Utrecht University

Wind-Powered Offshore Electrolysis

Diving into the Possibilities and Uncertainties of Hydrogen Production in the North Sea

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Abstract

The energy sector is one of the main contributors to global carbon emissions. To be able to keep the increase in global temperatures to a minimum, decarbonization of the sector is of paramount importance. In the Netherlands, there is a large potential for large offshore wind parks, which can produce high amounts of electrical energy. However, wind energy faces two challenges in comparison to carbon-rich fuels. Firstly, the storage of electricity is expensive and has a high depreciation rate. Secondly, there are sectors which require high-temperature heating for which electricity is not suitable. For these two challenges hydrogen provides an alternative pathway. Since a couple of years, an existing new field opened up combining these two factors in the North Sea, namely offshore hydrogen production.

This research aimed to understand the most influential parameters which influence the choice for performing the production of hydrogen onshore or offshore. In four case studies, the expected major contributors to the system costs were examined. First, a direct comparison was made between on- and offshore electrolysis. Secondly, the influence of the distance of the wind parks to the shore was examined. Thirdly, the influence of different allowed electrolysis capacities installed onshore was tested. Finally, the contribution of repurposing existing infrastructure was investigated.

For the base case comparison of on- and offshore electrolysis the LCOH was determined to be 4.60 €/kg and 5.46 €/kg respectively. An analysis of the costs of each component, designated the costs concerned with installing an electrolyser offshore to be the main contributor to the increase in LCOH. The distance at which offshore electrolysis was an economically viable option was determined to be 475 km. Moreover, the variation of onshore capacity and the decrease in network costs were proven to have no significant effect on the design and operation of the energy system. Lastly, the number of turbines installed, the combined electrolyser size and the size of the hydrogen cavern remained constant throughout this research.

The results in this research have yet to be subjected to an extensive sensitivity analysis to investigate the robustness of the results presented.

List of abbreviations

BoP	Balance of Plant
CBS	Centraal Bureau voor de Statistiek
DEA	Danish Energy Agency
GHG	Greenhouse Gas
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
IEA	International Energy Agency
IPPC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
KNMI	Koninklijk Nederlands Metreologisch Instituut
LCOH	Levelized Cost of Hydrogen
MES	Multi-Energy System
MILP	Mixed-Integer Linear Program
MIP	Mixed-Integer Program
NLOG	Nederlandse Olie- en Gasportaal
O&M	Operation & Maintenance
PEM	Polymer Electrolyte membrane
PtH	Power to Hydrogen
RO	Reverse Osmosis

List of Symbols

Latin

A	Constraint matrix for continuous variables
B	Constraint matrix for discreet variables
b	Constant term for constraints
c	Cost vector for continous variables
C	Cost parameter
d	Cost vector for discreet variables
F	Energy Consumed
I	Energy Imported
K	Costs
L	Energy Demanded
P	Energy Produced
S	Size
x	Continuous variable vector
y	Discreet variable vector

Greek

α_1	Dependent network cost parameter
α_2	Independent network cost parameter
γ	Annuity factor
δ	Distance
η_1	Electrolyser efficiency
μ	Mean

ρ	Desalination Unit Consumption
σ	Standard deviation
τ	Binary factor

Subscripts

a	Annuitized
Desal	Desalination
f	Fixed
i	Investment
j	Technology
inv	Investment
k	Carrier
max	Maximum
min	Minimum
n	Node
net	Network
Pem	Electrolyser Onshore
PemOff	Electrolyser Offshore
prod	Production
t	Time
u	Variable
v	Variable
ws	Windspeed

Others

$\mathbb{N}$	Natural numbers
$\mathbb{R}$	Real numbers
$\mathcal{T}$	Hourly time horizon
$\mathcal{M}$	Set of all technologies
$\mathcal{N}$	Set of all nodes

1 Introduction

Human-induced climate change has been to date, one of the greatest challenges humanity is facing. The most recent Intergovernmental Panel on Climate Change (IPPC) report states that temperatures will keep rising until at least 2050. Moreover, a global increase of 1.5 °C will be crossed if greenhouse gas (GHG)-emissions are not reduced to a significant extent[1]. More specifically, to keep average temperatures below 1.5 °C, emissions of CO_2 will have to drop to at least net-zero [1]. The energy sector is one of the major contributors to GHG emissions, with natural gas expected to reach 7.35 Gt CO_2 emissions in 2021, 22% of global CO_2 emissions [2]. Decarbonizing this sector can therefore make a large contribution to the mitigation of the effects of climate change. Phasing out fossil fuels such as coal, oil and, natural gas and moving towards renewable forms of energy generation is at the heart of the solution.

Besides internationally well-known global warming issues concerned with fossil fuels, the Netherlands experience local impacts as well. In the north, earthquakes caused by gas extraction, have been forcing the Dutch government to gradually terminate production from the Groningen gas field [3], [4]. Closing down the national natural gas production was recently one of the main causes of the natural gas prices to rise and increase. However, more recent developments in Ukraine have caused the European Union to declare to stop the importation of gas from Russia in the long-term and avoid it where possible. This has caused energy prices to reach record heights in the Netherlands and reinforces the push toward renewable energy sources.

Whereas electrification can aid sectors like personal transport and short-term storage to reduce the CO_2 emissions, it is more challenging for the sectors in which electricity is not an option. Heavy industries, like steel blasting, often require large amounts of thermal energy at high temperatures [5]. For these processes, electrification is costly and impractical with current technologies [6]. For these types of industries, hydrogen is a more suitable alternative to substitute fossil fuels. Like traditional fossil fuels, hydrogen is burned to generate thermal energy. However, water is the sole product of the reaction. In addition to water, the product of the burning of fossil fuels is CO_2. Although no CO_2 is emitted when burning hydrogen, 96% is generated from fossil fuels like coal and natural gas [7]. Therefore, when burning hydrogen, indirectly CO_2 is produced. For hydrogen to be able to decarbonize heavy industry, it has to be generated from renewable sources. Hydrogen from renewable sources is at this moment not yet competitive with the traditional steam-methane reforming and coal gasification methods [7]. Figure 1 displays the viability of hydrogen as an energy source for an industry. A technology has to be sufficiently mature and centralized since the production of hydrogen itself demands energy, increasing the total energy demand [8].

Offshore wind energy has gained significant momentum in the past decade with an average annual global growth rate of 22%. Especially in the Netherlands where in 2020, 24.6% of the world's new offshore wind installations were installed [9]. Moreover, the Dutch government plans to expand the offshore wind capacity from 1 GW in 2020 to 10.6 GW in 2030 [10]. An interesting pathway to utilize this energy is power to hydrogen (PtH). In this production pathway, water is split by an electrolyser to form the energy-rich hydrogen and oxygen. PtH can be realised via two configurations. Either the power is brought to shore via high-voltage direct current (HVDC) or high-voltage alternating current (HVAC) cables and the electrolyser and the complementary equipment are installed onshore or the power is directed to a hub offshore where the electrolyser is installed [11]. The North Sea shows great potential for offshore hydrogen production since a vast fossil fuel infrastructure already is in place. The oil and gas extraction in the North Sea has been declining and platforms and pipelines are to be decommissioned. As can be seen in Figure 2 wind parks are in relative proximity to the existing infrastructure. The re-use of this network could save investment costs drastically.

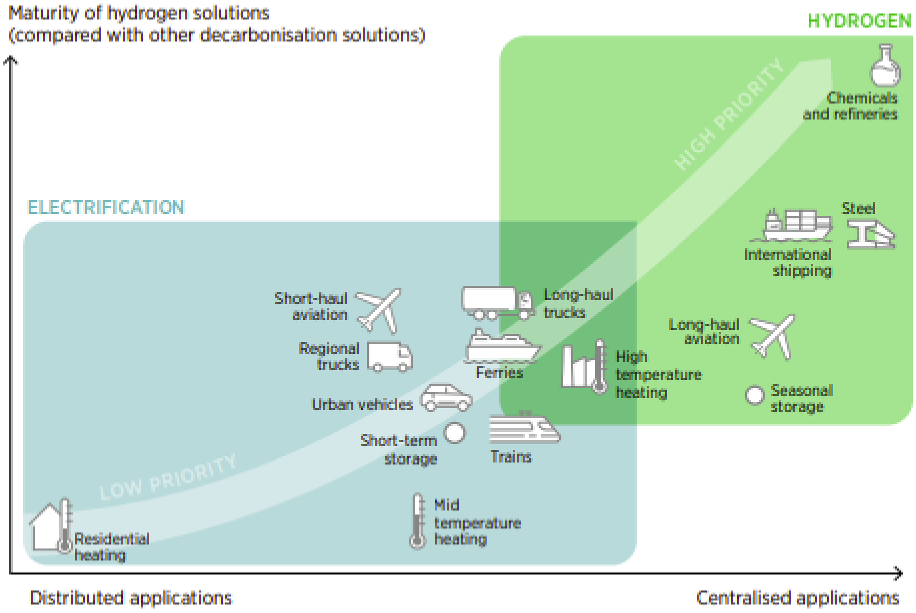


Figure 1: **Viability of Hydrogen**
On the x-axis, the measure of centralization is depicted and on the y-axis the maturity of a technology. This figure is adapted from the International Renewable Energy Agency (IRENA) report on Hydrogen [8].

In the last decade, off-shore hydrogen production has grown as an area of interest. Research by Meier[12], provided an insight into what offshore electrolysis could entail, what the technical requirements would be and if it could be feasible. This preliminary research came to a very wide price range of 5.20 e/kg to 106.10 e/kg. Jepma and Van Schot [13] analysed the usage of existing oil and gas platforms in the North Sea and conclude that in the future off-shore green hydrogen would range between 2.84 e/kg and 4.63 e/kg. In a subsequent study on the comparison between onshore and offshore electrolysis, Jepma et al. [14] concluded that the placement of the electrolyser in the in-turbine placement of the electrolyser would be optimal. However, this study is limited to two platforms in the North Sea. In further research on the placement of the electrolyser onshore, offshore or in-turbine in a case study of a Danish energy hub by Singlitico et al. [15]. They concluded that offshore hydrogen should be competitive with hydrogen produced from natural gas. However, they conclude as well that the in-turbine placement of the electrolyser is undesirable in comparison to a more central configuration of the electrolyser on, for example, an artificial island. Furthermore, the paper by Peters et al. [16] describes the world's first offshore hydrogen pilot project using the existing oil and gas infrastructure under the name of the "PosHYdon" project. The authors see this pilot as a stepping stone towards a potential of 1 GW next decade.

1.1 Research Questions

There is a large potential for offshore hydrogen production in the North Sea. However, there are a lot of uncertainties in the data as well as in how the energy system is going to be designed. Amongst others, the distance to the shore, the space available onshore and the cost parameters concerned with installing an electrolyser offshore are key data points that are accompanied by high uncertainties. Therefore, a better understanding of the optimal configuration for offshore hydrogen production in the North Sea is required. This research aims to identify under which circumstances offshore production will be feasible. To determine what these circumstances are, a basic understanding of how onshore and offshore electrolysis compare is required. Subsequently, an understanding of how the distances and space limitations onshore influence the energy system. Lastly, the possibilities of repurposing the existing oil and gas infrastructure are explored.

The main objectives of this research are structured along the main research question and 4 sub-questions:

Under what circumstances is offshore electrolysis technically and economically feasible for Dutch wind parks in the North Sea?

- How does the optimal offshore setup compare to the onshore setup?
- How do spatial limitations onshore and distance parameters influence the energy system?
- How can existent fossil fuel infrastructure be utilized in the new hydrogen infrastructure?
- What are the most uncertain parameters which influence the results?

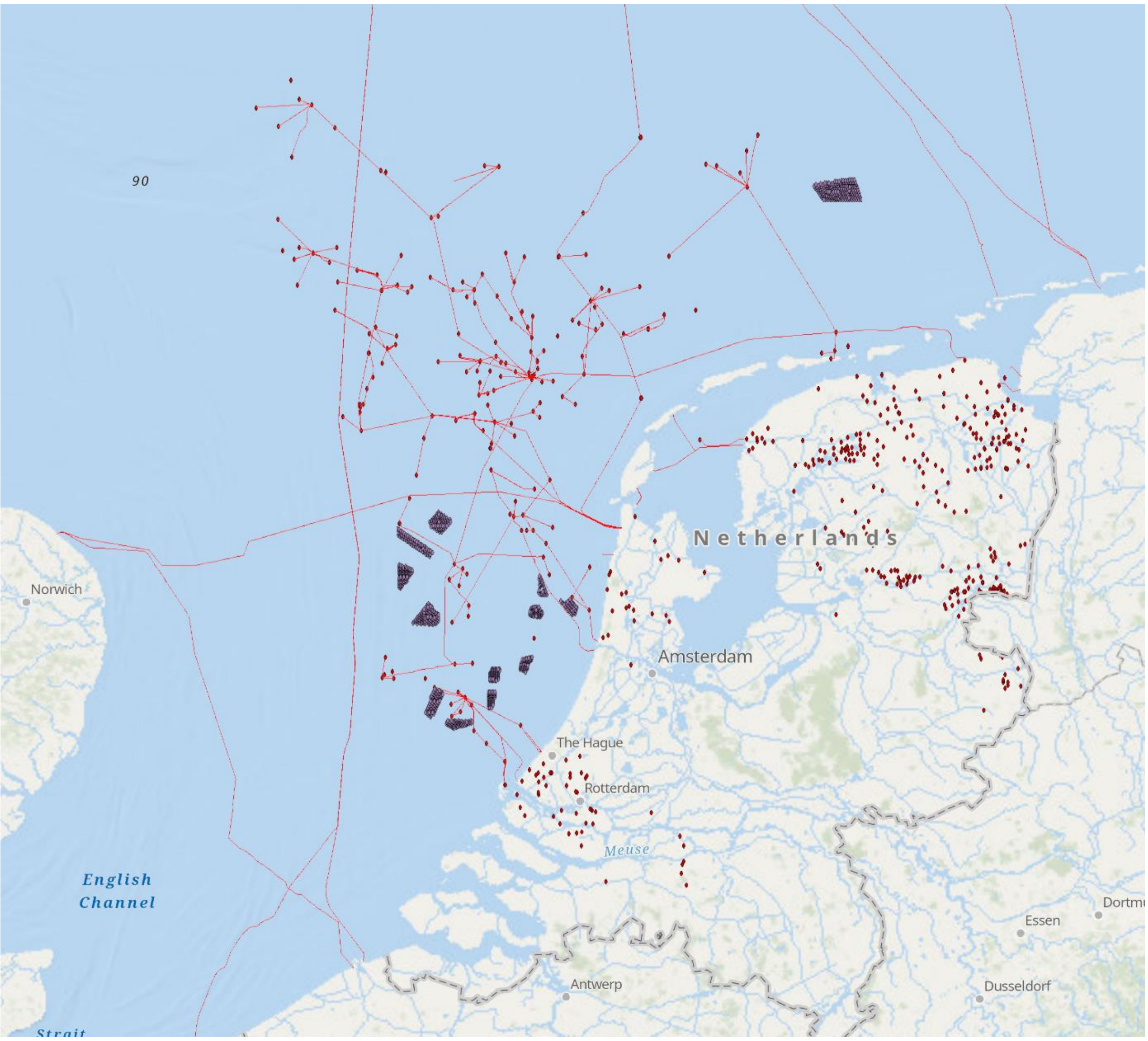


Figure 2: North Sea Energy Infrastructure.
On this map, the oil and gas pipelines and platforms (red), as well as the currently operating wind parks (purple), are displayed. (Data for this map was retrieved from the NLOG (Nederlandse Olie- en Gasportaal)[17]

2 Energy System Description

To investigate the problems posed by the research question and its sub-questions, a multi-energy system (MES) is defined. Within the boundaries of this MES, four case studies are described each taking varying one component of the system. First, a description of the general energy system is given. Thereafter, the four case studies are described in detail.

2.1 Energy System Description

The general energy system which is considered in this research is displayed in Figure 3. There are two different energy carriers considered, electricity and hydrogen. On the offshore side of the system, energy is generated in the form of electricity by wind turbines. Whereas on the onshore side of the system, energy is demanded in the form of hydrogen. To meet this demand, the wind has to be converted into electricity and subsequently, the electricity generated has to be converted to hydrogen. The electricity is converted using an electrolyser which can either be installed onshore, offshore or both. In the case it is installed onshore, the energy is transported in the form of electricity via HVDC or HVAC cables and in the case it is installed offshore, the energy is transported in the form of hydrogen via a pipeline. Additionally, in the case of offshore electrolysis water is abundant. However, it needs to be desalinated to be fit for electrolysis. Therefore, a desalination unit is required to be installed. Lastly, the amount of energy generated by the wind turbines is not equal to the demand. Thereby, there are instants at which no electricity is generated and hydrogen is demanded. Therefore, a component which can provide storage is required to supply the system with extra hydrogen in the case of insufficient production or to store hydrogen in the case of overproduction. In this research, the hydrogen is stored in a salt cavern. The cavern operates using a compressor, which requires electricity. For the system to be independent of electricity being transported from the turbines to the cavern, a small amount of electricity is allowed to be imported from outside the MES boundaries.

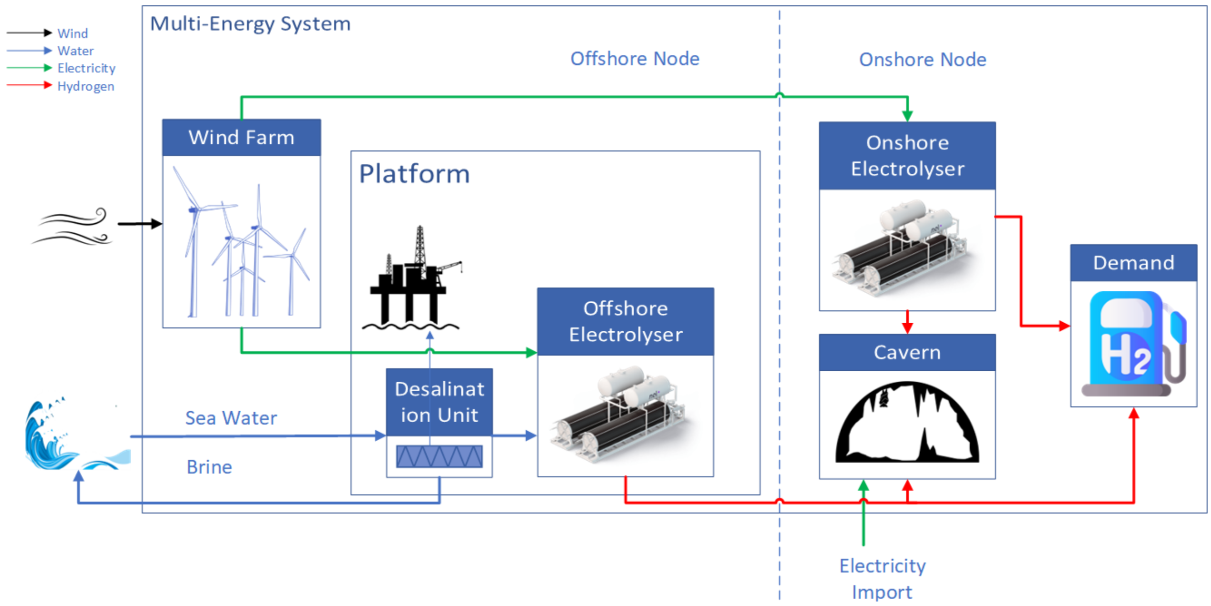


Figure 3: **Schematic Representation of the MES of Interest.**
On the left, wind (black) is converted into electricity (green) and transported to one of the electrolysers. These convert the electricity into hydrogen (red) which is directly sent to meet the demand or stored in the cavern.

2.2 Case Studies

This research focuses on four case studies of the MES. Each case study aims to answer a separate or part of a sub-question. The four studies that are considered are:

- Onshore vs. Offshore
- Shore Distance
- Restricting Onshore Capacity
- Repurposing Existing Infrastructure

The first three studies aim to get an understanding of in which cases offshore electrolysis is favored over onshore electrolysis. The fourth study focuses on the possibilities of repurposing existing oil and gas pipelines. In the following, a detailed description of these case studies is provided.

2.2.1 Case Study 1: Onshore vs. Offshore

The first study focuses on the first sub-question. Therefore, the goal of this study is to get a general understanding of the differences between the two extremes two extreme designs of the energy system, namely performing the electrolysis either fully onshore or fully offshore. A simplistic version of these MESs are displayed in Figure 4. In both cases the placement of the electrolyser is predetermined. This implicitly causes the type of network to be predetermined as well. Thus, this scenario will consist of directly comparing the results from two separate optimizations.

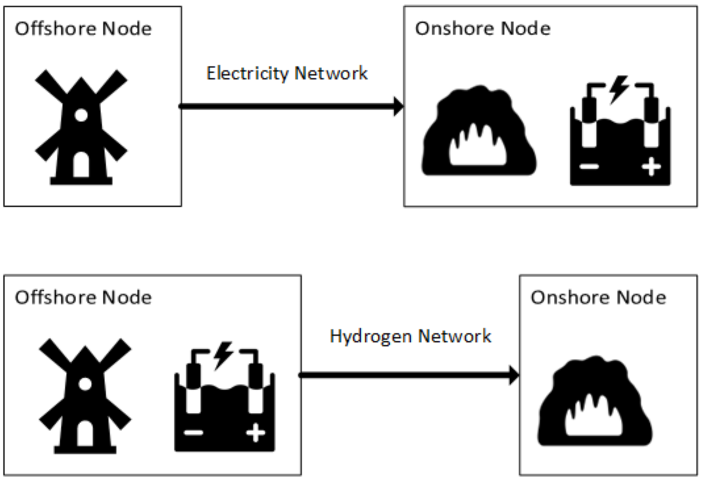


Figure 4: **Simplistic MES Representation with Relevant Components of Case Study 1.**

2.2.2 Case Study 2: Shore Distance

Hydrogen transport is a form of energy transport in the form of molecules. One of the main advantages of this form of transport is that there are barely any energy losses when the energy is transported. This is in contrast with electrical transport which is concerned with relatively high losses, especially over a larger distance. However, to transport energy in the form of hydrogen, it has to be converted offshore. Offshore electrolysis is concerned with several extra costs, such as general extra costs for installing technologies offshore and the need for a desalination unit. This study aims at finding the threshold at which the electrical transport losses are assuming such high values that the extra costs of offshore electrolysis are outweighed. In Figure 5 it can be observed that, in contrast to the first case study, the placement of the electrolyser is determined by its optimal location. This depends mainly on the extra costs made by offshore instalment and the amount of electrical losses through the cables.

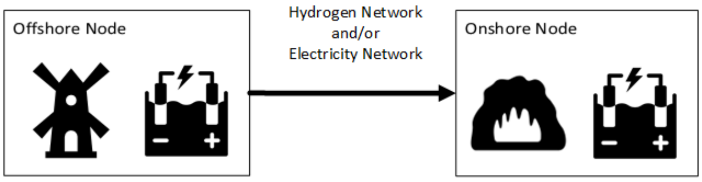


Figure 5: **Simplistic MES Representation with Relevant Components of Case Study 2.**

2.2.3 Case Study 3: Limiting Onshore Capacity

As discussed in the introduction, space is not abundant in the coastal industrial areas in the Netherlands. Moreover, it is becoming increasingly difficult to find ample space for large projects at desired sites. Therefore, it is valuable to gain insight into how the MES design and operation change when the maximum capacity of the onshore electrolyser is varied. In Figure 6 a schematic drawing of the key components of the MES is given, note that the size of the onshore electrolyser is they varying parameter.

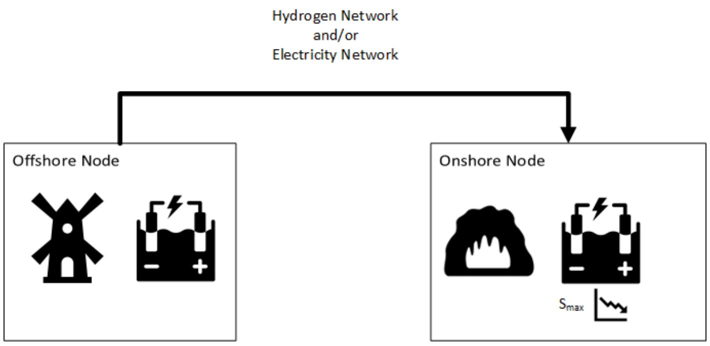


Figure 6: **Simplistic MES Representation with Relevant Components of Case Study 3.**

2.2.4 Repurposing Existing Infrastructure

As described in the introduction (section 1) there is a potential for reusing old gas and oil infrastructure in the North Sea for hydrogen purposes. However, data concerning the cost savings of repurposing pipelines and the number of pipelines that is fit for repurposing varies heavily [18], [19]. The schematic layout of the case study is presented in Figure 7. To get a broad understanding of how these variables change the overall network costs, the design and the operation of the MES, both the capacity of the allowed network and the amount of cost reduction that can be achieved are varied. Since this is a comparison between two types of hydrogen networks, no electricity network is concerned in this study, as can be seen in the figure.

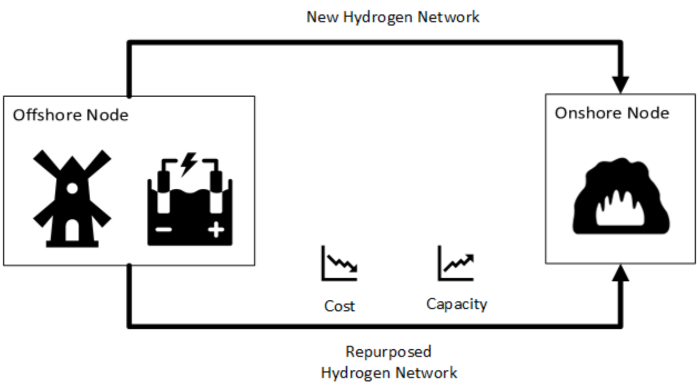


Figure 7: **Simplistic MES Representation with Relevant Components of Case Study 4.**

3 Methodology

The optimal MES design and operation in each of the scenarios considered in the case studies of the MES described in section 2.2 has to be determined. To find these optima, the scenarios are mathematically described in a model. The model used in this research is the energy hub modelling tool developed by Gabrielli et al**.** [20] and has since been used to perform multiple MES optimizations [21], [22]. To understand how the energy hub functions, an understanding of the type of model should be developed first. Therefore, this section starts with a brief description of mixed-integer linear programs (MILPs) in section 3.1. Thereafter, a short description of how the energy hub tool operates is given in section 3.2 together with a more detailed description of the used technologies and networks adjusted for this research. The results of the optimization of these scenarios are the most price-efficient arrangements of the selected technologies and networks. This section closes with an explanation of how these results are analyzed.

3.1 MILP

Even though the MESs seem relatively straightforward, due to the number of variables and the hourly resolution over a year, the complexity of the problem increases quite fast. In addition, several variables, such as the size of an electrolyser, are continuous. When variables are continuous, the solution to the optimization problem can take the form of any real number within the borders given to the problem. However, variables like the number of wind turbines are discreet. Discreet variables are required to describe the problem correctly, since purchasing half a wind turbine would not be feasible. However, this adds a layer of complexity because the optimal solution to the problem cannot contain any real number within the borders of the constraints of the model, but it is restricted to integer values. It can be more difficult to find the optimal solution since the discreet variables may only assume integer values. A very suitable method to describe these kinds of problems in a simulation is to use a MILP. In this type of programming, continuous as well as discreet (mixed) variables are described by two separate vectors. Below the mathematical description of the MILP is given in equation 1.

3.2 Energy Hub

In earlier research on energy system optimization by Gabrielli et al**.** [20] a MILP approach was successfully developed to optimize a multi-energy system with seasonal storage. In Weimann et Al. the same model is used to optimize a wind-dominated zero-emission energy system [22]. In this research, the model will be used as well. In a MILP the problem is defined by an objective function which is subjected to several constraints, input data and decision variables. In its mathematical general form, it can be written as:

$$\min_{x,y} \ (c^T x + d^T y)$$

$$\text{Subject to}$$

$$\boldsymbol{Ax} + \boldsymbol{By} = \boldsymbol{b}$$

$$\boldsymbol{x} \geq \boldsymbol{0} \in \mathbb{R}^{\boldsymbol{N_x}}, \qquad \boldsymbol{y} \geq \boldsymbol{0} \in \mathbb{N}^{\boldsymbol{N_y}} \tag{1}$$

In equation (1), on the first line, the objective function is displayed. The objective function in optimization is the mathematical representation of the goal, in the case of this research, to minimize the total costs of a hydrogen supply system. The function consists of x and y representing the continuous and discreet decision variables respectively. The decision variables are multiplied by their respective cost vectors c and d. The objective function is subjected to various constraints, described in equation 1 on the third line. These represent the physical properties of the energy system such as the location and distances between objects and the energy balances. A and B, are the constraint matrices, containing the physical parameters, for the decision variables x and y respectively. Together the constraint matrices, A and B, and the cost vectors c and d form the input data for the model. The final line in equation 1 represents the fact that decision variables x can be any real number, whereas y is restricted to be a natural number.

3.2.1 Decision Variables

As described above the optimization is defined by its decision variables. The variables for this MES can be described following categories:

- The size of installed technologies. If a technology is not selected for the MES, its size is equal to 0.
- The on/off status, input and output of the Polymer Electrolyte Membrane (PEM) electrolyser.
- The energy stored in the form of hydrogen in the hydrogen cavern.
- The energy imported at the onshore node.

3.2.2 Timescale

The number of days considered in the energy hub is determined by the time horizon ($\mathcal{T}$). This typically is set to 365 to represent a whole year. The resolution of the optimization is determined by the number of time intervals in each day, which is set to 24. This gives the energy hub 8760 hours to take into account for each optimization. The optimization can be simplified by K-means clustering. In this case, a number of typical days is determined. Such a typical day represents thus several other days throughout the year. For this research 40 typical days were used in each optimization.

3.2.3 Nodes

The energy system is described in the model using several nodes. A node is a representation of a spatial point to which and from which energy can flow towards other nodes through networks; energy can be stored or converted to other carriers using selected technologies and energy can be imported or exported. In this research, two nodes are considered, an offshore node at which energy is generated in form of electricity and an onshore node at which energy is demanded in the form of hydrogen.

3.2.4 Energy Balance

As described in section 3.2 the MILP is subject to several physical constraints. Each technology is subjected to its specific set of performance constraints, which are described in the appendix or their respective section. The central constraint that concerns the whole MES is the energy balance. The energy balance states that the sum of all energy produced (P) and imported (I) should be equal to all energy consumed (F) and demanded (L) at all nodes should be 0 for all time intervals ($t \ \in \{1, \mathcal{T}\}$).

$$\sum_{n \in \mathcal{N}} \left(\sum_{j \in \mathcal{M}} (P_{k,n,j,t} - F_{k,n,j,t}) + I_{k,n,t} - L_{k,n,t} \right) = 0 \tag{2}$$

Where *k* specifies the energy carrier, *n* indicates the nth node and *i* indicates the ith technology.

3.2.5 Cost Calculations

The total annual costs (K_a) for which the energy hub optimizes, are calculated by equation 3, which is the sum of the investment costs (K_i), the fixed operation and maintenance (O&M) costs (K_f), the variable O&M costs (K_v), carrier costs or benefits. For technologies, the investment costs are based on a cost factor that is multiplied by the size of a technology and an annuity factor which in turn is determined by the lifetime of a component and the interest rate. If a component is installed offshore, another multiplier is added to the equation. The offshore markup accounts for the extra costs considered with the instalment of a technology offshore. Besides being dependent on the required capacity, the networks are also dependent on the distance between nodes. This is explained in greater detail in section 3.2.7**.**

The O&M costs are split into fixed and variable costs. The fixed O&M costs are defined as a fraction of the investment cost. Whereas the variable O&M costs are based on the output of a component. Lastly, import costs are defined as the amount of imported energy at a certain point in time, multiplied by the price of that moment.

$$K_a = K_i + K_f + K_v + K_{imp} \tag{3}$$

3.2.6 Energy Conversion and Storage Technologies

In this section, a brief description of the technologies and networks used and how they are modelled in the energy hub, are given along with their technology-specific constraints. First, the size constraint, which applies to all technologies and networks is described. Thereafter, all technologies and networks adjusted in this research are given. In the **appendix**. A more complete description of all technologies used is given.

The size constraint is given by a minimal size that forms the lower bound of the values the size of a technology is allowed to assume and is capped by a maximum size it can assume. This is mathematically described by the following inequality:

$$\tau S_{min} \leq S \leq \tau S_{max}$$

Where τ is a binary factor indicating whether a network is installed between two nodes. All allowed technologies at each node are specified individually at each node. Therefore, τ can be considered to be equal to 1. S_{min}, S, and S_{max} are the minimal, assumed and maximal size of a technology or network respectively.

3.2.6.1 Offshore Electrolyser

To be suitable for electrolysis, sea water has to be desalinated. Although there are several pathways available for seawater desalination, reverse osmosis (RO) has been proven to be the most economical for seawater. Additionally, as opposed to thermal desalination, RO requires electricity only [23]. RO is a technology that uses a semi-permeable membrane, that allows water but not salt to pass through, for pressurized filtration. A schematic diagram of a desalination unit is presented in Figure 8. A typical unit consists of pre-treatment, a high-pressure pump and post-treatment. Before entering the membrane, the water feed is subjected to screening, filtration and addition of chemicals involving disinfectants and chlorine. Subsequently, the water is pushed through the membrane using a high-pressure pump, removing salts from the water feed. Lastly, in post-treatment gasses are removed and pH is adjusted [24].

The desalination unit requires electricity which can be directly supplied by the wind parks. Since it is not a complex energy conversion technology, the desalination unit can be incorporated into the offshore option of the electrolyser by correcting for the used electricity by adjusting the electrolyser efficiency. The extra investment costs related to desalination can be directly added to the investment costs of the electrolyser itself. This mathematical description of this is described in the following equations:

$$C_{inv,\ PemOff} = C_{inv,\ Pem} + C_{inv,\ Desal}$$
$$\eta_{1,PemOff} = \eta_{1,PemOn}\,(1 - \rho)$$

(4)

Where $C_{inv,\ PemOff}$, $C_{inv,\ Pem}$, and $C_{inv,\ Desal}$ are the investment costs for the offshore electrolyser, the onshore electrolyser and the desalination unit respectively. $\eta_{1,PemOff}$, is the new efficiency for the offshore electrolyser, calculated from the old efficiency($\eta_{1,PemOn}$) and the fraction of fuel, in the form of electricity, consumed by the desalination unit (ρ).

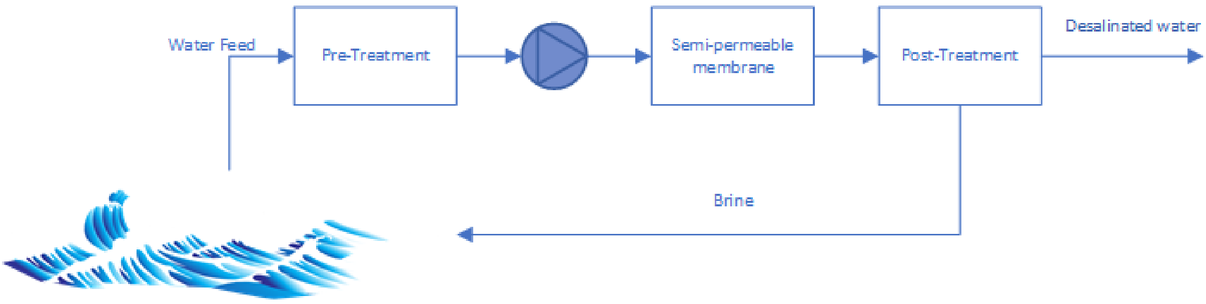


Figure 8: **Schematic Representation of the Desalination Unit**

3.2.7 Networks

The networks considered in this research are an offshore electricity network, an offshore hydrogen network and an offshore hydrogen network used created from repurposed oil and gas infrastructure. In the energy hub, there are several options to model the investment costs of networks. In this research two of these options are considered. Both options calculate the costs via two parameters. This option does take not only consider size, but also the distance between the two nodes it should connect. This is mathematically written as:

$$K_{inv,k}^{Net} = \gamma(\alpha_1 S_{Net}\delta + \alpha_2)$$

(5)

Where $K_{inv,k}^{Net}$ is the investment costs of the network for carrier *k*, γ is the annuity factor, α_1 is the cost coefficients applied to the distance and network capacity and α_2 is the independent cost parameter, S_{Net} the network size and δ the distance between the two nodes.

3.3 Analysis

The analysis of the results of the case studies is discussed in two sections. First, the system design and operation are discussed followed by, the economics, particularly the costs. In the system design technologies that are installed at both nodes and their respective size are described. Despite the sections being separated the economics, design and operation are deeply intertwined. The separation is therefore strictly for structural purposes.

3.3.1 MES Design & Operation

The design of the MES is determined by two classes of system components. The first class consists of the technologies that are installed at each node. These provide the energy conversions or storage used to meet the hydrogen demand. The second class consist of the networks used to connect the on- and offshore nodes. The costs and operation of a technology or network are largely determined by its size.

Additionally, for networks, the distance between nodes is the second parameter determining these properties. This parameter is, however, not a decision variable, but predetermined.

The operation of the MES is concerned with the energy flows between the nodes and technologies and the energy flows in and out of the MES. The analysis consists of a comparison of several outcomes. First of all, the utilization and capacity factors of the wind parks are calculated. Whereas the utilization of the wind parks is defined as the ratio of the total energy produced and the potential total energy given the hourly windspeed, the capacity factor is defined as the ratio of the total energy produced and the potential total energy when the turbine would be producing at its maximum capacity, regardless of the windspeed. Secondly, the hourly amount of energy stored in the hydrogen cavern is analyzed. Thirdly, the imported energy for the first three case studies is analyzed

3.3.2 Economic Analysis

In the economic analysis of the MES optimizations, three aspects are taken into account. Firstly, the levelized cost of hydrogen (LCOH) for both scenarios yields insight into the extra costs per kg of hydrogen for offshore production. The LCOH is analyzed for each of the first three scenarios. The LCOH form the ideal basis on which MES designs can be compared. However, it lacks to inform on how the costs originate. Therefore, in addition to the LCOH, the first scenario will be subjected to two cost distribution analyses. The cost distribution of the different components of the MES is provided and the cost distribution of the different types of costs is given. Both cost distributions give a clear insight into what components sort of costs are most determining in the system design and therefore in the optimization. Since the fourth scenario is a direct comparison between two alternative networks in which not all costs are taken into account, the LCOH would give a distorted representation in comparison with the rest of the case studies. Therefore, economic analysis in the fourth case study consists of a comparison of the total costs and the network costs between the different scenarios.

4 Input Data

The energy hub is dependent on a large amount of data for its optimization. The five classes of data required in this research are energy data, price data, climate data geographical data and finally, economic data on the technologies and networks concerned. The input data is divided into three sections. First, the climate and geographical data will be discussed, followed by the data concerning the energy balance including the energy prices. Lastly the economic data concerning the technologies, and networks.

4.1 Climate & Geographical

The energy system in this research is provided with energy from wind turbines. Therefore, hourly windspeed is of paramount importance. To determine if there is a significant difference between the location of the installed wind turbines, three different locations were compared. The selected locations are based on the location of existing wind parks. Borssele to the southwest of the Netherlands, IJmuiden to the west of the Netherlands and Gemini to the North of the Netherlands. The data used was retrieved from the KNMI [25]. Since the windspeed is higher at higher altitudes the height at which the windspeeds are measured is required, these are displayed in table 2.

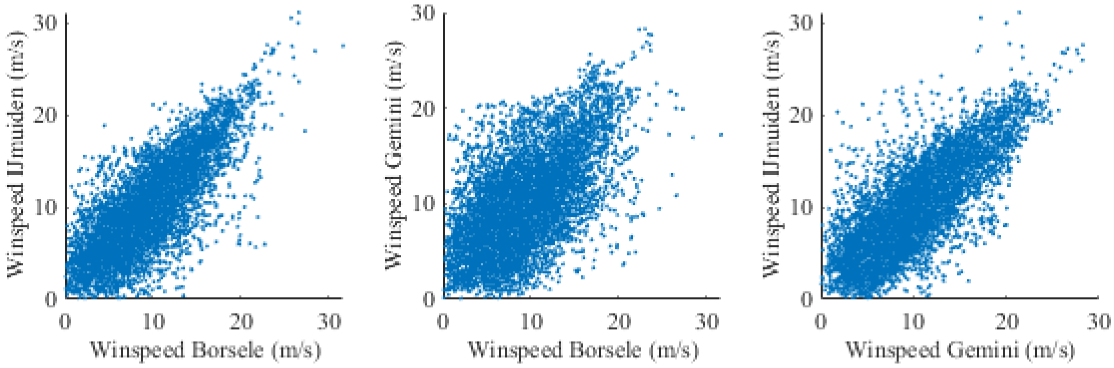
The correlation of the windspeeds was calculated and the windspeeds each were subjected to a simple energy system with 21 preinstalled wind turbines to compare average production. The correlation of IJmuiden with both Borssele and Gemini is close (see Figure 9). However, Borssele and Gemini correlate to a lesser extent. These correlations are intuitively logical, since the wind parks that are furthest apart from each other correlate to a lesser extent.

In table 1 the mean (μ) and standard deviation (σ) of both the windspeed and the production are displayed. As can be expected of windspeeds above the North Sea the variance is high with a standard deviation between 4.51 m/s and 4.72 m/s. However, the difference between these is relatively low as well as the average windspeeds. This holds as well for the mean of the total energy produced in the simple 21 wind turbine set up, where all three locations produce an equal amount of energy, albeit with a larger window of standard deviations. Based on the reasonable correlation with both the northern Gemini and the southwestern location of Borssele and the equal production, the selected windspeeds used in this research is the windspeed at IJmuiden.

Table 1: Means and Standard Deviations of the Windspeed Data.

Wind Park	μ_{ws} (m/s)	σ_{ws} (m/s)	μ_{prod} (MWh)	σ_{prod} (MWh)
Borssele	9.31	4.51	12.5	11.9
IJmuiden	9.81	4.78	12.5	13.5
Gemini	10.03	4.72	12.5	14.9

The geographical data is only required for the offshore node and consists of the shore distance the water depth and the distance from the onshore node. The shore distance and the water depth, are used in the calculation of the additional costs of installing turbines offshore. The distance between the two nodes is the distance used to calculate the required length of the network. The distances and depth can be found in table 2. In case studies 1, 2 and 4 the shore distance from the wind park Ijmuiden Ver was taken as a reference. In the third case study, the shore distance is the parameter that is varied across the different scenarios the shore distance and the distance between the two nodes. Due to a limit on the fitted function that determines the increased costs for the offshore wind turbines of 250 km, it was assumed that the costs would not further increase if the 250 km was exceeded. This assumption is strengthened by the fact that due to the proximity of Great Britain, the distance to a



(a) (b) (c)

Figure 9: **Correlation of 3 Dutch Windparks**

shore will always be limited. However, since the goal of this case study is to determine at which distance the offshore electrolysis is economically favorable, the distance between the nodes was assumed to be able to increase. This assumption can be reinforced by the fact that the required length of a network can exceed the shore distance because cables and pipelines are restricted to certain areas where they can be installed.

Table 2: Additional Climate and Geographical Data.

Scenario	1	2	3	4	Source
Wind Data Height (m)	120	120	120	120	KNMI [25]
Water Depth (m)	20	20	20	20	North Sea Atlas [26]
Shore Distance (km)	80	0-250	80	80	Google Maps
Distance Between Nodes (km)	80	0-500	80	80	Google Maps

4.2 Energy Balance & Price

For both nodes, the conditions to which the solution should comply are defined in table 3**.** As described in section 2.1**,** the MES is a system which does not concern any export from the system. However, a relatively small amount of electricity is imported at node 1 to allow the hydrogen cavern to operate without the need for an electricity network. The maximum allowed electricity import is 100 MW. In the ideal case, the electricity is not imported to be electrolysed, however, this cannot be predetermined in the energy hub. Therefore, to make the import option less attractive, the price of 0.3616 €/kWh was used. This relatively high costs are the costs from May 2022, when the electricity price in the Netherlands peaked.

Table 3: **Data Concerning the Energy Balance**

	Node 1		Node 2	
	Electricity	Hydrogen	Electricity	Hydrogen
Allowed Import (MW)	100	0	0	0
Allowed Export (MW)	0	0	0	0
Demand (MW)	Profile	0	0	0
Price	0.3616 [27]	n/a	n/a	n/a

The two contributors to the hydrogen demand are the industrial demand and the demand arising from road transport. In an earlier thesis, an hourly hydrogen transport demand profile for the Netherlands has been developed based on refuelling transactions [28]. This hourly profile considers variation in days of the week and the four seasons. In contrast to the transport demand, the continuous nature of industry causes little variance in the demand. Therefore, the industrial demand is assumed to be continuous throughout the year. The industrial demand in the Netherlands is 18.88 TWh on a yearly basis or 2.155 GW on an hourly basis. Adding both the transport and industrial demands together, yields the hydrogen demand profile in Figure 10**.**

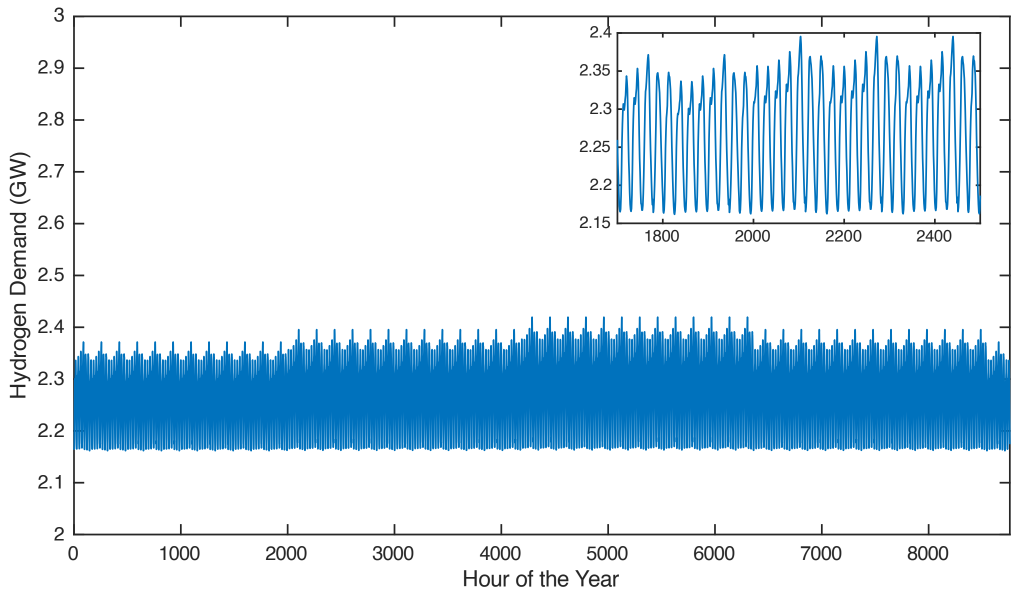


Figure 10: Hourly Hydrogen Demand Profile

4.3 Economic

Throughout literature often different approaches are taken to determine the projected costs of a technology. Whereas some reports and papers take merely the technology itself to be in scope for their research, others take the balance of plant (BoP) into account as well. The extent of these differences in costs can be clearly illustrated by looking at the estimated costs of an electrolyser. Reports range from a very conservative 345 €/kW to a very high 2800 €/kW [29]–[31]. In addition, the literature is not consistent in reporting how the costs of technologies are build-up. Whereas some report with investment costs, and fixed and variable operation costs, others choose different parameters. Due to the high variance between sources of data, this research attempts to collect as much data as possible from the same source. In this manner, the relative ratio between costs of different technologies can be ensured.

For all technologies, data could be retrieved from the same source. It should be noted that even though, the costs are subject to uncertainties as mentioned above, not all technologies experience that to the same extent. The costs of caverns are well understood from experience with methane storage in a similar cavern. The knowledge of installing wind turbines, pipelines and cables offshore has also rapidly increased over the last decades. However, offshore electrolysis is a new phenomenon and should therefore be treated with an extra amount of caution.

The costs of the cavern, electrolyser and turbines are taken interpolated to the year 2022 from the data retrieved from Danish Energy Agency (DEA) [32], [33]. The extra costs due to the desalination unit in the case of offshore electrolysis were determined to be 3% [34]. The parameters for the different networks are presented in Table 4. The values for the size and distance-dependent electricity network were calculated from Hartel et Al. [35] by taking the average of 6 cases in which the cable costs were separated from the size-dependent costs. For the hydrogen network, the parameters were determined from data from the DEA [36]. In this report, the costs of a submarine hydrogen network are determined for three different capacities. However, the largest capacity considered is 300 GW out of the scope of this research. Therefore, the average of the 4 GW and 13 GW cases was calculated.

Table 4: **Technology and Network Cost Parameters.**

Technologies	c_i		c_m	c_u	Source
Cavern	3		5%	2.50%	[33]
PEM Electrolyser	925		4%	0%	[32]
Electrolyser Offshore	1906		4%	0%	[32], [34]
11 MW Wind Turbines	2120		21%	0.47%	[32]
Networks	α_1 (€ kW^{-1} km^{-1})	α_2 (M€)			
Electricity	1.9409	664	10%	0%	[35]
Hydrogen	0.287125	75.4	4%	0%	[36]

5 Results

In this section, the results of the four case studies are discussed. As described in section 3.3, the results are analyzed following three categories, design, operation and economic analysis. The results of the operation and the design of the MES are closely related to each other and are therefore discussed within the same section. Subsequently, the results in terms of economics are provided. In general, it should be noted that a Mixed-Integer-Program (MIP)-Gap of 1% was allowed to keep optimization times within a reasonable timespan. This can result in the results of an optimization differing 1% from the optimal value of the objective function. For the first case study, the gaps were recorded. However, for the other four studies, the MIP-gap is not recorded. Therefore, deviations from a trend cannot be explained with certainty as it cannot be determined which scenarios were fully optimized and which were accepted with a gap to the optimal solution.

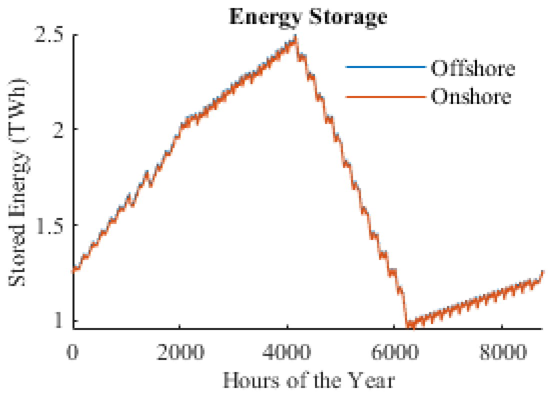


Figure 11: **Hourly Hydrogen Cavern Storage**

5.1 Onshore versus Offshore

In this case study, the focus of the analysis lies on the key differences between a MES with onshore electrolysis and a MES with offshore electrolysis. As mentioned above, the design and operation are presented first, followed by the economics. The economic results of this case study consist of the LCOH, the distribution of the costs over its components and over the different types of costs.

5.1.1 Design & Operation

The results of the on- and offshore comparison are displayed in Table 5. In the design of both the on- and offshore scenario, an approximately equal amount of wind turbines is installed and the electrolyser and cavern have approximately the same capacities. However, due to the network losses in the electricity network in the onshore electrolysis case, the installed network capacity is, with 21%, considerably larger than the required hydrogen network capacity for the offshore case.

The need for a larger electrical capacity becomes clear when the operation of the MES is analyzed. In the lower part of Table 5, the losses are displayed, which, at 91 GWh are relatively large in the case of the onshore electrolysis scenario. These losses are compensated for by the extra turbine and a lower curtailment percentage which results in extra production of 154 GWh over a year. An explanation for the extremely low curtailment rates can be found in the hydrogen cavern storage. Since this option is cheap and has a low discharge rate, it is profitable for the MES to store excess energy in times of lower demand and to withdraw from storage at times of higher demand. As can be seen in Figure 11**.**

Table 5: **Case Study 1 Design and Operational Results**

Design	Onshore	Offshore
Wind Turbines	533	532
Electrolyser (GW)	5.83	5.84
Hydrogen Cavern (GW)	9.85	9.88
Network (GW)	5.86	3.73
Operation		
Curtailment	0.30%	0.60%
Capacity Factor	63.7%	63.4%
Network losses (GWh)	91.47	0.21
Import (GWh)	12.05	72.63

The higher utilization of maximum wind power in the onshore electrolysis case is can be explained that the MES has an extra option for flexibility. In the onshore electrolysis scenario, there are two power sources which can be used to provide the need for electricity at the onshore node. Firstly, cheap electricity is provided by the wind turbines and transported via the cables to the onshore node. However, when a small amount of energy is required to meet the energy demand, it is not economically viable to install a new wind turbine. Instead, the system can import a relatively small amount of energy to the onshore node. This extra option allows the MES onshore to have higher utilization than its offshore counterpart. The absence of the electricity transportation option in the offshore case results in all the required electricity being imported. The extra 60 GWh imported in the offshore scenario combined with the network losses saved, accounts for extra electricity produced in the onshore scenario.

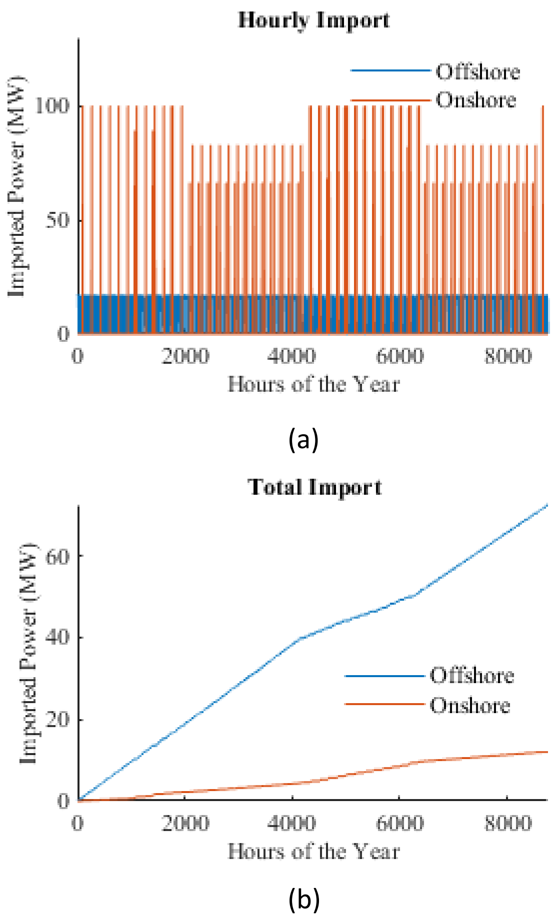


Figure 12: **Imported Power for Both Case Studies**
(a) Displaying the hourly imported power and (b) displaying the total imported power in one year.

The effect of the imported energy being used to cover high demand peaks in the system can be observed in Figure 12**.** In (b) can be seen that in the case of offshore electrolysis, in which imported energy cannot be used for electrolysis, the energy is imported on a constant basis. The total amount of imported energy also corresponds exactly to the energy required by the cavern (72.6 GW). Moreover, graph (b) neatly corresponds with the trend in the graph representing the total amount of stored energy. When more hydrogen is stored than extracted from the cavern, the gradient of the imported energy is steeper than when more hydrogen is extracted. On the contrary, the total imported energy increases more when hydrogen demand is high and increases to a lesser extent when hydrogen demand is low. The import of energy is not as regular as in the offshore scenario and accumulates to a total of 12 GW. However, if energy is imported the amount is significantly higher. In addition to that, in the lower graph 52 clusters of peaks can be observed, each corresponding to a weekly peak in the hydrogen demand profile described in section 4.2. This indicates the use of imported energy to cover the peaks of the hydrogen demand profile.

5.1.2 Economic

Comparing the scenarios in which hydrogen production takes place either fully onshore or fully offshore, several differences and similarities do appear. In Table 6 a breakdown of the total costs of the MES is given. As expected, the costs of producing hydrogen offshore, €5.46 per kg, are considerably larger than production onshore, €4.60 per kg, a difference of 18.7%. Taking a closer look at the costs structure, it can be concluded that the hydrogen network yields a major costs reduction in comparison to the electricity network. However, the higher costs of the electrolyser being installed offshore results in an economically unfavorable case for offshore electrolysis. The effect of the increased costs parameter of the electrolyser becomes clear in Table 6. The increase in the offshore electrolyser costs is mainly due to the assumed factor of 2 for the instalments for technologies offshore. A quick calculation learns that with a factor of 1.21, the options would be equally expensive. The investment costs account for the largest share of the costs in both system designs. Whereas the fixed and variable O&M costs remain roughly equal. The import costs are significantly higher in the case of offshore electrolysis since the functioning of the cavern in this case is dependent on the imported electricity.

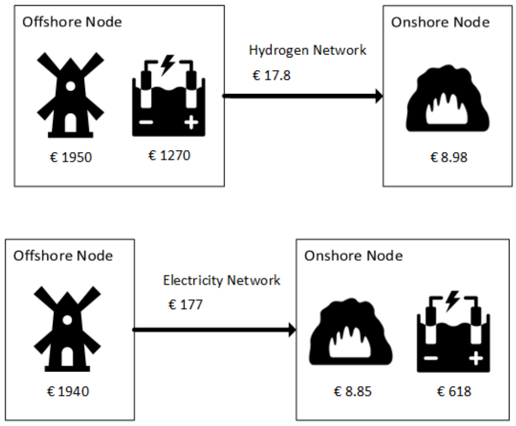


Figure 13: **Schematic Display of Cost per Component**
With the offshore electrolysis scenario above and the onshore scenario below

Table 6: **Costs Table Case Study 1**
In this table, the cost parameters of case study 1 are displayed and divided into three categories, the LCOH, the costs per sort of costs and the costs per component of the MES.

Costs	Onshore	Offshore
LCOH (€/kgH_2)	4.6	5.46
Per Cost Type		
Annuitized System costs (M€/y)	2750	3270
Investment (M€/y)	2370	2850
Fixed O&M (M€/y)	378	387
Variable O&M (M€/y)	6.05	6.15
Import (M€/y)	4.35	26.2
Per Component		
Wind Turbines (M€/y)	1940	1950
Electrolyser (M€/y)	618	1270
Hydrogen Cavern (M€/y)	8.85	8.98
Network (M€/y)	177	17.8

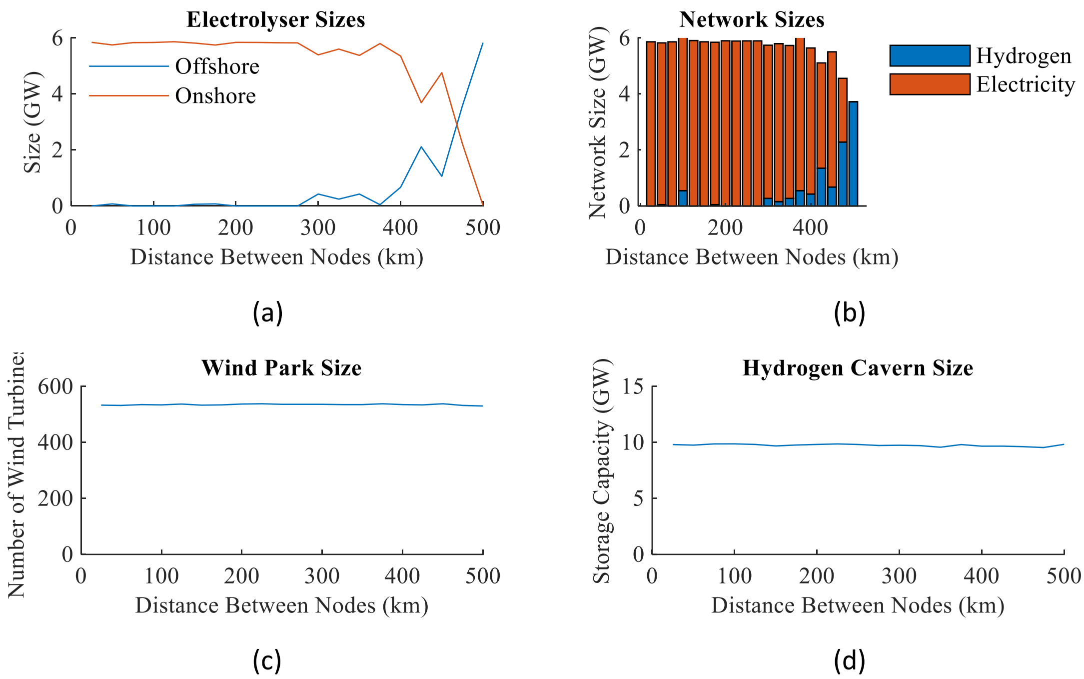


Figure 14: **Design Results of Case Study 2**
In this figure the sizes of the installed technologies and networks are displayed.

5.2 Case Study 2: Shore Distance

This case study aims to investigate the effect of an increasing distance between the nodes and the distance to the shore on the MES. The analysis is structured as follows, first, the distance at which offshore electrolysis is an economically viable option is discussed in section 5.2.1 together with the effects the increasing distance has on the design and operation of the rest of the MES. Thereafter, the increasing trend in costs with the distance and which factors contribute most to this trend are discussed.

5.2.1 Design and Operation

For this case study, 20 scenarios were optimized. In every consecutive scenario, the distance between the onshore and offshore nodes was increased by 25 km. The shore distance was increased as well by 25 km per scenario up to 250 km. As can be seen (a) and (b) in Figure 14 at a distance of 475 km offshore electrolysis is becoming economically feasible. However, it is not due to the energy losses in the electricity network. Since the number of turbines remains roughly the same (c) and the utilization is varying between 99% and 100% roughly the same amount of energy is transported through the network. The main cause of the switch to offshore electrolysis can be explained by the fact that the electricity network has to increase in size due to the distance. Since the electricity network is more expensive than the hydrogen network, the network costs exceed the costs extra costs of installing the electrolyser offshore.

As discussed in the previous results section, the MES can utilize imported energy for electrolysis. After 450 km, the amount of imported energy is far beyond the hourly level of the offshore base (8.2 MW) scenario described in section 5.1. This suggests that the price of imported electricity is competitive with the electricity produced offshore. The increased import in electricity might be the cause of the break in the trend around 425 km. However, since the MIP gaps are not recorded, this cannot be determined with certainty.

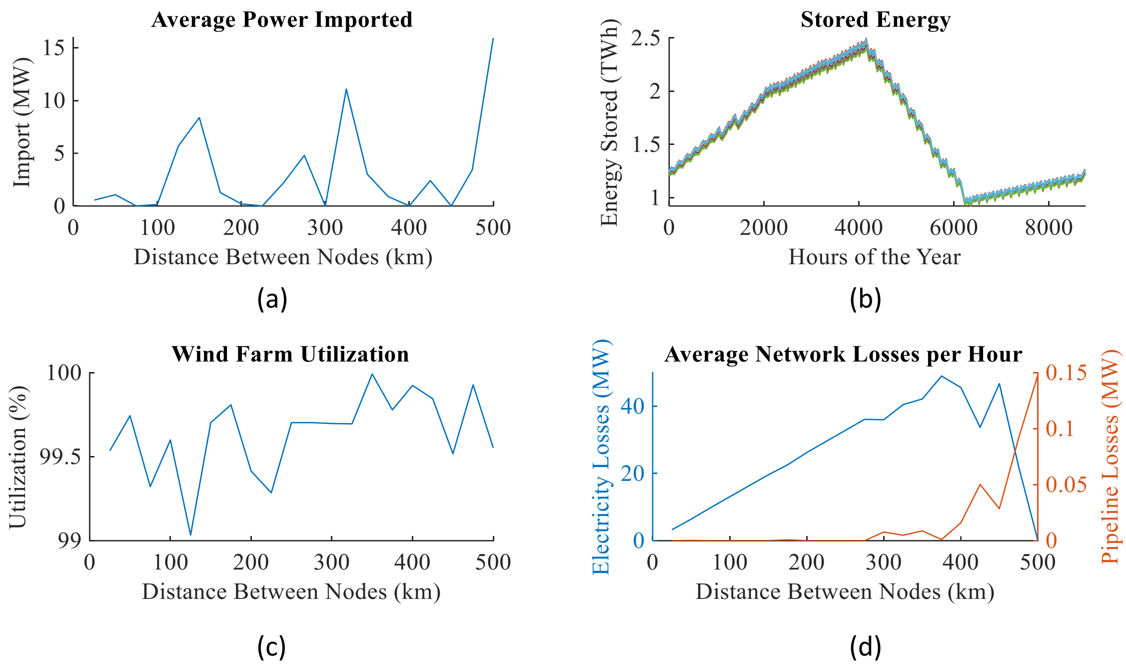


Figure 15: **Graphs on the Operation of Case Study 2.**
In this figure the operational graphs of the considered scenarios are displayed as a function of the distance.

Whereas the networks and electrolyser vary with the shore distance, the storage capacity of the hydrogen cavern and the energy stored are constant throughout all scenarios of the shore distance. Along with the capacity of the cavern, the amount of energy stored in the cavern is constant as well. The differences in starting load in the caverns are due to the modelling of the cavern. In the energy hub, the cavern is required to have as much energy at the end of the year as at the start of the year. However, the starting value is not a set number. In addition, the number of wind turbines remains roughly constant throughout the case study as well. This is largely consistent with the average loss of potential power observed in Figure 15d. These losses correspond with 1-10 wind turbines. As the switch is made to offshore electrolysis at 475 km, a small decrease can be observed in the number of turbines.

5.2.2 Costs

The main LCOH and the cost build-up from the MES components are displayed in Figures 16 and 17**.** The costs of the MES are increasing with the distance. Up to 250 km, this trend follows a linear path. It can be seen that the increase in costs can be contributed to an increase in the network costs and the increasing costs of installing wind turbines further from the coast. After 250 km, the trend the linear trend changes slope. Due to the fact that the offshore wind turbine costs function is not well

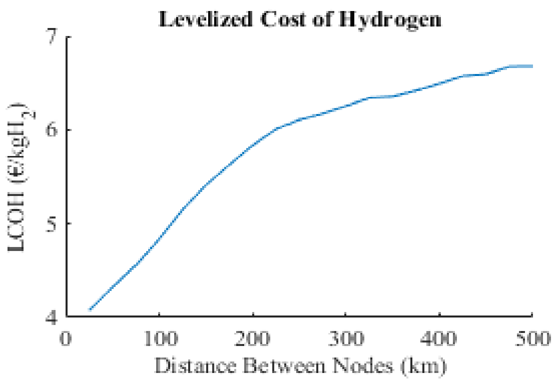


Figure 16: **LCOH of Case Study 2 as Function of the Distance.**

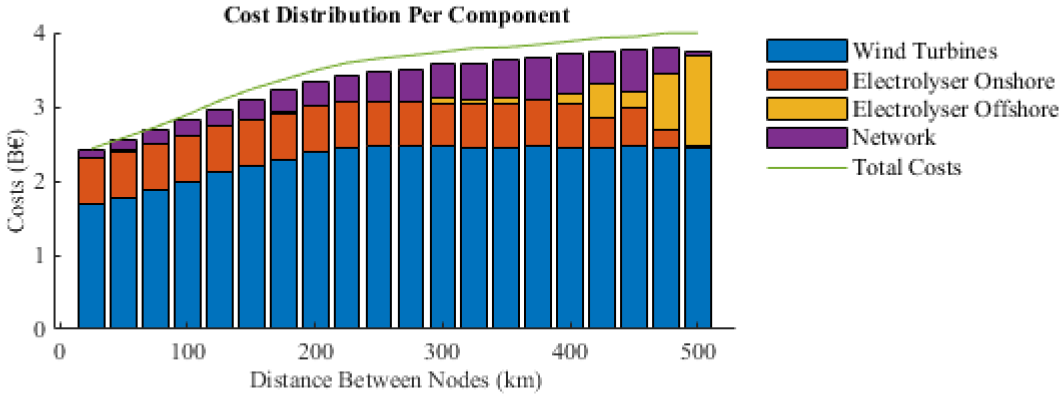


Figure 17: **Cost Distribution Case Study 2 per Component.**
In this figure the total MES costs are presented as a function of the distance. The bars represent how the main contributors build up the total costs.

defined after 250 km, it was assumed that costs for wind turbines would not increase further after such distance. The increase in costs is from that point mainly due to an increase in network costs. This changes from the point at 475 km, where the offshore electrolysis is becoming economically feasible. A large decrease in network costs is observed and a steep rise in the costs of the electrolyser can be seen.

5.3 Results Limited Onshore Capacity

This case study aims to discover the changes in the operation of the system with different capacities on- and offshore. Similar to the previous studies, the first section is focused on the design and operation, followed by the costs.

5.3.1 Design & Operation

The design of the MES remains constant through all scenarios with respect to the hydrogen cavern, the total added size of both the on- and offshore electrolyser and the number of wind turbines see Figure 18. The variation in the latter between 528 and 533 was most probably caused by the MIP gap

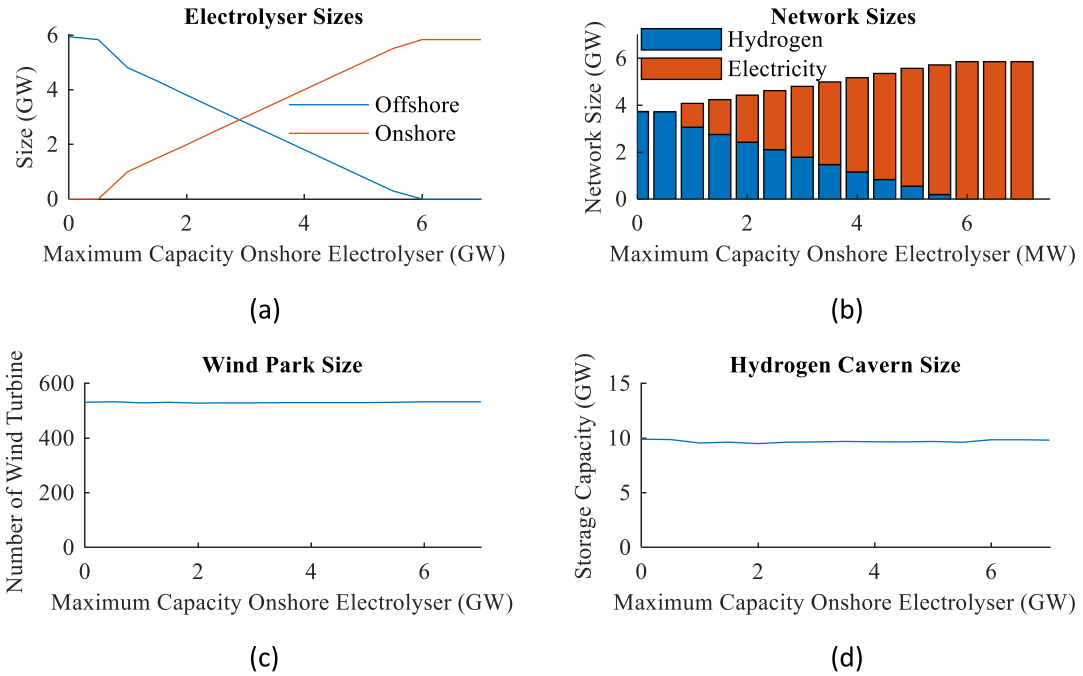


Figure 18: **Design Results of Case Study 3.**
In this figure the sizes of the installed technologies and networks are displayed.

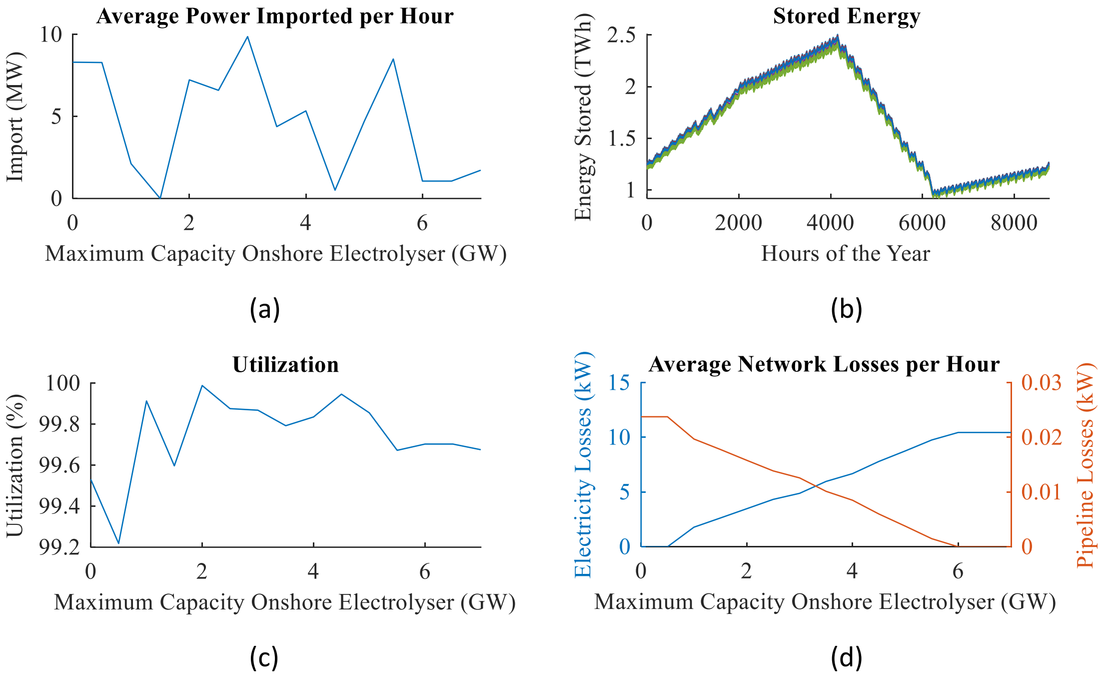


Figure 19: **Graphs on the Operation of Case Study 2**
In this figure the operational graphs of the considered scenarios are displayed as a function of the distance.

of 1% or the extra energy required due to higher losses in the network. However, the first hypothesis is supported by the utilization of wind turbines (see Figure 19). It can be seen that for a higher number of wind turbines the utilization drops. Since the windspeed and the hourly demand for hydrogen do not change in the considered scenarios, likely, the loss in the utilization of the wind turbines is caused by the suboptimal optimization. The maximum difference between utilization is 0.8% which corresponds to a loss of potential power of approximately 47 MW, assuming 530 turbines are installed. This is in good agreement with the number of five 11 MW turbines between which the scenarios vary. The fact that due to higher losses more electricity should be produced is not likely to influence the number of turbines significantly. The hourly maximum average loss of 11 MW corresponding to 1 turbine.

In Figure 20**,** it can be observed that the onshore electrolysis is growing when extra capacity is allowed to be installed. Since the onshore electrolysis is the economically more attractive option, this is to be

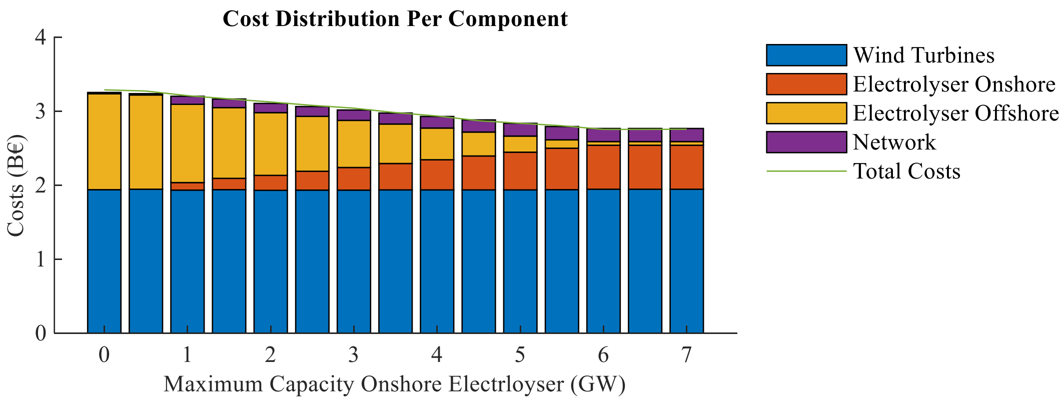


Figure 20: **Cost Distribution Case Study 3 per Component.**
In this figure the total MES costs are presented as a function of the distance. The bars represent how the main contributors build up the total costs.

expected. However, the capacity has to be sufficient. In the second scenario, the onshore electrolysis is not installed, even though the option of installing 500 MW was available. This observation can be attributed to the fact that installing both options require the system to install two networks as well. These extra costs exceed the advantage gained by installing a relatively small amount onshore and the remaining capacity offshore.

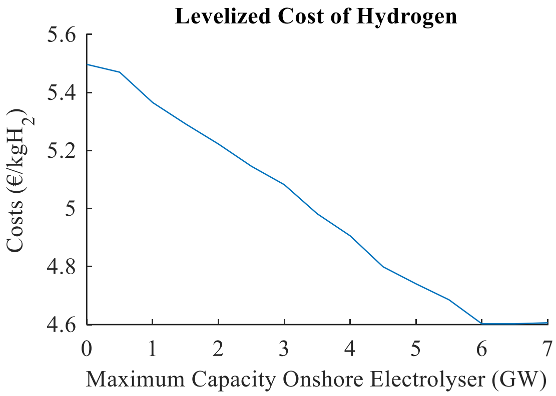


Figure 21: **LCOH of Case Study 3**

As the onshore electrolyser capacity increases, a larger electricity network is installed as well, whereas the capacity of the offshore electrolyser and the hydrogen network decrease (see Figures 18 and 20). As the electricity network increases in size, the network losses do as well (see Figure 19). Due to the losses in the electricity network, the total network capacity increases as well.

The imported energy and the operation of the hydrogen cavern, are proven to be similar to the previous case study on the shore distance (section 5.2). The operation of the hydrogen cavern is not affected by the variation in the onshore installed capacity of the electrolyser. The imported energy provides the energy for the hydrogen cavern when no electricity network is available to transport the electricity to shore and is used for electrolysis whenever a small amount of energy is required, but the instalment of an extra turbine is more costly.

5.3.2 Costs

In section 5.1.2 the major contributor to the difference in LCOH between on- and offshore production was determined to be the extra costs concerned with installing the electrolyser offshore. One major contributor is in good agreement with the linear trend of the LCOH observed in Figure 21**.** As discussed above no onshore capacity is installed short of 1 GW. This causes the trend line of the LCOH to deviate at 500 MW.

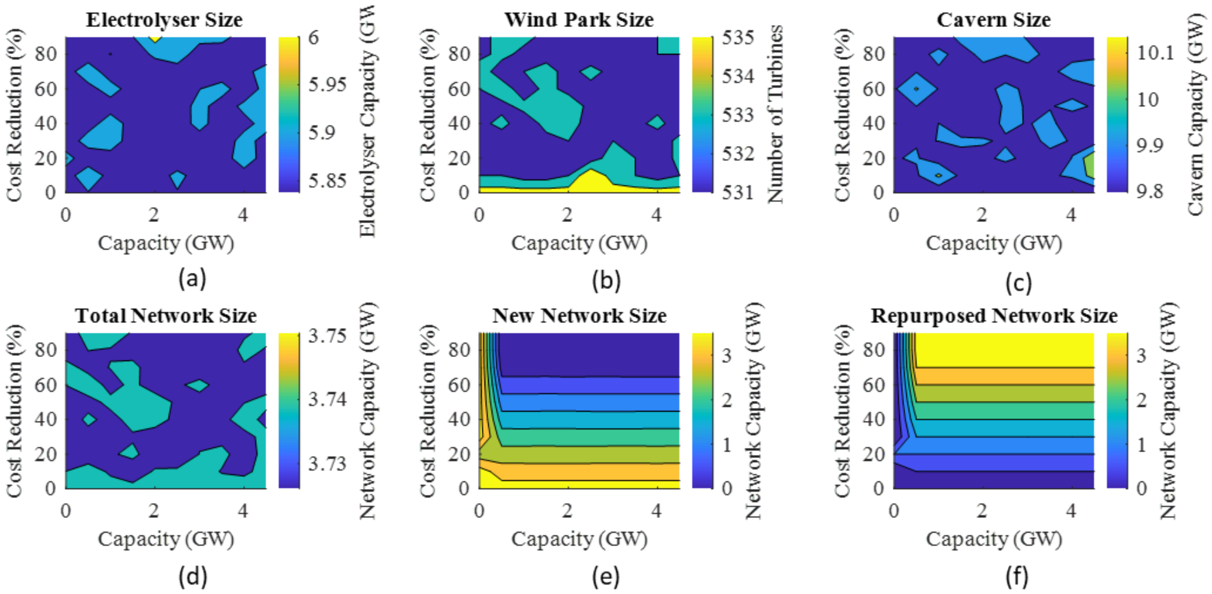
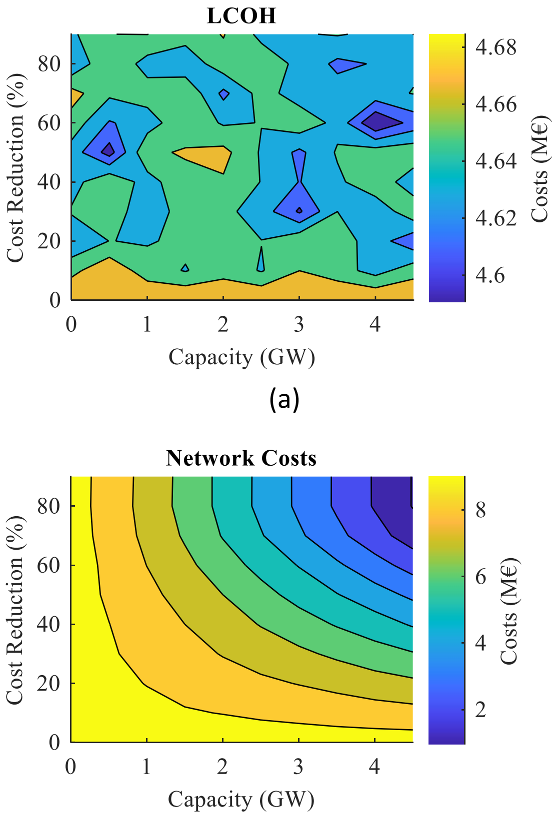


Figure 22: **Contour Graphs on the Design of Case Study 4**
In this figure the sizes of the MES components are displayed in contour graphs as a function of both the capacity and the cost reduction.

5.4 Results Repurposing Existing Infrastructure

In this case study both the amount of cost reduction that could be achieved and the amount of available old infrastructure fit for repurposing were varied. From the graphs in Figure 22**,** it can be observed that the design is not affected to a significant extent. The variation in the size of the cavern, electrolyser size and the total size of the network between the scenarios do not show a changing trend. A minor deviation is observed in the number of turbines when there is no existing infrastructure available.

Whereas the maximum of installed turbines is confined to 533 when there is existing infrastructure available, 536 turbines are installed when it is not. The amount of three extra turbines are within the MIP gap of 1%. However, it is notable that this occurs for every instance in which no extra network is available. Yet, optimization with a smaller MIP gap and with a higher resolution with respect to the available size of the repurposed network should be performed to draw any conclusions. The largest differences are, as expected, in the respective sizes of the repurposed and the new hydrogen network. In graphs (d)-(f) in Figure 22 it can be observed that the repurposed network is installed to the maximum extent. The fact that two networks have to be installed does not affect the total capacity that has to be installed.



(a)

(b)

Figure 23: **Contour Graphs of the LCOH and Networks Costs of Case Study 4.**

As discussed in section 5.1 the network does not contribute to the LCOH as much as the electrolyser and wind turbines. This is especially the case for offshore electrolysis. Therefore, the LCOH of the different scenarios in this case study does not show a decreasing trend with the cost reduction and the available capacity of the existing infrastructure (see Figure 23 (a)). However, the fact that it does not affect the total price of the system does not imply that cost reductions are not present. In Figure 23 (b) the total network costs of the optimized scenarios are displayed. Where a clear decreasing trend can be observed.

6 Discussion

In the first part of the discussion, a comparison of the key parameters of the production in the MES and the LCOH with values in the recent literature is discussed. Thereafter, the results of each of the four case studies are discussed. Subsequently, the major limitations of this research are described and recommendations for further research are presented.

Recent values from literature and reports of (semi-)governmental agencies report the LCOH of green hydrogen produced from offshore wind energy to be between 3.77 €/kg and 13.- €/kg [37]–[41]. These values are in good agreement with the values found throughout this research 4.60 €/kg to 6.70 €/kg. It should be mentioned that the costs from this research are annuitized. However, the hydrogen price does not take into account profit margins and taxes. The capacity factors (63%), caused by the high utilization of the wind turbines (99% - 100%), are optimistic compared to other sources. The Centraal Bureau voor de Statistiek (CBS) reports the capacity factor of 2020 to be between 41% and 43% for the Dutch offshore wind parks [42]. Whereas a prediction done by the center for sustainable systems at the University of Michigan, predicts that offshore wind turbines should be able to reach a capacity factor of 51% in 2022 [43]. Nevertheless, this is a large difference between literary values and the values obtained in this research. This discrepancy can be attributed to the fact that a large part of the lower factors is due to energy peaks which might overload the energy system and therefore turbines are curtailed. In the MES considered in this research, energy can be stored cheap and with low losses in the form of hydrogen in a cavern. Whenever peaks in the energy production can be covered by converting this into hydrogen, curtailment due to overloading the network can be avoided. This causes the utilization approaches 100% and therefore the capacity factors increase.

6.1 Case study 1: Onshore Offshore

One of the key findings in this case study is that the increase in the electrolyser cost, when installed offshore, is the major factor making the offshore electrolysis option more expensive. Since there is merely one pilot project which has installed an electrolyser offshore, the actual extra costs in the future are hard to determine [16]. In addition to this, the International Energy Agency (IEA) predicts that the costs of electrolysers will decrease in the near future from 1100 -1800 USD/kW in 2020 to 650-1100 USD/kW in 2030 and 200 – 900 USD/kW [44]. This reduction in costs could aid the development of offshore production. On the one hand, the major contributor to the disadvantage is decreased in costs. Where on the other hand, electricity cables keep their inconvenience of the high loss rates.

As was shown in the results section of this case study (5.1), the analysis is increased in complexity since energy is allowed to be imported at the onshore node. Since the required amount of imported energy is insignificant in comparison with the hydrogen demand of the system, it could be disregarded for this research. Thereby, in some cases, the energy imported does not serve its intended purpose. As can be seen in the onshore scenario, the imported energy is used for electrolysis instead of storage of energy. Furthermore, the imported energy is used to cover the peaks in the hydrogen demand profile, in some cases more than others. Besides the fact that this can diminish the purpose of having a profile with such peaks in the first place, it can give a distorted image when comparing scenarios within a case study.

6.2 Case study 2: Shore Distance

The shore distance and distance between the nodes have a high impact on the LCOH (see Figure 16). Due to the increasing losses of the electrical network and its higher costs compared to the hydrogen pipeline alternative, the pipeline is the more attractive option for distances exceeding 475 km. A similar comparison was performed by Taieb et Al. [45], who concluded that hydrogen is the preferred mode of transport for distances exceeding 740 km. Though being in the same order of magnitude, their conclusion is 64% higher than the 450 km determined by this research. It should be noted that this research considered an electricity demand and therefore required a fuel cell to convert the hydrogen back to electricity. This causes a second high loss factor for the hydrogen transport scenario with offshore electrolysis. The results do give a clear insight into from which distance the hydrogen pipeline is a better alternative from an economic point of view.

The trend in the results when increasing the distance is clear. However, the graphs in Figure 14 do not show a smooth trend, but a distorted one. The exact origin of these distortions is hard to determine since it could be the result of a high MIP gap, imported energy and a decrease or an increase in the utilization of the turbines or a combination of these. Recording the MIP gap, increasing the resolution by increasing the number of scenarios and disregarding the imported energy can help in further research to explain these distortions.

6.3 Case Study 3: Limited Onshore Capacity

The variation of the maximum onshore installed capacity does not affect the design and operation of the system in any other significant matter than that the onshore electrolyser is installed with maximum capacity. The exception to this is the second scenario in which the onshore capacity is allowed to be 500 MW. In this case, the costs of building an extra network do exceed the benefits of the cheaper onshore electrolysis. However, when these results are taken into a broader perspective, this will not influence the actual MES design in the Netherlands. The Netherlands already does possess multiple wind parks offshore which are connected by an electricity network to the shore. It can therefore be concluded, that the limited onshore capacity should not hinder the development of the hydrogen economy. The system can to a large extent be built either onshore or offshore without increasing the LCOH to tremendous heights.

6.4 Case Study 4: Repurposing Existing Infrastructure

In this case study, it is concluded that repurposing the existing infrastructure has no significant effect on the operation of the MES. However, these results should be placed in a larger picture. The representation of the required network in the model, discussed further in the modelling limitations (section 6.5.2), is vastly simplified. In this research, the repurposing of existing infrastructure is assumed to be able to substitute for a new pipeline that would have to be placed. In reality, the existing infrastructure is a vast network of pipelines throughout the North Sea (see Figure 2). Therefore, a more realistic case is that the existing infrastructure will serve as a connection between electrolysis platforms and a larger backbone [46].

Nevertheless, the results show that no significant changes in system design and the associated costs are observed as the result of using two separate hydrogen networks. It even seems that the introduction of a second network might increase the efficiency of the system. However, since these fall into the MIP gap they should be analyzed in further research to draw any conclusions.

6.5 Limitations

The limitations of this research can be split into two categories. Firstly, the limitations on input data and the model are discussed in section 6.5.1. Secondly, not all research questions can be answered since a major analysis was not performed due to lack of time.

6.5.1 Modelling Limitations

Underlying every model are major assumptions and simplifications. These are always required to obtain a workable model. However, it introduces inaccuracies in the representation of reality. Therefore, it is important to consider the most important limitations in the context of this research when interpreting the results. In the following, the most significant limitations arising from the assumptions made in this research are provided.

This research approached offshore electrolysis by assuming that all technologies are centralized within two nodes. Two major simplifications have been made by choosing this approach. Firstly, it is assumed that offshore wind energy is centralized in a specific area on the coast of the Netherlands. Whereas in reality, the Netherlands have wind parks spread over the whole length of the coast at different distances from the sure. Secondly, the concept of a node results in the fact that the model considers all technologies to be at the same physical point. For example, in the results of the offshore case in the first case study (section 5.1), the model does not consider the physical distance between wind turbines. It assumes the electricity is generated by the turbines at the same physical point as the electrolyser is installed. Therefore, any system parts that required the functioning of the MES between technologies installed at the same node, for example, cables between turbines, are not taken into account.

Offshore wind turbines are not yet finished developing. Whereas the largest Dutch offshore turbines at this moment have a capacity of 9.5 MW [47], and the parks built in the near future will contain mostly the 11 MW turbines, new turbines of 14 MW are announced for 2024 already [48]. No data on these turbines were obtained and were therefore not included in this research.

In the second case study, in which the distance between the nodes and the shore distance are increased, there are two major limitations. Firstly, the model calculates the increase of the investment costs as a function of the distance to shore and the water depth with a fitted function. The paper on which this function is based, however, does not provide data beyond 250 km. The assumption is made that above 250 km the increase in investment costs for the wind turbines is not significant. The second limitation is that it is assumed that the connection between the two nodes can simply be established by laying a cable or pipeline in a straight line. However, in almost all cases the connection will have to bridge a larger distance than the distance between the nodes, as the crow flies.

This assumption has a significant impact on the fourth case study. The networks in the energy hub are represented by one connection between two points and the existing infrastructure is most likely repurposed to connect several platforms in the North Sea instead of connecting offshore to onshore. These two factors combined reveal that the energy hub is not the most appropriate tool to analyze the repurposing of existing networks. The uncertainties in the costs of the network should, however, be taken into account when performing the sensitivity analysis in this type of research.

6.5.2 Monte Carlo analysis

The original goal of this research was to determine the uncertainties of which parameters had the largest impact on the MES design and operation and under which circumstances offshore electrolysis can be considered an economically and technically feasible option. Two parameters, the shore distance and the available capacity at the onshore node, were studied in case studies two and three. Additionally, in the fourth case study parameters considering the repurposing of existing oil and gas infrastructure are studied. These case studies have provided a clear insight into how they each influence the MES individually. However, they do not provide any insight on how strong their influence is with respect to each other. It was therefore initially proposed to perform a Monte Carlo analysis on the parameters which were likely to influence the design and operation of the MES to the largest extent.

Eventually, the Monte Carlo analysis was excluded from this research due to a lack of time. The energy hub proved to be a more challenging tool than was initially expected. Initially, a significant amount of time was spent on running optimization using existing wind parks. This proved to be the wrong set-up for answering the proposed research questions. The time that was required to set up the right case studies in the energy hub in combination with some challenging debugging, was the main cause of the lack of time.

6.6 Further Research

As discussed above, the major limitation of this research is that several factors which contribute to the feasibility of offshore hydrogen production, are yet to be related to each. It is therefore recommended to perform an extensive sensitivity analysis in the form of a Monte Carlo Analysis, as was the original aim of this research. The most obvious parameter to emerge from this research to subject to such an analysis are:

- The distance to shore
- The distance between nodes
- The offshore multiplication factor
- The electrolyser investment cost parameter
- Network cost parameter and capacity
- Windspeed
- Hydrogen Demand

The first four factors mentioned are the factors that are proven to have a large impact on the design of the MES in this research. The network cost parameter and the available capacity do not have a major impact. However, in the line of this research is sensible to take these factors into account for the sensitivity analysis. Furthermore, windspeed is of high importance to the production of electricity. In section 4.1 it is discussed that the production of the considered sites in the North Sea is approximately equal. However, their hourly correlation is modest. It would therefore be especially interesting to see the variation of windspeed in combination with alternative hydrogen profiles. This research is limited to one hydrogen profile combined with one wind speed profile. Which resulted in a similar operation of the cavern, for example, in all cases. Changing the demand and supply side of the system would give a much broader insight into how robust these results are.

Furthermore, it is recommended that the requirement for the hydrogen cavern is set to 0 for this type of MES. As discussed above, the complexity arising from the imported energy blurs the clarity of the results and causes no major differences in the total energy demand.

Lastly, this MES considers only a hydrogen demand. It is not realistic to assume that the entire Dutch offshore wind capacity will be utilized for the production of hydrogen. It is much more realistic than both, electricity and hydrogen will be provided in a hybrid system in which hydrogen can be produced at peak moments or at which electricity demand is low. Therefore, it would be interesting to consider a system in which both hydrogen and electricity are produced.

7 Conclusion

In this research, several optimal designs for wind-powered electrolysis were presented. A direct comparison between two scenarios in which electrolysis is performed. From this comparison, it is concluded that the additional costs concerned with the offshore installation of the electrolyser are the major contributor to the offshore system being more costly. It was assumed that the installation would be 100% more expensive than the installation onshore. If this could be reduced to 21% the costs of both MES would be equal.

Subsequently, the effect of the shore distance on the MES was investigated. Comparing 20 scenarios, with an increasing shore distance and distance between the on- and offshore node, yielded a distance of 475 km at which offshore electrolysis would be more cost-efficient. From the third scenario, it was discovered that the initial costs for an electricity network outweigh the benefits of onshore electrolysis when performed to a small extent onshore. Therefore, a minimal amount of approximately 1 GW has to be available onshore in this MES to be economically efficient.

The cost reduction achieved by repurposing existing infrastructure does not have a significant effect on the LCOH. However, the energy hub shows no need for extra network capacity or increased losses when existing infrastructures are utilized in a MES. The decision on repurposing should, therefore, based on this research, be made to a large extent on parameters out of the scope of this research such as costs of removal of existing infrastructure and political and social desirability of repurposing the existing network.

Through the four case studies it became apparent the number of wind turbines and the size of the hydrogen storage cavern remain constant regardless of the change in shore distance, the available capacity onshore, and the repurposing of pipelines. Furthermore, it does the operation of the hydrogen cavern and the turbines remain constant, with the same storage pattern in case studies 1, 2 and 3 and wind turbine utilization >99% throughout the research. This extraordinary utilization is the result of the ability to store energy in the form of hydrogen in a cavern. This is a strong argument for wind-powered electrolysis, irrespective of the placement of the electrolyser.

In conclusion, offshore electrolysis can be technically and economically feasible for the current hydrogen demand. The shore distance and electrolyser costs are proven to be major contributors to the design of the energy system and its related costs. Since both these factors are subject to a high level of uncertainty caution should be taken when interpreting these exact values. Furthermore, to determine how these uncertainties relate to uncertainties in other data, such as the hydrogen demand profile, an extensive sensitivity analysis should be performed.

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Appendix A

In this appendix, a general description of the generic technologies used in this research is given. First, the wind turbines are described followed by the electrolyser and the hydrogen cavern.

Wind turbines

Energy generation in this system is fully provided by wind turbines. The modelling of the wind turbines in the energy hub is described in great detail in **ref.** In this section, the equations most relevant to this research will be shortly described. Within the energy hub the maximum power output is given by the power curve of the wind turbines:

$$P^{max}(v) = \begin{cases} 0 & if\ v < v^{in} \vee v \geq v^{out} \\ p^r \dfrac{v^3 - (v^{in})^3}{(v^r)^3 - (v^{in})^3} & if\ v^{in} \leq v < v^r \\ p^r & if\ v^r \leq v < v^{out} \end{cases}$$

Where the maximum power output (P^{max}) is defined for four cases, depending on the rated power (p^r) and the magnitude of the windspeed (v) in comparison to v^{in}, v^r and v^{out}. As can be seen in the equation above the turbines start producing if the wind speed is larger than the cut-in wind speed (v^{in}). The turbines reach their rated power (p^r) whenever the windspeed (v) is larger than the rated windspeed (v^r) but is still smaller than the cut-off windspeed (v^{out}). If the windspeed (v) is larger than the cut-off (v^{out}) windspeed the turbine will be stopped.

Installing a wind turbine offshore comes, like other technologies, with extra investment costs. However, there has been more research on the installation of offshore wind than on most other technologies. For the wind turbines, the extra investment costs considered for installing equipment offshore are calculated by a polynomial fitting function (**eq**) based on the findings in **EEA (2009).**

$$\begin{aligned} F_{offshore} = 10^{-8} \times (&94700000 - 54060d + 119200D + 22820d^2 + 760.9dD + 1679D^2 \\ &+ 59.55dD^2 - 3.463D^2d - 4.984D^3) \end{aligned}$$

Where $F_{offshore}$ is the factor by which the regular investment costs (**ref**) are multiplied. The factor is a function of both the depth of the sea bottom (*d*) and the distance from the shore (*D*). Since the **ref** does not contain data onshore distances larger than 250 km and water depths higher than 45 m, the fitting function does not represent any shore distance value exceeding those values. Since in the Dutch maritime zone the furthest from the coast one could get is 260 km and the North Sea is not deeper than 20 m, these values will not be considered.

Electrolyser

Electrolysis is a low-carbon hydrogen-producing technology. Via an electrochemical pathway deionized water is converted to oxygen and hydrogen. Over the years several types of electrolysers have been developed. One of the newer technologies on a larger scale is the PEM electrolyser, which is considered in this research. A detailed description of how the electrolysers in the energy hub are modelled can be found in **ref**. The two most important constraints are formulated in the equations below**,** where O_t is the hydrogen output. η_1 is the efficiency by which electricity is converted into hydrogen. F_t is the fuel provided to the electrolyser in the form of electricity at time t. S is the size of the electrolyser and χ_t is a binary value, determining if the electrolyser is on or off at time *t*. Finally, η_3 is a factor that denotes the minimal production if the electrolyser is on. The **equation** describes the maximum output of hydrogen that can be provided by the electrolyser, whereas the second equation regulates the minimum and maximum amount of fuel.

$$O_t \leq \eta_1 F_t + \eta_2 S \chi_t$$

$$\eta_3 S \chi_t \leq F_t \leq S \chi_t$$

Cavern

The hydrogen cavern is a storage component in which hydrogen can be stored. The hydrogen cavern takes two inputs, hydrogen and electricity. The hydrogen is stored in the cavern to be utilized at a later point in time. Whereas the electricity is required for operating the compressor that is used to load the hydrogen in the cavern. An extensive description of the modelling of hydrogen caverns in the energy hub is given in **ref**. The two most relevant constraints for this research are described here. The first constraint is the time horizon equality constraint which states that the amount of energy stored in the cavern at t = 0 is equal to the amount of stored energy at $t = \mathcal{T}$. The second constraint states that the amount of energy stored may never exceed the actual size of the cavern. These constraints can be mathematically described as follows:

$$E_0 = E_T$$

$$0 \leq E_t \leq S$$

Where E describes the amount of energy stored at a certain point in time $t \in \{1, \cdots, \mathcal{T}\}$ and S represents the size of the cavern.