import and its possible forthcoming price-setter role is neglected.

Figure 5.1: Geographical scope Ten-year network development plan 2020 [25]

5.3. Plexos power market model

In real markets, the trade in power occurs on different markets that consider different timescales for different countries or regions. Different market timescales allow trade on future capacity, months ahead, or can consider market ancillary services, such as frequency regulation that is traded minutes before servicing. Furthermore, two main market organisation types in Europe differ in the underlying concept of power-trade, the Energy-only market (e.g., the Netherlands) and the Capacity market (e.g., France). The Energy-only market only allows trade on actual produced power whereas the Capacity market allows trade on the ability to produce power. The Plexos power market model is a simplified Energy-only market.

The Plexos model represents market clearings in which it calculates the optimal dispatch and market price solution for every time-step. In other words, minimizing the system cost is a unit commitment economic dispatch problem (that can be upgraded to include market other market dynamics). The input data for Plexos consist of three types of building blocks; objects, memberships and properties. Objects can be generators, nodes, lines, emissions, fuels, loads and storages. Memberships define the hierarchical relationship between the objects. Properties define the properties of the objects such as generator technical constraints (e.g. minimal up-time), the price of emissions, the capacity of a transmission line or the pump efficiency of a pumped hydro storage. The optimization problem, in this study spanning one year, consists of the optimization of each time-step, which is an hour. So, for each time-step an optimization problem is solved by minimizing the costs while committing the necessary amount of generation. Since there are binary and integer decisions to be made on which generator should stay on or off and how many, this problem cannot be solved using linear programming only. To include binary decision making and forthcoming integer values, the method of optimization is mixed integer programming. Since Plexos is not a solver itself, the Gurobi solver is linked to the model. This solver acts as optimizer of the centrally dispatched power pool and can optimize the system for different time scales.

Simulation phases

Solving a unit commitment economic dispatch problem with mixed integer programming in Plexos is done using three consecutive simulation phases: 1) Projected Assessment of System Adequacy; 2) Medium Term Schedule; and 3) Short Term Schedule. Commonly, multi-year simulations typically use a 4-phase approach, including a capacity-expansion simulation before the aforementioned simulation phases. This phase, however, is not needed for the present study because the Ten-year network development plan input data is already the result of a capacity expansion optimization that define the system states of 2030 and 2040.

Projected Assessment of System Adequacy: Maintenance scheduling

The objective of the Projected Assessment of System Adequacy simulating phase is to schedule the planned and forced outages that are set by the maintenance rate and forced outage rate. The down time of these outages is set by 'the mean time to repair' property. The Projected Assessment of System Adequacy scheduler uses a Monte-Carlo simulation to generate a set of maintenance outages. In this model, only the generators are assigned a certain unreliability rating.

Medium-Term Schedule: Inter-temporal constraints

Solving the unit commitment economic dispatch step by step does not adhere to inter-temporal constraints that have a longer time span. Examples of these are minimum up/down time, startup costs or optimal hydro storage management. To cope with these constraints, Plexos is equipped with a Medium term-scheduler that considers the optimization of long-term (more than one week) and inter-temporal decisions. These are decisions regarding the management of the battery and hydro storage systems, the recovery of fixed and variable operation and maintenance cost and the long-term technical constraints of the generators. The Medium-term scheduler does this by splitting these long term equilibrium outcomes into short term optimisation objectives. The results of the Medium-term schedule are then passed on and used in the Short-term schedule.

Short-Term Schedule: Load settlement

Other inter-temporal constraints that span less than a week can be optimized further in the Short-term scheduler by adjusting the 'foresight' parameter; the time the solver is allowed to look ahead - anticipating on near future developments. The load settlement model in Plexos function as a marginal bid auction system in which generators bid at their marginal cost, assuming perfect competition.

5.4. Modelling settings

The Medium-term-schedule step size is set to a month with a block count of 20. The default value is set to 12, however with higher numbers yielding more precision but also more computational power, iterative experimentation led to a block count of 20. As such, each month a load/price duration curve is created that is divided into 20 blocks using the least-squares technique. All generator unit commitment constraints and storage balances are optimized over the time step period. The outcomes of this optimisation consist of medium-term strategic objectives, a decomposition of medium-term constraints and pre-computed unit commitment decisions for baseload generators. These outcomes are passed on to the Short term-schedule.

The Short term-schedule functions as a real-time market that performs the dispatching of each time interval (hourly). A 'look ahead time' of 5 days is selected to anticipate on unit commitment decisions. The Plexos documentation advices to use at least 3 days look-head, the same trade-off has been made as with the block count. While minimizing production cost, the result of the market clearing is a nodal price that is equal to the shadow price of energy at that node. To reduce computation time, a rounded relaxation algorithm is used to transform the integer problem in a closely related linear problem that is solved by the Gurobi solver using the branch-and-bound method.

5.5. Modelling input data

The following paragraphs 5.5.1 to 5.5.7 present and explain the input elements of the model, and the assumptions made for these elements. Additional assumptions are described in paragraph 5.5.8. The most significant renewable energy source capacities and grid connection capacities of the Netherlands and surrounding countries are presented in paragraph 5.5.9.

5.5.1. Nodes

The countries within the scope of the Ten-year network development plan study are represented by 59 nodes in the electricity market model of this study. Only Turkey is left out due to insufficient data availability. The nodes are assigned generators, storages, weather profiles and demand profiles. Transmission between nodes occurs via the defined net transfer capacities represented by 'lines'.

5.5.2. Generators

The data in table 5.1 show the techno-economic parameters that are included in the model. The data are based on a variety of sources; NREL [44], Danish Energy Agency [15], ENTSOE [23] and Schmidt et al. [51]. See Appendix A for a detailed source referencing.

Table 5.1: Techno-economic parameters used per generator type, divided in two distinctive groups

Generator type	Efficiency	Economic	Technical limits	Outages & repair
Gas CCGT old Gas OCGT new Gas OCGT old Hard coal new Hard coal old Lignite new Lignite old Heavy oil Nuclear	Heat rate [GJ / MWh]	FOM [€/kW/year] VOM [€/MWh] Fuel costs [€/GJ] Emissions [kg/GJ] (linked to price) Start up fuel c/w/h start [GJ/MW] Start up fixed costs c/w/h start [€/MW]	Min load [% of max load] Ramp up rate [% of Pmax/min] Ramp down rate Min on time [h] Min off time Transition time (c/w/h) [h]	Forced outage [%] Mean time to repair [h] Planned outage [%]
Onshore wind Offshore wind Solar PV Solar Thermal Pumped Hydro ROR Reservoir Battery		FOM (€/kW/year) VOM (€/MWh)		Forced outage [%] Mean time to repair [h] Planned outage [%]

5.5.3. Fuels & Emissions

The fuel and emission prices for 2030 and 2040 are presented in table 5.2 and 5.3. Note the 'Global Ambition' emission price used in this study.

Table 5.2: Fuel prices, all Ten-year network development plan storyline scenarios [25]

Fuel	Fuel price 2030/2040 [€/GJ] (2020 euro)
Nuclear	0.47 / 0.47
Lignite	1.1 / 1.1
Oil	2.3 / 2.3
Coal	4.3 / 6.91
Natural gas	6.91 / 7.31
Oil (average of light and heavy oil)	17.55 / 19.7

Table 5.3: Emission prices [25]

Scenario	Emission price 2030/2040 [€/tCO_2] (2020 euro)
Global Ambition	**35 / 80**
Decentralised Energy	53 / 100
National Trends	28 / 75

5.5.4. Storage

The battery and hydro storages have defined storage capacities. The begin- and end state of all storage is set to 50% using the end-effects method. The Natural inflow of the hydro storage reservoirs is based daily normalised average values for the open storages and weekly averages for the run-of-river hydro generators (JRC hydro database) [27]. In the case of missing values or significant capacity expansion, the natural inflow has been given a constant value of 60% of their generator capacity or have been scaled to an annual capacity factor of 0.6 while retaining the natural inflow profile. This value of 60 % was based on the average capacity factor for reservoir and pumped hydro generators.

5.5.5. Demand & Demand side response

Power demand projections of the Ten-year network development plan 2020 study for 2030 and 2040 are used [25]. Because the Global Ambition dataset is incomplete, the missing loads are taken form the Ten-year network development plan National Trend scenario. This is done for the following countries for modelling year 2030: Albania, Switserland, France, Luxemburg, Poland, Ukraine; and for 2040: Spain, Malta, Albania, France, Luxemburg, Poland, Ukraine. Furthermore, the demand is assumed to have zero elasticity. The demand side response capacities of the Ten-year network development plan study are modelled as 'demand shifting' using pumped hydro storage. Hereby, the pump efficiency is set to 90 %, the pump power is set equal to the demand side response capacity. A maximum duration of demand shifting is set to 4 hours, which is represented by the Max volume of the hydro storage.

5.5.6. Renewables

The energy generation of the renewable energy sources (wind and solar PV) are established using normalised wind and irradiance profiles per node, multiplied with the installed capacity of the renewable energy source. These normalised wind and solar profiles are developed by the Pan European Climate Database, more information can be found in the Ten-year network development plan 2020 scenario guidelines report [25].

5.5.7. Electrolyser

The electrolyser is modelled as a pumped hydro storage, of which the initial and maximum volume of the tail storage, the maximum volume of the head storage and the max capacity of the pump are equal to the electrolyser installed capacity. The pump bid price is set to a specified threshold value that indicates a preference for hydrogen production over power-to-grid flow. The water pumped is equivalent to the hydrogen produced, corrected for energy losses.

5.5.8. Additional assumptions

The following additional modelling assumptions are made:

- The P2G installed capacity in the Ten-year network development plan data is not included in the model.
- ’Gas CCS’ capacity has been modelled a ’Gas CCGT new’.
- ’Light oil’ and ’Heavy oil’ are combined and are assigned the average fuel price of light and heavy oil.
- ’Other RES’ capacity is modelled as run-of-the river hydro generator with a constant power output of 80% of its installed capacity.
- ’Other non-RES’ is modelled as ’Gas CCGT new’.
- Electrolyser operation limits such as minimum stable input power and response time are neglected.
- Revenues from oxygen sales are neglected.

5.5.9. Most significant RES-capacities

The figures used from the Ten-year network development plan study are open-source and can be accessed on the Ten-year network development plan scenario study website [24]. Here, an overview is provided of the most significant RES-capacities. Table 5.4 shows the significant growth in RES capacity in the Netherlands’ surrounding countries. Table 5.5 provodies insight into the net transfer capacities, by presentign the net transfer capacity of the Netherlands’ connected countries. The expanded grid figures in this table are used in an additional simulation run that is not analysed in detail.

Table 5.4: Solar and wind installed capacity of the Netherlands and surrounding countries, Global Ambition scenario [24]

Country	2030			2040		
	PV solar [MW]	Onshore wind [MW]	Offshore wind [MW]	PV solar [MW]	Onshore wind [MW]	Offshore wind [MW]
The Netherlands	13750	8300	10000	19450	10100	16500
Germany	83877	78801	20000	105032	95401	23228
Belgium	9163	5930	5301	12318	7130	6030
Denmark	1550	5529	6401	1850	6329	13275
United Kingdom	17232	14308	29935	27232	15508	36765
France	29462	32455	4920	27232	43855	12425

Table 5.5: Net transfer import and export capacity to and from the Netherlands [24]

Connection	Reference grid net transfer capacity 2030=2040	Expanded grid additional net transfer capacity (added in year)
NL-BE	2400	2000 (2030)
NL-DE	5000	2000 (2040)
NL-DK	700	0
NL-NO	700	0
NL-UK	1000	1500 (2040)

5.6. Configuration decision making: Threshold values

The grid connected configurations can either sell the wind power on the grid or use it for electrolysis to produce and sell hydrogen. An optimal strategy can be determined if the power prices, hydrogen price and all capital and operational expenditures are known. The result of this optimisation would be the sizing of both the power- and hydrogen capacity and production. For any price or cost variation a new strategy needs to be determined, resulting in an iterative process. However, this study considers a 12 GW windfarm hub with a fixed 2 GW or 6 GW grid connection capacity combined with electrolysis capacity. Given the fixed capacities, an optimal strategy depends merely on the power prices and the hydrogen price(s). Power prices are known to be volatile while hydrogen prices, assuming to be a more easily stored commodity, are likely to be more stable price. A preliminary analysis of the power market model was used to present a price-duration curve that allows the formulation of a production strategy. This price-duration curve of the 2030 and 2040 Global Ambition models without active configuration is shown in figure 5.2.

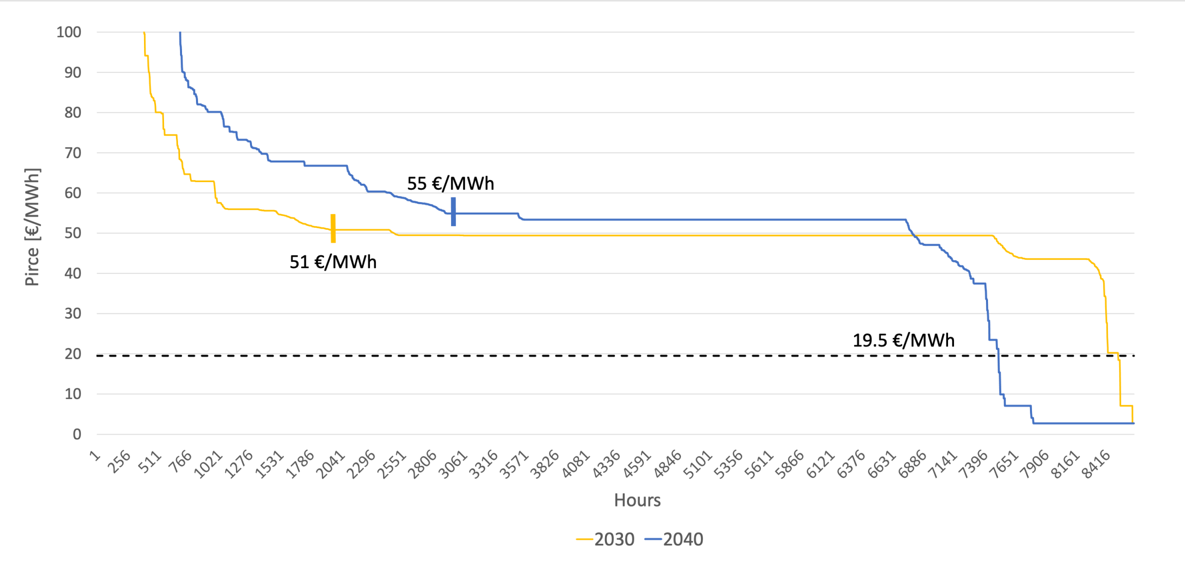

Figure 5.2: Price-duration curve, Global Ambition, weather year 1982

Given these power prices, the hydrogen price plus marginal production cost determine the threshold value at which price to produce and sell hydrogen. Additional revenues are obtained from hydrogen production as a result of cable saturation. However, these marginal production cost depend on the production volume, which depends on the hydrogen price plus marginal production cost. In short, there is a loop relation, which can only be modelled by an iterative process in which the hydrogen price is varied. In order to explore reasonable hydrogen price outcomes and to comply with the limited modelling time, the threshold values are fixed to ensure a relative high electrolyser load factor while exploring the potential benefits of selling power at high power prices. As shown in figure 5.2, the threshold value for 2030 is set to 51 €/MWh and for 2040 set to 55 €/MWh. The consequence of fixating the threshold value is a value loss whenever reviewing different hydrogen market prices. This value loss is either the result of lesser power revenues or lesser hydrogen revenues, depending on whether the new threshold value should be either lower or higher than the fixed threshold value. Furthermore, a lower threshold value is chosen for the grid-to-electorlyser flow to ensure only non-fossil sourced power is fed into the electrolyser.This lower threshold value is set to 19.5 €/MWh.

The complete production strategy is presented in the following formulas.

The power coming from the offshore wind farm can be described as:

$$P_{wind} = nwf * \bar{P}_{OWF} \tag{5.1}$$

in which *nwf* is the normalised wind factor and P_{OWF} the installed wind farm power of 12 GW.

For the full hydrogen configurations, the hydrogen power flow can be expressed as:

$$P_{H2} = P_{wind} * \eta_{OWF \to PtG^i} * \eta_{PtG} \tag{5.2}$$

With $\eta_{OWF \to PtG^i}$ as the transmission efficiency from the wind farm to the electrolyser of configuration 'i' and η_{PtG} as the efficiency of the electrolyser.

For the grid connected configurations, the hydrogen production is the result of power flow from the wind farm and power flow from the grid. The other way around, the grid connected configurations are able to transfer power to the grid. To optimize the revenues this leads to three possibilities:

1) If 51/55 €/MWh < power price > 19.5 €/MWh, the hydrogen production can be described as:

$$P_{H2}(1) = P_{wind} * \eta_{OWF \rightarrow PtG^i} * \eta_{PtG} \tag{5.3}$$

2) If the power price < 19.5 €/MWh, the power flow from the grid to the electrolyser can be expressed as:

$$P_{from\ grid} = \bar{P}_{PtG^i} - P_{wind} * \eta_{OWF \rightarrow PtG^i} = [0, 2000\rangle \tag{5.4}$$

Resulting in the hydrogen production from both the windfarm and the grid:

$$P_{H2}(2) = (P_{wind} * \eta_{OWF \rightarrow PtG^i} + P_{from\ grid} * \eta_{grid \rightarrow PtG^i}) * \eta_{PtG} \tag{5.5}$$

With $\eta_{grid>PtG^i}$ as transmission efficiency from the grid to the electrolyser of configuration 'i', with a maximum flow into the electrolyser:

$$P_{wind} * \eta_{OWF \rightarrow PtG^i} \leq \bar{P}_{PtG^i} \tag{5.6}$$

When the electrolyser is saturated, the surplus power flow will enter the grid:

$$P_{power^i}(1) = P_{wind} * \eta_{OWF \rightarrow grid} - \frac{P_{PtG^i}}{\eta_{OWF \rightarrow PtG^i}} \tag{5.7}$$

3) If the power price > threshold value, the power flow to the grid can be described as:

$$P_{power^i}(2) = P_{wind} * \eta_{OWF \rightarrow grid^i} \tag{5.8}$$

with constraint:

$$P_{power^i} \leq P_{cable^i} \tag{5.9}$$

With P_{cable^i} is the capacity of the cable(s) of configuration 'i'.

The power that cannot be fed into the grid will be fed in the electrolyser, resulting in a hydrogen production that can be expressed as:

$$P_{H2} = (P_{wind} – P_{power}) * \eta_{OWF \rightarrow PtG^i} * \eta_{PtG} \tag{5.10}$$

5.7. Hydrogen market price

The future price of hydrogen is uncertain since a hydrogen market is still non-existent. For now, trade in hydrogen is characterised by niche producers and consumers operating through bilateral agreements using dedicated infrastructure. However, given the hydrogen ambitions of the Dutch government and other European nations, the realisation of a national or transnational hydrogen infrastructure and hydrogen gas market is assumable. As with the power prices, scenario specific hydrogen prices can be established for such an open and connected hydrogen market. Given the high uncertainty, the influence on the hydrogen price of hydrogen imports and purification cost are neglected. For the Netherlands, three hydrogen demand sectors can be stated based on their willingness to pay as shown in table 5.6. For these sectors, demand projections are shown to be very varied, thereby, contributing to the hydrogen price uncertainty. When assuming perfect competition, a merit-order for a hypothetical hydrogen gas market is formed by the willingness to pay of the different market sectors. For the mobility sector, the price is set by the price of the current commodity: fuel. Since fuel is not included in the EU-ETS, the rising emission price does not affect the price range of fuel. For feedstock, the price is set by the production costs of Steam Methane Reforming plus the cost for CO_2 emissions or the cost of Carbon Capture and Storage (CCS). It is assumed that grey hydrogen is the price setter in 2030. Blue hydrogen is likely to become the price setter in 2040 as CCS has become profitable due to an increasing higher CO_2 price. Since the use of CCS and its effect on the hydrogen price is uncertain, the willingness to pay of feedstock is based on the use of grey hydrogen. The price setter in the electricity and high temperature heating is set by the natural gas price plus the CO_2 or CCS price.

It is assumed that hydrogen gas will be stored when significant price fluctuations occur, resulting in an equilibrium price, which is set by the willingness to pay of the feedstock sector. In accordance with the power price modelling, a hydrogen price based on the 'Global Ambition' Ten-year network development plan CO_2 price scenario is used for the analysis of the model results. To present a reference for the emission + SMR cost based hydrogen price, the price as a result of the emission price in the other scenarios is also presented in table 5.6.

Table 5.6: Willingness to pay per hydrogen market sector

H2 sector[1] [2]	Price setter	NL Demand range 2030 [PJ/year] [13][60]	NL Demand range 2040 [PJ/year] [13][60]	TYNDP DE 2030/40 [€/kg H2]	TYNDP GA 2030/40 [€/kg H2]	TYNDP NT 2030/40 [€/kg H2]
Mobility [3]	Fuel	2.5 - 40	22.5 - 160	3.0 - 4.75 [13]	3.0 - 4.75 [13]	3.0 - 4.75 [13]
Feedstock [4]	SMR + CO_2/CCS	22.5 - 100	70 - 190	1.99 / 2.48	**1.83 / 2.30**	1.75 / 2.26
Electricity + HT-heating [5]	Nat. gas + CO_2/CCS	15 - 170	30 - 330	1.32 / 1.53	1.23 / 1.45	1.20 / 1.43

5.8. Modelling omissions & fix

Three omissions' in the model have led to a re-analysis of the modelling results.

The first deficit is an unrealistic amount of hours of unserved energy. This is caused by the forced and planned outage of the accumulated generator capacity for each generator type per node. For example, all OCGT gas generators per country simultaneously face a forced outage, since their capacity is accumulated. This artificial handicap increases the model rigidity, causing price peaks and hours of unserved of which today's power system is exempted from. To limit the effect of this additional rigidity without neglecting plausible and realistic high price-hours, the maximum market price has been set to the highest short-run marginal cost of all generators.

The second and third modelling omission resulted in the malfunction of the configuration-to-grid power flow. The second omission occurred during high market prices at the Dutch node caused by high market prices in one or more surrounding countries. In these events, all dispatchable generation capacity at the NL00 node congested the export without including the configuration-to-grid power flow that should have been prioritised. The cause of this omission has been investigated but remains unknown. The third omission was caused by the difference in the amount of generator maintenance intervals in the model runs of the grid connected configurations. In these model runs, the amount of maintenance intervals of all generators increased while they were still admitted the same fixed percentage of forced and planned outage. As before, the cause of this omission has been investigated but remains unknown. To cope with the second and third modelling omission, a re-analysis of the configuration-to-grid power flow was performed using the baseline model results as a starting point to replace generated power and thereby establishing a new nodal power price. In this re-analysis, the shadow price of import and export flows have been used as a proxy (instead of decomposing it into all its offer bids) to determine the revenues as a result of replacing import flows or using leftover export flow.

[1] Hydrogen use in the build environment and in agriculture have been neglected.
[2] CO_2 and natural gas price based on scenarios of the Ten-year network development plan 2020 [28].
[3] Willingness to pay consumer price corrected for cost of compression and transport, estimated to be 50%.
[4] SMR cost based on [20].
[5] hydrogen gas use in gas turbine, HHV, CCGT efficiency= 0.55.

6

Power market model: Results

The aim of this chapter is to present the output of the model runs and the analysis of this data. The main output data of the simulations are the power prices per hour. First, paragraph 6.1 presents the power prices of the baseline model run, without active configuration. Furthermore, this paragraph describes what makes the power price distribution the way it is by identifying the most significant influences of the power system of 2030 and 2040. Then, paragraph 6.2 presents the performance of the configurations in terms of power flow and forthcoming revenues. This performance is based on the decision variables that act on the power price in order to maximize revenues as explained in chapter 5. The total revenues as a result of these power flows are presented in paragraph 6.3. Paragraph 6.4 discusses the model run results of an expanded grid scenario to consider what effect increased net transfer capacity might have on the power prices and the revenues per configuration for 2030 and 2040. This expanded-grid simulation has been performed without active configuration.

6.1. Power prices

The price-duration curves of the 2030 and 2040 Global Ambition model runs are shown in figure 6.1. The S-shape curve can roughly be divided into three distinct sections; a low price section, a price-plateau and a high price section. In general, the marginal generator sets the price. What generator is marginal at each hour depends on RES generation, power demand, storage levels and import/export. This paragraph reviews the marginal generator type per price-section. The low-price section represent the hours of high RES generation with low short run marginal cost, decreasing the market price. The price-plateau represents those hours in which the combined cycle gas generator is the marginal generator. At the above price-plateau power prices, generators with higher short run marginal cost are marginal. To understand the development of the price-duration curve from 2030 to 2040, a more detailed analysis is necessary of the factors that drive changes in the power prices at each price-section..

Low price

Low prices occur during high RES generation, mostly caused by high wind power generation and/or low power demand. An increase of RES capacity in 2040 (offshore & onshore wind, PV solar, CSP, hydro) and its higher share in the power generation mix causes an increase of low-price hours. For Europe, onshore wind becomes the largest RES generator. For the Netherlands, offshore wind becomes the largest RES generator. During low demand, the marginal generator is often nuclear power (with high capacities in France and Germany) or hydro power. The growth in open- and closed pumped storage capacity and the growth in battery storage capacity reduce the prices further.

Price plateau

The price plateau in both 2030 and 2040 is set by the CCGT gas generators short run marginal cost. The installed gas generation capacity is by far the largest controllable power generator in Europe. The increase of the plateau from 49.42 €/MWh to 53.36 €/MWh is caused by the increased CO_2 emission price from 35 €/tCO_2 to 80 €/tCO_2.

High price

High prices are caused by high demand, often combined with low generation. Both annual power demand and peak demand remain stable between 2030 and 2040 in the Netherlands but increase for Europe, especially for the EU-28 countries (i.e., 5.8% and 4.9% reps.), and thereby inflicting the Netherlands. This growth in Europe is caused by increased usage of electric cars, electric heat pumps and residential demand. At the same time, the installed capacity and annual generation of hard coal, lignite and nuclear generation decreases significantly from 2030 to 2040, thereby decreasing baseload generation. However, gas generation capacity and generation increases as does the import/export power flow to meet the demand in a power system with an increasing share of weather-dependent power generation. Obviously, high prices occurs mostly in winter, when demand is higher (e.g., heat pump usage), solar generation lower, Nordic hydro storage levels are lower, while at the same time import flows are of limited capacity and insufficient to supply peak demand and/or periods of low RES generation in e.g. the Netherlands, Belgium and Denmark simultaneously.

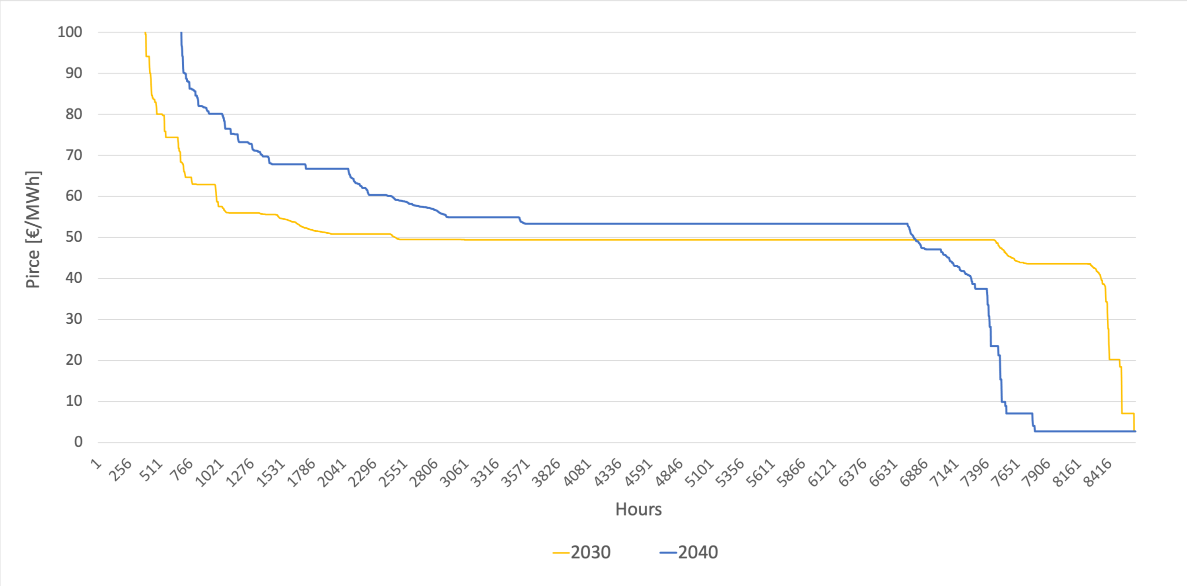

Figure 6.1: Price-duration curves 2030 and 2040, Global Ambition, weather year 1982

6.2. Power flows

The configurations participate in the settlement of the nodal price/ locational marginal price price by offering wind power at its short run marginal cost. Moreover, the grid connected configurations participate by bidding for grid-to-electrolyser feed-in power. The market settlement aims to minimize system cost with as output the power flow between power producers and power consumers. The follwing three subparagraphs describe the resulting power flows from the grid to the electrolyser, from the electrolyser to the grid, and within the configurations (i.e., the electrolyser load).

6.2.1. Grid-to-electrolyser power flow

The grid to electrolyser power flow occurs if the power price is below 19.5 €/MWh while there is electrolyser capacity available. Obviously, the 2 GW configurations will have a higher electrolyser capacity available since its capacity is 9.5 GW. This higher capacity allows higher grid-to-electrolyser power flow during high wind hours (possibly combined with high solar generation and low demand). Figure 6.2 shows the higher grid-to-electrolyser flow of the 2 and 6 GW configurations for 2030 and 2040. In 2030, grid-to-electrolyser power flow is negligible. In 2040, RES penetration causes the increase of <19.5 €/MWh power price hours that result in higher grid-to-electrolyser power flow, especially for the 2 GW configuration.

Figure 6.3 shows the effect of grid-to-electrolyser power flow on the power prices by presenting the simulation results with and without active configuration.

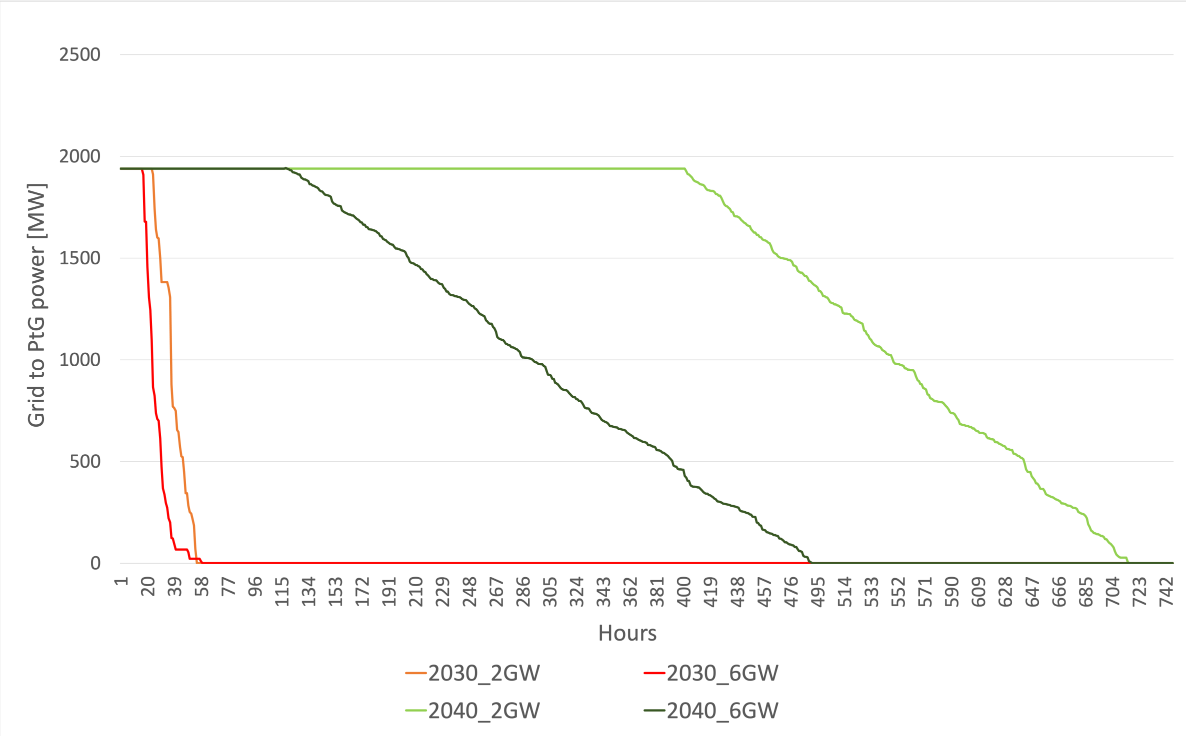

Figure 6.2: Grid-to-electrolyser load duration curve

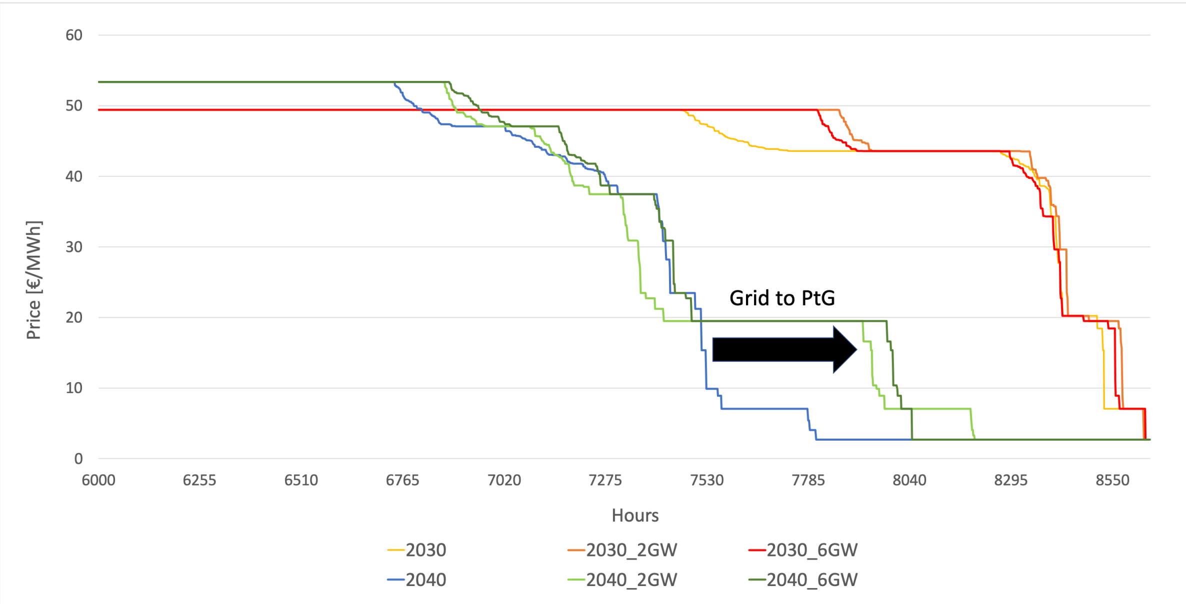

Figure 6.3: The effect of grid-to-electrolyser flow on the price-duration curve

6.2.2. Configuration-to-grid power flow

Wind power from the configurations is transported to the grid if either power prices are above the threshold price and/or if the electrolyser is saturated. Figure 6.4 presents both the sorted prioritised power flow and the total power flow. Consequently, energy transport is higher for the 6 GW (5.56 GW PtG) configuration than for the 2 GW (9.5 GW PtG) due to the the higher transport capacity and the smaller electrolyser capacity. Over time, the power flow as a result of electrolyser saturation is equal for 2030 and 2040, since the same weather year data is used. However, the above-threshold power flow of both configurations has significantly increased due to more high-price hours in 2040. For the majority of these high price hours, the above threshold power flow can be transported by a 2 GW cable.

The 6 GW cable shows negligible additional prioritised power flow in 2030 but a 27.9 % increase of total transported energy in 2040. All together, the total increase of above-threshold power can be largely attributed to the development in power prices. Nevertheless, the additional benefit of a 6 GW in 2030 and 2040 can only be evaluated by reviewing its total power revenues, including power flow as a result of electrolyser saturation. This review is done in paragraph 6.3.

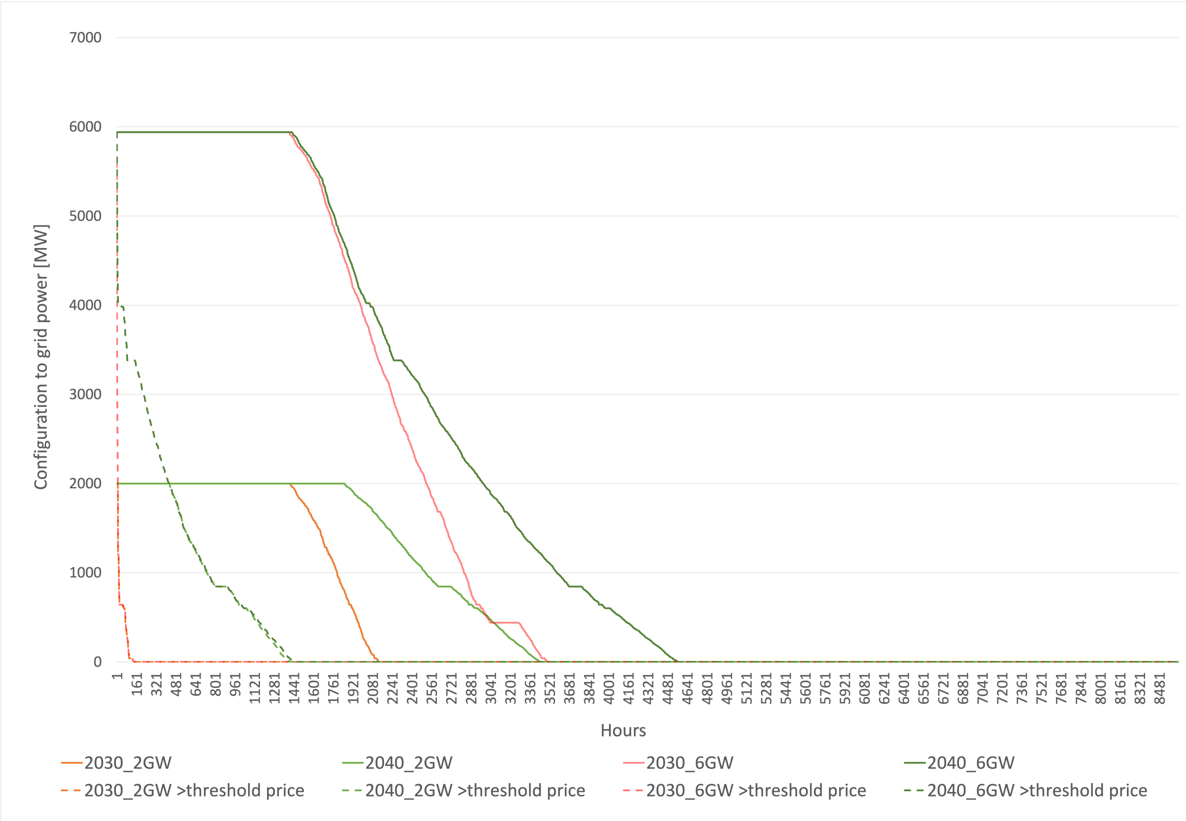

Figure 6.4: Configuration-to-grid load-duration curve

6.2.3. Electrolyser load

The electrolyser load consists of wind power that is produced during below-threshold power price hours complemented with power from the grid during below 19.5 €/MWh price hours. The resulting electrolyser load-duration characteristic of the configurations for 2030 and 2040 is shown in figure 6.5. As expected, the maximum load is limited by the different electrolyser capacities. Furthermore, the Full-PtG configuration load duration curve is analogous with the wind profile, adjusted for transmission losses. However, the electrolyser load of the grid connected configurations is subjected to power flows from- and to the grid as described in paragraphs 6.2.1 and 6.2.2. The modelling output shows that in 2040, a significant amount of wind farm power is prioritised for configuration-to-grid flow, thereby decreasing electrolyser input power at high price hours corresponding with low wind conditions. Furthermore, the output shows that the 2040 2 GW configuration profited from the grid-to-electrolyser flow, thereby increasing the amount of high-load electrolyser hours caused by other offshore and onshore wind farms feeding the electrolyser during low prices corresponding with high wind conditions.

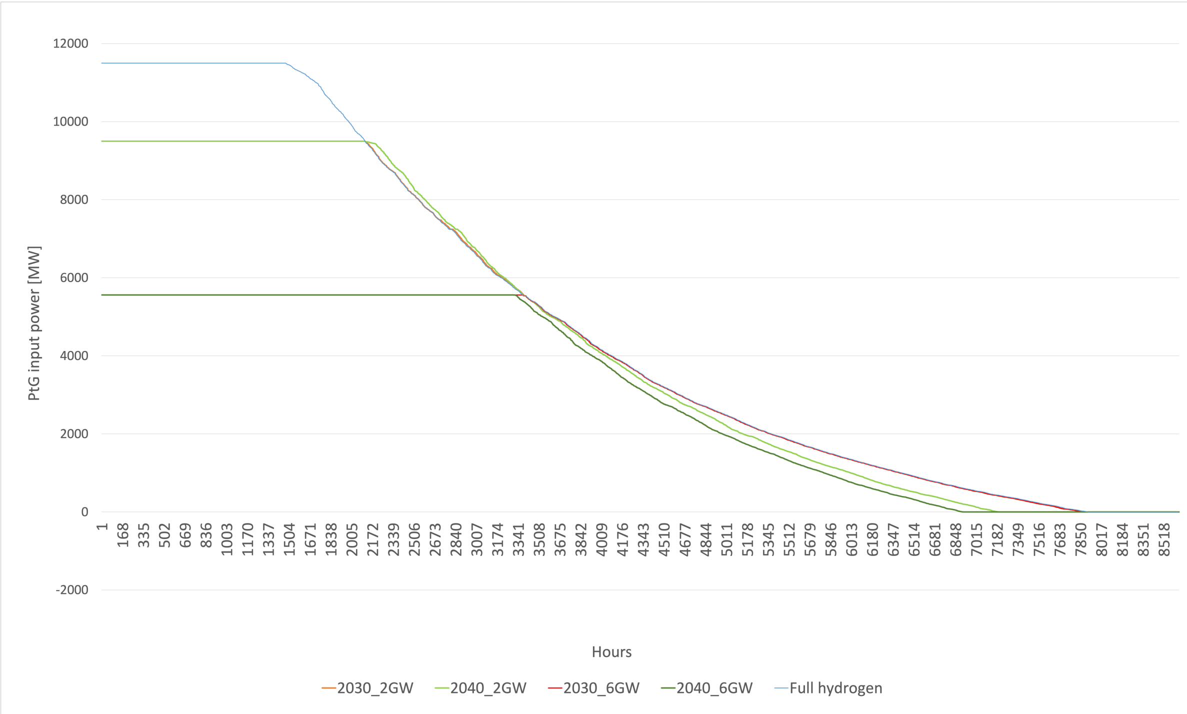

Figure 6.5: PtG input power for all configurations

6.3. Revenues

The total power flows and revenues of all configurations of 2030 and 2040 are presented in table 6.1. The hydrogen price is based on the Global Ambition CO_2 price resulting in 1.83 [€/kg] in 2030 and 2.30 [€/kg] in 2040.

Power revenues

The configuration to grid power flows are categorized in prioritised above threshold power flow and below threshold configuration-to-grid power flow as a result of electrolyser saturation. This latter category is divided into <51 €/MWh power flow and 0 €/MWh power flow to categorize the total energy that be attributed to full saturation at the power system node.

Sub-paragraph 6.2.2 showed that configuration to grid power flow increased from 2030 to 2040 due to more prioritised power flow and thus more configuration-to-grid power flow. However, as shown in table 6.1, the total revenues from the power flow decrease for both the 2 GW and 6 GW configuration from 2030 to 2040. This decrease in revenues is caused by the decrease in value of the saturated electrolyser power flow, as a result of high RES penetration in 2040.

Trade-off

The grid connection is beneficial in 2030, resulting in an increased total revenue. In 2040, the revenues loss from a decrease in hydrogen production is higher than the increase of revenues from configuration-to-grid power flow. This is because the configuration-to-grid power flow decreased in value while the hydrogen price increased in 2040. For the grid connection to be beneficial in terms of revenues, the average power price of the configuration-to-grid power flow has to be at least 37.7 €/MWh in 2030 and 47.42 €/MWh. Hereby it is important to note that the downsizing the electrolyser also results in lower investment cost, especially in 2030.

The only valid indicator to asses is the total annual revenue (and annual system cost). Comparing the LCOH of the configurations is not of interest since the grid connected configuration produce both power and hydrogen. Moreover, these grid connected configurations have, per definition, higher LCOE and higher LCOH than full hydrogen- or full power producing configurations since they will compromise in the production of each commodity and since energy is lost in the process of using the windfarm power to produce hydrogen.

Table 6.1: Annual power flows & revenues, hydrogen price: 2030; 1.83 [€/kg], 2040; 2.30 [€/kg].

Configuration	Power flow	[TWh] (electric power)	[M€]	Av. power price [€/MWh]	PtG load factor [%]
	OWF power	44.34	-		
2030: Full PtG	OWF to PtG	42.48	1602.9	-	42.75
	Energy losses	1.86	-		
	OWF power	44.34	-		
	OWF to grid >51 €/MWh	0.07	5.55		
	OWF to grid ≤ 51 €/MWh (PtG saturated)	3.45	170.33	49.30	47.33
2030: 2 GW	OWF to grid 0 €/MWh (PtG saturated)	0.05	0.00		
	Grid to PtG (<19.5 €/MWh)	0.07	1.23		
	OWF to PtG	38.78	1463.15		
	Energy losses	2.00			
	OWF power	44.34	-		
	OWF to grid >51 €/MWh	0.08	5.67		
	OWF to grid ≤ 51 €/MWh (PtG saturated)	13.02	642.66	47.55	59.83
2030: 6 GW	OWF to grid 0 €/MWh (PtG saturated)	0.53	0.00		
	Grid to PtG (<19.5 €/MWh)	0.03	1.09		
	OWF to PtG	28.71	1083.38		
	Energy losses	2.00	-		
	OWF power	44.34	-		
2040: Full PtG	OWF to PtG	42.48	2014.5	-	42.75
	Energy losses	1.86	-		
	OWF power	44.34	-		
	OWF to grid >51 €/MWh	1.65	93.02		
	OWF to grid ≤ 51 €/MWh (PtG saturated)	1.76	83.33	33.96	46.54
2040: 2 GW	OWF to grid 0 €/MWh (PtG saturated)	1.78	0.00		
	Grid to PtG (< 19.5 €/MWh)	1.08	51.22		
	OWF to PtG	37.12	1760.44		
	Energy losses	2.03	-		
	OWF power	44.34	-		
	OWF to grid >51 €/MWh	2.11	121.56		
	OWF to grid ≤ 51 €/MWh (PtG saturated)	6.65	297.62	25.66	55.35
2040: 6 GW	OWF to grid 0 €/MWh (PtG saturated)	7.58	0.00		
	Grid to PtG (<19.5 €/MWh)	0.59	17.29		
	OWF to PtG	25.99	1232.69		
	Energy losses	2.01	-		

6.4. Additional results: Global Ambition-Expanded grid

In addition to the Global ambition scenario simulation results, the expanded grid version of the Global Ambition scenario has been simulated. Due to time limitations, no model run has been performed with the configurations included. However, a qualitative analysis on how the expanded grid variant compares to the reference grid variant gives a general indication of how the power and hydrogen revenues would change as a result of grid expansion. Figure 6.6 shows the price duration curve of the Global Ambition scenario with and without grid expansion.

The results of the grid expansion analysis show that for 2030, the increase in net transfer capacity is limited and in accordance with the negligible effect of the grid expansion on the power prices. For 2040, however, two significant changes can be attributed to the grid expansion. First, the amount of low price hours is reduced. This is caused by the increased transmission capacity that allows pumped hydro storages and batteries to charge at a higher power rating and can now be reached by a larger transnational power flow. Furthermore, generated power can now more easily find demand as their amount of potential purchaser increases. Second, the amount of high price hours is reduced. This is caused by the increase of generation capacity that is available to each node. Also, this effect is further increased by the larger share of demand that can be served from power storage and demand side response. All-together, the grid expansion results in less hours of low prices and less hours of high prices. This will result in less power revenues from prioritised configuration-to-grid power flow but a possible increase in below threshold (electrolyser saturated) power flow. Furthermore, the grid-to-electrolyser power flow will decrease due to less hours of <19.5 MWh hours. Figure 6.6 shows that these effects are negligible in 2030 but significant in 2040. However, the additional revenues from the prioritised power flow were shown not to be a key source of revenue in 2040. Moreover, the high RES penetration caused the below threshold power revenues to shrink as well. It is therefore very likely that the hierarchy in the profitable of the configurations will not change as a result of grid expansion.

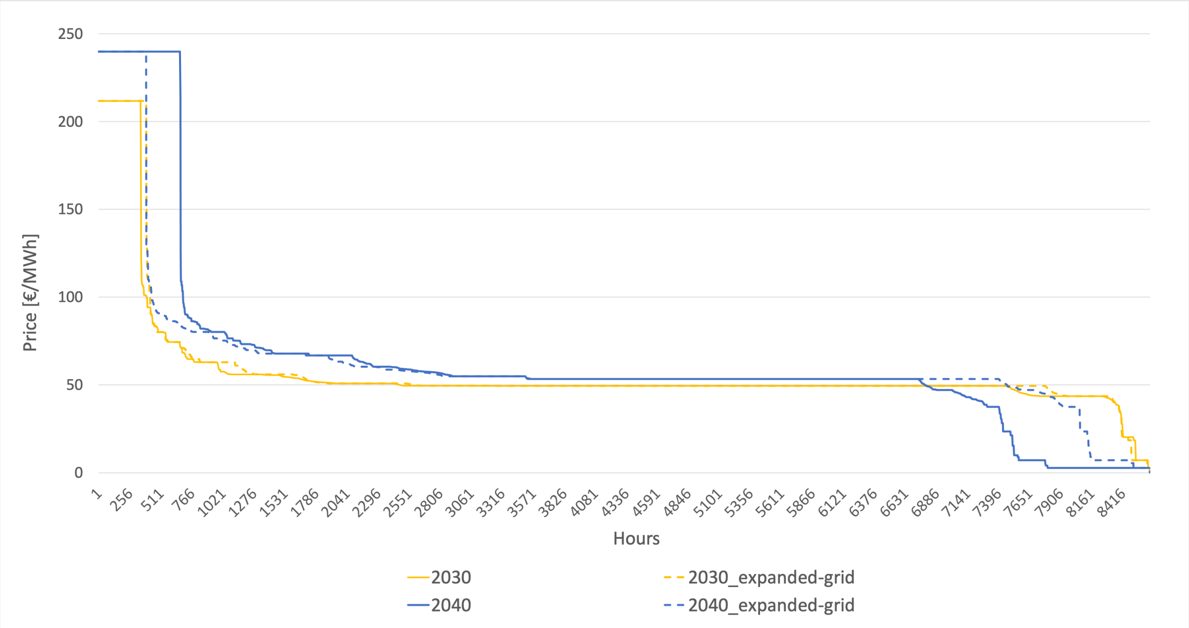

Figure 6.6: Price-duration curve 2030 and 2040, Global Ambition-Expanded grid, weather year 1982

7 Overall Results

This chapter combines the results of the cost analysis (chapter 3) with the results of the power market modelling (chapter 6). Paragraph 7.1 presents the cost and revenue breakdown and the profitability of the configurations for different hydrogen prices. Since system cost and revenues are uncertain, paragraph 7.2 builds on the sensitivity analysis on the HVDC-equipment cost, WACC and offshore installation factor (chapter 3) to assess the variability in profit resulting from variation in these cost factors. Paragraph 7.3 provides the hydrogen production cost as a result of an additional, more optimistic cost perspective that combines the maturity of innovations combined with their scale-up to GW-scale.

7.1. Cost and revenue breakdown

To understand how the configurations compete in revenues and cost, figure 7.1 shows both the annual revenues and cost of all configurations for 2030 and 2040 for a windfarm hub is located 209 km from shore.

In 2030, transmission system cost are strongly affected by electrolyser cost. As a result, the grid connection configuration benefit from a downscaled electrolyser combined with a relative high average power price. Together, this causes the 2030 6 GW configuration to be most profitable/least unprofitable at the 'Global ambition' H2 price level as shown in figure 7.2. A support scheme to ensure a configuration's profitability would be most economical for the 6 GW configuration. The hydrogen production cost are equal for all configurations.

In 2040, electrolyser cost have assumed to drop to 200€/kW, thereby decreasing the differences in transmission system cost of the configurations. Due to relatively low revenues from configuration-to-grid power flow and a higher hydrogen market price, the Full PtG and 2 GW configuration are most profitable as shown in figure 7.3. Since the electrolyser capital cost are assumed to be much lower in 2040, none of the transmission system types (i.e., gas, electric, and hybrid) are significantly more economical given their cost range. The optimal transmission system type of 2040 is now strongly dependent on exact figures regarding HVDC cost factor, offshore installation factor, WACC and the distance to shore. Overall, the annual profits of all configurations have increased as a result of lower cost and higher revenues. Only the 6 GW configuration shows to be significantly less beneficial.

It is important to note that the annual profits as shown here are dependent on the design considerations, especially the placement of the system boundary regarding the system cost and the chosen threshold value. Any placement of the system boundary is a compromise and thus the choices made here should be seen as just one perspective on what cost should be taken into account when weighing different options for far-offshore wind. The chosen level of the threshold value that is unequal to the hydrogen market price is per definition a loss of value. The threshold value was chosen to ensure that power prices at the price plateau would be used for the production of hydrogen and thereby define a minimum viability for any power- and hydrogen delivering configuration for a 12 GW windfarm hub.

Another important consideration is that the 'full PtG' and grid connected configurations differ in multiple properties that make it harder to attribute the benefit of one configuration over another to a single property. For instance, the grid-connection is accompanied by the downscaling of the electrolyser. Furthermore, grid-connection entails the simultaneous addition of grid-to-electrolyser grid connection and configuration-to-grid grid connection. As mentioned earlier, in 2040, the additional power revenues and cost savings are not worth the decrease in hydrogen revenues. However, for the 2 GW configuration, the grid-to-electrolyser revenues are, in fact, worth the additional infrastructure of connecting the onshore electrolyser to the grid. In contrast, an offshore connection would not be beneficial. The configuration-to-grid power revenues are worth the additional system cost but decrease total revenues.

Given the the value of these specific properties, in 2040, a 'full PtG' with grid-to-electrolyser power flow would be more beneficial than without this specific grid connection. Furthermore, overplanting the offshore wind farm would also be most beneficial for the 'Full PtG' configuration given the low average power price of the '2 GW' configuration that will decrease further with increasing wind farm capacity. The most effective overplanting percentage depends on generator-, turbine-, and windfarm design, meteorological conditions and outage ratings. The optimal overplanting is outside the scope of this study.

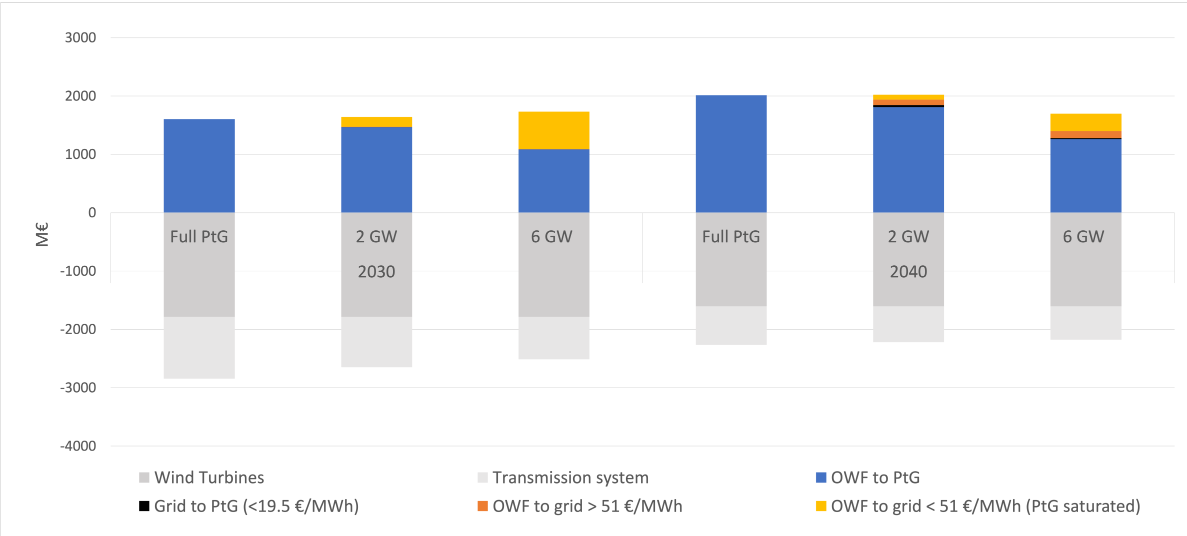

Figure 7.1: Annual revenues and cost components for the 209 km from shore case, hydrogen price: 2030; 1.83 [€/kg], 2040; 2.30 [€/kg].

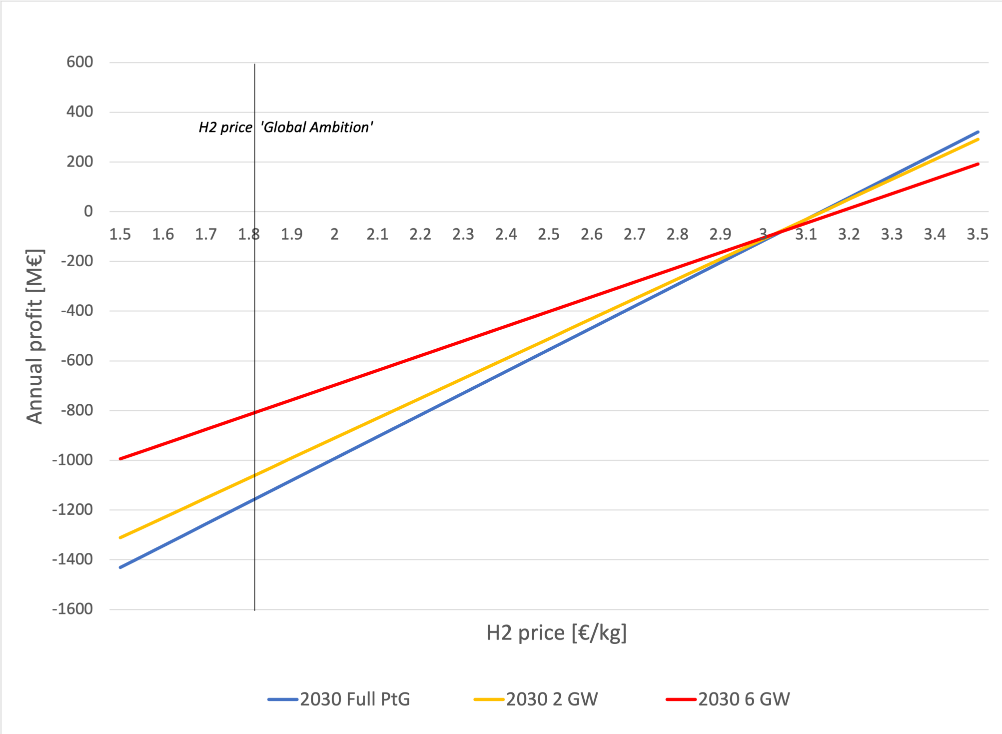

Figure 7.2: Annual profit of each configuration per hydrogen market price, 209 km, 2030

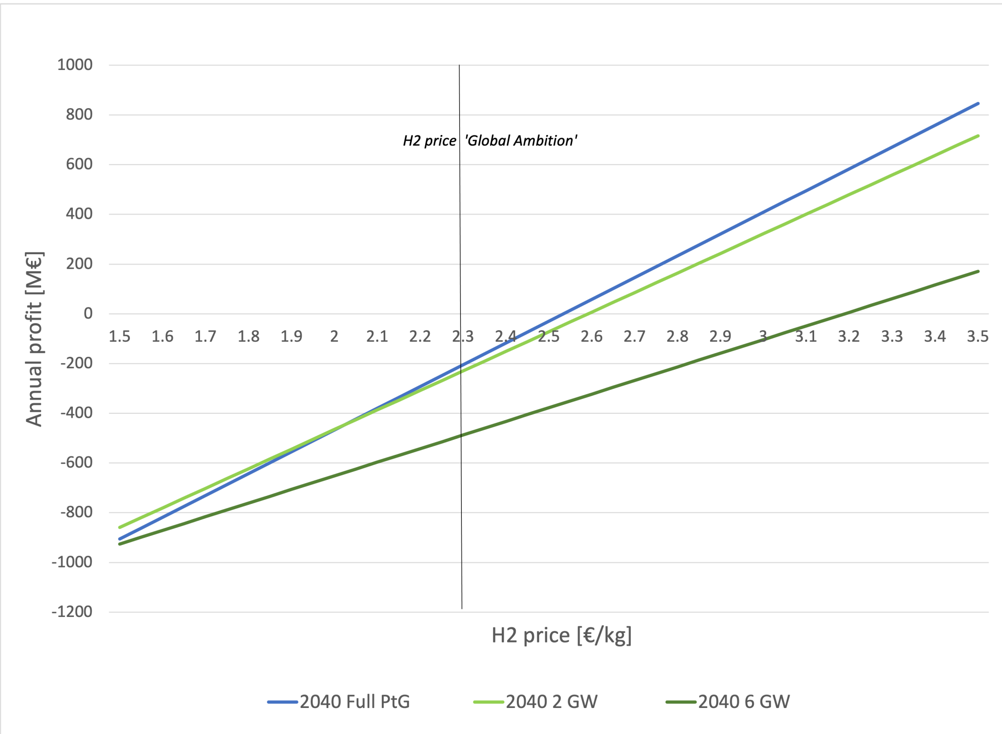

Figure 7.3: Annual profit of each configuration per hydrogen market price, 209 km, 2040

7.2. HVDC-equipment, Offshore installation factor, WACC

The uncertainty in the profitability of the configurations can be exposed by means of a sensitivity analysis. This analysis has been performed for the transmission system cost in chapter 3. Now, this paragraph aims to present what the aforementioned effects are on the annual profitability and the hydrogen production cost of each configuration in the 'Global Ambition' storyline. Furthermore, this paragraph evaluates the effect of an expanded-grid simulation run on the revenues of the grid-connected configurations.

The effect of the uncertainty margins for the HVDC-equipment and offshore installation factor on the annual profits depend on the configuration type and distance to shore. Furthermore, the effect of these potential fluctuations will be either strengthened or weakened by a higher or lower WACC value. To avert lists of cost data, the effects of the HVDC-equipment and offshore installation factor are given for the baseline WACC value of 4.8%, considering the electric transmission systems (onshore electrolysis) at 209 km from shore, the order of magnitude of cost variations in HVDC-equipment and offshore installation factor is rather similar. The maximum change in annual profits at a WACC of 4.8% of the HVDC-equipment uncertainty is -73 M€ and + 97 M€. These differences then cause the maximum variation on the hydrogen production cost of +0.11 €/kg and -0.12 €/kg. The maximum effect of the uncertainty margins of the offshore installation factor are + 68 M€ and -34 M€, causing hydrogen production cost changes of +0.08 €/kg and - 0.03 €/kg.

The effect of fluctuations in the WACC are more significant as they affect both the transmission system cost and the turbine cost. Figures 7.4 and 7.5 show the effect of a lower and higher WACC (2% & 8%) for the case of the reference location 2, located 209 km from shore. Since only cost are influenced, functions shift vertically in the graph. With the lower and higher WACC, the utmost hydrogen production cost are 2.35/3.95 €/kg for 2030 and 2.05/3.25 €/kg for 2040.

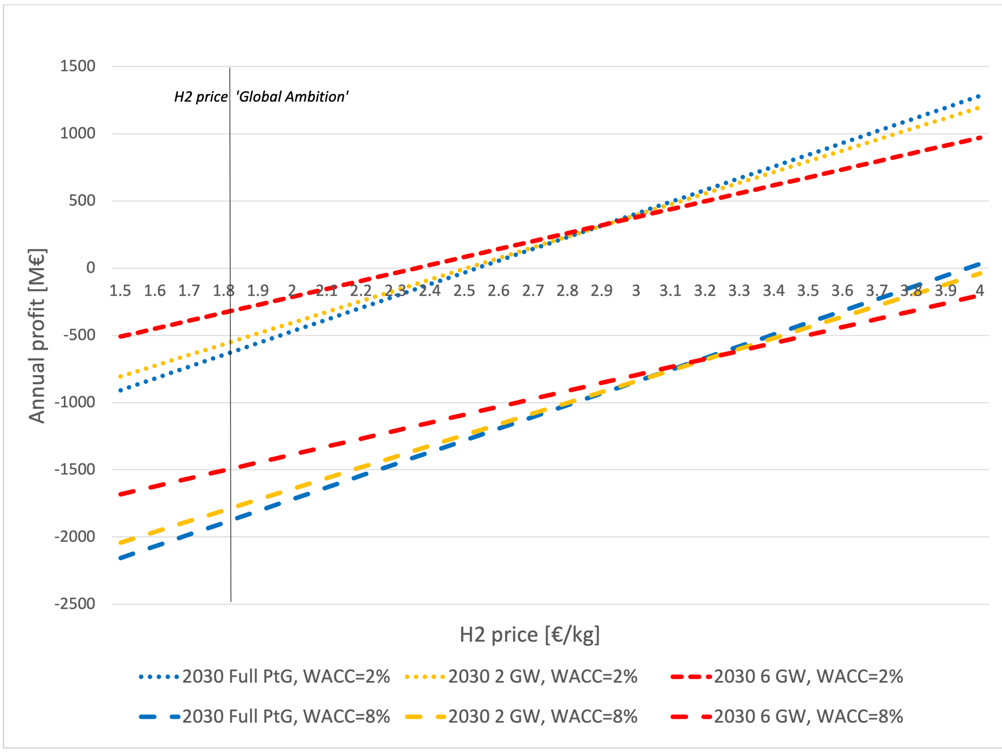

Figure 7.4: Impact of WACC variation on the annual profit, 209 km, 2030

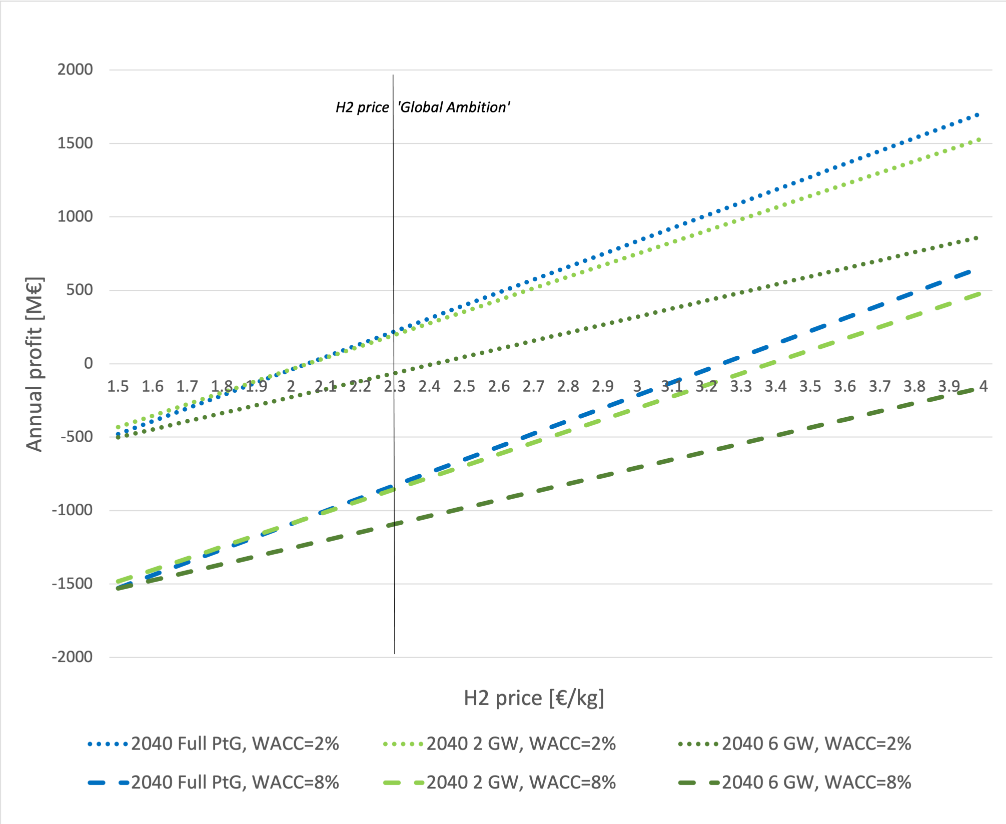

Figure 7.5: Impact of WACC variation on the annual profit, 209 km, 2040

7.3. Optimistic cost perspective: Combining innovation and scale-up

As cost data from the literature study focuses mainly on current or near-future technologies, a different, more optimistic perspective can be taken that combines significant techno-economic innovation with the realization of multi-GW infrastructure. Two pathways of such innovation in offshore wind-based hydrogen production can be identified. The first pathway consists of improvements of the components used in this study and the configuration of these components. The second pathway consist of the breakthrough of in-turbine electrolysis. In-turbine electrolysis is under development with pilot projects of kW-scale. Nonetheless, significant development could alter a change from centralized electrolysis towards decentralized in-turbine electrolysis as further mentioned in the 'energy system opportunities mentioned in paragraph 8.3. However, with in-turbine electrolysis, there is no flexibility in production and thus no need to ask the questions this study aims to answer. In contrast, the first pathway of improvements in centralized electrolysis can be evaluated by assuming significant techno-economical innovation can be combined with scale up. This is done by assuming the following changes in cost with respect to the cost data mentioned in chapter 3.

- Electrolyser Capex reduction to 300 €/kW in 2030 and 100 €/kW in 2040. [7] [40]
- 50 % converter cost reduction as a result of more efficient in-turbine power conversion (turbine DC output).
- No transformer cost of the dedicated hydrogen configurations as a result of efficient DC-DC conversion.
- 50 % compressor cost reduction as a result of more efficient electrochemical hydrogen compression.

These cost figures result in hydrogen production cost of 2.65 €/kg in 2030 and 2.30 €/kg in 2040. The hierarchy of profitability between the configurations has not changed as the cost reduction affect the configurations evenly. Thus, these hydrogen production cost are for all configuration in 2030 and for the ‘full PtG’ and ‘2 GW’ configuration in 2040.

8 Discussion

8.1. Key findings

1. **Is offshore or onshore electrolysis more profitable?**

The profitability of offshore versus onshore electrolysis depends mainly on the cost of the transmission system for each configuration. This is because turbine cost are equal for all configurations, and the revenues of the offshore or onshore variant only differ as a result of revenues from grid-to-electrolyser power flow. This thesis investigated 3 offshore and 3 onshore configurations under various conditions: 1) the years 2030 and 2040; 2) distances to shore of 88 km, 209 km, and 330 km; and 3) variations in costs (i.e., offshore installation factor, HVDC cost and WACC). The results of the transmission system cost analysis show that onshore electrolysis is more economical in 2030, but, in 2040, neither onshore nor offshore electrolysis is significantly most economical. Moreover, from 200 km to shore, offshore electrolysis becomes more economical (in 2040). The differences between unidirectional and bidirectional grid connection are negligible. Interestingly, the profitability of offshore versus onshore electrolysis is hardly affected by the energy system energy losses, which are limited and similar for all configurations.

2. **Does the distance to shore of the offshore wind farm hub affect the profitability of the configurations?**

The distance to shore affects both the turbine cost and the transmission system cost. The turbine cost depend mainly on the water depth, which is largest for reference location 2 (at 209 km). As a result, all configurations at this location have higher turbine cost and therefore a slightly lower hydrogen production cost in comparison with reference location 1 & 3. For the transmission system, cost increase with distance to shore as longer pipes and cables are needed, as well as more compressor power. Hereby, the pipeline cost show strong economies of scale with increasing distance to shore, in contrast to the cable cost. Besides the effect of the distance to shore, the larger water depth of reference location 2 (w.r.t. 1 & 3) causes higher sand island cost, resulting in a relative increase of total transmission system cost for this location. Additionally, distance to shore effects which type of transmission system (i.e., full gas or electric) is most economical.

In 2030, full electric transmission (onshore electrolysis) is most economical at all distances. In 2040, full electric or hybrid transmission have about the same cost at the 88 and 209 km from shore location. At the 330 km from shore location, the full gas (11,52 GW PtG) and hybrid (6,56 GW PtG) configuration are more economical than their full electric counterpart as cable cost increase significantly. The energy losses as a result of the long transmission distance are insignificant for both power and gas transport.

3. **Is hybrid production more profitable than full hydrogen production?**

The profitability of the hybrid- (power and hydrogen) and full hydrogen configuration depends on both the cost and revenues of the configuration. The cost of the configurations are calculated based on the literature study. The revenues of the full hydrogen configuration only depend on the hydrogen price. However, for the grid connected configurations, the revenues are a result of an optimised production of power and hydrogen as end product. This optimised performance aims to benefit from volatile power prices and a stable hydrogen price. The optimisation is done for 2030 and 2040 with the 'Global Ambition' storyline, weather year 1982 and a 'Global Ambition'-based hydrogen price for the respective years.

Results of this optimisation show that hybrid production (2 & 6 GW grid connection) is beneficial (w.r.t. full hydrogen) in 2030 but not in 2040 in the 'Global Ambition' scenario. However, in both years 2030 and 2040, none of the configurations show to be profitable at the established 'Global Ambition'-based hydrogen price. Still, it is relevant to understand why hybrid production is beneficial over full hydrogen production in 2030. This is a result of high electrolyser Capex and relatively high revenues from below the threshold (< 51 €/MWh) (saturated electrolyser) power prices. In 2040, hybrid production is not or of limited benefit as the loss in revenues from a decreased hydrogen production are equal with the lower system cost plus the lower average power revenues. The reason for this change between 2030 and 2040 is a lower electrolyser and wind turbine Capex, a higher hydrogen price as a result of a higher CO_2 price and a lower average power price with lower forthcoming revenues due to increased RES penetration. Thus, in 2030 hybrid production is most profitable / least unprofitable, whereas in 2040 it is most profitable to use full hydrogen production or limited hybrid (i.e. 2 GW) production.

4. **Does a grid connected electrolyser increase the profitability of hybrid configurations?**

In constrast to offshore electrolysis, onshore electrolysis allows grid-to-electrolyser power flow at low power prices for additional hydrogen production. To increase the probability that these grid-to-electrolyser power flows are from renewable energy sources, a lower threshold value is set to 19.5 €/MWh, representing the marginal cost of power from nuclear power. Hours of below 19.5 €/MWh are limited in 2030 but significant in 2040 as increasing RES penetration causes power prices to drop more often. In 2040, the '2 GW cable grid connected' configuration is able to benefit from grid-to-configuration flow as its electrolyser is sized at 9.5 GW, allowing power flow from the wind farm and from the grid simultaneously. Only for this 2 GW configuration, the additional revenues are worth the extra infrastructural cost of a grid-connected electrolyser. The difference in additional profits between the onshore grid connection and offshore grid connection are negligable.

5. **What are the hydrogen production cost for each hydrogen wind hub configuration?**

For all configurations, the hydrogen production cost is set to be a price for hydrogen and not for power, as (primary) hydrogen production is the focus of this study. Moreover, the 2030 and 2040 hydrogen market price is the greatest uncertainty while the future power prices have been modelled extensively. The difference between the hydrogen production cost and the 'Global Ambition' hydrogen price provides an indication of any necessary subsidy schemes - which are not uncommon for (new) sustainable energy technologies.

In 2030, the hydrogen production cost for all the configurations is in the order of 3.10 €/kg. The price gap between the 'Global ambition' storyline based hydrogen price and the hydrogen production cost is 1.20 €/kg. However, at lower WACC, annual cost decrease which causes the power revenues to become more significant, resulting in hydrogen production cost of 2.35 €/kg for the '6 GW' and 2.55 €/kg for the '2 GW' and 'Full PtG' configuration. The established hydrogen price from the 'Global ambition scenario' is too low for profitable primary hydrogen production in 2030.

In 2040, the 'Full PtG' and '2 GW' configuration are significantly more profitable than the '6 GW' configuration due to the higher 'Global Ambition' hydrogen market price. Furthermore, the hydrogen production cost of these two configurations are similar: 2.50 €/kg, with 10 % less hydrogen production in the '2 GW' configuration. The price gap between the 'Global ambition' hydrogen price and the hydrogen production cost has decreased to 0.20 €/kg as a result of a decrease in CO_2 price to 80 €/t CO_2. A (hydrogen based) subsidy scheme for this price gap for the 'full PtG' and '2 GW' configuration results in different annual subsidy cost as the annual hydrogen production differs. This annual subsidy amount for the 'full PtG' is estimated at 236 M€ for 876 M kg hydrogen whereas for the '2 GW' configuration it is estimated to be 252 M€ for 788 M kg hydrogen annually.

Overall, considering both 2030 and 2040 within one lifecycle, none of the configurations is significantly more favourable when reviewing the hydrogen production cost. The '6 GW' configuration is clearly the least profitable. However, the '2 GW' grid connected configuration offers the spreading of risks of power- and hydrogen revenues and transmission system cost.

6. **What are the most influential techno-economical developments for the profitability of each configuration?**

Techno-economic developments can influence the cost or the revenues of the configurations. A development may affect one configuration more than another or affect all configurations equally.

The most influential cost developments that affect all configurations are 1) the WACC and 2) the installation cost of the transmission system and the wind turbines. First, the uncertainty in future WACC has led this study to examine a range of 2 to 8 %, fed by the terra incognita of the current (ECB) monetary policy and uncertainty of future guarantees for renewable energy projects. The effect of this range has an enormous effect on the system cost and on the hydrogen production cost of all configurations. Second, the installation cost of the wind turbines are very project-specific, being especially dependent on water depth. Although this effect is equal for all configurations, its effect on the hydrogen production cost is significant. The effect of variations in installation cost for the transmission system is relatively small. A cost development that varies per configuration is the electrolyser cost, as its capacity varies per configuration. Logically, the higher electrolyser cost of 2030 show more significant cost differences between the dedicated hydrogen- and grid connected configurations. An higher WACC will enlarge this effect. Other cost developments that have been studied are less relevant for different reasons. The HVDC cost factor has shown to be of smaller influence in the transmission system comparison. The reason for this is the intensive use of transformers and converters in both the electric and gaseous transmission system.

The most influential revenue-related development is the CO_2 price. The CO_2 price is a significant part of both the hydrogen market price and the power market price. However, for the hydrogen price this depends on the price-setter of hydrogen (assuming grey hydrogen production cost) and for power it depends on the generator type. In the power price, the level of the power price plateau is set by the CCGT short run marginal cost of which the emission factor is higher than for grey hydrogen production. Consequently, the level of the power price plateau increases more as the emission price increases. This decreases the attractiveness of hydrogen production of fully electric power production. However, the comparison in this study is focused on the potential of the higher and lower power prices that are mainly weather- and demand-driven and the effect of the emission price is small. Besides, the volume of produced power are much lower than the volumes of produced hydrogen. As the volumes of produced hydrogen are high, an increase in CO_2 price increases the revenues of the more hydrogen producing configurations the most, lowering the hydrogen production cost. Depending on what hydrogen consuming sector will become price-setter, the gas price, oil price and the 'green premium' consumers are willing to pay are influential factors for the hydrogen price. The effect of grid expansion has shown to be of insignificant influence.

8.2. Comparison with existing research

The main result of this report are the cost and revenues per configuration. As the cost are based on existing figures, only the revenues per configuration and their realisation are worth to compare with existing literature. These revenues per configuration are a result of the configuration's power price-based decision making and the hydrogen price. As such, these parameters are worth to compare with existing literature. Comparing the simulated power prices with existing research gives an indication of the validity of the power market model. Comparing the hydrogen production cost of the configurations with those mentioned in existing literature might indicate any advantages or disadvantages in terms of profitability of the configurations examined in this thesis.

Publications on future power prices are scarce given their commercial viable character and since scientific research focuses mainly on system/production cost. However, the Danish transmission system operator (Energinet) established price duration curves for different scenarios. These price duration curves, shown in figure 8.1, provide a valuable comparison given the historic similarity in power prices (NL, GR, DK) and the significant interconnection capacity of the Netherlands and Denmark, direct and via Germany. Similar trends in power prices can be identified between the Energinet report and this thesis. Furthermore, the Energinet report provides a reference on the effect of grid-connection electrolysers on the price plateau and low price hours as shown in figure 8.1. (Part of the re-analysis in this study.) The effect of the configuration-to-grid power flow on the amount of low & zero price hours show that another 2 or 6 GW, on top of the 16 GW in 2040, causes significant saturation of the power system resulting in a rapid increase of low power prices. The power price modelling in this study, including the effect of the grid connected configuration on the power prices, form another perspective on how the power price distribution and potential revenues from power and hydrogen might look like in 2030 and 2040.

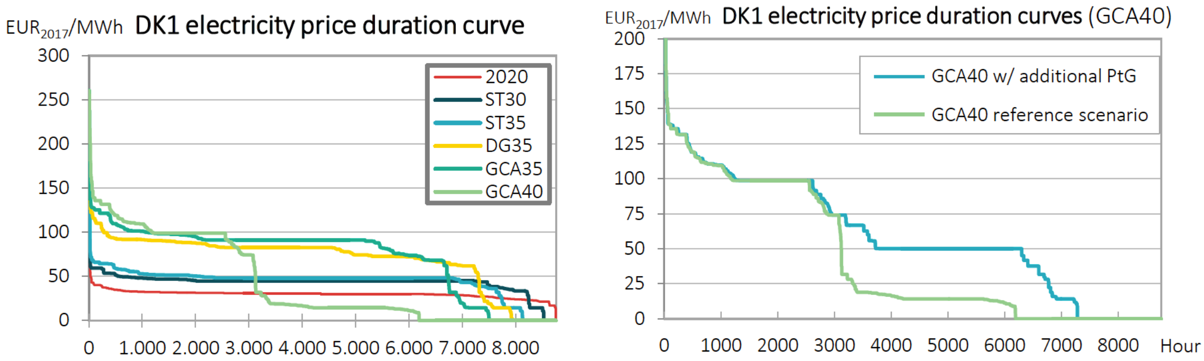

Figure 8.1: Left: Price duration curves in different projections by Energinet [22]. Right: Projection on PtG influence on DK1 power prices [22]

Publications on the hydrogen production cost in wind-based hydrogen production have focused primarily on small scale electrolysers (< 20 MW and pre-2014 research). Nevertheless, several policy papers have reviewed the hydrogen production cost for small-scale electrolysis in the Netherlands. The most prominent studies are Mulder & Perey [41] and DNV-GL IJmuiden Ver study [17], both focusing on post-2030 operation. Remarkably, the results of those studies show that the hydrogen production cost for primary hydrogen from this study is in the same order of magnitude with respect to small scale secondary hydrogen production. Mulder & Perey calculated the hydrogen production cost for a 20 MW 8000 hr electrolyser resulting in € 2,65/kg hydrogen, assuming a fixed power price of 47 €/MWh and 15 M€ CAPEX. The DNV-GL study reviewed different possible electrolyser capacities of 500, 1000 and 2000 MW considering different load profiles, resulting in hydrogen production cost between 1.50 - 3.50 €/kg hydrogen, without stating power prices or PtG Capex. Another policy paper by CE Delft reviewed electrolysis from both North Sea wind and solar energy for a 440 MW electrolyser with 5400 hr in 2030 using a CAPEX of 625 €/kW. This CE Delft review expressed integral cost and marginal cost of hydrogen production. Herein, integral cost include the recovery of all necessary investments of the production chain. The integral cost were calculated to be 2.92 €/kg and the marginal cost 1.72 €/kg. In sum, it seems that the hydrogen production cost of primary (large scale) and secondary hydrogen (small scale) production are similar. However, a high threshold value (for power sales over hydrogen sales) and a high hydrogen price is necessary for the viability of primary hydrogen production. Thus, a (viability) gap exists between small-scale and large-scale hydrogen production.

8.3. Limitations

This research contains limitations for different reasons and with different implications. The most important limitations are discussed in the following paragraphs.

Cost analysis

The value of the literature review- based system cost analysis is limited by the availability of the data and the uncertainty in the data. Data was available for the components within the configurations, but are often project-specific and commercially valuable and therefore data for the components as used within the present study were scarce. Furthermore, sizing the component to a 12 GW scale has not been done before, so data for this size were unavailable. To anticipate on footprint- and/or congestion-related problems, conservative estimates have been used with no or little economies of scale. Despite this limitation in availability, the results are still thought to be informative, given the similarity of the configurations that were compared in this study. That is, any bias in estimates will have affected the configurations about equally, thereby having limited effect on the rank order of these configurations in terms of profitability. Still, the uncertainty in the data does affect the absolute cost estimates. Uncertainty of the data is highest for the electrolyser cost for a number of reasons. First, multi-GW electrolysis has not been realised before. Second, key properties such as cell stack life, efficiency, reaction time and minimal load are uncertain since the technologies still mature. And third, following from the aforementioned properties, the Capex, Opex and total efficiency for the different electrolyser technologies are under development. Although parameters such as ramping rates have not been taken into account, the conservative efficiency and different Capex scenarios ensure a valid representation of the production cost of hydrogen.

Another cause of data uncertainty is the result of unknown cost figures, such as installation cost. A cost factor is used for the electrolyser installation cost. Although their installation cost will be related to their techno-economic maturity through efficient use of materials and pressurised operation - allowing smaller installations. However, a cost factor per capacity is a sub-optimal solution for these unknown cost figures. Also, this thesis neglected the cost related to the building time of different components nor the decommissioning cost. Especially the wind turbines and sand island take up multiple years of construction. These, and other offshore infrastructure components have a building time and building speed that are weather dependent and again, location specific (i.e., water depth, distance to shore, etc.), whilst cost numbers are taken for the first year of usage. The uncertainty of the data is tempered by the equal capacity of wind turbine capacity and the overlap of other components in the configurations. Furthermore, the research focus is on the macro economic developments towards 2030 and 2040.

Modelling data

Model results depend on the model input data. The input data consist of only one TYNDP scenario, which is a limitation of this study. To examine the effect of this limitation, the most influential power system figures are discussed: the installed capacities of power generators, the DSR and ('Global Ambition') PtG capacity and the CO_2 and fuel prices. Then, special consideration is given to the transmission system modelling. Offcourse, studying other future pathways (TYNDP or other) would give insight into the the spectrum of possible annual power prices and what effects can be allocated to either the storyline, weather year or grid expansion storyline.

The installed capacities of offshore wind in the Netherlands in the scenario is set to 10 GW in 2030 and 16.5 GW in 2040. However, the Dutch government has a target of 11.5 GW in 2030 already. No capacity target is set for 2040, however, there is a widespread understanding that offshore wind is a main driver in decarbonizing the Dutch energy system. Furthermore, the disappointing accomplished decarbonisation so far (anno 2021) has fed the urge to increase the tempo of offshore wind rollout. Although, the connected configuration already add power to the scenario, the offshore wind capacity data might to be conservative thereby underestimating the amount of low price hours. Another potential gamechanger would be the realisation of a nuclear power plant in the Netherlands, increasing baseload generation and decreasing low and high price hours.

On the power demand side, electrolysis and demand side can be considered influential depending on their size and modus operandi. For the P2G capacity however, scenario data on P2G capacity for 2030 and 2040 is not implemented in the model due to time considerations. This capacity would compete with the P2G of the configurations in terms of grid-to-electrolyser flow and the produced hydrogen. However, the omission of the scenario data on P2G capacity is unlikely to affect the findings of this study, because the configurations of this study have limited effect on the low power prices given the limited grid connection and the lower threshold value (19.5 €/MWh). For the Netherlands and surrounding countries, the TYNDP data foresees 1 GW P2G in Germany in 2030 and 2 GW in 2040. These capacities are grid-connected P2G facilities. This electrolysis capacity would decrease the low price hours. For the DSR capacity, the TYNDP data assigns 700 MW of DSR for the Netherlands for both 2030 and 2040. However, a gradual increase towards a higher capacity in 2040 seems more realistic. Given the development of 'prosumers', decentralised power, storage and flexible demand managed in a smart grid might result in a much higher capacity and may also lead to a different way of defining 'load' in energy modelling. But, the uncertainty in future DSR and PtG capacity that plays a major role on the profitability of electrolysis. Herein, the DSR capacity affects both the high- and low price levels and hours. The PtG capacity influences mainly the level and amount of low price hours. However, as PtG capacity increases further, back-to-back operation producing power during 'dunkelflautes' affects the duration and level of high prices as well. Also, the revenues of this back-to-back hydrogen usage during, for example, the increasing peak prices towards 2040, have not been taken into account.

In the simulation of the power prices, the fuel price and CO_2 price are underlying input variables that affect the entire price-duration distribution. These variables are volatile and uncertain but have been given a fixed value for 2030 and 2040 in the 'Global Ambition' scenario. The uncertainty of the gas price, influencing the level of the price plateau, is the result of developments in the continental gas market (left aside LNG), influenced by geopolitical developments (Nord Stream 2) as well as national developments (e.g. closing of the Groningen gas field). The uncertainty in the CO_2 for the Netherlands seems to be smaller as a minimum CO_2 price is entering in to force. Nevertheless, the CO_2 price path remains uncertain, especially post 2030 as phase 4 of the EU-ETS will come into an end in 2030. Given the current developments in the EU-ETS price and the annual emission reduction targets, the values for 2030 and 2040 (35/80 €/tCO_2) seem to be low estimates. This uncertainty of fuel price and CO_2 price affects both the power price as well as the hydrogen price. Whenever the CO_2 price would increase, this benefits the 'full PtG' more compared to the grid connected configurations given the large volumes of hydrogen. A demand driven influence on the power and hydrogen price is the 'green premium' consumers are willing to pay on top of the established power/hydrogen market price. Also, the question arises if the standard/certificate for the 'green' premium of hydrogen includes the possibility of power flow from the grid into the electrolyser. Establishing such a premium price (pathway) is beyond the scope of this study.

The transmission losses have been neglected in this thesis power model, which has led to an unrealistic amount of power imports and exports with unrealistic volatilty. This limitation explains the relative low bottom prices in the price duration curve; a power consumer is found easily, albeit a power storage. More realistically, power losses and transport fees would lead to more price-deviation between the nodes and at the nodes higher and more peak prices and lower and more bottom prices (including negative prices). As such, this would likely lead to an increase of the 'prioritised' power revenues and an increase of the grid-to-electrolyser power flow and forthcoming hydrogen revenues.

Less influential data limitations are the simplified weather patterns of solar, wind and precipitation and the techno-economical parameters and constraint of the generators. Weather patterns are represented by hourly normalised data per node. A more detailed modelling approach would require extensive geographical modelling and needs to take into account additional factors, including PV dynamic efficiency, turbine inertia, turbine height and specific generator sizing. Furthermore, natural inflow data for hydro generators in this study was based on daily and weekly averages natural inflow per node. Especially precipitation data is to be acquired by detailed modelling. The techno-economical parameters are set to be the same for 2030 and 2040 and are parameters for 2019. Although developments in gas turbines and coal plants might continue, their potential efficiency is limited due to the maturity of these generators. Developments in 'predictive' maintenance is likely to result in lower forces outage rates for all generator types thereby decreasing price peaks.

Power market simulations

Power market simulations intend to reflect real market dynamics. However, this approximation is limited. Not all market types and market timescales have been modelled in this study. Besides, market dynamics as a result of strategic behaviour are difficult to mimic. Furthermore, the power market is not a standalone market but interacts with other markets. Also, within the power market model, decisions are made on how to model the configurations that are the subject of this study, in which threshold values play an important role. In the performance of these configurations, modelling omissions have occurred. These limitations of the aforementioned are elaborated on in the following sections.

The power market model is used with the objective to determine the revenues of the configurations examined in this study. In this effort, real markets dynamics were approximated by a perfect competition system cost minimisation. However, the purpose of real markets is also the arbitrage of risks in the uncertainty of generation and demand on different timescales. The pricing of short- and long term risk (e.g., balancing market, day-ahead, futures) is not represented by the model, as is the case for the value of ancillary services on the balancing market, and - for some countries - the capacity market. Especially offshore wind-based power generation is traded in derivative market products given the short term risk such as forecast errors, but also given long-term risks such as climate change affecting regional weather patterns. Besides risk premiums and the recovery of long run marginal cost in the power market, also strategic bidding behaviour causes real power prices to deviate from theoretical perfect-competition power prices. The Plexos power market model is able to mimic certain market failures, by, for example, the Bertrand competition effect, including opportunity costs and including the recovery of fixed operation and maintenance costs (FOM) as well as equilibrium Nash-Cournot modelling. Due to limited time and data, these effects, however, were not included in the model. Also, some game-theory mimicking can turn into a black box.

Sector coupling of power and heat was not included in the 'screenshot' one-year modelling. However, with increasing RES penetration, heat pump usage and thermal storage, the coupling of power and heat will become stronger in the simulated years 2030 and 2040. Modelling both power and heat would increase the reliability of the results. Another possible extension would be the expansion towards an equilibrium model in which the power market is part of the whole economy, in which national developments in GDP affect the power sector as a whole.

When running the power simulation model, several omissions occurred. These modelling omissions had their influence on the results and led to a re-analysis of the models' baseline output. The first omission was the aggregated generator capacity per node (e.g., all OCGT aggregated to one installation per node). It has been shown that this can yield unrealistic generator outages. Generator/installation-specific maintenance would decrease the amount and duration of 'unserved energy' as a result of a forced outage followed by a slow response of other generators due to their startup times and/or ramping rates. The effect of this omission is small, as the revenues from prioritised power during these periods of unserved energy are 2.9 M€ in 2030 and 13.0 M€ in 2040, of which the estimated half are genuine power revenues.

The threshold value has been given a fixed value for two reasons. First, the power price distribution curve opts for one specific value at the high price side of the price plateau, since, higher power prices follow after a sharp increase in the power price. Second, the value is fixed to limit the amount of simulations, since, every new threshold price would need an extra round of simulations. Consequently, any hydrogen market price above the threshold value would result in a unnecessary decrease of hydrogen production, leaving the revenues unchanged, but affecting the qualitative assessment of hydrogen produced. In contrast, any hydrogen market price below the threshold would result in a value loss as a result of unnecessary electrolysis of relatively valuable power. Therefore, all hydrogen prices in the sensitivity analyses that deviated from the threshold price, contain an error in accordance with this difference.

The two other modelling omissions explained earlier led to a re-analysis of the baseline results by replacing the power imports, domestic generation, power export and potential extra power export in this chronology, based on the SRMC of domestic generators, and the average shadow price of import and export flows as a proxy for the market price. The uncertain and most significant revenues are from the 'PtG saturated' power flow that is most strongly affected by changes as a result of increased RES penetration, 'cranking' the price duration curve price plateau towards 0 €/MWh. These configuration-to-grid power flows are overestimated in the replacement of domestic generation (as the real price is higher if connected to other nodes) and the replacement of export flow is underestimated (as the real price should be lower as the shadow price should decrease while saturating demand). Given the large amount of connected countries, the average shadow price is less strongly affected changes as a result of an extra power flow of 2 or 6 GW (at turbine rated power). The order of magnitude of these effects are assumed to cancel each other out. Furthermore, the largest deviation (overestimating the revenues of 'saturated PtG') will occur for the 2040 6 GW configuration that is by far the least profitable configuration in 2040 under all circumstances.

System boundaries & drivers of decarbonisation

The configurations in this study have pre-defined system boundaries. However, the cost of the necessary (additional) onshore power and hydrogen infrastructure should also be considered in a long-term decarbonisation strategy. This exercise is beyond the scope of the present study but is a necessary exercise in order to establish realistic CO_2 abatement cost. For cost calculations, it is important to consider the effect of cost-socialisation of certain infrastructure which affects project risk and therefore affects the total system cost. Moreover, not only CO_2 reduction targets must drive power system strategies but also grid stability and reliability targets that become more important as variable RES capacity increases.The question arises whether markets reflect the value of these parameters in order to establish the necessary power storage options (such as hydrogen). Is there are enough retroactive stimulus for such key technologies and infrastructure? Coming from a reliable and stable grid, a self-defeating prophecy can lead to too much postponing of these key last pieces of the puzzle.

Energy system opportunities

Existing and future infrastructure might provide a valuable cooperation with offshore wind hydrogen production. Examples of these are the use of existing NGT offshore gas pipeline (for offshore electrolysis) and the cooperation with existing or future industrial areas, solar PV parks (congestion mitigation), district heating or power generators (nuclear, gas turbine).

Future hydrogen infrastructure could be designed for higher system pressures (e.g. 80 bar instead of 50 bar). This would lead to a decrease of pipeline diameter and thus pipeline cost. Pressurised electrolysis could improve electrolyser efficiency and decrease the electrolyser and compressor footprint. Furthermore, the advantages and limits of the different electrolyser technologies could be exploited by combining different electrolyser technologies (e.g., PEM, AEC, SOC). Or, a specific electrolyser technology can be provided with an optimal load profile, for example in the cooperation with a nuclear power plant or with the optimal wind turbine generator size.

A prominent development are the offshore in-turbine electrolysers that might reduce the cost of hydrogen production from offshore wind by decreasing power losses as a result of wind generator DC output and electronic power conversion designed for optimal electrolyser usage. A trade-off has to be evaluated on centralised versus decentralised desalination, compression and cell stack replacement a.o.. These design considerations can be seriously altered if an artificial island is needed anyway for turbine building and maintenance purposes.

8.4. Recommendations

Recommendations for the Gasunie in particular can be drawn from the results of this study, as well as from the context of which this study is situated in; hydrogen production from Dutch North Sea wind. The starting point of this study has been primary hydrogen production that was ensured by a full hydrogen design or a threshold value in case of the grid connected configuration. However, in reality, from the perspective of a wind farm investor, only a limited amount of power is to be sold to an electrolyser, resulting in an unviable situation for this electrolyser. This then leads to downscaling or the necessity for other (non renewable) power sources as electrolyser input. So, there is a gap between secondary and primary hydrogen production. As long as the business case for full hydrogen is not viable, another gap remains between dedicated power producing wind farms/hubs and dedicated or primary hydrogen producing wind farms/hubs. At some point, with increasing RES penetration and decreasing electrolyser Capex, primary hydrogen production will prevail over power production. However, Gasunie has the opportunity and responsibility to take a stance in the long term hydrogen strategy and thus to anticipate with infrastructure that is meant to last multiple decades and of which the correct sizing is essential to

provide optimal economic and societal value.
In order to be able to anticipate, the challenges for primary hydrogen production from offshore wind need to be identified. Beside the above-mentioned gaps, the increasing emission price benefits both full electric power producing- and full hydrogen producing offshore wind. To kickstart primary hydrogen production (generate a supply push), a non-emission related support scheme could make full hydrogen production more attractive for the offshore wind sector. Offcourse, a CO_2-based or EU-ETS-based support scheme will benefit the full hydrogen business case as well, especially for hydrogen-only sectors with no competition from power. However, it would be beneficial if shipping and aviation would be included in the EU-ETS or another emission framework. Another possibility to kickstart primary hydrogen production is a tender specifically for primary hydrogen production.
For the interpretation of the figures from this report, it is important to note that transmission system cost are not socialised, both for power and gas transport. Cost socialisation of transmission infrastructure offers an different perspective and different hydrogen production cost. Furthermore, the figures need to be considered in a long term North Sea and Dutch offshore wind strategy. Consequently, it is arguable that the '2 GW' grid connected configuration (equal performance to 'full PtG') is not efficient as the 2 GW windfarm to grid connection with relative low load factor is blocking a potential full power producing windfarm. The further expansion of specifically hydrogen offshore wind capacity towards 2050 (20, 30 or 40 GW PtG) should be considered as the economies of scale of hydrogen pipelines might favour offshore electrolysis as the overall cost might be lower. If so, both offshore and onshore hydrogen infrastructure will need to be able to adapt to a stepwise increase of hydrogen production as wind farms/hubs. Whether Gasunie can play a role in offshore gas transport, depends on the progress of in-turbine decentralised desalination, compression and electrolysis versus the offshore/onshore centralised alternative. Development in the electronic power conversion of variants are of significant influence, as also shown in this report. Long term strategic considerations should also take into account the onshore symbiosis with solar PV and nuclear power generator to limit grid congestion and increase the electrolyser load factor.

Besides applied recommendations, this thesis also yields recommendations for future research. Future studies should take time- and infrastructural planning into account when exploring potential offshore wind hubs in the North Sea area. The time planning is of special importance during the phase-in and phase-out/replacement of these capital intensive energy infrastructure. As the building time of multi-GW offshore wind farm design will span multiple years, the overall design must allow the step-wise activation of wind farms and electrolysers as well as the step-wise replacement of system components. The infrastructural planning must take into account the broader potential of 60 GW North sea wind in 2050 (+ 450 GW onshore in Europe) and the forthcoming power grid challenges in all North sea countries. Furthermore, the benefits of interconnection between the North sea countries must be investigated further, as is the case for dedicated wind farms for either hydrogen or power production.

Future modelling efforts that aim to value the benefits of combined hydrogen and power production should focus on different DSR and PtG capacities as both highly affect the (non-) volatility of the power prices. Also, CO_2 price developments post-2040 should be sought after as CO_2- free flexible power will likely to become more valuable as the decarbonisation efforts will force gas generation to shut down. Another reason to focus on post-2040 power- and hydrogen price developments is that the lifetime of most components span at least until 2055 when build in 2030. The value of future modelling efforts can be increased by taking into account the strategic behaviour of power generators and power storages, the sector-coupling effect of power and heat, and an equilibrium model that can consider the effect of economic performance and financial market developments on the power and hydrogen price. Also, the nodal and grid granularity must be increased to cope with the challenges of more local and decentralised weather patterns and grid capacity. The modelling of power transmission losses is essential to prevent unrealistic far transport and trade of power and to represent the losses as a result of the route from (relatively) low voltage power generator, via a high power back bone and/or power storage, to a low voltage power consumer.

Further research is needed to establish in what ratio a future hydrogen grid and power grid should be scaled. Hereby it is of importance to identify the long-term CO_2 total abatement cost and abatement potential, including the infrastructural cost such as hydrogen compression for transport and storage.

Multiple sectors can be identified that cannot be electrified such as aviation, heavy shipping and long-term power storage. Furthermore, hydrogen import and accompanying geopolitics of energy must be taken into account.

9 Conclusion

This research aimed to find the most profitable configuration of a 12 GW offshore hydrogen wind farm hub in 2030 and 2040. This was done by comparing dedicated hydrogen production with combined hydrogen and power production. For this optimisation, the profitability of six configurations were compared. These configurations differentiated in wind hub- and electrolyser location, electrolyser capacity and grid connection capacity. The cost of the different configurations were established through a literature study. In order to explore the value of benefitting from both high power prices and a more stable hydrogen price, future power prices were modelled to establish the revenues of the grid connected configurations.

In general, hydrogen production cost are very uncertain as electrolysis is still facing a large scale-up in production. With conservative - ready to scale up cost figures, results show hydrogen production cost of 3,10 €/kg in 2030 and 2,50 €/kg in 2040. When assuming the future technological maturity of turbines with DC output, efficient electronic power converters (DC-DC) and electrochemical compression combined with optimistic cost reduction of the electrolyser, the hydrogen production cost decrease to 2.65 €/kg in 2030 and 2.30 €/kg in 2040. Considering the 'Global Ambition' storyline, in 2030, the combination of a small onshore electrolyser and a larger grid connection (6 GW) is most profitable. In 2040, the 'Full PtG' and '2 GW' configurations with onshore electrolysis are equally profitable. However, overall, considering the operation of a hydrogen wind hub through 2030 and 2040 within one lifecycle, there is no significant advantage of grid connection as the break-even prices of the '2 GW' and 'Full PtG' turbed out to be similar. The larger grid connection of '6 GW' is definitely less profitable operating through 2030 and 2040. An advantage of the '2 GW' grid connected configuration is the spreading of risks in power and hydrogen revenues and transmission system cost.

Besides these general trends, results show that onshore electrolysis is most economical for majority of possible cost scenarios as it can benefit from grid-to-electrolyser power flow and forthcoming hydrogen revenues at low power prices. Only at the 330 km reference location in 2040, gas transport shows little benefit in the 'full PtG' configuration and 2 GW configuration. In 2030, grid connection (combined production) is beneficial in 2030 as electrolyser Capex are high and revenues from below 51 €/MWh (saturated electrolyser) are high. In 2030, the break-even price for all configurations is in the order of 3,10 €/kg. The price gap between the 'Global Ambition' scenario hydrogen price and the break-even price is 1,20 €/kg. In 2040, combined production is not or of limited benefit as the decrease of hydrogen revenues is larger than the potentially extra power revenues. The reason for this change between 2030 and 2040 is a higher hydrogen price as a result of a higher CO_2 price and lower power revenues due to increased RES penetration. The 2040 '2 GW' configuration is able to benefit from the wind hub-to-grid power flow and from grid-to-configuration flow as its electrolyser is sized at 9.5 GW and the presence of a large amount 19.5 €/MWh price hours. However, future modelling must include competing PtG facilities that will increase the lower power price limit to better evaluate the value of PtG-grid connection. Furthermore, the break even-price of these two configurations ('Full PtG' and '2GW') are similar; 2,60 €/kg, with 10 % less hydrogen production from the '2 GW' configuration. The price gap between the 'Global ambition' hydrogen price and the break-even price has decreased to 0,30 €/kg.

Additionally, results from the expanded grid simulation of 2030 and 2040 show that a decrease in both low- and high price hours is unlikely to change the hierarchy in profitability.

The approach chosen in this thesis had several strengths, including the extensive geographical scope, the use of the latest open-source data, and the high resolution of the power market model. Nonetheless, the modelling effort could be improved by including such factors as strategic behaviour in power markets and a variety of demand side response- and power-to-gas capacities. Concerning the comparison of the configurations, an alternative methodology would be to oversize the '2 GW' configuration in order to produce the same amount of hydrogen as in the 'full PtG' configuration and/or to allow grid-to-electrolyser power flow at all profitable power prices.

New questions have risen on how the future hydrogen market price will be established: What is the willingness to pay per market sector based on commodity prices, CO_2 development and regulatory schemes; And what level of 'green premium' are consumers willing to pay on top of the established hydrogen market price? Also, the question arises if the standard/certificate for the 'green' premium of hydrogen includes the possibility of power flow from the grid into the electrolyser.

The findings from this thesis extend the current knowledge on hydrogen production from offshore wind. Earlier research on this topic has reviewed small-scale electrolysis with different load profiles that resulted in a hydrogen price of the same order of magnitude as the larger-scale electrolysis examined in this thesis (i.e., 1.50 - 3.50 €/kg). This finding illustrates the economics of large-scale primary hydrogen production from offshore wind in the Netherlands in dedicated or hybrid operation. Herein, it shows the profitability of each configuration for a range of hydrogen prices.

Future research should focus on the development of 'prosumers', decentralised power storage, and flexible demand, because these factors might result in a higher demand-side-response capacity than used in this study. Future modelling efforts that aim to value the benefits of combined hydrogen and power production should focus on different demand-side-response and power-to-gas capacities as both affect the volatility of the power prices. Furthermore, the model can be improved by including the recovery of long run marginal cost, strategic bidding behaviour, sector coupling of power and heat and increasing the nodal and grid granularity to cope with the challenges of more local and decentralised weather patterns and grid capacity.

Appendix A

Table A.1: Source referencing of the techno-economic parameters of the generators, fuels, emissions and storages

Color	Source
Yellow	NREL, ATB 2019 [44]
Light green	Danish Energy Agency, Technology data 2020 [15]
Blue	ENTSO-E, MAF 2019 [23]
Red	Schmidt O, Melchior S, Hawkes A et al. 2019 [51]
Brown	IEA, Word Energy Outlook 2016 [33]
Magenta	ENTSO-E/ENTSO-G, TYNDP 2020 [25]
	Chosen by author

Generator	Heat rate [GJ / MWh]	FOM [€/kW/year] (2020 euro)	VOM [€/MWh] (2020 euro)	Emissions [kg/GJ]	Forced outage [%]	Mean time to repair [h]	planned outage/maintenance rate [%]
Gas CCGT new	6.6	9.36	2.84	57.0	5	24	7.4
Gas CCGT old	6.8	9.36	2.84	57.0	8	24	7.4
Gas OCGT new	9.6	10.21	6.62	57.0	5	24	7.4
Gas OCGT old	10.4	10.21	6.62	57.0	8	24	7.4
Hard coal new	7.9	51.03	7.56	94.0	7.5	24	7.4
Hard coal old	9.2	51.03	7.56	94.0	10	24	7.4
Lignite new	7.9	51.03	7.56	101.0	7.5	24	7.4
Lignite old	9.2	51.03	7.56	101.0	10	24	7.4
Heavy oil	11.6	7.98	5.67	78.0	10	24	7.4
Nuclear	11.0	95.45	1.89	0.0	5	168	14.8
Onshore wind	-	12.29	1.31	-	1.8%	9.00	0.30%
Offshore wind	-	35.16	2.65	-	2.5%	9.00	0.30%
Solar PV	-	9.04	0.00	-	-	-	-
Solar Thermal	-	48.20	3.31	-	0.50%	9.00	4
Pumped Hydro	-	7.34	0.49	-	6	9	4
ROR	-	7.34	0.49	-	6	9	4
Reservoir	-	7.34	0.49	-	6	9	4
Battery	-	9.29	2.92	-	-	-	-

Fuels	Fuel price 2030/2040, all scenarios [€/GJ] (2020 euro)
Nuclear	0.47/0.47
Lignite	1.1/1.1
Oil	2.3/2.3
coal	4.3/6.91
natural gas	6.91/7.31
Oil (average of light and heavy oil)	17.55/19.7

Emissions	Emission price 2030/2040 [€/tCO2] (2020 euro)
Co2 (Global Ambition)	35/80
Co2 (Decentralised Energy)	53/100

Storage	Inital SOC [%] / Initial Volume [% of Max volume]	Charge efficiency [%]	Pump efficiency [%]	End volume
Battery	50	80	-	= Initial volume
Reservoir, Open/closed pumped storage	70	-	80	= Initial volume

Min load [% of max load]	Min on time [h]	Min off time [h]	Start up fuel consumption warm start [GJ/MW]	Start up fixed costs warm start [€/MW]	Start up fuel consumption cold start [GJ/MW]	Start up fixed costs cold start [€/MW]
40	2	2	7.6	25.06	9.7	36.02
50	3	3	7.6	43.07	9.7	61.86
40	1	1	0.21	20.36	0.25	24.28
50	1	1	0.21	52.47	0.25	52.47
25	6	6	18	50.12	21	81.44
40	5	5	18	42.29	21	57.17
50	8	8	18	42.29	21	57.17
50	9	9	18	50.12	21	81.44
50	3	3	7.6	50	9.7	81.44
40	12	12	14	21		
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-

Start up fuel consumption hot start net [GJ/MW]	Start up fixed costs hot start [€/MW]	Transitation time, hot > wam [h]	Transitation time, hot > cold [h]
4.1	21.93	8	48
4.1	27.41	8	48
0.2	17.23	2	3
0.2	30.54	2	3
10.5	42.29	12	72
10.5	30.54	12	72
10.5	30.54	12	72
10.5	42.29	12	72
4.1	42.29	8	48
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-

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