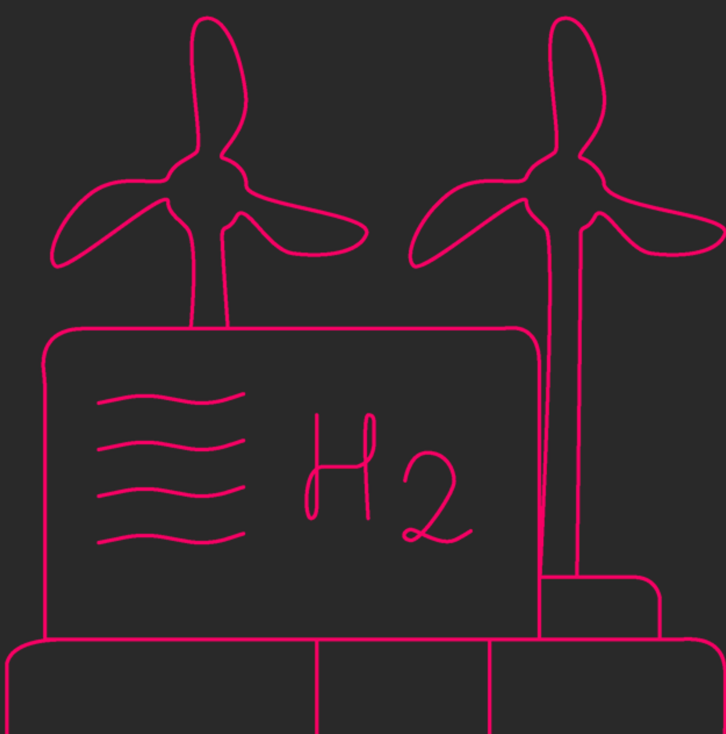
The technical and economic potential of underground hydrogen storage configurations in the Netherlands

A modelling approach



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The technical and economic potential of underground hydrogen storage configurations in the Netherlands: a modelling approach

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by

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Acknowledgement

Dear reader,

Before you lies my thesis on underground hydrogen storage, on which I have worked for the past six months. From the moment my father started taking me to wind turbines when I was a child, standing beneath them as the enormous blades swept past one by one, I've been fascinated by wind energy. Without hesitation, I chose the Energy and Industry domain for my Bachelor's program and the Offshore Wind Energy minor program. Now, as renewable electricity begins to dominate the electricity market, we are faced with an important challenge: the intermittent nature of renewable energy sources. I am incredibly grateful that in the final phase of my studies, I have now had the opportunity to immerse myself in underground hydrogen storage, which will become of utmost importance in the coming years.

I would like to express my deepest gratitude to my graduation committee. Kenneth, thank you for your direct communication during my research. Pieter, you have amazed me with your endless enthusiasm about many topics. You have been a great motivation for me throughout the whole process, and I have enjoyed our "short meetings" where I walked out of your office almost three hours later, full of new ideas. Last but not least, Edgar: I am incredibly grateful that you were my supervisor from Essent in the past six months because you never doubted me for a second and encouraged me to continue my work every week. Thanks to you, I have experienced my time at Essent as incredibly enjoyable. A final thank you goes out to all my friends who supported me during my research, especially my roommates, who were a great support during the process.

Lastly, all that remains for me is to wish the reader a lot of reading pleasure.

M.C. Esmeijer
March 14, 2024

Executive summary

The energy transition is taking an increasingly dominant role on the policy agenda due to mounting pressure from society. Hydrogen is seen as one of the key energy carriers that will play a role in the future energy system. On the one hand, hydrogen can contribute to the decarbonisation of industry and transport, and possibly the built environment and agriculture, and on the other hand, hydrogen can be utilised for seasonal electricity storage. However, there is a high level of uncertainty associated with underground hydrogen storage (UHS) because both the technology and the hydrogen market are still in their infancy. Based on literature research, three knowledge gaps have been identified that will be addressed in this research. Firstly, due to the high level of uncertainty regarding the future electricity and hydrogen market, there is insufficient information available about the role that UHS will play in the future energy system. Secondly, there is a lack of insight into the imposed design requirements of storage facilities and their configurations in the future energy system. Lastly, there is a lack of consensus regarding the economic feasibility of storage facilities in the prospective energy system of the Netherlands. Therefore, on the one hand, the performance of storage configurations in terms of operational system costs in the electricity and hydrogen systems is determined, while on the other hand, the more commercial aspect is assessed, focusing on the average system costs and potential revenues of the storage configurations.

Firstly, exploratory research has been conducted on the most promising UHS formations in the Netherlands, considering their availability and their Technology Readiness Level. This analysis revealed that in the Netherlands, gas fields are often designated as the best geological formation for seasonal hydrogen storage, while salt caverns are seen as the most suitable geological formation for short-cyclic storage. The modelling approach was used to model the Dutch electricity and hydrogen systems in 2040. This was done using Linny-R, a graphical software tool specifically designed for the formulation of Mixed Integer Linear Programming problems. Linny-R was used to model four different energy systems: the decentral, national, European, and international energy systems. These mainly differ in the degree to which the Netherlands is self-sufficient in electricity and hydrogen supply, and to what extent hydrogen is adopted in subsystems. Given the various policy choices that can be made regarding seasonal hydrogen storage, the number of additional required salt caverns was determined by analysing the reduction in system operating costs. The robustness of this initial choice for the number of salt caverns was tested through a robustness analysis of the most critical parameters. The robustness analysis was conducted using the Minimax regret principle, which aims to minimise the maximum regret associated with a certain decision, where regret refers to the difference between the actual outcome of a certain decision compared to the best possible outcome of another choice.

From the results of the robustness analysis, it emerged that under varying environmental variables, the initial choice for the number of salt caverns was not robust in almost all experiments. The minimum maximum regret was consistently attributed to a higher number of salt caverns than initially determined. The maximum regret associated with choosing a smaller number of salt caverns was consistently linked to a scenario with a high installed capacity of hydrogen turbines, indicating that this variable has a significant impact on operational system costs, which is an important insight for policymakers. What also emerged from the robustness analysis was that in an energy system already dominated by green and blue hydrogen and green electricity, the inclusion of additional salt caverns does not lead to further CO_2 reduction. In fact, a slight increase in CO_2 emissions could be observed. This is an important insight for policymakers as well, as hydrogen is seen as a key energy carrier on the path to a CO_2-neutral energy system.

When evaluating the performance of different storage configurations in terms of operational system costs, it became clear that in the national energy system, the storage configuration with the mid-seasonal storage policy performs the best, while in the decentral, European and international energy systems, configurations with a low-seasonal storage policy performed the best. In the national energy system, the installed capacity of renewable electricity generation units is the largest among all scenarios, resulting in a higher seasonal storage requirement.

In addition to determining which storage configurations result in the lowest operational system costs, the financial feasibility of the storage facilities has also been assessed based on the average system costs and the potential revenues. For the average system costs of salt caverns, a general trend has been observed: the system costs per kg of hydrogen increase in energy systems where higher hydrogen imports are possible. A larger hydrogen interconnection diminishes the importance of storage facilities, leading to lower injection and withdrawal from storage, thereby spreading the annual fixed operation and maintenance costs and capital costs over a smaller quantity of hydrogen. Table 1 summarises the values found for the different energy systems. The results further indicated that the variable operational system costs play a significant role in the total costs.

Table 1: Average system costs mid-cost scenario in €/kg.

	Salt cavern		Gas field	
Energy system	Lower bound	Upper bound	Lower bound	Upper bound
Decentral	0.30	0.50	0.75	1.85
National	0.28	0.44	0.70	1.80
European	0.35	1.30	0.75	2.00
International	0.80	5.80	0.75	2.00

Finally, the potential profit that Essent can possibly achieve in 2040 was analysed based on the national energy system as this energy system was deemed the most plausible since the input parameters align best with published Dutch electricity and hydrogen roadmaps. Non-plausible scenarios were filtered out from the data, and a best and worst-case scenario for Essent, as well as a best-case for the government, were determined. It became clear that storage facilities incur significantly higher losses in the government's best-case scenario compared to Essent's best-case scenario, whereas the government's best-case scenario is indeed a plausible future energy system because the societal costs are the lowest in this case. However, underinvestment in UHS in the future energy system would lead to increased operational system costs, which is undesirable, indicating that the government will need to provide subsidies to stimulate investments in UHS facilities because these facilities have proven to be unprofitable in energy systems where there is little to no scarcity in the electricity market. In the government's best-case scenario, Essent will need 0.26 €/kg in subsidies to recover their investment, amounting to 269 M€ of annual subsidy for hydrogen storage in salt caverns in the Netherlands. Compared to the 461 M€/year that would otherwise be paid by households and businesses due to the increased average electricity price in Essent's best-case scenario, the scenario leading to the lowest operational system costs appears to be the best choice from a government perspective. Given that the development and construction of salt caverns can take up to 8 years from the permit application stage, subsidy policies concerning UHS must be prioritised on the policy agenda to reduce investment risks for stakeholders. Failure to do so may lead to underinvestment, resulting in undesirable costs and effects in the future Dutch electricity and hydrogen systems.

Finally, the key future research topics have been identified. Firstly, investigating the performance of additional storage configurations in terms of the operating system costs of the entire system is crucial to gaining a comprehensive understanding of the most desirable storage configuration. Specifically, it would be interesting to explore systems where no seasonal storage occurs, as well as systems where salt caverns are utilised for seasonal storage instead of gas fields since the technical feasibility of hydrogen storage in gas fields has not been proven yet. This leads us to the next area of future research that is required, namely the investigation of the technical feasibility of hydrogen storage in gas fields. Pilots must be started promptly so that the Technology Readiness Level of hydrogen storage in gas fields can increase rapidly, and these storage facilities can become operational well before 2040. Furthermore, decisions regarding the strategic placement of UHS facilities require mapping the locations of consumers and major producers. Further research should also include the capital costs of not only the storage facilities but also the capital costs of all other installed capacities in the system. Finally, since this research has revealed that the installed capacity of hydrogen turbines is a key variable for both the operational system costs of the overall system and the economic feasibility of the UHS facilities, there is a need for investigation into the prudent installed capacity of hydrogen turbines under uncertain conditions.

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Abbreviations

CAES	Compressed Air Energy Storage
CapEx	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CGV	Cushion Gas Volume
FEED	Front-end Engineering Design
GF	Gas Field
GW	Gigawatts
HCP	Highest Cost Price
KPI	Key Performance Indicators
LCOH	Levelised Costs of Hydrogen
MILP	Mixed Integer Linear Programming
MMR	MiniMax Regret
MW	Megawatts
OM	Operation and Maintenance
OpEx	Operational Expenditures
PEM	Proton Exchange Membrane
RFD	Research Flow Diagram
SC	Salt Cavern
SMR	Steam Methane Reforming
Solar PV	Solar Photovoltaic
TRL	Technology Readiness Level
UC	Unit Commitment
UGS	Underground Gas Storage
UHS	Underground Hydrogen Storage
vRES	variable Renewable Energy Sources
WACC	Weighted Average Cost of Capital
WGV	Working Gas Volume

1 Introduction

In 2013, the Urgenda Foundation initiated the Climate Case on behalf of 886 Dutch citizens, filing a lawsuit against the Government of the Netherlands. The lawsuit alleged that the government had failed to implement adequate measures to reduce greenhouse gas emissions, which contribute to climate change and therefore its related hazards [1]. After a prolonged legal process spanning six years, the Supreme Court of the Netherlands, on December 20, 2019, upheld the decisions of both the District Court of The Hague on June 24, 2015, and the Court of Appeal on October 9, 2018. The rulings confirmed the directive that the Netherlands had to reduce its CO_2 emissions by a minimum of 25% before 2020 compared to the 1990 levels [1]. The court emphasised the need for the Dutch government to promptly implement effective measures to address climate change.

The above emphasizes the growing societal pressure to pursue sustainability. The impacts of climate change have become discernible in many parts of the world, manifested in phenomena such as increasing occurrences of floods and wildfires. Partly due to the heightened frequency of these events, the imperative to achieve carbon neutrality has risen on global agendas. This trend is reflected in the ambitious initiatives undertaken by countries like the Netherlands, which is actively advancing plans to transition towards a carbon-neutral society [2]. The Netherlands aims to achieve CO_2-neutrality in the electricity sector by 2035 [3]. As a result, the Dutch government attempted to achieve a rapid growth of solar photovoltaic (solar PV) in the Netherlands, which resulted in a rise from 3.5 gigawatts (GW) to 14.4 GW [4]. Not only solar PV has become an increasingly important source of electricity production, but the installed offshore wind power will also grow to 21 GW by 2030 [5]. The challenge that arises in this context is the intermittent nature of solar and wind energy, in contrast to the controllable operation of traditional fossil power plants. In the absence of intervention, future discrepancies between electricity demand and supply are anticipated to occur.

Over the years, the Dutch government's interest in green hydrogen has grown tremendously, since it has shown its ability to contribute to the sustainability of the industry and the mobility sector [6]. This triggered the pace of development of electrolysis projects in the Netherlands, where 7 big projects have now received government funding for realisation [7]. Although hydrogen's current application is predominantly in the industry in the Netherlands, hydrogen can also serve as a solution to the intermittent nature of the growing installed renewable power sources. Green hydrogen could therefore serve, on the one hand, as a fuel for decarbonising the industry and mobility sector and, on the other hand, as a flexibility option in an energy system dominated by renewable sources.

Given the advantageous geographical position of the Netherlands, particularly with respect to the North Sea with its operational and planned offshore wind farms, as well as its favourable location of the port of Rotterdam for the import of hydrogen and hydrogen-carrying fuels, there is a notable prospect for hydrogen to assume a significant role in the prospective Dutch energy system. To provide a continuous supply of hydrogen to the industry and address the intermittent nature of solar and wind energy, hydrogen storage will become essential. The literature so far mainly indicates that underground hydrogen storage (UHS) is most promising for the large quantities of hydrogen expected in the future [8]. From the investigated 2030 energy scenarios, a required storage capacity of 42 to 475 GWh follows for the Netherlands [9]. However, the role of hydrogen storage becomes increasingly important in the period between 2030 and 2050. Estimates of the storage capacity needed vary widely, but if hydrogen is chosen as the preferred large-scale flexibility option, 15-26 TWh of storage capacity may be needed by 2050 [9]. However, these quantities strongly depend on the extent to which hydrogen will be used in various sectors in the future and the development of installed renewable electricity capacity.

1.1 Background information

1.1.1 Hydrogen production methods

The literature identifies various hydrogen production pathways, often categorised by distinct colours. The literature encompasses a total of twelve categories [10], but the three most prevalent colours are grey, blue, and green hydrogen. The production of grey hydrogen primarily involves Steam Methane Reforming (SMR) of natural gas, representing the most common method. SMR is a method wherein methane extracted from natural gas undergoes heating, typically with steam and a catalyst, to generate a blend of carbon monoxide and hydrogen according to the following equation:

$$\mathrm{CH_{4\,(g)}} + \mathrm{H_2O_{(g)}} \longrightarrow \mathrm{CO_{(g)}} + 3\,\mathrm{H_{2\,(g)}} \tag{1}$$

This process results in the release of carbon dioxide into the Earth's atmosphere. When this greenhouse gas is captured and stored underground to mitigate further global warming, the resulting product is referred to as blue hydrogen. Conversely, green hydrogen is produced through electrolysis with renewable electricity, where water molecules are split into hydrogen and oxygen. This process is also referred to as Power-to-Gas, in which hydrogen is the energy carrier. This process is represented by the following equation:

$$2\,\mathrm{H_2O_{(l)}} \longrightarrow 2\,\mathrm{H_{2\,(g)}} + \mathrm{O_{2\,(g)}} \tag{2}$$

Finally, there is another green hydrogen production method gaining increasing attention due to the growing role of hydrogen in the energy system, namely the cracking of ammonia. In this chain, hydrogen is produced at a location in the world where abundant renewable electricity is available, after which it is synthesized with nitrogen based on the *Haber-Bosch process*. This results in the formation of ammonia according to the following reaction equation.

$$\mathrm{N_2(g) + 3H_2(g) \rightarrow 2NH_3(g)} \tag{3}$$

Ammonia can be transported as a liquid under normal conditions, unlike hydrogen. This makes it easier to transport the ammonia to other locations in the world where renewable electricity is more expensive. On-site, the ammonia would then need to be cracked to release the hydrogen. That process is as follows:

$$\mathrm{2NH_3(g) \rightarrow N_2(g) + 3H_2(g)} \tag{4}$$

The downside of ammonia is related to the associated safety challenges.

Although the SMR process and ammonia cracking are more or less controllable processes, assuming that sufficient ammonia can be imported at all times, the need for hydrogen storage is mainly caused by the electrolysis process. During periods of abundant renewable electricity, green hydrogen can be produced. However, the demand may not be aligned with this supply, necessitating hydrogen storage. The expectation is that the hydrogen market will grow in the coming years, and the demand will increasingly be decoupled from the supply, emphasising the need for UHS [11].

1.1.2 Storage function, time- and size-scale

Energy storage can serve multiple purposes, such as balancing supply and demand, reducing net congestion, and providing strategic reserves. The suitability of energy storage techniques for these purposes varies depending on their specific characteristics. Figure 1 shows the function of various techniques along with their respective time and size scales.

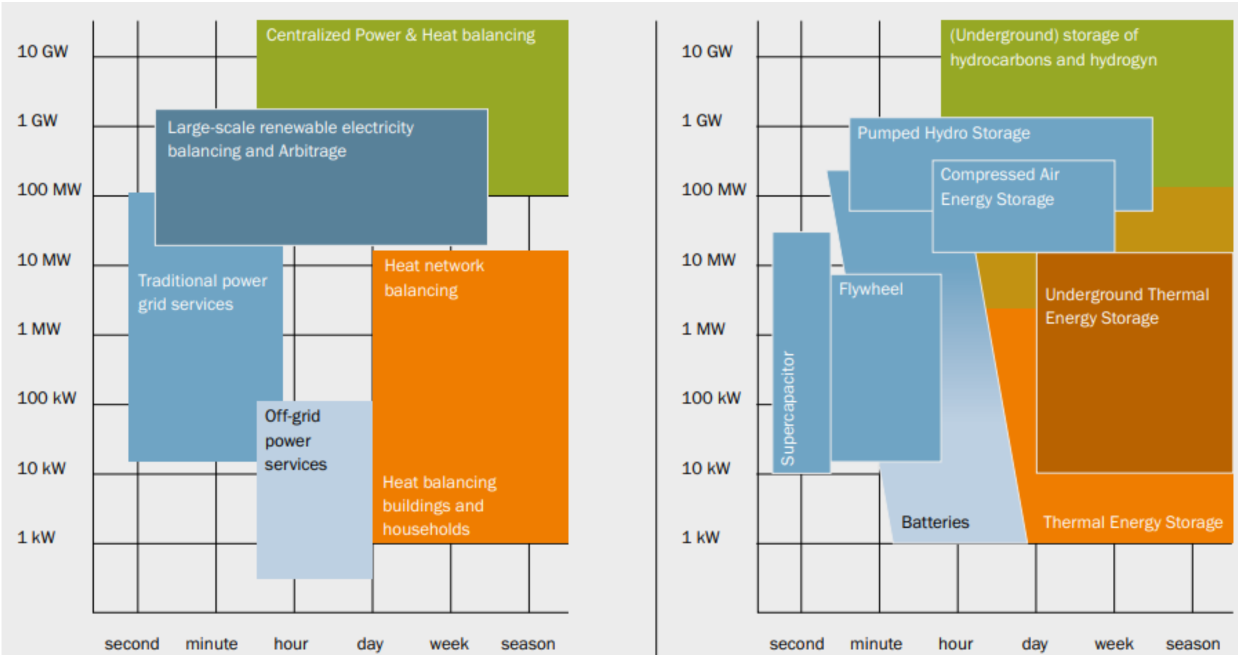


Figure 1: Functions of various storage techniques along with their respective time and size scales. Blue: electricity storage, green: molecule storage, orange: heat storage [12].

In the diagrams presented in Figure 1, electricity storage is predominantly positioned on the left side, indicating a short storage time. Currently, Li-ion batteries are identified as the most promising option for addressing short-term electricity fluctuations ($<$ day) [13]. Molecular storage, exemplified by hydrogen storage, is situated in the upper right corner, signifying a high-capacity storage technique suitable for longer storage duration. Since the overall efficiency of the power-to-gas-to-power process for green hydrogen is only 40% [14], hydrogen storage is generally not preferred for mitigating short-term electricity shortages by converting hydrogen back into electricity. However, it is noteworthy that gas storage is well-suited for effectively managing seasonal fluctuations throughout the year, successfully proven by the seasonal natural gas storage facilities in Norg, Alkmaar, Grijpskerk and Bergermeer. Molecular storage also presents a viable option for strategic reserves.

1.1.3 UHS in geological formations

There are several ways to store hydrogen underground. Besides cryogenic hydrogen tanks and high-pressure hydrogen tanks, underground geological structures can also be used for hydrogen storage. The availability of these storage facilities therefore varies greatly from country to country due to the difference in soil characteristics. In general, the following geological formations are under consideration as possible geological formations to store hydrogen:

Aquifers Aquifers are porous and permeable rock formations in which fresh or saline water at greater depths occupies the pore space [15]. Demonstrating the existence of a reliable and airtight seal for hydrogen typically requires geological surveys, exploratory drilling, and injection tests.

Salt caverns Cylindrical hollow voids within a subsurface rock salt formation, formed through the process of salt solution mining [15]. Rock salt has been demonstrated to be an effective seal for natural gas, hydrogen, and a variety of other gases, including nitrogen and helium.

Depleted oil reservoirs An oil field is created when oil enters a porous rock with a sealing layer above it [15]. The seal of oil fields is typically maintained by impermeable rock layers, such as shale or salt, which could prevent the upward migration of hydrogen. The suitability of these seals for hydrogen gas is currently under evaluation and testing.

Depleted gas reservoirs An underground gas storage facility is a man-made collection of gas at an approximate depth of 3 kilometres [16]. Impermeable cap rocks, such as mudstones and rock salt, are commonly used to seal gas fields. They have been shown to effectively seal natural gas. The suitability of these seals for hydrogen gas is currently under evaluation and testing.

Lined (hard) rock caverns Artificial tunnels and underground cavities constructed within rock formations with low permeability. Gas storage is accomplished by lining the walls of the cavern with a gas-impermeable material [17].

Figure 2 shows an overview of the depth and common capacities of the different geological formations that can potentially be used for hydrogen storage.

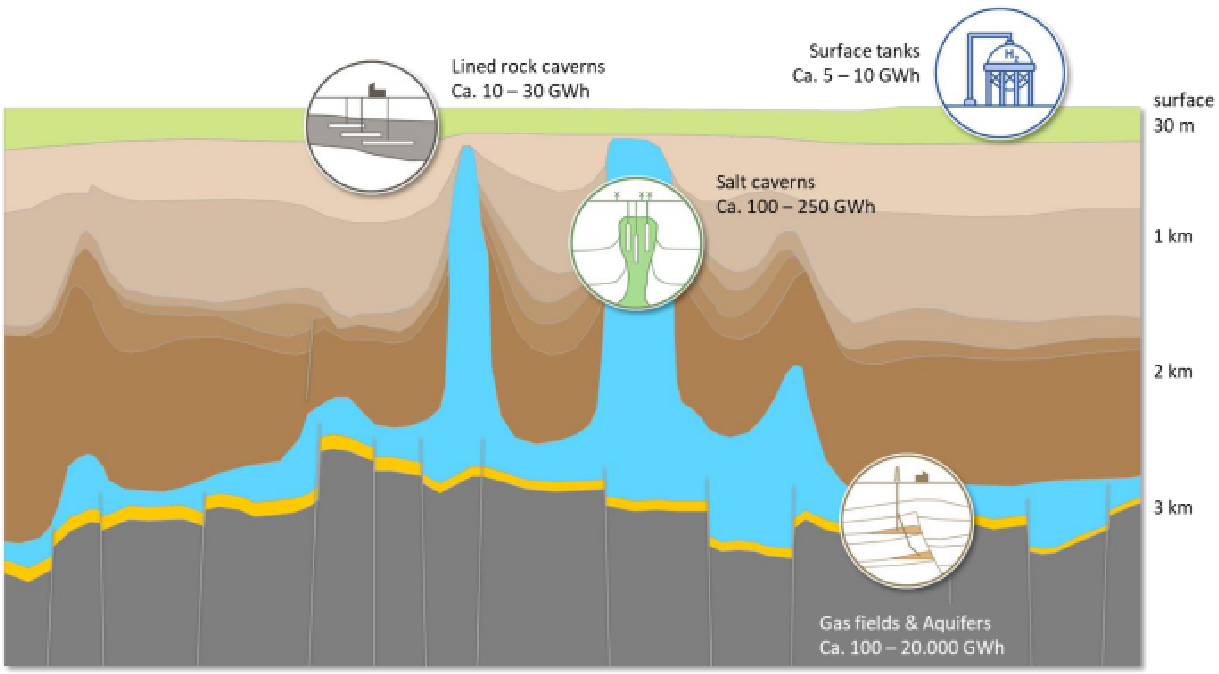


Figure 2: Depth of geological formations in the subsurface [17].

1.1.4 Working Gas Volume and Cushion Gas Volume

Within the underground hydrogen storage context, reference is made to the Working Gas Volume (WGV) and the Cushion Gas Volume (CGV). The WGV refers to the amount of gas in a storage facility that can be withdrawn from and injected into the storage. However, when discussing the total gas volume, this includes the CGV as well. Cushion Gas is injected at the beginning of the lifetime of a storage facility and remains in the storage throughout its operational lifespan at least. The cushion gas is used to maintain minimal pressure in the storage facility that is required to meet the production requirements. The presence of cushion gas is therefore crucial for the reliable functioning of the storage system.

The optimal ratio of cushion gas to working gas is closely tied to geological factors such as reservoir depth, the shape of the trap, and the permeability of the reservoir [18]. In this study, assumptions have been made about the WGV:CGV ratios, as there is no detailed examination of the geological factors of the storage facilities in this research.

1.2 Literature review

1.2.1 Literature review methodology

Table 2: Search strings.

Energy carrier	Hydrogen production	Storage	Context
Hydrogen	Green hydrogen	UHS	The Netherlands
	Blue hydrogen	Storage cycle	Hydrogen market
		Long-term storage	Hydrogen backbone
		Short-term storage	

To search and select literature on the current state of hydrogen production, the hydrogen market and UHS, a multi-step approach was adopted. At first, an extensive search of the Scholar database was conducted to explore available literature on the broader topic of hydrogen production and storage. Subsequently, a more focused and comprehensive search was performed to investigate existing studies on the Dutch hydrogen storage requirements. Therefore, the search strings that were used to come to the selected articles for this research have been provided in Table 2. These search strings were translated to Dutch to select Dutch reports. For articles that deal with the technical characteristics of the processes, no date limit has been set. However, for articles about the development of the hydrogen market, only articles published from 2018 and onwards were considered to remain relevant, given the rapidly evolving nature of hydrogen markets over the past few years. Table 2 provides an overview of the search strings employed to arrive at the selected 10 articles.

1.2.2 Selected literature

Table 3: Overview of the selected reports and literature.

Author	Year	Title	Reference
TNO	2018	Underground storage in the Netherlands	[19]
Staatstoezicht op de Mijnen	2018	Future visions of energy transition	[20]
Groenenberg et al.	2020	Large-scale energy storage in salt caverns and depleted gas fields	[12]
Den Ouden et al.	2020	Climate neutral energy scenarios 2050	[21]
Malachowska et al.	2022	Hydrogen Storage in Geological Formations: The Potential of Salt Caverns	[8]
Djizanne et al.	2022	Blowout Prediction on a Salt Cavern Selected for a Hydrogen Storage Pilot	[22]
NAM	2022	Underground hydrogen storage in gas fields	[11]
Schrotenboer et al.	2022	A Green Hydrogen Energy System: Optimal control strategies for integrated hydrogen storage and power generation with wind energy	[23]
Akarsu & Serdar Genc	2022	Optimization of electricity and hydrogen production with hybrid renewable energy systems	[24]

1.2.3 Discussion of the literature

The development of underground hydrogen storage is only feasible if there is a significant demand for hydrogen storage. Hydrogen has the potential to be used in industry, transport, and possibly in the built environment and agriculture. Currently, varying expectations regarding hydrogen usage lead to substantial variations in the predicted hydrogen storage capacities that may be needed in the future.

In recent years, numerous studies have been conducted on underground hydrogen storage in the Netherlands: TNO & EBN - Underground Storage (2018) [19], SodM Future Scenarios (2018) [20], TNO Large Scale Energy Storage (2020) [12], and the most recent one by Berenschot & Kalavasta (2020) [21].

The SodM Future Scenarios study introduces a national approach to the energy transition in one of its scenarios, incorporating a nationwide hydrogen network and associated hydrogen storage. According to this scenario, a storage capacity of 28 TWh would be required by the end of 2050. Less hydrogen storage is necessary in other scenarios where energy solutions are more locally oriented [20].

In the study of TNO & EBN, it is assumed that hydrogen is exclusively applied in the industry and as a backup for power plants, while green gas is utilised for smaller users [19]. They differentiated between winters of normal, severe, and extreme cold, resulting in a variation in the estimated storage needs for 2050 ranging from 4-23 TWh.

The most recent research on hydrogen storage needs in the Netherlands was conducted by Berenschot and Kalavasta. According to this study, the hydrogen storage requirement could reach 57 TWh in 2050, representing the highest estimate among all studies [21].

From the above studies, it becomes evident that the estimation of the required amount of underground hydrogen storage varies greatly among different studies. The estimation is highly dependent on the Dutch energy system and heavily influenced by the assumptions made in the studies regarding hydrogen production, electricity supply, weather patterns, energy policies, and the development of the hydrogen market. While the mentioned studies predominantly focus on the required amount of energy that needs to be stored in the form of hydrogen, the injection and production capacity are of equal importance. None of the studies provides insight into how the storage facilities ought to be sized. Additionally, information on future combinations of storage facilities, also referred to as storage configuration, is lacking. Underground hydrogen storage can potentially be carried out in different geological formations, each with specific characteristics that might be particularly suitable for a specific storage purpose. A combination of different storage facilities could be used to meet the requirements imposed by the Dutch energy system.

Only limited information on underground hydrogen storage performance can be derived from the literature since there are only three operational salt caverns: Teesside, Clemens, Moss Bluff, and Spindletop. They are all designed to secure a stable supply of feedstock to the chemical industry [8] [22] [12]. The annual demand profiles in this industry typically remain constant, in line with the continuous manufacturing processes within the chemical sector. The application of storage facilities in future energy systems, where there might be an extensive hydrogen network, could impose entirely different requirements on such facilities. Therefore, as the hydrogen market grows, gaining a better understanding of the required storage capacity and storage configuration becomes a prerequisite. Improved insight allows for better alignment of storage with the needs, contributing to a more effective and cost-efficient solution for society [11].

In addition to the varying outcomes regarding the required hydrogen storage capacity and the lack of insight into the design specifications that storage facilities must adhere to fit into the future Dutch energy system, there is also an ongoing debate about the economic feasibility of storing electricity in hydrogen. Schrotenboer et al. [23] assert that underground storage could be economically feasible provided that the price of hydrogen is higher than the expected electricity price, allowing for the compensation of conversion losses. They emphasize that the introduction of hydrogen storage units and competitive hydrogen market rates could lead to significant increases in operational revenues, up to 51% [23]. On the contrary, Akarsu and Genc [24] argue that underground hydrogen storage facilities will not become economically viable for electricity storage, considering the high costs of the power-to-gas-to-power cycle due to the low efficiencies associated with the electrolysis plant and fuel cells or hydrogen combustion turbines. The economic feasibility of underground hydrogen storage will heavily depend on the prices prevailing in the future electricity and hydrogen markets, necessitating careful consideration.

1.3 Knowledge gap and research questions

From the current state-of-the-art literature on underground hydrogen storage, it is evident that there are three existing knowledge gaps:

1. Insufficient information is available about the role that underground hydrogen storage will play in the future energy system.
2. Insight into the imposed design requirements of storage facilities and storage facility configurations in the future energy system is lacking.
3. There is a lack of consensus regarding the economic feasibility of storage facilities in the prospective energy system of the Netherlands.

Since the development of underground storage facilities takes a considerable amount of time, it is crucial to make decisions now regarding the required storage capacity and storage configurations needed in the future to provide flexibility to the electricity and hydrogen markets. To achieve this, insight into the possible future energy system is required, along with the uncertainties related to the hydrogen and electricity market. This will be done by modelling four different energy systems: the decentral, national, European and international energy systems. The geographical focus of this research is confined to the Netherlands, and the temporal scope encompasses the year 2040. In this context, the geographical scope does not mean that the Netherlands has a closed energy system, as all energy systems can import and export hydrogen and electricity. Rather, it refers to the consideration of only Dutch production and demand. This thesis aims to bridge the identified knowledge gaps and, consequently, seeks to address the primary research question, formulated as follows:

What is the technical and economic potential of different underground hydrogen storage configurations in the Netherlands in 2040, considering various future electricity and hydrogen systems?

The sub-questions that have to be answered to enable complete and structured research answering the main research question, are as follows:

1. Which types of underground hydrogen storage are most promising for the Netherlands, considering their availability and Technology Readiness Level?
2. How robust is the choice for the number of salt caverns in an energy system, in addition to different policies for seasonal hydrogen storage?
3. What storage configuration is most suitable to meet the required storage capacity in 2040 across various energy systems?
4. What are the average system costs in the different scenarios per kg of produced hydrogen?
5. What are the potential returns of the storage facilities in the various scenarios, and could it be profitable for Essent to invest in such storage?

The average system costs will be expressed per kilogram of produced hydrogen because this research is being conducted in collaboration with Essent, and they have expressed a desire to compare different hydrogen storage technologies. Additionally, they may also own production assets in the future and are interested in the costs per unit of hydrogen that a storage facility may add to their operations.

1.4 Relevance

1.4.1 Society

The importance of flexibility in the energy system has grown enormously in recent years and will become even more crucial in the future due to increasing reliance on vRES. However, there is still little insight into the integration of these flexibility options into the energy system because the technologies, or at least their large-scale integration, are still in their infancy. This research aims to provide more insight into the performance, expressed in operational system costs, CO_2 emissions, and electricity served with peak generators, of different storage configurations. The economic potential of storage facilities needs to be demonstrated because there is still much uncertainty about the future electricity and hydrogen markets, making the investment risk high. Therefore, investigating the economic feasibility is crucial because it would be highly undesirable if investment in flexibility options were to lag. This could result in power outages and it could lead to everyday processes being disrupted, thereby leading to undesirable societal effects and costs.

1.4.2 Scientific

Research into the integration of underground hydrogen storage facilities into the Dutch energy system holds significant scientific relevance in the pursuit of sustainable energy solutions. Understanding the feasibility and economic potential of these storage facilities is crucial for transitioning towards a low-carbon energy infrastructure. Studying the technical aspects of integrating these storage facilities into the existing energy grid provides valuable insights into grid stability, sustainable efficiency, and reliability.

Moreover, assessing the economic potential of underground hydrogen storage facilities is paramount for informed decision-making and investment strategies. By evaluating the costs associated with construction, operation, and maintenance alongside potential profits, researchers can provide stakeholders with vital information for assessing the viability of such projects.

1.4.3 MSc program

There are several reasons why this thesis aligns well with the contents and requirements of the Master Complex Systems Engineering and Management. Firstly, the topic is multidisciplinary by nature, containing technical, economic, and institutional aspects of hydrogen production, storage and possible re-electrification systems. The topic addresses hydrogen and electricity markets, the functioning of hydrogen as an energy carrier, electricity storage, and the technical and economic feasibility of different storage configurations, all within the geographical scope of the Netherlands. Additionally, the problem touches on values that originate from both the public and private domains. For instance, there is a need to balance the security of supply to ensure the provision of electricity to every individual in the Netherlands. Nonetheless, this must be accomplished in a sustainable and financially viable manner. This requires consideration of both societal and economic factors. Lastly, the electricity and hydrogen systems are highly interconnected with other critical systems in the Netherlands. Fluctuations in electricity and hydrogen prices may cause catastrophic effects in other sectors since other sector's services rely (partly) on electricity and/or hydrogen. This interdependency adds complexity to the issue at hand.

1.5 Thesis outline

In the following section, the Research Methodology will be explained. Following this, in Section 3, a comparison of geological formations potentially suitable for UHS in the Netherlands will be compared. The subsequent section is dedicated to elucidating the modelled system and the constructed model. In Section 5, the model will be verified and validated. Section 6 addresses the design of the various storage facilities, followed by Section 8 which outlines the experiment design and the method used for the robustness analysis. The results of these experiments are detailed in the Results, Section 9. Subsequently, the results of the most plausible energy system and scenarios have been discussed in Section 10. Finally, the report ends with the Conclusion, Discussion, and Reflection.

2

Research methodology

2.1 Research approach

To explore the possible performance of different storage configurations in the Netherlands in 2040, it is essential to examine two interconnected yet distinct subsystems: the electricity and hydrogen systems. Both of these systems are socio-technical by nature and are rapidly evolving, primarily driven by policy decisions that already have been made and will be made in the future to achieve the goals of the energy transition. Consequently, the selected research approach should be able to provide insight into the effects policy choices can have on the systems under consideration. Moreover, the development of these systems is accompanied by significant uncertainties. The chosen research approach should therefore incorporate functionalities to address these uncertainties. To meet these criteria, the modelling approach has been selected as the research approach due to several reasons explained in the next paragraph.

Models can provide a framework for addressing uncertainties associated with the evolution of the energy system. The uncertainty concerning the development of the electricity and hydrogen market stems from various factors, with policy choices being a crucial determinant. In the energy transition, uncertainties arise not only from policy choices but also from weather conditions and climate change, especially in an electricity system dominated by renewable sources. Dealing with these uncertainties is crucial for making informed decisions about the appropriate storage capacity and best-performing storage configuration in the future energy system. In the literature, it is emphasised how the modelling approach can be used as a pragmatic methodology for dealing with uncertainties [25]. Through modelling, a comprehensive range of parameters can be examined across diverse scenarios, aiding in the identification of key uncertainties within the system. The outcomes of the model can assist policymakers in formulating robust policy decisions [26]. Because the development of underground storage facilities can take up to 8 years, there is an urgency to currently visualise possible future energy and storage systems, allowing for well-founded policy decisions to be made.

2.2 Modelling cycle

For the modelling approach to be structured, a framework is used. The literature knows many ways of describing the modelling cycle, but in the course TB112 during the BSc Systems Engineering, Policy analysis and Management the following steps were distinguished [27]:

Questions This is the starting point of the modelling cycle. Researchers formulate specific questions that they want to answer or test using the model. The questions can help to define the scope of the model. To be able to generate such questions, the formulation of a problem definition is inevitable.

Conceptualisation This phase is about creating an abstract representation of the problem that the model will attempt to solve. This entails developing a conceptual model that outlines factors, key variables and relationships relevant to the research questions. In case a graphical model such as Linny-R is used, the conceptualisation can also be made in the modelling software.

Operationalisation The purpose of the operationalisation phase is to operationalise the concepts from the conceptual model. Based on the conceptual model that has been developed, the type of model is chosen. If this is a quantitative model, the concepts and relationships of the conceptual model need to be translated into variables and equations.

Implementation This phase involves collecting, gathering, or generating the necessary data and information based on the specified operationalised concepts. In this step, a computational model is created. Verification and validation play an important role in this phase of the modelling cycle.

Application Once the model is created, it can be applied to analyse the problem that is studied with the model. To gain insight into the model behaviour, different experimental designs need to be constructed.

Interpretation The last step of the process is interpreting the results obtained in the latter step. This information helps to answer the research questions, as formulated in the first step of the modelling cycle.

The modelling cycle is iterative, meaning that the process may loop back to earlier phases if necessary. This iterative nature allows for continuous improvement and refinement of the modelling process.

2.3 Modelling tool

The modelling tool that has been chosen for this research is Linny-R. This is a graphical language specifically designed for the formulation of Mixed Integer Linear Programming (MILP) problems, particularly for Unit Commitment (UC) problems [28]. Linny-R has been chosen for the following reasons:

1. Linny-R can optimally dispatch or operate energy systems.
2. MILP enables the inclusion of variables that vary from time step to time step [29]. This proves to be advantageous for this specific research, as the most cost-optimal dispatch of both electricity and hydrogen is determined anew every hour.
3. Various studies on the integration of storage facilities have been successfully conducted by formulating and integrating the problem into a unit commitment problem, and solving the problem with the MILP method [30] [31].
4. Linny-R provides the capability to work with scenarios, which is a stringent requirement in this research due to the high degree of uncertainty.
5. Linny-R offers the option to conduct sensitivity analyses and experiments, which is again crucial in this research due to the high degree of uncertainty.

A shortcoming related to the software is that it is still under development. Relatively new features have not undergone extensive testing yet [28]. However, throughout the entire research process, Pieter Bots provided close guidance, facilitating the fast resolution of any limitations related to the software.

2.4 Key Performance Indicators

To accurately evaluate the outcomes of the model, it is essential to identify the Key Performance Indicators (KPIs). KPIs are measurable and quantifiable metrics used to assess the performance of underground hydrogen storage in the model. In this study, the KPIs have been divided into two types: on the one hand, the KPIs that assess the performance of the entire modelled system, and on the other hand, the financial KPIs that play a significant role in evaluating the economic feasibility of UHS facilities.

KPIs regarding the performance of the entire system from a societal perspective:

1. **Total operating system costs:** This KPI is designated because Linny-R seeks to minimise the system's costs. Additionally, there is an expectation that hydrogen can reduce the overall system costs, making it a crucial metric for determining the required hydrogen storage capacity.

2. **Electricity served with peak generators:** The Netherlands is accustomed to high security of supply standards, up to 99.999% [32]. However, this is jeopardised by the growing dependence on renewable sources. The amount of electricity served with peak generators is therefore a good indicator of the extent to which the "normal" installed generation capacity can meet the electricity demand and is therefore included as KPI.

3. **CO_2 level:** Since UHS is regarded as an energy carrier that can play a significant role in the transition to a CO_2-neutral energy system, the annual CO_2 level is included as a KPI.

KPIs regarding the economic feasibility of the UHS facilities:

1. **Average system costs:** To ultimately map out the potential profits of the storage facilities, it is important to gain insight into the costs associated with underground hydrogen storage.

2. **Revenues storage facilities:** To ultimately map out the potential profits of the storage facilities, it is important to gain insight into the potential revenues of the storage facilities.

3. **Profits storage facilities:** In the final phase of the study, it will be determined whether the storage facilities in the modelled system can generate profits.

2.5 Modelling method

The model constructed is an operational optimisation model. An operational optimisation model is a mathematical framework used to optimise the operation of a system to achieve the objective function. In an operational optimisation model, decision variables, constraints, and an objective function are defined to represent the system being optimised. Decision variables represent the controllable aspects of the system. Constraints represent limitations or restrictions on the system, such as capacity constraints. The objective function quantifies the goal or objective of the optimisation problem, which is maximising the cash flow of the actors in the case of working with Linny-R. Therefore, the objective function of the modelling tool can be described by Equation 5.

$$\max : \sum_{t=1}^{N} \sum_{a} (CO_{a,t} - CI_{a,t}) \tag{5}$$

Where t is the time step, N is the total number of time steps, a stands for actor, and CO represents the Cash Out while CI represents the Cash In. The focus of the first part of this research is to minimise the operating system costs of the Dutch electricity and hydrogen market. In this part, the performance of various storage configurations is determined based on operational system costs. The system is subjected to certain prerequisites, such as electricity and hydrogen demand that must be met at each time step. The solver then determines how the units within the system are optimally operated based on the chosen level of prior knowledge regarding system parameters to meet the demand. However, the system is also subject to certain constraints, such as the maximum capacity of units that generate electricity and produce hydrogen or the ramp rate assigned to compressors.

The second KPI utilised to assess the performance of the entire energy system is the electricity served with peak generators. No specific formula is applied for this KPI as it is simply the sum of the level of this process throughout the year. This metric determines the frequency of peak generators being utilised for electricity production, which indicates the extent to which the normal installed generation capacity can meet the energy demand. The third KPI in the initial phase of this research is the measurement of CO_2 emissions, which have been determined as follows:

$$\begin{aligned} CO_2\ level = {} & [CO_2\ emission\ natural\ gas \,|\, L] \\ & - [CO_2\ reduction\ by\ CCGT\ CCS \,|\, L] \\ & - [CO_2\ reduction\ by\ SMR\ with\ CCS \,|\, L] \end{aligned} \tag{6}$$

Although CCS equipment has been installed in the CCGT and SMR processes, they exhibit only a limited carbon capture rate, still resulting in 10% of the CO_2 emissions.

The second part of this study focuses on the economic feasibility of storage configurations in the Dutch energy system. Future electricity and hydrogen prices play a crucial role here, as market prices determine the revenues that can be achieved with a storage facility. Before presenting the equations used to calculate the revenues of the storage facilities, an explanation is provided of how Linny-R operates with market prices.

2.5.1 Electricity market design

The potential revenues achievable through storage depend on the conditions in both the electricity and hydrogen markets. As electricity is converted into hydrogen and vice versa, these two markets are inherently intertwined. In this study, it is assumed that the electricity market will continue to operate in the same manner as today, as indicated by the recently published Adequacy Outlook by Tennet, which suggests that the current design of the electricity market theoretically functions in a future CO_2-free energy system [32].

2.5.2 Market price simulation

In Linny-R, products are used as inputs to a process. Each product can be assigned a certain price. When one product or a combination of products is used as input to a process, the costs incurred for consuming that product are passed on to the output of that process. For example, if 1 GWh of natural gas priced at €1 is needed, and 0.5 GWh of electricity priced at €1 is needed for the production of 1 GWh of blue hydrogen, then the produced blue hydrogen has a cost price of 1.5 €/GWh. In this way, the costs of all the processes' input products are basically added together as the hydrogen and electricity "flow" through the model.

It is assumed that the electricity and hydrogen markets operate based on the merit order principle. These two markets are modelled as two single products, where outputs of multiple processes come together. For instance, in the electricity market, both conventional electricity generation and renewable electricity from sources like solar and wind come together to serve electricity demand. These different generation technologies entail different cost prices. Since it is assumed that the markets operate based on the merit order principle, the Highest Cost Price (HCP) of the process supplying the market at that moment is used as a proxy for the market price.

The aforementioned is explained with the example of an underground hydrogen storage facility. The hydrogen stored in the facility is purchased on the hydrogen market. The hydrogen production or hydrogen import process that delivers to the market at the highest cost at that moment determines the market price. Therefore, the hydrogen entering the storage has a cost price equal to the market price at that moment. However, when hydrogen is injected into and withdrawn from a storage facility, additional costs are incurred for compression and purification/dehydration of the hydrogen, which are added to the cost price of the hydrogen. Therefore, the hydrogen ends up costing more when it's withdrawn from the storage compared to the hydrogen injected. For this reason, a storage facility may be able to set the price on the hydrogen market during times of withdrawal. Strategic bidding is abstracted from this model.

2.5.3 Peak generation capacity

In this study, experiments are conducted based on critical parameters identified in a sensitivity analysis, which have a significant impact on the system. When these critical variables are varied in value and combined, they can lead to both highly favourable and highly unfavourable scenarios, significantly affecting the operational costs of the energy systems. Consequently, there are scenarios in which relatively high shortages in electricity occur throughout the year, also known as "electricity not served". It is important to note that in reality "electricity not served" implies actual power outages, resulting in high societal costs. The costs associated with power outages in the Netherlands are estimated at 69000 €/MWh, according to the ACM [33]. However, given the high level of security of electricity supply currently in the Netherlands (99.999% [32]), it is expected that the country will uphold its high standards. Therefore, in this study, it is assumed that very expensive peak generators will bridge the gaps between electricity demand and supply at a cost of 3000 €/MWh, based on a study by Netbeheer Nederland [34]. Consequently, this study aims to offer a more realistic depiction of the potential revenues achievable with storage facilities. Utilising a value of 69000 €/MWh would overly inflate the economic potential of storage facilities, presenting an excessively optimistic business case.

2.5.4 Complex cycles

In the model, multiple cycles can be found. For instance, the electricity market is linked to the hydrogen market because electricity can be converted into hydrogen through electrolysis, and conversely, hydrogen can be converted into electricity using hydrogen turbines. However, Linny-R is having trouble determining the cost price of products involved in complex cycles. Therefore, a pricing process has been added to the model in the Hydrogen-to-power cluster, intended to approximate the cost price of the product by averaging over the previous block.

2.5.5 Economic analysis KPI equations

Table 4: Abbreviations used in formulas.

Abbreviation	**Meaning**
HCP	Highest Cost Price
F	Flow
L	Level

As aforementioned, the HCP serves as a proxy for the market price in this study. Therefore, the HCP is used in the calculation of the average electricity price. Equation 7 is used to calculate the average electricity price.

$$\text{Average electricity price} = \frac{\sum_{t=1}^{N} \text{HCP}_t}{N} \tag{7}$$

The average electricity price has been used in the calculation of the variable operational costs of the storage facilities because the compressors and the dehydration/purification units consume electricity.

Variable operational system costs

$$\begin{aligned}
&\textit{Variable operational costs gas field}\\
&= ([\textit{Compression}/L]\\
&\quad \times [\textit{Electricity consumption compression}]\\
&\quad \times [\textit{Average electricity price}])\\
&\quad + ([\textit{Purification}/L]\\
&\quad \times [\textit{Electricity consumption purification}]\\
&\quad \times [\textit{Average electricity price}])
\end{aligned} \tag{8}$$

$$\begin{aligned}
&\textit{Variable operational costs salt cavern}\\
&= ([\textit{Compression}/L]\\
&\quad \times [\textit{Electricity consumption compression}]\\
&\quad \times [\textit{Average electricity price}])\\
&\quad + ([\textit{Dehydration}/L]\\
&\quad \times [\textit{Electricity consumption dehydration}]\\
&\quad \times [\textit{Average electricity price}])
\end{aligned} \tag{9}$$

The fixed operating costs and the capital costs calculation are not linked to the outcomes of the model. Detailed information about this cost analysis can be found in Section 7.

Revenues

The revenues from storage are determined as the difference in the HCP on the hydrogen market at the time when the hydrogen is withdrawn from the storage minus the HCP on the hydrogen market at the time when the hydrogen is injected into the storage facility, representing the market selling and buying prices.

$$\begin{aligned}
\textit{Revenue gas field} = & \textit{[Purification to Hydrogen/F]} \\
& \times \textit{[Hydrogen/HCP]} \\
& - \textit{([Hydrogen to Compression gas field/F]} \\
& \times \textit{[Hydrogen/HCP]}
\end{aligned} \tag{10}$$

$$\begin{aligned}
\textit{Revenue salt cavern} = & \textit{[Dehydration to Hydrogen/F]} \\
& \times \textit{[Hydrogen/HCP]} \\
& - \textit{([Hydrogen to Compression salt cavern/F]} \\
& \times \textit{[Hydrogen/HCP]}
\end{aligned} \tag{11}$$

Profits

The profits of the UHS facilities are determined as the difference between the revenues of the storage facilities minus the total expenditures of the storage facilities.

$$\textit{Profit gas field} = \textit{Revenue gas field} - \textit{Total expenditures gas field} \tag{12}$$

$$\textit{Profit salt cavern} = \textit{Revenue salt cavern} - \textit{Total expenditures salt cavern} \tag{13}$$

All three KPIs regarding the economic analysis have been divided by the amount of hydrogen produced from such a storage facility as the final step of the calculation of the economic feasibility. By *produced hydrogen*, the amount of hydrogen annually withdrawn from the storage is meant. Therefore, the average system costs, revenues and profits will be expressed in €/kg. This approach is adopted due to the likelihood that Essent will not possess full ownership of the storage facility, but rather, will lease a portion of it. Therefore, it is interesting for them to map out the average system costs, revenues, and potential profits per kilogram of produced hydrogen, rather than the insight into the total system costs, revenues and profits of a facility.

2.6 Research Flow Diagram

The aim of this study consists of two aspects: firstly, determining the required storage capacity in the future Dutch electricity and hydrogen system and determining which configuration performs best in terms of operational system costs and capital costs. Secondly, determining the economic feasibility of underground hydrogen storage facilities. Thus, it concerns both the performance of the overall energy system and the commercial aspect of UHS facilities. When referring to storage configurations within the study, the combination of a specific seasonal storage policy and a certain number of salt caverns is meant. All analyses have been conducted for the decentral, national, European, and international energy systems. The energy systems mainly differ from each other in the extent to which the Netherlands is self-sufficient in electricity and hydrogen production. These energy systems can therefore actually be seen as four different models because not only do the installed capacities of electricity production and hydrogen production technologies differ, but also the electricity interconnection, hydrogen interconnection, and electricity and hydrogen demand. Furthermore, it is important to mention that when referring to scenarios in this research, a specific combination of critical parameters is meant. For example, a scenario could encounter high electricity demand in the built environment, a high installed capacity Li-ion batteries, the current electricity interconnection capacity and a low installed capacity hydrogen turbines. When referring to the low, mid, and high-cost scenarios, it's self-evident that this pertains to the cost scenario.

The Research Flow Diagram (RFD) in Figure 3 illustrates the research flow from the initiation of the modelling approach. Preceding this, an exploratory study is conducted on the potential of various geological formations that may be suitable for hydrogen storage in the Netherlands. However, due to the relatively simple nature of this preliminary analysis, it is not included in the RFD. The research flow diagram is traversed separately for all four energy systems. For each energy system, the required number of salt caverns is determined for low, medium, and high-seasonal storage policies. Thus, a total of 12 storage configurations are examined.

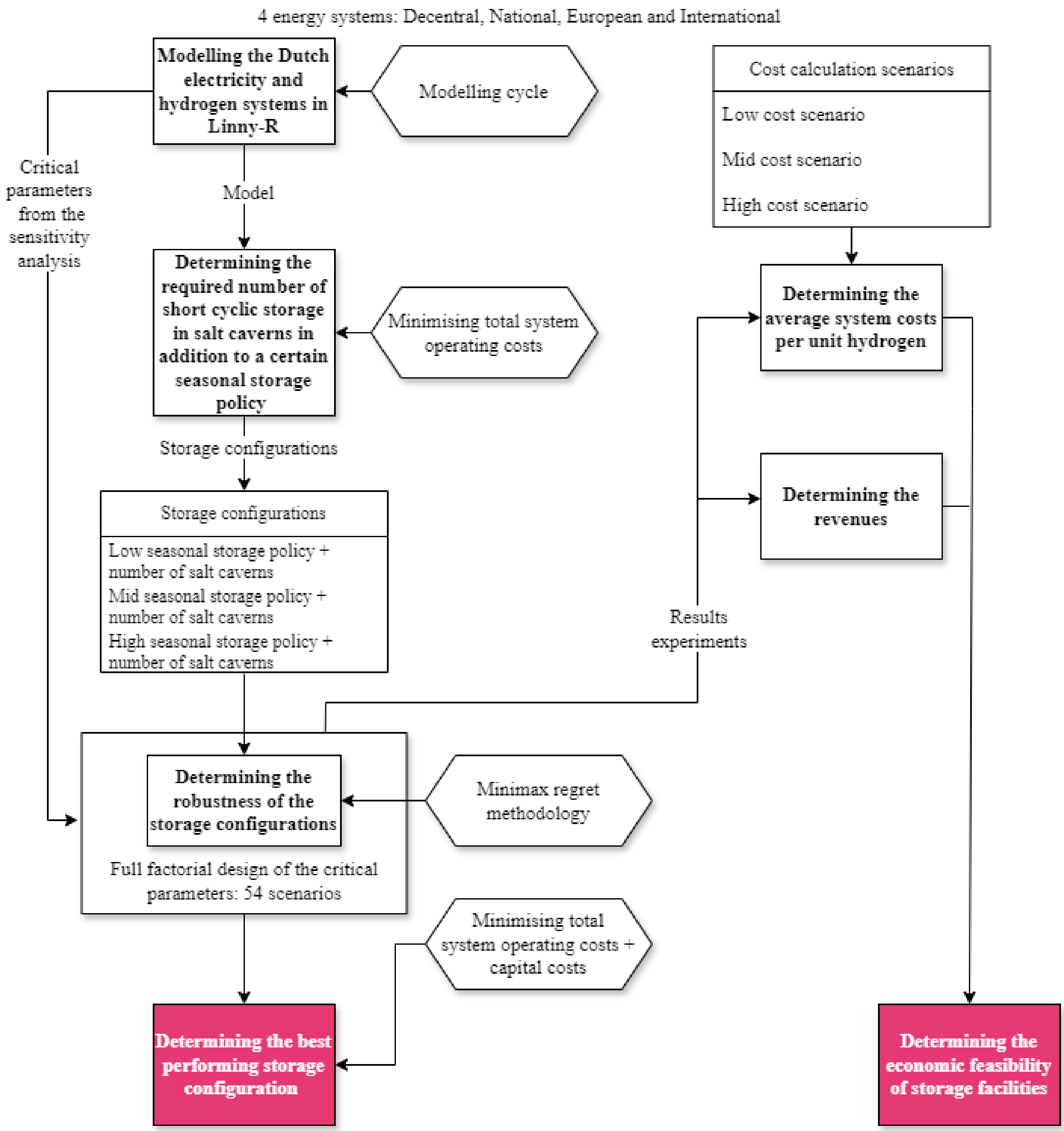


Figure 3: Research Flow Diagram (RFD).

3

Underground hydrogen storage

In this section, the availability of geological formations potentially suitable for hydrogen storage in the Netherlands is addressed first. Based on the selected geological formations, a Technology Readiness Level study is then conducted. The section will conclude with a comparison of the geological formations, along with a conclusion regarding the geological formations to be considered in this research.

3.1 UHS potential in the Netherlands

As mentioned in Section 1.1.3, five types of geological formations can potentially be used for underground hydrogen storage: salt caverns, gas fields, oil fields, aquifers, and rock caverns. Among these geological formations, rock caverns are exceedingly rare in the Netherlands [19] and are also on the world scale of no great relevance [35]. Therefore, rock caverns are excluded from the scope of this research. Oil fields are also present only to a limited extent in the Netherlands. From Figure 4 becomes clear that some oil fields are located in South Holland, which is not a favourable location due to the high population density. Additional oil fields can be found on the border of Drenthe and Germany and offshore. However, in most cases of oil production, there has been a limited decrease in pressure, resulting in little to no storage volume for gases [19]. This, in combination with their limited presence in the Netherlands, has led to oil fields also being excluded from the scope of this research. As a result, salt caverns, gas fields, and aquifers are the remaining options under consideration.

Figure 4 on the next page shows the availability of salt caverns and gas fields in the Netherlands. As becomes evident from the figure, the Netherlands is abundantly endowed with gas fields and salt layers, resulting in substantial technical potential for UHS in the country. The onshore and offshore gas fields alone contribute to a technical potential of 456 TWh [12]. When considering the salt caverns in Groningen, Friesland, and Drenthe, this potential is further increased to a total of 500 TWh [12]. This technical potential already exceeds the expected demand for UHS in 2050 by 19-33 times, without even accounting for the technical potential of offshore salt caverns and aquifers. Given the rich presence of aquifers in the Netherlands as well, this geological formation is also included in the subsequent investigation.

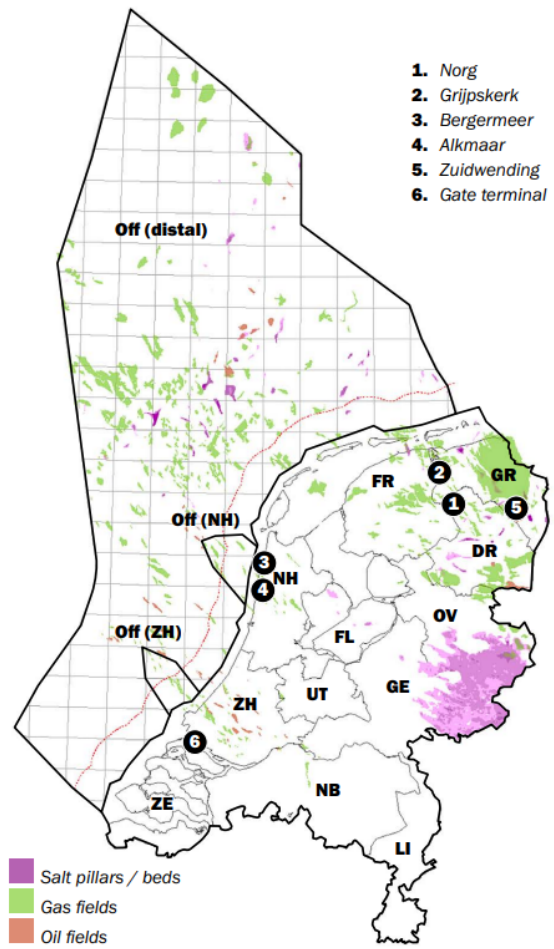


Figure 4: Availability salt caverns, gas fields and oil fields in the Netherlands [12].

3.2 Hydrogen storage in salt caverns

3.2.1 Salt cavern creation

Salt caverns are large hollow spaces within rock salt, created through a technique known as *solution mining*. This method involves injecting fresh water through a well into a salt formation or salt pillar of up to 1000-15000 meters below the earth's surface. The water dissolves the salt, and saturated brine is subsequently pumped to the surface for processing at a salt production facility [36]. As salt dissolves through this process in the subsurface, it creates a hollow space in the salt layer, which is called a salt cavern. The process of dissolving the salt into the water requires a significant amount of time. It typically spans three to four years for a cavern to develop the appropriate shape and size for effective gas storage [36].

Once the desired cavern size is achieved, tests are conducted to assess the integrity of the cement casing. When these results meet all technical requirements, hydrogen can be injected into the cavern. As the brine is displaced by introducing hydrogen into the cavern, this process is called debrining. Gas is injected through the outer pipe, while the brine is extracted through the inner leaching pipe. Some of the brine will remain in the cavern because the pipes do not extend to the bottom of the cavern. Figure 5 shows a simplified version of the leaching process of a salt cavern.

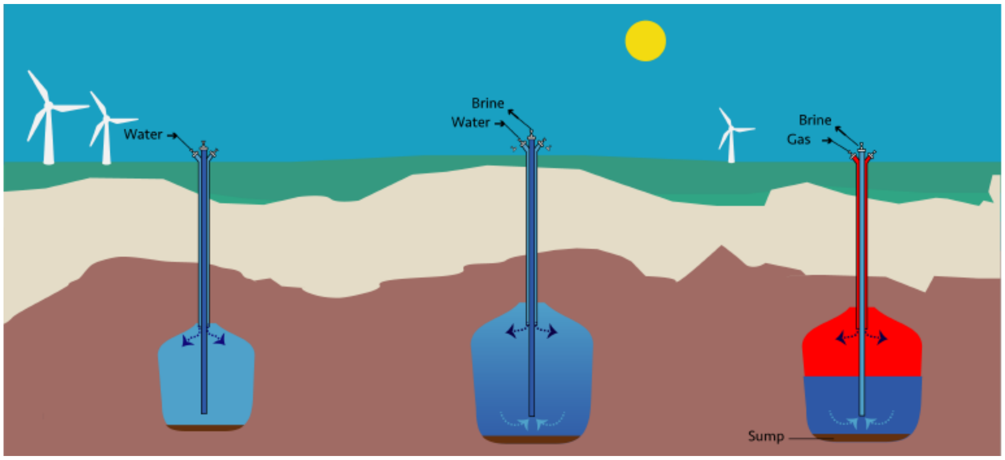


Figure 5: Simplified version of solution mining in a salt cavern [37].

3.2.2 Storage characteristics

An outstanding attribute of rock salt lies in its impermeability, effectively preventing the passage of any fluids or gases [8]. Consequently, a salt cavern emerges as a suitable geological formation for a wide range of fluids and gases. Moreover, salt caverns can be designed to the desired shape. While individual caverns possess limited volume, scalability is achievable through the creation of multiple caverns.

The storage of hydrogen in salt caverns is recognised for its minimal impact on the quality of the stored hydrogen, allowing for the attainment of a 98% purity level without the necessity for extensive purification [38]. However, it is noteworthy that a dehydration facility is required to dry the withdrawn hydrogen, as the extracted hydrogen will contain water upon withdrawal from storage [39].

3.2.3 State-of-the-art

Storing hydrogen in salt caverns has been proven both technically and economically. Currently, there are four locations worldwide where at least 95% pure hydrogen is stored commercially in salt caverns. These are situated in Clemens Dome, Moss Bluff, and Spindletop in the United States, and the fourth one is located in Teesside in the United Kingdom. Furthermore, there are dozens of projects that are currently in the pre-feasibility, proposal, construction, testing, permitting, or the Front-end engineering design (FEED) stage of the project [17].

Despite the existence of four commercially operational sites, the TRL is currently assessed at only 7 [12]. The reason for this is that the operational sites are all designed to serve the hydrogen demands of the chemical industry, which is known for its constant demand pattern throughout the year and slow-cyclic operation of the site. When the salt cavern is employed to address variations in supply and demand, higher injection and withdrawal rates and increased cyclic activity are necessary. These factors can potentially harm the integrity of the well materials, interfaces, and the salt cavern itself. So, the main challenge lies within the anticipation of more frequent cyclic injection and withdrawal, as well as higher volumetric rates than what is currently practised [12].

3.3 Hydrogen storage in gas fields

A depleted natural gas field is typically composed of a porous reservoir rock where gas has been accumulated and an impermeable overburden, like clay or salt, is serving as a seal to prevent the gas from migrating upwards through the subsurface. This seal kept the natural gas trapped in the pores of the reservoir rock for millions of years before extraction, making the reservoir an effective storage medium. Gas fields are known to store large amounts of energy due to their large size.

3.3.1 State-of-the-art

Storing gases in depleted gas fields is not a new technique since natural gas has been stored underground for many years. This is also successfully done in the Netherlands. There are four natural gas storage facilities in the Netherlands: Norg, Grijpskerk, Bergermeer and Alkmaar [40].

Although natural gas fields have demonstrated effectiveness as a storage medium for natural gas, the TRL for hydrogen storage in gas fields is currently assessed at only 3-4 [12], which means that the technology is between the phases of *Solution needs to be prototyped and applied* and *Prototype is proven in test conditions* [41]. Studies conducted in Austria [42] and Argentina [43] have shown that blending 10 to 20% hydrogen with natural gas does not pose safety issues for storage facilities, both above and below ground. However, there are currently no operational sites that store at least 95% of pure hydrogen in depleted gas fields, which still categorises it as a technology in its infancy. However, there are plans for the first pure hydrogen testing site in Austria, called the Sun Storage project [44].

Additionally, there is extensive experience with underground mixing of gases with hydrogen and other gases like methane, CO_2, and nitrogen in porous reservoirs, often referred to as town gas. For various gas mixtures it has already been demonstrated that it does not pose safety issues concerning the tightness and integrity of the caprock and well cement [12]. Nevertheless, complete recovery of hydrogen is hindered by factors such as diffuse loss, solution, and bacterial conversion to methane during the storage process.

Because pure hydrogen hasn't been stored in depleted gas fields until now, there are still fundamental questions regarding the impact of geochemical processes and biochemical interactions involving hydrogen within various fluids, rock formations and micro-organisms in depleted gas fields [12]. Regarding the reservoir challenges, there is still a lot of uncertainty about the performance, containment and seismicity. Besides, there is little known about the technical, economic and environmental risks that are associated with the deployment of gas fields for hydrogen storage. It's also crucial to conduct further research into the extent to which gas infrastructure in a broader context can be repurposed for hydrogen.

3.3.2 Re-use of natural gas equipment

Various types of gas fields may be suitable for serving as hydrogen storage: operational gas fields, abandoned gas fields, or natural gas reserves that have yet to be developed. In the case of operational or depleted gas fields, there are already several producing wells. The potential for reuse of the wells could result in significantly lower costs and enable relatively rapid storage development [9]. This potential exists not only for the reuse of the wells but also for the pipelines and surface installations.

3.4 Hydrogen storage in aquifers

Aquifers share similarities with gas fields as they are porous and permeable, but instead of holding natural gas, they contain water. Aquifers are the second most prevalent type of storage of natural gas, following depleted reservoirs. In contrast to the proven integrity of the caprock in depleted gas fields, geological surveys are essential to ensure the caprock's integrity when using aquifers for storage.

In aquifer-based hydrogen storage, the process involves injecting cushion gas followed by hydrogen through strategically positioned wells to displace the water to the lower section of the aquifer. Depending on the aquifer's structure and the placement of wells, water can sometimes be used as a substitute for cushion gas. However, the use of cushion gas is often favoured over water because it helps to maintain pressure within the aquifer, and now it is the cushion gas, rather than the working gas, that is confined by the water [15]. Significant quantities of cushion gas (up to 80% of the storage volume) are required in aquifers to prevent gas entrapment [45]. The exact amount of cushion gas needed depends on the aquifer's structure, operational purposes, and well placement. Figure 6 depicts a schematic representation of an aquifer structure before and after hydrogen storage.

In comparison to salt caverns, both gas fields and aquifers offer significantly larger storage capacities. Repurposing aquifers for hydrogen storage that were originally designed for natural gas storage is similar to adapting depleted gas fields due to the structural and initial condition similarities [46] [47].

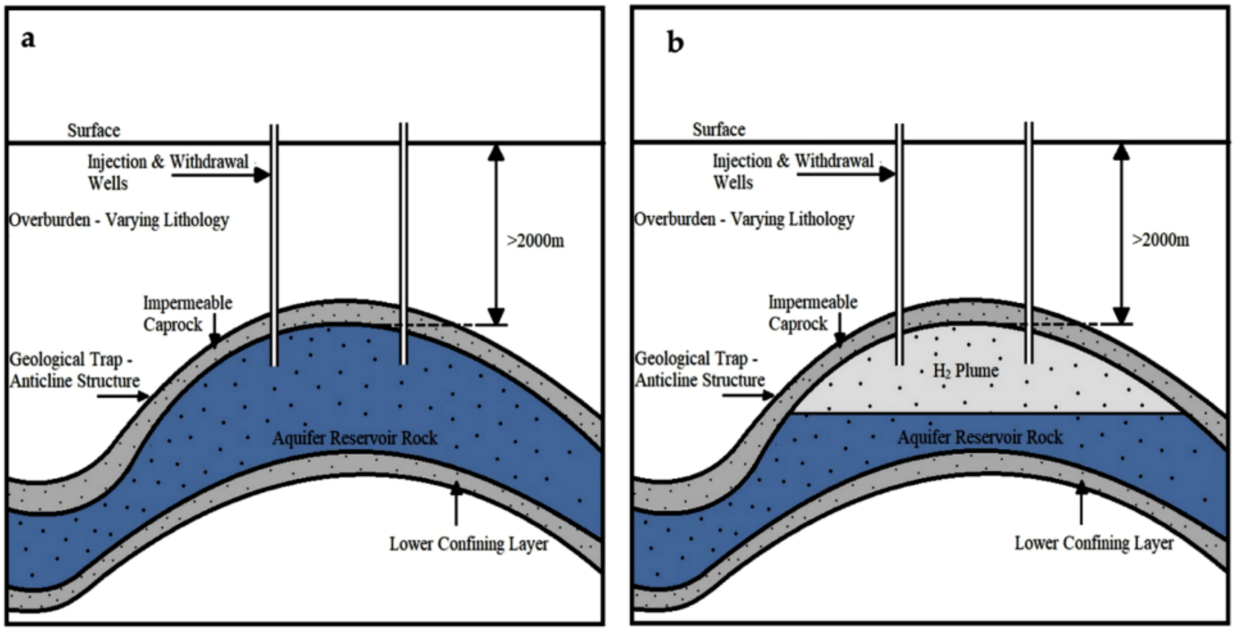


Figure 6: Schematic representation of an aquifer structure before (a) and after (b) hydrogen storage [45].

3.4.1 State-of-the-art hydrogen storage in aquifers

Since aquifers are already utilised for natural gas storage, they hold potential for hydrogen storage. However, the technology is still in its infancy. The geological storage of H_2, along with other gases such as CO_2, CH_4, CO, and N_2, has been documented in projects in Ketzin, Germany, Lobodice, the Czech Republic, and Beynes, France [46]. This is also referred to as *town gas* and can contain up to 50-60% hydrogen. However, from these projects, it was concluded that significant hydrogen losses were observed due to microbial processes. Therefore, there is a pressing need for further research on this matter in the context of aquifers and porous reservoirs in general [17].

Major challenges associated with aquifer formations for hydrogen storage in particular include potential interactions between hydrogen and microorganisms, as well as between hydrogen and the mineral components of the natural reservoir. Biological or mineral reactions of this nature may result in the degradation or reduction of hydrogen storage, or these reaction by-products could clog the tiny pore spaces [35].

The concept of storing pure hydrogen in aquifers is still in its early stages and necessitates extensive prototyping. The main difference between depleted gas fields lies in the incomplete understanding of the potential risk of gas contamination in aquifers [17]. Furthermore, our comprehension of the standard set of reservoir characteristics remains limited due to the lack of exploration data and production experiences in aquifers [17]. The TRL is therefore estimated at only 2-3 for the storage of pure hydrogen in aquifers by the International Energy Agency, which means that the innovation is positioned between the *Concept and application of solution have been formulated* and the *Solution needs to be prototyped and applied* phases [41].

3.5 Comparison of the UHS facilities

From sections 3.2, 3.3, and 3.4, it became evident that a great deal can be learned from previous storage projects. Underground gas storage has been in practice since 1915, with the first underground storage realised in a depleted gas field. Since then, the number of UGS facilities has significantly increased, with contributions not only from gas fields but also from aquifers and salt caverns. Currently, there are 662 UGS facilities worldwide, with 72% located in hydrocarbon reservoirs, 15% in salt caverns, and 11% in deep aquifers [17].

However, there is still a substantial amount of uncertainty regarding UHS. The TRL for hydrogen storage in salt caverns, gas fields, and aquifers are 7, 3-4, and 2-3, respectively. While gas fields and aquifers are both porous and permeable, there is a higher level of uncertainty concerning the standard set of aquifer characteristics and the comprehension of the contamination risk. This could be attributed to the greater number of UGS facilities in gas fields compared to the limited 11% storage facilities in aquifers. Additionally, the estimated required share of cushion gas compared to the total volume can rise to 80% [45], which is unfavourable for project-related costs. Moreover, the potential hydrogen losses due to microbial processes in the aquifer make the technology less appealing.

Due to the aforementioned reasons and the fact that the Netherlands has access to a substantial supply of gas fields and salt caverns, these geological formations are preferred over aquifers in this research. Therefore, aquifers are excluded from the scope of this study from this point onwards. This conclusion is affirmed by NLOG, indicating that in the Netherlands the preference generally leans towards gas fields over aquifers, except for thermal energy applications [48].

Main Takeaways

1. Salt caverns, gas fields, oil fields, aquifers, and rock caverns have the potential for underground hydrogen storage.
2. Given the limited availability of rock caverns and oil fields in the Netherlands, these geological formations have been excluded from the scope of this study.
3. After an analysis of the Technology Readiness Level of aquifers, salt caverns and gas fields, aquifers have been excluded from the scope of this study as well.
4. From this point forward, the focus of this study is therefore solely on salt caverns and gas fields.
5. In the model, seasonal storage will be conducted in gas fields due to their bigger storage capacities, and short-cyclic storage will take place in salt caverns because they allow for multiple cycles per year.

4

The model

The electricity and hydrogen markets in the Netherlands are complex and interconnected systems. In this section, these systems have been decomposed to enhance the understanding of their operation, aligning with the conceptualisation phase. The following subsection will provide more information on how this system is translated into an optimisation model, visually displaying all the relations between products, processes and clusters. Before conducting an in-depth analysis of the model, a higher-level system abstraction has been presented. Figure 7 shows the conceptual diagram of the Dutch electricity and hydrogen system and outlines the fundamental elements and relationships within the considered system.

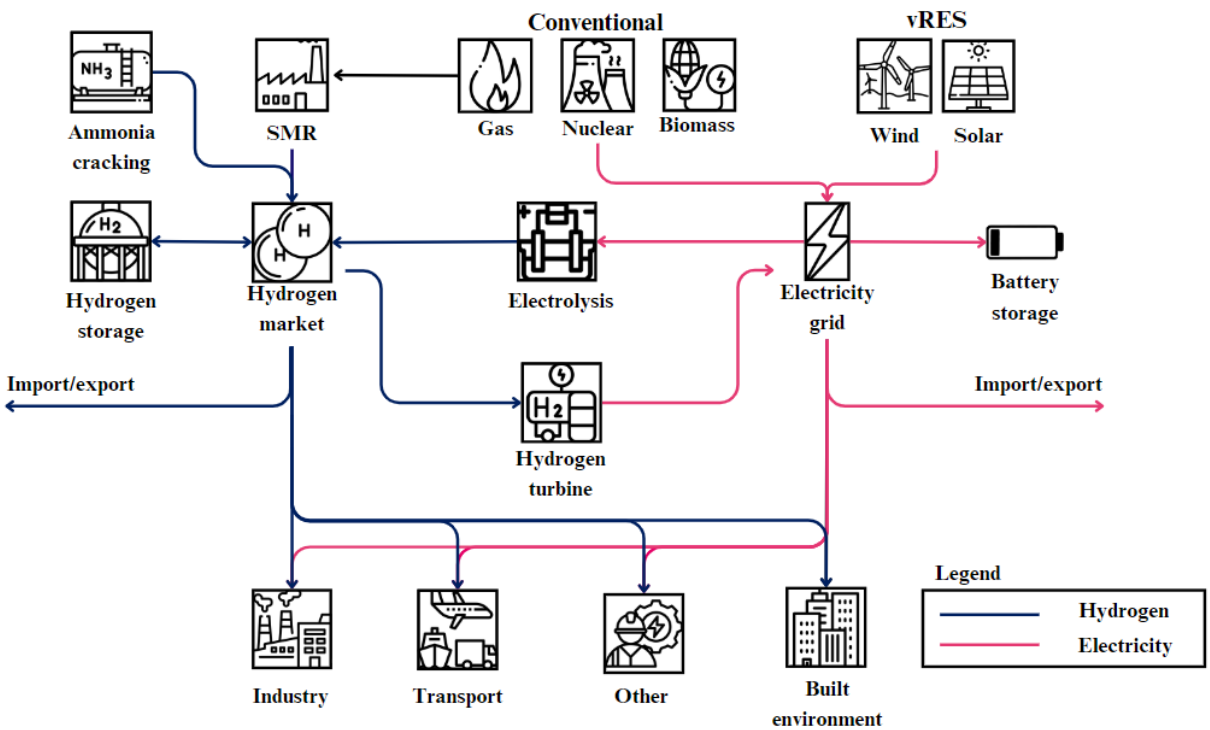


Figure 7: The conceptual overview of the system under consideration for the modelling.

4.1 The model

This section aims to enhance comprehension of the model devised for the simulation of the electricity and hydrogen markets in 2040, along with the underlying assumptions. Linny-R, the software in which the model is developed, is a graphical modelling tool, offering a conceptual representation of the products and processes falling within the scope of this study for each facet of the model. Details on the technical input parameters can be found in Appendix A.2.

4.1.1 Settings of the model

Depending on the model's objective, specific model settings can be chosen that may lead to different outcomes. Firstly, the time span for which the model is run must be determined. In this study, the model is run for 1 year with time steps of 1 hour, meaning that one run consists of 8760 time steps. It is crucial to note, for an understanding of the seasonal patterns in the model results, that the model is run from t=2160 to t=10920, where t=2160 corresponds to April 1. Therefore, modelling is not based on calendar years.

Additionally, two choices have been made, significantly influencing the runtime and computational burden of a run: the block length and the look-ahead. The block length indicates the number of time steps within which the solver optimises in a single iteration. On the other hand, the look-ahead denotes the information from consecutive time steps available to the optimiser beyond the defined block length. Both a larger block length and a greater value for the look-ahead result in a longer runtime. In this study, a block length of 240 hours and a look-ahead of 72 hours have been chosen. This leads to an average runtime of 2 minutes and 10 seconds per run.

4.1.2 Key concepts of Linny-R

To give the reader a general idea of how Linny-R operates, this section focuses on the fundamental components that Linny-R employs. Linny-R primarily comprises four key entities: products, processes, links, and clusters.

- A **product** within the framework represents a consumable or producible entity. On the one hand, these could be tangible products, such as electricity or fuel, but it could also be a *data product*, which solely conveys information. Additionally, we define a *stock* as a product serving as storage, bound by specified upper and lower bounds.
- An **process**, represents the conversion of one or more products into one or more distinct products. An example of this is the production of green hydrogen through electrolysis, where electricity is converted into green hydrogen.
- **Links** represent the relation between products and processes. Links may contain information about the flow between products and processes, such as efficiency.
- In the structural organisation of the model, we introduce **clusters**, essentially conceptual tools that facilitate the subdivision of the system into subsystems. Important to note is that clusters bear no impact on the optimisation process; their sole purpose is to enhance the model's oversight. Clusters also possess the "ignore" function within the program, enabling the deactivation of the segment of the model within the cluster for that particular run.

4.1.3 Top-level model

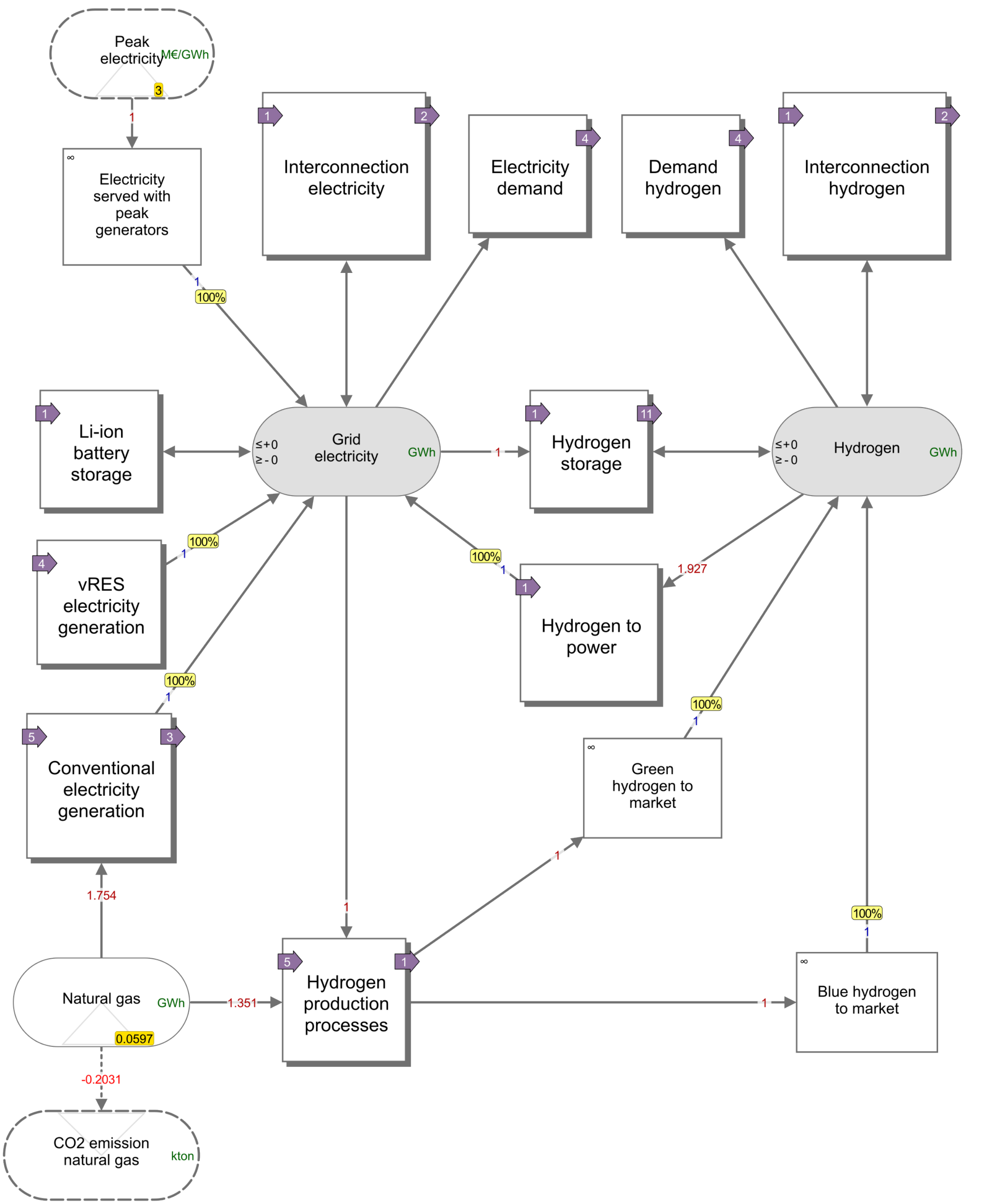


Figure 8: Linny-R. The top-level model.

The top-level model illustrates the clusters comprising the model and the relationships between these clusters. Distinctions are made among production/generation clusters, interconnection clusters, flexibility clusters, and energy demand clusters. The left part of the model focuses on the electricity market while the right side of the figure highlights the hydrogen market. The interaction between the electricity market and the hydrogen market is depicted through both the hydrogen production cluster and the hydrogen-to-power cluster.

The key assumptions made at this model level are as follows:

- All electricity required as process input originates from a central electricity grid. The fact that some processes are (partially) supported by a direct connection to an electricity generator, in reality, is therefore disregarded.
- All hydrogen supplied to customers, hydrogen stored or hydrogen converted back into electricity, originates from one market: the hydrogen market. It is therefore assumed that there will be, to some extent, a hydrogen market in the Netherlands by 2040.
- The model only incorporates blue and grey hydrogen, as grey hydrogen is not deemed suitable for a carbon-neutral energy system. Although blue hydrogen still emits 10% of CO_2 due to the limited carbon capture rate [49], it is considered a primary pathway for the development of green hydrogen and therefore, blue hydrogen is still included in the model [50].
- Electricity served by peak generators is incorporated into the model to offer insights into the costs associated with situations where the standard generation capacity cannot meet demand, necessitating the use of expensive peak generators.
- It is important to note that the model includes **only** operational costs; capital costs are **not** incorporated into the model.

4.1.4 Li-ion batteries

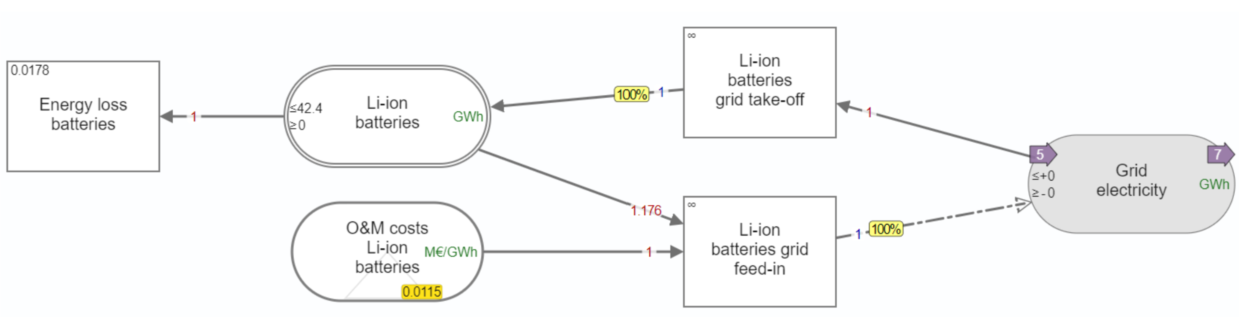


Figure 9: Linny-R. Li-ion battery storage.

- Apart from the efficiency, capacity, and self-discharge rate, no constraints have been imposed on the speed of charge and discharge processes of Li-ion batteries.
- The total installed capacity of Li-ion batteries includes the expected Li-ion battery capacity in electric vehicles. Of the total battery capacity of EVs, an EV-to-grid availability of 15% is assumed [51].

4.1.5 vRES electricity generation

The two dominant renewable sources used in the Dutch electricity generation are incorporated into the model: solar and wind energy. For solar energy, a distinction is made between decentralised solar panels (in the built environment) and central electricity generation (solar parks). Wind energy is divided into onshore and offshore wind turbines.

- The O&M (Operations and Maintenance) costs of the renewable sources are incorporated in the model. Although these entities offer their electricity at €0/kWh in the current electricity market, this will probably change in a system dominated by renewable sources. This transition takes place because the risk of being unable to cover O&M costs rises significantly when bidding at €0/kWh in a renewable-dominated electricity system.

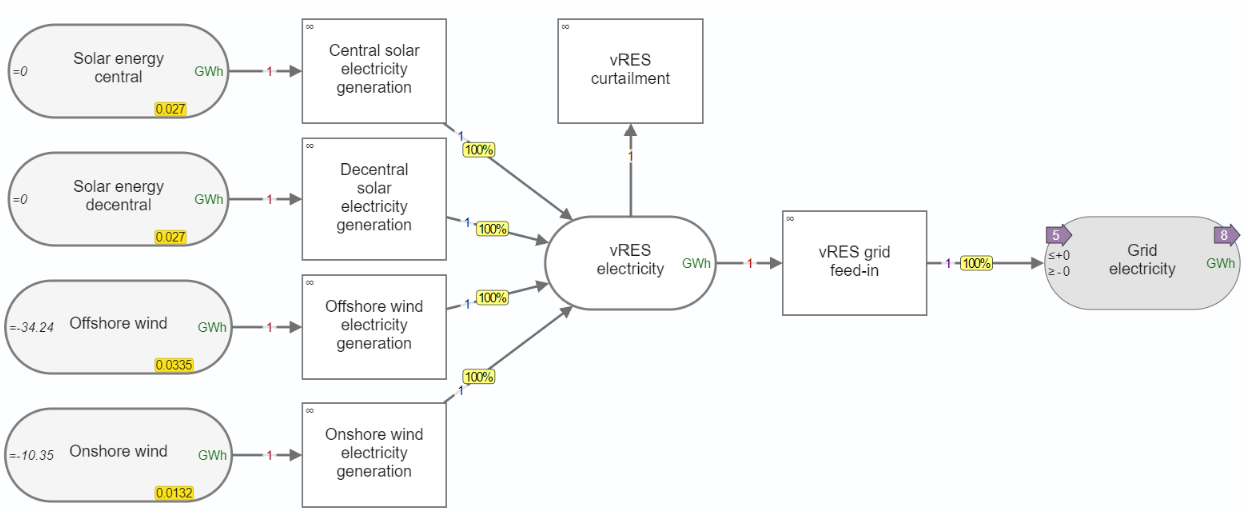


Figure 10: Linny-R. vRES electricity generation.

4.1.6 Conventional electricity generation

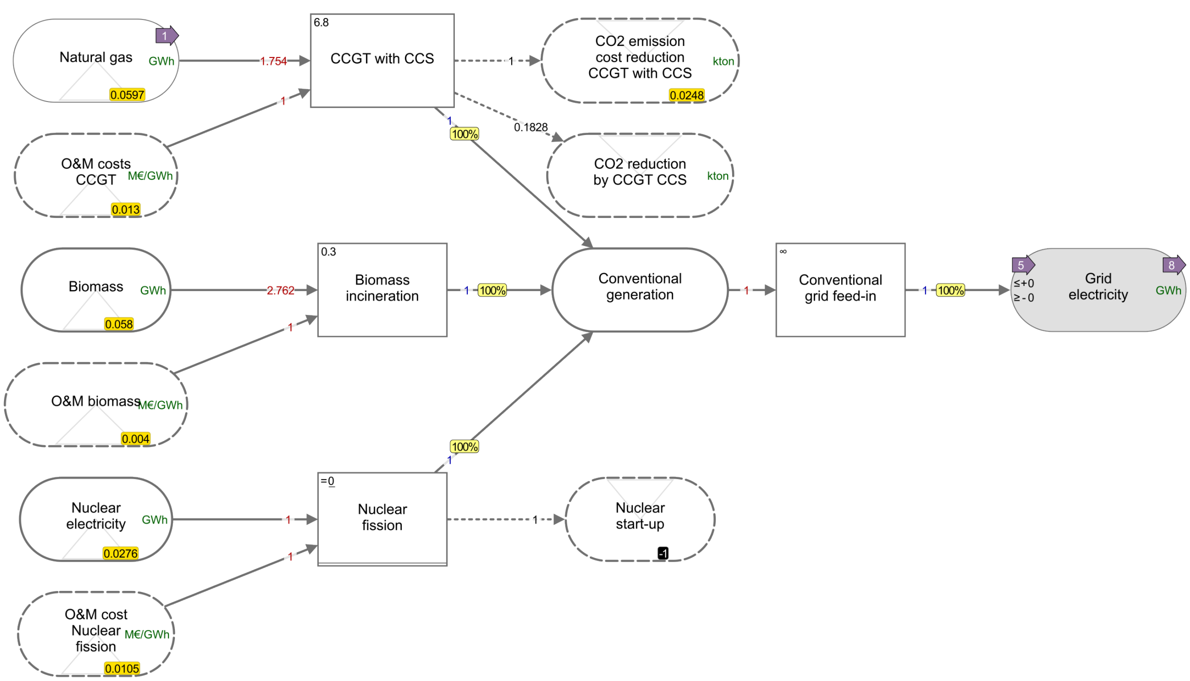


Figure 11: Linny-R. Conventional electricity generation.

Conventional electricity generation in the model comprises biomass incineration, CCGT with CCS and nuclear fission.

- The electricity sector of the model is CO_2 neutral, as the Dutch electricity sector is required to be CO_2 neutral by 2035 [3]. Therefore, the power plants emitting CO_2 are equipped with CCS facilities.
- No restrictions have been imposed on the ramping up and ramping down of conventional power plants.
- When the nuclear plant is operational, it must run at a minimum of 75% of its capacity. Additionally, it is expensive to turn the plant on and off.
- Biomass is considered a CO_2-neutral way to generate electricity [52].
- Carbon capture rates are assumed to be 90% [49].

4.1.7 Electricity demand

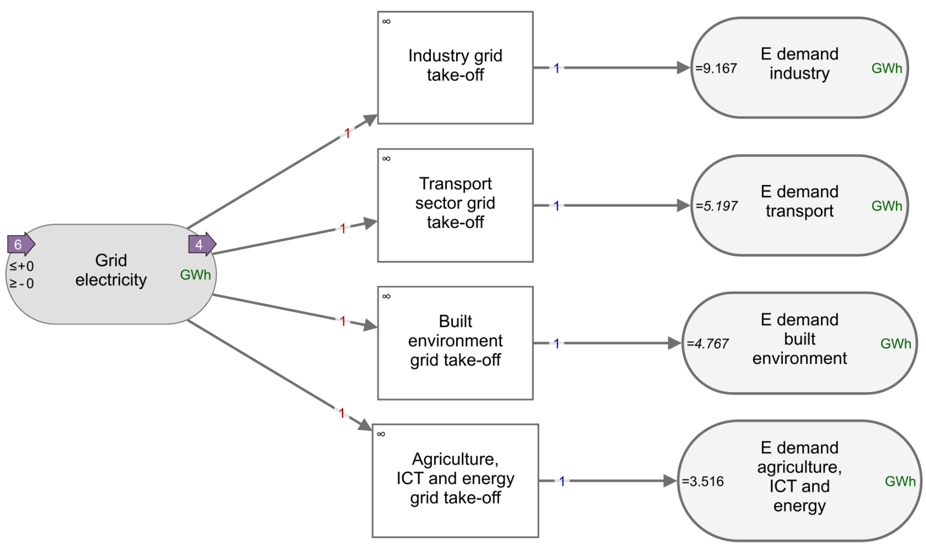


Figure 12: Linny-R. Electricity demand.

The electricity demand is divided into four sectors: the industrial sector, the transport sector, the built environment, and the agriculture, ICT, and energy sector. The following assumptions have been made regarding the electricity demand patterns:

- The electricity demand from the industry remains constant throughout the year.
- There is a constant base demand from the transport sector during both day and night, as people charge their vehicles either at home or at work. However, there is a peak between 17:00-23:00 when most people connect their cars to the electricity grid. No distinction has been made between weekdays and weekends.
- The demand pattern for the built environment is as follows: more electricity usage during the day than at night, with two peaks in the morning and evening when people wake up and return home from work. The exact pattern can be viewed in Appendix A.3.
- The electricity demand from the agriculture, ICT, and energy sectors is assumed to remain constant throughout the year.

4.1.8 Interconnection electricity

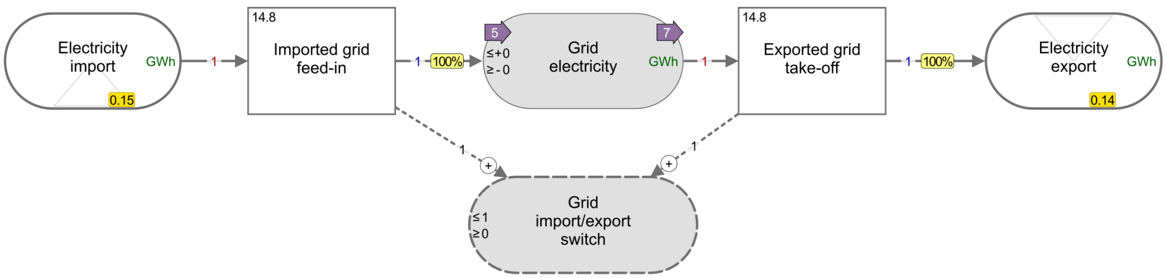


Figure 13: Linny-R. Electricity import and export.

The Netherlands has electricity connections with other countries, providing flexibility. For each energy system in 2040, this capacity is set at 14.8 GW, as the expectation is that this interconnection will only be strengthened by 2050 [51]. This connection is modelled in such a way that electricity import and export cannot occur simultaneously. The price of electricity import is set at 150 €/MWh [51].

4.1.9 Hydrogen production processes

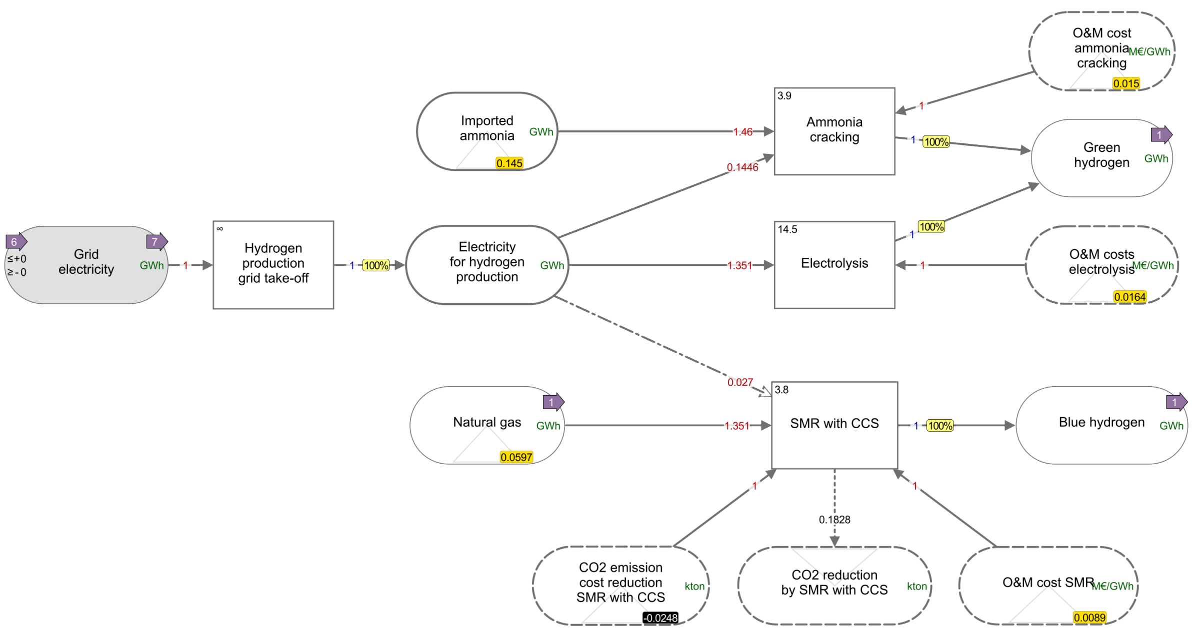


Figure 14: Linny-R. Hydrogen production processes.

Several processes are in place to produce hydrogen. As mentioned before, only green and blue hydrogen are incorporated into the model. Ammonia cracking and electrolysis are both green hydrogen production processes, while SMR with CCS is seen as a blue hydrogen production route.

- For electrolysis, electricity from the grid is used. The efficiency of the electrolyser is derived from that of a PEM electrolyser.
- Green hydrogen can also be produced by cracking ammonia. The required ammonia is imported. The concept is based on producing hydrogen via electrolysis at a location where renewable electricity is inexpensive and subsequently converting it into ammonia for easier transportation. The ammonia can then be converted back to hydrogen at the destination, in this case, the port of Rotterdam [53].
- Blue hydrogen is produced through SMR with CCS.

4.1.10 Hydrogen demand

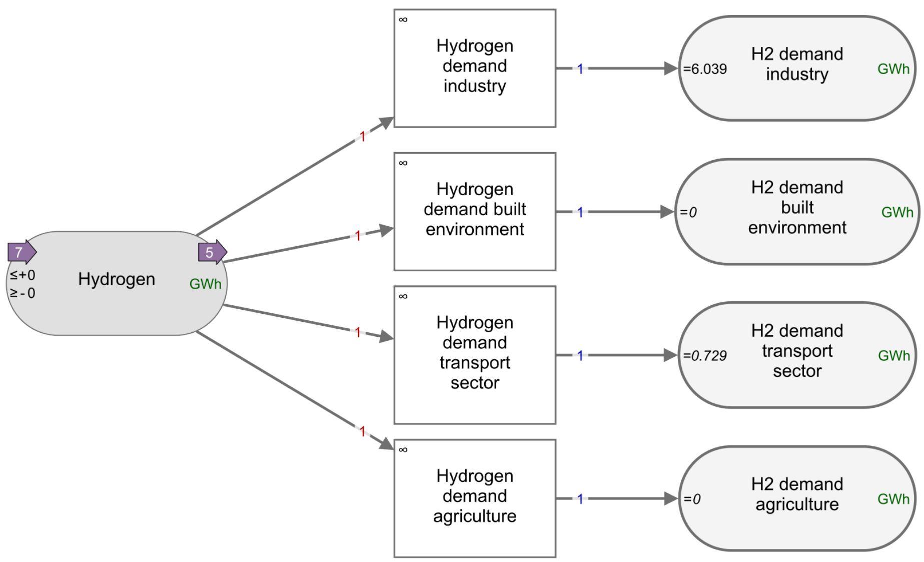


Figure 15: Linny-R. Hydrogen demand.

The hydrogen demand is divided into four sectors: the industrial sector, the transport sector, the built environment, and the agriculture sector. The following assumptions have been made about the hydrogen demand patterns:

- The hydrogen demand from the industrial sector remains constant throughout the year.
- There are day and night fluctuations in the use of hydrogen in the transport sector, but there are no seasonal fluctuations. There are two peaks during the day: when residents are on their way to work and when they go back home.
- The demand pattern for the built environment is as follows: more hydrogen usage during the day than at night, with two peaks in the morning and the evening when people wake up and return home from work. Seasonal fluctuations are also considered, with increased hydrogen demand during the winter.
- The hydrogen demand from the agriculture sector experiences slight seasonal fluctuations, with increased demand during the winter.

4.1.11 UHS in salt caverns

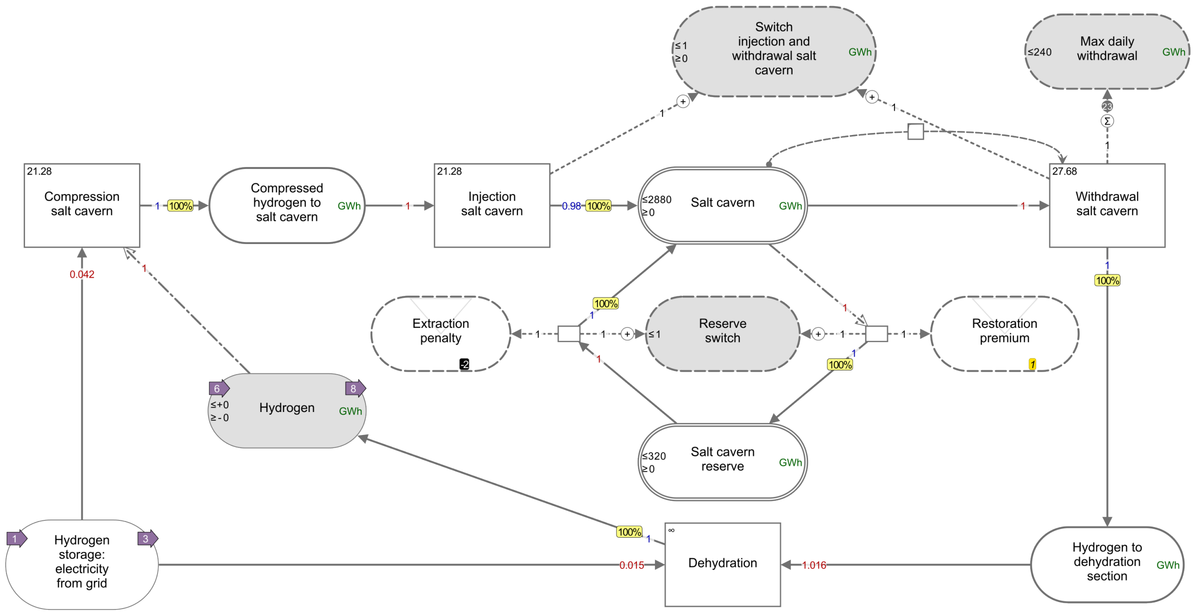


Figure 16: Linny-R. UHS in salt caverns.

- Salt caverns are used as short-cyclic hydrogen storage facilities because salt caverns allow for multiple storage cycles per year.
- The salt cavern is modelled in such a way that hydrogen injection and withdrawal cannot occur simultaneously.
- As the storage depletes, the withdrawal rate decreases.
- A maximum daily withdrawal has been established for the different salt cavern designs because only a pressure drop of 10 bar is allowed in the salt cavern to prevent salt creep and maintain the integrity of the storage [12].
- Both short-cyclic and seasonal natural gas storage facilities are never completely emptied under normal conditions, ensuring a certain reserve is always available for extreme emergencies [54]. In this study, it is assumed that this will also be the case for hydrogen. A margin of 10% of the storage capacity has been determined for emergencies.
- After storage in a salt cavern, a dehydration unit is needed to dry the hydrogen [9].

4.1.12 UHS in gas fields

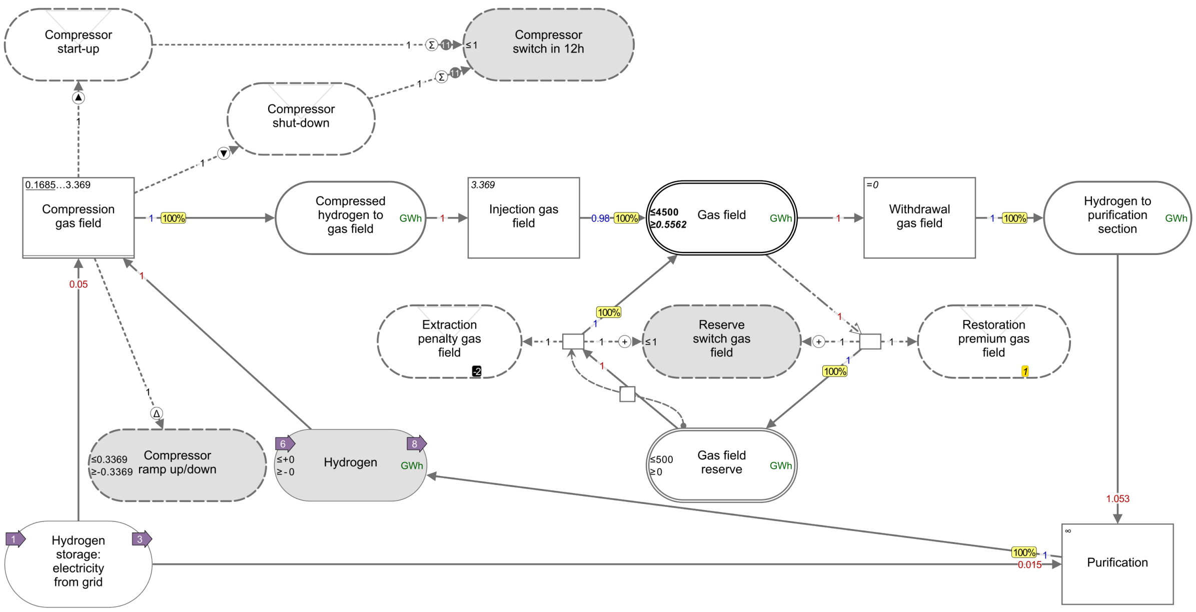


Figure 17: Linny-R. UHS in gas fields.

Gas fields are utilised for seasonal hydrogen storage due to their large storage capacities. However, the model does not run with complete prior knowledge due to the extended runtime associated with this setting, creating no incentive for the gas field to fill during the summer to ensure an adequate supply of hydrogen to the energy system in the winter. Instead, a lower bound has been added to the model, describing the filling and emptying process of seasonal storage.

$$\frac{[\text{Gas field storage capacity}]}{2} \cdot \left(1 - \sin\left(\frac{2\pi}{8760}(t-1)\right)\right) \tag{14}$$

To determine the minimum injection rate required to ensure that the gas field reaches its maximum capacity on October 1st, the derivative of Equation 14 has been calculated, as described by Equation 15.

$$-[\text{Gas field storage capacity}] \cdot \frac{\pi}{8760} \cos\left(\frac{2\pi}{8760}(t-1)\right) \tag{15}$$

Besides, the following assumptions have been made:

- The gas field is modelled in such a way that hydrogen injection and withdrawal cannot occur simultaneously.
- It is assumed that hydrogen storage in gas fields follows a similar design to natural gas storage in gas fields. This means that gas is injected from April 1 to October 1, and only withdrawn during the winter months.
- Similar to the salt cavern, a reserve margin of 10% is incorporated here as well. By assigning a relatively high cost to using this margin, it will only be used in emergencies.
- A ramp up/ramp down percentage of 10% has been assigned to the compressors.
- Additional restrictions have been imposed on the compressors, allowing them to be turned on/off only once every twelve hours.

- After storing hydrogen in a gas field, a purification unit is required to separate hydrogen from impurities [9].
- For gas fields, in principle, it also applies that as the storage depletes, achieving the same production capacity becomes more challenging compared to a full gas field. However, gas fields are designed to achieve a certain production volume over an extended production period, a concept known as plateau production, commonly used in the gas and oil industry. Therefore, it is assumed that there is no restriction on the first 90% of the storage, but limitations are imposed only when depleting the last 10%, referred to as the 'reserve'" [9].

4.1.13 Surface hydrogen storage

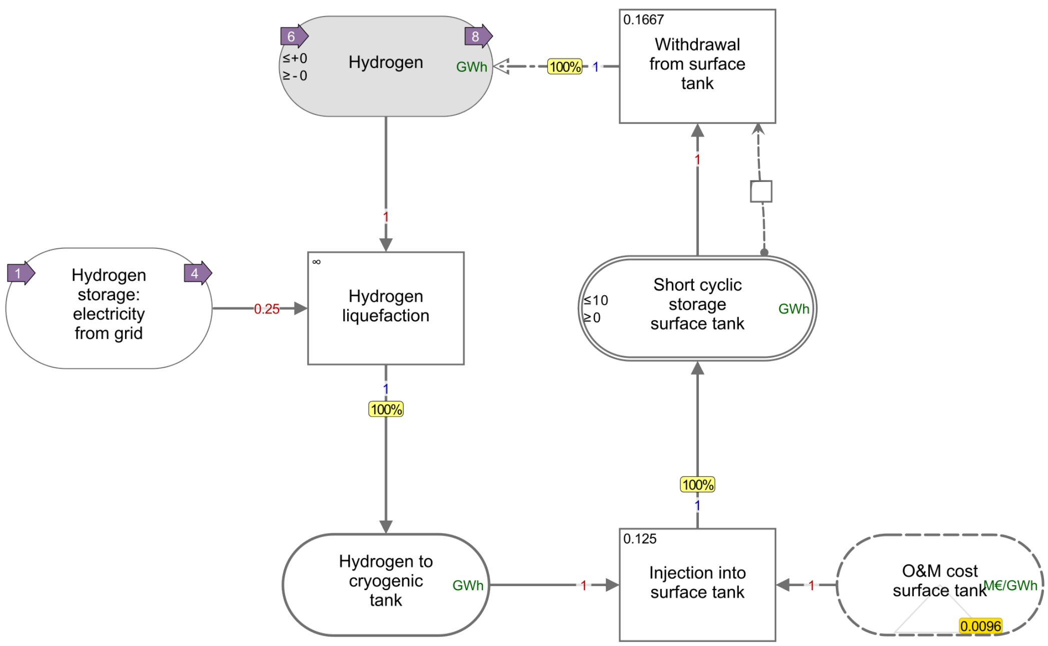


Figure 18: Linny-R. Hydrogen storage in surface tank.

In this study, it is assumed that above-ground storage is performed in cryogenic tanks: under atmospheric pressure but at extremely low temperatures. This tank will primarily be used as a peak shaver [55].

4.1.14 Interconnection hydrogen

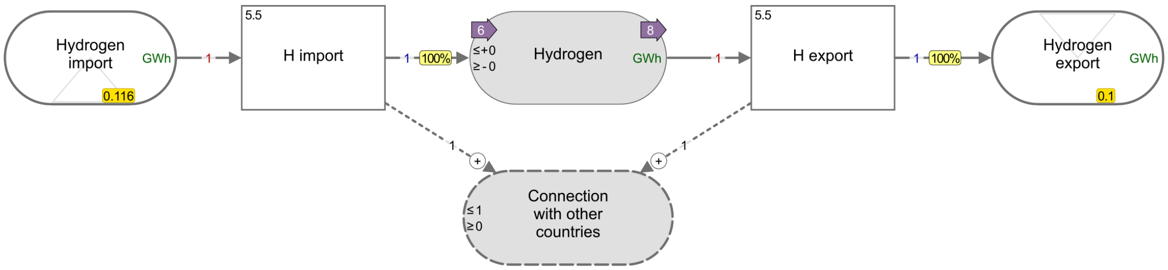


Figure 19: Linny-R. Hydrogen import and export.

Depending on the scenario, it is assumed that the Netherlands has hydrogen connections to some extent with other countries. Based on the expected import and export of hydrogen in 2040 in the various scenarios of the Integrated Energy System Exploration 2030-2050 [51], an assumption has been made for future interconnection in GW. This assumption considers a hydrogen network that may connect us with Belgium, Germany, the UK, Norway, and Denmark, depending on the scenario. In determining the interconnection capacity, European plans for the hydrogen backbone have been taken into account [56]. The price of hydrogen import is based on data from Aurora [57]. The interconnection is modelled in such a way that hydrogen import and export cannot occur simultaneously.

4.1.15 Hydrogen to power

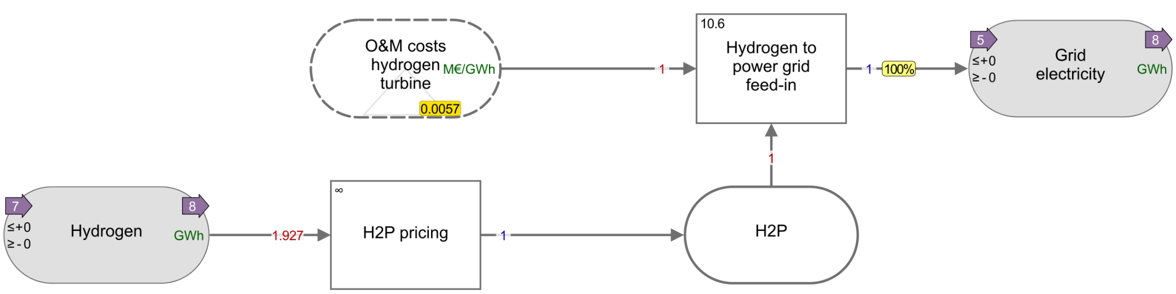


Figure 20: Linny-R. Hydrogen to power.

Hydrogen turbines are used to convert hydrogen (back) into electricity. The H2P pricing process, which can be seen in Figure 20, is used to approximate the cost price of hydrogen by averaging over the previous block. This is done because Linny-R has trouble with determining the cost price of products involved in complex cycles.

4.2 Dealing with modelling uncertainty

While the modelling approach has proven its suitability for addressing issues regarding electricity markets, storage optimisation problems, and hydrogen development, it also exhibits specific limitations. Since the hydrogen and electricity markets are still under development, the model has to cope with a lot of uncertainties [58]. Given that the year under consideration in this research, 2040, is far into the future, not all information on future hydrogen development and electricity projects is known or made available yet. Coarse assumptions were made for this, which means that there can be significant discrepancies between the model's outcomes and the actual situation in 2040. Therefore, different energy systems have been explored.

4.2.1 Scenarios

For this study, four energy systems are used to outline possible future systems for climate-neutral Dutch energy systems: the decentral, national, European, and international energy systems. The main distinction between the scenarios is the extent to which the Netherlands is self-sufficient. These energy systems represent four vertices of the playing field in which the Dutch energy transition will unfold. Based on this information, we can assess the potential need for underground hydrogen storage, given the extreme values within the playing field. The scenarios are based on the study Integral Infrastructure Exploration for 2030 to 2050 (II3050) [51] [21]. Below, the key takeaways that are important for this research are summarised for the different scenarios.

The decentral energy system

- Significant steering from local and regional authorities.
- The Netherlands is self-sufficient in energy, with almost no imports.
- Also on the regional level, the Netherlands endeavours to achieve a high degree of self-sufficiency.
- Decline in energy-intensive industry.
- Increase in electric vehicles.
- High level of energy saving.
- Substantial growth in local energy generation through solar, onshore wind, and geothermal sources.

The national energy system

- Energy transition in the Netherlands is directed by the central government.
- Large national projects (such as the heat roundabout in South Holland).
- High self-sufficiency, minimal imports.
- Significant electrification, particularly in industry.
- Extensive electricity generation from offshore wind and solar (the highest among all scenarios).
- Energy-intensive industry remains at the current level.

The European energy system

- European governance primarily driven by CO_2 pricing in all sectors, pushing towards green gas.
- The Netherlands is not self-sufficient.
- More imports compared to the decentral and national energy systems.
- Growth in energy-intensive industry.

- Significant growth in solar and wind energy.
- Carbon capture and storage (CCS) is prominent.
- Hybrid industry setups: partial electrification and CCS, such as blue hydrogen production.
- European market for hydrogen.
- Hydrogen will also be used in the built environment.

The international energy system

- International market dynamics govern.
- Global hydrogen market.
- Some space for CCS.
- Incentives for trade infrastructures.
- High hydrogen imports from countries with cost-effective production.
- Growth in energy-intensive industry.
- Lowest sustainable Dutch electricity production due to high hydrogen imports.
- High level of industry hybridisation using hydrogen.

4.2.2 Scenario input parameters

Table 5 represents the differences between scenarios on the main topics. Number 1 represents the highest value of the parameter, while number 4 represents the lowest value of the parameter. The exact input parameters of the different scenarios are presented in Appendix A.1.

Table 5: Differences in modelling scenarios.

Parameter	Decentral	National	European	International
Installed vRES capacity	2	1	3	4
Installed conventional capacity	3	2	1	4
Electricity demand	2	1	3	4
Installed hydrogen production capacity	2	1	3	4
Hydrogen demand	3	4	2	1
Hydrogen interconnection	3	4	2	1

4.2.3 Weather years

In a vRES-dominated energy system, weather stands out as a crucial yet inherently unpredictable variable. Given the impossibility of forecasting weather data for 2040, historical weather data was collected from renewables.ninja [59]. This database provides hourly production factors for solar PV, onshore wind, and offshore wind spanning from 1985 to 2019. For increasing knowledge of the system's functioning under uncertain weather conditions, we opted to use two distinct weather years: a standard year and a year representative of a *Dunkelflaute* scenario. The year 2015 is designated as the standard weather year for this research, following the Energy Transition Model's terms [21]. On the contrary, the year 1997 is used as a bad weather condition year, signifying a period with limited renewable generation (*Dunkelflaute*). Additionally, the average renewable energy generation in this year fell below the long-term average.

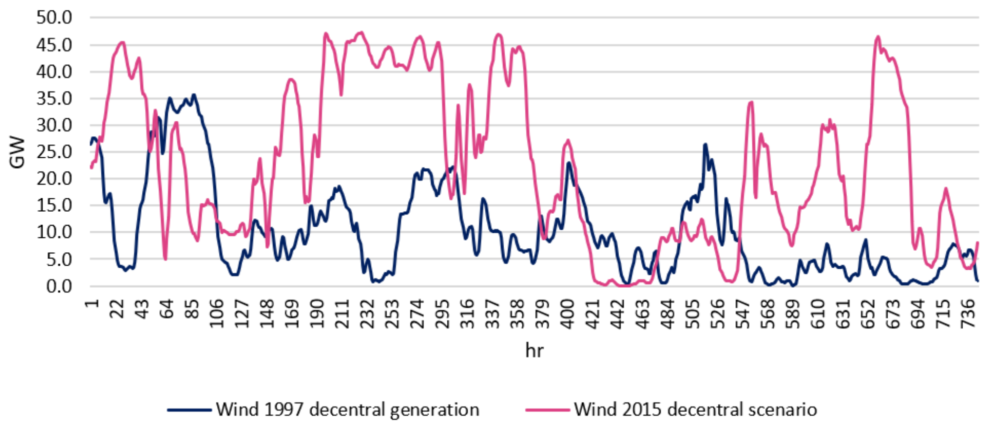


Figure 21: Wind generation for the decentral energy system in January for both weather years: 1997 and 2015. Installed capacity onshore wind: 12.1 GW, offshore wind: 36 GW.

The main period during which little renewable generation occurred was in January of the year 1997. This shortage was primarily attributed to the absence of wind, as depicted in Figure 21. In comparison to the year 2015, clear differences can be observed in electricity production from wind energy, with variances of approximately 42.5 GW at t=30, t=245, and t=673. Although wind and solar energy generally complement each other, the contribution of solar energy is not sufficient to eliminate the significant differences between the two weather years, as illustrated in Figure 22.

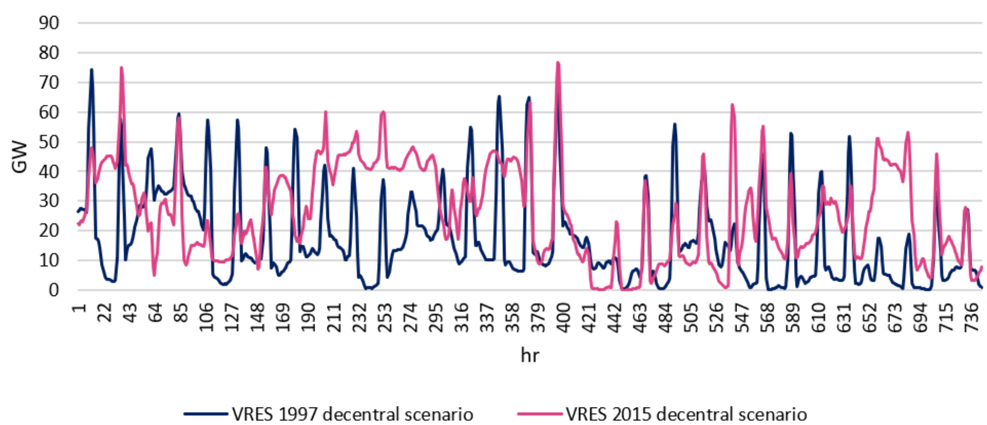


Figure 22: vRES generation for the decentral energy system in January for both weather years: 1997 and 2015. Installed capacity onshore wind: 12.1 GW, offshore wind: 36 GW, solar PV: 126.1 GW.

Main Takeaways

1. The Dutch electricity and hydrogen market in 2040 has been modelled in Linny-R, which is a graphical modelling tool specifically designed for MILP problems.

2. The model only incorporates operating system costs. Capital costs are not included in the model.

3. In the model, gas fields have been designed to provide seasonal storage and salt caverns have been designed to accommodate short cyclic storage.

4. Four possible energy systems have been used to determine the vertices in which the playing field of the energy transition will unfold in the Netherlands.

5

Verification and validation

5.1 Verification

Verification of a model involves confirming that the model accurately represents the intended system or phenomenon according to specified requirements and standards. The verification of the model will be assessed in three steps. First of all, the behaviour of the UHS facilities in the model will be compared to the behaviour of the operational gas storage facilities in Zuidwending and Grijpskerk, as natural gas serves as a proxy market in this research. Subsequently, the impact of the addition of seasonal storage will be evaluated based on its impact on the electricity served with peak generators and Hydrogen-to-power. Finally, a sensitivity analysis has been conducted.

5.1.1 Seasonal and short cyclic storage

Natural gas storage is used as a proxy market for this research. Although this choice may encounter criticism because the demand for natural gas is dominated by heating demand, which may not be the case for hydrogen, an argument in favour of using natural gas as proxy market arises from hydrogen's potential application in seasonal electricity storage. Therefore, natural gas storage has still been used as a proxy market.

To determine whether the storage facilities in the model show similar behaviour as the natural gas storage facilities, a comparison is made with the behaviour regarding the injection and withdrawal of seasonal natural gas storage in gas fields and the short-cyclic natural gas storage in salt caverns. The gas field in Grijpskerk and the salt caverns in Zuidwending have been chosen as reference storage facilities. Important to note for the interpretation of the figures presented below is that the time-frame in the figures from AGSI span from the 1st of January till the end of the year [54], while the graphs depicting the model's behaviour commence on the 1st of April. This choice is made because the seasonal storage is empty on the 1st of April, causing no difficulties regarding the costs of residual storage capacity in the model.

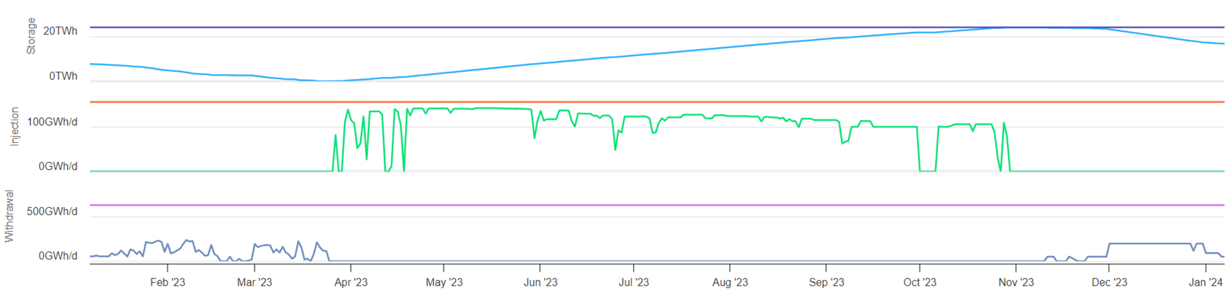


Figure 23: Gas field Grijpskerk. January 2023 - January 2024. Retrieved from [54].

The behaviour of seasonal storage in Grijpskerk is depicted in Figure 23. In this case, natural gas is stored in an underground gas field. During the summer months, the storage is filled, and during the winter months, the stored gas is withdrawn. Injection and withdrawal alternate only once a year. The timing of the switch between injection and withdrawal varies depending on the storage and weather conditions in a certain year. However, in this research, it is assumed that this switch occurs on October 1st, based on the comparison of historical data from Grijpskerk, Norg, and Bergermeer. Generally, a certain portion of gas is retained in the storage at all times, serving as a backup for emergencies. However, as shown in Figure 23, the storage is completely emptied during the winter of 2022-2023. This can be explained by the geopolitical turmoil surrounding Russia's invasion of Ukraine, which led to a gas crisis in Europe.

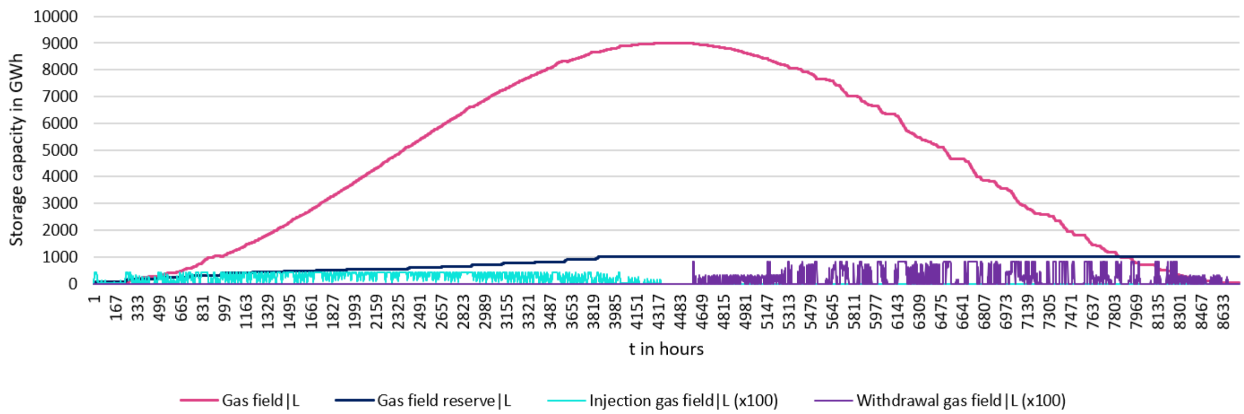


Figure 24: Gas field behaviour model.

Figure 24 represents the gas field's behaviour in the model. It reflects the same characteristics as Figure 23. A clear seasonal pattern is evident, and the single switch from injection to withdrawal occurs on October 1st. Additionally, reserve storage is modelled, which corresponds to the same gas field in reality. However, in the model, this gas is assigned a high cost, ensuring that the reserve is not used under normal circumstances but is only accessed during periods of high scarcity.

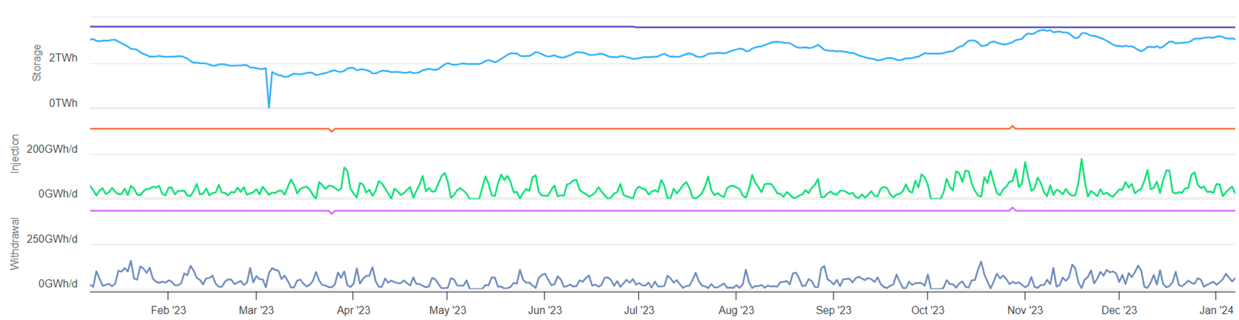


Figure 25: Salt caverns Zuidwending. January 2023 - January 2024. Retrieved from [54]

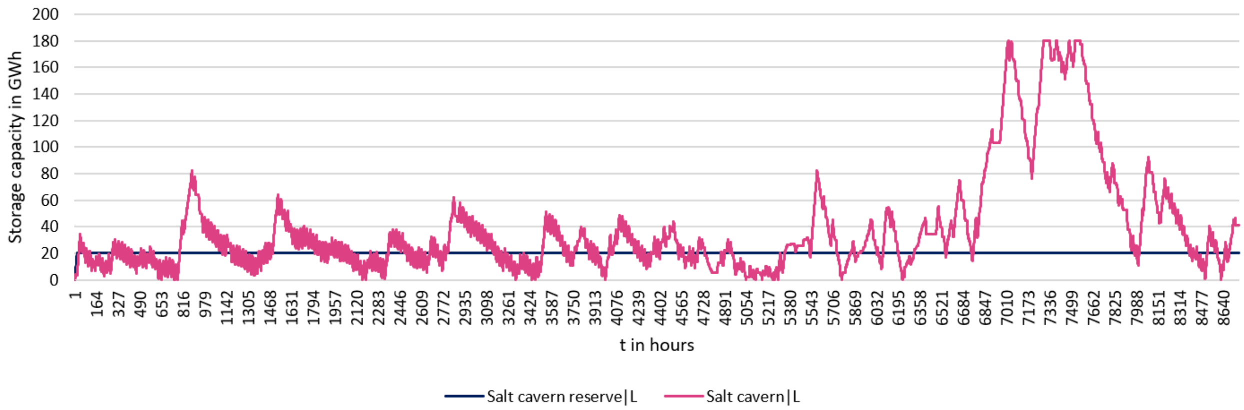


Figure 26: Salt cavern behaviour model.

Figure 25 distinctly illustrates the continuous injection and withdrawal throughout the entire year, in contrast to seasonal storage. The installations at the salt caverns in Zuidwending exhibit a rapid response capability to changes in the gas delivery system, allowing for a transition from maximum injection to maximum withdrawal within a 15-minute time-frame [60]. Given the 1-hour time step of the model, this exceeds the model's resolution. However, it is assumed that injection and withdrawal at the same time is not permitted. Due to the time step of 1 hour, this results in the ability to switch between injection and withdrawal only once per hour. While theoretically, such transitions could occur up to four times per hour (since it only takes 15 minutes), practical considerations, primarily associated with high costs, prevent this frequency in practice. For the modelling process, it will, therefore, have only a limited impact on the model outcomes compared to reality.

5.1.2 Seasonal electricity storage

As previously stated, hydrogen can be employed for long-term electricity storage. This is especially significant because there is typically a surplus of renewable electricity in the summer, while shortages are prevalent in the winter. The expectation is that as the magnitude of seasonal storage increases in the model, there will be fewer deficits in the winter. To evaluate whether the model accurately depicts this behaviour, the size of seasonal storage is varied across three values, and the impact is observed on the sum of the Hydrogen-to-Power process and the electricity served with peak generators. This experiment was conducted without any salt caverns to assess the actual impact of seasonal storage. The hypothesis is that as the scale of seasonal storage increases, the value for Hydrogen-to-power rises, while the value for the electricity served with peak generators decreases. Table 6 presents the results of this verification step:

Table 6: Values of electricity served with peak generators in GWh and Hydrogen-to-power for three different seasonal storage policy decisions.

	Electricity served with peak generators	**Hydrogen-to-power**
Low	897	1449
Mid	663	1665
High	433	1892

Table 6 supports the hypothesis: the electricity served with peak generators decreases as the size of seasonal storage increases, while the level of Hydrogen-to-power increases.

5.2 Sensitivity analysis

The final verification method involves conducting a sensitivity analysis of system variables to determine whether the observed relations between the variables and KPIs align with expectations. In addition to the

KPIs, also the average electricity price and the average hydrogen price are included in the sensitivity analysis to ensure the model is behaving in the way it should. In this sensitivity analysis, an initial baseline run is conducted to establish baseline values for total system operating costs and electricity served with peak generators. Subsequently, for each run, one variable is adjusted by +20% while keeping other variables constant to assess the impact of this variable on KPIs compared to the base case. The sensitivity analysis has been conducted based on the decentral and low-seasonal storage policy.

Table 7: Results of the sensitivity analysis of the decentral energy system.

		Avg electricity price	Avg hydrogen price	CO_2 level	Total system operating costs	Electricity served with peak generators
Base scenario		**0.1125**	**0.0784**	**10044**	**19687**	**242.5**
H2 demand agriculture	20%	0.00%	0.00%	0.00%	0.00%	0.00%
H2 demand built environment	20%	0.00%	0.00%	0.00%	0.00%	0.00%
H2 demand industry	20%	0.75%	10.67%	0.51%	5.64%	0.50%
H2 demand transport sector	20%	0.67%	1.77%	0.09%	0.79%	0.10%
Installed capacity electrolysers	20%	-0.05%	-1.79%	0.07%	-0.24%	0.00%
Installed capacity SMR with CCS	20%	0.19%	-5.16%	6.00%	0.19%	0.30%
Installed capacity ammonia crackers	20%	1.53%	0.02%	0.06%	0.00%	0.00%
Ammonia price	20%	-0.29%	-0.05%	0.04%	-0.02%	0.00%
Price natural gas	20%	4.32%	8.46%	-0.43%	3.87%	0.00%
Price biomass	20%	0.36%	0.13%	0.09%	0.06%	0.00%
Price nuclear	20%	0.00%	0.00%	0.00%	0.00%	0.00%
Installed capacity CCGT with CCS	20%	-3.80%	-0.21%	12.72%	-1.12%	-36.60%
Installed capacity nuclear plants	20%	0.00%	0.00%	0.00%	0.00%	0.00%
Installed capacity biomass incineration	20%	0.31%	0.19%	-0.04%	-1.35%	-1.70%
E demand agriculture, ICT and energy	20%	5.46%	1.20%	1.06%	3.35%	24.10%
E demand built environment	20%	19.51%	5.80%	2.16%	15.79%	223.50%
E demand industry	20%	8.62%	3.52%	2.58%	9.24%	68.80%
E demand transport	20%	4.09%	1.64%	1.39%	4.53%	32.80%
Installed capacity Li-ion batteries	20%	-5.12%	1.36%	0.63%	-2.50%	-36.00%
Installed capacity hydrogen turbines	20%	-3.94%	0.97%	0.01%	-1.38%	-50.40%
Installed capacity solar energy central	20%	-2.46%	-1.48%	-0.83%	0.38%	-1.00%
Installed capacity solar energy decentral	20%	-3.29%	-2.63%	-1.46%	0.94%	-1.90%
Installed capacity offshore wind	20%	-5.91%	-4.18%	-5.21%	-1.97%	-11.40%
Installed capacity onshore wind	20%	-2.93%	-1.15%	-1.44%	-1.28%	-3.40%

From the sensitivity analysis, it can be concluded that there are no relationships that contradict expectations. However, what becomes clear from Table 7 is that the system's sensitivity primarily lies with the variables related to the electricity market, rather than the hydrogen market. Especially the electricity demand of the built environment exhibits high sensitivity with respect to the electricity served by peak generators. This is because the peak generators are only utilised during periods of extreme scarcity, as they are extremely costly. Such circumstances typically arise during specific moments in winter when electricity demand in built environments is at its peak. When this demand increases by 20%, this effect is reflected in the electricity generation required from peak generators.

5.3 Validation

Validation of a model involves verifying whether the outcomes obtained with your computational model do indeed provide a satisfactory answer to the research question. This means that the results must exhibit sufficient agreement with empirical observations of the system [61]. In this study, however, the electricity and hydrogen markets in 2040 have been examined. Since this system does not yet exist, the model is referred to as a "constructive" model. Constructive models cannot be validated based on empirical data because this data simply does not exist yet. However, it is possible to validate the model using reports that have attempted to depict the future electricity and hydrogen markets as well. As the scenarios used in this study are based on the Integrated Energy System Exploration 2030-2050 [51], the outcomes of the constructive model have been compared with several graphs presented in their report. Although the study being compared is a heuristic model, of which is known that the model is not optimal, it is nonetheless valuable to make the comparison to determine if the results of the manufacturing model are in the correct orders of magnitude, in the absence of a better alternative.

5.4 Electricity supply

Firstly, a comparison has been made based on the composition of the total electricity generation. In Figure 27, the focus is on the middle four stacked columns: the decentral, national, European, and international energy systems in 2040.

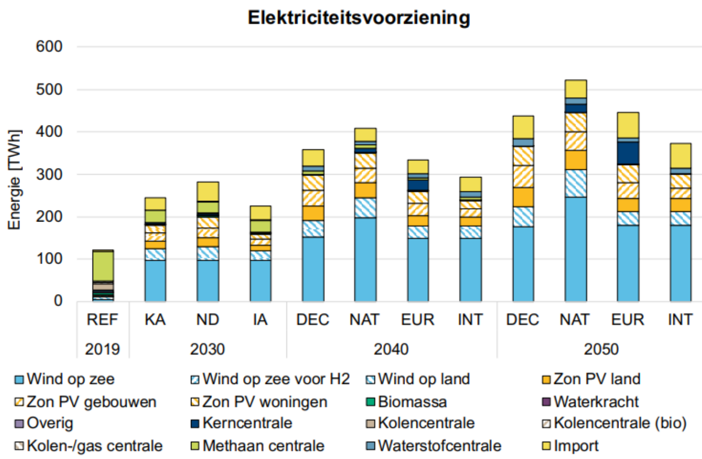


Figure 27: Integrated Energy System Exploration 2030-2050 [51].

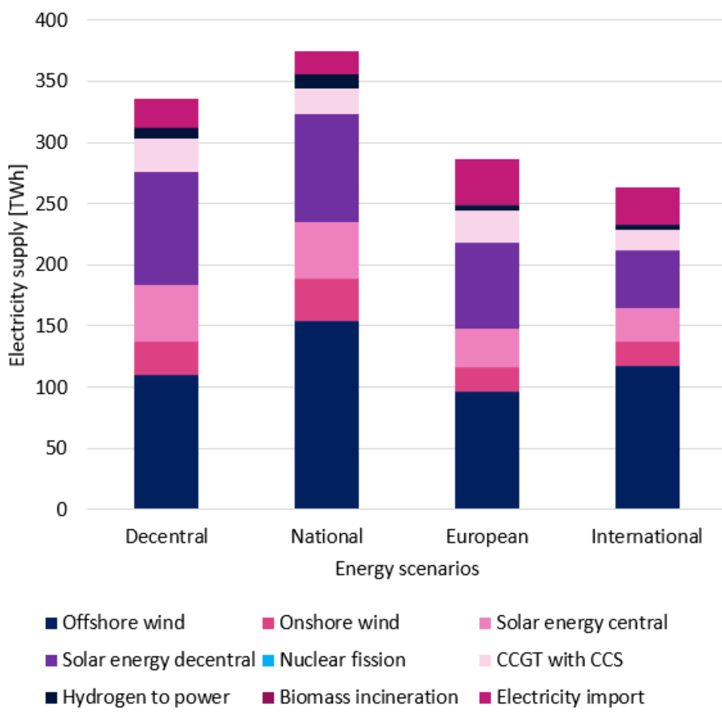


Figure 28: Electricity supply results from the constructive model.

When comparing Figures 27 and 28, it is evident that a similar composition of electricity generation technologies is observed in the overall electricity generation. Remarkably, the generated amounts of electricity do not correspond entirely. This can be explained for two reasons. Firstly, the graph of the constructive model is modelled based on the weather conditions in 2015, chosen as the standard weather year for this study. To determine the total vRES generation, the installed capacity needs to be multiplied by the capacity factor. Since the capacity factor varies with each weather year, it can result in differences in electricity generation from vRES. Additionally, the constructive model is optimised based on minimising system costs. Although the installed capacity of conventional generation units is the same in both studies, the actual generated electricity from such a generation unit in the constructive model may deviate from the prediction made in the Integrated Energy System Exploration 2030-2050 due to different model assumptions, modelling software, and modelling approaches.

5.5 Electricity demand

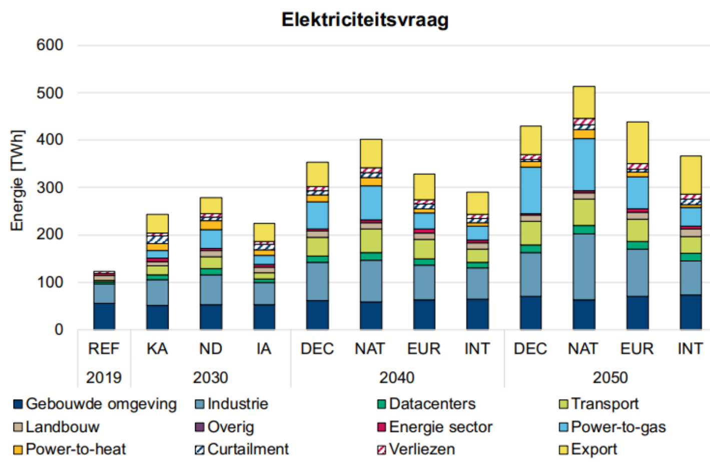


Figure 29: Integrated Energy System Exploration 2030-2050 [51].

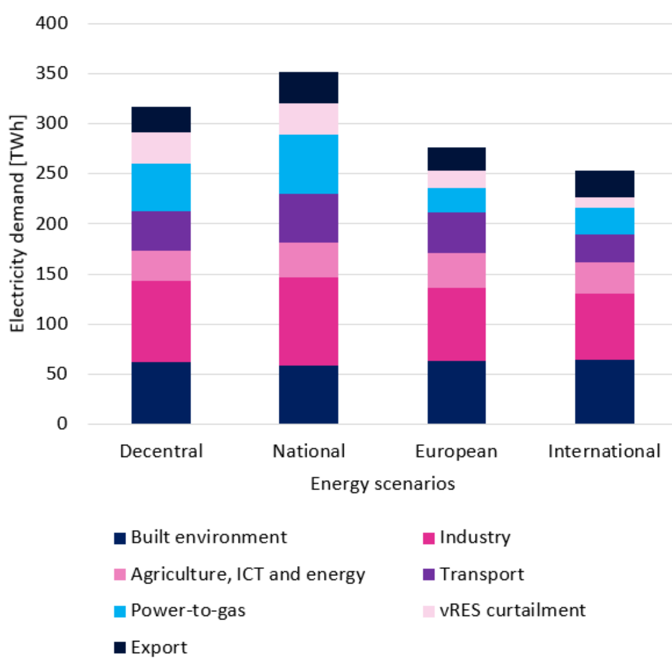


Figure 30: Electricity demand results from the constructive model.

Although differences between Figure 29 and Figure 30 emerge, generally the same trend is observed. In the Integrated Energy System Exploration, an estimate of the required underground hydrogen storage capacity has been made, but the specific configuration and characteristics of the storage facility design of that system have not been specified. Differences, such as in power-to-gas, can therefore be explained by variances in storage capacity and storage configuration between the two studies.

5.6 Hydrogen price

In the feasibility study report on offshore underground storage in the Netherlands [9], different scenarios of hydrogen costs are mentioned based on a study by CE Delft [62]. They distinguish three scenarios: the low scenario with a price of 2.2 €/kg, the mid scenario with a price of 2.7 €/kg, and a high scenario with a price of 3.5 €/kg. In this validation step, various experiments with different storage systems were conducted to determine if the hydrogen costs simulated in the constructive model fall within the range of 2.2 to 3.5 €/kg. This was done for the national energy system with a low-seasonal storage policy.

Table 8: Validation of the average hydrogen price in €/kg.

	CE Delft [62]		**Constructive model**
Low	2.2	**10 salt caverns**	2.2
Mid	2.7	**5 salt caverns**	2.5
High	3.5	**0 salt caverns**	3.6

As shown in Table 8, the values generated by the model generally fall within the range found in the CE Delft study. Only in the scenario with seasonal storage and no salt caverns, the price is 0.1 €/kg higher than in the high scenario of the other study. Since the difference is only 0.1 €/kg, this variance was deemed acceptable.

Main Takeaways

1. The model has been verified by analysing the behaviour of the UHS facilities and the impact of the low, mid and high-seasonal storage policy on the electricity served with peak generators and the amount of hydrogen-to-power.

2. The verification steps met the hypotheses. It was therefore assumed that the model was constructed correctly.

3. The model is validated by comparing the outcomes of the model with reports that have attempted to depict the Dutch future electricity and hydrogen markets as well.

4. The comparison has been made on the electricity supply, electricity demand and the hydrogen price.

5. Overall, it has been concluded that the variances of the constructive model compared to the other studies fall within an acceptable range.

6. Therefore, it can be concluded that the model has been successfully validated and may be used for the purpose of this research.

6

Storage facilities designs

Based on the study Integrated Energy System Exploration 2030-2050, the estimated hydrogen storage capacity varies for different scenarios, ranging from 8 TWh to 15 TWh [51]. This number includes both short-cyclic and seasonal storage. However, the study does not provide information regarding the proportion of this capacity dedicated to seasonal storage and short-cyclic storage, nor information on the designs of the storage capacities. In this research, it is assumed that seasonal storage will take place in gas fields due to their significantly larger capacity, while short-cyclic storage will take place in salt caverns, as salt caverns are pointed out in the literature to be suitable for multiple storage cycles per year. Currently, if you look at the underground storage of natural gas, the same division is seen.

6.1 Salt cavern designs

Based on the literature on salt caverns, four designs have been developed, which will be tested for their performance in various energy systems using the constructed model. Since this study does not delve into the specific geological characteristics of the storage facilities at a certain location, only three main design variables have been identified: the working gas volume, the injection rate, and the withdrawal rate. The designs are formulated based on the range of values found for these design variables in the literature.

6.1.1 Working gas volume

First and foremost, the storage capacity of a salt cavern is crucial. The storage capacity depends on various variables, such as the size or volume (m3) of the cavern and the work pressure range, which is influenced by the depth of the salt cavern. The deeper the salt cavern, the higher the pressure, the more hydrogen can be stored. Globally, there are already four operational salt caverns storing pure hydrogen: Clemens Dome, Moss Bluff, and Spindletop in the US, and Teesside in the UK. In the Netherlands, Gasunie is also constructing a salt cavern intended for pure hydrogen storage at Zuidwending. The parameters of these operational and planned hydrogen storage facilities are provided in Table 9.

Table 9: Parameters of operational salt caverns for hydrogen storage. Adjusted from [12].

Parameter	Clemens dome	Moss Bluff	Spindletop	Teesside	Zuidwending
Start [year]	1983	2007	2016	1972	2028
Geometric volume [m3]	580,000	566,000	906,000	3 x 70,000	600,000
Avg. depth [m]	1,000	1,200	1,340	365	1,250
Pressure range [bar]	70-137	55-152	68-202	45	70-140
Working volume [GWh]	81.9	124.5	277.8	27.36	200

As indicated in Table 9, the WGV ranges from 27 to 200 GWh. Considering that the first hydrogen storage facility in the Netherlands will have a capacity of 200 GWh, it is reasonable to choose higher WGV ranges for this research compared with the salt caverns in the US and UK, given its focus on the geographical scope of the Netherlands. Consequently, designs with WGV values of 100, 150, and 200 GWh have been selected for this study. For all designs, a working pressure range of 70-140 bar is assumed, aligning with the storage facility in Zuidwending. The salt cavern's storage capacity is crucial, as underutilisation of the total amount of WGV leads to the spreading of capital costs for cushion gas over a smaller WGV. This results in higher costs per stored kilogram or gigawatt-hour of hydrogen. Since cushion gas accounts for approximately 25% of the capital expenditures for salt caverns [9], this situation is undesirable from a cost perspective.

6.1.2 Withdrawal rates

For the planned hydrogen storage facility at Zuidwending, theoretical withdrawal rates of hydrogen up to 4.37 GWh/hr will likely be possible [12]. However, the withdrawal rate is mainly limited to a maximum pressure drop of 10 bar per day [12]. For the Zuidwending salt cavern, this equals a maximum withdrawal of 15 GWh per day. This way, storage integrity can be maintained, and the risk of geometric volume loss due to salt creep is limited. It is important to mention that this maximum applies per day, meaning that higher withdrawal rates than 0.625 GWh/hr per hour are possible as long as the maximum pressure drop per day is not exceeded. For the design of the salt caverns, this is an important aspect to consider, as increasing the hourly withdrawal rate will have little effect on storage utilisation due to the daily withdrawal limitations. The withdrawal rate per hour for the planned hydrogen storage in Zuidwending has been established at 1.73 GWh/hr [63]. Since increasing the withdrawal rate will have a limited impact on the robustness of the storage due to the aforementioned technical constraint, it has been decided to scale the withdrawal rate in the designs according to their capacity, with 1.73 GWh/hr being used for the largest cavern.

6.1.3 Injection rates

Regarding the injection rate, there is no specific limitation. However, it is commonly observed that the injection rate tends to be lower than the withdrawal rate. This is because the filling process of the storage is generally considered less time-critical than the emptying process, allowing for a more extended period for filling compared to emptying [9]. The generally lower injection rates are not primarily associated with the well design. What does play a crucial role in determining the injection rate is the installed compressor capacity, which is inherently linked to the magnitude of the injection rate. Compressing hydrogen significantly contributes to the overall cost of storage, both operationally and in terms of capital costs [64]. The impact of the injection rate or the required compressor power on costs will therefore be explained further in Section 7.

Based on the three main design variables of salt caverns, the following four salt cavern designs have been designed and presented in Table 10.

Table 10: Salt cavern designs.

	WGV [GWh]	**Injection rate [GWh/hr]**	**Withdrawal rate [GWh/hr]**
Design 1	100	0.67	1
Design 2	150	1	1.16
Design 3	200	1.33	1.73
Design 4	200	2	1.73

6.2 Gas field designs

In this study, the extent to which seasonal storage takes place is considered a policy choice. Based on the required storage range determined in the Integrated Energy System Exploration 2030-2050 for the year 2040, these policy choices have been set at 5, 10, and 15 TWh. Assuming that the seasonal storage of hydrogen will operate in the same way as seasonal storage facilities for natural gas, storage will start filling on April 1st and start emptying on October 1st. The injection rate required to have a fully filled storage on October 1st is determined by taking the derivative of Equation 14 which is formulated to describe the seasonal pattern. The derivative is presented by Equation 15. In the seasonal storage of natural gas in gas fields, a significantly higher withdrawal capacity is observed [54] because withdrawal is often considered a more critical variable for the performance of the storage facility. In this study, it has been chosen to determine the withdrawal rate twice as high as the injection rate. Additionally, the general assumption is made that the work pressure range of the storage facility is between 100 and 200 bar.

Table 11: Gas field designs.

	WGV [GWh]	Injection rate [GWh/hr]	Withdrawal rate [GWh/hr]
Low	5000	3.37	6.73
Mid	10000	4.09	8.17
High	15000	5.88	11.76

Main Takeaways

1. Three seasonal storage policies are considered in this research: the low (5 TWh), mid (10 TWh) and the high (15 TWh) seasonal storage policy.
2. Salt caverns experience withdrawal limits because of the maximum pressure decrease of 10 bar per day in a salt cavern designed like the one in Zuidwending.
3. The injection capacity is typically lower compared to the withdrawal capacity since the filling process of the storage is generally considered less time-crucial than the withdrawal process.
4. The work pressure range of gas fields is assumed to be higher for gas fields in comparison to salt caverns since the depth of gas fields is typically higher than the depth of salt cavern construction.

7

Cost analysis

7.1 Conceptual framework of the cost analysis

In addition to the underground storage facility itself, various components are required to ensure the successful operation of the storage facility. In this study, it is assumed that the hydrogen entering the facility originates from a pipeline of the hydrogen network. The hydrogen will be stored underground under pressure, and to achieve this, compressors are necessary. When the hydrogen is extracted from the storage facility, hydrogen treatment is required. In the case of hydrogen storage in salt caverns, the hydrogen will contain water and a drying step must be undertaken to remove the water from the hydrogen. For gas fields, a purification unit is required to remove contamination, such as natural gas.

These components not only contribute to the capital costs but also consume energy to achieve the desired purpose. This research maps the system costs of hydrogen storage in salt caverns and gas fields, taking into account all costs incurred from the point where the hydrogen leaves the hydrogen network, is compressed, injected into storage, stored in the cavern, extracted, and finally, the dehydration or purification of hydrogen before it can be re-injected into the hydrogen network. Figure 31 conceptually illustrates which part of the system is subjected to the cost analysis.

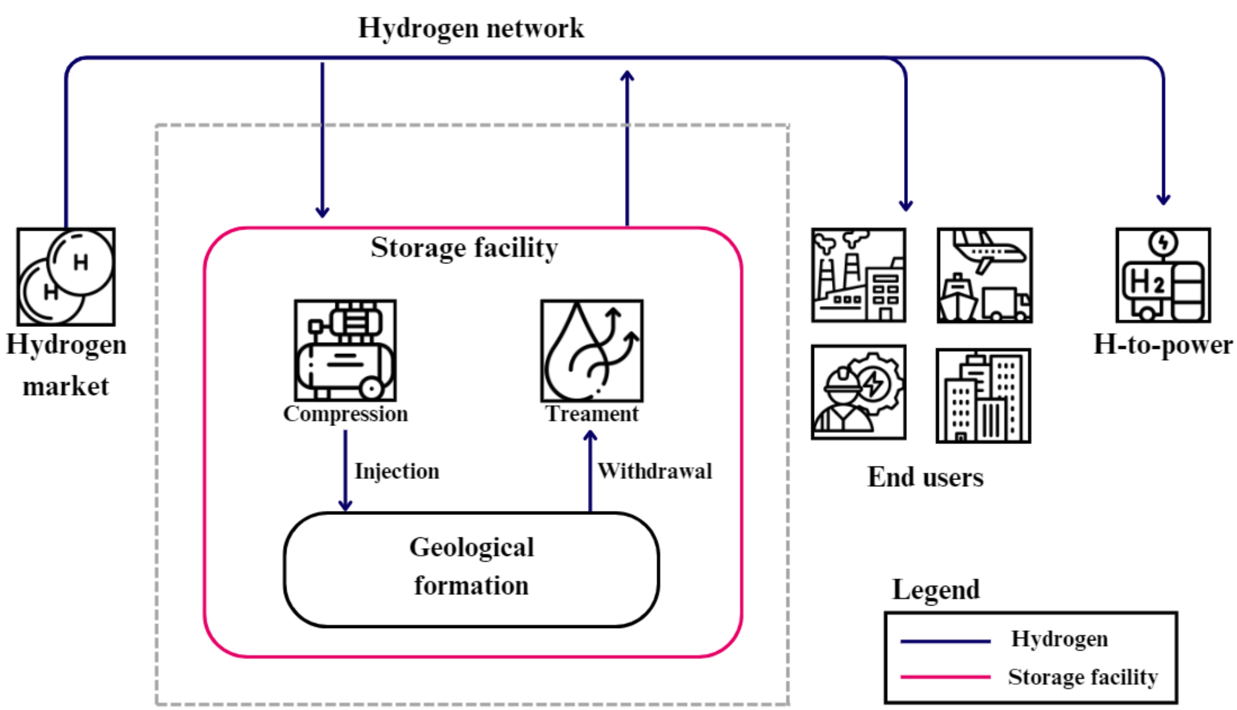


Figure 31: In the grey frame the system boundaries of the cost analysis.

For the cost analysis, three scenarios have been considered: the low, mid, and high scenario, where the low scenario represents the one with the lowest capital costs, and the high scenario depicts the other, more expensive extreme. Comprehensive information on the input parameters on the low, mid and high-cost scenarios is further elaborated in Appendix B.

7.2 Cost structure

In this study, it is assumed that future hydrogen storage will have a cost structure similar to current natural gas storage. This means that a market entity is responsible for facilitating the storage, including all costs related to the construction and operation of both underground and above-ground facilities. From this point onwards, the entity responsible for the construction and operation of the storage will be referred to as the asset owner. Once the storage is operational, parties can rent a part of the total storage capacity from the asset owner. In the current practice of natural gas storage, parties pay a fixed annual rate for using the storage for the duration of the contract. Additionally, they also pay a fee per injected or withdrawn GWh of natural gas. This will likely also be done for hydrogen in the future. This allows the asset owner to recover the costs incurred for compressing the hydrogen, dehydrating it, and purifying it. In this study, by mapping both the capital and operational costs, Essent gains insight into the magnitude of the expenses that the asset owner is likely to allocate to them.

7.3 Methodology for system cost calculation

To assess the economic viability of hydrogen storage facilities in the Dutch energy system in 2040, the system costs of the storage facilities are analysed. The desire to gain insight into the system costs is to provide Essent with an idea of the costs that the storage owner incurs per kilogram or GWh of hydrogen. Subsequently, they could use this information to negotiate price agreements in the contract or, in the case of a bidding process, have a guideline for determining the height of their bid. Besides, it is imperative to determine the costs before determining the potential profits of underground hydrogen storage facilities within the Dutch energy system by the year 2040. The system costs are determined from the average annual total expenditures of the hydrogen storage system:

$$TotEx = CapEx + OpEx \tag{16}$$

$$TotEx/year = CapEx/year + OpEx/year \tag{17}$$

$$TotEx/year = CapEx/year + fixed\ OpEx/year + variable\ OpEx/year \tag{18}$$

The OpEx is divided into fixed OpEx and variable OpEx. This division allows for a more detailed analysis of the operational costs associated with the hydrogen storage system. The fixed OpEx provides a stable cost component (expressed in % of CapEx), while the variable OpEx accounts for variations in production levels, offering insights into how operational costs may fluctuate based on the system's activity. In this study, the fixed operational costs are determined by taking a percentage of the capital costs, while the variable operational costs are extracted from the model, as aforementioned in Section 2.

The annual capital expenditures (CapEx/year) for each component are calculated by multiplying the investment cost by the annuity factor (AF), as expressed in the following equation:

$$CapEx/year = Investment \times AF \tag{19}$$

The annuity factor (AF) is calculated using the following formula:

$$AF = \frac{(1 + WACC)^n \times WACC}{(1 + WACC)^n - 1} \tag{20}$$

In this formula:

- AF is the annuity factor.
- WACC is the weighted average cost of capital.
- n is the depreciation period in years.

This formula is commonly used in financial analysis to determine the annual payment that, when discounted at the WACC, is equivalent to the initial investment over the given depreciation period. The value of WACC has been determined based on the average of two studies on underground hydrogen storage, assuming 9.16% [65] and 8% [66]. Therefore, for this study, a WACC of 8.6% has been used for the mid-case cost analysis. The annuity factor essentially represents the present value of a series of future cash flows.

When the CapEx/year is known, the fixed OpEx can be determined using the formula below:

$$Fixed\ OpEx/year = CapEx/year \times O\&M \tag{21}$$

Subsequently, the total system costs can be determined based on the TotEx per year and the amount of hydrogen leaving the storage facility yearly:

$$Average\ system\ costs\ per\ unit\ H_2 = \frac{TotEx/year}{H_2\ production/year} \tag{22}$$

Essent can use the average system costs per kg produced hydrogen as a comprehensive metric to understand the overall costs of the salt cavern and gas field storage systems and make informed decisions in investment decisions, contract negotiations or bidding processes.

7.4 Compressors

As previously mentioned, when considering the injection rate, it becomes crucial to analyse the correlation between the injection capacity and the associated compression power. The compression of hydrogen plays a substantial role in the overall cost of storage, impacting both operational and capital expenses [64] and is therefore considered in detail. Figure 32 shows the suitable compressor techniques for different discharge pressures and inlet volume flows. Underground hydrogen storage facilities will be subjected to high inlet volume flows and moderate required discharge pressures. Figure 32 shows that centrifugal multi-stage compressors are well-suitable for this purpose. In this research, it is therefore assumed that multiple-stage centrifugal compressors are used for hydrogen compression.

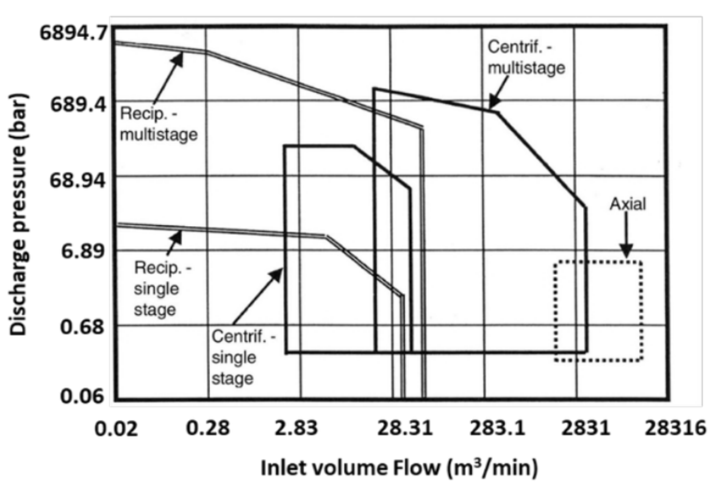


Figure 32: Compressor selection based on the injection rate and discharge pressure [64].

7.4.1 Determining the required compressor power

Based on the following formulas, the required compressor power has been determined for different injection rates [in GWh/hr] using the following equations:

$$N = \frac{log\left(\frac{P_{\text{discharge}}}{P_{\text{suction}}}\right)}{log(x)} \tag{23}$$

In this context, the parameter $P_{\text{discharge}}$ is assigned a value of 140 bar for the compression in salt caverns, signifying the upper limit to which the hydrogen must undergo compression. For gas fields, the $P_{\text{discharge}}$ is assigned a value of 200 bar, since the pressure in gas fields is generally higher as they are located at greater depth. Furthermore, for both gas fields and salt caverns, P_{suction} is established at 40 bar, representing the mean anticipated pressure within the prospective hydrogen network [12]. The variable x denotes the compression ratio per stage, a constant parameter set at 2.2 [64]. It is imperative to note that the value to be calculated, denoted as N, necessitates rounding up to the nearest integer.

$$T_{discharge} = T_{suction}\left[1 + \frac{\left(\left(\frac{P_{discharge}}{P_{suction}}\right)^{\frac{k-1}{Nk}} - 1\right)}{n_{isentropic}}\right] \tag{24}$$

In the aforementioned equation, the symbol k represents the adiabatic index, commonly referred to as the isentropic exponent, with a specific value of 1.4 for hydrogen. N denotes the number of required compression stages, and $n_{isentropic}$ is established at 80% [64].

$$P_{average} = \frac{2}{3} \cdot \frac{P^3_{discharge} - P^3_{suction}}{P^2_{discharge} - P^2_{suction}} \tag{25}$$

$$T_{average} = \frac{T_{suction} + T_{discharge}}{2} \tag{26}$$

Subsequently, based on T_{average} and P_{average}, Figure 60 and Table 36 in Appendix B.1.2 were used to determine the compressibility factor (Z), a parameter essential in Equation 28 for determining the required compressor power.

$$Molar\ flow\ rate = \frac{\frac{injection\ rate}{molar\ mass\ H_2}}{24 \times 60 \times 60} \tag{27}$$

In Equation 27, the injection rate depends on the established design and the molar mass of H_2 equals 2 grams per mole.

$$Required\ power = N\left(\frac{k}{k-1}\right)\left(\frac{Z}{n_{\text{poly}}}\right)T_{\text{suction}}(q_m)R\left(\left(\frac{P_{\text{discharge}}}{P_{\text{suction}}}\right)^{\left(\frac{k-1}{N\cdot k}\right)} - 1\right) \tag{28}$$

For injection rates ranging from 0.67 to 5.9 GWh/hr throughout the different salt cavern and gas field designs, the desired compressor capacity has been determined. Table 13 shows the required compressor power for the different salt caverns designs and Table 14 shows the required compressor power for gas fields. A distinction has been made between salt caverns and gas fields as the discharge pressure of the gas fields is typically higher, prompting for more compressor power.

Table 12: Required compressor power in MW per design.

Table 13: Salt caverns.

Salt caverns	Compressor power
Design 1	13
Design 2	19
Design 3	26
Design 4	38

Table 14: Gas fields.

Gas field	Compressor power
Low policy	87
Mid policy	115
High policy	148

7.5 Results of the CapEx calculation

In this section, the findings from the analysis of the capital costs are presented. The input values used in the calculations can be found in Appendix B.

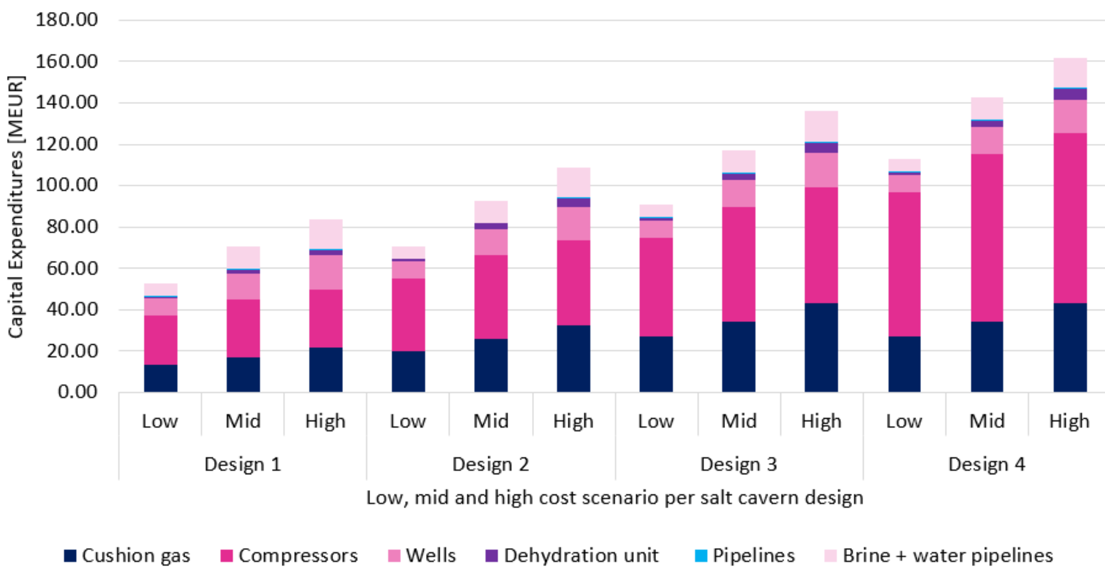


Figure 33: Capital costs of the salt cavern designs.

Figure 33 illustrates the breakdown of costs for four salt cavern designs, comparing three different cost scenarios (low, mid, and high). Prior to the economic analysis, attention was given to the magnitude of cost components in designing underground storage facilities. It was revealed that compressors had a significant share in the overall cost structure of such storage [64], as also becomes evident in Figure 33. Therefore, it was a validated decision to give considerable attention to this component. The total capital costs of salt cavern construction range from 53 M€ for the low-cost scenario of design 1, considered the most economical design, to 162 M€ for the high-cost scenario of design 4, representing the most expensive design.

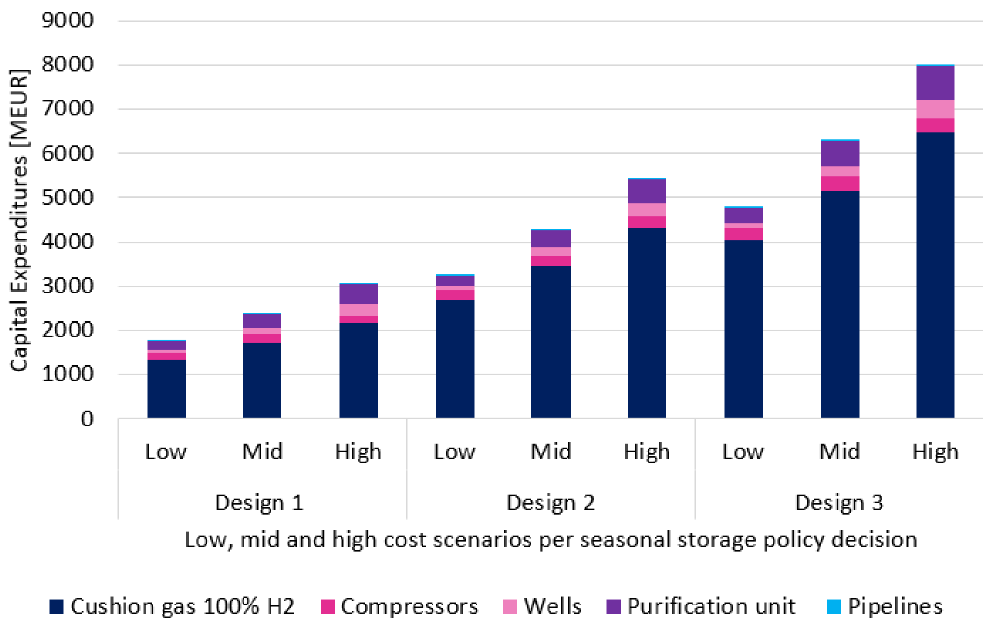


Figure 34: Capital costs of the gas field designs.

In comparison to salt caverns, gas fields have a completely different breakdown of total costs. Figure 34 illustrates that cushion gas, when H_2 is used, stands out as the largest cost component, reaching into the billions of euros. However, there is currently significant research being conducted on the use of alternative gas types as cushion gas. The primary drawback is that hydrogen in the gas field will mix with the cushion gas, leading to impurities in the extracted hydrogen. Hydrogen from a gas field already requires a purification step due to the presence of remaining natural gas in a depleted field. However, when the cushion gas consists partly or entirely of a different gas, a more extensive purification unit will be needed. For the economic analysis, beyond operational and capital costs, the recovery factor of hydrogen purification is seen as a crucial parameter for cost considerations [67]. The recovery rate when separating hydrogen from natural gas falls in the range of 85 to 95% [67]. Additionally, research is being conducted on the use of nitrogen as cushion gas, where the hydrogen recovery rate ranges from 70 to 90% [67]. The extent to which mixing occurs depends on various technical and geological factors such as storage duration, temperature, and pressure, which have been addressed only to a limited extent in this study. Simplified assumptions have therefore been made regarding the required size of the purification unit, based on the findings from the techno-economic case study of developing a UHS facility in the Roden gas field in the Netherlands [67].

For this research, various cushion gas cases have been formulated to determine the effect on capital costs. We have examined the use of natural gas as cushion gas. Because natural gas has a significantly high market price, it is unlikely to be used as cushion gas unless it is already stored in a field. Therefore, it is presumed that this gas comes at no cost since it originates from a gas field that has not yet been employed. Nitrogen, on the other hand, is considered a potential candidate for serving as cushion gas due to its lower capital costs, wide availability, and lower reactivity of nitrogen with hydrogen compared to other gases such as CO_2 and natural gas [18] [68]. Figure 35 shows the cost breakdown of the different cushion gas cases. Only the mid-cost scenario of the mid-policy seasonal storage design (10 TWh) is shown.

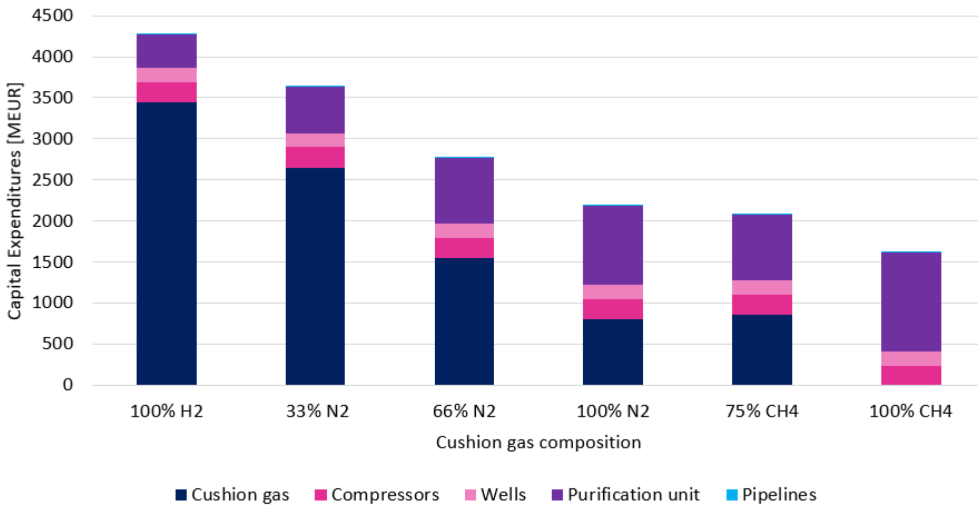


Figure 35: The effect of the different cushion gas cases on the capital costs of gas fields.

From Figure 35, it becomes evident that significant cost reductions can be achieved when hydrogen is replaced by natural gas or nitrogen, despite the markedly increasing costs for the purification unit when the share of alternative gases in the cushion gas increase.

In this study, it was assumed that the cushion gas could not be recovered. Although the NAM has conducted studies for natural gas to see if this is possible, there are still many concerns about subsidence and thus safety [69]. In the future, it may be found that this is possible, which could significantly reduce costs because the cushion gas can be sold at market prices when the storage facility reaches the end of its life.

Main Takeaways

1. This research maps the system costs of hydrogen storage in salt caverns and gas fields, taking into account all costs incurred from the point where the hydrogen leaves the hydrogen network, is compressed, injected into storage, stored in the cavern, extracted, and finally, the dehydration or purification of hydrogen before it can be re-injected into the hydrogen network.
2. The required compressor capacity has a significant impact on the capital costs of salt caverns.
3. The capital costs inquired for gas fields strongly depend on the cushion gas that is used.
4. The use of other cushion gas than hydrogen in gas fields prompts increased purification unit power, significantly affecting the capital costs.

8

Experiment design

In the pursuit of enhancing the understanding of the technical and economic potential of storage configurations in the future energy system, various experiments have been conducted. These experiments aim to delve into the societal and economic performance of different storage configurations in the future energy system. Through systematic investigation and analysis, this research seeks to uncover key insights that will inform the development and optimisation of underground hydrogen storage facilities, helping in the integration into the future energy system.

8.1 Determining the number of required salt caverns, considering the policy decision for seasonal storage

To determine the required amount of storage capacity, several experiments are conducted. Seasonal storage is considered a policy choice with three scenarios: low, mid, and high-seasonal storage policy. Detailed information about the technical parameters chosen for these storage facilities can also be found in Section 6.

Depending on the size of seasonal storage, a specific number of salt caverns will be required in the future energy system. This is because, alongside the desire for seasonal storage, there is also a need to provide short-cyclic storage to ensure a constant supply of hydrogen to industries, for example. In this context, not only is the storage capacity important but also the injection and production capabilities are crucial properties for the performance of storage facilities in the future energy system [70]. The injection and production capacity of a single salt cavern is limited, but when multiple salt caverns operate simultaneously, the desired injection and production requirements can still be met. Based on the literature, four designs for salt caverns have been developed and presented to the reader in Table 10 in Section 6. For each of these salt cavern designs, the number required will be determined for the low, mid, and high policy decisions for seasonal storage, considering the different future energy systems.

One salt cavern is added at a time to determine the amount of short-cyclic storage needed in addition to seasonal storage. The impact on operating system costs is assessed. Salt caverns are added until the reduction in operating system costs is smaller than the CapEx related to the salt cavern design, taking into account the lifetime of a salt cavern. It is worth noting that an increase in the quantity of identical elements within a system leads to a decreased value added to the corresponding system. This phenomenon is also referred to as diminishing returns.

This initial round of experiments involves four attributes, with a varying number of levels associated:

1. The decentral, national, European, and international energy systems, each representing a vertice of the playing field in which the energy transition is likely to unfold.
2. The low, mid, and high scenarios for seasonal storage represent policy choices.
3. The four different designs of the salt caverns, as determined in Table 10.
4. The number of salt caverns, added one by one to determine the reduction in operating system costs. These levels range from 0 and 25.

An experimental design as described above leads to 1248 possible combinations of variables. The runtime of a one-year simulation is approximately just over 2 minutes per run, resulting in a total runtime of approximately 42 hours. Due to the substantial scale of experiments involving four distinct salt cavern designs, resulting in relatively extensive experimental procedures and prolonged run times, it has been decided that after this initial experiment, an assessment will be conducted to determine which salt cavern design performs optimally across various scenarios. The performance will be determined based on the reduction in system costs that a design can accomplish, considering the different capital costs of salt caverns and the number of salt caverns required to achieve this reduction in operational system costs. Only the design that performs best will be considered in subsequent experiments, where the robustness of the choice for the number of required salt caverns is assessed, given the various storage configurations.

8.2 Robustness analysis

Once the number of required salt caverns per energy system is determined, a robustness analysis will be conducted to determine the robustness of the chosen number of salt caverns when the most influential environmental variables change in value. To identify which variables have the greatest impact on the system, a sensitivity analysis will be performed for each of the energy systems.

This sensitivity analysis will highlight several critical variables, which will be varied in value in the experiments. The experiments will be set up as a full factorial design, meaning that all possible levels of the different variables will be combined. The size of the experiments must not be too large due to the memory constraints of Linny-R, hence the decision to partition the experiments into smaller ones.

Each energy system has 3 system variations as an energy system can occur with low, medium, and high policies for seasonal storage. This results in 12 system variations across all energy systems. When accounting for 2 weather years, the number of experiments increases to 24. Figure 36 provides a conceptual overview of the experiment design.

Decentral	2015	1997
Low	Experiment 1	Experiment 4
Mid	Experiment 2	Experiment 5
High	Experiment 3	Experiment 6

National	2015	1997
Low	Experiment 7	Experiment 10
Mid	Experiment 8	Experiment 11
High	Experiment 9	Experiment 12

European	2015	1997
Low	Experiment 13	Experiment 16
Mid	Experiment 14	Experiment 17
High	Experiment 15	Experiment 18

International	2015	1997
Low	Experiment 19	Experiment 22
Mid	Experiment 20	Experiment 23
High	Experiment 21	Experiment 24

Figure 36: Experiment design.

The objective of these experiments is to assess the robustness of the chosen number of salt caverns, as determined in the previous section, under changing environmental variables. A robustness analysis is typically conducted based on the Minimax principle.

8.2.1 Minimax regret approach

Based on the model, a robustness analysis will be conducted later in this study. A robustness analysis is typically performed based on the Minimax regret (MMR) principle because it is a powerful decision-making tool under uncertain conditions. Regret refers to the difference between the actual result of a particular choice made and the results that could have been achieved if a different choice had been made. The Minimax regret criterion selects the alternative with the least maximum regret, minimising the impact of the worst-case scenario. An advantage of the Minimax regret approach is that it is a widely used method and is therefore well-known in the decision-making world. Another advantage mentioned in the literature is that when using this method, there is no need to consider probabilities or how likely specific situations are [71], making it a relatively simple approach. A drawback of the method is that it may ignore the potential benefits of other alternatives, and can therefore be overly pessimistic.

An example of the Minimax regret approach is given to demonstrate the approach to the reader.

Table 15: Minimax regret example.

	s1	**s2**	**s3**
d1	12	6	5
d2	9	5	4
d3	4	6	9
Best	12	6	9

	s1	**s2**	**s3**	**Max**	
d1	0	0	4	4	**<- Min**
d2	3	1	5	5	
d3	8	0	0	8	

In this example, the returns of certain decisions are presented across various scenarios, indicating that a higher value is positive. The optimal decision is assigned no regret, whereas decisions that perform less favourably in a particular scenario are assigned regret equal to the difference between the optimal decision and that particular decision. The regret table is displayed on the right-hand side. The maximum regret is determined for each decision, and this maximum regret is minimised. In this example, Decision 1 would therefore result in the least maximum regret.

Main Takeaways

1. First, an assessment of the required number of salt caverns in addition to a seasonal storage policy will be executed, which aims at minimising operational system costs.
2. Secondly, a robustness analysis will be conducted to determine the robustness of the chosen number of salt caverns. This robustness analysis will be done using the Minimax Regret approach.
3. The results of the experiments will finally be used to conduct the financial analysis.

9

Results

9.1 Determining the required number of salt caverns

To determine the operational system costs for all possible combinations of various attributes with their corresponding levels, an experiment of 1248 combinations was conducted. In other words, 1248 simulations were run, and with each run, the total operational system costs were determined. As a result, the difference in the operational system costs of different energy systems became evident, along with the extent to which hydrogen storage can reduce these costs within the different energy systems. Overall, it can be concluded that the addition of salt caverns leads to a significant decrease in system operating costs in all energy systems. Furthermore, in all energy systems, a trend was observed in the course of operational system costs, decreasing as more salt caverns were added to the system. As expected, the reduction in operational system costs with the addition of salt caverns becomes progressively less. This effect aligns with the *Diminishing returns principle*, explaining the diminishing value of adding identical elements to a system. The effect is shown in Figure 37 for design 3 in the decentral energy system and the low-seasonal storage policy storage configuration.

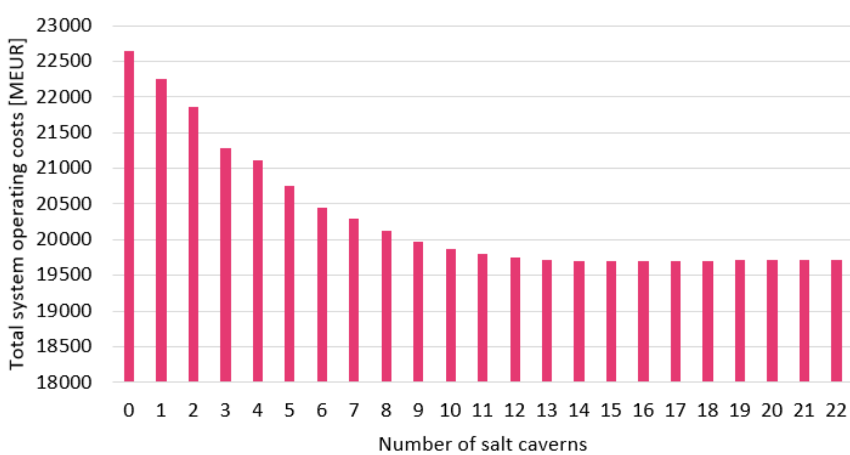


Figure 37: The diminishing return effect.

9.1.1 Performance salt cavern designs

When the performance of the different salt cavern designs (see Table 10) was compared, it became evident that design 3 outperformed designs 1, 2 and 4. *Good performance* was defined as achieving a high-operational-system-cost reduction with the fewest possible salt caverns, considering the fact that adding salt caverns to the system also leads to increased capital costs. From the results emerged that the higher capital costs of design 3 compared to designs 1 and 2 did not negate the effect of the lower operational system costs achieved with this design. On the other hand, design 4 could generally achieve a higher operational cost reduction with the same number of salt caverns in comparison to design 3. However, when the difference in capital costs was taken into account, it could be concluded that design 3 outperformed design 4 as well. Therefore, designs 1, 2 and 4 were excluded from the scope of this research from this point onwards.

The design characteristics of design 3 resemble the characteristics of the salt cavern currently being constructed in Zuidwending in terms of injection capacity, withdrawal capacity, and storage capacity. The expectation is that additional salt caverns intended for hydrogen storage will be developed at Zuidwending in the upcoming years and these caverns are expected to have the same design characteristics, as this design has already been technically validated by the six operational UGS facilities. Consequently, obtaining an understanding of the economic feasibility of this salt cavern design can prove beneficial.

9.1.2 Initial number of salt caverns

To determine the number of required salt caverns, the search initially focused on the lowest operational system costs associated with a specific number of salt caverns associated with a storage configuration in one of the four energy systems. Subsequently, corrections were made for the capital costs associated with salt cavern design 3 because the addition of extra salt caverns results in higher capital costs. When this increase in capital costs offset the reduction in operational system costs, it was concluded that more salt caverns would not be advantageous for the overall system costs. This led to the following determination of the required number of salt caverns:

Table 16: Number of required salt caverns per scenario and seasonal storage policy.

Number of required salt caverns	**Decentral**	**National**	**European**	**International**
Low-seasonal storage policy	14	11	4	10
Mid-seasonal storage policy	7	10	4	7
High-seasonal storage policy	5	8	4	3

In general, the numbers of salt caverns in Table 16 are in line with the expectations that in the scenarios with limited seasonal storage, more salt caverns are required to minimise operational system costs compared to the scenarios with high-seasonal storage.

9.2 Robustness analysis

Based on the outcomes of the previous experiment, which determined the number of required salt caverns per storage configuration in one of the four energy systems, a robustness analysis was conducted to assess how robust the determination of the required number of salt caverns is. To determine which variables were included in the robustness analysis, a sensitivity analysis was performed for each energy system. When a variable had an impact of >20% or >-20% on any of the KPIs, the variable was designated as a critical variable. However, considering the limited remaining time for this research, additional choices needed to be made to decrease the number of critical variables further. Therefore, an additional requirement was introduced. Parameters of different types needed to be included: demand, generation, and flexibility. Therefore, the following critical parameters have been selected and varied within a determined range.

Table 17: Selected parameters for the robustness analysis.

Parameter	**Type**
Electricity demand built environment	Demand
Installed capacity hydrogen turbines	Generation
Electricity interconnection	Flexibility
Installed capacity Li-ion batteries	Flexibility
Number of salt caverns	Flexibility

The values for the electricity demand in the built environment, installed capacity of hydrogen turbines and the installed capacity of Li-ion batteries variables can take three levels, and 1 variable can only take two levels (electricity interconnection). Only values for the base case and high case are defined for the latter variable, as there is already an existing interconnection of 14.8 GW, which will thus remain the same or increase. Together, they form 3x3x3x2 = 54 scenarios, following a full factorial design. The number of salt caverns is considered a decision variable. The initial value for the required number of salt caverns is included in the robustness analysis, and to determine if the choice for these numbers of salt caverns is robust under varying conditions, +2 and -2 are added to or subtracted from the initial number of salt caverns. Important to note is that a different number of salt caverns is required per energy system and seasonal storage policy, as presented in Table 16. The numbers from this table have been used as initial values in the robustness analysis, and therefore vary per experiment. The regret tables that will be interpreted will thus look like Table 18. Further details regarding the influence of critical parameters on the system and the ranges within the variables varied for each experiment can be found in Appendix C.2 and C.3. Furthermore, a more detailed sensitivity analysis has been conducted for the electricity and hydrogen interconnection because import and export can significantly influence the results of the model. The details of this sensitivity analysis can be found in Appendix C.1.

Table 18: Example regret table experiments. d= decision. s= scenario.

	s1	s2	s3	s4	s5	s6	s7	...	s54	Max
d1: initial number of salt caverns -2										
d2: initial determination of number of salt caverns										
d3: initial number of salt caverns +2										

9.2.1 Findings robustness analysis

For assessing the robustness of the initial choice for the required number of salt caverns in addition to seasonal storage, the same KPI, total system operating costs, is utilised. However, the systems have also been evaluated from a societal perspective, thus incorporating the CO_2 level and electricity served with peak generators in the analysis. The Minimax regret tables can be found in Appendix C.4. In this Appendix, a brief description of the observed results is written for each energy system separately. However, the main text focuses on the generic trends observed in the robustness analysis.

Overall, it can be concluded that for almost all 24 experiments, more salt caverns lead to less regret when regret is determined relative to the initial number of salt caverns chosen in a particular energy system. The operational system cost KPI has been designated as the determining factor for assessing the best choice regarding the number of salt caverns. The electricity served with peak generators significantly influences operational system costs significantly since the cost associated with these generators is 3000 €/MWh. In times of scarcity, these expensive peak generators thus results in increased system costs. Adding extra salt caverns can reduce the electricity served with peak generators in most scenarios, thus favouring a higher number of salt caverns.

Weather years

What is noticeable from the robustness analysis is that regret is generally greater when there are fewer salt caverns in the system during the normal weather year (2015) compared to the Dunkelflaute weather year (1997). This contradicts initial expectations, as one would anticipate higher regret in a weather year with a longer period of low wind electricity generation. To investigate this effect, the two experiments were compared based on the same scenario in which the highest maximum regret occurs: Edem68640, Li-ion33, Interc14, HT12. Figure 38 and 39 depict the electricity served with peak generators over time in the two different weather years.

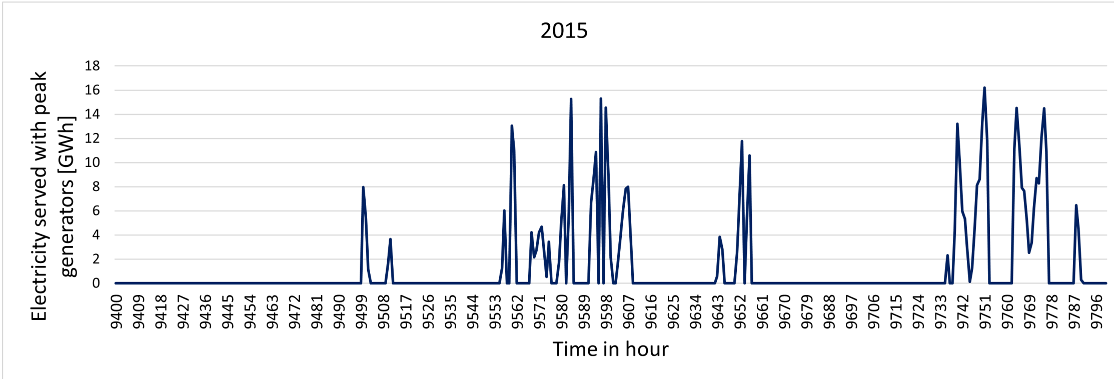


Figure 38: Electricity served with peak generators in weather year 2015.

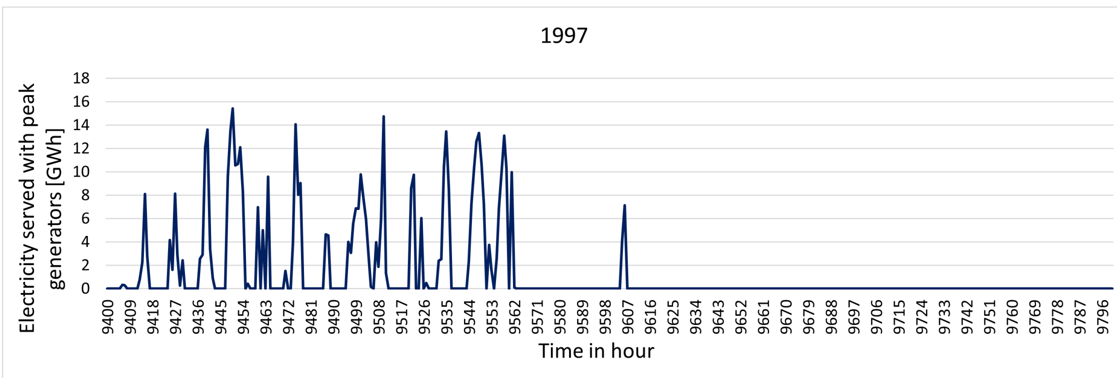


Figure 39: Electricity served with peak generators in weather year 1997.

In Figure 39, the Dunkelflaute is clearly recognisable. Between t=9400 and t=9560, there is a longer period of consecutive electricity served with peak generators, caused by a period without wind. Although this has a significant effect on system costs, the graph of the 2015 weather year clearly shows that, even though there is no single prolonged period without wind, electricity served with peak generators still occurs frequently in winter. In fact, the electricity served with peak generators is higher in the 2015 weather year than in the 1997 weather year. A Dunkelflaute does thus not necessarily lead to more regret when opting for a lower number of salt caverns compared to the 2015 weather year. However, when considering operational system costs, the operational system costs of the Dunkelflaute weather year are 3-5% higher.

CO_2 emissions

What stands out from the results is that CO_2 emissions do not necessarily decrease when more salt caverns are added to the energy system. In fact, the minimum maximal regret of CO_2 is in almost all experiments associated with the lowest number of salt caverns. Given that UHS is considered one of the most promising options for reducing CO_2 emissions, these results warrant further research. An experiment in the decentral energy system has been conducted to analyse the CO_2 emissions under the low-seasonal storage policy as the number of salt caverns increases from 0 to 16. The results are shown in Figure 40.

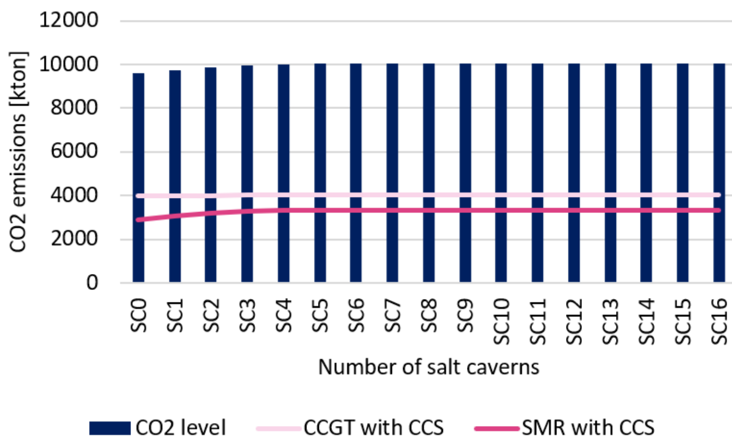


Figure 40: CO_2 emissions related to the addition of salt caverns to the decentral energy system, low-seasonal storage policy scenario.

From Figure 40, it is clear that adding salt caverns to the system indeed leads to higher CO_2 emissions. Especially when adding the first salt caverns, an increase in hydrogen production via the SMR process can be observed. Although the SMR process in the model is also equipped with carbon capture equipment, 10% of the CO_2 is still emitted. As more salt caverns are added to the model, the model experiences a financial incentive to produce more blue hydrogen, increasing CO_2 emissions. This is because storage enables reducing scarcity in the electricity market during winter by converting hydrogen into electricity. In January, there is high scarcity, and the salt caverns are completely emptied to alleviate shortages in the electricity market. Not long after, there is another similar moment of scarcity, during which the salt caverns are filled as much as possible between those moments. As a result, more blue hydrogen is produced via the SMR process during that period. The production of additional blue hydrogen, whose production cost amounts to 66 €/MWh, is much cheaper than the costs incurred for electricity shortages (3000 €/MWh) when there is not sufficient hydrogen available to convert to electricity to decrease the electricity shortage. More blue hydrogen is thus produced, leading to higher CO_2 emissions. However, the increase in CO_2 emissions amounts to only 458 kton/year. This difference is almost negligible when comparing it to the current CO_2 emissions in the Netherlands, which amount to 152 million tons [72]. On the path to 2040, both blue hydrogen and green hydrogen will play an increasingly dominant role in the energy system. By replacing grey hydrogen, significant CO_2 emission reductions can be achieved. However, when modelling the Dutch electricity and hydrogen systems in 2040, this effect is no longer visible. The modelled systems are already dominated by green electricity and green hydrogen. If the goal is to determine the CO_2 reduction that the transition to blue and green hydrogen can achieve and the role that UHS can play in it, the path to 2040 needs to be modelled. This falls without the scope of this research.

It should be noted that the above-mentioned CO_2 effect is not noticeable in the international energy system. This is because the hydrogen interconnection capacity in this scenario is very high, and a lot of hydrogen is imported. No CO_2 emissions are attributed to the import of hydrogen, which makes the CO_2 emissions in the international energy system relatively low compared to other energy systems. Although more hydrogen is imported when more salt caverns are added to the system, this does not lead to an increase in CO_2 emissions in this scenario.

Furthermore, all energy systems shared the characteristic that the maximum regret regarding the choice of the number of salt caverns was associated with a scenario featuring a high installed capacity of hydrogen turbines. In these scenarios, additional salt caverns could lead to a reduction in operational system costs of up to 856 M€ because hydrogen turbines can significantly reduce the electricity served with expensive peak generators. The fact that the maximum regret consistently occurs with a high installed capacity of hydrogen turbines is a crucial insight for policymakers. Therefore, if there is an insufficient number of operational salt caverns in a scenario with a high installed capacity of hydrogen turbines, significant regret may occur in terms of electricity served with peak generators and operational system costs. Particularly in scenarios where a high installed capacity of hydrogen turbines is combined with a low or mid-installed capacity of Li-ion batteries, the current electricity interconnection, and high electricity demand in the built environment, the maximum regret that occurs is very high.

9.3 Storage facility configurations

In this section, the performance of the storage configurations will be assessed. For this purpose, the low, mid, and high-seasonal storage policy decisions, along with their corresponding number of salt caverns, will be compared based on the operating system costs for each modelled energy system. In the main text, only the results of the total system operating costs are shown, as this KPI determines which configuration performs best in an energy system. The performance of the storage configurations on the other KPIs is presented in Appendix D. The results are presented in boxplots because this type of graph provides insight into the distribution of the data, central tendency, spreading, variability, and outliers. They offer a concise visualisation of data, making them efficient in conveying important information about the dataset in a compact form. To ultimately determine which storage configuration would operate best in a particular energy system, a comparison is made based on the median as it is more robust for outliers than the mean.

9.3.1 Decentral energy system

Table 19 provides insight into the configurations that emerged from the robustness analysis and the fixed costs associated with such a configuration.

Table 19: Capital and fixed O&M costs of configuration 1, 2 and 3.

			Cost scenario [M€/year]		
Configuration	Gas field [GWh]	Salt caverns	Low	Mid	High
1	5000	16	101	175	255
2	10000	9	95	167	263
3	15000	7	114	204	334

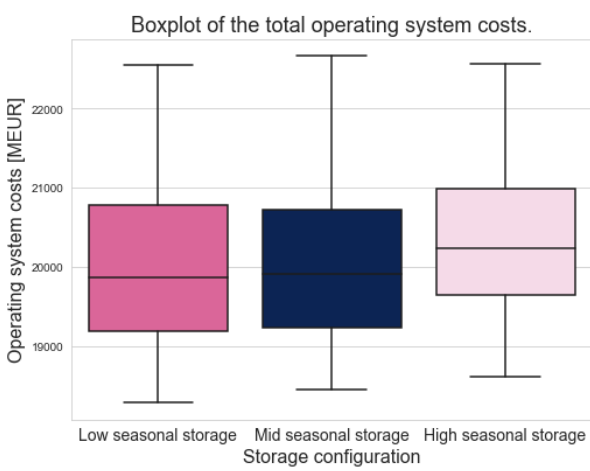


Figure 41: Total operating system costs, decentral energy system.

Table 20: Median of operating system costs in M€, decentral energy system.

	Conf. 1	Conf. 2	Conf. 3
Operating system costs	19863	19909	20242

From the above results, it can be seen that the performance of the different configurations is closely aligned. This outcome is unsurprising since the configurations were established based on the lowest possible operational system costs, given a certain seasonal storage policy. On the other hand, Table 19 indicates that the difference in the sum of capital and fixed O&M costs per year can vary widely based on the configuration.

Configuration 2 is the cheapest, while Configuration 3 is the most expensive. When comparing the median of the operating system costs, it can be concluded that the high-seasonal storage policy with 7 salt caverns leads to significantly higher annual operating system costs than the other two configurations. The latter combined with the fact that Configuration 3 is the most expensive, has resulted in this configuration no longer being considered for the best performance within the decentral energy system. The difference in annual operational system costs between Configuration 1 and 2 is 46 M€, which is greater than the difference in fixed costs, regardless of the cost scenario. Therefore, it is concluded that a low-seasonal storage policy in combination with 16 salt caverns (Configuration 1) is the most suitable in terms of system costs.

9.3.2 National energy system

Table 21 provides an overview of the capital and fixed O&M costs associated with configurations 4, 5, and 6 for the various cost scenarios. Configuration 4 is the cheapest, followed by configuration 5; configuration 6 is the most expensive.

Table 21: Capital and fixed O&M costs of configurations 4, 5 and 6.

			Cost scenario [M€/year]		
Configuration	Gas field [GWh]	Salt caverns	Low	Mid	High
4	5000	11	83	145	218
5	10000	10	99	173	270
6	15000	10	125	222	356

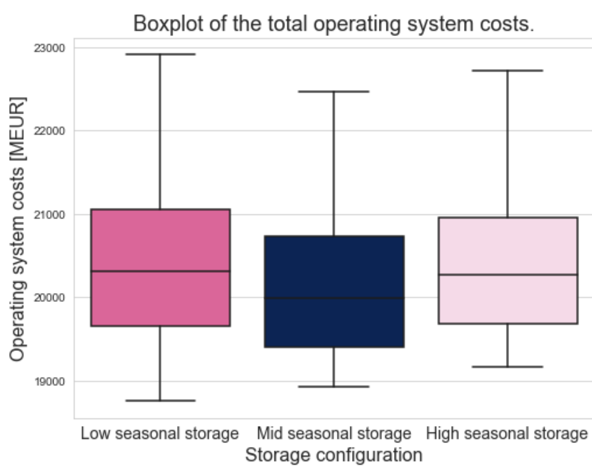


Figure 42: Total system operating costs, national energy system.

Table 22: Median of operating system costs in M€, national energy system.

	Conf. 4	Conf. 5	Conf. 6
Operating system costs	20314	19981	20269

From Figure 42, it is evident that Configuration 5 outperforms Configuration 4 and Configuration 6 significantly in terms of operational system costs. The higher capital and fixed O&M costs associated with Configuration 5 compared to Configuration 4 are offset by the lower operational system costs achievable per year.

9.3.3 European energy system

Table 23: Capital and fixed O&M costs of configurations 7, 8 and 9.

			Cost scenario [M€/year]		
Configuration	Gas field [GWh]	Salt caverns	Low	Mid	High
7	5000	6	64	114	182
8	10000	6	84	149	241
9	15000	6	110	198	327

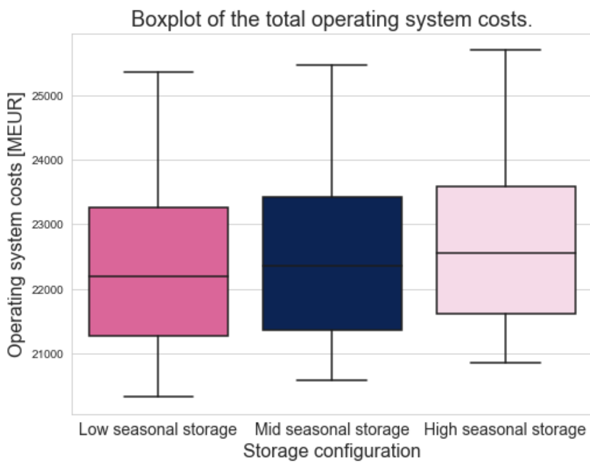


Figure 43: Total system operating costs, European energy system.

Table 24: Median of operating system costs in M€, European energy system.

	Conf. 7	Conf. 8	Conf. 9
Operating system costs	22201	22350	22555

From Figure 43, it is evident that Configuration 7 performs the best in terms of operational system costs. In the European system, the hydrogen interconnection is significantly larger than in the decentral and national energy systems, reducing the necessity for hydrogen storage. Therefore, Configuration 8 and 9, both having larger seasonal storage but the same number of salt caverns, do not necessarily outperform Configuration 7. In fact, the system costs are higher for these two configurations. This can be explained by the way seasonal storage in gas fields is modelled. As gas fields are being filled during the summer months, 5.9 GWh of hydrogen per hour has to be injected into the gas field. During periods of low or no hydrogen production via electrolysis due to a lack of abundant renewable electricity, alternative methods of hydrogen production or hydrogen importation must be employed to fill the gas field, resulting in higher system costs, while the higher seasonal storage policy does not appear to be beneficial to the overall operating system costs.

9.3.4 International energy system

Table 25: Capital and fixed O&M costs of configurations 10, 11 and 12.

			Cost scenario [M€/year]		
Configuration	Gas field [GWh]	Salt caverns	Low	Mid	High
10	5000	12	86	151	226
11	10000	9	95	167	263
12	15000	5	106	192	319

From Table 25, it becomes evident that Configuration 10 is the cheapest, and the costs increase as more seasonal storage is included in the configuration.

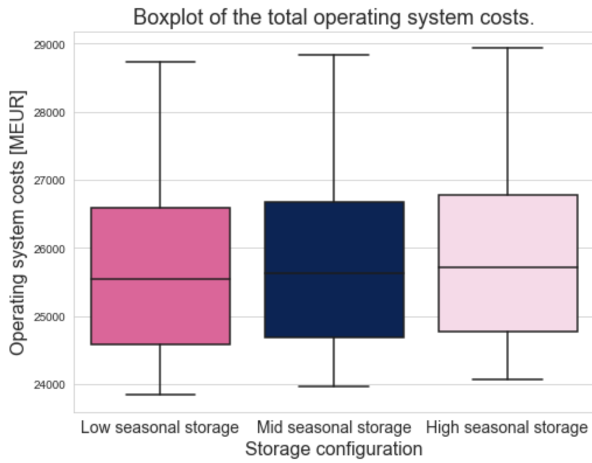


Figure 44: Total system operating costs, international energy system.

Table 26: Median of operating system costs in M€, international energy system.

	Conf. 10	Conf. 11	Conf. 12
Operating system costs	25542	25623	25723

When comparing the median of the operational system costs, it becomes clear that Configuration 10 can generate the lowest annual operational system costs. Since Configuration 10 is also the cheapest in terms of annual fixed OM and capital costs, the conclusion here is unequivocal: Configuration 10 performs the best in the international energy system.

9.3.5 General findings of the storage configurations

From the analysis, it emerges that the configuration with the low-seasonal storage policy performs best in the decentral, European and international energy systems. In the national energy system, the mid-seasonal storage policy performs best in terms of operational system costs. This can be explained by the high installed renewable energy capacity in this scenario compared to the other scenarios (123 GW solar PV and 66 GW wind power). Consequently, the electricity and hydrogen systems heavily rely on vRES. In winter, when electricity production from installed vRES capacity decreases, additional electricity generation is needed, which can be done using hydrogen-to-power. Therefore, the storage requirement in this scenario is greater than in the other scenarios. Another reason for the lower storage requirement in the European and international energy systems compared to the national energy system is that the hydrogen interconnection capacity is significantly higher in the former scenarios.

The calculation of the capital costs of the different configurations is based on the case where 100% N_2 is used as cushion gas in the gas field. If this were done with the more expensive 100% H_2, 33% N_2, or 66% N_2 cases, there would be no change in outcomes in the decentral, European and international energy systems because the preference already leans towards the low storage policy scenario. However, this needs to be checked for the national energy system because higher capital costs might lead to the preference for a low-seasonal storage configuration over a mid-seasonal storage configuration. For the national energy system, Configuration 5 performs better than Configuration 4 in terms of total system operating costs at 333 M€/year. The additional costs incurred regarding the more expensive cushion gas must therefore be lower than this to maintain the same configuration preference. For all three cushion gas cases, 100% H_2, 33% N_2, and 66% N_2, the additional costs incurred annually are below 333 M€, hence it can be concluded that regardless of the choice of cushion gas, Configuration 5 with the mid-seasonal storage policy is preferred over Configuration 4 with the low-seasonal storage policy.

Contrary to the just mentioned cushion gas cases, the 100% CH_4 and 75% CH_4 cushion gas cases are less expensive than the 100% N_2 cushion gas case. Therefore, it was also checked whether the preference changes when one of these options for cushion gas is used. The analysis showed that also the use of cheaper cushion gas does not bring about a change in configuration preference across the different scenarios.

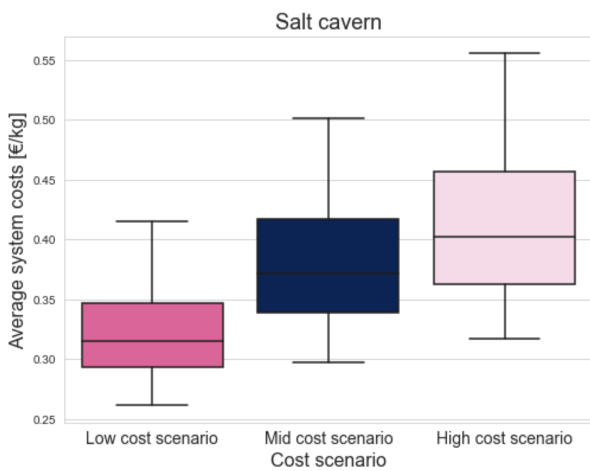
9.4 Results of the economic feasibility

Although in the previous section, it was concluded which configuration would best fit a certain energy system in terms of system costs, all configurations have nevertheless been included in the cost analysis because the strength of the financial analysis lies in determining the costs and revenues over a large dataset, thus providing good insights in the possible range of average system costs per kg hydrogen under uncertain conditions.

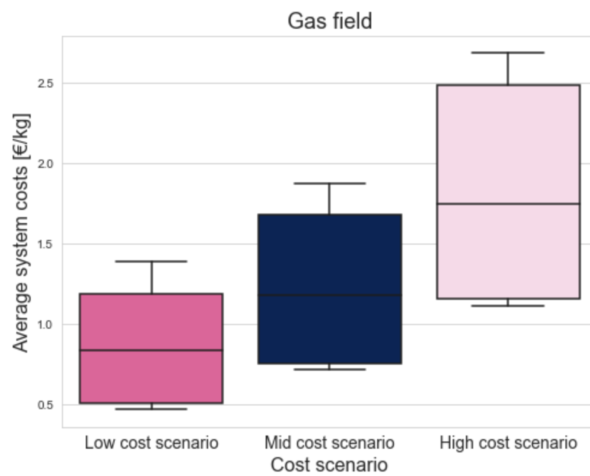
9.4.1 Average storage facility costs per kg produced hydrogen

The calculation of the average system costs is performed using the method outlined in Section 7.3. Three cost scenarios were considered, and the results of this cost analysis are presented for each energy system. A total of 972 data points are visualised in a single boxplot.

Decentral energy system



(a) Salt cavern, decentral energy system.

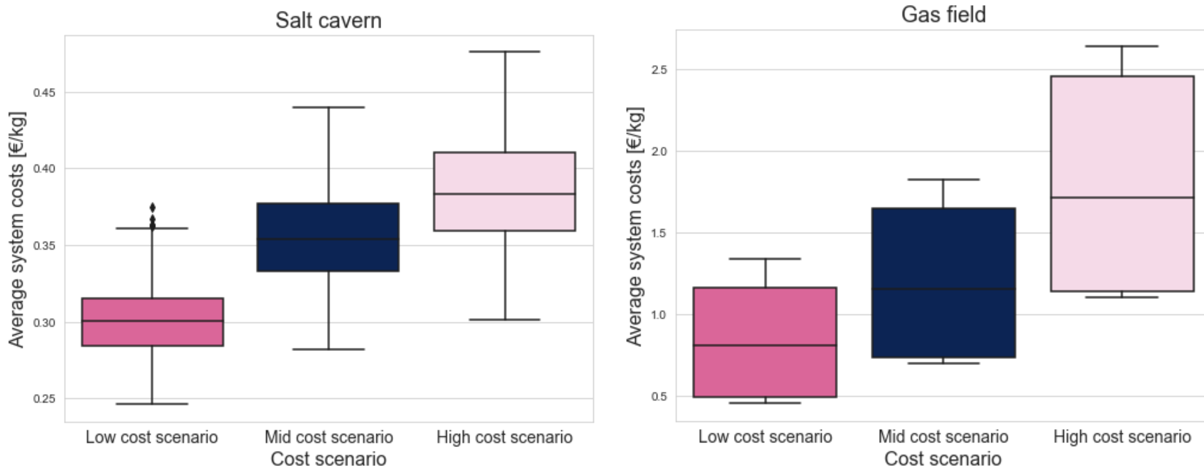


(b) Gas field, decentral energy system.

Figure 45: Box plots of the average system costs per kg produced hydrogen.

In Figure 45a, it can be seen that over the 972 runs, the average salt cavern system costs in the low-cost scenario vary between 0.27 and 0.42 €/kg, in the mid-cost scenario between 0.30 and 0.50 €/kg, and in the high-cost scenario between 0.32 and 0.56 €/kg. The costs associated with hydrogen storage in gas fields are up to 5 times higher than in salt caverns in the high-cost scenario in comparison to the low scenario. Additionally, it is also noticeable that the size of the box in the boxplot is more elongated in Figure 45b than in Figure 45a, and that the box also becomes more elongated in the mid-and high-cost scenarios. This is due to the significant contribution of cushion gas costs in gas fields. No outliers were identified in this scenario.

National energy system



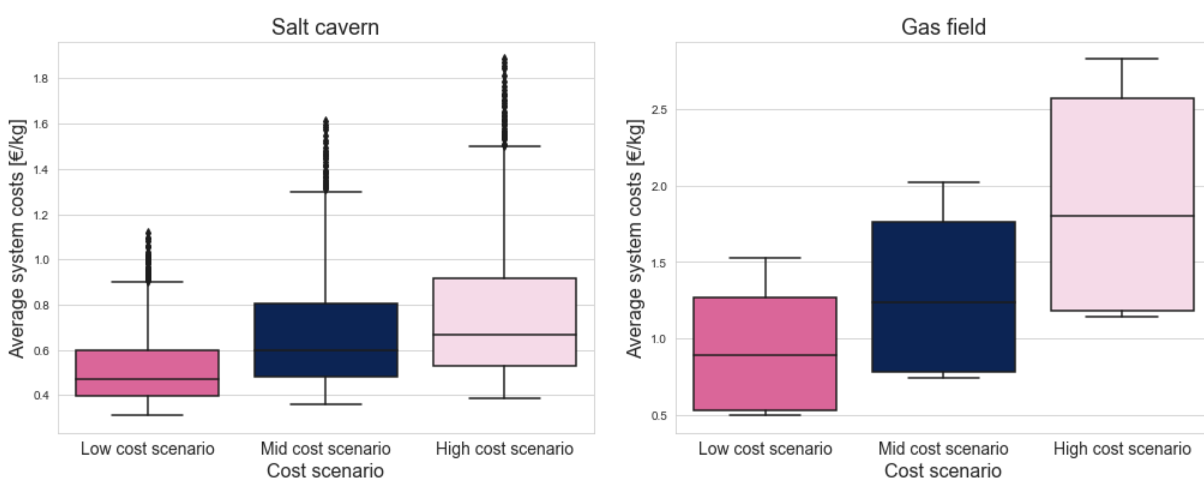
(a) Salt cavern, national energy system.

(b) Gas field, national energy system.

Figure 46: Box plots of the average system costs per kg produced hydrogen.

From the results of the national energy system, a similar outcome emerges as in the decentral energy system, although the average system costs for both salt caverns and gas fields are comparatively lower. This is related to the fact that the installed vRES capacity is higher in the national energy system, leading to a lower average electricity price in the low, mid and high-seasonal storage policies. This reduces the costs of surface facilities' electricity consumption significantly. The salt cavern costs vary in the low-cost scenario from 0.25 to 0.37 €/kg, in the mid-cost scenario from 0.28 to 0.44 €/kg, and in the high-cost scenario from 0.30 to 0.48 €/kg. In this instance as well, it is notable that the average system costs per kg of produced hydrogen for gas fields exhibit a significantly higher magnitude in comparison to those observed for salt caverns.

European energy system



(a) Salt cavern, European energy system.

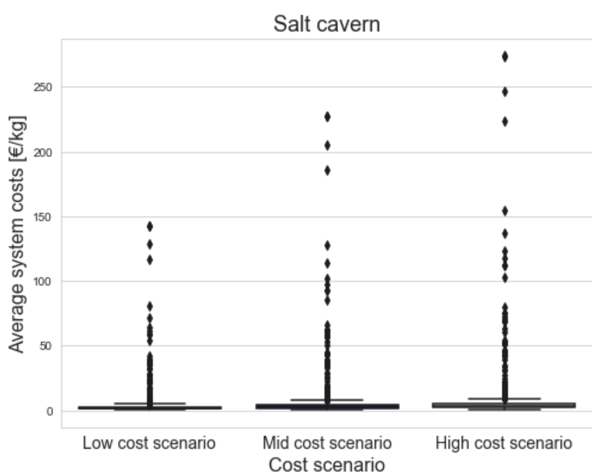
(b) Gas field, European energy system.

Figure 47: Box plots of the average system costs per kg produced hydrogen.

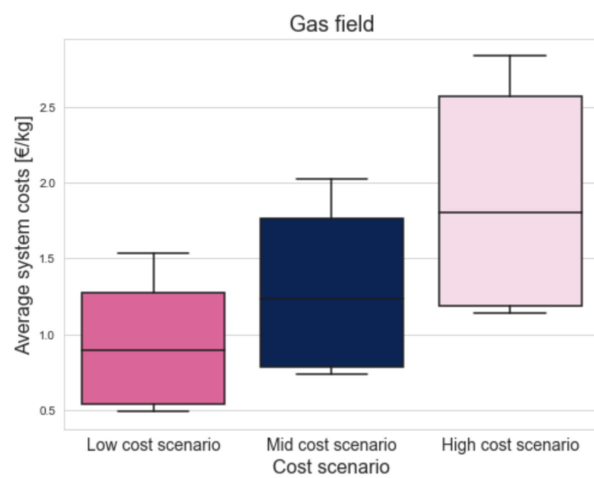
The range between the lowest and upper bound of the salt cavern system costs in the European energy system varies from 0.30 to 0.90 €/kg in the low-cost scenario, from 0.37 to 1.30 €/kg in the mid-cost scenario, and from 0.40 to 1.50 €/kg in the high-cost scenario. The costs in the European energy system are significantly higher than those in the decentral and national energy systems. This is related firstly to the higher average electricity price, which increases the variable operational costs of the surface storage facilities, and secondly to the smaller amount of hydrogen produced per salt cavern in the European energy system, spreading the system costs over a lower produced hydrogen capacity. The higher average electricity price in the European energy system is due to the lower installed capacity of vRES capacity.

In contrast to the decentral and national energy systems, it stands out from Figure 47a that for the European energy system, there are relatively many outliers here. Outliers can result from phenomena that naturally exhibit high variability, however, they may also be attributed to measurement errors. To rule out the latter, research has been conducted into the nature of the outliers. It was revealed that these outliers are linked to elevated costs stemming from the high-seasonal storage policy, particularly in scenarios where there are 6 salt caverns integrated into the system in addition to the high-seasonal storage. When this is the case, less hydrogen is injected and withdrawn from a single cavern, resulting in the fixed annual costs being divided by a smaller amount of hydrogen produced.

International energy system



(a) Salt cavern, international energy system.



(b) Gas field, international energy system.

Figure 48: Box plots of the average system costs per kg produced hydrogen.

From Figure 48a, it becomes evident that the storage costs per kg of hydrogen vary widely and can become extremely expensive in the international energy system. This can be explained by the fact that the hydrogen interconnection in this scenario is the largest of all, namely 19.4 GW. As a result, the need for storage capacity in this scenario is minimal. A deeper dive into the experiments has been executed to illustrate this.

The experiments of the most extreme outliers are shown in Figure 49 to provide insight into the origin of the outliers. For the low, mid, and high-seasonal storage policies, the same scenario leads to the most extreme outlier: the scenario with low electricity demand in the built environment (Edem57690), high electricity interconnection (interc17), high installed capacity of Li-ion batteries (Li-ion 29), and low installed capacity of hydrogen turbines (HT8). The combination of these values of the critical variables results in a worst-case scenario for hydrogen storage in the international energy system. In this scenario, almost no hydrogen storage is used, resulting in the capital costs being shared across a very small amount of hydrogen produced by the salt caverns.

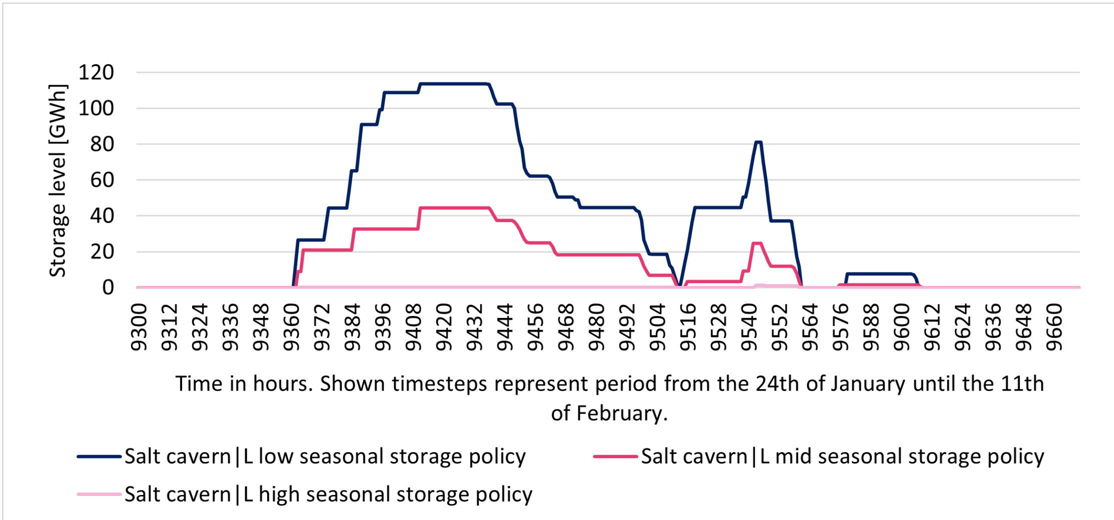


Figure 49: Worst case cost scenario for the international energy system. The period shown in Figure: 19 November to 10 January.

In Figure 49, the filling level of the salt caverns is plotted against time. Time steps smaller than 8000 have been disregarded because the shown time steps are the only moments during the year when the salt caverns are used. Although more storage occurs in the low-seasonal storage policy, this remains limited to just that one moment of scarcity in the winter as well. Because the salt caverns are hardly used in this scenario of the international energy system, the costs per kg of hydrogen are disproportionately high. Apart from this single scenario, there are several other scenarios where costs rise to a high level. Due to the outliers, there is no longer a clear insight into the costs related to storage in the more favourable scenarios. For this reason, the outliers have been removed from the dataset, and in Figure 50, the boxplot with the new dataset excluding outliers is shown.

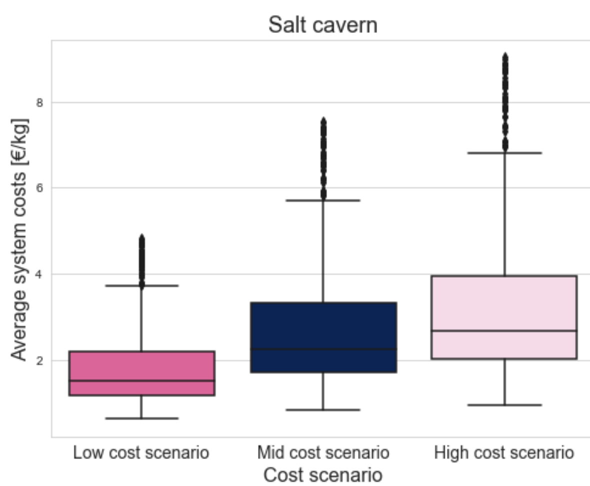


Figure 50: The box plot of the international energy system without outliers.

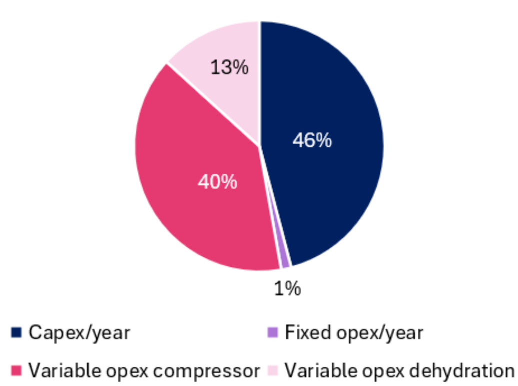
By removing the extreme outliers, a clearer insight into the average system costs of the salt caverns per kg of produced hydrogen has been obtained in Figure 50. Although the extreme outliers have been removed, there are now new values in this dataset that are considered outliers. However, these values now fall within a range that still makes the rest of the data points interpretable. When comparing the average system costs per kg of produced hydrogen of the salt caverns with other scenarios, it becomes clear that the average costs are significantly higher than in the European energy system, particularly in comparison to the decentral and national energy systems. In the international energy system the system costs per kg produced hydrogen ranges from 0.67 to 5.00 €/kg in the low-cost scenario, from 0.83 to 7.50 €/kg in the mid-cost scenario and from 0.83 to 9.00 €/kg in the high-cost scenario. Although the average electricity price is similar in both the European and international energy systems, the amount of hydrogen produced per salt cavern is significantly smaller in the international energy system compared to the European energy system. This results in much higher average system costs per kg of hydrogen in the international energy system.

General findings from the average system cost analysis

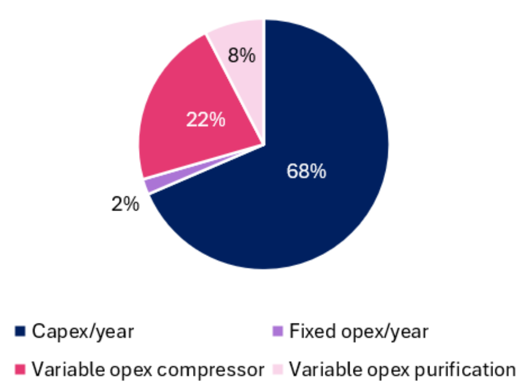
First and foremost, it becomes evident in all scenarios that gas fields, in comparison to salt caverns, incur higher average system costs. This is partly related to the higher variable compressor costs of gas fields because compression needs to reach higher pressures, and on the other hand, to the higher capital costs compared to salt caverns. Besides, a greater variability of average system costs in the graphs representing salt caverns compared to those of the gas fields is observed. This is due to the modelling approach applied to the gas fields. They have a strict lower bound that governs their filling and emptying behaviour. This strict lower bound compels gas fields to fill and empty according to a certain seasonal pattern, regardless of the conditions in the electricity and hydrogen markets. The utilisation of gas fields is therefore not contingent upon the energy system, unlike salt caverns.

Additionally, it can be concluded that the storage facilities system costs, particularly in the international energy system but also in the European energy system, are significantly higher than in the decentral and national energy systems. In the decentral and national energy systems, a high installed capacity of vRES leads to lower average electricity costs, which is advantageous for the surface facilities consuming electricity. In the European and international energy systems, electricity is generated using more expensive generation units, and there is more electricity imported, resulting in higher electricity prices. Furthermore, particularly in the international energy system, the impact of hydrogen import becomes apparent. Due to extensive interconnection, there is minimal need for storage, and salt caverns are primarily utilised during extreme winter scarcity, resulting in a very small amount of produced hydrogen per storage unit. Consequently, the fixed system costs are distributed over a small quantity of hydrogen. Overall, it can be concluded that in terms of average system costs per kg of hydrogen from storage facilities, the decentral and national energy systems outperform scenarios with higher levels of hydrogen import.

Lastly, the variable costs incurred for compressing hydrogen and for the dehydration and purification of the hydrogen, have a significant share in the total cost breakdown, both for salt caverns and gas fields. In the decentral energy system with the low-seasonal storage policy and the mid-cost scenario, the cost breakdown of salt caverns and gas fields is shown in a circle diagram in Figure 51a and 51b.



(a) Salt cavern.



(b) Gas field.

Figure 51: Cost breakdown of the storage facilities in the decentral energy system.

9.4.2 Revenues

Besides costs, revenues are also an important component of the cost analysis. The revenues from storage facilities are simply defined as the difference in the price at which hydrogen is sold minus the price at which hydrogen is purchased. Since gas fields are modelled in such a way that injection can only occur in the summer months and extraction only in the winter months, revenues are always negative in the summer and positive in the winter. This limitation does not apply to salt caverns, and negative and positive revenues can occur throughout the year. This phenomenon is illustrated in Figure 52.

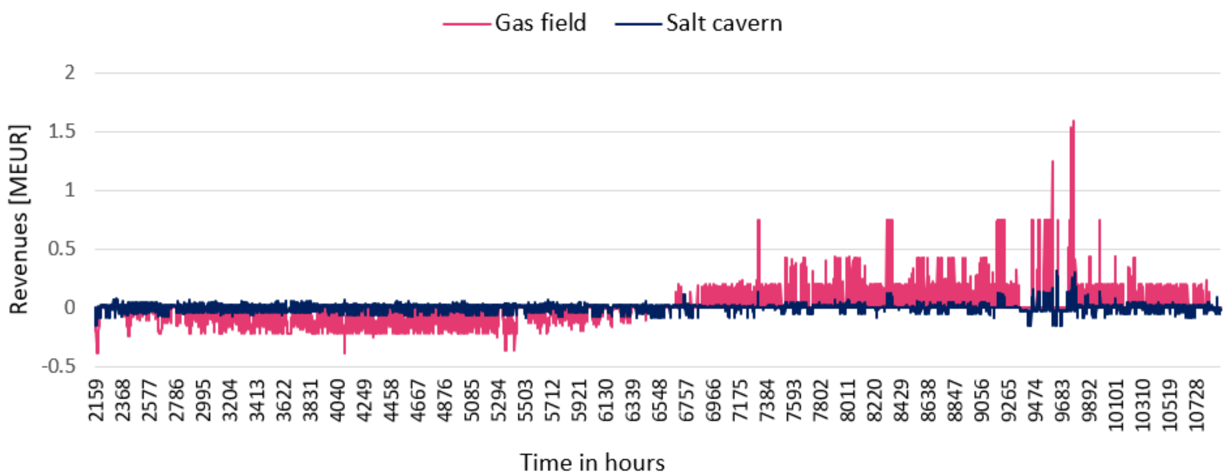


Figure 52: The difference in revenue pattern for salt caverns and gas fields.

General trends in the revenues

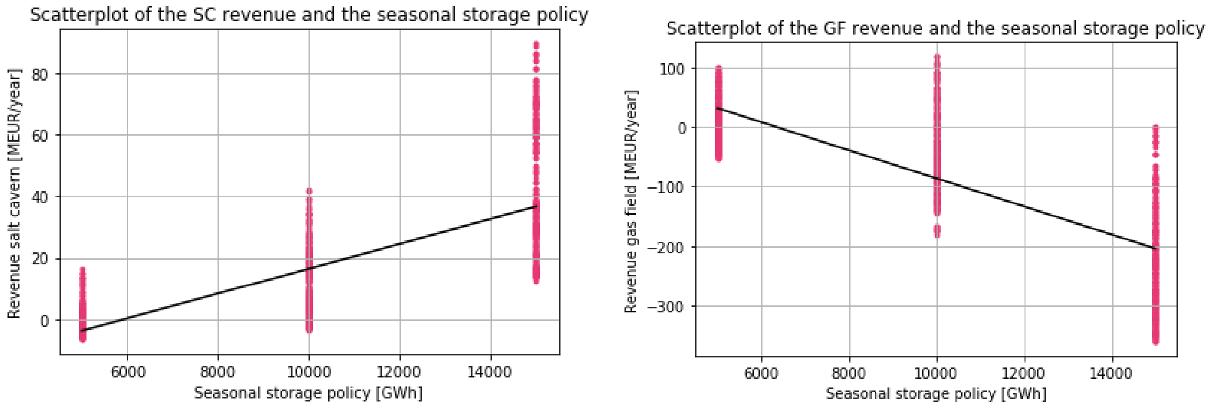
Firstly, heat maps have been created to gain insight into the relationships between critical parameters and the revenues of gas fields and salt caverns. Two heat maps can be found in Appendix B.4 and show a similar pattern for the gas field and salt caverns. The left side of the heat maps is generally coloured red, indicating negative revenues. The right side of the heat map is generally green, indicating positive revenues. The heat map has been used to observe possible relations between the critical parameters and the revenues of salt caverns and gas fields that have been further investigated with scatter plots. Based on the scatter plots in Appendix B.5, the following relationships were determined:

Table 27: Influence on revenues based on scatter plots.

		Salt cavern revenues	Gas field revenues
Electricity demand built environment	+10%	6%	37%
Installed capacity hydrogen turbines	+20%	13%	23%
Installed capacity Li-ion batteries	+20%	-5%	-13%
Electricity interconnection capacity	+20%	-25%	-160%

The results from the scatter plots in Appendix B.5 conclude that the scatter plots align with the observations from the heat map. It is important to mention that the values presented in Table 27 are based on a wide range of scenarios, and that this is a general trend that can be derived from all data points combined. This does not necessarily mean that this trend applies within each scenario.

From the single heat map did not emerge what the effect of the low, mid, or high-seasonal storage policy is on the revenues of the salt caverns and the gas fields. However, when comparing the heat maps of the low-seasonal storage policy and the high-seasonal storage policy, it becomes evident that the storage policy also has a significant impact on the returns. Since this effect is contradicting expectations, this relationship has been investigated in detail.



(a) Revenue salt cavern.

(b) Revenue gas field.

Figure 53: Scatter plots of the salt cavern and gas field revenues with different seasonal storage policies.

In Figure 53a and 53b the effect of the seasonal storage policy is clearly visible. It can be seen that as there is more seasonal storage, the revenues of the salt caverns significantly increase. When the seasonal storage amount increases by 100%, the revenues of the salt cavern increase by approximately 360%. The opposite effect is observed for gas fields. The higher the seasonal storage, the lower the revenues. If the seasonal storage amount increases by 100%, the revenues of the gas field decrease by 200%. Appendix B.6 displays the revenue graphs of one scenario for a salt cavern and a gas field in low and high-seasonal storage policies. It becomes evident that salt caverns under a high storage policy achieve significantly higher revenues. This can be explained by two reasons: firstly, the fact that there are fewer salt caverns in the high-seasonal storage policy. Hence, the revenues, need to be distributed across fewer salt caverns. Secondly, the revenues, particularly in summer, are considerably higher compared to the low-seasonal storage policy. The latter can be explained by the fact that salt caverns can take advantage of moments throughout the year when hydrogen is inexpensive to fill the storage and empty it when prices are higher. Because the injection rate of the gas field in the high-seasonal storage scenario is three times higher compared to the low-seasonal storage, the gas field significantly contributes to a higher hydrogen demand. This higher hydrogen demand enables the salt cavern also in the summer to maximise its revenues by filling when there is abundant electricity and emptying when the hydrogen price is high.
When examining the revenues of the gas field under both low and high-seasonal storage policies, it becomes clear that the higher revenues that can be generated in the winter due to more stored hydrogen do not outweigh the additional costs incurred in the summer to fill the storage.

9.4.3 Profits

This subsection will provide insight into the profits that Essent can potentially achieve when they invest in salt caverns and gas fields in the various energy systems. The profits are given in €/kg produced hydrogen. In the graphs, only the mid-cost scenario is depicted, along with the range of values within the 1st and 3rd quartiles. The full information on the potential profits per kg of hydrogen, including outliers, is presented in Appendix B.7 in box plots.

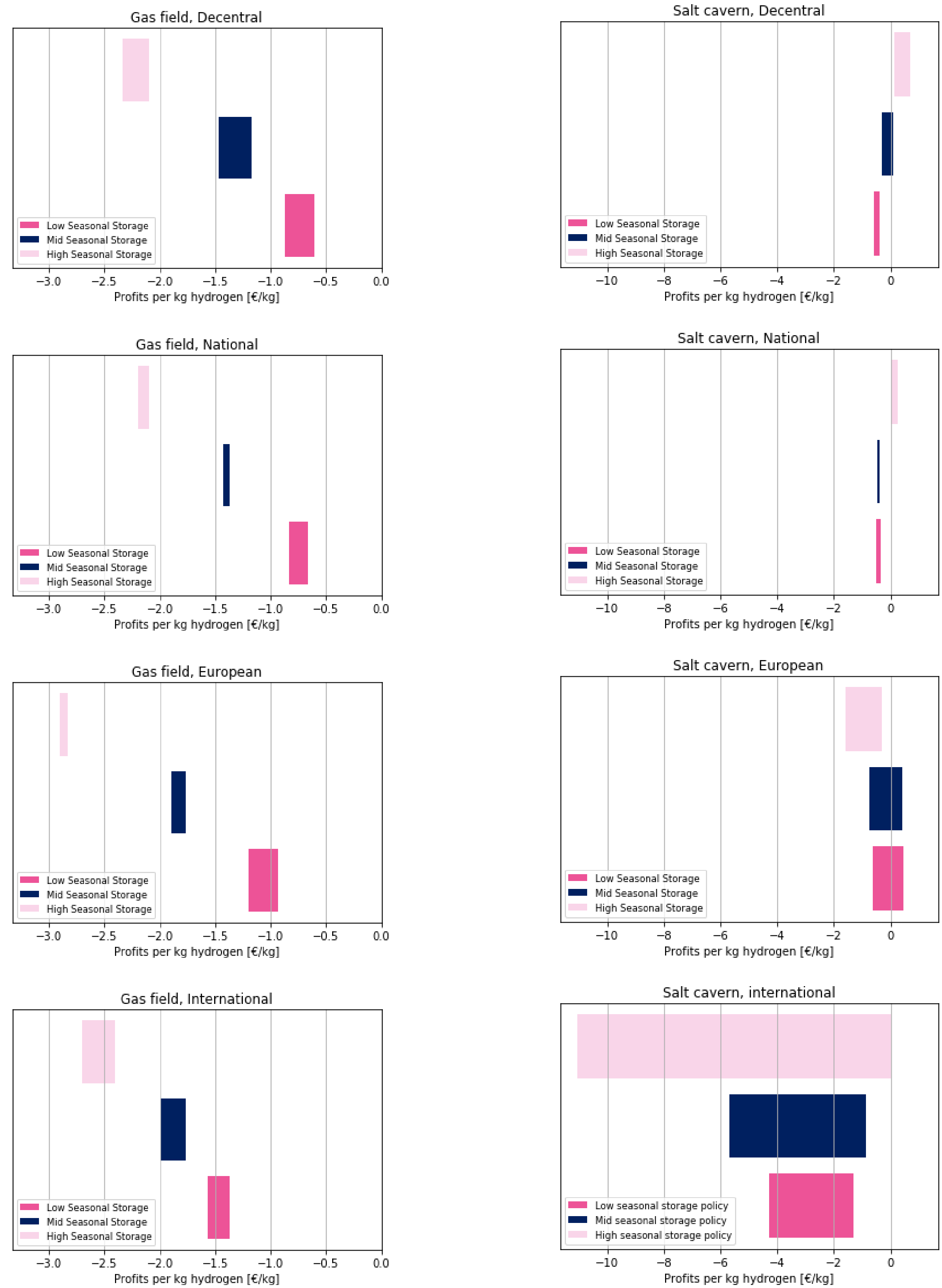


Figure 54: The potential profits across the energy systems.

From the figures, it becomes evident that gas fields are not profitable in any scenario. Additionally, it is clear that the larger the seasonal storage, the greater the losses per kg of produced hydrogen. Furthermore, a clear trend is observable among the scenarios: the losses of the gas field in the decentral and national energy systems are significantly lower than the losses in the European and international energy systems. This is because the first two energy systems rely more on vRES for electricity generation, and therefore benefit more from seasonal storage. Moreover, in the European and international energy systems, the hydrogen interconnection is significantly larger, leading to a lower need for seasonal storage.

As explained in Subsection 9.4.2, the profitability of the salt caverns in the decentral and national energy systems is higher with higher seasonal storage policies. Conversely, in the European energy system, the opposite effect is observed. As seasonal storage decreases, higher profits or smaller losses can be achieved with the salt caverns. The plot of the salt caverns in the international energy system suggests that this scenario could be the most unfavourable for the profits of the salt caverns. The high hydrogen interconnection results in low utilisation of the salt caverns, spreading the costs over a low quantity of produced hydrogen. A large range of values is observed for the salt cavern profits in the international energy system, indicating a high scenario dependency.

Subsidy

From the above results, it is clear that gas fields are not profitable in any case, and that salt caverns also often incur losses per kg of hydrogen in most scenarios and energy systems. This serves as important guidance in formulating policy regarding the subsidies needed to make investments in hydrogen storage profitable. Based on the profit analysis, Tables 46 and 47 in Appendix E show the range of the minimum subsidy required to facilitate investments in UHS facilities per storage configuration. The subsidy ranges are based on the first and third quartiles, meaning that 50% of the observations lie within this range.

The found ranges for the required subsidies per kg of hydrogen are very wide. For gas fields, values ranged from 0.37 to 3.70 €/kg, while for salt caverns, this ranged from 0 to 12.73 €/kg. Because the highest value found for the salt caverns does not paint a realistic picture, Section 10 is devoted to determining the most plausible energy system. Subsequently, the implausible scenarios within that energy system are also removed from the dataset to give Essent the best possible estimate of the costs and profits they can expect in the future.

10

Plausibility

The study comprises numerous results related to various energy systems and different scenarios, but as Essent generally operates with a base scenario, this section will be used to identify the most plausible energy systems and scenarios based on current announcements of future developments in the vRES electricity generation and hydrogen network in the Netherlands and neighbouring countries.

10.1 Energy systems

10.1.1 vRES generation capacity

The installed capacity of solar and wind energy is much higher in the decentral and national energy systems in comparison to the European and international energy systems because, in these systems, the Netherlands is to a higher extent self-sufficient. It appears that the Netherlands is moving in that direction when looking at the roadmaps for the development of solar and wind energy in the country.

In 2023, 4.8 GW of solar energy was installed in the Netherlands, resulting in a total installed capacity of 24.4 GW [73]. It is expected to grow to over 30 GW by the end of 2024 [74]. If the installed capacity of solar energy continues to grow at this pace, it will exceed 105 GW by 2040. This number aligns more closely with the decentral and national energy systems, especially considering the fact that the First Chamber voted against phasing out the Dutch *salderingsregeling*, leading to the expectation that the growth of installed solar PV capacity will further increase in the coming years [75].

In addition to solar energy, the Netherlands also has high ambitions in the field of wind energy, particularly offshore. Currently, the installed capacity of offshore wind energy is 4.7 GW. Plans exist to construct 21 GW of offshore wind energy by 2024, which would already result in 25 GW of installed capacity by the end of 2024 [76]. The government has also announced plans to further increase the installed capacity to 50 GW by 2040 and 70 GW by 2050 [77]. The installed capacity of onshore wind turbines already exceeded 6 GW by the end of 2022 [78], creating the expectation that it will grow towards 12 or 15 GW (decentral and national energy systems) in the years leading up to 2040, rather than the 8.7 GW used in the European and international energy systems.

Overall, it can be concluded that considering the announced Dutch plans regarding vRES capacity, the decentral and national energy systems seem more plausible than the European and international energy systems. Although the installed capacity of solar and onshore wind turbines in the decentral and national energy systems are comparable, the national system seems more aligned with the plans published regarding offshore wind power.

10.1.2 Hydrogen backbone

In the Netherlands, concrete plans are made for the creation of a national hydrogen network. The first step in this process involves connecting the four industrial clusters located along the coast, which will make the greatest contribution to hydrogen production due to their advantageous location in relation to offshore wind energy. The second phase will involve connecting Chemelot, the fifth industrial cluster, to the network of the other industrial clusters. By 2027, all industrial clusters are expected to be interconnected, the network should be linked to storage facilities, and connections should be established with neighbouring countries [79]. Plans are being developed to interconnect European countries to provide additional flexibility. Currently, Gasunie is exploring the possibilities of connecting the Dutch industrial clusters with those in Belgium [80]. Furthermore, they are in the feasibility/pre-FEED phase of the interconnection with Germany with a capacity of 6 GW [81]. The planned interconnection capacity with Belgium is not yet announced, but based on the fact that the Netherlands and Germany will be connected with 4 pipelines while the Netherlands will be connected with only 1 pipeline to Belgium, it is assumed that the interconnection capacity with Belgium will be in the order of 1.5 GW. There are also considerations for establishing a more extensive hydrogen network, such as by interconnecting with the UK or Denmark, but since no concrete Dutch plans have been made for this yet, this has been excluded from consideration in this research.

Overall, with the knowledge available today, it can be concluded that the planned hydrogen interconnection capacity for 2040 is 7.5 GW. This value is closer to the values established for the decentral and national energy systems compared to the 13 and 19 GW assumed in the European and international energy systems, respectively. Once again, the value established for the hydrogen interconnection in the national energy system aligns more closely with the value found in the hydrogen roadmap of the Netherlands compared to the value for the decentral energy system, similar to the case with installed vRES capacity.

10.1.3 Hydrogen application in subsystems

The hydrogen roadmap of the Netherlands indicates that hydrogen will primarily play a dominant role in three applications: seasonal electricity storage, and the decarbonisation of industry and the transportation sector [82]. While the report does not exclude the possibility of hydrogen being used in the built environment, it is already noted that alternative heating methods, such as electrification, will likely assume a more dominant role. The role of hydrogen in agriculture is also mentioned, but it appears that process electrification and electrical agricultural vehicles, along with the use of biogas and biomass, are gaining traction due to the availability of technologies and infrastructure. Therefore, the role of hydrogen in agriculture is likely to remain very limited in the Netherlands. In this case as well, both the decentral and national energy systems align more closely with the picture painted in the hydrogen roadmap for the Netherlands than the European and international energy systems [82].

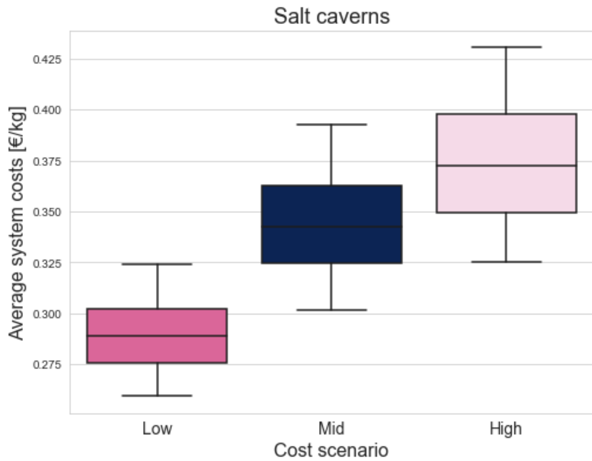
Based on the comparison of the values assumed for the installed vRES capacity, hydrogen interconnection, and the hydrogen adaptation in the four energy systems and considering current and announced future developments, it has been determined that the national energy system is the most plausible because the values assumed in this energy system are best aligned with the published values in Dutch roadmaps. Therefore, this energy system will be used as the base case for the recommendations to Essent.

10.2 Exclusion of scenarios

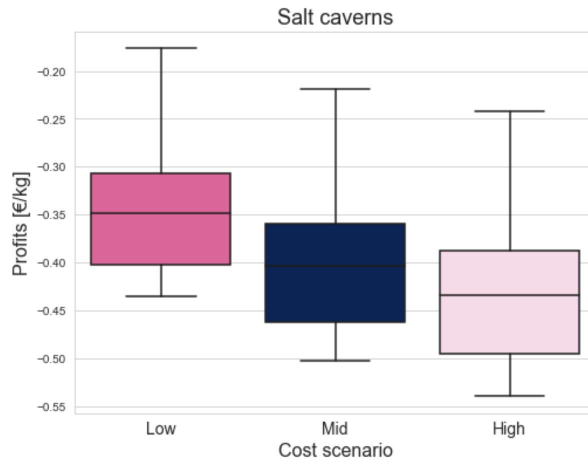
The results presented in Section 9 have been obtained from the robustness analysis conducted, encompassing 54 scenarios with different combinations of critical parameters. This subsection will exclude scenarios that are not plausible for the national energy system to provide Essent with the best possible understanding of the costs and profits that can be expected in a best and worst-case scenario. Appendix F gives an overview of which scenarios are assumed to be plausible, and which scenarios are excluded from this analysis.

Scenarios in which the electricity served with peak generators was greater than 200 GWh were determined to be not plausible, as these amounts would be highly undesirable in an energy system because the peak generators drive up the costs, leading to significantly higher prices for consumers. This criterion led to the exclusion of 28 scenarios, resulting in 26 remaining scenarios under consideration. If a maximum of 200 GWh is generated by peak generators, this means that in the worst-case scenario from a societal perspective, a maximum of 0.09% of the electricity is generated using expensive peaking generators in the national energy system. This is deemed acceptable. However, it is important to note that due to the high costs associated with electricity generation with peak units, the annual average electricity price increases by 10% compared to a scenario in which 0 GWh shortages occur.

In Section 9.3.2, it has been concluded that for the national energy system, the mid-seasonal storage policy performed better in terms of operational system costs compared to the low and high-seasonal storage policies. Therefore, the latter two seasonal storage policies were also disregarded.



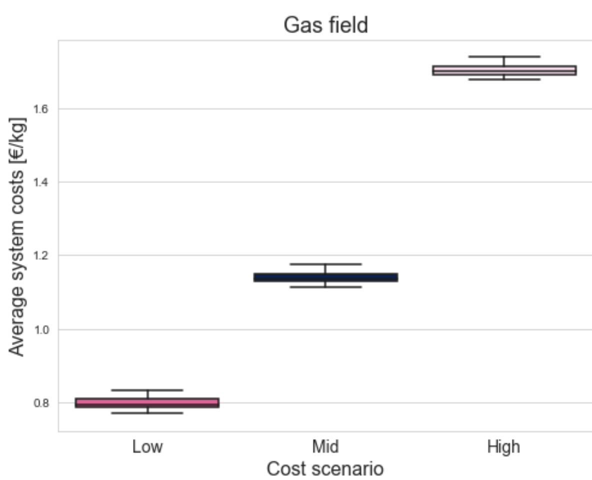
(a) Average system costs salt cavern.



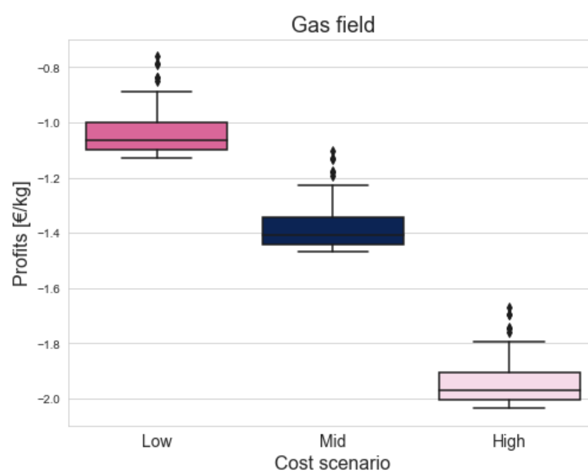
(b) Profits salt cavern.

Figure 55: Cost results of salt caverns in the national energy system.

Figure 55a shows the average system costs per kilogram of hydrogen from salt caverns in the national energy system, after removing scenarios that were deemed implausible from the dataset. Comparing this result to the average system costs when the implausible scenarios were still included, it appears that the found values are closer to each other for each cost scenario. Additionally, the median is lower in each cost scenario compared to Figure 46a in Section 9. There is no profit in any plausible scenario. Therefore, regardless of the cost scenario, subsidies will be required to initiate investment in hydrogen storage in salt caverns.



(a) Average system costs gas field.



(b) Profits gas field.

Figure 56: Cost results of gas fields in the national energy system.

For the gas fields, a small range of values is found for each cost scenario. The average system costs per kilogram of hydrogen from gas fields are on average 2.8 to 4 times higher than hydrogen storage in salt caverns. What is noticeable from Figure 56a is that the range found is much smaller compared to Figure

46b in Section 9, where none of the scenarios were excluded. However, gas fields are also not profitable in any situation, even when the implausible scenarios are excluded. In fact, their losses are much greater than the losses that occurred with salt caverns.

The above analysis shows that salt caverns outperform gas fields in terms of average system costs and profits. Therefore, salt caverns would be a better investment for Essent. Not only because of the lesser losses but also because Essent's portfolio is likely to consist mostly of industrial clients with a relatively constant demand pattern throughout the year. It is important for them to be able to manage the flexibility of fluctuating green hydrogen production throughout the year. From this point on, the focus will therefore be solely on salt caverns.

10.3 Best and worst case

Essent is interested in both the best and worst-case scenarios. Therefore, from the plausible scenarios of the national energy system, the best and worst cases have been determined for the profits, and the average system costs associated with these scenarios have been presented in Table 28 and Table 29. However, in this study, two aspects have been highlighted: on the one hand, the economic feasibility of storage facilities for market players such as Essent, and on the other hand, the desire to minimise the operational system costs of the overall Dutch energy system. Therefore, in addition to the best and worst-case scenarios for Essent, a scenario has also been added in which the lowest operational system costs could be achieved, as it is a logical assumption that the Dutch infrastructure will move towards that energy system. This scenario is referred to as the Government's best case. Appendix F.2 presents tables containing the specifications of both the most favourable and the most unfavourable scenarios for Essent and the best case for the government.

Table 28: Average system costs for the worst and best case scenario in €/kg.

	Cost scenario		
	Low	Mid	High
Essent's worst case	0.32	0.38	0.42
Essent's best case	0.26	0.30	0.33
Government's best case	0.26	0.31	0.33

Table 29: Profits for the worst and best case scenario in €/kg.

	Cost scenario		
	Low	Mid	High
Essent's worst case	-0.44	-0.50	-0.54
Essent's best case	-0.18	-0.22	-0.24
Government's best case	-0.26	-0.31	-0.34

An important insight that can be drawn from Table 29 is that the profits that Essent can make in the government's best-case scenario are lower than Essent's best-case scenario, but much higher than Essent's worst-case scenario. Although the government's best case is less advantageous for Essent compared to their best-case scenario, it is also not the case that such an energy system has extremely negative implications for Essent. That is a valuable insight for Essent, given that there is a significant chance that the energy system will take a form in which there are hardly any moments of extreme scarcity, considering the societal importance of maintaining consumer prices of essential needs such as electricity and hydrogen relatively low.

The difference between the two scenarios associated with Essent's best case and the Government's best case lies solely in the electricity interconnection capacity. In the Government's best-case scenario, this capacity is 17.8 GW, providing significant import flexibility, meaning that peak generators do not need to be deployed at any point during the year. In Essent's best-case scenario, the electricity interconnection is equal to the current capacity of 14.8 GW, which, compared to the Government's best-case scenario, leads to scarcity in the electricity market, requiring 50 GWh to be generated with peaking generators. This allows Essent to convert hydrogen into power to reduce the scarcity in the electricity market.

10.4 Seasonal revenue opportunities of salt caverns

As mentioned earlier, the salt caverns in the model cannot take advantage of seasonal opportunities because the model can only look ahead 72 hours. As a result, salt caverns do not experience a financial incentive to purchase more hydrogen in the summer. Therefore, in cases where there is no perfect storage, seasonal opportunity revenues may be missed. To determine if this is the case, the average hydrogen price during summer and winter was compared for both the best and worst-case scenarios within the national energy system. The reasoning here is based on the principle that if there is perfect storage in a system, the price would be constant throughout the year. If the price is not constant throughout the year, it indicates that some value is being left on the table with a certain storage configuration, of which salt caverns could possibly take advantage.

Table 30: Opportunity values in €/kg.

	Opportunity value
Essent's worst case	0.11
Essent's best case	0.18
Government's best case	0.05

This means that the difference between the average summer market price and winter market price, depending on the scenario, is 0.05, 0.11 or 0.18 €/kg. On the one hand, this indicates that these storage configurations do not result in perfect storage because the price is not constant throughout the year. On the other hand, it implies that in these storage configurations, there is an opportunity for salt caverns to increase their revenues by purchasing hydrogen during the cheaper summer months and selling it in the winter. In that case, salt caverns will also exhibit a clearer seasonal pattern. This effect would not lead to a positive profit, but it can significantly reduce the magnitude of the losses. Taking into account these seasonal opportunity revenues, the salt cavern profits can change towards the values presented in Table 31.

Table 31: Profits for the worst and best case scenario in €/kg, considering seasonal opportunities.

	Cost scenario		
	Low	Mid	High
Essent's worst case	-0.33	-0.39	-0.43
Essent's best case	0.00	-0.04	-0.06
Government's best case	-0.21	-0.26	-0.29

It emerges from Table 31 that when considering the potential seasonal opportunities of salt caverns, the profits of Essent's best-case scenario far exceed those of the government's best-case scenario, whereas these values were much more aligned previously. The discrepancy arises because, in the government's best-case scenario, electricity is not generated using expensive peak generators, leading to a much smaller difference between summer and winter prices and, consequently, fewer seasonal opportunities. As a result, the costs that would need to be allocated in the form of subsidies in the government's best case would be considerably higher than in Essent's best case. Annually, in the government's best case in the mid-cost scenario, 269 M€/year would be spent on subsidies compared to 34 M€/year in Essent's best case.

However, the average electricity price in Essent's best-case scenario is 96 €/MWh, whereas in the Government's best-case scenario, it is 94 €/MWh. This difference significantly impacts the annual electricity costs incurred by households and businesses. For the national energy system's annual electricity demand of 231 TWh, this would result in an increase in electricity costs of 461 M€/year. Therefore, the societal costs of Essent's best-case scenario exceed the costs the government would incur for subsidising the government's best-case scenario. Although the former costs would be borne by residents and businesses, this is undesirable from a societal cost perspective, mainly because electricity is considered a basic necessity, and consumers need protection from high prices. Consequently, it is in the government's best interest to choose an energy system without electricity scarcity.

11 Conclusion

The Netherlands aims to have a CO_2-neutral energy system by 2050. Hydrogen is seen as an important energy carrier that can contribute to this transition. Not only can hydrogen potentially decarbonise industry, transportation, and possibly agriculture and the built environment, but it can also be used to store electricity for longer periods. As more green hydrogen is produced over the years by electrolysis, the hydrogen demand and supply will increasingly diverge. Underground hydrogen storage can provide a solution for the imbalance between hydrogen demand and supply in both the short and long term. Several geological formations are currently being investigated to determine their suitability for hydrogen storage. This research aims to provide insight into the technical and economic potential of different storage facilities and configurations in the Dutch energy system by 2040. Five sub-questions have been answered to ultimately answer the main research question.

SQ 1. Which types of underground hydrogen storage are most promising for the Netherlands, considering their availability and Technology Readiness Level?

Globally, salt caverns, gas fields, oil fields, aquifers and rock caverns are being explored for their suitability for hydrogen storage. Salt caverns, gas fields, and aquifers are, unlike rock caverns and oil fields, available in large quantities in the Netherlands. However, when considering the maturity of the technologies, it appears that salt caverns and gas fields both perform better in terms of Technology Readiness Level (TRL). Although the TRL of gas fields is only 1 point higher than aquifers on a scale from 1 to 10, gas fields in the Netherlands are preferred over aquifers due to the high cushion gas requirements and the potential hydrogen losses due to microbial processes in aquifers. Overall, based on the availability and the TRL, gas fields and salt caverns are identified as the most promising UHS solutions for the Netherlands. Gas fields are often pointed out as suitable formations for seasonal hydrogen storage due to their size, while salt caverns are pointed out as formations suitable for short-cyclic storage.

SQ 2. How robust is the choice for the number of salt caverns in an energy system, in addition to different policies for seasonal hydrogen storage?

The initial determination of the number of salt caverns required, in addition to the policy being pursued regarding seasonal storage, was tested for robustness. The results of this robustness analysis based on the Minimax regret principle indicate that in all energy systems, the initial choice of the number of salt caverns was not robust under varying values of the most influential environmental variables: the electricity demand in the built environment, the electricity interconnection capacity, the installed capacity of hydrogen turbines, and the installed capacity of Li-ion batteries. An important observation was that in all energy systems, the highest regret compared to a larger number of salt caverns was attributed to scenarios with a high installed capacity of hydrogen turbines. This is because a high installed capacity of hydrogen turbines can significantly reduce electricity scarcity in the electricity market by converting hydrogen into electricity. Another important insight for policymakers that emerged from the robustness analysis is that adding salt caverns to an energy system already dominated by green electricity and green and blue hydrogen no longer leads to a reduction in CO_2 emissions. In the decentral, national, and European energy systems, it was even observed that adding salt caverns leads to a small increase in CO_2 emissions because more blue hydrogen was produced as the number of salt caverns increased. Although CO_2 is captured during the production of blue hydrogen, the carbon capture rate is limited to only 90%.

SQ 3. What storage configuration is most suitable to meet the required storage capacity in 2040 across various energy systems?

The various storage configurations in a particular energy system, consisting of a specific policy for seasonal storage and a certain number of salt caverns in addition, have been compared based on operational system costs and capital costs to determine which storage configuration performs best in a given energy system. From this analysis, it became clear that the low storage policy with its corresponding number of salt caverns performed the best in terms of operational system costs and capital costs for the decentral, European, and international energy systems. For the national energy system, the mid-seasonal storage policy in combination with ten salt caverns leads to a significantly better performance in terms of annual operational system costs and capital costs. This is because the national energy system has the largest installed capacity of vRES of all energy systems. In this scenario, the installed capacity of solar PV is 123 GW and the installed capacity of wind turbines is 66 GW. Due to the high dependence on vRES in this system, a larger seasonal storage policy compared to the other energy systems is preferred.

SQ 4. What are the average system costs in the different scenarios per kg of produced hydrogen?

The average system costs per kg of produced hydrogen in the mid-cost scenario varies from 0.30 to 0.50 €/kg for salt caverns across 54 different scenarios in the decentral energy system. In the national energy system, values between 0.28 and 0.44 €/kg have been observed. The values observed for the European and international energy systems are significantly higher. In the European energy system, the values range from 0.37 to 1.64 €/kg. Very high costs were found for the international energy system due to the extremely low amounts of produced hydrogen associated with certain scenarios. Even after removing these outliers, the average system costs per kg of produced hydrogen remained higher than in other scenarios, ranging from 0.80 to 7.50 €/kg. From this, it becomes clear that the costs per kg of hydrogen for salt caverns tend to rise as the system's capacity for hydrogen import and export increases. In these scenarios, short-cyclic storage is less necessary, resulting in less hydrogen being injected and withdrawn, leading to higher costs per kg of hydrogen as the fixed annual costs are spread over a smaller quantity.

The average system costs per kg of produced hydrogen for gas fields were much closer aligned because the amount of hydrogen produced from the gas fields was the same for each energy system. The average system costs per kg of produced hydrogen varied from 0.7 to 2.00 €/kg for gas fields across 54 different scenarios in the decentral, national, European, and international energy systems.

The higher average system costs per kg of hydrogen in gas fields compared to salt caverns are attributed to the high capital costs associated with large quantities of cushion gas and the increased purification unit investments required when a cushion gas other than hydrogen is used. Additionally, operational costs are also higher due to the higher pressure changes that need to be achieved through compression.

SQ5. What are the potential returns of the storage facilities in the various scenarios, and could it be profitable for Essent to invest in such storage?

For the analysis of potential profits for Essent, the national energy system was determined as the most plausible energy system, as the Dutch electricity and hydrogen road maps align best with the energy demand and installed electricity generation and hydrogen production units defined for this energy system. Implausible scenarios within that energy system were removed from the dataset, resulting in 26 plausible scenarios. The gas fields were found to perform, in terms of profits, on average 3.5 times worse for the mid-cost scenario, making salt caverns the better investment decision for Essent. However, even in the best-case scenario from Essent's perspective, a loss of -0.22 €/kg was incurred in the mid-cost scenario. However, when considering the seasonal opportunities of salt caverns in the best-case scenario that remained unexploited, the loss could be reduced to -0.04 €/kg. When adhering to the government's goal of minimising the operational system costs of the overall system, a less favourable business case for salt caverns emerges, namely -0.26 €/kg. The aforementioned makes it clear that the business case for underground hydrogen storage, when linked to the hydrogen market, cannot be profitable without subsidies. The amount of subsidy required to initiate investments in UHS will strongly depend on the choices that the government will make regarding the allowable electricity scarcity within the Dutch energy system.

Now that responses to all sub-questions have been formulated, the main research question can be addressed.

What is the technical and economic potential of different underground hydrogen storage configurations in the Netherlands in 2040, considering various future electricity and hydrogen systems?

The technical potential for hydrogen storage in gas fields and salt caverns is substantial in the Netherlands. While there is already ample hydrogen storage capacity on land, successful studies have also been conducted on the technical potential offshore. The technical potential of salt caverns and gas fields alone already exceeds the expected underground hydrogen storage demand in 2040 by 26 to 52 times, according to the required storage capacity determined for the decentral, national, European and international energy systems in this study. Therefore, no issues are expected regarding the spatial integration of underground hydrogen storage.

When analysing the economic potential, a distinction was made between two financial aspects. On the one hand, minimising the operational system costs of the overall system and on the other hand, maximising the profit that can be achieved with the storage facilities. This study demonstrated that there are some conflicts arising from these different purposes. First of all, the results showed that integrating underground hydrogen storage facilities results in a significant reduction in operational system costs. The lowest operational system costs were associated with scenarios where little to no scarcity occurred in the electricity market, as expensive peak generators did not need to be utilised to address electricity shortages. However, in these systems, the business case for storage facilities becomes less favourable because the revenue model of storage facilities is based on price fluctuations, particularly price peaks. This creates a conflict of interest, wherein the government must decide on the policy they wish to pursue regarding the acceptable scarcity in the Dutch hydrogen and electricity market in 2040. If the choice is made for an energy system with little to no scarcity, significant financial support in the form of subsidies will need to be provided to stimulate investment in underground hydrogen storage, as it has become evident in this research that without underground storage facilities, highly undesirable high operational system costs are incurred. For salt caverns, this subsidy will amount to 0.26 €/kg hydrogen, but for seasonal storage in gas fields, this will increase to 1.35 €/kg.

There are many critical voices to be heard when it comes to the role hydrogen will play in the coming years, including concerns about the cost aspect. This research has shown that hydrogen storage only contributes a small amount to the overall cost picture. Storage in salt caverns adds 0.30 to 0.39 €/kg to the costs in the mid-cost scenario, while gas fields would add 1.15 €/kg. Compared to the 10 €/kg related to the business case of wind turbines, cables, and electrolysers, the costs of underground storage are relatively low. Therefore, the potential for cost reductions within the hydrogen business case primarily lies in the production aspect of hydrogen rather than in its storage counterpart.

12 Discussion

12.1 Storage facilities and configurations

12.1.1 Storage configurations

In this research, it is assumed that seasonal storage of hydrogen will take place in gas fields due to the larger storage capacity of gas fields compared to salt caverns and that salt caverns will be used for short-cyclic storage because they allow for multiple cycles per year. The extent to which seasonal storage occurs is considered a policy choice. These policy choices are set at 5000, 10000, and 15000 GWh and are based on estimates of the required storage capacity in 2040 and 2050 from other studies. While the performance in terms of operational system costs of three configurations per energy system has been examined, there are many more possible configurations to consider. For example, seasonal storage could theoretically also be done in salt caverns, and there is even research being conducted into the possibility of short-cyclic storage in smaller gas fields. Only a limited number of storage configurations of all possible options have been tested in this research. Particularly in the European and international energy systems, where UHS plays a smaller role due to the low installed capacity of vRES and high hydrogen interconnection, it would be valuable to also consider storage configurations where no, or significantly lower, seasonal storage takes place.

Furthermore, because the most optimal number of salt caverns was determined separately for each energy system (decentral, national, European, international) in addition to the policy regarding seasonal hydrogen storage, insight was gained into what type of storage configuration would function best in a particular energy system. However, there is limited to no insight into how the choice of one storage configuration would perform in the different energy systems. It would be very valuable to investigate this aspect because in the coming years, choices need to be made about how the storage system should look in 2040, while during those years, there will still be much uncertainty about how the future electricity and hydrogen markets will be structured.

12.1.2 Storage facilities

Although the technical characteristics of the designs of storage facilities are based on literature, this research did not consider a specific site, while the limitations and constraints of underground storage heavily depend on site-specific features such as subsurface composition, porosity, and permeability. In the study, a work pressure range of 70-140 bar for salt caverns and a working pressure range of 100-200 bar for gas fields were assumed. However, the work pressure range is dependent on the depth of the geological formation and significantly impacts the required compressor power. Additionally, the location of UHS needs to be strategically chosen based on users, hydrogen production sites, infrastructure, and other underground storage facilities. Again, this aspect was not addressed in this research.

Moreover, the fact that the Technology Readiness Level of hydrogen storage in gas fields is estimated at only 3-4 on a scale of 1 to 10 indicates that the technology is still in its infancy. Although gas fields have proven their suitability for storing natural gas for millions of years, there is still insufficient knowledge available regarding the integrity of wells, environmental effects, and the technical challenges associated with mixing hydrogen with the cushion gas used. However, it is expected that these challenges will be overcome in the coming years. Therefore, this research assumes that gas fields can be used for seasonal storage by 2040. Whether this will be the case will be highly dependent on the conclusions drawn from the results of pilots that will be conducted in the coming years. For a country like the Netherlands, which has many gas fields, conducting pilots should therefore be high on the agenda.

While hydrogen storage will be used to provide a constant hydrogen supply to the industry, it will also play a role in seasonal electricity storage, thus serving as a flexibility option in the electricity market. In this study, besides UHS, only Li-ion batteries were considered as another flexibility option. Li-ion batteries are generally used for a different purpose, namely to address short-term shortages in the electricity market. However, it has become clear in this study that the installed capacity of batteries does impact the revenues that can be generated with UHS facilities, indicating some level of competition between them. Additionally, besides UHS, there are other ways to store electricity for a season, such as Compressed Air Energy Storage (CAES). Alternatives were not included in the model, potentially resulting in an overestimation of the required seasonal storage in this study. Additionally, this study focused solely on the storage of pure hydrogen. No attention was given to intentionally blending hydrogen with other gases, such as town gas.

12.2 Robustness analysis

An important limitation of this study is that the robustness analysis of the choice for the number of salt caverns, in addition to the seasonal storage policy, was only conducted with the initially determined number of salt caverns, the initial number of salt caverns plus 2, and the initial number of salt caverns minus 2. The robustness analysis revealed in almost all experiments that the minimum maximum regret occurred when the choice was made for the initial number of salt caverns plus 2 as decision variables. While this suggests that, under varying environmental variables, it may be preferable to choose the initial number of salt caverns plus 2 instead of the initial number of salt caverns, it provides little insight into the actual number of salt caverns required. Potentially, the initially defined number of salt caverns plus 4, for instance, could lead to even better performance in terms of operational system costs, but this was not further investigated due to time constraints.

Another point of discussion is related to the Minimax regret approach used to interpret the results of the robustness analysis. In this study, the choice of the number of salt caverns was tested for robustness using 54 scenarios. Since the Minimax regret method only focuses on minimising the maximum regret occurring in one of the 54 scenarios, there is little insight into the average performance of a certain number of salt caverns across 54 scenarios. An adapted version of the MMR approach could provide better insight into this. For example, it is possible to take the sum of all regrets across all tested scenarios and, based on this sum, determine the minimum maximum regret.

A final limitation related to the robustness analysis is that due to time constraints, the robustness analysis was conducted with only four influential parameters, whereas multiple influential variables were identified in the sensitivity analysis.

12.3 Cost analysis

12.3.1 Electricity price

The cost analysis is based on the results of the experiments. In the 54 scenarios, representing all possible combinations of the established values of the critical variables, the values observed for the electricity served with peak generators varied significantly. In some scenarios, the electricity served with peak generators was 0. However, there were also scenarios, such as those with high electricity demand, low electricity interconnection, and low installed capacity of Li-ion batteries and hydrogen turbines, in which the electricity served with peak generators was substantial. In such scenarios, depending on the energy system, the electricity served with peak generators could reach up to 1200 GWh. This is highly undesirable for an energy system from a societal perspective. Given that a price of 3000 €/MWh was assigned to the electricity served with peak generators, the electricity price became significant when the electricity served with peak generators process was active. Although this is not inherently problematic because prices also rise in times of scarcity in reality, it is important to bear in mind during the interpretation of the cost analysis results that these scenarios also contributed to the final ranges found for costs and revenues.

As mentioned above, the model does allow for price spikes, but it does not account for negative electricity prices. The latter negatively influences the business case, whereas negative electricity prices are now occurring almost daily due to the large number of solar panels in the built environment.

12.3.2 Re-use of natural gas equipment

A frequently mentioned advantage of hydrogen storage in depleted gas fields is that the equipment used for extracting natural gas from the gas field could potentially be partially reused when storing hydrogen in the same depleted gas fields. In a depleted gas field, there are often multiple wells already in place that could potentially be repurposed. This potential exists not only for the reuse of wells but also for pipelines and surface installations. Altogether, this could potentially lead to cost reductions. However, since there has been little research conducted on the reuse of natural gas equipment, this potential cost reduction has been left out of consideration in this study.

12.3.3 The modelling

A limitation of this study is related to how the UHS facilities are modelled. For the salt caverns, the model misses out on seasonal opportunity costs. This is because the model was not run with complete foreknowledge and therefore, salt caverns do not experience any financial incentive in the summer months to start the winter season with a higher filling degree of the cavern. Although it is impossible to make a perfect prediction of uncertain factors such as weather conditions, market players usually do have some foresight due to the re-occurring seasonal pattern and will likely ensure that the salt caverns are filled to a high degree to avoid missing out on opportunity costs. However, because the look-ahead in this study is only 72 hours, anticipation can only occur within that period. The opportunity costs associated with the seasonal pattern can therefore not be exploited by the salt caverns. For that reason, the results regarding the revenues of the salt caverns may have turned out lower than they would be in reality. However, in Section 10, an attempt was made to map out these seasonal opportunities by comparing the average hydrogen price between summer and winter, and incorporating the difference into the business case, as this price differential is defined as the seasonal value that can still be captured in that specific energy system.

Additionally, because the gas fields in this study are designated for seasonal storage, a fill-and-empty pattern following the seasonal cycle is modelled. As this is modelled as a hard constraint, gas fields can never capitalise on the opportunities that arise during the summer months to generate extra revenue. Consequently, the potential revenues from gas fields may also be lower than would be the case in reality.

12.3.4 Lifespan of the storage facility

Another factor that can have a significant impact on the outcomes of the cost analysis is the assumption made for the lifespan of the storage facilities. The lifespan of the surface storage facilities is assumed to be 25, 20, and 15 years for the low, medium, and high-cost scenarios. This lifespan is also applied to the gas fields and salt caverns, although the storage facility itself may potentially remain operational for longer. The salt cavern in Teesside in the United Kingdom was built in 1971 and is still operational, meaning that its lifespan is already exceeding 50 years. It is worth noting that this storage facility was designed to serve the hydrogen demands of the chemical industry, known for its consistent demand pattern throughout the year and slow-cyclic operation of the site, which imposes less stress on the storage facility than would be the case in fast and short cyclic salt caverns. Assuming a longer lifespan for the geological formations could spread a portion of the capital costs over a longer period, resulting in a significant decrease in the cost per kg of hydrogen.

12.3.5 Variable operational costs

A final point of discussion related to the cost analysis is that the research has shown that the contribution of the variable costs of compressors and dehydration and purification units significantly affects the system costs per kg of produced hydrogen. To determine the variable costs, electricity consumption was multiplied by the average electricity price observed in a run. Therefore, it was assumed that no price opportunities were used for the storage facility. However, if a battery were installed, compression and dehydration/purification could be done at lower average electricity costs. This could be a possible solution to the high variable costs.

12.4 Hydrogen market and backbone

Although the hydrogen demand and supply are increasing and official plans have already been announced to interconnect the industrial clusters through pipelines suitable for hydrogen transport, significant uncertainty remains regarding the development and extent of the future hydrogen network. In this study, it is assumed in the four different energy systems that there is to some extent a hydrogen network. Therefore, the demand and supply of hydrogen are combined into one market: the hydrogen market. Bilateral contracts between producers and consumers are excluded in this study, while bilateral contracts are currently the dominant negotiation form and will likely stay partially in place, especially in the industry.

Furthermore, the desire for a hydrogen network exists not only because it facilitates hydrogen transport but also because a hydrogen network can serve as a flexibility option to some extent. Short cyclic storage could be accommodated through pressure regulation using the backbone, affecting the required storage capacity in salt caverns. However, since the physical characteristics of the hydrogen network are not modelled, this aspect is not considered in this research.

Moreover, in this study, an assumption has been made regarding the hydrogen connection with neighbouring countries. Although this assumption is based on the annual import and export of hydrogen in other studies and on the information on the European hydrogen backbone plans, there is significant uncertainty about the development of this interconnection. Sensitivity has been tested by varying the value by +10%, -10%, +20% and -20% to determine the impact on the KPIs. The influence was found to be limited within these ranges. However, further research should investigate the impact across a full range of interconnection capacities, as the results from the European energy system with an interconnection of 12 MW compared to the international energy system with an interconnection of 19 MW differ significantly from each other.

12.5 Climate change

A final, more general point is that this research does not consider climate change, despite its potentially significant effects on model outcomes, particularly in energy systems with a high degree of vRES penetration. Greater attention must be devoted to this in the near future so that the impacts of climate change on electricity generation using solar and wind energy can be assessed.

12.6 Comparison to the literature

In this study, both the average system costs of storage facilities and the potential revenues have been examined. Since there were no studies found in the literature that investigate the potential revenues of hydrogen storage facilities in the future Dutch energy system in 2040, the results in this study have only been compared based on the average system costs of the storage facilities. Since at the end of the study it was determined that the results of the national energy system are most likely the most plausible, the comparison with the literature was first conducted based on this energy system. In this literature comparison, only the scenarios deemed plausible in Section 10 were considered.

12.6.1 Salt caverns

Table 32: Average system costs found in the literature for salt caverns in €/kg.

Study	Value found in the literature
[83]	0.13
[84]	1.21
[85]	0.23 - 0.33
[86]	0.66 - 1.75
[87]	< 0.5
[88]	0.3 - 0.6

As is evident from Table 32, the range found in the literature varies widely. In this research, the ranges found for the salt caverns are 0.28 to 0.33 €/kg in the low-cost scenario, 0.30 to 0.39 €/kg in the mid-cost scenario, and 0.33 to 0.43 €/kg in the high-cost scenario. While the majority of the literature falls within this range, there are also some values that fall outside of it. The 0.13 €/kg found in the study by Abdin et al. [83] falls at the lower end of the range. Capital costs are estimated at 50 M€ in this study, whereas in this research, depending on the cost scenario, they are estimated at 90, 115, and 130 M€. However, no cost breakdown of the capital costs is provided and detailed information about the design of the salt cavern is lacking, making it impossible to determine where this difference primarily lies.

Additionally, the study by EWI finds a range that, compared to the values found in this study, is also considerably higher: 0.66 to 1.75 €/kg [86]. The higher values found in this research are related to the models where there was low capacity utilisation. The lower values were related to the models where hydrogen was injected and withdrawn more frequently throughout the year. The latter aligns more closely with the values found in this model since hydrogen in the model in this study can be injected and withdrawn multiple times throughout the year.

The study by Lord et al. also finds a relatively high value compared to other literature studies and the results of this research [84]. Firstly, they assume a cushion gas price of 4.5 €/kg, whereas in this research, the assumption is made of 2.2, 2.7, and 3.5 for the low, mid, and high-cost scenarios. Since cushion gas constitutes approximately 25% of the total capital costs of salt caverns, a higher hydrogen price can lead to significant differences in costs. Additionally, the site preparation costs are also estimated higher than in this study. They estimate 28 M€ for this, while in this research, the costs are estimated at 6 M€, 12 M€, and 17 M€ for the low, mid, and high-cost scenarios, respectively.

12.6.2 Gas fields

Table 33: Average system costs found in the literature for gas fields in €/kg.

Study	Value found in the study
[67]	0.5
[84]	0.93

Firstly, it becomes apparent that there has been much less research conducted on hydrogen storage in gas fields compared to hydrogen storage in salt caverns. Worldwide, there is not yet any operational gas field that stores pure hydrogen. Additionally, Table 33 shows that the costs found in the literature for the two studies are significantly lower than the values found in this study. In this study, values of 0.8, 1.4, and 1.7 €/kg were found for the low, mid, and high-cost scenarios, respectively.

For the study by Lord et al. [84], the difference is largely due to the assumption for the required cushion gas. Since gas fields have a large capacity, large amounts of cushion gas are also required. However, in this research, a WGV:CGV ratio of 1:2 was assumed based on the TNO report on the feasibility of offshore underground hydrogen storage [9]. However, in the study by Lord et al. [84], a WGV:CGV ratio of 1:1 was assumed. The WGV:CGV ratio of 1:2 is less advantageous from a cost perspective, which explains why the costs found in this research are significantly higher. The site-specific characteristics of gas fields such as depth and size, as well as the desired production capacity, are crucial for determining the required amount of cushion gas.

In the study by Yousefi et al. [67], the costs are significantly lower compared to the costs found in this research. This is not particularly related to the capital costs, but significant differences are observed for the operational costs of the above-ground storage facilities. This is because in this research, an average electricity price of 60 €/MWh was used, whereas in this research, depending on the scenario, the average electricity price equals approximately 90 €/MWh.

In general, it can be concluded that the values found in this study are in the correct order of magnitude. Additionally, the values deviate from those found in the literature in some cases, but this could be explained by either different assumptions or by the use of a different method.

12.7 Recommendations

12.7.1 Policy

The first recommendation is based on the installed capacity of hydrogen turbines, which convert hydrogen to electricity. If underground hydrogen storage becomes the dominant form of seasonal electricity storage, the installed capacity of hydrogen turbines is of great importance. On the one hand, a large installed capacity can result in a decrease in operational system costs as scarcity during the winter months can be better accommodated. On the other hand, it leads to an increase in revenues from underground hydrogen storage facilities. A large installed capacity of hydrogen turbines can therefore significantly enhance the business case of UHS facilities, serving as a strong incentive for investment.

Furthermore, seasonal storage will increasingly play a role in future energy systems, especially in systems with high penetration of vRES. While seasonal storage could technically be feasible in salt caverns, gas fields offer larger-scale capabilities. However, the Technology Readiness Level of gas fields is still relatively low. Therefore, the Dutch government should assess their technical suitability for large-scale hydrogen storage. Additionally, the potential reuse of wells and above-ground facilities of depleted gas fields should be further investigated, as it could significantly enhance the business case.

Thirdly, considering that both gas fields and salt caverns have proven to be unprofitable in most scenarios, subsidies will be required to incentivise companies to invest in UHS facilities. This policy regarding the subsidies must be announced in the coming years because the development of salt caverns can take up to 8 years from obtaining permits to the first day of operation. Underinvestment or delayed investments can result in significant societal consequences, such as power outages and disruptions to industrial processes, resulting in high societal costs.

Lastly, as the Dutch government strives to achieve a CO_2-neutral electricity system by 2035 and a fully CO_2-neutral energy system by 2050, action must be taken regarding CO_2 emissions as long as the carbon capture rate remains limited to only 90%. Depending on the design of the future electricity and hydrogen system, around 10,000 kilotons of CO_2 are still emitted annually. To become fully CO_2-neutral, the Dutch government must therefore consider negative emission measures such as reforestation and ecosystem restoration.

12.7.2 Essent

This study clearly indicates that both in terms of average system costs per kg of produced hydrogen and the potential profits that can be achieved from salt caverns compared to gas fields generally yield more favourable results for Essent. Given the expectation that Essent's hydrogen portfolio will largely consist of industrial customers with relatively constant demand patterns throughout the year, salt caverns also emerge as the preferred choice, especially in energy systems with large vRES and electrolysis capacity and therefore a significant share of fluctuating hydrogen production. However, it is prudent to await developments regarding potential subsidies, as salt caverns have also proven to be unprofitable in most scenarios within the energy systems.

Furthermore, there is a high investment risk associated with investing in salt caverns in energy systems with high hydrogen import capabilities. In these energy systems, the necessity for underground hydrogen storage is minimal, making it challenging to recover investment costs. Conversely, in energy systems where the Netherlands is largely self-sufficient in both electricity generation and hydrogen production, salt caverns present a more compelling business case. In such systems, the average system costs per kg of produced hydrogen are more stable, indicating that the system costs are less dependent on environmental variables, thereby reducing investment risk. Therefore, it is in Essent's interest to sit down with the government to guide them towards an energy system where the Netherlands is largely self-sufficient in electricity and hydrogen demand, as this results in a more advantageous business case than in energy systems with higher imports.

The storage capacity of future hydrogen storage facilities is expected to be auctioned, equal to the process observed in natural gas storage. In this regard, Essent can use the average system costs per kg of produced hydrogen as a guideline in determining their bid. By that time, Essent will need to assess, based on their portfolio, how much hydrogen they expect to inject into and withdraw from the storage. Based on the system costs found in this study, they can make an initial estimate of the height of their bid.

12.7.3 Conflict of interest

This study focuses on the societal operational costs of the energy system versus the financial feasibility of underground hydrogen storage facilities. From these two objectives, a dilemma has emerged because a positive outcome for one goal does not necessarily coincide with a positive outcome for the other goal, as became clear from Section 10.

The government prefers an energy system where operational system costs are reduced to a minimum. Therefore, they favour a system where peak generators are not required to reduce scarcity in the electricity market, thereby preventing these expensive generators from setting the price and significantly increasing the average electricity price. This situation occurs in a system with sufficient flexibility and high-capacity generation units installed. The dilemma arising here is that the revenue model of storage facilities lies in being able to capitalise on price fluctuations. Entities like Essent therefore benefit more from energy systems where scarcity occurs, enabling them to maximise their revenues using the price spikes. This stands in direct opposition to the government's objective.

From Section 10 became clear that there are higher societal costs associated with Essent's best-case scenario in comparison to the costs that the government should incur for subsidising hydrogen storage in salt caverns in the government's best case. While residents and businesses would bear the additional costs related to the higher average electricity price in the Essent's best-case scenario, this is undesirable from a societal cost perspective, chiefly due to electricity being deemed a fundamental necessity. Consequently, consumers require protection against high electricity prices. Therefore, it is in the government's best interest to opt for the energy system without electricity being served with peak generators because the costs that would need to be allocated to subsidies in this system do not exceed the societal costs incurred when a higher average electricity price is induced in the most favourable scenario for entities such as Essent.

The stakeholders must collaborate and engage in consultation regarding the design of the future energy system. To mitigate the risk of underinvestment, the government should assess the financial viability of underground hydrogen storage in collaboration with investors such as Essent and provide them with subsidies accordingly.

12.7.4 Storage facility asset owners

For storage facility asset owners, an important insight is that the operational costs of compression and dehydration/purification units account for a large share of the average storage facility costs. To reduce electricity consumption costs, consideration can be given to the use of an on-site battery. The effect this could have on the overall costs incurred needs to be investigated.

12.8 Future research

Firstly, further research is needed to explore the operational system costs achievable with alternative storage configurations. This study revealed a preference for a low-seasonal storage policy in three out of four energy systems, suggesting that storage configurations with even lower seasonal storage policies may possibly lead to lower system costs. The same methodology can be employed to investigate this as it merely involves an extension of the experiments. Additionally, it is crucial to explore how the system would perform if seasonal storage were to take place in salt caverns instead of gas fields, as the technical feasibility of underground hydrogen storage (UHS) in gas fields has not yet been proven. The model developed for this research could be reused, but some adjustments would need to be made to the storage clusters. The cluster containing seasonal storage would need to be modified to accommodate the characteristics of salt caverns. The model would then still distinguish between short-cyclic storage and seasonal storage, but both storage purposes would be designated to salt caverns.

Building on this, it is crucial to establish the technical feasibility of hydrogen storage in gas fields. While gas fields have proven their capability to store natural gas over millions of years, there still exists a significant knowledge gap in understanding the well integrity, environmental effects, and the technical challenges associated with blending hydrogen with the cushion gas used. For this, a more technical investigation is required, involving measurements and monitoring conducted at promising gas field sites.

Moreover, the underground hydrogen storage locations must be taken into consideration. The location of hydrogen storage facilities needs to be strategically chosen based on the location of hydrogen production and major consumers. This requires consideration of the hydrogen demand from industrial clusters in the Netherlands, as well as the identification of suitable locations within the country, along with spatial planning considerations. The constructed model could be expanded with a hydrogen network to determine the most cost-effective locations for placing underground storage facilities, taking into account the transport limitations. This can be done in Linny-R because the behaviour of gases in pipelines is relatively easy to control with valves. Introducing the geographical scope of the electricity grid would be beneficial as well because the capacity constraints on the electricity grid can have crucial implications for the placement of vRES capacity and electrolysers, thereby also affecting the location of hydrogen production. However, Linny-R is not capable of modelling the electricity grid because it involves the laws of Ohm and Kirchhoff's second law. To accomplish this, another software tool such as Python would need to be used.

The technical and geological characteristics of a particular site also influence the performance of the storage, thereby affecting the costs, emphasising the need to consider the location aspect in future research.

Furthermore, further research should include the capital costs of not only the storage facilities but also the capital costs of all other installed capacities in the system. As more installed capacity is added to the system, it is logical that operational system costs decrease. However, there may be an increase in the total system costs of such a system when the rise in capital costs exceeds the reduction in operational system costs when adding additional production, generation, or flexibility capacity. Linny-R offers the possibility to incorporate capital costs into the model. Therefore, this expansion can build upon the existing model.

A final recommendation for future research relates to the installed capacity of hydrogen turbines. In this study, this has proven to be a crucial variable in the extent to which electricity scarcity occurs during the winter, in a system where hydrogen plays a dominant role. However, it has not been determined what the prudent installed capacity of hydrogen turbines would be under uncertain conditions. A similar type of research to that conducted by Joerie Kluijtmans for determining prudent electrolysis capacity could be carried out to determine prudent hydrogen turbine capacity [89].

13
Reflection

13.1 Reflection on the process

While I am generally satisfied with the process of my thesis research, there are several things I would have done differently in hindsight. Throughout the process, particularly during the modelling phase, choices needed to be made. In my opinion, I revisited previous decisions too often, causing the entire process to stagnate and even regress. Even as I began conducting experiments, I reconsidered a choice I had made earlier regarding the import and export of electricity and hydrogen. Since this choice proved to have a significant impact, the experiments I had already conducted had to be redone. This consumed a considerable amount of time, leading to time constraints towards the end. Consequently, I was compelled to exclude certain variables from the scope of the experiments, which could have yielded interesting results. Additionally, I would have preferred to focus on a single energy system rather than four different systems. The number of experiments required became extensive because each experiment had to be conducted for each energy system. Given that this also had to be done for low, medium, and high-seasonal storage policies, it resulted in a large number of experiments. Although this broadened the research's scope, it sacrificed depth. While I believe it was beneficial for this research to have a broad focus due to the uncertainty surrounding every variable in these future systems, it could also have been valuable to extensively analyse one single system rather than examining multiple systems.

13.2 Reflection on working with Linny-R

In general, I have a positive attitude towards working with Linny-R. Nevertheless, I faced various challenges throughout my research related to the modelling tool. Firstly, Linny-R has limited memory, which constrained the size of my experiments. Partitioning the experiments into 24 smaller ones required a significant amount of time and planning for setup, operation and data processing. Although this was not a huge problem, it demanded considerable attention throughout the entire process.

Furthermore, another obstacle I encountered was the lack of an existing manual, resulting in a heavy reliance on Pieter Bots. It had been five years since I last worked with Linny-R, and during that time, numerous improvements and changes were made to Linny-R, requiring me to relearn the entire modelling tool. Fortunately, I now know that he is actively working on creating a manual, which will resolve this issue for successors.

Moreover, it would be advantageous if Linny-R were to provide the capability of excluding variables after running experiments, thereby enabling users to examine only the selected variables within Linny-R.

Lastly, providing Essent insights into Linny-R was challenging since nobody was familiar with Linny-R as they are all working with Python. Despite my efforts to communicate this as clearly as possible to Essent, they still only had a limited understanding of the potential that Linny-R has in general. This complicated stakeholder management within my research.

13.3 Personal reflection

First and foremost, I have had an incredibly enriching and enjoyable experience during my thesis project. I found my chosen topic interesting from start to finish, which was very motivating throughout the whole process. However, the process did cause me stress at certain moments. Reflecting on this, I realise it mostly stems from my perfectionism, making it challenging to make decisions because I was always searching for a better choice. It was challenging for me to accept that research can always be more extensive and better, but you can never execute a perfect study, especially not in seven months.

Furthermore, I believe I effectively managed the communication aspect throughout the entire process, both in my interactions with my supervisors and with employees of Essent. I have had the opportunity to meet many new people and exchange knowledge at Essent, for which I am extremely grateful.

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A

Input model

A.1 Scenario input parameters

Table 34 presents an overview of the different scenarios' input parameters.

Table 34: Input parameters for the different modelling scenarios [51].

		Decentral	**National**	**European**	**International**	**Units**
E generation	Solar PV on land and water	41.8	41.8	29.2	24.6	GW
E generation	Solar PV on buildings and households	84.3	80.9	63.4	43.6	GW
E generation	Wind onshore	12.1	15.1	8.7	8.7	GW
E generation	Wind offshore	36	50.5	31.5	38.5	GW
E generation	Nuclear	0	1.5	4	0	GW
E generation	Coal	0	0	0	0	GW
E generation	Natural gas CCGT with CCS	6.8	6.3	5.5	4.0	GW
E generation	Hydrogen CCGT	10.6	8.9	8.9	10.6	GW
E generation	Biomass incineration with CCS	0.3	0.3	0.5	0.5	GW
E demand	Built environment	62.4	59.0	63.0	64.1	TWh
E demand	Transport	38.9	49.4	41.1	28.1	TWh
E demand	Industry	80.3	88.0	73.5	66.6	TWh
E demand	Agriculture, ICT, energy	30.8	34.1	34.0	30.5	TWh
E flexibility	Li-ion batteries incl. EVs	42.4	42.0	29.2	24.7	GW
E flexibility	Interconnection	14.8	14.8	14.8	14.8	GW
E import price	Interconnection	0.15	0.15	0.15	0.15	M€/GWh
H production	SMR with CCS	3.8	3.8	4.9	4.2	GW
H production	Electrolysis	14.5	16.8	8.5	7.8	GW
H production	Ammonia cracker	3.9	3.9	3.9	3.9	GW
H demand	Built environment	0	0	2.3	11.9	TWh
H demand	Transport	8.1	5.9	6.4	24.4	TWh
H demand	Industry	52.9	50.5	60.6	72.8	TWh
H demand	Agriculture	0	0	0	3.2	TWh
H flexibility	Interconnection	5.5	5.2	12.8	19.4	GW
H import price	Interconnection	0.116	0.116	0.114	0.117	M€/GWh

A.2 Technical input parameters

Table 35: Technical input parameters of the model.

Parameters	Value	Unit	Reference
Gas price	0.0321	€/kg	[90]
Biomass price	0.058	M€/GWh	[51]
Nuclear electricity price	0.02759	M€/GWh	[51]
price	0.1358	M€/kton	[91]
Carbon capture rate	90	%	[49]
O&M costs CCGT	0.013	M€/GWh	[92]
O&M costs biomass incineration	0.0276	M€/GWh	[93]
O&M costs nuclear fission	0.0105	M€/GWh	[94]
Efficiency nuclear power plant	32	%	[95]
Efficiency CCGT	57	%	[95]
Efficiency biomass incineration plant	36.2	%	[96]
emission of gas	0.2031	kton/GWh	[89]
O&M costs solar central	0.027	M€/GWh	[92]
O&M costs solar decentral	0.027	M€/GWh	[97]
O&M costs offshore wind	0.0335	M€/GWh	[98]
O&M costs onshore wind	0.0132	M€/GWh	[99]
O&M costs ammonia cracker	0.015	M€/GWh	[100]
O&M costs electrolyser	0.0164	M€/GWh	[101]
O&M costs SMR	0.0089	M€/GWh	[102]
Efficiency SMR	74	%	[103]
Efficiency electrolysis	74	%	[57]
Efficiency ammonia cracker	68.51	%	[100]
E consumption SMR	0.027	GWhe/GWh H_2	[104]
E consumption ammonia cracker	0.1446	GWhe/GWh H_2	[100]
Self-discharge rate Li-ion battery	1	%/day	[105]
Li-ion efficiency	85	%	[105]
O&M costs Li-ion batteries	0.01145	M€/GWh	[106]
Capacity surface tank	10	GWh	Based on Peakshaver Gasunie.
Injection rate surface tank	0.125	GWh/hr	Based on Peakshaver Gasunie.
Withdrawal rate surface tank	0.1667	GWh/hr	Based on Peakshaver Gasunie.
O&M costs surface tank	0.0096	M€/GWh	[107]
E consumption liquefaction	0.25	GWhe/GWh H_2	[108]
O&M cost hydrogen turbine	0.0057	M€/GWh	[109]
Hydrogen recovery rate salt caverns	98	%	[38]
Extraction penalty salt cavern reserve	-2	M€/GWh	Own assumption
Restoration premium salt cavern reserve	1	M€/GWh	Own assumption
E consumption compressor salt cavern	0.042	GWhe/GWh H_2	[110]
E consumption dehydration unit	0.015	GWhe/GWh H_2	[111]
Recovery rate dehydration unit	98.4	%	[111]
Hydrogen recovery rate gas fields	98	%	[112]
Extraction penalty gas field reserve	-2	M€/GWh	Own assumption
Restoration premium gas field reserve	1	M€/GWh	Own assumption
E consumption compressor gas field	0.05	GWhe/GWh H_2	[110]
E consumption purification unit	0.015	GWhe/GWh H_2	[113]
Recovery rate purification unit	90	%	[67]
Compressor ramp up/down rate	10	%/hr	Own assumption
Electricity import price	0.15	M€/GWh	[51]
Interconnection capacity electricity	14.8	GW	[51]
Price peak generation	3	M€/GWh	[34]
Hydrogen import price	0.116	M€/GWh	[57]

A.3 Built environment demand pattern

For the electricity demand in the built environment, historical data has been utilised. The dataset illustrating the demand pattern is derived from the Energy Transition Model and is depicted in Figure 57 and 58 [114].

Figure 57: Electricity demand pattern - week.

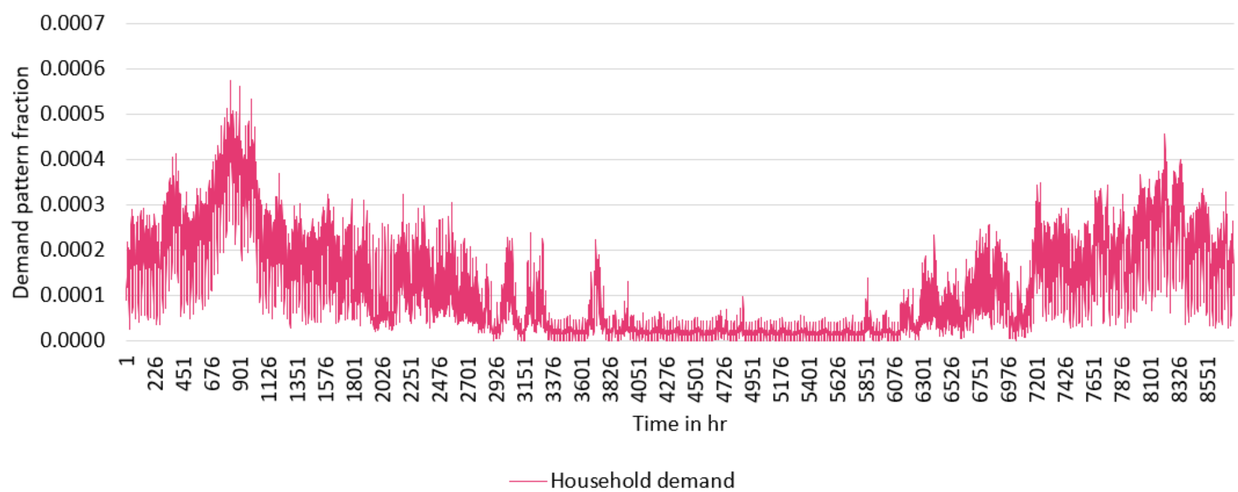


Figure 58: Electricity demand pattern - year.

Figure 57 clearly illustrates the weekly pattern of electricity demand, and Figure 58 provides insight into the seasonal pattern.

B

Cost analysis

B.1 Compressors

B.1.1 Capital costs compressors

In the literature, numerous equations are available for estimating the cost of compressors, resulting in very dispersed data with a wide price range. These estimations are typically dependent on the compressor size. Given the considerable uncertainty in compressor costs, three studies have been selected, representing low, moderate, and high-cost scenarios. Figure 59 illustrates the relationship between compressor power and the associated capital costs determined in different studies.

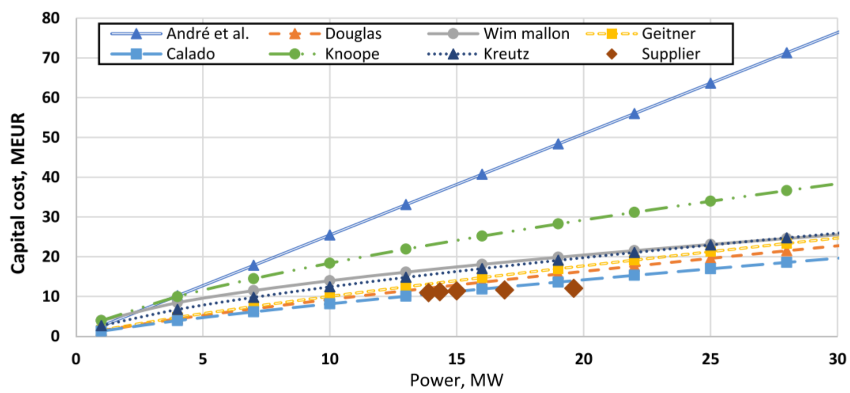


Figure 59: Relation between compressor power and capital costs, based on a variety of compressor studies [67].

Since the majority of studies fall within a similar range and are thus likely to be the most appropriate, it has been decided to include the equations of Calado, Geitner, and Douglas as scenarios in the cost analysis. Despite the decreasing costs as the compressor power increases, it has been chosen to operate with multiple compressors of 10 MW. This ensures that injection can still proceed partially in case of compressor malfunctioning or when scheduled maintenance needs to be executed. The low, mid, and high scenario costs for a 10 MW compressor have been established at 9, 10 and 10.5, respectively.

B.1.2 Hydrogen compressibility

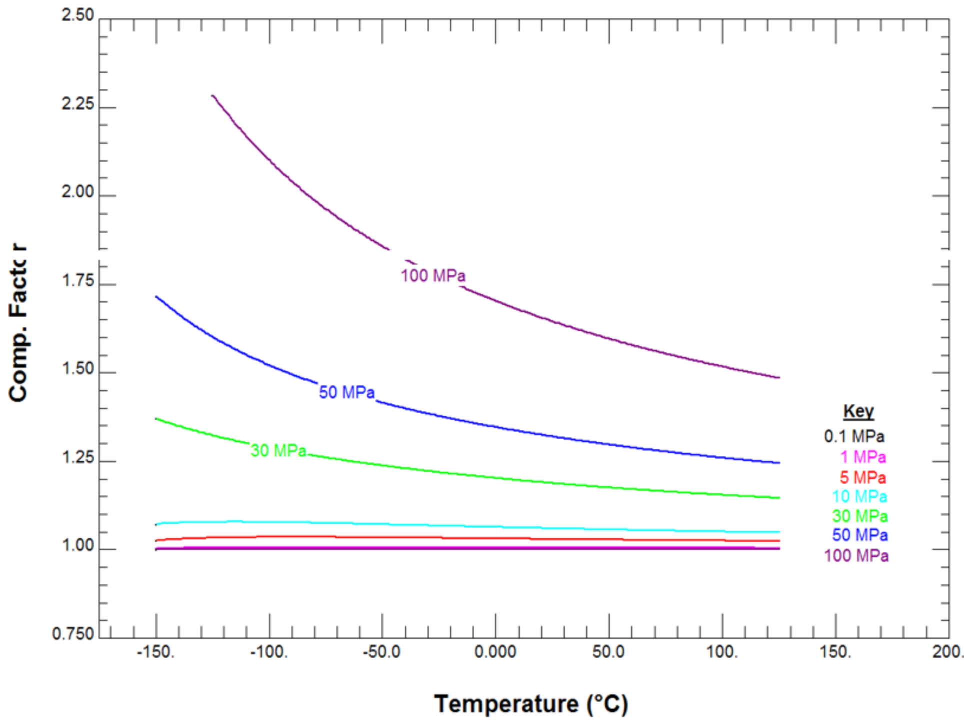


Figure 60: Compressibility factor hydrogen [115].

Table 36: Compressibility factor table [115].

	Pressure (MPa)						
Temperature (Celsius)	**0.1**	**1**	**5**	**10**	**30**	**50**	**100**
-150	1.0003	1.0036	1.0259	1.0726	1.3711	1.7167	
-125	1.0006	1.0058	1.0335	1.0782	1.3231	1.6017	2.2856
-100	1.0007	1.0066	1.0356	1.0778	1.2880	1.5216	2.1006
-75	1.0007	1.0068	1.0355	1.0751	1.2604	1.4620	1.9634
-50	1.0007	1.0067	1.0344	1.0714	1.2377	1.4153	1.8572
-25	1.0006	1.0065	1.0329	1.0675	1.2186	1.3776	1.7725
0	1.0006	1.0062	1.0313	1.0637	1.2022	1.3462	1.7032
25	1.0006	1.0059	1.0297	1.0601	1.1879	1.3197	1.6454
50	1.0006	1.0056	1.0281	1.0567	1.1755	1.2969	1.5964
75	1.0005	1.0053	1.0266	1.0536	1.1644	1.2770	1.5542
100	1.0005	1.0050	1.0252	1.0507	1.1546	1.2596	1.5175
125	1.0005	1.0048	1.0240	1.0481	1.1458	1.2441	1.4852

B.2 Input parameters cost analysis

Table 37: Input parameters cost analysis.

	Parameter	Low	Mid	High	Unit	Reference
Compressor	10 MW compressor cost	9	10	10.5	M€	[67]
	Lifetime	25	20	15	years	[67]
Purification	50 mln Sm3/day unit costs	86	143	200	M€	[9]
	Lifetime	25	20	15	years	[67]
Dehydration	50 mln Sm3/day unit costs	8	16	24	M€	[9]
	Lifetime	25	20	15	years	[67]
Wells	Salt cavern	4	6	8	M€	[9]
	Gas field	5	9	17	M€	[9]
Fixed OM	Surface	3.7	3.7	3.7	%	[17]
	Subsurface	1.5	1.5	1.5	%	[17]
Pipelines	Hydrogen pipelines	0.03	0.05	0.07	M€/km	[9]
	Brine + water pipelines	1.2	2	2.8	M€/km	[9]
Cushion gas	Hydrogen	2.2	2.7	3.5	€/kg	[9]
Cushion gas	WGV:CGV ratio salt cavern	1:1	1:1	1:1	-	[9]
Cushion gas	WGV:CGV ratio gas field	1:2	1:2	1:2	-	[9]
Cushion gas	Nitrogen	0.015	0.045	0.055	€/m3	[67]

B.3 Capital costs breakdown

B.3.1 Gas fields

In Section 7, it has become clear that cushion gas used in gas fields has a significant impact on the overall cost scenario. Therefore, various cushion gas cases have been identified in this study to obtain a comprehensive understanding of the costs associated with hydrogen storage in gas fields. This section delineates the related costs for each cushion gas case and assesses their influence on the total capital costs. The unit used in the tables is M€.

100% hydrogen cushion gas case

	Design 1			Design 2			Design 3		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
Cushion gas 100% H2	1347	1725	2160	2693	3449	4321	4040	5174	6481
Compressors	160	185	188	211	245	248	272	315	320
Wells	71	134	245	92	172	315	122	230	420
Purification unit	189	329	444	230	399	539	330	573	775
Pipelines	0	1	1	0	1	1	0	1	1
Totaal	1767	2373	3038	3226	4265	5423	4765	6293	7996

Figure 61: Cost breakdown of a gas field with 100% H_2 cushion gas.

Cushion gas 100% H2		Low	Mid	High
Low policy	Surface	349	514	633
	Subsurface	1418	1859	2405
Mid policy	Surface	441	644	788
	Subsurface	2785	3621	4635
High policy	Surface	603	889	1095
	Subsurface	4162	5403	6901
OPEX				
Gas field		**Low**	**Mid**	**High**
Low policy	Surface	13	19	23
	Subsurface	21	28	36
	Totaal	**34**	**47**	**59**
Mid policy	Surface	16	24	29
	Subsurface	42	54	70
	Totaal	**58**	**78**	**99**
High policy	Surface	22	33	41
	Subsurface	62	81	104
	Totaal	**85**	**114**	**144**

Figure 62: OpEx of a gas field with 100% H_2 cushion gas.

100% natural gas cushion gas case

	Design 1			Design 2			Design 3		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
Cushion gas 100% CH4	0	0	0	0	0	0	0	0	0
Compressors	160	185	188	211	245	248	272	315	320
Wells	71	134	245	92	172	315	122	230	420
Purification unit	568	986	1332	689	1196	1616	991	1720	2325
Pipelines	0	1	1	0	1	1	0	1	1
Totaal	800	1306	1766	992	1613	2180	1386	2266	3065

Figure 63: Cost breakdown of a gas field with 100% CH_4 cushion gas.

Cushion gas 100% CH4		Low	Mid	High
Low policy	Surface	728	1172	1521
	Subsurface	71	134	245
Mid policy	Surface	901	1441	1865
	Subsurface	92	172	315
High policy	Surface	1263	2036	2646
	Subsurface	122	230	420
OPEX				
Gas field		**Low**	**Mid**	**High**
Low policy	Surface	27	43	56
	Subsurface	1	2	4
	Totaal	**28**	**45**	**60**
Mid policy	Surface	33	53	69
	Subsurface	1	3	5
	Totaal	**35**	**56**	**74**
High policy	Surface	47	75	98
	Subsurface	2	3	6
	Totaal	**49**	**79**	**104**

Figure 64: OpEx of a gas field with 100% CH_4 cushion gas.

75% natural gas cushion gas case

	Design 1			Design 2			Design 3		
	Low	**Mid**	**High**	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Cushion gas 75% CH4	337	431	540	673	862	1080	1010	1293	1620
Compressors	160	185	188	211	245	248	272	315	320
Wells	71	134	245	92	172	315	122	230	420
Purification unit	379	657	888	459	797	1077	661	1147	1550
Pipelines	0	1	1	0	1	1	0	1	1
Totaal	947	1408	1862	1436	2077	2721	2065	2986	3910

Figure 65: Cost breakdown of a gas field with 75% CH_4 cushion gas.

Cushion gas 75% CH4		Low	Mid	High
Low policy	Surface	539	843	1077
	Subsurface	408	565	785
Mid policy	Surface	671	1042	1326
	Subsurface	765	1035	1395
High policy	Surface	933	1462	1870
	Subsurface	123	230	420
OPEX				
Gas field		**Low**	**Mid**	**High**
Low policy	Surface	20	31	40
	Subsurface	6	8	12
	Totaal	**26**	**40**	**52**
Mid policy	Surface	25	39	49
	Subsurface	11	16	21
	Totaal	**36**	**54**	**70**
High policy	Surface	35	54	69
	Subsurface	2	3	6
	Totaal	**36**	**58**	**76**

Figure 66: OpEx of a gas field with 75% CH_4 cushion gas.

33% nitrogen cushion gas case

	Design 1			Design 2			Design 3		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
Cushion gas 33% N2	1036	1327	1662	2072	2653	3324	3107	3980	4985
Compressors	160	185	188	211	245	248	272	315	320
Wells	71	134	245	92	172	315	122	230	420
Purification unit	271	470	635	328	570	770	473	820	1108
Pipelines	0	1	1	0	1	1	0	1	1
Totaal	1538	2116	2730	2703	3641	4658	3975	5345	6834

Figure 67: Cost breakdown of a gas field with 33% N_2 cushion gas.

Cushion gas 33% N2		Low	Mid	High
Low policy	Surface	431	656	824
	Subsurface	1107	1461	1907
Mid policy	Surface	540	815	1019
	Subsurface	2163	2826	3638
High policy	Surface	745	1136	1429
	Subsurface	3230	4210	5405
OPEX				
Gas field		**Low**	**Mid**	**High**
Low policy	Surface	16	24	30
	Subsurface	17	22	29
	Totaal	**33**	**46**	**59**
Mid policy	Surface	20	30	38
	Subsurface	32	42	55
	Totaal	**52**	**73**	**92**
High policy	Surface	28	42	53
	Subsurface	48	63	81
	Totaal	**76**	**105**	**134**

Figure 68: OpEx of a gas field with 33% N_2 cushion gas.

66% nitrogen cushion gas case

	Design 1			Design 2			Design 3		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
Cushion gas 66% N2	607	776	973	1212	1554	1945	1820	2328	2919
Compressors	160	185	188	211	245	248	272	315	320
Wells	71	134	245	92	172	315	122	230	420
Purification unit	379	657	888	459	797	1077	661	1147	1550
Pipelines	0	1	1	0	1	1	0	1	1
Totaal	1217	1753	2295	1975	2768	3586	2875	4021	5210

Figure 69: Cost breakdown of a gas field with 66% N_2 cushion gas.

Cushion gas 66% N2		Low	Mid	High
Low policy	Surface	539	843	1077
	Subsurface	678	910	1218
Mid policy	Surface	671	1042	1326
	Subsurface	1304	1726	2259
High policy	Surface	933	1462	1870
	Subsurface	1942	2558	3339
OPEX				
Gas field		**Low**	**Mid**	**High**
Low policy	Surface	20	31	40
	Subsurface	10	14	18
	Totaal	**30**	**45**	**58**
Mid policy	Surface	25	39	49
	Subsurface	20	26	34
	Totaal	**44**	**64**	**83**
High policy	Surface	35	54	69
	Subsurface	29	38	50
	Totaal	**64**	**92**	**119**

Figure 70: OpEx of a gas field with 66% N_2 cushion gas.

100% nitrogen cushion gas case

	Design 1			Design 2			Design 3		
CAPEX	Low	Mid	High	Low	Mid	High	Low	Mid	High
Cushion gas 100% N2	314	402	504	628	804	1007	942	1206	1511
Compressors	160	185	188	211	245	248	272	315	320
Wells	71	134	245	92	172	315	122	230	420
Purification unit	460	799	1079	558	968	1309	803	1393	1883
Pipelines	0	1	1	0	1	1	0	1	1
Totaal	1006	1520	2016	1489	2190	2880	2139	3145	4134

Figure 71: Cost breakdown of a gas field with 100% N_2 cushion gas.

Cushion gas 100% N2		Low	Mid	High
Low policy	Surface	620	984	1268
	Subsurface	385	536	748
Mid policy	Surface	770	1214	1558
	Subsurface	720	976	1322
High policy	Surface	1075	1709	2204
	Subsurface	1064	1436	1930
OPEX				
Gas field		**Low**	**Mid**	**High**
Low policy	Surface	23	36	47
	Subsurface	6	8	11
	Totaal	**29**	**44**	**58**
Mid policy	Surface	28	45	58
	Subsurface	11	15	20
	Totaal	**39**	**60**	**77**
High policy	Surface	40	63	82
	Subsurface	16	22	29
	Totaal	**56**	**85**	**110**

Figure 72: OpEx of a gas field with 100% N_2 cushion gas.

B.3.2 Salt caverns

For salt caverns, there is no discussion regarding the cushion gas to be used, as the required amounts of cushion gas are significantly smaller. If a different cushion gas than hydrogen were to be used in salt caverns, the additional costs required for a more extensive purification unit would offset the lower costs for the cushion gas. Therefore, it was chosen to only examine the use of hydrogen as cushion gas in salt caverns. The unit used in the tables is M€.

	Design 1			Design 2			Design 3			Design 4		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Cushion gas	13.47	17.25	21.60	20.20	25.87	32.41	26.93	34.49	43.21	26.93	34.49	43.21
Compressors	23.87	27.67	28.08	34.89	40.45	41.04	47.74	55.35	56.16	69.77	80.90	82.09
Wells	8.16	12.77	16.46	8.16	12.77	16.46	8.16	12.77	16.46	8.16	12.77	16.46
Dehydration unit	0.82	1.70	2.47	1.22	2.55	3.70	1.63	3.41	4.94	1.63	3.41	4.94
Pipelines	0.31	0.53	0.72	0.31	0.53	0.72	0.31	0.53	0.72	0.31	0.53	0.72
Brine + water pipelines	6.12	10.64	14.40	6.12	10.64	14.40	6.12	10.64	14.40	6.12	10.64	14.40
Total	52.74	70.57	83.73	70.89	92.82	108.73	90.89	117.20	135.89	112.92	142.74	161.81

Figure 73: Cost breakdown of a salt cavern.

Salt caverns		**Low**	**Mid**	**High**
Design 1	Surface	31.11	40.55	45.67
	Subsurface	21.63	30.02	38.06
	Totaal	**2.11**	**3.53**	**5.58**
Design 2	Surface	42.54	54.18	59.87
	Subsurface	28.36	38.64	48.86
	Totaal	**2.84**	**4.64**	**7.25**
Design 3	Surface	55.80	69.93	76.22
	Subsurface	35.09	47.26	59.67
	Totaal	**3.64**	**5.86**	**9.06**
Design 4	Surface	77.83	95.48	102.14
	Subsurface	35.09	47.26	59.67
	Totaal	**4.52**	**7.14**	**10.79**
OPEX				
Salt caverns		**Low**	**Mid**	**High**
Design 1	Surface	1.15	1.50	1.69
	Subsurface	0.32	0.45	0.57
	Totaal	**1.48**	**1.95**	**2.26**
Design 2	Surface	1.57	2.00	2.22
	Subsurface	0.43	0.58	0.73
	Totaal	**2.00**	**2.58**	**2.95**
Design 3	Surface	2.06	2.59	2.82
	Subsurface	0.53	0.71	0.89
	Totaal	**2.59**	**3.30**	**3.72**
Design 4	Surface	2.88	3.53	3.78
	Subsurface	0.53	0.71	0.89
	Totaal	**3.41**	**4.24**	**4.67**

Figure 74: OpEx of a salt cavern.

B.4 Heat maps of the revenues

Revenue gas field low seasonal storage policy			Configurations																	
			Edem56160						Edem62400						Edem68640					
			Low						Low						Low					
			Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50	
			Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17
Scenario space	HT8	SC12	-16	-26.4	-15.5	-30.3	-16.7	-29.6	-8.7	-20.8	-10.7	-23.2	-10.9	-21.6	8.2	-13.2	5	-11.9	-0.5	-16.2
		SC14	-14.8	-26.1	-14.3	-29.6	-18.2	-30.5	-9.9	-18.6	-8.1	-24	-10.2	-25.2	9.6	-10.9	3.6	-13.8	-2.2	-19
		SC16	-13.7	-27.4	-12.6	-26.5	-16.7	-32.2	-5	-19.4	-7.6	-22.5	-13.6	-25.4	8.5	-12.2	3	-13	-0.6	-17.7
	HT10	SC12	2	-25.7	1.2	-28.1	-2.9	-31.2	46.4	-6	45.9	-9.2	29.5	-12.9	89.3	26.3	85.7	21.6	78.7	9.7
		SC14	-12.7	-28	-13.6	-30.1	-16.6	-31.8	3.7	-20.2	1	-22.7	-5.7	-25	52.7	-6.5	48.5	-10.1	38.8	-14.2
		SC16	-10.7	-28.6	-16.4	-27.9	-16	-29.7	-2.1	-22.3	-8.2	-25.3	-9.7	-26.1	17.8	-11.1	11	-17.3	8	-17.6
	HT12	SC12	36.4	-21.1	27.7	-27.8	21.2	-29.1	72.6	25.7	71.2	19.3	60.4	6.7	99.8	62.5	95.6	51.2	89.9	42.3
		SC14	25.1	-27.2	16.1	-26.3	7.1	-32.4	54	11.2	48.1	0.7	38.8	-4.9	99.6	45	92.8	36.9	85.1	32
		SC16	3	-25.4	-3.9	-27.8	-14.1	-31.8	23	-10	23	-14.4	14.9	-25.1	82.1	16.1	77	17.4	56.5	10.2

Revenue salt cavern low seasonal storage policy			Configurations																	
			Edem56160						Edem62400						Edem68640					
			Low						Low						Low					
			Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50	
			Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17
Scenario space	HT8	SC12	-3.47	-3.82	-3.83	-3.84	-3.95	-3.97	-3.15	-3.65	-3.72	-3.84	-3.88	-4.04	-2.62	-3.77	-3.4	-4.03	-3.73	-3.99
		SC14	-3.51	-3.55	-3.61	-3.67	-3.57	-3.69	-3.13	-3.45	-3.75	-3.46	-3.69	-3.66	-2.98	-3.8	-3.2	-3.7	-3.32	-3.79
		SC16	-3.19	-3.45	-3.51	-3.53	-3.6	-3.45	-3.25	-3.31	-3.36	-3.46	-3.47	-3.51	-2.67	-3.56	-3.14	-3.48	-3.33	-3.44
	HT10	SC12	-0.63	-3.63	-1.53	-3.79	-1.22	-3.79	4.74	-2.3	5.08	-2.53	2.66	-2.05	13.7	3.17	13.29	1.99	11.7	0.84
		SC14	-3.62	-3.57	-3.71	-3.61	-3.75	-3.65	-1.63	-3.73	-1.76	-3.89	-2.09	-3.86	4.69	-2.4	4.43	-2.24	3.64	-2.84
		SC16	-3.41	-3.4	-3.59	-3.52	-3.56	-3.52	-3.46	-3.4	-3.63	-3.41	-3.62	-3.64	-1.2	-3.74	-1.91	-3.82	-2.42	-3.56
	HT12	SC12	4.63	-2.86	3.56	-3.99	2.94	-3.68	11.23	3.24	10.88	3.23	8.48	0.58	16.52	9.08	14.79	7.59	13.68	5.97
		SC14	2.22	-3.61	1.81	-3.73	-0.58	-3.64	7.68	0.74	6.37	-0.33	5.36	-1.52	15.11	6.44	13.39	5.33	12.67	4.77
		SC16	-1.69	-3.5	-2.15	-3.65	-2.94	-3.48	2.26	-2.53	1.61	-3.04	0.98	-3.57	11.97	0.76	10.18	0.42	8.76	0.32

Figure 75: Heat map of the decentral 2015, low-seasonal storage policy scenario.

From Figure 75, it emerges that the revenues from both salt caverns and gas fields are generally higher when there is a high electricity demand scenario, low electricity interconnection, low installed capacity of Li-ion batteries, and high installed capacity of hydrogen turbines. The unit used in the heat maps is M€/year.

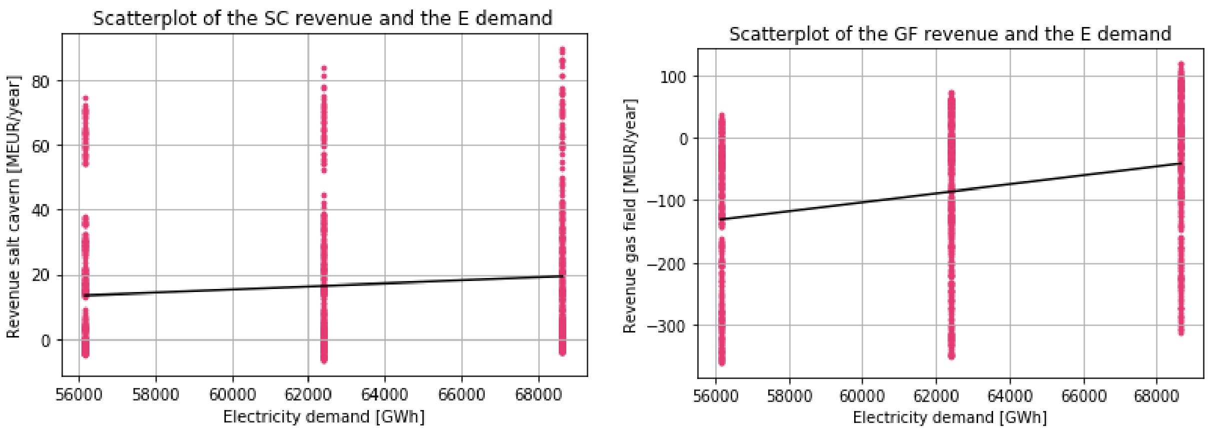
Revenue gas field high seasonal storage			Configurations																	
			Edem56160						Edem62400						Edem68640					
			High						High						High					
			Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50	
			Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17
Scenario space	HT8	SC3	-308	-337	-313	-341	-318	-344	-259	-326	-260	-333	-274	-346	-208	-294	-224	-302	-234	-306
		SC5	-273	-310	-278	-321	-281	-324	-247	-315	-253	-318	-262	-322	-236	-292	-239	-300	-248	-307
		SC7	-255	-291	-260	-298	-265	-303	-223	-279	-234	-283	-232	-292	-212	-260	-224	-273	-227	-273
	HT10	SC3	-185	-279	-206	-305	-230	-330	-88	-220	-104	-236	-133	-251	-2	-140	-27	-159	-46	-176
		SC5	-197	-289	-205	-302	-206	-306	-135	-233	-151	-247	-158	-246	-18	-187	-24	-203	-45	-197
		SC7	-230	-288	-238	-292	-245	-302	-199	-261	-214	-272	-212	-273	-148	-244	-177	-244	-181	-253
	HT12	SC3	-198	-284	-216	-311	-230	-321	-94	-220	-106	-243	-136	-266	-6	-134	-27	-163	-46	-177
		SC5	-176	-292	-194	-303	-206	-322	-80	-210	-109	-231	-127	-244	-1	-142	-14	-166	-33	-182
		SC7	-162	-278	-181	-301	-198	-298	-85	-177	-109	-220	-126	-237	1	-142	-14	-161	-24	-177

Revenue salt cavern high seasonal storage			Configurations																	
			Edem56160						Edem62400						Edem68640					
			High						High						High					
			Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50		Li-ion33		Li-ion42		Li-ion50	
			Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17	Interc14	Interc17
Scenario space	HT8	SC3	64.7	60.14	62.19	59.7	61.13	59.37	64.7	60.67	63.22	61.57	62.67	59.56	69.62	60.5	64.77	60.2	63.49	59.14
		SC5	30.54	30.32	28.99	28.6	28.93	27.4	29.15	30.56	28.71	28.81	29.62	28.55	31.45	29.47	29.94	27.55	28.77	27.17
		SC7	15.03	14.54	15.26	15.09	14.44	15.16	13.86	14.98	14.81	14.78	13.34	15.04	15.34	15.28	14.69	14.26	14.38	14.59
	HT10	SC3	74.7	65.5	70.84	63.87	68.67	58.94	81.47	71.87	78.3	69.53	72.66	66.69	89.59	75.43	86.22	72.82	81.67	69.49
		SC5	35.84	32.64	35.55	30.17	36.08	30.49	38.13	35.83	37.22	33.99	36.44	34.12	49.24	36.54	48.15	34.84	46.06	33.81
		SC7	14.76	15.65	14.51	15.33	14.74	14.62	15.18	15.19	16.38	15.44	14.72	15.13	20.8	16.32	20.1	15.75	17.24	14.75
	HT12	SC3	72.33	66.7	71.09	61.97	70.02	60.55	83.75	71.15	77.47	70.47	74.33	67.42	88.95	75.99	84.28	72.85	81.35	70.48
		SC5	37.76	32.43	37.42	30.3	35.89	28.9	44.51	38.23	42.13	36.84	40.85	33.19	52.96	42.81	49.77	38.6	48.67	37.03
		SC7	21.61	16.52	19.8	15.14	18.81	15.1	24.91	21.23	24.38	20.7	22.95	19.17	33.57	24	32.83	22.62	31.14	21.26

Figure 76: Heat map of the decentral 2015, high-seasonal storage policy scenario.

Because Figure 75 couldn't depict the effect of low, medium, or high-seasonal storage policies as it resulted from the low-seasonal storage policy, Figure 76 illustrates the revenues from salt caverns and gas fields under the high-seasonal storage policy. A comparison of Figure 75 and 76 reveals that the revenues from salt caverns are significantly higher under the high-seasonal storage policy, while the revenues from gas fields are significantly lower.

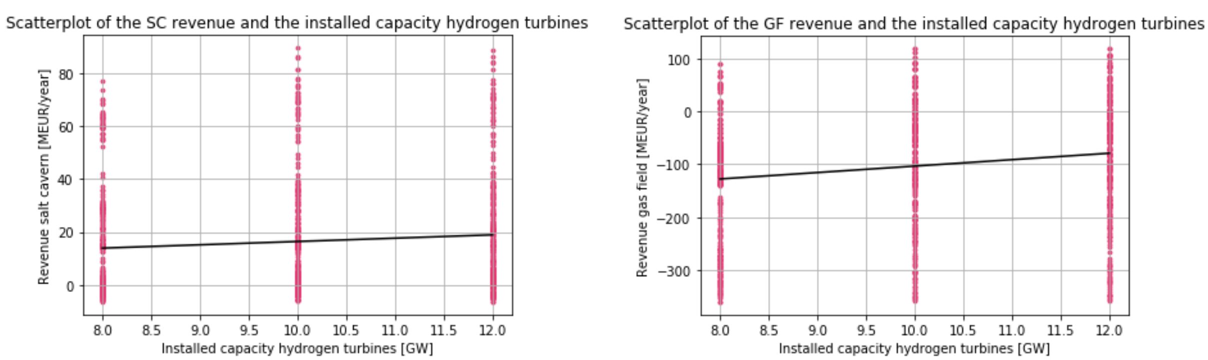
B.5 Scatter plots



(a) Revenue salt cavern.

(b) Revenue gas field.

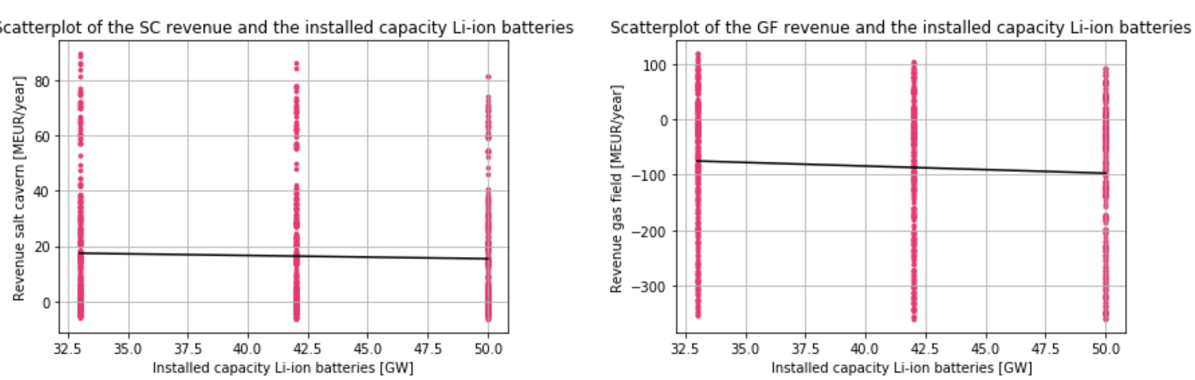
Figure 77: Scatter plots of the salt cavern and gas field revenues with different E demand.



(a) Revenue salt cavern.

(b) Revenue gas field.

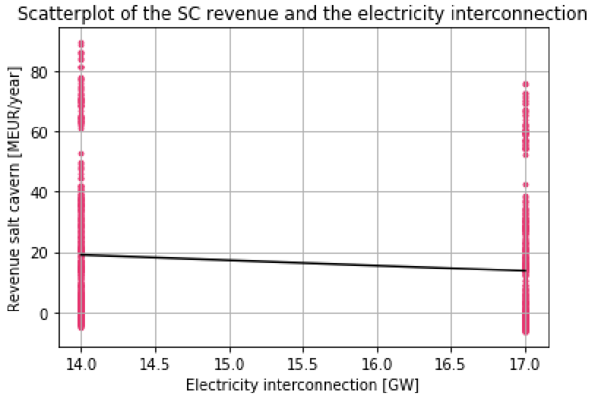
Figure 78: Scatter plots of the salt cavern and gas field revenues with different installed hydrogen turbines capacity.



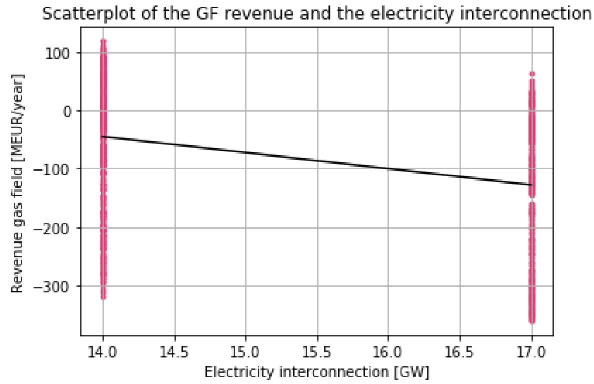
(a) Revenue salt cavern.

(b) Revenue gas field.

Figure 79: Scatter plots of the salt cavern and gas field revenues with different installed capacity Li-ion batteries.

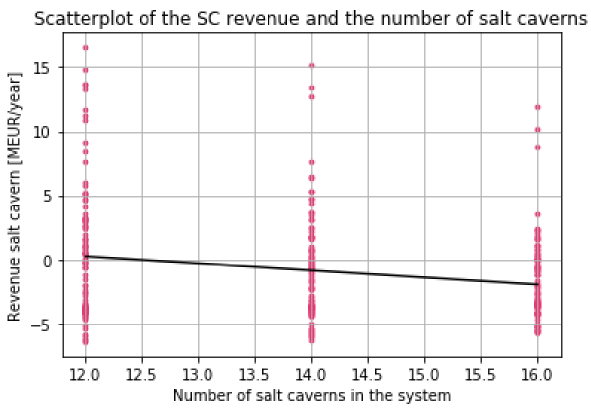


(a) Revenue salt cavern.

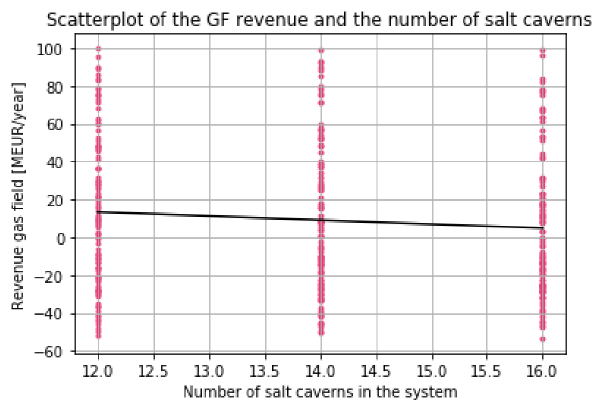


(b) Revenue gas field.

Figure 80: Scatter plots of the salt cavern and gas field revenues with different electricity interconnection capacity.



(a) Revenue salt cavern.



(b) Revenue gas field.

Figure 81: Scatter plots of the salt cavern and gas field revenues with different numbers of salt caverns.

B.6 Influence seasonal storage policy on revenues

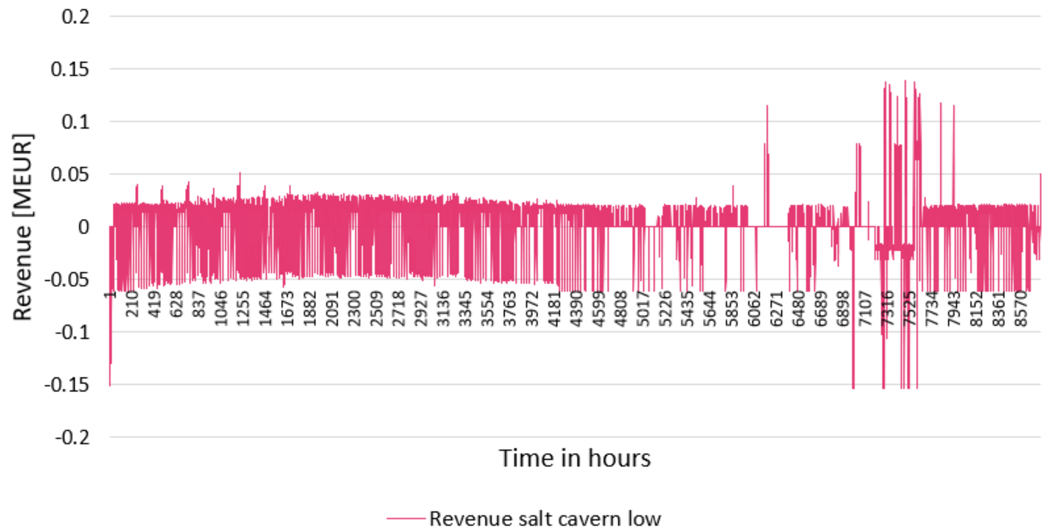


Figure 82: Revenue salt cavern, low-seasonal storage policy.

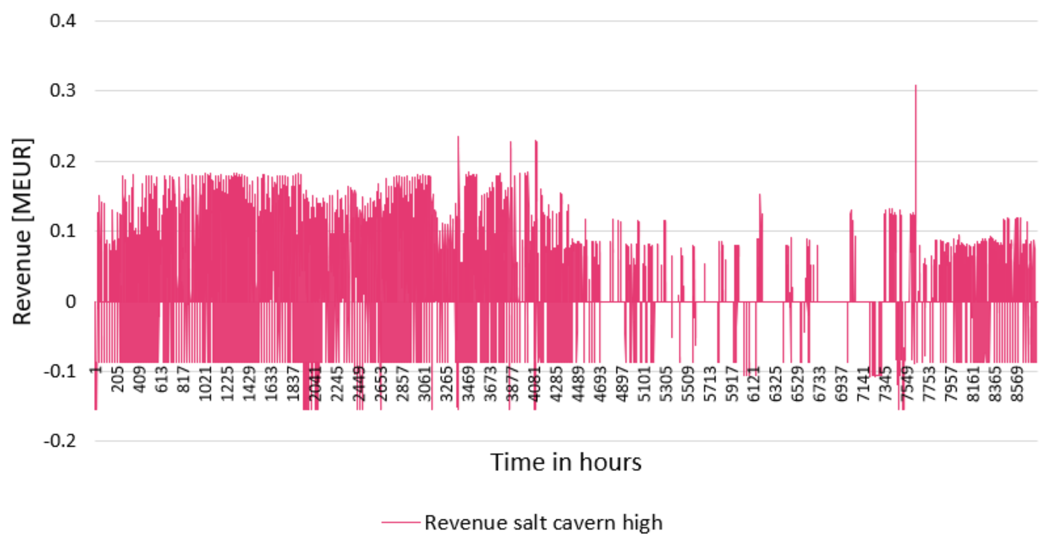


Figure 83: Revenue salt cavern, high-seasonal storage policy.

Because the effects visible in the heat maps were not immediately explainable, a comparison was made between the same scenario with a low-seasonal storage policy and another with a high-seasonal storage policy. Figures 82 and 83 clarify that as more seasonal storage occurs, salt caverns can generate higher revenues. Especially during the summer months, when the gas field is being filled, significant revenues can be generated with salt caverns. This is because the hydrogen demand increases significantly due to injection into the gas field, and salt caverns can capitalise on this.

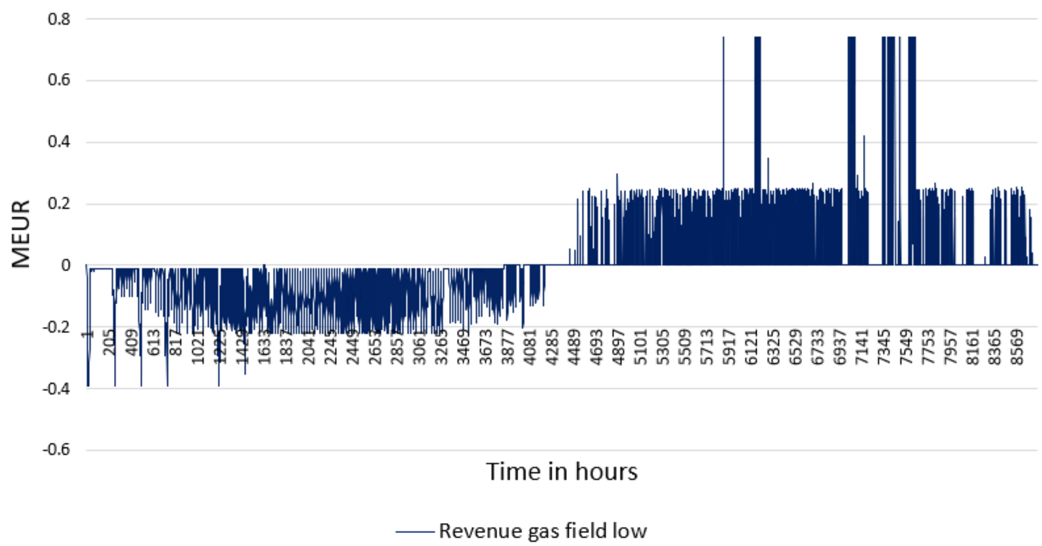


Figure 84: Revenue gas field, low-seasonal storage policy.

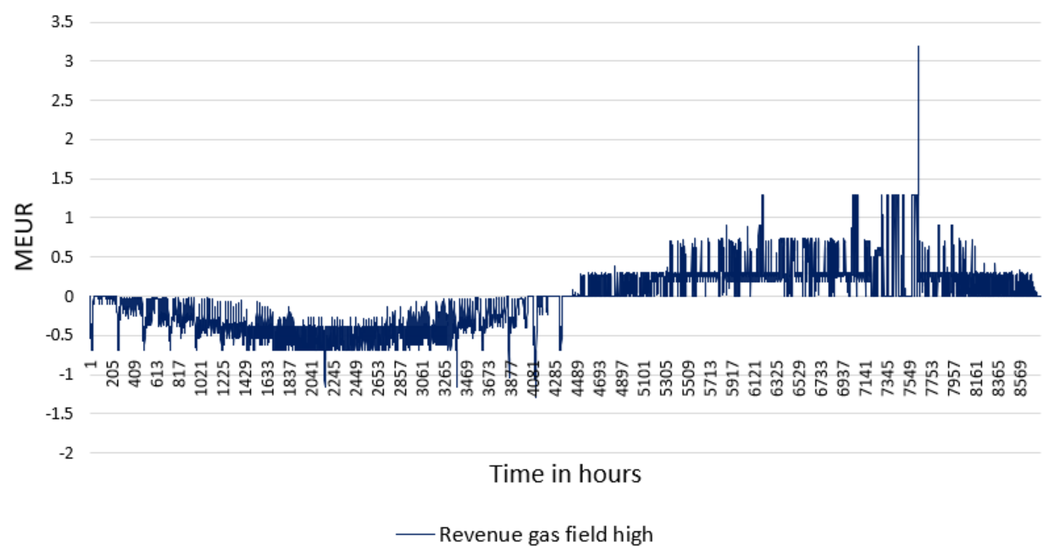


Figure 85: Revenue gas field, high-seasonal storage policy.

For gas fields, the opposite effect is observed. As the seasonal storage policy increases, the revenues become smaller or more negative. The higher costs incurred to fill the gas field cannot be offset by the revenues that can be achieved in the winter months.

B.7 Profits

Figure 86: Legend of the profit box plots.

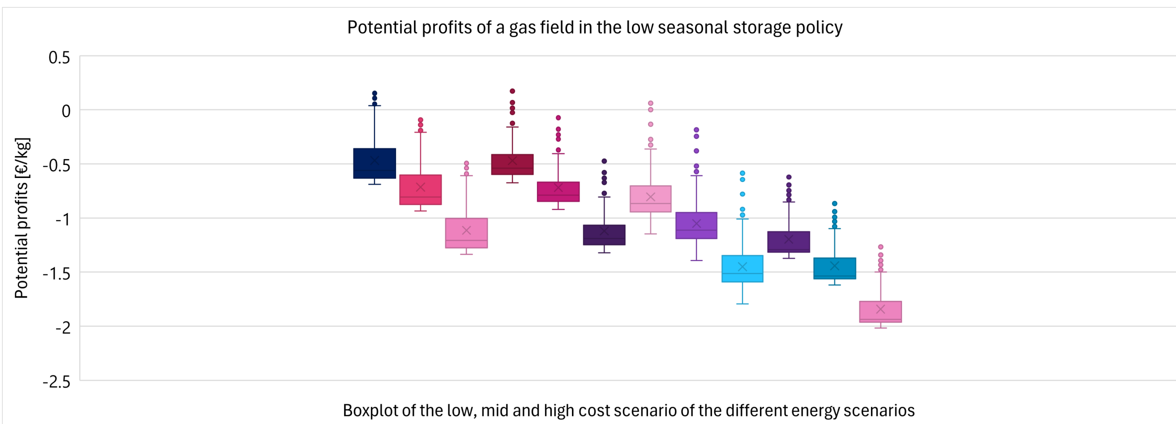


Figure 87: Box plots of the potential profits of gas fields in the low-seasonal storage policy scenario.

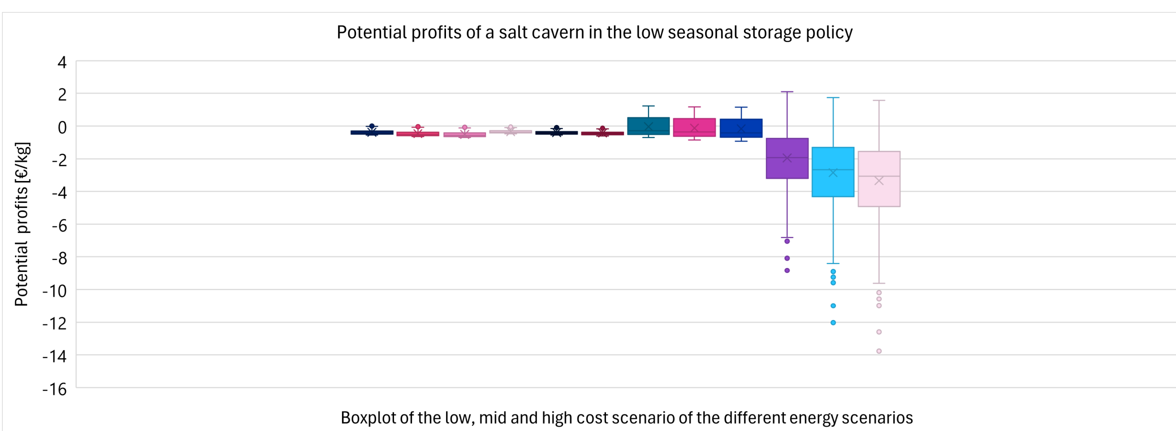


Figure 88: Box plots of the potential profits of salt caverns in the low-seasonal storage policy scenario.

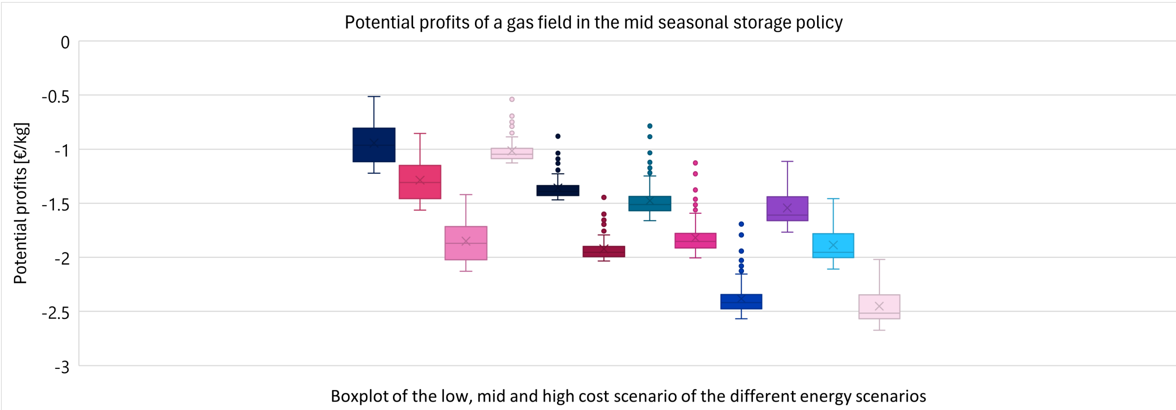


Figure 89: Box plots of the potential profits of gas fields in the mid-seasonal storage policy scenario.

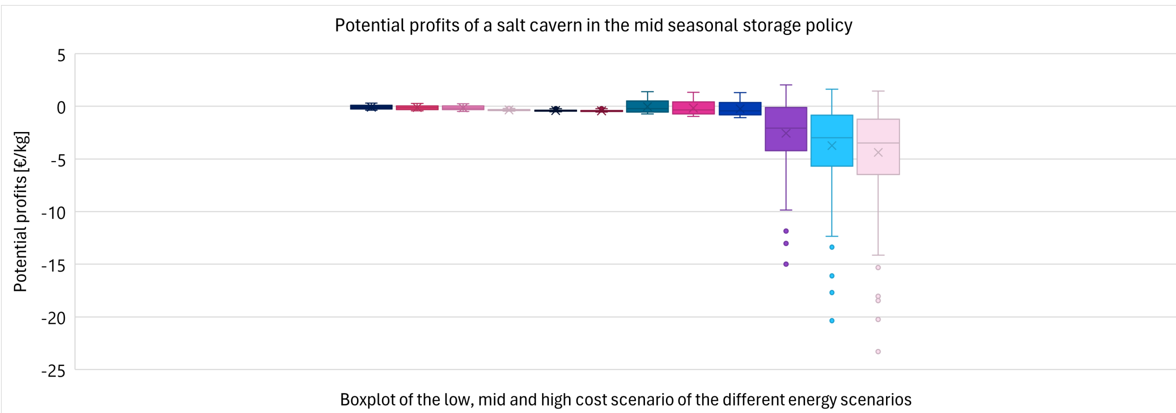


Figure 90: Box plots of the potential profits of salt caverns in the mid-seasonal storage policy scenario.

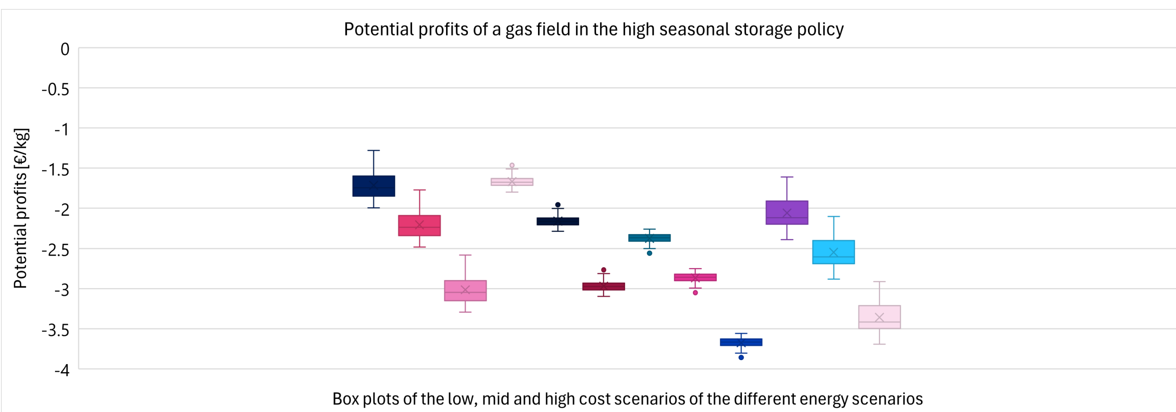


Figure 91: Box plots of the potential profits of gas fields in the high-seasonal storage policy scenario.

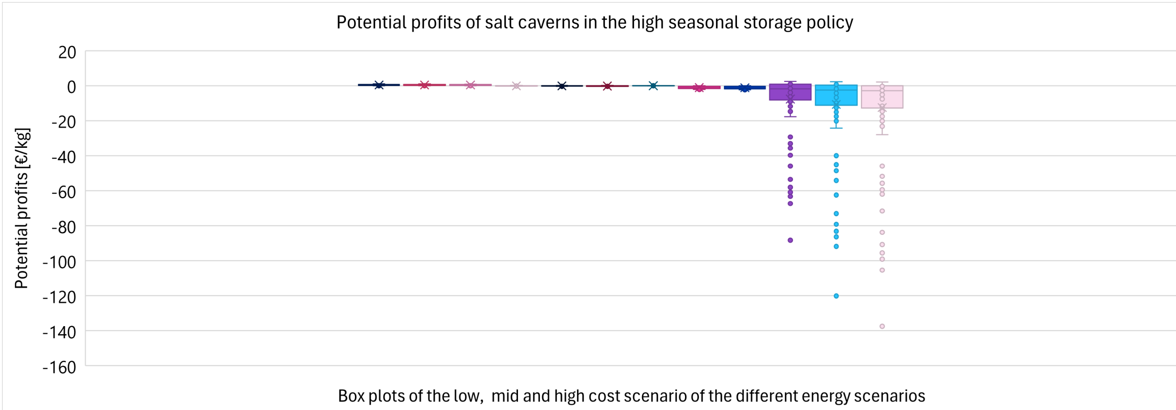


Figure 92: Box plots of the potential profits of salt caverns in the high-seasonal storage policy scenario.

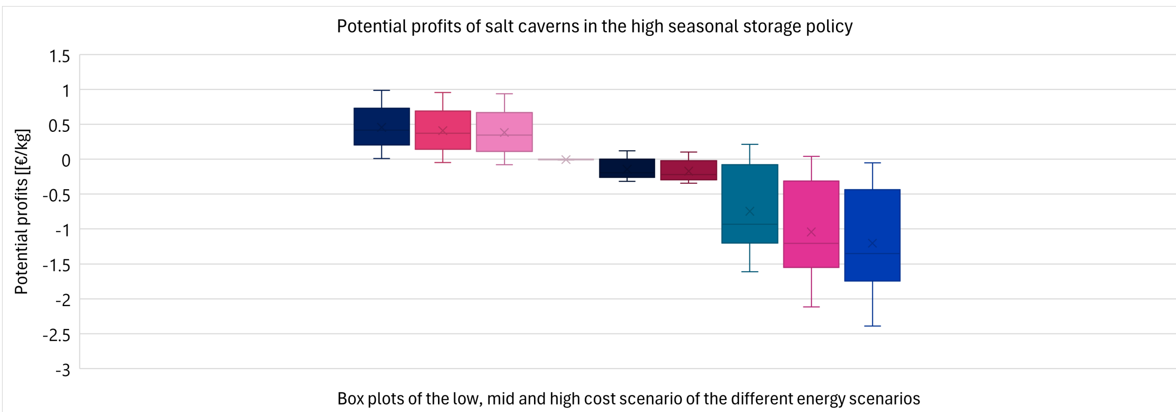


Figure 93: Box plots of the potential profits of salt caverns in the high-seasonal storage policy scenario, minus the international energy system data points.

C

Robustness analysis

C.1 Interconnection sensitivity

The model that has been simulated is not a closed system. This allows the model to import and export electricity and hydrogen to and from abroad. The electricity interconnection is based on the current capacity: 14.8 GW. The hydrogen interconnection, which has not yet been realised, is estimated based on the report of the Integrated Energy Outlook 2030-2050 [51]. The import price of electricity is based on the same report, and the import price of hydrogen is based on data from Aurora [57]. The import and export of both hydrogen and electricity are assigned a price. Because this can significantly impact the system, a sensitivity analysis regarding the price and capacity of the interconnection has been conducted to assess whether these price and capacity differences would have a significant effect on the KPIs. It is important to mention that the export price of both electricity and hydrogen has been kept lower than the import price because otherwise, the interconnection would be used as a means to generate cash flow by importing electricity and immediately exporting it again in the model. The results are shown in Figure 94 and Figure 95.

Decentral		**System operating costs**	**Loss of Load**	**CO2 level**
Hydrogen interconnection	-20%	0.52%	0.90%	0.33%
	20%	0.20%	-0.90%	8.00%
Price hydrogen export	-20%	-0.11%	0.00%	-0.25%
	10%	4.40%	0.00%	0.32%
Price hydrogen import	-20%	4.12%	0.00%	0.36%
	20%	1.06%	0.00%	0.42%
Electricity interconnection	-20%	**13.91%**	**214.90%**	-3.77%
	20%	-4.60%	**-98.80%**	3.91%
Price electricity export	-20%	-0.75%	0.00%	-0.56%
Price electricity import	-20%	-1.11%	0.00%	-0.06%
	20%	2.75%	0.00%	0.04%

European		**System operating costs**	**Loss of Load**	**CO2 level**
Hydrogen interconnection	-20%	1.60%	9.80%	0.03%
	20%	0.24%	-0.88%	0.21%
Price hydrogen export	-20%	-0.08%	0.60%	0.00%
	10%	4.86%	3.27%	0.68%
Price hydrogen import	-20%	-0.35%	2.80%	0.15%
	20%	6.91%	0.80%	1.60%
Electricity interconnection	-20%	6.09%	**99.50%**	1.43%
	20%	-6.90%	**-87.60%**	2.32%
Price electricity export	-20%	-1.13%	0.90%	-0.89%
Price electricity import	-20%	-2.65%	1.00%	-0.15%
	20%	3.62%	0.30%	0.03%

Figure 94: Sensitivity analysis of the import and export variables of the decentral and European energy system.

National		System operating costs	Loss of Load	CO2 level
Hydrogen interconnection	-20%	0.05%	3.70%	0.01%
	20%	0.06%	-1.00%	0.30%
Price hydrogen export	-20%	-0.07%	0.00%	-0.12%
	10%	1.77%	0.00%	1.41%
Price hydrogen import	-20%	3.08%	-0.22%	-0.17%
	20%	0.54%	0.00%	0.19%
Electricity interconnection	-20%	12.22%	230.50%	-4.17%
	20%	-4.80%	-97.40%	3.44%
Price electricity export	-20%	-0.75%	0.32%	-1.09%
Price electricity import	-20%	-0.80%	0.00%	-0.58%
	20%	2.48%	0.00%	0.00%

International		System operating costs	Loss of Load	CO2 level
Hydrogen interconnection	-20%	1.60%	5.60%	3.20%
	20%	0.25%	-2.90%	-0.04%
Price hydrogen export	-20%	-2.55%	0.00%	0.07%
	10%	3.44%	0.76%	3.40%
Price hydrogen import	-10%	-2.80%	0.00%	-0.36%
	20%	9.61%	0.00%	0.08%
Electricity interconnection	-20%	4.69%	89.00%	-2.00%
	20%	-4.74%	-94.90%	3.59%
Price electricity export	-20%	-0.90%	0.00%	-0.40%
Price electricity import	-20%	-2.60%	0.00%	-1.70%
	20%	2.52%	0.00%	-0.01%

Figure 95: Sensitivity analysis of the import and export variables of the national and international energy system.

From the results, it is clear that the influence of these variables is limited. The variables that do have a significant impact on the system (>10%) are highlighted in pink. What becomes evident from Figures 94 and 95 is that the sensitivity is more linked to the electricity system than to the hydrogen system. In every scenario, the electricity interconnection capacity plays a significant role. Therefore, it has been included in the robustness analysis. However, a limitation of this research is that the import and export prices of electricity and hydrogen are assumed to be constant. In reality, this depends on the situation abroad at that time. If there is scarcity, prices will be higher than when renewable electricity is abundant. The hydrogen production capacity in the model offers more variability compared to electricity generation.

C.2 Sensitivity analysis

Decentral. Low scenario. 14 salt caverns.		Total system operating costs	Loss of Load	CO2 level
Electricity demand built environment	20%	16.59%	233.80%	1.95%
Installed capacity Li-ion batteries	20%	-2.51%	-35.80%	0.53%
Installed capacity hydrogen turbines	20%	-1.13%	-40.50%	-0.06%
Electricity interconnection	20%	-4.60%	-98.80%	3.91%

National. Low scenario. 11 salt caverns.		Total system operating costs	Loss of Load	CO2 level
Electricity demand built environment	20%	12.90%	161.90%	1.64%
Installed capacity Li-ion batteries	20%	-3.09%	-31.50%	-0.16%
Installed capacity hydrogen turbines	20%	-1.24%	-34.60%	0.11%
Electricity interconnection	20%	-4.80%	-97.40%	3.44%

European. Low scenario. 4 salt caverns		Total system operating costs	Loss of Load	CO2 level
Electricity demand built environment	20%	17.03%	212.80%	0.86%
Installed capacity Li-ion batteries	20%	-2.36%	-27.40%	0.50%
Installed capacity hydrogen turbines	20%	-1.18%	-40.50%	-0.06%
Electricity interconnection	20%	-6.09%	-99.50%	2.30%

International. Low scenario. 10 salt caverns		Total system operating costs	Loss of Load	CO2 level
Electricity demand built environment	20%	15.45%	175.10%	1.68%
Installed capacity Li-ion batteries	20%	-1.45%	-19.00%	0.67%
Installed capacity hydrogen turbines	20%	-1.35%	-35.20%	0.00%
Electricity interconnection	20%	-4.74%	-94.90%	3.59%

Figure 96: Sensitivity of the parameters selected for the robustness analysis.

Figure 96 provides insight into the results of the sensitivity analysis of the variables identified as critical variables and included in the robustness analysis.

C.3 Experiment input

Critical parameters	Values decentral, low		
	Base	High	Low
E demand built environment	62400	68640	56160
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	42.4	50.88	33.92
Number of salt caverns	14	16	12
turbines	10.6	12.72	8.48

Critical parameters	Values decentral, mid		
	Base	High	Low
E demand built environment	62400	68640	56160
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	42.4	50.88	33.92
Number of salt caverns	7	9	5
turbines	10.6	12.72	8.48

Critical parameters	Values decentral, high		
	Base	High	Low
E demand built environment	62400	68640	56160
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	42.4	50.88	33.92
Number of salt caverns	5	7	3
turbines	10.6	12.72	8.48

Critical parameters	Values national, low		
	Base	High	Low
E demand built environment	59000	64900	53100
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	42	50.4	33.6
Number of salt caverns	11	13	9
Hydrogen turbines	8.9	10.68	7.12

Critical parameters	Values national, mid		
	Base	High	Low
E demand built environment	59000	64900	53100
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	42	50.4	33.6
Number of salt caverns	10	12	8
Hydrogen turbines	8.9	10.68	7.12

Critical parameters	Values national, high		
	Base	High	Low
E demand built environment	59000	64900	53100
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	42	50.4	33.6
Number of salt caverns	8	10	6
Hydrogen turbines	8.9	10.68	7.12

Figure 97: Experiment input variables of the decentral and national energy systems.

	Values European, low		
Critical parameters	Base	High	Low
E demand built environment	63000	69300	56700
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	29.2	35.04	23.36
Number of salt caverns	4	6	2
Hydrogen turbines	8.9	10.68	7.12

	Values European, mid		
Critical parameters	Base	High	Low
E demand built environment	63000	69300	56700
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	29.2	35.04	23.36
Number of salt caverns	4	6	2
Hydrogen turbines	8.9	10.68	7.12

	Values European, high		
Critical parameters	Base	High	Low
E demand built environment	63000	69300	56700
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	29.2	35.04	23.36
Number of salt caverns	4	6	2
Hydrogen turbines	8.9	10.68	7.12

	Values International, low		
Critical parameters	Base	High	Low
E demand built environment	64100	70510	57690
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	24.7	29.64	19.76
Number of salt caverns	10	12	8
Hydrogen turbines	10.6	12.72	8.48

	Values International, mid		
Critical parameters	Base	High	Low
E demand built environment	63000	69300	56700
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	29.2	35.04	23.36
Number of salt caverns	7	9	5
Hydrogen turbines	10.6	12.72	8.48

	Values International, high		
Critical parameters	Base	High	Low
E demand built environment	63000	69300	56700
Interconnectie E	14.8	17.76	n.a.
Li-ion battery	29.2	35.04	23.36
Number of salt caverns	3	5	1
Hydrogen turbines	10.6	12.72	8.48

Figure 98: Experiment input variables of the European and international energy systems.

Figures 97 and 98 provide more information about the experiments conducted. In each experiment, the same variables were considered, but the values chosen for these variables differ for each energy system.

C.4 Minimax Regret tables

Tables 38, 39, 40 and 41 present the regret tables of the experiments for the decentral, national, European and international energy systems and will be discussed in this Appendix.

C.4.1 Decentral energy system

Table 38: Maximum regret results of the decentral energy system. In pink the minimum maximum regret.

				System operating costs	Electricity served with peak generators	CO_2 level
Decentral	Low	2015	SC12	505	163	14
			SC14	255	62	50
			SC16	205	0	45
		1997	SC12	125	41	24
			SC14	251	16	43
			SC16	106	0	39
	Mid	2015	SC5	781	234	14
			SC7	322	110	22
			SC9	197	0	43
		1997	SC5	685	79	23
			SC7	230	35	16
			SC9	107	0	32
	High	2015	SC3	856	206	8
			SC5	432	91	50
			SC7	50	0	60
		1997	SC3	744	92	0
			SC5	408	46	62
			SC7	153	1	83

When considering the total operational system costs of the decentral regret table, the regret consistently remains lowest when opting for a greater number of salt caverns than initially determined in the first experiment. This indicates that among the 54 combinations of critical parameter level combinations, also referred to as scenarios, the least maximum regret occurs when selecting 16 (low-seasonal storage policy), 9 (mid-seasonal storage policy), or 7 (high-seasonal storage policy) salt caverns. Therefore, it can be concluded that the number of salt caverns resulting from the initial experiment was not robust for both the low, mid, and high-seasonal storage policy scenarios under different circumstances.

C.4.2 National energy system

Table 39: Maximum regret results of the national energy system. In pink the minimum maximum regret.

				System operating costs	Electricity served with peak generators	CO_2 level
National	Low	2015	SC9	290	65	16
			SC11	194	18	36
			SC13	193	2	50
		1997	SC9	319	79	15
			SC11	200	28	17
			SC13	245	27	38
	Mid	2015	SC8	298	28	8
			SC10	173	15	54
			SC12	182	4	60
		1997	SC8	292	52	16
			SC10	207	23	47
			SC12	328	1	48
	High	2015	SC6	312	14	0
			SC8	218	2	56
			SC10	184	2	83
		1997	SC6	286	48	9
			SC8	286	27	49
			SC10	234	4	56

For the energy systems with low and mid-seasonal storage policies in the national energy system, it has been determined that the initial number of established salt caverns, respectively 11 and 10, is robust when tested against 54 scenarios. When the high-seasonal storage policy is subjected to the 54 scenarios, it is found that the initial value is not robust and the maximum regret is smaller when more salt caverns are added to the system, for both weather years. If only the winter months were considered, one would expect the choice for the number of salt caverns to be robust in the high-seasonal storage policy, rather than in the low and medium storage policies. Since this is not the case, it suggests that more salt caverns in the system are also desirable when the gas field needs to be filled with 15,000 GWh of hydrogen during the summer months.

C.4.3 European energy system

Table 40: Maximum regret results of the European energy system. In pink the minimum maximum regret.

				System operating costs	**Electricity served with peak generators**	**CO_2 level**
European	**Low**	**2015**	**SC2**	464	97	**0**
			SC4	**260**	24	39
			SC6	280	**12**	50
		1997	**SC2**	514	59	**0**
			SC4	261	21	41
			SC6	**172**	**6**	51
	Mid	**2015**	**SC2**	415	32	**0**
			SC4	278	12	34
			SC6	**259**	**11**	41
		1997	**SC2**	247	19	**0**
			SC4	196	**17**	22
			SC6	**91**	18	33
	High	**2015**	**SC2**	366	**7**	**9**
			SC4	**283**	10	12
			SC6	317	12	19
		1997	**SC2**	227	11	**5**
			SC4	114	23	21
			SC6	**38**	**10**	24

For the European energy system, it becomes clear from Table 40 in Appendix C.4 that the initial choice of 4 salt caverns is not robust when tested for robustness across 54 scenarios for the European energy system in general. Having more salt caverns in the system leads to lower maximum regret in experiments 20, 22, 23 and 24.

C.4.4 International energy system

Table 41: Maximum regret results of the international energy system. In pink the minimum maximum regret.

				System operating costs	**Electricity served with peak generators**	**CO_2 level**
International	**Low**	**2015**	**SC8**	400	148	**1**
			SC10	143	46	3
			SC12	**14**	**0**	4
		1997	**SC8**	183	81	**0**
			SC10	102	50	5
			SC12	**49**	**16**	5
	Mid	**2015**	**SC5**	342	123	**1**
			SC7	109	33	**1**
			SC9	**14**	**0**	2
		1997	**SC5**	180	75	**1**
			SC7	106	50	**1**
			SC9	**20**	**0**	2
	High	**2015**	**SC1**	403	144	**1**
			SC3	130	37	**1**
			SC5	**11**	**1**	**1**
		1997	**SC1**	431	164	**1**
			SC3	149	58	**1**
			SC5	**14**	**0**	**1**

From the regret table of the international energy system, it becomes evident that the initial choice for the number of salt caverns is not robust. The minimum maximum regret occurring across 54 scenarios is consistently associated with a greater number of salt caverns in all experiments. This implies that for the low, mid and high-seasonal storage policy, respectively, 12, 9 and 5 salt caverns would be the best choice in terms of electricity served with peak generators and system operating costs.

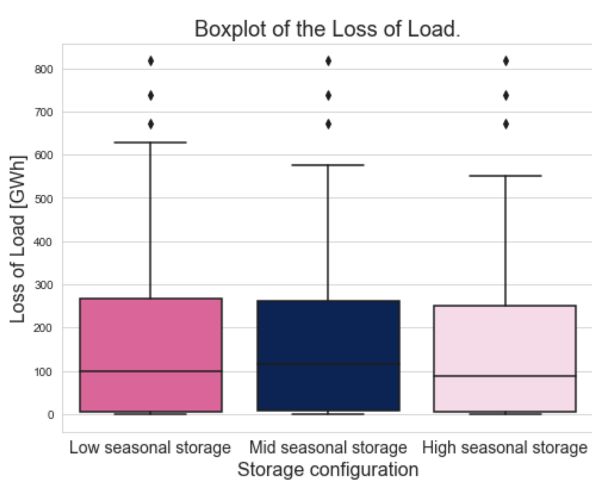
D

Storage configuration analysis

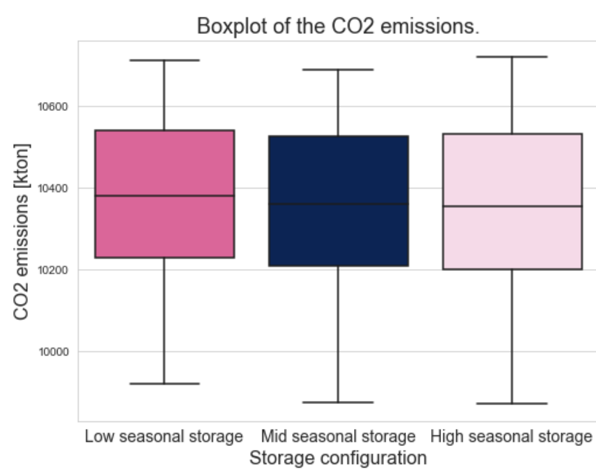
D.1 Decentral energy system

Table 42: Decentral energy system.

	Storage configuration	Median
	1	19863
Operating system costs [M€]	2	19909
	3	20242
	1	100
Electricity served with peak generators [GWh]	2	116
	3	89
	1	10379
CO_2 emissions [kton]	2	10359
	3	10354



(a) Electricity served with peak generators, decentral energy system.



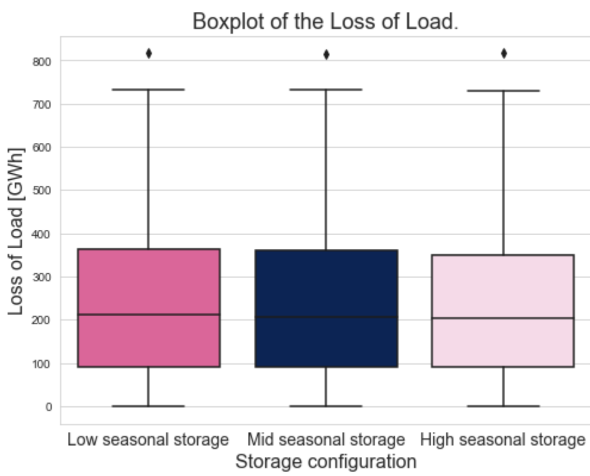
(b) CO_2 emissions, decentral energy system.

Figure 99: Electricity served with peak generators and CO_2 emissions in the decentral energy system.

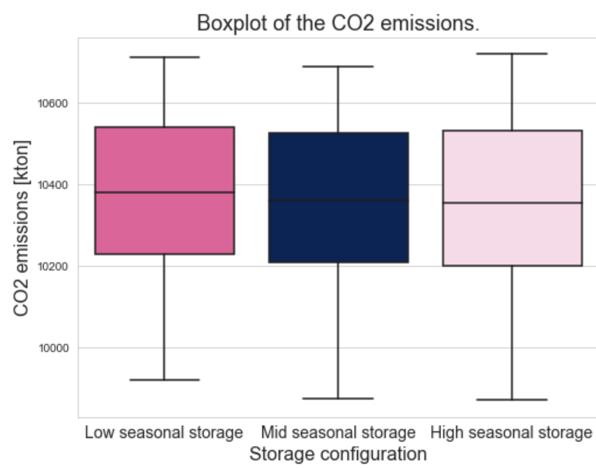
D.2 National energy system

Table 43: National energy system.

	Storage configuration	Median
Operating system costs [M€]	4	20314
	5	19981
	6	20269
Electricity served with peak generators [GWh]	4	211
	5	206
	6	203
CO_2 emissions [kton]	4	8962
	5	8970
	6	8948



(a) Electricity served with peak generators, national energy system.



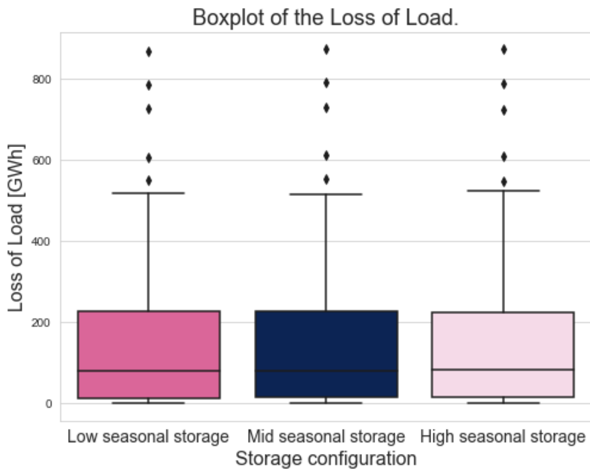
(b) CO_2 emissions, national energy system.

Figure 100: Electricity served with peak generators and CO_2 emissions in the national energy system.

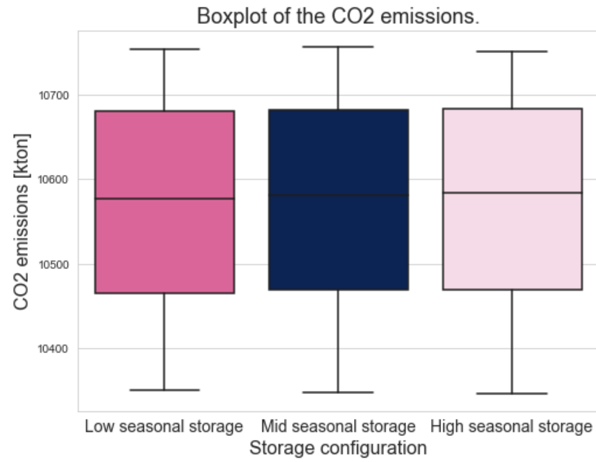
D.3 European energy system

Table 44: European energy system.

	Storage configuration	Median
Operating system costs [M€]	7	22201
	8	22350
	9	22555
Electricity served with peak generators [GWh]	7	79
	8	78
	9	82
CO_2 emissions [kton]	7	10577
	8	10581
	9	10584



(a) Electricity served with peak generators, European energy system.



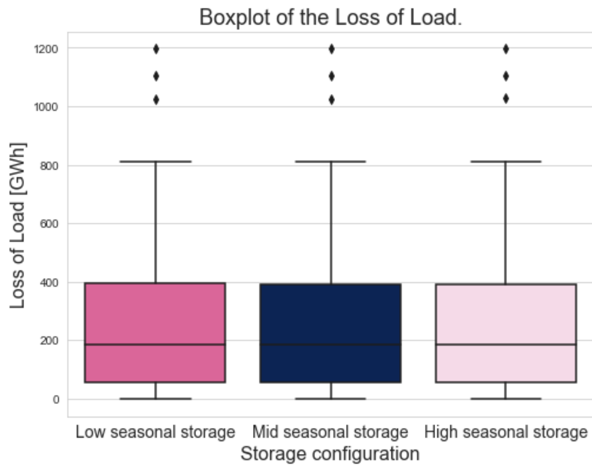
(b) CO_2 emissions, European energy system.

Figure 101: Electricity served with peak generators and CO_2 emissions in the European energy system.

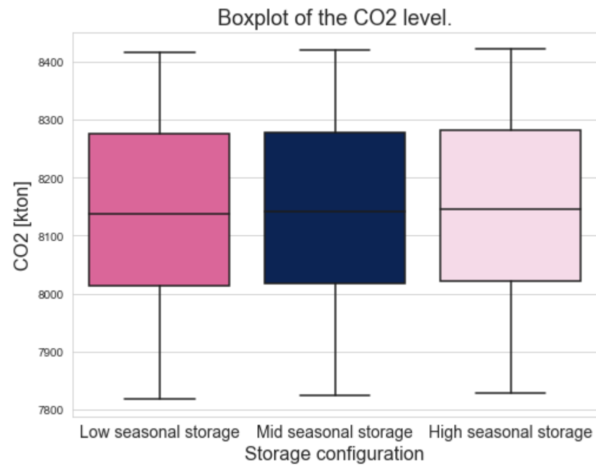
D.4 International energy system

Table 45: International energy system.

	Storage configuration	Median
Operating system costs [M€]	10	25542
	11	25623
	12	25723
Electricity served with peak generators [GWh]	10	184
	11	184
	12	184
CO_2 emissions [kton]	10	8138
	11	8142
	12	8146



(a) Electricity served with peak generators, international energy system.



(b) CO_2 emissions, international energy system.

Figure 102: Electricity served with peak generators and CO_2 emissions in the international energy system.

E

Subsidy

Table 46 provides the required subsidy ranges for the gas fields, and Table 47 presents the required subsidy for the salt caverns.

Table 46: Subsidy ranges for gas fields in €/kg.

		Cost scenario					
		Low		Mid		High	
		Lower bound	Upper bound	Lower bound	Upper bound	Lower bound	Upper bound
Decentral	Low-seasonal storage policy	0.37	0.63	0.60	0.87	1.00	1.27
	Mid-seasonal storage policy	0.80	1.10	1.17	1.47	1.70	2.03
	High-seasonal storage policy	1.60	1.83	2.10	2.33	2.90	3.13
National	Low-seasonal storage policy	0.43	0.60	0.67	0.83	1.07	1.23
	Mid-seasonal storage policy	1.00	1.10	1.37	1.43	1.93	2.00
	High-seasonal storage policy	1.63	1.70	2.10	2.20	2.93	3.10
European	Low-seasonal storage policy	0.69	0.93	0.93	1.20	1.33	1.60
	Mid-seasonal storage policy	1.43	1.57	1.77	1.90	2.33	2.47
	High-seasonal storage policy	2.33	2.40	2.83	2.90	3.63	3.70
International	Low-seasonal storage policy	1.13	1.30	1.37	1.57	1.77	1.97
	Mid-seasonal storage policy	1.43	1.67	1.77	2.00	2.33	2.57
	High-seasonal storage policy	1.90	2.20	2.40	2.70	3.20	3.50

Table 47: Subsidy ranges for salt caverns in €/kg.

		Cost scenario					
		Low		Mid		High	
		Lower bound	Upper bound	Lower bound	Upper bound	Lower bound	Upper bound
Decentral	Low-seasonal storage policy	0.30	0.50	0.37	0.60	0.43	0.63
	Mid-seasonal storage policy	0.00	0.27	0.00	0.30	0.00	0.33
	High-seasonal storage policy	0.00	0.00	0.00	0.00	0.00	0.00
National	Low-seasonal storage policy	0.30	0.43	0.33	0.50	0.37	0.53
	Mid-seasonal storage policy	0.33	0.40	0.37	0.47	0.40	0.50
	High-seasonal storage policy	0.00	0.20	0.00	0.27	0.03	0.33
European	Low-seasonal storage policy	0.00	0.50	0.00	0.63	0.00	0.70
	Mid-seasonal storage policy	0.00	0.57	0.00	0.73	0.00	0.83
	High-seasonal storage policy	0.07	1.20	0.30	1.57	0.43	1.73
International	Low-seasonal storage policy	0.77	3.20	1.30	4.30	1.57	4.93
	Mid-seasonal storage policy	0.10	4.33	0.87	5.70	1.23	6.50
	High-seasonal storage policy	0.00	8.09	0.00	11.10	0.00	12.73

F

Plausibility analysis

F.1 Plausible and implausible scenarios.

Figure 103 shows per scenario of the national energy system with the mid-seasonal storage policy which scenarios are assumed to be plausible and which scenarios are excluded from this research. Scenarios met electricity served with peak generators greater than 200 GWh were assumed to be not plausible, considering the high associated societal costs.

		Li-ion33						Li-ion42						Li-ion50					
		HT7		HT8		HT10		HT7		HT8		HT10		HT7		HT8		HT10	
		Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14
		Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid
Scenario space	SC8	P	NP	P	P	NP	P	P	NP	P	P	P	P	P	NP	P	P	P	P
	SC10	P	NP	P	P	NP	P	P	NP	P	P	P	P	P	NP	P	P	P	P
	SC12	P	NP	P	P	NP	P	P	NP	P	P	P	P	P	NP	P	P	P	P

		Edem59000																	
		Li-ion33						Li-ion42						Li-ion50					
		HT7		HT8		HT10		HT7		HT8		HT10		HT7		HT8		HT10	
		Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14
		Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid
Scenario space	SC8	NP	NP	P	NP	P	NP	NP	NP	P	NP	P	NP	P	NP	P	NP	P	P
	SC10	NP	NP	P	NP	P	NP	NP	NP	P	NP	P	P	P	NP	P	NP	P	P
	SC12	NP	NP	P	NP	P	NP	NP	NP	P	NP	P	P	P	NP	P	NP	P	P

		Edem64900																	
		Li-ion33						Li-ion42						Li-ion50					
		HT7		HT8		HT10		HT7		HT8		HT10		HT7		HT8		HT10	
		Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14	Inter17	Interc14
		Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid	Mid
Scenario space	SC8	NP	NP	NP	NP	NP	NP	NP	NP	NP	NP	P	NP	NP	NP	NP	NP	P	NP
	SC10	NP	NP	NP	NP	P	NP	NP	NP	NP	NP	P	NP	NP	NP	NP	NP	P	NP
	SC12	NP	NP	NP	NP	P	NP	NP	NP	NP	NP	P	NP	NP	NP	NP	NP	P	NP

Figure 103: Assumed plausibility of the different scenarios of the national energy system. NP refers to Not Plausible, while P refers to Plausible.

F.2 Best and worst case input parameters

Table 48: Specifications of the best and worst case scenario for the profits of Essent.

Best case scenario

Parameter	Value	Unit
Number of salt caverns	8	-
Seasonal storage in gas fields	10	TWh
Installed capacity hydrogen turbines	10.8	GW
Interconnection capacity electricity	14.8	GW
Electricity demand built environment	53.1	TWh
Installed capacity Li-ion batteries	50.4	GW

Worst case scenario

Parameter	Value	Unit
Number of salt caverns	12	-
Seasonal storage in gas fields	10	TWh
Installed capacity hydrogen turbines	8.9	GW
Interconnection capacity electricity	17.8	GW
Electricity demand built environment	59	TWh
Installed capacity Li-ion batteries	42	GW

In Table 48, the differences between the best and worst-case scenarios in the national energy system with a mid-seasonal storage policy are depicted. The parameters not shown in this table have the same values as defined in Table 34 in Appendix A.1 for the national energy system.

Table 49: Specifications of the best and worst case scenario for the average system costs of Essent.

Best case scenario

Parameter	Value	Unit
Number of salt caverns	8	-
Seasonal storage in gas fields	10	TWh
Installed capacity hydrogen turbines	10.8	GW
Interconnection capacity electricity	14.8	GW
Electricity demand built environment	53.1	TWh
Installed capacity Li-ion batteries	50.4	GW

Worst case scenario

Parameter	Value	Unit
Number of salt caverns	12	-
Seasonal storage in gas fields	10	TWh
Installed capacity hydrogen turbines	7.1	GW
Interconnection capacity electricity	17.8	GW
Electricity demand built environment	53.1	TWh
Installed capacity Li-ion batteries	50.4	GW

Table 50: Specifications of the best and worst case scenarios for the government.

Best case scenario government

Parameter	Value	Unit
Number of salt caverns	8	-
Seasonal storage in gas fields	10	TWh
Installed capacity hydrogen turbines	10.8	GW
Interconnection capacity electricity	17.8	GW
Electricity demand built environment	53.1	TWh
Installed capacity Li-ion batteries	50.4	GW