Large scale electricity storage using Power-to-Gas in a 100% renewable power system

Comparison study P2G storage using H_2, NH_3 or CH_4

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EES-2019-368

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Research report of Joachim Kooijinga

Report: EES-2019-368

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ACKNOWLEDGEMENTS

I want to thank René Benders and Piet Nienhuis for their kind and professional supervision during my master thesis.

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SUMMARY

In order to reduce the GHG emission by 95% in 2050, the Netherlands is in a transition towards a fully renewable electricity system. The intermittent nature of solar and wind energy, creates a problem with the balance between supply and demand. Therefore, large scale flexibility and storage will be needed. In the Netherlands, chemical energy storage with power to gas is the only option for large scale electricity storage. Power to gas is the concept of converting electrical energy to chemical energy in the form of hydrogen using the electrolysis process. However hydrogen can be further combined with nitrogen or carbon dioxide to form ammonia or methane that both have a higher energy density and are therefore easier to store. This study aims to make a comparison is between a power to gas storage system based on hydrogen, ammonia or methane for the Dutch power system in 2050. The main research question was therefore: *How do hydrogen, ammonia and methane compare, when produced using power-to-gas, as a flexible electricity storage technology in a fully renewable power system in 2050 in the Netherlands?*

The first part of the research focused on the Dutch power system in 2050 which is assumed to be fully renewable. Using weather patterns from multiple locations, a representative production pattern for the Netherlands was created for offshore and onshore wind and solar PV. Multiple scenarios with different renewable energy capacities were investigated. Due to electrification the demand for electricity was assumed to be increased to 150 TWh per year and the load pattern of 2017 was used. The RES capacities in the scenario that was used for the second part of this research were 40 GW offshore wind, 8 GW onshore wind and 35 GW solar PV. The results showed that in this fully renewable power system, large scale flexibility and storage is indeed needed due to large imbalances during the year.

In the second part of this study, a comparison was made between a power to gas storage system based on hydrogen, ammonia or methane in the Netherlands. First an extensive literature review was performed to determine the system structures and to gather technological and economic information. An important conclusion from this review was that the ammonia and methane system were limited in flexibility due to the ammonia synthesis and methanation process. This created the need for a very large hydrogen buffer storage. Furthermore, it was found that hydrogen storage in salt caverns is energy and cost efficient and that the potential for salt caverns in the Netherlands is large enough to meet the needs as calculated in this study. An Excel based model was made to analyze the power to gas systems on energy efficiency, storage requirements and costs. The results from the model showed that the round trip efficiency of the hydrogen, ammonia and methane system were 40.1%, 28.3% and 29.1% respectively. The ammonia and methane system were less efficient mainly due to the lower reconversion efficiency to electricity (ammonia system) and the low efficiency of the methanation process. In all three systems the storage efficiency was not the decisive factor for the system efficiency or costs. The storage requirements for the hydrogen, ammonia and methane system were found to be 8.33 TWh, 9.21 TWh, 7.34 TWh respectively. The total system costs of the three system were found to be 9.2, 11.8 and 13.3 billion euros per year corresponding to an price of electricity price of 6.1, 7.2 and 8.9 eurocent/kWh for the hydrogen, ammonia and methane system respectively.

In conclusion, in a fully renewable power system in the Netherlands, large scale flexibility and storage is needed. Power to gas can offer both this flexibility and storage. The hydrogen system was proven to be the most energy and cost efficient system in comparison with the ammonia and methane system. Hydrogen storage in salt caverns is possible in the Netherlands and offers a cost and energy efficient way of storing electricity at large scale. The hydrogen storage system was therefore concluded to be most suitable for the Dutch power system of 2050.

SAMENVATTING

Om de uitstoot van broeikasgassen in 2050 met 95% te verminderen, ondergaat Nederland een transitie naar een volledig duurzaam elektriciteitssysteem. Door het variabele productiekarakter van zon- en windenergie ontstaat een probleem met de balans tussen vraag en aanbod. Daarom is flexibiliteit in het elektriciteitssysteem en de opslag van elektriciteit vereist. Grootschalige elektriciteitsopslag in Nederland is alleen mogelijk in een chemische vorm door gebruik te maken van power to gas. Power to gas is de conversie van elektrische energie naar chemische energie in de vorm van waterstof met behulp van elektrolyse. Waterstof kan ook verder gecombineerd worden met stikstof of koolstofdioxide om ammoniak te vormen. Deze chemische stoffen hebben beide een hogere energiedichtheid en zijn daarom gemakkelijker op te slaan. In deze studie wordt een vergelijking gemaakt tussen een elektriciteitsopslag systeem op basis van waterstof, ammoniak of methaan voor het Nederlandse elektriciteitssysteem in 2050. De hoofdvraag van deze studie is: *Hoe vergelijken waterstof, ammoniak en methaan zich, geproduceerd met power to gas, als een flexibele elektriciteit opslag technologie in een volledig duurzaam elektriciteitssysteem in 2050 in Nederland.*

Het eerste deel van het onderzoek richt zich op het Nederlandse elektriciteitssysteem in 2050, waarbij wordt aangenomen dat deze volledig duurzaam is. Weerdata is verzameld van verschillende meetlocaties door Nederland, om een representatief productiepatroon te creëren voor windenergie op zee, op land en voor zonne-energie. Meerdere scenario's met verschillende capaciteiten voor duurzame bronnen zijn onderzocht. Door de toenemende elektrificatie van processen werd aangenomen dat de vraag naar elektriciteit toenam tot 150 TWh per jaar en het vraagpatroon van 2017 werd gebruikt. De capaciteiten van duurzame bronnen in het scenario dat gebruikt werd in het tweede deel van deze studie bestond uit 40 GW wind op zee, 8 GW wind op land en 35 GW zonne-energie. De resultaten lieten zien dat in een volledig duurzaam elektriciteitssysteem zowel grootschalige flexibiliteit als opslag nodig is door de grote onbalans door het jaar heen.

In het tweede deel van dit onderzoek is een vergelijking gemaakt tussen een power to gas opslagsysteem op basis van waterstof, ammoniak of methaan in Nederland. Hiervoor werd eerst een uitgebreide literatuurstudie uitgevoerd om de systeemstructuren te bepalen en om technologische en economische informatie te verzamelen. Een belangrijke conclusie van deze literatuurstudie was dat het ammoniak- en methaansysteem beperkt waren in flexibiliteit door de ammoniak synthese en methaniserings proces. Daardoor was er een zeer grote waterstof opslagbuffer nodig. Verder bleek dat waterstof opslag in zoutcavernes zowel energie als kosten efficiënt is en dat het potentiaal voor zoutcavernes in Nederland groot genoeg is voor de opslagbehoeften die berekend zijn in deze studie. Om de power to gas systemen te analyseren op energie-efficiënte, opslagbehoeften en kosten is een Excel model gemaakt. De resultaten van het model toonden aan dat de 'round trip' efficiëntie van het waterstof-, ammoniak- en methaansysteem respectievelijk 40,1%, 28,3% en 29,1% was. Het ammoniak- en methaansysteem waren minder efficiënt, voornamelijk vanwege de lagere reconversie-efficiëntie naar elektriciteit (ammoniaksysteem) en het lage rendement van het methanisatie proces. In alle drie de systemen was de opslagefficiëntie niet de doorslaggevende factor voor de systeemefficiëntie of -kosten. De opslagvereisten voor het waterstof-, ammoniak- en methaansysteem bleken respectievelijk 8,33 TWh, 9,21 TWh, 7,34 TWh te zijn. De totale systeemkosten van het drie systeem bleken 9,2, 11,8 en 13,3 miljard euro per jaar te bedragen, wat overeenkomt met een prijs van elektriciteit van 6,1, 7,2 en 8,9 eurocent/kWh voor respectievelijk het waterstof-, ammoniak- en methaansysteem.

Concluderend, in een volledig duurzaam elektriciteitssysteem in Nederland is grootschalige flexibiliteit en opslag nodig. Power to gas technologie kan zowel deze flexibiliteit als opslag bieden. Het waterstofsysteem bleek het meest energie- en kostenefficiënte systeem te zijn in vergelijking met het ammoniak- en methaansysteem. Waterstofopslag in zoutcavernes is mogelijk in Nederland en biedt een kosten- en energie-efficiënte manier om elektriciteit op grote schaal op te slaan. De conclusie is daarom dat het waterstofopslagsysteem het meest geschikt is voor het Nederlandse energiesysteem van 2050.

1. INTRODUCTION

1.1 Changing energy systems

Global warming is one of the major challenges of human kind today. The Netherlands committed to the Paris Agreement which was signed in 2015 to substantially reduce greenhouse gas emissions in a try to limit global temperature increase below 1.5°C (UNFCCC, 2015). Relative to 1990, the greenhouse gas emissions have to be 49% and 80% lower in 2030 and 2050 respectively, while the Netherlands is setting an additional target of 95% reduction is 2050 (NRC, 2018). To reach these targets, electrification of polluting sectors such as transport, household heating and industrial processes is seen as part of the solution. However, the electricity sector needs to be decarbonized because currently 84% of the electricity is produced using fossil resources (Schoots et al., 2017). Therefore, in the coming decades, the Dutch government is planning to extend the share of renewable energy sources (RES) in the energy mix significantly, such that in 2050 all electricity is produced from RES (Netherlands Ministry of Economic Affairs, 2016; Wiebes, 2018). The development of wind and solar energy are expected to provide the largest share of renewable energy in the future (Blanco and Faaij, 2018).

In the Netherlands, the offshore wind energy potential in the North sea is very large (Matthijsen et al., 2017), and the government has already planned to install 11.45 GW of new wind parks until 2030 (Wiebes, 2018). In the most optimistic scenario of the Netherlands Environmental Assessment Agency (PBL), 60 GW of wind power will be installed on the North Sea by 2050 (Matthijsen et al., 2017). However, the disadvantage of renewable energy sources (RES) such as wind and sun, is their intermittency and the associated uncertainty in production. This causes problems with the balance between supply and demand of the electricity network. With an increasing share of renewables in the energy mix, an increased flexibility of the grid will be become more important. Flexibility of the electricity system is defined as the ability "to cope with short term uncertainty and deviations between forecasted and actual energy delivery. It refers to how fast the system can change the supply or demand curves to restore the balance" (Blanco and Faaij, 2018). Balancing will be needed on any timescale, from milliseconds to months (seasonal). Long term balancing will be needed for longer periods with large oversupply or shortage of electricity.

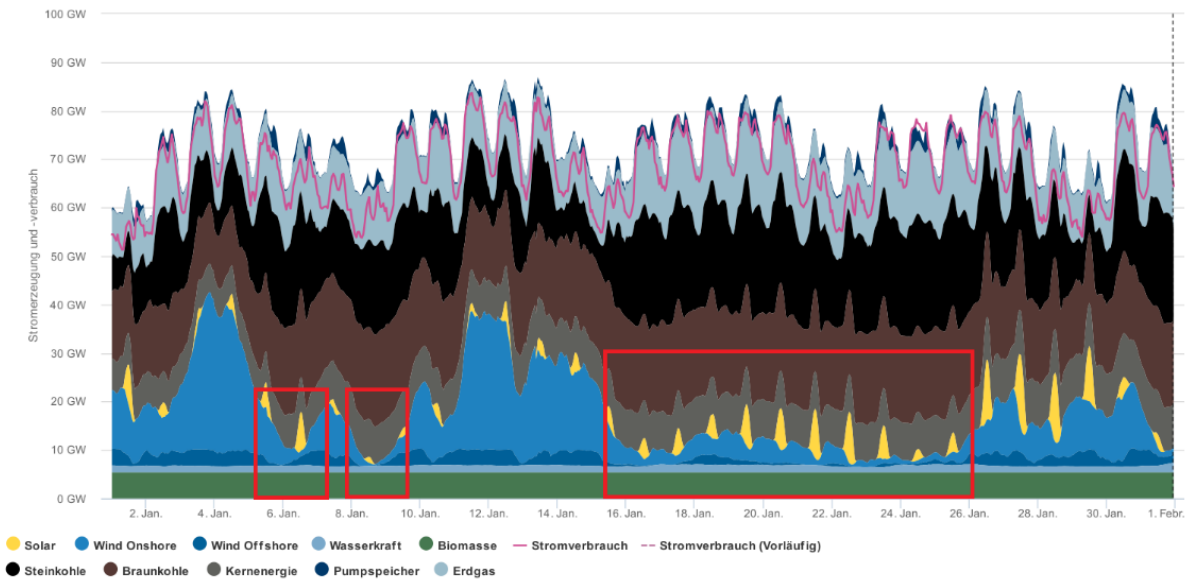

Figure 1. Electricity production in Germany from 2 January – 1 February. The dark and light blue parts represent offshore and onshore wind and the yellow parts solar PV production. The areas depicted with red squares show low RES production. Adapted from (NEXT Kraftwerke, n.d.)

In an energy system which is heavily reliant on RES, long periods of over a week can occur with low energy production. In Germany such a period is called a 'Dunkelflaute' (NEXT Kraftwerke, n.d.) and is seen as a large challenge for the future power system. An example was January 2017 when 11 consecutive days of low wind and sun production occurred in Germany as shown in Figure 1. Currently, there is still enough fossil capacity that can work as a backup to stabilize the grid, but with the goals of deep de-carbonization (95% reduction in 2050), fossil capacity must drastically decrease.

1.2 Electricity storage systems

Currently, there are no large scale electricity storage options for seasonal demand (Blanco and Faaij, 2018). Pumped hydro storage (PHS) is a mature technique which is currently used, but is restricted to geographical locations and therefore not technical feasible in the Netherlands (Blanco and Faaij, 2018). Compressed air energy storage (CAES) is another technique that can potentially be used for large scale energy storage using underground salt caverns. CAES is still in the development phase, and is limited by the low energy storage density. If the all locations for potential salt caverns in the Netherlands were used for CAES, 0.56 TWh could be stored which is a factor 78 lower than if those are utilized for hydrogen storage (Gessel et al., 2018). For significant large scale electricity storage CAES is therefore also not suited (Gessel et al., 2018). Chemical energy storage using power to gas (P2G) can provide long term storage due to its high capacity, high power and relatively low cost of storage. An overview of different storage techniques is shown in figure 2 (ISPT, 2017). P2G is currently at an early stage of development and has high specific costs and low efficiency as its limitations (Blanco and Faaij, 2018). However, research has shown that in an power system with 100% RES, long term electricity storage capacity of more than 1.5% of the total yearly demand is needed (Blanco and Faaij, 2018). It is therefore expected that P2G will play a significant role in future highly renewable energy systems.

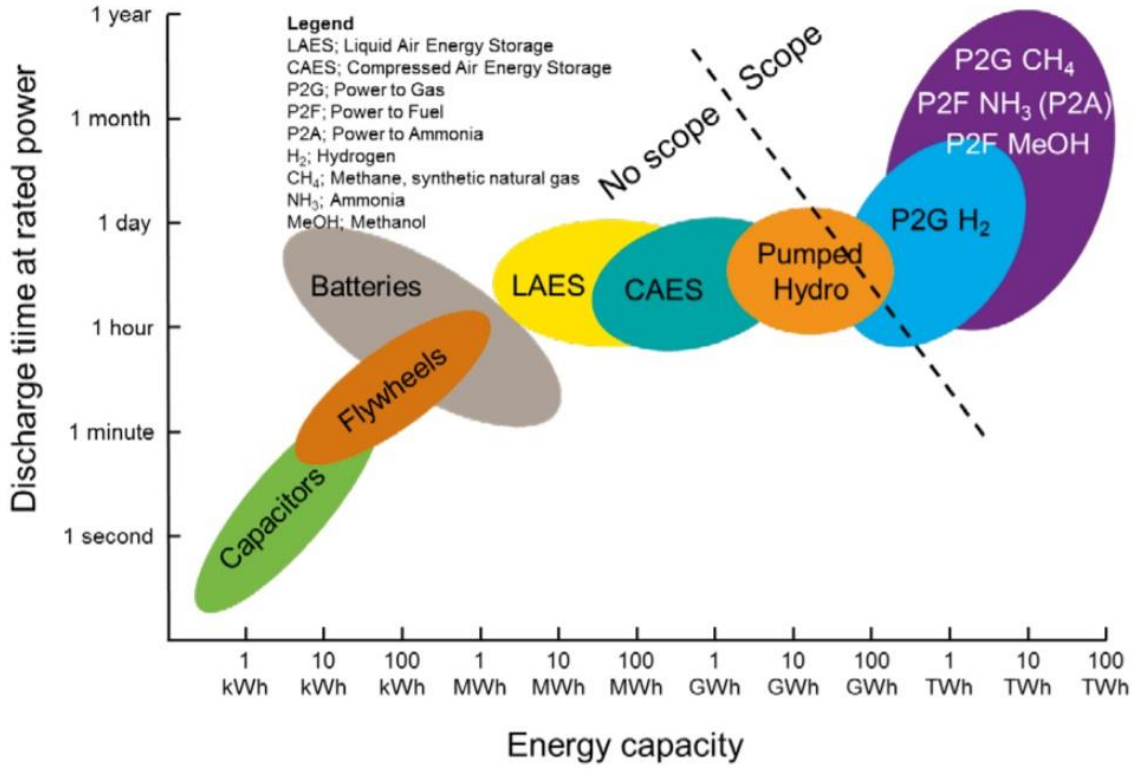

Figure 2. Comparison of different storage techniques. Adapted from (ISPT, 2017)

1.3 Power-to-Gas

The power to gas concept relies on the conversion of electricity to a chemical energy carrier. Electrolysis is the process which uses electricity to split water in to hydrogen and oxygen. The produced hydrogen can be stored under pressure or in liquid form which enables large scale and long term electricity storage. The stored hydrogen can be used for electricity production using fuel cells or gas turbines in times of shortage or high energy prices. Furthermore, hydrogen can be used for other applications such as transport and feedstock for industry. Power to gas research was initially mainly focused on hydrogen production and storage, but other energy carriers such as methane (by further combing it with CO_2) and ammonia (by further combing it with N_2) for electricity storage recently got more interest.

Ammonia (NH_3) and methane (CH_4) both have specific advantages over hydrogen mainly due to their higher volumetric energy density which makes it easier to store. Ammonia is an chemical that is widely used in industry today, mostly for the production of fertilizers. Ammonia can be produced from green hydrogen using the Haber-Bosch process and can be conveniently stored in large quantities using large cooled tanks. Methane is widely used in the current society and especially the Netherlands has an extensive existing infrastructure for methane. Methanation from green hydrogen and carbon dioxide enables the use of this infrastructure and the option for large scale storage of renewable electricity.

1.4 Problem definition

In an energy system with a high share of renewable energy sources large scale flexibility and storage will be needed. The power to gas technology could offer both flexibility and storage and therefore research is needed to investigate the technical and economic feasibility. Currently, 45 pilot projects with P2G plants are realized or are about to be commissioned in Europe (Holstein and van den Noort, 2018). It is expected that with a rising share of RES, the business case for P2G and storage will improve due to the increased demand for flexibility for the electricity grid. Therefore, in the coming decades decisions should be made about which specific technology and energy carrier will be used for long term energy storage for electricity, as economies of scale and the associated improvement of the supply chain will lead to necessary cost reductions (Holstein and van den Noort, 2018). Energy storage systems based on power to gas with hydrogen, ammonia or methane are proposed in literature (Bañares-Alcántara et al., 2015; Bennani et al., 2016; Ghaib and Ben-Fares, 2018; Götz et al., 2015). However, a study with a comparison between the different energy carriers with a multi-criteria analysis for the complete power-to-gas-to-electricity system efficiency, storage possibilities, costs and transport possibilities was not found for the Netherlands.

1.5 Research questions

The research question that follows from the problem definition is therefore:

How do hydrogen, ammonia and methane compare, when produced using power-to-gas, as a flexible electricity storage technology in a fully renewable power system in 2050 in the Netherlands?

To answer this question, the following sub questions will be studied.

1. How could the electricity generation mix of the Netherlands look like in 2050 assuming 100% renewables with a large contribution from offshore wind?
2. How does the hourly sun and wind pattern (offshore and onshore) and the corresponding electricity production look like?
3. What does the hourly Dutch electricity demand pattern for a year look like?

4. How much RES capacity is needed, how much oversupply has to be converted and what is the peak power demand for the G2P plants for times of shortages?
5. How does the P2G system structure and value chain look like for hydrogen, ammonia and methane?
   5.1. How do hydrogen, ammonia and methane compare in energetic efficiency for the P2G to electricity system?
   5.2. What are the storage and transport possibilities for hydrogen, ammonia and methane in terms of capacity and costs?
   5.3. How do hydrogen, ammonia and methane compare economically?

2. SYSTEM DECRIPTION

2.1 System boundaries future electricity system

The complete energy system is a very complex system in which every subsystem such as the power-, heat- and mobility system, are interconnected and influence the other sectors. This makes that the energy transition towards renewables is complex, and research on this topic preferably is done from the complete system perspective. However, in this study only the power sector will be assessed, ignoring other large transitions in the transport and heat sector.

Most likely, P2G will not only be implemented for electricity storage, but also to produce feedstocks for industry and fuel for the transport sector for example. However, this will not be covered in this research. Nonetheless, research showed that long term energy storage with P2G will be needed in high RES energy systems (Blanco and Faaij, 2018).

The development of the Dutch electricity system is uncertain. It is expected that renewable sources will grow significantly and become the dominant source of electricity already in the coming decades (Netherlands Ministry of Economic Affairs, 2016; Schoots et al., 2017). However, fossil based power plants will most likely also still play a role in the coming decades, perhaps in combination with CCS. But as this research is focused on the intermittency of renewables and the extra flexibility that is needed, it is decided to make scenarios with only offshore wind, onshore wind and solar PV power. Including fossil based plants would decrease the need for flexibility, but would be contradictory with the deep carbonization goals of the Netherlands of 95% greenhouse gas reduction in 2050.

Other renewable electricity production options such as biomass and biogas based plants, fossil fuelled plants with CCS, tidal and wave energy, hydropower and nuclear power are excluded as well. In some studies, large import of biomass and subsequent use, among other use cases, for electricity production is assumed for the electricity mix of 2050 (den Ouden et al., 2018). However, the global demand for biomass is expected to grow significantly, causing stress on agricultural land availability and increasing prices. The domestic biomass potential is not sufficient and import brings large uncertainties and dependency on foreign countries (Ros and Prins, 2014). Most scenario studies therefore don't assume extensive electricity production capacity from biomass in the Dutch system (den Ouden et al., 2018).

Consequently, the energy generation mix of the Netherlands in these scenarios will only comprise offshore and onshore wind energy and solar PV. A literature study is performed to determine the maximum possible capacities of wind energy and solar PV in the Netherlands in 2050. Various energy outlook studies have been done that made scenarios for the complete energy system of the Netherlands while achieving the 95% or 100% GHG emission reduction goals. In (den Ouden et al., 2018) an overview of these scenario studies is provided and this will be used in this research.

It can be expected that with the increase of renewable energy sources, demand response measures will be implemented to partly match production patterns. Moreover, interconnection capacity with other countries will most likely increase to solve unbalances in national electricity grids (ECN, 2017). However, these measures will not be taken in to account in this study because the aim of this study is to investigate the possibilities for a power to gas based storage system. The data of the hourly electricity demand pattern of a year 2017 will be used, for which a linear increase of electricity demand towards 2050 is assumed due to electrification, population growth and GDP growth.

3. METHODOLOGY

This research is split up into two parts. The first part of this research will address the future electricity demand and production in the proposed scenarios, creating an hourly pattern over a year. The scenario of the energy mix of 2050 will be created using PowerPlan software, an interactive simulation model that allows the user, among other things, to investigate the implications of future energy systems.

The second part of this research will comprise the comparison between hydrogen, ammonia and methane as a chemical energy carrier which is used for large scale electricity storage. After a literature review, an Excel model has been made in which the transport of electricity, the P2G system, storage system and G2P system are included. Using this model, system efficiencies, costs, and storage and transport possibilities are compared.

3.1 PowerPlan

PowerPlan is an interactive simulation model that can be used to model the electricity production and demand of a country (Benders, 1996). For this study, the required inputs for the PowerPlan model are the load pattern, electricity production patterns from the renewable energy sources and the capacities. Multiple scenarios with different RES capacities are made for the Dutch electricity system in 2050.

3.1.1 Solar PV

To calculate the solar output of the solar PV capacity in the Netherlands, the We-Energy model was used that was developed by the System Integration Modeling Group at the Research Center Energy of the Hanze University of Applied Sciences. This is an Excel based model which uses weather data from the KNMI as input. The KNMI is the Dutch national weather forecasting service which has measurements stations all over the Netherlands. Among other things, the solar irradiance on a level surface is measured on an hourly basis at the measurement locations of the KNMI. The We-Energy model accounts for the orientation, tilt, panel efficiency and yearly solar variation to calculate the power output of a solar panel. For this study, it is assumed that all the panels are on a tilt of 35 degrees, and south orientated. This is the optimal orientation for solar panels in the Netherlands in terms of total energy production over the year. However, in practice this will not be the case for all solar panels. Therefore this will have an influence on the results for the electricity output of the assumed installed solar PV capacity. Furthermore, a solar PV module efficiency of 15.5% is assumed and a power output of 300Wp per panel based on the TSM-PC14 utility PV module from Trina Solar (Trina Solar, 2014).

In order to simulate a representative solar production pattern of solar panels all over the Netherlands, the weather data of five measurements stations that are evenly spread around the Netherlands was used (KNMI, 2018). As the total capacity solar PV will be (roughly) spread evenly around the Netherlands, this represents the actual output better than using only one measurement station. The KNMI measurement stations that are used for this research are Eindhoven, Vlissingen, De Bilt, Heino and Eelde (see Figure 3).

Figure 3. Weather stations of the KNMI in the Netherlands used for Solar PV and onshore wind. Adapted from (van Assen, 2012).

The data from the We-Energy model is further processed and normalized in another Excel file. This hourly pattern for a complete year is used as input in PowerPlan.

The theoretical potential for solar PV in the Netherlands is estimated at 150 GW (Lemmens et al., 2014). A large share of the solar PV capacity can be installed on rooftops. The rest will be utility scale solar parks. Based on the scenarios in (den Ouden et al., 2018), the assumed capacity of solar PV is between 20 and 60 GW.

3.1.2 Offshore wind production

The hourly production pattern from offshore wind will be calculated using an Excel model that was previously used in the work of (Schroeder, 2017; van Assen, 2012). This Excel model uses hourly wind patterns from offshore measurement stations as input for further calculations.

As the height of the measurement station is not the same as the rotor height of the wind turbines, a windspeed correction has to be made. Windspeed increases with height, due to surface friction, air density and pressure differences. In the following equation, the wind profile as a function of height is given as described in (Wieringa and Rijkoort, 1983).

$$v_1 = v_2 * \frac{\ln(\frac{z_1}{z_0})}{\ln(\frac{z_2}{z_0})}$$

In this equation, v_1 is the windspeed at height z_1, v_2 the measured windspeed at height z_2 and z_0 the roughness length of the earth's surface. In this mathematical description, the roughness length is the height at which the windspeed would be zero. It represent how rough the surface is at which the measurement is done and therefore how much influence it has on the windspeed curve for different altitudes. The data from weather stations that are used for offshore wind in this research are all located on or near sea, and therefore a roughness length of 0.0002 meter is used (van Assen, 2012; Wieringa and Rijkoort, 1983).

The height for which the measured wind speed has to be corrected depends on the rotor height of the wind turbines that will operate in 2050. The wind park that is currently built in the North Sea will exist

of the Siemens Wind turbines SG 8.0 that have an rotor height of around 115 meters and 8 MW nominal power (Koster and NOS, 2018; Siemens, 2018). Experts on this topic expect further upscaling of wind turbines, as it will provide more economical benefits and more energy efficiency (Wiser et al., 2016b). Figure 4 shows the realized and project growth of wind turbines (Wiser et al., 2016a). A rotor height of 130 meters is assumed in this study, and the windspeed is corrected accordingly (Wiser et al., 2016b).

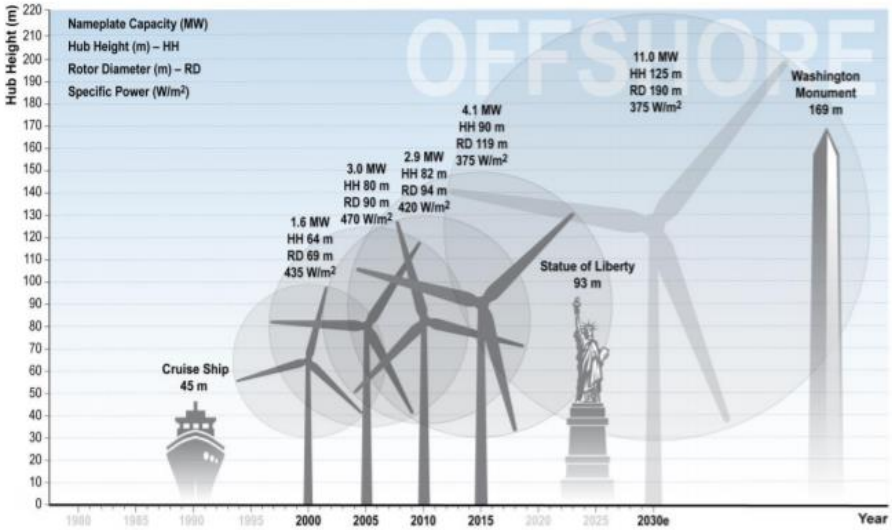

Figure 4. Expected growth in Offshore turbine size. Adapted from (Wiser et al., 2016a).

To calculate the power output of the wind turbines, a multi-turbine power curve for the average wind turbine in a windfarm is used that was created by (van Assen, 2012). A power curve for a wind turbine gives the output of the wind turbine as a function of windspeed.

The report 'Routekaart windenergie op Zee' (Wiebes, 2018) describes the locations and the capacity of windfarms that are currently being built and will be built until 2030 on the North Sea. For the period beyond 2030, the PBL made a scenario study for the spatial planning of the North Sea for which the extensive growth of windfarms and CO_2 storage in empty gas fields were important parameters (Matthijsen et al., 2017). The assumptions of the scenario 'Samen Duurzaam', in which 60 GW of wind energy is installed on the North Sea is used for this research for which the map of the North Sea is shown in Figure 5 (Matthijsen et al., 2017).

The output of the Excel model is normalized such that it can be used in PowerPlan. In this study, offshore wind capacity is allocated to the different wind measurement stations according to the scenario study of the PBL (Matthijsen et al., 2017). Using this approach, the wind energy production data represents all the windfarms on the North Sea, resulting in a smoother and more representative production pattern.

Currently, there are four windfarms (OWEZ, PAWP, LUD and Gemini) in the North Sea with a total capacity of 957 MW (Noordzeeloket, n.d.). Offshore wind capacity in the North Sea will grow significantly in the next decade. The minister of Economic Affairs and Climate Policy presented the "Routekaart windenergie op zee" which contains concrete plans for new windfarms in the North Sea in the designated areas Hollandse Kust, Borssele, IJmuiden Ver and ten noorden van de Waddeneilanden (Wiebes, 2018). The current plans and the scenario study of (Matthijsen et al., 2017) for the North Sea in 2050 are used for locations and the potential capacity of the wind farms. According to the assessed scenario studies, the offshore wind capacity is varied between 20 GW and 60 GW (den Ouden et al., 2018).

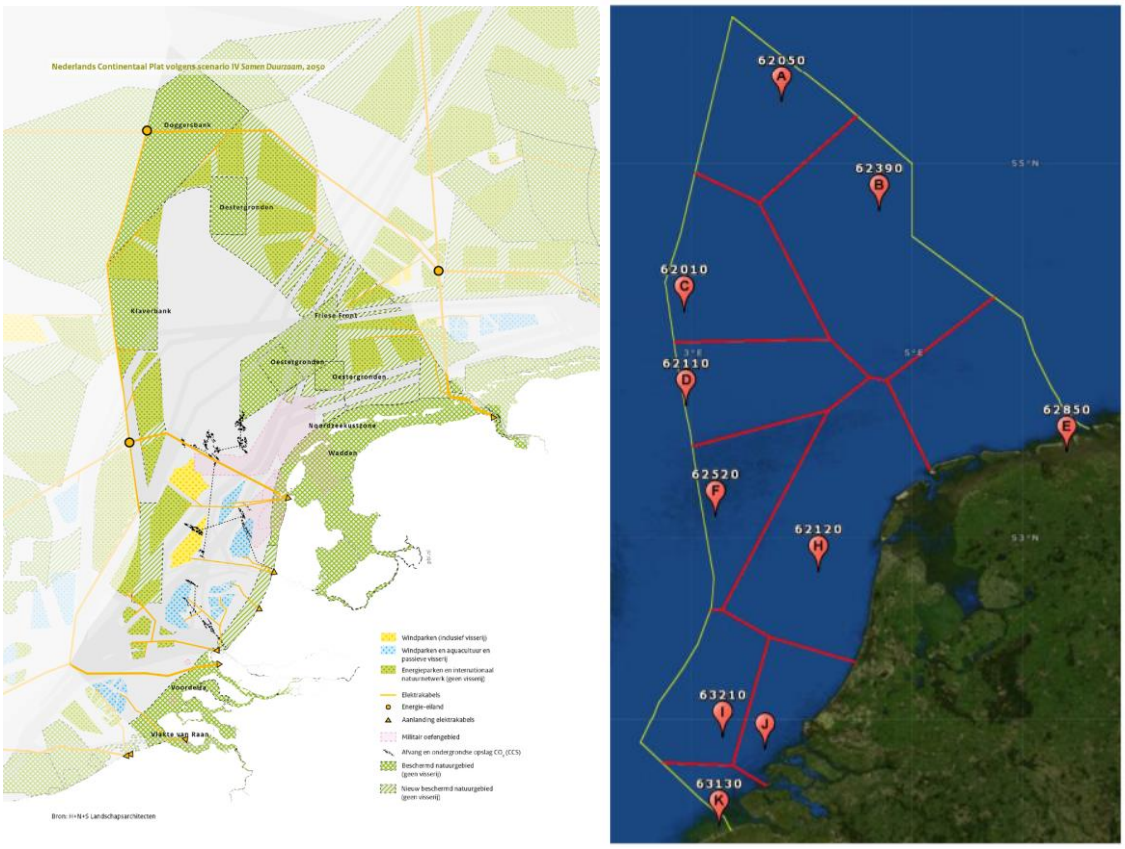

Figure 5. Future North Sea space planning from the 'Samen Duurzaam' scenario of the PBL (left figure) and the weather measurement stations used in this study (right figure). Adapted from (Matthijsen et al., 2017; van Assen, 2012) .

3.1.3 Onshore wind production

The calculation method for onshore wind generation was very similar as that for offshore wind. The same Excel model was used to correct for the measuring height and calculate the hourly output over a full year using hourly windspeed data from the KNMI (KNMI, 2018). The assumed rotor height of future wind turbines is 120 meters following the predictions in (Wiser et al., 2016a). Furthermore, 8 measurement locations were chosen as a representation of the total onshore wind energy capacity in 2050. The KNMI measurement stations near the shore, Vlissingen, Lauwersoog, De Kooy and Hoek van Holland were allocated with twice the capacity as the inland measurement stations to account for the fact that onshore wind capacity is mostly located near the shoreline. The other inland KNMI measurement stations that are used are De Bilt, Heino, Eelde and Eindhoven (see Figure 3).

At the end of 2017 there was 3249MW of operational onshore wind energy capacity. The government has set a target of 6000MW capacity in 2020 (RVO, 2018). However, after 2020 the capacity of onshore wind will not grow significantly anymore. Most scenario studies that were reviewed assume 6 to 10 GW of installed onshore wind capacity (den Ouden et al., 2018). In this research it is therefore assumed that the capacity of wind onshore will be 8 GW and is not varied in the different PowerPlan scenarios.

4. RESULTS FUTURE ELECTRICITY SYSTEM

In this chapter, the future electricity demand and production for scenarios with 100% renewable electricity is determined using the modelling software PowerPlan.

4.1 Dutch load pattern and future developments

In order to calculate an hourly year pattern of oversupply and undersupply of a future energy system, an assumption has to be made about the future electricity demand in terms of total energy per year and hourly load. This is a complex question due to the energy transition and the large number of associated changes for electricity demand. For example the transport sector will undergo a transformation from fossil based vehicles towards electric, hydrogen or bio fuel vehicles. In 2016 the final energy consumption for road transport in the Netherlands was 414.4 PJ (CBS, 2018a) against 432,3 PJ (120.1 TWh) of electricity consumption (CBS, 2018b). A transformation to a predominantly electric vehicle fleet, will therefore have large impact on the electricity demand. Although again, the implications are not as straightforward as adding the numbers. However, electrification of processes that currently use fossil fuel such as residential heating, industrial processes and transport will indeed lead to a higher electricity demand. On the other hand, energy efficiency of electric appliances will decrease the current electricity demand. In the review of (den Ouden et al., 2018) most scenario studies assume 35% improvement in energy efficiency in 2050 (-1% per year). Using literature studies on the future energy system, that take these processes of electrification and energy efficiency improvements in to account, the total electricity demand in 2050 is estimated at 150 TWh per year (Afman and Rooijers, 2017; den Ouden et al., 2018; PBL, 2017).

The pattern of electricity demand will most likely also change, due to (among others) the introduction electric cars, heat pumps for residential heating and demand response measures (ECN, 2017). However, how the hourly load pattern will change in 2050 is again a very complex question which depends on many factors for which the development is also uncertain. This question is outside the scope of this research and therefore it is chosen not to change the current load pattern. The hourly load data of the year 2017 was used in this study (entsoe, 2018). To increase the yearly demand to 150 TWh, all the datapoints are multiplied with a fixed constant. In the PowerPlan scenarios, the 'maximum simultaneous demand' throughout the year is therefore set at 25 GW, resulting in a total annual electricity demand of 149.9 TWh. The load duration curve for the this data is shown in Figure 6. The load duration curve shows the total power consumption in the Netherlands in a sorted order. It can be observed that the maximum load is 25 GW, and the minimum load is 11.4 GW.

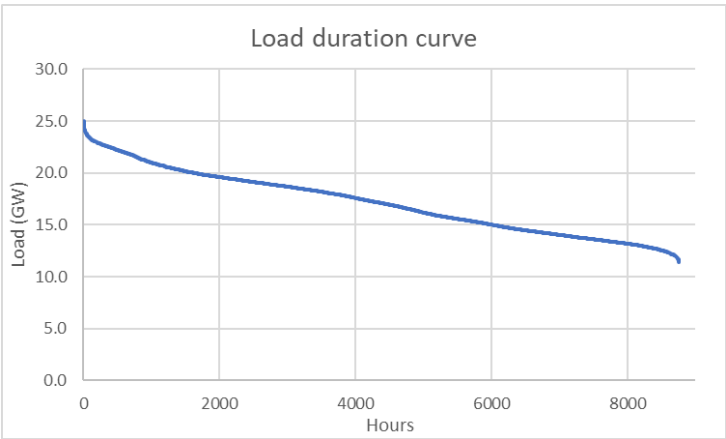

Figure 6. Adjusted load duration curve with data from 2017.

4.2 Results modelled production patterns

In the next subchapters the modelled production patterns for offshore and onshore wind and solar PV are presented with the weather data from 2011.

4.2.1 Offshore wind energy

For offshore wind, the average for all locations combined, the lowest average (Huibertgat WP) and the highest average (A12-CCP) measured windspeed is 8.2 m/s, 8.7 m/s and 7.2 m/s respectively. The lowest (Huibertgat WP) and highest (A12-CCP) measured windspeed data over the year are shown in Figure 7.

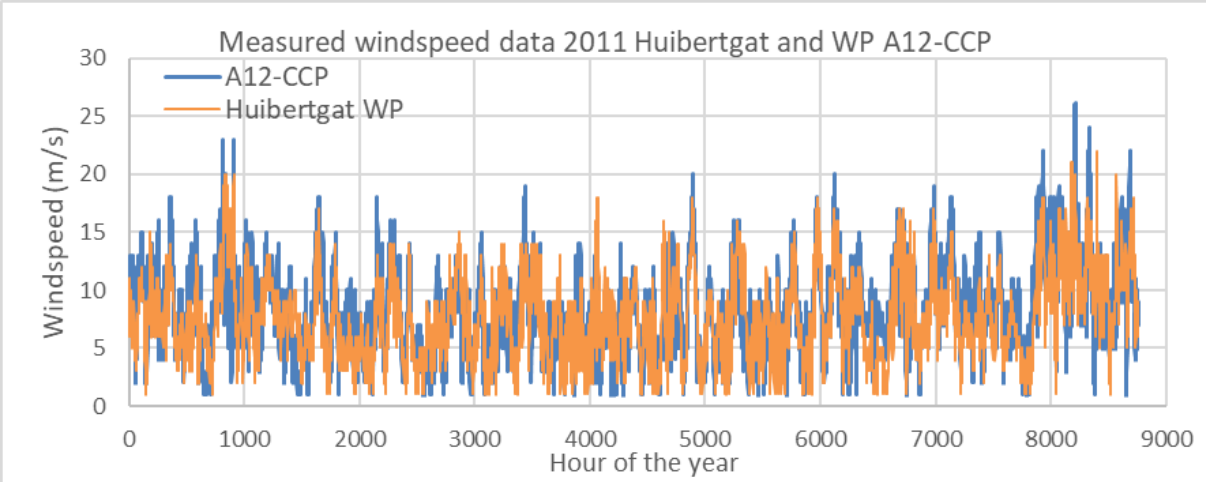

Figure 7. Measured windspeed data 2011 from the measurement stations Huibertgat and WP A12-CCP.

The windspeed data is used to calculate the power output of the wind turbines over the year. An average output pattern is created with offshore wind energy capacity that is installed at different locations in the North Sea as described in the method section. The power output of this weighted average over the year is shown in Figure 8**.**

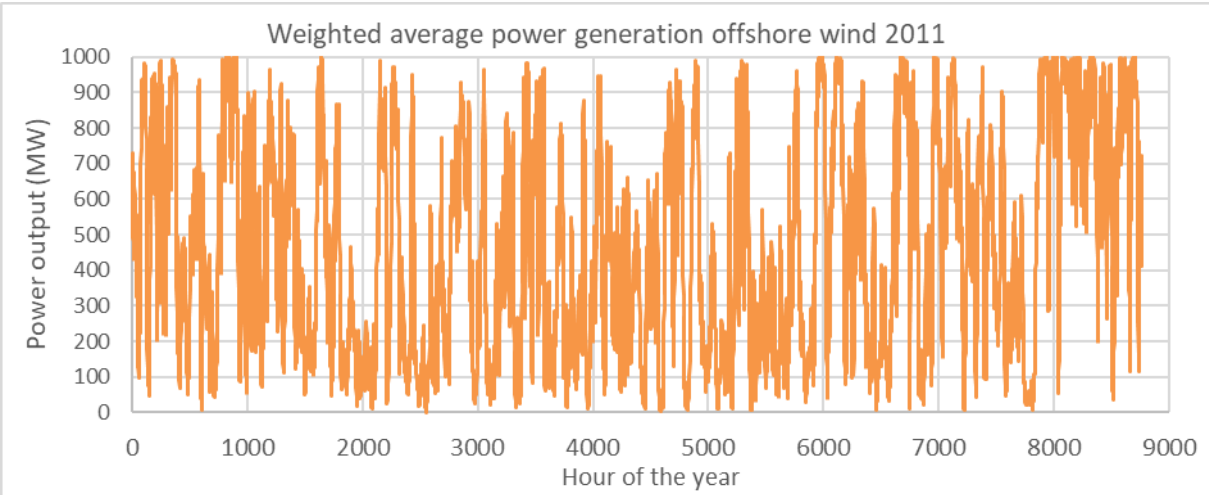

Figure 8. Weighted average power generation offshore wind. Weather data from 2011.

4.2.2 Onshore wind energy

For onshore wind, the average for all locations, the lowest (Heino) and the highest (Hoek van Holland) measured windspeed is 5.0 m/s, 3.1 m/s and 7.2 m/s respectively. The measured windspeed data of Heino (lowest average windspeed) and Hoek van Holland (highest average windspeed) is shown in Figure 9.

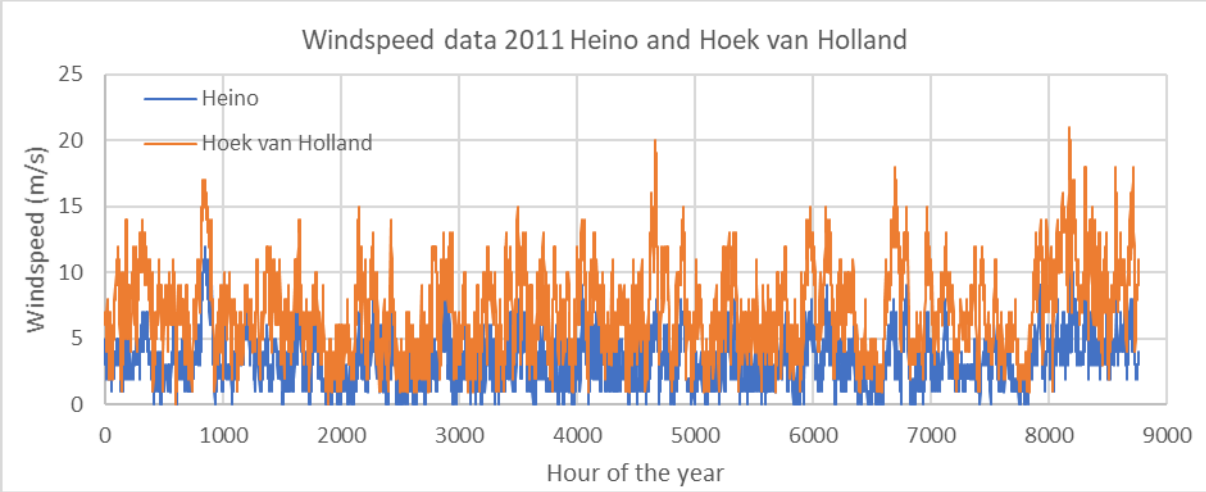

Figure 9. Measured windspeed data 2011 from the KNMI measurement stations Heino and Hoek van Holland.

The onshore windspeed data is again used to calculate the power output of the total capacity of wind turbines over the year. An average output pattern is created for the onshore wind energy that is installed at different locations as described in the method section. The power output of the this weighted average over the year for onshore wind is shown in Figure 10.

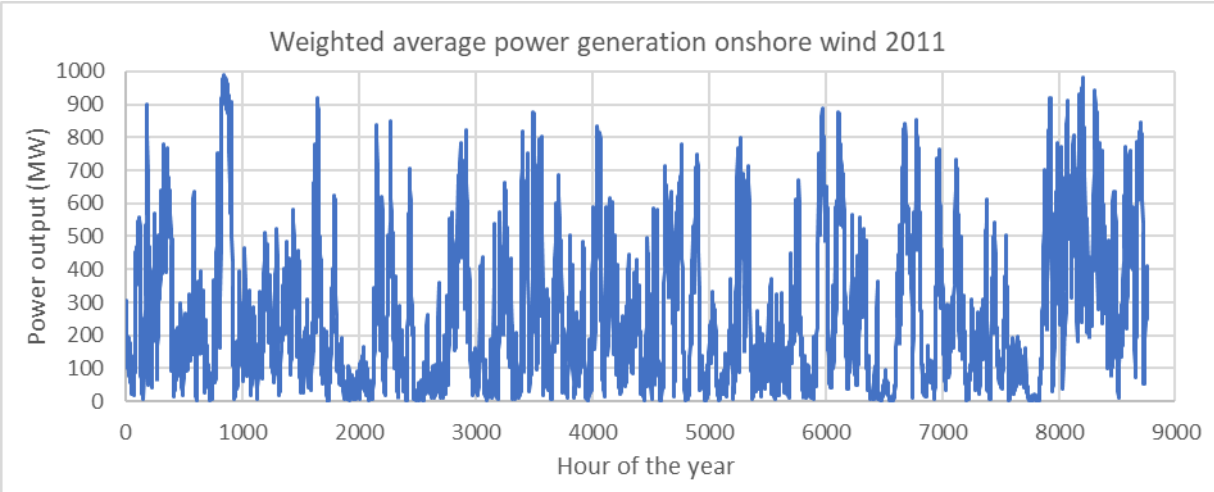

Figure 10. Weighted average power generation onshore wind. Weather data from 2011.

4.2.3 Solar PV

The production from solar PV in the Netherlands was calculated using the We-Energy model as described in the method. The data of the year 2011 was used. The average of the five measurement locations for the production from solar PV over the year is shown in Figure 11. Note that due to the large time range, the daily cycle of solar PV is not visible.

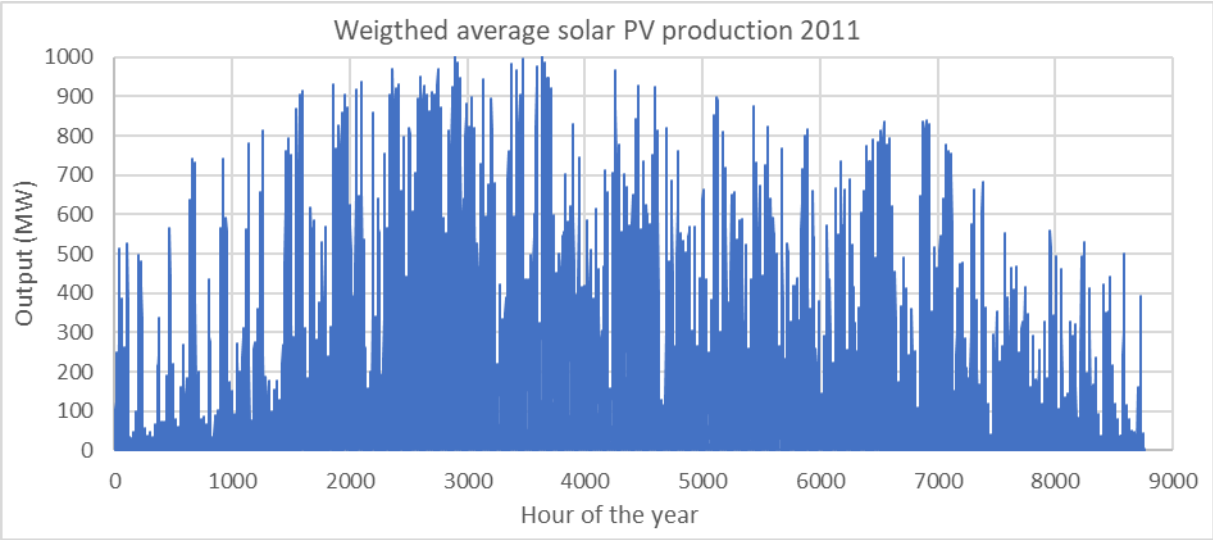

Figure 11. Weighted average solar PV production. Weather data from 2011.

4.3 PowerPlan results

The yearly production pattern of offshore and onshore wind and solar PV and the electricity load data are used in PowerPlan. In order to investigate the consequences of different capacities of wind offshore and solar PV, multiple scenarios were made. The capacity of onshore wind was assumed to be 8 GW in all the scenarios. In total, 13 scenarios were made and 4 scenarios were chosen to investigate further because these fitted best within the possibilities for RES capacities in the Netherlands and the requirements for the power to gas system. In Table 1, the capacities in these scenarios are specified.

Table 1. RES capacities for PowerPlan scenarios.

-	Wind offshore (GW)	Solar PV (GW)	Wind onshore (GW)
Scenario 1	40	35	8
Scenario 2	35	52.5	8
Scenario 3	38	38	8
Scenario 4	45	20	8

The most important results are summarized in Table 2. The demand of 149.9 TWh is the same in every scenario. The production of electricity varies between 210.5 to 214.3 TWh for the scenarios considered. The shortage is the total electrical energy that was not delivered during times with higher demand than production. The total shortages vary between 24.4 and 25.1 TWh. The excess energy is the total of electrical energy which was produced when production exceeded the demand and ranges between 85.3 and 89.5 TWh. The excess energy in this research will be used for P2G, to create a chemical energy carrier. The P2P (power to power) potential estimate gives an estimate of the amount of energy that can be produced using the power to gas storage system from the excess energy. A round trip efficiency of 30% for the complete cycle of P2G, transport, storage and reconversion to electricity is assumed for this estimate (Blanco and Faaij, 2018; Ghaib and Ben-Fares, 2018; ISPT, 2017).

Table 2. Results for the power system in the PowerPlan scenarios.

Scenario	1	2	3	4
Demand (TWh)	149.9	149.9	149.9	149.9
Production (TWh)	212.3	213.1	210.5	214.3
Shortage (TWh)	24.4	25.1	24.7	25.1
Excess (TWh)	86.7	88.3	85.3	89.5
P2P potential estimate (TWh)	26.0	26.5	25.6	26.9
Hours of overproduction	5622	5626.0	5607.0	5493.0
Hours of shortage	3138	3134.0	3153.0	3267.0
Storage capacity (TWh)	8.13	9.31	8.80	9.55
Max shortage (GW)	22.7	22.8	22.7	22.6
Max RES prod. (GW)	70.9	82.0	72.7	62.1
Max overproduction (GW)	54.3	65.6	56.1	45.1

The P2P potential estimate should be greater or equal to the total shortage in order to supply electricity at any given time. The total hours of overproduction give an indication of the available hours of overproduction in which (part of) the P2G installations can run. The hours of storage give an indication of how many hours electricity production is needed from G2P plants. The storage capacity is an estimate using rough number from literature for P2G (60%) and G2P (50%) efficiencies (ISPT, 2017).

In (Blanco and Faaij, 2018; Heide et al., 2011) the influence of the ratio of solar PV and wind energy on the storage demand is discussed. Following this reasoning, the solar PV/wind energy ratio is varied in the scenarios. From the results, it can be seen that scenario 1 results in the lowest required storage capacity. In scenario 1, the total RES capacity consists of approximately 58% wind energy and 42% solar energy which is comparable to the conclusions of (Heide et al., 2011) for a completely renewable energy system.

Scenario 1, with 40 GW offshore wind, 35 GW solar PV and 8 GW onshore wind capacity, is chosen for further investigation due to the lowest required storage capacity. Scenario 1 will be the starting point for the second part of the research.

In Figure 12, the sorted unbalance (production minus demand) is shown for this scenario. It can be observed that the maximum over production is 56.1 GW. The maximum shortage is 22.7 GW and determines in the power to gas system the required capacity of the CCGT's for electricity production. The total excess is 87 TWh and the shortage is 25 TWh. Moreover, 5622 hours of overproduction and 3138 hours of shortage occur during the modelled year. Furthermore, it can be observed that there is large increase in overproduction for only a limited amount of hours in the year. If the capacity of electrolysers is less than the maximum overproduction power this electricity will be curtailed. This means that production of the renewables is lowered by partly shutting of wind or solar electricity production. This will have implications for the choice of the capacity of the electrolyser system and will be further elaborated in section 7.1.

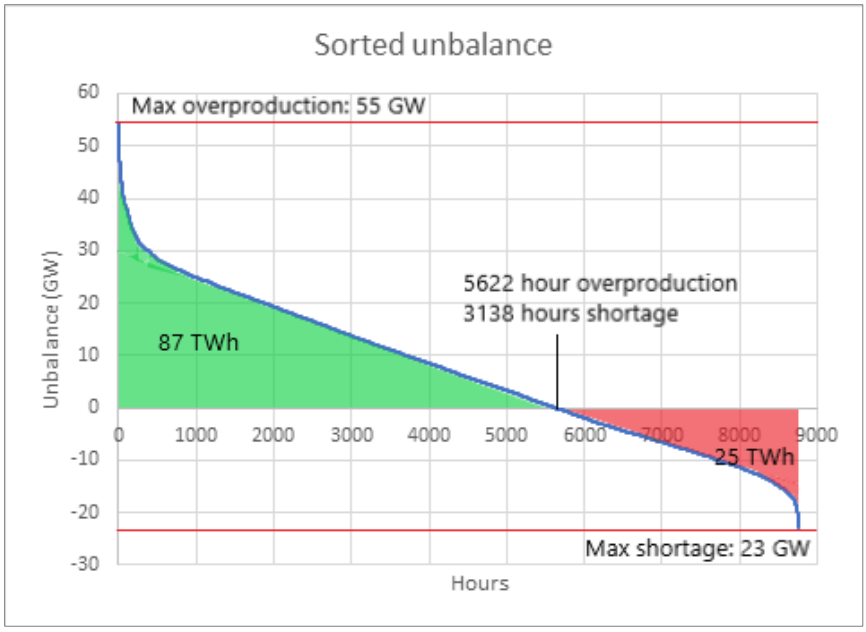

Figure 12. Sorted unbalance (production minus demand) of the scenario used for part two of this research.

Figure 13 shows the production and demand for a winter period in the modelled scenario. It can be observed that in the first two weeks, large shortages occur. The area that is depicted with the red circle accounts for a shortage of 1.5 TWh. To supply this electricity from storage a total of 18 standard sized salt caverns with hydrogen would be needed or 111 million Tesla powerwall batteries (Gessel et al., 2018; Tesla, 2019). However, the weeks after the large shortage, 3 consecutive weeks with excess electricity occur accounting in total for 10.2 TWh. In appendix 11.1, more information is provided about the frequency and duration of excess and shortage periods. It can be concluded that in this fully renewable power system both large scale electricity storage and flexibility are needed.

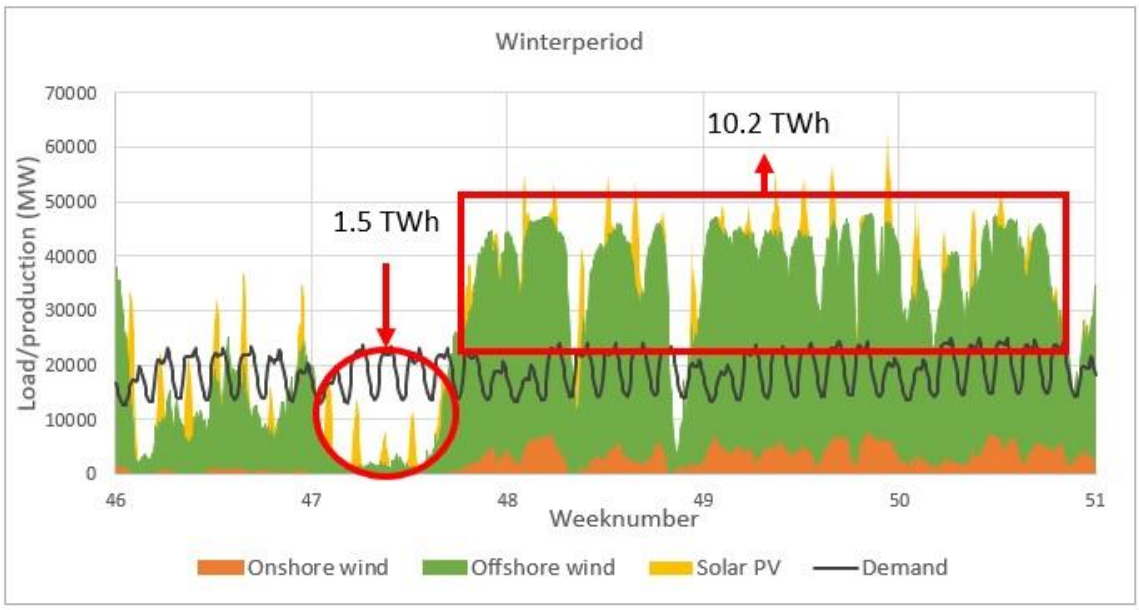

Figure 13. Production and demand for a winter period from the modelled PowerPlan scenario. The depicted areas in red show a significant shortage and excess period.

5. SYSTEM DECRIPTION P2G SYSTEMS

In this chapter, the system structures of the energy storage systems using hydrogen, ammonia and methane are explained. The required technologies will be reviewed and different techniques are discussed, explaining why design choices in the P2G excel model are made as they are. For all systems, significant technological and economic improvements are assumed based on predictions from literature. The starting point of the three systems is the excess electricity pattern that is produced in the PowerPlan scenario described in the previous chapters.

5.1 System boundaries P2G storage system

The mismatch between demand and supply due to the renewable energy sources is assumed to be completely solved with the P2G storage system. The hours with oversupply are used to produce either hydrogen, ammonia or methane. It is assumed that there is no other demand for the excess energy or systems that can provide flexibility. Most likely there will be more systems that build a business case with cheap excess electricity or providing flexibility for the power grid, creating competition for P2G systems. This would have both implications for the total quantity of available electricity as the economic business case for the P2G storage system.

The electrolyser capacity will be assessed in section 7.1. The capacities for the methanation plant and ammonia synthesis plant are assumed to be determined by the maximum hydrogen input such that all the energy can be converted to a chemical energy carrier. This will however lead to a low utilization and will have economic implications.

The losses due to transport of electricity are partly accounted for in PowerPlan. However, losses for transport from offshore wind might be more significant and are not taken into account. However, this would not have an influence on the comparison of the three scenarios. If these were taken into account, it would increase the required capacity of the renewable energy sources.

The electrolyser systems are assumed to be optimally located near large scale onshore wind parks, solar PV parks or at offshore cable landing places to reduce the stress on the national electricity grid. The produced hydrogen is assumed to be transported further in the existing pipeline system (see section 5.2.2). The cost and energy requirements for this transport are not taken into account due to the limited information available. For the ammonia system, the produced hydrogen is assumed to be transported to the ammonia synthesis plant. For the reconversion of electricity the ammonia is assumed to be cracked to hydrogen before transport to the hydrogen CCGT. In the methane system hydrogen from the electrolyser system is transported to the methanation plant. The produced methane is transported in the existing pipeline system. This is in favor of the methane system because the current infrastructure can be used. It is assumed that it would not change the results of the comparison study because the transport of energy in the methane and ammonia system is also assumed to be (partly) in the form of hydrogen.

5.2 Hydrogen system

An energy storage system based on hydrogen would comprise an electrolyser system, hydrogen transport, hydrogen storage and the reconversion of hydrogen in to electricity. In this subchapter, these parts are explained.

5.2.1 Electrolyser systems and future developments

The conversion of electric energy into chemical energy, in the form of hydrogen, is the core element of the power-to-gas concept and is done using water electrolysis. The overall reaction that occurs in an electrolyser, in which water is electrochemically split into hydrogen and oxygen, is given by the following formula:

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2$$

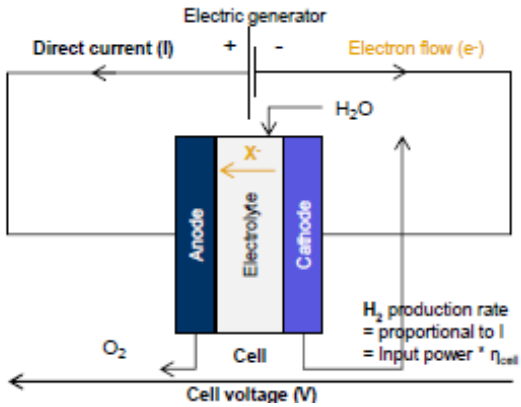

Figure 14, Schematic principle of a water electrolysis cell. Adapted from (Decourt et al., 2014)

Next to the cathode and anode, that apply the electric potential, an electrolyser cell consists of an electrolyte, which conducts ions, and a diaphragm which is an electric isolator and keeps the product gasses H_2 and O_2 separate (Schiebahn et al., 2015). A schematic overview of the principle of a water electrolysis cell is shown in Figure 14 (Decourt et al., 2014). The operating voltage in an electrolyser cell is depended on the type and lies above 1.48 V for low temperature electrolysers (Buttler and Splietho, 2018). The current density on the cell is therefore approximately proportional to the production rate of hydrogen, as the product of voltage and current gives the power input. However, the efficiency of an electrolyser decreases with current density and therefore a trade-off takes place between the efficiency of the cell and the H_2 production rate (Decourt et al., 2014).

An electrolyser consists of multiple electrolyser cells in series, forming the electrolyser stack. Other components needed for the electrolyser system are the gas water separators, gas drying equipment, water management equipment (pumps, heat exchanger), control system (including safety devices) and the power supply (transformer, rectifier) (Bertuccioli et al., 2014). In this study, only the complete electrolyser system is considered if performance indicators are discussed.

The overall energy demand of the reaction can be partly supplied by heat. Temperature therefore lowers the electrical demand of an electrolyser to a certain degree. In the temperature range of 0-1000°C the theoretical overall energy demand varies only slightly with increasing temperature, while the electric demand decreases with about 25% at 1000°C. In the range of 0-100°C (low temperature electrolysers), both the total energy demand (including heat) is supplied electrically. Due to the internal losses, heating of the cells occurs and thus creates the need for external cooling of the electrolyser module. In the range of 100-1000°C additional heat is required for the reaction (Buttler and Splietho, 2018).

The theoretical minimum energy required is 39.4 kWh/kg H_2 produced if water is fed at ambient temperature and pressure (ISPT, 2017). This is equal to the higher heating value of hydrogen, but due to the inevitable losses, the actual power consumption of electrolyser is always higher. The higher and lower heating value (HHV and LHV) of a fuel differ due to the latent heat of vaporization of water that is taken into account (HHV) or not (LHV). When hydrogen is combusted and the energy from the

resulting water vapor is not recovered, the maximum deliverable energy content is the LHV. In the evaluation of an overall process chain, the partial efficiencies are referred to the LHV (Buttler and Splietho, 2018). Therefore, in this study, electrolyser efficiencies are also referred to the LHV unless otherwise indicated. The efficiency of an electrolyser can be calculated with the following formula;

$$\eta_{LHV} = \frac{LHV_{H_2}}{E_{demand}}$$

In this formula η_{LHV} is the efficiency of the electrolyser system in percentage, LHV_{H2} the lower heating value of hydrogen of 33.3 kWh/kg H_2 and E_{demand} the energy demand in kWh/kg H_2 produced hydrogen (Buttler and Splietho, 2018). In this study, the efficiency of an electrolyser system is assumed to be constant, also in part load operation. However, in practice the efficiency of an electrolyser system changes in part load operation relative to nominal load. As mentioned before, the efficiency of an electrolyser cell goes down with increasing current density (and therefore increasing H_2 production rate). On the other hand, electricity consumption of the utility system does not decrease linearly with the load. Figure 15 shows the efficiency of a PEM electrolyser versus its load. An optimum is seen around 15% of its nominal load. In literature, electrolyser efficiencies are normally stated as the efficiency at nominal load. In this study, no adaptions were made to account for efficiency changes over the total load, as data is not easily available and the influence will be averaged when the load varies constantly. However, the maximum excess power occurs only at a limited amount of hours so the electrolysers will operate mostly in part load and therefore the actual efficiency can be higher.

Pressurized operation of an electrolyser can reduce the costs and energy requirements for external compression that is needed for transport or storage of hydrogen. This is due to the fact that it is energetically favorable to increase the pressure of a liquid (feed water) than a gas (the produced hydrogen). Increasing pressure has almost no influence on the efficiency, but will create extra mechanical stress inside the electrolyser cell. However, it is expected that future electrolyser systems will provide hydrogen at elevated pressures (Bertuccioli et al., 2014).

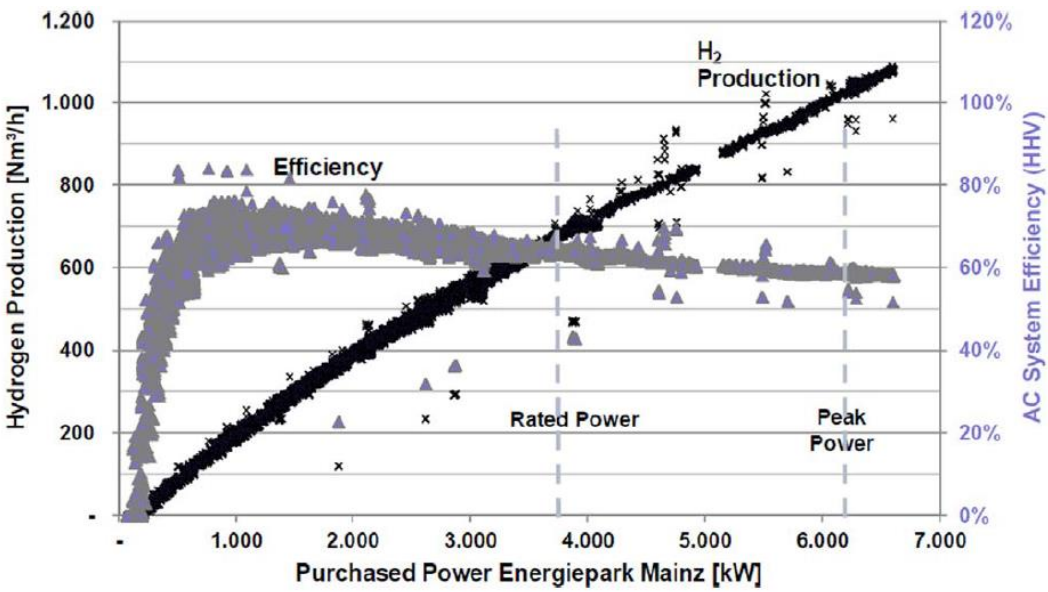

Figure 15. H_2 production and efficiency evaluation including all system components (compression, cooling, purification, control) of the Siemens PEM electrolysis system at Energiepark Mainz. Adapted from (Buttler and Splietho, 2018).

The market for electrolysers is developing fast, as the demand for electrolysers for power-to-gas applications is new due to the transition towards renewable energy systems. The current electrolyser systems were optimized for baseload operation and mainly used for industrial purposes. However, hydrogen production through steam methane reforming (SMR) is economically more attractive and therefore the electrolyser market was not developed fully. Studies expect a large increase in demand for and installed capacity of electrolysers in the coming decades (Bertuccioli et al., 2014; Gigler and Weeda, 2018). Therefore large technical and economic developments are expected in the coming years.

Electrolysers are classified according to the electrolyte used and can also be distinguished according to the temperature at which it operates (low and high temperature). The main electrolyser types are Alkaline Electrolysis (AEL), Proton Exchange Membrane (PEM) and Solid Oxide Electrolysis Cell (SOEC).

Alkaline electrolysis is the most mature technology that has already been used for large scale hydrogen production with MW-scale electrolyser systems. AEL has been commercial available for several decades. The electrodes are immersed in an aqueous alkaline solution (KOH or NaOH) that works as the electrolyte and conducts OH^- ions (Schiebahn et al., 2015). The electrodes are separated by a highly insulating diaphragm that only conducts OH^- ions. Typical operation temperatures are around 80°C with relatively low current densities of 0.2-0.4 A/cm^2.

PEM electrolysers are currently not available at large scale as they are still in the development phase. The technology has been developed for about 20 years and has the benefit that extensive research is done on PEM fuel cells for electric vehicles which relies on the same physical principles (Decourt et al., 2014). A PEM electrolyser consist of a proton (H^+) membrane that separates the two half cells and the electrodes are normally directly connected to this membrane. The operating temperature is limited to about 80°C while high pressurized operation up to 350 bar is possible (Buttler and Splietho, 2018; Schiebahn et al., 2015). High current densities of 0.5-2.0 A/cm^2 are allowed, as well as very low part loads of 0-5% of the nominal load. In Figure 16, a cell schematic of a PEM electrolysis cell is shown.

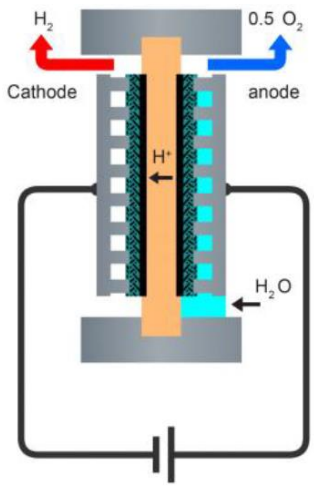

Figure 16. PEM cell schematic. Figure adapted from (Decourt et al., 2014).

The Solid Oxide Electrolysis Cell (SOEC) technology is based on high temperature steam electrolysis. It is the most recently developed electrolysis technology and is still in the stage of basic research (Ghaib and Ben-Fares, 2018; Götz et al., 2015). Due to the recent developments in SOEL technology, it got increased interests from researchers and industry. The operating temperature is between 700-900°C and the feed in stream is in the water of steam instead of liquid water. As explained before, this temperature increase can lead to higher efficiencies but also creates a significant challenge for material stability and the lifetime of the electrolyser (Buttler and Splietho, 2018). A heat exchanger is used to extract heat from the hot product gasses and to heat up the incoming stream of water. Extra energy has to be supplied by an external heat source or electric heater to achieve the correct inlet temperature. The SOEC technique is currently in the early development phase and concerns about material stability are not sure to be fixed**.** Also the flexibility is low due to the temperature variations and associated material stress, making it less suitable for the application of converting excess electricity from intermittent renewables (Schiebahn et al., 2015). Therefore, this technique is not considered as an option for this study. However, if the technology develops and problems are fixed, it would offer great options for heat integration to increase the total system efficiency significantly.

To evaluate different technologies, key performance indicators are chosen that are important for the application in a P2G storage system: Efficiency (at a system level), Dynamic and flexible operation, Lifetime, Pressurization, Capital and operational costs. Table 3 shows the predicted efficiency developments of AEL and PEM electrolysers (Bertuccioli et al., 2014). As mentioned before, the theoretical minimum energy requirement for low temperature electrolysers is 39.4 kWh/kgH_2. It can be seen that PEM electrolysers in 2030 are predicted to produce hydrogen with an energy requirement of 47 kWh/kgH_2 which translates to an efficiency of 70.85%$_{LHV}$. This is somewhat lower than AEL that is projected to have an energy requirement of about 50 kWh/kgH_2. These energy requirements are for the electrolyser system at a system level and are given as nominal efficiency at full load. As electrolysers are more efficient in part load, this can have a positive influence on the operating efficiency of the electrolysers in the application of this study. On the other hand, electrolysers degrade over time due to voltage degradation. This could lead to an average efficiency penalty of about 5% over the lifetime of the electrolyser. For this study it is assumed that the part load efficiency improvements and the efficiency penalty due to degradation cancel each other out and therefore the provided system efficiency is used.

Table 3. Predicted efficiency developments AEL and PEM electrolysers. Adapted from (Bertuccioli et al., 2014).

Electricity input [1]			Today	2015	2020	2025	2030
kWh_{el}/kg_{H2}	Alkaline	Central	**54**	**53**	**52**	**51**	**50**
		Range [2]	50 - 78	50 - 73	49 - 67	48 - 65	48 - 63
	PEM	Central	**57**	**52**	**48**	**48**	**47**
		Range [2]	50 - 83	47 - 73	44 - 61	44 - 57	44 - 53

[1] at system level, incl. power supply, system control, gas drying (purity at least 99.4%). Excl. external compression, external purification and hydrogen storage

[2] some outliers excluded from range

For the application of power to gas from intermittent renewables, the electrolyser system should be capable of flexible operation with fast load changes and low minimum part load capability. PEM and AEL electrolysers are expected to have a minimum part load of 0-5% and 10-20% and a load change capability of 10-100%/s and <25% respectively (Schiebahn et al., 2015). PEM electrolysers are from the perspective of the flexibility requirement more suitable for the power to gas application.

The costs of electrolysers are expected to drop significantly due to the increased interest for the power to gas application in highly renewable energy systems. Costs reductions are expected to be mainly due to higher volume/mass production, supply chain development and technological innovations (Bertuccioli et al., 2014). The expected costs for PEM and AEL electrolysers are depicted in Table 4.

Table 4. Cost reductions for electrolysers over time. Adapted from (Bertuccioli et al., 2014).

System cost [1]			Today	2015	2020	2025	2030
EUR/kW	Alkaline	Central	**1,100**	**930**	**630**	**610**	**580**
		Range	1,000 - 1,200	760 - 1,100	370 - 900	370 - 850	370 - 800
	PEM	Central	**2,090**	**1,570**	**1,000**	**870**	**760**
		Range	1,860 - 2,320	1,200 - 1,940	700 - 1,300	480 - 1,270	250 - 1,270

[1] incl. power supply, system control, gas drying (purity above 99.4%). Excl. grid connection, external compression, external purification and hydrogen storage

Considering the key performance indicators of both technologies, the PEM electrolyser technology is chosen to be implemented in the power to gas system in this study. This is due to the ability of the

PEM technology to follow the variable pattern of excess electricity in order to convert all the excess energy and to be able to provide grid balancing services. Furthermore, the PEM technology is expected to have significant cost reductions, pressurized operation is possible without significant efficiency reduction and is expected to have a reasonable and comparable (to AEL) lifetime (Bertuccioli et al., 2014; Buttler and Splietho, 2018).

5.2.2 Hydrogen transport

The scenarios used for this study compromise a large capacity of offshore and onshore wind and solar PV in a fully renewable energy system. Due to the inherently lower capacity factor and intermittency of renewable energy sources, more installed capacity is needed than in the current fossil based electricity system. As a consequence, the electricity grid and components such as transformers, have to be reinforced significantly if all electricity has to be transported at all times (de Joode et al., 2014). This would result in significant investments, that are indirectly paid by the taxpayer in the Netherlands. Implementing large scale power-to-gas systems could offer a technical and possible economic solution. Electrolyser systems can be placed close to large renewable energy sources such as solar PV and wind parks. As a result, the peak transport capacity of the electricity grid could be lower (de Joode et al., 2014). This system would require large transport of hydrogen in the GW scale.

Technologies to transport hydrogen are mature, due to the fact that is has been used for a long time in the petrochemical, refining and fertilizer production industries (Decourt et al., 2014). The main techniques for hydrogen transport are compressed hydrogen tanks or cryogenic liquid hydrogen tanks with road or water transport and hydrogen pipeline transport. The choice of the type of hydrogen transport depends on the desired transport capacity and distance.

Compressed hydrogen tanks have pressures of 200-700 bars, but have only a limited capacity per truck of 25 MWh which makes them mostly suitable for small scale transport to specific places over moderate distances. Hydrogen can also be transported in its liquid form at low pressure when it is cooled to -253°C. In this form, the energy density increases from 0.003 kWh/L at ambient conditions to 2.4 kWh/L (Reuß et al., 2017). Up to 150 MWh of hydrogen per truck can be transported using cryogenic tank transport (Decourt et al., 2014). But cooling hydrogen to -253°C requires up to 45% of the energy content (LHV) of hydrogen (Reuß et al., 2017) and also boil-off losses have to be taken into account. Both compressed and cryogenic hydrogen transport are therefore not ideal for large scale hydrogen transport (Decourt et al., 2014).

Pipelines can transport large volumes of hydrogen at relatively low costs. The operating pressure is usually between 40 and 70 bar, close to the output pressure of high pressure electrolysers. Compression requirements are therefore minor, also because hydrogen has a low viscosity (in comparison to methane) resulting is low friction losses (Decourt et al., 2014). New pipeline construction requires large capital investments that vary according to distance and flow rate and range between 0.3$ and 1.5$ million per kilometer. However, operational costs are very low and therefore the levelized cost of transport per kg of hydrogen are the lowest for large scale transport (Decourt et al., 2014).

Due to the large natural gas reserves that were found in the Netherlands, an extensive gas transport system was constructed all over the country. This system consists of pipelines, compressor stations, measure equipment and pressure regulating stations (van den Noort et al., 2017). In the coming decades, the Netherlands aims to reduce the use of natural gas significantly and set a target to make the built environment completely natural gas free by 2050 (EZK, 2019). As a result, the use of the existing gas grid for natural gas transport will decline. However, multiple studies are performed to investigate whether the existing gas grid can be used for hydrogen transport and what modifications

are needed (Hermkens et al., 2018; van den Noort et al., 2017). Using the existing gas network would create significant cost and construction benefits.

Hydrogen has significant lower energy density than methane and therefore the energy transport capacity would decrease with about a factor three, if pressure and flow speeds stay the same. In order to maintain the same energy transport capacity three times more volume of hydrogen has to be transported using a higher flow speed. Currently, the flow speed of methane is limited due to the vibrations and the associated noise disturbances, caused by interference at tube separation points. The density of hydrogen is about 1/9 of natural gas and causes less friction and consequently also less vibrations. Hence it is assumed that hydrogen can flow at higher speeds without vibration problems. Therefore, if the gas network would be used with 100% hydrogen, the energy transport capacity would still be 98% relative to the current capacity with natural gas (van den Noort et al., 2017). The compressor stations in the current gas infrastructure are designed for natural gas. Because three times as much volume (for the same energy) has to be compressed, it is not sure whether the compressors can be used for 100% hydrogen. However, as this research is focused on the year 2050 and beyond, it can be assumed that current compressors are already replaced due to their lifetime. For pressure regulation systems and measurement stations for quantity and quality, no significant issues are expected (van den Noort et al., 2017). Furthermore, the current regulations in the Netherlands do not allow 100% hydrogen transport through the gas grid due to safety regulations and will therefore have to be changed. But most importantly, from literature it is concluded that the existing gas infrastructure can be used to transport 100% hydrogen without degradation problems of the materials or excessive safety problems (Hermkens et al., 2018; van den Noort et al., 2017). Changing the gas infrastructure for 100% hydrogen transport will require a significant initial investment (order of magnitude 500 million euro) and will also increase the yearly maintenance/conservation costs due to extra safety precautions. Taking into account the economic lifetime of the additional required infrastructure and the yearly costs, it is concluded that the overall costs for costumers will increase with less than 50 % (Hermkens et al., 2018).

5.2.3 Hydrogen storage

Hydrogen has a very low energy density at ambient temperature and pressures compared to fuels like natural gas or oil. Therefore, hydrogen storage happens pressurized and/or at low temperatures to increase the energy density. The four main storage technologies for hydrogen storage are pressurized tanks, metal hydrides, liquid storage and underground storage. These technologies all have their benefits and drawbacks and the selection of the most appropriate storage technology depends mostly on the required capacity, space constraints and cycling rate.

Currently, the most common way is to store hydrogen using high pressure tube/tank systems with pressures between 200 and 350 bar. For hydrogen in cars and trucks, a higher pressure of 700 bar is generally used (Reuß et al., 2017). However, the energy density of hydrogen is still low at these high pressures, making this technology not suitable for large scale storage. Hydrogen Furthermore, the gas vessels have high investment costs and from an economic point of view it is therefore desirable to have a high cycling rate (Decourt et al., 2014).

Liquid hydrogen, at -253°, has a significant higher energy density. However, the storage efficiency is only 55-75% due to the energy required in the liquefaction process. Typical boil-off rates of 0.1-0.5% occur, making this technology also not suitable for long term storage (Decourt et al., 2014). This technology is mainly suitable for large-scale, centralized storage in combination with long distance transport (by truck, rail or ship) to various end users.

A relatively new technique is hydrogen storage in metal hydrides. Certain metals bind very strongly with hydrogen, forming a metal hydride compound. This absorption process is exothermic so cooling

is required to optimize the adsorption rate. The reversible process, the desorption of hydrogen from the metal is therefore endothermic (heat is needed). The storage efficiency is between 80-98%, depending on whether heat storage is applied from the absorption process. The main advantage of this technique is the low pressure operation which leads to high safety and no need for compression. It also has a high energy storage density. However, this technique is still in the demonstration phase and has further drawback such as slow charging/discharging and low lifetime. It could be a solution for relatively large size storage (ten of MWh's) where underground storage is not available (Decourt et al., 2014).

The last, and best suitable technology for the application of this research, is underground hydrogen storage. Hydrogen can be stored in man-made salt caverns with very large capacities relative to the other storage technologies, with relatively high storage efficiency and moderate costs (Decourt et al., 2014). The salt keeps the cavern completely gas-tight, preventing any leakage, and does also not react with the hydrogen. Leakage of hydrogen is negligible so the storage efficiency mainly depends on the energy needed for compression in to the salt cavern. This storage efficiency is assumed to be 95% in this research after the study of (Decourt et al., 2014). Salt caverns are constructed by pumping fresh water in to a salt dome and pumping saturated salt water (brine) up. This leaching process takes about 2-3 years after which cushion gas is pumped in to the cavern to remove the brine that is still in the cavern (EnergyStock, 2019). The brine is further processed in a salt processing factory to produce salt (Gessel et al., 2018). In the Netherlands, already five salt caverns are constructed in Zuidwending for natural gas storage with high output/input capacity for peak balancing. Both on land and in the North Sea there are salt layers that are suitable for the construction of salt caverns. However, the potential on the North Sea is not taken into consideration because the potential on land is large enough for the future demand for salt caverns (Gessel et al., 2018). Furthermore, the construction of salt caverns on sea is both economically and technically unfavored over land based caverns. A recent study by TNO (Gessel et al., 2018) made an overview of the underground storage potential for hydrogen. Figure 17 shows the potential for salt mining in the Netherlands, and the potential locations for salt caverns in the Netherlands (Gessel et al., 2018). Note that the potential is mostly in the Northern part in the Netherlands. The total potential in terms of number of caverns, effective working volume and energy storage capacity is shown in Table 5 which is adapted from (Gessel et al., 2018). The total energy storage potential for hydrogen in salt caverns in the Netherlands is 43.25 TWh.

Table 5. Overview of salt cavern potential in the Netherlands. Adapted and modified from (Gessel et al., 2018).

Location	Number of caverns (50% theoretical)	Effective working volume natural gas (10^9 m^3)	Effective working volume hydrogen (10^9 m^3)	Effective energy storage capacity methane (TWh)	Effective storage capacity hydrogen (TWh)
GRONINGEN	**230**	**12.2**	**10.37**	**132.06**	**31.00**
Zuidwending	52	2.76	2.35	29.86	7.00
Winschoten	22	1.17	0.99	12.64	2.97
Pieterburen	39	2.07	1.76	22.39	5.25
Onstwedde	66	3.50	2.98	37.78	8.89
Boertange	51	2.70	2.30	29.28	6.86
FRIESLAND	**31**	**1.64**	**1.39**	**17.81**	**4.17**
Ternaard	31	1.64	1.39	17.81	4.17
DRENTHE	**60**	**3.2**	**2.72**	**34.44**	**8.08**
Anloo	14	0.74	0.63	8.03	1.89
Hooghalen	37	1.96	1.67	21.25	5.00
Hoogeveen	1	0.05	0.04	0.58	0.14
Schoonloo	8	0.42	0.36	4.58	1.08

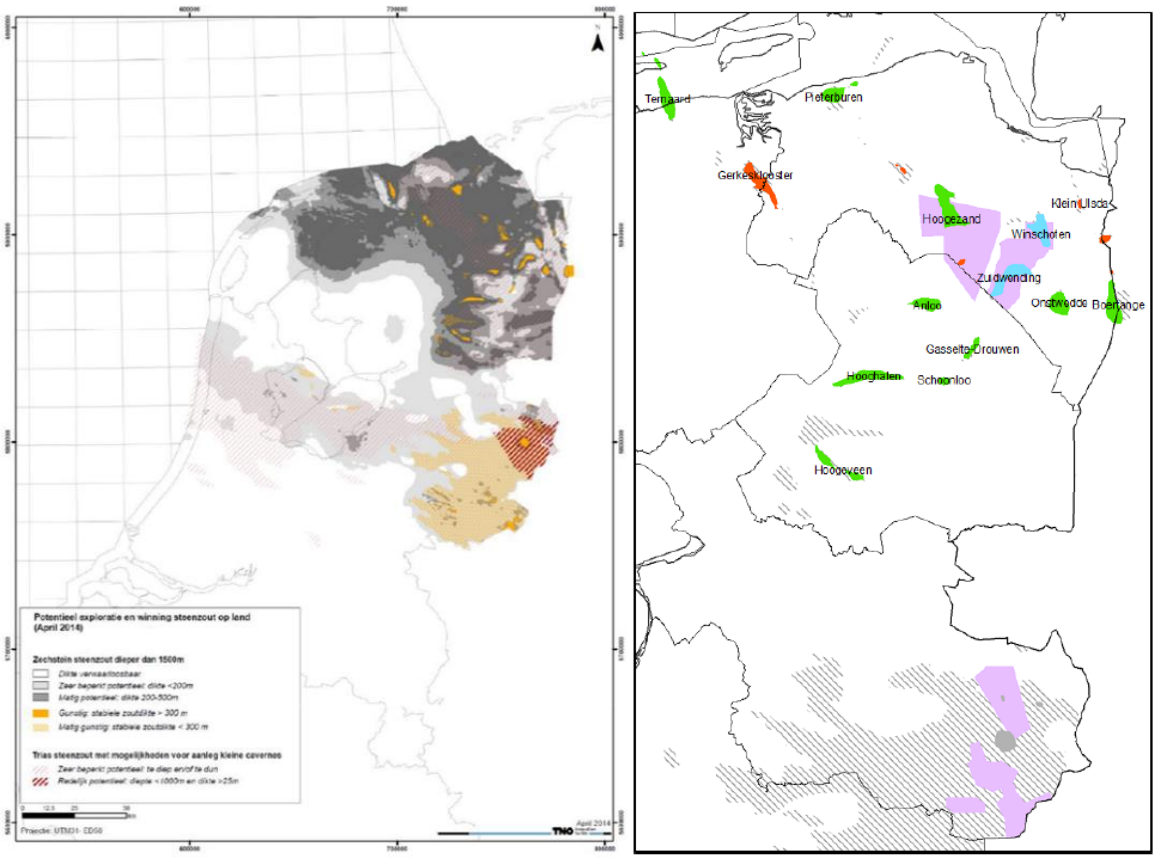

Figure 17. Salt structures in the Netherlands (left) and the potential locations for salt caverns in the Netherlands (right). Adapted from (Gessel et al., 2018).

In the Netherlands, on average 6.3 million tonnes of salt was extracted in the years from 2006 to 2017. At that rate, about 4-5 salt caverns of 600.000m^3 can be constructed each year resulting in a potential of more than 100 salt caverns in 2050 (Gessel et al., 2018). Another option is to create dedicated salt caverns for hydrogen storage and disposing the salt, but this is economically not beneficial.

As the caverns are man-made, they can be constructed in the required size within the limitations of the salt layer on the location. A typical salt cavern for hydrogen storage, as specified in (Gessel et al., 2018), has a volume of 600.000m^3 at a depth between 1000 and 1500 meters. However, also larger caverns can be constructed of 1.000.000m^3 or more. The pressure range in the cavern is about 80-180 bar due to safety requirements concerning the stability of the cavern. The working volume of the cavern is the volume of hydrogen gas what can be used for storage. This is less than the total volume of gas in the caverns, due to the cushion gas that has to stay in the cavern. For the standard cavern that is assumed in this study, the working volume is 45 million m^3. The typical output capacity of a salt cavern of this size with one well is 4 million m^3 per day (Gessel et al., 2018). However, if multiple wells are made for one caverns, the output capacity can be significantly increased. The salt caverns for natural gas in Zuidwending in the Netherlands have two wells per cavern and have an output capacity of almost 8 million m^3 per day with comparable sizes and storage pressures as the standard cavern.

Table 6. Specifications standard salt cavern

Standard hydrogen salt cavern

Volume cavern (m^3)	600.000
Energy capacity LHV (GWh)	134.6
Depth (m)	1000-1500
Pressure range (bar)	80-180
Working volume H_2 (million m^3)	45
Ratio working volume/cushion gas	1:1
Output capacity (million m^3 H_2 /day)	4
Output capacity (GWh_{LHV}/day)	12

Hydrogen storage might also be possible in depleted gas fields. However, hydrogen storage in salt caverns is already a proven technique, the ratio between cushion gas and working volume is better and it is expected that there is enough capacity in the Netherland (Decourt et al., 2014; Gessel et al., 2018). However, in the future depleted gas fields or aquifers could be interesting if no salt structures are available at a certain location and for very large and low grade hydrogen storage (due to possible mixing). The technical feasibility still has to be proven (Gessel et al., 2018).

5.2.4 Electricity production from hydrogen

Stored hydrogen can be used to produce electricity using either fuel cells or gas turbines. Fuel cells work by the reverse process of electrolysis, combining hydrogen and oxygen to convert chemical energy in-to electrical energy. Fuel cells do not require any moving parts, making it a very reliable technology that requires little maintenance. Similar to electrolyser systems, fuel cells are modular and can be used for a wide range of power capacity demands. The concept of fuel cells exists already since the 1970s, but recently the development got more interest due to the application for electric vehicles driven by fuel cells. The efficiency of a fuel cell depends on the applied load and is similar to electrolysers more efficient on minimal load. Energy losses in the fuel cell result from heat production due to the resistive Joule effect and due to hydrogen that does not react within the fuel cell (about 5%). The electrical efficiency of fuel cells is only between 30-50% and are not expected to become much higher in the future. However, there are significant opportunities for heat integration as fuel cells can will have a CHP efficiency of about 76-80% around 2050 (Decourt et al., 2014).

The other technology to convert hydrogen to electrical energy is the combustion of hydrogen in gas turbines. The same principle that is currently used for natural gas turbines can be used for hydrogen turbines. A gas turbine based on hydrogen would have a slightly different design due to the hydrogen

burning properties but the balance of the plant is similar. Currently, hydrogen gas turbines are still in the development phase, but are expected to be developed in the coming years due to the increased demand for this technology. The efficiency and flexibility of a hydrogen combined cycle gas turbine (CCGT) will be the same as the current CCGT's on natural gas. Due to the burning properties of hydrogen the efficiency of the plant can even be somewhat higher. In this study the efficiency of a hydrogen CCGT is assumed to be 60% (Decourt et al., 2014).

5.3 Ammonia system

An energy storage system based on ammonia would comprise an electrolyser system for hydrogen production, hydrogen transport, nitrogen production system, ammonia synthesis plant, ammonia storage and the reconversion of ammonia in to electricity. The electrolyser system and hydrogen transport in this ammonia storage system do not differ from those in the hydrogen energy storage system that are explained in the previous subchapter. Therefore, these components are not explained again and the reader is advised to read subchapter 5.2 for more information. The rest of the system is explained is this subchapter.

5.3.1 Conventional ammonia production

Ammonia is currently the second most industrial produced chemical worldwide and is mostly used for the production of fertilizers (Cheema and Krewer, 2018). The annual worldwide production is approximately 180 million tonnes and is expected to increase to 270 MT/year in 2050 (Ye et al., 2017). The current production of ammonia is responsible for 1% of the greenhouse gas emissions and 1.8% of the worlds consumption of fossil fuels (Ye et al., 2017).In the Netherlands, approximately 2.7 million tonnes of ammonia is produced in by two multinational companies (ISPT, 2017).

The production process of ammonia (NH_3) currently uses fossil fuels, air and water. Natural gas is mostly used as fossil fuel, accounting for 77% of the worlds ammonia production. The rest is produced from coal, heavy fuel oil or vacuum residue. A schematic of the process of ammonia production from natural gas is shown in Figure 18 (ISPT, 2017). Natural gas is used in a process called steam methane reforming (SMR) for which a series of steps is need to produce and purify hydrogen. This hydrogen (H_2) is then further combined with nitrogen (N_2) in the right stoichiometry after which it reacts using a metal catalyst under high pressures and temperatures in order to form ammonia. The process reaction is given in the following formula;

$$N_2 + 3\,H_2 \leftrightarrow 2\,NH_3$$

This process is known as the Haber-Bosch process and operates at temperatures of around 450-500°C and pressures of 200 bars (Morgan et al., 2017). The Haber-Bosch process is commercially mature and is changed little over the last 50 years (Bañares-Alcántara et al., 2015).

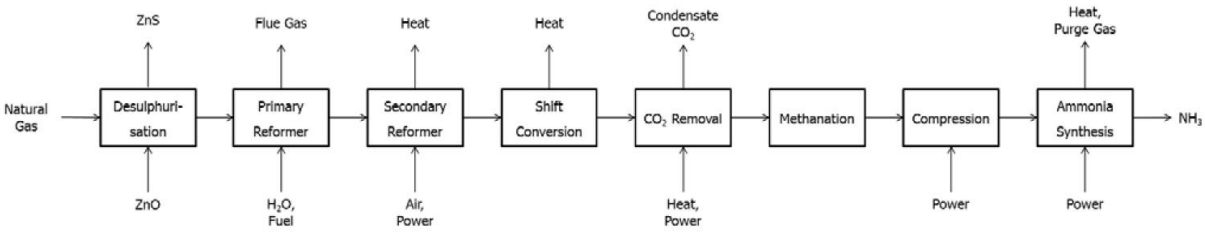

Figure 18. Block diagram of a natural gas based ammonia plant. Adapted from (ISPT, 2017).

5.3.2 Power to Ammonia

This research focuses on an all-electric ammonia production process and this has intrinsic differences to the conventional Haber-Bosch process. Power to ammonia is the concept in which the input stream of hydrogen is supplied by electrolysis. In this process the production and clean-up part of the synthetic gas (H_2 and N_2) are replaced by the electrolysis system and a nitrogen production system. The nitrogen is derived from an air separation unit. Currently, there are no ammonia plants of this type operational. Figure 19 shows a schematic of the process of power to ammonia (ISPT, 2017).

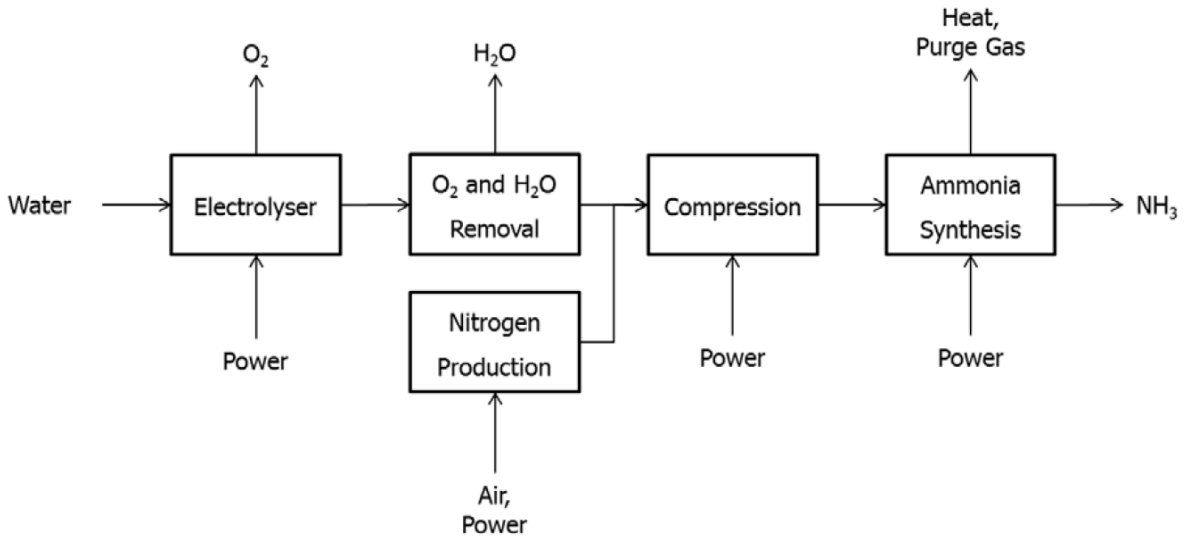

Figure 19. Block diagram of Power to Ammonia. Adapted from (ISPT, 2017).

5.3.2.1 Nitrogen production

From the complete ammonia system, the nitrogen production system requires the least amount of energy and is also relatively cheap (Bañares-Alcántara et al., 2015). Air consist for 78% out of nitrogen and is therefore used as nitrogen source. The most used technique for large scale nitrogen production is cryogenic distillation also referred to as the air separation unit (ASU). Other techniques are membrane separation and pressure swing absorption. The main performance indicators for nitrogen production are production capacity, nitrogen purity and energy efficiency. A high nitrogen purity is important because impurities lead to lower yield in the ammonia synthesis process and creates the risk for damaging the catalyst (Morgan et al., 2017). Both membrane separation and pressure swing absorption are both limited in their production capacity on an economic competitive level and are therefore not suited for the application of large scale ammonia production. Cryogenic air separation uses the difference in boiling points of the main constituents (nitrogen oxygen and argon) of air. The process consist of the following steps (Bennani et al., 2016):

- Compression and cooling of air
- Purification of dry air stream
- Cooling the air to the dew point of air (-176.15°C)
- Distillation of air

Cryogenic air separation produces high purity nitrogen, suitable for the ammonia synthesis process. The process mainly uses energy for the compressors and the coolers. In (Bañares-Alcántara et al., 2015) an energy requirement of 0.11 kWh/kg N_2 is reported. However, for this research, data from the nitrogen separation plants from the Dutch gas transport operator (Gasunie) were obtained. From this data an energy requirement of 0.23 kWh/kg N_2 was calculated. Furthermore, the load range is reported to be between 60-100%. This creates a problem for flexible ammonia production. This can be solved by introducing multiple cryogenic separation units or overproduction of nitrogen. The lack of flexibility in the nitrogen production process is not considered in this project but is instead incorporated in the flexibility of the whole ammonia plant.

5.3.2.2 Ammonia synthesis

The feed gas entering the ammonia synthesis loop has very high purity requirement of 99.99% for both hydrogen and nitrogen to prevent damage or deactivation of the catalysts. The all-electric system that is used in this study has the advantage over the conventional ammonia production system that the feed gas from the electrolyser and air separation unit (ASU) are both very pure and therefore no or less purification is needed. Within the ammonia synthesis reactor, the chemical equilibrium of forming NH_3 creates the limitation that only 20 to 30% of the hydrogen and nitrogen is converted. Therefore, a recycling system is used in which the ammonia is first condensed, after which the hydrogen and nitrogen are again used for ammonia synthesis. This results in a conversion of about 98% (ISPT, 2017). In the ammonia synthesis reactor, the temperature is carefully managed by exchanging heat between the outlet and inlet stream as they have to be cooled and heated respectively. The synthesis reaction is exotherm and the heat from the reaction is sufficient for maintaining the temperature level in the reactor system. The study of (Cheema and Krewer, 2018) mentions three bottlenecks in the ammonia synthesis loop: catalytic reaction, NH3 separation by condensation and recycling of unreacted reactants. Furthermore, the catalytic reaction was said to have a three times higher influence than the other two bottlenecks. In their study, the operating and production flexibility of the Haber-Bosch ammonia reactor was investigated using a mathematical model. It was found that a 16% hydrogen intake reduction was possible. However, the H_2-to-N_2 ratio gave the most flexibility with up to 67% decrease in H_2 intake. However, it was not investigated how this would affect the total energy efficiency. The study of (Bañares-Alcántara et al., 2015) reports a large drop in energy efficiency when the ammonia synthesis process is operated at lower loads. In that study it is assumed that the synthesis loop is operated at stable conditions at most of its lifetime. In the study of (Bennani et al., 2016) it is stated that the synthesis loop requires a stable flow of hydrogen. In order to create this stable flow of hydrogen, a hydrogen storage buffer is used. In the study of (Bañares-Alcántara et al., 2015) it is also stated that the ammonia synthesis loop has to operate continuously for the lifetime of the plant. In that study that is accomplished by the implementation of a hydrogen buffer and by using previously produced ammonia for electricity production in times of shortages for the ammonia synthesis loop.

An alternative for the production of ammonia that is currently in the development phase is electrochemical ammonia synthesis which can be subdivided in to liquid electrolyte, molten salt, composite membrane and solid state electrolyte synthesis. The solid state ammonia synthesis is reported to be the most promising technology in which ammonia is directly produced from a source of hydrogen (water) and nitrogen (air) using a fuel cell. The synthesis occurs at temperatures between room temperature and 800°C depending on the type of electrolyte that is used (Giddey et al., 2017). This technology is now only researched on the fundamental scale and the ammonia synthesis rates obtained are very low at this stage and need to be improved by at least 1 or 2 orders of magnitude to become commercially attractive for small scale applications (ISPT, 2017). However, the advantage of this technology is the potential large reduction in system costs because there is no need for an electrolyser system and ammonia synthesis plant and the much improved flexibility such that it can be integrated with intermittent renewables. It is expected that the energy requirements for this technology are in the same range as the electrolyser/Haber-Bosch route (Giddey et al., 2017).

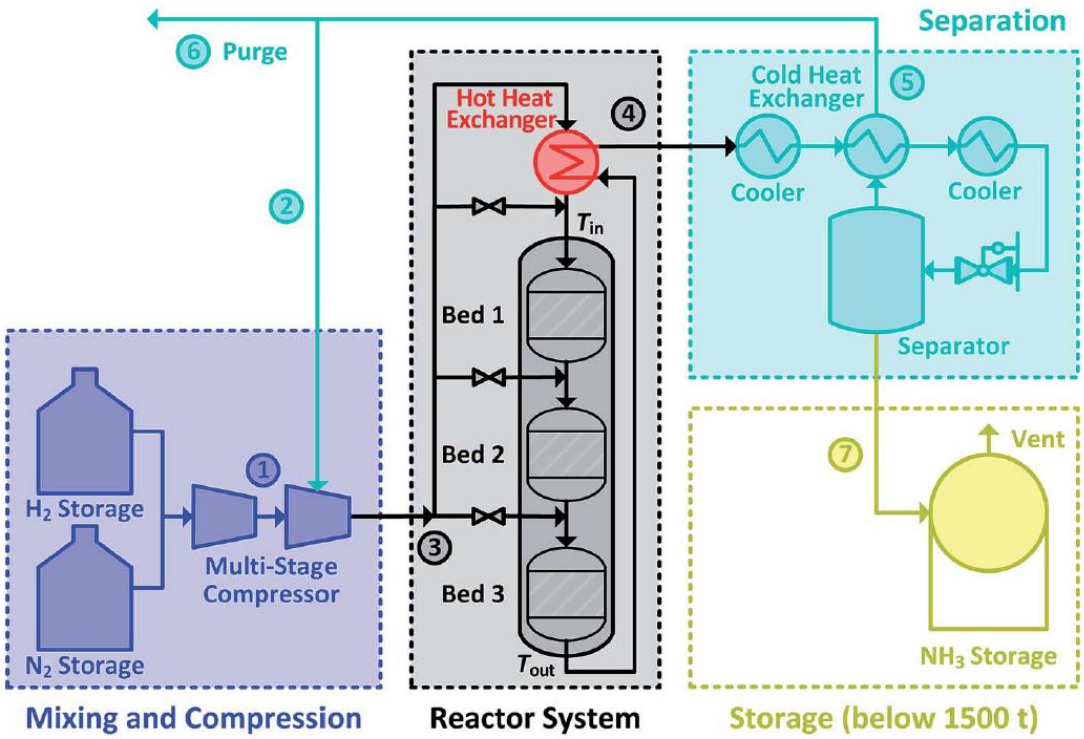

Figure 20. Schematic example of an ammonia synthesis plant. Adapted from (Cheema and Krewer, 2018).

5.3.3 Ammonia storage

Similar to hydrogen, ammonia can be stored either cooled as a cryogenic liquid or under medium pressure (8-17 bar) to increase its energy density relative to ambient temperature and pressure. The major difference with hydrogen is that ammonia becomes a cryogenic liquid at -33°C instead of -253°C for hydrogen at atmospheric pressure (Bañares-Alcántara et al., 2015). For large scale applications, ammonia is normally stored in large insulated cylindrical tanks at atmospheric pressure and maintained at a temperature of -33°C. In this state, ammonia has a volumetric energy density of 15.37 MJ/L. Pressurised ammonia storage vessels have a lower maximum capacity of about 270 tonnes and are therefore less suitable for large scale storage. Low temperature storage tanks have a maximum storage capacity of about 60.000 tonnes of ammonia which is 156 GWh based on the LHV of ammonia. In the Netherlands, large ammonia storage tanks are present at large ammonia plants in the city of Geleen (2x15 kton), Rozenburg (2x15kton) and Sluiskil (1x10 kton and 1x20 kton) (ISPT, 2017). Due to heat transfer from the outside of the tank, boil-off of ammonia occurs of about 0.04% per day. A recompression/refrigerating loop is applied that condenses the ammonia boil-off and returns it to the tank. The power requirements for ammonia storage are only from this recompression/refrigerating loop and in (Morgan et al., 2017) the power requirements are stated as 15 kW for a 9000 tonnes ammonia storage tank. For this study this is recalculated to 1.667 kW/10^6 kg NH_3 and used for further calculations. Furthermore, a standard storage tank of 30.000 tonnes is assumed which represents 156 GWh of ammonia storage based on the LHV.

5.3.4 Electricity production from Ammonia

For the production of electricity from ammonia there are two main routes that are direct combustion or decomposition in to hydrogen and nitrogen and the subsequent use of hydrogen in fuel cells or gas turbines. In the study of (ISPT, 2017) the optimal technology for ammonia to power was investigated together with the University of Twente and the energy company Nuon. The direct combustion of ammonia has some fundamental difficulties over hydrogen and methane. Ammonia has a much lower volumetric energy density, wobbe index and flame speed than methane. Especially the low flame speed makes the direct combustion of ammonia difficult and would require a fundamental different design of the combustor. Furthermore, the risk of NO_x formation due to the existence of nitrogen is high. The development of an ammonia based powerplant is therefore not expected in the (near) future (ISPT, 2017). It was concluded that the most optimal technology to produce electricity from ammonia is to decompose/crack the ammonia in to hydrogen and nitrogen and to use the hydrogen in a hydrogen CCGT. This is also the assumption for this study.

The cracking process of ammonia happens at a temperature of around 400°C using a catalyst. This process is endotherm so heating is required. The energy losses in the ammonia cracker occur due to ammonia boil off based on heat of evaporation (liquid ammonia to gaseous form), the energy required for heating the ammonia to 400°C, ammonia conversion to hydrogen losses and thermal energy losses (Giddey et al., 2017). The cracker efficiency was assumed to be 76% after the 'best case scenario' results in (Giddey et al., 2017). Large scale ammonia crackers are not yet commercially available but are expected to be developed in the near future. Furthermore, technological improvements are needed in the flexibility of the cracking process because the CCGT should be able to operate in a flexible way (ISPT, 2017). The produced hydrogen is combusted in a hydrogen CCGT that is described in paragraph 5.2.4 with an efficiency of 60%. The efficiency of ammonia to electricity is therefore 45.6%.

5.4 Methane system

An energy storage system based on methane would comprise an electrolyser system for hydrogen production, hydrogen transport, a carbon dioxide production system, a methanation plant, methane storage and a system for the reconversion of methane in to electricity. The electrolyser system and hydrogen transport in this methane storage system do not differ from those in the hydrogen system that are already explained. Therefore, these components are not explained again and the reader is advised to read subchapter 5.2 for more information. The rest of the system is explained is this subchapter.

5.4.1 Power to Methane

Power to methane is the concept of converting electricity in to hydrogen and subsequently convert the hydrogen to methane by combining it with CO_2 in a methanation plant. The methanation process can either be biological or chemically. The process of biological methanation suffers from slow kinetics and low mass transfer, making not suitable for large scale methanation processes (Ghaib and Ben-Fares, 2018; Götz et al., 2015). Therefore, in this study chemical methanation is assumed which is a technology that is currently commercially available. The methanation reaction is given by the following formula:

$$4\,H_2 + CO_2 \leftrightarrow CH_4 + H_2O$$

In the methanation process hydrogen and carbon dioxide are combined in presence of a catalyst to form methane and water. Hydrogen and carbon dioxide will adsorb to the catalyst surface where the reaction takes place. Initially only the products methane and water are formed until a balance situation is achieved. In the balance situation methane and water are formed at the same rate from hydrogen and carbon dioxide as the reverse reaction. In a next step, the reactants are cooled such that the water will condensate after which the resulting gas mixture is led to the next reactor. Therefore, multiple steps are needed to accomplish a near 100% conversion (Vlap et al., 2015). The conversion in to methane is a exothermic reaction, releasing 165 kJ/mole in the form of heat. The efficiency of the methanation reaction is at maximum 83% and the remaining 17% is released as heat (Ghaib and Ben-Fares, 2018). To start up the reaction a certain amount of activation energy in the form of heat is required. When the process is operating, no external heat source is needed due to the exothermic reaction.

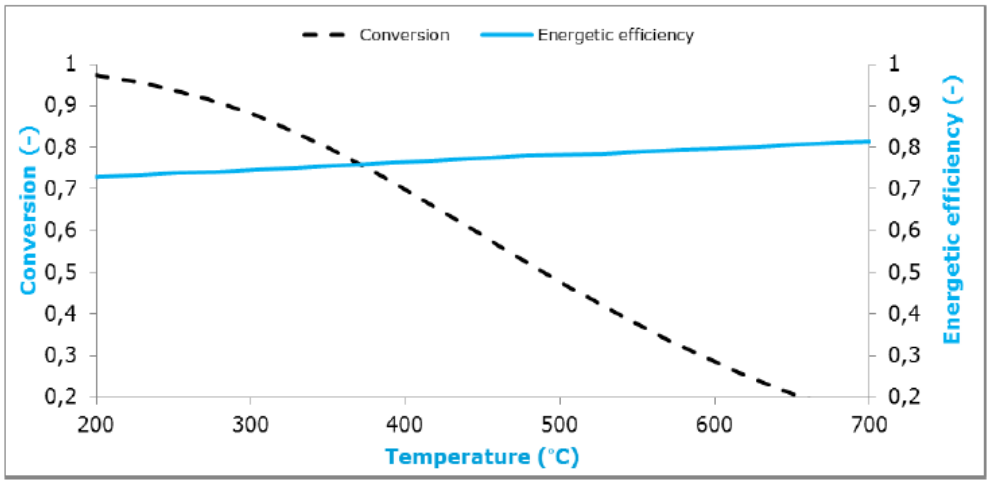

Figure 21. Theoretical efficiency and conversion of methanation plotted against temperature. Adapted from (Vlap et al., 2015).

Due to the exothermic reaction, the process is thermodynamically favored towards low temperature and high pressure. However, this leads to reduced kinetics and therefore an optimum is chosen between efficiency and reaction speed. Figure 21 shows the theoretical efficiency and the conversion of the methanation process against temperature. It can be observed that there is a breakeven point at 377°C for optimal energetic efficiency and conversion. The energetic efficiency of operational methanation plants is between 70-80% (Götz et al., 2015; Grond et al., 2013). For this study the energetic efficiency of methanation is assumed to be 80%. It is assumed that technological developments will enable this high efficiency. An extra opportunity for improved efficiency lies in the utilization of the heat from the methanation reaction. However, this is not considered in this study.

Multiple reactor types have been adapted for methanation and the most relevant ones are fixed-bed, monolith microchannel, membrane and sorption-enhanced reactors (Ghaib and Ben-Fares, 2018). The fixed-bed technology is the only mature technology. The other technologies are in the development phase and have to prove their technological and economic feasibility. As the methanation reaction is exothermic, a significant issue in the design of a reactor is the heat management to realize a good temperature control. For the common fixed-bed reactors mostly a series of adiabatic (no heat exchange) reactors are used with intercooling and gas recirculation (Götz et al., 2015). Due to the adiabatic operation, the catalyst have to be able to withstand a broad temperature range of 250 to 700°C. Dynamic operation of a methanation plant is difficult due to the temperature differences that would occur due to the exothermic methanation reaction. Therefore, most methanation plants are operated in steady state. The power to gas concept demands variable operation due to the intermittency of renewables. Therefore, research is done to improve the variability of the process (Ghaib and Ben-Fares, 2018). However, to overcome the variable hydrogen input stream mostly a hydrogen buffer storage is applied (Götz et al., 2015).

The type of catalysts in the methanation process is important and various materials can be used. This is also a research topic that has a lot of interest. Main parameters of the catalyst choice are the temperature resistance (material durability), costs and efficiency. Nickel is the most used catalysts because of the low costs and relative high efficiency. Other materials can be more effective but are generally not used due to their high costs.

5.4.2 CO_2 sources

Carbon dioxide sourcing is in this study limited by the assumption that the power sector is totally renewable and without greenhouse gas emissions in 2050. This implies that the CO_2 has to be from a renewable source such as biomass, the atmosphere or from carbon capture and storage (CCS) with a power plant on green gas (biogas or methane from P2G). Therefore, CO_2 sources from fossil fueled power plants or processes such as steam methane reforming for the production of grey hydrogen are not considered. CO_2 is mostly not available as a pure gas or in suitable gas mixtures that can be used in the power to methane process. Therefore, a separation process is needed from a source of CO_2. Multiple CO_2 separation technologies exist such as absorption, adsorption, membrane and cryogenic distillation.

CO_2 from biomass can be produced by fermentation, gasification and combustion with CCS. If a biogas plant is available near the methanation plant the produced biogas could be used, after removing harmful trace components, directly in the methanation process. Another option is to use the CO_2 that is produced in a biogas upgrading plant. Depending on the allocation of the costs and energy requirements, this could be a low cost and energy demanding source of CO_2 (Ghaib and Ben-Fares, 2018).

Recently many studies investigated the separation of CO_2 from ambient air. This process is technically possible, but has a high energy demand and costs relative to the other sources. This is due to the very

low abundance of about 400 ppm of CO_2 in the air. The advantage of this technique is that it can be done at every location and therefore removes the need of CO_2 transport or/and storage (Schiebahn et al., 2015).

For this study it is assumed that the CO_2 is captured with CCS from the CCGT that uses the produced methane from the methanation system. CCS is a technology that is already widely studied due to the opportunities for greenhouse gas emission reduction with the current fossil fuel plants. For this process 2-4.2 GJ/tonne of CO_2 is needed (Grond et al., 2013). For this study an average of this range is used which translates to 0.86 kWh/kgCO_2. Transport of CO_2 is not taken into account in this study.

5.4.3 Methane storage

Methane storage is a mature technology that is already widely adopted in the Netherlands. The current gas storage facilities are used for delivering peak demand. The current storage facilities have a storage capacity of 12.9 billion m^3 which is more than 110 TWh (LHV) (Gessel et al., 2018). As the total demand for electricity is assumed to be 150 TWh in 2050, it can be concluded that the current gas storage facilities are sufficient for this application.

Table 7. Current natural gas storage facilities in the Netherlands. Adapted from (Gessel et al., 2018).

Location	Formation type	Start	Working gas/cushion gas (10^9 Nm^3)	Production/injection capacity (10^6 Nm/day)	Number of wells
Norg	Gasfield	1997	5.6/ -	76 / 36	6
Grijpskerk	Gasfield	1997	2.4 / 11.4	50 / 12	10
Alkmaar	Gasfield	1997	0.5 / 3.1	36 / 3.6	
Bergermeer	Gasfield	2015	4.1 / 4.3	57 / 42	
Zuidwending	Salt caverns (5)	2011	0.31 / 0.31	43.2 / 26.4	10

5.4.4 Electricity production from methane

The reconversion of methane in-to electricity is done using a combined cycle gas turbine (CCGT). This is a mature technology with relative high efficiency. In this study the efficiency of the CCGT is assumed to be 60% (Seebregts, 2010).

5.5 General overview system structures

Figure 22 shows the simplified system structure for the three power to gas storage systems. All three systems use electrolysis to convert the excess renewable electricity in to hydrogen. In the hydrogen system, this hydrogen is then stored in salt caverns. In times of shortage the hydrogen is extracted for electricity production in a hydrogen CCGT. In the ammonia system, the produced hydrogen is further combined with nitrogen to form ammonia in the ammonia synthesis plant. The produced ammonia is then stored in large cooled tanks. To reconvert the ammonia to electricity the ammonia is first cracked in to hydrogen and nitrogen after which the hydrogen is combusted in a hydrogen CCGT. The methane system uses the produced hydrogen in the methanation plant. The produced methane is stored in empty gas fields. In times of shortage the methane is combusted in a conventional CCGT.

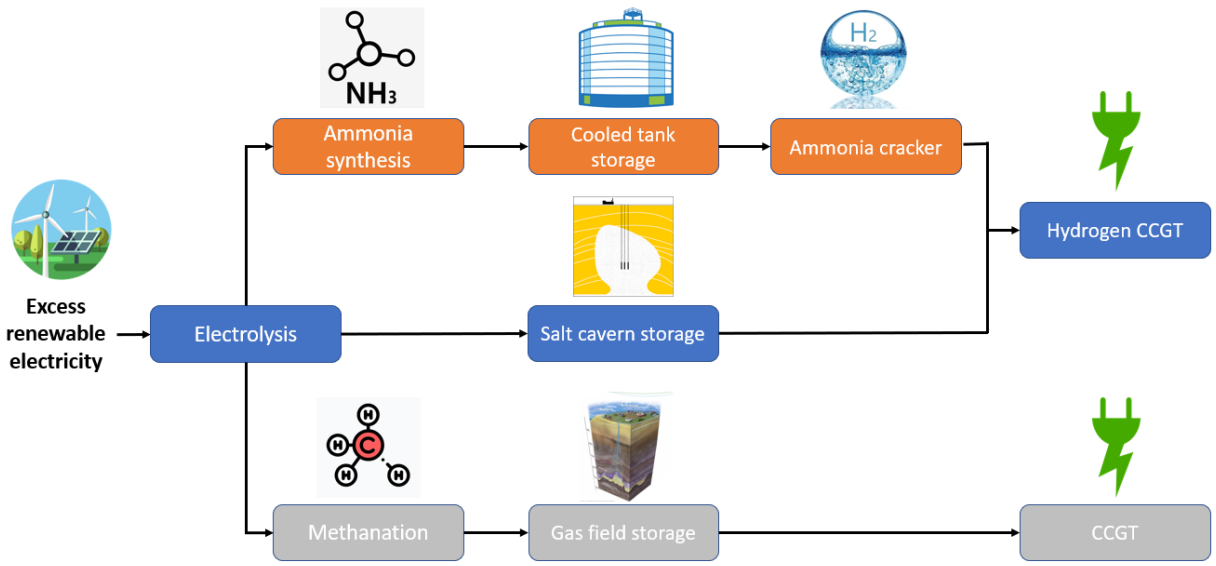

Figure 22. Simplified system structure power to gas systems.

6. METHODOLOGY POWER TO-GAS STORAGE SYSTEM

In this chapter, the methodology is explained that was used to compare hydrogen, ammonia and methane for the energy storage system. The technical properties of the applied technologies are from the literature review from chapter 5.

6.1 Excel model

The output of the PowerPlan scenarios that were made, as described in chapter 4, are exported as an Excel file. This Excel file contains the hourly demand, production, shortage, and excess patterns that are used as an input for the Excel model made for this research.

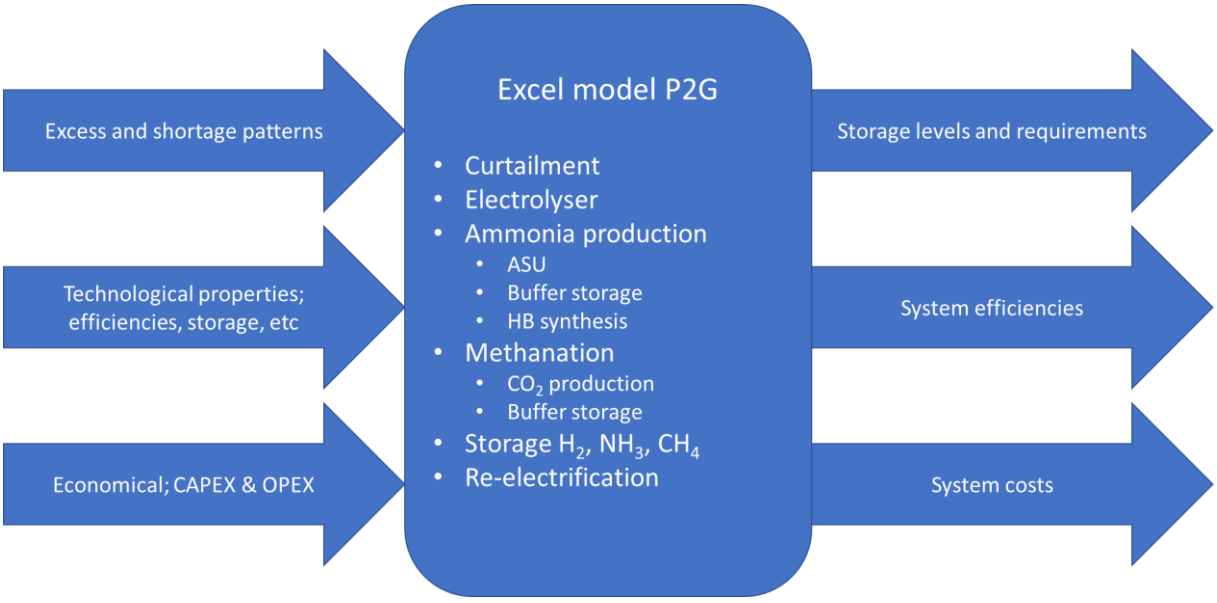

Figure 23. Overview of input and outputs of the Excel model.

6.1.1 General description

The objective of the model is that the demand is always met by the production of the RES and the electricity produced from the stored chemical energy carrier from the power to gas storage system. Three scenarios exist for system;

1. Production exceeds demand and P2G capacity: The demand is completely satisfied, the P2G plants run on maximum load and the surplus of produced electricity is curtailed.
2. Wind power exceeds demand but is lower than demand and P2G capacity: The demand is completely satisfied and the P2G plants are operated at partial load.
3. Production is lower than the demand: All the electricity production is used to satisfy part of the demand. The rest of the demand is satisfied by G2P plants.

The demand pattern is not changed, and stays the same for all scenarios. The hourly shortage pattern is used to determine the extraction rate from the storage system, and the conversion of the chemical energy carrier into electricity. This assumption implies that the production and storage of the chemical energy carrier, taking into account the corresponding efficiencies, have to equal the use from the demand side over the total year. The hourly pattern of excess energy is used as an input for the production of the chemical energy carrier (H_2, NH_3 or CH_4) which is subsequently stored in the large scale storage system. To alter the production such that over the total year the production equals the demand, the RES capacity in the base scenario from PowerPlan is varied up and down. Because wind

and solar energy have different production patterns, all the installed RES capacities in the base scenario are changed such that the share of each source stays the same (fixed ratio).

The input of the PowerPlan scenarios is first analyzed for total energy demand, production, shortage and excess and the hours of overproduction and shortages are calculated. The next block of the model uses the hourly excess pattern to calculate the hydrogen production from the electrolyser systems which is the same for the hydrogen, ammonia and methane based storage system. The hydrogen production pattern is then used as an input for the ammonia synthesis and methanation. The pattern of the produced chemical energy carriers is an input for the storage module. The storage module is affected by both the input from the P2G system and the extraction pattern for the production of electricity. Using this information, the required storage capacity is calculated. The gas to power capacity (hydrogen and methane CCGT's) is assumed to be equal to the maximum shortage that occurs in the system.

6.1.2 Hydrogen system

The results from the PowerPlan scenario shows that there is a steep increase in excess power for a limited number of hours in the year as shown in Figure 24.

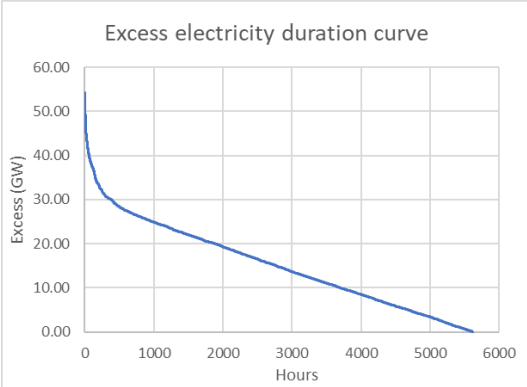

Figure 24. Excess electricity duration curve for the basis scenario from PowerPlan.

The electrolyser capacity can be set to the maximum oversupply power, such that all excess electricity can be converted to hydrogen. However, this would result in a low utilization of the electrolyser systems. It is therefore interesting to look at the installed electrolysers and the corresponding full load hours and what share of excess electricity is that is converted. The electrolyser capacity is therefore varied between the maximum excess energy and zero. When the excess electricity exceeds the assumed electrolyser capacity, the surplus energy will be curtailed. The share of converted energy is calculated using the following formula;

$$Converted\ excess\ electricity\ (\%) = 1 - \frac{Curtailed\ electricity\ (EL_{cap})}{Total\ excess\ electricity}$$

The curtailed electricity in TWh, varies with the installed electrolyser capacity (EL_{cap}). The total excess electricity follows from the PowerPlan scenario. The full load hours of the installed electrolysers are calculated using the formula;

$$FLH\ (hours) = \frac{Total\ converted\ electricity\ (EL_{cap})}{EL_{cap} * 8760}$$

Where FLH stands for full load hours, the total converted electricity by the electrolysers in GWh, EL_{cap} is the installed electrolyser capacity in GW and 8760 is the number of hours in a year. From these calculations, a graphical representation is created after which the electrolyser capacity can be chosen in the model. With this restriction, the hourly pattern of usable electricity for the electrolyser system is determined. This pattern in used to calculate the produced hydrogen each hour.

$$H_2\ production\ (kg)\ =\ E_{input} * EL_{eff}$$

In the formula above, the conversion from power to hydrogen is given, where H_2 production is in kilograms, E_{input} the electricity input in kWh and EL_{eff} the system efficiency of the electrolyser system in kWh/kgH_2.

To account for energy losses during underground hydrogen storage due to compression and hydrogen loss, the hydrogen input stream is multiplied with an efficiency of 95% that is derived from literature (Blanco and Faaij, 2018; Decourt et al., 2014; Ripepi, 2017).

The hourly shortage pattern determines the production pattern of electricity from the energy storage system. It is therefore used to calculate the extraction of hydrogen from the underground storage. Using the efficiency of 60% of the of the hydrogen CCGT (Decourt et al., 2014), the hydrogen extraction in kilograms is calculated for every hour using the following formula;

$$H_2\ extraction\ (kg) = \frac{E_{shortage}}{CCGT_{efficiency} * LHV_{H2}}$$

Finally, the storage level is calculated using the input and extraction pattern. The minimum storage level is then calculated, after which the initial storage level is set to this value (given that the number is negative) to ensure the storage level is never negative. As explained before, the user has to alter the input scenario to ensure that the final storage level is equal to the initial level.

6.1.3 Ammonia system

The ammonia storage system starts with the same modules as the hydrogen system. The hourly excess electricity pattern is used to produce hydrogen with the same assumptions and calculations. This hydrogen stream is then used as an input for the ammonia synthesis module. However, there are multiple system parts that also use electricity in the total system. Therefore, not all excess electricity can be utilized by the electrolyser system which will lead to a decrease in H_2 production. The other system that use electricity are the compressors for the buffer storage, ammonia synthesis, nitrogen production and the cooling for the ammonia storage. The total electricity use of these systems are calculated, and this is subtracted from the original total electricity input for the electrolysers.

$$H_2 input\ stream\ correction\ (\%) = \frac{Original\ total\ input\ electrolyser - Other\ electricity\ use}{Original\ total\ input\ electrolyser}$$

In this formula the 'original total input electrolyser is' is the electricity input for the electrolyser before the correction for other electricity use and 'other electricity use' is the sum of the electricity consumption of the other parts in the system. However, the electricity use of the other parts in the system are directly depended on the hydrogen input. The actual H_2 input stream correction has to be determined with an iterative process where the input is changed a number of times, such that the electricity used for electrolysis and the other systems is equal to the total excess energy.

To ensure a smoother input of hydrogen for the ammonia synthesis, a hydrogen buffer is implemented. The buffer storage has three objectives:

- Decrease variability in the hydrogen input stream
- Ensuring a minimum number of hours of consecutive operation time
- Ensure a minimum input stream for the ammonia synthesis

The hydrogen buffer storage is assumed to be filled to half its capacity before the ammonia synthesis plants are put in operation mode. This ensures that the ammonia synthesis plants can run a minimum number of hours, in case a period of low (or zero) hydrogen input follows.

This hydrogen buffer storage is modelled such, that the hydrogen input stream for the ammonia synthesis is only changed in timesteps of 48 hours (can be changed in the model). An average of the input stream of hydrogen from the electrolyser is calculated for every block of 48 hours. The underlying assumption is that the hydrogen production can be predicted on a 48 hour time scale, because this calculation uses data from upcoming hours. It is assumed that weather predictions and the associated RES production and excess energy are accurate enough. Further parameters of the buffer storage are the storage size in kg of hydrogen and the minimum hydrogen stream to the ammonia synthesis.

The electricity use for the compression of hydrogen in the buffer storage is calculated using the following formula;

$$Compression\ electricity\ use\ (MWh) = H_2\ input\ buffer * electricity\ use\ compressor$$

In this formula, the electricity use compressor is given in kWh/kg stored hydrogen (Bertuccioli et al., 2014).

The input stream of hydrogen is further used in the ammonia synthesis process. The produced ammonia is calculated using the following formula;

$$NH_3\ production\ (kg) = \frac{H_2\ input\ stream\ (kg) * LHV_{H_2}}{LHV_{NH_3}}$$

Where H_2 LHV and NH_3 LHV are the lower heating values of hydrogen and ammonia respectively. The electricity use for the ammonia synthesis of every hour is calculated using the following formula;

$$NH_3\ synthesis\ electricity\ use\ (MWh) = NH_3\ production\ * Energy\ requirement\ NH_3$$

Where 'Energy requirement NH_3' is the electricity use per kg of NH_3 synthesis (Bañares-Alcántara et al., 2015; Morgan et al., 2017).

The required nitrogen for this process is calculated using the stoichiometric ratio (SR_{NH3}) of the reaction (Bañares-Alcántara et al., 2015). The required electricity for this process is calculated using the energy requirement per kilogram of nitrogen from the ASU.

$$N_2\ production\ electricty\ use\ (MWh) = SR_{NH3} * H_2 input\ stream * Energy\ req. N_2\ prod.$$

The produced ammonia is stored in large cooled tanks. The energy requirement for the storage is calculated using the following formula where 'Electricity cooling req' is the electricity use per kg of stored ammonia (Bartels, 2008; Morgan et al., 2017):

$$Electricity\ use\ storage\ cooling\ (MWh) = NH_3\ storage\ level * Electricity\ cooling\ req$$

The hourly shortage pattern determines the production pattern of electricity from the energy storage system. It is therefore used to calculate the extraction of ammonia from the storage. Using the efficiency of the cracking process (Giddey et al., 2017) and the efficiency of the of the hydrogen CCGT (Decourt et al., 2014), the ammonia extraction in kilograms is calculated for every hour using the following formula;

$$NH_3\ extraction\ (kg) = \frac{E_{shortage}}{CCGT_{efficiency} * \mathrm{Cracking_{efficiency}} * LHV_{\mathrm{NH_3}}}$$

The hourly patterns of the input stream and the extraction of ammonia determine the storage levels during the year.

6.1.4 Methane system

The model for the methane storage system works for the most part the same as the ammonia storage model. The compression for the hydrogen buffer storage and the production of CO_2 require electricity and therefore a similar hydrogen input stream correction for the methanation system is done. The buffer storage is modeled in the same manner as in the ammonia storage system. The methane production is calculated using the following formula (Ghaib and Ben-Fares, 2018; Grond et al., 2013):

$$CH_4\ production\ (kg) = \frac{H_2 input\ stream * Methanation_{efficiency} * LHV_{H_2}}{LHV_{CH_4}}$$

The required CO_2 for the methanation process is calculated using the stoichiometric ratio (SR_{CH4}) of the reaction (Vlap et al., 2015). The electricity use of the CO_2 production is calculated with the following formula (Grond et al., 2013):

$$CO_2\ production\ electricity\ use\ (MWh) = SR_{CH4} * H_2\ input\ stream * Energy\ req. CO_2\ prod.$$

The produced methane is stored in empty gas fields. To account for the compression and other storage losses a storage efficiency is used (Blanco and Faaij, 2018). The incoming methane stream is adjusted for this efficiency.

6.1.5 Economic analysis

For the economic analysis of the complete energy system the Capital Expenditures (CAPEX), Operating Expenses (OPEX) and economic lifetime of all the parts in the system were gathered from literature. In this research the situation in the year 2050 and beyond is studied and therefore costs estimations from literature had to be used. Multiple studies were compared when possible and an average value was used for the calculations.

The production of electricity is determined by the cost of offshore wind, onshore wind and solar PV. Depending on the round trip efficiency of the different systems, the capacities (with fixed ratio) were altered such that the production was equal to the total use of electricity. Therefore, the electricity production costs differed for every scenario with different capacities. The cost specifications that were used for the renewable energy sources in this study are given in Table 8. Costs that were stated in dollars were converted to euros using the yearly exchange rate from the year of publication of that study.

Table 8. Costs specifications of renewable energy sources.

	CAPEX (€/kW)	CAPEX (€/kW/year)	OPEX (€/kW/year)	Economic lifetime	Source
Offshore wind turbines	1100	45.8	40	24	(Wiser et al., 2016b)
Onshore wind turbines	1760	70.4	49.2	25	(Lensink and Pisca, 2019)
Solar PV	900	30	20	30	(Chiantore et al., 2015)

The specifications for the components used for the cost calculations in the hydrogen, ammonia and methane energy storage system are listed in Table 9. The required capacity of the components are outputs from the model and are dependent on the excess and shortage electricity pattern and the design choices for the buffer storage (for the ammonia and methane system).

Table 9. Cost specifications hydrogen, ammonia and methane system.

	CAPEX (€/kW)	CAPEX (€/kW/year)	OPEX (€/kW/year)	Economic lifetime	Source
PEM electrolyser	700	23.3	14	30	(Buttler and Splietho, 2018; Schiebahn et al., 2015)
Methanation plant	710	67.77	70	10.5	(Schiebahn et al., 2015)
CO_2 sourcing CCS	802	26.7	32	30	(Grond et al., 2013)
Ammonia plant incl. nitrogen separation	1054	70.3	26.3	15	(Bennani et al., 2016; Morgan et al., 2017)
Hydrogen CCGT	732.7	24.4	29.3	30	(Decourt et al., 2014)
Methane CCGT	680	23	27.2	30	(Seebregts, 2010)

The storage costs are listed in Table 10 and are also used for the economic analysis. Using the hourly input and extraction patterns in the model, the total stored energy is calculated and the associated total storage costs are calculated using the costs of storage.

Table 10. Storage costs for the different energy carriers and storage techniques.

Storage technique	**Cost of storage (€/MWh)**	**Source**
Hydrogen salt cavern	2.97	(Decourt et al., 2014; Ouden et al., 2018)
Hydrogen high pressure	7.69	(Decourt et al., 2014)
Underground methane	0.87	(EnergyStock, 2019; Gasunie, 2010; Hinchey, 2017)
Ammonia storage	0.35	(Bartels, 2008; Morgan et al., 2017)

7. RESULTS POWER-TO-GAS STORAGE SYSTEMS

In this chapter the results from the excel model are presented.

7.1 Electrolyser capacity

The results for the sorted unbalance from the PowerPlan scenario showed that there is a limited amount of hours in the year for which there is a significant increase in oversupply (see Figure 12 and Figure 24). Varying the installed electrolyser capacity will decrease the percentage of the total excess electricity that is converted (curtailment) and will increase the running time of the electrolyser system. Figure 25 shows the result of this relation. It can be observed that 100% of the excess energy is converted when the electrolyser capacity is set to the maximum over production of 55 GW. However, this results in only 1600 full load hours for the electrolyser system. An electrolyser capacity of 9.2 GW would still result in a conversion of 50% of the total excess energy and 4740 full load hours for the electrolyser system.

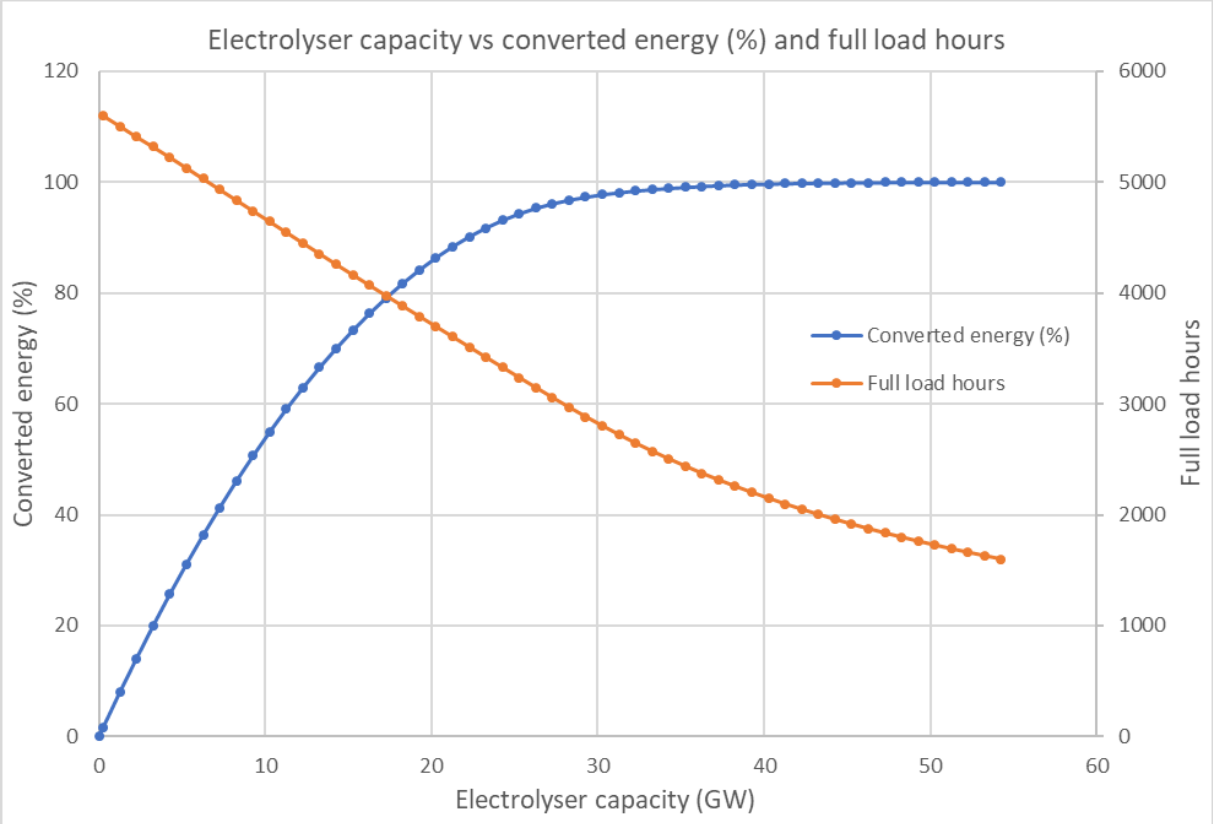

Figure 25. Electrolyser capacity versus percentage of converted excess energy and full load hours of the electrolyser systems.

A basic calculation for the hydrogen production price was made using the CAPEX and OPEX costs of the electrolyser, economic lifetime and the electricity price. The results are presented in Figure 26 and show that the hydrogen price is dominated by the CAPEX costs under approximately 1800 full load hours. After that point, the hydrogen price decreases further with more full load hours. For this research it is assumed that 30 GW of electrolyser capacity is installed in all scenarios. In the base scenario this results in 97% conversion of the total excess energy and 2800 full load hours for the electrolyser system. These calculations are correct for the base scenario of 40 GW of offshore wind, 8 GW onshore wind and 35 GW of solar PV. However, to match the total electricity production and use

in every scenario, these capacities are changed up or down (with fixed ratio). This will result in different shares of curtailment in every scenario because the demand for electricity is not changed.

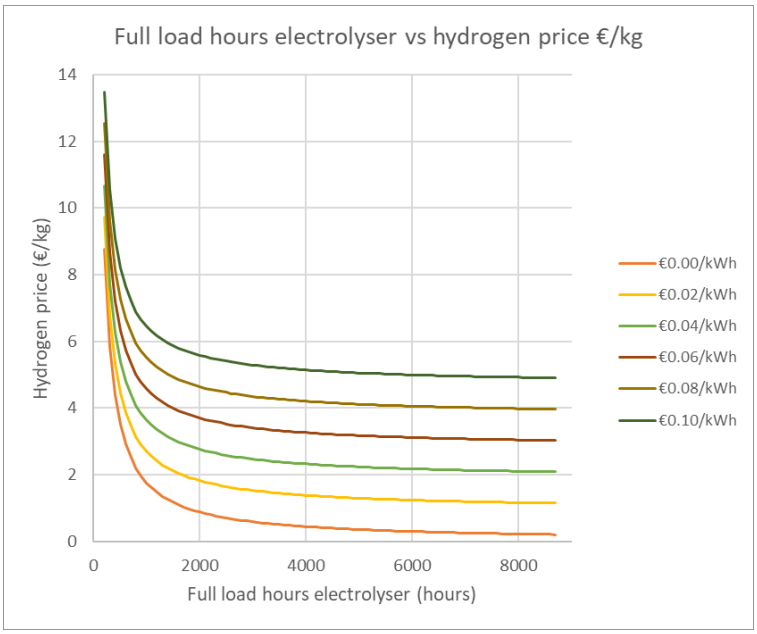

Figure 26. Hydrogen price vs full load hours with various electricity prices.

7.2 System efficiencies

This section presents the system efficiencies of the energy storage system based on hydrogen, ammonia and methane. For the ammonia and methane system the results are shown for the system with a hydrogen buffer storage for peak limitation.

In Figure 27, a waterfall chart of the hydrogen system is presented. In total there is an excess of 68.7 TWh. The used input scenario is 10% lower than the base scenario with 36 GW offshore wind, 7.2 GW onshore wind and 31.5 GW of solar PV. This is due to the high round trip efficiency of the hydrogen storage system. In this system, 0.7 TWh is curtailed due to the design choice of 30 GW of electrolysers. This is significantly lower than in the ammonia and methane systems because the installed capacity of RES is lower. The during the electrolysis process the largest share of energy is lost, accounting for 19.8 TWh. This is due to the assumed efficiency of 70.85% of the electrolyser system (based on the LHV). Hydrogen storage is relatively efficient and 2.4 TWh of energy is lost mainly due to the compression in to the salt caverns. The reconversion of hydrogen to electricity accounts for a loss of 18.4 TWh. This is the most inefficient part of the system with a hydrogen CCGT efficiency of 60%. The shortage, and therefore also the supplied electricity from the hydrogen CCGT's, is 27.6 TWh. The ratio between the shortage and excess electricity gives the round trip efficiency of 40.1%.

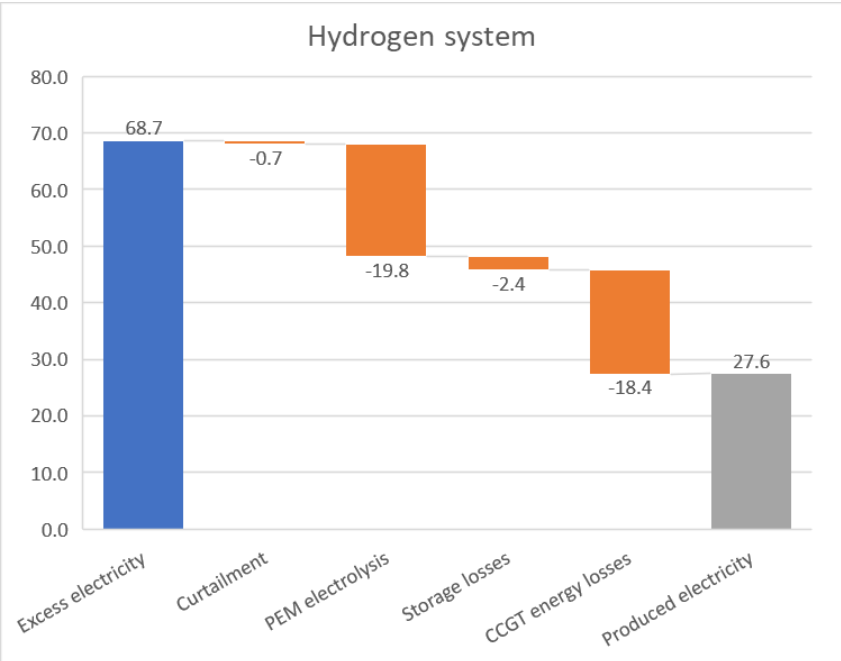

Figure 27. Waterfall chart of the hydrogen system. The blue bar represents the total excess electricity, the orange bars the losses in the system and the grey bar the total produced electricity from the power to gas storage system.

In Figure 28, the waterfall chart of the ammonia system is presented. In total there is an excess of 86.7 TWh. The used input is the base scenario with 40 GW offshore wind, 8 GW onshore wind and 35 GW of solar PV. Curtailment accounts for a loss of 2 TWh after which 22 TWh is lost in the conversion to hydrogen with electrolysis. The ammonia production process has losses from the buffer storage, nitrogen production and ammonia synthesis. The buffer storage used for peak limitation creates a loss of 0.7 TWh. Nitrogen production is not very energy demanding and requires 1.7 TWh. The ammonia synthesis accounts for a loss of 6.6 TWh. Ammonia storage is very efficient relative to the other steps in the system and the losses are negligible. The ammonia cracking process to hydrogen and nitrogen

accounts for a significant loss of 12.8 TWh after which 16.2 TWh is lost in the reconversion to electricity in the hydrogen CCGT. The total shortage and therefore also the produced electricity is 24.5 TWh. This results in a round trip efficiency of 28.3 %.

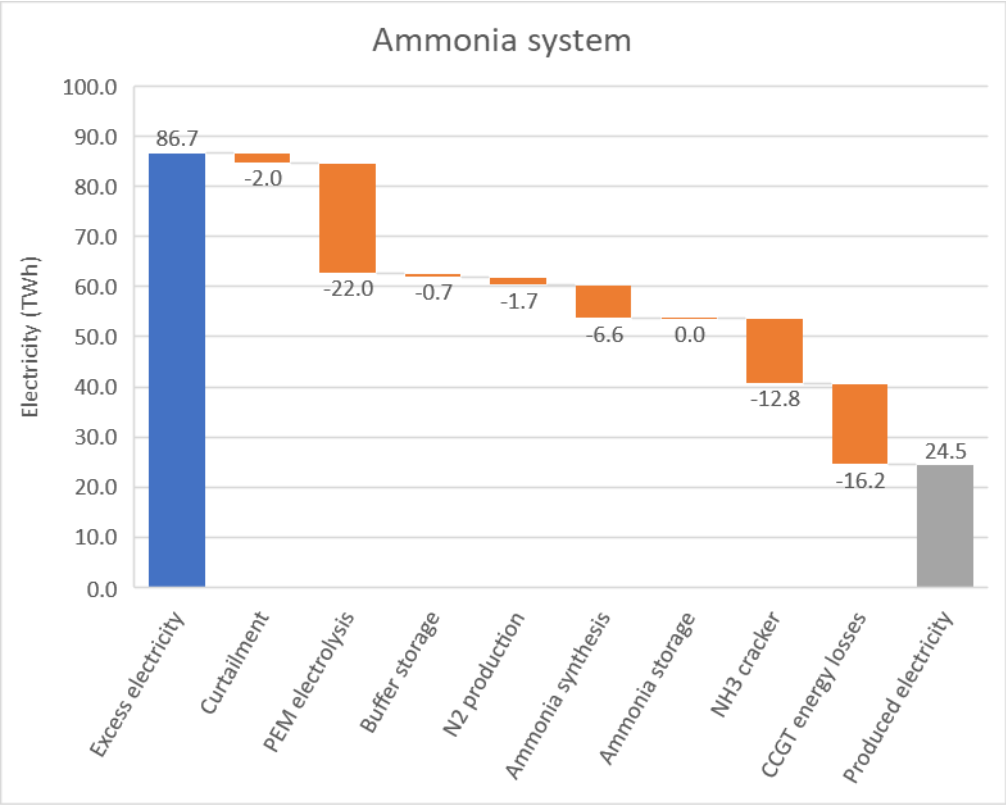

Figure 28. Waterfall chart of the ammonia system. The blue bar represents the total excess electricity, the orange bars the losses in the system and the grey bar the total produced electricity from the power to gas storage system.

In Figure 29, the waterfall chart of the methane system is presented. In total there is an excess of 84.9 TWh. The used input scenario is 1% lower than the base scenario with 39.6 GW offshore wind, 7.92 GW onshore wind and 34.65 GW of solar PV. In this system, 1.8 TWh of electricity is curtailed due to the electrolyser capacity of 30 GW. The conversion to hydrogen accounts for a loss of 21.8 TWh. The buffer storage has only a minor influence with 0.7 TWh. This is due to the relative high storage efficiency in salt caverns and the fact that only a small part of the total produced hydrogen is stored in the buffer storage. Methanation and CO_2 production both account for significant losses with 10.6 and 7.5 TWh. The storage losses in the methane system are 1.3 TWh. In the process of reconversion to electricity a large share of 16.4 TWh is lost. The shortage for this scenario and therefore also the produced electricity is 24.7 TWh. This results in a roundtrip efficiency of 29.1%.

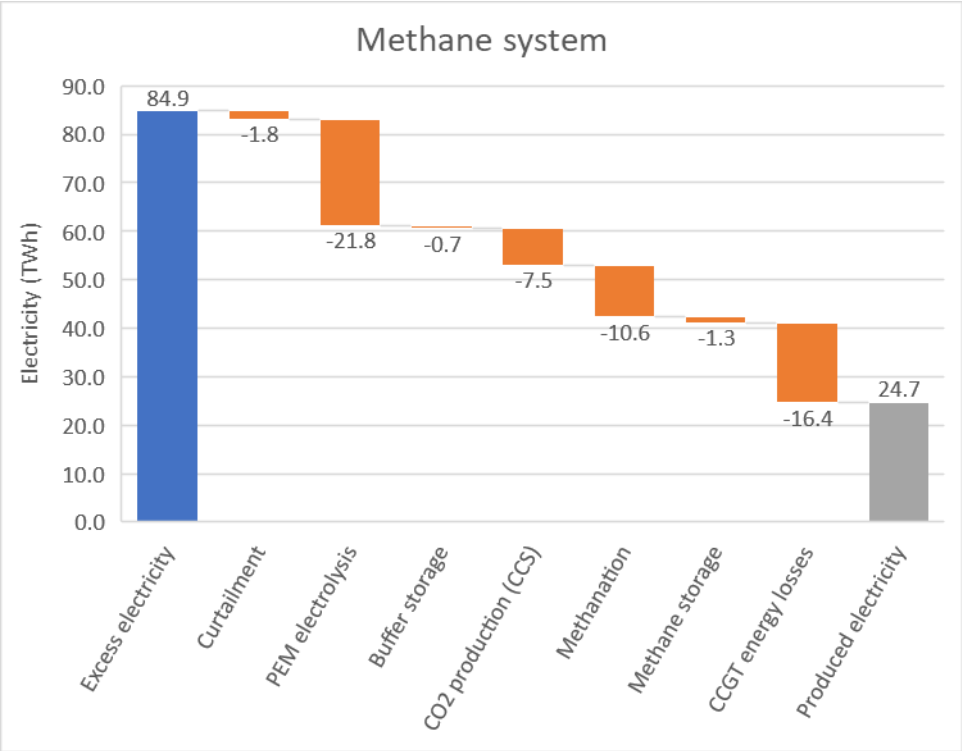

Figure 29. Waterfall chart of the methane system. The blue bar represents the total excess electricity, the orange bars the losses in the system and the grey bar the total produced electricity from the power to gas storage system.

7.3 Buffer storage

The hydrogen buffer that was used for the previous described results of the ammonia and methane system was limited to one salt cavern. Two other scenarios with variable ammonia and methane production (AVP and MVP) and constant ammonia and methane production (ACP and MCP) were investigated. In the variable production scenario it was assumed that the ammonia synthesis and methanation plant could be operated dynamically without efficiency implications. In the constant production scenario it was assumed that the ammonia synthesis could only be operated with constant production. It was investigated how large the hydrogen buffer storage has to be and what the efficiency implications are.

In Figure 30 the hydrogen stream and storage level are presented for the constant production scenario. This result is from the ammonia scenario but the buffer storage for the constant methane production scenario is the same and shows the same results for size and input pattern. The analysis showed that the buffer storage needed a capacity of 5.0 TWh for the scenarios with constant production. For this storage capacity, 38 standard sized salt caverns are needed. The methane and ammonia production is completely constant when it is in operation and four shut downs occur during the year.

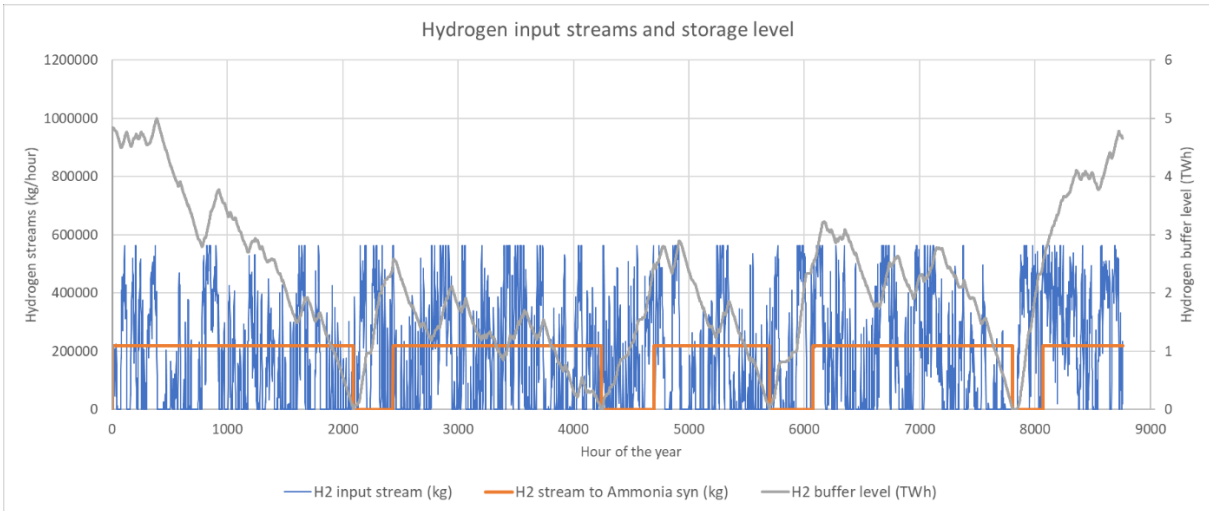

Figure 30. Hydrogen input streams and storage level for the constant production scenario. The grey line represents the hydrogen buffer storage level. The blue line is the hydrogen input stream from the electrolyser system and the orange line is the resulting hydrogen stream to the ammonia synthesis.

Figure 31 shows the efficiency results for the different buffer storage scenarios. MBSS and ABSS are the methane and ammonia buffer storage salt cavern storage scenarios and the results are already presented in the previous subchapter. For the variable and constant methane production scenario (MVP and MCP) the round trip efficiency changes to 29.5% and 28.8% respectively. Relative to the normal buffer scenario (MBSS) this is 0.5% higher and 0.2% lower for the variable and constant production scenario respectively. The ammonia system shows similar results with an increase in round trip efficiency of 0.3% for the variable scenario (AVP) and a decrease of 0.4% for the constant production scenario.

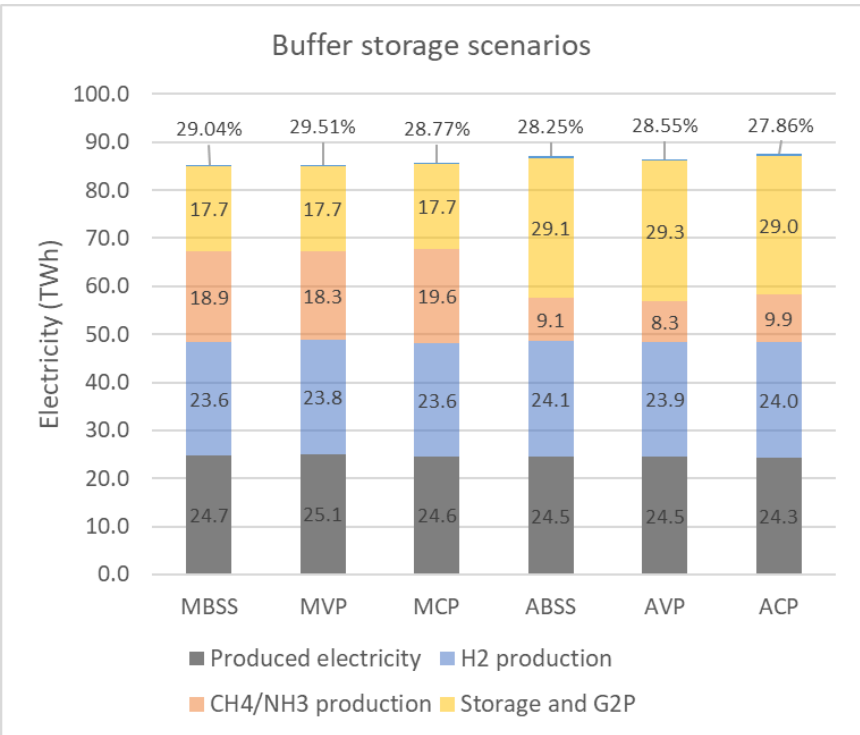

Figure 31. Buffer storage scenarios.

7.4 Storage requirements

The storage requirement of the hydrogen, ammonia and methane system is determined by the maximum storage level during the year. The storage capacity is modelled such that the minimum storage level is exactly zero. For the standard hydrogen system the storage level during the year is presented in Figure 32. The required storage size for the hydrogen system is 8.33 TWh based on the lower heating value of hydrogen. The standard sized salt cavern used for hydrogen storage in this study has a capacity of 134.6 GWh as specified in Table 6. Therefore, 62 salt cavern are needed for the required storage capacity. This is well within the salt cavern potential of the Netherlands. With the current salt production rate, this amount of salt caverns is possible to construct before the year 2050. The maximum required output capacity is 706 GWh/day. Therefore, 59 salt caverns are needed due to the maximum output of a standard sized cavern with one well. However, if multiple wells are installed per salt cavern the output capacity can be increased as discussed in section 5.2.3.

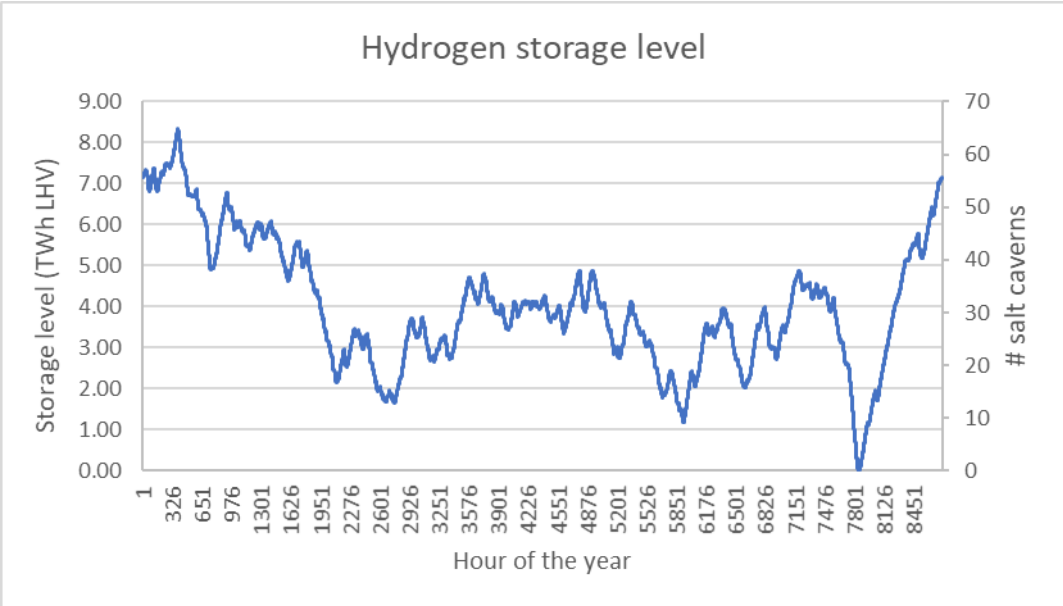

Figure 32. Hydrogen storage level based on the LHV in TWh and number of salt caverns.

The storage level of the ammonia and methane system are shown in Figure 33. The required storage size for the ammonia system is 9.21 TWh based on the LHV of ammonia. This is the highest storage requirement of the three systems and is caused by the low efficiency of the conversion from ammonia to electricity. This can be observed in Figure 33 by steeper decrease of the storage level in periods with shortage. With the ammonia storage tanks with a capacity of 30000 tonne (156 GWh), a total of 60 tanks are required. There are no technical limitations for this storage requirement.

The storage requirement in the methane system is 7.34 TWh. This is the lowest of the three systems and is caused by the relative high efficiency of methane to power. Furthermore, the installed capacity in the methane system is higher than in the hydrogen system (due to the round trip efficiency) and therefore less shortages occur during the year. The storage requirement 7.34 TWh of methane is possible with the existing methane storages in the Netherlands (Gessel et al., 2018).

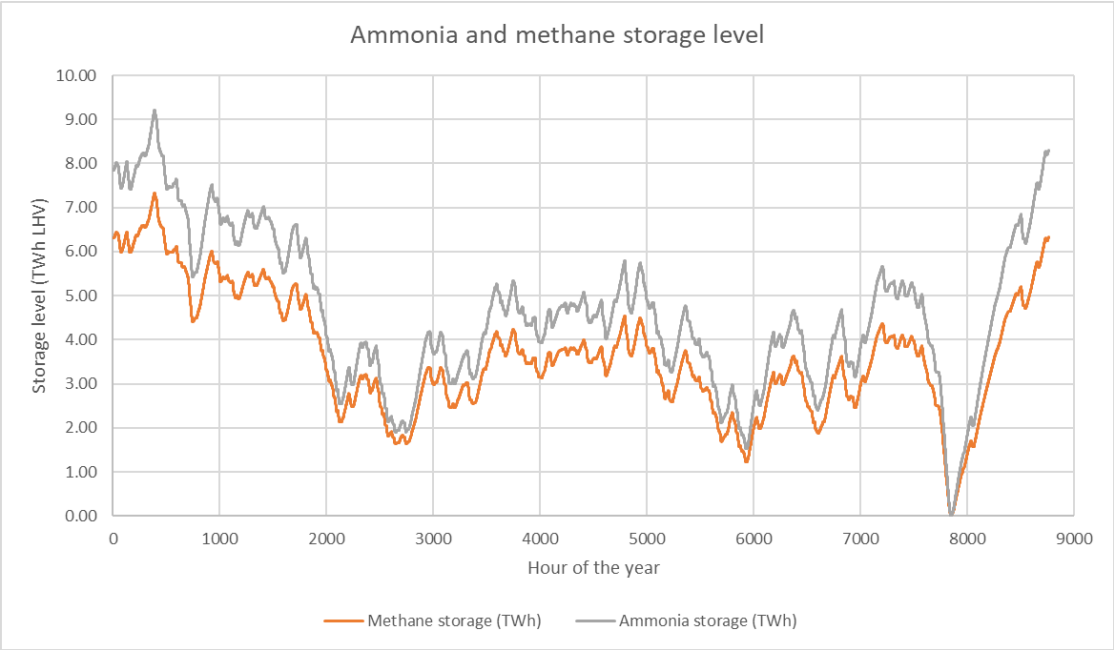

Figure 33. Ammonia and methane storage level in TWh based on the LHV.

7.5 Economic analysis

Figure 34 shows the system costs of the hydrogen system. It can be observed that the largest cost are the electricity production costs of onshore and offshore wind and solar PV. The total system costs are 9.2 billion of euros per year. The electricity production costs are 6.61 billion euros per year which is about 72% of the total system cost. The electrolyser system costs 1.12 billion euros per year which is similar to the costs for the hydrogen CCGT of 1.31 billion euros per year. The hydrogen storage costs are relatively low with 0.17 billion of euros per year. The storage costs are not the decisive factor in the total system costs. The price per kilowatt hour including the energy storage system based on hydrogen is 6.1 eurocent/kWh. The production price of electricity is 4.4 eurocents/kWh and the hydrogen storage system accounts for 1.7 eurocent/kWh.

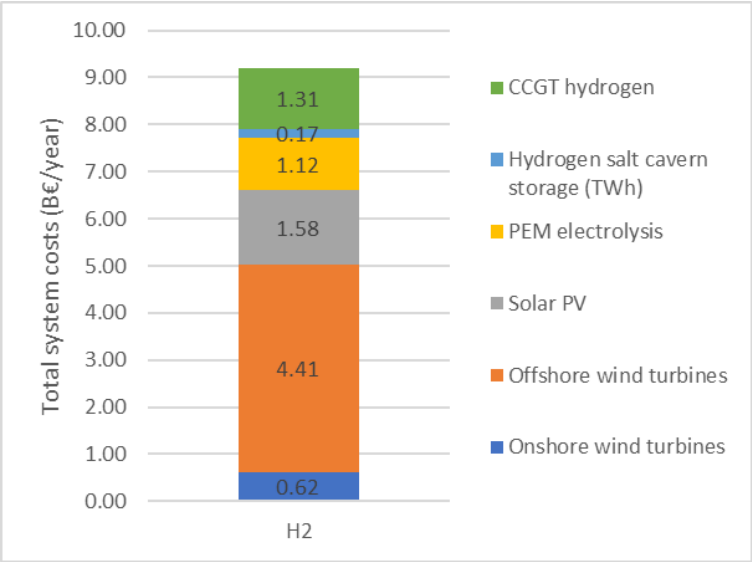

Figure 34. System costs of the hydrogen system.

The economic results for the ammonia system scenarios are shown in Figure 35. The results for the three scenarios with the normal buffer storage (ABSS), constant production (ACP) and variable production (AVP) are presented. The total system costs for the ABSS scenario are 11.77 billion euro per year. The total costs for the variable production are slightly higher at 11.91 billion euro per year. The constant production scenario (ACP) shows the lowest cost of the ammonia scenarios with 10.80 billion euros per year. This is significantly lower than the other scenarios and is mainly due to the fact that a lower ammonia synthesis capacity is needed such that the ammonia plant has a higher utilization. In the variable production (AVP) and normal buffer storage (ABSS) scenario the ammonia synthesis capacity is determined by the maximum hydrogen input.

The normal scenario with buffer storage (MBSS) will be discussed in further detail. Also in the ammonia system, the largest costs are from the electricity production accounting for 7.19 billion euros per year. The cost for the ammonia synthesis plant (including nitrogen production) are moderate, accounting for 1.76 billion euros per year. The ammonia storage costs are 0.03 billion euros per year which is a factor 5-6 lower than the hydrogen system and slightly lower than the methane system. The price of electricity including the energy storage system based on ammonia is 7.2 eurocent/kWh. The electricity production price is 4.8 eurocents/kWh and the ammonia storage system accounts for 3.1 eurocents/kWh.

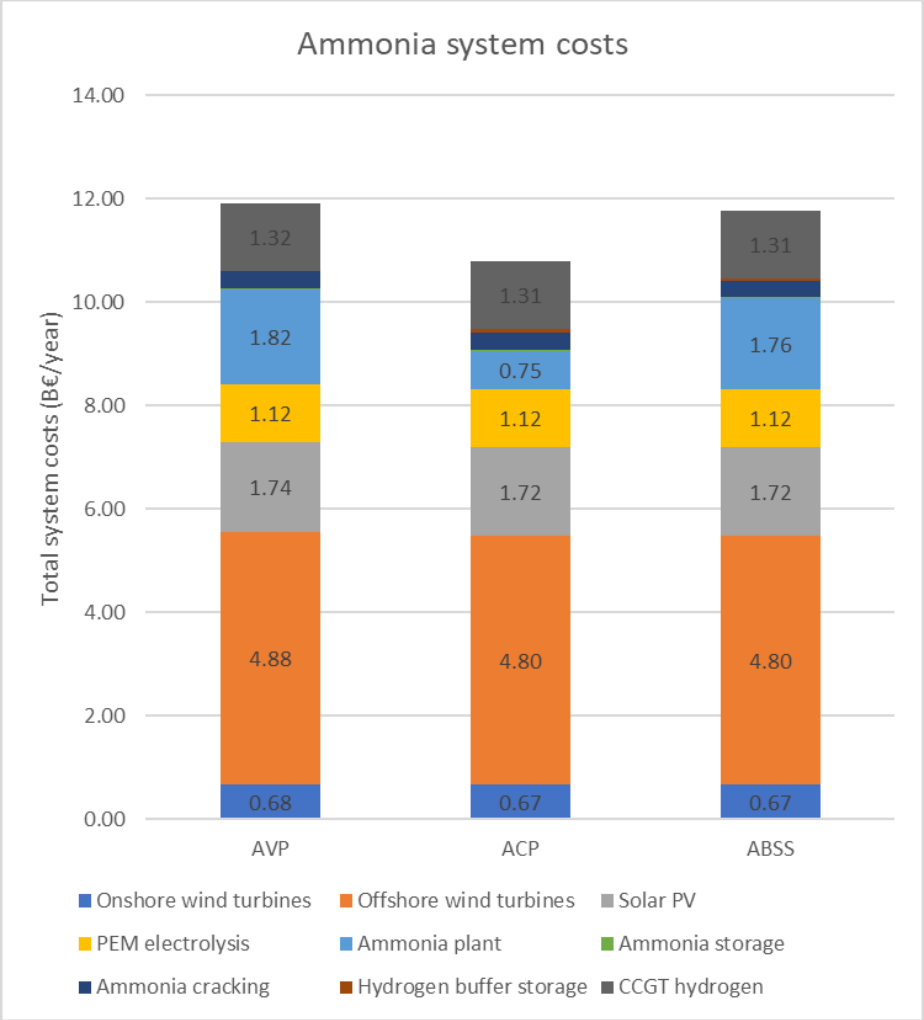

Figure 35. System cost for the ammonia scenarios.

The economic results for the methane system scenarios are shown in Figure 36. The results for the three scenarios with the normal buffer storage (MBSS), constant production (MCP) and variable production (MVP) are presented. The total system cost for the MBSS scenario are 13.34 billion euro per year. The total costs for the variable production are only slightly lower at 13.31 billion euro per year because of the absence of the buffer storage cost. The constant production scenario (MCP) shows the lowest cost of the methane scenarios with 11.92 billion euros per year. This is significantly lower than the other scenarios and is mainly due to the fact that a lower methanation capacity is needed and the methanation plant has a higher utilization. In the variable production (MVP) and normal buffer storage (MBSS) scenario the methanation capacity is determined by the maximum hydrogen input. The methanation plant accounts for a significant share of the total system cost and the results show that a large buffer storage results in lower system costs.

The results of the MBSS scenario will be discussed in more detail. It can be observed that the electricity production cost account for the largest share of the system costs with 7.15 billion euro per year. However, the storage system based on methane also comes with significant costs. The methanation plant together with the required CO_2 production account for 3.69 billion euro per year (MBSS scenario). The methane storage cost are only 0.04 billion euros per year. This is a factor 4 lower than in the hydrogen system. The price of electricity including the energy storage system based on methane is 8.9 eurocent/kWh. The electricity production price is 4.8 eurocents/kWh and the methane storage system accounts for 4.1 eurocents/kWh.

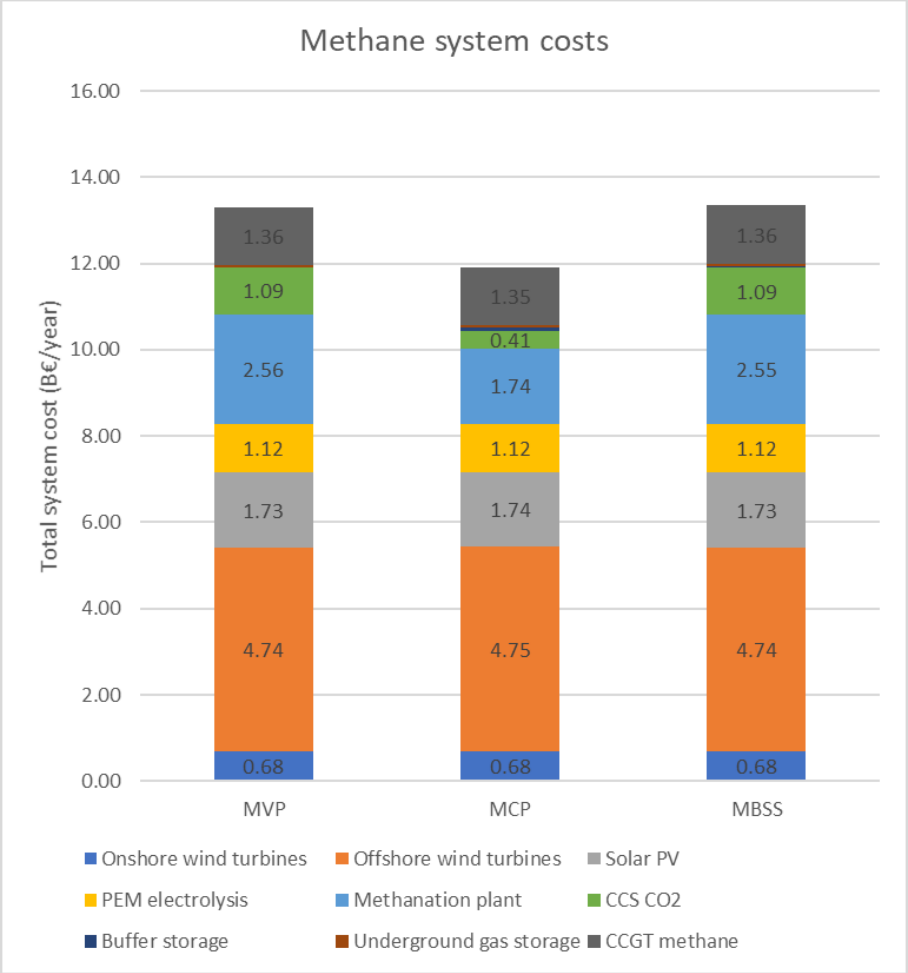

Figure 36. System cost for the methane system scenarios.

To conclude the economic analysis, the results for the hydrogen (H2), ammonia (ACP and ABSS scenario) and methane (MBSS and MCP scenario) are shown in Figure 37. It can be concluded that the hydrogen system has the lowest system cost. The electricity production has in all the scenarios the largest cost and is proportional to the round trip efficiency of the storage system. The deciding cost component is the conversion to the chemical energy carrier. The methanation process comes with the highest cost and therefore the complete methane system also has the highest total costs. The storage and CCGT costs are not the decisive cost component and are more or less equal for all the scenarios. Lastly, the constant production scenario for the ammonia and methane system appeared to have lower cost than the normal buffer storage scenario. This was due to the reduced required ammonia synthesis/methanation capacity that is relatively more expensive than the hydrogen buffer storage.

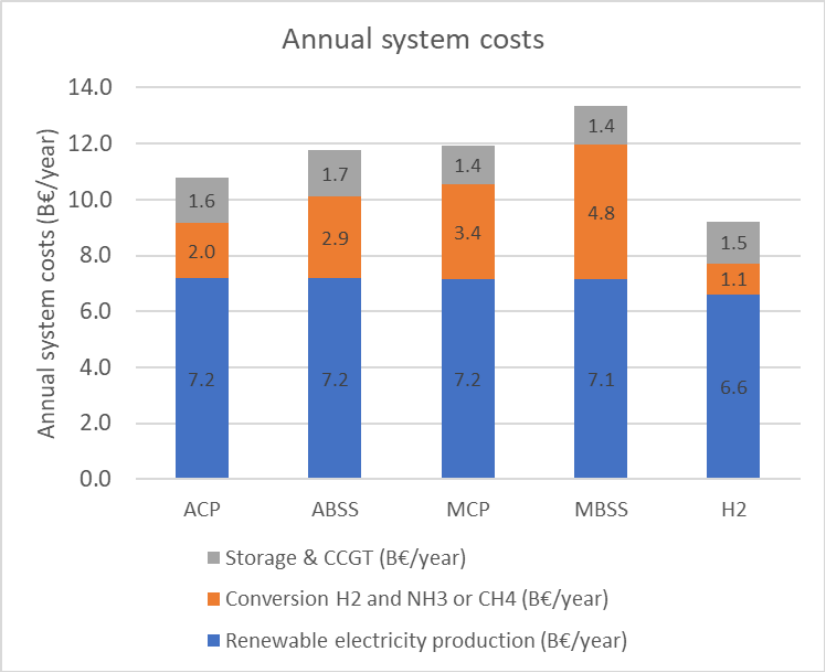

Figure 37. Overview economic analysis. The cost components are categorized by electricity production cost, conversion cost and storage and reconversion costs.

8. DISCUSSION

In this study the power system of the Netherlands in 2050 was considered. It was assumed that the Netherlands will indeed comply with the goals from the Paris Agreement and will reduce its GHG emissions with 95% in 2050. During the coming decades the political situation in the Netherlands will mostly determine the extent to which these goals will be met. Moreover, achieving deep decarbonation will be possible in multiple ways. Therefore, also the development of the power sector is uncertain. Scenario studies on the future Dutch power system that were considered for the assumptions of this study also showed a large variation for renewable energy sources in both the type of technologies and the absolute amount of installed capacity. Furthermore, the complete energy system is a very complex system in which every subsystem such as the power-, heat- and mobility system, are interconnected and influence the other sectors. This makes that the energy transition towards renewables is complex, and research on this topic preferably is done from the complete system perspective. However, in this study only the power sector was considered. Therefore, the influence on the power sector through interactions with the other sectors are not taken in to account. On the one hand, synergies with other sectors are possible. For example hydrogen and ammonia are both needed as a feedstock for industry. Furthermore, hydrogen or methane from power to gas can be used for high temperature heat in industrial processes. The extra demand for these chemical energy carriers will most likely create economic benefits and the option for more flexibility in the power to gas system. On the other hand, processes like the electrification of low temperature heat (heat pumps) and transport can cause stress on the electrical system. This could change the load pattern and introduce, in the case of electrification of heat, a more seasonal trend. This would influence, and most likely increase, the storage requirements.

In this research the assumption was made that the power to gas storage system was the only system that provides storage and flexibility. Although there is no general consensus to what extent power to gas will be implemented in the future power system, it is sure that other flexibility options will be used such as demand response technology, battery systems, interconnection capacity, fossil based power plants (with or without CCS) and curtailment. The implementation of these technologies will probably decrease the storage requirements and the need for flexibility from the power to gas system. However, the analysis of this research showed long periods with both large shortages and overproduction (see Figure 13). For such large quantities of excess or shortage electricity it can be assumed that storage is indeed needed and it was concluded that chemical storage using power to gas is the only large scale storage option for the Netherlands. Another possibility is the import of renewable energy in the chemical form. There are other countries in the world that have more potential for renewable energy sources due to better weather conditions and space availability which reduces the cost of electricity significantly. A solar park in Abu Dhabi will produce electricity for 23 USD/MWh where the latest Dutch wind parks produce electricity for 43 €/MWh (ISPT, 2017). The concept of power to gas would enable transport of large quantities of cheap renewable energy. More research on this topic would be needed, but ammonia and methane will have significant benefits for long distance transport due to their higher energy density. Import would have an influence on the result of this study and can decrease the required installed capacity of RES and the storage capacity.

For the electricity production of renewables, the weather data from multiple measurement locations from the North Sea and on land were used. With this method, a more representative production pattern for the Netherlands was created. However, on a regional level, the production pattern can be more variable and will require larger flexibility of the electricity system. The literature review into electrolysers showed that the PEM electrolysers, that are assumed for this study, are capable of following the variable excess electricity pattern on a second scale. Furthermore, the weather data of the year 2011 was used. For further research, the influence of other weather patterns should be investigated because the pattern and production of the RES can differ significantly.

The power to gas system and the technical requirements such as conversion and storage capacities were analysed using one scenario with 40 GW offshore wind, 8 GW of onshore wind and 35 GW of solar PV. This capacity mix is based on research (Blanco and Faaij, 2018; Heide et al., 2011) that investigated the optimal mix of wind and solar PV in an energy system for minimizing the storage capacity. However, the future electricity mix can differ significantly and would therefore have other implications for both the required flexibility and storage capacities.

The system structures of the three systems were determined after an extensive literature review. The most likely systems with technological and economic feasible components were used and modelled for this study. Due to the complexity of all three systems, the analysis was limited to a certain degree and most likely all three systems can be optimized. For all components, significant technological and economic improvements were assumed as the analysis is focused on the year 2050. However, not for all components reliable technological and cost predications were available. Furthermore, for this study the heat streams were not utilized and considered as waste. Research on heat integration for improved efficiency and cost benefits should be done to investigate the potential. For example high temperature electrolysis in combination with ammonia synthesis or methanation show promising results (Giglio et al., 2018; Wang et al., 2017). The calculated round trip efficiencies are the product of many assumptions and factors. Therefore, the round trip efficiencies come with relatively high uncertainties. The round trip of the ammonia and methane system differ with less than 1% point but due to the uncertainty it cannot be concluded that the methane system is more efficient. However, the round trip efficiency of the hydrogen system is significantly higher and can be assumed to be most efficient.

The economic analysis in this study was performed to get an indication of the system cost rather than a full economic costs calculation. The transport costs were omitted from the analysis and will therefore add to the total system costs. The power to gas storage concept is in the development phase and costs development predictions are prone to large uncertainties. An example is the price for solar PV, which dropped faster in the last decades than most expert predicted. Therefore, the economic analysis comes with significant uncertainties. However, the literature review and the results showed that the hydrogen system is both technically and economically the most feasible and also the most efficient of the three systems. This conclusion will most likely not change due to technological or economic developments. This is because the storage technique (H_2, NH_3 or CH_4) is the main distinguishing factor. The analysis showed that storage is not the decisive factor in both the efficiency and economic results.

9. CONCLUSION

The Netherlands aims for reduce its GHG emissions with 95% in 2050 relative to 1990. The power sector is currently 84% fossil based and therefore a transition towards a 100% renewable power system is needed. The intermittent power generation and the associated uncertainty in production creates the need for large scale flexibility and electricity storage. For large scale electricity storage batteries are not suitable due to the limited capacity, PHS is geographically restricted and not possible in the Netherlands and CAES also lacks the capacity for large storage in the TWh scale. Therefore, the only option for the Netherlands is chemical energy storage using power to gas. Power to gas is the concept of converting electrical power to chemical energy using electrolysis, in which electricity is used to produce hydrogen from water. Hydrogen can be stored and later be used for reconversion in to electricity which enables large scale electricity storage. Hydrogen can also be further combined with nitrogen or carbon dioxide to form ammonia and methane respectively. Ammonia and methane both have a higher volumetric energy density than hydrogen and are therefore easier to store. In literature, power to gas storage systems with hydrogen, ammonia and methane are proposed. However, it is not clear how these system compare technically and economically and what the possibilities are in the Netherlands. Therefore, the main research question of this study was: *How do hydrogen, ammonia and methane compare, when produced using power-to-gas, as a flexible electricity storage technology in a fully renewable power system in 2050 in the Netherlands?*

In order to answer this question this research was split up in two parts. In the first part, the Dutch power system in 2050 and the associated excess and shortage patterns was investigated. Weather data from multiple measurements stations were used to create power production patterns for offshore and onshore wind and solar PV in the Netherlands. Due to electrification the demand for electricity was assumed to be increased to 150 TWh per year and the load pattern of 2017 was used. The RES capacities in the scenario that was used for the second part of this research were 40 GW offshore wind, 8 GW onshore wind and 35 GW solar PV. The results showed that in this fully renewable power system, large scale flexibility and storage is indeed needed. The maximum over production and shortage are 55 and 23 GW respectively, with in total 87 TWh of excess electricity and 25 TWh of shortage (see Figure 12).

In the second part of the study the comparison between a power to gas storage system based on hydrogen, ammonia or methane was made. First an extensive literature was performed to determine the system structures and to gather technological and economic information. For the hydrogen system the main components were the electrolyser system, hydrogen salt cavern storage and a hydrogen CCGT. For the ammonia system, the produced hydrogen was further recombined in an all-electric ammonia synthesis plant, stored in large cooled tanks and reconverted to electricity by decomposing it to hydrogen and nitrogen before using it in a hydrogen CCGT. The methane system used the produced hydrogen in a methanation plant, methane was stored in depleted gas fields and used in conventional methane CCGT's. An important conclusion from the literature review was that the ammonia and methane system were limited in flexibility due to the ammonia synthesis and methanation process. This created the need for a large hydrogen buffer storage.

The results from the model showed that the round trip efficiency of the hydrogen, ammonia and methane system were 40.1%, 28.3% and 29.1% respectively. In all three systems, the electrolysis step and the reconversion to electricity accounted for significant losses. Due to the extra conversion, the methane and ammonia system were less efficient. This was mostly due to the methanation process in the methane system and the reconversion to electricity in the ammonia system. The storage efficiency of the ammonia system was found the be the highest, but in all three systems the storage efficiency was not the decisive factor for the total round trip efficiency. The storage requirements for the hydrogen, ammonia and methane system were found to be 8.33 TWh, 9.21 TWh, 7.34 TWh respectively. This is technically possible in the Netherlands for all three systems. For the constant

production scenario of the ammonia and methane system, the hydrogen buffer capacity was found to be 5.0 TWh. It can therefore be concluded that the ammonia and methane system are required to be operated in a (semi) flexible manner in order to be suitable for this application.

The economic analysis showed total system cost of the hydrogen, ammonia and methane system are 9.2, 11.8 and 13.3 billion euros per year respectively. The corresponding electricity price for the power system including the power to gas storage system was found to be 6.1, 7.2 and 8.9 eurocent/kWh for the hydrogen, ammonia and methane system respectively. The largest cost component was the electricity production from the RES. Furthermore, the storage costs were found to be low compared to the other cost components. The constant production scenario for the ammonia and methane system was found to have lower total costs than the other scenarios. This was due to the reduced required ammonia synthesis/methanation capacity that is relatively more expensive than the hydrogen buffer storage.

In conclusion, in a fully renewable power system, large scale flexibility and storage is needed. Power to gas can offer both this flexibility and storage. The hydrogen system was proven to be the most efficient and cost efficient system. The ammonia and methane system both lack the desired flexibility and are less energy and cost efficient than the hydrogen system. Hydrogen storage is often mentioned as problematic due to the low volumetric energy density of hydrogen. However, hydrogen storage in salt caverns enables large scale storage with high efficiency. The Netherlands has a high potential for salt cavern storage and therefore the implementation of a power to gas storage system based on hydrogen is technological and economical feasible and the best choice for the Netherlands.

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11. APPENDIX

11.1 Additional model outputs

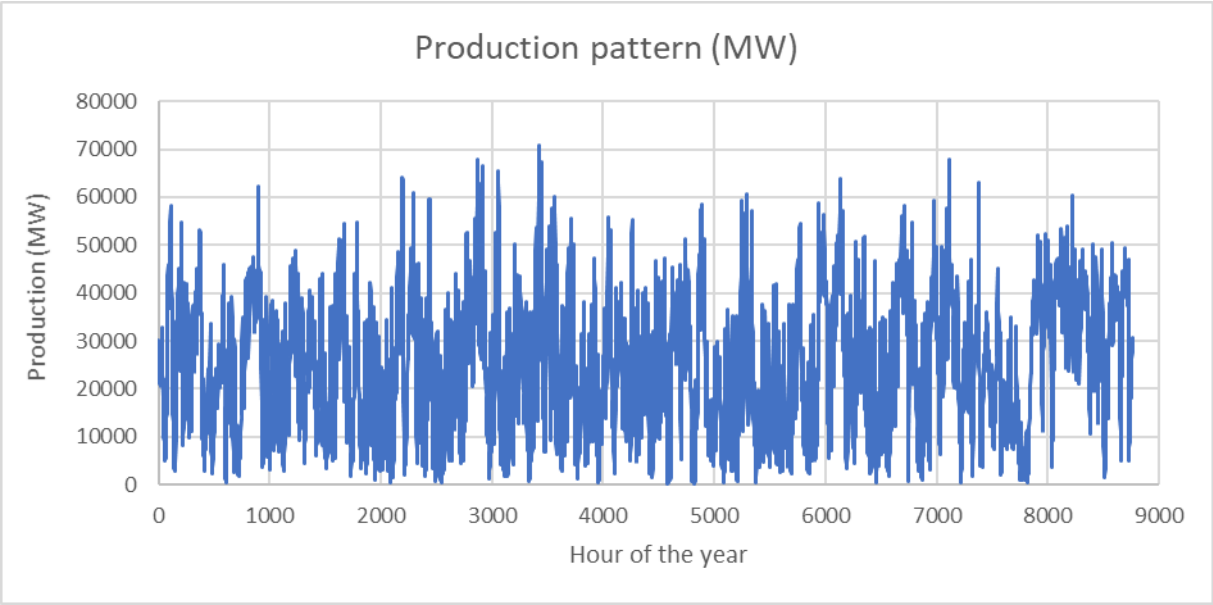

Figure 38. Production pattern for base scenario (scenario 3).

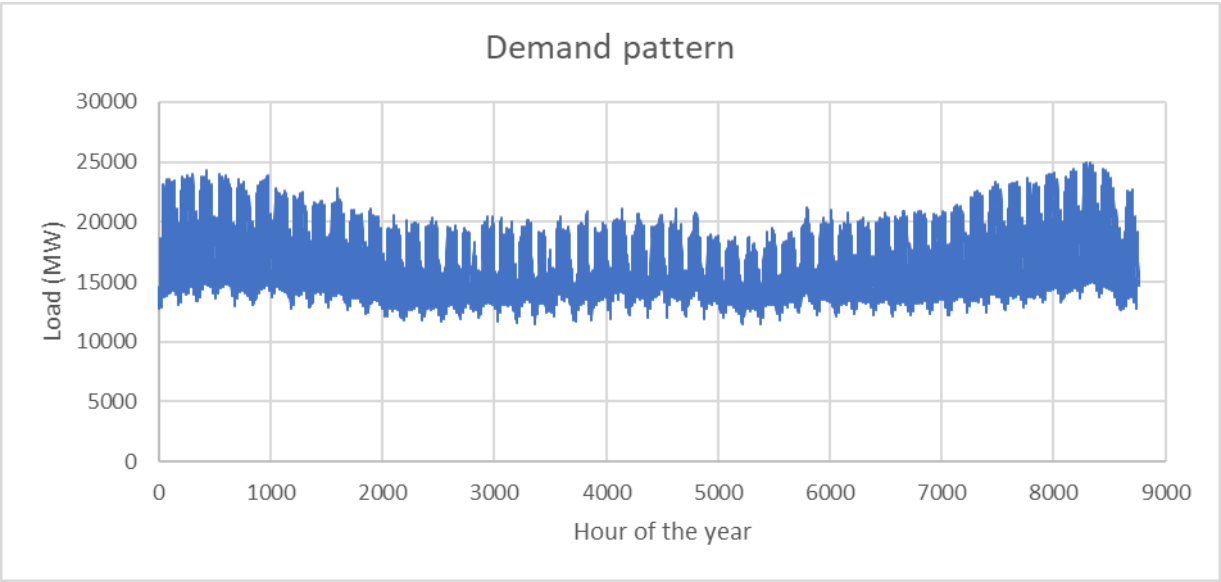

Figure 39. Adjusted demand pattern. Data from 2017.

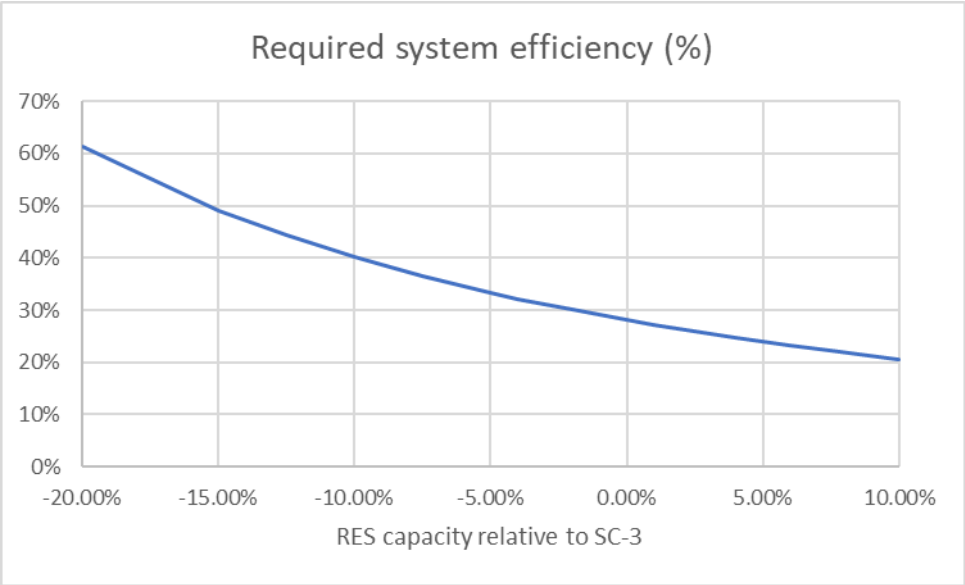

Figure 40. Required system efficiency versus installed capacity change from the base scenario (that is at 0%).

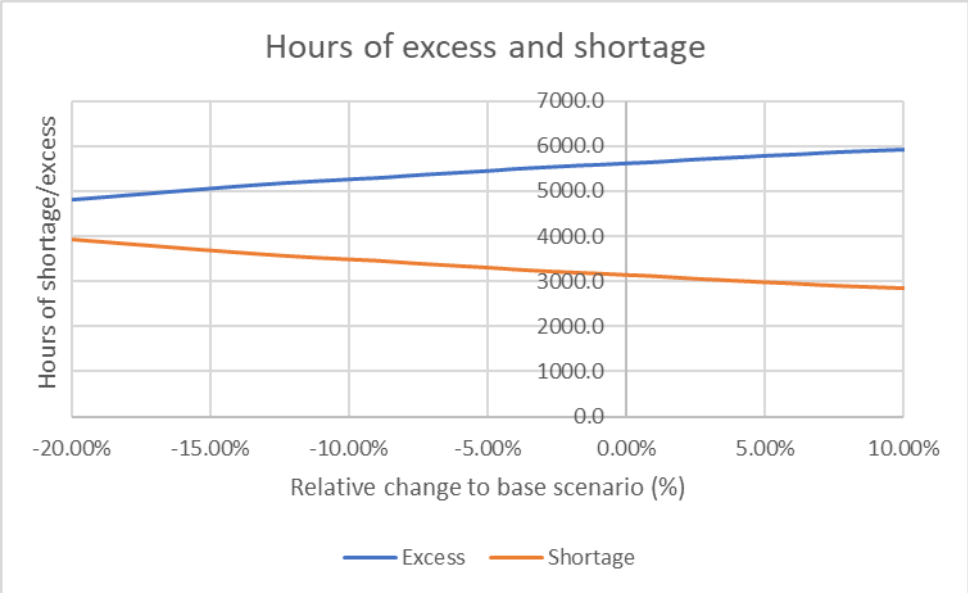

Figure 41. Excess and shortage hours versus installed capacity change from the base scenario (that is at 0%).

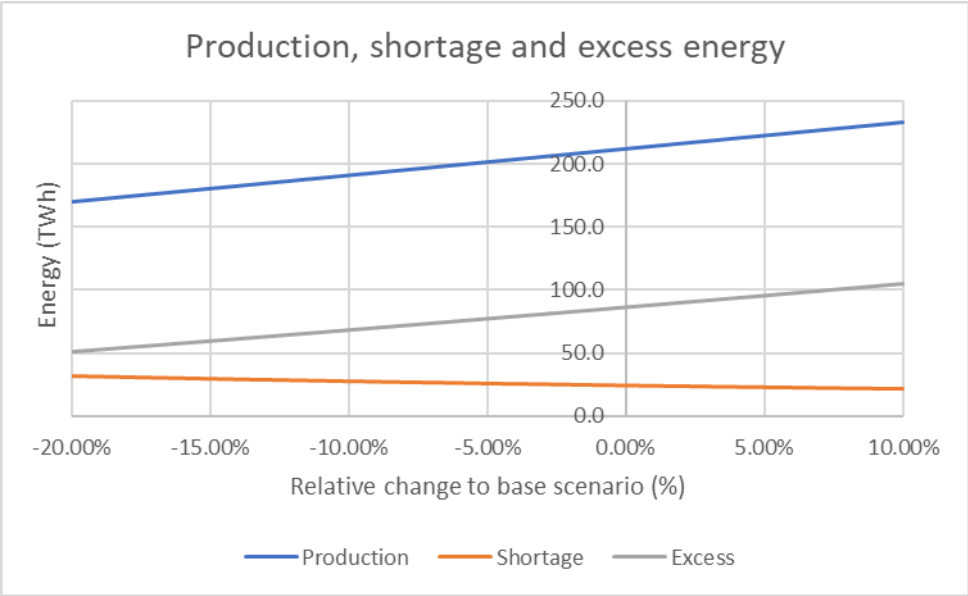

Figure 42. Production, shortage and excess energy versus installed capacity change from the base scenario (that is at 0%).

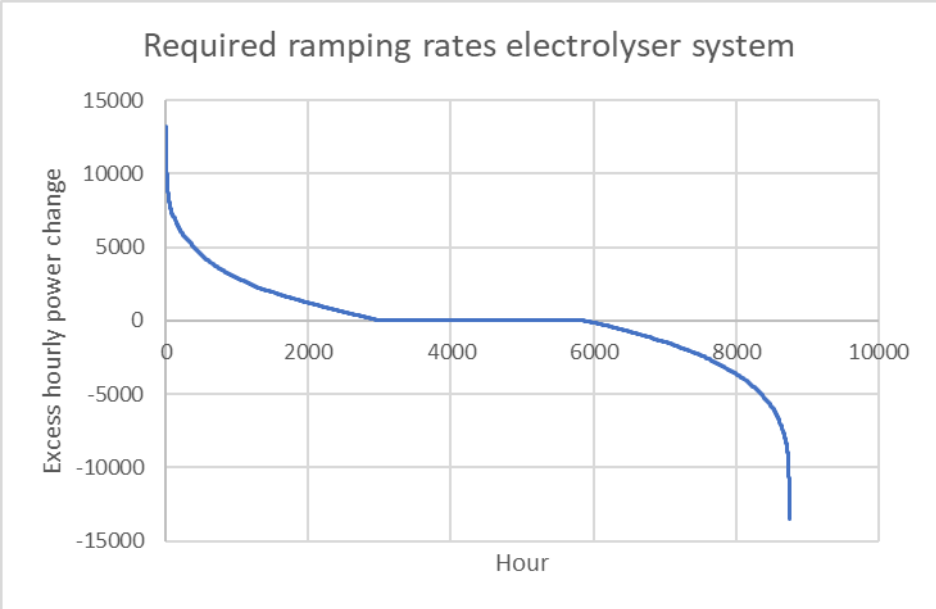

Figure 43. Required ramping rate per hour of the electrolyser system. The figure shows the change in power input for the electrolyser system. The maximum upward change is 13.2 GW in one hour and the maximum downward change is 13.5 GW in an hour.

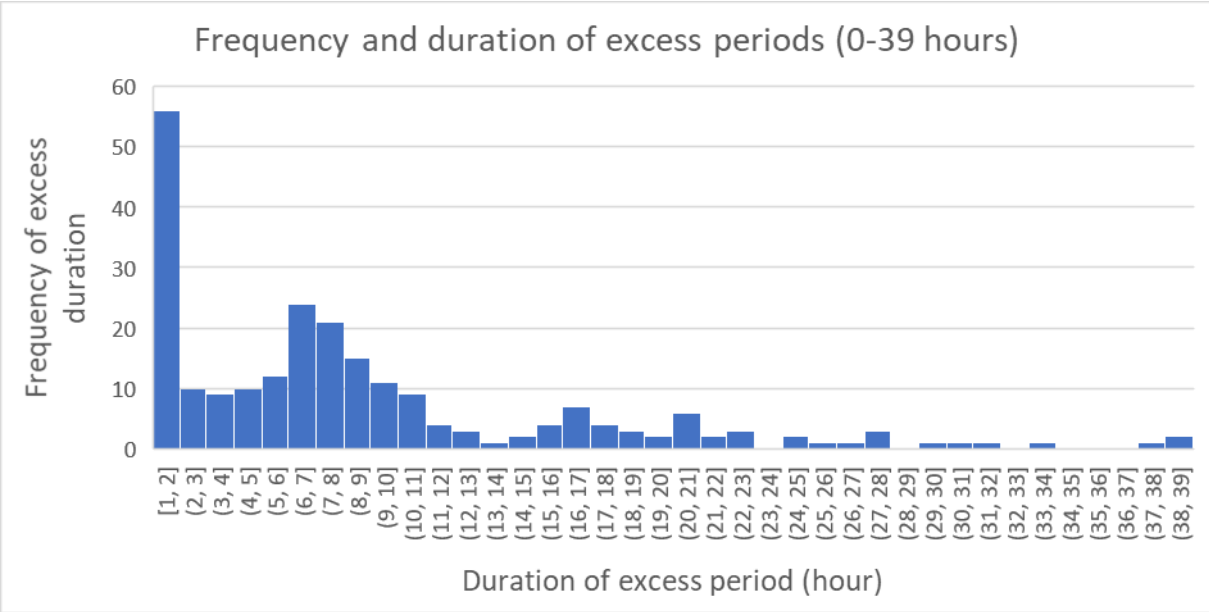

Figure 44. Frequency and duration of excess periods. This graph shows only the excess periods with a length up to 39 hours. Results for the base scenario (scenario 3).

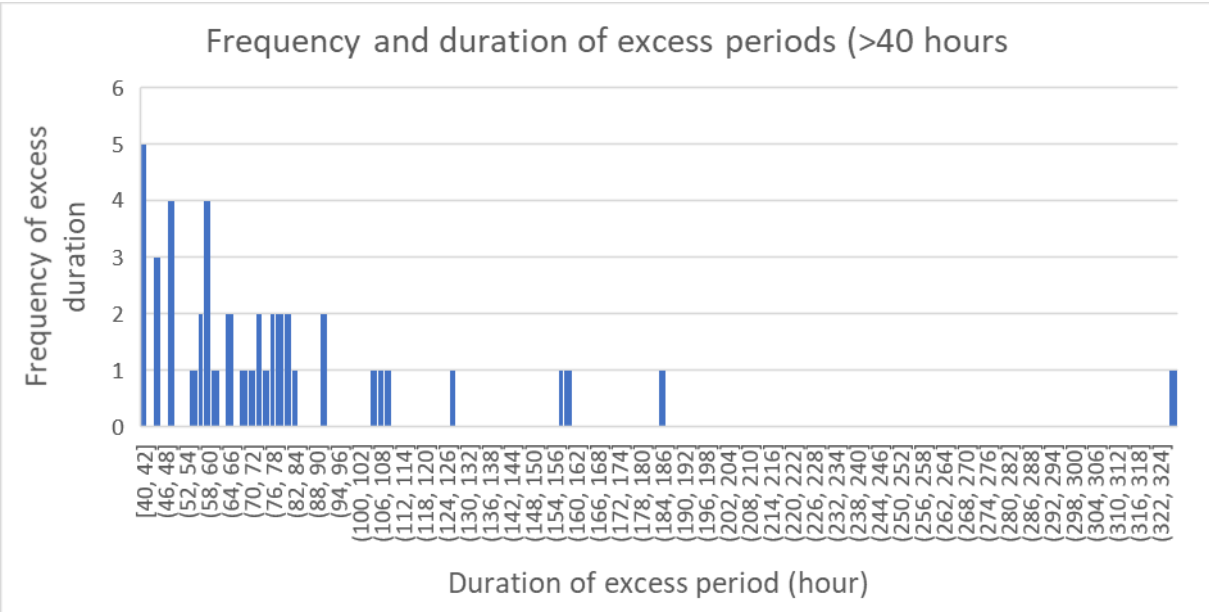

Figure 45. Frequency and duration of excess periods. This graph shows only the excess periods with a length longer than 40 hours. Results for the base scenario (scenario 3).

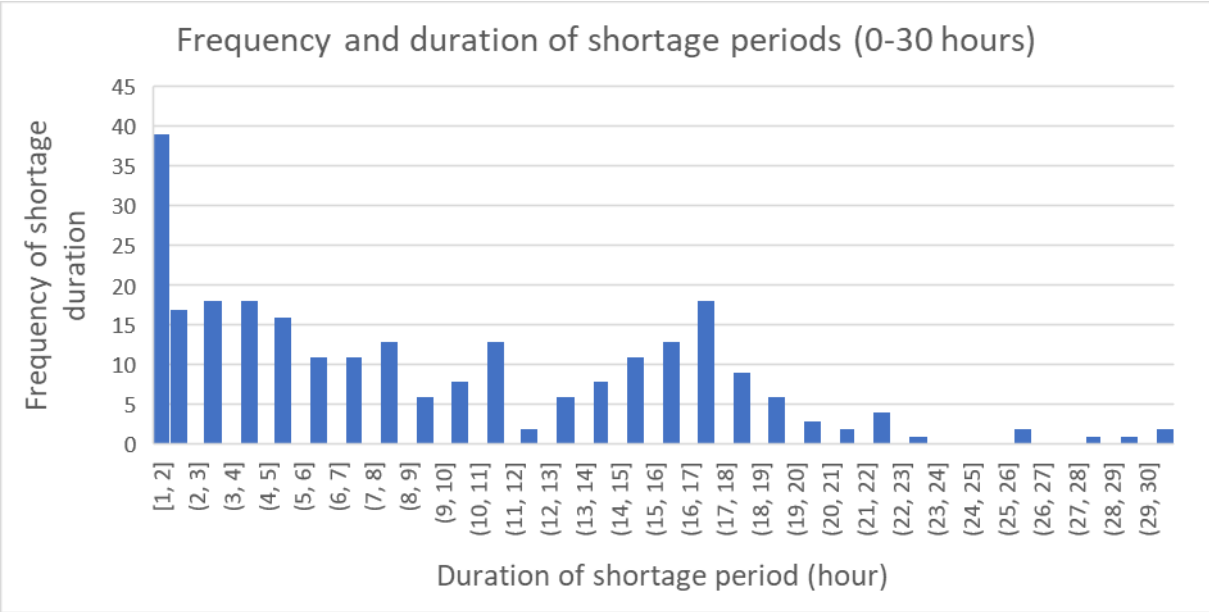

Figure 46. Frequency and duration of shortage periods. This graph shows only the shortage periods with a length up to 30 hours. Results for the base scenario (scenario 3).

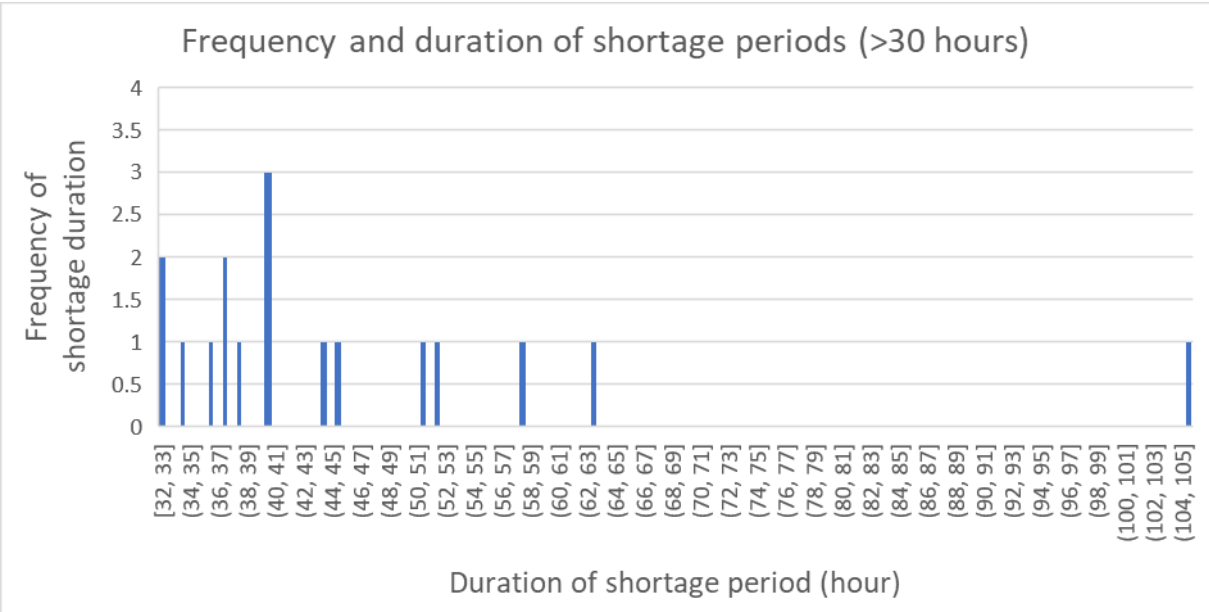

Figure 47. Frequency and duration of shortage periods. This graph shows only the shortage periods with a length up longer than 30 hours. Results for the base scenario (scenario 3).

11.2 Salt cavern potential Zuidwending

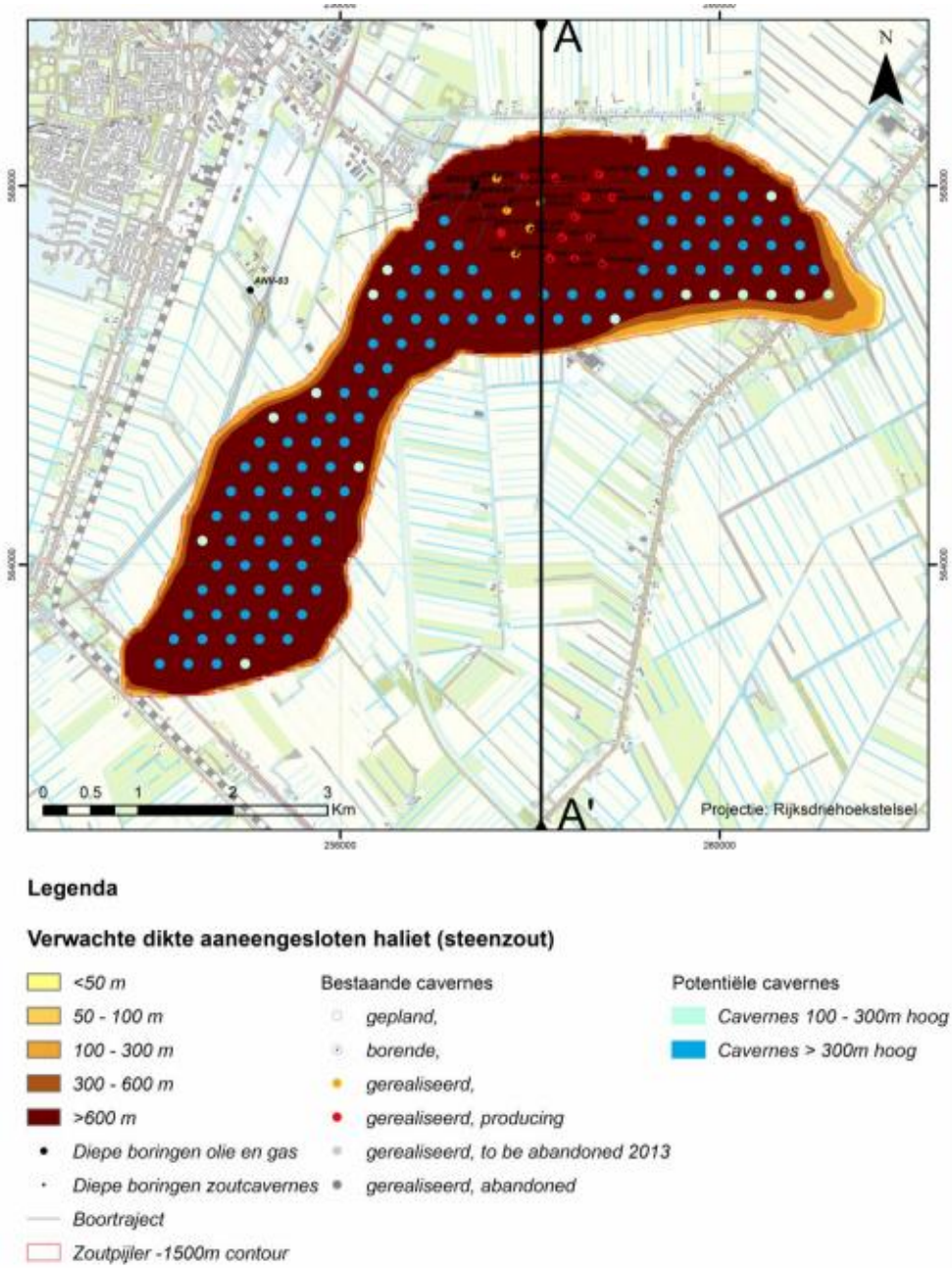

Figure 48. Potential salt caverns at the Zuidwending location.