# Underground hydrogen storage

## Researching security of supply in a net-zero future

Thesis MSc Engineering and Policy Analysis
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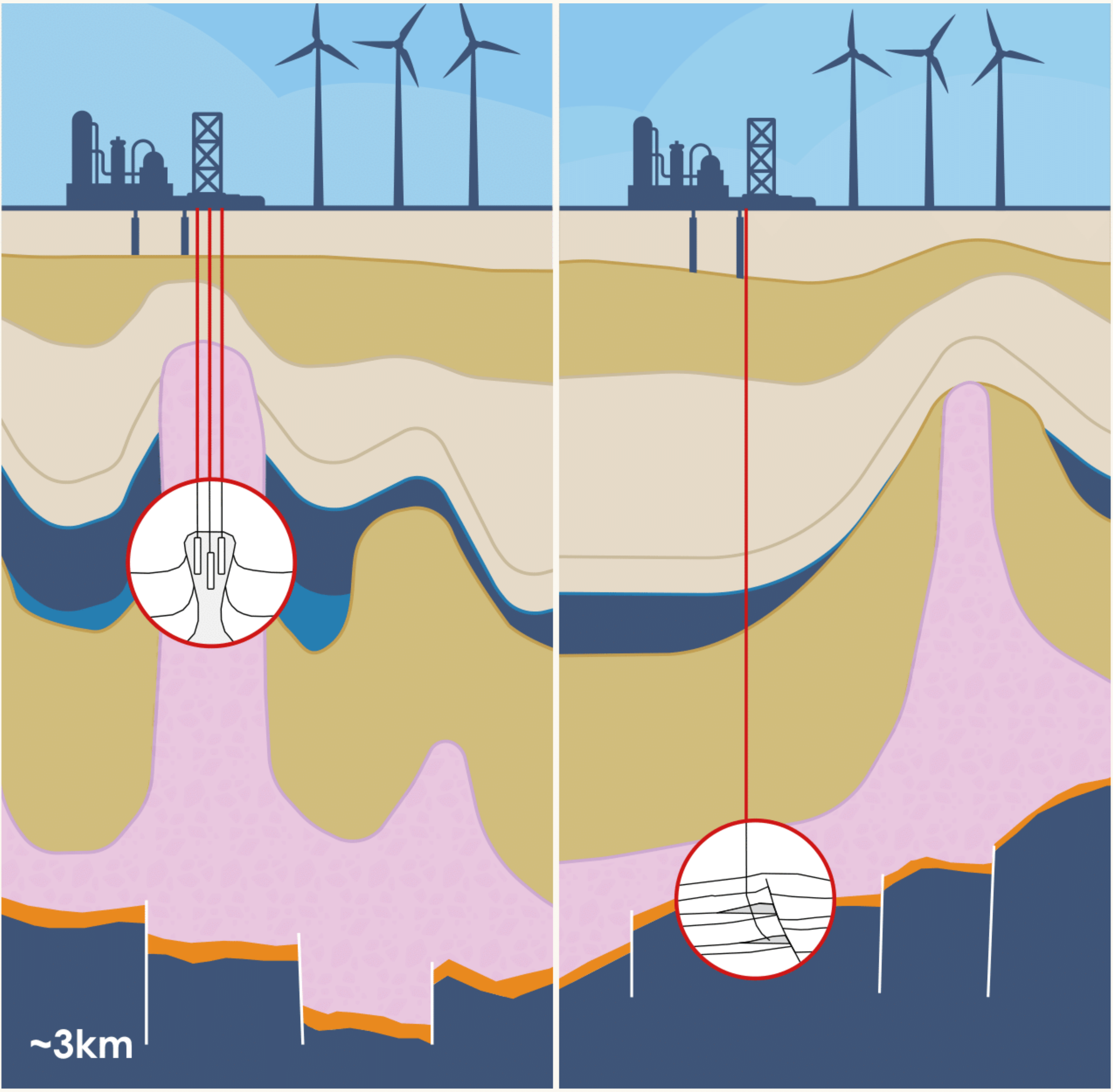

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by

Eva-Britt Reddingius

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| Project Duration | February, 2024 - July, 2024 |
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| Cover: | EBN and TNO |

# Acknowledgment

*Dear reader,*

*Before you lies the thesis on which I have worked over the past six months. I am deeply grateful to the people at EBN for their supervision and for integrating me into the team. A special thank you to Timme, Barthold, and Marlijn (for all the coffee). I discovered with you that I have a yellow and red DISC profile and thrive on collaboration. Being able to come into the office every day and engage with everyone, whether with questions or small talk, was invaluable.*

*To be honest, it has been a tough period in my personal life, and finding the motivation and drive I would have liked to dedicate to this final part of my study was not easy. I want to thank Laurens and Pieter for their supervision and their kind, supportive advice. Their flexibility was immensely important to me during this project.*

*This project also marks the end of my years as a student, so I want to thank all the people who have made my time in Delft and Rotterdam the best years of my life. A gigantic thank you to my amazing housemates, the Maxies. All 29 of you taught me various lessons, and it is in this house that I became the adult I am today. We had so much fun together, even during Covid, and I cherish the memories from the bunker. To the Badeendjes, thank you for all the laughter, fun, and friendship. It's amazing how we have grown into the women we are today, and I enjoy our time in Rotterdam together so much. Students4Sustainability 13, you helped me feel seen in my struggles about sustainability. Our discussions and hard work brought me peace and a clearer worldview. It is with you that I feel understood. I thank Techniek Bedrijven 21 for showing me that the work-hard, play-hard approach is the perfect combination to get things done. To the hockey team Dopie Eendjes, thank you for your devotion and discipline during the five years I proudly played with you. Leonidas D5, thank you for making Rotterdam feel like home. Also a big thanks to my friends from EPA: Finn, Friso, Suze, Kas, and Mart. The various projects we tackled were challenging but simultaneously hilarious. From back home, I want to thank 't Sub for the support and love in Utrecht and from Bergen.*

*The most important words of appreciation go out to my family. My four parents and sister have supported me throughout my years of studying. I thank them for helping me develop my vision of the world, see the best in people, and live life according to my principles. Thank you opa en oma for burning a candle in 't kapelletje every day. Having this unconditional love as a foundation is a privilege I will never take for granted.*

*These past months have felt like there was an army who had back, ready to support me in during a crisis. I am so grateful to all of you.*

*Eva-Britt Reddingius*
*Utrecht, August 2024*

# Summary

Climate change demands a transition to a carbon-neutral energy system. In the Netherlands, this shift involves electrifying sectors, predominantly by increasing energy sources like solar PV and wind power. This comes with flexibility challenges during times with insufficient variable Renewable Energy Sources and extended periods with wind droughts, or a dunkleflaute which is a period of more or less two weeks with insufficient wind and a cold front. Electricity generation from molecule based fuels can play this flexible role to balance the system in the future. Hydrogen is a versatile energy carrier that can play this role in a low carbon manner. Hydrogen can be stored in large volumes underground in salt caverns and in depleted gas fields. To ensure security of supply in different scenarios it is necessary to understand what volume of hydrogen should be stored in storage facilities to withstand a dunkleflaute. What is also necessary is to understand with what speed this hydrogen should be injected and produced from storage facilities, in other words: in how many days the storage can empty and fill. The production of green hydrogen with which the storage is filled is produced through the process of electrolysis. There are different types of technologies to produce green hydrogen. This research also focuses on the trends in developments regarding electrolysers and their impact on the system. As well as on the policy goals set by European Union and the Dutch government.

The method in which the research was set up is by determining the system characteristics and uncertainties and going through the motion of the modelling cycle multiple times. This research is conducted by simulating the Dutch energy system in Linny-R, a mixed integer linear programming software tool. The model is made for the years 2035 and 2050. A sensitivity analysis is done to determine the most influential keys in the system. Based on literature and this sensitivity analysis, a scenario analysis was determined. Many scenario's were then tested in the model to determine their impact. The system is measured with the following KPI's: Carbon emissions, Loss of Load Expectation and Expected Energy Not Supplied, System costs and Production cycles.

The conceptualisation in this thesis details the intricacies of the Dutch energy system and its simulation within the Linny-R model, offering a foundational understanding essential for later analyses. This chapter dissects the components and operational settings of the model, emphasizing their significance in shaping outcomes. The Dutch energy system's transition from fossil fuels to renewable energy sources is mapped within Linny-R, highlighting the interplay of various energy forms and the constraints inherent to the system. The setup includes explanations of Linny-R's key entities and discusses the model's execution over a yearly timeline with hourly steps to capture dynamic system behaviours. Special attention is given to the settings impacting computational efficiency and the incorporation of historical weather data to account for variability in renewable energy production. After discussing the system a framework is presented, detailing the external factors, policy levers, system relationships, and performance metrics that guide the analysis.

The analysis focuses on verifying the model, conducting a sensitivity analysis, and beginning scenario discovery to test the model's performance. Verification ensures the model accurately represents real-world systems by examining storage facilities' behaviors and hydrogen-to-power conversion during low variable renewable energy supply (vRES) periods. Sensitivity analysis tests how changes in input parameters impact outputs, identifying critical inputs that influence the model's performance and ensuring robustness. Key findings show that hydrogen and electricity demand parameters significantly affect system costs and efficiency. Scenario discovery assesses the model's resilience under various conditions, including extreme weather years, to identify potential bottlenecks. This chapter establishes the model's reliability and guides improvements in its predictive capabilities.

The results show the findings from the scenario analysis aimed at evaluating the potential of underground hydrogen storage in the future energy system. These experiments investigate various performance parameters to inform decision-making for effective integration of underground hydrogen storage. Key findings include the impact of electrolyser capacity on hydrogen production and system efficiency, revealing that increased electrolyser capacity significantly reduces carbon emissions, though it must scale parallel to storage capacity to be effective. The analysis of different storage types highlights the importance of sufficient electrolysis capacity to fully utilize storage facilities. Concluding their dependence on one another. Additionally, scenarios exploring battery capacity, gas power plant use, and demand variations provide insights into optimizing the energy system while achieving policy goals. The results underscore the complex interplay between various components of the hydrogen storage system, emphasizing the need for balanced and integrated approaches to meet future energy demands and sustainability targets.

The discussion interprets the research findings, emphasizing the anticipated demand for underground hydrogen storage and the required production capacity for 2035 and 2050. The study reveals that while there will be significant storage needs in 2035 due to hydrogen shortage, the demand will decrease by 2050 as renewable energy sources and electrolysis capacity increases. Economically and functionally, a combination of salt caverns and gas fields is recommended, with optimal configurations identified for injection and production capacities. The research also highlights the critical role of electrolysers and their efficiency. Limitations of the study are discussed and recommendations for future research directions suggest exploring blue hydrogen, integrating hydrogen flow dynamics, and considering regional energy needs. The study's findings have practical implications for policy decisions for Dutch hydrogen storage.

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# 1

# Introduction

## 1.1. Problem definition and context

One of the most complex challenges that we face today is climate change. Human activity has increased our planet's global surface temperature by 1.1°C above the 1850-1900 standard in 2011-2020 [13]. Since the industrial revolution, human activities have raised atmospheric carbon dioxide by 50% – meaning the amount of carbon dioxide is now 150% of its value in 1750 [13]. Worldwide development and economic growth have been made possible by fossil fuels, and an entire system has been designed to provide and secure energy all over the world. However, now that we understand that fossil fuels harm the environment, it is necessary to transition toward a carbon-neutral energy system. To facilitate this transition, the European Union has mandated member states to reduce their carbon emissions, which has been incorporated in the Paris Agreement [18]. To comply to this agreement and go beyond it, the Dutch government has pledged to a net zero electricity network by 2035 [2]. Consequently, the development of a carbon-neutral energy system is now a pressing issue.

### 1.1.1. Flexibility in the energy system

For this development of a carbon-neutral energy system, the increase of renewable energy sources is important. However, these sources lack the capability to be activated or deactivated to meet periods of high demand. This discrepancy between supply and demand introduces a challenge in terms of flexibility within the energy system. Besides the cost developments of variable Renewable Energy Sources (vRES), there is a growing recognition that achieving a low-carbon electricity system hinges on the availability of 'flexibility.' Flexibility is not a standalone product but a characteristic found in generation, storage, interconnection, and demand management [61]. While expanding electricity network capacity can help mitigate fluctuations by covering a larger area, it won't eliminate the need for flexibility. Flexible demand, also known as demand response, plays a crucial role in narrowing the gap between vRES and electricity demand. However, even with these measures, there remains a significant difference between energy supply and demand. This gap must be addressed through the utilization of storage solutions and controllable generation methods [22]. These energy storage solutions are necessary in any future energy system according to TNO and EBN [25]. In the article by Lysyy, Fernø, and Ersland [61], hydrogen storage in depleted oil and gas reservoirs is proposed as a strategy to increase flexibility for future supply and seasonal outtake. In summary, achieving a carbon-neutral energy system will require a combination of renewable energy, flexible demand management, and advanced storage solutions, with hydrogen storage in depleted reservoirs being a promising strategy to bridge the gap between supply and demand.

The global momentum towards low-carbon flexible energy is exemplified by hydrogen's emergence as a possible key player. This role is projected in scenario sketches outlined by various entities, including Netbeheer Nederland [73], TNO [36], Nationaal Waterstof Programma (National Hydrogen Program) [76], University of Groningen [65], International Renewable Energy Agency (IRENA) [14], and Shell [59]. Most importantly, the role of hydrogen is embraced in the National Plan Energy Systems (NPE) of 2023, which is the long-term vision for the energy system of the Netherlands in 2050 made by the Ministry of Economic Affairs [66]. Hydrogen is increasingly recognized as a crucial component in the global shift towards low-carbon, flexible energy systems, with its potential role emphasized in various scenario projections and national strategies.

This hydrogen is a gaseous fuel, which is referred to as Power-to-gas (P2G) which is the conversion of electrical energy into gaseous fuels, such as hydrogen, through the processes of electrolysis. This hydrogen can then be stored for extended periods, offering a more durable storage solution compared to conventional battery systems. Hydrogen is an energy carrier that can be used as a fuel in hydrogen power plants to produce electricity or in combustion by reacting with oxygen to produce heat. Especially during a 'dunkelflaute' which is a period characterized by simultaneous low wind and solar generation, hydrogen can replace the role that natural gas now plays in the system, ensuring flexibility. Hydrogen emerges as an essential element in mitigating the intermittent nature of renewable energy sources. Hydrogen's versatility also positions it as a possible energy source for hard-to-abate sectors, limiting the need for fossil fuels such as natural gas, coals, oil, and other derivatives. Low carbon hydrogen can also replace grey hydrogen, made from natural gas, which is currently responsible for 8% of national emissions. In order to access this hydrogen during times of high demand, it needs to be stored. Due to the gaseous nature of hydrogen at regular temperatures and the relatively low energy density, a voluminous facility is required for storage. This can be above ground, which is relatively small, or underground in depleted gas fields, aquifers or salt caverns. In short, hydrogen is a flexible and long-lasting energy source that can help balance renewable energy's ups and downs, reduce the need for fossil fuels, and lower emissions, but it needs large storage facilities to be used effectively.

A closer examination of the current state of the Dutch hydrogen system reveals a landscape dominated by stable industrial demand met with grey, natural gas-based, hydrogen. Shifting the perspective to global hydrogen use, at of the end of 2021, almost 47% of the global hydrogen production is from natural gas, 27% from coal, 22% from oil (as a by-product), and only around 4% is produced by electrolysis. In the Dutch mix of hydrogen, a substantial part of hydrogen is a by-product from other processes which use oil as feedstock. The global average renewable share of electricity was about 33% in 2021, indicating that only about 1% of the global hydrogen output is produced with renewable energy. Electrolytic hydrogen from dedicated production remained limited to demonstration projects, totaling a worldwide capacity of 1.1 GW in 2023 [16]. In contrast, in the 1.5°C scenario, we would need to generate 4-5 TW by 2050. This requires an even faster growth rate than that experienced by solar photovoltaic (PV) and wind turbines to date [82]. Besides the shift from the current grey hydrogen volume towards blue and green hydrogen, there is also the prediction that the hydrogen demand will increase due to industries switching from natural gas towards blue and green hydrogen. Further explanation about the hydrogen colours can be found in 2. So, the Dutch hydrogen system, like much of the world, currently relies heavily on fossil fuels, with only a small fraction produced using renewable energy, highlighting the need for rapid growth in green hydrogen production to meet future demand and climate goals.

It is clear that the demand for low-carbon hydrogen is likely to increase significantly for both the industry and the electricity network and in order to have it accessible, there is a need for storing large volumes. This research focuses on the required need of volume of these facilities and at which speed they need to be able to inject and produce the hydrogen in and out of these facilities to react to high demand peaks and ensure the security of supply to the electricity network.

## 1.2. Societal and academic relevance

The transition to a carbon-neutral energy system is not only an environmental imperative but also a societal necessity. The European Union's Green Deal, which aims to achieve carbon neutrality by 2050, represents a significant policy initiative with profound implications for industry, economy, and society [93]. The allocation of €503 billion through the Green Deal Industrial Plan (GDIP) underscores the importance of this transition. Renewable energy sources, particularly offshore wind and solar photovoltaic (PV), are central to achieving these goals, with ambitious capacity targets set for the coming decades [49]. This transition is essential for reducing the reliance on fossil fuels and mitigating climate change impacts. Moreover, the development and deployment of hydrogen as a flexible energy carrier are crucial for addressing the intermittency of renewable energy sources. This research focuses on storage possibilities and requirements that can ensure a stable and resilient Dutch energy system. The outcomes will define and underscore the need for hydrogen storage in the future, which is what EBN, the creator of this research, is interested in for their advising role towards the Ministry of Climate Policy and Green Growth. Academically, this research is relevant in fields of study such as renewable energy technologies, energy storage solutions and underground storage technologies. Transitioning to a carbon-neutral energy system is both an environmental and societal necessity, with a crucial role for renewable energy and hydrogen storage in achieving long-term climate goals.

## 1.3. Report Structure

This report is organized into several key sections to provide a comprehensive analysis of the Dutch energy system with the impact and need of underground hydrogen storage. Chapter 2, the literature review, synthesizes existing research on underground hydrogen storage providing a foundation for understanding the current state of knowledge in this research field. The research questions that are designed following the knowledge gap are introduced in this chapter as well. The methodology chapter 3 outlines the research design, data collection methods, and analytical approaches that are used in this study. In the conceptualisation chapter 4 the design of the model is discussed and all assumptions are laid out. After this the analysis chapter 5 will discuss the verification and validation of the model. It is also in this chapter that a sensitivity analysis and a scenario analysis is conducted. In chapter 6 results the outcomes of the scenario analysis with regards to the research questions are answered. The discussion in chapter 7 will reflect on the research and discuss limitations and possible future research. Finally the conclusions, chapter 8, will summarise the outcomes of the research questions.

# 2

# Literature review

As discussed in the introduction, chapter 1, underground hydrogen storage is expected to play an important role in the future energy system of the Netherlands. However, many uncertainties exist regarding the technological characteristics of the storage facilities and electrolysers and their influence on the system as a whole. To gain a better understanding of the current state of these technologies a literature research is conducted. This chapter begins by detailing the methodology employed for the literature review, followed by an explanation of the findings including the technical knowledge necessary to comprehend the subsequent research. The chapter concludes with the identification of knowledge gaps and the formulation of research questions.

## 2.1. Methodology of literature review

To gather comprehensive and relevant information for this research, a systematic literature review was conducted using various tools and methodologies. Google Scholar was used to collect literature studies regarding this research. Zotero was used to order and store notes of all the research material. The search keywords were the following: electricity demand, energy flexibility, underground hydrogen storage, hydrogen in the energy system, future energy system, green hydrogen, hydrogen for electricity, seasonal energy storage, hydrogen for grid balancing, green hydrogen grid balancing services, salt cavern hydrogen storage, gas field hydrogen storage. Forward and backward snowballing was also applied to find more relevant and similar papers. Papers from the thesis research of Kluijtmans [52] were looked into as well, because this research is a direct suggestion from his work. Besides academic publishing, scenario developments and strategies from prominent companies in the energy sector, research agencies and the Dutch government are used. Another source of information is the papers and reports provided by EBN.

The decision was made to be selective in the publishing date of papers in regards to required storage estimations, overall hydrogen technology (e.g. production efficiency and storage), demand and supply estimations, governmental incentives and the selection of sectors that will make use of hydrogen. Most papers were from the year 2020 or above. Selection decisions of papers were based on titles, keywords, contributors and abstracts. This resulted in a selection of papers and reports which can be found in appendix A. Incorporating these diverse sources ensured a well-rounded understanding of the current landscape in hydrogen storage and its role in the energy system.

## 2.2. Findings of literature review

### 2.2.1. Policy plans

#### The Netherlands

The Netherlands and Europe have big hydrogen ambitions to achieve a climate-neutral energy system and a sustainable industry. According to the previous ministers Micky Adriaansens (Economic Affairs and Climate) and Rob Jetten (previous Minister of Climate and Energy), these ambitions require an energetic policy aimed at both the supply and demand sides of hydrogen. To scale up the hydrogen market, the government is subsidising electrolysis and wants to encourage the industry with subsidies and an obligation to use more renewable hydrogen as of 2026. €9 billion has been made available for this purpose in the Climate Fund. The Climate Agreement stipulates that the Netherlands will have at least 4 Gigawatts of electrolysis capacity by 2030 and 8 Gigawatts by 2032. This feasibility will depend on the rollout of offshore wind energy, the expansion of energy infrastructure and the demand for electricity from users such as industry. On top of the subsidies that already exist for electrolysis (such as

SDE++ and IPCEI), the government will make an additional € 1 billion available in 2024. For the following years, the government has reserved €3.9 billion for scaling up renewable hydrogen. By granting a €300 million subsidy under the H2Global initiative, the import of hydrogen to Northwestern Europe will receive a major boost. Lastly, the government is also working on the necessary infrastructure for the transport and storage of hydrogen [80]. The Netherlands is making significant investments and policy changes to boost its hydrogen market and infrastructure, reflecting a strong commitment to achieving climate neutrality.

#### Trends

The operational costs of variable Renewable Energy Sources (vRES) continue to decline [88]. Capital expenditures for off-shore wind are however not decreasing. Eneco withdrew at the end of March 2024 from a tender they had won in 2022 with Shell, called Hollandse Kust West, due to high interest rates, material costs and uncertain electricity market [28]. They view the investment risks as too high and due to the increase in demand for wind turbines and lacking production capacity, prices have increased. These set backs in costs expectations are also affecting the investment plans for green hydrogen production. The market is reluctant to invest in large electrolyser projects, the government is trying to encourage development trough tenders. An example is the 30-50 MW electrolyser tender which will function in combination with the Hollandse Kust Noord wind farm [62]. While trends show both progress and challenges in hydrogen production and renewable energy integration, ongoing efforts and strategic policies at the European level aim to support the development of a sustainable hydrogen economy.

#### European Union

Hydrogen is also an important part of the EU energy system integration strategy (COM/2020/299). The EU Hydrogen Strategy (COM/2020/301) was adopted in 2020 and proposed policy action points in five areas: investment support; supporting production and demand; creating a hydrogen market and infrastructure; research and cooperation and international cooperation. The Fit-for-55 package, introduced in July 2021, outlines the EU's hydrogen strategy, including targets for renewable hydrogen uptake and infrastructure development by 2030 [94]. It involves funding through the Recovery and Resiliency Facility and support from IPCEIs like "Hy2Tech" and "Hy2Use." The Clean Hydrogen Partnership facilitates research, while delegated acts ensure criteria for renewable hydrogen products and emission calculations are met. Together, these initiatives form a comprehensive framework for advancing hydrogen as a sustainable energy source in the EU [30]. The EU's comprehensive framework for hydrogen, including funding and regulatory measures, highlights the EU's belief in the critical role of hydrogen in the future energy system and the collective effort required to meet ambitious climate goals.

**Table 2.1:** Policy overview

| Goal | Timing | Level | Ref |
|---|---|---|---|
| 42 per cent of hydrogen used in industry must be green hydrogen | 2030 | EU RED | [53] |
| 60 per cent of hydrogen used in industry must be green hydrogen | 2035 | EU RED | [53] |
| The agreement sets an indicative target of at least 49 per cent share of renewable energy in buildings | 2030 | EU RED | [53] |
| The goal is to have 10 gigawatts of flex-fuel electricity generation capacity (natural gas and hydrogen/ammonia) | 2030 | The Netherlands | [53] |
| The electricity network is targeted to be carbon neutral | 2035 | The Netherlands | [2] |
| Member states emit 55% less greenhouse gases | 2030 | EU Fit for 55 | [94] |

### 2.2.2. The spectrum of colours of hydrogen

The different colors of hydrogen reflect how it is produced and its impact on the environment. The hydrogen landscape is marked by a spectrum of colours, each representing a distinct production pathway. The three most important colours are grey, blue and green. Grey hydrogen, made from fossil fuels, emits substantial amounts of carbon, making up 81% of global hydrogen. Blue hydrogen integrates carbon capture and also has controllable production capacity. Green hydrogen is made from renewable electricity through the process of electrolysis, currently making up around 1% of hydrogen worldwide [82]. Because the energy to produce green hydrogen is from renewables such as wind and solar, this is not a controllable production process. The current dominance of grey hydrogen and the small amount of green hydrogen show the need for more sustainable production methods.

### 2.2.3. Hydrogen production technologies

The previous section highlighted various hydrogen production pathways, setting the stage for a detailed look into specific production technologies. Grey hydrogen production in the Netherlands relies heavily on steam methane reforming (SMR), creating syngas from natural gas. Auto thermal reforming (ATR) also plays a role, producing hydrogen and necessitating a closer look due to its potential for low-carbon production. Globally the by-products from chemical processes contribute around 20% to the hydrogen supply. Catalytic reforming and steam cracking in refineries, along with hydrogen from the chlor-alkali process, complete the spectrum. Electrolysis takes centre stage in the production of green hydrogen, with three prominent technologies—Alkaline (AEL), Solid Oxide (SOEC), and Proton Exchange Membrane (PEM) electrolysis—leading the way. Each technology offers a unique set of characteristics, from capital and maintenance costs to efficiency levels. Considering the investment decisions in the Netherlands, AEL electrolysers emerge as the front-runner. The discussion extends to the spatial and economic implications of onshore and offshore electrolysis, addressing the challenges and benefits associated with each. For this research, it is interesting to look into the flexibility of electrolysers and their ability to ramp up and down. The type of electrolyser used in a scenario can have an interesting impact on the outcome of the model and will therefore be compared in different scenarios. The share of alkaline electrolysers is expected to make up around 90% of all electrolysers, and the other 10% is expected to be PEM electrolysers in 2035 [67]. Understanding these production technologies is crucial for assessing their suitability and impact on future hydrogen systems.

#### Alkaline Electrolysis

Alkaline electrolysis is an already well-established and commercialised technology for the large-scale production of hydrogen. Holland Hydrogen 1, Shell's announced hydrogen production plant, will be based on a 200 MW alkaline electrolyser [59]. It is characterized by low capital and operation and maintenance (O&M) costs. The downsides of this technology are the reduced efficiency with partial loading, being important for grid balancing purposes and the relatively longer ramping times. The difficulty with alkaline electrolysers is that they are not well suited to be turned off completely, as they will break down each time doing so. That is why it is preferred that an alkaline electrolyser runs on a stand-by mode at the least, which requires between 1 and 5% of the electrolyser full load capacity [6]. The minimum operating power of an alkaline electrolyser to produce hydrogen is between 15-30%. The ramping-up time from the standby state and operating state is negligible quickly, whereas starting up from an off state to an on state is around 20 minutes [6]. The choice of electrolysis technology will influence the efficiency and flexibility of hydrogen production, with alkaline electrolysis offering a balance of cost and performance.

#### Proton Exchange Membrane Electrolysis

In contrast to alkaline electrolysis, PEM electrolysers are well-suited for short-term changes in load. They are characterized by their efficient production in partial loads and quick ramping times and are currently utilized for large-scale applications beyond 10 MW. However, the technology still experiences durability and deterioration issues. For the project from Neptune called PosHYdon a PEM electrolyser of 1MW is installed as a pilot study on the North Sea. This pilot has the goal to determine the risks and test uncertainties of electrolysis from off-shore wind, which is flexible supply and environmental conditions, such as high salt content in the air. In contrast to AE stacks, PEM stacks rely on crucial raw materials. In 2018, the worldwide production of platinum and iridium for the electrochemical sector amounted to 135 tons/year and 8.5 tons/year, respectively. With a projected installed capacity of 91 GW by 2030 to be fulfilled by PEM electrolysers, the current global iridium production falls short of meeting the required demand for iridium loading in PEM electrolysers. Therefore, it is essential to decrease the iridium loading by at least a factor of 5 by 2030, especially if a factor of 20 reduction (as assumed for advanced PEM design) cannot be attained. This underscores the need for significant research and development efforts aimed at reducing iridium loading by 2030 while ensuring optimal stack performance [54]. A recent problem that came up with PEM electrolysers is their emissions of

PFAS (per- and polyfluoroalkyl substances). Producer NEL is currently exploring alternative solutions; however, they report that these alternatives remain several years away from achieving commercial or technical viability. Multiple studies have demonstrated that these membranes have a maximum operational lifespan of 100 hours under base load current conditions. For context: to establish a viable business model, customers need to operate their electrolysers for a minimum of 5,000 to 8,000 hours annually [74]. Addressing issues like iridium scarcity, high costs, and PFAS emissions will be crucial for PEM electrolysis to become a viable and sustainable option for large-scale hydrogen production.

#### Solid Oxide Electrolysis

Solid Oxide Electrolysis stands out for its high efficiency [100] and low production costs but is hindered by high initial costs and durability issues. Consequently, it enables lower production costs by reducing electricity consumption. However, it is plagued by several drawbacks, including high initial costs, extended ramping times and issues regarding stack durability and degradation. Despite these challenges, solid oxide technology holds promise for industrial applications that operate at elevated temperatures. The technology readiness level of SOE is around 6, which is not near the levels 8 and 9 of Alkaline and PEM electrolysers [58]. It is expected however that its TRL will be around 9 in 2050. Future advancements in SOE technology could make it a viable option for industrial-scale hydrogen production, pending improvements in its readiness and performance.

### 2.2.4. Hard-to-abate sectors

The exploration of hydrogen production technologies leads naturally to a discussion on how these advancements can support sectors that are difficult to decarbonise. Apart from sectors that can easily transition to be powered by electricity, there are also industries heavily reliant on molecule-based energy. These are referred to as hard-to-abate sectors, encompassing aviation, shipping, heavy-duty transportation, chemical industry, heavy industry (such as steel), and agriculture. Together, these sectors contribute approximately 31% to global CO2 emissions [72]. To address their energy needs sustainably, the focus should be on the development of molecule-based fuels like ammonia, hydrogen, sustainable aviation fuel, and bio fuels. Meaning that there is a demand from two sides of the system for molecule-based energy: flexibility in the electricity network and powering the hard-to-abate sectors. To effectively tackle the energy needs of hard-to-abate sectors and reduce their substantial CO2 emissions, developing sustainable molecule-based fuels will be crucial for both flexibility in the electricity network and meeting industrial energy demands.

### 2.2.5. Power-to-hydrogen-to-power

The discussion on hard-to-abate sectors highlights the importance of efficient energy solutions, which leads to a consideration of the effectiveness of hydrogen in power-to-hydrogen-to-power applications. Due to the relatively low efficiency of the power-to-gas-to-power process for green hydrogen, which stands at approximately 40%, utilising hydrogen storage to mitigate short-term electricity shortages by converting hydrogen back into electricity is generally not preferred [29]. Nonetheless, gas storage has proven highly effective for managing seasonal fluctuations. Furthermore, molecular storage represents a viable strategy for maintaining strategic reserves and not being reliant on imported energy. Despite its lower efficiency for short-term electricity shortages, hydrogen storage remains valuable for managing energy fluctuations and maintaining strategic reserves.

### 2.2.6. Difference between security of supply and energy security

Understanding the current reliance on natural gas highlights the need to maintain reliable energy systems during the transition to cleaner sources. As a society, we are highly dependent on and used to our energy needs being provided at a relatively affordable cost. This is possible due to natural gas availability, however, in the future, this will not be the source for flexibility needs, due to the carbon emissions. For a future system and during the transition to that system we want to have the same security of supply that we are used to now.

There is a difference between the security of supply and energy security, but also overlap. Security of supply means that there is enough energy in storage, facilities and plants to keep the lights on in a system. Energy security is defined as the uninterrupted availability of energy sources at an affordable price and is more focused on long-term strategies. In this research, the term security of supply will be used. While security of supply ensures immediate energy availability, distinguishing it from broader energy security is crucial for developing effective long-term strategies in the future energy system.

### 2.2.7. Electricity import dependency

The transition to cleaner energy sources and the challenges of maintaining security of supply lead to a critical examination of the Netherlands' reliance on energy imports. An import dependency analysis from Tennet describes a hypothetical situation in which the Netherlands is not connected to other bidding zones and operates independently under the same scenario assumptions. The analysis reveals that in the scenarios for 2028, there is a shortage of 0.2 GW of capacity, which will increase to 5.0 GW by 2030 and 8.4 GW by 2033, to maintain a supply security standard of 4 hours per year. Therefore, the Netherlands relies on foreign capacity to meet these needs. The significance of this analysis for actual required capacity is limited due to large differences in LOLE (Loss of Load Expectation) and EENS (Expected Energy Not Supplied) between simulations with and without interconnection capacity. For instance, by 2030, the absence of interconnection capacity could result in extreme shortages, with a LOLE of 626 hours and an EENS of 1.1 TWh. Overall, it can be concluded that the Netherlands is not energetically independent. Achieving such independence post-2028 would be very difficult, likely undesirable, and unfeasible. Additionally, the analysis shows that 74% of the hours with shortages in the Netherlands coincide with shortages in Germany, whereas only 10% of the hours with shortages in Germany coincide with shortages in the Netherlands. The analysis underscores that the Netherlands will remain dependent on external energy sources to meet future capacity needs, highlighting the importance of interconnections for managing energy security and avoiding extreme shortages.

### 2.2.8. Types of underground hydrogen storage

As discussed there will be a need to store hydrogen in large volumes. There are multiple ways to store hydrogen underground. Below in table 2.2 the potential capacity of these options is shown. One observation that can already be made is that there is an abundance of structures underground to create possible storage facilities as can be seen in figure2.2.

**Table 2.2:** Capacity spectrum of different storage options and Dutch potential storage capacity [91, 92, 37]

| Type | Volume [GWh] | Offshore potential [TWh] | Onshore potential [TWh] |
|---|---|---|---|
| Surface tanks | 5 - 10 | | |
| Salt cavern | 100 - 250 | 170 | 42 |
| Gas fields | 100 - 20000 | 294 | 279 |

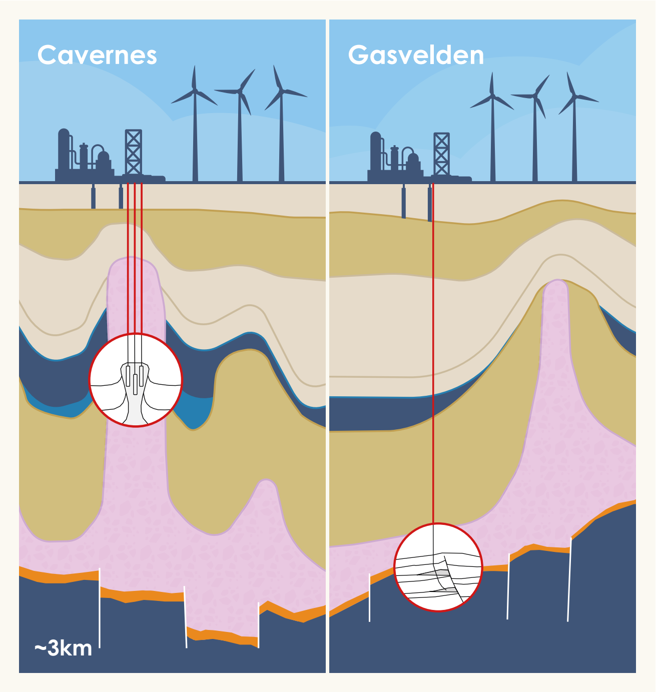


**Figure 2.1:** Visualisation of gas fields and salt caverns [24]

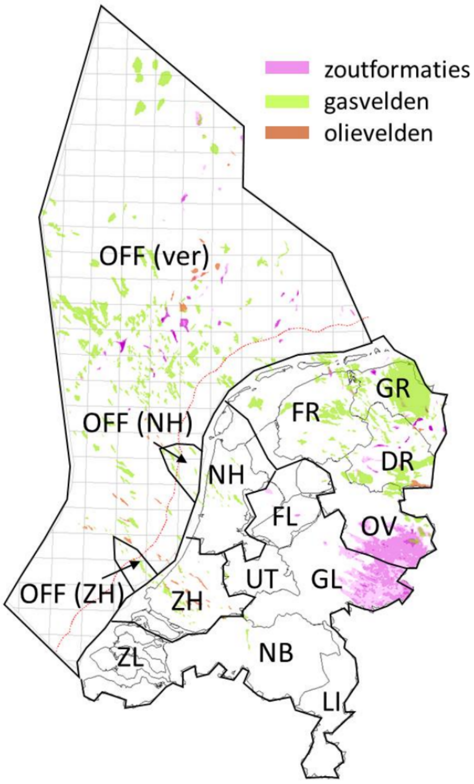


**Figure 2.2:** Classification of regions within which storage capacities are determined [25]

### Salt caverns

Salt caverns are underground storage facilities constructed by water dissolving in deep salt formations [60]. Underground salt cavern storage is one of the most promising geological storage technologies for hydrogen, due to its technological maturity, fast cycling flexibility and large volume storage capacity [47]. They provide good sealing and have stable chemical properties and good self-healing ability. They are internationally recognized as the ideal storage facilities for oil and gas storage and waste disposal. The faster the working capacity of a salt cavern needs to be, the quicker the erosion of a cavern will be.

The caverns are made by drilling two several hundred-meter-deep holes in a salt formation. Then water is pumped into the salt layer causing the salt to dissolve. The dissolved salt, called brine, is pushed up and needs to be used or disposed of. This process takes time and dumping the brine in the sea is not possible due to regulations. It takes three to four years before a cavern is of the shape and size suitable for gas storage. It is then filled with gas for the first time. By injecting pressurized gas into the cavern, the last brine is pressed out. However many plans exist for building salt caverns, there is one investment decision made to date in the Netherlands: HyStock by GasUnie. Salt caverns offer a mature and flexible solution for large-scale hydrogen storage, though their development involves a lengthy process and significant planning, with the Netherlands' HyStock project being a notable example.

#### HyStock

In the Netherlands, there is a salt cavern storage project in the pipeline, which is HyStock. On June 26, 2019, the green hydrogen installation HyStock was opened, in Veendam, Groningen, a project by GasUnie [97]. HyStock, a subsidiary of GasUnie, has been actively involved in the hydrogen sector and related infrastructure for several years. Situated in Zuidwending, the company benefits from a robust connection to the national gas transport network. HyStock works together with EnergyStock B.V., a subsidiary of GasUnie specialising in natural gas storage. Zuidwending hosts ten locations for salt caverns, with six presently allocated for natural gas storage. The remaining caverns are being considered for repurposing to store hydrogen. In the hydrogen cavern A5, 216 GWh of hydrogen will be stored, and it is expected to be operational by 2028. The goal of GasUnie is that another three caverns will be in function by 2030 [43].

**Other projects in the EU**

One of the initial projects under the EU's funding umbrella is the Hystories project, which aims to deliver insights into underground hydrogen storage for policymakers in government and industry [44]. Another notable project, initiated in 2021, is the EU-funded HyUSPRe project [45]. This initiative seeks to establish the feasibility and potential for large-scale storage of renewable hydrogen in porous reservoirs, such as gas fields and aquifers, across Europe.

#### Gas fields

Another interesting option for storing hydrogen in large volumes is in depleted gas fields. These volumes are often higher than those in salt caverns, however, there is still a lot of research conducted and pilot studies need to prove their efficiency and economical feasibility [61, 63, 64, 79, 91]. For this research, the assumption is made that these gas fields will be operable in the future. The rate at which hydrogen can be extracted from gas fields is significantly slower than that from salt caverns, which influences the operational viability of these gas fields. Consequently, the utilization of gas fields is more suitable for maintaining a consistent hydrogen supply over extended periods, such as days, weeks, and annually, rather than addressing immediate, hourly fluctuations in demand. This slower production capability thereby impacts the flexibility of the energy system. Depleted gas fields present a promising but still under-researched method for large-scale hydrogen storage, with their slower extraction rates making them more suitable for long-term storage rather than rapid, short-term supply adjustments.

### 2.2.9. Duration of storage

As hydrogen storage solutions must cater to varying demands and time scales, it is essential to differentiate between short-term and long-term storage strategies to address different energy needs effectively. There are different purposes for storing hydrogen, suited for short-term, long-term storage, or a combination of the two. Short- and long-term storage is also known as hourly storage and seasonal storage is mainly applicable to the 'old' natural gas system. The main difference is that hourly storage is aimed at the fluctuations in demand on an hourly basis and seasonal storage is designed to address variations over longer periods, such as the difference in energy demand in summer and winter. Provision of flexibility over longer time spans is more difficult because many demand response facilities are not able or willing to lower electricity consumption for a longer period (days or longer). In winter high pressure areas can create wind droughts (dunkelflaute) lasting several weeks during which there is low solar output and high heating demand. Because these events are weather-driven, surrounding countries experience similar conditions, resulting in low gains from cross-border transmission capacity [22]. Investments in short-term solutions for hourly storage may be good business cases, whereas long-term storage investments are associated with high risk because these large storage facilities might not be used annually or in the following ten years and their return on investment needs to be made during extreme weather. But still, during such weather conditions society wants a secure supply of energy. Doorman and de Vries (2018) believe that a system called Capacity Subscription combined with tenders for variable renewable energy can finance these larger storage facilities. Seasonal storage options include utilising underground storage in salt caverns or repurposed gas fields to accommodate large volumes of hydrogen.

The primary distinction between the previous energy system, which relied on natural gas to provide flexibility, and the modern energy system with a higher share of variable Renewable Energy Sources (vRES), lies in the introduction of a new time scale for storage: spanning from days to weeks. Below in figure 2.3 the distinctions in capacity, volume and time of different storage techniques are visible. Overall, while seasonal storage options like underground facilities are crucial for handling longer-term fluctuations in energy demand, the transition from natural gas systems to renewable energy sources introduces new challenges and time scales for effective storage management.

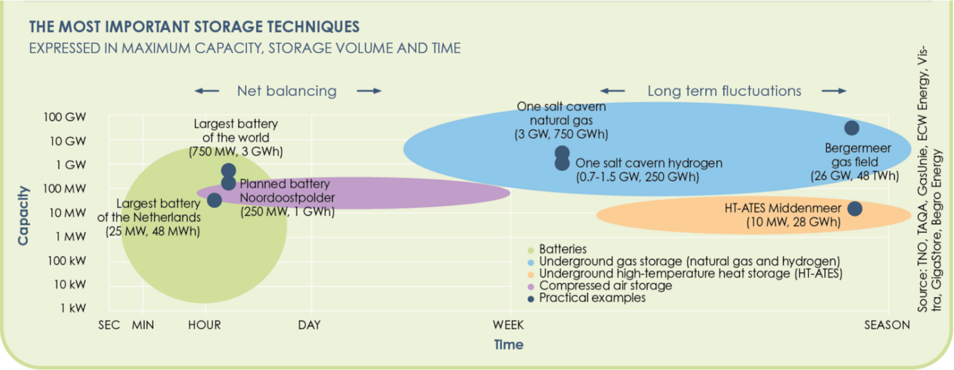


**Figure 2.3:** The different functions and characteristics of energy storage from EBN

## 2.2.10. Capacity of storage

To fully understand how hydrogen can fit into our future energy system, it's important to look at its storage capacity and the role it plays in meeting energy needs. In contemplation, hydrogen emerges as a potential, versatile and sustainable option, meeting the demands of challenging sectors, possibly contributing to grid stability, and playing a role in shaping a flexible and environmentally conscious energy landscape. However, the conceptualization of green hydrogen as a potential energy carrier is shrouded in uncertainties, and its role as a definitive solution remains unestablished. A significant contributing factor to this uncertainty is the current high cost of green hydrogen [81]. This predicament mirrors a classic chicken-and-egg scenario for investments. Without an established network and a consumer base able to afford it, there is a dearth of investments, leading to limited supply. Consequently, the system's viability is yet to be substantiated through practical implementation and real-world success. If hydrogen were to be a key player in the future; hydrogen storage plays a key role in the security of supply of the network and thus the willingness to invest in such an infrastructure. This research will focus on the required storage capacity, types of hydrogen storage, storage characteristics and time frame of storage capacity necessary to comply with the predicted supply and demand in the coming decades.

## 2.2.11. Injection and production capacity

Understanding the injection and production capacities of hydrogen storage facilities is crucial for assessing how effectively these facilities can meet fluctuating energy demands. An important characteristic of storage facilities is the associated injection and production capacity. Peak injection capacity is the maximum speed with which storage can be filled with hydrogen in GW. Peak production capacity is the maximum speed with which the hydrogen can be extracted from storage, also in GW. There is a substantial difference in injection and production capacity of regular gas field storage and peak gas field storage. This characteristic is important because it determines how flexible the storage can be used, adding to its value. The injection and production capacity of facilities is not set in stone but mostly comes from the design requirements of natural gas storage. Even though there are technical limitations to increasing this by a lot, there is room for improvement if sufficient investments are made. The size of these investments is interesting to look into in this research. This research will examine the current capabilities in injection and production capacities of storage facilities, highlighting the impact of these factors on the flexibility and value of hydrogen storage solutions.

## 2.2.12. Transportation

To facilitate widespread adoption, hydrogen transportation is envisioned to leverage existing gas networks and other dedicated transport options [34]. This integration into the established energy infrastructures enhances the practicality of hydrogen. "One of the preconditions for the development of a hydrogen market is the infrastructure for transport and storage. The network will also link to import terminals at seaports, domestic hydrogen production sites and large-scale storage facilities" - GasUnie [12]. It is estimated that about 85% of the hydrogen network will consist of recycled natural gas pipelines. These plans are ambitious and there are still many uncertainties. This research is not focused on the transportation of hydrogen or the network, therefor the so-called copper plate is assumed, where transportation and distribution are disregarded. While this research does not delve into the specifics of hydrogen transportation or infrastructure, it assumes the use of existing networks and infrastructure, acknowledging that these aspects are crucial yet uncertain for the future development of the hydrogen market.

## 2.3. Knowledge gaps

Research on the anticipated demand for underground hydrogen storage capacity (in TWh) and their injection and production capacities (in GW) for 2035 and 2050 exists, but it is still quite sparse and does not sufficiently cover the impact of varying policy intentions and sustainable energy development scenarios. Existing studies do not sufficiently integrate these projections with current policy frameworks and investment plans to assess their alignment with climate targets.

Moreover, there is insufficient analysis of the economic and functional efficiency of different underground hydrogen storage options, such as salt caverns versus gas fields, in the Netherlands. Detailed studies are needed on the number of cycles these storage facilities can handle annually and their economic viability.

Additionally, the desired injection and production capacities of underground hydrogen storage facilities to ensure optimal functioning within technologically feasible limits are not well-defined. Research is required to establish these capacities, considering the technical capabilities and limitations of different storage options and their role in balancing supply and demand.

Limited research exists on how variations in the efficiency and ramp-up/down capabilities of different types of electrolysers (such as AEL, PEM, SOEC) impact the overall hydrogen storage and energy system. Detailed studies are necessary to understand these impacts and guide the development of electrolysis capacity in energy market models.

There is also a gap in comprehensive scenario-based analyses that explore future uncertainties in the energy system, particularly those related to the interplay between renewable energy development, electrolyser advancements, and hydrogen storage needs. Research is needed to incorporate these uncertainties into strategic planning for hydrogen storage capacity.

Existing policies and strategies do not adequately address the uncertainties associated with hydrogen storage capacity needs. More research is needed to determine whether current policies can meet projected storage demands and how they can be adjusted to better manage these uncertainties. Furthermore, the role of hydrogen storage within the broader energy transition, including potential bottlenecks and challenges, is under-researched. Additional studies are required to identify and address obstacles to achieving a reliable hydrogen storage system that supports overall energy transition goals. Addressing these gaps through targeted research will be crucial for developing effective strategies and policies that ensure the reliability and efficiency of hydrogen storage systems in support of the broader energy transition goals.

## 2.4. Research questions

### 2.4.1. Main research question

The question is how quickly and how much hydrogen storage is needed, given current policy intentions and scenarios regarding the development of sustainable energy, electrolysers and hydrogen consumption.

***What is the anticipated demand for underground hydrogen storage capacity (in TWh) and their injection and production capacity (in GW) based on supply and demand for hydrogen in 2035 and 2050 and how does this compare to the climate targets and investment plans?***

The core objective of this research is to determine the storage capacity for green electrolytic hydrogen in the Netherlands, amidst significant uncertainties in key input variables such as supply and demand. Instead of removing these uncertainties for policymakers, the goal is to understand their behaviour and relationship to the storage capacity. This will be achieved by constructing a combined electricity and hydrogen market model, with electrolysis capacity as the independent variable. By comparing and utilising forecasting studies like IP2024, II3050 and NPE, the study will design an experiment to explore future uncertainties in the energy system. The insights gained will identify which elements could be focused on when advising about storage policy and whether current policies adequately address uncertainties. Scenarios will be analysed for the years 2035 and 2050. Additionally, this study will highlight any potential bottlenecks or challenges that need to be addressed to achieve a robust and reliable hydrogen storage system capable of supporting the broader goals of the energy transition.

### 2.4.2. Sub research questions

- What is the anticipated demand for underground hydrogen storage (in TWh H2) considering current policy objectives, sustainable energy development scenarios and electrolyser advancements?
- What is the economically and functionally efficient capacity and combination of underground hydrogen storage facilities, considering utilising both salt caverns and gas fields in the Netherlands?
- What are the desired injection and production capacities of underground hydrogen storage facilities to ensure the efficient functioning of storage systems within technologically feasible limits?
- How do variations in the efficiency and ramp-up/down capabilities of different types of electrolysers impact the overall system?

**Sub-Research Question 1** The Netherlands and the European Union have established policies regarding renewable electricity and hydrogen usage for 2030. This research question aims to evaluate these targets and determine their justification. The analysis will provide insights into whether current efforts are on track or if additional measures are necessary. This serves as both a validation of the methodology and a basis for assessing current policy goals.

**Sub-Research Question 2** This sub-question focuses on exploring the differences between salt caverns and gas fields, and how they can each play a role in the system. The analysis through scenarios will identify the most influential and uncertain parameters of the storage itself and other factors surrounding the storage, such as the capacity of electrolysers. One focus when answering this question will lay on the number of cycles a gas field or cavern can go through in one year this will give insight into how economically efficient their investment will be. This will help guide policymakers in navigating the storage transition. Data for these scenarios will be obtained from literature and ongoing developments and will be aggregated in uncertainty ranges.

**Sub-Research Question 3** This question aims to determine the desired injection and production capacities of underground hydrogen storage facilities to find their optimal functioning within technologically feasible limits. Identifying these capacities is crucial for optimising the performance of hydrogen storage systems, which play a crucial role in balancing supply and demand in the energy transition.

# 3
# Research methodology

This chapter discusses the assignment that was constructed. After this the different methods are discussed, these include the modelling cycles and framework, the XLRM framework, Linny-r as modelling tool and the analysis types of the sensitivity analysis and the scenario analysis. The chapter concludes with the key performance indicators.

## 3.1. Research approach

An operational model for the Dutch electricity and hydrogen system, incorporating storage, has been constructed to explore how hydrogen storage can enhance flexibility for the electricity network. Building on the Linny-R model, this research integrates diverse scenarios aligned with current policy objectives and empirical studies, such as the Energy Transition Model [48], II3050 [73], IP24 [69], NPE [66], and EIPN [71]. Expert insights from EBN connections further enhance the model's reliability.

This research aims to offer EBN valuable insights to guide their strategy and investment decisions in hydrogen storage. Key questions include the significance of injection and production capacities, the impact of the number and volume of storage facilities, the dependency on the expansion of wind power and solar PV, the role of blue hydrogen, and the feasibility of a net-zero electricity network by 2035. The model serves as a tool to elucidate the interactions and sensitivities within the energy system, handle uncertainties, identify bottlenecks, and support strategic decision-making.

## 3.2. Research methods

### 3.2.1. Modelling cycle and framework

The modelling cycle below shows that a modelling process is iterative, which means that steps can be repeated if it turns out that the intermediate product needs to be adjusted. Moreover, the whole series of steps of a modelling cycle is often gone through several times, hence the term cycle. In the framework of Pieter Bots [10] this is achieved by following the steps in figure 3.1. Another way of structuring the modelling cycle is by using the Modelling and Simulation Life-cycle of Alexander Verbraek [95]. This framework consists of the steps in figure 3.2.

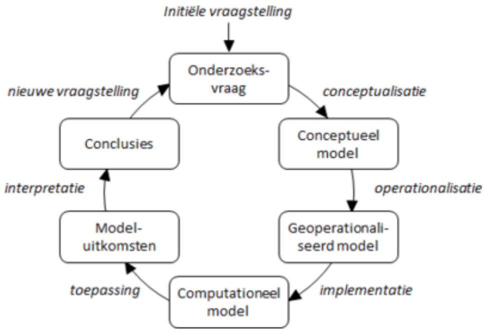


**Figure 3.1:** Modelling cycle Pieter Bots

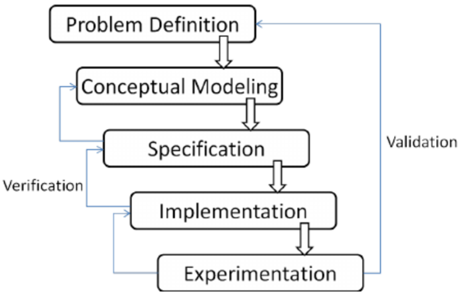


**Figure 3.2:** Modelling cycle Alexander Verbraek

From these two approaches, the main lesson is that the process is cyclical and iterative. From Verbraek's cycle, a takeaway is that every step requires verification of the previous step. Another key point is that the problem definition or research question is validated and re-evaluated after each cycle. This research will incorporate both approaches, this is evident from how the chapters are structured.

### 3.2.2. Assessing and measuring system characteristics and uncertainties

XLRM is a framework where robustness is described as a management decision strategy made against multiple future scenarios and critical uncertainties. It is well suited for ongoing decision-making, which is the case for the energy system and the role of EBN within it. The XLRM framework is based upon the following, also visualized below in figure 3.3. The XLRM framework for this research is visible in appendix C.

- Exogenous uncertainties (X) refer to external factors beyond the control of decision-makers, yet they hold significance in influencing the outcomes of their strategies.
- Policy levers (L) encompass near-term actions that constitute alternative strategies, subject to exploration by decision-makers in various combinations.
- Relationships (R) depict potential pathways through which the future unfolds, particularly about attributes addressed by the measures, influenced by the decision-maker's choices of levers and the manifestation of uncertainties. A specific combination of Rs and Xs represents the anticipated future state of the world.
- Measures (M) serve as performance standards, enabling decision-makers and other stakeholders to assess the desirability of different scenarios.

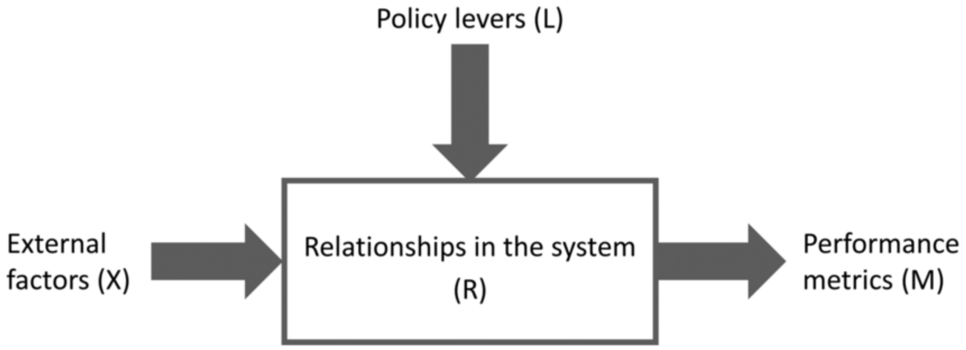


**Figure 3.3:** XLRM framework

### 3.2.3. Modelling tool

This research utilises a model that is made in Linny-R, a language for linear programming graphically and visually developed by Pieter Bots [11]. This model is easy to use for communicating with the client, EBN. Their understanding of the model is crucial to receiving feedback about the operationability and functionalities of the energy system that is imitated in the model. Besides that, Linny-R is an excellent tool for Mixed Linear Programming (MILP) problems, especially for Unit Commitment (UC) problems and generation expansion planning (GEP). Linny-R also allows a quick validation by enabling modellers to switch time steps with a single click, facilitating efficient model behaviour testing and runtime reduction. In its essence, Unit Commitment (UC) seeks to optimize the operation of a set of generators, ensuring they meet demands while adhering to operational and engineering standards most cost-effectively or profitably. This optimization framework aligns with neoclassical economic theory, which posits that individuals make rational decisions based on their preferences and constraints, with markets serving as efficient distributors of resources. However, it's essential to recognize that real-world scenarios often diverge from these idealized conditions. Disparities in access to information and unforeseeable factors such as weather patterns can hinder the ability to predict outcomes with certainty. Moreover, rational decision-making isn't always guaranteed, as market parties may overlook crucial information or have underlying motives that influence their behaviour. Hence, when evaluating the findings of this research, it's important to consider these complexities and potential limitations. In summary, while the Linny-R model is a useful tool for simulating energy systems, it's important to remember that real-world complexities and limitations might affect the accuracy of the results.

### 3.2.4. Sensitivity analysis

The Linny-R results will be tested on their robustness by conducting a sensitivity analysis. This sensitivity analysis will also show what parameters of the system the model is sensitive to, which shows the factors most relevant to keep an eye on. See chapter 5 and appendix D for the results of this analysis.

### 3.2.5. Scenario analysis

The model will be set up to run different scenarios with different conditions to find what type of strategy is most robust for the future. By measuring the KPI's for different scenarios the influence of parameters is understood. This scenario analysis will thereby help to find the most robust strategy for the security of supply. See chapter 5 and appendix D for the results of this analysis.

### 3.2.6. Measuring performance

These desired outcomes or Key Performance Indicators (KPIs) will help assess the performance of the model and the different scenarios that are tested.

- **Carbon emissions**
  The reduction of carbon emissions is key to the energy transition and a key driver for redeveloping the system to potentially include hydrogen storage. This KPI measures the effectiveness of the proposed scenarios in reducing carbon emissions, quantified in kilotonnes (kton).

- **LOLE (Loss of Load Expectation) and EENS (Expected Energy Not Supplied)**
  Preserving security in supply is crucial in forming energy policies. Transitioning to a carbon-neutral system must not compromise this security. This study aims to minimize LOLE and EENS through storage development, thus the inclusion of this KPI. EENS is measured in GWh and LOLE in the number of hours of shortage.

- **System costs**
  Cost minimization is a core aspect of Dutch and European energy policy. The 2022 energy crisis underscored the importance of affordable energy prices for system stability and geopolitical positioning. System costs are a KPI because Linny-R optimizes system costs by utilising diverse generation units, necessitating cost evaluation. System costs are measured in million euros (MEURO).

- **Production cycles**
  The amount of times per year a storage is emptied and filled is calculated by dividing the total volume of energy that passes through the facility per year by the maximum storage capacity.

# 4
# Conceptualisation

This chapter delves into the operational intricacies of the Dutch energy system and its simulation within the Linny-R modeling framework. It begins by detailing the setup and configuration of the model, highlighting the key settings that significantly influence the simulation outcomes. Subsequently, each section of the model is examined in depth to provide a comprehensive understanding of its components. Additionally, an overview of the XLRM framework is presented, summarizing its application within the context of this study. Through this thorough exploration, the chapter aims to elaborate on the conceptual foundation upon which the analyses are built.

## 4.1. The energy system in the Netherlands

The Dutch energy system is intertwined, consisting of variable (renewable) energy sources for electricity and fossil fuels and non-fossil fuels as energy sources. This chapter aims to explain the system bit by bit, how it is related and how this is incorporated into the Linny-R model. Since the model covers the entire energy system, several assumptions are made and limits to the model exist, which will be addressed in the upcoming chapter. In figure 4.1 below is a conceptual overview of the system, which shows what is included and how all of this is interconnected. This part of the research corresponds with the conceptualisation phase of the modelling cycle.

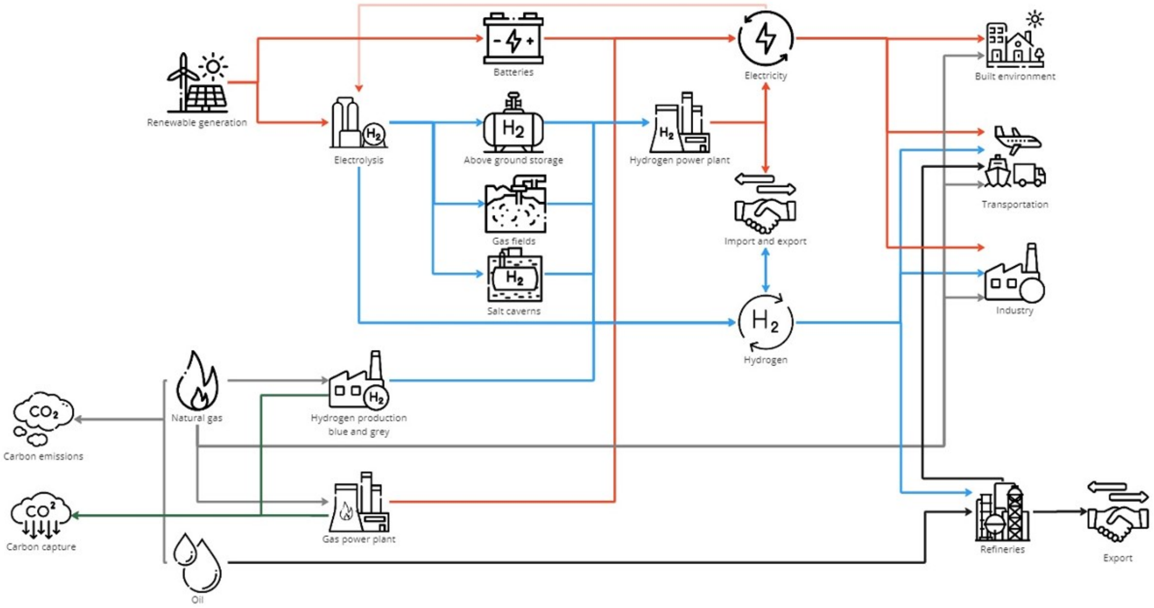


**Figure 4.1:** Conceptual overview of the system

For years, the Dutch electricity system has relied on centralised generation with a flow of electricity from producers to consumers. Historically, this centralized generation has been predominantly fueled by conventional power plants, particularly gas-fired facilities, influenced by past policies promoting gas usage since the discovery of the Groningen field. These conventional power plants, also including coal and nuclear, offer the advantage of controllable power generation: output can be scaled down during periods of low demand and ramped up during peak demand. Dutch industry became heavily reliant on the affordable supply from Groningen, which has now been terminated due to the earthquakes caused by gas exploration. Besides that, there is of course the goal to become carbon neutral. The industry is therefore looking for energy alternatives to stay economically resilient.

In alignment with climate agreements, there is a mandated shift towards renewable energy sources. By 2030, it is targeted that 70% of electricity will be sourced from renewables such as wind and solar PV. Additionally, the Dutch Parliament has stipulated that the electricity network must achieve carbon neutrality by 2035 [3]. This transition will lead to an increasingly weather-dependent and seasonal electricity supply, contributing to greater volatility in the system. As the Dutch electricity system increasingly relies on weather conditions, this means that it requires even more carbon-neutral backup generation capacity to offset momentous deficits in renewables.

Conversely, there is a rising demand due to the electrification of various sectors including industry, the built environment, and transportation. This dual trend, shifting to renewable generation while facing increasing electrification, poses significant challenges and necessitates careful management of the electricity grid and energy policies moving forward. A significant challenge encountered by the system is network congestion, impeding industries aiming to transition by limiting their connectivity to the network. The transportation of electricity, crucial but not considered in this study and model, deserves attention as it could pose a substantial hurdle in the transition process. This model uses the copper plate approach. Thus, addressing network congestion and the complexities of electricity transportation will be critical in ensuring a smooth transition to a renewable and electrified future.

An uncertainty which could limit the reliability of supply is that the current market model will be used to set the price for energy. There is a possibility that in the future system, some kind of capacity mechanism will be required to ensure incentives to provide generating capacity and thus energy security. Or that would encourage the built environment and industry to lower their demand during low availability of renewables. It is possible that in the future this market design will change; this possibility is not included in this research.

EU ETS pricing is a market design, so the value of a carbon allowance is not known for 2035. Therefore the 'CO2-heffing' law of the Netherlands is used to calculate the price for 2035. In the current political climate with a new cabinet, it is however unsure if the 'CO2 heffing' law still will be applied. Since it is part of the 'Klimaat Akkoord', it is decided to keep the value at this level [27].

In summary, the Dutch energy system faces a complex transition marked by a shift to renewables, increasing electrification, and evolving policy frameworks, highlighting the need for adaptable and forward-thinking strategies to ensure a reliable, sustainable, and economically resilient energy future.

## 4.2. The model set-up

### 4.2.1. Linny-R key concepts

To provide the reader with a comprehensive understanding of how Linny-R operates, this section elaborates on the fundamental components employed by Linny-R. The framework of Linny-R consists primarily of four key entities: products, processes, links, and clusters.

**Products**

Within the framework, a product represents an entity that can be consumed or produced. These entities can be tangible, such as electricity or fuel, or intangible, such as data products that convey information. Additionally, a stock is defined as a product that serves as storage, bounded by specified upper and lower limits.

**Processes**

A process represents the transformation of one or more products into one or more different products. For example, the production of green hydrogen via electrolysis is a process in which electricity is converted into green hydrogen.

**Links**
A link represents the relationships between products and processes. They may contain information about the flow between products and processes, such as efficiency.

**Clusters**
A cluster is a conceptual tool used for the structural organization of the model, facilitating the subdivision of the system into subsystems. It is important to note that clusters do not influence the optimization process; their primary function is to enhance the oversight of the model. Clusters also have an ”ignore” function within the program, allowing the deactivation of the model segment within the cluster for a specific run.

**Arrows**
A purple arrow on clusters or products represents the interconnection between this part and others in the model that are not in the cluster. The number shows the number of connections.

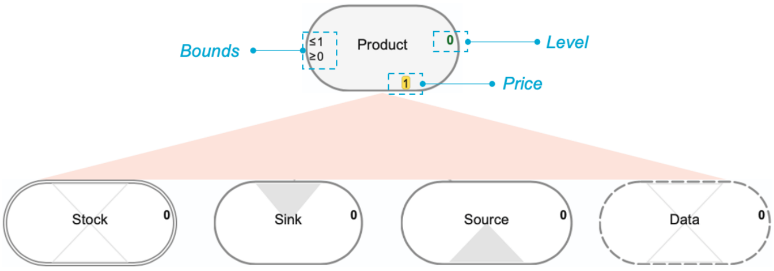


**Figure 4.2:** Default product and its four variants. Adopted from Groenewoud [39]

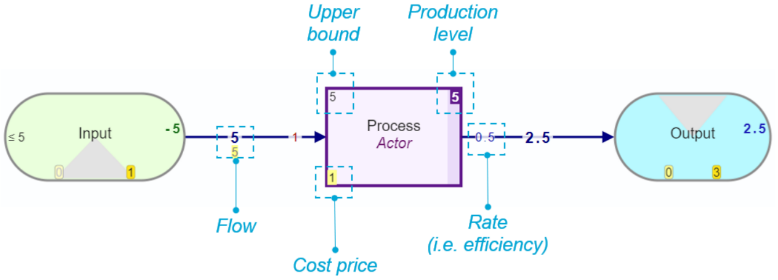


**Figure 4.3:** Process with input, output and flows. Adopted from Groenewoud [39]

## 4.2.2. Model settings

The model’s objective influences the selection of specific settings, which can yield different results. First, the duration at which the model is executed must be defined. In this study, the model runs for one year, with hourly time steps, resulting in a total of 8760 time steps per run. Hourly time steps are of great importance for this model, since the reactivity of processes is crucial for testing the flexibility of the system. For a thorough understanding of the seasonal patterns in the model results, it is crucial to note that the model runs from t=7300 to t=16060, where t=7300 corresponds to October 1st. October 1st is chosen because the filling degree of a gas field is often set at this point to prepare for the colder months ahead. This approach means the modelling is not based on calendar years.

Two additional settings that greatly affect the runtime and computational burden are the block length and the look-ahead period. The block length refers to the number of time steps over which the solver optimizes during a single iteration. The look-ahead period denotes the additional future time steps available to the optimizer beyond the block length. Both a longer block length and a greater look-ahead period increase the runtime. In this study, a block length of 8760 hours and a look-ahead period of 8760 hours were selected. This setup results in an average runtime of 17-24 minutes per run for the

2035 model, depending primarily on how much gas field storage is assumed. The modelling part of the gas field is most complex, resulting in higher run times. This is also why the runtime for the 2050 model is above 30 minutes.

### 4.2.3. Weather Years

In an energy system with a high amount of variable Renewable Energy Sources (VRES), weather constitutes one of the most critical yet uncertain parameters. Given the impossibility of predicting weather data for 2035 and 2050, we utilize historical data obtained from renewables.ninja [75]. This database provides hourly production factors for solar photovoltaic (PV) and both onshore and offshore wind from 1985 to 2019.

To optimize this model, two specific weather years are selected: a typical year and a year characterized by a ”dunkelflaute.” The typical year helps to understand the system’s normal functioning, while the dunkelflaute year tests the system’s robustness against periods of low renewable electricity production. The year 2019 is chosen as the normal weather year because it is the most recent year without extended periods of low sun or wind.

#### Dunkelflaute

The years 1987 and 1997 are often referred to as years which had a dunkelflaute [25]. This dunkelflaute is a prolonged period without significant wind production and represents a critical test for the system’s resilience. A limitation of this model is that during a dunkelflaute, the demand in the built environment is expected to be higher due to lower temperatures, but this is not simulated in this study, due to a lack of data for this consumer behaviour. Additionally, a factor that is not further studied is the impact which climate change could play on the capacity factors of solar PV and wind in the future, causing different weather patterns throughout the year. The analysis chapter 5 shows a visualisation and comparison of the weather years.

### 4.2.4. Data collection

In appendix B all the data points are listed for the base cases for 2035 and 2050.

#### Energy Transition Model

The Energy Transition Model by Quintel Intelligence [48] is an excellent dataset and model, based on various datasets from Klimaatmonitor, CBS, RVO, Emissieregistratie and TNO. This model results in hourly demand and supply profiles of hydrogen. On an annual basis, this leads to an imbalance of hydrogen supply and demand, which is equalized in ETM by adjusting import and export (both in base load). An imbalance also arises on an hourly basis; this shows the theoretical need for hydrogen storage without limitations on storage capacity and capabilities. Costs are not optimized to meet needs; storage ensures that all surplus hydrogen is stored and all hydrogen demand is met by storage at times when there is less green hydrogen. This model does not have the optimal storage capacity as an outcome. Many storage characteristics are not taken into account in the model.

#### II3050, IP24 and the NPE

The IP24 scenarios (scenarios up to 2035) and the II3050 scenarios (2035-2050) of the grid operators outline future visions and transition paths for the Dutch energy system up to 2050. These scenarios are well established and new revised versions are published often. There are therefore reliable scenarios to feed into the ETM model. The Nationaal Plan Energiesysteem (NPE) is the latest plan by the Dutch government to tackle the energy transition.

#### EBN

Technical measurements and information about for example the injection and production capacity are provided by EBN. Besides that, the knowledge of EBN colleagues provides insights into the feasibility of certain values from the policy plans and the most recent developments in technology and policy.

# 4.3. The model design

## 4.3.1. Top-level overview

An overview of the Linny-R model is shown below in 4.4.

The initial design of the model gives an overview of how the system operates and is connected. Some assumptions apply to the model in a general sense and not only to the subsections, these assumptions are as follows:

- Transportation and transmission of energy sources are not taken into account, because it would be too time-consuming to include in the scope of this research. This approach is called the 'copper plate' assumption.
- It is important to elaborate on in this overview the Value of Lost Load (VoLL) values for green hydrogen, hydrogen and electricity. The value of lost load for electricity is determined by averaging multiple values of research done on the VoLL in the Netherlands, leading to an estimation of VoLL of 22.31 million euros per GWh. This value is also chosen for green hydrogen because green hydrogen can be converted to electricity from which the energy mismatch would then be managed. For hydrogen, the VoLL is set lower because it is primarily used in the industry, and it is safe to assume that they will halt operations when the price is too high. Therefore this price is set at 6 million euros per GWh.

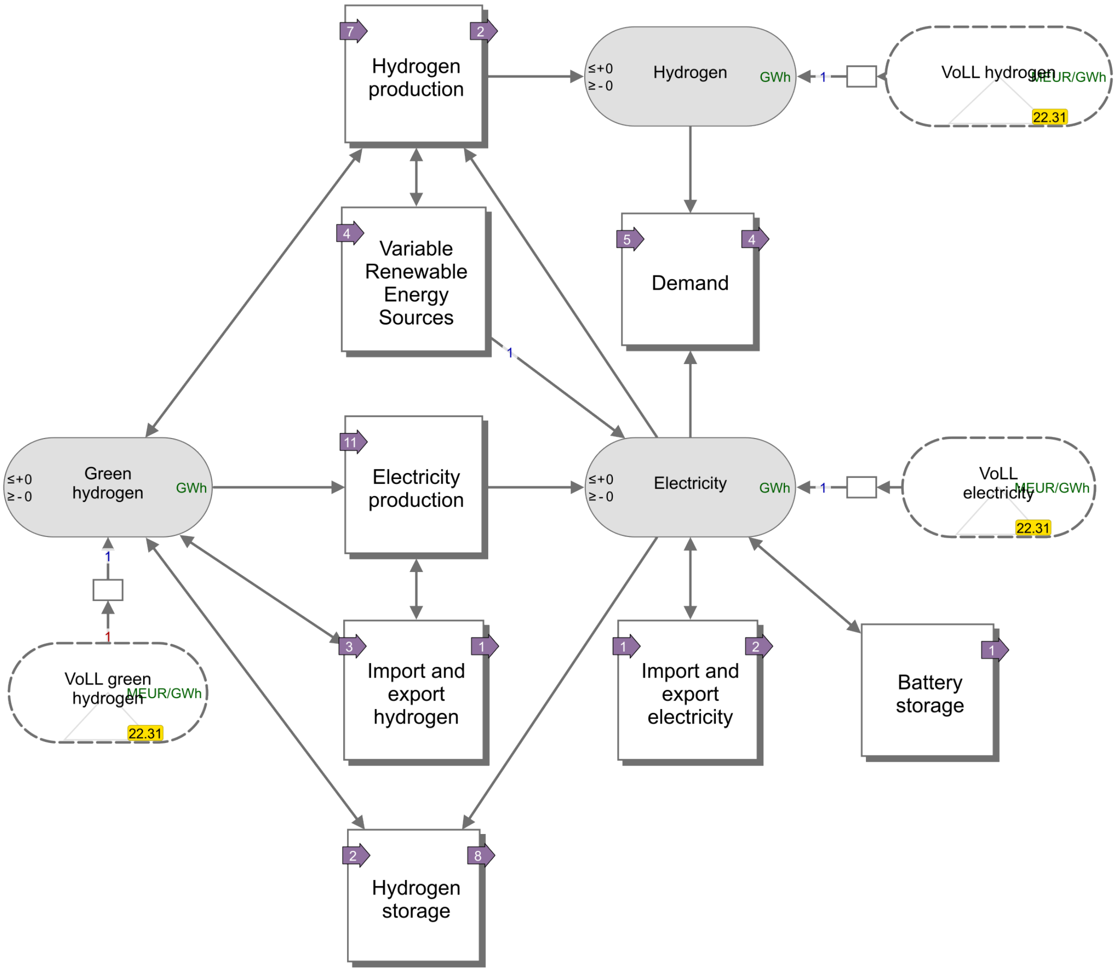


**Figure 4.4:** The Linny-R model overview

### 4.3.2. Hydrogen production

The grey hydrogen emissions share of the Dutch national emissions is around 8%, 3Mton carbon dioxide a year. The goal is to eventually switch from this natural gas-based grey hydrogen to green hydrogen. In this transition, the expectation is that blue hydrogen will play an important role in lowering emissions. The expectation is that SMR, production plants of grey hydrogen, will be equipped with CCS, which has a capture rate of around 70-90%. Another option for blue hydrogen production is Autothermal Reforming (ATR), which is expected to achieve a capture rate of 90%. CCS installations require additional electricity during production, resulting in higher hydrogen prices, but lower carbon tax prices.

The cluster for hydrogen production is made up of five different production methods for hydrogen. The production process is a process block in Linny-R and their source of feedstock is a product property. Biomass incineration, dedicated electrolysis and electrolysis are production processes of green hydrogen. Dedicated electrolysis has a wind park as an electricity source which is only connected to the electrolyser and not connected with the electricity network. This is why it has the properties of a PEM electrolyser because it needs to be able to shut down if there is no wind.

The electrolysers are considered to be mainly alkaline electrolysers, due to their technology readiness level and lower investment prices. However alkaline electrolysers have the limitation that they damage themselves each time that they are shut down, meaning that they require a base load of electricity input to have a lifetime of approximately 20 years. This standby state of an alkaline electrolyser is between 1-5% at which there is no production of hydrogen [6] and the on-baseload state is between 15-20% at which there is production. A simplified assumption has been made that the plant can produce hydrogen at 5%, which is set as the lower boundary of the process in the model. The efficiency of the alkaline electrolysers is 70% [70] and for PEM electrolysers this is 75% [70].

A small percentage of 10% is expected to be PEM electrolysers in 2035, for 2050 this is assumed to be 30%. The technology still needs to prove itself and besides that, there are concerning signals about the PFAS emissions of PEM electrolysers [74]. The percentage of dedicated PEM electrolysers is that it will be around 10% of the installed PEM, which results in 1% for the 2035 model and 3% in 2050.

The aimed amount of electrolyser capacity for 2035 in the NPE is around 9,5 GW, which is highly unlikely to be achieved with the current lack of investments being made into the technology. A more realistic estimate is around 6 GW for 2035, which is already ambitious. The policy goal for 2050 lies around 20 GW according to the NPE. Since 2050 is so far in the future 20GW will be used in the model for 2050.

Another form of hydrogen produced is blue hydrogen by the production process steam methane reformer. Blue hydrogen is produced by steam methane reformers (SMR) with CCS abilities with a carbon capture rate efficiency of 90%. Another form of blue hydrogen production is that of Autothermal Reformer (ATR). It is however highly uncertain how much capacity will be installed by 2035. An estimated assumption of 1 GW is therefore made. ATR can make a large impact on flexibility in our energy system as new plants might be able to convert natural gas into both hydrogen and electricity [20]. This is not modeled in the base case design, because the facility is still theoretical.

The production of grey hydrogen is taken into account for 2035, which is not in line with the assumptions of the ETM [48]. However, the only policy goal defined by the Dutch government is that the share of green hydrogen is 60% in 2035 for industry, but has not specified that the remaining 42% is prohibited to be grey hydrogen [53]. The taxing on carbon emissions is taken into account for the price of grey hydrogen. In the model for 2050, there will be no grey hydrogen production.

The green, blue and grey hydrogen are grouped as hydrogen to become the supply for hydrogen demand. Green hydrogen is used in many aspects of the system where it is unlikely that blue and grey will ever be used, due to policy restrictions.

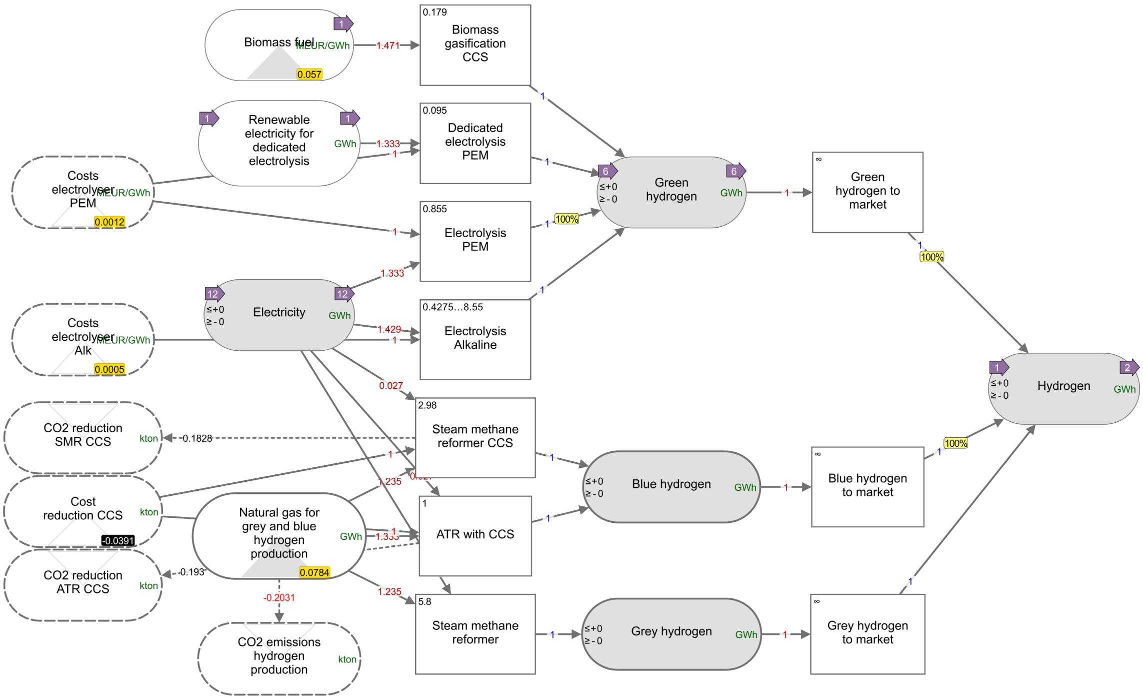


**Figure 4.5:** Hydrogen production

## 4.3.3. Variable Renewable Energy Sources

In the Dutch energy systems, significant renewable energy sources are taken into account for this model. These are wind, onshore and offshore, and solar PV. When there is little to no wind and solar radiation, the remaining demand must be met through either controllable power and storage or absorbed with flexible demand. Within the cluster of variable Renewable Energy Sources (vRES), different weather years are used to simulate the amount of generated wind and solar energy by multiplying the capacity factor of weather data with the installed capacities for onshore and offshore wind and solar PV.

Curtailment occurs when the network does not require additional supply to meet the current demand or store the energy. During such times, the production of green hydrogen is maximized. The model does not account for the scenario where wind speeds are excessively high, necessitating the shutdown of some windmills.

The offshore wind-to-power-to-X (P2X) process relies on dedicated wind farms that supply electricity solely for electrolysis and are not connected to the shore's electricity network. Consequently, they require their curtailment process. A dedicated wind farm has the disadvantage of limited access to wind energy from other farms with different wind profiles or to solar energy. Additionally, the wind farm cannot discharge its energy when the electrolyser does not require it, such as during maintenance periods.

Offshore wind, onshore wind, and solar PV are grouped as renewable electricity. Moreover, increased renewable generation capacity necessitates greater electrolysis capacity and storage to handle more frequent overshoots of renewable electricity. Otherwise, this energy is 'lost' in curtailment.

The plans of NPE, EIPN, and II3050 are all considered in the scenario runs conducted later in the study. For the base case, the values of the NPE are used.

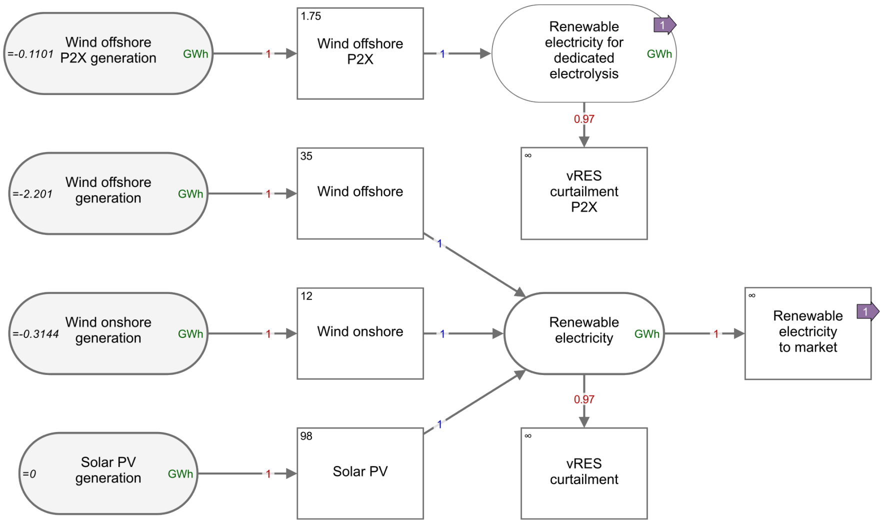


**Figure 4.6:** variable Renewable Energy Sources

### 4.3.4. Electricity production

Besides variable Renewable Energy Sources, there are many more production methods for electricity. In this cluster, these are incorporated into the model. First off there is nuclear energy production. Nuclear plants nearly never shut down have a minimum production rate of 75% at all times and provide a base load of electricity to the system. The goals in the NPE stated that it was expected to have a capacity of 2 GW by 2035, however, it is not in line with current investment plans and the long project development timeline that a nuclear power plant requires. Therefore a more conservative capacity of 0.5 GW is used in the model.

The second production method is waste-to-energy conversion. The conversion of waste to electricity is cheap because the feedstock is free in the Netherlands. This capacity is not expected to grow in the future.

Thirdly, there are biomass plants, which represent another limited source of energy constrained by its feedstock availability. A growing trend indicates that biomass will be increasingly utilized for fuels rather than electricity in the future.

Gas CCGT with CCS is built into the model but only used in certain scenarios. It will be set to zero in all base cases because the Dutch Parliament has declared that the electricity network is to be carbon neutral in 2035 [2] and that would not be possible to achieve with gas power plants. This will give insight into how much pressure is put upon other assets of the system due to this exclusion of gas CCGT and OCGT. In the scenarios that will incorporate gas CCGT as back-up, the price will be set at a high of 3000 euro/MWh, for it to be highest in the merit order. 3000 euro/MWh is the maximum price on the Dutch energy market, the EPEX.

The primary uncertainty regarding conventional generation lies in the varying installed capacities of different controllable technologies. The proportion of these capacities that comprise hydrogen turbines notably impacts the demand for green hydrogen, particularly during periods of low renewable generation. Hydrogen CCTG and hydrogen OCTG both have green hydrogen as feedstock and convert hydrogen to electricity. Their capacity is set at the values the ETM predicted, which is 3,5-8,5 GW combined in 2035 and in 2050 this is between 14-21 GW. Because hydrogen turbines are a bottleneck and not the focus of this study, the choice is made to insert a value so high that it will not become a limiting factor, which is 20 GW. In the scenario analysis, the values of the II3050 will be tested and will show the impact on the system.

Ammonia synthesis plants are installed to have a direct link from the imported ammonia to electricity, which otherwise would be utilised for electricity production through the conversion of hydrogen, which is not an efficient use of energy.

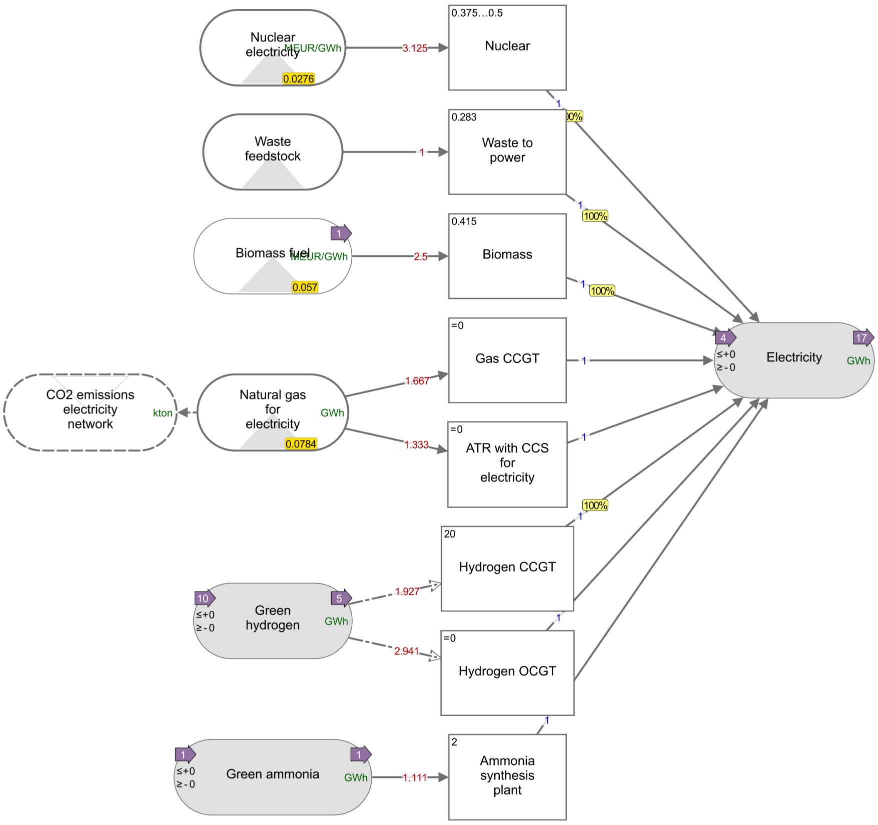


**Figure 4.7:** Electricity production

### 4.3.5. Hydrogen storage

Hydrogen storage is possible in above-ground hydrogen storage, salt caverns and gas fields. Storage of hydrogen is only applied for the green hydrogen, as blue and grey hydrogen is not likely to need much storage, because their production is not dependent on vRES.

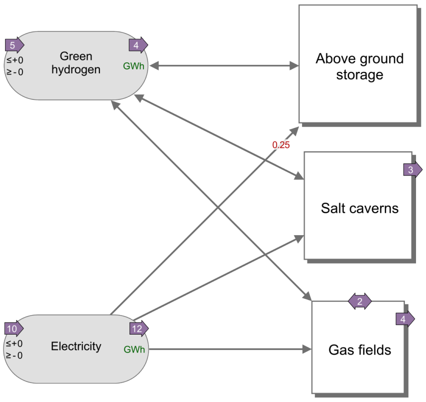


**Figure 4.8:** Hydrogen storage

#### Above ground hydrogen storage

In this study, it is assumed that above-ground storage is conducted in cryogenic tanks, which operate at atmospheric pressure but maintain extremely low temperatures. These tanks will primarily be used as peak shavers. For the storage of hydrogen above ground the process of liquefaction is required. This requires quite a significant amount of electricity [8], which is provided for by the net. There will be no further focus on above-ground hydrogen storage, because of its high energy use.

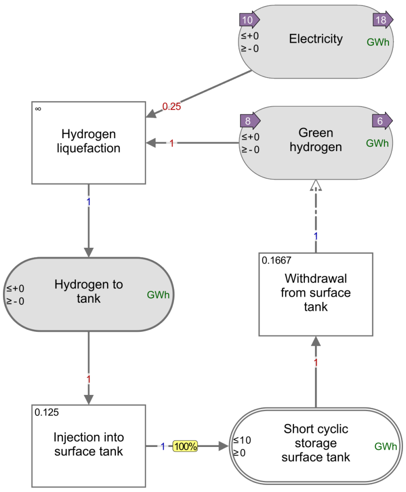


**Figure 4.9:** Above ground hydrogen storage

#### Salt caverns

The storage in salt caverns has relatively high injection and production capacities, which makes it a flexible tool in the energy system. One reason why salt caverns are fast is due to multiple wells installed in the salt formation, in this model, the values of TNO research are used [38]. This makes it possible to change the number of wells of the average salt cavern which has implications on the speed at which hydrogen can be injected or produced.

One salt cavern is under construction at this moment (Hystock [43]) and the expectation is that in 2035 there will be up to four salt caverns from this project alone. The first salt cavern of Hystock is expected to have a volume of 200 GWh. In many other studies and scenario sketches the average volume of a salt cavern is nearly always set to 250 GWh. Therefore the value of the first Hystock cavern is set to 200 GWh in the 2035 model, but all that follow are set to be 250 GWh in both the 2035 and the 2050 model.

The pressure regulation of a salt cavern is simplified in this model by the maximum production capacity per day. In the research of Juez-Larre the salt caverns in Zuidwending are discussed [50]. This research shows that a salt cavern can sustain a maximum withdrawal rate of 15 GWh/day, and a natural gas cavern can achieve up to 67 GWh/day. This disparity underscores the impact of operational constraints, particularly daily pressure depletion limits enforced to safeguard the structural integrity of the cavern. In practical terms, the hydrogen storage cavern has a capacity of approximately 250 GWh, which means that the daily maximum withdrawal rate would represent about 6% of its total capacity. Another research by TNO shows that a maximum production capacity of 24% is possible, with 9 to 13 wells in place per salt cavern. For the determination of the maximum daily production rate, the value of 20% is chosen, due to the assumption that in 2035 the technology will have further evolved.

The compression of hydrogen and the filtration process both require energy, which is taken into account. Their capacities are not expected to limit the system's injection and production capacities, thus speed, and are therefore modelled equal to the injection or production. Switching between injection and production is possible every hour, simultaneous injection and production is not possible in the model. Due to the run time of this model, which is one hour, we cannot however interpret the ability of salt caverns to switch within 15 minutes [35]. This is not completely realistic in practice due to associated costs. It would also increase the runtime of the model significantly, making analysis more difficult. Therefore it is chosen to keep the model setting at a one-hour time step.

Off gas is the residual product of the filtration required to clean the hydrogen. It is not quite clear what will be done with off-gas in the future, but this model will give insight into the volumes that will be acquired. Possible leakage, which means losing hydrogen in the cavern due to cracks etc, is not taken into account.

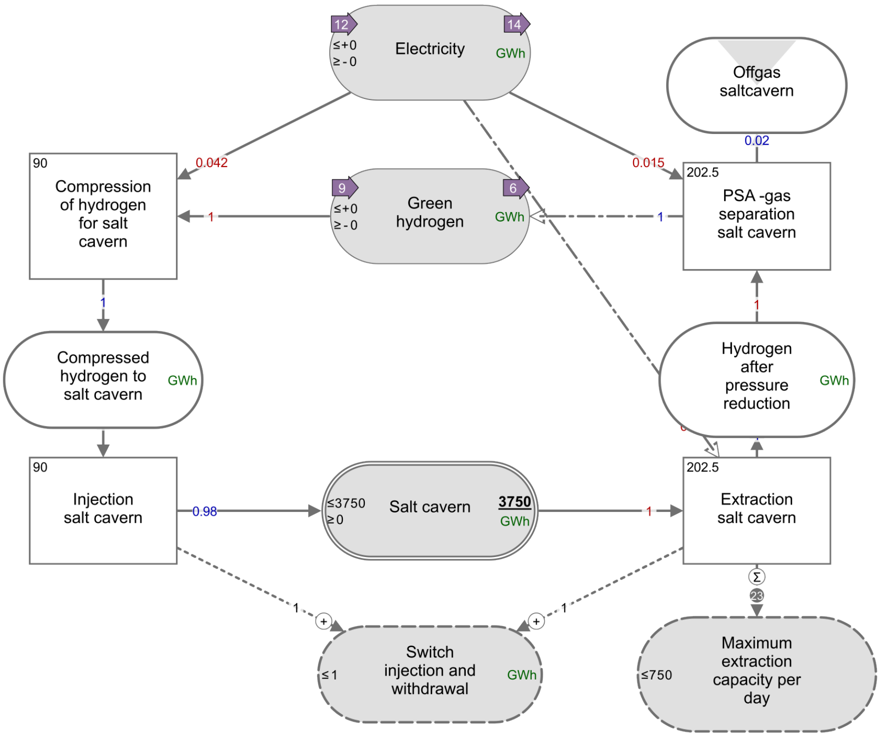


**Figure 4.10:** Salt caverns

### Gas fields

Storage of hydrogen in depleted gas fields is another large-volume storage option besides salt caverns. The expectation is that if there is to be a gas field operating in 2035, this will be a peak gas installation (PGI), which is smaller than average gas fields that are used for seasonal natural gas storage.

The compression process of hydrogen has a certain ramping up and down time and between the switch of compressing and not compressing is a time limiting factor of 12 hours.

The injection and production rates for the peak gas installation fields are based on the performance of the PGI in Alkmaar [67]. The second type of gas field that is modelled is 'kleine velden' which translates to small fields. These kleine velden are considered by EBN to be a logical next step after salt caverns and PGI's to be used for storage of hydrogen due to their size, which is averaged in this model at 2,5 TWh. Kleine velden has slower injection and production capabilities than PGI's. For the larger gas fields (5,5 TWh) in the scenarios for 2050 the rates are similar to those of the kleine velden. The injection rate is higher when the field is not filled and lower when the field is nearly full. The same accounts for the production, but in the opposite direction. This is modelled in Linny-R with a constraint. For gas fields, the production speed lowers linearly when the fields empty, with the slowest rate being only 41,66% of full production capacity [67]. For the injection rate, the speed lowers when the field is filling, by the end, a full gas field, the injection rate is at 50% [67].

The gas field is modelled in such a manner that the final 10% of the field will only be emptied as a last resort. This is done by setting the price for this reserve at the maximum price of the market, which is 3000 euro per MWh. The reserve is then modelled in a way that it wants to fill as soon as possible. This is modelled in a way that Linny-R is ordered to a full reserve at least once a week.

The gas field is also modelled in a way that it can either fill or empty, but not both at the same time. This is modelled by the switch function.

The maximum daily production of the gas field is lower than that of the salt cavern, with a maximum production capacity of 5% of the total capacity of all gas fields per day [67]. This metric applies universally across all types of gas fields discussed in this research for simplification, thereby establishing it as a somewhat constraining factor.

The initial degree of the filling of the gas fields is determined by running the model for two years without import, in a dunkelflaute year, with one salt cavern and one gas field installed. The average degree of filling in October is taken as the initial value, which is 750 GWh, or 54% of the gas fields. The salt caverns will also be tuned to this degree of filling. October will be the starting point for the model because October 1st is also the starting year for the gas fields.

Lastly, off-gas is acquired when filtering the extracted hydrogen and possible leakage is not taken into account.

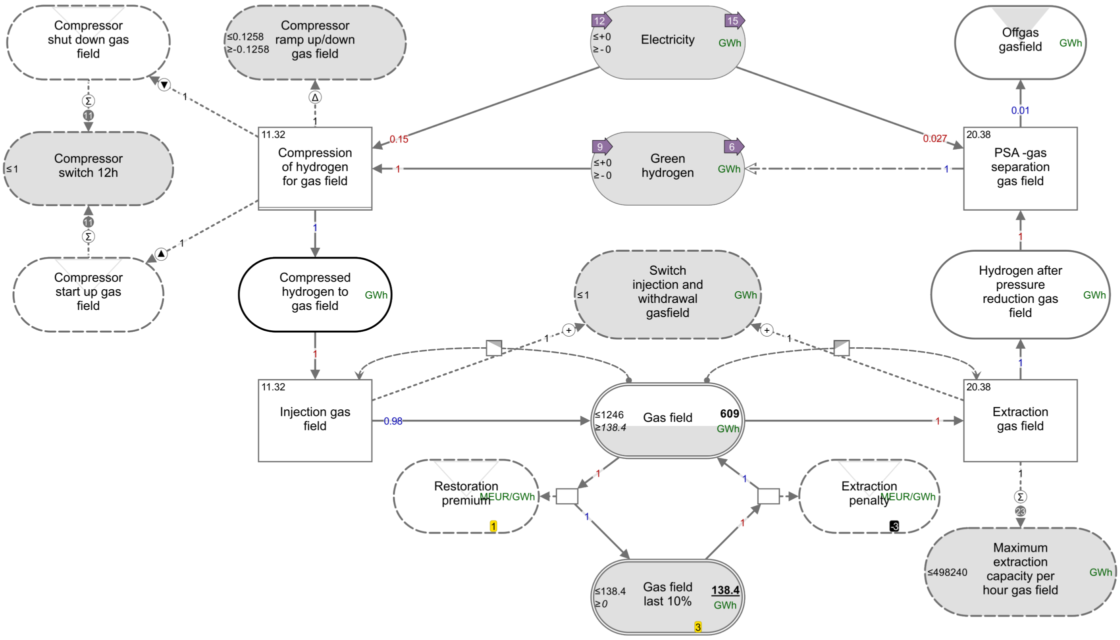


Figure 4.11: Gas fields

### 4.3.6. Import and export hydrogen

The import dynamics of hydrogen are modelled within this energy cluster. Ammonia cracking is considered to be done with only green ammonia which is produced at a different location which has inexpensive renewable electricity. This is then converted to ammonia for easier transportation. Wilco van der Lans and Randolf Weterings of the Port of Rotterdam enlightened this research with their insights into the import of ammonia and e-methanol. The port is already used to handling large quantities of grey ammonia and methanol, the switch to green versions of this same chemical is not a notably large transition. The import of liquefied hydrogen (LH2) will require adjustments to the port, but due to the difficulty of transportation of LH2, the majority of hydrogen, around 80%, will come in the form of ammonia or methanol in 2030 and 2040. For simplification reasons, only ammonia is used in this model. Approaching 2050 the trend that is expected is that the LH2 will make up over 50% of the import, due to scaling up of transportation opportunities. Due to the high energy density of ammonia and methanol in comparison to hydrogen, the storage requires less volume. OCI has a current storage of 60 thousand cubic meters and is planning on doubling that. Which is equal to 423 GWh ammonia. For reference, a salt cavern can store around 200 to 250 GWh of hydrogen. The expected amount of import of hydrogen, ammonia and methanol together in 2035 is 1450 TWh and 3500 TWh in 2050. However, part of this import is dedicated to other countries, such as Germany and their industry. This projection is based on a scenario outlined by a single entity, which introduces a degree of uncertainty and potential bias. The focus of this research is to identify what is necessary to ensure the security of supply within the Dutch energy system. Relying so heavily on imported energy would present a distorted view of maintaining system supply. Achieving independence from imported energy supplies positions a country to better withstand potential crises. This leads to the decision to put a limit on the capacity to convert this imported energy into a usable source for the system. It will however be discussed more in depth in the scenario analysis.

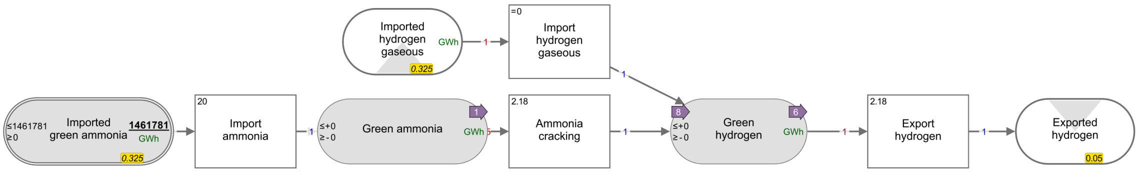


**Figure 4.12:** Import and export hydrogen

### 4.3.7. Import and export electricity

Notably, the costs associated with importing electricity are higher than those for exporting, a trend that similarly applies to hydrogen. The interconnection capacity for electricity trade between countries is projected to grow, reaching nearly 13 GW by 2035 [89]. However, this increased capacity does not necessarily equate to an available surplus of energy in the interconnected countries. During periods of dunkelflaute, it is likely that other countries will also face shortages of renewable energy sources and will not be able to supply other countries through the interconnections. To assume that full interconnection capacity can always be utilized is unrealistic, as this would imply an unlimited and freely accessible form of energy storage, which is not reflective of actual conditions. Therefore, a more realistic and conservative approach to modelling these imports is required.

Tennet recently published an analysis about import dependency [89]. They analysed a scenario in which our energy system operates independently without being connected to other countries. This analysis resulted in a shortage of 0,2 GW in 2028, 5,0 GW in 2030 and 8,4 GW in 2033. With this increasing trend of shortages, one may conclude that in the 2035 scenario of this study, this shortage will be even greater. Interesting findings of this study were the number of hours that simultaneous shortages occurred in neighbouring countries, see figure4.14. Percentage of LOLE hours in Zone 2 occurring simultaneously with deficits in Zone 1. For the Netherlands, row NL00 indicates the proportion of LOLE hours in which there was also LOLE in the other countries shown. As an example, in 74% of the hours with shortages in the Netherlands, there were also shortages in Germany, conversely only 10% of hours with shortages in Germany were also shortages in the Netherlands. Meaning that Germany has more to gain from the interconnection capacity with the Netherlands than the other way around. With Norway we do not have an overlap in LOLE (Loss-of-Load Expectation), meaning that the interconnection is more dependable.

Because it would require a much more complex model to implement the availability behaviour of neighbouring countries, a conservative approach is chosen. In this approach, only the Norwegian interconnection is considered available, which is 0,7 GW. This connection is considered to be always available at full capacity. In the scenario analysis 5 this section will be explored further to show the complexity and dependency of the Dutch energy system on import and export. It is important to note that this part of the model is highly influential and sensitive in a direct way to the value of the lost load that the model predicts.

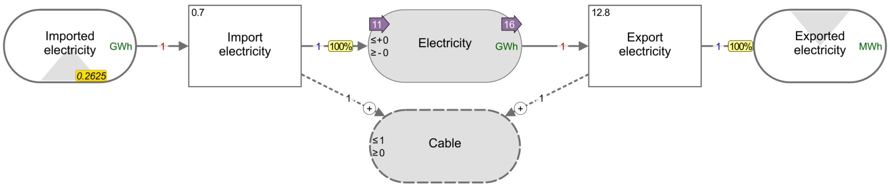
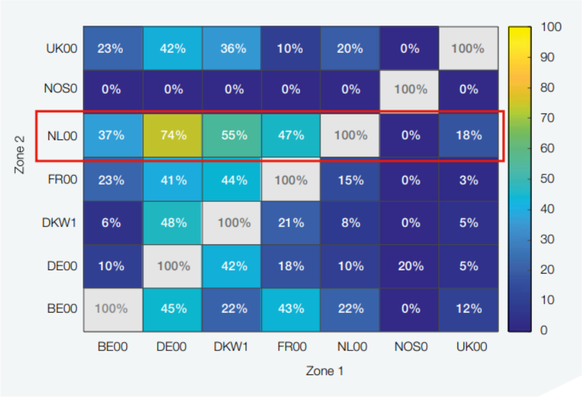


**Figure 4.13:** Import and export electricity



| | BE00 | DE00 | DKW1 | FR00 | NL00 | NOS0 | UK00 |
|---|---|---|---|---|---|---|---|
| UK00 | 23% | 42% | 36% | 10% | 20% | 0% | 100% |
| NOS0 | 0% | 0% | 0% | 0% | 0% | 100% | 0% |
| NL00 | 37% | 74% | 55% | 47% | 100% | 0% | 18% |
| FR00 | 23% | 41% | 44% | 100% | 15% | 0% | 3% |
| DKW1 | 6% | 48% | 100% | 21% | 8% | 0% | 5% |
| DE00 | 10% | 100% | 42% | 18% | 10% | 20% | 5% |
| BE00 | 100% | 45% | 22% | 43% | 22% | 0% | 12% |

**Figure 4.14:** Tennet analysis [89]

## 4.3.8. Battery storage

Electricity storage is crucial for managing the short-term volatility of variable Renewable Energy Sources (VRES). Various forms of electrical energy storage exist, including large-scale lithium-ion batteries, supercapacitors, household batteries, flow batteries, and batteries in electric vehicles (EVs). However, this research simplifies the storage of electricity to exclusively utilize lithium-ion batteries. The numerous smaller batteries distributed throughout the country are aggregated into a singular large battery system for modelling purposes. The considered amount of batteries is adopted from the ETM model, based on the II3050v2. However the NPE bases their assumptions on studies by TNO [42]. Here the assumption is made that the battery capacity will be between zero and 15 GW. This results in the choice to eliminate the scenario ND (Nationale Drijfveer) of the IP24 which assumes 21.8 GW. This leaves the KA (Klimaatambitie) which is 15.19 GW and IA (Internationale Ambitie) at 8.6 GW.

This assumption is based on two key considerations. First, these types of batteries are anticipated to offer the most potential for short-term grid balancing, thereby exerting the most significant influence on the system. Second, incorporating a wider variety of storage types into the model would significantly increase its computational burden and runtime. A longer runtime would limit the number of experiments that can be conducted, thereby reducing the quality of the analysis.

Additionally, it is important to note that lithium-ion batteries cannot charge and discharge simultaneously, necessitating the implementation of a switching mechanism within the model. The model also incorporates the high energy loss properties inherent to lithium-ion batteries to provide a realistic portrayal of their performance. Batteries from electric cars are not considered for battery storage, as they are likely not as responsive and efficiently utilized by consumers as regular batteries.

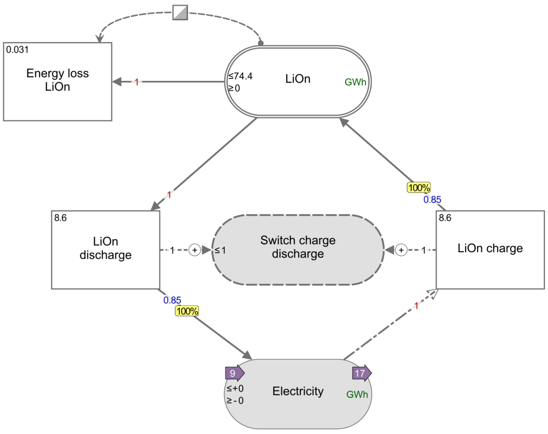


**Figure 4.15:** Battery storage

### 4.3.9. Demand

Within this cluster, all demand is added, which requires hydrogen, coal, oil, heat, natural gas and electricity. All scenarios are predictions of the future demand and supply. We don't know how the hydrogen market will look like in the future, this is all highly dependent on public policy and the economy. Both can be influenced by all kinds of factors. The values that are used in this section of the model are based on the values of the ETM [48].

Electrification in industries is expected to lower the demand for fossil fuels. Some sectors will be dependent on both fossil sources and renewable sources, these are the built environment and agriculture. The sectors built environment, agriculture and mobility have demand patterns based on differences throughout the year or day incorporated.

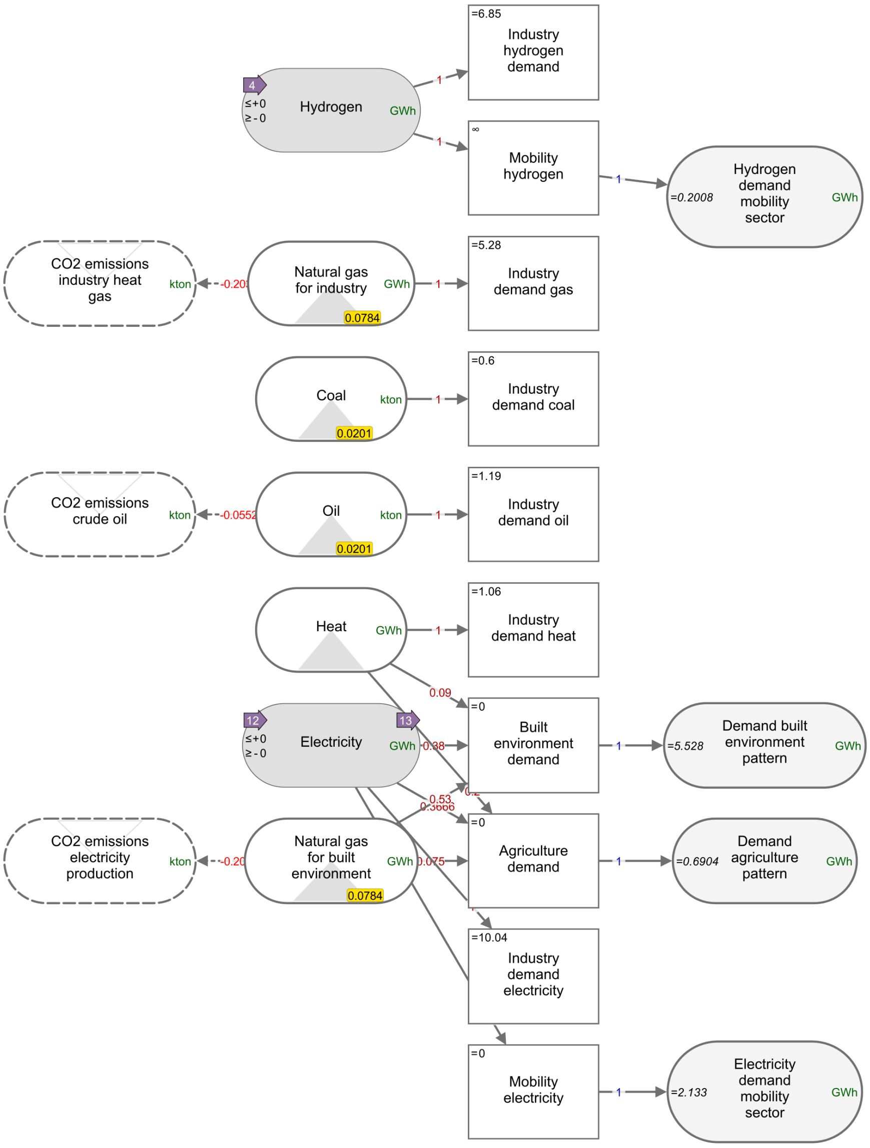


**Figure 4.16:** Demand

## 4.4. XLRM framework

In appendix C the XLRM framework shows the external factors, the policy levers, the relationships in the system and the performance metrics. In summary, this framework entails the relationships listed below.

**External factors:**

- Installed capacities for electricity production
- Installed capacities for hydrogen production (non-electrolysis and SMR)
- Demand profiles

**Policy levers:**

- Salt cavern capacity
- Gas field capacity
- Injection and production capacities salt caverns and gas fields
- Electrolyser capacity
- Hydrogen turbine capacity
- Gas turbine capacity
- SMR capacity
- Import and export capacities
- Battery storage capacity

**Relationships in the system:**

- Electricity production
- Hydrogen production
- Storage levels salt caverns and gas fields
- Import and export

**Performance metrics:**

- Carbon emissions
- LOLE and EENS electricity, green hydrogen and hydrogen
- System costs
- Injection and production cycles

# 5

# Analysis

This chapter is set up to analyse the model by verification, a sensitivity analysis and the first part of the scenario discovery in which the model is tested on performance.

Verification of the model means to confirm that the behaviour displayed by the model represents the system that it is trying to mimic. This verification process will be conducted by first analysing the behaviour of the most prominent storage facilities, the salt cavern and gas fields. The second verification of the behaviour of this system is the conversion of hydrogen to power from the storage facilities at times of insufficient vRES.

Lastly, performing a sensitivity analysis on a model is essential for verification because it allows us to assess how changes in input parameters impact the model's outputs. By systematically varying these parameters across feasible ranges, the analysis identifies which inputs exert the greatest influence on outcomes and which have minimal impact. This approach aids in assessing the model's robustness and ensures its logical behaviour across different scenarios. Upon concluding the sensitivity analysis, the objective is to derive conclusions about the model's reliability. This examination yields insights into which parameters are most sensitive, guiding efforts to enhance the model's accuracy and predictive capabilities. The parameters most sensitive in the model will be used in the scenario analysis. The scenario discovery also entails model verification, which is conducted in this chapter.

## 5.1. Verification

### 5.1.1. Behavioural analysis

In appendix D the behavioural analysis is discussed in depth. The conclusion can be drawn that the behaviour of the model is as expected. A few observations are that the storage is nearly empty at the beginning of the summer. The salt caverns are able to react more quickly, which results in frequent switching between producing and injecting. This confirms their position in the energy system regarding flexibility to be higher than that of gas fields. In the gas field graph, the reserve of 10% is depicted as being utilized only during three instances throughout the year. This usage pattern validates the purpose of maintaining this reserve. It aims to mirror policy-driven behaviour in the model as it underscores the cautious approach taken towards managing the final portion of energy reserves in storage. It is also shown in the graph of the gas field behaviour that the volume at the end of the year is again at 54%. This is modelled as a requirement that the model will manage at any given cost. In a regular weather year, this behaviour should be designed, however, one could argue that in a year in which a dunkelflaute occurs, this might not be the priority. In appendix D more behaviour of the model is shown, such as the demand profile through the year and the electricity production of the variable Renewable Energy Sources.

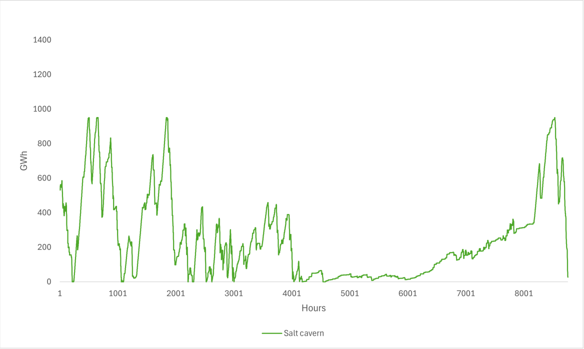


**Figure 5.1:** Salt cavern behaviour throughout the year

**Figure 5.2:** Gas field behaviour throughout the year

## 5.2. Sensitivities of the model

As mentioned above, the last step in the verification of the model is the sensitivity analysis. In addition to addressing the instabilities and uncertainties identified in the literature and recent developments, this analysis will also provide insights into sensitivities in the model and thus the system. This is achieved by applying a 20% increase to critical values within the model. Due to computational limitations, the sensitivity is run for the base case of 2035. The input of the 2035 model has a more diverse portfolio of production capacities, which is more interesting to test.

A method employed to validate the model is a sensitivity analysis. This approach allows for the verification of the effects of altering all input variables on the Key Performance Indicators (KPIs) in a clear and concise manner. Additionally, the sensitivity analysis serves as a tool for designing the scenario experiments, with analyses conducted for base scenarios 2035. This enables the identification of critical input variables that significantly influence the optimization model's output, allowing them to be prioritized in the scenario discovery.

The analysis method used is one-variable-at-a-time (OVAT), where each input variable is individually adjusted by a predetermined percentage of +20%, while the remaining variables are kept at their standard values. Variables with a zero value in the base scenario are excluded from this analysis. Additionally, the KPI 'total costs' is divided into 'costs electricity', 'cost green hydrogen' and 'costs hydrogen' to determine whether changes in system costs are due to variations in electricity or hydrogen production.

For a sensitivity analysis in general, if the absolute impact of an input variable on an output variable exceeds delta (δ), the original alteration in the input variable is deemed sensitive. With delta defined as +20%, any input variable inducing a change exceeding 20%, whether positive or negative, is considered sensitive for the variables CO2 total, electricity costs, green hydrogen costs, hydrogen costs and system costs. For the LOLE, an exceeding value of over 50% is chosen.

The sensitivities of the model that came to light in this analysis are the following:

- Steam methane reformer (with CCS)
- Installed battery storage capacity
- Hydrogen demand mobility sector
- Industry hydrogen demand
- Electricity demand industry
- Electricity demand mobility
- Built environment demand

It is in line with expectations that if demand increases, the KPIs increase as well. With *hydrogen demand mobility sector* and *hydrogen demand refineries*, *built environment* and *electricity demand industry* being the largest, it is expected that the system costs will be sensitive to their increase. In that scenario analysis all demand is taken into account.

A value in the model that is unexpectedly sensitive under a 20% increase is the *Fuel price nuclear*. It is clear that hydrogen prices of both *Average green hydrogen costs* and *Average hydrogen costs*, in table 5.2, increase significantly, which tells us that the base load supply from nuclear plants is important for the production of hydrogen. A possible explanation is that due to the base load that alkaline electrolysers require it will use the electricity from nuclear base load during low availability of renewable energy.

The increased installed capacity of different generation and production units leads to decreased system costs. However, that is partly because the capital expenditure and the operational expenditure are not taken into account. Only the marginal costs of production are included. It is intuitive in this model that the higher the installed amount of production capacity, the lower the system costs because the loss of load will be remedied. Two things are noteworthy to address. First, the battery storage capacity reduces system costs by 60,84%, which is quite impressive. This will largely stem from the reduction of loss of load. Secondly, the impact is not visible in the increased storage capacity of salt caverns and gas fields. This could be because of the facilities around salt caverns and gas fields that are not increased with the capacity, such as the injection and production capacities.

## 5.3. Scenario discovery set up

One method to identify a robust strategy and pinpoint potential bottlenecks involves testing various scenarios in the model. It is crucial to test these scenarios under specific conditions, particularly during a dunkelflaute like 1987, which is therefore the weather input setting with which of the scenarios are tested. The first scenarios that will be examined are of parameters that have to do with the model settings. This is done to verify the correct functioning of the model. Following this, the evaluation will proceed to scenarios designed to address the main and sub-research questions. Lastly, scenarios resulting from sensitivity analysis will be examined. All details of the scenario discovery can be found in appendix D. Only the first goal, which is to verify the model by scenario analysis will be discussed in this chapter. The results regarding the scenarios that answer the research questions and the impact of the parameters from the sensitivity analysis will be discussed in the chapter 6, Results.

### 5.3.1. Model verification

#### Dunkelflaute vs regular weather year

**2035**

The aim is to evaluate the resilience of the energy system under the most extreme foreseeable weather conditions. Historical weather years serve as reference points for this assessment. The years 1997 and 1987 were selected because both experienced a "dunkelflaute," a period of low wind and solar power generation. Consequently, these years were analyzed in this study. Selecting a weather year that imposes the greatest strain on the energy system is prudent for determining the necessary robustness of the system. The figures 5.3, 5.4 and 5.5 below illustrate the EENS in the base case scenario of 2035 for the two weather years 1987 and 1997. From this analysis, it can be concluded that the year 1987 places more strain on the system, making it the chosen reference year. In the year 2019, which represents a 'normal' year, there are 84 hours of LOLE (Loss of Load Expectation), which indicates that the base case, with its assumptions, is not sufficient to support the energy system.

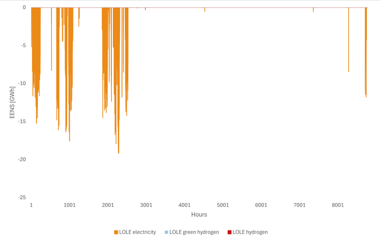


**Figure 5.3:** Base case 2035 with weather year 1987

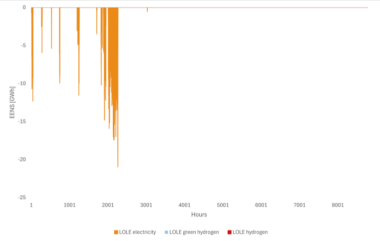


**Figure 5.4:** Base case 2035 with weather year 1997

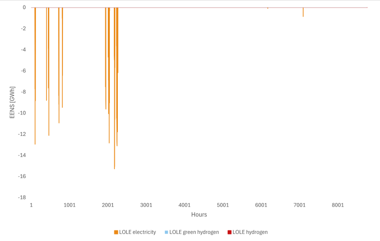


**Figure 5.5:** Base case 2035 with weather year 2019

### 2050

The year 2050 presents significant challenges due to various uncertainties and ambitious policy goals. The distant timeline introduces greater unpredictability, and many policy objectives set for 2050 are highly ambitious. Additionally, there are currently few projects in the early stages of development. While demand is expected to be higher, it is also subject to considerable uncertainties. Consequently, projections for 2050 are thus uncertain and they are generally less informative than those for 2035. On the other hand, it is encouraging to note that the model suggests the policy plans are adequate to support the energy system in 2050. In simulations with both weather years 1987 and 1997, there were no instances of EENS.

### Look-ahead time

The look-ahead time in a Linny-r model determines the amount of information you provide for the model. In the case of this model of the energy system, that entails for example that the solver knows what the wind capacity will be and how much green hydrogen will be produced in the time frame that is given in the look-ahead. With this information, the solver can determine the optimal economic strategy for energy utilization, such as whether to store the energy or use it directly to avoid producing grey hydrogen. The model will thus minimise the loss of load, which is the most expensive source of energy in the model. This way the model is optimising the available energy as efficiently as possible. This means that the model can choose to use the value of lost load, resulting in LOLE, early in the year instead of emptying the storage at that time, to hold out energy for a moment that is in more dire need of it, which would otherwise be even more expensive.

One limitation of modeling with a perfect forecast is the insufficient incorporation of risk management strategies. Nonetheless, this risk is mitigated by basing the model on the forecast of the worst weather year. This gives results that will suffice in regular weather years, given that the use of storage is still managed efficiently.

The model was run with variations in look-a-head time of one week, ten days and a year. The results are shown in table 5.4. With a ten-day look-ahead, the system experiences a 22% increase in EENS measured in GWh, while the one-week look-ahead scenario results in a 45% greater EENS.

The duration during which energy is not supplied increases notably when the look-ahead period is less than a full year. This trend similarly affects the operational cycles of salt caverns and gas fields.

### Gas field reserve

The gas field reserve is a component designed to simulate the energy market, particularly focusing on the cautious management of the final 10% of energy stored within the system. This approach mirrors the uncertainty inherent in real-world energy markets, where future conditions are unpredictable. In contrast, the model possesses complete knowledge of future states, creating a controlled environment. This feature significantly enhances the model's realism, particularly in accurately representing the dynamics of energy storage usage by decision-makers. From the outcomes of the KPI, the conclusion can be made that the system with the 10% reserve functions most favourably.

### Import

As discussed in the conceptualization chapter, import represents a highly uncertain parameter within the model. To assess the impact of import on the system, the model evaluates this variable through incremental increases of 20% until it reaches a full interconnection capacity of 12.8 GW for electricity. In a second scenario the the capacity for hydrogen import and the cracking capacity of ammonia increased by one GW in each step. The base case scenario adopts a conservative approach, which consequently diminishes the model's realism. This reduction in economic realism arises because, in many instances, it is more economically feasible to import available energy in the form of electricity rather than produce it from green hydrogen from storage. However, the complexity associated with modelling interconnection capacity availability results in its exclusion from the model.

The results of the scenario analysis for the electricity interconnection demonstrate that increasing import capacity within the model results in a significant reduction in the LOLE and system costs. Notably, in the 60% import capacity scenario, the LOLE approaches a nearly acceptable level with six hours of LOLE. This indicates that during periods of severe energy demand and extremely low renewable supply, an interconnection capacity of a staggering 60% needs to be available, with the remaining demand being met through the conversion of hydrogen to electricity. It is highly unlikely that this value will be met by neighbouring countries because they will likely have a low supply of renewable energy sources also.

Furthermore, the analysis reveals a notable shift in the behaviour of the model concerning storage options. The frequency of storage cycles diminishes, which consequently reduces the economic appraisal of storage facilities. This reduction in usage underscores the decreased reliance on storage solutions as import capacity increases, highlighting a critical trade-off in the system's economic and operational dynamics.

In the scenario which looks into the hydrogen import capacity the same trends are visible, where there is a decrease in loss of load. What is however interesting is to see that the cycles of the salt caverns and gas fields do not decrease. This is likely because the imported hydrogen will be stored in the system. Economically this is not likely to happen, but it is interesting to see that the model does solve the shortage of energy (EENS) this way.

Relying on energy import in the form of hydrogen or a derivative thereof is a functional way of managing the demand in the Netherlands. however, it is also a strategy in which the country is highly dependent on others.

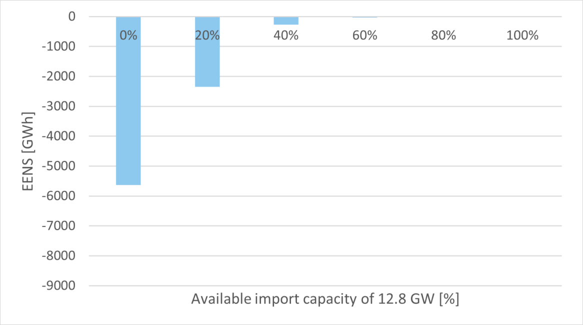


**Figure 5.6:** Available import capacity and EENS

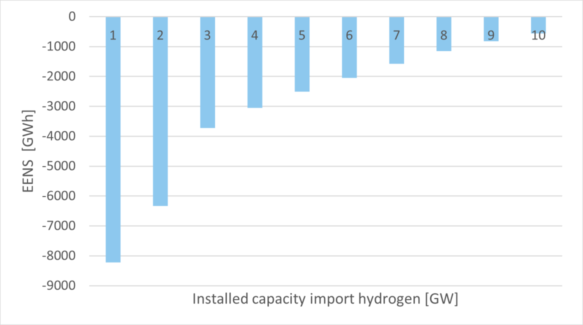


**Figure 5.7:** Available import capacity hydrogen and EENS

### Hydrogen conversion to electricity

The model demonstrates high sensitivity to the installed capacity of hydrogen power plants, identifying it as a bottleneck during periods when storage production operates at full capacity. Although the energy volume meets demand, the electricity network remains under-supplied due to limited conversion capacity. Consequently, the base case scenario employs a capacity of 20 GW for hydrogen power plants, a value determined through careful evaluation of various runs and scenarios as never being reached.

However, it is acknowledged that in practical applications, this capacity could impact the system. Therefore, this variable is incorporated into the scenario analysis. The Energy Transition Model (ETM) projects that by 2035, the required capacity will range between 3,5 GW and 8,5 GW. It is important to note that the ETM model also includes gas CCGT capacity, ranging from 3,9 GW to 6,2 GW, which is not accounted for in the present model. The results show that there is a need for nearly 20 GW for conversion capacity from molecular energy sources to electricity, which implies that the assumption of 20 GW hydrogen power plants is not unrealistic.

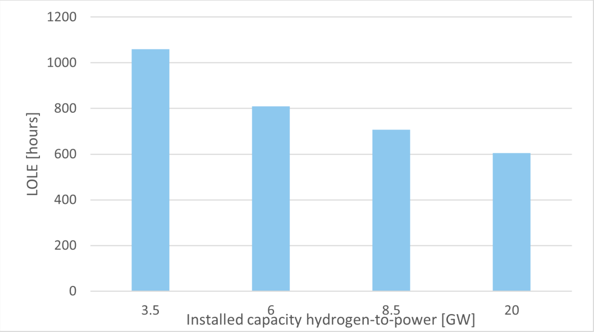


**Figure 5.8:** Installed capacity hydrogen to power and hours of LOLE

### Variable Renewable Energy Sources

The installed capacity wind turbines and solar PV is logically an important parameter to evaluate in this research. The policy goals of the Dutch government are increasingly ambitious throughout the years, with the latest being the NPE goals. Which are set at 35 GW offshore wind, 12 GW onshore wind and 98 GW solar PV. This particular scenario analysis is focused on the impact that this ambitious goal has compared to the goals formulated in the II3050, which on average are 27,5 GW offshore, 10,4 GW onshore and 60,6 GW solar PV. For hydrogen production this is a direct link to the volumes that can be produced, because there will be more overshoot of energy that can be used as feed stock for the electrolysers. To evaluate this scenario analysis the addition values are taken into consideration: amount of curtailment, the run hours of the electrolyser and the production of green hydrogen.

The analysis shows that the system is greatly helped with the additional capacity installed vRES. This leads to the conclusion that the requirements of storage in the system is highly dependent on the development of the vRES capacity. This correlation should be monitored throughout the years to avoid over-investment in storage options that cannot be filled with green hydrogen.

However ambitious the NPE goals may be, it is used for the base case nonetheless because this research focuses on green hydrogen storage. Researching this volume hydrogen is only possible if the intended amount of vRES is installed to produce it. Besides that, it will show how much electrolyser capacity could be installed in addition to improve the system.

In the figure below the levelised values of KPIs and other relevant measurement parameters are set out. Is shows the impact of the increased capacity of vRES in the system for both 2035 and 2050. This impact in significant on all KPIs.

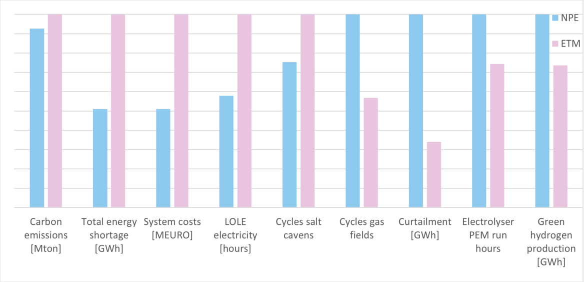


**Figure 5.9:** NPE vs ETM impact 2035

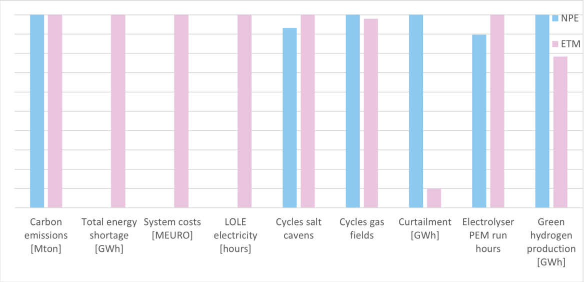


**Figure 5.10:** NPE vs ETM impact 2050

## 5.4. Main takeaways

## 5.5. Analysis

This chapter is set up to analyse the model by verification, a sensitivity analysis, and the first part of the scenario discovery in which the model is tested on performance.

### 5.5.1. Model verification

The model accurately reflects the behaviour of key storage facilities like salt caverns and gas fields, and its response to hydrogen conversion during periods of insufficient variable Renewable Energy Sources (vRES) is consistent with expectations. The behaviour of the model, such as storage patterns and reserve management, aligns with real-world scenarios, confirming its reliability.

### 5.5.2. Sensitivity analysis

The sensitivity analysis reveals which input parameters have the most significant impact on model outputs, including system costs and performance indicators. Key sensitive parameters include steam methane reformer capacity, installed battery storage, and hydrogen demand across different sectors. Unexpected sensitivity was observed in the fuel price of nuclear energy, highlighting its importance in hydrogen production.

### 5.5.3. Scenario discovery

Various scenarios, including extreme weather conditions (dunkelflaute) and different levels of import capacity, were tested to evaluate system resilience and identify potential bottlenecks. The analysis of import capacity indicates that increasing import options can reduce loss of load and system costs but also shifts the reliance away from storage solutions.

### 5.5.4. Look-ahead time

The length of the look-ahead period in the model affects system performance, with shorter look-ahead times leading to increased loss of load and operational challenges. The model’s ability to optimise energy usage improves with a longer look-ahead period.

### 5.5.5. Hydrogen conversion to electricity

The installed capacity of hydrogen power plants is critical for meeting demand during high storage utilisation periods. The model’s assumption of 20 GW for hydrogen power plants appears realistic based on scenario analyses.

### 5.5.6. Impact of variable Renewable Energy Sources (vRES)

Increasing the installed capacity of vRES, such as wind and solar PV, significantly affects system performance and storage requirements. Higher vRES capacity reduces the need for extensive storage solutions and enhances overall system efficiency.

### 5.5.7. Import and hydrogen capacity

The model shows that relying on energy imports, whether as electricity or hydrogen, can effectively manage demand but increases dependency on external sources. The impact on storage and system costs varies with the level of import capacity.

# 6

# Results

To explore the potential of underground hydrogen storage in future energy systems, a series of experiments have been conducted, detailed in D and E. These experiments focus on evaluating various performance parameters within the system. By analysing the results of these experiments, the research aims to uncover valuable insights that will aid in the decision-making surrounding underground hydrogen storage facilities, ensuring their effective integration into the energy systems of the future. This chapter is structured by addressing the sub-research questions and ultimately the main research question.

## 6.1. Outcomes scenario discovery

### 6.1.1. Electrolysers

#### Electrolyser capacity

A development intrinsically linked to the optimal utilization of hydrogen storage is the installed capacity of electrolysers. This interdependence arises because current storage facilities are unable to inject hydrogen at the desired speed, at technologically feasible capacities, and within the required short time frames. These limitations culminate in undesirable high levels of curtailment within the system and a shortage of stored energy in times of need. High curtailment is detrimental to energy prices and is also not the most efficient way to use the capacities of installed wind and solar energy. The scenario analysis also investigates the implications of a situation where the installed capacity exceeds the NPE goals for the installed capacity of electrolysers. Although this scenario is highly improbable, it serves as a valuable exercise for understanding the system's relationships and dependencies.

The results show that there is much more hydrogen produced when there is more installed electrolyser capacity. It also shows that the carbon emissions were reduced significantly, due to the reduced need for SMR and ATR. And that storage cycles increase because they are able to fill. Curtailment reduces by a significant 25% on average. It is curious to see that however much impact it has on many KPIs, it does not seem to matter much for the LOLE hours. This leads to the conclusion that installing 'sufficient' electrolysers alone will not solve the issue at hand. It needs to increase parallel to the storage capacity.

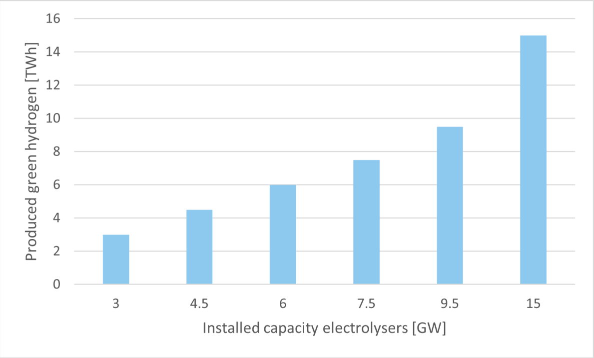


**Figure 6.1:** Hydrogen production with varying installed capacity electrolysers

### Efficiency

The efficiency of the technology of both alkaline and PEM are analysed. They show that due to more hydrogen being produced in the system the EENS is lower. When the efficiency of alkaline and PEM both increase by a factor of 1.1, there is an increase in the production of hydrogen of 2,6% and a decrease of 2.1% of EENS.

### Ratio alkaline and PEM

The ratio of the different technologies is assumed to be 9 to 1 for alkaline and PEM in the system in 2035. If this is modelled differently the main difference is that there is less base load electricity required to keep the alkaline electrolysers running. This results in a decline across all significant indicators; however, the extent of this decline is not as substantial as one would expect.

### Lower bound alkaline

The assumption that is made in the model is that the lower bound of the alkaline electrolysers is 5%. This test looks into the impact that that assumption has on the system. It shows an increase in carbon emissions when there is a lower bound, this is likely due to the fact that during moments of low renewable production, the electrolyser still needs to run, using energy that is needed elsewhere. It is observed that there is a substantial increase in energy shortage with a lower bound in place, which increases even more when the bound is higher. The elimination of the lower bound would mean nearly 9% less EENS and the higher lower bound would have an increase of 20% EENS. The hydrogen production is higher, but this does not benefit the system.

## 6.1.2. Underground hydrogen storage capacity

As discussed in the analysis, the base case is not sufficient for preventing loss of load in the system. Besides that, this previous section showed us that the electrolysis capacity is highly influential in the amount that the storage is able to fill itself due to the surplus of hydrogen in the system. Because we now know that with 6 GW of electrolysis capacity, the system will not be able to tackle the demand this analysis is also done with an electrolysis capacity of 9.5 GW, which the NPE sets out as a goal for 2035. Besides that, we want to differentiate the influence of salt cavern storage from the storage in gas fields. That is why the two are analysed separately. Quite extreme values had to be chosen, in order to see results. An aspect that is looked at besides the KPIs is whether the volume of the salt caverns is ever in full use throughout the year. If it is not ever filling to the upper bound, this indicates that there is not sufficient green hydrogen to supply the storage facilities to fill. From the model with lower installed capacity electrolysers, we know that with 15 installed salt caverns the filling degree will never be 100%. For the model with higher installed capacity electrolysers, the caverns are filled once during the whole year. This led to the conclusion that if the installed capacity of electrolysis does not exceed 6 GW, it would be impossible to fill the storage, thereby discouraging investment.

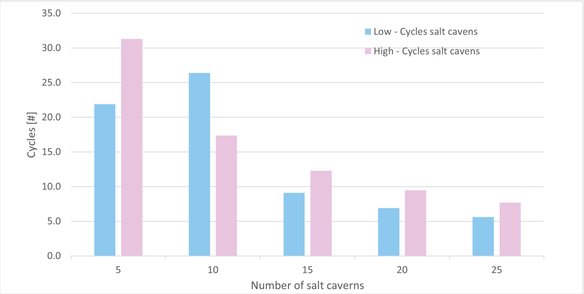


**Figure 6.2:** Number of salt caverns and amount of cycles

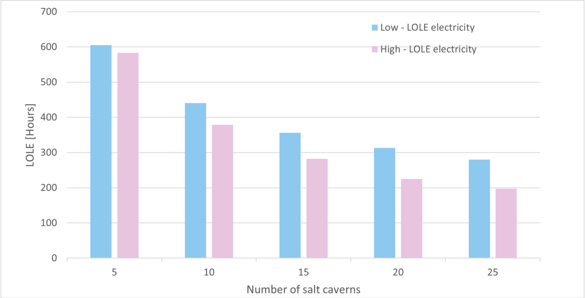


**Figure 6.3:** Number of salt caverns and hours of EENS

### Combination of storage facilities without value of lost load 2035

The combination in which there was no LOLE and EENS was with the installed volume of 4,5 TWh salt cavern, which equals 18 caverns and 5,5 TWh volume of gas fields, which is approximately four times the PGI storage facility of Alkmaar.

A side note must be made that this model was run with the exclusion of the compressor switch time of the gas fields and the filling degree was set at 100% at the beginning of the year and was 10% at the end of the year. Lastly, the 10% reserve did not have to be met once a week, but it did eventually fill itself near the end of the year. The number of cycles of the salt caverns is 7,2 and for gas fields, it is 3,7.

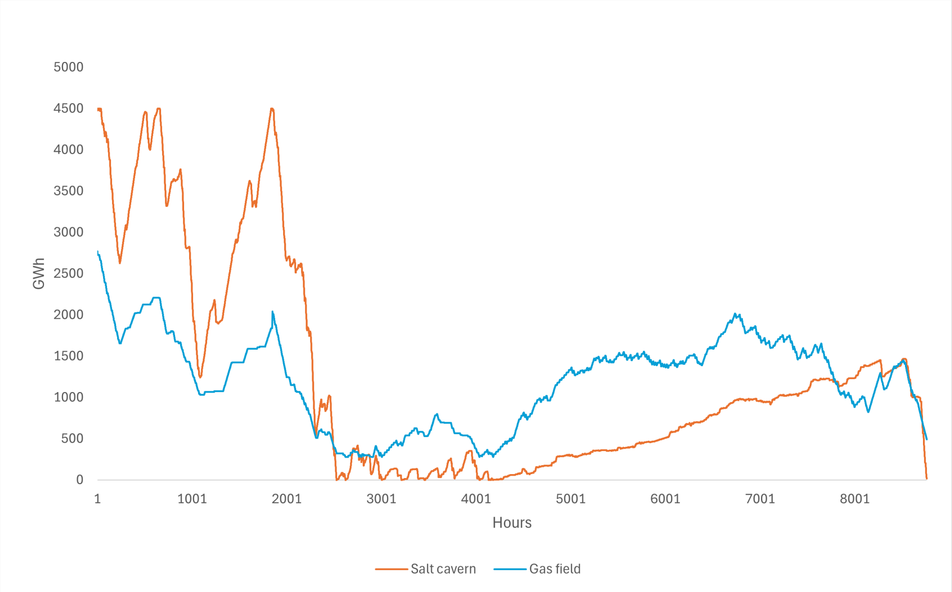


**Figure 6.4:** Storage behaviour 4,5 TWh salt caverns and 5,5 TWh gas fields in 2035

### Combination of storage facilities without value of lost load 2050

Achieving the goal of 20 GW of electrolysers by 2050 will provide significantly more flexibility to the system and reduce the need for storage. Besides that, the battery capacity and nuclear capacity will increase. The model for 2050 demonstrates an ability to endure a dunkelflaute without any loss of load, utilising 1.75 TWh salt caverns and 4 TWh gas fields, of which 1 PGI and one Klein veld. This is feasible even with a filling degree of 54% at both the beginning and end of the year, as well as the compressor constraint for gas fields.

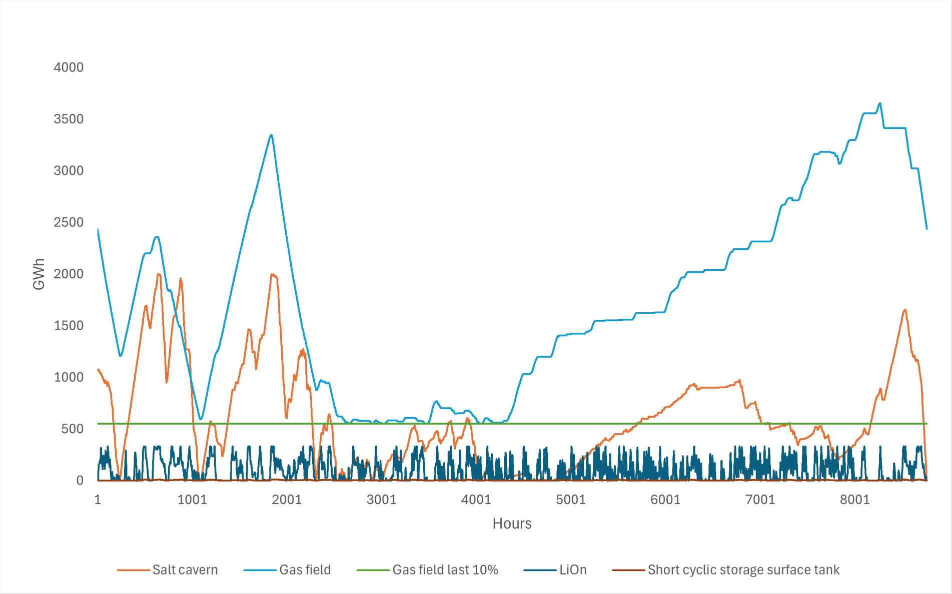


**Figure 6.5:** Storage behaviour 4,5 TWh salt caverns and 5,5 TWh gas fields in 2050

### 6.1.3. Injection and production capacity

The difficulty with injection and production capacity is that the pressure that needs to be maintained in a gas field or salt cavern is a grave bottleneck in the production possibilities for a storage facility. It is however interesting to find out where this ceiling lies and which height of injection and production capacity is worth the instalment.

It can also be calculated by changing the number of wells in a field or cavern, which in the case of the Linny-r model is easiest to differentiate.

It seems that increasing the injection and production capacity of salt caverns does not influence the system much. Decreasing does however have a negative effect. This leads to the conclusion that the capacity is already at a nearly optimal level.

The figure below shows that increasing the number of wells in gas fields does have an effect. This analysis shows the number of wells in a field like the PGI of Alkmaar. It shows that by increasing the number of wells the value of lost load goes down. However, this is only with the increment of many wells, which is probably not worth the investment. Another curious observation is that for the gas fields, the cycles increase by a lot, while for the salt caverns, they stay the same.

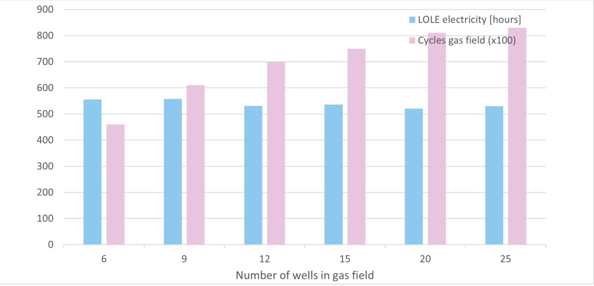


**Figure 6.6:** Number of wells in gas field and the associated value of lost load

### 6.1.4. Batteries

In all scenarios that have been tested in this research, the main observation when it comes to the battery capacity and volume is that it is used at full capacity most of the year. Which indicated that more capacity will aid the system. The values of the different scenarios are based on the values from II3050 and the ETM [48]. From scenarios 2 to 3 there is an increase of energy stored by batteries of 25%, with a energy equivalent of 13,8 TWh and a decrease of nearly 15% in lost load hours.

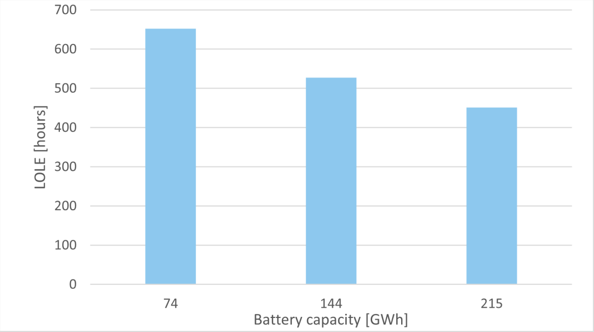


**Figure 6.7:** Battery capacity and hours of lost load occurrence

### 6.1.5. Gas power plant

As mentioned in the hydrogen conversion to electricity analysis, the anticipated capacity for gas CCGT with CCS capacity assumed in the ETM model lies between 3,9 and 6,2 GW. Carbon capture and storage (CCS) is an additional installation to the plant to minimise the carbon emissions in the system. However, it is not carbon neutral, because the carbon capture rate of a CCS installation is projected to be around 90% by 2035 [17]. Although it is plausible that CCS efficiency will improve over time, achieving a 100% capture rate remains unlikely.

Given the Dutch parliament's policy goals of achieving a carbon-neutral electricity network by 2035, relying on gas power plants would be insufficient unless additional measures are implemented to offset the residual emissions. This constraint underpins the decision to exclude gas power plants from the model, thereby emphasising the challenge in meeting these policy objectives and underscoring the urgency for developing alternative technologies.

An added problem with maintaining gas technology as a backup is that it necessitates the preservation of the extensive gas network, which significantly escalates operational costs due to the distributed nature of these costs across a decreasing amount of power plants, this applies for 2050, not 2035. Consequently, the parameter of carbon emissions becomes critical in evaluating the outcomes of the scenario analysis. Also shown in the table below is the difference in production hours of the hydrogen power plants.

Policy-wise is it an additional difficulty that the gas turbines will only serve as a backup, during times of extreme shortage in a dunkelflaute. Which is only a dozen hours in a time span of approximately 10 years. The lifetime of such a plant is around 30 years and this investment of needs to be paid off in only a few hours. Logically this is an extremely high-risk investment, which is difficult to expect from market parties if the maximum value of the energy market is 3000 EUR/MWh. Their risk should be mitigated by an incentive to have backup capacity.

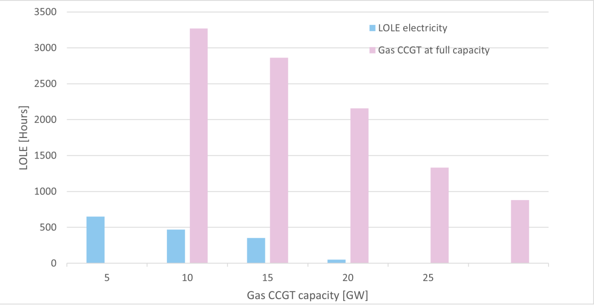


**Figure 6.8:** Gas CCGT capacity and hours of lost load occurrence

### 6.1.6. Steam methane reformer installed capacity

In the base case, the SMR with CCS plants with a production capacity of nearly 3 GW produces hydrogen at full capacity for all hours of the year. The grey hydrogen production is at full capacity for nearly 20% of the year. It makes sense that the model prefers the SMR with CCS, due to the carbon tax.

One thing that is very curious to observe is that the increase of both regular SMR and SMR with CCS will decrease carbon emissions. This is due to the fact that the SMR with CCS will take over production from the regular SMR. Another conclusion that we can take from this analysis is that the increased demand for hydrogen in 2035 will either require blue hydrogen production (SMR with CCS) or more green hydrogen by an increased capacity of electrolysers. This blue hydrogen could also be provided by for example an Autothermal Reformer (ATR).

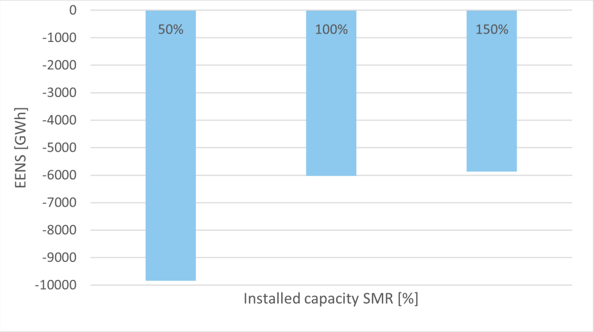


**Figure 6.9:** Installed capacity SMR and EENS

### 6.1.7. Demand

By increasing the demand we see that the carbon emissions are highly affected, with a 34% increase and decrease. The EENS increase by 100% if demand increases by 20% and a decrease of 20% leads to a decrease of 58% in EENS. The cycles of the salt caverns are not impacted heavily, with a difference of -5.3% and +10.6%.

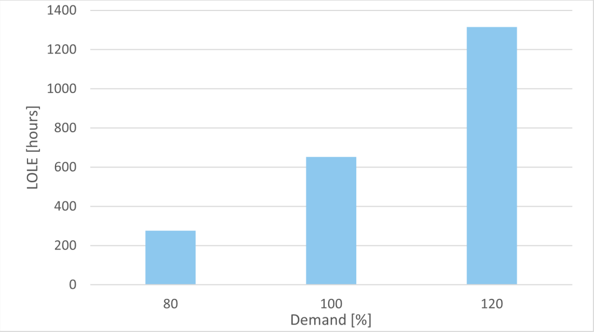


**Figure 6.10:** Variations in demand effect on EENS

### 6.1.8. Additional findings with high impact

A significant and noteworthy observation is that the fill level of the storage facilities greatly impacts the model. The initial volume of hydrogen, influenced by this fill level, substantially affects the required number of storage facilities.

Another assumption in the model with considerable impact is the mandatory end-of-year fill level being equal to the starting level. Achieving this fill level is challenging in the event of a ”dunkelflaute” (a period of little wind and solar power production). Given the low probability of two consecutive years experiencing a dunkelflaute, it seems reasonable to discard this assumption. Instead, maintaining a reservoir level of at least 10% by year-end would be more feasible.

Additionally, the model is hindered by the constraint that gas fields have a 12-hour switching period. The model aggregates all gas fields, which makes it unrealistic to expect uniform behaviour. In reality, if one gas field cannot switch quickly, another field is likely capable of compensating. Furthermore, within a rapidly cycling gas field, it is plausible that if one well requires switching, another well can respond more swiftly.

The optimal solution and truth lie somewhere in between. Removing these constraints entirely might render the model too flexible and less reliable. As previously indicated, this model provides a highly conservative perspective to ensure robustness in the security of supply.

### 6.1.9. Policy goals

Another analysis that is obtained is to see if the policy goals of the EU and the Dutch government are achieved.

### Blending restrictions industry

One goal of the European Union is that in 2035 60% of the hydrogen used in the industry is green hydrogen. In this model that was not a hard requirement, because all the hydrogen was bundled and divided across the different sectors that required hydrogen. The electricity network only allowed green hydrogen as a feedstock for the hydrogen plants. This means that the other sectors that require hydrogen received less green hydrogen than the average in the system. Calculating the hydrogen production afterwards, for the scenario in which there is no lost load and an electrolyser capacity of 9.5 GW, gives us the results shown below. Which indicates that the goal is not reached.

**Table 6.1:** Types of hydrogen used in the system

| **Type** | Volume [GWh] | Percentage [%] |
|---|---|---|
| Grey | 22727 | 22.46 |
| Blue | 34869 | 34.46 |
| Green | 43600 | 43.08 |
| Sum | 101195 | 100.00 |

### Renewable energy in buildings

The model's design mandates a carbon-neutral electricity network. The proportion of renewable energy utilized in buildings must at minimum match the percentage of the demand attributed to electricity. According to the assumptions posited by the Energy Transition Model (ETM), the share of demand accounted for by electricity is 38%. Additionally, heat, another energy source for the built environment, is projected to constitute 9% of the energy mix from renewable sources by 2035. Collectively, these sources account for 47% of the energy demand. The remaining energy required for the built environment is supplied by natural gas. This means that the goal, which is set for 2030, is nearly reached in the model for 2035.

### 10 Gigawatts of flex-fuel electricity generation capacity

The policy goal: The goal is to have 10 gigawatts of flex-fuel electricity generation capacity (natural gas and hydrogen/ammonia). The model does not contain electricity generation plants that use multiple fuel sources. However, the model does contain electricity generators from different sources. There are plants which run on ammonia, hydrogen, biomass, waste and nuclear. The innovations that Siemens announces are in line with obtaining these goals according to Jan Prins, Vice President of Siemens Energy.

### The electricity network is targeted to be carbon neutral

This goal is obtained because there is no source of energy that emits carbon allowed to provide for the electricity system in the design of the model.

### Member states emit 55% less greenhouse gases

The emissions that are measured in this model are the emissions of natural gas for the built environment and agriculture, grey and blue hydrogen production, and oil and gas for the industry. Due to this limited scope, we cannot argue that this measurement of carbon emissions equates to the whole system. The policy goal is set for the year 2030, so this model for 2035 and 2050 is not ideal to check this policy goal. The estimated emissions in 2030 are between 97-123 Mton, corresponding to an emission reduction of 46-57% compared to 1990 [19]. It does seem that the total emissions, which are 24.5 Mton CO2, that are emitted in the model for 2035 is lower than the 55% goal.

## 6.2. Main takeaways

In summary, the experiments conducted to explore the potential of underground hydrogen storage in future energy systems reveal several critical insights and implications. These experiments focus on evaluating various performance parameters within the system to aid in decision-making surrounding underground hydrogen storage facilities.

### 6.2.1. Electrolysers

- Increasing electrolyser capacity leads to higher hydrogen production and reduced carbon emissions due to less reliance on steam methane reforming (SMR) and autothermal reforming (ATR).
- Curtailment decreases significantly, but increasing electrolyser capacity alone is insufficient; it must be paired with increased storage capacity.
- Higher efficiency in electrolysis technology leads to reduced energy not served (EENS) and increased hydrogen production.
- The ratio of alkaline to PEM electrolysers affects base load electricity requirements, but the impact is less than anticipated.
- Lower bounds on alkaline electrolyser capacity result in increased carbon emissions and energy shortage.

### 6.2.2. Underground hydrogen storage capacity

- With lower electrolyser capacity, storage facilities are insufficient to meet demand; higher capacity (9.5 GW) is required.
- Salt cavern storage, when analyzed separately, does not fill to capacity with lower electrolyser capacity; with higher capacity, caverns are only occasionally full.
- Combinations of storage facilities with sufficient capacity can meet demand without loss of load by 2050.

### 6.2.3. Injection and production capacity

- Increasing the number of wells in gas fields reduces the value of lost load, but the benefit may not justify the cost.
- Increased injection and production capacity in salt caverns has a minimal impact on the system.

### 6.2.4. Batteries

- Battery capacity is used at full capacity for most of the year. Increasing capacity reduces lost load hours.
- A 25% increase in stored energy from batteries leads to a 15% decrease in lost load hours.

### 6.2.5. Gas power plant

- Gas power plants with carbon capture and storage (CCS) cannot achieve carbon neutrality, and operational costs are high.
- Backup gas technology investments are risky due to limited use and high costs.

### 6.2.6. Steam methane reformer installed capacity

- Increased capacity of SMR with CCS reduces carbon emissions and could be necessary to meet future hydrogen demand.
- The demand for hydrogen could be met by either increased green hydrogen production or more blue hydrogen from SMR with CCS or ATR.

### 6.2.7. Demand

- Increased demand results in higher carbon emissions and EENS. Reducing demand leads to lower EENS but has minimal impact on salt cavern cycles.

### 6.2.8. Additional findings with high impact

- The fill level of storage facilities significantly impacts the model, with challenges in maintaining the end-of-year fill level during extended periods of low production.
- Removing constraints like gas field switching periods might make the model too flexible and less reliable.

### 6.2.9. Policy goals

- The model does not fully achieve the EU goal of 60% green hydrogen in industry by 2035.
- The policy goals for renewable energy in buildings and flex-fuel electricity generation capacity are nearly met.
- The electricity network is carbon neutral in the model, and the total emissions are below the 55% reduction goal, though this is not ideal for 2030.

# 7

# Discussion

The goal of this discussion chapter is to interpret and analyze the results presented earlier, putting them into the wider context of the research field. This chapter will evaluate the findings, discuss their implications, and show how they add to existing knowledge. It will also address the research questions set out at the beginning, providing a thorough understanding of the study's outcomes. Additionally, the discussion will point out any limitations of the research, consider other possible explanations for the results, and suggest future research directions. This chapter aims to highlight the significance of the study and its potential impact and applications.

## 7.1. Addressing the research questions

### 7.1.1. Main research question

***What is the anticipated demand for underground hydrogen storage capacity (in TWh) and their injection and production capacity (in GW) based on supply and demand for hydrogen in 2035 and 2050 and how does this compare to the climate targets and investment plans?***

The anticipated demand for storage capacity for the year 2035 is around 7.2 TWh of which 4,5 TWh in salt caverns and 2.8 GWh in gas fields, specifically peak gas installations. The production capacity that is required lies at 48 GW, from which most operational speed is acquired from salt cavern installations, which is 39 GW. This is however with a filling degree of 100% at October 1st.

For the year 2050, the storage requirements are lower than for the year 2035. The final need for storage volume in 2050 is 1.75 TWh in salt caverns and 4 TWh in gas fields, which consist of one PGI and one Klein veld. In 2050 there is more demand for hydrogen, but due to a larger share of vRES, nuclear and electrolysis capacity the need for hydrogen-to-power is reduced. The higher amount of storage capacity in 2035 is also due to shortage of hydrogen over the whole year. The storage facilities and their initial filling degree have a role of emptying over the year, as a source, and not acting as a buffer for the system.

### 7.1.2. Anticipated demand for underground hydrogen storage

The first sub-question is:
*What is the anticipated demand for underground hydrogen storage (in TWh H2) considering current policy objectives, sustainable energy development scenarios and electrolyser advancements?*

One clear takeaway is that with the capacity of 6 GW electrolysers and the anticipated installed blue and grey hydrogen capacity, the goal of reaching a net zero electricity network is impossible because storage facilities are not able to fill as there is not enough surplus green hydrogen to store.

An important assumption in the model that made it possible to withstand a dunkelflaute without EENS is the degree of filling of 100% on October first and a filling requirement of 10% at the end of the year. Having this volume of hydrogen readily available will resolve the issue of EENS. This is with the volumes of 4,5 TWh salt caverns and 5,5 TWh gas fields. Another assumption that shows to impact the model is the compressor restraint of 12 hours in the gas field, waiving this is the only way to ensure there is no EENS.

If the goals for electrolysis capacity are not met by 2035, a solution could be to keep gas power plants with CCS as backup capacity. Another solution is strong agreements on import of hydrogen and derivatives of hydrogen, such as ammonia.

For 2050 the goal of 20 GW electrolysers brings significantly more flexibility to the system and requires less storage. In 2050 the model has no trouble in withstanding the dunkelflaute without EENS with the storage volume of 1.75 TWh salt caverns and 4 TWh gas fields. This is even possible with the filling degree at only 54%, the filling degree at the end of the year is 54% and the compressor constraint for gas fields is in place.

### 7.1.3. Economically and functionally efficient combination of storage facilities

The second sub-question that is addressed is:
*What is the economically and functionally efficient capacity and combination of underground hydrogen storage facilities, considering utilising both salt caverns and gas fields in the Netherlands?*

In the appendix F, the calculations for the investment requirements for 2035 and 2050 are shown. These calculations are based on the calculated requirements for salt cavern and gas fields storage facilities and associated electrolysers in the system.

To determine the economically and functionally efficient capacity and combination of underground hydrogen storage facilities in the Netherlands, a balanced approach involving both salt caverns and gas fields is necessary. This approach should take into consideration both the economic efficiency and functional requirements of the storage system.

Utilizing storage facilities more frequently is economically advantageous. In scenarios of high hydrogen demand or anticipated high demand during cold winters, storage facilities that can cycle hydrogen more frequently can generate higher profits. This is because increased cycling translates to more transactions and greater utilization of the stored hydrogen. Salt caverns are favored in the initial stages due to their ability to provide faster production rates. This makes them more economically attractive when rapid response and quick turnover are necessary. Although they might not store as much volume as gas fields, their high cycling potential makes them economically viable, particularly when quick production is needed to meet immediate demand. For functional efficiency, the system needs to prioritize facilities that can produce hydrogen quickly. Salt caverns are particularly suited for this due to their high discharge rates, making them essential for meeting sudden spikes in demand. Gas fields, despite their slower production rates, are valuable for their large storage capacities. They serve a strategic role in the overall hydrogen storage system by acting as reserves that can be tapped into during prolonged periods of high demand or when there are supply disruptions. Functionally, gas fields are less about quick turnover and more about ensuring long-term energy security. A robust system, which relies heavily on gas fields for strategic reserves, might not be as economically profitable due to the less frequent cycling of hydrogen. However, this robustness is crucial for the stability of the hydrogen supply, ensuring that there is always a backup during times of high or unpredictable demand.

The system should integrate both salt caverns and gas fields. In the early stages, a higher emphasis should be placed on developing salt caverns to meet immediate and fast production needs. As the hydrogen market and infrastructure mature, gas fields should be incorporated to provide the necessary strategic reserves. A flexible approach should be adopted where salt caverns handle the day-to-day high-frequency cycling, while gas fields are reserved for longer-term storage and strategic uses. This combination ensures that the system is both economically efficient in the short term and functionally robust in the long term. In conclusion, the economically and functionally efficient capacity and combination of underground hydrogen storage facilities in the Netherlands involves a dynamic balance of salt caverns for rapid production and high-frequency cycling, and gas fields for large-volume, more strategic storage. This hybrid approach ensures both immediate responsiveness to market demands and long-term stability in the hydrogen supply chain.

### 7.1.4. Injection and production capacity

The third sub question that is answered is:

*What are the desired injection and production capacities of underground hydrogen storage facilities to ensure the efficient functioning of storage systems within technologically feasible limits?*

For salt caverns the optimal capacity is modelled, which is 6 injection wells and 9 production wells. The injection wells have an injection capacity of 1 GW and the production wells have a production capacity of 1.5 GW, resulting in an injection capacity of 6 GW and a production capacity of 13.5 GW per salt cavern.

For gas fields, the number of wells only had a significant impact when increased by a factor of 2 to 3. Most scenarios did not reach the maximum daily production capacity of the gas fields, suggesting that there is additional capacity that could be utilized. This increase led to more frequent cycling, which improves the business case. However, it did not substantially reduce the LOLE and EENS.

### 7.1.5. Electrolysers

The final sub-question that is answered is:

*How do variations in the efficiency and ramp-up/down capabilities of different types of electrolysers impact the overall system?*

At the beginning of this thesis when this question was derived, the assumption was that the ramp-up and down made great impact for the system. However, in retrospect the ramp-up and down time of an electrolyser is below one hour, which is the run time of this model. That is why it is not relevant any longer for this analysis.

The efficiency of electrolysers is noteworthy. The analysis demonstrated that improvements in electrolyser efficiency significantly impacted energy shortages, carbon emissions, and green hydrogen production within the system. However, this impact is not the most compelling finding from this model.

The proportion of installed electrolysers is crucial for the system, particularly because alkaline electrolysers require a consistent base load of energy. While an increased installation of PEM electrolysers would benefit the system, the half/half scenario is improbable due to the higher associated investment costs.

The base load energy requirement of alkaline electrolysers was also analyzed, revealing that the system is highly sensitive to variations in this parameter. If the lower bound exceeds 5%, the energy not served increases significantly. Specifically, an increase of 5%, resulting in a lower bound of 10%, would lead to a 20% rise in the energy not served.

## 7.2. Interpretation of the results

The research highlights several critical insights for the future of underground hydrogen storage and the broader energy system. By 2035, there is a significant need for storage due to anticipated hydrogen shortages, with salt caverns and gas fields playing a crucial role, especially during a dunkelflaute. However, by 2050, the demand for storage decreases as the energy system becomes more balanced, relying more on renewable energy, nuclear power, and advanced electrolysis technology. This should not imply to hold back investments in storage, because the increase in the capacities of these technologies in the future is still highly uncertain.

One of the most evident conclusions from this research is that the scarcity of salt caverns and gas fields will lead to increased cycling, making them more frequently used. This could implicate that the first storages will make more profits then the last storage built. However, the capacity of hydrogen CCGT or OCGT plants is insufficient to meet future energy needs on their own. This emphasizes the need for parallel development across multiple technologies, as no single solution can provide all the necessary storage and flexibility.

The evolving energy system is marked by rivalry among different technologies. For instance, more battery deployment reduces the need for underground storage, while expanding salt caverns and gas fields decreases the frequency of storage cycles, potentially weakening their business case. Similarly, retaining gas power plants can reduce the necessity for extensive storage, as they can serve as backup power sources. Additionally, fewer electrolysers mean less green hydrogen production, leading to challenges in maintaining adequate storage levels. This ”chicken and egg” situation underscores the interconnectedness of various technologies, where the success of one often depends on the development and availability of others.

In this complex landscape, strategic decisions and investments are crucial to ensuring a reliable and sustainable energy infrastructure. Balancing the development of salt caverns, gas fields, batteries, and other technologies is key to creating a flexible and resilient energy system that can meet future demands.

## 7.3. Comparison with existing literature

Existing studies like research by TNO [25] emphasise the need for storage facilities. Their scenarios range from 2 to 52 TWh in salt caverns and gas fields. Their middle scenario ranges from 4 - 12 TWh hydrogen storage. The outcomes of this research are in range, but on the lower side. Their research for the middle scenario does not include extreme weather years, but their high scenario does. The range they give for this is between 12 and 32 TWh of hydrogen storage. This is much more than this study indicates. Possible explanations could be the difference in modelling tools, them making use of OPERA and COMPETES and this research developing a model in Linny-R.

## 7.4. Limitations of the study

Because the model lumps all gas fields together and salt caverns together, it is difficult to show individual storage behaviour. It could be the case that the individuals role of storage facilities can have a more active role in the system due to their location for example. It is also realistic to assume that facilities have slightly different capabilities which answer for local demand. This would also have impact on the compressor switch, which is one of the most computational heavy aspects of the model.

An under-explored aspect of this research is the role of heat networks in supplying the built environment. The model only quantifies the demand for heat from heat networks by attributing a percentage to industry, the built environment, and agriculture. However, the associated costs of this heat supply are not considered.

Additionally, the demand-side response of the industry is not extensively examined. Projections suggest that the industrial demand-side response could reduce peak demand by approximately 1.9 GW [89]. Modelling this in Linny-R is challenging because many industries require a certain number of operational hours annually to remain profitable. Consequently, modelling this constraint in Linny-R is not possible due to the runtime which can vary, leading to a constant reduction in industrial demand, which is not a realistic scenario. Therefore, it was decided to exclude this aspect from the research.

Cushion gas is another factor not accounted for in this research. Given that cushion gas represents a one-time investment, it is not modelled as it remains a constant factor. Additionally, there are complexities due to the varying ratios of cushion gas to working gas required for salt caverns, as well as differences within the varying types of gas fields. Nevertheless, these calculations can be performed retrospectively for scenarios and specific fields.

Due to the aggregation of various technologies, the limitations associated with these technologies apply to the entire system. For instance, the compression time limitations modeled in Linny-R are unlikely to occur simultaneously across all fields. It is more plausible that these limitations would be monitored and managed more intelligently, preventing the system from injecting hydrogen when there is a sudden surplus.

In some scenarios the model falls back on the product of VoLL, which has no carbon emissions. This can give a skewed image of the true carbon emissions of the system in the case of a shortage of energy. This makes the interpretation of the carbon emissions less reliable.

## 7.5. Suggestions for future research

Future research should explore the role of blue hydrogen. Key areas include investigating the feasibility and benefits of storing blue hydrogen. A swift transition from grey to green hydrogen may offer significant advantages, but it requires a robust interim solution. Blue hydrogen could pave the way by establishing the necessary infrastructure and frameworks for a sustainable hydrogen economy.

It is worthwhile to investigate the potential benefits of integrating hydrogen flow from gas fields to salt caverns within the system. The production speed of salt caverns significantly surpasses that of gas fields, giving them a disproportionate influence on the system relative to their volume. By combining these two characteristics—utilizing the large storage capacity of gas fields to supply hydrogen to the high-production-rate salt caverns—the production capacities of salt caverns could be optimally exploited. However, this process necessitates the compression of hydrogen on two separate occasions, which could render it economically non viable.

In some technologies to produce energy, such as SMR and ATR, the use of CCS is modelled and the reduction of carbon dioxide is taken into account in the calculations for carbon emissions. The actual storage is interesting to add to the system in terms of volume requirements in depleted gas fields and additional costs that come into play.

This research would also be more realistic if specific wind parks were modelled to provide for specific electrolysers. In this model, the energy production of wind parks and solar PV are huddled together to provide for all different processes including the electrolysers.

Another factor that would make the model more realistic is the differentiation between onshore hydrogen production and offshore production. This would be able to account for delays in utilisation of hydrogen produced offshore.

As mentioned for gas fields and salt caverns, this model hurdles technologies together which provide for the Dutch system as a whole. It could be interesting to divide the model into regions which use a significant amount of energy, such as the Port of Rotterdam or Eemshaven. This would give insight in the regional needs and is crucial for the potential selection on gas fields and salt caverns in the regions.

This research could improve if it is able to use the outcomes of the pilot testings of hydrogen in gas fields. The first pilot that has began research in Europe is EUH2STARS. These results will come available to EBN, due to their support in the project.

## 7.6. Significance and potential impact of the study

It can be used in the advising role that EBN has for the Ministry of Climate Policy and Green Growth. Also as underpinning that there is a need to start a hydrogen storage pilot in the Netherlands in a depleted gas field. This research underscores the need for flexibility and the potential role that hydrogen storage can perform.

This research identified parameters in the energy system that are of great importance for investment decisions and therefore should be kept an eye on.

# 8
# Conclusion

In this conclusion, we will summarize the key findings, address the research questions posed, and discuss the implications of our results for policy. By doing so, the aim is to provide a comprehensive understanding of how these elements can contribute to a more stable and efficient energy system.

## 8.1. Conclusion

The storage of hydrogen is attaining much more attention and the market is realising that there is a need for this in the future. The storage in salt caverns is a widely accepted course of action, however, the need for larger quantities in gas fields is still in an early phase of development and consensus. Due to high uncertainties about many factors in the energy system, market parties are reluctant to invest in technologies that are not proven to be profitable. The study underscores the critical role of both salt caverns and gas fields in meeting the anticipated hydrogen demand for 2035 and 2050.

### Anticipated Storage Demand

The anticipated demand for hydrogen storage in 2035 is projected at 7.2 TWh. This is divided into 4.5 TWh in salt caverns and 2.8 TWh in gas fields, specifically peak gas installations. The production capacity required for 2035 is 48 GW, with salt caverns contributing 39 GW due to their higher operational speed.

By 2050, the storage requirements shift, reflecting a more mature hydrogen economy. The need reduces to 1.75 TWh in salt caverns and 4 TWh in gas fields. The reduced need in 2050 is attributed to an increased share of variable renewable energy sources (vRES), nuclear, and electrolysis capacity, reducing the dependency on hydrogen storage for power.

### Economic Efficiency

Economic efficiency in hydrogen storage is enhanced by frequent cycling of storage facilities. In years of high hydrogen demand, storage facilities that can cycle hydrogen more frequently can generate higher profits. This increased cycling translates to more transactions and greater utilization of stored hydrogen, making storage facilities economically viable.

In the early stages, salt caverns are preferred due to their ability to provide faster production rates. They are more economically attractive when rapid response and quick turnover are necessary, despite their lower storage volume compared to gas fields.

### Functional Efficiency

For functional efficiency, the system needs storage facilities that can produce hydrogen quickly to meet sudden spikes in demand. Salt caverns, with their high discharge rates, are essential for this purpose.

Gas fields, while slower in production rates, offer significant storage capacity and serve a strategic role in the hydrogen storage system. They act as reserves that can be tapped during prolonged periods of high demand or supply disruptions, ensuring long-term energy security.

### Balancing Salt Caverns and Gas Fields

In the early stages, the focus should be on developing salt caverns to meet immediate and fast production needs. Their ability to quickly respond to demand makes them invaluable for maintaining supply stability in the short term.

As the hydrogen market matures, incorporating gas fields becomes crucial. They provide the necessary strategic reserves for long-term storage, ensuring that there is always a backup during times of high or unpredictable demand.

### Challenges and Considerations

The study underscores the importance of meeting the electrolysis capacity goals. If these goals are not met by 2035, alternatives such as maintaining gas power plants with Carbon Capture and Storage (CCS) or securing strong agreements on hydrogen imports may be necessary.

The assumption of maintaining a 100% filling level on October 1 and a 10% minimum by the end of the year is critical for ensuring Energy Not Served (EENS) is resolved during periods of high demand.

In conclusion, the economically and functionally efficient capacity and combination of underground hydrogen storage facilities in the Netherlands involve a balanced integration of salt caverns for rapid production and high-frequency cycling, and gas fields for large-volume, strategic storage. This hybrid approach ensures both immediate responsiveness to market demands and long-term stability in the hydrogen supply chain, making it a robust strategy for future energy security.

## 8.2. Policy recommendation

The findings of this study are significant for policymakers and stakeholders in the hydrogen energy sector, emphasizing the need for a balanced and phased approach to hydrogen storage. To enhance energy security, efficiently meet future hydrogen demand, and contribute to climate targets, the Netherlands should initially focus on constructing and optimizing salt cavern storage, which can address immediate demand with rapid production capabilities. At the same time, strategic planning and investment in gas fields are necessary to establish long-term energy reserves. This phased approach underscores the importance of flexibility and strategic planning in deploying underground hydrogen storage facilities, paving the way for a resilient and economically viable hydrogen infrastructure. By following these recommendations, the Netherlands can effectively balance short-term needs with long-term energy security, contributing to the broader goals of sustainable energy development. This phased approach includes several key policy actions:

- **Immediate investment in salt caverns**: Allocate resources and incentives for the rapid development and deployment of salt cavern storage facilities to address short-term hydrogen demand efficiently.
- **Long-term strategic planning for gas fields**: Develop a comprehensive plan for utilizing gas fields as strategic reserves, ensuring they are ready to be integrated into the hydrogen storage system as demand grows and the market evolves.
- **Support for technological advancements**: Encourage research and development in hydrogen storage technologies, particularly focusing on improving the efficiency and production capacity of both salt caverns and gas fields. Also support the advancements in technologies of electrolysers and hydrogen transportation.
- **Pilot projects**: Initiate pilot projects to test and refine the integration of hydrogen storage in gas fields, using real-world data to optimize storage strategies and infrastructure.
- **Start preparing for public approval**: Start early on securing areas and licenses for land-based hydrogen storage, as getting public support and going through the necessary approvals can take a long time. Planning ahead is important to make sure everything is ready when needed.

## 8.3. Personal reflection

Choosing to focus on the hydrogen economy stemmed from my keen interest in understanding our future energy needs and the hurdles we face in transitioning to hydrogen as a major energy source. I wanted to explore the complexities and challenges of this field. I anticipated that the process would be demanding, especially in trying to fit various unknown factors into a unified model.

Researching this topic proved more complicated than I expected. Understanding and modeling different technologies and uncertainties took longer than planned, as I needed to thoroughly grasp each component. Data collection and literature review were time-consuming, and modeling came with many errors, although analyzing the data was somewhat easier. Writing was another challenge; I struggled to organize my thoughts clearly and maintain a coherent narrative. Accessing EBN daily was incredibly helpful for managing my time better.

Throughout this process, I developed valuable skills, including proficiency in Linny-R for data analysis and improved critical thinking and uncertainty estimation. Working in a company environment also gave me insights into the operations of a state-owned enterprise, contributing to my personal growth. Facing and overcoming challenges, especially maintaining self-discipline during a tough personal period, strengthened my problem-solving skills and resilience. My understanding of the hydrogen system and the energy transition deepened significantly.

I am thankful for the excellent guidance from my supervisors at EBN and the support from professors Laurens de Vries and Peter Bots at TU Delft. Their feedback was crucial in refining my work. Additionally, the ETM Energy Transition Model provided essential information that shaped my analysis and understanding of the topic.

I am proud of how the model developed, despite my struggles with writing. If I were to undertake this project again, I would prioritize starting the modeling phase earlier and transition from literature review to model development more quickly. This would allow for a more focused approach and smoother transitions between different stages of the project.

This thesis has strengthened my interest in the hydrogen sector and the energy transition, and I plan to pursue opportunities in this area for my career. The experience has solidified my career goals and provided a strong foundation for future work.

Overall, I found the topic and thesis both engaging and relevant due to their impact on future energy systems. While working independently on the project was challenging and sometimes made it hard to keep the bigger picture in view, I am satisfied with the results and the knowledge gained. This experience has been rewarding and educational, and I am eager to apply what I've learned to future projects.

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[99] Seyed Hamidreza Yousefi et al. “Techno-economic analysis of developing an underground hydrogen storage facility in depleted gas field: A Dutch case study”. en. In: *International Journal of Hydrogen Energy* 48.74 (Aug. 2023), pp. 28824–28842. ISSN: 03603199. DOI: `10.1016/j.ijhydene.2023.04.090`. URL: `https://linkinghub.elsevier.com/retrieve/pii/S0360319923018256` (visited on 03/14/2024).

[100] Meiling Yue et al. “Hydrogen energy systems: A critical review of technologies, applications, trends and challenges”. en. In: *Renewable and Sustainable Energy Reviews* 146 (Aug. 2021), p. 111180. ISSN: 13640321. DOI: `10.1016/j.rser.2021.111180`. URL: `https://linkinghub.elsevier.com/retrieve/pii/S1364032121004688` (visited on 04/02/2024).

[101] Federico Zenith et al. “Value of green hydrogen when curtailed to provide grid balancing services”. en. In: *International Journal of Hydrogen Energy* 47.84 (Oct. 2022), pp. 35541–35552. ISSN: 03603199. DOI: `10.1016/j.ijhydene.2022.08.152`. URL: `https://linkinghub.elsevier.com/retrieve/pii/S0360319922036801` (visited on 03/01/2024).

# A

# Literature review

**Table A.1:** Literature overview

| ID | Title | Ref |
|---|---|---|
| 1 | Optimal hydrogen production in a wind-dominated zero-emission energy system | [96] |
| 2 | The shape of future electricity demand: Exploring load curves in 2050s Germany and Britain | [9] |
| 3 | Outlook for a Dutch hydrogen market | [65] |
| 4 | Electricity market design based on consumer demand for capacity | [22] |
| 5 | The importance of water electrolysis for our future energy system | [57] |
| 6 | How flexible electricity demand stabilizes wind and solar market values | [84] |
| 7 | The Role of Green and Blue Hydrogen in the Energy Transition | [72] |
| 8 | Seasonal hydrogen storage in a depleted oil and gas field | [61] |
| 9 | Should we inject hydrogen into gas grids? Practicalities and whole-system value chain optimisation | [78] |
| 10 | Toward a Fundamental Understanding of Geological Hydrogen Storage | [1] |
| 11 | A comprehensive review of the mechanisms and efficiency of underground hydrogen storage | [90] |
| 12 | A holistic overview of underground hydrogen storage: Influencing factors, current understanding, and outlook | [79] |
| 13 | Numerical simulation of large-scale seasonal hydrogen storage in an anticline aquifer: A case study capturing hydrogen interactions and cushion gas injection | [15] |
| 14 | Hydrogen storage in saline aquifers: The role of cushion gas for injection and production | [41] |
| 15 | Optimal design of multi-energy systems with seasonal storage | [32] |
| 16 | Seasonal energy storage for zero-emissions multi-energy systems via underground hydrogen storage | [33] |
| 17 | Assessment of underground energy storage potential to support the energy transition in the Netherlands | [51] |
| 18 | Profitability of an electrolysis based hydrogen production plant providing grid balancing services | [40] |
| 19 | Optimisation of a hydrogen production – storage – re-powering system participating in electricity and transportation markets. A case study for Denmark | [5] |
| 20 | Optimal operation of a wind-electrolytic hydrogen storage system in the electricity/hydrogen markets | [98] |
| 21 | Decarbonization synergies from joint planning of electricity and hydrogen production: A Texas case study | [7] |
| 22 | Large-scale compressed hydrogen storage as part of renewable electricity storage systems | [26] |
| 23 | A Review on Hydrogen-Based Hybrid Microgrid System: Topologies for Hydrogen Energy Storage, Integration, and Energy Management with Solar and Wind Energy | [4] |
| 24 | Value of green hydrogen when curtailed to provide grid balancing services | [101] |
| 25 | Hydrogen in Grid Balancing: The European Market Potential for Pressurized Alkaline electrolysers | [86] |
| 26 | Safe underground Hydrogen storage IN porous subsurface rEservoirs | [55] |

**Table A.2:** Reports overview

| ID | Title | Ref |
|---|---|---|
| 1 | Scenario study on the Integrated Infrastructure exploration by Netbeheer Nederland | [68] |
| 2 | Scenarios Investment Plans 2024 profiles from Netbeheer Nederland, used in the Energy Transition Model (ETM) by Quintel Intelligence | [69, 48] |
| 3 | National Plan Energy System by the Ministry of Economic Affairs and Climate Policy | [66] |
| 4 | Underground energy storage in the Netherlands 2030 – 2050 by EBN and TNO | [92] |
| 5 | Underground energy storage necessary for future energy system by EBN and TNO | [25] |
| 6 | Feasibility study of offshore underground hydrogen storage by EBN and TNO | [36] |
| 7 | Techno-Economic Modelling of Large-Scale Energy Storage Systems by TNO | [38] |
| 8 | Route map Hydrogen by Nationaal Waterstof Programma (National Hydrogen Program) | [76] |
| 9 | Interaction of gas fields and salt caverns for hydrogen storage by Common Futures for EBN | [31] |
| 10 | Net Zero by 2050 by the IEA | [46] |
| 11 | Hydrogen policy in the Netherlands - Laying the foundations for a scalable hydrogen value chain | [77] |

# B

# Data input model

**Table B.1:** Input values in the model for 2035 and 2050

| Cluster | Variable | Scenario 2035 | Value 2035 | Scenario 2050 | Value 2050 | Unit | Reference |
|---|---|---|---|---|---|---|---|
| **Value of LOLE** | Electricity | | 22.3 | | 22.3 | MEUR /GWh | [56, 87, 21] |
| | Hydrogen | | 6 | | 6 | MEUR /GWh | See chapter 4 |
| | Green hydrogen | | 22.3 | | 22.3 | MEUR /GWh | See chapter 4 |
| **Electricity production** | Installed capacity nuclear | NPE | 2 | NPE | 7 | GW | [66] |
| | | Realistic | **0.5** | Realistic | **7** | GW | Assumption |
| | Installed capacity waste to power | | 0.28 | | 0.28 | GW | [48] |
| | Installed capacity biomass | | 0.42 | | 0 | GW | [48] |
| | Installed capacity CCGT with CCS | CA | 6.08 | CA | 0 | GW | [48] |
| | | IA | 3.85 | IA | 0 | GW | [48] |
| | | ND | 6.18 | ND | 0 | GW | [48] |
| | | Tennet | 12.4 | Tennet | 0 | GW | [89] |
| | Installed capacity hydrogen OCGT | | no limit | | no limit | GW | See chapter 4 |
| | Installed capacity ammonia synthesis plant | | 2 | | 2 | GW | Assumption |
| **vRES** | Installed capacity wind onshore | NPE | **12** | NPE | **17** | GW | [66] |
| | | CA | 10.6 | DI | 15 | GW | [48] |
| | | IA | 8.1 | EI | 10 | GW | [48] |
| | | ND | 12.7 | IT | 10 | GW | [48] |
| | | Average II3050 | 10.47 | ND | 20 | GW | [48] |
| | Installed capacity wind offshore | NPE | **35** | NPE | **72** | GW | [66] |
| | | CA | 27.5 | DI | 37 | GW | [48] |
| | | IA | 25.5 | EI | 38 | GW | [48] |
| | | ND | 29.5 | IT | 38 | GW | [48] |
| | | Average II3050 | 27.5 | ND | 52 | GW | [48] |

Continued on next page

Table B.1 – continued from previous page

| Cluster | Variable | Scenario 2035 | Value 2035 | Scenario 2050 | Value 2050 | Unit | Reference |
|---|---|---|---|---|---|---|---|
| | Installed capacity wind offshore for P2X | NPE | **1.75** | NPE | **3.6** | GW | Assumption, [66] |
| | | CA | 1.98 | DI | 0 | GW | [48] |
| | | IA | 3.96 | EI | 0 | GW | [48] |
| | | ND | 1.32 | IT | 5.28 | GW | [48] |
| | | Average II3050 | 2.42 | ND | 13.2 | GW | [48] |
| | Installed capacity solar PV | NPE | **98** | NPE | **172** | GW | [66] |
| | | CA | 60.8 | DI | 133 | GW | [48] |
| | | IA | 42.6 | EI | 89.9 | GW | [48] |
| | | ND | 78.3 | IT | 74.1 | GW | [48] |
| | | Average II3050 | 60.6 | ND | 126.9 | GW | [48] |
| **Hydrogen production** | Installed capacity biomass gasification | CA | 0.18 | DI | 0.28 | GW | [48] |
| | | IA | **0.18** | EI | **0.34** | GW | [48] |
| | | ND | 0 | IT | 0.38 | GW | [48] |
| | | | | ND | 0.17 | GW | [48] |
| | Electrolysis capacity total | NPE | 9.5 | NPE | 20 | GW | [66] |
| | | Realistic | **6** | Realistic | **20** | GW | [67] |
| | Alkaline | | 90 | | 70 | % | Assumption |
| | PEM | Regular | 9 | Regular | 7 | % | Assumption |
| **Import and export** | Interconnection capacity electricity | Total | 12.8 | | | GW | [89] |
| | | Norway | 0.7 | | | GW | [89] |
| | Imported hydrogen (derivatives) | | 37 | | 89 | Mton h2 eq | [83] |
| | | | 1233 | | 2966 | TWh | [83] |
| | | | 141 | | 339 | GW | [83] |
| | Ammonia percentage | | 80 | | 50 | % | [83] |
| | Installed capacity ammonia cracking | | 2.18 | | 6.4 | GW | [48] |
| **Battery storage** | Installed capacity LiOn batteries | CA | 15.19 | DI | 61.95 | GW | [48] |
| | | IA | **8.6** | EI | **32.38** | GW | [48] |
| | | ND | 21.8 | IT | 35.38 | GW | [48] |
| | | | | ND | 51.76 | GW | [48] |
| | | | 7.2 | | | GW | [89] |
| | Installed volume LiOn batteries | CA | 144.87 | DI | 501.72 | GWh | [48] |
| | | IA | **74.40** | EI | **331.41** | GWh | [48] |
| | | ND | 215.38 | IT | 336.24 | GWh | [48] |
| | | | | ND | 483.90 | GWh | [48] |
| **Hydrogen storage** | Volume | | 10 | | 10 | GWh | [48] |
| | Injection rate | | 0.125 | | 0.125 | GW | [48] |
| | Production rate | | 0.167 | | 0.167 | GW | [48] |
| Salt caverns | Volume | | 250 | | 250 | GWh | [67] |
| | Number | | 4 | | 28 | # | [43] |

Continued on next page

Table B.1 – continued from previous page

| Cluster | Variable | Scenario 2035 | Value 2035 | Scenario 2050 | Value 2050 | Unit | Reference |
|---|---|---|---|---|---|---|---|
| | Injection rate | | 0.8-1.2 | | 0.8-1.2 | GW/h | [85] |
| | Production rate | | 1.2-1.8 | | 1.2-1.8 | GW/h | [85] |
| | Number of injection wells | | 4 to 6 | | 6 | # | [85] |
| | Number of production wells | | 9 to 13 | | 9 | # | [85] |
| | Maximum daily production | | 20 | | 20 | % | [60, 85] |
| | Initial value salt cavern | | 54 | | 54 | % | Own calculation |
| | Off-gas | | 2 | | 2 | % | [67] |
| | Efficiency injection | | 98 | | 98 | % | [67] |
| Gas field storage | Volume PGI | | 1500 | | 1500 | GWh | [67] |
| | Injection rate | | 2.52 | | 2.52 | GW | [67] |
| | Production rate | | 4.53 | | 4.53 | GW | [67] |
| | Volume small field | | 2500 | | 2500 | GWh | [67] |
| | Injection rate | | 0.47 | | 0.47 | GW | [67] |
| | Production rate | | 1.8 | | 1.8 | GW | [67] |
| | Volume large field | | 5500 | | 5500 | GWh | [67] |
| | Injection rate | | 0.47 | | 0.47 | GW | [67] |
| | Production rate | | 1.8 | | 1.8 | GW | [67] |
| | Maximum daily withdrawal | | 5 | | 5 | % | [67] |
| | Initial value gas field | | 54 | | 54 | % | Own calculation |
| | Off-gas | | 1 | | 1 | % | [67] |
| | Efficiency injection | | 98 | | 98 | % | [67] |
| | Ramp up/down rate | | 0.25 | | 0.25 | hours | [99] |
| | Compressor switch time | | 12 | | 12 | hours | [67] |
| **Demand** | Industry demand | Hydrogen | 6.9 | | 7.6 | GW | [48] |
| | | Gas | 5.3 | | 3.4 | GW | [48] |
| | | Coal | 0.6 | | 0.3 | GW | [48] |
| | | Oil | 1.2 | | 0.8 | GW | [48] |
| | | Heat | 1.1 | | 0.1 | GW | [48] |
| | | Electricity | 10 | | 13.5 | GW | [48] |
| | Mobility | Hydrogen | 20081 | | 13436 | GWh/y | [48] |
| | | Electricity | 21193 | | 14180 | GWh/y | [48] |
| | Built environment | Heat | 5150 | | 10771 | GWh/y | [48] |
| | | Electricity | 21747 | | 45988 | GWh/y | [48] |
| | | Gas | 30328 | | 16018 | GWh/y | [48] |
| | Agriculture | Heat | 1606 | | 1066 | GWh/y | [48] |
| | | Electricity | 2943 | | 1954 | GWh/y | [48] |
| | | Gas | 3412 | | 2266 | GWh/y | [48] |

# C

# XLRM Framework

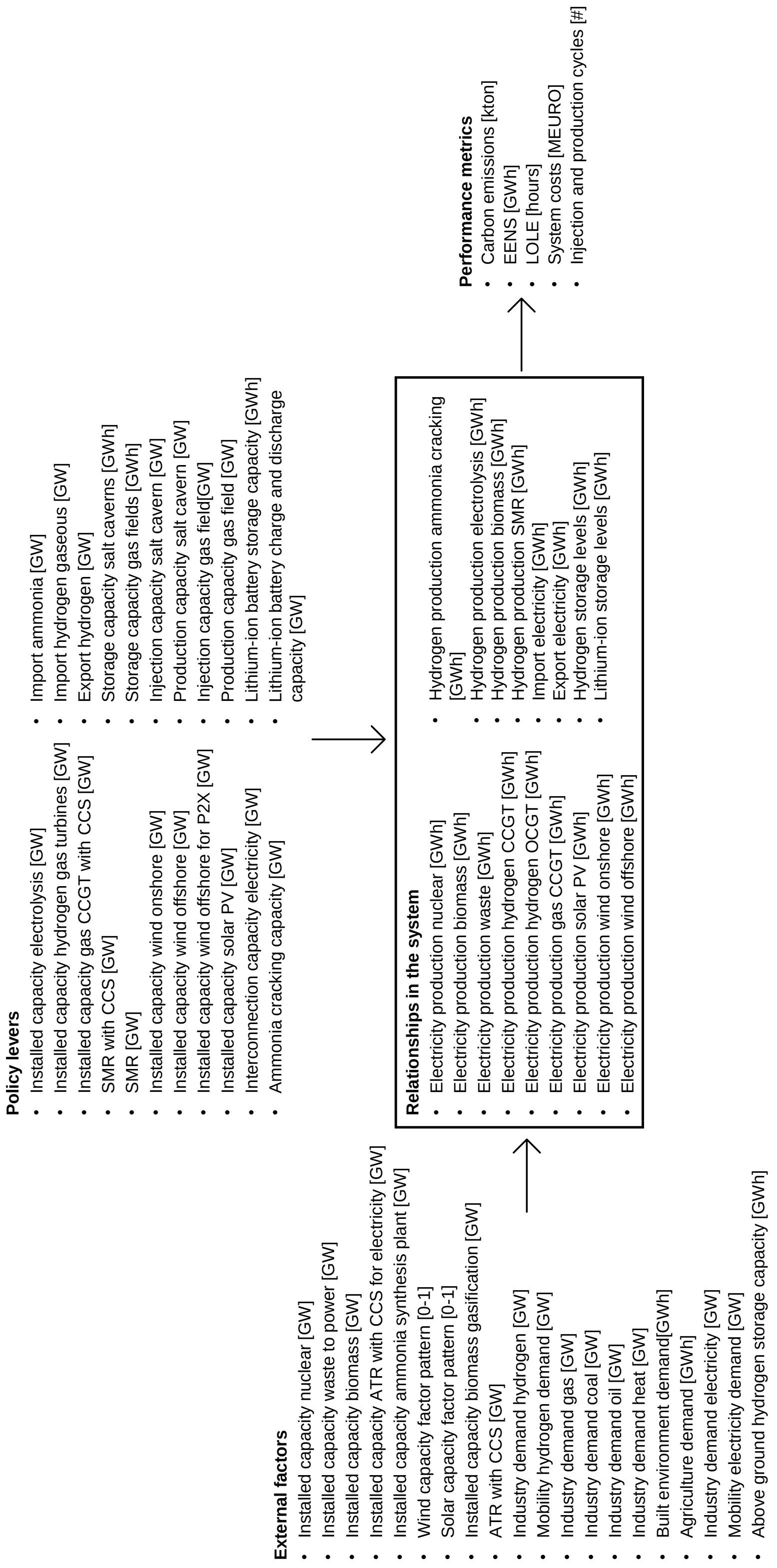

**Figure C.1:** XLRM framework

# D

# Analysis

## D.1. Verification

### D.1.1. Behavioural analysis

Below in figures D.1, D.2, D.3 and D.4 the behaviour of the cumulative salt caverns and the gas field is shown in total volume and injection and production activity. As a reminder: the year starts on October 1st and these graphs show the base case model for 2035 with 4 salt caverns (1 TWh) and one PGI gas field (1,4 TWh). The most prominent observation is the low degree of filling during the summer months, which is expected. The salt caverns show more responsive behaviour than the gas field, due to their ability to inject and produce quickly. This confirms their position in the energy system regarding flexibility to be higher than that of gas fields. In the gas field graph, the reserve of 10% is depicted as being utilized only during three instances throughout the year. This usage pattern validates the purpose of maintaining this reserve. It aims to mirror policy-driven behaviour in the model as it underscores the cautious approach taken towards managing the final portion of energy reserves in storage. It is also shown in the graph of the gas field behaviour that the volume at the end of the year is again at 54%. This is modelled as a requirement that the model will manage at any given cost. In a regular weather year, this behaviour should be designed, however, one could argue that in a year in which a dunkelflaute occurs, this might not be the priority.

In appendix D more behaviour of the model is shown, such as the demand profile through the year and the electricity production of the variable Renewable Energy Sources.

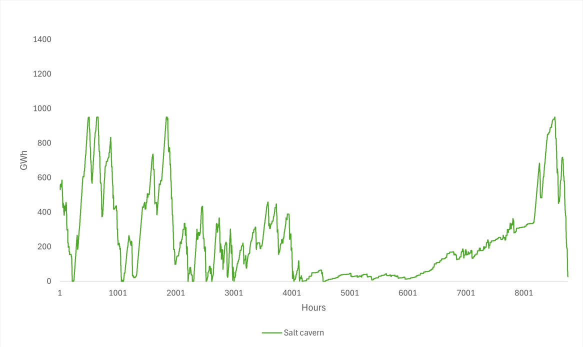

**Figure D.1:** Salt cavern behaviour throughout the year

**Figure D.2:** Gas field behaviour throughout the year

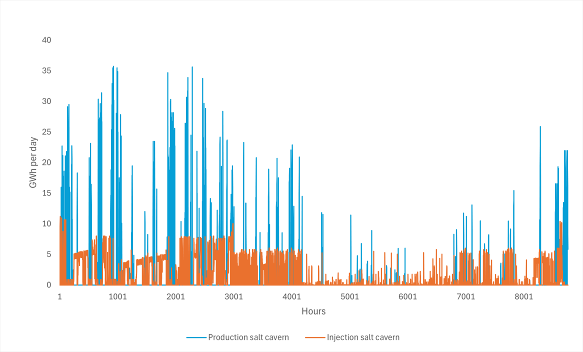

**Figure D.3:** Salt cavern injection and production behaviour

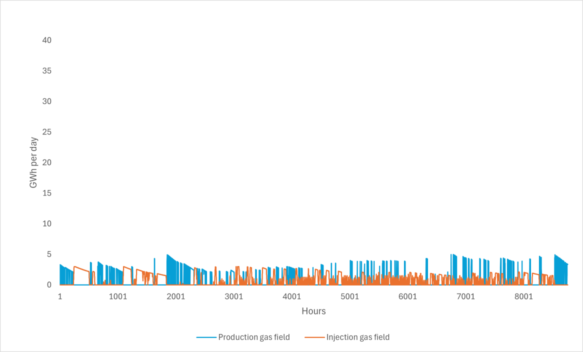

**Figure D.4:** Gas field injection and production behaviour

As mentioned the second behaviour that is interesting to analyse in the model is that of the ability of the model to convert hydrogen to power at times of low renewable energy sources. The week with the extremely low average electricity production from renewable sources is taken, which is 7,52 GW between the hours 1838 till 2005. This week is compared to a week with high production of energy from renewables. Below in table D.1 we can see that the model is demonstrating elevated power production from hydrogen during periods of renewable energy scarcity and reduced output during times of ample renewable energy availability.

**Table D.1:** Behaviour hydrogen to power

| Moment in time [week in hours] | Average vRES energy production [GW] | Average production rate hydrogen ccgt [GW] | Average production rate salt and gas combined [GW] |
|---|---|---|---|
| 1838 - 2005 | 7,52 | 4,52 | 8,03 |
| 4338 - 4505 | 39,46 | 0,04 | 0,03 |

## D.1.2. Curtailment

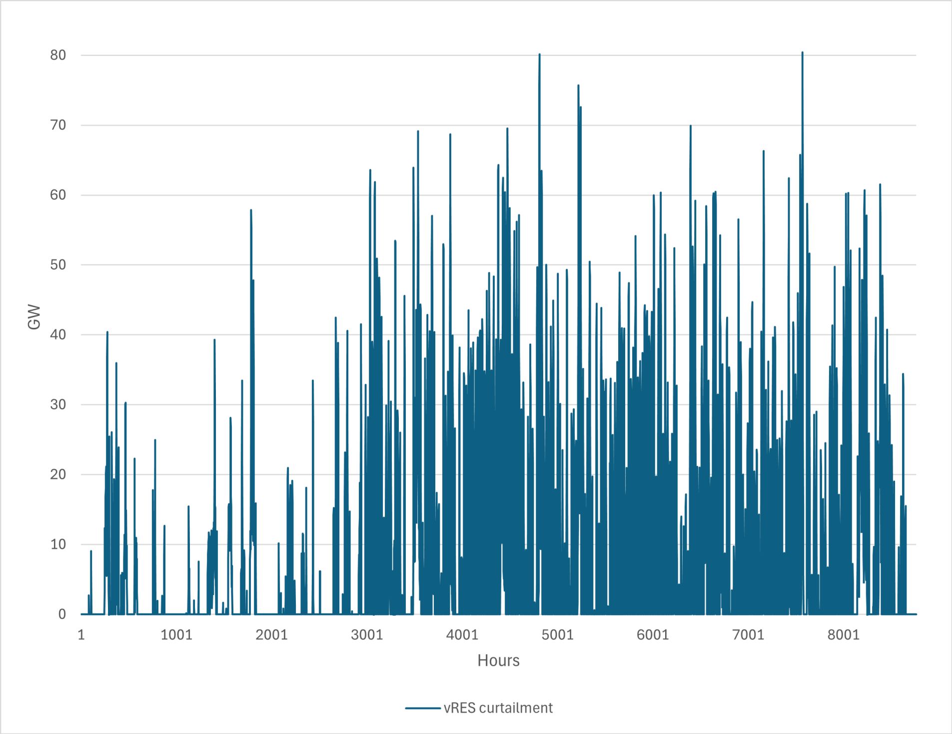

**Figure D.5:** Curtailment

## D.1.3. Demand

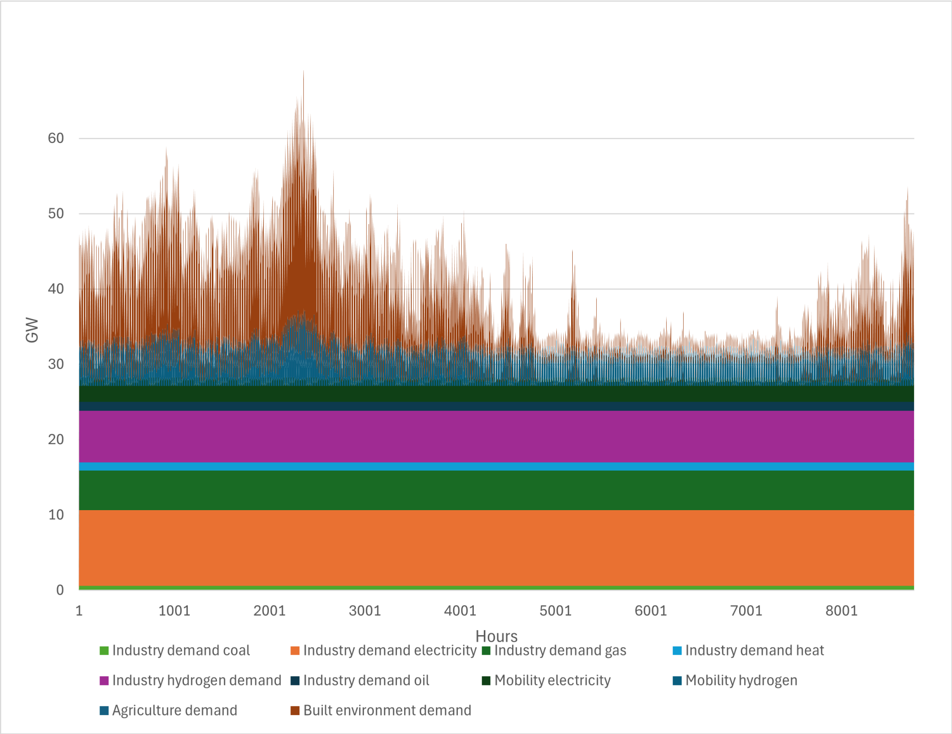

**Figure D.6:** Demand

### D.1.4. Renewable energy production

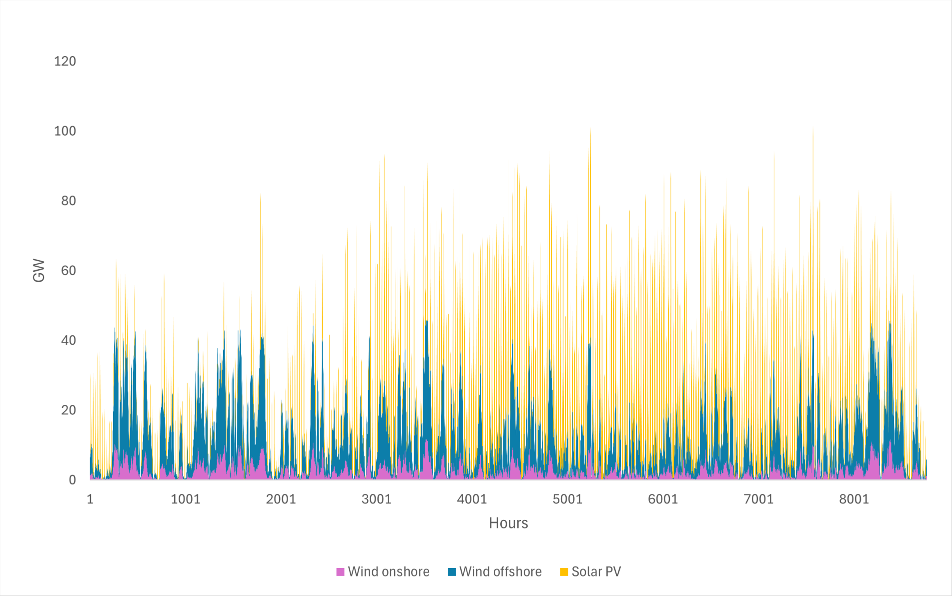

**Figure D.7:** Renewable energy production

### D.1.5. Injection and production gas field

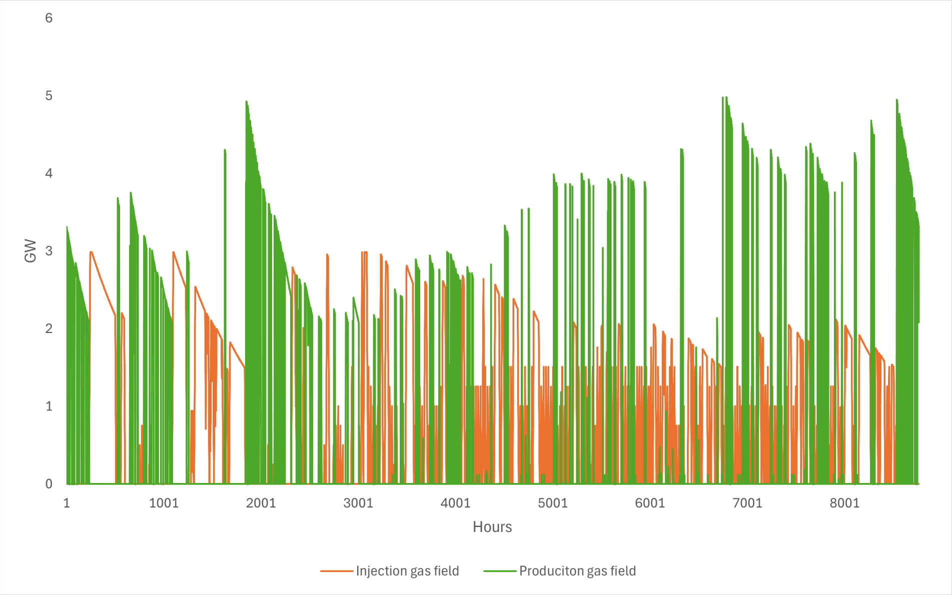

**Figure D.8:** Injection and production gas field

## D.2. Sensitivity analysis

**Table D.2:** Sensitivity analysis 2035

| | CO2 total | Average electricity costs | Average green hydrogen costs | Average hydrogen costs | System costs | LOLE electricity | LOLE green hydrogen | LOLE hydrogen |
|---|---|---|---|---|---|---|---|---|
| | kton | MEURO | MEURO | MEURO | MEURO | GWh | GWh | GWh |
| *Base scenario 2035* | 2.998 | 0.1339 | 0.0014 | 0 | -3.947 | 1398 | 0 | 88.18 |
| Installed capacity electrolysis alkaline | -3.91% | -0.44% | -2.91% | -11.40% | -1.04% | 0.00% | 0.00% | 0.00% |
| Installed capacity electrolysis PEM | -0.46% | -0.17% | -2.00% | 14.40% | -0.04% | 0.10% | 0.00% | 0.00% |
| Installed capacity electrolysis dedicated PEM | -0.10% | -0.10% | -1.57% | -0.90% | -0.19% | -0.10% | 0.00% | 1.00% |
| Installed capacity biomass gasification | -0.22% | -0.18% | -2.43% | -1.80% | -0.52% | -0.50% | 0.00% | 1.00% |
| Installed capacity SMR | 0.28% | -1.34% | -5.29% | -10.20% | -1.38% | 0.20% | 0.00% | -100.00% |
| Installed capacity SMR CCS | -3.24% | -1.24% | -4.29% | -4.90% | -1.79% | 0.14% | 0.00% | -88.00% |
| Installed capacity ATR CCS | 0.35% | -0.43% | -3.77% | -1.70% | -0.89% | -4.60% | 0.00% | -34.00% |
| Installed capacity ammonia cracking | 0.01% | -0.07% | -4.08% | -1.60% | -6.41% | -12.10% | 0.00% | -1.00% |
| Capacity interconnection import electricity | -0.20% | -0.22% | -1.68% | -2.20% | -3.76% | -9.00% | 0.00% | 0.00% |
| Installed capacity nuclear | -0.28% | -0.73% | -2.85% | -2.31% | -2.60% | -7.90% | 0.00% | 0.00% |
| Installed capacity waste to power | -0.28% | -0.48% | -3.95% | -1.87% | -1.58% | -6.60% | 0.00% | 0.00% |
| Installed capacity biomass | -0.21% | -0.60% | -2.28% | -2.13% | -2.13% | -7.40% | 0.00% | -1.00% |
| Installed capacity hydrogen CCGT | -0.01% | -0.03% | 0.01% | 0.12% | 0.00% | -4.90% | 0.00% | 0.00% |
| Installed capacity wind offshore | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.02% |
| Installed capacity wind onshore | -0.10% | 0.00% | 0.00% | -0.05% | 0.06% | -0.14% | 0.00% | 0.80% |
| Installed capacity wind offshore P2X | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.10% | 0.00% | 0.00% |
| Installed capacity solar PV | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | -0.55% | 0.00% | 0.68% |
| Fuel price biomass | 0.83% | 2.71% | 1.81% | 4.10% | 0.16% | 0 | 0.00% | 0.00% |
| Fuel price natural gas | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0% | 0.00% | 0.00% |
| Fuel price nuclear | 0.02% | 7.91% | 14.10% | 16.82% | 0.15% | 0% | 0.00% | 1.00% |
| Installed salt cavern storage capacity | 0.20% | -0.09% | 0.86% | 1.92% | -4.98% | -1% | 0.00% | 1.00% |
| Injection capacity salt cavern | -0.01% | 0.03% | -0.01% | -0.76% | 0.10% | 0.00% | 0.00% | 0.02% |
| production capacity salt cavern | -0.01% | -0.04% | 0.04% | 0.43% | -0.01% | -0.14% | 0.00% | 0.80% |
| Installed gas field storage capacity | -0.28% | -0.73% | -2.85% | -2.31% | -2.60% | -0.55% | 0.00% | 0.68% |
| Injection capacity gas field | -0.28% | -0.48% | -3.95% | -1.87% | -1.58% | 0.00% | 0.00% | 0.02% |
| Production capacity gas field | -0.21% | -0.60% | -2.28% | -2.13% | -2.13% | 0.10% | 0.00% | 0.00% |
| Installed volume short cyclic storage surface tank | -0.01% | -0.03% | 0.01% | 0.12% | 0.00% | -0.14% | 0.00% | 0.80% |
| Injection capacity surface tank | 0.00% | 0.00% | 0.02% | 0.03% | 0.00% | -0.55% | 0.00% | 0.68% |
| Production capacity from surface tank | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.02% |
| Installed battery storage capacity | 8.62% | 13.89% | 54.90% | -13.90% | 60.84% | 66.33% | 0.00% | 85.47% |
| Charge capacity batteries | -0.98% | -0.77% | 1.25% | 2.38% | -4.02% | -4.35% | 0.00% | 0.41% |
| Discharge capacity batteries | -0.98% | -0.77% | 1.12% | 2.30% | -4.02% | -4.35% | 0.00% | 0.41% |
| Carbon price | -0.10% | -0.13% | 0.23% | -0.10% | -0.15% | -0.11% | 0.00% | -1.84% |
| Hydrogen demand mobility sector | 3.37% | 0.17% | 0.54% | 9.94% | 0.21% | -3.79% | 0.00% | 162.50% |
| Industry hydrogen demand | 11.06% | 0.63% | 2.79% | 30.92% | -7.94% | -18.55% | 0.00% | 316.60% |
| Gas demand industry | 7.47% | 0.01% | 0.02% | -0.05% | -3.29% | -3.85% | 0.00% | 0.20% |
| Coal demand industry | 0.12% | 0.00% | 0.02% | -0.03% | -3.25% | -3.79% | 0.00% | -0.30% |
| Electricity demand industry | 6.29% | 3.43% | -11.50% | -12.00% | 75.04% | 83.33% | 0.00% | 72.10% |
| Heat demand industry | 0.13% | 0.00% | 0.00% | 0.00% | -3.30% | -3.85% | 0.00% | -0.30% |
| Oil demand industry | 0.58% | 0.00% | 0.00% | 0.00% | -3.32% | -3.88% | 0.00% | -0.30% |
| Built environment demand | 6.31% | 0.81% | -2.70% | -3.30% | 33.70% | 36.66% | 0.00% | 60.70% |
| Agriculture demand | 0.51% | 0.16% | 0.30% | -0.20% | 2.29% | 2.52% | 0.00% | 0.00% |
| Electricity demand mobility sector | 2.25% | 0.87% | -4.00% | -3.50% | 12.12% | 12.44% | 0.00% | 45.20% |

## D.3. Scenario discovery

**Table D.3:** Input for scenario discovery

| **Scenario** | **Version** | **Variable** | **Unit** | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|---|
| **Dunkelflaute vs regular weather** | 2035 | Wind and solar capacity factor | *Year* | 1987 | 1997 | 2019 | | | |
| | 2050 | Wind and solar capacity factor | *Year* | 1987 | 1997 | 2019 | | | |
| **Look-a-head time** | 2035 | | *Hours* | 168 | 240 | 8760 | | | |
| **Gas field reserve** | 2035 | | *%* | 10% | 20% | 0% | | | |
| **Import** | 2035 | Ammonia cracking | *GW* | 0 | 0.436 | 0.872 | 1.308 | 1.744 | 2.18 |
| | 2035 | Imported hydrogen | *TWh* | 0 | 292 | 585 | 877 | 1169 | 1462 |
| | 2035 | Import electricity | *GW* | 0 | 2.56 | 5.12 | 7.68 | 10.24 | 12.8 |
| **Hydrogen conversion to electricity** | 2035 | Hydrogen gas turbine capacity | *GW* | 3.5 | 6 | 8.5 | 20 | | |
| **vRES** | | | | NPE | II3050 | | | | |
| | 2035 | Wind offshore | *GW* | 35 | 27.5 | | | | |
| | | Wind onshore | *GW* | 12 | 10.4 | | | | |
| | | Solar | *GW* | 98 | 60.58 | | | | |
| | 2050 | Wind offshore 2050 | *GW* | 72 | 41.15 | | | | |
| | | Wind onshore 2050 | *GW* | 17 | 13.75 | | | | |
| | | Solar 2050 | *GW* | 172 | 106 | | | | |
| **Electrolysers** | 2035 | Capacity | *GW* | 3 | 4.5 | 6 | 7.5 | 9.5 | 15 |
| | | Alkaline | *GW* | 2.7 | 4.05 | 5.4 | 6.75 | 8.55 | 13.5 |
| | | PEM | *GW* | 0.3 | 0.45 | 0.6 | 0.75 | 0.95 | 1.5 |
| | 2035 | Efficiency Alkaline | *%* | 90% | 100% | 110% | 120% | | |
| | | Efficiency PEM | *%* | 90% | 100% | 110% | 120% | | |
| | 2035 | Ratio Alkaline/PEM | *0-1* | 0.9 | 0.7 | 0.5 | | | |
| **Underground storage capacity** | 2035 | Salt caverns storage capacity | *#* | 5 | 10 | 15 | 20 | 25 | |
| *With high electrolyser capacity* | 2035 | Salt caverns storage capacity | *#* | 5 | 10 | 15 | 20 | 25 | |
| | 2035 | Gas fields storage capacity PGI | *#* | 1 | 2 | 3 | 4 | 5 | 6 |
| *With high electrolyser capacity* | 2035 | Gas fields storage capacity PGI | *#* | 1 | 2 | 3 | 4 | 5 | 6 |
| | 2050 | Total capacity | *TWh* | 7.25 | 5.75 | 7.5 | 8 | | |
| | | Salt caverns storage capacity | *GWh* | 1750 | 1750 | 2000 | 2500 | | |
| | | Gas fields storage capacity | *GWh* | 5500 | 4000 | 5500 | 5500 | | |
| | | PGI | | 2 | 1 | 2 | 2 | | |
| | | Small gas fields | | 1 | 1 | 1 | 1 | | |
| **Injection and production capacity** | 2035 | Gas field injection | *GW* | 90% | 110% | 120% | | | |
| | | Gas field production | *GW* | 90% | 110% | 120% | | | |
| | | Salt cavern injection | *GW* | 90% | 110% | 120% | | | |
| | | Salt cavern production | *GW* | 90% | 110% | 120% | | | |
| | 2035 | Salt wells injection | *#* | 4 | 6 | 8 | | | |
| | | Salt wells production | *#* | 9 | 13 | 17 | | | |
| **Batteries** | 2035 | | *IP24* | IA | CA | ND | | | |
| | | Installed battery storage capacity | *GWh* | 74.4 | 144.87 | 215.38 | | | |
| | | Installed battery discharge /charge capacity | *GW* | 8.6 | 15.19 | 21.8 | | | |
| | 2050 | | *II3050* | EI | IT | ND | DI | | |
| | | Installed battery storage capacity | *GWh* | 331.41 | 336.24 | 483.9 | 501.73 | | |
| | | Installed battery discharge /charge capacity | *GW* | 32.38 | 35.38 | 51.76 | 61.95 | | |
| **Gas turbine power plant** | 2035 | Gas CCGT capacity | *GW* | 0 | 3 | 6 | 9 | 12 | |
| **Steam methane reformer (with CCS)** | 2035 | Installed capacity | *GW* | 50% | -50% | | | | |
| **Demand** | 2035 | | | -20% | 20% | | | | |
| | 2050 | | | -20% | 20% | | | | |

## D.3.1. Model verification

### Dunkleflaute vs regular weather

This scenario is run with four salt caverns and one PGI gas field.

**Table D.4:** Weather years scenarios

| **Year** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles salt caverns | Cycles gas fields |
|---|---|---|---|---|---|---|---|---|
| 1987 | 27.9 | -4564 | 101829 | 605 | 0 | 0 | 20.8 | 8.1 |
| 1997 | 27.6 | -2078 | 46368 | 264 | 0 | 0 | 19.6 | 8 |
| 2019 | 26.7 | -567 | 12660 | 84 | 0 | 0 | 17.9 | 6.1 |

### Look-ahead time

This scenario is run with four salt caverns and one PGI gas field.

**Table D.5:** Look-ahead scenarios

| **Look-ahead** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles salt caverns | Cycles gas fields |
|---|---|---|---|---|---|---|---|---|
| 8760 | 30.3 | -2791.55 | 144 | 507 | 0 | 384 | 33.3 | 9.7 |
| 240 | 31.7 | -3414.02 | 70587 | 598 | 0 | 576 | 18.5 | 9.7 |
| 168 | 32 | -4059.31 | 85644 | 696 | 0 | 509 | 18.2 | 7.7 |

### Gas field reserve

This scenario is run with four salt caverns and one PGI gas field.

**Table D.6:** Gas fields reserve

| **Reserve** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles salt caverns | Cycles gas fields |
|---|---|---|---|---|---|---|---|---|
| 0% | 32.5 | -2876.75 | 64180.28 | 394 | 0 | 0 | 24.8 | 7 |
| 10% | 32.5 | -2776.44 | 61942.31 | 379 | 0 | 0 | 24.5 | 7.9 |
| 20% | 32.4 | -3045.22 | 67938.84 | 419 | 0 | 0 | 24 | 7.2 |

### Import

This scenario is run with four salt caverns and one PGI gas field.

**Table D.7:** Import electricity scenario analysis

| **Import electricity** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles salt caverns | Cycles gas fields | Total imported electricity [GWh] |
|---|---|---|---|---|---|---|---|---|---|
| Base case | 28 | -4564 | 101829 | 605 | 0 | 0 | 21 | 8 | 2423 |
| 0% | 28 | -5635 | 125722 | 686 | 0 | 0 | 24 | 8 | 0 |
| 20% | 27 | -2353 | 52504 | 350 | 0 | 0 | 17 | 6 | 7898 |
| 40% | 26 | -269 | 5999 | 54 | 0 | 0 | 14 | 5 | 13397 |
| 60% | 26 | -28 | 632 | 6 | 0 | 0 | 9 | 3 | 15376 |
| 80% | 25 | 0 | 0 | 0 | 0 | 0 | 4 | 2 | 17549 |
| 100% | 24 | 0 | 0 | 0 | 0 | 0 | 4 | 2 | 18760 |

**Table D.8:** Import hydrogen scenario analysis

| **Import hydrogen** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles salt caverns | Cycles gas fields | Total imported hydrogen [GWh] |
|---|---|---|---|---|---|---|---|---|---|
| Base case 2.18 GW | 28 | -4564 | 101829 | 605 | 0 | 0 | 21 | 8 | 7337 |
| 0 GWh | 29 | -8221 | 183395 | 958 | 0 | 19 | 24 | 8 | 0 |
| 1 GW | 29 | -6330 | 141233 | 733 | 0 | 0 | 22 | 8 | 3833 |
| 3 GW | 28 | -3723 | 83056 | 475 | 0 | 0 | 20 | 8 | 9133 |
| 4 GW | 28 | -3053 | 68104 | 437 | 0 | 0 | 21 | 8 | 10752 |
| 5 GW | 28 | -2513 | 56077 | 350 | 0 | 0 | 22 | 8 | 12016 |
| 6 GW | 28 | -2050 | 45728 | 303 | 0 | 0 | 22 | 8 | 13190 |
| 7 GW | 28 | -1580 | 35249 | 250 | 0 | 0 | 23 | 7 | 14562 |
| 8 GW | 28 | -1158 | 25834 | 197 | 0 | 0 | 23 | 8 | 15530 |
| 9 GW | 28 | -816 | 18218 | 143 | 0 | 0 | 23 | 7 | 16352 |
| 10 GW | 28 | -557 | 12428 | 104 | 0 | 0 | 22 | 8 | 16704 |

## Hydrogen conversion to electricity

This scenario is run with four salt caverns and one PGI gas field.

**Table D.9:** Hydrogen conversion to electricity scenario analysis

| **Hydrogen conversion** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles salt caverns | Cycles gas fields |
|---|---|---|---|---|---|---|---|---|
| 3.5 GW | 27 | -6529 | 145651 | 1060 | 0 | 0 | 13 | 8 |
| 6 GW | 28 | -4879 | 108850 | 810 | 0 | 0 | 20 | 8 |
| 8.5 GW | 28 | -4589 | 102388 | 707 | 0 | 0 | 21 | 8 |
| Base case 20 GW | 28 | -4564 | 101829 | 605 | 0 | 0 | 21 | 8 |

## Variable Renewable Energy Sources

This scenario is run with four salt caverns and one PGI gas field.

**Table D.10:** vRES scenario analysis 2035

| **vRES** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Cycles gas fields | Curtailment [GWh] | Electrolyser PEM run hours | Green hydrogen production [GWh] |
|---|---|---|---|---|---|---|---|---|---|
| Base case NPE | 28 | -4564 | 101829 | 605 | 25 | 8 | 63951 | 5374 | 28219 |
| ETM | 30 | -8960 | 199898 | 1046 | 28 | 5 | 21729 | 3993 | 20774 |
| Delta [%] | 7 | 49 | 49 | 42 | 25 | -43 | -66 | -26 | -26 |

**Table D.11:** vRES scenario analysis 2050

| **vRES** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Cycles gas fields | Curtailment [GWh] | Electrolyser PEM run hours | Green hydrogen production [GWh] |
|---|---|---|---|---|---|---|---|---|---|
| Base case NPE | 9.9 | 0 | 0 | 0 | 10.8 | 5 | 121082 | 6133 | 122208 |
| ETM | 9.9 | -239 | 5331 | 24 | 11.6 | 4.9 | 11835 | 6841 | 95715 |
| Delta [%] | 0 | 100 | 100 | 100 | 7 | -2 | -90 | 10 | -22 |

# E

# Results

## E.1. Outcomes scenario discovery

### E.1.1. Electrolysers

#### Electrolyser capacity

**Table E.1:** Electrolysis scenario analysis

| **Electrolysis** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Cycles gas fields | Electrolyser PEM run hours | Green hydrogen production [GWh] |
|---|---|---|---|---|---|---|---|---|
| 3 | 30 | -5179 | 115533 | 640 | 17 | 8 | 5546 | 15665 |
| 4.5 | 29 | -4787 | 106791 | 639 | 19 | 8 | 5457 | 22346 |
| Base case 6 | 28 | -4564 | 101829 | 605 | 21 | 8 | 5374 | 28219 |
| 7.5 | 27 | -4512 | 100663 | 543 | 24 | 7 | 5231 | 33513 |
| 9.5 | 26 | -4494 | 100251 | 540 | 34 | 7 | 5121 | 39779 |
| 15 | 24 | -4623 | 103143 | 546 | 53 | 7 | 4855 | 53238 |

#### Efficiency

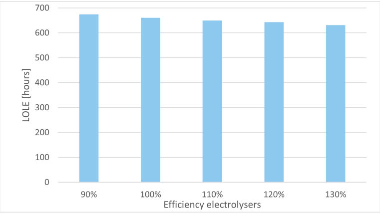

**Figure E.1:** Efficiency electrolysers with EENS

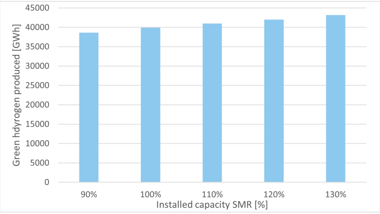

**Figure E.2:** Efficiency electrolysers with green hydrogen produced

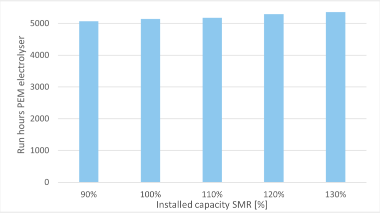

**Figure E.3:** Efficiency electrolysers with run hours PEM

**Table E.2:** Efficiency decrease and increase electrolysers

| **Efficiency decrease/ increase** | Efficiency alkaline | Efficiency PEM | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Electrolyser PEM run hours | Green hydrogen production [GWh] |
|---|---|---|---|---|---|---|---|---|---|
| 90% | 0.63 | 0.675 | 25.6 | -6098 | 136042 | 674 | 36.8 | 5066 | 38617 |
| 100% | 0.7 | 0.75 | 25.3 | -5953 | 132804 | 660 | 38 | 5137 | 39910 |
| 110% | 0.77 | 0.825 | 25.1 | -5828 | 130033 | 649 | 39.3 | 5176 | 40961 |
| 120% | 0.84 | 0.9 | 25.1 | -5724 | 127703 | 643 | 40.4 | 5294 | 41979 |
| 130% | 0.91 | 0.975 | 24.7 | -5629 | 125579 | 631 | 41.3 | 5358 | 43171 |

### Ratio alkaline and PEM

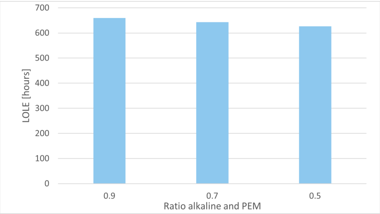

**Figure E.4:** Ratio Alkaline and PEM with EENS

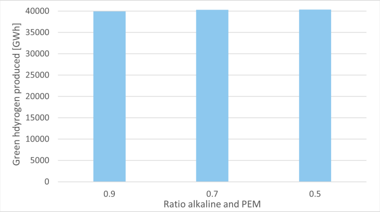

**Figure E.5:** Ratio Alkaline and PEM with produced green hydrogen

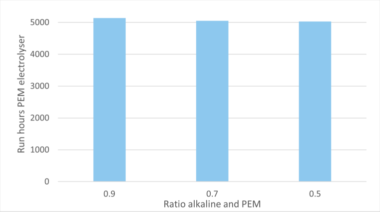

**Figure E.6:** Ratio Alkaline and PEM with run hours PEM

**Table E.3:** Ratio alkaline and PEM

| **Ratio alkaline/ PEM** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Electrolyser PEM run hours | Green hydrogen production [GWh] |
|---|---|---|---|---|---|---|---|
| 0.9 | 25.3 | -5953 | 132804 | 660 | 38 | 5137 | 39910 |
| 0.7 | 25.18 | -5759 | 128491 | 643 | 38.4 | 5055 | 40329 |
| 0.5 | 25.1 | -5606 | 125075 | 627 | 38.5 | 5029 | 40343 |

### Lower bound alkaline

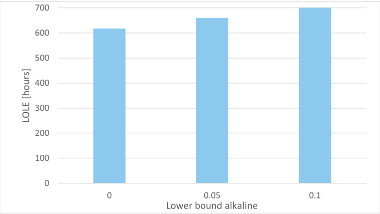

**Figure E.7:** Lower bound alkaline with EENS

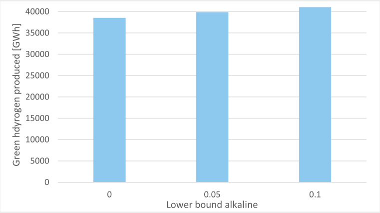

**Figure E.8:** Lower bound alkaline with green hydrogen produced

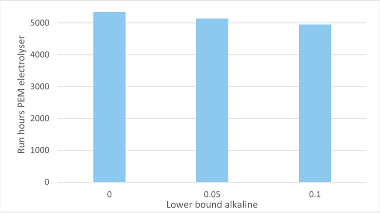

**Figure E.9:** Lower bound alkaline with run hours PEM

**Table E.4:** Lower bound alkaline

| **Lower bound alkaline** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Electrolyser PEM run hours | Green hydrogen production [GWh] |
|---|---|---|---|---|---|---|---|
| 0 | 25.2 | -5428 | 121098 | 618 | 37.8 | 5348 | 38527 |
| 0.05 | 25.3 | -5953 | 132804 | 660 | 38 | 5137 | 39910 |
| 0.1 | 25.5 | -6514 | 145320 | 713 | 38.5 | 4949 | 41333 |

### E.1.2. Underground hydrogen storage capacity

**Table E.5:** Salt cavern storage with 6 GW electrolysers

| **Salt caverns [#]** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEUR] | LOLE electricity [hours] | Cycles salt cavern |
|---|---|---|---|---|---|
| 1 | 27.5 | -554 | 123737 | 605 | 21.9 |
| 2 | 27.9 | -4078 | 90995 | 441 | 26.4 |
| 3 | 27.9 | -3434 | 76619 | 356 | 9.1 |
| 4 | 27.9 | -3104 | 69254 | 313 | 6.9 |
| 5 | 27.9 | -2774 | 61890 | 280 | 5.6 |

**Table E.6:** Salt cavern storage with 9.5 GW electrolysers

| **Salt caverns [#]** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEUR] | LOLE electricity [hours] | Cycles salt cavern |
|---|---|---|---|---|---|
| 5 | 25.5 | -5459 | 121803 | 583 | 31.3 |
| 10 | 26 | -3663 | 81716 | 379 | 17.4 |
| 15 | 26 | -2721 | 60716 | 282 | 12.3 |
| 20 | 26 | -2212 | 49349 | 225 | 9.5 |
| 25 | 26 | -1889 | 41985 | 197 | 7.7 |

**Table E.7:** Gas fields with 6 GW electrolysers

| **PGI gas fields [#]** | Volume gas fields [GWh] | Carbon emissions [Mton] | EENS [GWh] | System costs [MEUR] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles gas fields |
|---|---|---|---|---|---|---|---|---|
| 1 | 1384 | 26.2 | -8904 | 198629 | 1314 | 0 | 4 | 9.4 |
| 2 | 2768 | 27.2 | -6985 | 155680 | 1062 | 23 | 26 | 7.9 |
| 3 | 4152 | 27.7 | -5603 | 124601 | 928 | 68 | 54 | 6.6 |
| 4 | 5536 | 27.78 | -5568 | 123856 | 903 | 63 | 48 | 4.9 |
| 5 | 6920 | 27.88 | -4209 | 93234 | 770 | 130 | 87 | 5 |
| 6 | 8304 | 28.54 | -4009 | 88961 | 748 | 82 | 60 | 4.1 |

**Table E.8:** Gas fields with 9.5 GW electrolysers

| **PGI gas fields [#]** | Volume gas fields [GWh] | Carbon emissions [Mton] | EENS [GWh] | System costs [MEUR] | LOLE electricity [hours] | LOLE green hydrogen [hours] | LOLE hydrogen [hours] | Cycles gas fields |
|---|---|---|---|---|---|---|---|---|
| 1 | 1384 | 24.5 | -9160 | 204337 | 1342 | 0 | 4 | 10.6 |
| 2 | 2768 | 25.18 | -7205 | 160596 | 1100 | 21 | 26 | 9.26 |
| 3 | 4152 | 25.8 | -6185 | 137610 | 1004 | 76 | 46 | 7.1 |
| 4 | 5536 | 26.5 | -4767 | 105921 | 830 | 89 | 57 | 6.47 |
| 5 | 6920 | 26.6 | -4175 | 92602 | 757 | 140 | 65 | 5.3 |
| 6 | 8304 | 26.7 | -3876 | 85692 | 742 | 187 | 91 | 4.5 |

### Combination of storage facilities 2035

**Table E.9:** Storage combinations 2035

| **Storage 2035** | Filling degree | Volume salt caverns [TWh] | Volume gas fields [TWh] | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Cycles gas fields | Total stored hydrogen [GWh] |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 54 | 4 | 18 | 23.6 | -1192 | 26591 | 162 | 15.2 | 2 | 79828 |
| 2 | 54 | 2 | 18 | 26.1 | -1863 | 41561 | 264 | 8.49 | 3.1 | 51281 |
| 3 | 70 | 2 | 18 | 26.2 | -625 | 13936 | 81 | 6.5 | 7.3 | 46793 |
| 4 | 80 | 2 | 18 | 26.2 | -677 | 15095 | 88 | 6.5 | 7.1 | 49371 |
| 5 | 90 | 2 | 18 | 26.2 | -320.5 | 7151 | 41 | 6.6 | 7.5 | 49030 |
| 6 | 100 | 2 | 18 | 26 | 0 | 0 | 0 | 6.9 | 7.4 | 50554 |

### Combinations of storage facilities 2050

**Table E.10:** Storage combinations 2050

| **Storage 2050** | Volume salt caverns [TWh] | Volume gas fields [TWh] | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Cycles gas fields | Total stored hydrogen [GWh] |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 1.75 | 5.5 | 9.9 | -26 | 582 | 2 | 17 | 0.6 | 33154 |
| 2 | 1.75 | 4 | 9.9 | -26 | 582 | 2 | 17 | 0.8 | 33307 |
| 3 | 2 | 5.5 | 9.9 | 0 | 0 | 0 | 17.8 | 0.6 | 34399 |
| 4 | 2.5 | 5.5 | 9.9 | 0 | 0 | 0 | 13.7 | 0.6 | 37321 |

## E.1.3. Injection and production capacity

**Table E.11:** Number of wells salt caverns

| **Injection wells** | **Production wells** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns |
|---|---|---|---|---|---|---|
| 2 | 2 | 25.2 | -6269 | 139868 | 860 | 36.8 |
| 4 | 7 | 25.3 | -6026 | 134435 | 664 | 37.8 |
| 6 | 9 | 25.3 | -6026 | 134435 | 652 | 37.8 |
| 6 | 13 | 25.3 | -6026 | 134435 | 665 | 37.8 |

**Table E.12:** Number of wells gas fields

| **Injection and production wells** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Cycles gas fields |
|---|---|---|---|---|---|---|
| 6 | 25.83 | -4844 | 108079 | 556 | 35.3 | 4.6 |
| 9 | 25.9 | -4547 | 101452 | 558 | 34 | 6.1 |
| 12 | 25.97 | -4447 | 99220 | 531 | 33 | 7 |
| 15 | 25.99 | -4372 | 97539 | 536 | 32 | 7.5 |
| 20 | 25.99 | -4271 | 95289 | 521 | 31.9 | 8.1 |
| 25 | 26 | -4258 | 94987 | 530 | 31.7 | 8.3 |

### E.1.4. Batteries

**Table E.13:** Batteries

| **Batteries** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Cycles batteries | Volume battery storage [GWh] |
|---|---|---|---|---|---|---|---|
| 1 | 25.3 | -6026 | 134435 | 652 | 37.8 | 471 | 74 |
| 2 | 23.57 | -5126 | 114355 | 527 | 32.4 | 376 | 144 |
| 3 | 22.5 | -4670 | 104187 | 451 | 27.3 | 320.6 | 215 |

### E.1.5. Gas power plant

**Table E.14:** Gas turbines

| **Gas CCGT capacity** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt cavern | Gas CCGT at full capacity [hours] |
|---|---|---|---|---|---|---|
| 0 | 25.3 | -6026 | 134435 | 652 | 37.8 | 0 |
| 1.5 | 26.3 | -4080 | 91026 | 469 | 37.2 | 3271 |
| 3 | 26.9 | -2618 | 58424 | 352 | 34.9 | 2862 |
| 6 | 28.3 | -276 | 6164 | 51 | 32.6 | 2157 |
| 9 | 28.5 | -21 | 471 | 4 | 27.4 | 1331 |
| 12 | 28.6 | 0 | 0 | 0 | 27.3 | 880 |

### E.1.6. Steam methane reformer installed capacity

**Table E.15:** SMR performance metrics

| **SMR** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Full capacity run hours SMR | Full capacity run hours SMR with CCS | Produced green and blue hydrogen |
|---|---|---|---|---|---|---|---|---|
| 50% | 24.8 | -9843 | 219588 | 1078 | 35.2 | 7036 | 8761 | 33.9 |
| 100% | 25.3 | -6026 | 134435 | 652 | 37.8 | 1004 | 8761 | 45.3 |
| 150% | 23.4 | -5868 | 130915 | 633 | 43.4 | 129 | 8761 | 49.7 |

### E.1.7. Demand

**Table E.16:** Demand increase and decrease

| **Demand** | Carbon emissions [Mton] | EENS [GWh] | System costs [MEURO] | LOLE electricity [hours] | Cycles salt caverns | Total demand [TWh] |
|---|---|---|---|---|---|---|
| 80% | 16.6 | -1832 | 40887 | 275 | 35.8 | 263.8 |
| 100% | 25.3 | -6026 | 134435 | 652 | 37.8 | 329.9 |
| 120% | 34.0 | -14355 | 320256 | 1315 | 41.8 | 396.0 |

# F

# Investments

## F.1. Investment costs 2035

**Table F.1:** Investment costs 2035

| Input | Data | Unit | Reference |
|---|---|---|---|
| Volume required for gas field storage | 5.5 | TWh per year | |
| Volume required for salt cavern storage | 4.5 | TWh per year | |
| Investment costs for salt cavern storage | 0.25 | MEUR/GWh | [99] |
| Investment costs for gas field storage | 0.195 | MEUR/GWh | [99] |
| Total costs for salt caverns | 1,125,000 | euro | |
| Total costs for gas fields | 1,072,500 | euro | |
| Total costs for storage | 2,197,500 | euro | |
| Amount of electrolysers | 9.5 | GWe | |
| Cost of electrolysers | 2,630 | MEUR/GWe | [23] |
| Investment costs for electrolysers | 24,985 | MEUR | |
| **Total Investment Costs** | 2,222,485 | MEUR | |

## F.2. Investment costs 2050

**Table F.2:** Investment costs 2050

| Input | Data | Unit | Reference |
|---|---|---|---|
| Volume required for gas field storage | 4 | TWh per year | |
| Volume required for salt cavern storage | 1.75 | TWh per year | |
| Investment costs for salt cavern storage | 0.25 | MEUR/GWh | [99] |
| Investment costs for gas field storage | 0.195 | MEUR/GWh | [99] |
| Total costs for salt caverns | 437,500 | euro | |
| Total costs for gas fields | 780,000 | euro | |
| Total storage costs | 1,217,500 | euro | |
| Number of electrolysers | 20 | GWe | |
| Cost of electrolysers | 2,630 | MEUR/GWe | [23] |
| Investment cost of electrolysers | 52,600 | MEUR | |
| **Total Investment Costs** | 1,270,100 | MEUR | |

TU Delft

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